The potential of district heating networks in Belgium – barriers and opportunities

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***Abstract*—District heating networks have the potential to contribute to reaching the three targets, better known as the "20-20-20" targets, set out in the EU Climate and Energy Package. This work tries to give a realistic estimate of the CO_2-emission savings that can be obtained by implementing gas-fired Combined Heat and Power District Heating (CHP-DH) schemes in Belgium. In addition, a cost benefit analysis is performed and a CHP-DH emission abatement cost is derived. To obtain realistic values of the emission reductions resulting from CHP-DH, an integrated dynamic analysis based on the unit commitment problem is implemented to take into account the interactions of the CHP unit with the electricity production park. Furthermore, different scenarios are created to analyze different CHP-DH configurations. The results show that emission savings of 115-120 ton/GWh$_{th}$ can be achieved if large CHP-CCGTs power the heating network. However, the fuel and emission savings do not counterbalance the higher investment and operational costs associated with the heating network and the CHP plants. For this reason, the potential for CHP-DH in Belgium seems limited.**

I. Introduction

The main idea behind district heating has evolved from benefiting from economies of scale in large boiler installations to creating a market for low temperature heat from local energy sources which would otherwise have been wasted or difficult to utilize. Five strategic heat sources often indicated suitable for district heating are cogeneration plants, waste incineration, surplus heat from industry, geothermal heat and fuels which are difficult to handle in small boilers [1]. By either facilitating the uptake of renewable energy sources such as geothermal heat, biomass and waste or by improving the energy efficiency, district heating networks have the possibility to contribute to reaching the targets in the EU Climate and Energy Package.

This work focuses on the potential of gas-fired CHP-DH to reduce CO_2-emissions. The potential is investigated from both a technical as an economical perspective. It is important to note that the economical analysis is performed from a country-wide perspective and that the results do not indicate the profitability of investments in district heating from the private invester perspective.

II. Methodology

The goal is to compare the total cost of the CHP-DH cases with the total cost in a corresponding reference scenario in which heat and electricity are produced separately. The main premise is that new investments are needed to provide the heat demand and to ensure sufficient installed electrical capacity. So either investments in a district heating network, CHP units and back-up boilers, or investments in domestic gas-fired boilers and an additional new CCGT[1] (with equal electrical capacity as the installed CHP unit(s)) is required. The potential of CHP-DH can therefore be regarded as the potential to offset the higher investment and operational costs associated with the heating network by reducing the fuel and emission cost.

To incorporate the dynamics of the CHP plant (or the newly installed CCGT) with the electricity production park, an integrated dynamic analysis based on the mixed integer linear programming (MILP) formulation of the unit commitment problem [2] is performed. The unit commitment problem involves the optimal dispatch of power plants while satisfying different constraints. However, in this work, the model is extended to dispatch regular power plants, the CHP units and back-up/peak DH boilers.

In the district heating case, the CHP unit(s) together with the Belgian electricity production park supply electricity. The heat demand is delivered by the CHP unit in combination with large back-up/peak DH gas-fired boilers. In contrast, in the reference scenario, the target area heat demand is provided by domestic gas-fired boilers, while the Belgian electricity demand is supplied by the electricity production park complemented with an additional new CCGT with equal electrical capacity as the CHP unit(s). The time horizon for all simulations is the year 2025.

A. Model Description

The most fundamental equations in the unit commitment model are presented in equations (1)-(9). A detailed description of the MILP formulation of the unit commitment problem can be found in [2] and [3].

$$\begin{aligned} min\Bigg(&\sum_{i,j}(c_{i,j}^{fuel} + c_{i,j}^{CO_2} + c_{i,j}^{su}) + \\ &\sum_{j}(c_{j}^{fuel,CHP} + c_{j}^{CO_2,CHP} + c_{j}^{su,CHP}) + \\ &\sum_{j}(c_{j}^{fuel,boiler} + c_{j}^{CO_2,boiler})\Bigg) \end{aligned} \tag{1}$$

The objective function aims to minimize the sum of fuel costs, emission costs and start-up costs, and this for the entire

[1] This is in line with recent investments observed in the Belgian electricity sector

Belgian electricity production park, the CHP-unit(s) and the boiler installations, as given in equation (1). In this equation, index i and j represent the set over all power plants and all time periods respectively. c^{fuel}, c^{CO_2} and c^{su} respectively represent the fuel costs, costs related to the emission of carbon dioxide and the start-up costs.

