Exergetic, environmental and economical analysis of a cogeneration plant connected to a district heating network.

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## Introduction

During the design of a cogeneration plant intended to feed a district heating network, the selection of the water temperature level of a district heating network (DHN) is an important step as it is directly linked to the power consumed by the circulation pumps and the heat losses to the environment. If the DHN is fed by natural gas boilers, the influence of the temperature level is not that important as the natural gas boiler efficiency varies slightly between 97 and 105 % (based on LHV) [1]. Lately, the use of low temperature DHN (the return water temperature is lower than 50 $^\circ$C enabled the exploitation of latent due to flue gas condensation. However, this type of DHN, so-called 4th generation DHN, is not widespread nowadays and most of the DHN in operation have supply temperature around 80 $^\circ$C [2]. However if a cogeneration plant based on a Rankine cycle is used to feed the DHN, lowering the network temperature enables an increase of the electricity production. Indeed, the use of back pressure steam turbine allows the production of high temperature steam supplied in a heat exchanger heating the DHN water by condensing the steam. Setting the temperature of the DHN together with the heat exchanger efficiency, fixes the steam saturation temperature and consequently the level of back pressure. The lower the temperature requirement of the DHN is, the lower the pressure level of the back pressure and the higher the electricity production.
In this matter, the cogeneration efficiency defined as the sum of the electrical efficiency and thermal efficiency is often misleading. Indeed, increasing the level of temperature required by the DHN increases the back pressure which, in turn, decreases the electrical efficiency. However, the thermal energy not converted into electricity is available as useful thermal energy. As a result, changing the level of water temperature into the DHN slightly affects the cogeneration efficiency. As it will be shown herein, the cogeneration efficiency is a poor indication of the plant performance. To underline this fact, an economic study is carried out to check the influence of the DHN temperature on the cost of thermal energy generated by the plant.
To support the discussion, an existing cogeneration plant connected to a DHN installed on the University Campus in Liège (Belgium) is used as an application test case. Based on actual operational and financial data, a detailed economic, environmental and energetic evaluation is carried out that is supported by a calibrated simulation model of the whole installation (this model is detailed in other contributions by the authors [3, 4]) in order to study the influence of the network temperature level on the CHP plant performance. In a second step, the simulation model is used to perform an exergetic analysis intended to give physical insights to the economical study. This results in a broader discussion on the several methods available to assess the quality of cogeneration plants and the opportunity to develop such a technology together with district heating networks.

## Problem Statement

When using a CHP to feed a DH network, a conventional goal is to optimize the conversion efficiency ($\eta_{CHP}$) of the primary energy into useful energy namely electricity and heat. If $P_{prim}$ is the rate of primary energy consumption and $P_{elec}$ ($P_{heat}$) is the electricity (thermal) production, the electrical (thermal) efficiency is defined by $P_{elec} = \eta_{elec} / P_{prim}$ ($P_{heat} = \eta_{heat}/P_{prim}$). Consequently, the cogeneration efficiency is $\eta_{CHP} = \eta_{heat} + \eta_{elec.}$. Similar indicator may be defined from an environmental point of view by noting that the combustion of one kilowatt-hour (kWh) of natural gas releases 251 g of $CO_2$ while the same primary energy of biomass releases between 0 and about 30 g of $CO_2$ depending on the supply chain [5]. Biomass fuels may be of very different types and it is beyond the scope of the present contribution to exhaustively list them and it will be considered herein that the biomass fuel generates 30 g of $CO_2$ per kWh of primary energy which corresponds to wood pellets [6]. Most of the European countries have policies to reward the use of biomass fuels under the form of subsidies or premium on the energy selling price [7, 8]. Other methodologies are available (e.g., life cycle analysis) that take into account the whole production process from the construction of the plant to its decommissioning to assess the actual saving in terms of CO2 emissions. In the framework of the

