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High-Efficiency Cogeneration: A Viable Solution for the Decarbonization of Cities with District Heating Systems

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Abstract: In a global context marked by increasingly evident climate change and an urgent need to reduce carbon emissions, efficient and environmentally friendly energy solutions are no longer just an option, but a necessity. Decarbonizing cities is an essential process for combating climate change and creating a sustainable urban environment. This article provides an analysis of the decarbonization possibilities of the building heating sector in the case of cities with district heating systems. A case study referring to the district heating system of Suceava city, Romania, is provided. The results of this study show a significant reduction in carbon emissions per unit of thermal energy delivered (95.97%) from the district heating system after 2015 because of the change in technology and primary energy source (cogeneration and biomass). Also, a comparative analysis is provided: district heating vs. individual heating in terms of carbon dioxide (CO_2) emissions for the same amount of heat supplied to end consumers in 2023. The comparative analysis highlights a difference in CO_2 emission of 81.66% (0.220 kg CO_2/kWh for individual heating and 0.040 kg CO_2/kWh for district heating). The implications of high-efficiency cogeneration in the decarbonization of the building heating sector are analyzed and highlighted.

Keywords: high-efficiency cogeneration; district heating; decarbonization of cities; primary energy saving; sustainable development; energy efficiency; heating and cooling of buildings

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Academic Editors: Christian Inard and Antonio Rosato

Received: 16 February 2025
Revised: 9 March 2025
Accepted: 20 March 2025
Published: 21 March 2025

Citation: Atănăsoae, P.; Pentiuc, R.D.; Milici, L.D. High-Efficiency Cogeneration: A Viable Solution for the Decarbonization of Cities with District Heating Systems. *Energies* **2025**, *18*, 1581. https://doi.org/10.3390/en18071581

1. Introduction

Energy is the foundation of the progress of our civilization, being essential for the production and consumption of goods and services, from household appliances to transportation and industrial processes. The intensive use of fossil fuels to produce energy has a significant impact on the environment, generating polluting emissions at an alarming rate. Although these fuels have advantages such as high energy output and ease of production, their negative impact on the environment is becoming increasingly evident.

Globally, urban areas consume over 65% of the world's energy, generating over 70% of carbon dioxide (CO_2) emissions. Therefore, it is important for cities to act as ecosystems of experimentation and innovation to become climate neutral. Elavarasan et al. (2022) analyses effective decarbonization strategies in the context of the European climate-neutral vision [1] and Maya-Drysdale et al. (2020) investigates what strategic practices European cities currently use to promote decarbonization in energy planning [2]. Barriers and pathways to decarbonizing cities are identified in [3].

The European Union's objective of reaching net zero carbon dioxide emissions by 2050 will require significant changes to energy systems by limiting conversion processes that result in polluting emissions. Climate change and increasingly ambitious goals to reduce global CO_2 emissions are driving the transition from fossil fuels to renewable sources. Efforts are currently being made to promote green and sustainable energy production, with the goal of achieving carbon neutrality, recognizing that an energy transition is essential, despite our current dependence on traditional energy sources. Understanding and quantifying energy efficiency is essential for achieving sustainable practices. Through the meticulous measurement and analysis of various indicators, information can be obtained about the performance of systems, buildings and processes.

Decarbonizing the building heating sector must be included in any serious climate change mitigation effort [4]. Improving the energy performance of buildings is one of the pathways to decarbonize residential buildings and significantly reduce the cost of climate policy [5].

An overview of the current state of district heating and cooling systems in Europe, with information and suggestions on future trends, is presented in [6].

The economic performance of different heating strategies in decarbonizing the thermal sector through coordinated operation with the electrical system is analyzed in [7].

Hansen et al. (2019) compared the levelized cost of heating using district heating and individual heating solutions. The results highlighted district heating as one of the key technologies for achieving climate goals and reducing emissions [8]. Yoon et al. (2015) evaluated and compared the economic value that consumers assign to different types of convenience between individual heating and district heating. Strategies to promote the many external benefits of district heating systems should emphasize not necessarily their lower cost, but their convenience and safety [9].

Vilen et al. (2023) investigated the cost-effective heating of new housing at the city level from a systems perspective in different scenarios. The results indicate that the most efficient heating systems are district heating for apartment blocks and individual heating options for single-family homes with low heat requirements [10].

District heating networks are often presented as a sustainable heating solution, where heat is generated centrally and then distributed to different buildings and homes. A method for temporal and spatial modeling of heat demand for district heating system expansion is presented in [11]. Fallahnejad et al. (2024) evaluated the impact of heat demand and provided information on economic areas, expansion potential and the average costs of heat distribution in a district heating system [12]. The results confirm the need to expand district heating networks to maintain supply levels because of decreasing heat demand.

Jimenez-Navarro et al. (2020) examined the role of cogeneration plants integrated into district heating systems as one of the potential paths to a future decarbonized energy system [13]. Results show that the cogeneration plants increase the efficiency and reduce both the operating costs and the environmental impact of the energy system.

New concepts such as "energy demand management" and "smart district heating networks" are also starting to be used in district heating systems [14,15].

Many district heating systems in Eastern Europe are currently old and inefficient due to a lack of investment in recent decades, leading to an unreliable supply and loss of consumers [16,17]. The need to increase the energy efficiency of district heating systems is obvious. The directions in which research is focused can be summarized in the increasing flexibility and diversification of energy sources used in district heating systems [18–21].

The integration of renewable energy resources and heat storage in district heating systems is analyzed in [22,23].

Reducing the specific space heating demand in residential buildings, integrating renewable energy sources and using heat pumps in district heating networks are paths that must be applied simultaneously to decarbonize district heating systems [24–27].

Reducing carbon dioxide emissions and increasing the efficiency of heating systems are research directions with diverse approaches in some previous research works. For example, Liu et al. (2022) analyzed the carbon emissions and energy consumption of natural gas pipelines [28] and Wang et al. (2012) studied a new method for enhancing heat transfer to end users using nanofluids [29].

The integration of both technologies (cogeneration and heat pumps) in district heating systems results in a stronger synchronization of heat and electricity demand for continental climatic conditions [30–32]. The joint effect of cogeneration plants and heat storage in district heating systems on efficiency and operating cost is presented in [33]. The defining features of the five generations of district heating (1GDH-5GDH) that differentiate them from previous generations are presented in [34]. The latest generation of district heating (5GDH) facilitates the integration of low-temperature renewable heat sources, but also of a significant number of end users, both consumers and heat suppliers, called prosumers.

A synthesis of previous research studies shows that district heating and cogeneration offer promising prospects in the context of the energy transition and sustainability concerns in the decarbonization of cities. Traditionally, fossil fuels were the main source of heat generation for district heating systems. Currently, district heating systems are gaining ground by expanding the network and diversifying the sources for producing thermal energy and hot water. Solutions exist and differ from city to city, depending on the specifics and energy potential of each region.

While there are many previous papers focused on the topic of cogeneration, high-efficiency cogeneration is less addressed, and the two concepts can often be confused. High-efficiency cogeneration is a more efficient and sustainable variant of cogeneration, with strict energy efficiency requirements. The current methodology for defining high-efficiency cogeneration is relevant and beneficial for promoting efficient and sustainable technologies in district heating systems. However, there is room for improvement, especially in terms of flexibility, adaptability to local conditions, and the integration of new technologies and low-temperature energy sources.

The main objective of this study consists of identifying alternatives for decarbonizing the building heating sector and using biomass as an energy vector to mitigate climate change by replacing fossil fuels.

The implications of high-efficiency cogeneration in the decarbonization of the building heating sector represent the main novelty of the approach proposed in this study. In this sense, the analysis in this study was oriented towards the entire system of the generation, transmission, distribution, supply and use of heat for heating buildings.

The main contributions of this paper can be summarized as follows:

- Application of the proposed calculation methodology in the case of a district heating system with a biomass cogeneration plant;
- A comparative analysis of fulfilling the qualification criteria for energy production in high-efficiency cogeneration in three scenarios;
- A comparison of district heating vs. individual heating in terms of CO_2 emissions for the same amount of heat supplied to end users;
- Identifying solutions to increase energy efficiency and decarbonization for the Suceava district heating system compared to the current situation.

2. Materials and Methods

This section describes the model used to evaluate a district heating system with a cogeneration heat generation source from the point of view of achieving decarbonization targets and energy efficiency (high-efficiency cogeneration). The application of this methodology aims to identify alternatives for the decarbonizing of cities and using biomass as an energy vector to mitigate climate change by replacing fossil fuels.

The key variables tracked were carbon dioxide emissions and the amount of electricity generated in high-efficiency cogeneration. The results obtained were compared with the reference values established in the European directives presented below.

Figure 1 shows milestones in the chronology of European directives on combating climate change (energy efficiency, cogeneration and greenhouse gas emissions).

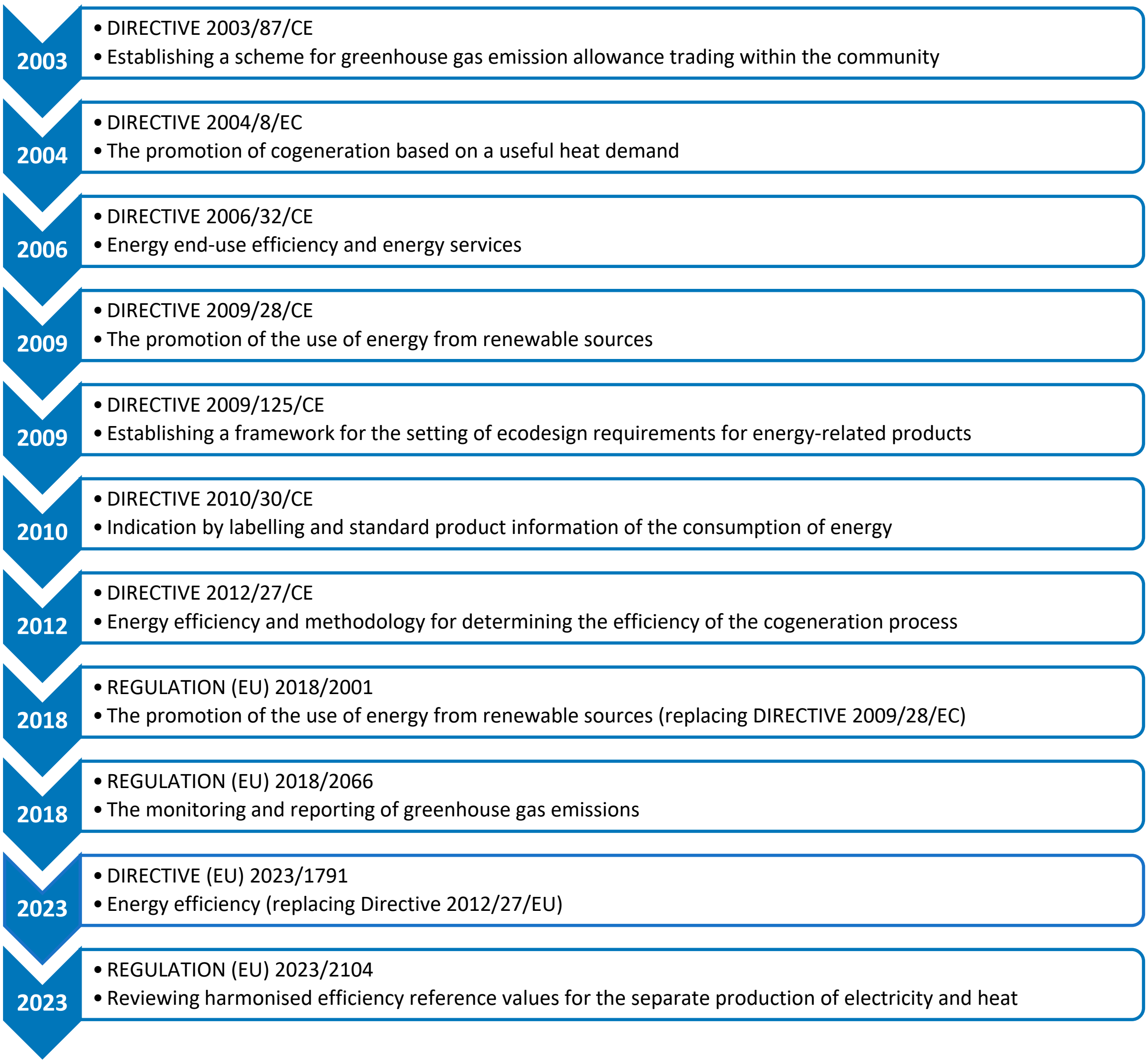

Figure 1. Milestones in the chronology of European directives on combating climate change (energy efficiency, cogeneration and greenhouse gas emissions).

The decarbonization targets for district heating systems set out in Directive (EU) 2023/1791 are presented in Figure 2 [35]. Thus, Directive (EU) 2023/1791 sets phased thresholds, applicable between 2027 and 2050, for the gradual increase in the share of renewable energy sources and the reduction in greenhouse gas emissions in district heating systems.

The efficiency of cogeneration is defined by the primary energy savings achieved by combined production compared to the separate production of electricity and heat. A primary energy savings of more than 10% justifies the use of the expression "high-efficiency cogeneration". Also, in the case of low-power and micro-cogeneration units, cogeneration production that ensures primary energy savings can be considered as high-efficiency cogeneration.

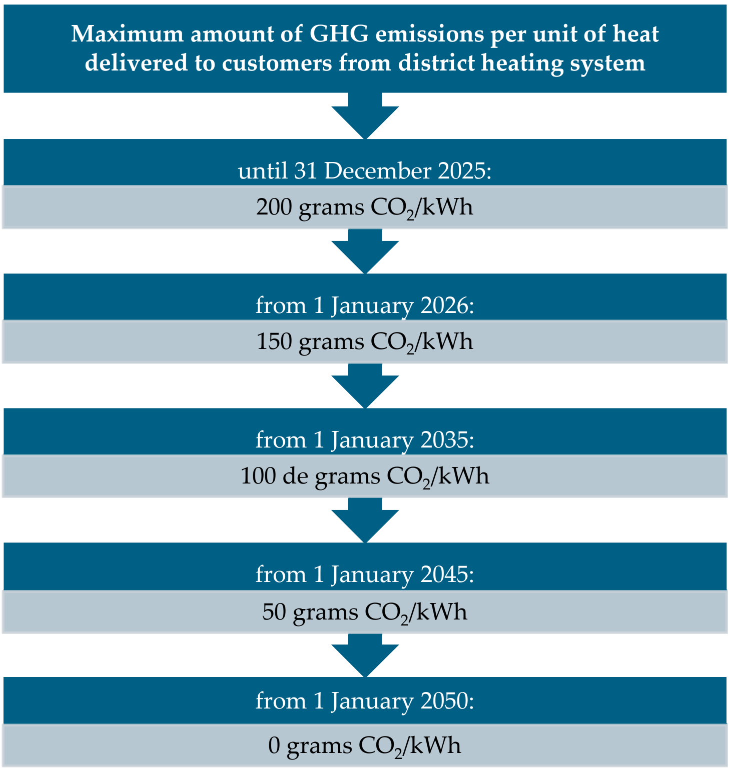

Figure 2. Criteria regarding the amount of greenhouse gas emissions generated by district heating systems [35].

Therefore, high-efficiency cogeneration means cogeneration that meets the criteria set out in Annex III of Directive (EU) 2023/1791 (updated Directive 2012/27/EU) on energy efficiency (Table 1).

Table 1. High-efficiency cogeneration—necessary criteria.

CHP Unit Power	Primary Energy Saving (PES)	Quality Factor (QF)	Total Efficiency ($\eta_{gl,CHP}$)
Pe $\leq$ 1 MWe	$\geq$0%	$\geq$1.00001	unrestricted
1 < Pe $\leq$ 25 MWe	$\geq$10%	$\geq$1.11112	unrestricted
Pe > 25 MWe	$\geq$10%	$\geq$1.11112	$\geq$70%

The mathematical model used to verify the criteria that define high-efficiency cogeneration is presented below.

The primary energy saving (*PES*) can be expressed in terms of the quality factor of the cogeneration unit (*QF*) [36]:

$$PES = \left(1 - \frac{1}{\frac{\eta_{e,CHP}}{p_{loss} \cdot \eta_{e,Ref}} + \frac{\eta_{h,CHP}}{\eta_{h,Ref}}}\right) \times 100 \ \ (\%) \tag{1}$$

Or

$$PES = \left(1 - \frac{1}{QF}\right) \cdot 100 \ (\%) \tag{2}$$

The quality factor considers alternative options for the separate production of electricity (*X*) and heat (*Y*):

$$QF = X \cdot \eta_{e,CHP} + Y \cdot \eta_{h,CHP} \tag{3}$$

where X is the coefficient that considers the alternative option for separate electricity generation:

$$X = \frac{1}{p_{loss} \cdot \eta_{e,Ref}} \quad (4)$$

and Y is the coefficient that considers the alternative option for separate heat generation:

$$Y = \frac{1}{\eta_{h,Ref}} \quad (5)$$

The meaning of the terms used in Equations (1)–(5) is as follows:

- $\eta_{e,Ref}$ is the efficiency reference value for the separate production of electricity (%);
- $\eta_{h,Ref}$ is the efficiency reference value for the separate production of heat (%);
- p_{loss} is the correction factor for avoided losses in the electrical networks (-);
- $\eta_{e,CHP}$ is the electrical efficiency in cogeneration (%);
- $\eta_{h,CHP}$ is the heat efficiency in cogeneration (%).

The efficiency reference values for the separate production of electricity and heat are differentiated by relevant factors according to Commission Delegated Regulation (EU) 2023/2104 (Tables 2 and 3): year of construction, type of fuel, type of heat supplied and technology used.

Table 2. Efficiency reference values for separate production of electricity (%) [37].

Energy Source	Year of Construction		
	Before 2016	2016–2023	From 2024
Hard coal	44.2	44.2	53.0
Lignite	41.8	44.2	53.0
Natural gas	52.5	53.0	53.0
Heavy fuel oil	44.2	44.2	53.0
Biomass	33.0	37.0	37.0

Table 3. Efficiency reference values for separate production of heat (%) [37].

Energy Source	Year of Construction					
	Before 2016		2016–2023		From 2024	
	Hot Water	Steam	Hot Water	Steam	Hot Water	Steam
Hard coal	88.0	83.0	88.0	83.0	92.0	87.0
Lignite	86.0	81.0	86.0	81.0	92.0	87.0
Natural gas	90.0	85.0	92.0	87.0	92.0	87.0
Heavy fuel oil	89.0	84.0	85.0	80.0	92.0	87.0
Biomass	86.0	81.0	86.0	81.0	86.0	81.0

In the case of using several types of fuel in the cogeneration plant, the reference efficiency values for the separate production of electricity are weighted as follows:

$$\eta_{e,Ref} = \sum_{j=1}^{m} \left(b_j \cdot \eta_{e,Ref,j} \right) \quad (6)$$

If the useful heat is delivered in different forms of thermal agent (direct use of exhaust gases/steam/hot water) and several types of fuel are used in the cogeneration plant, the reference efficiency value for separate heat production is weighted as follows:

$$\eta_{h,Ref,j} = \sum_{k=1}^{p} \left(q_k \cdot \eta_{h,Ref,k} \right) \tag{7}$$

$$\eta_{h,Ref} = \frac{\sum_{j=1}^{m} \left(Q_j \cdot \eta_{h,Ref,j} \right)}{\sum_{j=1}^{m} Q_j} \tag{8}$$

The meaning of the terms used in Equations (6)–(8) is as follows:

- b_j is the share of fuel consumption of type *j* in total fuel consumption (-);
- $\eta_{e,Ref,j}$ is the efficiency reference value for the separate production of electricity when operating on fuel *j* (%);
- q_k is the share of the delivered heat agent (direct use of exhaust gases/steam/hot water) (-);
- $\eta_{h,Ref,k(j)}$ is the efficiency reference value for the separate production of heat related to the thermal agent used (exhaust gases/steam/hot water) and the fuel type *j* (%);
- Q_j is the energy consumed from fuel type *j* (MWh).

For cases where the cogeneration unit does not operate in full cogeneration mode under normal conditions of use, it is necessary to identify the electricity and heat that are not produced in cogeneration mode and distinguish them from the cogeneration production (Figure 3).

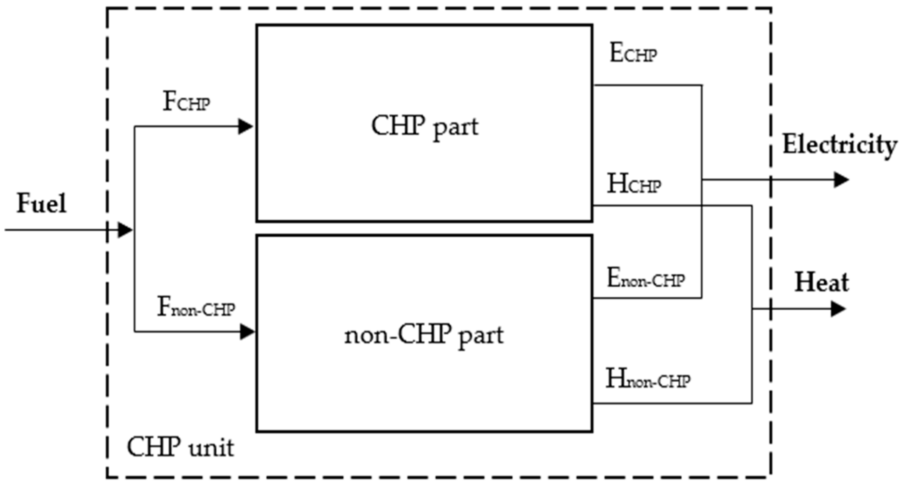

Figure 3. Separation of quantities of energy generated in cogeneration and non-cogeneration regimes.

Non-CHP electricity means electricity generated by a cogeneration unit in a reporting period, where one of the following situations occurs: the related thermal energy is generated by the cogeneration process or part of the thermal energy generated cannot be considered useful thermal energy (e.g., heat given off to the cooling tower).

Heat demand is the decisive aspect in justifying the efficiency of the cogeneration solution and is the basic element for qualifying electricity in high-efficiency cogeneration. If the quality factor determined by Equation (3) is lower than the minimum value, the amount of electricity that can be considered as being produced in high-efficiency cogeneration is recalculated.

For this purpose, the efficiency values for the combined production of electricity and heat are recalculated to achieve the minimum quality factor (QF_{min}):

$$\eta_{h,HEC} = \frac{QF_{min} - X \cdot \eta_{e,CHP}}{Y} \tag{9}$$

$$\eta_{e,HEC} = \eta_{e,CHP} \tag{10}$$

The power-to-heat equivalent ratio C_{ech} is calculated by the equation:

$$C_{ech} = \frac{\eta_{e,HEC}}{\eta_{h,HEC}} \tag{11}$$

The electricity generated in cogeneration mode (E_{CHP}):

$$E_{CHP} = H_{supplied} \cdot C_{ech} \tag{12}$$

The assessment of the potential for high-efficiency cogeneration is carried out in several stages, starting with an understanding of the infrastructure and operating requirements of the cogeneration system.

To compare the energy consumption for heating buildings, the specific heating consumption was used, calculated as follows:

$$C_{SH} = \frac{H_{supplied}}{S_{heated}} \left(\frac{\mathrm{kWh}}{m^2 \cdot year}\right) \tag{13}$$

where

$H_{supplied}$ is the useful heat supplied to consumers (kWh/year);

S_{heated} is the useful heated surface of buildings (m^2).

Biomass from forestry and related wood-based industries may be considered CO_2-neutral if it complies with the sustainability criteria set out in Article 29 (6) and (7) of Directive (EU) 2018/2001 [38]. Figure 4 shows the decision tree for applying the sustainability and greenhouse gas (GHG) reduction criteria to biomass [39].

The conversion factors used to determine the equivalent CO_2 emissions in this paper are presented in Table 4 [40].

Table 4. Conversion factors used to determine CO_2-equivalent emissions [40].

Fuel Type	Emission Factor (t CO_2/TJ)	Net Calorific Value (TJ/Gg)	Emission Factor (kg CO_2/kWh)
Lignite	101.0	11.9	0.364
Hard coal	94.6	28.2	0.341
Heavy fuel oil	73.3	42.3	0.264
Natural gas	56.1	48.0	0.202
Wood/wood waste	0	15.6	0
Other primary solid biomass	0	11.6	0

Biomass represents an appropriate ecological alternative to fossil fuels if it is exploited in a sustainable manner. Biomass is currently considered a renewable resource that has two major advantages: it stores solar energy through biological processes and transfers carbon dioxide from the atmosphere to the biosphere, so, by definition, energy production from biomass is a neutral process in terms of CO_2 emissions. However, biomass combustion can only be considered neutral in terms of emissions or with a very low conversion factor if it is certified by guarantees of origin that attest to the source of origin with reference to sustainable and long-term exploitation. As a result, local biomass resources can be used more energy efficiently in cogeneration applications. The problems caused by polluting gases resulting from incomplete combustion in small and inefficient plants are thus avoided.

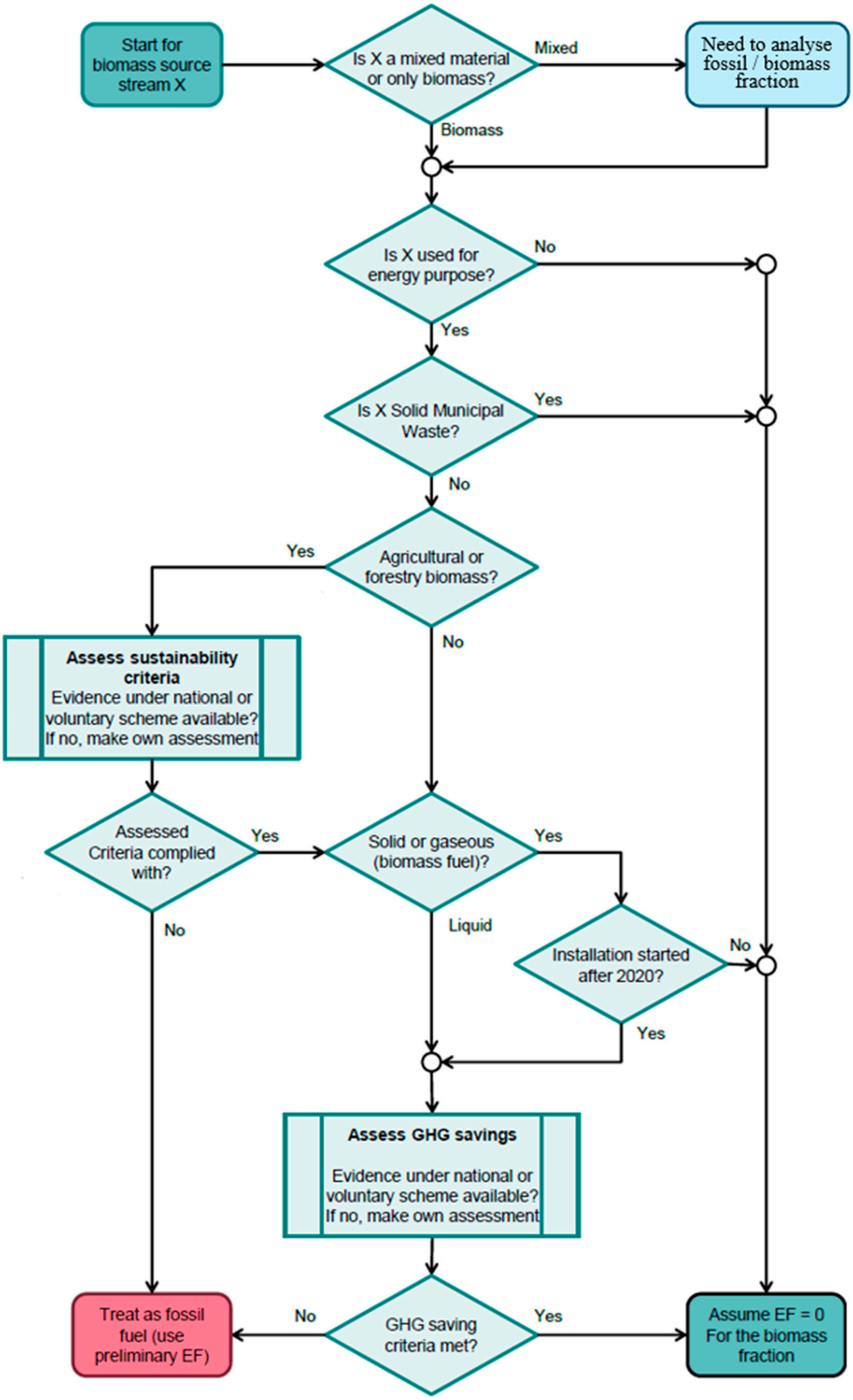

Figure 4. Decision tree for applying sustainability criteria and establishing emission factor (EF) for biomass [39].

Table 5 presents the conversion factors of equivalent CO_2 emissions depending on the type of biomass and the degree of fulfillment of the sustainability criteria, provided for in Romanian legislation [41].

Table 5. Conversion factors used to determine CO_2-equivalent emissions for biomass [41].

Fuel Type	Emission Factor (kg CO_2/kWh)
Firewood (without biomass certification/unsustainable source)	0.390
Biomass—firewood	0.019
Biomass—wood waste, sawdust	0.016
Biomass—briquettes/pellets	0.039
Biomass—agricultural waste	0.016
Biogas (from certified biomass)	0.000

In Romania, the origin of biomass is confirmed by environmental protection authorities. The ISO 38200 standard [42] helps buyers track biomass batches from different sources, thus helping to avoid the introduction of wood from illegal sources into the supply chain.

Carbon dioxide emissions in this study were calculated using the appropriate conversion factors (Tables 4 and 5) with the following equation:

$$E_{CO2} = \sum_{j=1}^{n} \left(E_{p,j} \cdot f_{CO2,j}\right) \tag{14}$$

where

- $E_{p,j}$ is the consumption of primary energy (fuel) of type j (kWh/year);
- $f_{CO2,j}$ is the conversion factor into CO_2-equivalent emissions for primary energy type j (kgCO_2/kWh).

3. Case Study: District Heating System of Suceava City, Romania

This section reports operating data about the cogeneration plant and district heating system serving of Suceava city, as well as historical data about the heat generation sources.

Suceava is a city in northeastern Romania. The district heating system of Suceava city was developed in stages starting in 1965 as the city expanded.

The sources of thermal energy production for the Suceava district heating system, depending on the primary energy source and operating period, are as follows:

- 1964–2015 hydrocarbon thermal plant (withdrawn from operation):
    - 2 industrial steam boilers of 105 t/h (17 bar; 250 °C);
    - 3 hot water boilers of 58.15 MW;
    - 2 hot water boilers of 116.30 MW;
    - 1 peak boiler of 17.45 MW.
- 1987–2013 coal-fired combined heat and power plant (CHP) 2 × 50 MWe (withdrawn from operation):
    - 2 steam boilers of 420 t/h (137 bar; 540 °C) operating on lignite (1987–2000) followed by conversion to hard coal (2000–2013);
    - 2 power units of 50 MWe (condensing steam turbines and sockets type DSL-50-1);
    - 2 basic boilers 2 × 98.86 MW;
    - 3 peak boilers 3 × 46.52 MW.
- 2015–present BIOENERGY cogeneration plant (in operation):

- Steam turbine cogeneration unit (29.65 MWe; 71.43 MWt) running on biomass;
- 1 hot water boiler operating on biomass 15 MWt;
- 3 hot water boilers operating on natural gas 3 × 14.7 MWt.

3.1. A Brief Presentation of the District Heating System and the Cogeneration Plant

The district heating system includes all activities regarding the production, transport, distribution and use of thermal energy to provide the thermal energy necessary for heating and preparing hot water for consumption.

The district heating system of Suceava city includes the following:

- Thermal energy generating plant (Figure 5).
- Transport networks, with a length of approximately 55 km, of which approximately 72% of the route is underground, and the rest is above ground. The transport networks are made of steel pipes with diameters between Dn 800 and Dn 50, insulated with mineral wool mattresses protected with galvanized sheet metal.
- A total of 59 district heating substations with plate heat exchangers for both heating and domestic hot water. All district heating substations are metered.
- The distribution networks, with a length of 455 km, with diameters ranging from DN 15 to DN 300, are laid in thermal channels. Their thermal insulation is made of mineral wool, protected with polyethylene foil or asphalt cardboard, or polyurethane foam insulation.
- End-users: apartments, public institutions and economic agents.

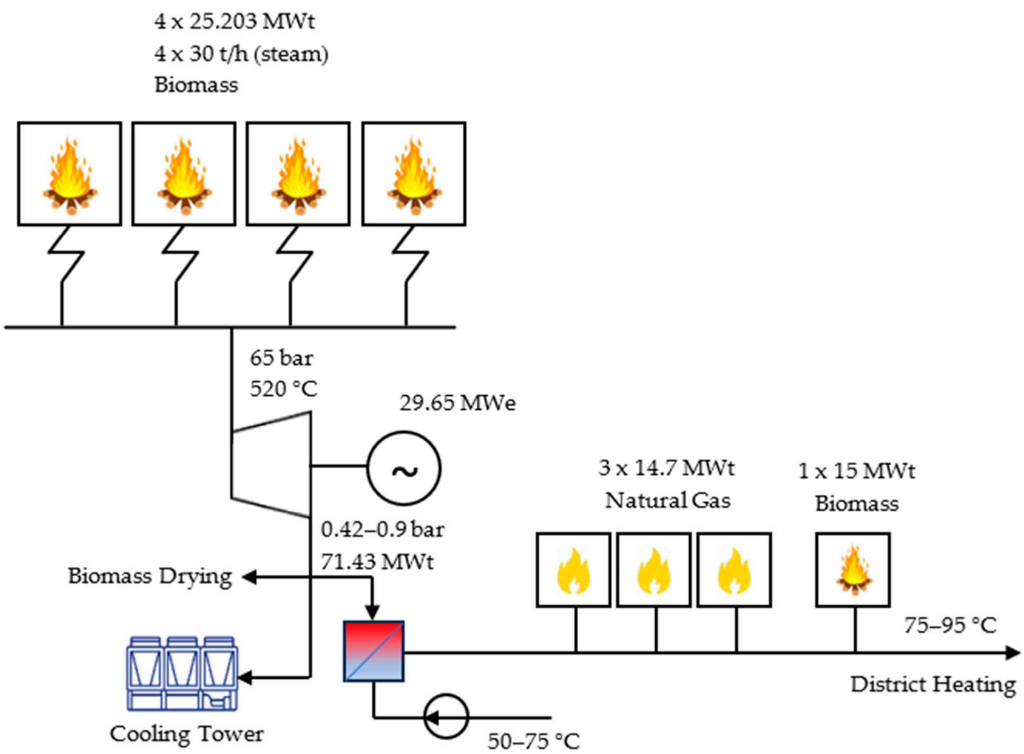

Figure 5. Schematic diagram of the cogeneration plant.

The heat transport and distribution system were developed in stages, starting in 1965, so currently, a large part of the component elements are almost 60 years old. During the period 2007–2015, 16 district heating substations out of a total of 59 were rehabilitated/modernized and some of the district heating pipes were replaced with pre-insulated pipes.

The schematic diagram of the cogeneration plant is shown in Figure 5. The hot water boilers were sized to ensure peak thermal load and also to enable use during periods of unavailability of the cogeneration unit.

The district heating system of Suceava city is considered a large-sized system with over 10,000 consumers. In 2023, the total number of consumers was 15,459: 15,021 apartments (97.17%); 37 public institutions (0.27%); and 401 economic agents (2.59%). The total percentage of disconnections in the period 2000–2006 was about 22%, with peaks recorded in the years 2001–2003, and starting with the years 2005–2006, disconnections decreased by about 80% compared to 2003. This indicates the trust of an important segment of the population in the district heating system.

3.2. Production Data and Heating Energy Needs of Suceava City

The production data for the district heating system of Suceava city in the period 2019–2023 are presented in Table 6 [43].

Table 6. Production data for district heating system of Suceava city.

Energy Flow	U.M.	2019	2020	2021	2022	2023
Electrical energy generated	MWh	108,932	126,140	222,245	218,612	126,678
Thermal energy generated	MWh	230,360	253,798	284,501	265,963	205,023
Biomass consumption	MWh	549,965	592,680	950,335	1,051,639	635,576
Natural gas consumption	MWh	656.28	0	0	0	0
Thermal energy delivered	MWh	188,913	179,004	194,515	174,269	167,391
Thermal energy sold to final consumers	MWh	112,397	101,407	99,330	98,352	94,726

Figure 6 shows the evolution of thermal energy sold to consumers in Suceava city connected to the district heating system during the period 2010–2023 [44].

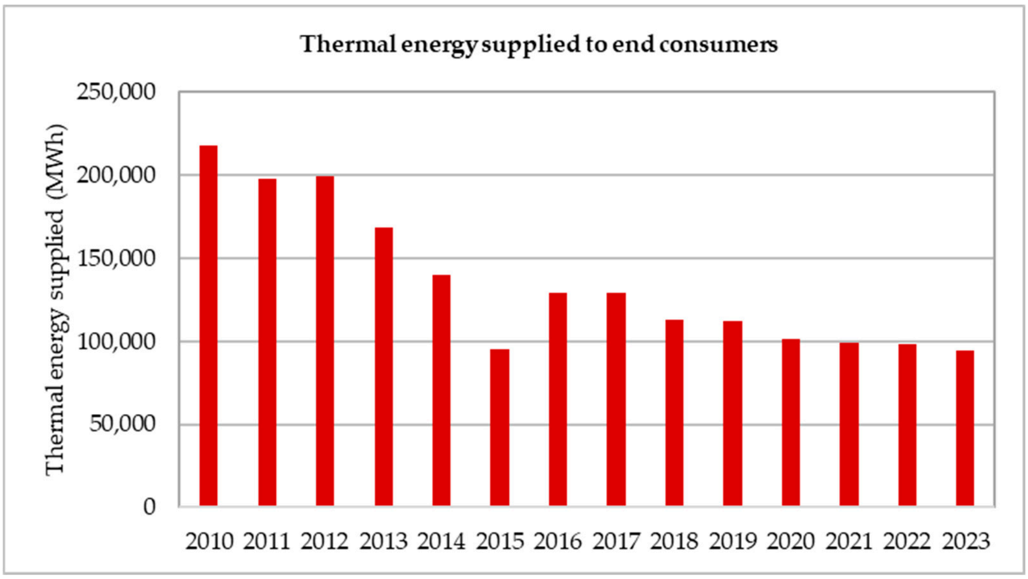

Figure 6. Thermal energy supplied to end consumers.

In recent years, biomass has been the main fuel for the district heating system of Suceava city due to the availability of this primary energy resource in the area. Biomass burns in the boilers of the cogeneration plant without combustion support and comes from the primary industrialization of wood (chips, bark and sawdust) and from the collection of residues left after forest cleaning (branches, tree bark, logs etc.).

The disconnection of some consumers from the district heating system but also some partial works to increase the energy performance of buildings at end consumption were the main causes of this trend of reducing the annual quantity of thermal energy sold to end consumers.

Difficulties in supplying biomass to the cogeneration plant in 2015 were the cause of the deviation from the general trend of reducing the quantity of thermal energy supplied.

4. Results and Discussion

The district heating system of Suceava city was developed in stages starting in 1964 because of the development and expansion of the city through the construction of new residential and non-residential buildings. During this period, heat for the district heating system was provided from different technologies and primary energy sources which are presented in Section 3: coal, fuel oil, natural gas and biomass.

Table 7 presents the comparative results of the calculation regarding the fulfillment of the qualification criteria for energy production in high-efficiency cogeneration in three scenarios, using Equations (1)–(8):

- Scenario 1: Nominal technical data for the cogeneration unit;
- Scenario 2: Operating data achieved in 2023 (excluding the heat lost to the cooling tower);
- Scenario 3: Operating data obtained in 2023 (including the heat given off to the cooling tower as heat potential available for connecting new consumers).

Table 7. Qualification of electricity production in high-efficiency cogeneration.

Energy Flow	U.M.	Scenario 1	Scenario 2	Scenario 3
Power, *P*	MWe	29.65	15.92	15.92
Heat, *H*	MWt	71.43	20.27	42.56
Fuel, *F*	MW	126.17	73.48	73.48
Reference electricity efficiency, $\eta_{e,Ref}$	%	33.00	33.00	33.00
Reference heat efficiency, $\eta_{h,Ref}$	%	86.00	86.00	86.00
Correction factor for avoided losses, p_{loss}	-	0.918	0.918	0.918
Alternative option for separate electricity generation, *X*	-	0.0330	0.0330	0.0330
Alternative option for separate heat generation, *Y*	-	0.0116	0.0116	0.0116
Electric efficiency in cogeneration, $\eta_{e,CHP}$	%	23.50	19.93	21.66
Heat efficiency in cogeneration, $\eta_{h,CHP}$	%	56.61	32.26	57.93
Total efficiency in cogeneration, $\eta_{gl,CHP}$	%	80.11	52.19	79.59
Quality factor of cogeneration unit, *QF*	-	1.434	1.033	1.389
Primary energy saving, *PES*	%	30.26	3.19	27.99

The results of this study show that in the current scenario (Scenario 2) the qualification criteria for electricity production in high-efficiency cogeneration are not met:

- Primary energy saving: $PES = 3.19\% < 10\%$;
- Total efficiency: $\eta_{gl,CHP} = 52.19\% < 70\%$.

The cogeneration unit operated at partial loads depending on the heat demand in the district heating system but also depending on the electricity demand in the liberalized energy markets: Centralized Market for Electricity Bilateral Contracts (CMBC); Day-Ahead Market (DAM); and Balancing Market (BM). Participation in liberalized energy markets requires adapting the operation of the cogeneration plant according to the revenue potentials of the different markets.

The load on the electrical side of the cogeneration group in 2023 was 54% of the nominal load. The heat lost at the cooling tower significantly influences the qualification of the electricity production in high-efficiency cogeneration. Scenario 3 highlights this aspect compared to Scenario 2:

- Primary energy saving: $PES = 27.99\% > 10\%$;
- Total efficiency: $\eta_{gl,CHP} = 79.59\% > 70\%$.

In scenario 2 (operating data achieved in 2023), because $QF < QF_{min}$, using Equations (9)–(12), the quantity of electricity generated in cogeneration was calculated to identify the high-efficiency cogeneration mode.

Table 8 shows the separation of the quantities of energy produced in cogeneration and non-cogeneration regimes, highlighting the quantity of electricity generated in high-efficiency cogeneration.

Table 8. The separation of the quantities of energy generated in cogeneration and non-cogeneration regimes.

Energy Flow	U.M.	2023
Electricity generated in cogeneration mode, E_{CHP}	MWh	102,610.94
Electricity generated in non-cogeneration mode, $E_{non\text{-}CHP}$	MWh	24,067.06
Heat generated in cogeneration mode, H_{CHP}	MWh	161,295.35
Heat generated in non-cogeneration mode, $H_{non\text{-}CHP}$	MWh	43,727.60
Heat lost to the cooling tower, $H_{cooling\ tower}$	MWh	177,424.88
Fuel consumed in cogeneration mode, F_{CHP}	MWh	584,729.48
Fuel consumed in non-cogeneration mode, $F_{non\text{-}CHP}$	MWh	50,846.04

The results obtained show that the electricity generated in high-efficiency cogeneration was 81% of the total electricity generated in 2023. Therefore, considering that the cogeneration unit operated at 54% of its nominal capacity (but even in this case not all the electricity was generated by high-efficiency cogeneration (only 81%)), there is a significant potential for the useful heat available for connecting new consumers to the district heating system.

Carbon dioxide emissions were calculated using Equation (14) in different operating scenarios depending on the heating sources used, with the results obtained being highlighted in Figures 7 and 8. Figure 7 shows the comparative specific CO_2 emissions ($kgCO_2/kWh$) for thermal energy supplied to consumers connected to the district heating system, calculated as average values for the respective periods depending on the mix of primary energy sources used. In the first stage of the analysis (2010–2014), the disconnection of some consumers from the district heating system and the switch to individual gas heating sources had a significant impact in terms of reducing greenhouse gas emissions compared to providing heat from the district heating system using coal and fuel oil as primary energy sources. Currently, the solution of individual gas heating is no longer a viable solution in terms of gas emissions in cities with high population densities. In the case of Suceava city, a significant reduction in carbon dioxide emissions per unit of energy supplied (95.97%) occurred after 2015 because of the change in technology and primary energy source (high-efficiency cogeneration and biomass). Thus, the coal-fired combined heat and power plant was withdrawn from operation and replaced with a cogeneration plant operating on biomass and natural gas (Figure 5). The thermal energy generation technologies for the Suceava district heating system, depending on the primary energy source and operating period, were presented at the beginning of this section.

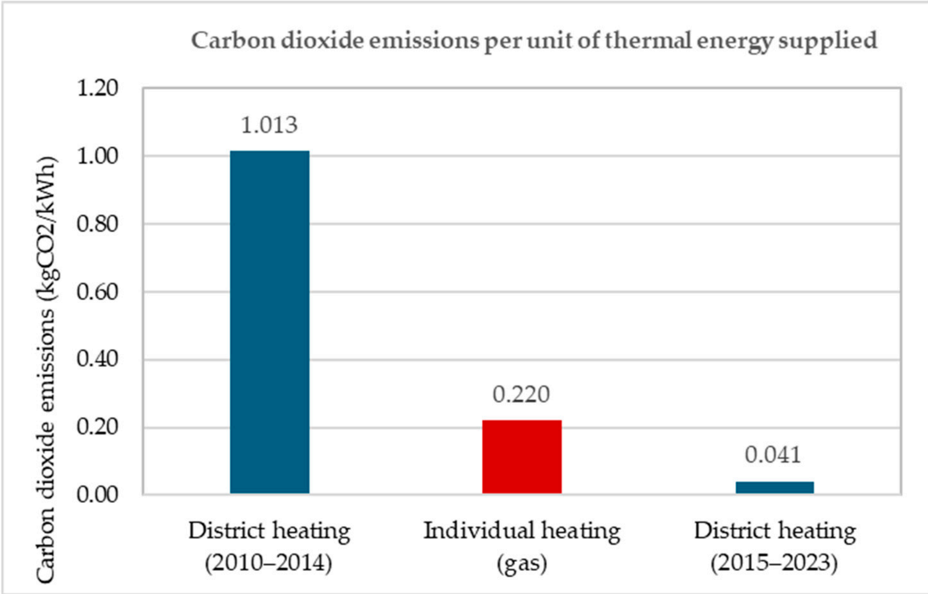

Figure 7. Carbon dioxide emissions per unit of thermal energy supplied.

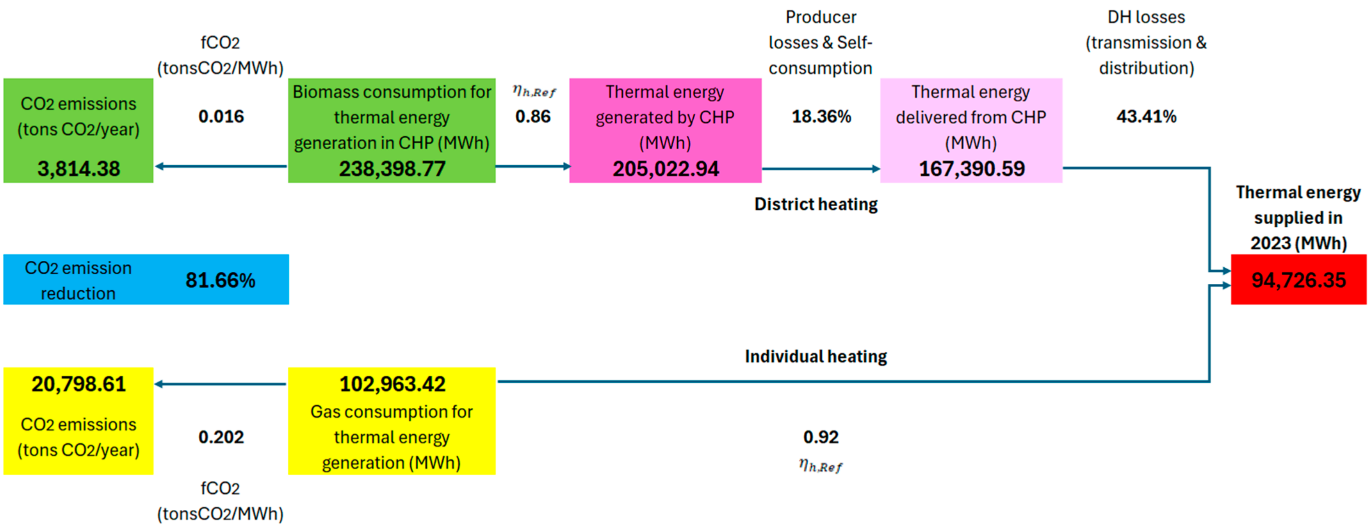

Figure 8. Comparison of district heating vs. individual heating in terms of CO_2 emissions for the same amount of heat supplied to end consumers in 2023.