The variables are subject to different constraints. The most fundamental ones are that the electricity and heat demand must be met at all times (equations (2)-(9)):

$$\forall j : \sum_i (g_{i,j} + g_j^{wind} + g_j^{solar} + MR_j^{other} + E_j^{CHP} + \sum_r (ps_{r,j}^{down} \cdot \epsilon_r^t) = demand_j + \sum_r (ps_{r,j}^{up} / \epsilon_r^p) \quad (2)$$

In equation (2), $g_{i,j}$ represents the produced electricity of power plant i in period j. Similarly, g_j^{wind} and g_j^{solar} are the wind turbine and solar panel electricity production. Furthermore, MR_j^{other} is the electricity production of other types of power plants[2]. The output of these plants is assumed constant throughout the year such that the yearly generation equals historical generation levels, as provided by the Belgian transmission system operator (TSO) [5]. E_j^{CHP} represents the electricity produced in the CHP unit in period j. Finally, $ps_{r,j}^{down}$ and $ps_{r,j}^{up}$ represent the changes in potential energy in pumped storage plant r, with turbine efficiency ϵ_r^t and pump efficiency ϵ_r^p.

The fuel and emission cost of power plants are modeled by a quadratic fuel and emission cost curve [3]. The quadratic cost curve of each type of power plant is approximated by a piecewise linear function as shown in figure 1. The operational range is divided into two areas with constant marginal fuel cost $MA1^i$ and $MA2^i$. C_i represents the fuel cost of plant i when running at minimal generating capacity P_{min}. The efficiency at maximal, intermediate and minimum generation level is expressed by η^{max}, η^{int} and η^{min} respectively. Equations (3)-(8) present the relation between these parameters:

$$c_{i,j}^{fuel} = C_i \cdot z_{i,j} + g_{i,j}^A \cdot MA_i^2 + g_{i,j}^B \cdot MA_i^1 \quad (3)$$

$$g_{i,j} = P_i^{min} \cdot z_{i,j} + g_{i,j}^A + g_{i,j}^B \quad (4)$$

$$0 < g_{i,j}^A < (P_i^{int} - P_i^{min}) \cdot z_{i,j} \quad (5)$$

$$0 < g_{i,j}^B < (P_i^{max} - P_i^{int}) \cdot z_{i,j} \quad (6)$$

$$MA_i^2 = \frac{\left(\frac{P_i^{int}}{\eta_i^{int}}\right) - \left(\frac{P_i^{min}}{\eta_i^{min}}\right)}{P_i^{int} - P_i^{min}} \quad (7)$$

$$MA_i^1 = \frac{\left(\frac{P_i^{max}}{\eta_i^{max}}\right) - \left(\frac{P_i^{int}}{\eta_i^{int}}\right)}{P_i^{max} - P_i^{int}} \quad (8)$$

Technical characteristics of the different types of power plants are displayed in table I. The different types of plants

[2]This includes biomass plants, industrial CHP plants, waste incineration plants and plants with a lower capacity than 40 MW

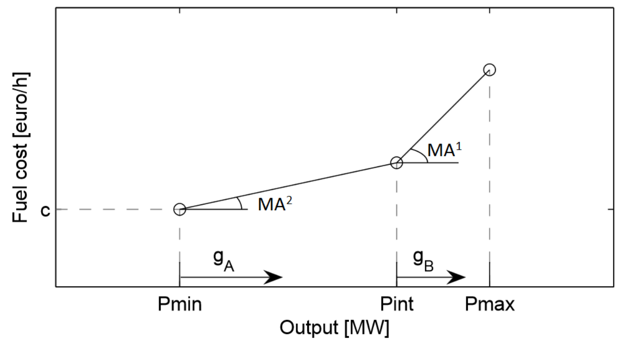

Fig. 1. Linearized fuel cost curve [2]

TABLE I
TECHNICAL CHARACTERISTICS OF POWER PLANTS [3]

Technology	η_{max} [%]	Pint [%]	η_{int}[%]	Pmin [%]	η_{min}[%]	Ramp-up [% Pmax/h]	Min up-time [h]	Min down-time [h]	SC [€/MW]
PC ST	40	70	38.5	30	33	40	6	4	10
CCGT old	55	85	54.5	45	47.5	100	1	1	5
CCGT new	59.5	85	59	45	52.5	100	1	1	5
OCGT	32	75	30	20	25	100	1	1	0

considered in this work are pulverized coal steam turbines 5PC ST), new and old combined cycle gas turbines (CCGT) and open cycle gas turbines (GT). Some assumptions need to be made about the future lay-out of the Belgian electricity production park. In this work, it is assumed that the electricity production park in 2025 is the current production park, complemented with planned power plants with generating capacities above 25MW, as well as planned off-shore wind farms, which received permits and are not yet fully operational. In addition, to cope with the planned nuclear phase out, additional CCGTs are added to ensure security of supply. Data on the current electricity production park and planned power plants are made available by the Belgian TSO [5].