present study, these more advanced methodologies do not bring any significant change in the conclusions and it is decided to stick to the simple approach.
In addition to the energetic analysis, an exergetic analysis of the whole system is carried out. the exergy e is defined as $e = (h - h_0) - T_0 \cdot (s - s_0)$ where h stands for the enthalpy, s for the entropy and the subscript 0 for the reference conditions namely a pressure of 101 kPa and an absolute temperature of 288.15 K [9].
Besides the energetic and environmental aspects, the most critical and decisive criteria for the development of such technologies is the cost of the energy. The problem of optimizing a CHP plant connected to a DH network is considered herein as designing the CHP plant minimizing the cost of heat (COH) supplied to the user. To do so, a cost model for the heat production is setup that takes into account the cost of capital (i.e., the initial investment), the fuel costs, the operation and maintenance cost as well as the selling price of the electricity produced. The previous consideration translates the fact that the plant is supposed to be heat-driven, the electricity being considered as a by-product sold to the grid operator or consumed locally.
The cost model per unit of thermal energy used herein is derived similarly to the one defined for electricity in [10]. According to this model, the cost of heat is expressed as:

$$COH = \underbrace{\frac{1}{\xi_{DHN}}}_{DHN\ losses}\left[\underbrace{\frac{C\cdot\psi+U_{fix}}{P_{i,th,CHP}}}_{Fixed\ cost}+\underbrace{\frac{y_f}{\bar{\eta}_{th,CHP}}+u_{var}}_{Variable\ cost}-\underbrace{(y_e+T_e\cdot y_{CV})\cdot\frac{\bar{\eta}_{el,CHP}}{\bar{\eta}_{th,CHP}}}_{Electricity\ selling\ price}\right] \quad (1)$$

In the above formula, $C$ represents the initial investment cost and ψ is the annuity factor taking into account the present value of money ( $C\psi$ is the annual repayment for the initial investment expressed in $year^{-1}$) assessed through:

$$\psi = \frac{d}{1-(1+d)^{-N}} \quad (2)$$

where $d$ is the discounting rate per year and $N$ the number of years for which the installation is used (e.g., the life time of the plant). $P_{i,th,chp}$ is the installed thermal power of the CHP plant in MW and $\tau_e$ is the equivalent utilization time at rated power output. $\tau_e$ embeds the availability factor of the plant. $y_f$ is the cost of fuel in €/MWh, $U_{fix}$ is the fixed cost of operation, maintenance and administration in €/year and $u_{var}$ is the variable cost of operation, maintenance and repair in € /MWh. $\bar{\eta}_{th,chp}$ , $\bar{\eta}_{e,chp}$ are respectively the annual average thermal and electricity efficiencies yet taking into account the start/stop procedures (if any) and the part load efficiency. $y_e$ is the price of electricity in €/MWh while $\tau_{cv}$ and $y_{cv}$ are respectively the number of green certificates per MWh of electricity produced[1] and the unit price of a green certificate. The term $\tau_{cv}y_{cv}$ is replaced by the premium on the electricity selling when feed-in tariffs are used instead.
The determination of $C$, $U_{fix}$, $u_{var}$, $d$ and $N$ is not within the scope of the present contribution and reliable estimates can be found e.g., in [1, 10]. Neither the influence of fuel cost $y_f$ nor the one of the supporting policies $\tau_{cv}y_{cv}$ will be long discussed herein and representative value of the market in Belgium will be used, as it is relatively straightforward for the reader to include relevant data into the above model.
The determination of $\tau_e$, $\bar{\eta}_{e,chp}$ and $\bar{\eta}_{th,chp}$ is not straightforward and very often overlooked as these values strongly depend upon the size of the CHP plant and the evolution in time of the heat demand. Studying how the CHP plant matches the heat demand and assessing the resulting performance is not the main subject of the present contribution and it is treated in [3]. Herein, the focus is set on the influence of water temperature level of the DHN on the final cost of energy. As this temperature level has a direct influence on the heat losses, a transport efficiency $\xi_{DHN}$ is introduced in Eq. 1 to assess the influence of these heat losses and to express the cost of heat per unit of heat delivered to the customer. It is defined as the ratio of the heat delivered to the consumer to the heat produced by the plant. As previously said, this temperature level has a significant influence on the global CHP plant efficiency if it is based on a Rankine cycle: assuming the plant is made of one back pressure steam turbine, the condenser located downstream of the steam turbine exchanges heat to the DHN. The electricity production of this steam turbine being expressed as $P_{elec.} = \varepsilon \cdot \eta_{alt} \cdot \dot{M}_{steam} \cdot (h_{su} - h_{ex,s})$ where $h_{su}$ and $h_{ex,s}$ stand for the supply and isentropic exhaust enthalpy of the steam, $\eta_{alt}$ the alternator efficiency, ε the isentropic steam turbine efficiency and $\dot{M}_{steam}$ the steam mass flow rate. Depending on the supply DHN water temperature, the requirements on the exhaust steam vary: the higher the supply water temperature, the higher the required steam temperature and pressure are. The electricity production decreases when the DHN temperature increases. This aspect is discussed in the following by taking into account the modification of the thermodynamic cycle during its design phase to minimize the cost of heat.
In the case in which the heat delivered by the CHP plant for the base load and by a backup generation for the