Figure 8 shows the comparison of district heating vs. individual heating in terms of CO_2 emissions for the same amount of heat supplied to end consumers in 2023.

The following calculation assumptions were considered:

I. District heating

Calculation assumptions:

- Amount of heat supplied to final consumers in 2023 from the district heating system: 94,726 MWh;
- All losses from the source to the final consumers were considered: losses on the transmission and distribution networks (43.41%), losses at the producer and self-consumption (18.36%) levels;
- The allocation of fuel consumption (biomass) for heat generation in cogeneration was made according to the "Alternative heat generation method" [45] with a reference efficiency $\eta_{h,Ref}$ = 86%.

Result:

- Carbon dioxide emissions: 3814.38 tons CO_2.

II. Individual heating

Calculation assumptions:

- The same amount of heat supplied to final consumers in 2023 from the district heating system if it had been generated in individual gas heating sources: 94,726 MWh;
- Individual heating source: gas boiler with a reference efficiency $\eta_{h,Ref}$ = 92%.
- Result:
- Carbon dioxide emissions: 20,798.61 tons CO_2.

The comparative analysis highlights a reduction in carbon dioxide emissions of 81.66%.

What possibilities/opportunities for increasing energy efficiency and decarbonization are there for the Suceava district heating system compared to the current situation?

A. Heat use area at the level of end consumers:

- Energy renovation/rehabilitation of apartment buildings. There is a potential to increase the energy efficiency of buildings by reducing specific heating consumption below 100 kWh/m^2·year. For comparison, the specific heating consumption in 2023 was 180 kWh/m^2·year (calculated using Equation (13)).
- Attracting new customers. Connecting apartments/public institutions/economic agents located in the DH area:
  - number of apartments connected to DH in 2023: 15,021 (44.70%);
  - total number of apartments that could be connected to DH: 33,604.
- Connection of new buildings located in the DH area:
  - meeting NZEB (Nearly Zero Energy Building) requirements for new buildings.
- Heat metering at apartment level (installing smart equipment that optimizes energy flows based on real demand).

B. Heat transport and distribution area:

- Reducing losses in heat transport and distribution networks by replacing classic thermal pipes with pre-insulated pipes (losses in heat transport and distribution networks in 2023 were 43.41%);
- Rehabilitation of recirculation pipes for hot water consumption (ensuring optimal supply parameters);
- Refurbishment, automation and remote monitoring of district heating substations;
- Real-time monitoring of heating networks to quickly detect faults or heat loss.

C. Heat generation area:

- Follow-up in operation of the efficiency of heat generation in cogeneration (fulfillment of the criteria for high-efficiency cogeneration);
- Diversification of production sources/modular sizing/use of renewable energy sources (other than biomass);
- Integration of modern technologies for the efficient utilization of primary energy sources with thermal potential at medium and low temperatures (cogeneration with ORC technology and heat pumps);
- Using heat storage to increase the flexibility of the district heating system.

The results obtained in this study show that the decarbonization targets for the district heating system of Suceava city set out in Directive (EU) 2023/1791 (Figure 2) have been met. Greenhouse gas emissions per unit of heat delivered to customers from the district heating system of Suceava city were 0.040 kg CO_2/kWh. If the biomass did not have guarantees of origin, the greenhouse gas emissions criterion would not have been met. On the other hand, from an energy efficiency point of view, the criteria for "high-efficiency cogeneration" are not met. Therefore, solutions for rehabilitation and increasing energy efficiency are necessary.

The current district heating system of Suceava city has the characteristics of third-generation district heating (3GDH). The defining feature of 4GDH and 5GDH systems is to operate heat distribution systems at low temperatures [46]. The need for significantly larger pipe diameters to allow heat delivery temperatures (less than 45 °C) is considered a disadvantage for the fifth-generation district heating (5GDH). From this perspective, the current infrastructure of the district heating system of Suceava city can be an advantage for the transition to the next generations (4GDH and 5GDH). The current infrastructure can be considered oversized (large pipe diameters and high flow rates) for the quantities of heat that are delivered to end users. As a result, the premises are created for reducing the temperature of hot water but also for integrating low-temperature energy sources (for example, heat pumps).

The availability of power installed in the cogeneration unit, but also the continuation of investments in the modernization and rehabilitation of the heating system, create conditions for connecting new consumers who currently use individual gas heating. The expansion of the district heating system to areas with high population densities will have beneficial effects in reducing carbon dioxide emissions compared to the current model, in which a significant number of apartments have individual gas heating sources.

The district heating system of Suceava city has faced numerous problems in the past due to outdated infrastructure, underfinancing or lack of investment, but also dependence on fossil fuels (coal and fuel oil). The efforts to modernize, develop and streamline the district heating system in recent years have, as their main goal, the regaining of the trust of end consumers in this public utility system. The results of this study show a significant reduction in carbon emissions per unit of energy delivered (95.97%) from the district heating system after 2015 because of the change in technology and primary energy source (cogeneration and biomass).

Currently, 44.70% of the apartments in the city of Suceava are connected to the district heating system, the rest of the apartments having individual gas heating sources.

The comparative analysis between individual heating and district heating highlights a difference in carbon dioxide emissions of 81.66% (0.220 kg CO_2/kWh for individual heating and 0.040 kg CO_2/kWh for district heating).

The selection of Suceava city within the EU Mission "Smart and climate-neutral cities—100 climate-neutral cities by 2030" represents an important motivation in increasing the energy efficiency of the district heating system as part of urban development plans in achieving sustainability objectives [47].

5. Conclusions

The diversity of primary energy sources that can be used by cogeneration technologies makes high-efficiency cogeneration a viable option in the decarbonization of cities with district heating systems. In urban areas with high population densities, district heating is the only possible solution that can integrate large amounts of heat from renewable sources into the building heating sector.

High-efficiency cogeneration should be analyzed in the context of the energy transition, not only against conventional systems. The analysis should take into account several factors, including the relevance of the criteria, comparability with separate generation alternatives, flexibility in different energy contexts and adaptability to local conditions, and the integration of new distributed technologies located close to users.

The results obtained in this study show that the decarbonization targets for the district heating system of Suceava city set out in Directive (EU) 2023/1791 are met. Greenhouse gas emissions per unit of heat delivered to customers from the district heating system of Suceava city were 0.040 kg CO_2/kWh. If the biomass did not have guarantees of origin, the greenhouse gas emissions criterion would not have been met. On the other hand, from an energy efficiency point of view, the criteria for "high-efficiency cogeneration" are not met (primary energy savings: PES = 3.19% < 10%; total efficiency: $\eta_{gl,CHP}$ = 52.19% < 70%). Therefore, solutions for rehabilitation and increasing energy efficiency are necessary. Also, Scenario 3 highlights the potential of useful heat for connecting new users to the district heating system.

Applying the calculation methodology for high-efficiency cogeneration presupposes a very good knowledge of the technology and the particularities of the operation of the cogeneration plant for the correct identification of the quantities of energy generated in cogeneration and non-cogeneration regimes. Therefore, the results obtained and the conclusions of this study refer to the case study considered. This aspect represents one of the limitations of this study.

Also, the energy and environmental performances of a heating system depend on the involvement of local public authorities in promoting plans aimed at maximizing the use of renewable resources available at the local level, reusing residual heat and developing heat storage solutions. To maximize the impact, these measures should be complemented by ambitious building renovation plans.

Future research directions will be oriented towards the integration of modern technologies for the efficient use of primary energy sources with thermal potential at medium and low temperatures (cogeneration with ORC technology and heat pumps) and the use of heat storage to increase the flexibility of the district heating system.

Author Contributions: All authors contributed equally to the idea and the design of the methodology proposed, and to the production of the research paper. Conceptualization, P.A. and R.D.P.; methodology, P.A.; software, L.D.M.; validation, P.A., R.D.P. and L.D.M.; formal analysis, R.D.P.; investigation, P.A.; resources, L.D.M.; writing—review and editing, P.A.; visualization, L.D.M.; supervision, R.D.P. All authors have read and agreed to the published version of the manuscript.

Funding: This work is supported by the NetZeRoCities Competence Center, funded by European Union—NextGenerationEU and the Romanian Government, under the National Recovery and Resilience Plan for Romania, contract no.760007/30 December 2022, with the Romanian Ministry of Research, Innovation and Digitalization through the specific research project P2-Sustainable energy & environments.

Data Availability Statement: The original contributions presented in the study are included in the article, further inquiries can be directed to the corresponding author.

Conflicts of Interest: The authors declare no conflicts of interest. The funders had no role in the design of the study; in the collection, analyses, or interpretation of data; in the writing of the manuscript; or in the decision to publish the results.

Nomenclature

PES	Primary energy saving (%)
QF	Quality factor of the cogeneration unit (-)
E_{CHP}	Electricity generated in cogeneration mode (MWh)
$E_{non\text{-}CHP}$	Electricity generated in non-cogeneration mode (MWh)
H_{CHP}	Heat generated in cogeneration mode (MWh)

$H_{non\text{-}CHP}$	Heat generated in non-cogeneration mode (MWh)
$H_{cooling\ tower}$	Heat lost to the cooling tower (MWh)
F_{CHP}	Fuel consumed in cogeneration mode (MWh)
$F_{non\text{-}CHP}$	Fuel consumed in non-cogeneration mode (MWh)
C_{SH}	Specific consumption for heating buildings (kWh/m^2·year)
$H_{supplied}$	Thermal energy supplied to end consumers (kWh)
S_{heated}	Heated surface of buildings (m^2)

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Article

Allocation of Joint Costs and Price Setting for Electricity and Heat Generated in Cogeneration

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Abstract: In the case of cogeneration, the allocation of operation costs has a particularity specific to the joint production of heat and electricity from the same primary energy source. The cost allocation is also influenced by the demand conditions faced by the joint products, and prices must be sufficient for both products to remain profitable and competitive with other power generation alternatives in the respective markets. Therefore, the choice of cost allocation methodology is influenced by market conditions. The paper presents an algorithm for determining the prices of energy and heat produced in cogeneration according to demand and market conditions. The economic market method was extended with an algorithm based on duality theory for verifying allocation methods and establishing forecasting strategies. An example is provided for a cogeneration plant (1.287 MWe; 5.386 MWth) based on ORC (Organic Rankine Cycle) technology and biomass fuel. The fuel cost has a major influence on the total costs of the cogeneration plant, between 68% and 77% in the analyzed scenarios. The fuel cost variation is considered in the application of the cost allocation methods for setting the prices of heat and electricity.

Keywords: combined heat and power; CHP; cogeneration economics; cost allocation; energy prices

1. Introduction

The complexity of aspects related to the generation, transmission, distribution, and the use of energy has considerably increased recently, with the worsening of environmental problems worldwide, climate changes, and the depletion of natural reserves, but also in the current context of the energy crisis. Therefore, current concerns in the field of energy generation are oriented towards the application of technologies with the least impact on the environment. Moreover, energy consumption must be controlled and managed, especially through careful monitoring of energy efficiency and diversification of primary energy sources. In this context, the combined generation of electricity and heat or cogeneration (CHP—combined heat and power) is significantly more efficient than separate production [1]. Cogeneration considerably reduces the consumption of primary energy and consequently leads to a reduction in greenhouse gas emissions. Cogeneration technologies can be connected to different primary energy sources. The carbon dioxide emission factors are presented in Table 1 [2,3].

Distributed generation is a suitable option for future energy systems in terms of sustainable development and expanding the use of renewable energy sources. The main reason for using low-power cogeneration in distributed generation applications is the efficient utilization of heat and electricity as close as possible to the place of consumption.

In recent years, there have been major changes in the energy markets, with new challenges for the market participants, but also with an intense promotion of renewable energy sources. Compared to solar and wind energy sources, cogeneration plants have the advantage of a stable and continuous source of heat and electricity for consumers. In this context, operators of cogeneration plants cannot remain indifferent to the changes in

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Citation: Atănăsoae, P. Allocation of Joint Costs and Price Setting for Electricity and Heat Generated in Cogeneration. *Energies* **2023**, *16*, 134. https://doi.org/10.3390/en16010134

Academic Editor: Lin Wang

Received: 25 November 2022
Revised: 18 December 2022
Accepted: 21 December 2022
Published: 23 December 2022

the energy markets and are looking for solutions to maximize profitability and maintain competitiveness with other energy sources [4–6].

Table 1. Greenhouse gas emissions coefficients by primary energy sources (CO_2 equivalent).

Type of Primary Energy Source	Emission Factor	
	tCO_2/TJ	$kgCO_2/kWh$
Lignite	101.1	0.364
Coal	96.7	0.348
Anthracite	98.3	0.354
Crude oil	74.4	0.268
Diesel oil	74.1	0.267
Liquefied petroleum gases (LPG)	63.1	0.227
Gas natural	56.1	0.202
Biomass (firewood)	5.3	0.019
Biomass (wood waste, sawdust, agricultural waste)	4.4	0.016
Biomass (briquettes/pellet)	10.8	0.039
Biogas, solar energy, wind energy, geothermal energy	0	0

Knowing the specific conditions of the energy markets and adapting the mathematical calculation models to the technical features of the cogeneration plant can guarantee success on the market. Thus, paper [7] proposes an algorithm for economic dispatching of high-power cogeneration units and paper [8] proposes an algorithm for optimal operation based on real-time forecasting of prices on deregulated energy markets.

There is currently a tendency to produce energy as close as possible to the place of consumption with the help of medium- and low-power energy sources [9]. To achieve the balance between production and consumption, these small generation units can be integrated and managed collectively as a single source (virtual power plant) through a flexible collaboration between the independent entities [10]. The high volatility of energy prices caused by geopolitical developments causes CHP profitability to fluctuate [11].

A specific problem for cogeneration sources is the need to distribute the total operating costs between the two forms of useful energy generated: heat and electricity. Knowing the elements related to the production structure of the two forms of energy and their related fuel consumption, we can move on to establishing the costs of heat and electricity generation.

Conventionally, the total operating costs of a cogeneration plant can fall into two large categories: variable costs (which depend on the heat and electricity production of the cogeneration plant) and fixed costs (the rest of the costs that do not depend on production). The allocation of the two categories of costs can be realized according to various methods [12–14]. Allocation methods produce different results. An example in this sense is presented in paper [15] in the case of a combined cycle cogeneration plant.

The impact of the adjustment of energy demand (electricity and hot water) on the cost and environmental performance of cogeneration systems according to the priorities of the interested parties is presented in [16]. Trigeneration is widespread in the case of buildings, and the cost allocation methods can be extended in such cases [17–19].

Depending on the cogeneration technology adopted (steam turbines, gas turbines, gas and steam combined cycles, reciprocating engines, Organic Rankine Cycle), cogeneration systems can have different operating regimes, from pure cogeneration modes (in which all the electricity is generated in cogeneration mode based on heat demand) to non-cogeneration modes (in which the system only produces electricity).

A comparison between different cogeneration technologies can be made according to different criteria (energy, environmental, and economic) [20]. Due to its modular construction, Organic Rankine Cycle (ORC) technology can be coupled to different primary energy resources: solar, geothermal, biomass, and waste heat recovery. In addition, unlike the conventional Rankine Cycle, local production of medium- and low-power electrical and thermal energy is possible. The long-term uncertainty of energy demand has an influence on the dimensioning of the cogeneration unit in the design phase, but also for the estimation of the annual operating costs [21]. Thermal energy storage is necessary to be used in case of variations in heat demand [22–24].

Different approaches can be found in specialized literature regarding the allocation of products generated in cogeneration and trigeneration. The paper [25] presents the allocation of primary energy consumption in cogeneration in a local (regional) production scenario. Approaches to thermoecological and exergoeconomic costs of multiproduct systems are presented in papers [26–30]. The quantity and quality of energy are considered in [31,32]. Marginal costs are considered in the allocation of resources in the case of district heating [33,34]. The allocation of carbon dioxide emissions for products generated in cogeneration are presented in [35,36]. Depending on the methodology used, the allocation of joint costs can lead to different outputs that reflect the link between the joint costs and the objectives pursued.

The generation of electricity in cogeneration and from renewable energy sources is encouraged through various support schemes [37,38]. The participation of cogeneration plants (without support schemes) in competitive energy markets is the objective of this study.

Setting prices for electricity and heat generated in cogeneration in a market economy depends on the type of market: competitive markets where prices are a consequence only of the supply–demand ratio; regulated markets in which prices are a consequence of both the supply–demand ratio and the action of specific regulations. The type of energy market in which the cogeneration producer operates has a major impact on the choice of the allocation methodology. From an economic point of view, there is a considerable margin to allocate the costs of one of the products according to the interests of the cogeneration producer on the respective energy markets.

Usually, a cogeneration plant that delivers heat in a district heating system is often viewed as a monopoly or in a dominant market position. Therefore, the cogeneration producers may face competition from other heating alternatives, such as individual gas boilers. In these cases, the heat price must be set at competitive levels with alternative heating sources.

The economic viability of a cogeneration plant will depend on the demand for heat and electricity. These two factors must be accurately evaluated when analyzing the feasibility or operating strategies of a cogeneration plant to ensure the correct calibration of the plant and thus to ensure long-term viability.

If the installation is incorrectly calibrated, for example, if the entire available heat is not used, the economic viability of the cogeneration system will be negatively affected. To maximize the savings of the CHP plant in relation to the initial capital investment, com-pared to the separate production of electricity and heat, the annual operating time should be sufficiently high.

The main contributions and novelty elements of this paper can be summarized as follows:

- The use of allocation methods in determining heat and electricity prices in the case of a cogeneration plant based on Organic Rankine Cycle (ORC) and biomass fuel.
- The economic market method was extended with an algorithm based on the theory of duality, useful in the operation of the cogeneration plant and for the performance of management strategies on the energy markets.
- The example provided demonstrates how cogeneration benefits can be shared between heat and electricity to increase the competitiveness of the CHP plant i the energy markets.

The paper is organized as follows. Section 2 presents the methodology used. Section 3 presents a case study for a CHP plant based on ORC and biomass fuel. The findings and their implications are summarized in Section 4. Finally, the conclusions of this paper are summarized in Section 5.

2. Materials and Methods

2.1. Modeling Costs and Fuel Consumption in Cogeneration Plants

The annual operation costs of a cogeneration plant can be expressed with the following equation [39]:

$$TC = V + F + T + E + R - B + b \quad [\text{EUR/year}] \tag{1}$$

The variable costs (V) consist of the annual expenses for the fuel consumed, those for the energy consumed, for the water consumed, and the electricity of the cogeneration plant. If the volume of production is equal to zero, then the variable costs are also zero.

The fixed costs (F) consist of the annual expenses for the amortization of the investments, those with the operating personnel, and with the plant maintenance. In general, they include expenses independent of the energy production of the cogeneration plant.

Annual fees and taxes (T) and also ecotaxes (E) are included in the total costs. The ecotaxes are generally environmental, dependent on the size of the potential emissions (especially CO_2 emissions). As the emissions are dependent on the amount of energy produced and on the fuel consumption, they can be considered dependent on the annual fuel consumption.

The rates (R) are dependent on the loans to be repaid correlated with the repayment period and the annual interest rate. They are independent of the values of the plant's annual energy production.

Bonuses (B) are dependent on the amount of electricity produced in cogeneration based on conventional fuels and/or based on renewable energies. They represent a source related to each kWh produced in cogeneration, fixed or variable, depending on the annual amount of electricity demonstrated (certified/qualified) to be produced in cogeneration, according to the methodology established by the regulator.

The profit/benefit (b) desired by the producer is also included in the total costs.

A correct delimitation of costs in fixed or variable costs is useful in making forecasts and implicitly in making decisions at the management level. The total costs TC of the cogeneration plant can be expressed with the equation:

$$TC = FC + VC(H, E) \tag{2}$$

where FC represents the fixed costs that include all expenses that do not depend on production, but indirectly depend on it through the nominal capacity installed in the CHP plant, and VC (H, E) are the variable costs and whose value depends on the size of the annual production of electricity and heat of the cogeneration plant.

The total fuel consumption of a cogeneration plant can be expressed according to the quantities of energy produced with the relation [40]:

$$B = a + b \cdot E_G + c \cdot E_G^2 + d \cdot H_G + e \cdot H_G^2 + f \cdot E_G \cdot H_G \tag{3}$$

where:

E_G is the electricity generated (kWh);

H_G is the heat generated (kWh);

a, b, c, d, e, and f are the coefficients of the polynomial.

The determination of the coefficients a–f can be realized by applying the least squares method on as many characteristic regimes as possible to cover the range of possibilities for the operation of the cogeneration unit.

Using the function:

$$F(a, b, c, d, e, f) = \sum_{j=1}^{n} \left[B_j - \left(a + b \cdot E_{Gj} + c \cdot E_{Gj}^2 + d \cdot H_{Gj} + e \cdot H_{Gj}^2 + f \cdot E_{Gj} \cdot H_{Gj} \right) \right]^2 \tag{4}$$

the coefficients a–f result by solving the system of equations:

$$
\begin{aligned}
\frac{\vartheta F}{\vartheta a} &= -2\sum_{j=1}^{n}\left(B_j - a - b\cdot E_{Gj} - c\cdot E_{Gj}^2 - d\cdot H_{Gj} - e\cdot H_{Gj}^2 - f\cdot E_{Gj}\cdot H_{Gj}\right) = 0\\
\frac{\vartheta F}{\vartheta b} &= -2\sum_{j=1}^{n} E_{Gj}\cdot\left(B_j - a - b\cdot E_{Gj} - c\cdot E_{Gj}^2 - d\cdot H_{Gj} - e\cdot H_{Gj}^2 - f\cdot E_{Gj}\cdot H_{Gj}\right) = 0\\
\frac{\vartheta F}{\vartheta c} &= -2\sum_{j=1}^{n} H_{Gj}^2\cdot\left(B_j - a - b\cdot E_{Gj} - c\cdot E_{Gj}^2 - d\cdot H_{Gj} - e\cdot H_{Gj}^2 - f\cdot E_{Gj}\cdot H_{Gj}\right) = 0\\
\frac{\vartheta F}{\vartheta d} &= -2\sum_{j=1}^{n} H_{Gj}\cdot\left(B_j - a - b\cdot E_{Gj} - c\cdot E_{Gj}^2 - d\cdot H_{Gj} - e\cdot H_{Gj}^2 - f\cdot E_{Gj}\cdot H_{Gj}\right) = 0\\
\frac{\vartheta F}{\vartheta e} &= -2\sum_{j=1}^{n} H_{Gj}^2\cdot\left(B_j - a - b\cdot E_{Gj} - c\cdot E_{Gj}^2 - d\cdot H_{Gj} - e\cdot H_{Gj}^2 - f\cdot E_{Gj}\cdot H_{Gj}\right) = 0\\
\frac{\vartheta F}{\vartheta f} &= -2\sum_{j=1}^{n} E_{Gj}\cdot H_{Gj}\cdot\left(B_j - a - b\cdot E_{Gj} - c\cdot E_{Gj}^2 - d\cdot H_{Gj} - e\cdot H_{Gj}^2 - f\cdot E_{Gj}\cdot H_{Gj}\right) = 0
\end{aligned}
\tag{5}
$$

An algorithm for solving the system of Equation (5) implemented in the MATLAB computing environment is presented in Appendix A.

In a competitive economy, prices are directly related to the ratio between supply and demand. For a certain product, it is considered that the market stabilizes for that price value for which the amount of energy demanded by consumers is equal to that offered by the producer. The price that establishes this state is an equilibrium price called the market price p_0 [39].

On the other hand, the price proposed by the producer (p_p) for negotiation with buyers is given:

$$p_p = c + b \tag{6}$$

where c is the unit cost of production and b is the desired profit.

Comparing the market price p_0 with the producer's proposed price p_p allows an initial estimate of the producer's efficiency:

(a) $p_0 \geq p_p$, the producer covers his/her production costs and achieves a higher profit, or at least equal to the initially estimated one;
(b) $c \leq p_0 \leq p_p$, the producer covers his/her production costs and achieves a lower profit than initially estimated;
(c) $p_0 < c$, the producer does not cover his/her production costs. In this case, a reduction in production costs is necessary.

Therefore, knowing the costs is an essential condition in analyzing the profitability of the cogeneration process.

2.2. Methods of Allocating Costs and Fuel in Cogeneration

Over time, several methods of allocating fuel and costs have been developed. The most used ones are shown in Figure 1 [39,41–43].

The main difference between the two categories is that commercial methods do not distinguish between production cost differences, for example, for different steam extraction pressures or between cogeneration and condensation electricity. In contrast, thermodynamic methods consider this type of cost differences. In addition to costs, the methods can also be applied for the allocation of fuel or emissions related to the products (useful energies) resulting from the cogeneration process.

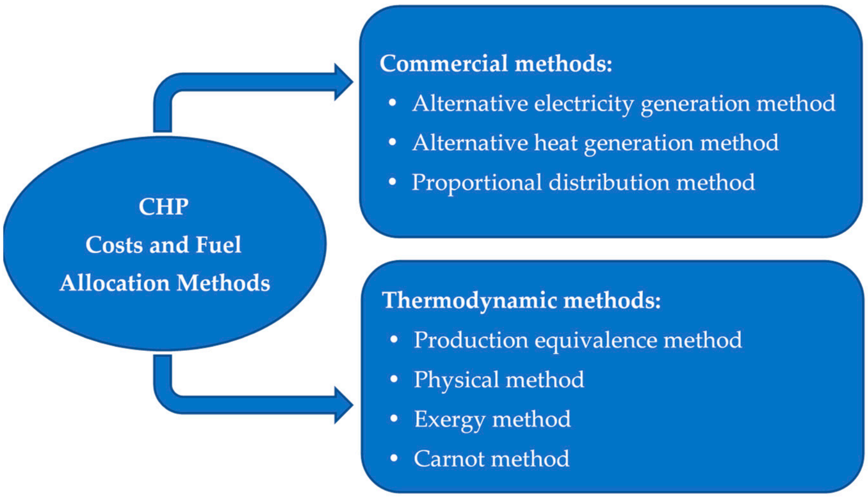

Figure 1. Methods of allocating costs and fuel in cogeneration.

2.2.1. Alternative Electricity Generation Method

The annual fuel consumption allocated for the electricity is considering the alternative option of separate electricity production, with performant technologies, using the same primary energy source (fuel):

$$B^{e}_{CHP} = \frac{E_{CHP}}{\eta_{e,sep}} \tag{7}$$

where:

E_{CHP} is the electricity generated annually in the cogeneration plant (kWh/year);

$\eta_{e,sep}$ is the reference efficiency of a power plant that produces only electricity with the same type of primary fuel (for example, a thermoelectric power plant with a condensing turbine).

Therefore, the fuel consumption is assumed to be equal to that which would result if the respective electricity was produced in a thermal power plant with a condensation turbine.

The annual fuel consumption for heat generation in the CHP plant results from the fuel difference:

$$B^{h}_{CHP} = B_{CHP} - B^{e}_{CHP} \tag{8}$$

where B_{CHP} is the total annual fuel consumption of the cogeneration plant (kWh/year).

The variable costs of electricity production (VC_e) in cogeneration are equated to the variable production costs in the case of separate electricity production:

$$VC_e = VC_{e,sep} \tag{9}$$

and the variable costs for heat production in cogeneration (VC_h):

$$VC_h = VC - VC_e \tag{10}$$

where VC represents the total variable costs of the CHP plant.

Accordingly, the fixed costs can be allocated according to the fixed costs of the alternative electricity generation technology.

2.2.2. Alternative Heat Generation Method

Similarly, this method represents the opposite trend in which the annual fuel consumption allocated for heat production is considered in the alternative option of separate heat production, with efficient technologies, using the same primary energy source:

$$B^h_{CHP} = \frac{H_{CHP}}{\eta_{h,sep}} \tag{11}$$

where:

H_{CHP} is the useful heat generated annually in the CHP plant (kWh/year);

$\eta_{h,sep}$ is the reference efficiency of a plant that only produces thermal energy with the same type of primary fuel (for example, a steam or hot water boiler).

Therefore, the fuel consumption is assumed to be equal to that which would result if the respective electricity was generated in a thermal power plant with a condensing turbine.

The annual fuel consumption for thermal energy generation results from the fuel difference:

$$B^e_{CHP} = B_{CHP} - B^h_{CHP} \tag{12}$$

The variable costs of thermal energy generation in VC_h cogeneration are equated to the variable production costs in the case of separate generation:

$$VC_h = VC_{h,sep} \tag{13}$$

and the variable costs for the electricity generation in cogeneration VC_e:

$$VC_e = VC - VC_h \tag{14}$$

2.2.3. Proportional Distribution Method

The specific fuel consumption for heat production in cogeneration is considered to be equal to that of separate generation, i.e., the inverse of the heat efficiency:

$$k_h = \frac{1}{\eta_{h,sep}} \tag{15}$$

The specific fuel consumption for cogeneration electricity generation can be calculated with the equation:

$$k_e = \frac{B_{CHP}}{E} - k_h \cdot \frac{H}{E} \tag{16}$$

where:

B_{CHP} is the total fuel consumption of the CHP plant (kWh/year);

E is the annual electricity production of the CHP plant (kWh/year);

H is the annual heat production of the CHP plant (kWh/year);

$\eta_{h,sep}$ is the reference efficiency in the case of the alternative heat production option.

The variable costs allocated to the production of electricity in cogeneration (VC_e) can be calculated as follows:

$$VC_e = k_e \cdot \frac{E}{B_{CHP}} \cdot VC \tag{17}$$

Similarly, the variable costs allocated to the production of heat in cogeneration (CV_h) can be calculated as follows:

$$VC_h = k_h \cdot \frac{H}{B_{CHP}} \cdot VC \tag{18}$$

2.2.4. Proportional Distribution Method

The proportional distribution method (benefit distribution) distributes the total fuel consumption between the two forms of energy, proportional to their energy equivalent in the common production process:

$$B^{e}_{CHP} = B_{CHP} \cdot x_e \tag{19}$$

respectively:

$$B^{h}_{CHP} = B_{CHP} \cdot x_h \tag{20}$$

where x_e and x_q represent the total consumption breakdown keys:

$$x_e = \frac{E_{CHP}}{E_{CHP} + H_{CHP}} \tag{21}$$

$$x_h = \frac{H_{CHP}}{E_{CHP} + H_{CHP}} \tag{22}$$

2.2.5. Physical Method

This method considers that the annual fuel savings achieved in cogeneration compared to separate production have two components:

$$\Delta B = \Delta B_e + \Delta B_h \tag{23}$$

Thus, the annual fuel savings are allocated to both products resulting from the cogeneration process and calculated with the following equations:

$$\Delta B_e = E_{CHP} \cdot \left(\frac{1}{\eta_{e,sep}} - \frac{1}{\eta_{CHP}} \right) \tag{24}$$

respectively:

$$\Delta B_h = H_{CHP} \cdot \left(\frac{1}{\eta_{h,sep}} - \frac{1}{\eta_{CHP}} \right) \tag{25}$$

From Equations (24) and (25), it is observed that the fuel saving in cogeneration is due to the superiority of the overall efficiency of the CHP plant (η_{CHP}) compared to the separate generation of heat and electricity.

2.2.6. Exergy Method

In the case of the exergetic method, the cost allocation is based on the exergetic flows (useful energy flows) of the energy products resulting from the cogeneration process: electricity and useful heat. Exergy is a thermodynamic term that defines the quality of energy. As energy is used in a process, it loses quality, and its exergy decreases. Exergy flows of thermodynamic processes can be calculated with enthalpies (the degree of energy content as a function of pressure, temperature, and humidity) and entropies (the degree of disorder or uncertainty in a closed thermodynamic system as a function of absolute temperature).

The application of this method requires deep knowledge of the thermodynamic processes and operating peculiarities of the cogeneration plant, and therefore, it is quite complicated to use. However, the method is considered the most thermodynamically correct method to share the benefits of the simultaneous production of electricity and heat generated in cogeneration.

2.2.7. Carnot Method

The Carnot method uses, as an allocation procedure, the maximum potential to provide useful energy (exergy). This maximum potential is evidenced by the efficiency of the Carnot cycle, applied only to heat production, Equation (29). For electricity generation, η_C = 1. Therefore, the Carnot method is a form of exergetic allocation.

The allocation of fuel consumption to generate electricity E and useful heat H in cogeneration can be carried out in accordance with the first and second laws of thermodynamics, respectively, as follows:

$$a_e = \frac{\eta_{e,CHP}}{\eta_{e,CHP} + \eta_C \cdot \eta_{h,CHP}} \quad (26)$$

$$a_h = \frac{\eta_C \cdot \eta_{h,CHP}}{\eta_{e,CHP} + \eta_C \cdot \eta_{h,CHP}} \quad (27)$$

with:

$$a_e + a_h = 1 \quad (28)$$

where:

a_e is the fuel allocation factor related to electricity production;
a_h is the fuel allocation factor related to heat production;
η_C is the efficiency of the Carnot cycle.

The efficiency of the Carnot cycle is applied only to heat production (the exergetic fraction within the useful thermal energy):

$$\eta_C = 1 - \frac{T_0}{T_h} \quad (29)$$

where:

T_h is the useful heat delivery temperature (K);
T_0 is the ambient temperature, set at 273.15 degrees Kelvin (equivalent to 0 °C).

2.3. Setting Prices for Electricity and Heat Generated in Cogeneration

The cost allocation methods in cogeneration allow an elastic setting of tariffs for the two forms of energy depending on the producer's management strategies on the energy markets. Thus, between the possible annual receipts and the total operating costs of the cogeneration plant, a balance equation can be established, with the graphical representation in Figure 2:

$$TC = p_{mE} \cdot E + p_{mH} \cdot H \quad (30)$$

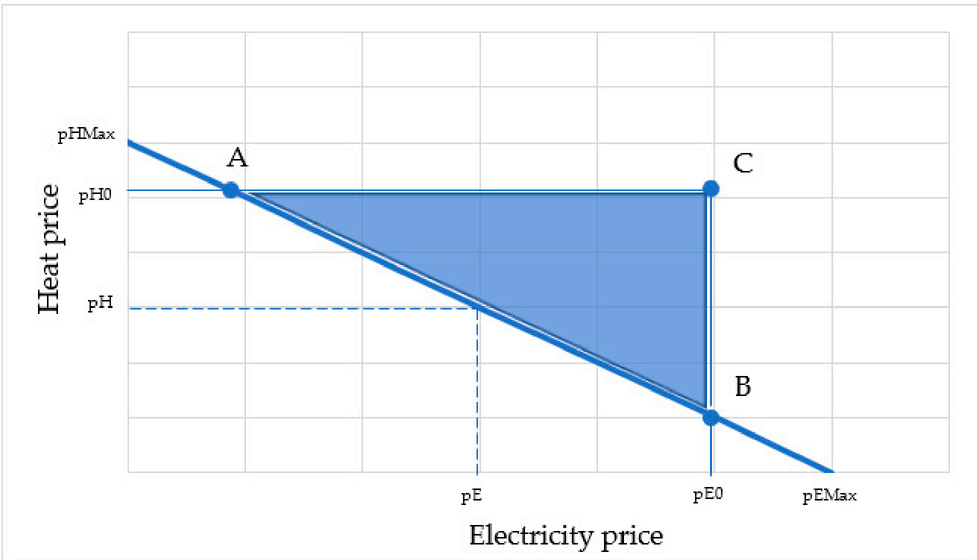

Figure 2. Setting prices for electricity and heat generated in cogeneration.

The line AB in Figure 2 indicates the pairs of p_E and p_H values which, for the quantities of energy E and heat H, balance the total operating costs of the cogeneration plant. The electricity price will be the maximum (p_{EMax}) when the heat is sold for free (p_H = 0), and implicitly, the heat price will be the maximum (p_{HMax}) when electricity is sold for free (p_E = 0).

The equilibrium Equation (30) must also be corrected with other possible receipts, for example, revenues from different support schemes (B), but also with the desired profit (b in %) by the cogeneration energy producer:

$$\frac{(100+b)}{100}TC = p_{mE} \cdot E + p_{mH} \cdot H + B \tag{31}$$

If p_{E0} and p_{H0} are the average electricity and heat prices existing in the energy markets, it is easy to find the area where the pairs of p_E and p_H values can be positioned, respectively, above the balance line in the area delimited by points A, B, and C.

2.4. The Use of Dual and Primal Problems in Cogeneration Applications

The dual of a canonical form of maximization is a canonical form of minimization and vice versa:

$$\left\{\begin{array}{cc} a_{11} \cdot x_1 + a_{12} \cdot x_2 + \cdots + a_{1n} \cdot x_n \leq b_1 & y_1 \geq 0 \\ a_{21} \cdot x_1 + a_{22} \cdot x_2 + \cdots + a_{2n} \cdot x_n \leq b_2 & y_2 \geq 0 \\ \cdots\cdots\cdots & \cdots \\ a_{m1} \cdot x_1 + a_{m2} \cdot x_2 + \cdots + a_{mn} \cdot x_n \leq b_m & y_m \geq 0 \\ x_1 \geq 0 & a_{11} \cdot y_1 + a_{21} \cdot y_2 + \cdots + a_{m1} \cdot y_m \geq c_1 \\ x_2 \geq 0 & a_{12} \cdot y_1 + a_{22} \cdot y_2 + \cdots + a_{m2} \cdot y_m \geq c_2 \\ \cdots & \cdots\cdots\cdots \\ x_n \geq 0 & a_{1n} \cdot y_1 + a_{2n} \cdot y_2 + \cdots + a_{mn} \cdot y_m \geq c_n \\ max(f) = c_1 \cdot x_1 + c_2 \cdot x_2 + \cdots + c_n \cdot x_n & min(g) = b_1 \cdot y_1 + b_2 \cdot y_2 + \cdots + b_m \cdot y_m \end{array}\right\} \tag{32}$$

The system of Equation (32) can be customized to maximize the possible revenues and thus minimize the total operating costs in cogeneration applications.

3. Case Study

A power cogeneration plant (1.287 MWe; 5.386 MWth) based on ORC technology and biomass fuel is used in the case study (Figure 3). In the case of cogeneration, the abbreviation MWe refers to electrical power and the abbreviation MWth refers to thermal power. The nominal technical characteristics of the CHP plant are presented in Table 2.

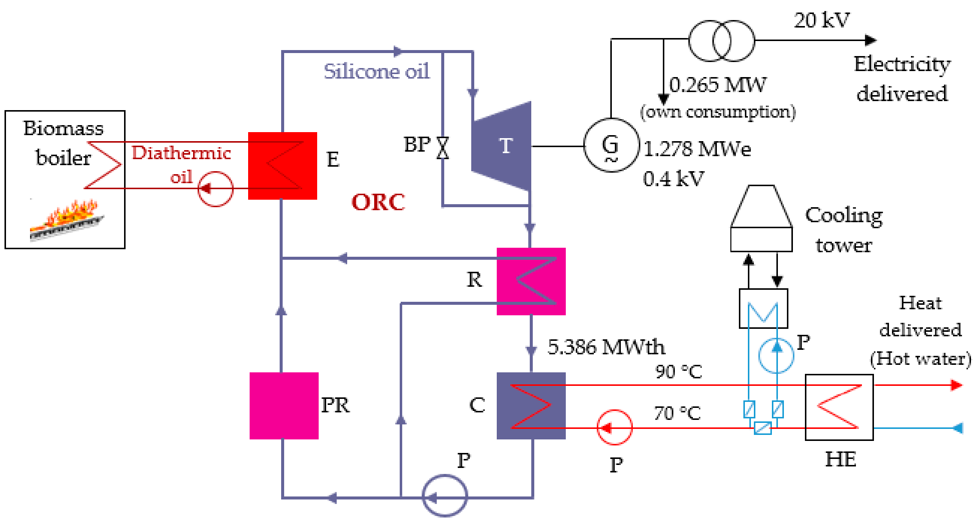

Figure 3. Schematic representation of the CHP plant (E—evaporator; T—turbine; BP—by-pass; G—generator; R—regenerator; C—condenser; PR—preheater; P—pump; HE—heat exchanger).

Table 2. Nominal technical characteristics of the CHP plant.

Parameter	Unit of Measure	Value
Rated electrical power	MWe	1.278
Rated thermal power	MWth	5.386
Fuel	MW	7.971
Own electricity consumption	MWe	0.265
Power to heat ratio	MWe/ MWth	0.237
Overall efficiency	%	83.60

The heat demand of the cogeneration plant is continuous for approximately 8200 h per year, being used for technological purposes for drying wood. The CHP plant entered commercial operation in 2015. The biomass used in the plant is made up of waste resulting from the primary industrialization of wood and from agriculture (wood chips, bark, sawdust straw).

Figure 4 shows the distribution of fuel consumption between the two forms of useful energy generated (heat and electricity) using the allocation methods.

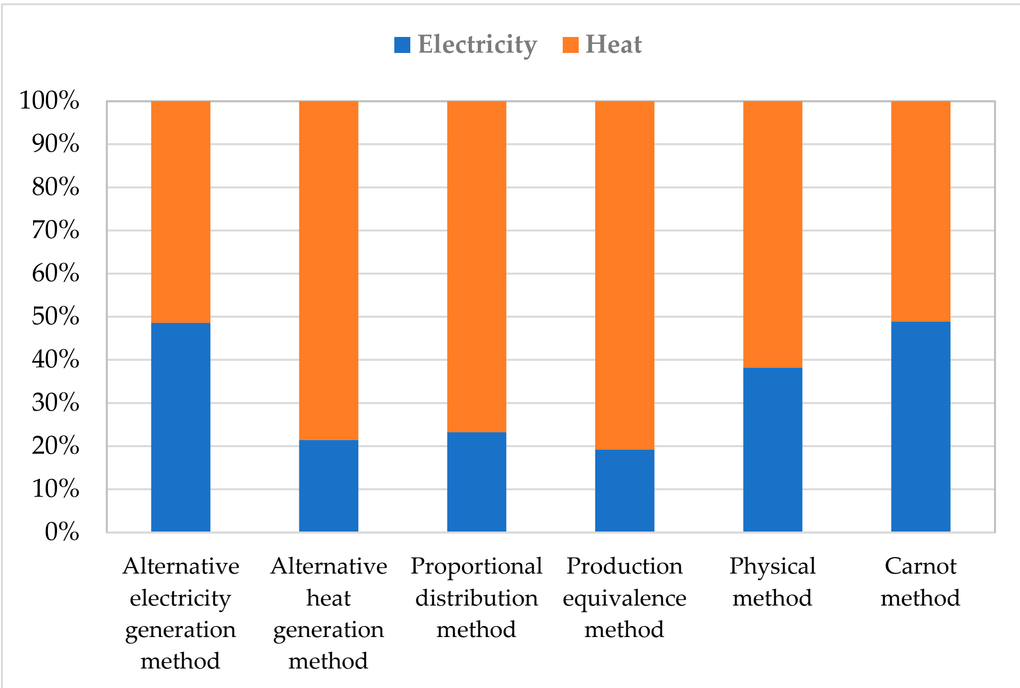

Figure 4. Distribution of fuel consumption between heat and electricity using different allocation methods.

As alternative options for electricity and heat generation, the reference values presented in the EU Regulation [44] for the same type of fuel were considered (η_{Eref} = 32% and η_{Href} = 86%).

It can be seen in Figure 4 that the power to heat ratio C (C = E/H) considerably influences the allocation of fuel consumption in the case of the analyzed cogeneration plant. Thus, three allocation methods (alternative electricity generation method, the physical method, and Carnot method) allocate fuel consumption in proportion of approx. 40–50% of the heat generation, and the other three methods (alternative heat generation method, proportional distribution method, and production equivalence method) distribute the fuel consumption in a proportion of approx. 80% of heat generation and only 20% of electricity generation.

The application of allocation methods in the case of the analyzed CHP plant highlights the following extreme cases:

- Alternative electricity generation method: 50.10% of the fuel is allocated to electricity generation, the scenario in which all the economy achieved in cogeneration is attributed to heat production with a minimum heat sale price of 20.58 EUR/MWh;
- Production equivalence method: 19.18% of the fuel is allocated to the generation of electricity, the scenario that significantly benefits electricity, contributing to the cheapening of its production, with a minimum selling price of electricity of 33.34 EUR/MWh.

Figure 5 shows the heat and electricity prices resulting from the application of fuel allocation methods and fixed and variable costs, respectively.

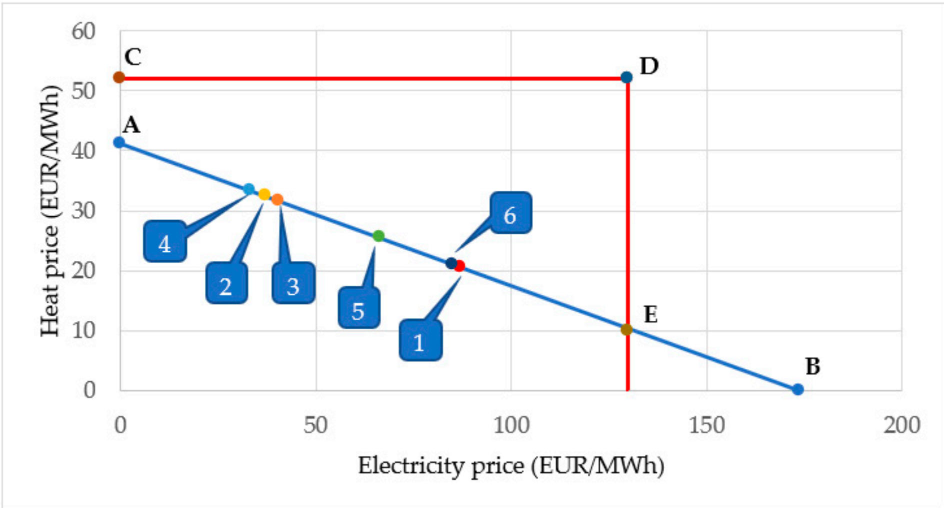

Figure 5. Heat and electricity tariffs that balance the total costs.

In Figure 5, points 1–6 represent the heat and electricity prices resulting from the application of the allocation methods:

- Point 1: Alternative electricity generation method;
- Point 2: Alternative heat generation method;
- Point 3: Proportional distribution method;
- Point 4: Production equivalence method;
- Point 5: Physical method;
- Point 6: Carnot method.

Regardless of the cogeneration technology and the allocation method used, the resulting heat and electricity prices must balance the total costs and the proposed profit.

The variation in the total costs (including the desired profit) or the reduction in heat production will change the shape of the economic characteristic of the cogeneration plant (Figure 6).

In Figures 5 and 6, the line AB represents the economic operation characteristic of the CHP plant on the electricity and heat markets. Point A corresponds to the situation $p_E = 0$ when the electricity would be delivered for free, all costs being allocated to heat generation; similarly, point B corresponds to the situation $p_H = 0$ when the heat would be delivered for free, all costs being allocated to electricity generation. Therefore, any distribution of total costs that leads to pairs of p_H and p_E values located on the AB line is mathematically correct. Thus, the multiple possibilities of allocating the operating costs of the cogeneration plant according to different methods are explained, but at the same time, a simple means is available to check the price of heat or electricity if one of them is artificially increased or cheapened.

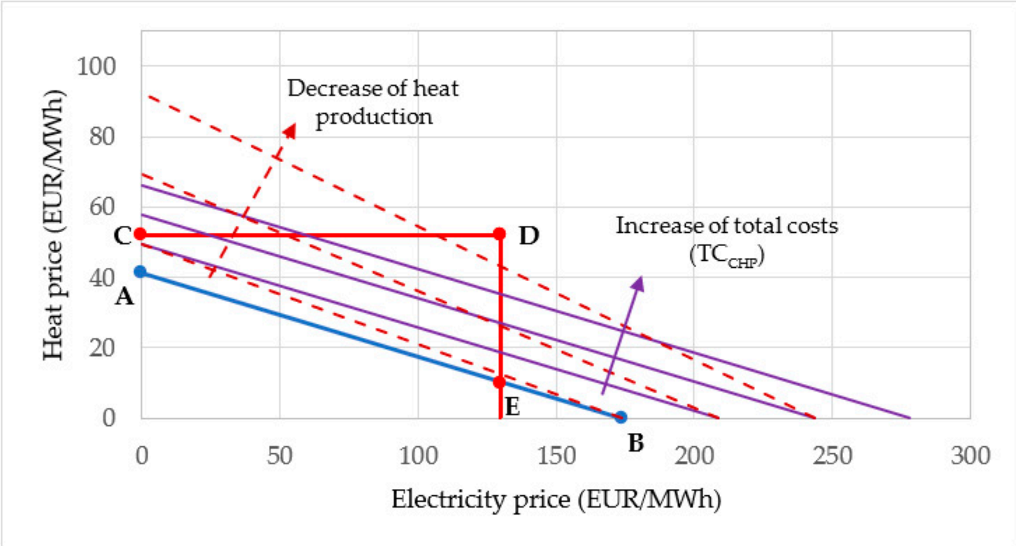

Figure 6. Heat and electricity prices that balance the total costs.

