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Is There a Future for Small-Scale Cogeneration in Europe? Economic and Policy Analysis of the Internal Combustion Engine, Micro Gas Turbine and Micro Humid Air Turbine Cycles

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Abstract: If more widely deployed, small-scale cogeneration could increase energy efficiency in Europe. Of the two main commercially available technologies—the Internal Combustion Engine (ICE) and the micro Gas Turbine (mGT)—the ICE dominates the market due to its higher electrical efficiency. However, by transforming the mGT into a micro Humid Air Turbine (mHAT), the electrical efficiency of this cycle can increase, thus enhancing its operational flexibility. This paper presents an in-depth policy and economic assessment of the the ICE, mGT and mHAT technologies for dwellings based in Spain, France and Belgium. The hourly demands of average households, the market conditions and the subsidies applicable in each region are considered. The aim is twofold: to evaluate the profitability of the technologies and to assess the cogeneration policies in place. The results show that only the ICE in Brussels is economically viable, despite all units providing positive energy savings in all locations (except mHAT in Spain). Of the three different green certificate schemes offered in Belgium, Brussels is the one leading to the best outcome. Spain awards both capital and operational helps, although auto-consumption is not valued. The same applies to the complex French feed-in tariff. Conclusively, with the current policies, investing in small-scale cogeneration is in general not attractive and its potential efficiency gains remain unveiled.

Keywords: economic analysis; policy analysis; cogeneration; micro Gas Turbine; internal combustion engine

1. Introduction

Cogeneration—also known as Combined Heat and Power (CHP)—enables the simultaneous production of electricity and heat, saving a substantial amount of primary energy compared to traditional energy generation [1]. Nowadays, cogeneration units can be mostly found in large commercial or industrial facilities; however, a more wide deployment of micro (up to 50 kW) and small-scale (up to 1 MW) CHP could further contribute to increasing energy efficiency in smaller applications [2]. There are two main technologies currently commercially available for small-scale cogeneration: the Internal Combustion Engine (ICE) and the micro Gas Turbine (mGT). The market is still largely dominated by the ICE due to its higher electrical efficiency (∼35 % for a unit with a power output of 100 kW_e as opposed to ∼30 % for an mGT of the same capacity) [3]. Nevertheless, mGTs do offer some advantages compared to ICEs: the absence of reciprocating and friction components means that balancing problems are few and the need for lubricant oil is very low. The maintenance and engineering costs are thus minor as well as the noise and vibration levels. In addition, mGTs have multi-fuel capabilities, with reduced emissions and cleaner exhaust. Finally, the recoverable heat is high-grade and concentrated in the exhaust gases, while in the ICE cycle it is spread between the exhaust gases, cooling jacket and lubricant oil [4–6].

Users with a constant heat demand throughout the year are the perfect candidates for CHP units as they can fully benefit from the high nominal energy efficiencies. Small-scale cogeneration could also potentially provide the energy needs of a group of dwellings—in a large building or a neighbourhood, for example [7]. The main issue for this type of consumers is that the heat demand is variable during the year, peaking in winter and reaching minimum values in the summer [8]. When the heat demand is not high enough, the exhaust gases of the small scale CHP units have to be blown off at a high temperature; thus, the overall cogeneration efficiencies (of around 80 % to 85 %) are reduced to the electrical efficiency. For the case of mGTs, their rather low electrical efficiency results in unsustainable operation. The units are thus forced to shutdown in these situations, which in turn reduces their profitability.

An option to increase the electrical efficiency of mGTs in moments of curtailed heat demand is to use the energy in the exhaust gases to warm up water and then inject it in the cycle, at the back of the compressor. This can be achieved by introducing a saturation tower and transforming the mGT into a micro Humid Air Turbine (mHAT). Part of the hot water injected in the saturator evaporates in the compressed air: increasing the mass flow rate through the turbine for a given compressor input; thus, a higher electrical efficiency is obtained [9]. Water injection in mGTs allows decoupling heat and electricity production: if the heat demand is high enough, the unit can run in cogeneration mode following the traditional mGT configuration; when the heat demand decreases, water injection enables re-using the heat in the exhaust gases to increase the electrical efficiency of the engine.

The beneficial effect of transforming an mGT into an mHAT has been broadly studied from numerical [10–14] and experimental perspectives [15–20], as summarised by De Paepe et al. [21] in our review of humidified microturbines. In terms of the economics of mHAT, the authors of this paper compared the profitability of the ICE, mGT and mHAT cycles for a wide variety of natural gas and electricity price scenarios [22,23]. Our studies confirmed that the three technologies are economically feasible in markets with low natural gas and high electricity prices. Furthermore, whenever investing in CHP technologies is profitable, the revenues of mHAT are the highest. Although these conclusions throw light over the profitability of cogeneration technologies from a generic viewpoint, the performance of these units (especially of the novel mHAT cycle) remains to be assessed taking into account the specific market conditions of certain countries with the corresponding awarded subsidies, if applicable.

In this paper, we carry out an economic and policy analysis of the mGT, mHAT and ICE cycles for domestic users placed in Madrid (Spain), Paris (France) and Brussels (Belgium). These three countries have been chosen as their cogeneration policies differ and span from green certificates and feed-in tariffs to capital subsidies and operational helps. The hourly heat and electricity demands of average users in each of the countries have been considered in addition to the specific market conditions and the applicable CHP policies in each state. The objective of this work is twofold: to analyse the economic and environmental performance of the three technologies in the examined countries as well as to assess the effect of the awarded subsidies in the economic results of the cogeneration units.

The paper is organised so that Section 2 summarises the small-scale cogeneration policies applicable in the three studied countries. Subsequently, Section 3 introduces the basics of the mHAT cycle functioning as well as the specificities of the engines representing the three considered technologies. Section 4 elaborates on the developed economic model: how the units operate following the heat demand, the model input (users demands and electricity and natural gas prices) and output (the economic and environmental metrics used to assess the performance of the technologies). In Section 5, the results are presented and discussed while the conclusions and policy implications are summarised in Section 6.

2. Small-Scale Cogeneration Policies

The current cogeneration policies of the three studied countries (Spain, Belgium and France) are outlined in this section and further summarised in Table 1. Given the vast amount of subsidies, only those relevant for small-scale CHP units have been taken into consideration. The three states were chosen because of the wide nature of the policies they offer: from capital investment and operational subsidies to feed-in tariffs and green certificates.

Table 1. Summary of the cogeneration policies applicable to 100 kW_e units in the studied three countries (five regions).

Country	Type of Policy	PES	Span	Price & Conditions
Brussels	Green Certificates	>5% [a]	10 years	€ 90/GC 1 GC per 217 kg of CO_2 avoided Multiplying factor of 2 for collective housing
Flanders	Green Certificates	>0	∞	€ 31/GC 1 GC per 1000 kW_e of CHP savings
Wallonia	Green Certificates	>0	15 years	€ 65/GC 1 GC per 456 kg of CO_2 avoided
France	Feed-in tariff	>10%	15 years	Equations (2) and (3) Only available during the winter period
Spain	Capital subsidy Operational subsidy	>0 >0	25 years 25 years	€ 179/(kW·y)[b] € 69/MWh[b]

[a] Brussels applies its own reference values
[b] The values correspond to the first operational year of an mGT installed in 2017.

2.1. Spain

Policies regarding cogeneration have undergone numerous changes in Spain in recent years due to the economic crisis experienced by the country and to the exponential growth of renewable energy (especially solar photovoltaic) in the electricity market. This, combined with the generous subsidies to renewables—which were fundamentally financed by the consumers through the electricity bill—ended up risking the financial stability of the system. High efficiency cogeneration and renewable energy are governed under the same laws in Spain: currently, the Royal Decree 413/2014 [24] and the Order IET/1045/2014 [25]. According to these directives, the producer receives a specific remuneration regime that is granted to facilities not being able to compete on equal grounds with other technologies in the market. The economic support depends on the specific technology, the market conditions and the year of investment. It is divided into two components:

- Remuneration on the investment (R_{inv}) is an annual retributive term expressed per unit of installed capacity. It aims at covering, where applicable, the investment costs of the unit that cannot be recovered from the sale of energy in the market. This remuneration considers the standard costs of the initial investment, comprising: the cost of the facility itself and of all the control and electromechanical systems, measurement equipment, and connection lines (including their transport, installation and start-up). It is expressed as € per MW of electrical power.
- Remuneration on operation (R_{o}) is an operational aid which covers the difference between operating costs and operating income of the facility. For its calculation, the variable installation

costs have been considered: insurance, administration, fuel, etc. It is expressed as € per MWh and it applies only to the energy that is sold in the market.

Once the facilities reach their regulatory lifetime, they stop perceiving these aids. If a unit starts to be profitable within its regulatory lifetime, it stops perceiving R_{inv}, but it can continue receiving R_{o}. If at any time during the lifetime the income exceeds the costs of the facility, the unit stops perceiving R_{o}. For both a microturbine and a piston engine with an electrical power output of 100 kW_e, the regulatory lifetime is fixed at 25 years and a minimum of 2500 h of operation during the year is required. The R_{inv} and R_{o} variables are updated every year (for each technology depending on the year in which it was installed). For the present study, historical data published in [26] has been considered. The values of R_{inv} and R_{o} corresponding to 2017 for an mGT and an ICE installed in this same year are shown in Table 1.

2.2. Belgium

Although we have considered the demands of a user based in Brussels, we will explore the policies of the three regions in Belgium. Due to the small size of the country, the demand per dwelling is not likely to diverge much from one region to another; thus, this gives us the opportunity to understand the effect of different policy implementations for a given demand.