[1] For the Walloon region of Belgium one green certificate is granted for every 456 kg of $CO_2$ saving. A maximum of 2 green certificates are allowed per MWh of electricity produced.

peak load (e.g., a natural gas boiler), the average cost of heat must be weighted proportionally to the production of the heat sources. If the costs of heat generated through relation (1) are denoted respectively $COH_{chp}$ and $COH_{bck}$ for the CHP plant and the backup boiler and Θ is the ratio of the thermal energy generated by the CHP plant to the total thermal energy for the considered time interval, the average cost of heat is assessed through:

$$COH = \theta \cdot COH_{CHP} + (1 - \theta) \cdot COH_{bck} \tag{3}$$

Note that, in the case of natural gas boilers, the last term in equation 1 is cancelled.

## Simulation model

The simulation model is used to assess the exact amount of heat supplied by a CHP plant to a DH network whose heat profile is known. Through the calibrated simulation model, the net electricity production of the plant is known for both rated and part load operation together with the heat losses related to the DHN. The considered biomass CHP plant consists of a biomass furnace connected to a boiler made of an economizer, an evaporator and super-heater section. The steam is expanded into two successive steam turbines to produce electricity. After the steam expansion at the high pressure steam turbine, a portion of the steam is extracted to supply heat to the DHN through a heat exchanger. A schematic of the cycle is represented in Figure 1.

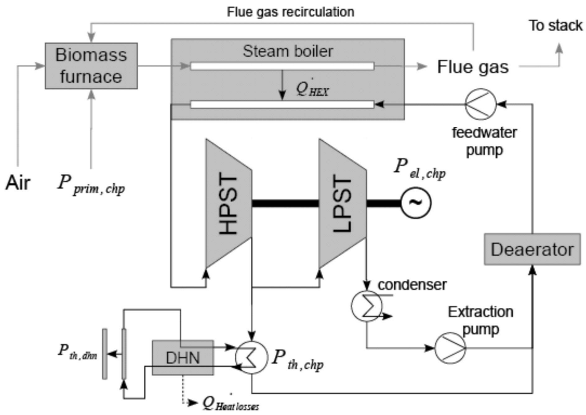



**Figure 1:** Schematic of CHP plant

For sake of simplicity, a brief description of the model is provided in this section but more information can be found in [3, 4] to which the interested reader is referred to. The complete simulation model of the plant is an aggregation of basic components modeled by a zero-dimensional (i.e., input-output) approach (biomass furnace, steam boiler, steam turbines, district heating network) verifying the conservation of mass, energy and momentum. The biomass combustion model is handled through a general biomass composition $C_mH_nO_xN_yS_z$ (where the subscripts are the ratio between wet basis mass fraction of each component to its molar mass) able to assess the composition of 15 species of the flue gas products namely $H_2$, $O_2$, $H_2O$, $CO$, $CO_2$, $OH$, $H$, $O$, $N_2$, $N$, $NO$, $NO_2$, $CH_4$, $SO_2$, $SO_3$.