The cogeneration plant remains competitive on the market only if the prices of heat and electricity are located on the AB line or above it in the area delimited by points A, C, D, and E (Figure 5). This area decreases accordingly in the case of an increase in total costs (especially due to the purchase of fuel) but also in the case of a reduction in the production of heat and electricity or the duration of operation of the CHP plant (Figure 6).

A change in the purchase price of the fuel but also in the quantities of heat and electricity delivered from the CHP plant will damage this balance. Thus, the economic market method was extended with a price verification algorithm useful also for making forecast calculations to maintain the profitability of the cogeneration plant in response to changes in production and market conditions.

The objective of the primary problem is to determine the minimum quantities of heat (H) and electricity (E) required to be generated by the cogeneration plant that will balance the production costs and the proposed profit (TC_{CHP}) and the respective maximization of revenues (R_{CHP}).

The primal problem is given in the form:

$$max(R_{CHP}) = p_E \cdot E + p_H \cdot H \tag{33}$$

with the constraints:

$$\begin{bmatrix} b_E & b_H \\ vc_{NFE} & vc_{NFH} \\ fc_E & fc_H \end{bmatrix} \cdot \begin{bmatrix} E \\ H \end{bmatrix} \leq \begin{bmatrix} BC_{max} \\ VC_{NF} \\ FC \end{bmatrix} \tag{34}$$

and:

$$N_H \leq N_{Hmax} \tag{35}$$

$$N_{Emin} \leq N_E \leq N_{Emax} \tag{36}$$

where b_E is the fuel consumption for the electricity generation (kWh/kg); b_H is the fuel consumption for the heat generation (kWh/kg); B_{CHP} is the fuel consumption of the CHP plant (kWh); vc_{NFE} represents the variable costs (excluding fuel) allocated to electricity (EUR); vc_{NFH} represents the variable costs (excluding fuel) allocated to heat (EUR); VC_{NF} represents total variable costs without fuel costs (EUR); fc_E represents the fixed costs allocated to electricity (EUR); fc_H represents the fixed costs allocated to heat (EUR); FC represents total fixed costs (EUR); N_H is the thermal power of the CHP; N_E is the electrical power of the CHP.

With the help of the dual problem, the maximum specific cost of the purchased fuel can be estimated to minimize the total costs and maintain the profitability of the CHP plant on the market:

$$min(TC_{CHP}) = B_{CHP} \cdot p_b + VC_{NF} + FC \quad (37)$$

with the constraints (the dual problem has as many restrictions as the primal problem has variables):

$$\begin{bmatrix} b_E & vc_{NFE} & fc_E \\ b_H & vc_{NFH} & fc_H \end{bmatrix} \cdot \begin{bmatrix} p_b \\ 1 \\ 1 \end{bmatrix} = \begin{bmatrix} p_E \\ p_H \end{bmatrix} \quad (38)$$

The application of the duality theory assumes that the two functions of revenue maximization and operating cost minimization are equal [45]:

$$max(R_{CHP}) = min(TC_{CHP}) \quad (39)$$

In this way, additional useful information is obtained in the economic analysis and the substantiation of the decisions regarding the operation of the cogeneration plant. The Excel Solver program was used to solve the optimization problem.

4. Summary Results and Discussion

Depending on the allocation method used, different outputs are obtained for heat and electricity prices. Table 3 summarizes the results obtained in the reference scenario for a specific fuel cost p_b = 18.95 EUR/MWh.

Table 3. Summary of results in the reference scenario.

Parameter	Unit of Measure	Alternative Electricity Generation Method	Alternative Heat Generation Method	Proportional Distribution Method	Production Equivalence Method	Physical Method	Carnot Method
bE	MWh/MWh	3.13	1.34	1.45	1.20	2.43	3.05
bH	MWh/MWh	0.74	1.16	1.14	1.20	0.90	0.76
$BCHP$	MWh	65362	65,362	65,362	65,362	65,362	65,362
VC_{NF}	EUR	218,606	218,606	218,606	218,606	218,606	218,606
FC	EUR	364,343	364,343	364,343	364,343	364,343	364,343
TC_{CHP}	EUR	1,821,714	1,821,714	1,821,714	1,821,714	1,821,714	1,821,714
vc_{NFE}	EUR/MWh	10.45	4.47	4.84	4.00	8.12	10.20
vc_{NFH}	EUR/MWh	2.47	3.89	3.80	4.00	3.02	2.53
fc_E	EUR/MWh	17.42	7.45	8.07	6.67	13.54	17.01
fc_H	EUR/MWh	4.12	6.48	6.33	6.67	5.04	4.21
p_E	EUR/MWh	87.10	37.25	40.36	33.34	67.69	85.03
p_H	EUR/MWh	20.58	32.41	31.67	33.34	25.19	21.07
E	MWh	10,479.60	10,479.60	10,479.60	10,479.60	10,479.60	10,479.60
H	MWh	44,165.20	44,165.20	44,165.20	44,165.20	44,165.20	44,165.20
p_b	EUR/MWh	18.95	18.95	18.95	18.95	18.95	18.95

The analysis of the structure of the annual operating costs of the cogeneration plant shows a major influence of the annual costs with the primary energy source (fuel). Their share of the total costs is all the greater, as the unit cost of fuel increases and as the basic installations of the plant are more modern and with a more advanced degree of automation. A fuel price sensitivity analysis is presented in Table 4 and Figure 7. The sensitivity analysis allows the identification of those critical variables of the total operating costs, and it is a useful tool for measuring how their variation (in the sense of decrease or increase) has an impact on the economic performance of the CHP. A fuel price increase of 10% influences the total operating costs of the cogeneration plant by approximately 7%.

Table 4. Sensitivity of total costs to the fuel price changes.

Parameter	Unit of Measure	0	+10%	+20%	+30%	+40%	+50%	+60%	+70%	+80%	+90%	+100%
p_b	EUR/MWh	18.95	20.85	22.74	24.64	26.53	28.43	30.32	32.22	34.11	36.01	37.90
TC_{CHP}	EUR	1,821,714	1,945,750	2,069,285	2,194,127	2,317,661	2,441,196	2,564,730	2,688,919	2,812,453	2,936,641	3,060,829

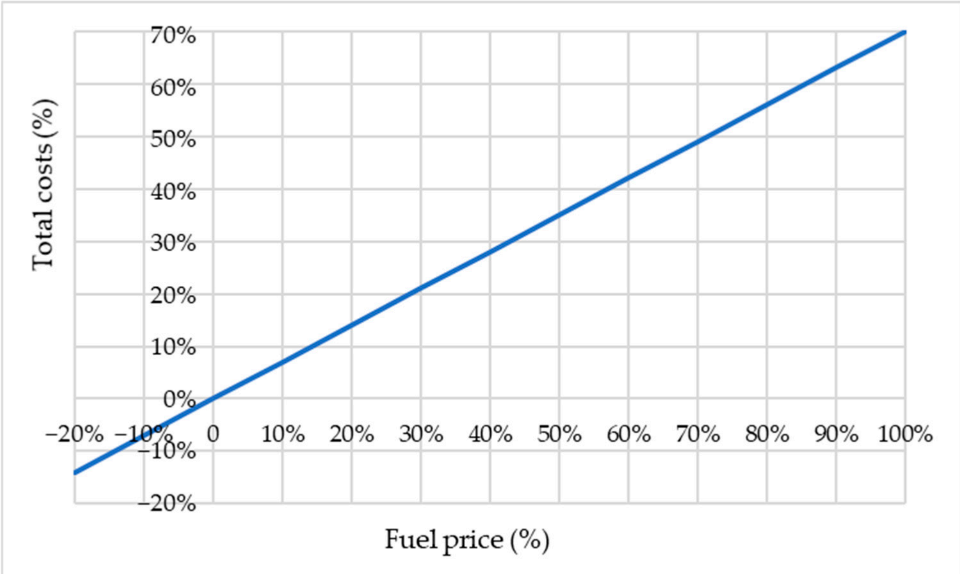

Figure 7. Sensitivity of total costs to the fuel price changes.

The algorithm proposed in this study aims to find the answer to the following question: Can the CHP still be competitive on the energy markets with a significant increase in the price of fuel?

Therefore, a 60% increase in the price of fuel is simulated in the following scenarios (Table 5 and Figure 8). In this way, new values of heat and electricity prices are obtained that balance the total costs and allow the CHP to remain profitable in the absence of a support scheme.

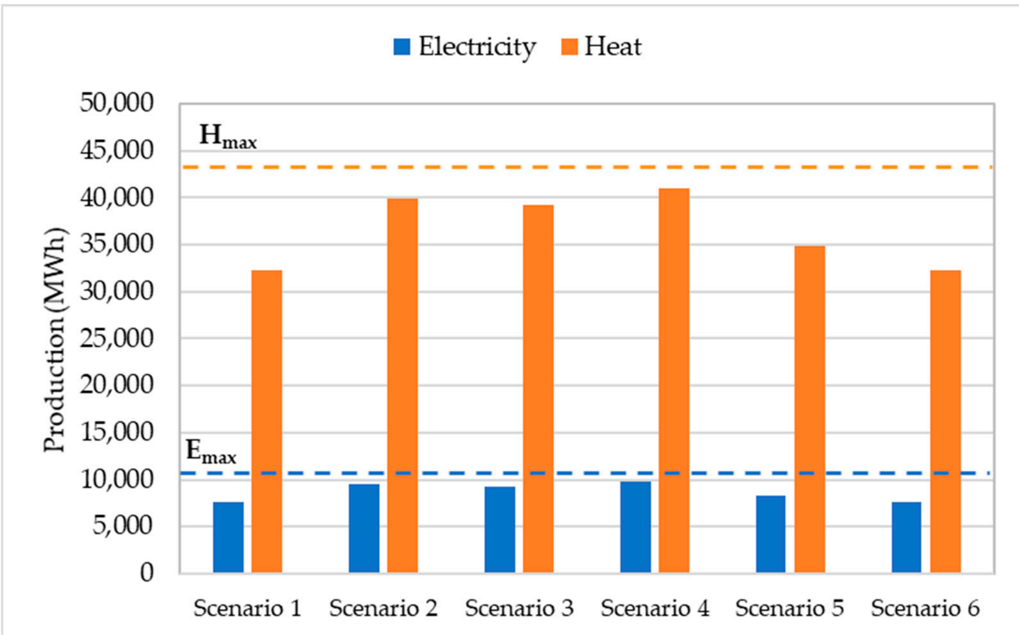

Figure 8. The minimum production of heat and electricity required to be achieved.

Table 5. Summary results for a 60% increase in the fuel price.

Parameter	Unit of Measure	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
p_b	EUR/MWh	30.32	30.32	30.32	30.32	30.32	30.32
TC_{CHP}	EUR	2,564,730	2,564,730	2,564,730	2,564,730	2,564,730	2,564,730
p_E	EUR/MWh	130.00	65.56	71.02	58.67	104.83	130.00
p_H	EUR/MWh	48.60	48.60	48.60	48.60	48.60	48.60
E	MWh	7660	9486	9298	9734	8283	7660
H	MWh	32,282	39,976	39,184	41,022	34,906	32,282

Scenarios 1–6 from Figure 8 correspond to the allocation methods analyzed in this study with the following calculation assumptions:

- The value of the electricity price was established as a result of the application of the allocation methods in the new conditions of increasing fuel costs.
- The price of heat was considered the same in all scenarios because, as a rule, cogeneration plants supply heat to captive consumers. Therefore, the producer has a monopoly character. However, the producer must propose a lower price or at most equal to the price expected on the thermal energy market if the heat consumer were to opt for an alternative option of separate heat generation. Thus, the producer will remain attractive on the thermal energy market.

Unlike the price of heat, which can be forecasted and kept constant for a longer time, the situation is different in the case of the price of electricity, which is much more volatile, being influenced by the specific conditions of the power markets in which the producer operates: centralized market for bilateral contracts, intraday market, and day ahead market.

The strict application of the allocation methods without being collated with the specific conditions of the power markets can lead to price values located outside the range in which the CHP plant would remain competitive on the market. Such an example can be seen in Scenarios 1 and 6 from Table 3 where the price of electricity would have exceeded the maximum value expected at a given moment on the market. Therefore, in the simulation, the maximum value expected on the power market was considered for the price of electricity.

Figure 8 shows the minimum quantities of heat and electricity that balance the operating costs (including the desired profit) under the new conditions of increasing the price of the purchased fuel. It can be easily seen that the CHP plant has a reserve of production growth between 7% and 27% (7% in Scenario 4; 27% in Scenario 1 and Scenario 6) which can maximize annual receipts and implicitly increase profit.

The proposed algorithm can be used to obtain additional information useful for establishing the operation strategies of the cogeneration plant on the energy markets, such as fuel price variation, increase in variable costs, increase in fixed costs, the variation in heat and electricity prices on the energy markets, reducing the operating time of the CHP plant, and reducing heat demand.

5. Conclusions

Whatever the cogeneration technology used and the type of energy market in which the cogeneration producer operates, the establishment of electricity and heat prices is based on knowing the costs. The joint generation of electricity and heat from the same primary energy source allows a flexible setting of prices for the two forms of useful energy but conditioned by the particularities of the energy markets and the management strategy of the cogeneration producer.

The prices applied for the sale of heat and electricity are the basis of the economic success of a cogeneration plant in attracting, maintaining, or rejecting consumers of heat and/or electricity.

In this paper, the economic market method was extended with an algorithm based on the duality theory. Thus, the decision makers can have a useful and fast tool for carrying out management strategies and keeping the CHP plant competitive in the energy markets.

An example of a cogeneration plant (1.287 MWe; 5.386 MWth) based on ORC technology is provided in this study. The fuel has the greatest influence on the variable costs and implicitly on the total operating costs of the CHP plant. A 60% increase in fuel prices was simulated in all scenarios, resulting in a 41% increase in total operating costs. Under the conditions of keeping the price of heat at a constant value (48.60 EUR/MWh), the price of electricity has the most competitive values in scenarios 3–5 (58.67–71.02 EUR/MWh) with a production reserve between 7% and 11%, sufficient for maximizing the profit. In scenarios 1, 2, and 6, the price of electricity has less attractive values, being located towards the maximum limit expected on the market (104.83–130 EUR/MWh) but with a larger production reserve (21–27%) that can maximize the producer's profit of energy in cogeneration.

Therefore, depending on the type of energy markets it operates on (regulated or competitive), the cogeneration producer has a useful tool for performing economic market analyses and establishing operating strategies for the CHP plant.

Funding: This research received no external funding.

Data Availability Statement: Not applicable.

Conflicts of Interest: The author declares no conflict of interest.

Appendix A

```
function FUELCHP
% This file calculates the polynomial coefficients of the Equation (3)
EG=[EG1 EG2 . . .  EGn]; % "EG is the electricity generated"
HG=[HG1 HG2 . . .  HGn]; % "HG is the heat generated"
B=[B1 B2 . . .  Bn]; % "B is the fuel consumption"
t11=k; % "k is the number of determinations"
t12=sum(EG);
L=EG.^2;
t13=sum(L);
t14=sum(HG);
M=HG.^2;
t15=sum(M);
N=EG.*HG;
t16=sum(N);
t21=t12;
t22=t13;
O=EG.^3;
t23=sum(O);
t24=t16;
P=EG.*M;
t25=sum(P);
Q=HG.*L;
t26=sum(Q);
t31=t13;
t32=t23;
U=L.^2;
t33=sum(U);
t34=t26;
V=L.*M;
t35=sum(V);
W=HG.*O;
```

```
t36=sum(W);
t41=t14;
t42=t16;
t43=t26;
t44=t15;
X=HG.^3;
t45=sum(X);
t46=t25;
t51=t15;
t52=t25;
t53=t35;
t54=t54;
Y=M.^2;
t55=sum(Y);
Z=EG.*X;
t56=sum(Z);
t61=t16;
t62=t26;
t63=t36;
t64=t25;
t65=t56;
t66=t35;
G1=sum(B);
g2=EG.*B;
G2=sum(g2);
g3=B.*L;
G3=sum(g3);
g4=HG.*B;
G4=sum(g4);
g5=B.*M;
G5=sum(g5);
g6=B.*N;
G6=sum(g6);
D=[t11 t12 t13 t14 t15 t16; t21 t22 t23 t24 t25 t26; t31 t32 t33 t34 t35 t36; t41 t42 t43 t44 t45 t46; t51 t52 t53 t54 t55 t56; t61 t62 t63 t64 t65 t66];
Do=det(D);
D1=[G1 t12 t13 t14 t15 t16; G2 t22 t23 t24 t25 t26; G3 t32 t33 t34 t35 t36; G4 t42 t43 t44 t45 t46; G5 t52 t53 t54 t55 t56; G6 t62 t63 t64 t65 t66];
Do1=det(D1);
D2=[t11 G1 t13 t14 t15 t16; t21 G2 t23 t24 t25 t26; t31 G3 t33 t34 t35 t36; t41 G4 t43 t44 t45 t46; t51 G5 t53 t54 t55 t56; t61 G6 t63 t64 t65 t66];
Do2=det(D2);
D3=[t11 t12 G1 t14 t15 t16; t21 t22 G2 t24 t25 t26; t31 t32 G3 t34 t35 t36; t41 t42 G4 t44 t45 t46; t51 t52 G5 t54 t55 t56; t61 t62 G6 t64 t65 t66];
Do3=det(D3);
D4=[t11 t12 t13 G1 t15 t16; t21 t22 t23 G2 t25 t26; t31 t32 t33 G3 t35 t36; t41 t42 t43 G4 t45 t46; t51 t52 t53 G5 t55 t56; t61 t62 t63 G6 t65 t66];
Do4=det(D4);
D5=[t11 t12 t13 t14 G1 t16; t21 t22 t23 t24 G2 t26; t31 t32 t33 t34 G3 t36; t41 t42 t43 t44 G4 t46; t51 t52 t53 t54 G5 t56; t61 t62 t63 t64 G6 t66];
Do5=det(D5);
D6=[t11 t12 t13 t14 t15 G1; t21 t22 t23 t24 t25 G2; t31 t32 t33 t34 t35 G3; t41 t42 t43 t44 t45 G4; t51 t52 t53 t54 t55 G5; t61 t62 t63 t64 t65 G6];
Do6=det(D6);
```

```
a=Do1/Do;
b=Do2/Do;
c=Do3/Do;
d=Do4/Do;
e=Do5/Do;
f=Do6/Do;
Bc=a+b*EG+c*EG^2+ d*HG+e*HG^2+d*EG*HG;
end
```

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Article

Opportunity Analysis of Cogeneration and Trigeneration Solutions: An Application in the Case of a Drug Factory

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Abstract: Increasing the energy efficiency of a drug factory is the main purpose of this paper. Different configurations of cogeneration systems are analyzed to meet most of the heat demand and to flatten the heat load duration curve. Due to the variable nature of heat demand, there is a need for heat storage, but there is also a need for the fragmentation of power into two units of cogeneration to increase the operational flexibility in these plants. When the heat produced by the combined heat and power (CHP) unit is insufficient to meet the heat load, the heat stored can then be used to meet that demand. Heat storage plays a significant role in managing the heat supply and demand profiles in the CHP system, and in reducing its capacity and size. Trigeneration and heat storage are used as options to increase the operating time of cogeneration units and, implicitly, the amounts of heat and electricity generated in cogeneration. The results of this study demonstrate the economic and technical viability of the cogeneration and trigeneration solutions proposed. For the values of electricity and natural gas prices at the time of the analysis (2021), Scenario 4 is characterized as the optimal economical and technical option for the current rate of consumption, as it ensures the highest values of heat and electricity production and the shortest investment payback period (5.06 years). Compared with separate heat and power generation, we highlight a primary energy saving of 25.35% and a reduction in CO_2 emissions of 241,138 kg CO_2/year.

Keywords: cogeneration; CHP; combined heat and power; trigeneration; opportunity analysis; heat load duration curve

Citation: Atănăsoae, P.; Pentiuc, R.D.; Milici, L.D. Opportunity Analysis of Cogeneration and Trigeneration Solutions: An Application in the Case of a Drug Factory. *Energies* **2022**, *15*, 2737. https://doi.org/10.3390/en15082737

Academic Editor: Abu-Siada Ahmed

Received: 6 February 2022
Accepted: 6 April 2022
Published: 8 April 2022

1. Introduction

The environmental constraints of energy use have become increasingly evident in recent times. The decarbonization of the energy sector is a very complex issue in which many environmental, economic, technical, social, and political aspects need to be considered simultaneously [1–3]. An analysis based on the optimization of decarbonation pathways, and the flexibility requirements in highly renewable power systems, is presented in [4]. In [5], the historical development of the global decarbonization process and an assessment of the technology options for decarbonization in each sector are discussed. Current research on the transition to a decarbonized energy system in the future is dominated by renewable energy solutions and energy storage [6,7]. The author of [8] compares levelized costs of electricity (LCOE) for different electricity generation technologies, including both fossil and renewable sources, by considering a wide range of values for each of their determinants. In [9,10], the economic profitability of sizing photovoltaic systems without storage is analyzed. A model-based decarbonization pathway for Europe's electricity supply system until 2050 is presented in [11]. Therefore, the current concerns in the field of energy generation are oriented towards the application of technologies with the least impact on the environment [12–14]; however, there are also opportunities for commercially mature technologies that use a combination of other low-carbon energy sources and mixed technologies. Furthermore, final energy consumption must be controlled and managed by closely monitoring energy efficiency and diversifying the primary energy sources [15,16]. A resilient power system is generally characterized by high redundancy, functional diversity, adaptability, and modularity [17]. In this context, combined heat and power (CHP), or cogeneration, is significantly more efficient than separate generation. Cogeneration significantly reduces primary energy consumption and consequently reduces greenhouse gas emissions [18,19]. A cogeneration system is not a single technology, but an energy system that can be structured according to the needs of the end energy user. The prime mover that drives the system is usually identified as the type of cogeneration system [20].

The ability to extract more useful energy from the primary energy source is the main technical advantage of a cogeneration system compared with traditional power systems, such as conventional power plants that only generate electricity and boilers that only produce steam or hot water for final users.

Promoting high-efficiency cogeneration [21] based on the demand for useful heat is a priority for many governments, given the potential benefits of cogeneration in terms of saving primary energy, avoiding grid losses, and reducing greenhouse gas emissions. In this sense, there are many support schemes either for investment support (capital grants, exemptions, or reductions in purchases of goods) or for operating support (price subsidies, green certificates, auction schemes, and tax exemptions or deductions).

Another factor that has significantly contributed to the expansion of cogeneration applications is the diversity of primary energy sources, both conventional and renewable, that can be used, and the ease with which one can switch from one primary energy source to another in the case of the same technology [22–26].

The efficient use of natural gas in cogeneration applications is the main aim of this study. Compared with other fossil fuels, the use of natural gas has a much lower impact on the environment in terms of carbon dioxide emissions; thus, the continued use of natural gas seems to be one solution for the energy transition to carbon-free power generation. In the coming decades, natural gas will play an important role in the energy sector, replacing coal in energy production, and ensuring the flexibility of energy systems [27–29]. The natural gas industry is also moving towards a gradual transition to low carbon, decarbonate, and renewable gases. With the help of carbon capture and sequestration technology, natural gas and the related infrastructure will play an important role in the development of the hydrogen economy. Natural gas transmission and distribution infrastructure can help achieve decarbonization targets by gradually integrating renewable gases, such as hydrogen and biomethane, thus ensuring the transport and storage of these gases. The production of energy from renewable sources, mainly photovoltaic and wind, is fluctuating, but this technology allows the conversion of excess electricity into hydrogen and then biomethane in a secondary process [30–32]. Hydrogen and biomethane can then be introduced into the natural gas network for various uses in domestic and industrial consumption. New gas-to-power and power-to-X concepts can provide greater stability and security for energy supplies [33–36]. Power-to-gas is considered a promising technology for seasonal renewable energy storage, enabling a bidirectional coupling of electricity and gas grids. The use of existing natural gas transmission infrastructure for the transport of hydrogen is an efficient solution for the large-scale development of this technology [37]. The convergence of these systems can ensure a sustainable supply of electricity, heat, and fuel based on wind and solar energy, using the existing networks and infrastructures for distribution and storage.

The main contributions and novelty elements of this paper can be summarized as follows:

- The heat demand of a drug factory was analyzed in detail and with high accuracy to identify the hourly, daily, weekly, monthly, and annual load profiles;
- Meeting the variations in heat demand, flattening the load duration curve, and increasing energy efficiency were the challenges we overcame.

The paper is organized as follows. Section 2 presents the methodology used. The technical and economic viability of cogeneration and trigeneration solutions is discussed in Section 3. The findings and their implications are summarized in Section 4. Finally, the conclusions of this paper are presented in Section 5.

2. Materials and Methods

The process for assessing the appropriateness of applying cogeneration to a site begins with an assessment of technical potential and continues with an assessment of cost-effectiveness [38]. Figure 1 shows the steps in the initial assessment of a cogeneration application. As a first step, the compatibility of any existing heating system with the proposed cogeneration plant must be established. This will help the designer to use the existing infrastructure. Important user features to consider include electricity and heat demand profiles, the predominant costs of conventional utilities, and any physical location restrictions.

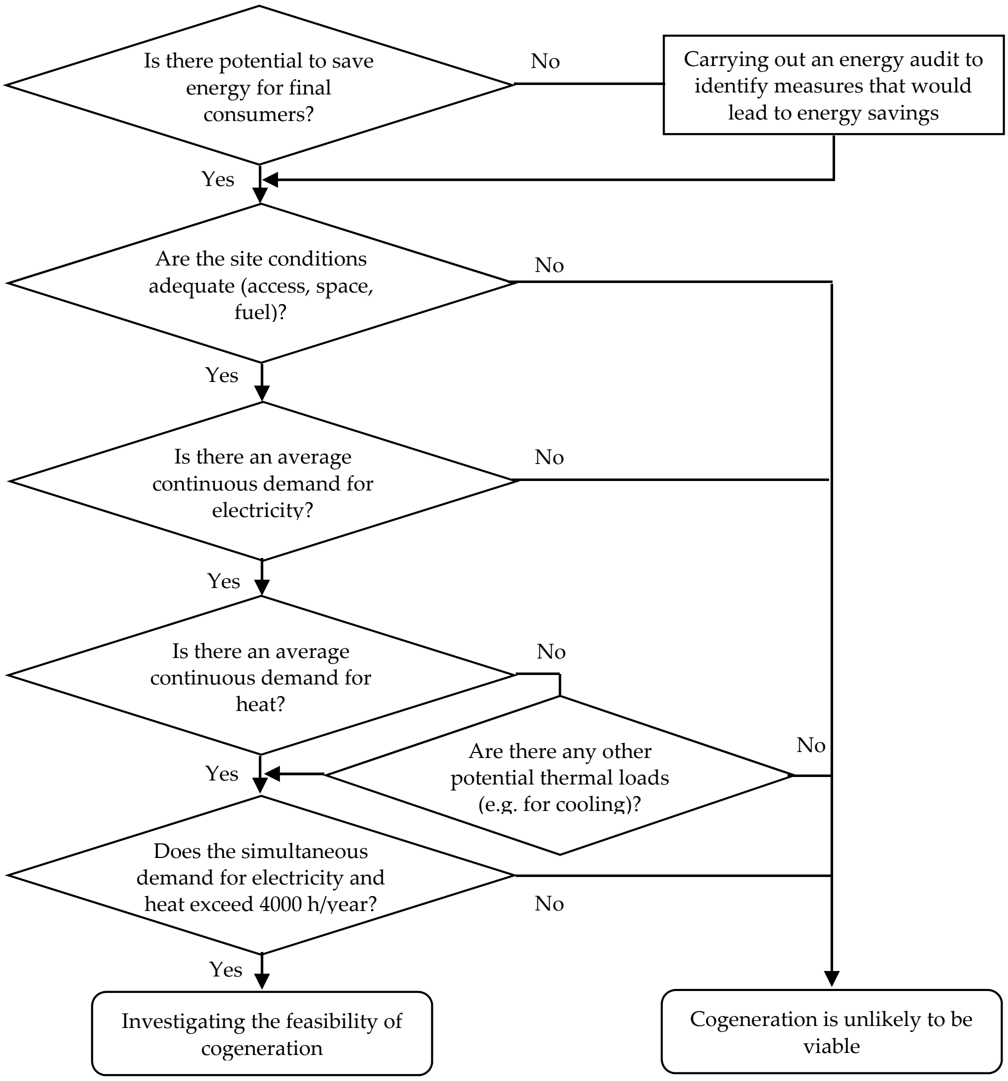

Figure 1. Initial assessment of cogeneration application.

A successful evaluation study, despite having the characteristics of an analytical tool, involves a practical approach, with extensive fieldwork, data collection, and measurements, but with a rigorous technical and financial analysis. The aid of a computer is very useful in such analyses, with its function being to complete and support the main activities of field work and direct metering.

Avoiding the oversizing of the cogeneration plant by applying traditional energy efficiency measures is also an efficient way to reduce costs; therefore, it is necessary to carry out an energy audit in advance, and to ensure that potential energy saving opportunities are implemented before adopting the cogeneration and trigeneration solutions. The correct identification and consideration of the actual energy demand of the analyzed contour will help to avoid the problem of oversizing the cogeneration system.

The consumption curve or load profile illustrates the variation in the final energy demand over a certain time interval. A load curve describes the variation in electrical or thermal power over time (day, month, year). The load duration curve for the heat demand is obtained from the chronological load curve. The load duration curve is a curve ordered by the value of the power, starting from the highest value to the lowest (Figure 2). Thus, the load duration curve is always a downward curve and shows how long a certain power is required.

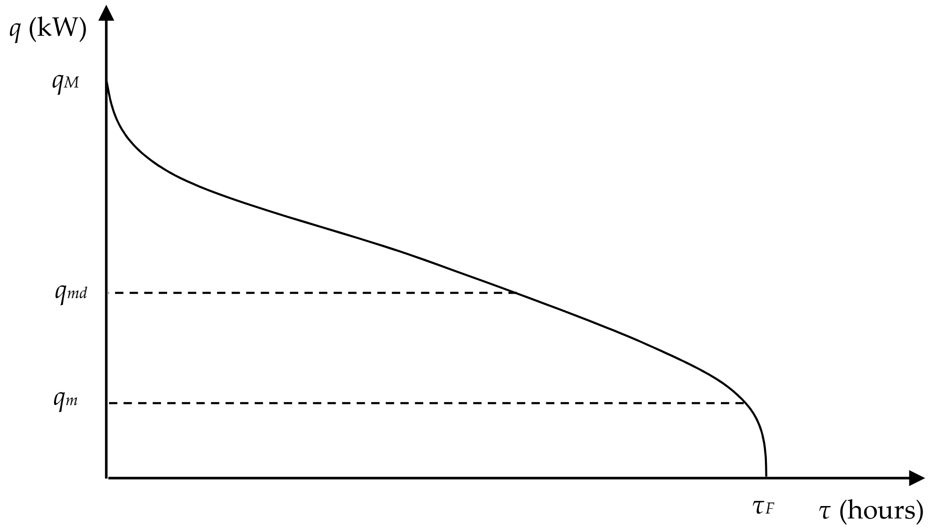

Figure 2. Load duration curve for the heat demand.

The shape of the graded curve $q = f(\tau)$ can be expressed analytically using the Sochinsky–Rossander equation [39,40]:

$$q_h(\tau) = q_M \left[1 - \left(1 - \frac{q_m}{q_M} \right) \left(\frac{\tau}{\tau_F} \right)^{\beta} \right] \quad (1)$$

where the coefficient of non-uniformity β is:

$$\beta = \frac{q_{md} - q_m}{q_M - q_{md}} \quad (2)$$

and where: q_m is the minimum heat demand (kW_t); q_{md} represents the average heat demand (kW_t); q_M denotes the maximum heat demand (kW_t); and τ_F stands for the annual time of heat demand (hours/year).

The annual heat demand is determined either by summing the records of the heat meters (steam and/or hot water, if any) or by processing the fuel consumption records. Heat consumption is almost always variable over time, with a "basic" component (long/quasi-constant) overlapping "peak" components (shorter/interrupted). Variations in consumption are determined by both the outside temperature and the specific periods, durations, and regimes of the technological processes.

The correct determination of the final energy consumption curves (electricity, heat, cooling) is of particular importance for the choice of cogeneration technology. With the help of the annual graded heat consumption curve, the main indicators necessary for the choice of cogeneration solution will be determined: cogeneration coefficient and duration of annual use of the installed thermal power.

The annual heat demand Q:

$$Q = \int_{0}^{\tau_F} q_h \cdot d\tau \quad (\text{kWh/year}) \tag{3}$$

The cogeneration coefficient α_{cogen}:

$$\alpha_{cogen} = \frac{Q_{CHP}}{Q} \tag{4}$$

The amount of heat generated by the cogeneration plant Q_{CHP}:

$$Q_{CHP} = \int_{0}^{\tau_{CHP}} P_h \cdot d\tau \quad (\text{kWh/year}) \tag{5}$$

The duration of annual use of installed thermal power τ_{mdCHP}:

$$\tau_{mdCHP} = \frac{Q_{CHP}}{P_{nh}} \qquad (\text{h/year}) \tag{6}$$

The total fuel consumption of the cogeneration plant W_{CHP}:

$$W_{CHP} = \int_{0}^{\tau_{CHP}} b_{CHP} \cdot d\tau \quad (\text{kWh/year}) \tag{7}$$

The fuel consumption for cogeneration heat generation W_{hCHP}:

$$W_{hCHP} = \frac{Q_{CHP}}{\eta_{boiler}} \qquad (\text{kWh/year}) \tag{8}$$

The electricity generated by the cogeneration plant E_{CHP}:

$$E_{CHP} = P_{ne} \cdot \tau_{mdCHP} \qquad (\text{kWh/year}) \tag{9}$$

The fuel consumption for cogeneration electricity generation W_{eCHP}:

$$W_{eCHP} = W_{CHP} - W_{hCHP} \quad (\text{kWh/year}) \tag{10}$$

The cost of fuel for the generation of electricity in cogeneration C_{eCHP}:

$$C_{eCHP} = W_{eCHP} \cdot p_{natural\ gas} \quad (\text{EUR/year}) \tag{11}$$

The cost of electricity that is no longer purchased from the public network $C_{enetwork}$:

$$C_{enetwork} = W_{eCHP} \cdot p_{electricity} \quad (\text{EUR/year}) \tag{12}$$

The operating and maintenance costs (O&M) of CHP $C_{O\&MCHP}$:

$$C_{O\&MCHP} = W_{eCHP} \cdot p_{O\&MCHP} \quad (\text{EUR/year}) \tag{13}$$

The annual saving in monetary units C_t (the yearly revenue):

$$C_t = C_{enetwork} - C_{eCHP} - C_{O\&MCHP} \quad (\text{EUR/year}) \tag{14}$$

The investment cost, C_0, refers to the costs of equipment and services required for the installation and commissioning of a cogeneration or trigeneration system. The unit value of investment costs varies significantly between different cogeneration technologies. However, basic economies of scale logic apply to all cogeneration technologies in terms of installed unit capacity. Figure 3 shows the specific investment i_{sp} depending on the installed capacity P_{ne} of the cogeneration unit in the case of reciprocating gas engines [41]:

$$i_{sp} = 9332.6 \cdot P_{ne}^{-0.4611} \qquad (\text{EUR/kW}_e) \tag{15}$$

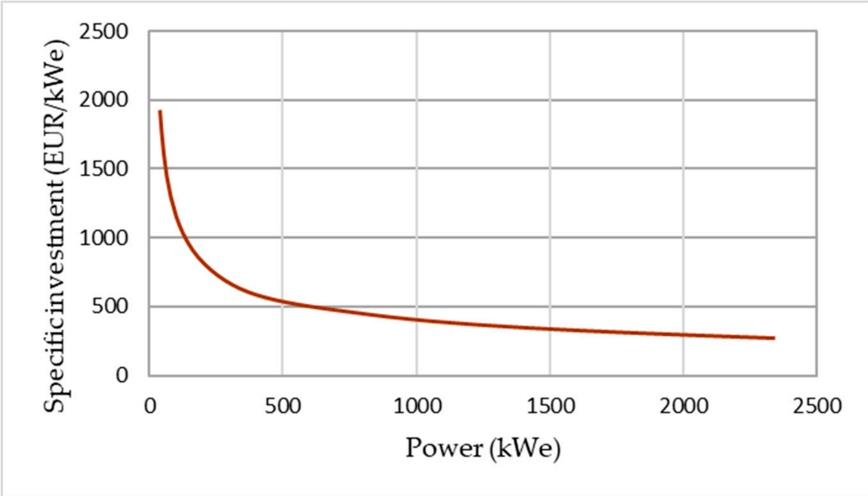

Figure 3. Costs of natural gas–fired CHP engines.

All costs associated with the cogeneration project must be considered; thus, the costs for planning, design, construction, operation, and maintenance (O&M) are added to the investment costs of cogeneration units. The share of operation and maintenance (O&M) costs is usually in the range of 1.5–3.0% per year of total capital costs. An example of the distribution of investment costs is shown in Figure 4 [41]. The technology and size of CHP unit may influence these shares.

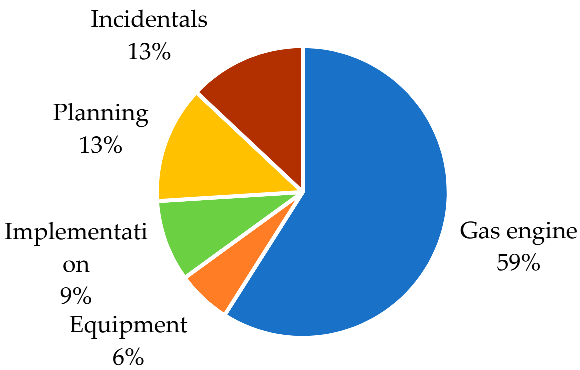

Figure 4. Distribution of investment costs for a cogeneration project [41].

The investment cost (C_0), the annual saving in monetary units (C_t), and the discount rate (i) are taken into account for the selection of the optimal variant from an economic, technological and ecological point of view. The evaluation is made during the lifetime of the investment in years (N). Several economic indicators can be used to assess the technical and economic viability of the proposed technical solutions [42]:

$$\begin{gathered} NPV = \sum_{t=1}^{N} \frac{C_t}{(1+i)^t} - C_0 \\ C_0 - \sum_{t=1}^{N} \frac{C_t}{(1+IRR)^t} = 0 \end{gathered} \tag{16}$$

$$SPBP = \frac{C_0}{C_t} \tag{17}$$

where: NPV is net present value; IRR represents internal rate of return; $SPBP$ indicates a simple payback period.

Primary energy saving (PES) is used to compare cogeneration production and separate production of heat and electricity using the same type of fuel [43]:

$$PES = \frac{W_{sep} - W_{CHP}}{W_{sep}} \tag{18}$$

or:

$$PES = \left(1 - \frac{1}{\frac{\eta_{hCHP}}{\eta_{hRef}} + \frac{\eta_{eCHP}}{p_{loss} \cdot \eta_{eRef}}}\right) \cdot 100 \ \ (\%) \tag{19}$$

where: W_{sep} is the primary energy consumption for separate production of electricity and heat (kWh); W_{CHP} indicates the primary energy consumption in cogeneration (kWh); η_{hCHP} represents the heat efficiency of CHP (%); η_{eCHP} denotes the electricity efficiency of CHP (%); η_{hRef} stands for the reference heat efficiency (%); η_{eRef} represents the reference electricity efficiency (%); and p_{loss} is correction factor for η_{eRef}.

The carbon dioxide emissions are calculated by use of the following equation:

$$E_{CO2} = PES \cdot W_{sep} \cdot f_{CO2} \qquad (\mathrm{kgCO_2/year}) \tag{20}$$

where f_{CO2} is emission factor (for natural gas f_{CO2} = 0.205 $kgCO_2$/kWh).

In this paper, the cogeneration and trigeneration solutions are compared with the reference scenario in which the heat is generated separately from the gas boilers and the electricity is purchased from the grid. In Table 1, we present the prices of natural gas and electricity that were taken into account in our analysis, at the time of the analysis in 2021 [44,45]. The harmonized reference values for the efficiency of separate heat production and separate electricity production (established on the basis of Directive 2012/27/EU) are given in Table 2 [46].

Table 1. Natural gas and electricity prices.

Electricity (EUR/kWh)	Natural Gas (EUR/kWh)
0.11	0.036

Table 2. Efficiency reference values for separate production of electricity and heat [46].

Parameter	U.M.	Natural Gas
Reference electricity efficiency η_{eRef}	%	53.00
Reference heat efficiency η_{hRef}	%	92.00
Correction factor for η_{eRef}	–	0.851

Trigeneration and heat storage are used as solutions to increase the flattening degree of the heat demand curve μ and to increase the operating time of the cogeneration units:

$$\mu = \frac{q_{md}}{q_M} \tag{21}$$

Trigeneration is an extension of cogeneration that includes cooling as the final form of energy use. The combined generation of electricity, heat, and cooling from the same primary energy source offers even more flexibility for a cogeneration plant. The extension consists of the integration of an absorption refrigeration system, which consumes the available thermal energy of the cogeneration plant in the hot season. The balance of cogeneration energy production and the demand for electricity and heat is an important challenge in the implementation of CHP units. In addition, variations in electricity and heat demand can make CHP units difficult to operate. Balancing the production and demand of electricity can be done easily if the CHP unit is connected to the public grid. In case of heat demand variations, they can be taken up using heat storage solutions [47–52]. Thermal energy storage (TES) will increase the flexibility of the cogeneration unit and ensure the simultaneous demand for electricity and heat.

3. Case Study

This section provides a case study on the application of cogeneration and trigeneration solutions in a drug factory.

3.1. Current Situation Regarding Energy Sources and Consumers in the Drug Factory

Currently, the drug factory purchases natural gas and electricity to meet the needs of the final consumers of energy in the form of heat, cooling, and electricity.

In addition to the technological needs of steam and electricity, the drug production process also requires energy for air conditioning and ventilation of the production facilities, offices, and laboratories. A total of 39 pieces of heating, ventilation, and air conditioning (HVAC) equipment are used in the whole factory. A basic diagram of a piece of HVAC equipment is shown in Figure 5.

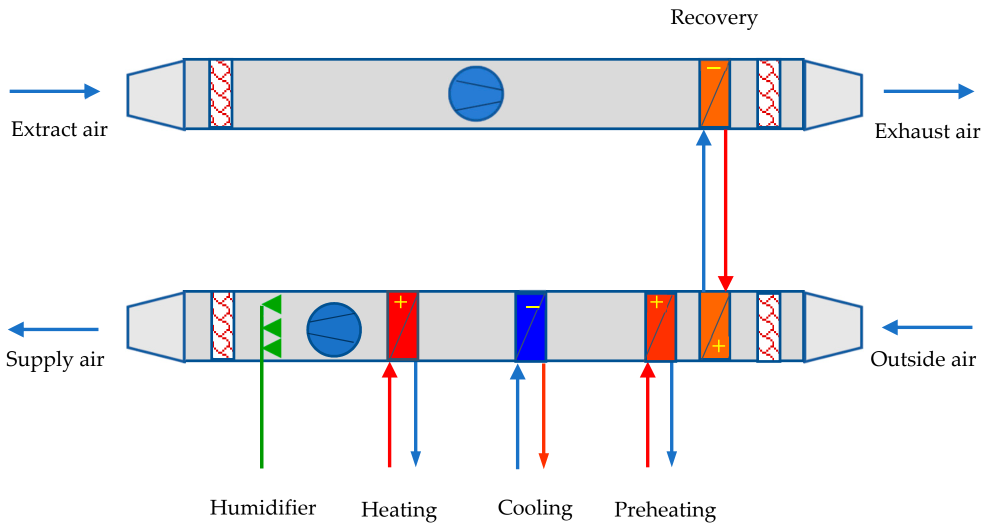

Figure 5. Diagram of heating, ventilation, and air conditioning (HVAC) equipment.

Thermal agents, or energy carriers, currently in use:

- Steam: 4.5 bar; 150 °C;
- Hot water: 80/60 °C;
- Cold water: 7/12 °C.

The following energy sources currently provide thermal energy requirements (steam and hot water):

- Two steam boilers (type WNS1-07YQ); rated steam flow 1.0 t/h; nominal efficiency 91.00%; nominal gas consumption 77.60 m^3/h;
- Two hot water boilers (type ICI CALDAIE, model REX 100); nominal thermal power 1000 kW; nominal efficiency 92.90%; nominal gas consumption 119.10 m^3/h.

To ensure cooling needs (cold water), the following cooling sources are installed:

- Chiller HUMMER with cooling tower (1800 kW);
- Chiller Daikin EWADC18CZ-XS 1760 kW (free cooling 600 kW);
- Chiller REFTECO (free cooling 950 kW) (used in winter).

The power from the electrical distribution network is supplied by means of four MV/LV transformers with a nominal power of 1000 kVA each.

3.2. Monthly Consumption of Natural Gas, Heat, and Electricity

The monthly consumption of natural gas, heat, and electricity for the previous year of operation of the medicinal plant are shown in Table 3.

Table 3. Monthly consumption of natural gas, thermal energy, and electrical energy in the previous year of operation.

Energy Type	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Natural gas (m^3)	26,303	38,323	26,387	6758	14,618	18,300	20,332	13,550	22,665	23,394	47,551	36,238
Thermal energy (kWh)	228,286	332,609	229,016	58,653	126,871	158,828	176,464	117,602	196,712	203,039	412,700	314,513
Electrical energy (kWh)	124,800	113,800	100,800	129,800	230,600	252,991	321,000	247,600	278,000	237,200	221,200	177,000

Figure 6 shows the total monthly heat demand (steam and hot water) and the heat demand only at low temperature (hot water). The total heat consumption in the previous year of operation was 2,555,293 kWh, of which (Figure 7):

- Low temperature heat (hot water) was 1,828,213 kWh (72%);
- High temperature heat (steam) was 727,080 kWh (28%).

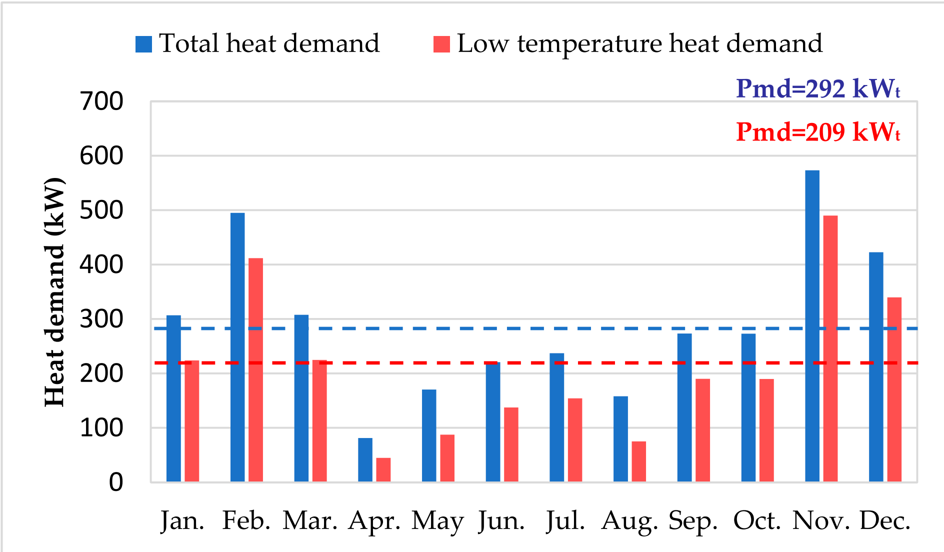

Figure 6. Average monthly heat demand.

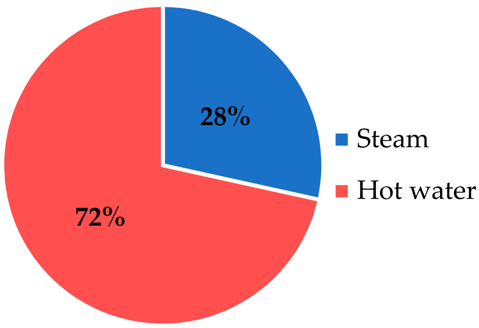

Figure 7. Structure of heat demand.

The total electricity consumption was 2,434,791 kWh. Figure 8 shows the average monthly electricity demand.

Using a comparative analysis of the heat and electricity demand from Figures 6 and 8, the following findings can be made:

- The average power of the two types of consumption is comparable (292 kW_t and 278 kW_e, respectively), and even lower in the case of heat, if only the consumption of heat in the form of hot water is taken into account (209 kW_t);
- The heat demand is higher in the cold season and lower in the warm season;
- Although, the electricity demand is lower in the cold season and higher in the warm season.