Within the Belgian legislation, energy is managed both by the federal government and by the regions (Wallonia, Flanders and Brussels). Nonetheless, energy efficiency has been a fundamentally regional competence since 2013, when the federal government withdrew tax reductions for cogeneration. Hence, CHP in Belgium is currently supported at the regional level through different regional Decrees. In all regions, a certificate-based support system is enforced, although the practical implementation differs between them. Whereas Wallonia and Brussels have certificates that comprise both renewable energy and cogeneration—Green Certificates (GC)—Flanders gives specific certificates for cogeneration—CHP certificates.

2.2.1. Brussels-Capital Region

Currently, the Brussels-capital region promotes cogeneration solely through GCs goverened by the "19th July 2001 Ordinance on the organisation of the electricity market" [27]. Several subsequent norms regulate the calculations and practical awarding procedures for GCs.

Certificates in Brussels are issued quarterly by BRUGEL (the energy regulator in this region) for facilities achieving at least 5 % CO_2 savings compared to the reference installation [28]. Such reference is defined as with an electrical efficiency of 55 % and a heat production efficiency of 90%. Every GC is attributed per block of 217 kg of CO_2 avoided [29]. High efficiency CHP units running on natural gas which furnish heat to several residential clients benefit from a multiplying coefficient applied to the number of green certificates. Since October 2017, this coefficient is equal to 2 for cogeneration units with an electrical power output of 100 kW_e [30]. An installation can benefit from GCs for a maximum of 10 years [31].

The owner of the installation sells the GCs to the electricity suppliers, who have the obligation of buying a number of certificates per year (quota) from green electricity producers in order to avoid fines of € 100 per missing certificate [32]. Latest publications report a rise in the market price of the Brussels GCs, which is approaching the price of the fine [33]. Companies like EDF and ENGIE are offering fixed prices at around € 90 per certificate [34,35]. Thus, this is the price that has been considered in our model.

The Brussels-Capital Region also used to issue investment support for CHP units; however, these subsidies have not been in place since 2016 [36].

2.2.2. Flanders

Cogeneration in Flanders is subsidised with specific CHP certificates that are monthly issued by VREG (the energy regulator in this region). The certificate scheme was first established in the 2009 Energy Decree "het Energiedecreet" [37] and subsequent norms in 2010 and 2012 have further regulated its implementation. In order to have access to CHP certificates, the unit needs to be classified as high-efficient cogeneration. Facilities with power outputs below 1 MW_e are considered high-efficient when their relative Primary Energy Savings (PES) are positive. Above 1 MW_e, PES need to be above 10%. The PES are calculated according to the formula and corrections established by the European Commission, which are explained in detail in Section 4.3.2.

The owner of a high-efficiency cogeneration unit is entitled to one certificate for each 1000 kWh of CHP savings, which are calculated according to the following equation [38]:

$$\mathrm{CHP_{savings}} = \frac{E}{\eta_{\mathrm{ref,E}}} + \frac{Q}{\eta_{\mathrm{ref,Q}}} - F. \quad (1)$$

For the purpose of this calculation, the reference electrical efficiency is 50% and the reference heat production efficiency is 90%—values defined in the Flemish Energy Decree, which are different to those required for the calculation of the PES, where the European definitions are adopted [39].

The certificates can be sold on the market or to Elia (the transmission system operator) for a guaranteed minimum price of €31/GC. Electricity suppliers not meeting the market share have to pay a fine of €38 per missing certificate. It is striking that the price of the certificates in this region is much lower compared to Brussels and Wallonia. The same happens when comparing the prices of CHP certificates to other technologies. In Flanders, renewable energies have been given a priority, leaving fossil fuel cogeneration in a secondary plane. For example, the guaranteed minimum price for biogas plants is €110/GC, which represents more than three times the amount for natural gas-fuelled CHP plants [40].

2.2.3. Wallonia

CHP in the Walloon region is covered by the 2006 Decree on the promotion of electricity produced by renewable energy sources or cogeneration [41]. Green certificates, issued both for renewable energy and for cogeneration, are regulated by CWaPE (the energy regulator in Wallonia) who is also responsible for determining the required quota to the electricity distributors. One certificate is awarded per 456 kg of CO_2 avoided, which—for the case of a cogeneration unit fed with natural gas—is calculated based on the fuel savings compared to a reference electrical efficiency of 52.5 % and a heat production efficiency of 90%. A conversion factor of 0.217 kg of CO_2 per kWh of natural gas is applied [42,43]. The PES should be at least 10% for units with power outputs above 1 MW_e and positive for units below this value. The right to obtain green certificates is limited to 15 years. The fine for not achieving the quota is €100 per missing certificate, while the guaranteed price is €65 per certificate, which was taken for this study [44].

2.3. France

The "Energy Code" in France governs all the energy-related aspects in the country, establishing a classification on the different energy production technologies and regulating the energy market. The technical characteristics required for the high efficiency cogeneration units are fixed in [45], where it is outlined that natural gas-fed CHP units of more than 50 kW_e need to have PES superior to 10%.

The calculations to estimate the cogeneration primes in France depend on factors such as the daily price of natural gas and the hourly price of electricity. In addition, the nominal values are corrected by coefficients calculated with macroeconomic indeces difficult to appraise. Such complex legislation may represent a barrier for producers willing to invest in CHP, who are likely to require aid from experts in order to calculate the amount of the subsidies.

The different aids for which cogeneration units are eligible are laid out in [46]. For the studied facilities, two main subsidies would apply, both for a maximum duration of 15 years:

- Purchase Obligation (PO): the producer engages with the energy distributor in a contract by which all the energy produced by the facility (deducing what is consumed on-site) is sold to the distributor. During the contract winter period (from November to March), the price, expressed in €/MWh$_e$, is set with the following equation:

$$\mathrm{PO} = 54 + 1.26 \times \mathcal{P}_{\mathrm{gas}} + 130 \times (\mathrm{PES} - 0.1), \tag{2}$$

  where $\mathcal{P}_{\mathrm{gas}}$ stands for the price of natural gas. During the contractual summer (April to October), the electricity price is determined by the directive as the settlement price of the half-hourly positive differences in the mechanism of adjustment as defined in [47].
- Remuneration Complement (RC): in addition to the purchase obligation, natural gas-fired small scale CHP is eligible for an economical aid during the winter (in this case re-defined as from October to April). The aid is granted for the first 3624 h working at full power. RC, expressed in €/MWh$_e$, is calculated using the following equation:

$$\mathrm{RC} = 47 + 1.37 \times \mathcal{P}_{\mathrm{gas}} + 130 \times (\mathrm{PES} - 0.1). \tag{3}$$

The PO and RC formulas are further corrected, according to the French norm, with certain indexing factors (named *K* and *L*) based on economic rates of the evaluated year. Their impact on the value of the helps is of around 1–4%. Due to the complexity of their calculation and to the limited effect that they have on the final result, they have not been included in the economic model of this study.

3. The Studied Technologies

The economic performance of mHAT is compared in this study to that of the simple mGT and of the small-scale CHP market leader: the ICE. This section first describes the functioning of the mHAT cycle; subsequently, the specific engine versions considered for the three technologies are introduced.

3.1. The Basics of the Micro Humid Air Turbine Cycle

mGTs are based on a typical Brayton cycle with recuperation: the air first passes through the compressor, where the pressure is raised, before being preheated with the exhaust gases in the recuperator. Thereafter, it is burnt with natural gas in the combustion chamber and it subsequently expands in the turbine. The turbine drives the compressor through the rotating shaft: the remaining mechanical energy is transformed into electricity in the generator: the cycle has an electrical efficiency of around 30% for a unit with a power output of 100 kW$_e$. After leaving the recuperator, the exhaust gases are still at a high enough temperature to warm up water in an economiser. This water is then used for external heating purposes, with a heat production efficiency of around 50%.

When converting an mGT into an mHAT, a saturation tower (shown in black in Figure 1) is added in between the compressor and the recuperator. Thus, whenever the external heat demand is low and there is no useful output for the heat produced by the mGT, the exhaust gases can be utilised to warm up water (as in the traditional CHP configuration), but this water is routed towards the saturation tower and sprayed over the compressed air. Humidifying the mGT therefore enables increasing the electrical efficiency in moments of low external heat demand by recovering the heat in the exhaust gases and injecting it back into the cycle. This means that the operational flexibility of the units is enhanced, as they are able to run in cogeneration mode when there is an external heat demand and with water injection the rest of the year. The detailed thermodynamic mechanisms that lead to an increase in electrical efficiency through water injection can be found in [20].

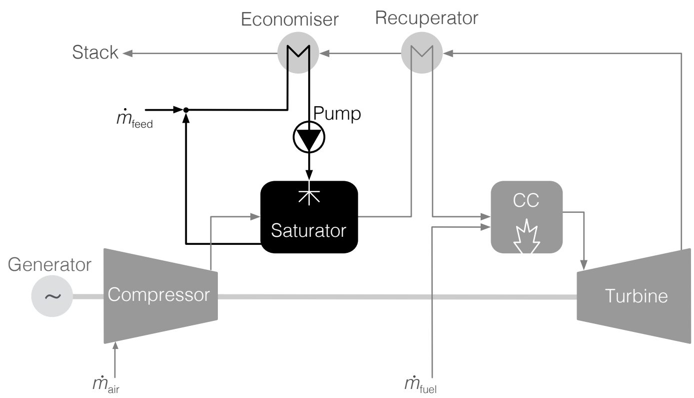

Figure 1. By introducing a saturation tower and a humidification unit (shown in black), the mGT cycle (in grey) is transformed into an mHAT.