Steam turbines are modeled by the Stodola line [11] where the steam turbine is considered as a nozzle whose mass flow rate depends upon the inlet pressure and temperature and the outlet pressure: $\frac{\dot{m}_{st}\sqrt{T_{su,st}}}{\sqrt{p_{su,st}^2 - p_{ex,st}^2}} = K$ where the parameter $K$ is constant for a wide range of operation and therefore can be determined from nominal operation. $\dot{m}_{st}$ stands for the steam mass flow in the turbine, $p$ for the pressure, $T$ for the absolute temperature. The subscripts *s*tand *ex* stands for respectively for supply and exhaust. Concerning the DHN heat losses, their assessment rely on a the resolution of a steady-state two-dimensional heat conduction-convection problem. This enables the calculation of a global heat transfer coefficient, $\Lambda$ $(\frac{W}{K})$ used to assess the heat losses as a function of ambient temperature and DHN water temperature level as $\dot{Q}_{losses,DHN} = \Lambda\ (T_{fd} - T_{ambient})$ where $T_{fd}$ is an average temperature of the water circulating in the DHN.

## Application test case

The aforementioned simulation model is applied to a typical district heating application available on the University campus in Liège(Belgium). The installed network has a total length of 10 km and distributes pressurized hot water at about 125 °C, on average, to approximately 70 buildings located in the University campus representing a total heat area of about 470 000 m$^2$. Buildings are very different in nature namely, classrooms, administrative offices, research centers, laboratories and a hospital. The hospital represents about 25% of the total heated area and requires steam for the kitchen and air humidity control system that justified this water temperature level. The effective peak power of the network is around 56 MW for a total of 61 000 MWh per year.

While all the buildings are heated between 4:00 to 20:00, the hospital needs heating and steam 24 hours a day, 365 days per year. The DH network is operating since the 60's and was originally operated from natural gas boilers. In order to cope with the restrictions in terms of $CO_2$ emissions, the University of Liège decided to invest in a biomass CHP plant whose purpose is to feed the base load heat demand of the campus. The CHP plant has started full operation in 2012. It is made of a moving grid biomass boiler with nominal primary power of 12 MW supplying steam to a back-pressure turbine and a condensing turbine with nominal power of 2.4 MW. The extracted steam is condensed in a heat exchanger feeding the DH network with a nominal power of 7 MW. The remaining thermal power needed by the DH network is provided by two natural gas boilers with a total installed power of 54 MW. The flue gas at the exhaust of the furnace passes successively through an evaporator (platen), screen tubes, two super-heaters, one evaporator and four economizers. Exhaust gases are filtered before being directed to the stack. The steam cycle is representative of a traditional cycle with extraction turbines and the steam generated has a temperature of about 420 °C. The district heating network is divided into twenty-three sections having the same geometric characteristic but pipe diameters ranging from from 50 to 350 mm. The insulation used is mineral wool with an identified thermal conductivity of 0.047 W m$^{-1}$ K$^{-1}$.

With respect to [3, 4] the CHP plant studied herein is slightly different as an exhaust gas recirculation at the level of the primary air was added together with a modification of the steam cycle. Indeed, instead of injecting saturated steam from the steam drum to heat the deaerator, a portion of the extracted steam is now used which improves the conversion efficiency.

## Results

The existing plant being already built, it is not possible to change the level of back pressure. In order to underline the potential of optimizing the level of DHN temperature, the simulation model is used to study the influence of the turbine back pressure on the whole plant efficiency and generation costs. In the following figures, the results corresponding to the existing plant are referred to as existing plant while those related to the simulated one are referred to as optimized back-pressure. The net electricity production is sketched for these two situations as a function of the heat delivered to the DHN (figure 2).

When the temperature of the DHN is modified, the cogeneration efficiency as well as the $CO_2$ emissions can be assessed and compared to the separated generation of heat and power. They are represented for full load conditions in Figures 3a and 3b. Representing these results at full load makes the cogeneration efficiency directly proportional to the electrical efficiency.