Aside from the Belgian electricity demand, the target area heat demand has to be supplied as well:

$$\forall j : Q_j^{CHP} + Q_j^{boiler} + S_j^{discharge} - S_j^{store} = HD_j / \xi \quad (9)$$

Here, $Q_j^{CHP/boiler}$ represents the heat delivered by the CHP/boiler. In addition, in case a thermal energy storage is present, heat can be delivered ($S_j^{discharge}$) or stored (S_j^{store}) by the storage. Furthermore, HD_j is the heat demand in period j. Finally, ξ is the heat utilization fraction which takes the heat losses in the heating network into account. Furthermore, equations (10)-(13) ensure a realistic behavior of the heat storage. Here, SOC_j is the state of charge of the storage in period j. It is assumed that no heat losses arer present in the

TABLE II
TECHNICAL CHARACTERISTICS OF CONSIDERED CHP UNITS

CHP type	$P_{e,max}$ $[MW_e]$	E/Q [ϕ]	α_0 [%]	α_e [%]	α_q [%]	Q_{min} [%]	Min up-time [h]	Min down-time [h]	Z-factor [ϕ]
CCGT	100-400	1.34	55	50.1	37.4	0	1	1	7.69
GT	10	0.82	37	37	45	75	1	1	-
ICGE	5	0.92	44	44	48	50	1	1	-

heat storage.

$$SOC_j = SOC_{j-1} - S_j^{discharge} + S_j^{store} \tag{10}$$

$$S_j^{discharge} < S_{max}^{discharge} \tag{11}$$

$$S_j^{store} < S_{max}^{store} \tag{12}$$

$$SOC_{min} \leq SOC_j \leq SOC_{max} \tag{13}$$

In case of separate production, there is no CHP unit and no thermal energy storage so that heat demand is simply supplied by domestic gas-fired boilers with an efficiency of 90%. In the district heating case, the heat utilization fraction is assumed to be 90%, which represents network heat losses of 10%.

In addition, different operational constraints and a demand for reserve capacity are implemented. The most important operational constraints for power plants are a maximal and minimal power level, ramping rate limitations and minimal up and down times. For more details on the models employed in this work, see [4].

B. Scenarios

Different scenarios are created to compare different district heating configurations, as well as the importance of certain assumptions made.

First, three types of CHP units are considered. This could be either a large CHP combined cycle gas turbines (CHP-CCGT) located at some distance of the target area, a couple of smaller CHP open cycle gas turbines (GTs) or multiple internal combustion gas engines (ICGEs). The characteristics of the different CHP types are presented in table II. Here, the E/Q ratio represents the power-to-heat ratio in the nominal operating point, which is identical to the ratio of the nominal electric efficiency α_e to the nominal thermal efficiency α_q. Furthermore, Q_{min} represents the lower limit for (thermal) modulation. For CHP-CCGTs, two additional parameters are added: the electrical efficiency in full condensation mode α_0 and the Z-factor, which is the number of units of useful heat gained for each sacrificed unit of electricity production when operating at maximal primary power.

Second, thermal storage(s) are optional. If thermal storages are present, each storage is dimensioned to be able to store 3 hours of the maximal thermal output of the CHP unit(s).

Third, the importance of the target area heat demand density is investigated by doing a case study for a typical Belgian city (identified as Leuven) and a typical Belgian town (identified as Heverlee). Heat demands of Leuven and Heverlee are approximated through a bottom-up approach utilizing available benchmarks ([6], [7]). The characteristics of both Leuven and Heverlee are presented in table III. The heat demand and heat demand density in Leuven is signifficantly higher than in Heverlee. In both cases, the CHP units are dimensioned to be able to deliver a maximal fraction of the heat demand (largest rectangle method).