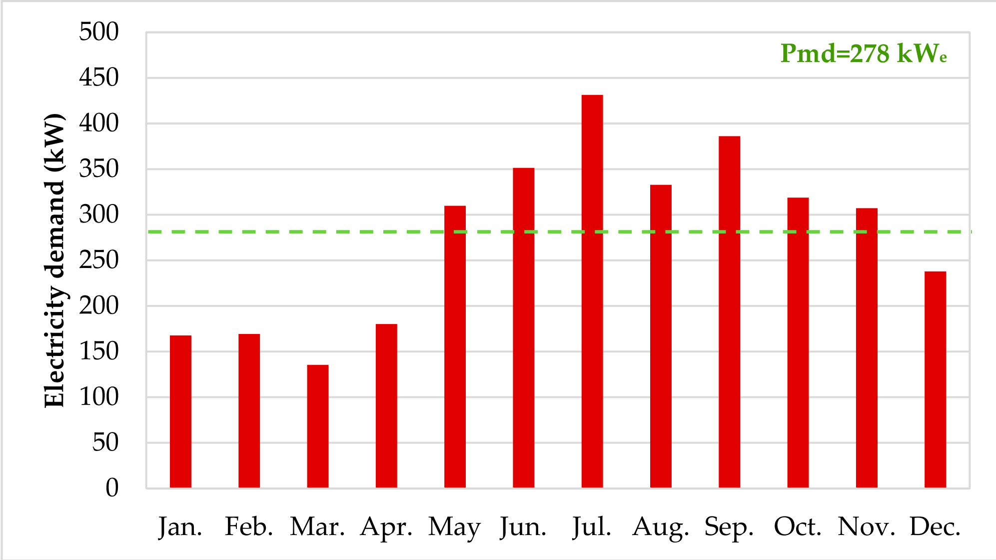

Figure 8. Average monthly electricity demand.

3.3. Unit Costs of Fuel and Electricity Purchased

The unit costs of fuel and electricity purchased from the public networks at the time of analysis was:

1. Electricity: 0.11 EUR/kWh;
2. Natural gas: 0.036 EUR/kWh.

3.4. Analysis of Heat Demand

The variation in the total heat consumption in the previous year of operation is shown in Figure 9. The load duration curve for heat demand, highlighting the low heat demand, is displayed in Figure 10. The operating time of a cogeneration unit at rated thermal load should be at least 4000–5000 h/year for the cogeneration system to be economically viable. From the load duration curve it can be seen that, currently, the heat demand at 4000 operating hours is 160 kW_t, and at 5000 h, the heat demand is 110 kW_t. These values are considered as reference values in the choice of possible variants of cogeneration and trigeneration solutions.

Two months of the year (July and December) were analyzed, as they were characteristic in terms of heat consumption. In July (Figure 11), there is an average variation between 130 kW_t and 370 kW_t; whereas in December (Figure 12), an average variation between 300 kW_t and 900 kW_t exists between the heat demand outside working hours (approximately 14 h) and daytime heat demand (approximately 10 h). The variation in thermal energy consumption can be easily observed in the weekly heat demand (Figures 13 and 14) and the daily heat demand (Figures 15 and 16), respectively.

3.5. Analysis of Electricity Demand

As there are no hourly or daily records for electricity, measurements were made to estimate the average and maximum demand on a winter day and a summer day, respectively (Figures 17 and 18).

The analysis of electricity demand highlights the following characteristic aspects of the drug factory:

- The maximum demand for electricity is between 721 and 1445 kW in summer, and between 249 and 500 kW in winter;
- The average demand for electricity is between 443 and 887 kW in summer, and between 164 and 309 kW in winter;

- The minimum electricity demand is between 320 and 642 kW in summer, and between 126 and 225 kW in winter.

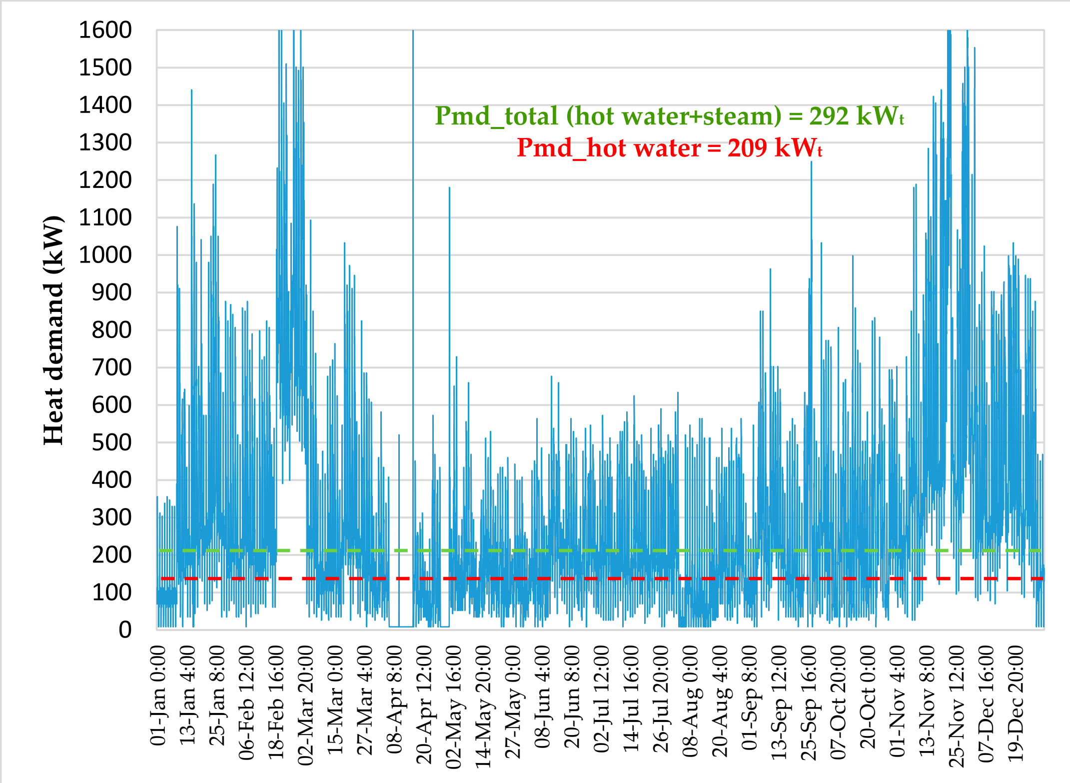

Figure 9. Seasonal variation in the heat demand.

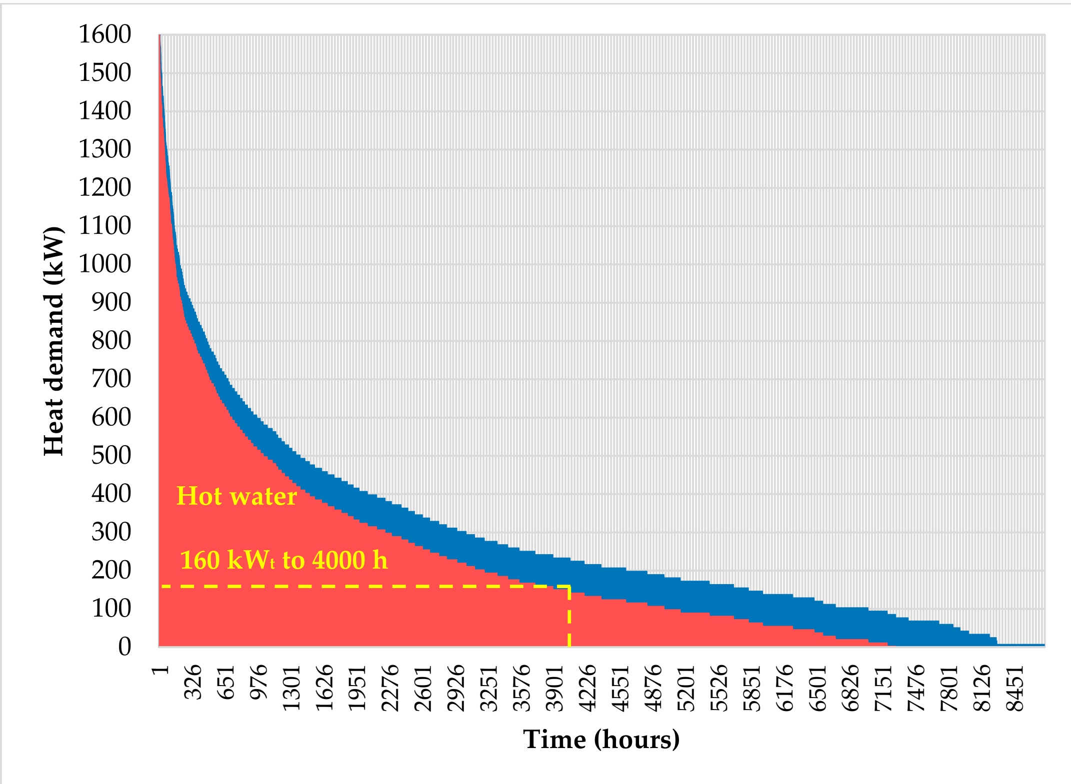

Figure 10. Load duration curve for the heat demand.

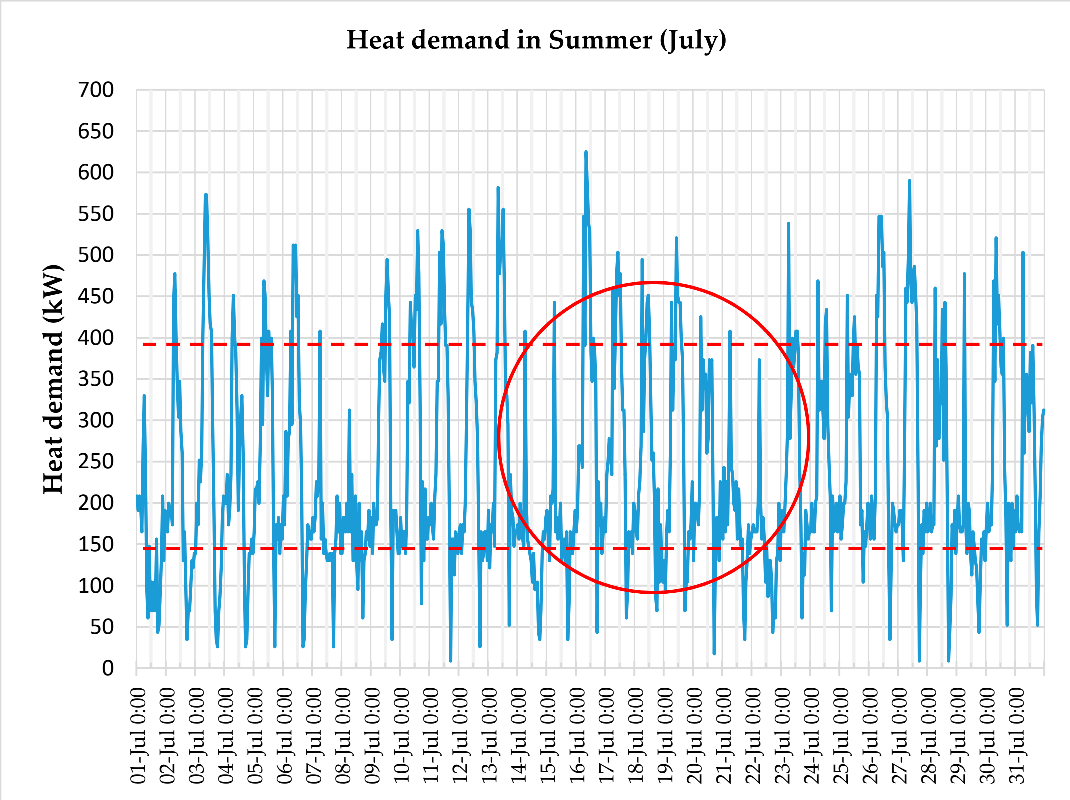

Figure 11. Heat demand in July.

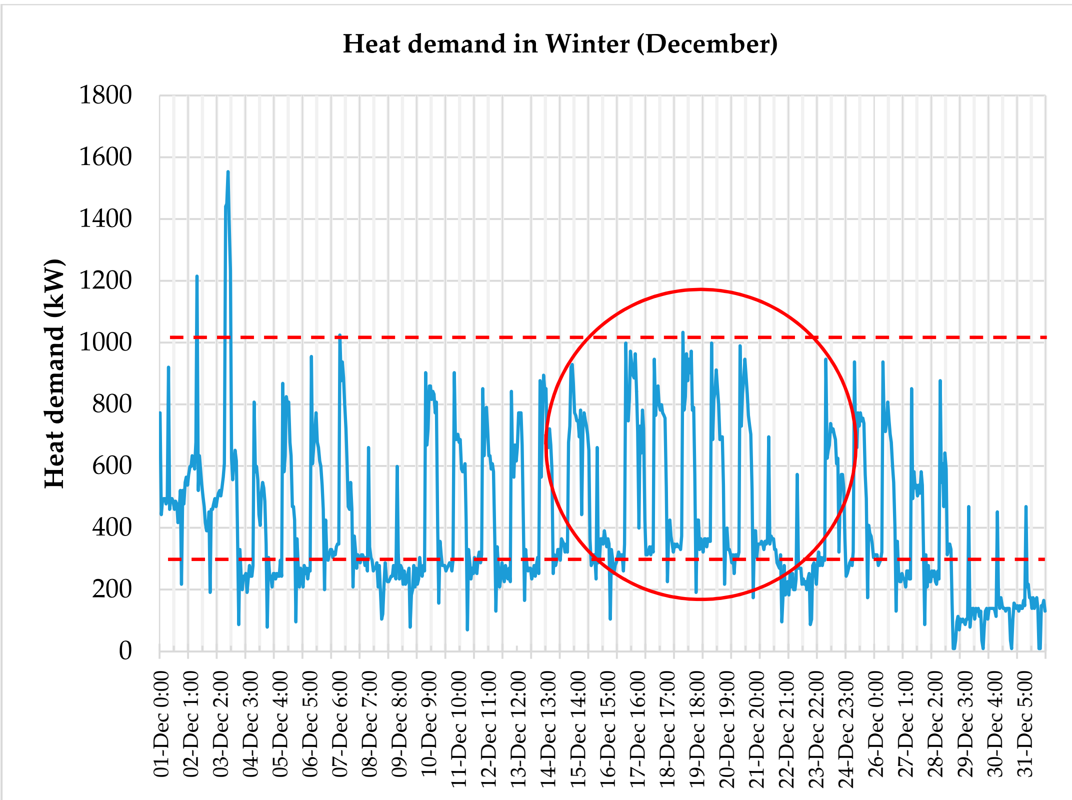

Figure 12. Heat demand in December.

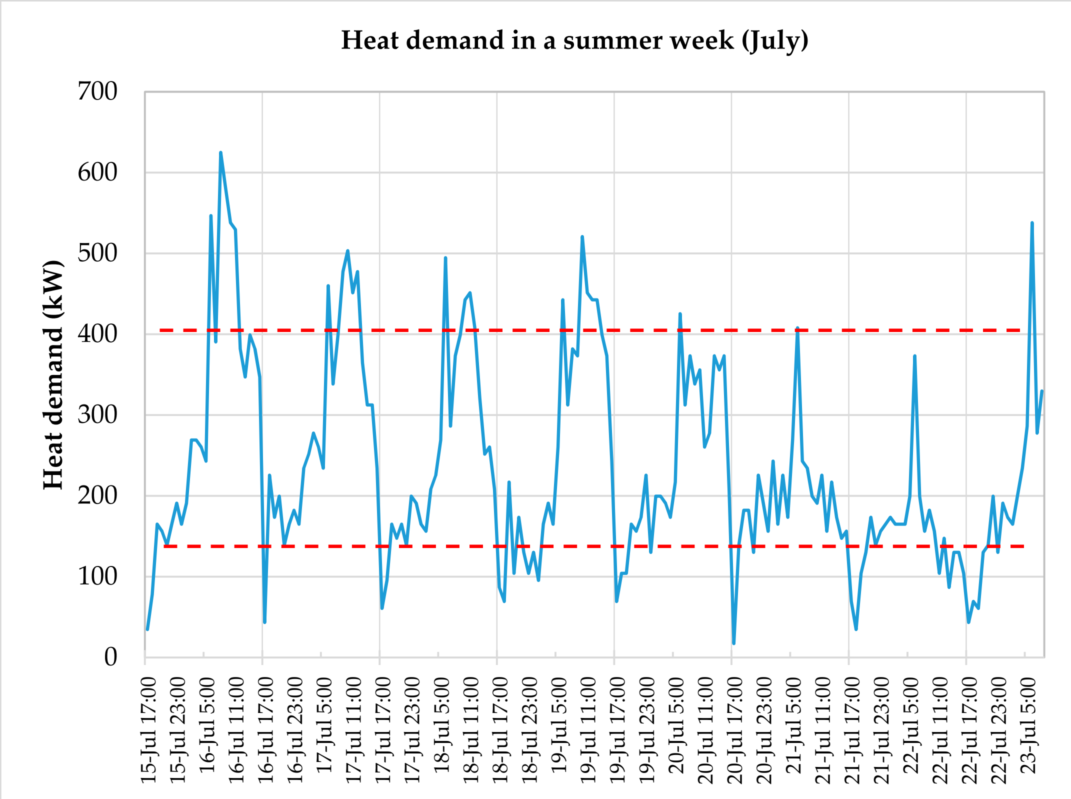

Figure 13. Heat demand in a summer week (July).

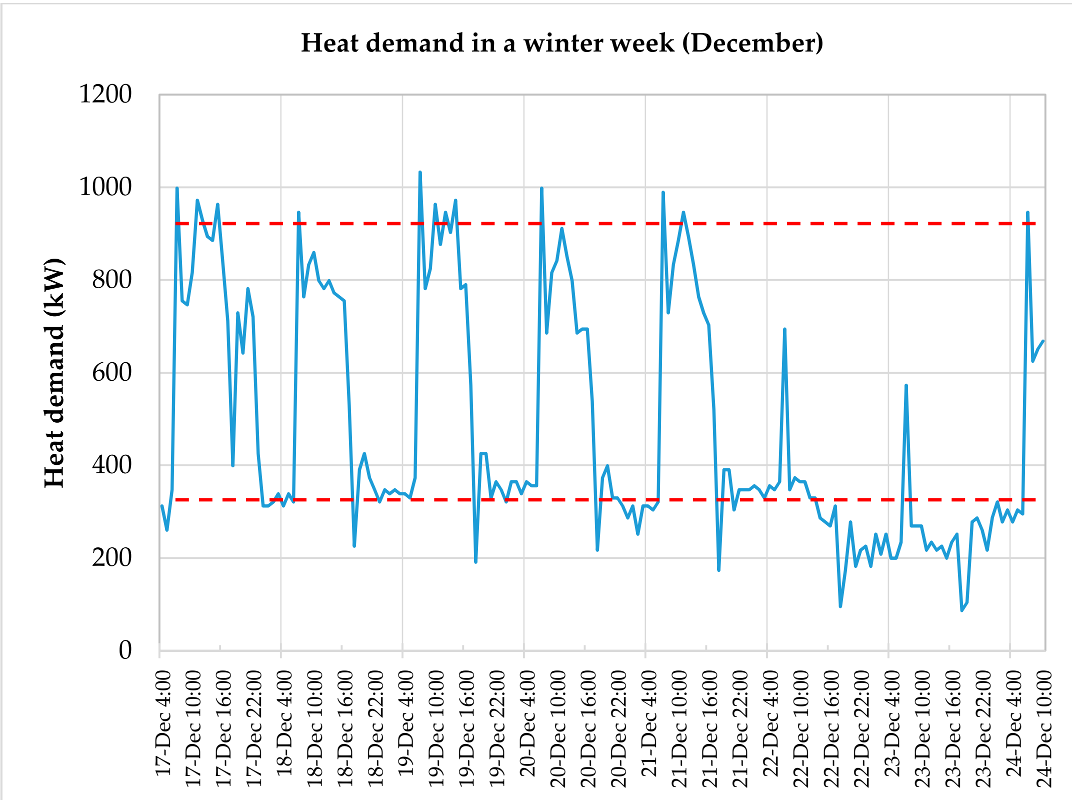

Figure 14. Heat demand in a winter week (December).

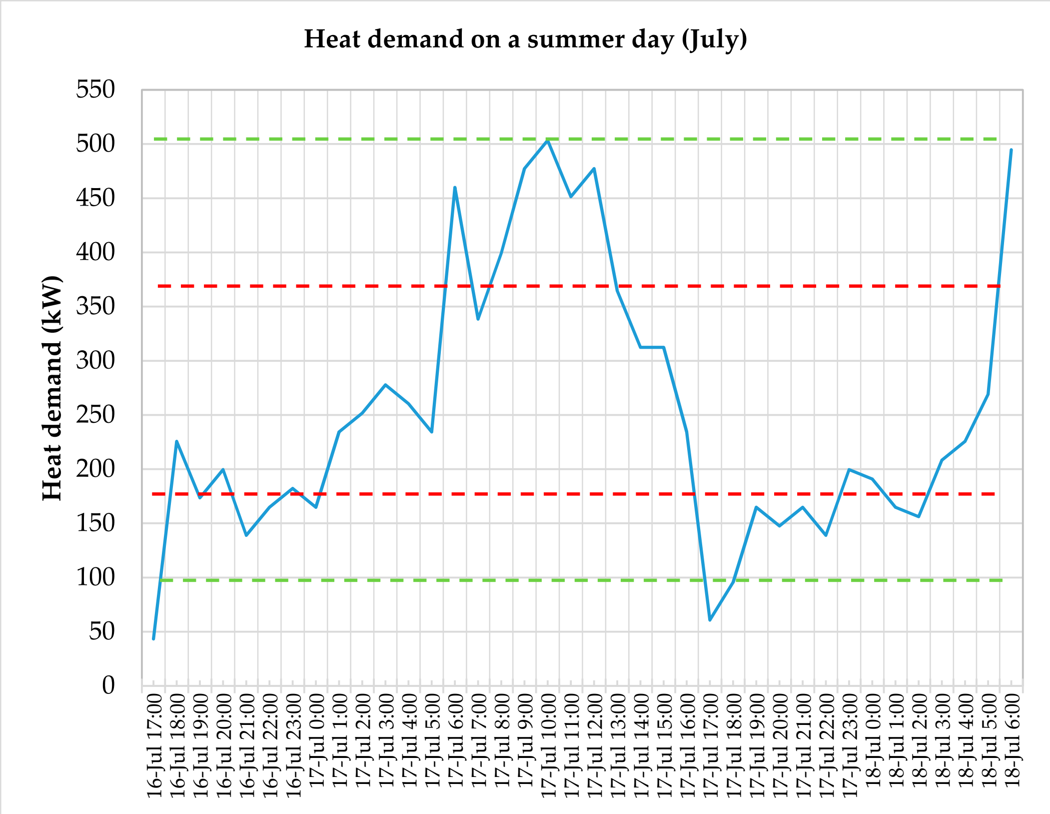

Figure 15. Heat demand on a summer day (July).

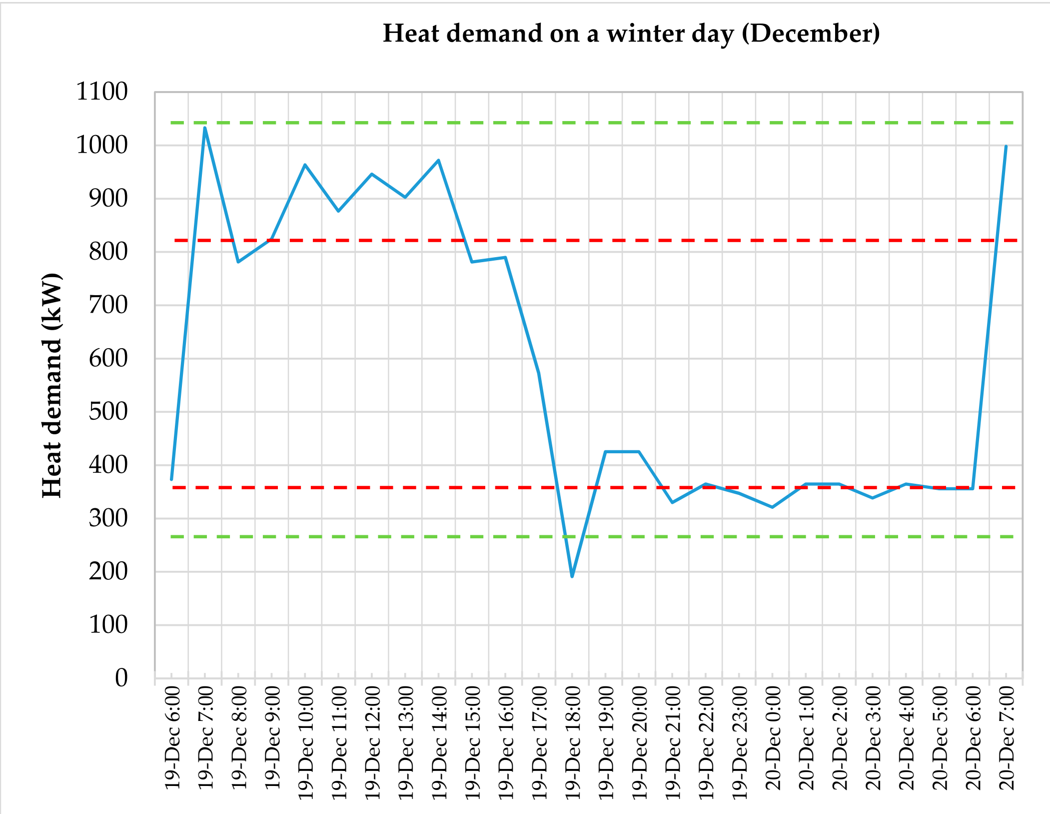

Figure 16. Heat demand on a winter day (December).

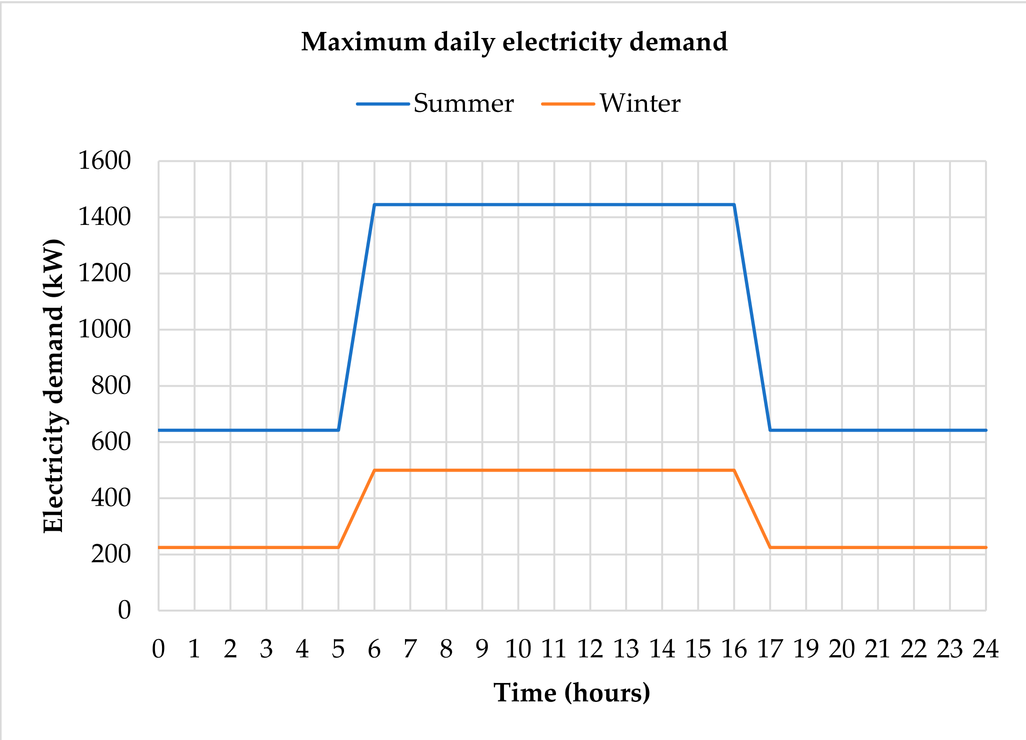

Figure 17. Maximum electricity demand on a summer/winter day.

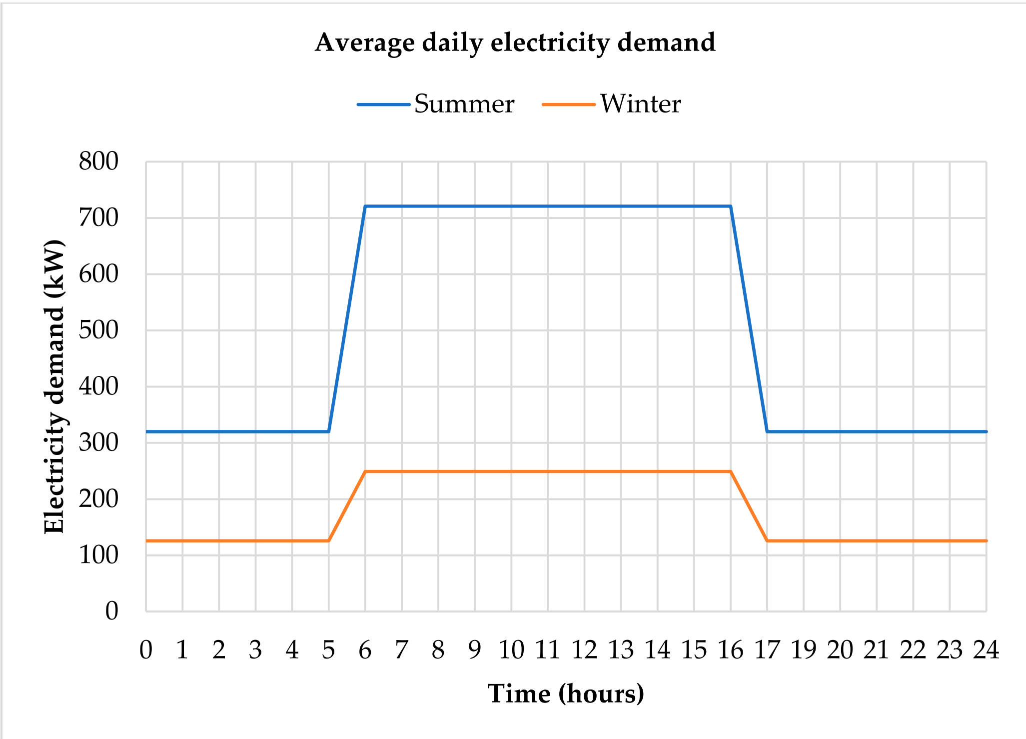

Figure 18. Average demand for electricity on a summer/winter day.

4. The Results of the Investigations

The results of the investigations regarding the viability of cogeneration and trigeneration are highlighted in the following scenarios.

4.1. Case 1. Cogeneration (1 × 200 kW$_e$, 1 × 256 kW$_t$)

In the first case (Figure 19), the economic viability of a cogeneration unit with an internal combustion engine using natural gas combustion with the following nominal characteristics is analyzed:

- Electrical power: 200 kW$_e$;
- Thermal power: 256 kW$_t$;
- Fuel power: 535 kW;
- Electricity efficiency: 37.38%;
- Heat efficiency: 47.85%;
- Overall efficiency: 85.23%.

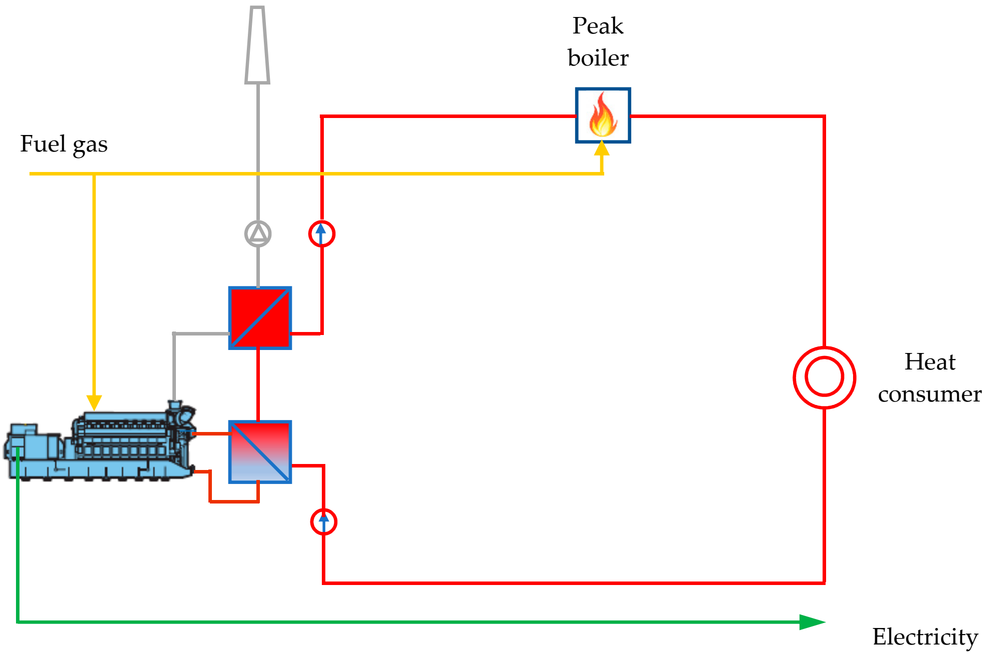

Figure 19. Cogeneration with a single unit and peak boiler.

Given the load duration curve for the heat demand (Figure 10), the operating time at the rated thermal load is 2504 h/year. The following are the characteristic data results for the cogeneration system:

- Heat production: 256 × 2504 = 641,024 kWh (35% of the low temperature heat consumption in the form of hot water, recorded in the previous year of operation);
- Electricity production: 200 × 2504 = 500,800 kWh (21% of electricity consumption, recorded in the previous year of operation);
- Natural gas consumption: 535 × 2504 = 1,339,640 kWh (127,828 m^3).

To estimate the annual savings, it is necessary to break down the fuel consumption of the two forms of useful energy generated, according to the following algorithm:

1. Thermal energy considered to be generated with the efficiency of the current hot water boilers: 641,024/0.92 = 696,765 kWh;
2. This amount is subtracted from the total amount of natural gas consumed in cogeneration, resulting in the fuel consumption for electricity generation: 1,339,640 kWh − 696,765 kWh = 642,875 kWh;
3. The cost of fuel consumed to generate electricity in cogeneration: 642 875 kWh × 0.036 EUR/kWh = 23,143 EUR/year;
4. The cost of electricity currently purchased from the public energy grid, which will be generated in cogeneration: 500,800 kWh × 0.11 EUR/kWh = 55,088 EUR/year;
5. Operation and maintenance cost (O&M): 7920 EUR/year;
6. Annual savings: 55,088 − 23,143 − 7920 = 24,025 EUR/year.

The following investment values were considered for the calculation of the payback period:

- Specific investment: 1320 EUR/kW$_e$;
- Total investment: 1320 × 200 = EUR 264,000;
- Payback period: EUR 264,000/24,025 EUR/year = 10.99 years.

The results obtained for this scenario are summarized in Figure 20 and Table 4. The scenario was also estimated when the specific investment was 20% higher (unforeseen expenses) at 1584 EUR/kW$_e$. This results in a payback period of 13.19 years. The reduction in CO_2 emissions in this scenario is 87,044 kgCO_2/year.

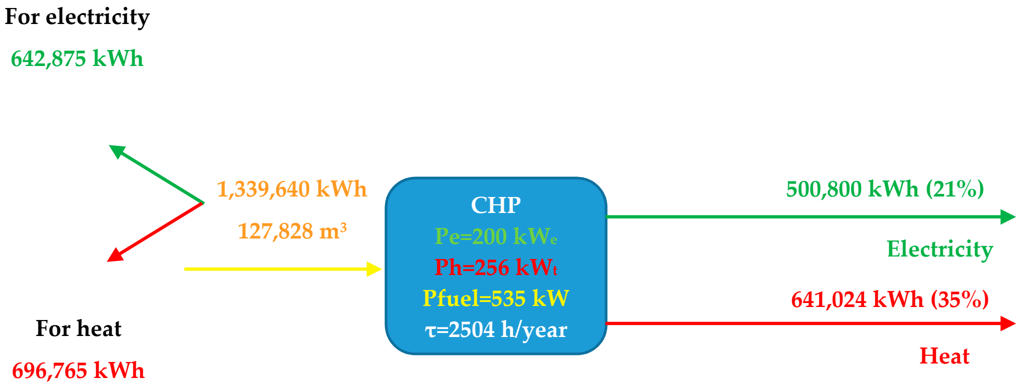

Figure 20. Cogeneration (1 × 200 kW$_e$, 1 × 256 kW$_t$).

Table 4. Cogeneration (1 × 200 kW$_e$, 1 × 256 kW$_t$): summary results.

	U.M.	Value	Investment Growth by 20%
Cost of electricity purchased	EUR/year	55,088	55,088
Fuel cost for electricity generation	EUR/year	23,143	23,143
O&M costs	EUR/year	7920	7920
Specific investment in CHP	EUR/kW$_e$	1320	1584
Annual savings	EUR/year	24,025	24,025
Total investment	EUR	264,000	316,800
Payback period	Years	10.99	13.19

Note: The determination of the annual savings and the payback period for the following scenarios, is based on the same calculation algorithm; therefore, only the main characteristics of the analyzed variants and the data synthesis will be presented.

4.2. Case 2. Cogeneration (2 × 100 kW$_e$, 2 × 130 kW$_t$)

In the second case, the economic viability of a cogeneration system with two identical cogeneration units is analyzed (Figure 21):

- Electrical power: 2 × 100 kW$_e$;
- Thermal power: 2 × 130 kW$_t$;
- Fuel power: 2 × 271 kW;
- Electricity efficiency: 36.90%;
- Heat efficiency: 47.97%;
- Overall efficiency: 84.87%.

Given the load duration curve for the heat demand (Figure 10), the operating time at the rated thermal load is 4998 h/year for the first CHP unit, and 2492 h/year for the second CHP unit. The following are the characteristic data results for the cogeneration system:

- Heat production: (130 × 4998) + (130 × 2492) = 973,700 kWh (53% of the low temperature heat consumption in the form of hot water, recorded in the previous year of operation);
- Electricity production: (100 × 4998) + (100 × 2492) = 749,000 kWh (31% of electricity consumption, recorded in the previous year of operation);
- Natural gas consumption: (271 × 4998) + (271 × 2492) = 2,029,790 kWh (213,128 m^3);

- Annual savings: 37,939 EUR/year;
- Total investment: 316,000 EUR/year;
- Payback period: 8.33 years;
- Reducing CO_2 emissions: 128,429 $kgCO_2$/year.

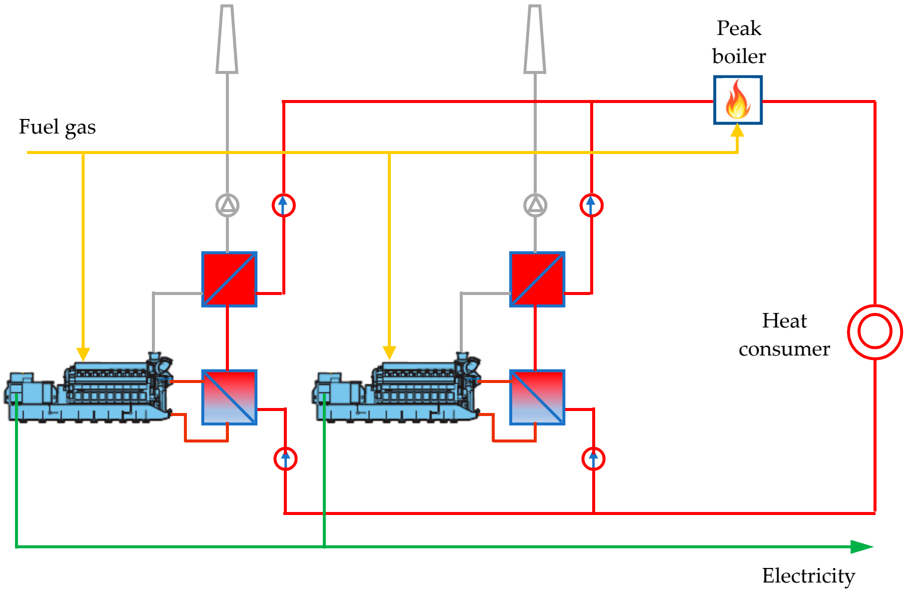

Figure 21. Cogeneration with two units and a peak boiler.

The results obtained for this scenario are summarized in Figure 22 and Table 5.

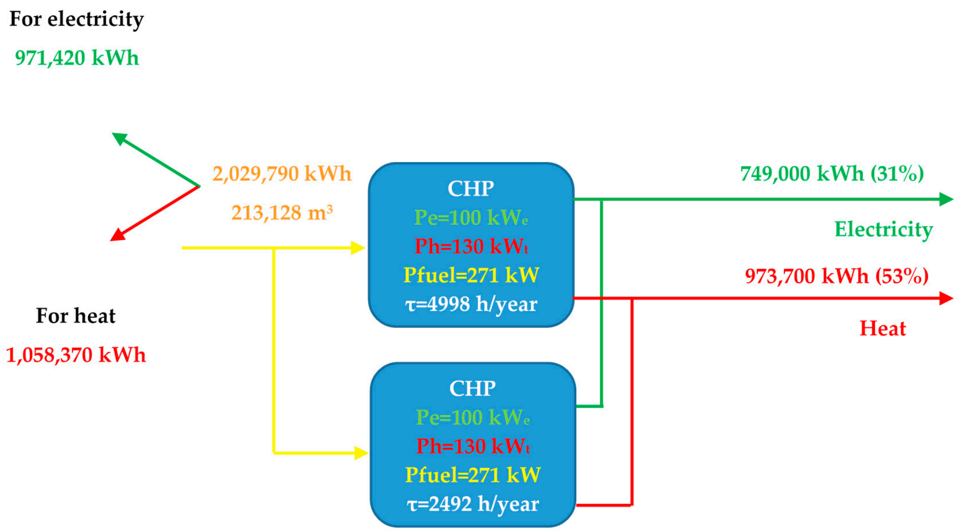

Figure 22. Cogeneration (2 × 100 kW_e, 2 × 130 kW_t).

Table 5. Cogeneration (2 × 100 kW_e, 2 × 130 kW_t): summary results.

	U.M.	Value	Investment Growth by 20%
Cost of electricity purchased	EUR/year	82,390	82,390
Fuel cost for electricity generation	EUR/year	34,971	34,971
O&M costs	EUR/year	9480	9480
Specific investment in CHP	EUR/kW_e	1580	1896
Annual savings	EUR/year	37,939	37,939
Total investment	EUR	316,000	379,200
Payback period	Years	8.33	10.00

4.3. Case 3. Cogeneration (2 × 100 kW$_e$, 2 × 130 kW$_t$) and Heat Storage (3000 kWh)

In this scenario, in addition to the previous scenario, heat storage is used (Figure 23) using 3000 kWh (heat accumulation 200 kW$_t$ for an operating time of 15 h). The results obtained for this scenario are summarized in Figure 24 and Table 6.

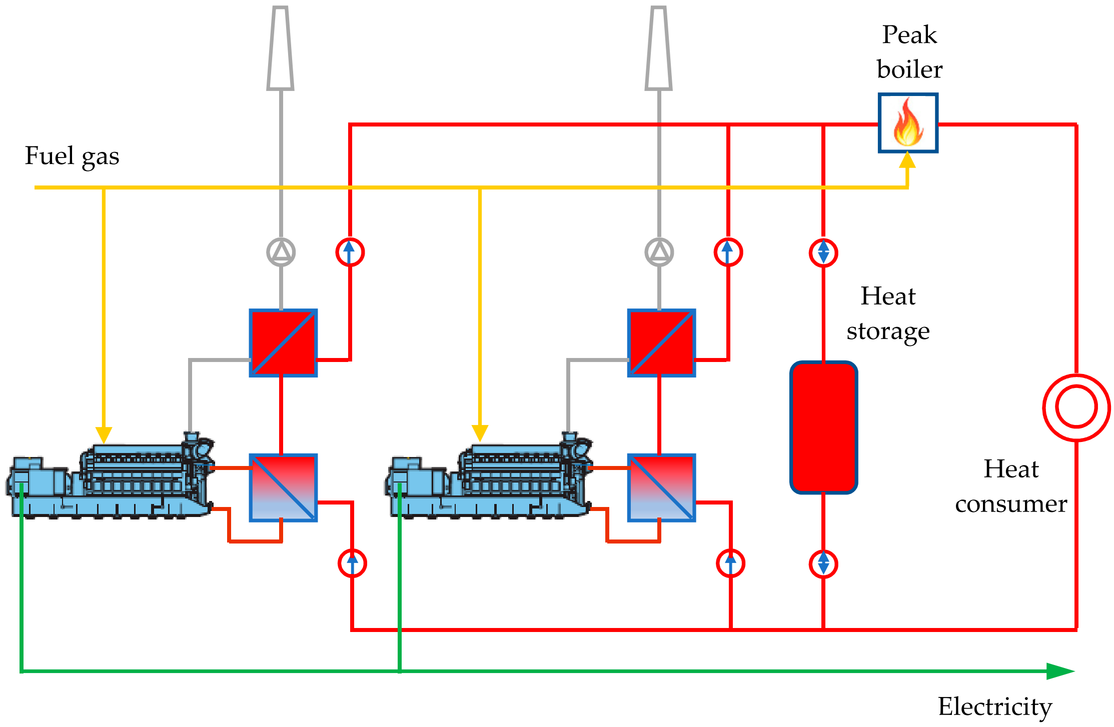

Figure 23. Cogeneration with two units, heat storage, and a peak boiler.

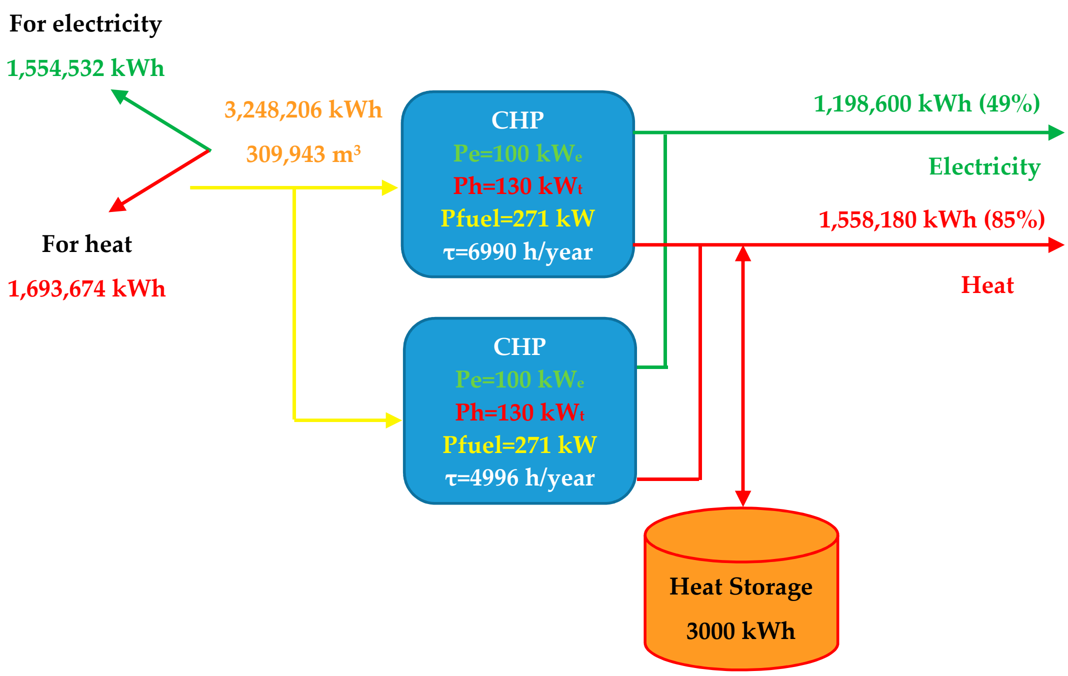

Figure 24. Cogeneration (2 × 100 kW$_e$, 2 × 130 kW$_t$) and heat storage.

Table 6. Cogeneration (2 × 100 kW_e, 2 × 130 kW_t) and heat storage: summary results.

	U.M.	Value	Investment Growth by 20%
Cost of electricity purchased	EUR/year	131,846	131,846
Fuel cost for electricity generation	EUR/year	55,963	55,963
O&M costs	EUR/year	10,380	10,380
Specific investment in CHP	EUR/kW_e	1580	1896
Specific investment in heat storage	EUR/kW_t	10	12
Annual savings	EUR/year	65,503	65,503
Total investment	EUR	346,000	415,200
Payback period	Years	5.28	6.34

By introducing heat storage, the operating time at the rated thermal load will increase to 6990 h/year for the first CHP unit, and 4996 h/year for the second CHP unit. The following are the characteristic data results for the cogeneration system:

- Heat production: (130 × 6990) + (130 × 4996) = 1,558,180 kWh (85% of the low temperature heat consumption in the form of hot water, recorded in the previous year of operation);
- Electricity production: (100 × 6990) + (100 × 4996) = 1,198,600 kWh (49% of electricity consumption, recorded in the previous year of operation);
- Natural gas consumption: (271 × 6990) + (271 × 4996) = 3,248,206 kWh (309,943 m^3);
- Annual savings: 65,503 EUR/year;
- Total investment: 346,000 EUR/year;
- Payback period: 5.28 years;
- Reducing CO_2 emissions: 205,521 $kgCO_2$/year.