3.2. The Three Engine Versions

The studied mGT is the Turbec T100, with a nominal electrical power output of 100 kW_e and a thermal power output of 165 kW_{th} [48]. The studied reciprocating ICE is the 2G Cenergy Patruus Series, an engine running on natural gas with an identical nominal electrical power output (100 kW_e) but with a thermal output of 143 kW_{th} [49]. Both the T100 and the Cenergy Patruus are representatives of their specific cycle. As widely known, reciprocating ICEs have higher electrical efficiencies than mGTs. This is also obvious in the studied units: while the electrical efficiency of the 2G Cenergy amounts to 34.8%, the Turbec T100 is limited to 30% at nominal conditions and International Organisation for Standardisation (ISO) ratings [48,49]. The part load electrical efficiencies and thermal power output for both units are depicted in Figure 2.

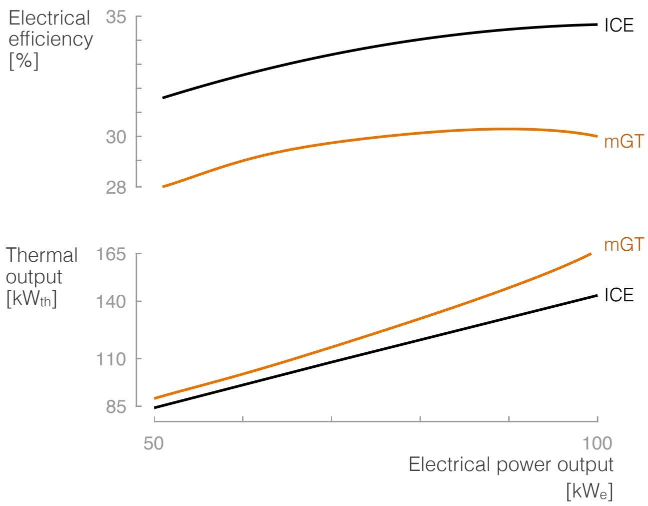

Figure 2. The reciprocating ICE offers a higher electrical efficiency compared to the mGT cycle, also at part load operation. However, both cycles present a very similar thermal efficiency (∼50%). Data sources: [48,49].

The studied mHAT in this analysis is based on the first-of-a-kind facility present at the Vrije Universiteit Brussel (VUB) laboratory. The VUB mHAT is composed of a Turbec T100 mGT coupled with a novel spray saturator. At nominal conditions, water at around 80 °C is sprayed in the saturator in the form of small droplets over the compressed air to favour evaporation. Thus, for a fixed turbine output (as this component is chocked in nominal conditions), the compressor work is reduced, leading to an increased electrical efficiency. Only ∼50 g/s of the 2.5 kg/s of injected water evaporate in the saturation tower: the rest is conducted back to the economiser while a feed-in water line makes up for the evaporated water. As proved by De Paepe et al., if Turbine Inlet Temperature (TIT) is kept constant at its original value of 950 °C, the electrical efficiency increasewith water injection amounts to 3.8%-pt. [14]. For the economic model described in this paper, we have assumed that the mHAT unit has been optimised and the control unit modified so that the electrical efficiency increase—at nominal conditions, when the hot water is injected in the saturator at the highest temperature—to the most promising value of 3.8%-pt.

The efficiency figures above correspond to mHAT full load operation, i.e., nominal conditions. In this study, the units operate following the heat demand and are required to run at part load during a certain number of hours in the year. Part load operation for mHAT units is more complex than for simple mGTs: the electrical efficiency increase obtained thanks to water injection depends on the temperature at which the water is actually injected into the saturation tower, which in turn depends on the heating demand of the user. When operating with water injection, the mHAT unit can actually also fulfil the heat demand of the user. To do so, the exhaust gases warm up water in the economiser. This hot water is first used to fulfil the potential external heating needs (step one, Figure 3). Thereafter, it is routed towards the saturation tower (step 2). However, if the external heat demand is high (between 165 kW_{th} and 130 kW_{th}), the temperature of the water after step 1 is not high enough to allow for an electrical efficiency increase if injected in the saturation tower, as shown in Figure 4. In such cases, the unit is run dry, without water injection. When the heat demand reaches values below 130 kW_{th}, water injection takes place, leading to an increase in electrical efficiency. As the external heat requirements decrease (and so does the thermal power output of the unit), the hot water is injected in the saturation tower at a higher temperature and the electrical efficiency of the mHAT increases. The maximum electrical efficiency is obtained when the unit does not produce any external heating; hence, the hot water warmed up by the exhaust gases is directly injected in the saturation tower.

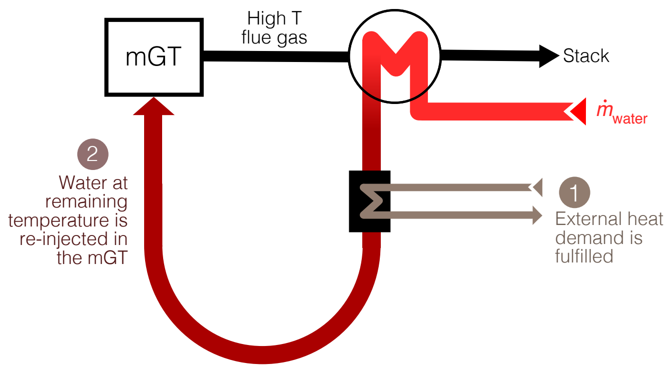

Figure 3. The exhaust gases of the mHAT unit warm up water in the economiser. This hot water is first used to fulfil the external heating needs (step 1). If the water temperature is high enough, they are then injected in the saturation tower (step 2).

Environmental conditions, namely temperature, can affect the performance of mGT and ICE units: the higher the inlet air temperature, the lower the electrical efficiency. For example, for the case of the T100 mGT, the electrical efficiency descends from 30% at 15 °C to 29.4% at 20 °C [48]. The effect of inlet air temperature is not taken into account in this study though: the authors did not consider that it would have a substantial effect in the model results. As the temperatures rise, the heat demand decreases to minimum values and the mGT and ICE units are then shut down (see Section 4.1 for more details on how the units operate in the model). For the case of the mHAT unit, the effect of rising inlet temperatures is filtered out by the injection of water, as further explained in [18,21].

In the model, all the units have a lifetime of 60,000 h of operation [48,49]. This is a positive assumption for the ICE, which would usually be decommissioned after 50,000 h in order to avoid a dramatic increase in Operation & Maintenance (O&M) costs. The lifetime in years of each technology depends on the yearly running hours of the unit.

The three cogeneration units generate electricity at 380 V and are designed to be connected to a hot water 50 °C–70 °C heating network.

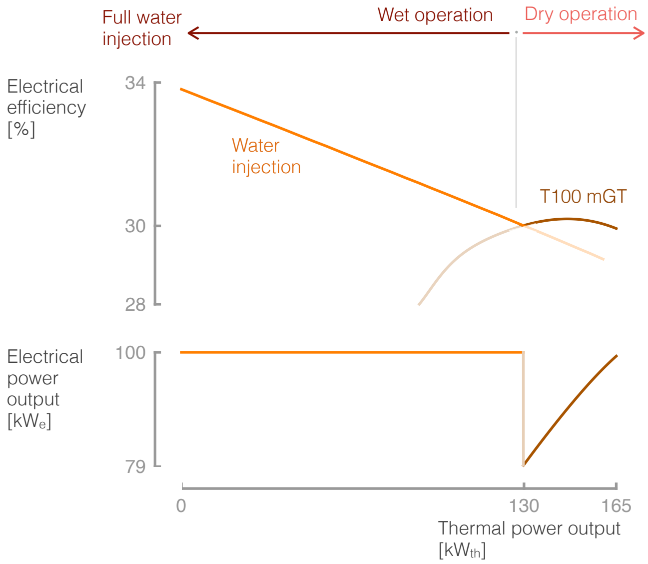

Figure 4. When the heat demand is between 130 kW_{th} and 165 kW_{th}, it is not worth injecting water as the electrical efficiency actually reduces. For heat demand values below 130 kW_{th}, the mHAT operates at a full electrical load with water injection.

The technical characteristics in nominal conditions for the three engines are summarised in Table 2.

Table 2. Main technical characteristics of the three cycles.

	mGT T100	mHAT T100		ICE 2G Cenergy
		Dry	Wet [a]	
Electrical power	100 kW_e	100 kW_e	100 kW_e	100 kW_e
Thermal power	165 kW_{th}	165 kW_{th}	-	143 kW_{th}
η_E	30 %	30 %	33.8 %	34.8 %
η_Q	50 %	50 %	-	49.8 %
η_{total}	80 %	80 %	33.8 %	84.6 %

[a] Value corresponding to full water injection, assuming that the unit is only producing electricity and the hot water warmed up by the exhaust gases is directly injected in the saturation tower.

4. The Economic Model

On an hourly basis, the economic model evaluates the heat demand of the users and sets up the operation of the units. Based on the costs and benefits derived from such operation, the economic and environmental performance of the technologies is determined. In this section, the procedure which decides how the units run is first explained. Subsequently, the required inputs by the model are described, namely the heat and electricity demands of the different users and the electricity and natural gas prices of the specific location. Finally, the outputs of the model—Net Present Value (NPV), Internal Rate of Return (IRR) and PES—are outlined.

4.1. Operation of the Units in the Model

Every hour in the year, the model evaluates the demand of the user: the decision on how the unit is run depends on the specific value of the heat demand and on the technology. The produced electricity thus comes as a by-product and is used to fulfil the electricity demand of the consumer in the given hour. If the demand exceeds the production, the lacking electricity is bought from the grid; otherwise, the excess of generated electricity is sold to the grid.