For the existing plant, the cogeneration efficiency is strictly constant as the back-pressure is fixed, this sets the steam mass flow rate at a constant value (as the heat demand is constant) and keeps the cogeneration efficiency constant. When the back-pressure is optimized to the DHN temperature level, the cogeneration efficiency increases. Additionally, it can be seen that the cogeneration efficiency increases when the level of temperature decreases up to a point where the efficiency remains constant. This saturation of the cogeneration efficiency is due to the fact that a minimum of steam extraction is required to maintain the level of temperature in the deaerator. In order to go a step further, a third test case is developed where the deaerator temperature can be decreased down to 115 °C.

This test case is referred to as lower deaerator pressure in Figures 3a and 3b. It has to be noted that variations of the efficiency appear important due to the scale used in the figures yet they are limited to 3% which is relatively low for the large range of DHN temperature studied.

When looking at the exergetic efficiency of the plant taking into account the exergy content of the hot water and the net electricity production, it can be seen from Figure 4a that the exergetic efficiency of the plant increases with

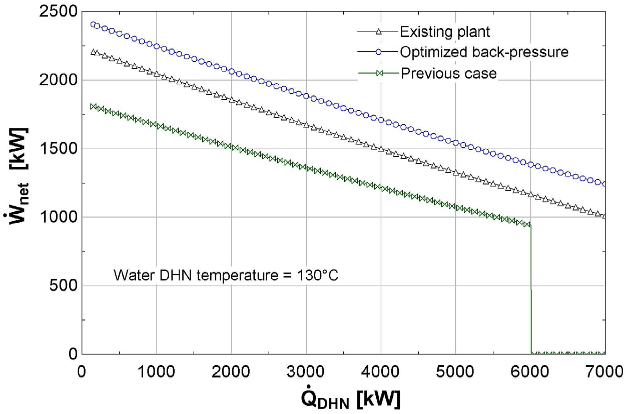
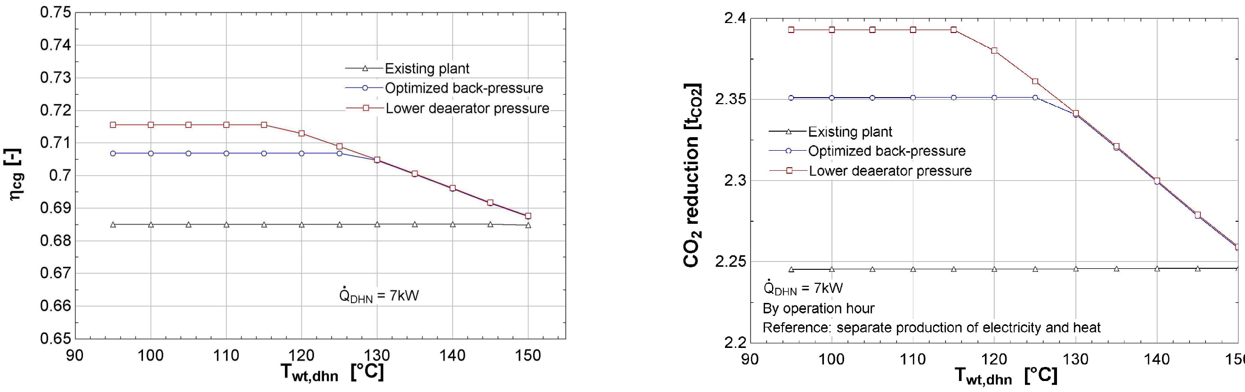