4.4. Case 4. Trigeneration (2 × 100 kW_e, 2 × 130 kW_t), Heat Storage (3000 kWh), and Absorption Chiller (180 kW)

In this scenario, in addition to the previous scenario, an absorption chiller is used, with a cooling power of 180 kW, and coefficient of performance (COP) = 0.7 (Figure 25). The results obtained for this scenario are summarized in Figure 26 and Table 7.

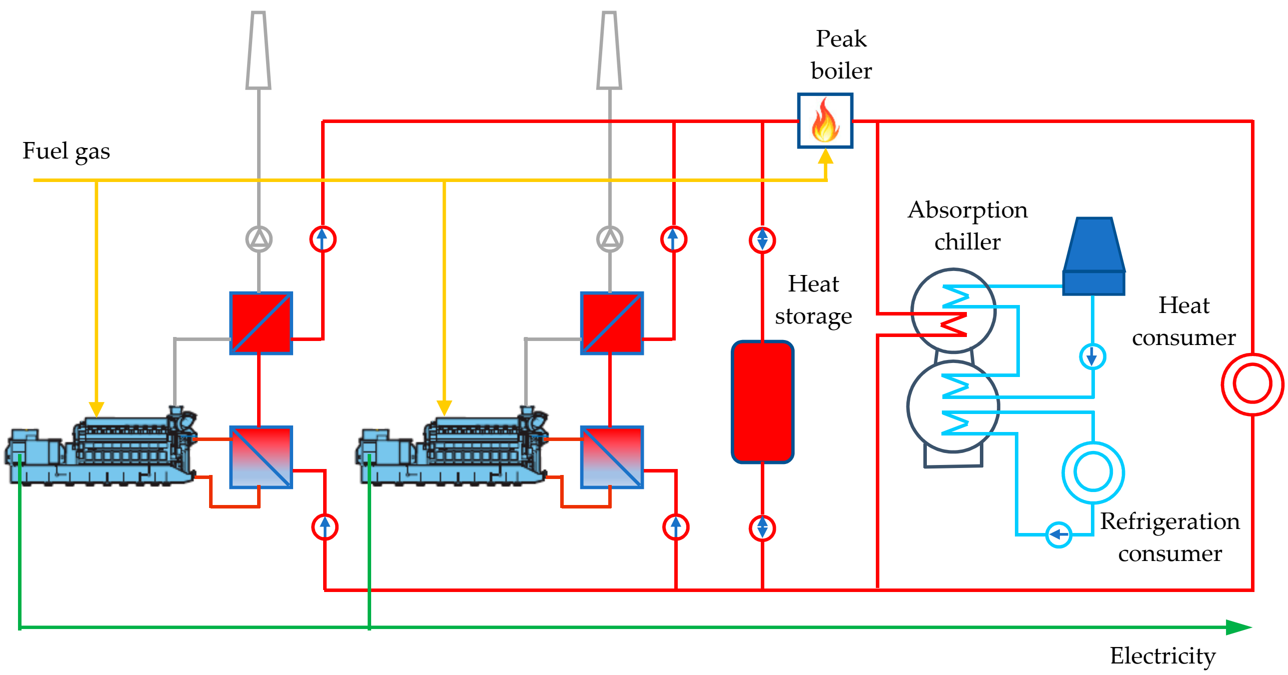

Figure 25. Trigeneration with two units, heat storage, and a peak boiler.

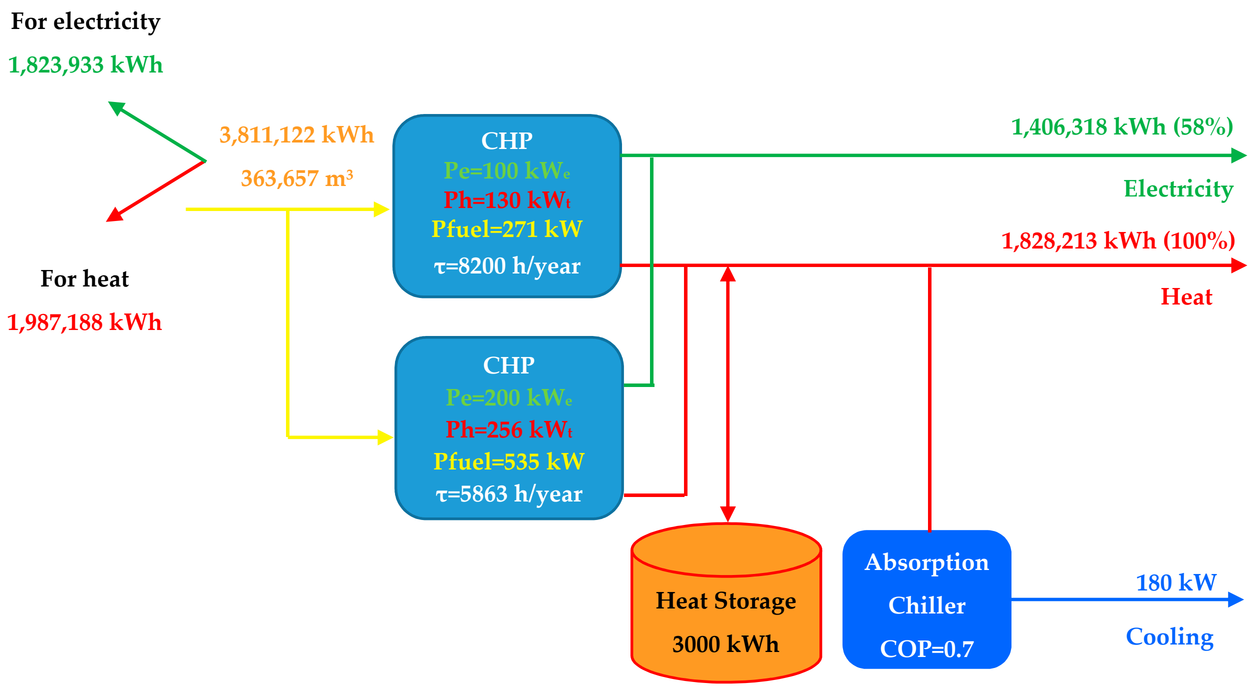

Figure 26. Trigeneration with two units (2 × 100 kW_e, 2 × 130 kW_t) and heat storage (3000 kWh).

Table 7. Trigeneration (2 × 100 kW_e, 2 × 130 kW_t) and heat storage: summary results.

	U.M.	Value	Investment Growth by 20%
Cost of electricity purchased	EUR/year	154,695	154,695
Fuel cost for electricity generation	EUR/year	65,662	65,662
O&M costs	EUR/year	11,730	11,730
Specific investment in CHP	EUR/kW_e	1580	1896
Specific investment in heat storage	EUR/kW_t	10	12
Specific investment in chiller	EUR/kW	250	300
Annual savings	EUR/year	77,303	77,303
Total investment	EUR	391,000	415,200
Payback period	Years	5.06	5.37

The thermal potential available during the summer (hot water 80/60 °C), and which can be delivered from the cogeneration plant, was considered when sizing the absorption chiller. Therefore, for this thermal level, single-stage chiller modules were considered for their flexibility in operation.

By introducing heat storage and using the heat available during the summer in an absorption refrigeration system, the operating time at the rated thermal load will increase to 8200 h/year for the first CHP unit, and 5863 h/year for the second CHP unit.

The following are the characteristic data results for the cogeneration system:

- Heat production: (130 × 8200) + (130 × 5863) = 1,828,213 kWh (100% of the low temperature heat consumption in the form of hot water, recorded in the previous year of operation);
- Electricity production: (100 × 8200) + (100 × 5863) = 1,406,318 kWh (58% of the low temperature heat consumption in the form of hot water, recorded in the previous year of operation);
- Natural gas consumption: (271 × 8200) + (271 × 5863) = 3,811,122 kWh (363,657 m^3);
- Annual savings: 77,303 EUR/year;
- Total investment: 391,000 EUR/year;
- Payback period: 5.06 years;
- Reducing CO_2 emissions: 241,138 $kgCO_2$/year.

4.5. Case 5. Trigeneration (1 × 100 kW$_e$, 1 × 200 kW$_e$, 1 × 130 kW$_t$, 1 × 256 kW$_t$), Heat Storage (3000 kWh), and Absorption Chiller (250 kW)

In this scenario, the economic viability of the trigeneration system with two different cogeneration units of the type used in the previous variants is analyzed:

- Electrical power: 1 × 100 kW$_e$;
- Thermal power: 1 × 130 kW$_t$;
- Fuel power: 1 × 271 kW;
- Electricity efficiency: 36.90%;
- Heat efficiency: 47.97%;
- Overall efficiency: 84.87%;
- Electrical power: 1 × 200 kW$_e$;
- Thermal power: 1 × 256 kW$_t$;
- Fuel power: 1 × 535 kW;
- Electricity efficiency: 37.38%;
- Heat efficiency: 47.85%;
- Overall efficiency: 85.23%;
- Heat storage: 3000 kWh (heat accumulation 200 kW$_t$ for an operating time of 15 h);
- Absorption chiller, cooling power: 250 kW (COP = 0.7).

The results obtained for this scenario are summarized in Figure 27 and Table 8.

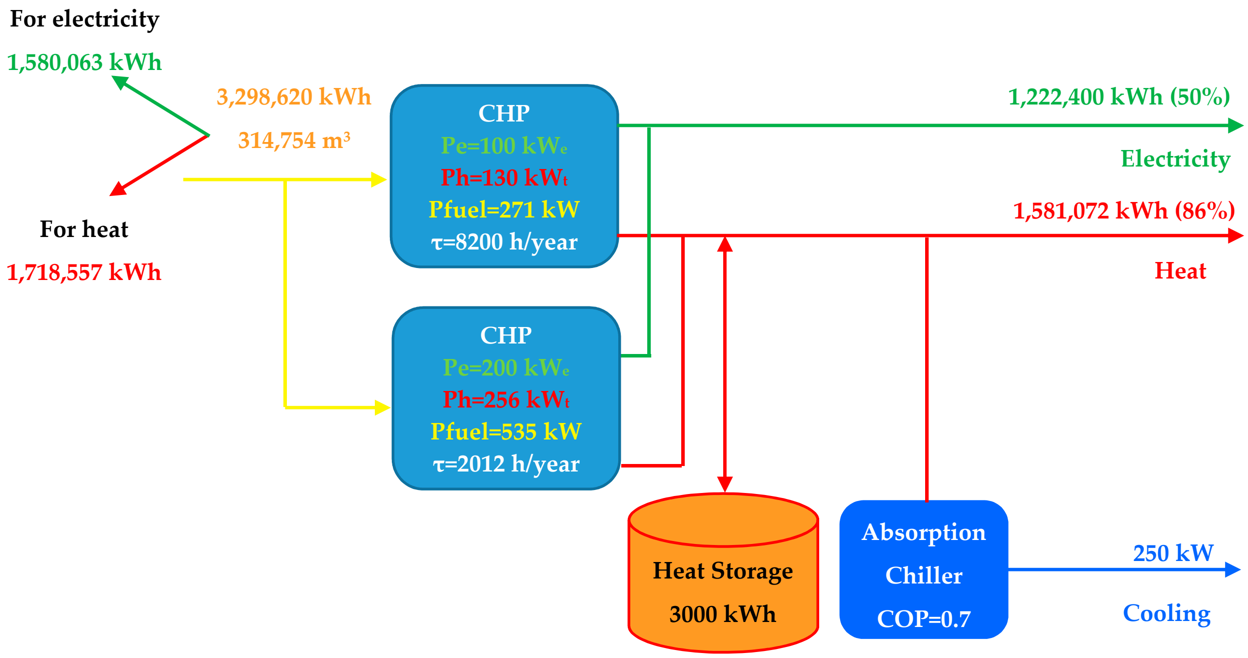

Figure 27. Trigeneration with two different units (1 × 100 kW$_e$, 1 × 200 kW$_e$, 1 × 130 kW$_t$, 1 × 256 kW$_t$) and heat storage.

By introducing heat storage and using the heat available during the summer in an absorption refrigeration system, the operating time at the rated thermal load will be 8200 h/year for the first CHP unit, and 2012 h/year for the second CHP unit. It can be seen that, in this scenario, there is a thermal power reserve installed in the second CHP unit (higher power unit); therefore, the annual operating time of this CHP unit will increase with increased drug production and heat demand.

Table 8. Trigeneration (1 × 100 kW_e, 1 × 200 kW_e, 1 × 130 kW_t, 1 × 256 kW_t) and heat storage: summary results.

	U.M.	Value	Investment Growth by 20%
Cost of electricity purchased	EUR/year	134,464	134,464
Fuel cost for electricity generation	EUR/year	56,882	56,882
O&M costs	EUR/year	15,435	15,435
Specific investment in CHP_{100}	EUR/kW_e	1580	1896
Specific investment in CHP_{200}	EUR/kW_e	1320	1584
Specific investment in heat storage	EUR/kW_t	10	12
Specific investment in chiller	EUR/kW	250	300
Annual savings	EUR/year	62,147	62,147
Total investment	EUR	514,500	604,800
Payback period	Years	8.28	9.73

5. Summary Results and Discussion

Heat demand is the decisive factor in justifying the efficiency of the cogeneration solution and is foundational for sizing a cogeneration unit; therefore, at the installation site, the most rigid conditioning of the operating regime, in the case of cogeneration systems, is determined by the thermal consumption. The differences in electricity between the on-site consumption and the production of the CHP plant (proportional to the thermal load) are compensated, without technical difficulties, from the public electricity network to which the CHP plant is connected. In order for a cogeneration system to be viable in energy savings (with sufficient energy savings to compensate for the investment effort), the annual operating time of the cogeneration plant must be sufficiently long, loading as close as possible to the rated load. An annual operating time of at least 4000 h/year for a cogeneration unit can be considered as one of the basic rules that are necessary to abide by.

The basic question that any potential investor faces is the viability and profitability of the cogeneration solution under the specific conditions of the plant location. Figure 28 comparatively shows all the scenarios analyzed in terms of the payback period and the reduction in carbon dioxide emissions. The economic and environmental viability of cogeneration and trigeneration solutions can be easily seen in all scenarios. Obviously, the heat demand and the annual time of this demand are the main factors that influence the profitability of cogeneration solutions.

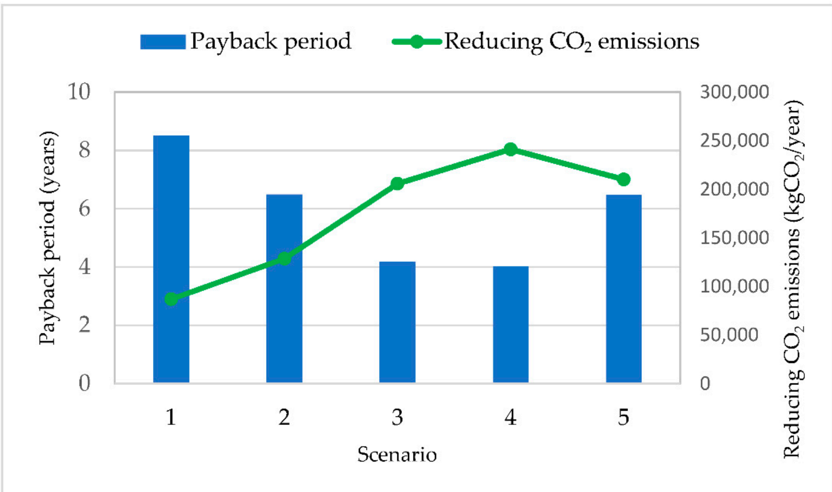

Figure 28. The payback period (PBP) and reducing CO_2 emissions.

Of all the scenarios analyzed, Scenario 4 and Scenario 5 can be considered as possible solutions to be implemented. Due to the variable nature of heat demand, there is a need for heat storage, as well as the fragmentation of power, in several cogeneration units to increase the operational flexibility of these units.

Scenario 4 is characterized as the optimal economic option for the current energy demand profiles. This scenario ensures the highest values of heat and electricity production, respectively, but also the shortest payback period on investment. In addition, the reduction in carbon dioxide emissions has the greatest value in this scenario.

In Scenario 5, there is a thermal power reserve installed in the second CHP unit (the higher power unit); therefore, the annual operating time of this CHP unit will increase with the expansion in drug production and, implicitly, the payback period on investment will reduce.

6. Conclusions

Current research on the transition to carbon-free energy generation are dominated by renewable energy solutions; however, the continued use of natural gas with the aid of energy efficient technologies, such as cogeneration, seems to be one of the solutions for transitioning to a decarbonized energy system.

The proper sizing and selection of equipment is the most important factor for the success of any cogeneration project. If the selection is incorrect, the CHP system will not properly meet the energy demand or the expected payback period.

The main issues investigated by us in this case study were the variation in heat and electricity demands, and the flattening of the load duration curve for the heat demand. Thus, the heat demand was analyzed in detail and with high accuracy to identify the hourly, daily, weekly, monthly, and annual load profiles. The main purpose of integrating heat storage is the takeover of load variations and to increase the flexibility of the cogeneration plant. A heat storage system will allow a cogeneration unit to work continuously and, consequently, avoid repeated startups and stops that may harm it.

The oversizing of a cogeneration system compared with the consumption needs of an analyzed meter can negatively influence the economic viability of cogeneration and trigeneration projects. If the power of the CHP plant exceeds the consumption needs of the site, the surplus electricity will be delivered to the public electricity network, usually at a much lower rate than the purchase. On the other hand, if the thermal power in cogeneration exceeds the consumption needs, the resulting excess heat will usually be discharged into the atmosphere, as a lost amount of heat. In both cases, the energy savings achieved are not as expected, and the payback period of the cogeneration project increases accordingly.

A major economic incentive for the application of cogeneration technology is the reduction in operating costs by generating electricity at a lower cost than the cost of purchase from the local electricity supplier; therefore, the application of cogeneration can be viable if there is a significant difference between the cost of natural gas and the cost of electricity purchased from the public network. An approximate 1:3 ratio between the cost of natural gas and the cost of electricity was considered in this study. Electricity is significantly more expensive than natural gas, and the viability of cogeneration applications is therefore much more sensitive to changes in the unit price of electricity purchased from the public network.

The results of this study demonstrate the economic and technical viability of the proposed cogeneration and trigeneration solutions. For the values of the electricity and natural gas prices at the time of the analysis (2021), Scenario 4 is characterized as the optimal economical and technical option for the current consumption situation, as it ensures the highest values of heat and electricity production, and the shortest investment payback period (5.06 years). Compared with the separate generation of heat and power, we highlight a primary energy saving of 25.35% and a reduction in CO_2 emissions of 241,138 kg CO_2/year.

Author Contributions: All authors contributed equally to the idea and the design of the methodology proposed, and to the production of the research paper. Conceptualization, P.A. and R.D.P.; methodology, P.A.; software, L.D.M.; validation, P.A., R.D.P. and L.D.M.; formal analysis, R.D.P.; investigation, P.A.; resources, L.D.M.; writing—review and editing, P.A.; visualization, L.D.M.; supervision, R.D.P. All authors have read and agreed to the published version of the manuscript.

Funding: This research received no external funding.

Institutional Review Board Statement: Not applicable.

Informed Consent Statement: Not applicable.

Data Availability Statement: Not applicable.

Conflicts of Interest: The authors declare no conflict of interest.

Nomenclature

q_m	minimum heat demand (kW_t);
q_{md}	average heat demand (kW_t);
q_M	maximum heat demand (kW_t);
τ_F	annual time of heat demand (hours/year);
q_h	heat demand (kW_t);
Q_{CHP}	amount of heat generated in cogeneration (kWh/year);
P_h	thermal load of the cogeneration plant (kW_t);
P_{nh}	rated thermal load of the CHP plant (kW_t);
b_{CHP}	fuel consumption of the CHP plant (kW_t);
η_{boiler}	boiler efficiency (%);
P_{ne}	rated power of the CHP plant (kW_e);
$p_{naturalgas}$	price of natural gas (EUR/kWh);
$p_{electricity}$	price of electricity (EUR/kWh);
$p_{O\&MCHP}$	operation and maintenance cost (EUR/kWh);
i	discount rate;
N	lifetime of the investment (years);
W_{sep}	primary energy consumption for separate generation (kWh);
W_{CHP}	primary energy consumption in cogeneration (kWh);
η_{hCHP}	heat efficiency of cogeneration generation (%);
η_{eCHP}	electrical efficiency of cogeneration generation (%);
η_{hRef}	efficiency reference value for separate generation of heat (%);
η_{eRef}	efficiency reference value for separate production of electricity (%);
p_{loss}	correction factor for avoided grid losses.

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Review

Future Research Tendencies and Possibilities of Using Cogeneration Applications of Solar Air Heaters: A Bibliometric Analysis

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Abstract: Solar air heater systems are equipment that uses energy captured directly from the sun to heat an existing airflow through the module. The technology to operate these systems is based on clean, renewable and free energy. Solar air heaters absorb thermal energy from the sun using an ab-sorption surface and achieve a transfer of heat from the absorption surface to the air flow supplied by one or two fans. This type of equipment can be used for space heating, drying, or ventilation processes. In addition, the equipment is capable of operating in cogeneration with other systems, e.g., preheating the air used for drying wood, preheating the air used to heat industrial premises, or preheating the water used in different heating systems. This scientific work is meant to reveal the current research context and the future opportunities in the case of cogeneration applications of solar air heaters, which are analyzed in light of their actual evolving dynamics. On this basis, we highlight expectations regarding the main problems that the regenerable energy is currently facing in this specific research and development environment as well as focusing our direction on the eventual solutions that are considered in the present and on their shortcomings in the future with evolved necessities.

Keywords: research tendencies; cogeneration; optimization; bibliometric; solar air heater; SAHs; solar energy; VosViwer; bibliometrix

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Citation: Ifrim, V.C.; Milici, L.D.; Atănăsoae, P.; Irimia, D.; Pentiuc, R.D. Future Research Tendencies and Possibilities of Using Cogeneration Applications of Solar Air Heaters: A Bibliometric Analysis. *Energies* **2022**, *15*, 7114. https://doi.org/10.3390/en15197114

Academic Editor: Dimitrios Katsaprakakis

Received: 5 September 2022
Accepted: 25 September 2022
Published: 28 September 2022

1. Introduction

Bibliometrics involves achieving quantitative analyses in the field of academic literature and represents the statistical analysis of publications in different research fields. Bibliometric analyses are studies used to clarify the significance of different areas of research. The scope of this study is to perform a bibliographic analysis in the field of solar air heating systems (SAHs). The importance and usefulness of these systems is found in various applications where hot air is a necessity, due to the simplicity in operation and low costs of realization and operation.

Membrane distillation (MD) lags behind due to the relatively high energy consumption compared to other desalination processes, e.g., reverse osmosis. Membrane heating in distillation is the key and significant component of total energy consumption. To make membrane distillation competitive with existing technologies, research should turn to low-cost energy sources or alternative heating methods. The development of alternative methods of heating is based on the direct heating of the supply water. Direct heating of the water supply near the surface of the membrane by means of solar air heating systems can improve the thermal efficiency and economy of the distillation process [1].

A desalination system with humidification and dehumidification (HDH) requires heat to carry out the process of seawater desalination [2]. An effective and environmentally friendly approach to obtain heat energy is the use of solar energy using solar air heaters. Seawater, air, or both are usually preheated by desalination systems before they are entered into the humidifier. Compared to preheating only water or just air, preheating both is preferable, since this results in high performance and productivity. The most proposed desalination model is the one with a double preheating system that uses two separate solar systems for the simultaneous preheating of air and seawater. Simultaneous heating of sea water and air can also be carried out with a single solar air heating system. This type of system has at mass flow rates of 0.005, 0.010 and 0.020 kg/s the maximum air temperature values 66 °C, 62 °C and 57 °C, respectively, while the maximum values achieved for the seawater temperature were 83 °C, 78 °C and 73 °C, respectively. The maximum hourly productivity observed for the desalination system with humidification and dehumidification with a single SAH was 6.20 kg/h for an air mass flow of 0.005 kg/s. The highest values for the average monthly air temperature and for the sea water temperature were 60 °C and 69 °C, respectively.

The solar air heater is a device with huge potential for harnessing solar thermal energy [3]. The main advantages of this type of equipment are its simple technology and the abundance of solar energy. Globally recorded data show a huge consumption of energy used to heat spaces. This thus justifies the need for and usefulness of a SAH for space heating. The most common problem for this type of system, in some areas, is the day–night variation and the uncertainty of solar radiation, due to the seasons. For high thermal efficiency, modifications were made to the systems, especially the absorption surfaces, for the use of a longer period of a solar heating system with air at the day–night variation. Solar systems with thermal energy storage were proposed for a while. The question remains of the variation of the seasons that force the use of these systems in areas with solar radiation for a long time of the year.

For energy saving, solar air-heating systems are of high interest in the drying field of agri-food products. Among the dried products with such systems, we mention the following: figs [4], grapes [5], tapioca [6], medicinal herbs [7], red algae [8], black pepper [9], chili peppers [10], corn kernels [11], and bananas [12]. In addition, solar air heaters can be used in hybrid and cogeneration systems, such as a transpired solar air heater with a heat exchanger type capillary tube [13,14]; solar air heater, heat pump and ionic liquids; SAH and PV-T; SAH with thermochemical heat storage system; and solar air heater with a ventilation system [13].

The optimization of systems in this field is closely related to the type of application used or studied. The present study highlights the evolution of solar air heaters (SAHs) and the future trends of this field of study. The bibliometric study was conducted making use of the "Web of Science" database for the analysis of scientific articles published between 2017 and 2021 in the field of solar air-heater systems. The information used for the analysis was collected during February 2022 from 1355 articles constituting the total of articles published over the five-year period in the field of solar air-heating systems, wherein the words "solar air heater" was met at least once. From preliminary analyses of future trends in this area, important possibilities emerged. The scientific data were centralized and analyzed with the help of the following software: Microsoft Excel, VosViwer and Bibliometrix. The main recommendation of the study is to continue optimizing and improving solar air heaters applicable in other areas, not just in areas where air heating is required.

The bibliometric analysis was made out of the desire to better understand the scientific directions in the realm of solar air heater systems. Analyses of this type look for publications and their properties to expose them visually for a better understanding of the evolution in the studied field [15]. The quality of the results of a bibliometric study depends on the correctness of the information and the information entered. For a fair appreciation it is significant to approach the literature of solar air heating systems in an objective, unbiased manner.

Bibliometric analysis is an area that provides help in analyzing publications, delivers support in evaluating research and helps authors find new collaborators and possible topics with major impact. Bibliometric analysis is based on bibliographic information and can be a way to increase visibility into the specific field of research [16].

The use of bibliometric analysis helps to understand the structures and knowledge in a particular field of research, representing a start in the realization of a publication for researchers at the beginning of the road.

In the purpose of creating bibliometric networks with the help of bibliometric analyzers, the results are generated, mainly, starting from text-based data, which are saved in the form of an appropriate file (e.g., txt), after it is generated and downloaded directly from one of the online platforms that host databases of scientific papers (e.g., Web of Science) so that it includes complete data fields (e.g., title, authors, affiliation, and abstract) regarding a collection of scientific papers that are selected for analysis [17,18].

After they are gathered, a selected collection of data is imported into the analysis software and is further interpreted according to specific software configurations, which are slightly adjusted to provide improved readability after they are individually chosen and imposed for each generated result, as, in this manner, it is easy to obtain a bibliometric network that offers a raw and clear overview, while it highlights un-distorted ideas that address the proposed topic [17,19].

2. Scope

Bibliometric analysis is used to obtain quantitative analyses in the field of academic literature and represents the statistical analysis of publications in different research fields. Bibliometrics are used to determine the strength and weakness of a field of study from an objective point of view. At the moment, there are many bibliometric studies in the field of renewable sources, but very few are centered on the bibliometric inquiry of solar air heaters. Researcher A. Benhamza from the Faculty of Technology, Levres Laboratory, University of El Qued, Algeria, very briefly addressed the problem of bibliometrics in the field of SAHs, in the paper, "Multi-objective design optimization of solar air heater for food drying based on energy, exergy and improvement potential". The emphasis in the work is placed on the methods used to optimize the solar air heaters. Regarding the study and evaluation of the outcome of geometrical indexes on SAHs performance, the paper deals with the response surface methodology (RSM) alongside a numerical model [20].

The current paper presents the bibliometric study of SAHs in an attempt to discover and understand past, current and future trends in research on these systems. Therefore, using the "Web of Science" database, the scientific articles published between 2017 and 2021, in the area of solar air heaters, were analyzed. The articles analyzed represent all the publications where the words "solar air heater" are found at least once. The authors' keywords, the countries with the highest production of articles in the field and the main authors that dominate the area of these solar systems were analyzed. To ease the visualization and understanding of data, graphs were made with the help of the following software: Microsoft Excel 2019, version 2201, developed by Microsoft, Houston, TX, USA; Bibliometrix 3.1 R Package, developed by K-Synth Srl, Naples, Italy; and VosViwer 1.6.17, Centre for Science and Technology Studies, Leiden University, The Netherlands.

Mainly, the purpose of this study is to discover the topic trends and to determine the amount of literature published in the solar air heaters domain considering different solar equipment, different technologies, and different systems combinations, such as hybrid and cogeneration systems.

3. Methodology

For the bibliometric analysis, the steps suggested by two researchers, Zhao D. and Strotmann A., in the paper "Analysis and Visualization of Citation Networks", published in 2015, were followed. The four recommended steps are as follows: the first step (i) is to define the words needed for the search; the second step (ii) is to filter and format the information; in the third step (iii), the initial analysis is conducted; and in the fourth step (iv) the final analysis of the information is carried out. The search was implemented using the topic field which allows searches title, abstract, author keywords and Keywords Plus [21].

With regard to the first step (i) in this bibliographic analysis, the words selected for the search are "solar air heater". The word search was conducted using the data platform "Web of Science" in the title, summary and keywords of the authors.

The “Web of Science” database provides access to publications and their citations for different academic disciplines, for a total of 256 disciplines. The multidisciplinary platform connects data, regional, specialty and patent indices comprising 1.7 billion cited references, over 155 million records and over 34,000 journals [22].

In step two (ii), for the same criteria, 1355 articles were identified representing the total of publications, over the period 2017–2021, in the domain of solar air heating systems in which the words “solar air heater” are found at least once. In order to be uploaded and used in the VosViwer version 1.6.17, software developed by Centre for Science and Technology Studies, Leiden University, The Netherlands and in Bibliometrix program version 3.1 R Package software developed by K-Synth Srl, Naples, Italy, item data were filtered, standardized, and formatted in a text file.

The third step (iii) is to develop and analyze the temporal trends of publications and their citations, classify them by domains, identify terms with a major impact and establish the network of keywords.

Step four (iv) links meanings to filtered patterns and data. The interpretation of information helps to understand the evolution over time of research interests and indicates the future directions of trends in the field of solar air heater systems.

All of the information taken from the “Web of Science” database was previously used for an overview of solar air heating systems. Thus, the following are analyzed: the distribution by fields of SAHs articles, the classification of the main countries that have contributions in the field and the scientific production in the considered period, 2017–2021. The data were taken directly from the search made in the database, visually exposed with the help of Microsoft Excel 2019 and are analyzed in Section 4.2 (An Overview over SAH Research).

Uploading text files to VosViwer version 1.6.17 developed by Centre for Science and Technology Studies, Leiden University, The Netherlands and Bibliometrix 3.1 R Package version, developed by K-Synth Srl, Naples, Italy, making bibliometric maps and analyzing them are presented in Section 4 (Results and Discussions).

4. Results and Discussions

This section provides a concise and precise bibliographic analysis of the solar air heaters literature published during the considered period, as well as the emerged discussions and trends. In addition, the research evolution of renewable sources is also analyzed.

4.1. Renewable Sources Articles Evolution

Renewable energy sources are an alternative that meets energy standards and requirements for the sustainable and lasting development of the world [23,24]. Solar energy is taken into account as one of the best and most relevant alternatives to conventional systems for the production of heat and electricity.

This is due to the ability of solar systems to convert solar energy directly into electricity in the case of photovoltaic systems, and indirectly in thermal energy, as is the case with concentrating systems that convert solar energy into thermal energy and then heat into electricity [25,26]. Additionally, another way to transform solar energy into thermal energy is by using solar air heaters (SAHs), which converts solar energy into thermal energy through the greenhouse effect [27].

In order to expose and analyze the level of interest that researchers carry in the known types of solar systems, the articles analyzed and exposed by the graphs below are part of the most cited publications in which the words “photovoltaic system”, “solar air heater system”, “solar hybrid system”, “solar thermal system” and “concentrated solar system” are encountered at least once.

The information was extracted out of the “Web of Science” database, for the analysis of scientific articles published between 2011 and 2021 and centralized with the help of Microsoft Excel 2019, version 2201.

From the graph of Figure 1, it can be noted that photovoltaic systems hold the highest percentage of published articles, with 47.0–55.71%, within the considered period. The share of scientific articles in the field of solar thermal systems is between 25.56% and 31.47%, occupying the second place after the percentage of articles published in the field of photovoltaic systems. In third and fourth places are the articles published in the fields of hybrid solar systems, with values between 10.35% and 15.92%, respectively, and concentrating solar systems with percentages between 6.01% and 7.65%. The articles published in the domain of solar air heater systems fills the last place, with the smallest share and values between 0.71% and 1.15%.

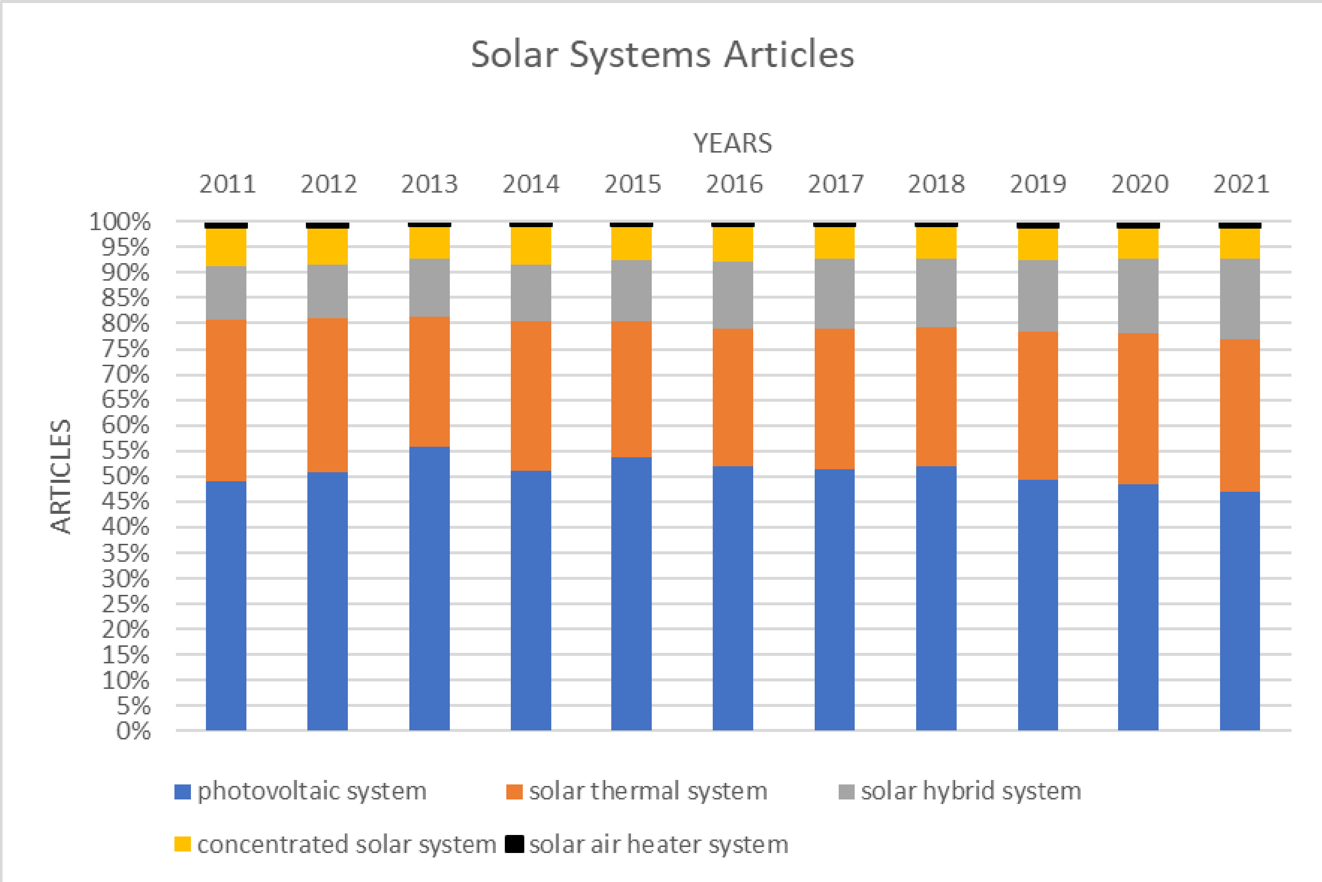

Figure 1. Articles percent for solar systems, period of 2011–2021.

In the graph shown in Figure 2, it can be analyzed the trend in which the researchers' attention turned during the period of time considered. The percentage of articles published in the fields of photovoltaic systems, respectively, of concentrating solar systems, is decreasing almost every year. Thus, photovoltaic systems are decreased in percentages in 2021 by 8.63% compared to the year with the largest share, 2013, and concentrating solar systems are decreased by 1.63% in 2021 compared to 2011, the year with the largest share. On the other hand, articles within the fields of solar thermal and hybrid solar systems are up by 4.27% and 5.57%, respectively, in 2021, compared to 2013 and 2012, respectively.

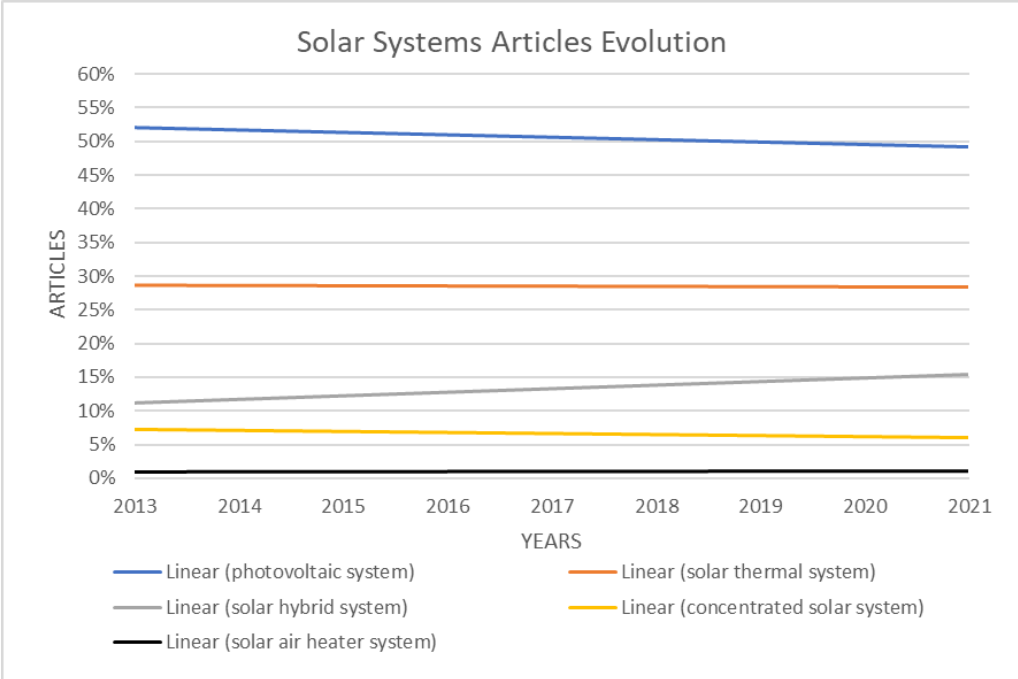

Figure 2. Articles evolution for solar systems, period of 2011–2021.

The percentage of articles published taking into consideration the domain of solar air heater systems is also increased by 0.44% in 2021 compared to 2015, the year with the lowest share. Solar air heaters are found to be useful in many processes where moderate or hot air temperatures are required due to energy availability and savings [28]. This type of system is mainly used to dry crops and to heat habitable spaces [20,29].

4.2. *An Overview over SAH Research*

With the help of the greenhouse effect, this solar air heating equipment manages, to a greater or lesser extent, to transfer the captured temperature to an air flow for different uses.

The graphs in this subchapter are made with the support of publications from the "Web of Science" database for the period considered. The literature in this field is not as vast as that in the field of photovoltaic systems, thus leaving room for optimization and continuous development. The evolution of articles in the area of solar air heating systems in the period 2017–2021 can be seen in Figure 3. Analyzing the chart over a period of five years, although 2021 is not as productive as the year 2020, it can be seen the upward slope of the number of articles, published in the field.

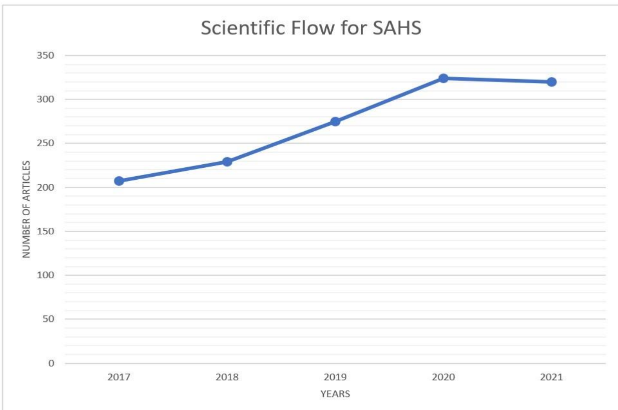

Figure 3. Number of articles published on SAHs.

The year 2020 was the most productive year of the considered period, with the most publications in the field of solar air heaters. It is meaningful to note that the number of items represented in the graph is the total of the articles in which the words "solar air heater" are found at least once.

The selected articles were published in a series of conferences and journals designated to one or more categories of topics. Figure 4 illustrates the main categories, based on the classification by category of subjects made using the "Web of Science" database, where articles based on solar air heating systems have been published.

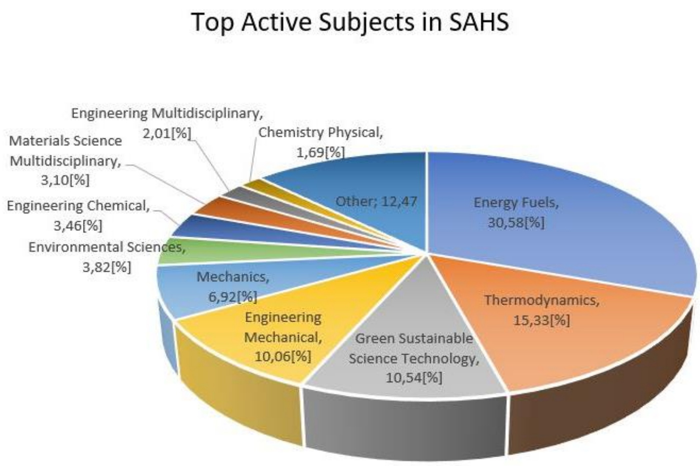

Figure 4. Top active categories in SAHs publication.

To be noted is the fact that the predominant area in which the problem of solar air heating systems has been addressed is the energy fuels domain, with 30.58 percent, followed by the thermodynamics domain, with a percentage of 15.33. The research carried out so far indicates that all the components of a solar air heater system, such as the material that absorbs and the material through which the solar radiation penetrates, the ducts, the insulation, the material of the enclosure, the air flow, and the angle of inclination, have a considerable impact on the thermal performance of the equipment. For superior performance, different methods are used, including optimizing the dimensions of the equipment, testing of solar radiation catchment surfaces with different shapes and sizes, using heat storage media, testing of solar radiation concentrators and the implementation of photovoltaic equipment in the capture room [30–32].

Additionally, the field of green sustainable science technology, with a percentage of 10.54, is very important because the equipment used must be suitable for the requirements dictated by the environment: safe, environmentally friendly and durable [33,34].

Regarding Figure 4, it is important to note that the percentages assigned to visible categories are percentages of the number of 2485 keywords that hold the percentage of one hundred percent. If we add up the percentages in the figure, we will have a total of 100%; the 12.47 percent assigned to other represents the categories in which the keywords were below two percent.

The categories with percentages between 1 and 2, which cannot be viewed, are physics applied, electrical engineering electronic, construction building technology, environmental engineering, chemistry analytical and civil engineering. The categories that are below one percent are water resources, multidisciplinary sciences, nuclear science technology, environmental studies, chemistry multidisciplinary, mathematics interdisciplinary applications, nanoscience nanotechnology, engineering manufacturing and optics.

The contributions made by different countries to the field of the analyzed systems are centralized, most often, using the location of the system investigated by the article. Thus, the most productive countries are those where the largest number of articles in the field of SAHs is identified.

The spatial distribution of the five most productive countries in the field of solar air heaters can be seen in Figure 5. The countries identified as the most productive in the field under review are India with 37.81%; China with 10.27%; Iran with 8.42%; Turkey with 5.98%; and Iraq with 4.14%. The countries listed together hold 66.62% of all publications made between 2017 and 2021.

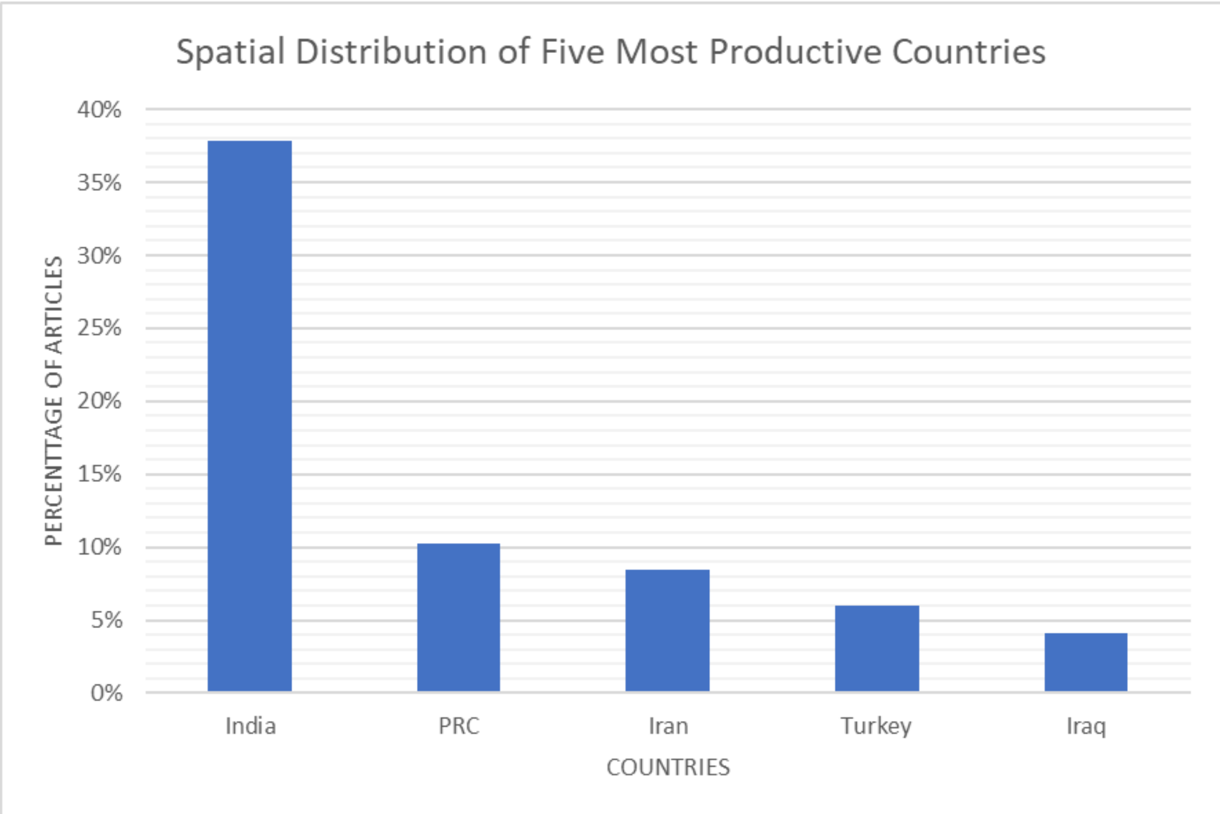

Figure 5. Spatial distribution of the most productive countries in SAHs.