For the mGT and reciprocating ICE engines, the operational strategy is the same: when the heat demand is above the nominal heat output of the unit (165 kW_{th} for the mGT and 143 kW_{th} for the ICE), the engines run at full load providing all the produced electricity to the user. The extra required heat is then generated with a boiler. When the heat demand is between the nominal thermal output and the value corresponding to 50 % load (90 kW_{th} for the mGT and 84 kW_{th} for the ICE), the units run at part load producing the exact heat required by the user. It is assumed that the lowest operating point for both engines is this 50% load; thus, when the heat demand is below this threshold, the cogeneration units are shut down: the required heat is then provided by the boiler and the demanded electricity is all bought from the grid. A summary, mGT and ICE operation depicted over the heat load curve are shown in Figure 5.

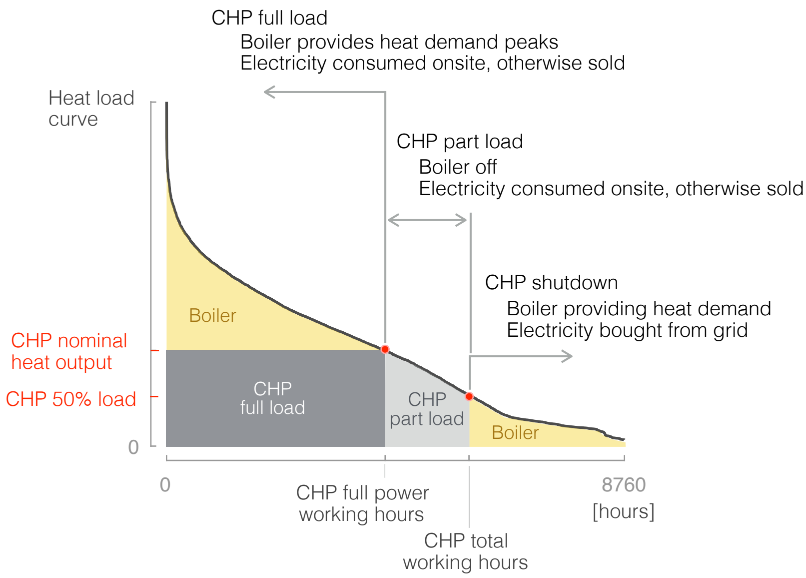

Figure 5. The mGT and the reciprocating ICE units run following the heat demand: the excess or lack of electricity is sold/bought to/from the grid depending on the electricity demand at a given moment.

In terms of mHAT operation, whenever possible, the unit runs in its original CHP configuration providing the nominal heat and electricity output (100 kW_e and 165 kW_{th}), as this is the mode with the overall highest energy efficiency. Thus, if the user's heat demand is equal to or above 165 kW_{th} the mHAT unit runs 'dry' at full load—without water injection. The required 'extra' heat is provided by a boiler. Whenever the user's heat demand descends to a value between 165 kW_{th} and 130 kW_{th}, the temperature of the water after delivering heat for external heating purposes is not high enough to provide an electrical efficiency increase if injected in the saturation tower (see Figures 3 and 4). Therefore, in these cases, the mHAT runs at part load without water injection, provisioning all the required heat. Once the heat demand descends to a value below 130 kW_{th}, water injection starts: the mHAT unit still fulfils the external heat demand while the hot water injected in the saturator delivers an electrical efficiency increase (following the efficiency curves of Figure 4).

As opposed to mGT and ICE, the mHAT cycle is thus capable of following the heat demand of the user while maintaining a high electrical efficiency and without dumping heat that could be potentially used for external heating. Thereupon, mHAT can run all year long: see the summary of mHAT operational strategy based on the user's heat load curve in Figure 6. mHAT operation is ruled by the mode that leads to the highest electrical efficiency: if the external heat demand is high enough (above 130 kW_{th}) the mHAT runs dry (either at part or full load), as a common mGT. For lower heat demands, the unit operates in wet mode with an incremented electrical efficiency.

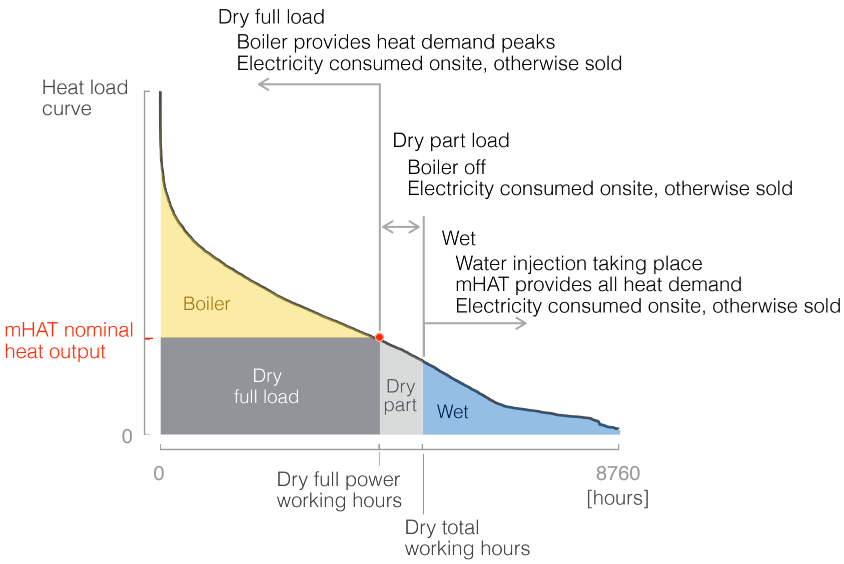

Figure 6. The flexibility of mHAT units allows them to operate all year long whatever the heat demand. The mHAT cycle runs in the mode that delivers the highest electrical efficiency.

4.2. Model Input

The economic model requires as an input the hourly heat and electricity demands of the user and the applicable electricity and natural gas prices. This section covers how the users' demands in the studied countries are obtained, the sizing method followed to fit the output of the units and the electricity and natural gas prices utilised according to each region.

4.2.1. User Demands

The investigated domestic users are based in the capitals of the three studied countries: Madrid (Spain), Paris (France) and Brussels (Belgium). In order to assess as accurately as possible the performance of the three CHP technologies, hourly heat and electricity demands throughout the year have been considered. However, such detailed data are not readily available for these three cities. As a workaround, two databases have been consulted: the first one, Open Energy Information, contains hourly heat and electricity data for different types of users based in cities across the US [50]; the second, Codeminders, allows comparing meteorological data accumulated over more than a hundred years from weather stations worldwide [51]. The climatic American equivalent for the city of Madrid is Sacramento (98% overlap); for Paris, it is Seattle (99% overlap) and for Brussels, it is Olympia (99% overlap).

A household energy consumption does not only depend on the weather but also on the behaviour of its inhabitants. To incorporate the cultural differences between American and European families that might affect the energy demand, the heat and electricity data from the selected American cities are further scaled so as to better fit the actual demand of average dwellings in Belgium, France and Spain. The Odyssee-Mure project publishes data on total energy consumption per dwelling in European cities [52]. Thus, the available hourly heat and electricity demand trends from the American cities (Olympia, Seattle and Sacramento) are scaled down so that the total energy consumption over the year matches the corresponding of the European cities (Brussels, Paris and Madrid, respectively). The resulting energy demands are shown in Figure 7.

While the shape of the energy demands is similar in Belgium and in France, the climatic differences are obvious for the case of Spain: winters are shorter; hence, from May till November the heat demand is minimum. Furthermore, because of the use of air conditioning, the electricity demand substantially increases between June and September.

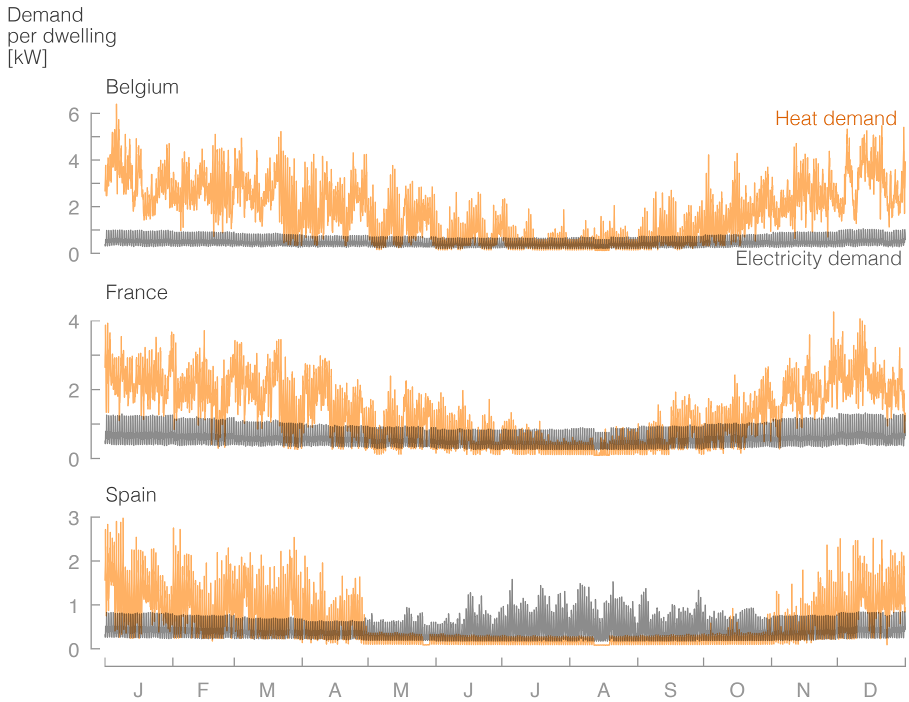

Figure 7. The hourly heat and electricity demands follow similar patterns in France and Belgium; nevertheless, in Spain, they differ: the shorter winters result in a minimum heat demand from May until November, and the use of air conditioning is obvious from an increased electricity demand in the summer.