TABLE III
CHARACTERISTICS OF THE HET DEMAND IN BOTH TARGET AREAS

Target area	Heat demand [GWh$_t h$/year]	Heat demand density [kWh$_{th}$/(m^2.year)]
Leuven	508	84.8
Heverlee	337	17.4

III. RESULTS

A. Emission Savings

The emission savings in the different scenarios are presented in figure 2. The target area heat demand is indicated by L (Leuven) or H (Heverlee). Furthermore, the presence of a thermal energy storage is indicated by st (storage) or nost (no storage).

Figure 2 shows that CHP-CCGTs obtain the largest emission savings. ICGEs achieve somewhat lower emission savings, while the potential to reduce greenhouse gas emissions with GTs appears limited. Note that in the scenario in Leuven with GTs and without a thermal storage even negative emission savings are obtained.

Furthermore, the inclusion of a thermal energy storage seems to be imperative to obtain high emission (and fuel) savings. In most scenarios, the emission savings more than double when a thermal energy storage is included.

As long as the heat demand density does not influence the share of thermal network losses, the emission savings have an approximately linear relation to the target area heat demand. The result is that, in absolute values, emission savings are generally larger in Leuven than in Heverlee. Deviations from this linear relationship occur as a result of the different shape of the heat demand profiles in both areas and an accompanying difference in dimensioning of the CHP unit(s).

In the Leuven scenarios with a thermal storage included, CHP-CCGTs obtain emission savings of 115-120 ton/GWh_{th} delivered heat at the consumer. For ICGEs, this drops to 90 ton/GWh_{th}, while GTs merely achieve 34-41 ton/GWh_{th}.

B. Economical Analysis

First, the difference in investment cost between the DH scenarios and the corresponding reference scenarios are estimated

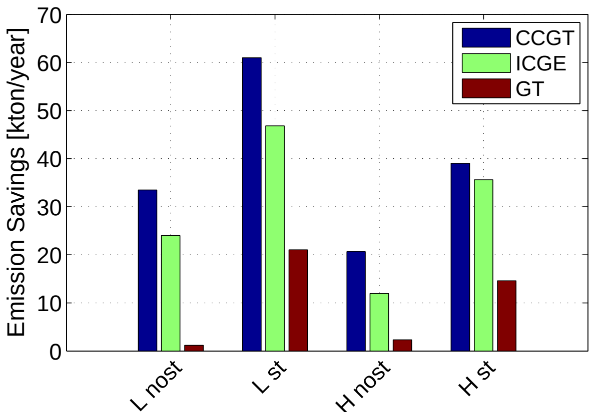

Fig. 2. Emission savings for the different scenarios

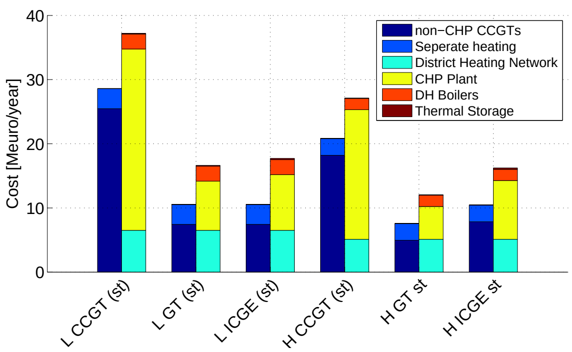

Fig. 3. Annuitized investment costs of the different scenarios.

based on a literature review. Results of this comparison are illustrated for the different scenarios in figure 3. All costs are expressed as annuities based on the installation lifetime and an interest rate of 5%.

A first thing to notice is that the investment cost is higher in the CHP-CCGTs scenarios, compared to ICGE or GT scenarios. This is a result of the high E/Q ratios of the CHP-CCGT and the fact that the CHP-CCGTs are dimensioned to be able to deliver peak heat demand. From the main premise of the analysis, it follows that the investment cost of the corresponding reference scenario is also large. Furthermore, it can be observed that the cost of the DHN is the main cause of the higher investment costs in case of district heating. Finally, the additional cost of the thermal energy storage(s) is very small. As section III-A pointed out that emission and fuel savings are considerably higher if there is a thermal energy storage present, only scenarios with a thermal energy storage are considered in the further analysis.

To compare the total costs of the DH scenarios with the reference case, it is essential that the cost of fuel and emission savings resulting from the presence of the DHN are included. In addition, the operational expenditures need to be considered. The total annuitized additional cost of CHP-DH for the different scenarios are presented in figure 4.