India has a total of 512 published works, of which six works fall into the category of the most cited articles of the period considered. These papers address the following important topics for SAHs:

- Use of state change materials (PCM) in order to increase and enhance solar air heaters' performance [35];
- Study of state-changing nano compounds (nanoPCM) [36];
- Use of solar air heater systems for agricultural purposes, such as drying food products and drying wood [37];
- Protecting the environment and decreasing CO_2 [38];
- Study of thermal performance of a solar air heater with double porous bed in the form of serpentines [39];
- Investigation of different obstacles introduced in solar air-heater systems, such as helical inserts in the exhaust tube [40].

The time distribution of the five leading countries in the area of solar air-heater systems is visually represented in Figure 6. From 2017 to 2021, all the countries represented in the figure have an upward slope, with India being the country that leads detachedly in the field of SAHs.

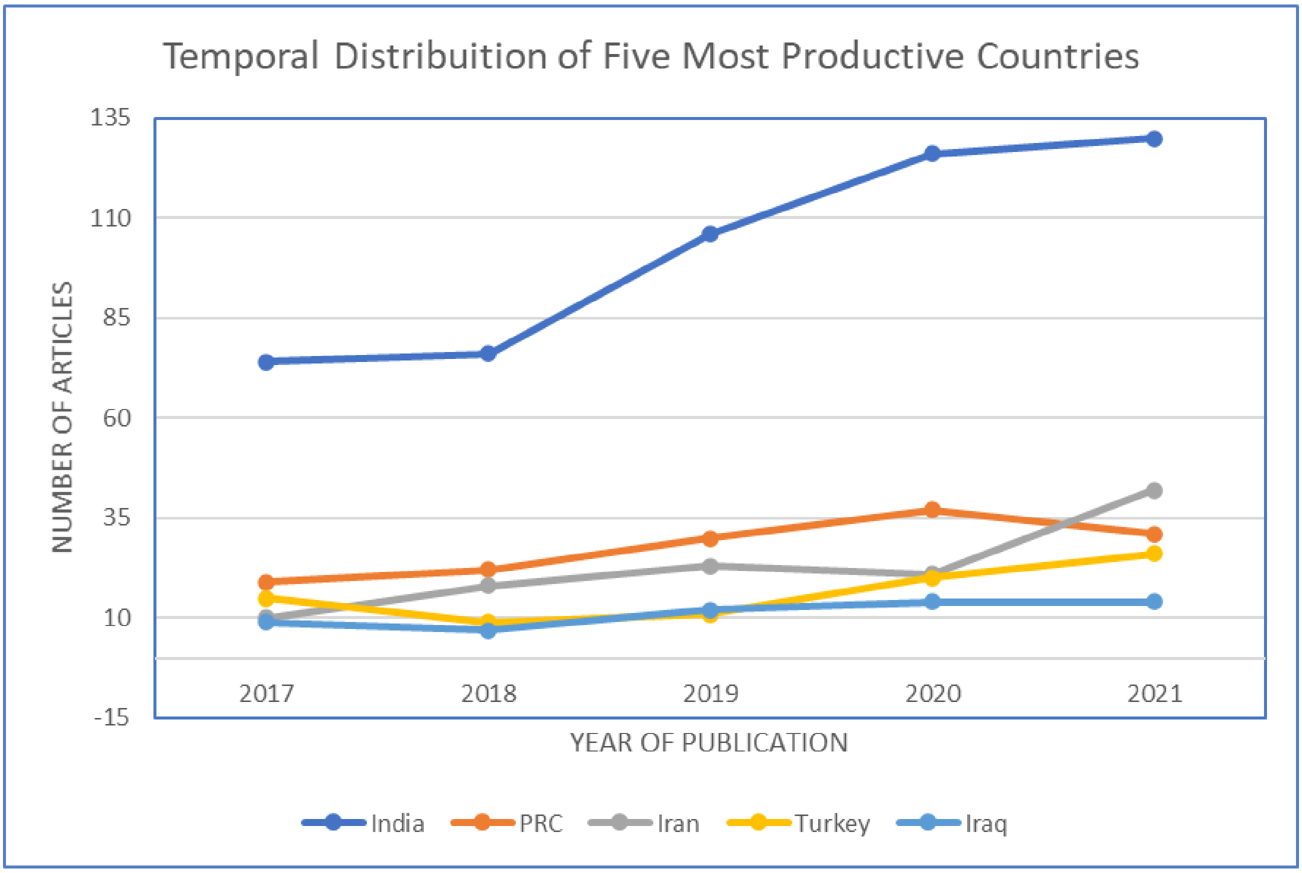

Figure 6. Temporal distribution of the most productive countries in SAHs.

Among the common interests of the main countries in the field of solar air heaters, it is worth mentioning the analysis through experiments and optimization through modeling and simulation with the support of programs specialized in computational fluid dynamics (CFD). In his work, Bezbaruah investigated by experimental method and numerical method SAHs with conical vortex generators modified in a staggered way. For the study of the characteristics of heat transfer and airflow, the results obtained numerically using a modeling program were validated using the physical model. Using the general evaluation criterion for optimization, the researcher managed to achieve a 257% improvement in the thermal performance of a modeled and physically realized system. The material used to capture solar radiation in the system developed and analyzed does not have energy storage capacity, but the author did not exclude the possibility of using such a material in a future study [41].

Aiming to improve the thermal performance of a solar air heater with a spiral labyrinth-shaped solar energy capture system, Jia Binguang developed four different three-dimensional mathematical models: spiral labyrinth pattern with arched corners (ARC-SSAH); pattern with a spiral labyrinth with rectangular corners (RA-SSAH); pattern with spiral labyrinth with arched corners and holes in the corners of the material (ARC-RH-SSAH); and pattern with spiral labyrinth with rectangular corners and holes in the corners of the material (RA-RH-SSAH). Patterns were developed for the study of the effect of deflector structures on the microscopic features of heat flux and transfer. Experimental data demonstrated the accuracy of the mathematical models. The model with the best results was the rectangular one with holes in the material of the spiral labyrinth [42]. We remain in the area of optimization of the airflow channels with the work conducted by Khosravi and Mortazavi. The authors proposed a number of 14 different models of disruptive channels of air flow through solar air heating systems. The proposed models were implemented on the solar radiation capture material to study flow behavior and thermal performance. The deflectors proposed for this work have simple forms, are easy to manufacture, and economical, gaining superior performance compared to previous models in the literature [43]. Abusca Mesut investigated the thermal performance of a SAHS with conical inserts on the surface of the material that absorbs solar radiation. By comparing the numerical results obtained by the CFD method with the experimental data, it resulted that the speed and temperature distributions are in harmony. Furthermore, it was discovered that conical inserts on the absorbent material are good for storing thermal energy [44]. The article by Al-Damook researches the impact of different airflow configurations on the thermal performance of SAHs. Three models were numerically analyzed: with inserts in the same orientation as the air flow, with inserts against the flow and a U-shaped model. Because the U-shaped model had higher thermal performance than the other models, experimentally, three different U-shaped models were made: without disruptive inserts, with straight inserts and with staggered disruptive inserts. The model with high thermal efficiency was U-shaped SAH with staggered inserts [45].

The works mentioned above are similar due to the fact that they deal with the same topic, optimization through CFD modeling and physical experiment, and are different because they have different authors, from five different countries, but in the top in the field of solar air heater systems.

4.3. Research Trend Topics

Identifying the trends prevailing during the analysis period presents a quick and efficient way to form an overview of solar air heating systems. The text files taken out of the “Web of Science” database for the analysis of scientific articles published during the years 2017–2022 in the field of SAHs were uploaded to the Bibliometrix 3.1 R Package software. Thus, a time map was made that presents the directions of the researchers in the publications recorded in the period 2017–2021. To highlight the main ideas, it is worth noting, in Figure 7, five trends for each year of the period under review.

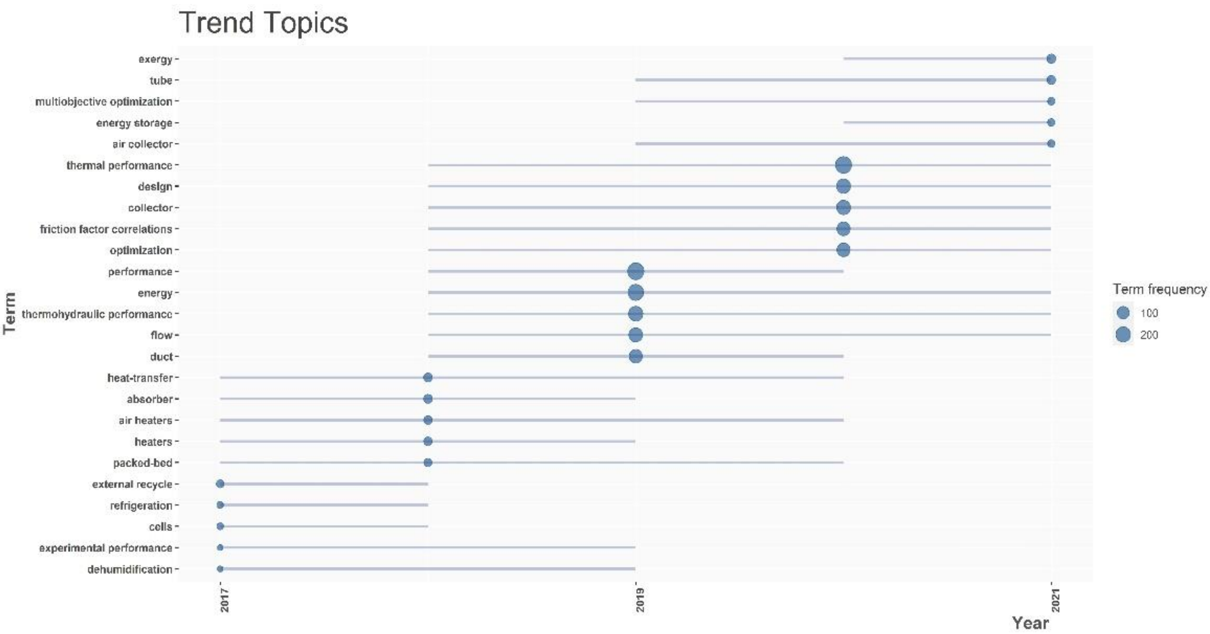

Figure 7. Research trend topics during 2017–2021 for solar air heater domain.

Studies on solar air heaters with packed bed predominate the year 2017. The author Chouksey made during this period a theoretical analysis of the performance of a solar air heater with a packed bed, made with a semitransparent optical material. Heat transfer equations were used to analyze thermal and exergy performances and to study operating parameters. The results obtained, the increase in thermal efficiency and temperature,

were in line with the available results from the literature. There was also a considerable improvement in thermal efficiency [46]. Nems Magdalena of the University of Sciences and Technologies in Wroclaw, Poland, conducted a thermal analysis of a brick heat storage system. The project is part of a heating system assembled in a family home, integrated with a SAH adapted to the climatic conditions of Poland. The scope of the analysis was to verify the concept of energy storage within solar air heating systems, with the intention of achieving thermal self-sufficiency of a single-family building [47].

The studies conducted in 2018 are based on analytical, mathematical, numerical models and ANN (artificial neural network) models. Researcher Ghritlahre, from the National Institute of Technology, developed a neural network for the model of SAH with absorbent material, roughened with spring-shaped wire ribs. Statistical results indicated that the ANN model successfully predicted the exergy performance of the chosen solar air heater [48]. In 2019, researchers focused on the study and development of different types of surfaces with the ability to retain solar heat and succumb it to the flow of air that pervades the equipment. Experimentally, various tests were performed with the following materials: slag/chips of copper, iron, paraffin wax, cast iron and aluminum. Iron chips were distinguished in the study by the highest heat storage capacity [49]. Additionally, during this period, the thermal performance of SAH systems was studied. With the aim of improving these performances, various experiments were carried out, among which we mention artificial techniques using nanofluids, titanium dioxide nanoparticles (TiO2) in water [50,51] and the use of PCM macro capsules [52].

The articles published in 2020 addressed the issue of optimizing heat transfer by equipping SAHs with devices to change the direction of airflow [53], adding iron meshes to the airflow channel [54], using fluids with high thermal conductivity [55] and rough arc-shaped surfaces [56]. Exergy was the most in-depth topic in 2021 in the field of SAHs, centered on determining optimal geometry and operational parameters [28], the use of different air flows [57] and the design of new heat absorption surfaces [29]. The last paper listed examined experimentally from an energetic, ecological and exergy point of view the performance of a SAH designed with adjacent parallel tubes that absorb solar radiation. The outcomes were compared with the outcomes of a flat absorbent SAH system. The exergy efficiency proved to be higher in the tube system when passing an air flow equal to 0.025 kg/s, compared to the flat system. Additionally, when increasing the airflow for the tube model under analysis, it was observed to reduce the percent of the exergy efficiency and increase the thermal efficiency value [29].

4.4. Keywords Co-Occurrence Analysis

The network shown in Figure 8 resulted from the analysis of the frequency of occurrence of the keywords associated with SAHs in the titles and summaries present in the articles published in the period 2017–2021 in the area of SAHs on the "Web of Science" database.

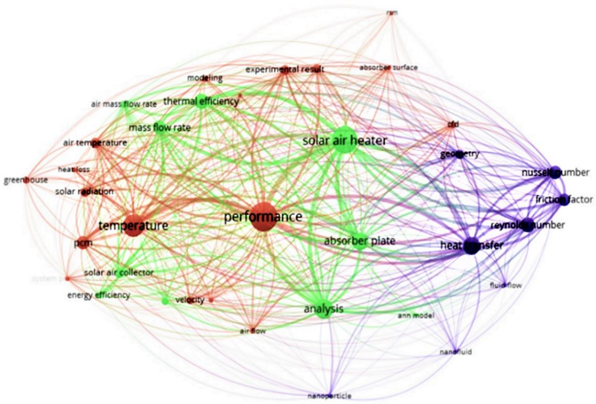

Figure 8. Solar air heaters keyword bibliometric overlap network.

Acquired data were introduced into the VosViwer software. For the generated map, the minimum occurrence of a keyword is 9. For better effective visualization and analysis, the keywords that appear are filtered so that Figure 8 can expose the most important and relevant keywords. The keyword creation network shown above in Figure 8 has three sets: the first set consists of 18 keywords, the second set consists of 10 keywords, and the third set contains 8 keywords.

Crowds, word counts, related colors, keywords, appearance number, links, and total link strength can be analyzed in Table 1.

Table 1. Solar air heaters keywords bibliometric network details.

Cluster Number	Items Amount	Keywords [1]	Cluster Color [2]	Occurrences	Links	Total Link Strength
1	18	Absorber surface		52	27	517
		Air flow		59	31	557
		Air temperature		203	35	1778
		CFD		80	31	857
		Experimental result		165	34	1592
		Glass cover		47	29	415
		Greenhouse		101	16	421
		Heat loss		50	32	383
		Modeling		74	33	621
		Optimization		149	32	1142
		PCM		340	31	2359
		Performance		1625	35	11399
		RSM		9	18	67
		Solar radiation		173	33	1328
		System performance		47	30	351
		Temperature		904	35	5579
		Temperature distribution		33	27	309
		Velocity		115	31	996
2	10	Absorber plate		52	27	517
		Air mass flow rate		59	31	557
		Analysis		203	35	1778
		Ann model		80	31	857
		Energy efficiency		165	34	1592
		Exergy analysis		47	29	415
		Mass flow rate		101	16	421
		Solar air collector		50	32	383
		Solar air heater		74	33	621
		Thermal efficiency		149	32	1142
3	8	Fluid flow		52	27	517
		Friction factor		59	31	557
		Geometry		203	35	1778
		Heat transfer		80	31	857
		Nanofluid		165	34	1592
		Nanoparticle		47	29	415
		Nusselt number		101	16	421
		Reynolds number		115	31	996

[1] Keywords presented are selected to better represent the analyzed domain. [2] The table colors represent the keyword creation networks shown above in Figure 8.

The visualization of bibliometric networks is carried out by means of overlapping networks, such as the network in Figure 8, or by means of density networks, seen in the figure below, Figure 9. The information used for the analysis was collected from 1355 articles signifying the total of publications in the domain of solar air heaters, extracted from the "Web of Science" database considering the interval of 2017–2021. The figure below represents the density network of the analysis of key terms. The terms that appear often are closely related to the color intensity of the nodes and the size of the writing. The most commonly used terms appear with a large writing size and pronounced color (e.g., "performance", and "temperature"), and the less used terms have a small writing size and fad color (e.g., "air flow", and "rsm").

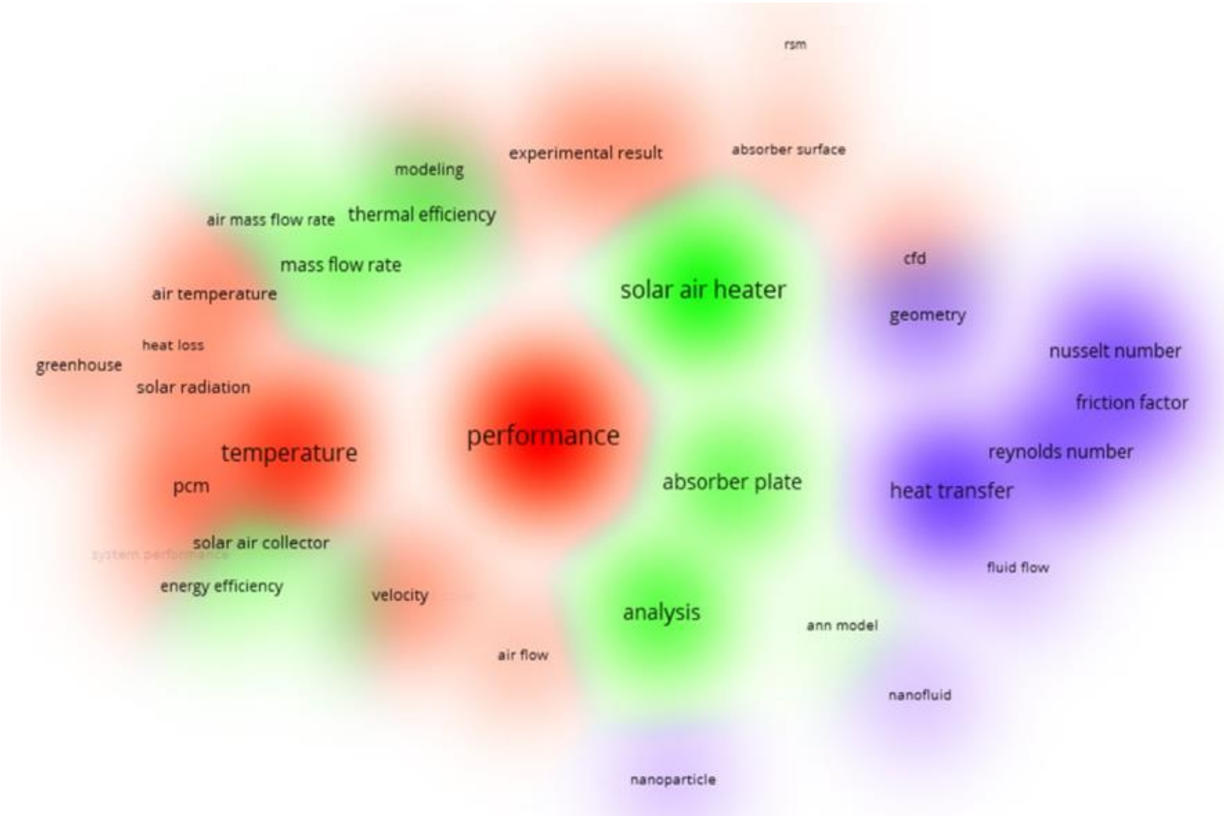

Figure 9. Solar air heaters keyword bibliometric density network.

Due to the minimum chosen in terms of the number of appearances of a keyword, although they will be of particular importance in the future, some keywords are not found in the occurrence maps generated in Figures 8 and 9. Among these words, the following are listed: hybrid, cogeneration, trigeneration, polygeneration and organic Rankine cycle (ORC).

Under natural meteorological conditions, the hybrid system realized by integrating a photovoltaic panel into a solar air heating panel was experimentally investigated. The manufactured PV/T system consists of a single-pass air channel with double flow. The absorption surface of the solar air heating panel was changed with an integrated photovoltaic panel. Ribs with uneven cross-section were attached to the module to augment the performance of heat transfer amongst the air flow and the photovoltaic module [13,58].

To cover the lack of cogeneration systems literature in solar air heaters domain, a system containing a transpired solar air heater with heat exchanger type capillary tube was experimentally realized. The system aims to preheat the air and improve the comfort of an industrial building used as a factory. The system allows the use of heated air based on solar radiation and a heat exchange system when solar energy is missing or does not provide enough thermal energy. The main components of the realized system are a transpired solar air heater, capillary tubes for heat exchange between cold air and hot water, and an integrated plate for the heat exchange between SAH and the compressor [13,14].

In order to recover and collect the thermal energy lost from the operation of solar-based ventilation equipment, a system was implemented that works on the organic Rankine cycle (ORC) principle. This system is an innovative method of producing electricity from thermal energy using the existing walls of a building. The method also contributes to the improvement and inward processing of solar air heaters in the field of ventilation with the help of solar energy. The use of the organic Rankine cycle in this system should produce electrical energy and construct buildings with a low carbon foot print. The optimal ventilation system with efficient organic Rankine cycle in hot air recovery, discovered by CFD simulation, has the air intake of 2–3 m/s, absorbing surface type rectangular tube with a cross section of 10 × 1 cm, air channel length of 4 m, and inactive air layer equal to 2 cm. The proposed method is suitable for heated air with solar air heaters and used for the production of electricity considering a system based on organic Rankine cycle [59]. Combining the hot air produced by solar air heaters with the heat recovered when producing cement and generate electricity using organic Rankine cycle-based systems is another important step in demonstrating the contribution that can be provided by the solar air heater systems. The study concluded that such systems could bring significant benefits to industry in terms of economic and environment advantages [60].

From the study carried out and the visualized analysis through the overlapping networks, respectively of density, in the domain of solar air heating systems, the following observations result for the analyzed time period:

1. Solar air heater systems (SAHS) are used for drying in agriculture of various crops and for heating habitable spaces [51,56];
2. The efficiency of SAH systems depends on the material used for the absorption of sunlight and the heat transfer achieved among the material and the air/fluid flow passing through [49,55];
3. Optimizing nanotechnology performance [50,51];
4. Use of solar air heaters in hybrid, cogeneration, trigeneration or polygeneration systems [13,14,58].
5. Recovery of thermal energy from ventilation systems and converting it to electrical energy considering systems based on the organic Rankine cycle (ORC) [59,60].
6. The exergy is widespread among researchers, but there are few publications in the field of SAHs dealing with this topic [29,61];
7. SAHs optimization procedures are based on the following methods: PCM method (phase change materials), RSM method (response surface methodology), DoE method (design of experiments), and the computational fluid dynamics (CFD) method. The RSM method was used intensively until 2017; the CFD method was used more after this year [28]. The latest research tries to combine methods with each other to improve system performance, for example, combinations of DoE and CFD [62], and RSM and CFD [63].

4.5. Countries Bibliometric Evolution

The network of cooperation between countries with researchers and publications in the domain of solar air heaters shown in Figure 10 was developed for the period 2017–2021 using the "Web of Science" database. The bibliometric network was developed in the VosViwer software. The information used for this analysis was gathered from 1355 articles representing the total of articles published in the field of solar air heating systems, extracted from the "Web of Science" database for the period considered. Each node in the graph represents a country. The size of the node constitutes the number of publications of each country, the lines in color express the collaborations between countries and the thickness of the line indicates how close the connection between them is. The network in Figure 10 consists of 25 countries, with 98 links, total bond power of 268 and three sets: the first set consists of 9 countries, and the second and third sets have 8 countries each. The minimum number of published documents in a country is 15. The sets, the number of terms, the countries, the associated colors, the number of documents, the links and the total strength of the links can be analyzed in Table 2.

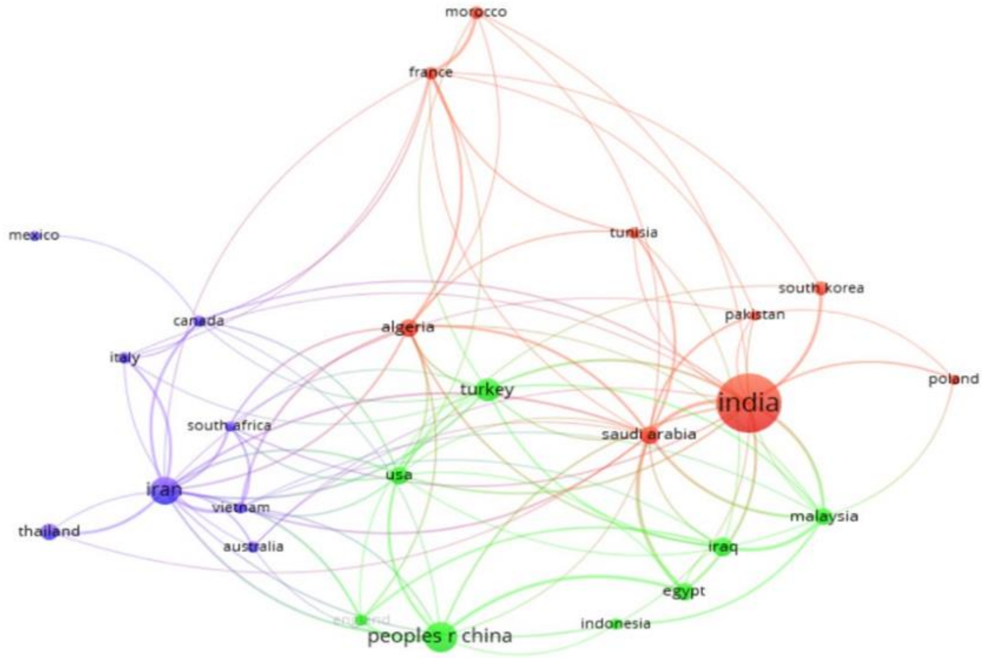

Figure 10. Solar air heaters countries cooperation network.

Table 2. Solar air heaters country bibliometric network details.

Cluster Number	Items Amount	Countries [1]	Cluster Color [2]	Article Amount	Links	Total Link Strength
1	9	Algeria		46	12	33
		France		25	10	22
		India		525	16	54
		Morocco		24	5	12
		Pakistan		16	6	9
		Poland		15	3	5
		Saudi Arabia		49	16	58
		South Korea		30	3	9
		Tunisia		19	5	10
2	8	Egypt		51	5	25
		England		19	5	14
		Indonesia		20	4	7
		Iraq		57	8	22
		Malaysia		40	10	32
		China		144	10	29
		Turkey		82	12	24
		United States of America		52	13	25
3	8	Australia		20	5	7
		Canada		22	8	16
		Iran		117	15	59
		Italy		20	6	11
		Mexico		15	1	1
		South Africa		17	6	17
		Thailand		40	3	8
		Vietnam		22	9	27

[1] Top listed country in the analyzed domain. [2] The table colors represent the networks of cooperation between countries shown above in Figure 10.

Looking at the cooperation network, we see three majority countries with significant impact: India, China and Iran. India has the largest node, which means it has the most partners and leads detached with the highest number of articles, 525, published in the field of SAHs. Next is China, with 144 articles and Iran with 117 articles published in the analyzed field. Although Iran is among the top three countries, there is no direct link between India and Iran; the link of cooperation is made indirectly through the countries China, Turkey, Saudi Arabia, the United States of America, Pakistan, Indonesia, South Africa, Australia, Canada and Italy. It is worth noting that although India has the highest number of publications compared to Saudi Arabia, both countries have developed the same number of ties with other countries. India and Saudi Arabia have a significant direct link between them. Mexico is the only country with a single cooperation direct link with Canada, through which several indirect links are made.

4.6. Authorship Bibliometric Evolution

Using the "Web of Science" database, the authors' bibliometric network was created for scientific articles from 2017 to 2021 with the help of the VosViwer program. The minimum of articles published by each author encountered on the network is 5. Although some authors have over 5 publications, they are not in the network listed in Figure 11 because the network only presents authors with links to each other.

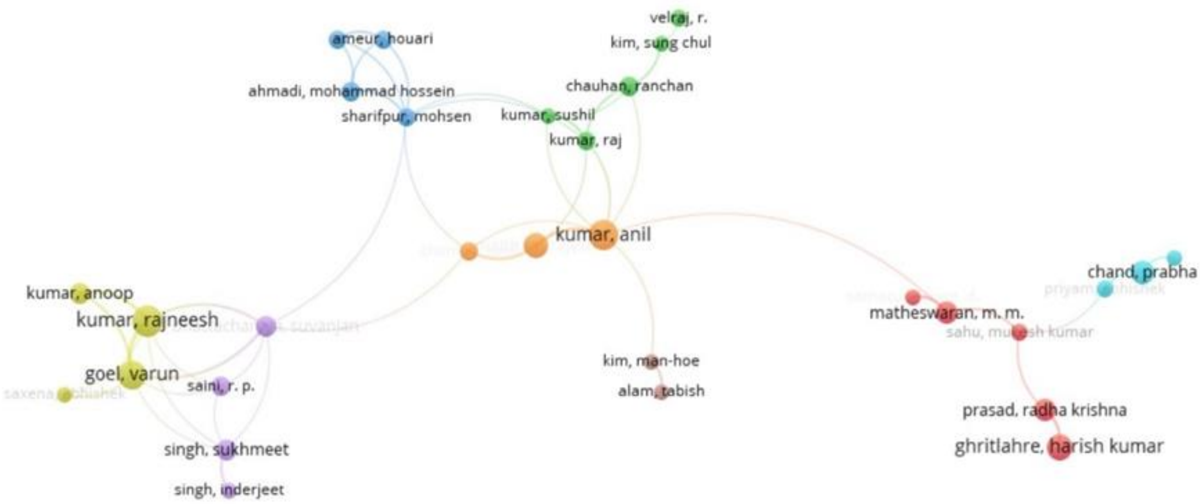

Figure 11. Solar air heaters authors' cooperation network.

Each node in the graph represents an author. The size of the node represents the number of publications of each author, the lines in color express the collaborations between them and the thickness of the line indicates how close the connection between them is. The network in Figure 11 consists of 30 authors, with 48 links, a total link power of 143 and 8 sets.

The table below shows the top five authors and the number of articles each published in the area of solar hot air heater systems.

The authors shown in Table 3, the number of publications and the links between them are taken from the network made with the VosViwer program, shown in Figure 11, and not from the filter for authors in the "Web of Science" database, since some authors have no links to each other although they have a large number of publications. Another thing to note is that on 12 February 2022, the database "Web of Science" associates the name Kumar A. with two different authors: Kumar Amit and Kumar Anil. The number of articles per author does not distinguish between one author and the other, associating all articles with the name Kumar A. for a total of 57 articles. This is another reason why we took the information for Table 3 from the VosViwer software and not from the site. The VosViwer software offers the possibility for the user to choose either an interconnected network or several networks without links to each other, depending on what is desired to be expressed through the network made.

Table 3. Solar air heaters authors' bibliometric network details.

Authors	Number of Publications	Number of Links
Kumar Rajneesh	21	6
Kumar Anil	19	7
Goel Varun	18	6
Ghritlahre H. Kumar	15	1
Maithani Rajesh	13	2

4.7. Sankey Diagram

Shortest way to view multiple attributes in the field of publications in SAHs at the same time is to plot a Sankey chart. The text files were taken out of the "Web of Science" database for the analysis of scientific articles.

The considered articles were published during the years 2017–2022 in the field of SAHs and were uploaded to the Bibliometrix 3.1 R Package software. Figure 12 listed below shows a graph with three fields that displays the following: on the left side of the graph are the main countries, in the middle of the graph, we have the keywords plus, and on the right side of the graph, we can analyze the keywords of the authors. The maximum number of terms for each field is 25.

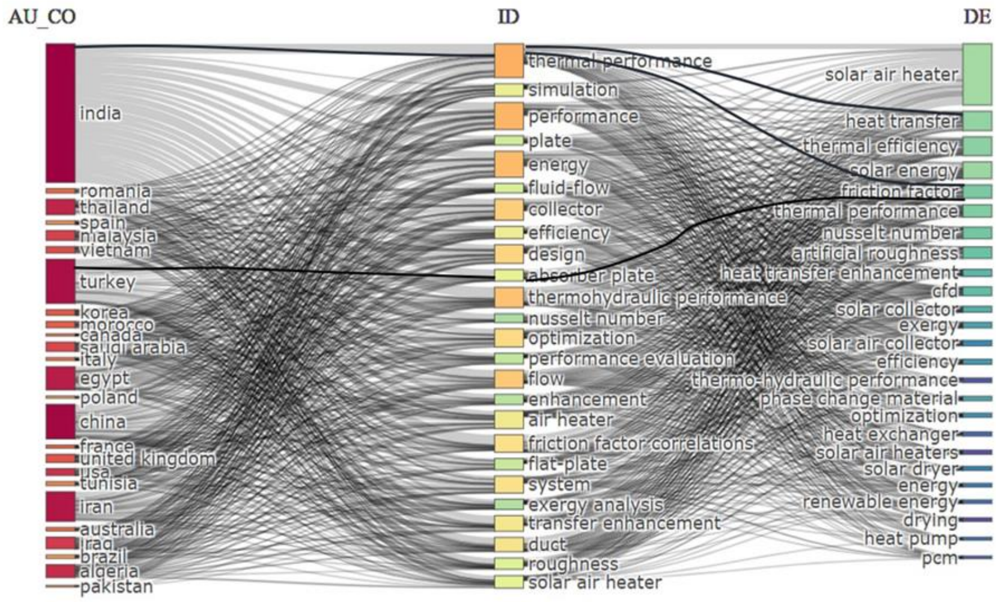

Figure 12. Sankey diagram for solar air heaters.

The keywords plus generated by the "Web of Science" database for the period considered and used for the study of publications are the index terms automatically generated from the titles of the cited articles. Regarding bibliometric analysis that analyzes the structure of knowledge in scientific fields, keywords plus are just as effective as the authors' keywords, but in representing the content of an article they are less comprehensive [64].

As an example, for a country like India, from the keywords plus for a published article the title refers to the thermal performance "thermal performance" of solar air heating systems and from the author's keywords one of the topics addressed in the text is heat transfer "heat transfer" and friction factor "factor friction" [65].

Another example would be to choose the country Turkey; from the keywords plus for a published article, the summary refers to the element that absorbs the solar radiation "solar absorber" of solar air heating systems, and from the author's keywords, one of the topics addressed in the text is the friction factor "friction factor" [66]. Figure 12 also shows the links made between the mentioned terms.

4.8. Future Research Tendencies

Aiming to get an idea of the future trends in the range of solar air heating systems, we will analyze the articles published in the period 1 January–6 February 2022 in which the words "solar air heater" are found at least once through the prism of the information provided by two databases "Web of Science" and "Scopus". The articles provided by the "Web of Science" database were 30 in number and the articles in the "Scopus" database were 49. Out of the total number of articles, 79 in total, 22 identical articles were found. For analysis, we selected and combined the items from the two databases by removing duplicates. We finally analyzed a number of 57 publications. The text files were retrieved on 6 February 2022 and uploaded to Bibliometrix 3.1 R Package for analysis. The trends for the period 1 January–6 February 2022 are shown in Figure 13.

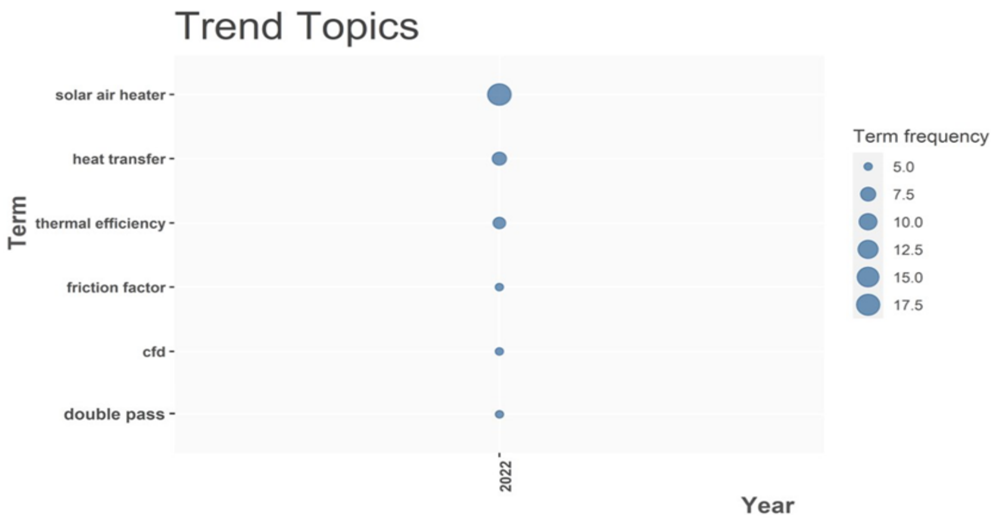

Figure 13. Solar air heaters trends during the period 1 January – 6 February 2022.

The publications of researchers in the realm of solar hot air heating systems for the period 1 January–6 February 2022 address the following issues:

- Improving heat transfer [67,68];
- Thermal performance analysis [69–71];
- Impact of friction on performance [67,72];
- Modeling and simulation using programs specialized in computational or numerical fluid dynamics (briefly called CFD—computational fluid dynamics) [73–75];
- Enhancing the performance of SAHs [76–78].

Researchers Kumar and Verma in the paper "Heat transfer and fluid flow analysis of sinusoidal protrusion rib in solar air heater" reviewed all types of shapes used on the absorbent plate and proposed a new model with sinusoidal protruding ribs with the aim of streamlining heat transfer in SAHs. The results obtained by analyzing the model made three-dimensionally with the help of a CFD program were validated with the results of a real model. The thermal efficiency of the analyzed model was 69% [68]. Another current work is "Experimental performance of a solar air heater using straight and spiral absorber tubes with thermal energy storage" by authors Muthukumaran and Senthil. The analyzed models had copper tubes as an absorbent material and as an energy storage system. For one model, a coiled spiral-shaped copper pipe was used, and for the other model, a straight copper pipe with uniform spaces. The models were filled with paraffin and glycerin, respectively. The most important conclusion is that the results of the enviro-economic study show that spiral structured heat storage is better than the horizontal parallel tube structure. In addition, the PCM integrated collector offers a lower energy payback period, carbon payback period, and simple payback period when compared to glycerol due to higher latent heat storage capacity. The experimental results concluded that SAH with paraffin-filled spiral copper pipe has higher thermal performance than the model of SAH with straight copper pipe filled with glycerin [76].

For a number of reasons, such as the growing number of articles published in the solar air-heater domain, viewing, analyzing and comparing the trends for different periods of the year 2022, with the mention that the first period is included in the second period, a trend analysis was also realized for the 1 January–1 August period of 2022. The trend topics presented in Figure 14 are based on the articles published in the period 1 January–1 August of the year 2022 in which the words “solar air heater” are found at least once, considering the information provided by the “Scopus” database. The reason for choosing the “Scopus” database over the “Web of Science” database is the higher number of articles returned by the “Scopus” database. The number of items displayed when searching for “solar air heater” keywords was equal to 181 for the “Web of Science” database and equal to 242 for the “Scopus” database. Additionally, the retrieved files on 01.08.2022 from “Scopus” database were uploaded to Bibliometrix 3.1 R Package for analysis.

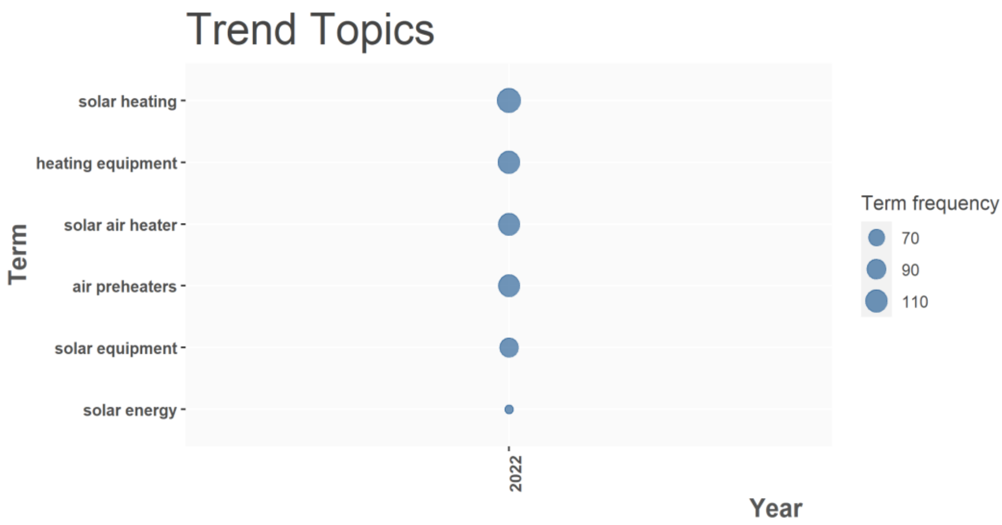

Figure 14. Solar air heaters trends during the period 1 January–1 August of 2022.

The presented trend topics in Figure 14 indicate, as the topics from Figure 13, the highest six words in terms of frequency occurrence.

Considering that the first analyzed period directed the trend of solar air heaters toward their performances, it is observed that the researcher’s attention, in the second analyzed period, focused more on air-heating equipment technologies based on solar energy [79–81]. Of particular importance is shown toward systems that preheat air. Preheating air with solar air heaters automatically implies using these equipment in hybrid, cogeneration, trigeneration and polygeneration systems [82].

A combination between solar air heater and gas heater has been proposed to dry agricultural products. Depending on the consideration of each researcher, such a system can be analyzed from two points of view, namely a system in which the products are dried with the help of a solar air heater and the gas heater is used when the solar radiation is low or missing during the night, or a system in which the products are dried based on the gas heater and the solar air heater is used to preheat the air. The drawback of the system based mainly on the solar air heater sustained with the gas heater is the considerably higher amount of time needed to dry the products compared to the fully gas dryers. Preheating the air using solar air heaters for drying systems based on gas heaters represents a more feasible solution [83].

The system proposed by the researchers Pandey T. and Tejes P. can be used to enhance the conventional LDAC (liquid desiccant air conditioning) system performance, extract freshwater from the atmospheric air, dry agricultural/food products and room air conditioning. Additionally, the realized tests indicate a significant reduction in the energy consumption of the system [84].

5. Conclusions

The most in-depth studies in the field of solar air heater systems during the considered period are related to the optimization of solar energy capture and heat transfer through new absorbent surfaces, the testing of different air flows, experimentation, modeling and simulation. Energy, exergy and nanotechnology are less studied and experienced fields when talking about SAHs, with a high potential to provide major contributions in improving the performance and optimizing these systems. It was noted that maximizing the contact surface area amongst the PCM and the absorbing surface significantly augments the outlet temperatures.

The bibliometric analysis performed in the realm of solar air heaters provides the following information:

- Evolution or involution of publications in the field;
- The trend in which the attention of researchers has turned over a period of time considered;
- Broad vision on the study of the capabilities and performance of these equipment;
- Understanding the structure of basic knowledge in the field of SAHs;
- The researchers focused on the study and development of different types of surfaces with the ability to retain solar heat and release it to the airflow that pervades the equipment, improving heat transfer from the material to the air flow and optimizing performance;
- The trend in which most of the articles to be published will be directed.

Among the advantages of the solar air heaters, the following could be considered:

- Reducing energy consumption for drying agricultural products and heating spaces;
- Producing and using clean, renewable and sustainable energy;
- Zero CO_2 emissions during operation;
- Corrosion, leakage and freezing do not create any problems for solar air heaters;
- The possibility to use solar energy in countries with abundant solar climate but also in countries with different climates with the help of cogeneration systems;
- The use of solar air heaters in ventilation and cooling systems;
- Generating thermal energy without additional costs or electricity.

The results of the realized study are rather unsatisfactory because of the lack of articles published in the analyzed domain, yet somehow satisfying because they offer study opportunities to new researchers. In conclusion, the attention of researchers in the field of solar air heaters in the first half of 2022 is focused on increasing the performance of these equipment by modifying the component parts, improving the friction factor and enhancing heat transfer. It is also proposed and attempted to introduce solar air heaters in cogeneration systems, such as those for drying agricultural products, wood drying, space cooling or water heating.

The use of solar air heaters in cogeneration remains an unexplored field because existing studies are insufficient to determine the efficiency of this equipment in different combinations of systems. Considering this and the abundancy of solar energy, as future perspectives, the study of cogeneration systems, such as combinations of solar air heaters with photovoltaic panels, drying equipment, water desalination, cooling and preheating systems, is subject to be taken into consideration.

Author Contributions: All authors contributed equally to the idea and the design of the methodology proposed and to the deployment of the research paper. Conceptualization, V.C.I. and L.D.M.; methodology, V.C.I.; software, L.D.M. and D.I.; validation, V.C.I., L.D.M. and P.A.; formal analysis, D.I. and R.D.P.; investigation, V.C.I.; resources, L.D.M. and P.A.; writing—review and editing, V.C.I.; visualization, L.D.M.; supervision, P.A. and R.D.P. All authors have read and agreed to the published version of the manuscript.

Funding: This research received no external funding.

Data Availability Statement: Not applicable.

Conflicts of Interest: The authors declare no conflict of interest.

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Technical and Economic Assessment of Micro-Cogeneration Systems for Residential Applications

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Received: 21 November 2019; Accepted: 1 February 2020; Published: 3 February 2020

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Abstract: The benefits of cogeneration or combined heat and power (CHP) of large power systems are well proven. The technical and economic viability of micro-cogeneration systems is discussed in this paper as it compares to the separate production of electricity and heat. A case study for an individual household is also provided to better understand the benefits of small power cogeneration from renewable energy sources. Two micro-CHP systems are considered for analysis: the first with Stirling engine, and the second with Rankine Organic Cycle. The reference scenario is an individual household with a gas boiler and electricity from the public network. The results show that it is possible that the payback period for the micro-CHP from renewable energy sources will fall below the accepted average value (<15 years) without the support schemes. The economic and environmental benefits of small power cogeneration systems compared to the traditional scenario are highlighted.

Keywords: combined heat and power plants; micro-CHP; cost benefit analysis; renewable energy sources; residential applications; investment analysis

1. Introduction

Energy efficiency in buildings is a priority of European energy and climate change policies along with policies regarding the security of energy supply and the fight against energy poverty. In the European Union (EU), the energy consumption of buildings accounts for around 40% of the final energy consumption and is responsible for approximately 36% of all carbon dioxide emissions [1]. Therefore, there is a significant potential to reduce these emissions through actions to increase the energy performance of buildings.

The Romanian housing fund consists of approximately 8.2 million homes, distributed in 5.1 million buildings. In urban areas, 72% of the dwellings are in city blocks, while in rural areas, 94.5% of the dwellings are single-family houses.

In domestic households, biomass and natural gas are the main fuels currently used not only for cooking, but also for heating and hot water. Over 90% of households in rural areas and 15% of those in urban areas use biomass (mainly wood) as their main source of heating. The energy efficiency of biomass use is low due to the conversion systems used (especially traditional stoves).

Currently, in the case of new buildings but also of rehabilitated ones, the most common solution to provide utilities for small consumers is a gas or a biomass boiler and electricity from the public network.

Generally, the use of renewable energy technologies in residential buildings is not yet a common practice due to higher investment costs compared to conventional sources. Increasing the share of energy supplied from renewable energy sources is a priority for the EU. Different support schemes to stimulate the production of renewable energy sources are used by EU countries, especially for electricity. The support schemes can be divided into investment support (capital grants, exemptions, or reductions in purchases of goods) and operating support (price subsidies, green certificates, auction schemes, and tax exemptions or deductions) [2,3].

The benefits of medium and large combined heat and power (CHP) plants have been widely recognized throughout the world. In recent years, there has been an increase in the number of research and development projects worldwide regarding the use of micro-CHP for small residential and commercial applications.

Currently, there is a great diversity of micro-cogeneration technologies available on the market (e.g., Stirling engine, fuel cells, microturbines, internal combustion engines, Rankine Organic Cycle) that can harness primary energy resources, both conventional and renewable [4–9]. There is also a tendency for more than one primary energy source available to be used on a single site [10–12].

In accordance with Directive 2012/27/EU, "micro-cogeneration unit" means a cogeneration unit with a maximum capacity below 50 kWe, and "small scale cogeneration" means cogeneration units with an installed capacity below 1 MWe [13].

Compared to other fossil fuels, the use of natural gas has a much lower impact on the environment in terms of carbon dioxide emissions. Thus, the further use of natural gas seems to be one of the energy transition solutions to a carbon-free energy generation and should be made with the help of the most energy-efficient technologies [14–17]. However, the energy import dependence due to the utilization of natural gas is not negligible in the case of several EU countries, and the vulnerability of a certain country depends on the diversity of its energy sources.