4.2.2. Demand Sizing

The sizing procedure followed in this study is the maximum rectangle area method, commonly used for cogeneration units. This methodology finds the capacity of the energy generator that covers the maximum energy consumption; thus, it minimises the primary energy required to fulfil the demand of the user [53–55]. As the units run following the heat demand, the sizing is performed based on the heat load curve of the users. Traditionally, the sizing of CHP units starts from the demand of the user and looks for the engine size that best suits it; some examples can be found in [56,57]. In this study, we have followed a reversed method: as we have accurate data on specific machines, we group the demand corresponding to several single dwellings (assuming they would all belong to a large building or a small neighbourhood) to fit the studied technologies.

By arranging the hourly heat demand of the user in descending order, the so-called heat load curve of a single dwelling is obtained: the area under this curve represents the total thermal energy consumed by the user during the year. For the purposes of this study, the maximum rectangle area methodology has been adapted: the demand of a single dwelling is multiplied by the required factor so that the height of the maximum rectangle area under the resulting heat load curve is equal to the nominal heat output of the considered unit (165 kW_{th} for the mGT and mHAT and 143 kW_{th} for the ICE): the full approach is illustrated in Figure 8. As a result, the number of dwellings grouped for the mGT and mHAT units is different to that of the ICE.

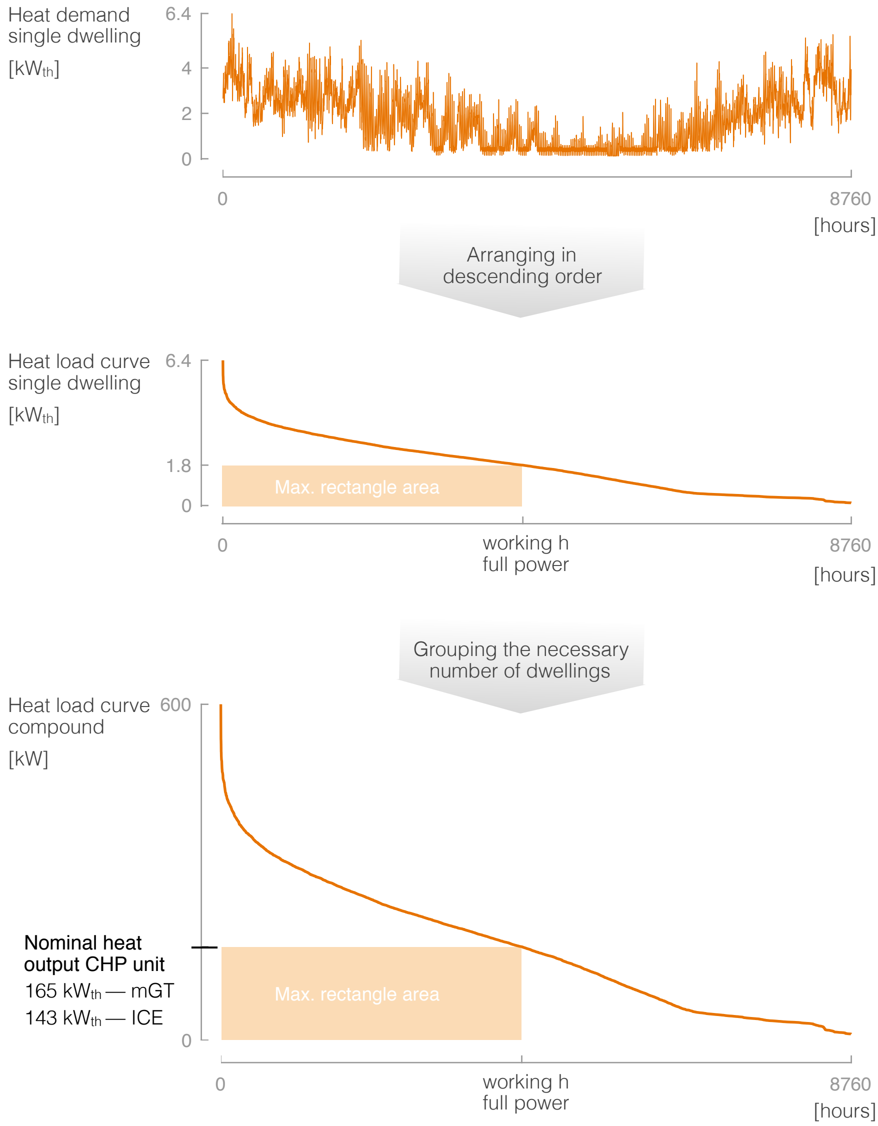

Figure 8. The demand sizing procedure consists of grouping dwellings so that the maximum rectangle area under the heat load curve has a height equal to the nominal heat output of the CHP units.

4.2.3. Electricity and Gas Prices

The profitability of small-scale CHP technologies is especially sensitive to gas and electricity prices, as demonstrated by the authors in [22,23]. Thus, it is utterly important for a reliable economic analysis to estimate these values in a precise way.

The price of the electricity that end consumers purchase depends on the contract that the electricity provider establishes with the user. In most cases, the consumer chooses fixed rates which stabilise the price along the year. Thus, in our model, the price of the electricity that cannot be provided by the CHP units and needs to be purchased from the grid is assumed to be fixed and equal to the price reported by Eurostat for the first semester of 2018 for the three studied countries (see Figure 9) [58].

The cogeneration technologies sell their surplus electricity in the wholesale market, where price fluctuations are wide and common during the day and throughout the year. In this case, our aim has been to track the price per kWh in the wholesale market throughout the year to simulate a price scenario as realistic as possible. Hence, a more methodical approach has been followed: as hourly data cannot be publicly accessed, monthly averages based on the available literature for 2018 for the three countries have been calculated, leading to the curves also shown in Figure 9 [59–61].

In terms of the natural gas, the prices considered were those reported by Eurostat for 2018 for each country, i.e., €0.0536/kWh for Belgium, €0.0665/kWh for Spain and €0.0665/kWh for France [62].

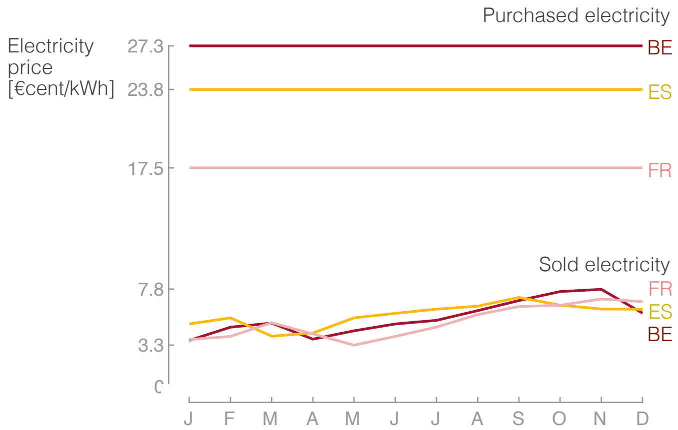

Figure 9. For the three studied countries, there is a substantial gap between the price of the electricity purchased from the grid by the users and the price of the electricity that is sold to the grid.

4.3. Model Outputs

The model provides two types of outputs for each technology: the economic performance by computing the NPV and the IRR, and the environmental performance by estimating the PES.

4.3.1. Net Present Value and Internal Rate of Return

NPV and IRR are two metrics that allow evaluating the profitability of investment projects. The NPV is the sum of the present values of the annual incoming and outgoing cashflows—or benefits (B_n) and costs (C_n)—over the lifetime (L) of the evaluated project, as shown in

$$\mathrm{NPV} = -C_0 + \sum_{n=1}^{L} \frac{B_n - C_n}{(1+r)^n}, \tag{4}$$

where C_0 stands for the capital costs of the project and r represents the discount rate. For the purposes of this study, the discount rate r is assumed to be 10%: the International Energy Agency and several other authors have also accounted for discount rate values around 10% for small-scale cogeneration projects [63–65].

An alternative metric to assess the profitability of an investment is the IRR, which is defined as the discount rate that leads to an NPV of zero. The IRR calculation anticipates net cash outflows in the first years which are utterly counterbalanced by incoming returns, leading to net cash inflows in the last years of the project. That is, first costs and then benefits. For these types of profiles, IRRs can be found and explained. Nonetheless, if the stream flows diverge from the anticipated trend—e.g., by having discounted costs that surpass the benefits, or by yielding negative present values by the end of the lifetime—the IRR formula may not give any result for such stream flow or the found value may be negative. In such cases, the obtained value for the IRRs could be hard to interpret or meaningless [66].

The definition of costs and benefits in the NPV and IRR metrics is determined by the established reference scenario, which commonly delivers heat and electricity to the average user. In this study, the reference scenario is characterised by a boiler, which supplies heat with a 90% efficiency and the electricity grid, which provides the required electricity to the user. The CHP unit is assumed to be a new installation, i.e., there was no previous boiler or other equipment providing heat and/or electricity to the user. Therefore, the costs of the CHP projects are:

- The capital cost of the CHP unit, described in Table 3. Founded on the cost of the VUB mHAT, and taking into account the extra heat exchanger needed to deliver external heating (depicted in

Figure 3), the capital cost of the mHAT is assumed to be 10% greater than the capital cost of the T100 mGT.