**Figure 2:** Electricity production for the three cases studied [kW]

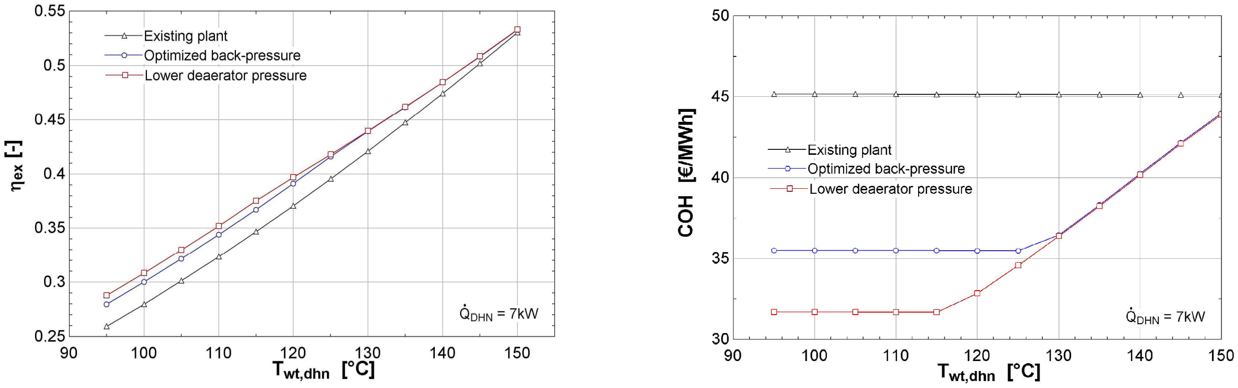



**(a)** CHP plant efficiency [-]

**(b)** $CO_2$ emissions reduction [t/h]

**Figure 3:** cogeneration efficiency $\eta_{CHP}$ and $CO_2$ emissions as a function of the water temperature supplied to the DHN for nominal heat load.

the DHN temperature. This is a straightforward consequence from the exergetic efficiency definition. As the energy of the hot DHN water increases with the level of temperature, the energy produced increases. However, when taking a look at Figure 4b, the cost of the generated heat increases with an increasing DHN temperature level which tends to underline, as others studies [8, 12–14], an incorrect definition in the current subsiding policies for the CHP plant. In equation 1, the yearly average of the thermal and electrical efficiencies are calculated from the instantaneous efficiencies at full load obtained from the model and multiplied by 0.98 and 0.92 to take into account the reliability and the availability of the plant. All the values used to compute the COH defined in Equation 1 were extracted from a previous study detailed in [3].




**(a)** Exergetic efficiency [-]

**(b)** Cost of heat [€/MWh]

**Figure 4:** Exergetic efficiency and cost of heat as a function of the water temperature supplied to the DHN for rated CHP plant output.

For the existing plant, the cost of heat is constant whatever the level of temperature (it is only influenced by the level of heat transport losses) but when the back-pressure is optimized lower generation costs can be obtained. Furthermore, when the deaerator temperature is adapted, another cost reduction can be achieved. For a deeper understanding of the cost structure, the COH can be also detailed for the existing plant and optimized back-pressure for the actual annual load profile to focus on the difference between raw CHP plant performances and the influence of the annual load of a DHN (Table I). The indicated costs correspond to the COH computed through Equation 3 for a backup natural gas boiler with COH of 65.37 € per MWh (see [3]).
Concerning the optimized pressure configuration, it leads to higher annual average thermal and electricity efficiencies and a higher electricity production (in absolute value) and therefore a reduced COH.

**Table I:** Energy-based COH comparison for two cases investigated for a DHN temperature level of 130 °C for the current load profile of the ULg.

| **Configuration** | **Current** | **Optimized pressure** |
|---|---:|---:|
| $\tau_e$ [-] | 0.6613 | 0.6613 |
| $\overline{\eta}_e$ Annual mean electricity efficiency [-] | 0.1070 | 0.1251 |
| $\overline{\eta}_{th}$ Annual mean thermal efficiency [-] | 0.4412 | 0.4412 |
| Fixed costs [€/MWh] | 25.27 | 25.27 |
| Variable costs [€/MWh] | 87.18 | 87.19 |
| Electricity production [€/MWh] | -69.61 | -81.41 |
| DHN costs [€/MWh] | 2.25 | 2.25 |
| Total CHP plant COH [€/MWh] | 45.10 | 33.30 |
| Global application COH [€/MWh] | **52.7** | **44.84** |