Biomass is a "local fuel". There is now a great diversity of biomass in agriculture and forestry activities that produce large quantities of solid waste and residues. Significant quantities of wood waste come from timber factories and wood processing factories, such as bark, sawdust, wood chips, boards, and parts. Many of these wastes can be used for consumption in small installations in the form of wood pellets or briquettes. Support for the heating sector is highly diverse with price subsidies, tax exemptions, or investment grants [18]. Local biomass resources can be used with a higher energy efficiency in CHP applications [19].

Organic Rankine Cycle (ORC) is increasingly used in medium- and low-power cogeneration applications [20,21]. ORC technology is similar to the classic Rankine cycle but uses an organic liquid instead of water. This technology allows efficient use of heat sources with low thermal potential, such as biomass, geothermal energy, and solar energy [22–24]. In this case, the heat input to the system can be delivered by several renewable energy sources available locally, e.g., solar energy and biomass [25,26].

The cost of the cogeneration units (the specific investment in EURO/kWe) has a tendency of considerable reduction compared to the values of the past years [27–29].

Active energy consumers, often called "prosumers" (because they both consume and produce electricity) introduce new challenges at the level of the public electricity network. Prosumers are a relatively new concept in the distribution grid, and they are a consequence of increasing the share of renewable energy from decentralized systems (distributed generation). In many countries, there is a simplified procedure for connecting to the public network of low power generation systems. Thus, new business models are appearing that have begun to be exploited on the trading platforms for electricity [30–32].

The energy balancing problem is the main challenge for the effective application of micro-CHP in a residential context. The addition of a heat storage system will increase the flexibility of a micro-cogeneration system [33–35]. The energy demand of residential buildings (heating, cooling, and electricity for lighting and appliances) has great importance in the sizing of cogeneration units [36–38].

The specific cost is considerably higher compared to conventional technologies for separate heat production (biomass boiler or natural gas boiler), which is a great current disadvantage of micro-cogeneration units. The main objective of this paper is the economic assessment of micro-cogeneration units from renewable energy sources under current market conditions.

The methodology used is in accordance with the recommendations set out in [39,40]. The case of reference is an individual household with a gas boiler and electricity from the public network.

The paper is organized as follows: Section 2 presents a brief description of micro-cogeneration systems, while Section 3 presents the used methodology. The technical and economic viability of small cogeneration systems is discussed in Sections 4 and 5, comparing to the separate production of electricity and heat. Two micro-cogeneration systems are compared to the reference case: A gas boiler and electricity from the public network. Finally, the conclusions of this paper are summarized in Section 6.

2. Description of Different Micro-Cogeneration Systems

In Romania currently, in the case of new domestic households but also of rehabilitated ones, the most common solution to provide utilities is the gas or the biomass boiler and electricity from a public network (Figure 1).

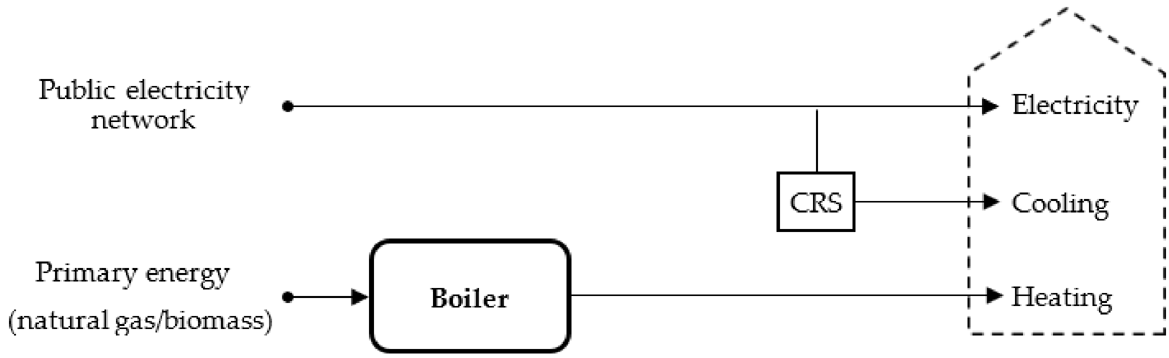


Figure 1. Separate generation of heat and power (CRS, compression refrigeration system).

In the residential sector, micro-cogeneration can be applied using a variety of prime mover technologies such as microturbines, internal combustion engines, fuel cells, Stirling engines, or Rankine Organic Cycle (ORC). The available local renewable energy sources and the conventional sources can be converted together by Stirling engines and Rankine Organic Cycle. Silicon oil is the organic working fluid. Thus, in the operation of the micro-cogeneration system, the sharing of the use of renewable energy sources can be increased and the sharing of conventional sources can be reduced. Some examples of micro-cogeneration units are presented in Table 1 [7,29].

Table 1. The technical characteristics of micro-cogeneration units.

CHP Technology	Manufacturer	P_e (kW)	P_h (kW)	η_e (%)	η_h (%)	η_{CHP} (%)	C_{CHP}
Stirling	Microgen	1.0	6.0	13.5	81.1	94.6	0.167
Stirling	Infinia	1.0	6.4	12.5	80.0	92.5	0.156
Stirling	Sunmachine	3.0	10.5	20.1	70.5	90.6	0.286
Stirling	Disenco	3.0	12.0	18.4	73.6	92.0	0.250
ORC	Cogen Microsystems	1.0	8.8	10.0	88.0	98.0	0.114
ORC	Energetix	1.0	8.0	10.0	80.0	90.0	0.125
ORC	Otag	2.0	16.0	10.4	83.6	94.0	0.124

Stirling engines use an external heat source to produce power. The mechanical energy is generated due to two different temperature zones in the Stirling engine, in which encased process gas is heated and cooled. The Stirling engine has a very special construction, which is free from bearings, joints, and shafts. Longer operational lifetimes are possible with this technology in comparison to traditional internal combustion engines [41,42].

The ORC operation principle is the same as the conventional Rankine cycle, but in this case, the working fluid is an organic compound of low boiling point instead of water, thus decreasing the temperature needed for evaporation. Its main applications are the generation of electricity from renewable heat sources (geothermal, biomass, and solar) and the heat recovery from industrial processes.

Both technologies are considered with “external combustion”. Due to the modular construction, they can use a variety of primary energy sources such as natural gas, heating oil, biomass, solar, geothermal, and waste heat. The combined heat and power generation is shown in Figure 2.

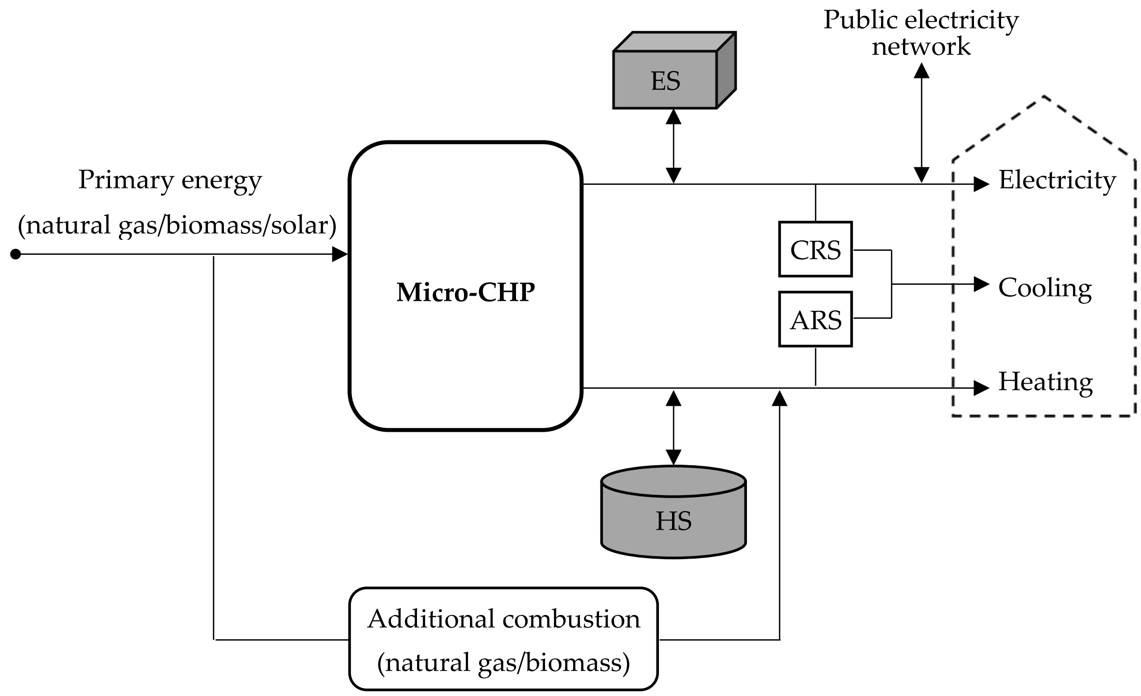


Figure 2. Combined generation of heat and power (ES, electricity storage; HS, heat storage; CRS, compression refrigeration system; ARS, absorption refrigeration system).

Demand for electricity will be ensured by the micro-CHP unit and the public electricity network. The electricity differences between local consumption and production are compensated without technical difficulty from the public electricity network. There is also the possibility of storing the electricity generated in cogeneration to be used according to needs. The heat storage system will be used to compensate for the load variations and for increasing the flexibility of the micro-CHP unit. Cooling requirements will be ensured from the absorption refrigeration system or compression refrigeration system depending on the heat available from the micro-CHP unit.

3. Methodology

Identifying the optimal size of micro-CHP systems and the most appropriate operation strategy to be adopted are essential requirements to maximize the benefits of using this technology. Overestimating the size of a micro-CHP unit decreases its feasibility, while underestimating its size reduces the benefits. Consequently, the energy demand profiles of the residential building are necessary.

3.1. Determination of Energy Consumption Related to the Building's Utilities

3.1.1. Energy Consumption for Heating

The calculation method is based on non-stationary heat transfer through the opaque and transparent construction elements of the building envelope. It takes into account the effect of the contributions due to human activity and solar radiation on the resulting indoor temperature imposed by the thermal comfort norms.

The heat losses of the building envelope, the need to heat infiltration air, and the heating of ventilation supply air in the room from supply air temperature to indoor temperature are considered. The heat demand of a building during the heating season [43]:

$$Q_h = 0.024 \cdot C \cdot \left(\frac{S_E}{R'_m} + 0.33 \cdot n_a \cdot V \cdot B_{1S} \right) \cdot N_{GZC} \quad (\text{kWh/year}) \tag{1}$$

where:

C is the correction coefficient for the variation in time of indoor and outdoor temperatures (C = 0.905);
S_E is the total area of the building envelope (m^2);
R'_m is the average corrected thermal resistance of the building envelope (m^2 °C/W);
n_a is the ventilation rate (h^{-1});
V is the heated volume of the building (m^3);
B_{1S} is the correction coefficient of the thermodynamic potential characteristic of the fresh air needed to ensure physiological comfort (B_{1S} = 1.104);
N_{GZC} is the number of heating degree days (HDDs).

The average corrected thermal resistance of the building envelope:

$$R'_m = \frac{\sum A_j}{\sum \left(A_j \cdot U'_j \right)} \tag{2}$$

where U'_j is the corrected thermal transmittance of area Aj (walls, top floor, lower floor, windows, and doors).

The duration of the heating season D_Z (the beginning and end of the heating season) is determined from the verification of the equality condition between the reduced indoor temperature in the heated space $\overline{\theta}_{iR}$ and the external reference temperature characteristic of the heated space $\overline{\theta}_{eR}$:

$$\overline{\theta}_{iR}(D_Z) = \overline{\theta}_{eR}(D_Z) \tag{3}$$

The number of heating degree days of a building is determined according to the normal duration of the heating season D_Z and the climatic conditions characteristic of the area in which the building is located:

$$N_{GZC} = \sum_k \left(\overline{\theta}_{iRk} - \overline{\theta}_{eRk} \right) \cdot D_{Zk} \tag{4}$$

The external climatic parameters are used in the form of the monthly averages of the external temperatures and the intensity of the solar radiation. In the thermal balance of the occupied spaces, the heat contributions due to solar radiation and human activity are considered.

3.1.2. Energy Consumption for Cooling

The calculation method is based on the thermal balance of the building. The heat flows through transmission, ventilation, the contribution of the internal heat sources, and the solar radiation are considered. The cooling demand of the building in summer [43]:

$$Q_c = \sum_j \left[\frac{S_E}{R'_m} \cdot \left(\overline{\theta}_{i0} - \overline{\theta}_{eRj} \right) + 1.1 \cdot n_a \cdot V \cdot \rho_a \cdot c_{pa} \cdot \left(\overline{\theta}_{i0} - \overline{\theta}_{ej} \right) \right] \cdot D_{Cj} + a_S \cdot S_{loc} \quad (\text{kWh/year}) \tag{5}$$

where:

$\overline{\theta}_{i0}$ is the indoor temperature of comfort (°C);

$\overline{\theta}_{ej}$ is the outside temperature (°C);
$\overline{\theta}_{eRj}$ is the outside reference temperature of the envelope's elements (°C);
D_{Cj} is the cooling time of the building (h);
a_s are the releases of heat (W/m^2);
S_{loc} is the total area of the building's envelope (m^2);
ρ_a is the air density (ρ_a = 1.2047 kg/m^3 at 20 °C);
c_{pa} is the air specific heat (c_{pa} = 0.281 Wh/kg°C at 20 °C).

The duration of the cooling process is determined as a result of the analysis of the variation of the indoor air temperature $\overline{\theta}_a(t)$ in the absence of equipped cooling systems in occupied spaces. The operating time of the cooling system results from the equation:

$$\overline{\theta}_{i0} = \overline{\theta}_a(t) \tag{6}$$

The solar heat contributions are according to the solar radiation level of the locality in which the building is located, the orientation of the receiving surfaces, their coefficients of transmission, absorption and reflection of the solar radiation, as well as the transfer characteristics of these surfaces.

3.1.3. Energy Consumption for Domestic Hot Water

The energy demand to prepare domestic hot water corresponds to the energy needed to heat the hot water required by the consumer at the desired temperature [43]:

$$Q_w = \sum_{i=1}^{n} \rho_w \cdot c_w \cdot V_w \cdot (\theta_{wh} - \theta_{wc}) \quad (\text{kWh}/\text{year}) \tag{7}$$

where:

ρ_w is the water density (ρ_a = 985.6 kg/m^3 at 55 °C);
c_w is the water specific heat (c_w = 1.161 Wh/kg°C at 55 °C).
V is the required volume of hot water for the period considered (m^3);
θ_{wh} is the temperature of hot water (°C);
θ_{wc} is the temperature of cold water (°C);

In the total energy consumption for hot water, the heat losses on the distribution pipes also are considered.

3.2. Primary Energy Savings

The comparison between combined production and separate production of heat and electricity is based on the principle of comparing the same types of fuel [39]. Primary Energy Saving (PES) is calculated by the equation:

$$PES = \left(1 - \frac{1}{\frac{\eta_{hCHP}}{\eta_{hRef}} + \frac{\eta_{eCHP}}{p_{loss} \cdot \eta_{eRef}}} \right) \cdot 100\ (\%) \tag{8}$$

where:

η_{hCHP} is the heat efficiency of the cogeneration production;
η_{eCHP} is the electrical efficiency of the cogeneration production;
η_{hRef} is the efficiency reference value for separate production of heat;
η_{eRef} is the efficiency reference value for separate production of electricity;
p_{loss} is the correction factor for avoided grid losses.

3.3. Carbon Dioxide Emissions

The carbon dioxide emissions are determined based on the primary energy source by using an appropriate conversion factor (Table 2):

$$E_{CO2} = \sum_{i=1}^{n} Q_{f,i} \cdot f_{CO2,i} \quad \left(\text{kgCO}_2/\text{year}\right) \tag{9}$$

where:

$Q_{f,i}$ is the energy consumption (kWh/year);
$f_{CO2,i}$ is the carbon dioxide emission factor (kgCO_2/kWh).

Table 2. The carbon dioxide emission factor [43].

The Primary Source of Energy	kgCO_2/kWh
Natural gas	0.205
Biomass—wood	0.019
Biomass—sawdust	0.016
Biomass—pellets/briquettes	0.039
Biomass—agricultural waste	0.010
Electricity from the public network	0.299

3.4. The Cost Benefit Analysis

The cost benefit analysis (CBA) contains a set of analytical tools used to assess the financial and economic viability of a proposed investment. The most often used tools are the cash flow, the simple payback period (SPBP), the discounted payback period (DPBP), the net present value (NPV), and the internal rate of return (IRR). The NPV, the IRR, the SPBP, and the DPBP indices are defined by the following expressions [44–46]:

$$NPV = \sum_{t=1}^{N} \frac{C_t}{(1+i)^t} - C_0 \tag{10}$$

$$C_0 - \sum_{t=1}^{N} \frac{C_t}{(1+IRR)^t} = 0 \tag{11}$$

$$SPBP = \frac{C_0}{C_t} \tag{12}$$

$$DPBP = -\frac{ln(1 - SPBP \cdot i)}{ln(1 - i)} \tag{13}$$

where:

C_0 is the initial investment cost (Euro);
N is the lifetime of the investment;
i is the discount rate;
C_t is the yearly revenue (Euro/year).

4. Case Study

For the analysis, a single-family residential building with the following characteristics was considered: the heated surface 263 m^2; the heated volume 684 m^3; the thermal resistance of the outer walls 2.21 m^2 °C/W; the thermal resistance of the upper floor 5.11 m^2 °C/W; the thermal resistance of the lower floor 4.67 m^2 °C/W; the thermal resistance of the windows and doors 0.77 m^2 °C/W. The building was located in the Suceava region (47.642353, 26.229929), Romania, climate zone IV. The annual energy consumption and type of primary source used for each utility are shown in Table 3.

Table 3. Annual energy consumption for utilities (reference case).

Type of Utility	Primary Source of Energy	Annual Energy Consumption (kWh/year)	(kWh/m^2·year)
Heating	Natural gas	21,303	81
Hot water	Natural gas	9468	36
Cooling	Electricity from the public network	4208	16
Lighting and appliances	Electricity from the public network	3156	12

The variation of the monthly consumption of the building's utilities is shown in Figure 3. Because the structure of the on-site energy demand may vary in different moments of the day and seasons of the year, energy storage is required for the optimal operation of micro-cogeneration systems.

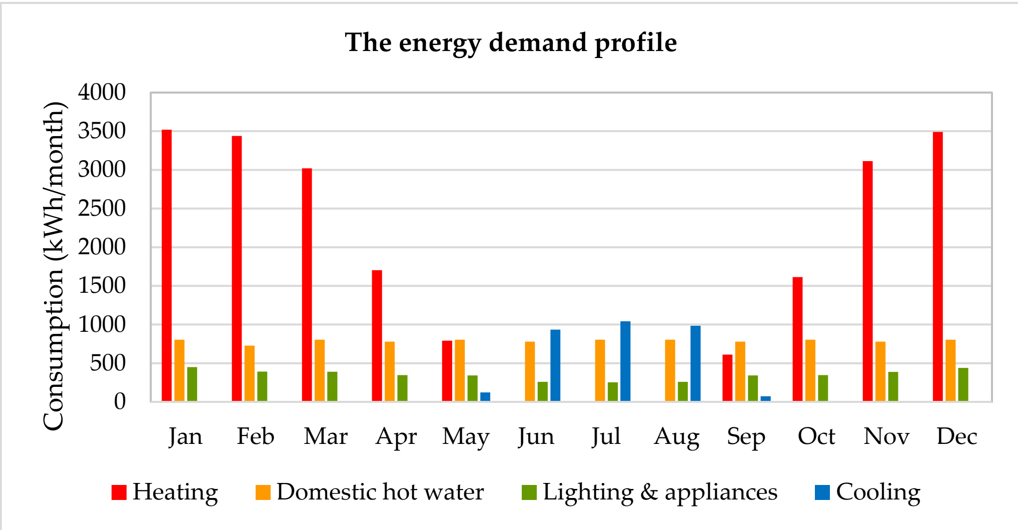


Figure 3. The variation of the monthly consumption of the building's utilities.

To ensure the energy demand in the building, two cogeneration plants are compared to the reference case: A gas boiler and electricity from the public network. The tariffs for energy consumed from public networks (taxes included) are shown in Table 4 [47]. The reference values for the separate generation of electricity and heat are presented in Table 5 [48]. Table 6 shows the nominal technical characteristics of the two cogeneration plants considered in the case study.

Table 4. The tariffs for energy consumed from public networks.

Electricity (Euro/kWh)	Natural Gas (Euro/kWh)
0.159	0.035

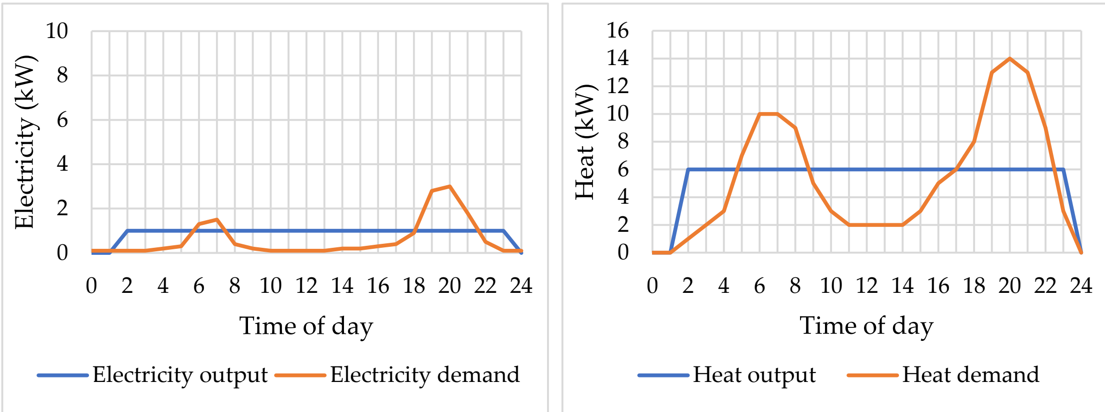
Table 5. Reference values [48].

Parameter	U.M.	Natural Gas	Biomass	Solar Energy
The reference electrical efficiency	%	53.00	37.00	30.00
The reference thermal efficiency	%	92.00	86.00	92.00
The factor for avoided grid losses	-	0.851 (U < 0.45 kV; on-site)		

Table 6. Nominal technical characteristics.

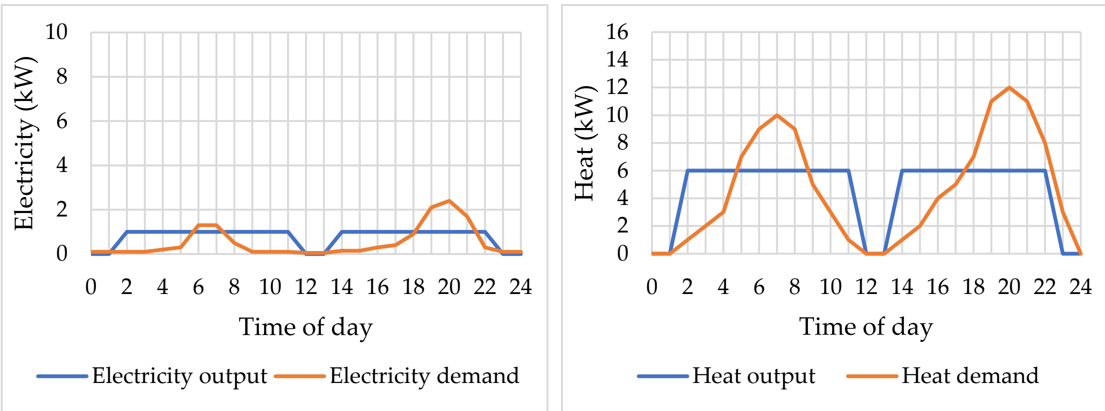
Parameter	U.M.	Stirling Engine CHP	ORC CHP
Primary source of energy	-	Natural gas	Biomass and Solar energy
Electric power output	kWe	1.0	1.0
Heat power output	kWt	6.0	8.8
Electrical efficiency	%	13.50	10.00
Thermal efficiency	%	81.10	88.00
Overall efficiency	%	94.60	98.00

Figures 4–9 show the end user behavior and its match with the micro-CHP operating mode for several typical days: maximum winter load, average winter load, and minimum summer load.



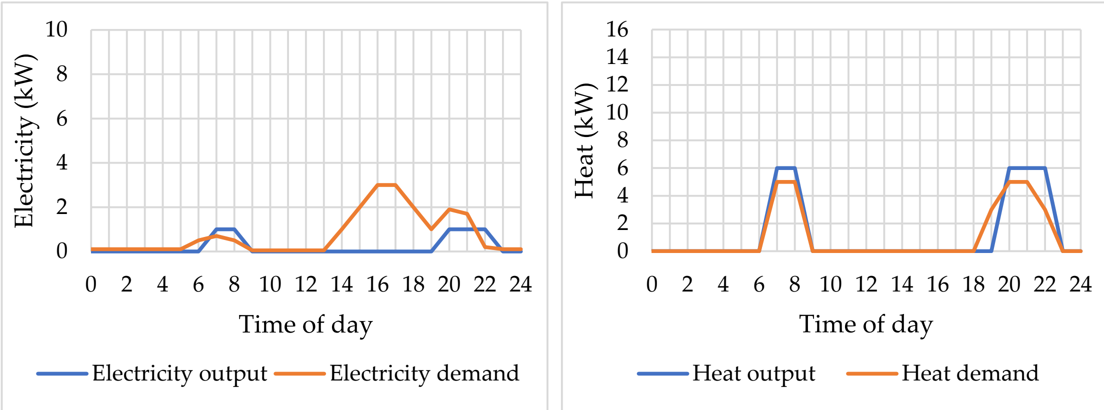
(**a**) (**b**)

Figure 4. Typical maximum winter load profile of the Stirling engine CHP: (**a**) electricity; (**b**) heat.



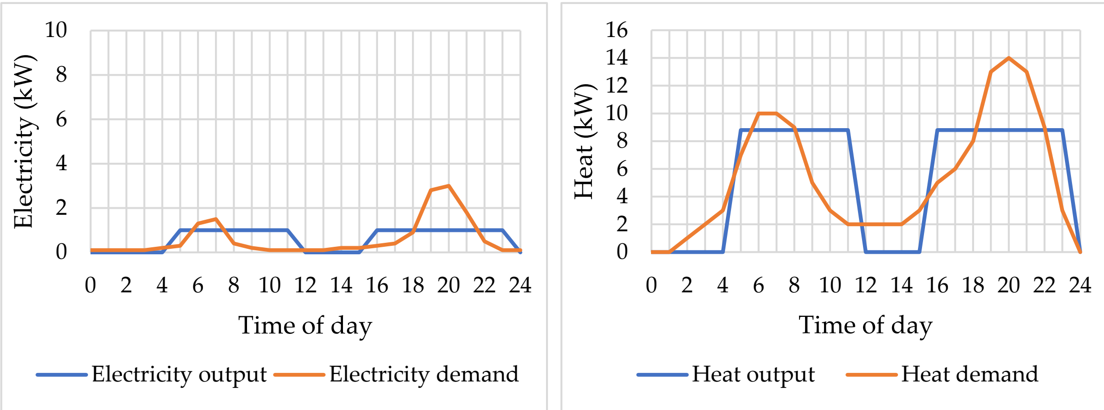
(**a**) (**b**)

Figure 5. Typical average winter load profile of the Stirling engine CHP: (**a**) electricity; (**b**) heat.



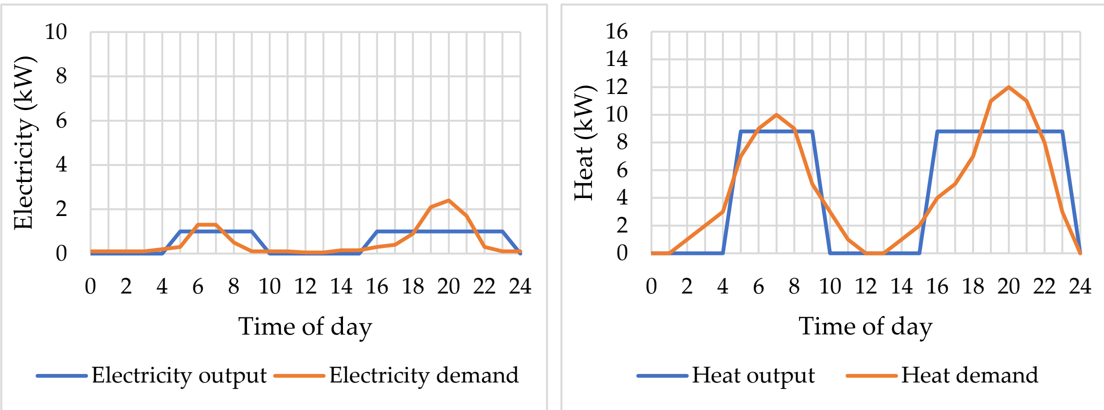
(**a**) (**b**)

Figure 6. Typical minimum summer load profile of the Stirling engine CHP: (**a**) electricity; (**b**) heat.



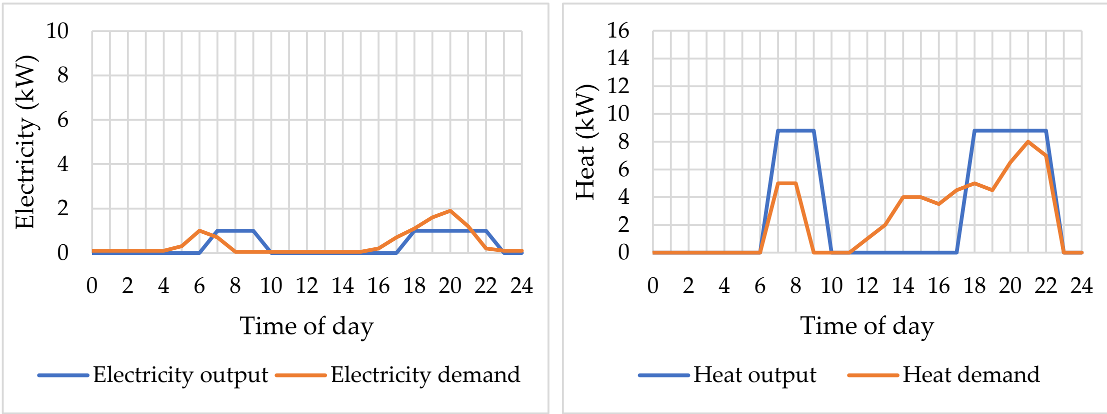
(**a**) (**b**)

Figure 7. Typical maximum winter load profile of the ORC CHP: (**a**) electricity; (**b**) heat.



(**a**) (**b**)

Figure 8. Typical average winter load profile of the ORC CHP: (**a**) electricity; (**b**) heat.



(**a**) (**b**)

Figure 9. Typical minimum summer load profile of the ORC CHP: (**a**) electricity; (**b**) heat.

It is observed that the operating mode of the two cogeneration systems is different and depends on the power-to-heat ratio. There is a need for flexibility in the use of the available heat or electricity generated by the micro-CHP unit at a given time. Thus, in winter, excess electricity can be stored in the form of heat and used for heating or domestic hot water. In the summer, excess heat can also be stored and used for cooling. Figures 10 and 11 show how the requirements of utilities in the building were correlated with the cogeneration production of heat and electricity for one year.

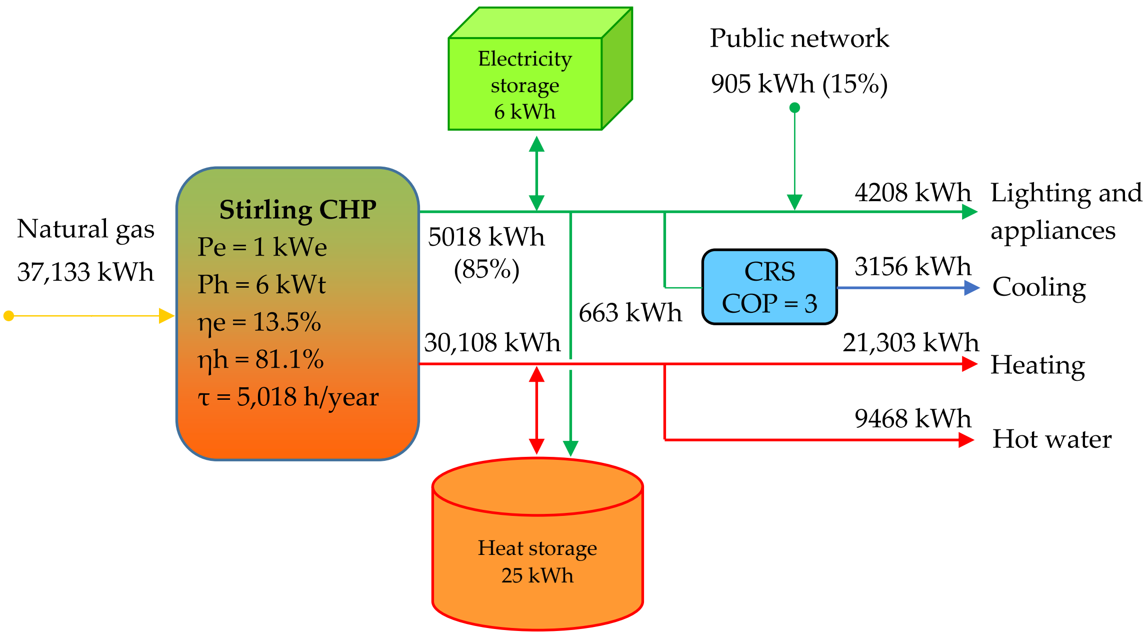


Figure 10. Stirling engine CHP.

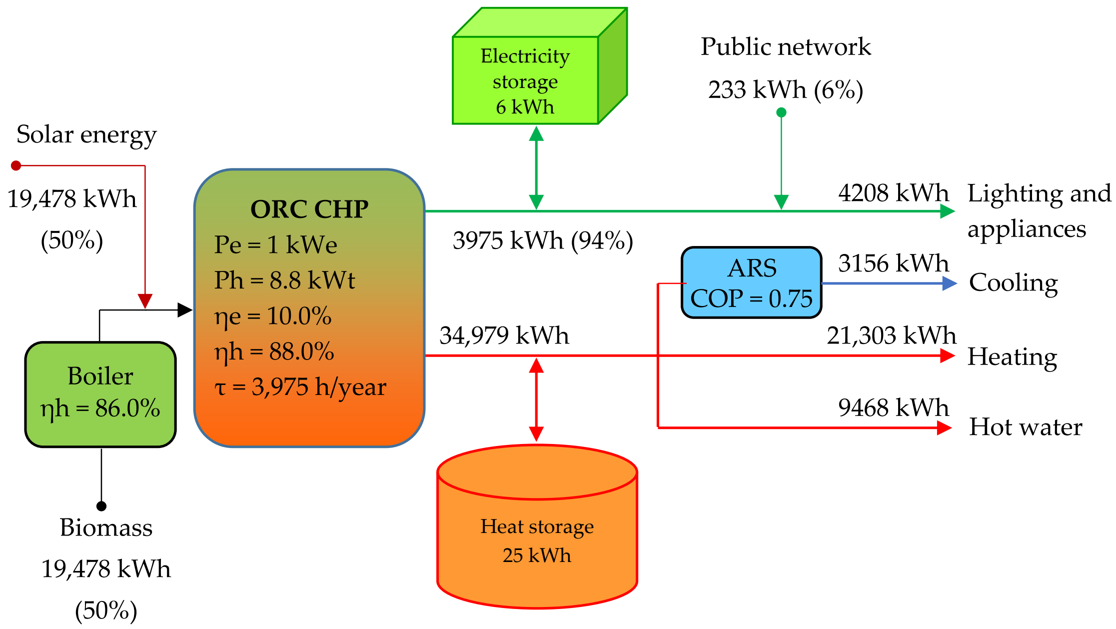


Figure 11. ORC CHP.

The primary sources used may also cover peak thermal demands when the load provided by the cogeneration system is insufficient. In most cases, because the demands for building utilities (heating, cooling, domestic hot water, and electricity) are not at the same time, energy storage is required. The heat storage system represents a key component for the micro-CHP systems since it permits to store the unused heat during electricity production for a later use. The micro-CHP system can primarily track heat demand by supplying electricity as a byproduct or can track electricity demand to generate electricity and use heat as a byproduct. The heat storage will allow the system to capture heat when not in use and then deliver it when the process requires more heat than the cogeneration unit can offer. Electricity storage is used for the same reasons. Depending on the particulars of household consumptions, the storage systems have been dimensioned according to the maximum duration loads to ensure at least three to four hours thermal load and at least two hours electrical load. Oversize of the storage systems can reduce the profitability of the micro-CHP system.

5. Results and Discussion

In order to analyze the feasibility, the difference of investment costs for a micro-CHP system compared to the reference scenario is taken into account. Due to the low power of the micro-CHP system, there is no major difference in operating costs compared to the reference case. Therefore, in this study, the operating and maintenance costs (O&M) are equivalent to a domestic gas boiler [49]. Also, there are no additional costs to staff for the use of biomass. Material handling is done by the owner of the individual household. Table 7 shows the cost range based on the type of prime mover that drives the CHP system [29,50–54]. The results of the technical and economic calculation are presented in Table 8. The cost of the ORC CHP system also includes the cost of solar panels. Pellets and briquettes are the type of biomass considered in the calculation and the price is 0.025 EUR/kWh. Figures 12 and 13 show the Net Present Value (NPV) in both cases.

Table 7. Micro-CHP costs.

Parameter	Investment Costs (EUR/kWe)	*O&M Costs (EUR/year)
Stirling engine micro-CHP	2000–8000	50
ORC micro-CHP	4000–12,000	50

*O&M are the operating and maintenance costs.

Table 8. Cost benefit analysis.

Parameter	U.M.	Stirling CHP	ORC CHP
Electric power	kWe	1.0	1.0
Cogeneration investment difference	EUR	3500	8000
Electricity storage investment	EUR	720	720
Heat storage investment	EUR	1250	1250
Cooling investment	EUR	-	2940
Total investment	EUR	5470	12,910
Annual savings	EUR/year	658	1288
The internal rate of return	%	10.35	7.73
The simple payback period	Years	9.71	10.02
Discount rate	%	5.00	5.00
The discounted payback period	Years	13.62	14.25
Reduction of CO_2 emissions	kgCO_2/year	1377	8544

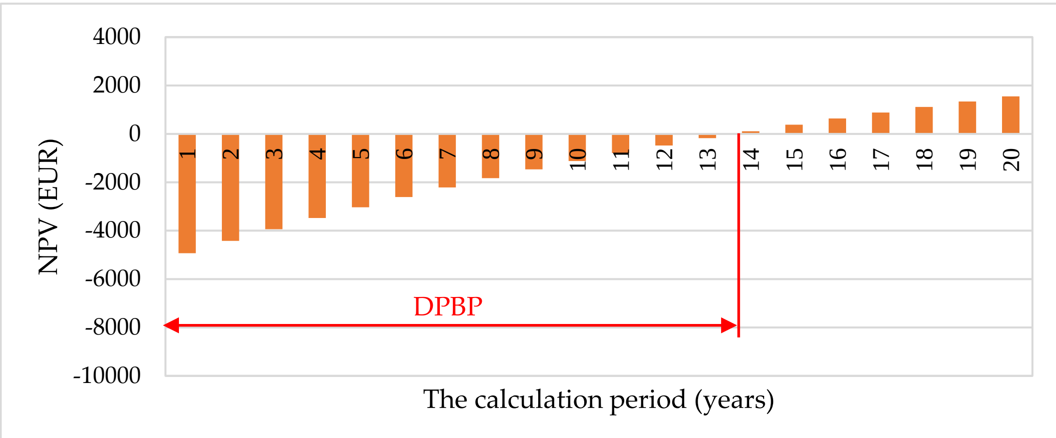


Figure 12. Net Present Value (NPV) for the Stirling engine CHP.

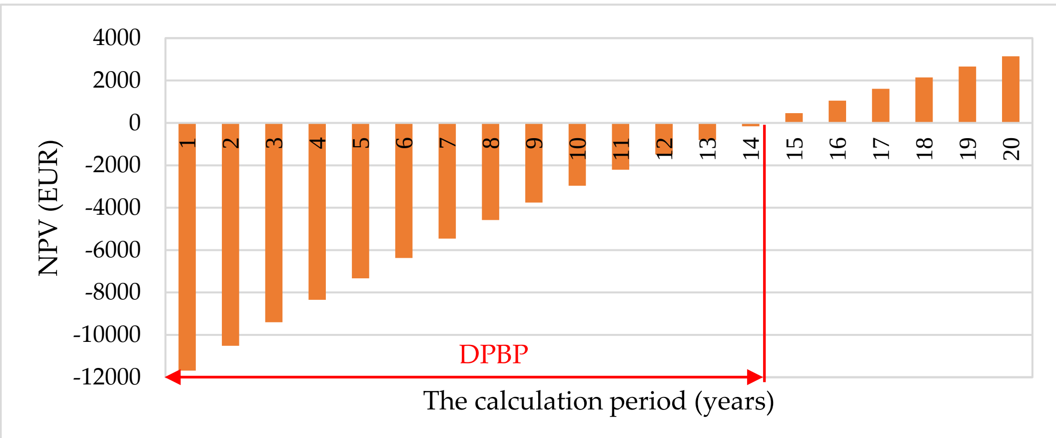
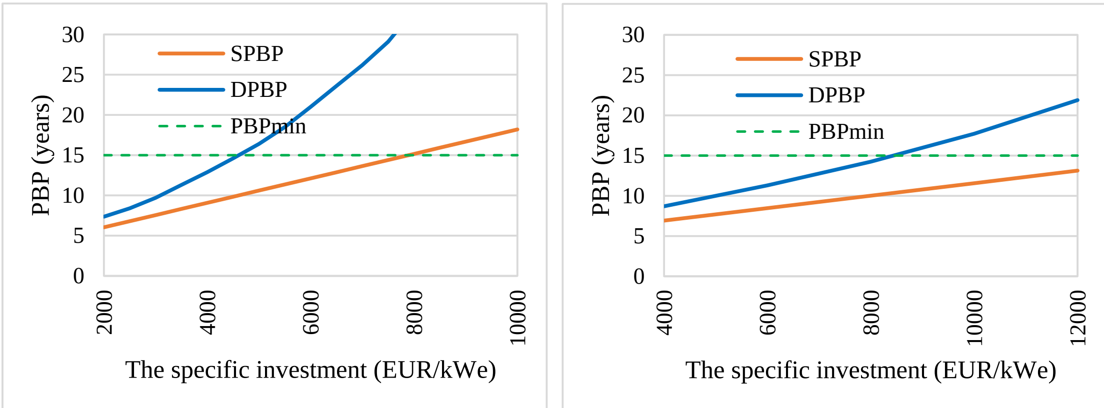


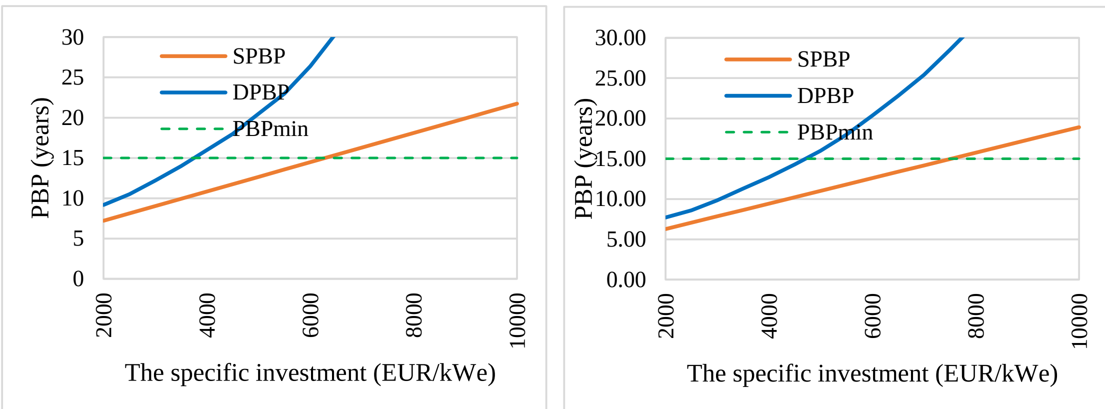
Figure 13. Net Present Value (NPV) for the ORC CHP.

The discounted payback period (DPBP) is more reliable than the simple payback period (SPBP) as it accounts for time value of money. The DPBP shows the operating period, at the end of which, through the updated cash flow generated, the investment is fully recovered and there is still the possibility of obtaining a cash flow that corresponds to the discount rate. Mathematically, the DPBP is the operating period after which NPV is null. In this case study, the DPBP is 13.62 years in the Stirling CHP case (Figure 12) and 14.25 years in the ORC CHP case (Figure 13). Figure 14 shows the influence of the specific cost of cogeneration technologies on the SPBP and the DPBP. Figure 15 shows how the price increase of natural gas and electricity affects the DPBP. Increasing the price of natural gas as a result of import dependence has the effect of reducing the profitability of the investment, while increasing the price of electricity has the opposite effect. The profitability of the investment is even greater as the difference between the price of electricity from public network and the price of the fuel used in the micro-CHP plant increases as in the case of biomass.



(**a**) (**b**)

Figure 14. The payback period (PBP): (**a**) the Stirling engine CHP; (**b**) the ORC CHP (50% share of solar energy).



(**a**) (**b**)

Figure 15. The payback period (PBP) of the Stirling engine CHP: (**a**) natural gas price increase by 10%; (**b**) electricity price increase by 10%.

Figure 16 shows the influence of the solar energy share on the payback period in the ORC CHP case. Thus, even under the conditions of a higher specific investment cost, it is possible that the payback period for the micro-CHP will fall below the accepted average value (<15 years) [43,46].

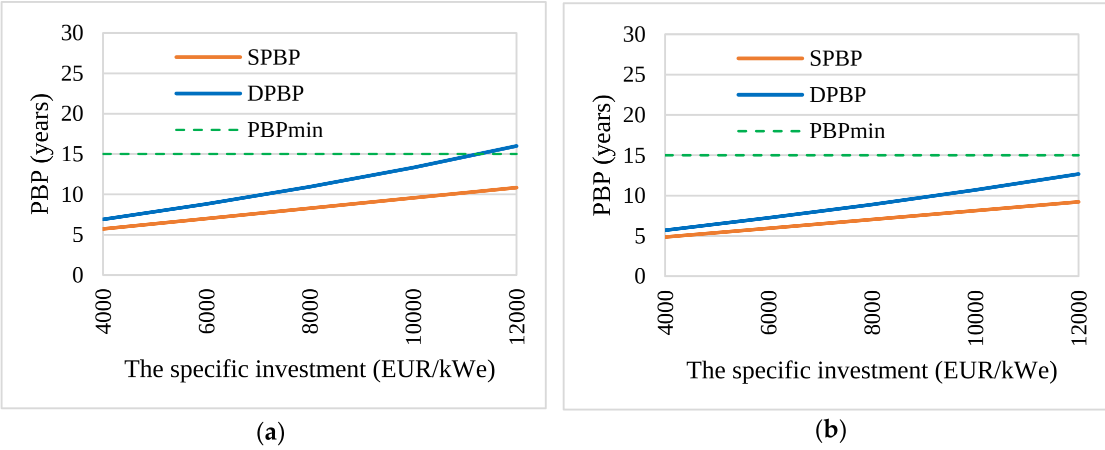


Figure 16. The influence of the solar energy share on the PBP in the ORC CHP case: (**a**) the ORC CHP (70% share of solar energy); (**b**) the ORC CHP (90% share of solar energy).

Figure 17 shows the reduction of annual carbon dioxide emissions in both scenarios. Compared to the reference scenario, the annual reduction of CO_2 emissions is 1377 $kgCO_2$ in Scenario 1 and 8544 $kgCO_2$ in Scenario 2. Obviously, a higher production of renewable energy sources in Scenario 2 will lead to a greater reduction of CO_2 emissions.

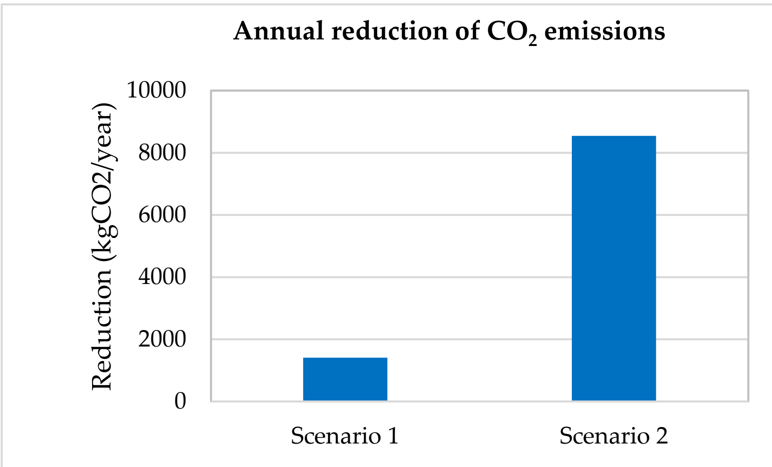


Figure 17. The reduction of annual CO_2 emissions.