- The installation costs of the CHP units. These include a variety of issues, such as the cost of the installation of the chimney, the cost of transporting the machine and the gas and electricity connection. Based on real cogeneration ICE machines currently operating in Brussels, these costs were estimated as € 80,000 for all the units—no significant variations are expected between ICE, mGT and mHAT on this matter [67].
- The capital cost of the boiler necessary to provide the peaks in heat demand. A boiler with the required power is approximated to amount to € 15,000 [68].
- Fuel costs of the CHP unit and the boiler.
- O&M costs as described in Table 3. mGTs have lower O&M costs per kWh_e than ICEs because of their fewer moving parts. Hence, they require a lower amount of lubricating oil, which is in addition not contaminated with combustion products. There is no information on the O&M costs of mHAT technology as it has not been yet commercialised. Therefore, we have estimated that, following the same trend as capital costs, O&M costs are 10% higher for mHAT compared to mGT: this increment is mainly related to the maintenance and cleaning of the water circuit.
- Water cleaning costs, only applicable to the mHAT unit. The price of surface water would only amount to a few €cents/m^3; however, adopting a conservative approach, we have assumed a value of € 2.35/m^3 (which corresponds to the ion exchange technology used to obtain de-mineralised water from tap water to feed boilers) [69].
- The purchased electricity in those moments when the electricity produced by the unit is below the user's demand.

On the other hand, the annual benefits (B_n) of the CHP unit consist of:

- The avoided natural gas cost associated with the consumption of the boiler in the reference scenario, which does not need to be installed because the CHP unit is in place.
- The avoided electricity cost for the electricity that is generated by the CHP unit and therefore does not need to be purchased from the grid.
- The sold electricity. The CHP units operate following heat demand; thus, there might be moments when the produced electricity exceeds the user's demand. This extra electricity is sold to the grid, hence becoming a benefit for the project.

Table 3. Capital and operation and maintenance costs for the mGT, mHAT and ICE.

Cost	mGT	mHAT	ICE
Cost of the CHP unit	€180,000	€198,000 [a]	€150,000 [70]
Installation costs [67]	€80,000	€80,000	€80,000
O&M costs	€0.015/kWh_e [71]	€0.0165/kWh_e [b]	€0.0225/kWh_e [70]

[a] Founded on the cost of the humidification unit of the mHAT at VUB.
[b] mHAT O&M costs are assumed to be 10% higher than for the mGT, following the same trend as capital costs.

4.3.2. Primary Energy Savings

The PES of a certain technology allow assessing its environmental performance with respect to a reference scenario. They are used in the European Union (EU) directives as a way of evaluating the efficiency of cogeneration units [72]. PES are computed according to

$$\mathrm{PES} = 1 - \frac{1}{\dfrac{\eta_{\mathrm{CHP,E}}}{\eta_{\mathrm{ref,E}}} + \dfrac{\eta_{\mathrm{CHP,Q}}}{\eta_{\mathrm{ref,Q}}}}, \tag{5}$$

where $\eta_{\mathrm{CHP,E}}$ is the electrical efficiency of the cogeneration unit, defined as the annual electricity generated by the engine divided by the annual fuel consumption. Similarly, $\eta_{\mathrm{CHP,Q}}$ stands for the heat efficiency of cogeneration. $\eta_{\mathrm{ref,E}}$ and $\eta_{\mathrm{ref,Q}}$ are the reference efficiencies for separate electricity and heat production, respectively. The EU outlines in [73] these values, which for the case of a unit constructed after 2016, fed with natural gas, and with a hot water heat recovery system, are set to 53% for the reference electricity production and 92% for the reference heat production.

The EU also points out two correction factors for the reference electrical efficiency value [73]. The first (τ) corresponds to the average climatic situation: it is based on the difference between the annual average temperature in a Member State and the standard atmospheric ISO conditions (15 °C). For every degree above 15 °C, $\eta_{\mathrm{ref,E}}$ is decreased by 0.1%, whereas, for every degree under 15 °C, a 0.1% efficiency gain is considered.

The second correction factor for the reference electrical efficiency is related to the avoided grid losses and depends on the proportion of electricity generated by the unit that is consumed on-site or sold to the grid. For a unit connected to the grid at a voltage level below 450 V that consumes a certain part of the electricity generated onsite (E_{onsite}) and feeds to the grid the rest of the electricity (E_{offsite}), the reference electrical efficiency would be

$$\eta_{\mathrm{ref,E}} = (53\,\% + \tau) \times (0.851 \times E_{\mathrm{onsite}} + 0.888 \times E_{\mathrm{offsite}}), \tag{6}$$

where both E_{onsite} and E_{offsite} are expressed as a percentage of the total generated electricity by the unit.

5. Results and Discussion

As a result of the maximum rectangle area sizing procedure and due to the distinctive heat demand profiles of the modelled users, the CHP working hours at full load in Spain are substantially lower compared to France or Belgium. While in the northern countries the summer is shorter (in April–May and September–October the heat demand is still significant); in Spain, from April until November the heat demand is minimal. Thus, the Spanish heat load curve has a strong inflection point (Figure 10) and the area of the sizing rectangle (which represents the kWh produced by the CHP units working at full load) is larger in Belgium and in France.

The required number of dwellings to reach the heat output of the small-scale cogeneration units is much larger in Spain (193 as opposed to 94 dwellings in Belgium for the mGT case, see Table 4). The electricity demand per dwelling is also higher in the southern country, especially during the summer due to air conditioning. The calculation of the number of dwellings is performed as an approximation to assess how the sizing methodology affects the users in different climates. District heating losses have not been taken into account in this estimate; however, their effect would be limited to perhaps a slight reduction of the number of dwellings that the CHP units provide to, not to the economic and policy analysis results.

In Spain and France, a great part of the electricity produced by the mHAT unit is consumed on-site, even requiring extra electricity to be purchased from the grid—especially in Spain during the summer. The contrary situation occurs in Belgium: mHAT electricity production is always greater than the user demand, resulting in most of the electricity being sold to the grid and no extra electricity needed to be purchased. This is obvious from Figure 11, which illustrates how the demand by each group of users relates to the electricity production from the mGT and mHAT units: ICE production is not depicted in order not to saturate the Figure, but it is very similar to the one of the mGT.

Table 4. Results of the sizing methodology: grouping of dwellings per country and working hours.

	No of Dwellings		Working Hours			
	mGT & mHAT	ICE	Full Power All Units	Part Load mGT	Part Load ICE	Wet mHAT
Belgium	94	80	4182	1604	1420	3753
France	115	99	3802	1714	1474	4113
Spain	193	165	2092	859	762	6246

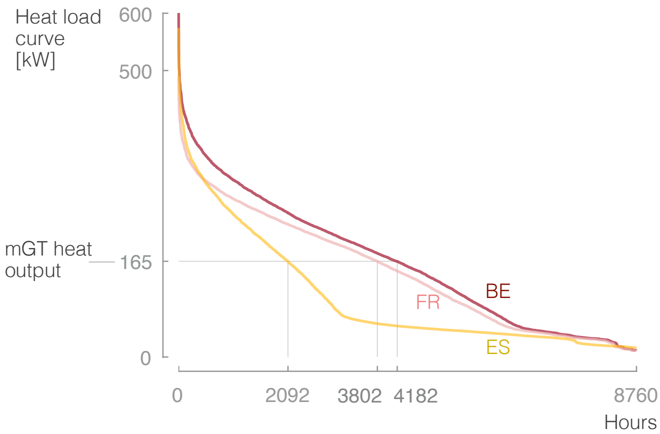

Figure 10. Heat load curves of mGT and mHAT in the three countries. Due to the sizing methodology, the number of working hours at full load in Spain are substantially lower than in Belgium or France.

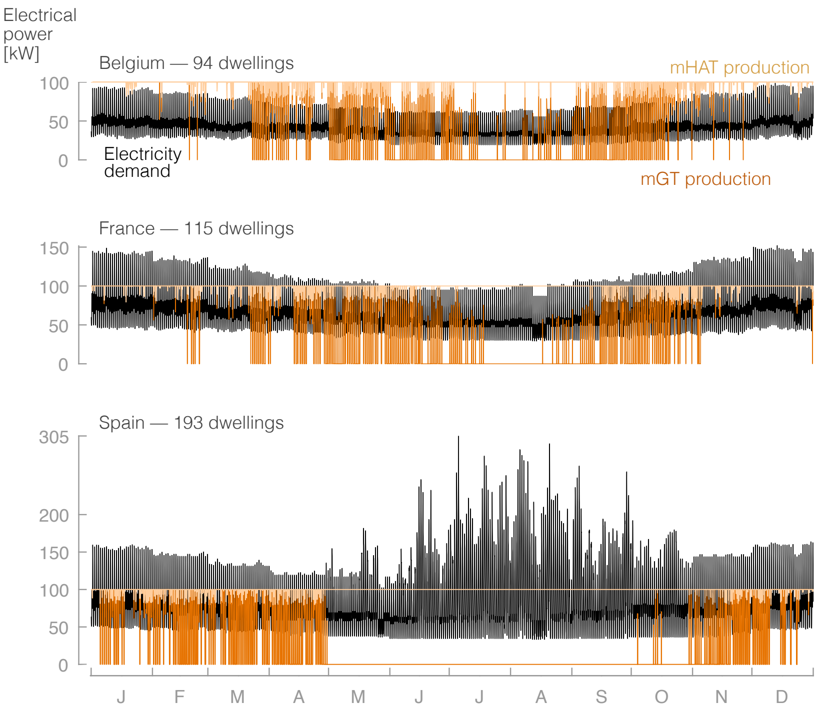

Figure 11. In Brussels, the units are capable of fulfilling the electricity needs of the user while they run. In France, there are moments when it is necessary to buy electricity from the grid. The Spanish electricity demand has peaks all year long above the production of the units.