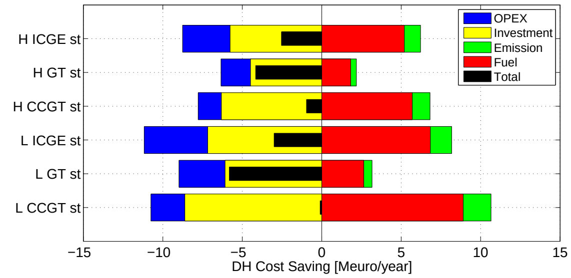

Fig. 4. Total Cost Savings in the phase out scenarios

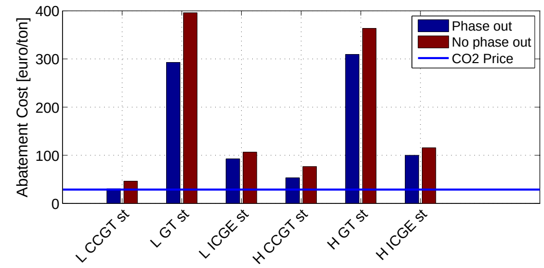

Fig. 5. District heating emission abatement cost of the different scenarios

In these figures, cost components of the district heating scenarios are compared to those of the corresponding reference scenarios. Negative values represent an additional cost in the district heating scenario.

Besides the total additional cost, a district heating CO_2-emission abatement cost is derived. This cost is useful as it allows comparison with other technologies capable of reducing greenhouse gas emissions. The emission abatement cost for the different economically driven scenarios with a thermal storage is presented in figure 5. This figure also displays the projected price of emission allowances [8].

IV. Discussion

Figure 4 shows that in all scenarios, negative cost savings are obtained. Negative cost savings indicate a higher total cost of the district heating case compared to the reference scenario. This means that the fuel and emission savings do not counterbalance the additional investment and operational costs associated with district heating. This is reflected in the district heating emission abatement costs which are higher than the projected price of emission allowances of 28,74 €/ton (as projected by the new policy scenario of the world energy outlook 2012 of the IEA [8]) for all scenarios. Emission abatement costs in the different scenarios which include a thermal storage range from 30 €/ton up to 396 €/ton.

To realize cost-effective emission reductions, measures with the lowest marginal abatement cost should be targeted first. This way, the price of emission allowances is set by the cost of the last abated unit. The fact that the emission abatement cost of district heating is higher than the projected emission allowance price reveals that it is expected that sufficient emission reductions can be realized more cost-effectively by investing in other measures. One of these measures that typically has a low abatement cost, is increased insulation for buildings. An important consequence for the feasibility of DH is that the decrease in heat demand density resulting from an increase in insulation levels, will cause an increase in the specific heatig network investment cost (€/GWh$_{th}$) and a decrease of the heat utilization fraction. Therefore, this will increase the district heating emission abatement cost even further.

A clear distinction can be made between the emission abatement costs of the different types of CHP units. The emission abatement cost of district heating is clearly highest for the scenarios with GTs, while CHP-CCGTs entail the lowest values.

Finally, one can observe that a higher heat demand density results in lower emission abatement costs. This is a result of the heating network investment cost which decreases less with a decreasing heat demand than the fuel savings.

V. Conclusion

The results of the analysis indicate that the introduction of CHP-DH has the potential to reduce carbon dioxide emissions. The optimization shows that the type of CHP unit has an important impact on the attainable emission reductions: CHP-CCGTs achieve larger reductions than gas engines, which in turn do better than small gas turbines. Also, the inclusion of a thermal energy storage is crucial to obtain high primary energy and emission savings.

Unfortunately, the obtained emission savings come with an additional cost. That is, at the projected fuel and emission prices, the fuel and emission savings do not offset the additional investment and operational costs associated with district heating. This is reflected in the district heating emission abatement costs which are higher than the projected price of emission allowances of 28,74 €/ton for all scenarios. Emission abatement costs in the different scenarios which include a thermal storage range from 30 €/ton up to 396 €/ton. Future heat demand density is expected to decline, which would further increase the DH emission abatement cost.

For these reasons, the potential for combined heat power district heating in Belgium seems limited. However, an increase of the fuel prices or emission allowances as well as a decrease of district heating network investment costs could render CHP-DH feasible.

The cost-effectiveness of district heating networks supplied by other heat sources requires further investigation. Furthermore, the benefits of the CHP plants to enter into the balancing market requires some more investigation.

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