To compensate the subsiding policies inconsistency previously identified and to assess correctly energy systems performance, several indicators could be used [8, 12, 13, 15, 16]. The alternative way proposed in this study is to assess the COH considering that the efficiencies defined in Equation 1 are replaced by the thermal and electrical *exergetic* efficiencies. The exergy-based COH are represented in Figure 5 with plain symbols while the energy-based COH are represented with empty symbols as a reminder.
For the existing plant, the exergy-based COH decreases when the water temperature increases while the exergetic efficiency increases due to the higher water exergy content. When the back-pressure is optimized and is not restricted by any external stress, in the range of water temperature of 125 - 150 °C, the exergy-based COH is quite constant (about ± 1 € per MWh of exergy compared to ± 10 per MWh of energy). In the other range of temperature, when no improvement is feasible, it follows the same trend that of the existing case.
This constancy reflects that the available exergy is used in a better way for each DHN temperature level. Indeed the exergy degradation that occurs in the steam extraction valve decreases through the back-pressure adjustment. Therefore the exergy analysis seems to be a better indicator to rank energy systems such as CHP plants. It should

be promoted in the subsiding policies while the cogeneration efficiency, which is generally used, is not a good indicator to correctly assess the CHP plant performance while the production costs increase with the exergetic efficiency.

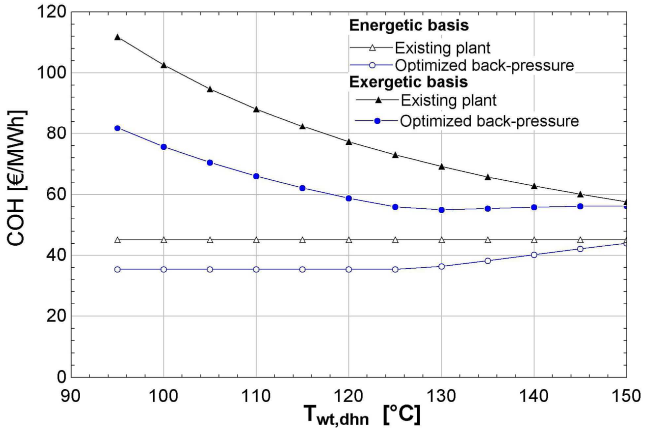



**Figure 5:** Comparison of the COH energy and exergy-based as a function of the water temperature supplied to the DHN for rated CHP plant output.

## Conclusions

This contribution extends previous studies on the energetic, environmental and economical analysis of a CHP plant connected to a district heating network considering the exergy aspect. The exergy analysis is a lean indicator to show the irreversibilities of a system and which is proposed as an indicator to rank the CHP plant. Several cases are studied: an existing plant and two alternatives of improvement which could be investigated during the CHP plant design process.
For the existing CHP plant, the energy-based COH, the $CO_2$ emissions reduction and the cogeneration efficiency of the CHP plant remain constant whatever is the DHN temperature level while the exergetic efficiency increases with this temperature leading to a lower exergy-based COH.
When the back-pressure can be adjusted, i.e. an improvement is performed, a reduction of $CO_2$ emissions (0.15 t of $CO_2$ avoided per hour of production) and higher cogeneration efficiency (about 3%) can be achieved but they are quite limited for the large range of the DHN temperature level considered. When this back-pressure adjustment is not constrained by any external stress and safety margin, the energy-based COH increases significantly with the DHN temperature level while the exergetic efficiency increases which seems to be a paradox (about 35% or 13 € per MWh of energy). On the other hand, the related exergy-based COH is quite constant which means the *available exergy* is used in a better way for each DHN temperature level. In the other temperature range, the COH (energy and exergy-based) follows the same trends that in the existing plant while there is no improvement anymore.
These examples tend to underline that the current subsiding policies, energy-based, do not encourage the thermodynamic improvements and are not a good indicator to rank the CHP plant performance. Therefore modified subsiding policies and indicators, like the exergy system analysis studied herein, have to emerge to rank correctly the CHP plant and assess others systems which could be connected like DHN.
As discussed briefly, the authors wish also to remind the major aspect of the load profile on the energy-based COH while a large difference between the raw and the annual COH is shown: an increase of 17 % or 8 € per MWh of energy for the annual COH.

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