5.1. Effect of Policies in the Current Situation

Considering the current policy system and up-to-date electricity and natural gas prices, none of the modelled scenarios reaches economical feasibility, i.e., their NPVs are negative—except for the case of mHAT in Brussels, see Figure 12. Nonetheless, all the technologies provide positive PES: the only exception being mHAT in Spain, whose PES are slightly negative (-1.3%). The worse performance of mHAT in the southern country is related to the reduced amount of CHP working hours at full load in this state. Water injection helps adding flexibility to the system by decoupling heat and electricity production in the mGT; however, if the heat demand is limited throughout the year, the time that the unit is running with the high energy efficiencies corresponding to CHP mode is restricted. Thus, the mHAT will run most of the year in wet operation mode with a maximum electrical efficiency of

33.8%—which is not high enough to 'compete' with the the reference electrical efficiency, eventually leading to negative PES.

In terms of IRR, the obtained results are meaningless for all the cases except for the reciprocating ICE and the simple mGT in Brussels. The former has an IRR of 14.3% and the latter 5.5%. These are also the two cases with the highest NPV, even if for the mGT it is still negative. Therefore, the NPV and the IRR results are consistent: the discount rate for the NPV calculation is 10% and the only technology reaching a positive NPV has an IRR of 14.3%. The mGT in Brussels reaches a meaningful IRR but below the assumed discount rate value for the NPV calculation. For the rest of the cases, no IRR is found because of their negative economic performance, with cashflow streams that are not as the IRR metric 'expects'.

The policies implemented in the five European regions fail in helping small-scale cogeneration technologies become feasible for domestic users, even if these units allow saving CO_2 emissions with respect to the reference scenario, as proven in Figure 12. The two exceptions are the reciprocating ICE in Brussels, which reaches a positive NPV and the mHAT unit in Spain, whose PES are slightly negative. The performance of the technologies depends on several factors (such as the heat and electricity demands and the specific market conditions of the country); thus, in order to fully comprehend the effect of the policies, we need to compare both the NPV including subsidies and without considering them. This information is shown in Figure 13.

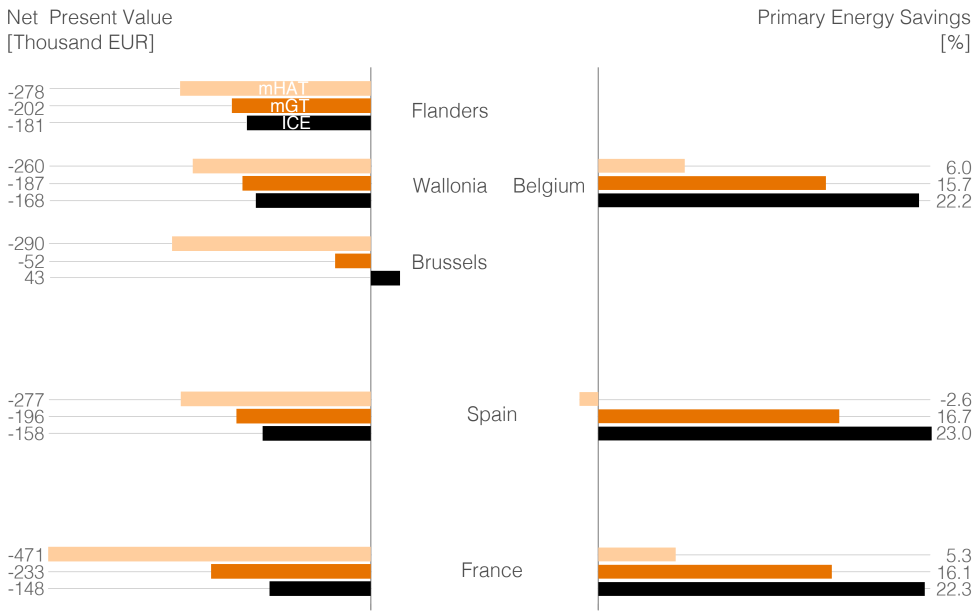

Figure 12. None of the technologies is feasible in any of the countries, despite the fact that (except mHAT in Spain) they all provide PES.

If the effect of policies is not taken into account, the economic performance of the three units in Belgium is rather similar, ranging from € −290,000 for mHAT and € −248,000 for ICE. The economic results in France are the worst for all technologies, with larger differences between them. In Spain, if subsidies are not considered, mHAT is the technology with the best economic performance. Again, this relates to the high electricity demand in this country (especially during the summer) which is fulfilled by the mHAT when working with water injection (thus allowing for substantial economic savings).

mHAT only receives subsidies in Wallonia and Flanders. Brussels imposes its own reference electrical efficiency values (55% as opposed to the EU reference which is 46.57% in this case, once the temperature and grid loss correction factors are taken into account). Thus, mHAT does not reach the minimum 5% required PES even if according to the EU reference its PES are 6.0%, see Figure 12. In Spain, only high efficiency cogeneration has access to subsidies (which for small scale units means positive PES), while it is the only country where this unit yields negative PES. In France, the minimum required PES are 10% and mHAT only reaches 5.3%. As a result, in Figure 13, the grey bar for mHAT totally overlaps the light orange one in these three regions.

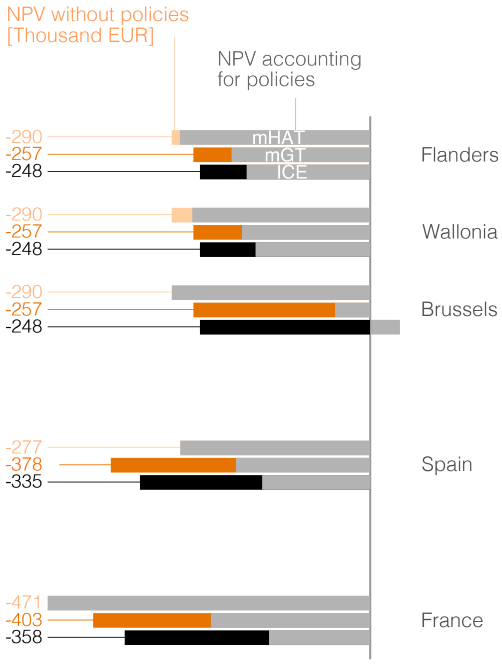

Figure 13. mHAT does not receive any subsidies in Brussels, Spain or France. The effect of policies is visible for the rest of the cases as the difference between the grey bars (representing the NPV with subsidies) and the coloured bars (NPV without subsidies).

Brussels is the only studied region with policies that allow one of the commercially available technologies (the reciprocating ICE) to reach economic feasibility. In Belgium, the three regions offer green certificates for small scale cogeneration, although—as previously explained—the conditions differ. Looking into the actual effect of the policies, Figure 14 displays the number of GC awarded to each technology in every Belgian region, as well as the final contribution of the subsidy. Brussels is the area where the most GC are allocated (for mGT and ICE) and where the price for these certificates is the highest. In turn, in Wallonia, the required CO_2 emissions saved to get a GC are more than twice than those in Brussels and collective housing buildings are not rewarded, resulting in a much lower number of assigned GC. Although in Flanders CHP units have access to more GC than in the Walloon region, the price is substantially lower (€ 31 as opposed to € 65 and € 90); thus, the final amount of the help is the lowest of all the studied cases. It is worth pointing out that, despite the limited effect of the subsidies in Wallonia and Flanders, they are the only studied regions where mHAT units would be entitled to any help.

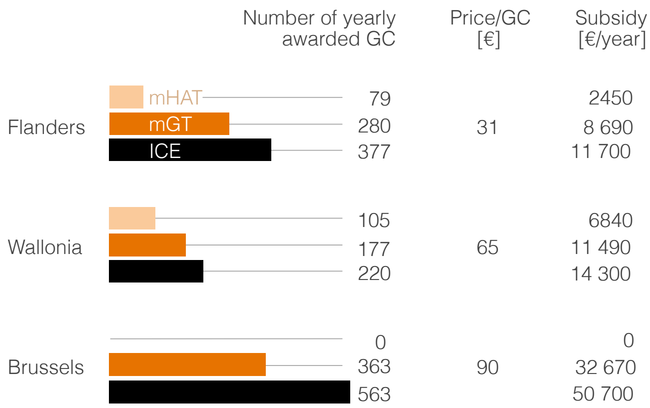

Figure 14. Brussels-capital is the region in Belgium giving the highest subsidies, although as it applies its own definition for PES, mHAT does not have access to GC.

In Spain, the contribution of the different remunerations is limited if we compare them to the fuel costs over the year, as shown in Figure 15. Surprisingly, the remuneration on investment is higher than the remuneration on operation. This is due to the latter being awarded based on the energy sold to the market, i.e. the auto-consumed electricity (which is very high for the Spanish dwelling) is not valued. This policy was probably drafted assuming that the CHP engines act as boiler replacement units—with all the produced electricity being sold to the grid—instead of as real cogeneration units, making use of both the generated electricity and the heat to fulfil the energy demand of the consumers. In fact, despite being called a remuneration on operation, this help resembles in practice a feed-in tariff. Thus, the value of the remuneration on operation matches the one of the O&M costs, but is in no way useful to face the high fuel costs of the studied units. Nonetheless, the model shows that if the operational helps were awarded based on the actual electricity produced (hence also valuing the electricity consumed on-site), the NPVs of mGT and ICE units would reach a better value but still be negative (€ −66 160 for the former and € −53 540 for the latter).

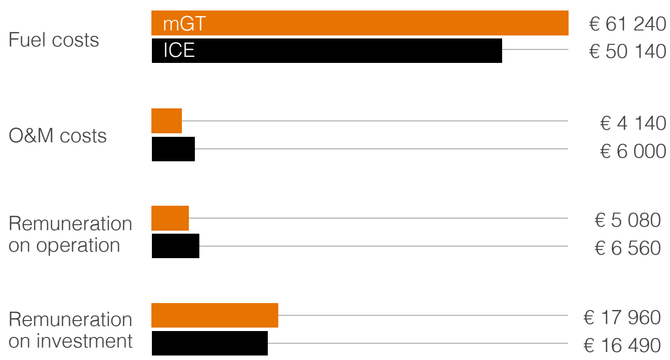

Figure 15. Effect of Spanish policies: the remuneration on operation amounts to a similar value to the O&M costs but it is still very far from the fuel costs.

Finally, the price of the feed-in tariffs that ICE and mGT units perceive in France is depicted in Figure 16. The help allows for substantially increasing the price of electricity sold to the grid during the winter months, although the price perceived in summer is lower than the wholesale market one. However, as already shown in Figure 11, the French user also consumes a great part of the electricity produced by the unit. Hence, the potential effect of the feed-in tariffs is restricted, as by definition they solely apply to the electricity sold in the market.

In the previous paragraphs, we have proved that CHP policies currently implemented in Belgium, France and Spain are not effective in their objective: enabling cogeneration technologies to become feasible, triggering investment to eventually make them self-sufficient. Thus, in the following subsection, we will investigate by how much this help needs to be increased so that feasibility is reached.

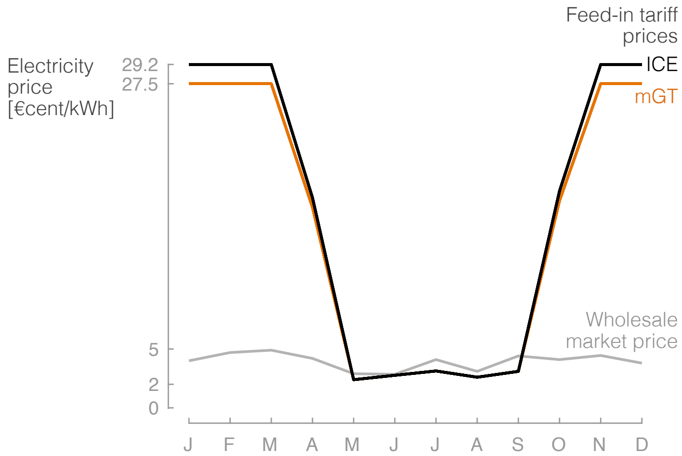

Figure 16. The feed-in tariff price during the winter is more than five times greater than the the wholesale electricity market price.

5.2. Optimisation of Current Implemented Policies

If the conditions are kept untouched in Brussels, in order for mGT to become economically feasible, the price per green certificate should increase from the current market price to €112.9. As mHAT does not reach the required 5% PES with the current Brussels references, it would never have access to subsidies. If, instead of increasing the price per green certificate, the references of the EU are adopted, mGT would already reach positive NPVs with a value of €150,330. In this case, mHAT would already have access to policies, but would not yet reach feasibility with the current GC price of €90: the price per certificate would need to increase to €148.6 for this to happen.

Since in Spain the PES for mHAT are negative, it is not worth studying how the policies would need to be modified to make this cycle profitable. It is interesting to simulate the conditions under which ICE and mGT would become feasible though. With the current awarding system, the remuneration on operation would need to be increased by a factor of 5.17 for mGTs and by 3.84 for ICEs so that these technologies can reach an NPV of zero. If the remuneration on operation would be assigned based on the produced electricity by the cogeneration unit (instead of the 'extra' electricity sold to the grid), the current values would still need to be multiplied by 1.37 for mGT and by 1.33 for ICE to reach feasibility.

According to the way in which feed-in tariffs are defined in France (see Equations (2) and (3)), they only make sense if PES are greater than 10%. Thus, the optimisation analysis to reach feasibility is again only performed for mGT and ICE cycles, as mHAT PES amounted to 6.7 % in this country. In order for mGT to be profitable, the Purchase Obligation (Equation (2)) would need to increase by 3.60, while for ICE it would need to augment by a factor of 2.35. This means that mGT would inject electricity to the market at a price of €0.644/kWh and ICE at €0.496/kWh.

As a final step, we have assumed that the minimum required PES are lowered in France to 5% and to 0 (i.e., as if only positive PES would be required). Equations (2) and (3) have also been accordingly modified. As shown in Figure 17, the projects do not reach feasibility in any case. In fact, the resulting NPVs are not substantially modified, except for the case of mHAT, where the change from not qualifying for helps (when the minimum required PES are 10%) to receiving subsidies (minimum PES 5%) can be clearly appreciated. Once again, this proves that the existing policy mechanisms—even if modified to more favourable conditions—are not enough for helping cogeneration units for domestic users.

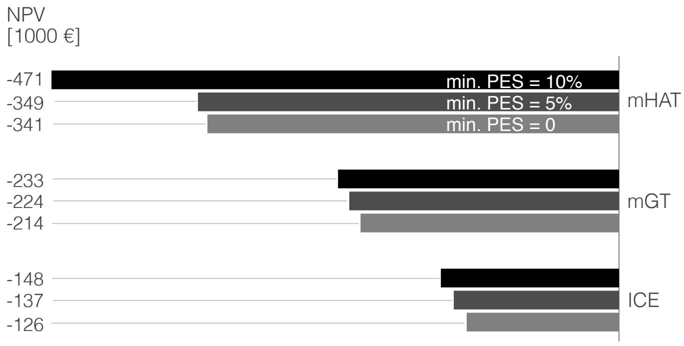

Figure 17. Even if the required minimum PES are lowered in France to 5 % or to 0, the NPVs of the units do not substantially improve.

6. Conclusions

In the current paper, the economic feasibility of mGT, mHAT and ICE technologies has been studied for the specific case of domestic users in three European countries: Belgium, France and Spain. To this end, the particular market conditions in each state have been taken into account as well as the cogeneration policies relevant in every region. The three countries have been chosen as the CHP subsidies that they offer range from feed-in tariffs and green certificates to operational and investment helps.

The results show that the studied policies fail in helping small-scale mGT, ICE and mHAT technologies become economically viable: except for the particular case of ICE in Brussels, the NPVs of all the units are all negative. However, the engines always provided positive PES, reaching values in the order of 24% for ICE, 17% for mGT and 7% for mHAT. The only exception if mHAT in Spain, whose PES are slightly negative (-2.6%) due to the high electricity demand of the user in this country.

mHAT only qualifies for subsidies in Wallonia and Flanders: for the rest of the regions, its PES are either not high enough (like in Brussels and France) or negative (like in Spain). This is related to the limited electrical efficiency of the units when water injection is taking place ($\sim$34%) if compared to the high overall cogeneration efficiencies of the units which only work in CHP mode. It is worth noting that, in the EU directives, small-scale CHP units are classified as high-efficiency if their PES are simply positive. The only country that respects this definition and awards subsidies according to this threshold is Spain.

In Belgium, the region where GCs have the most beneficial effect is in Brussels, in spite of applying a more restrictive definition of the reference electrical efficiency for the PES calculation. Wallonia requires four times more CO_2 savings to award the same number of GCs. In Flanders, the main limitation is the very low price for cogeneration GCs, resulting in the lowest subsidies to the technologies.

Spain is the only country providing helps related to the capital investment. However, the operational subsidies do not take into account the auto-consumed electricity (which is the highest in this country): they only apply to the energy sold to the grid. Hence, despite being called 'Remuneration on Operation', they are rather allocated as feed-in tariffs. This indicates that, in Spain, CHP technologies are treated as boiler replacement units, as the simultaneous generation and consumption of both electricity and heat are not rewarded.

Finally, in France, two feed-in tariffs are assigned to small-scale cogeneration. Again, such type of policies do not reward the auto-consumed electricity, which is non-negligible given the electricity demand of the user in this country. The minimum required PES to have access to subsidies are 10%, the highest prerequisite of all the studied regions. Furthermore, the complex formulation of the French policies could contribute to discouraging potential investors.

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Abbreviations

The following abbreviations are used in this manuscript:

Acronyms

CHP	Combined Heat and Power
EU	European Union
GC	Green Certificates
ICE	Internal Combustion Engine
IRR	Internal Rate of Return
ISO	International Organisation for Standardisation
mGT	micro Gas Turbine
mHAT	micro Humid Air Turbine
NPV	Net Present Value
O&M	Operation and Maintenance
PES	Primary Energy Savings
PO	Purchase Obligation
RC	Remuneration Complement
TIT	Turbine Inlet Temperature
VUB	Vrije Universiteit Brussel

Roman symbols

B_{n}	Beneit on year n	(€)
C_0	Capital cost	(€)
C_{n}	Cost in year n	(€)
E	Electricity produced by the cogeneration unit	(kWh)
E_{offsite}	Proportion of E fed to the grid	(%)
E_{onsite}	Proportion of E consumed onsite	(%)
F	Fuel consumed by the cogeneration unit	(kWh)
L	Lifetime	(years)
$\mathcal{P}_{\text{gas}}$	Price of natural gas	(€ /MWh$_{\text{e}}$)
Q	Heat produced by the cogeneration unit	(kWh)
r	Discount rate	(%)
R_{inv}	Remuneration on the investment	(€ /MWh$_{\text{e}}$)
R_{o}	Remuneration on operation	(€ /MWh$_{\text{e}}$)

Greek symbols

$\eta_{\text{CHP,E}}$	Electrical efficiency of cogeneration production	(%)
$\eta_{\text{CHP,Q}}$	Heat efficiency of cogeneration production	(%)
η_{E}	Electrical efficiency	(%)
η_{Q}	Heat production efficiency	(%)
$\eta_{\text{ref,E}}$	Reference electrical efficiency	(%)
$\eta_{\text{ref,Q}}$	Reference heat production efficiency	(%)
η_{total}	Total efficiency (electrical plus heat production)	(%)
τ	Temperature correction factor of $\eta_{\text{ref,E}}$	(%)

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