Although it is expected that the sharing of renewable energy will increase in the coming decades, the fossil fuels (especially natural gas) and other alternative fuels (biomass, biofuels, LPG, etc.) will continue to play a major role in the transition to new and renewable energy sources. Therefore, it is desirable to make efficient use of these fuels with the most energy efficient technologies and with the least environmental impact.

The compact dimensions and the combination with established technology allow the generation of heat and electricity in the modernization of the households. The storage tank volume is a key parameter to optimize the system performance. However, this volume could be limited because it can slightly affect the economic performance of the system. Therefore, it is necessary to optimize the operation in hybrid mode of the cogeneration system in order to maximize the renewable energy sources used.

The investment return is maximum if the volumes of electricity and heat generated will be consumed almost entirely within the perimeter of the location where the micro-CHP unit is located.

The success of implementing a micro-cogeneration system will be based on how well the system economically meets the thermal and electric loads and priorities of the residential building.

The benefits of the cogeneration of large power systems are well proven. In the case of micro-CHP, the still large specific investment represents a barrier to its expansion. The main objective of this paper was the economic assessment of the micro-CHP units under the current market conditions. The correct choice of the micro-CHP system and its matching with the consumption demands of the building shows the profitability of the micro-CHP without support schemes.

6. Conclusions

In this case study, two micro-cogeneration systems were compared to the reference case: the first case (Scenario 1) with the Stirling engine CHP, and the second case (Scenario 2) with the ORC CHP. The case of reference was an individual household with a gas boiler and electricity from the public network.

The results of this study show that the investment in a micro-cogeneration system can be attractive and economic performances can be obtained without subsidies (without government or local support schemes). The profitability of the micro-cogeneration system is even higher as the power and heat ratio provided better matches the daily profiles of electric, thermal, and cooling loads.

The conditions (limitations) of obtaining the results and future directions of the research were highlighted. The results were obtained when the electricity generated by the CHP unit is consumed almost entirely inside the household. Also, the average monthly temperatures were used for estimating energy consumption for heating and air conditioning. The analysis of the dynamic factors that can influence the energy consumption in the building represents future directions of study.

If environmental benefits are considered, support from government and local authorities can increase the attractiveness for such systems and the primary sources of energy near the place of consumption are more efficiently used.

Therefore, the micro-cogeneration from renewable sources can be one way of achieving the objectives regarding the competitiveness, security, and sustainability of the energy supply of the individual residential consumers.

In addition, a further criterion for sustainable energy is that any biomass harvested to make household fuels should be done so on a renewable basis to ease pressure on forests and other natural ecosystems.

From this point of view, micro-cogeneration offers optimal solutions for both fossil and renewable fuels. Thus, in the case of small households, the share of primary energy from classical sources can be gradually reduced and the share of primary energy from renewable energy sources can be increased to ensure utilities in the building. The implementation of a micro-cogeneration project in residential applications must consider all of the aspects related to the location and the operating strategies to ensure the profitability of such an investment.

Funding: This research received no external funding.

Acknowledgments: The author did not receive any funds for covering the costs to publish in open access.

Conflicts of Interest: The author declares no conflicts of interest.

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13th International Conference Interdisciplinarity in Engineering (INTER-ENG 2019)

The Efficient Use of Natural Gas in Cogeneration Applications for Small Consumers

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Abstract

Currently, the natural gas still has a very high use in small households not only for cooking but also for heating and hot water. The most common solution to provide utilities for small consumers is the gas boiler and electricity from public network. The paper presents an analysis of the use of micro cogeneration in small households for increasing the energy efficiency in the use of natural gas. Two micro cogeneration systems were considered for analysis: the first with Stirling engine and the second with fuel cells. The case of reference is a small household with gas boiler and electricity from public network. The reduction of carbon dioxide (CO_2) emissions and the payback period of investment are highlighted in the case of the two micro cogeneration systems compared to the existing situation.

Keywords: Natural gas; micro cogeneration; fuel cells; Stirling engine; cost-benefit analysis.

1. Introduction

Compared to other fossil fuels, the use of natural gas has a much lower impact on the environment in terms of carbon dioxide emissions. Thus, the further use of natural gas seems to be one of the energy transition solutions to a carbon-free energy generation. Currently, the natural gas has a very high use in providing heating and domestic hot water for small consumers. The further use of natural gas should be made with the help of the most energy-efficient technologies [1,2]. The viability of cogeneration is well proven in the industrial applications of medium and high

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10.1016/j.promfg.2020.03.053

power and is further investigated to meet the needs of small residential, commercial or industrial consumers [3-6]. The benefits of cogeneration are multiple. The combined heat and power generation enables more efficient use of fuel and the reduced global emissions of carbon dioxide (CO_2) compared to separate generation. The cogeneration technologies most used in small applications are Stirling engine CHP and Fuel cells CHP [7,8]. These technologies have good performance and in the case of partial loads [9,10].

Nomenclature

CHP	combined heat and power
PES	primary energy saving
TPP	thermal power plant
TP	thermal plant
$W_{e,sep}$	the energy consumption for separate electricity generation
$W_{h,sep}$	the energy consumption for separate heat generation
W_{CHP}	the energy consumption for combined heat and power generation
$\eta_{e,ref}$	the efficiency reference value for separate generation of electricity
$\eta_{h,ref}$	the efficiency reference value for separate generation of heat
p_{loss}	the correction factor for avoided grid losses
$\eta_{e,CHP}$	the electrical efficiency of the cogeneration generation
$\eta_{h,CHP}$	the heat efficiency of the cogeneration generation

2. Methodology

Figure 1 shows comparatively the increase in fuel use efficiency to the combined heat and power generation with conventional station power generation and on-site boiler. By generating electricity on site, it is also avoided the transmission and distribution losses of electricity at a distance.

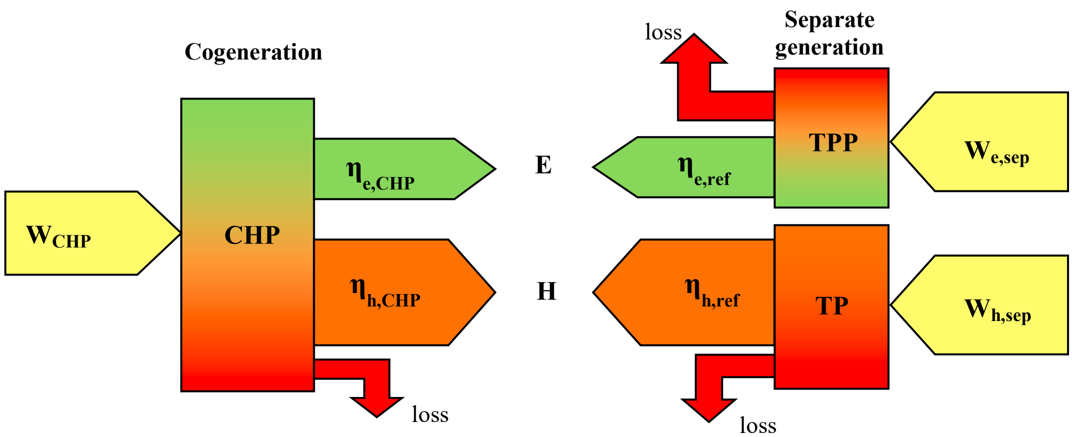

Fig. 1. Combined heat and power versus separate heat and power generation.

In addition to cost savings, the cogeneration offers significantly lower emissions rates compared to separate heat and power generation. The reduction of CO_2 emissions is calculated on the basis of the primary energy saving of cogeneration systems compared to the conventional separate systems:

$$PES = \frac{W_{sep} - W_{CHP}}{W_{sep}} = \frac{(W_{e,sep} + W_{h,sep}) - W_{CHP}}{W_{e,sep} + W_{h,sep}} \quad (1)$$

or:

$$PES = 1 - \frac{1}{\left(\frac{\eta_{e,CHP}}{\eta_{e,ref} \cdot p_{loss}} - \frac{\eta_{h,CHP}}{\eta_{h,ref}}\right)} \tag{2}$$

The reduction of CO_2 emissions in cogeneration mode versus separate generation:

$$\Delta e_{CO2} = PES \cdot f_{CO2} \;\; (kgCO_2/year) \tag{3}$$

Respectively:

$$E_{CO2} = \Delta e_{CO2} \cdot p_{CO2} \;\; (EUR/year) \tag{4}$$

where:

f_{CO2} is the CO_2 emission factor for natural gas ($kgCO_2/kWh$);

p_{CO2} is the price of CO_2 certificates (EUR/certificate CO_2).

The annual revenue consists of the energy saving when running in cogeneration mode plus the revenue from the reduction of carbon dioxide emissions quantified by the current price of gas emission certificates.

The payback period (PBP) is the time required to earn back the amount invested and it is a simple way to evaluate the risk associated with a proposed project.

$$PBP = \frac{Cost\ of\ the\ investment}{Annual\ net\ cash\ flow} = \frac{Cost\ of\ the\ investment}{(W_{sep} - W_{CHP}) \cdot p_{fuel} + E_{CO2}} \;\; (years) \tag{5}$$

3. Case study

For the analysis was considered a single-family residential building with the following characteristics: the heated surface 265 m^2; the heated volume 689 m^3; the thermal resistance of the outer walls 2.21 m^2°C/W; the thermal resistance of the upper floor 5.11 m^2°C/W; the thermal resistance of the lower floor 4.67 m^2°C/W; the thermal resistance of the windows and doors 0.77 m^2°C/W. The building is located in the Suceava region, Romania, the climate zone IV. The annual energy consumption and type of primary source used for each utility are shown in Table 1. Table 2 shows the nominal technical characteristics of the two cogeneration plants considered in the case study.

Table 1. Annual energy consumption for utilities.

Type of utility	Primary source of energy	Annual energy consumption (kWh/year)
Heating	Natural gas	20140
Hot water	Natural gas	9805
Lighting and appliances	Electricity from the public network	5035

Table 2. Nominal technical characteristics.

Type CHP	U.M.	Stirling engine CHP	Fuel cells CHP
Fuel	-	Natural gas	Natural gas
Electric power output	kWe	1.0	1.9
Heat power output	kWt	4.8	3.4
Electrical efficiency	%	16.00	33.93
Thermal efficiency	%	76.80	60.71
Overall efficiency	%	92.80	94.64

A cogeneration system can primarily track heat demand by supplying electricity as a byproduct or can track electricity demand to generate electricity and use heat as a byproduct. When used primarily for heating, micro cogeneration systems can generate more electricity than is required instantly under fluctuating electrical demand. Using of the energy storage can eliminate this inconvenience. Figures 2 and 3 show how to cover energy demand by the Stirling engine CHP and respectively Fuel cells CHP.

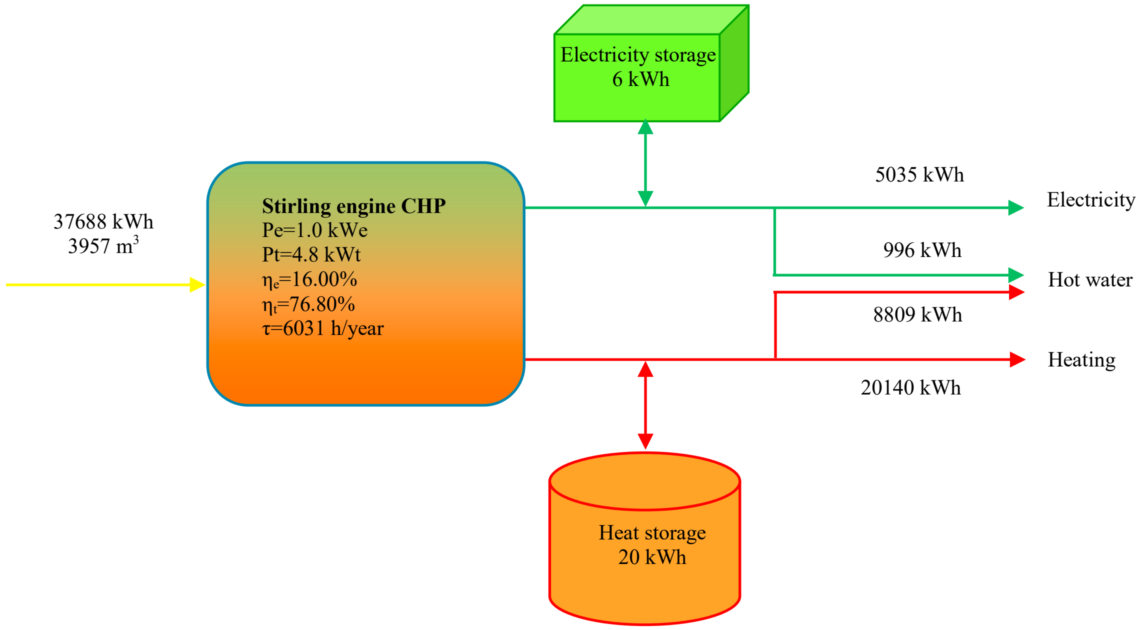

Fig. 2. Stirling engine CHP.

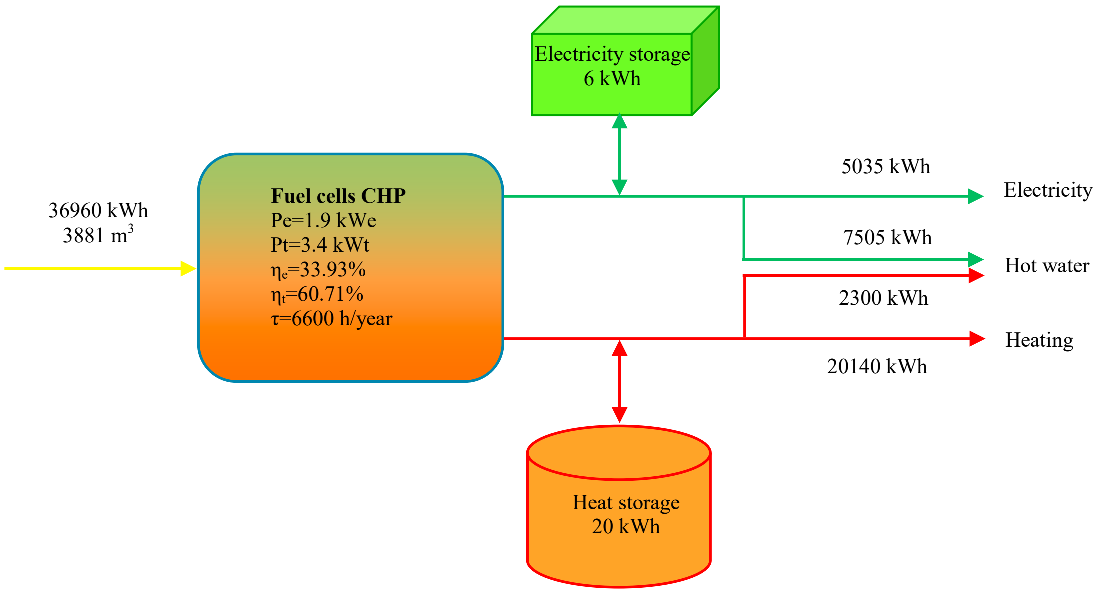

Fig. 3. Fuel cells CHP.

The two cogeneration plants are compared to the reference case: gas boiler and electricity from public network. The reference values for the separate generation of electricity and heat are presented in Table 3 [11]. To quantify the reduction of CO_2 emissions was considered the current value of CO_2 certificates [12]. The results of the technical and economic calculation are presented in Table 4. Because in most cases, the demands for building utilities (heating, domestic hot water and electricity) are not at the same time, energy storage is required. Thus, in order to ensure the optimal operating conditions of the cogeneration plant, it is necessary to store both the heat and the electricity. Figure 4 shows the influence of the specific cost of cogeneration technologies on the payback period (PBP).

Table 3. Reference values.

Parameter	U.M.	Value
The reference electricity efficiency	%	53.00
The reference heat efficiency	%	92.00
The network loss correction factor	-	0.851
The CO_2 emission factor	$kgCO_2/kWh$	0.205
The price of CO_2 certificates	EUR/CO_2 certificate	24
Electricity price	EUR/kWh	0.159
Natural gas price	EUR/kWh	0.035

Table 4. Cost-benefit analysis.

Type CHP	U.M.	Stirling engine CHP	Fuel cells CHP
Electric power	kWe	1.0	1.9
Cogeneration investment	EUR	3500	9500
Electricity storage investment	EUR	720	720
Heat storage investment	EUR	1000	1000
Total investment	EUR	5220	9700
Annual savings	EUR/year	680	693
Reduction of CO2 emissions	EUR/year	35	75
Total annual revenue	EUR/year	715	768
The payback period	Years	7.30	14.60

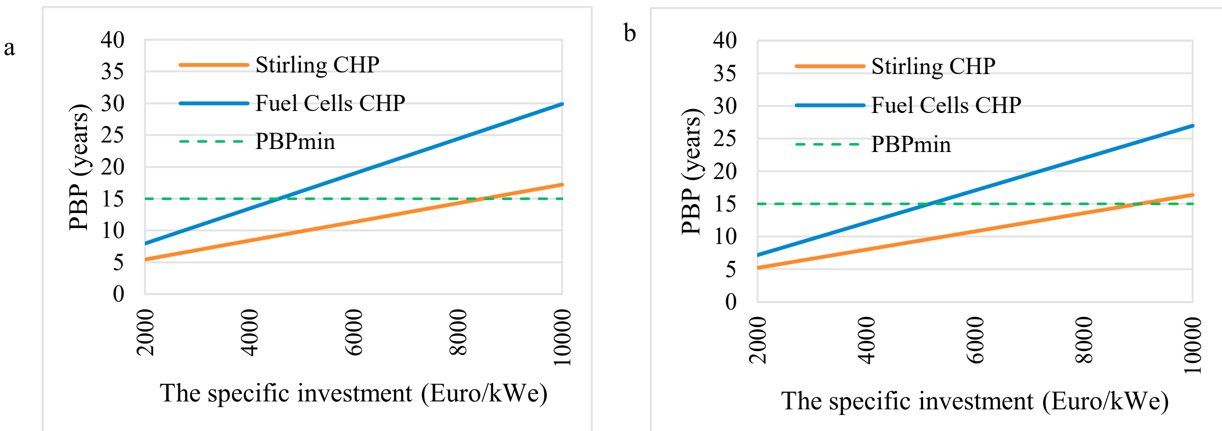

Fig. 4. The payback period (PBP): (a) without taking into account CO_2 emissions; (b) with taking into account CO_2 emissions.

From the technical and economic analysis results a lower payback period for the Stirling system compared to the fuel cells system. This is due to the smaller specific investment in Stirling engine cogeneration but also the power and heat ratio more favorable to the demand for building utilities. The quantifying of CO_2 emissions reduction in cogeneration can influence the payback period in the sense of reducing it. Thus, for the present conditions (natural gas price, specific investment) it is possible that the payback period for the fuel cells CHP will fall below the accepted average value (< 15 years). It is noted that the structure of energy consumption in the building is one of the decisive factors in the choice of cogeneration technology. For the analysed building, the electricity consumption is much lower than the heat demand. Therefore, the cogeneration technology with the power and heat ratio to the most appropriate energy demand can be a viable option for small residential and industrial consumers.

4. Conclusions

The use of natural gas in individual households is still widespread both for heating and domestic hot water. The most common solution for provides the utilities of individual houses is represented by gas boiler and electricity from public network. Both utilities (heat and electricity) can be generated in cogeneration with higher energy efficiency. The main purpose of cogeneration is to use more energy from the fuel but also to reduce greenhouse gas emissions compared to separate production.

Two micro cogeneration technologies were analysed in the paper compared to the existing situation considered as reference. The primary energy saving is 15.93% for the Stirling engine CHP and 29.19% for the fuel cells CHP. The reduction of carbon dioxide emissions is 14.02% the Stirling engine CHP and 23.46% the fuel cells CHP. The payback period is higher for the fuel cells CHP due to both the higher specific investment and the power and heat ratio different from the Stirling engine CHP.

Because the structure of on-site energy demand may vary in different moments of the day and seasons of the year, the energy storage is required for the optimal operation of micro cogeneration systems.

The profitability of a cogeneration plant is conditional on the proper matching of the system with the energy demand so as to ensure maximum use of the energy contained in the fuel. An appropriately chosen cogeneration system leads to a reduction in the costs of final energy production and contributes to the reduction of carbon dioxide emissions.

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Procedia Manufacturing 32 (2019) 385–389

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The 12th International Conference Interdisciplinarity in Engineering

The Cost-Benefit Analysis of the Electricity Production from Small Scale Renewable Energy Sources in the Conditions of Romania

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Abstract

The electricity production from renewable energy sources is promoted across European Union by support schemes that are applied in order to achieve energy policy goals of sustainability, security of supply and improved competitiveness. In Romania, the electricity production from renewable energy sources in power stations with over 1 MW capacity is supported by the mechanism of mandatory quotas combined with the transaction of green certificates.
Currently, there is no support for electricity production from small scale renewable energy sources. The paper presents the economic viability assessment of electricity production from small scale renewable energy sources by using a cost-benefit analysis approach.

Selection and peer-review under responsibility of the 12th International Conference Interdisciplinarity in Engineering.

Keywords: Renewable energy sources; small scale electricity generation; cost-benefit analysis; support schemes; feed-in tariff.

1. Introduction

Increasing the share of electricity from renewable energy sources is a priority for the European Union (EU). The main advantage of renewable energy sources over conventional energy generation is that they contribute to the preservation of public goods, namely clean air and climate stability. Various support schemes for sustaining the

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2351-9789
Selection and peer-review under responsibility of the 12th International Conference Interdisciplinarity in Engineering.
10.1016/j.promfg.2019.02.230

production of electricity from renewable energy sources are used by the EU countries [1,2]. The support schemes are a key mechanism to help achieve national renewable energy targets.

The market for renewable energy technologies shows a trend towards lowering the specific investment costs, especially of photovoltaic technology. On the back of price declines for solar PV modules, the installed costs of utility-scale solar PV projects fell by 68% between 2010 and 2017 [3].

The integration of variable renewable energy sources significantly influences the short-run operation costs of the power system to balance and manage congestions [4].

The supply and demand must always match with great precision to maintain a stable frequency of the power system. In principle, this balance is ensured by the wholesale electricity market. The suppliers purchase electricity on wholesale markets according to their demand and producers deliver only the amount of electricity that have notified it. But deviations from contracted positions are unavoidable due to imperfect forecasts and unforeseen events such as interruption of power plants or power grids. The resulting imbalances are managed and corrected by the system operator that contracts reserve capacity to be used in real time. The cost of these operations is usually recovered through network charges and/or imbalance prices (penalties for deviation from the program).

A higher percentage of renewable energy accepted in the power system involve large amounts of conventional energy reserves and immense energy storage [5].

The structure of electricity production is needed to be changed around the world to combat climate change and increase energy security. As a result, the renewable energy sources and distributed generation receive support and their share in electricity production increases.

The support schemes fall into two main categories that are either price-based or quantity-based in their approach [6,7]. The feed-in tariff scheme involves an obligation on the suppliers to purchase the electricity produced by renewable energy producers at a tariff determined by the public authorities and guaranteed for a specified period of time.

In the case of tradable green certificates schemes, the electricity suppliers are obliged to distribute a certain quota of renewable energy. The producers of electricity from renewable sources receive income in two different ways: by selling electricity on the network at the market price, and by selling certificates on the green certificates market.

Romania has adopted the mechanism of mandatory quotas combined with the transaction of green certificates since 2008 for the electricity production from renewable energy sources in power stations with over 1 MW capacity. The electricity production from small scale renewable energy sources is not currently supported. A support scheme for small scale renewable energy sources will allow the guaranteed connection of residential prosumers to the grid (priority/guaranteed grid access) and the obligation for network operators to feed energy produced by renewable generation units into the grid (priority dispatch).

In the paper we analyzed the economic viability of the production of electricity from small scale renewable sources of energy under the conditions of a feed-in tariff support scheme.

2. The cost-benefit analysis

The following financial analysis tools were used for economic evaluation: the cash flow, the payback period (PBP), the net present value (NPV) and the internal rate of return (IRR). The PBP, NPV and the IRR indices are defined by the following equations:

$$PBP = C_0 / C_t \tag{1}$$

$$NVP = \sum_{t=1}^{N} \frac{C_t}{(1+i)^t} - C_0 \tag{2}$$

$$C_0 - \sum_{t=1}^{N} \frac{C_t}{(1+i)^t} = 0 \tag{3}$$

where:

- C_0 is the initial investment cost (Euro);
- N is the lifetime of the investment (years);
- i is the Weighted Average Cost of Capital (WACC);
- C_t is the yearly revenue (Euro/year).

The yearly revenue for 1 kW of installed power:

$$C_t = \left(a \cdot p_{Edelivered} + b \cdot p_{Eself.consumption}\right) \cdot CF \cdot t_{year} - c_{fix} \cdot C_0 - c_{\mathrm{var}} \quad (4)$$

where:

- a – the share of electricity delivered (selling electricity);
- $p_{Edelivered}$ – the price feed-in tariff for the delivered electricity (Euro/kWh);
- b – the share of electricity produced from renewable sources for self-consumption;
- $p_{Eself.consumtion}$ – the average price of electricity from the public network (Euro/kWh);
- CF – the usage factor of the installed capacity (%);
- t_{year} – the duration of year (hours/year);
- c_{fix} – fixed costs of operation and maintenance (%/year);
- c_{var} – variable operating costs (Euro/kW·year).

The usage factor of the installed capacity is the ratio between the electrical energy delivered from the power plant in the analysis year and the electrical energy that could be produced if the power plant would operate for the analyzed duration to the installed capacity, expressed as a percentage.

The specific investment is the volume of investment needed to achieve a capacity unit, determined as the ratio between the total investment value and the installed electrical capacity. *The fixed costs* represent the production costs of the power plant and does not depend on the production of electrical energy. *The variable costs* represent the production costs of the power plant and they are dependent on the volume of production.

The specific investment costs of renewable energy sources are one of the reasons that limited the use of these resources by small electricity consumers. Currently, there are many technical possibilities to use of renewable energy sources. Two categories are distinguished: on-grid and off-grid. The off-grid technical solutions have costs of 3-4 times higher than on-grid. An example of computing for an off-grid system with storage is shown in the paper [8]. The integration of variable renewable energy sources into the power system network depends on the energy generation scale. In the case of the small scale renewable energy sources, it is possible to use the entire renewable energy production by on-grid connection (Figure 1). The on-grid system allows to cover its own consumption and provides the excess of electricity in the public network. If the consumption is higher than the production of renewable sources, the electricity difference is taken from the public network.

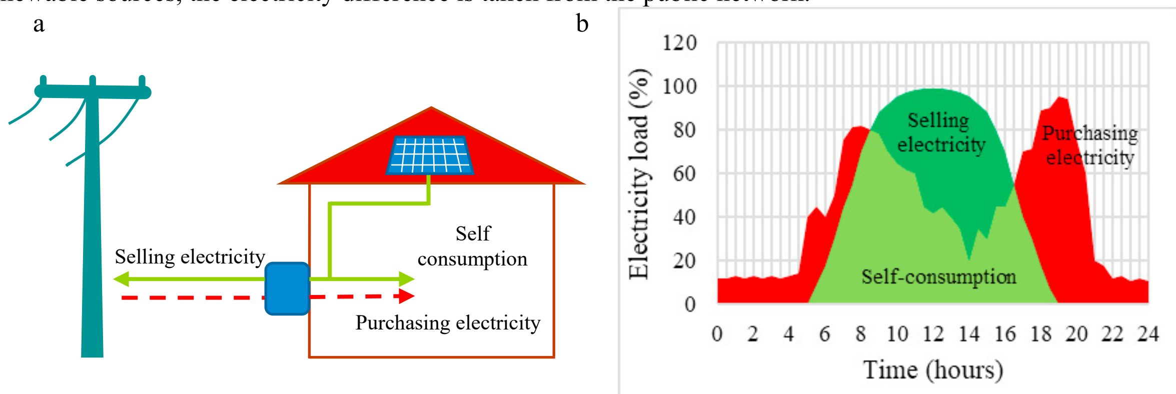

Fig. 1. Integration of small scale renewable energy sources: (a) solar PV connection to the grid; (b) electricity daily profile.

Under these circumstances, the use of energy from renewable sources can result in a number of benefits for both consumers and the whole power system. However, the surplus of electricity injected into the network can create new challenges for network operator in terms of the balancing process.

Figure 2 shows the payback period and Figure 3 the internal rate of return according to the specific investment of the renewable energy source and the price of electricity delivered to the public network: the average price on the Day-Ahead Market (DAM) in 2017 (a) and respectively the average price achieved on the Centralized Market of Bilateral Contracts (CMBC) in 2017 (b). We considered different values for the share of electricity delivered to the network and implicitly for the self-consumption.

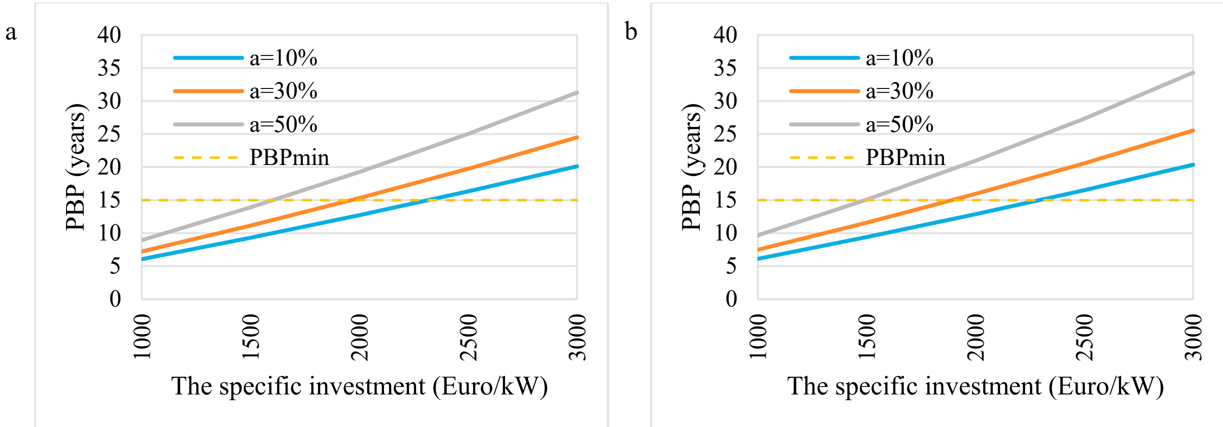

Fig. 2. The payback period: (a) 48.12 Euro/MWh the average price on the DAM in 2017; (b) 38.60 Euro/MWh the average price on the CMBC in 2017.

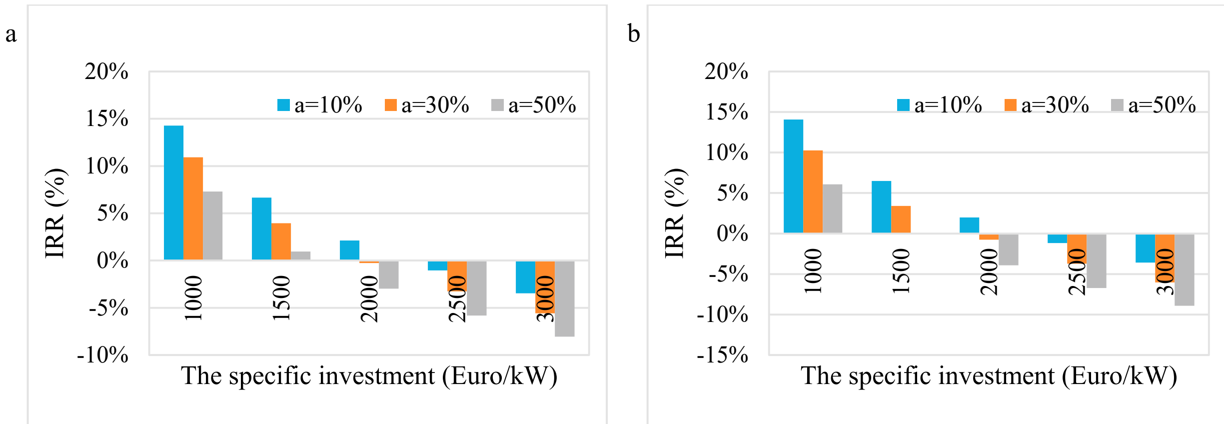

Fig. 3. The internal rate of return: (a) 48.12 Euro/MWh the average price on the DAM in 2017; (b) 38.60 Euro/MWh the average price on the CMBC in 2017.

The price of electricity purchased from the public network for the residential consumers is currently around 0.145 Euro/kWh. There is currently the intention of introducing a feed-in tariff support scheme for the small scale renewable energy sources (prosumers). The selling price of electricity in the public grid would be set at the level of the average price recorded on the DAM in the previous year.

For the current prices of electricity on the DAM, we estimate that specific investment values of less than 2300 Euro/kW would allow the investment to be recovered within a reasonable time (less than 15 years).

The obtained results show that a lower payback period and a higher internal rate of return are obtained if the self-consumption has a bigger share of the total amount of renewable energy produced. This finding suggests that the sizing of the renewable energy source should be based on the consumer's electricity demand. The specific investment costs of renewable energy sources are currently declining. Under these conditions, the consumers can save money by generating electricity from renewable sources rather than purchasing it from the public network.

3. Conclusions

Through the self-consumption process, the small traditional consumers of electricity can become prosumers (renewable energy consumers and producers). The self-consumption therefore has the potential to stimulate consumers to adopt flexibility measures, while helping to facilitate the integration of variable renewable energy sources into the power system. The electricity generation and consumption at local level also has the effect of reducing losses in the transmission and distribution networks.

In this paper, we have estimated that under the current conditions of Romania, the renewable energy sources of low on-grid power can be profitable at a specific investment of less than 2300 Euro/kWh. The profitability also depends on the share of electricity from renewable sources used for self-consumption. A higher share of electricity delivered to the public network creates problems for the network operator in terms of balancing, especially when there are more local producers of renewable sources.

The self-consumption is encouraged by a lower tariff for electricity injected into the public network than purchasing electricity from the supplier. In this context, the consumers are encouraged to adopt flexibility measures to increase their own consumption rate by using smart devices especially in times of production from renewable sources (e.g. washing machine, tumble dryers, dishwasher, hot water preparation etc.). Obviously, a great importance is also the correct dimensioning of the renewable energy source according to the consumer's energy needs.

Acknowledgements

This work was supported by a grant of the Romanian Ministry of Research and Innovation, CCCDI – UEFISCDI, project number PN-III-P1-1.2-PCCDI-2017-0404/31PCCDI/ 2018, within PNCDI III.

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Article

The Operating Strategies of Small-Scale Combined Heat and Power Plants in Liberalized Power Markets

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Received: 24 September 2018; Accepted: 8 November 2018; Published: 10 November 2018

Abstract: Distributed generation is a good option for future energy systems with respect to sustainable development. In this context, the small-scale combined heat and power (CHP) plants are seen as an efficient way to reduce greenhouse gas emissions due to lower fuel consumption compared to the separate generation of the heat and electricity. The objective of this paper is to establish operating strategies of the small-scale CHP plants to reduce operational cost and increase revenue in liberalized electricity markets. It analyzes a cogeneration plant with organic Rankine cycle and biomass fuel under the conditions of the Romanian electricity market and the green certificates support scheme for electricity generated in high efficiency cogeneration and from renewable sources. The main finding is that choosing an appropriate mode of operation and using correlated prices of heat and electricity can increase the trading profitability of a CHP plant in liberalized power markets. This can be done by an analysis of the particularities and the specific operating conditions of the CHP plant. The results show that the operating strategies of the CHP plant can yield substantial net revenues from electricity and heat sales. The CHP plant can be economically operated to a useful heat load of more than 40% when operating strategies are applied.

Keywords: combined heat and power plants; cost allocation in cogeneration; operating strategies of CHP plants; power markets; electricity and heat prices

1. Introduction

The energy markets of the whole world are influenced by increasing energy production from renewable sources (electricity, heating, and cooling). Distributed generation is favored by people concerned about climate change and the increasing consumer demand for electricity. A good option for consumers to protect themselves against changes in energy prices is to invest in on-site distributed generation for energy self-consumption. Also, distributed generation offers the opportunity to sell surplus power to other consumers. The lowering of capital costs for small-scale power plants increases the feasibility and attractiveness of this option. The combined heat and power (CHP) plants have many benefits in this context. The CHP is flexible, has low gas emissions and provides a rapid response to energy needs. Competition on liberalized power markets creates incentives that lead to more efficient decisions in the operation of power systems and the investments in energy sources.

The electricity must be generated at the moment of demand. Currently, at the level of the power system, the quantities of electricity that can be stored are insignificant compared to the power. Thus, most electricity transactions take place before the time of delivery.

The ability to forecast prices on the power market is important for energy producers in long-term strategic planning [1–3]. In reference [4], the authors analyze the interaction between the green certificate prices, the carbon dioxide emission price, and the electricity prices in Nord Pool Spot. A detailed description of an electricity national market, such as the case of Croatia, can be found in [5]. The liberalization of the national electricity markets in the European Union (EU) has the ultimate goal of integrating these markets into a pan-European network. There are already several regions in the EU whose electricity markets are coupled by price [6,7].

Lately, changes in the power markets offers various opportunities to increase revenues for the cogeneration producers. Programming the operation of the combined heat and power (CHP) plants can be achieved with the help of operating strategies depending on the potential incomes from the power markets. The decision to allocate the quantities of electricity on the electricity markets should be taken on after a detailed analysis of the operating regimes for each cogeneration plant. Different approaches to the participation of the CHP plants in the energy markets can be found in works [8–13]. There are several publications that take various aspects into consideration (low operation cost, reduction of fuel consumption, low carbon dioxide emission) and therefore algorithms for economic dispatching of CHP are proposed [14–18]. A model for economic assessment of virtual power plants using the scenario methodology is presented in [19].

The economic feasibility of a cogeneration project for a university campus is presented in [20]. The results highlight the economic and environmental viability of the cogeneration project. Reference [21] investigates the effect of electricity price, natural gas price, and taxation on the profitability of cogeneration plants.

In references [22,23], the situation of cogeneration in the EU and in the Nordic Area is analyzed in terms of electricity and gas prices estimates. The importance of support schemes to minimize the risk of investments in cogeneration is highlighted.

The paper [24] presents an analysis of the residential heating systems in terms of the equivalent annual costs and the electricity price variation. The heating technologies with low carbon emissions are important options in this analysis. In reference [25], a cogeneration system versus natural gas steam boiler is analyzed.

The need of small cogeneration producers to adapt their trading behavior to changes in competitive electricity markets is the motivation of this paper. An algorithm for determining the operating strategies of the CHP plants is proposed in this paper. The quantities of electricity to be bidding on the liberalized electricity markets are determined by this algorithm. The operating strategies are based on the generated electricity in high efficiency cogeneration and the correlated prices of heat and electricity for the CHP plant to be operated profitably. This approach is the main contribution of this paper compared to the optimization algorithms that already exist in the literature. The algorithm proposed is used to determine the total costs and revenue according to the operating strategies of the CHP plant. The proposed methodology was applied in the case of a biomass CHP plant with organic Rankine cycle (ORC). The nominal technical specifications of the CHP are: electrical output of 1278 kWe and a heat output of 5380 kWth. The CHP plant became operational in the year 2015 and benefits from the green certificates support scheme for electricity generated in high efficiency cogeneration and from renewable sources. Based on the proposed algorithm, an optimization problem has been formulated in this case and the minimum value of the useful heat demand for which the operation of the CHP plant is profitably has been identified.

The paper is structured as follows. Section 2 presents a brief description of the liberalized power markets in Romania. Section 3 presents the used methodology. Section 4 presents a case study for a biomass CHP plant with Organic Rankine Cycle. Finally, the conclusions of this paper are summarized in Section 5.

2. A Brief Description of the Liberalized Power Markets in Romania

Electricity trading between market participants is performing on the following specific markets [26–28]: The centralized market for electricity bilateral contracts (CMBC); The day-ahead market (DAM); The intra-day market (IDM); The balancing market (BM); The ancillary services market (ASM); The capacity allocation market (CAM); green certificates market (GCM). Small producers can trade the electricity generated mainly in the first three markets, namely: CMBC, DAM, and IDM.

The CMBC works as a market where participants may propose contracts containing their own delivery graphs, delivery periods (more than a month), hourly power levels and contractual conditions. The electricity bilateral contracts are traded individually between market players. The trading mechanisms used are extended auctions and continuous negotiation. These allow competition and the interaction between buyers and sellers. The bilateral contract includes all aspects of the sale and purchase of electricity. The main advantage of the CMBC is the long-term price stability (during the term of validity of the contract).

The DAM is a spot market where the transactions take place the day before the day of delivery. The main purpose of the DAM is to achieve a balance between the quantities of electricity already traded on the bilateral contract market and the next day's consumption forecast. The transactions are independent for each time interval of the delivery day. The closing price of the market is determined by the supply and demand of electricity on each trading time interval.

The IDM is the last component of the wholesale electricity market where transactions can be made before the physical delivery of electricity. The technical availability of the generating units, the consumption forecast, and the quantities of electricity already traded are taken into account to minimize the operational risks. Minimizing the balancing costs is the main purpose of participating in this market. The transactions in the IDM take place after the DAM closure, up to two hours before the physical delivery of electricity. The market participant must register as a party responsible for balancing or associate with a party in charge of balancing who already exists. The main purpose of short-term transactions is to enable market participants to adjust their contracting portfolio almost in real time. The electricity producers can adjust their planned production, and suppliers can increase or decrease the amount of electricity they buy. Intraday traders always face inherent risks that exist in the stock markets. The price volatility is the main risk of short-term markets.

Figure 1 shows the main moments of electricity trading for the three components of the wholesale electricity market as compared to the delivery day.

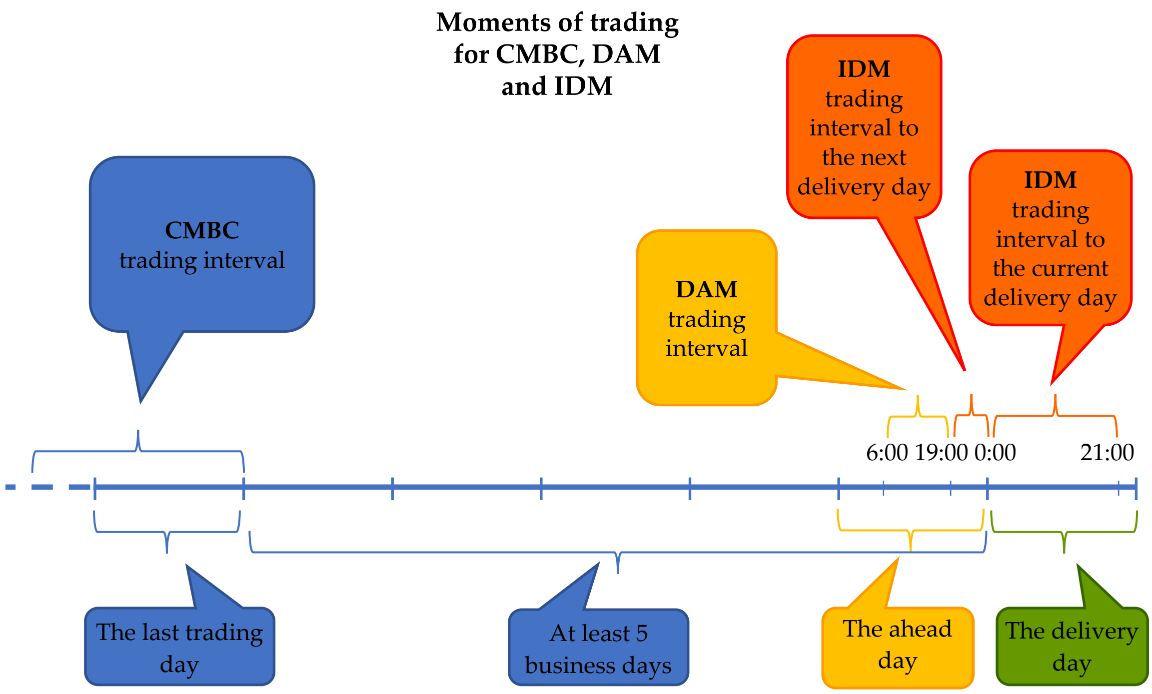

Figure 1. Trading electricity on Centralized Market for Electricity Bilateral Contracts (CMBC), Day-Ahead Market (DAM), and Intra-Day Market (IDM).

Transactions of electricity can be achieved in the short or long term. The electricity is delivered the same day or the next day in the case of short-term transactions. The long-term transactions have a longer delivery time, usually between one month and one year, and the physical delivery of electricity begins at a later date of the trading day.

Currently, there is a trend towards a single European electricity market by price coupling of regions for the day ahead market. Starting in 2014, the DAM of Romania is coupling with the DAM of Czech Republic, Slovakia, and Hungary through a price coupling mechanism.

Figure 2 shows the monthly average values of electricity price and market share for CMBC, DAM, and IDM in 2017.

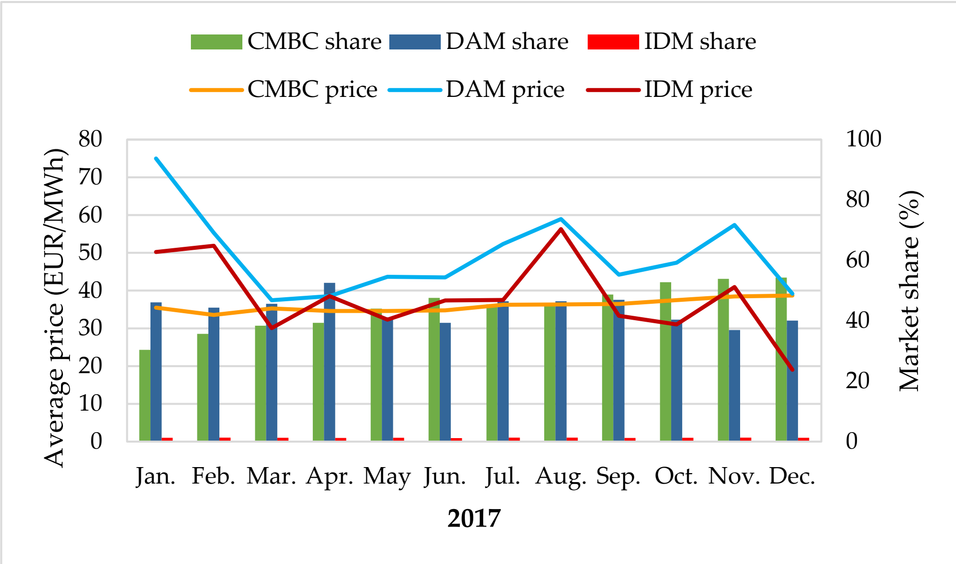

Figure 2. Electricity price and market share for CMBC, DAM, and IDM in 2017.

The majority of the electricity quantities are traded on the CMBC and the DAM. The IDM has a lower participation at present. The deviations from the programmed values of electricity production and consumption are then offset on the balancing market. The balancing costs are significant and should be avoided.

The trading principles and the particularities of the electricity markets must be understood for avoiding market risks by the participants. The main advantage of long-term transactions is to hedge market participants against short term prices in the liberalized contest.

In Romania, the generation of electricity from renewable energy sources is supported by the green certificates system and mandatory annual quotas. The green certificates (GC) can be traded separately from renewable electricity. The green certificates are traded between the electricity producers from renewable sources and the electricity suppliers.

The process of liberalization of the electricity markets in Romania was accompanied by the creation of new pricing mechanisms for trading electricity. The DAM represents the component of the wholesale electricity market on which competition is best manifested.

3. Cost Allocation and Estimation of Market Prices for the CHP Plant

3.1. Algorithm for Determining the Operating Strategies of the CHP Plant

There are different cost allocation methods for a cogeneration plant [29–33]. The main difference between the different methods used is the allocation of fuel consumption for the production of electricity and respectively of heat in cogeneration. Cost allocation must consider the demand conditions of the two utilities generated at the same time in cogeneration. The heat and electricity prices must ensure the profitability and competitiveness of the cogeneration plant compared to other production options.

The annual revenues of a cogeneration plant must cover the production costs but also the desired benefit (profit). The total costs *TC* of the cogeneration plant can be expressed with the equation:

$$TC = FC + VC(H, E) \tag{1}$$

where *FC* are fixed annual costs: costs for depreciation of investments, personnel costs, operating and maintenance costs, taxes, and fees; *VC (H, E)* are variable annual costs that are dependent on the heat and electricity production of the cogeneration plant: especially fuel costs, costs of accidental outages, variable start-up costs.

The fuel costs have the largest share in total annual costs. However, applying a cost allocation method to a cogeneration plant is an energy policy decision. Thus, for a cogeneration plant, regardless of the technology used, one can write the following equation between production costs and possible annual incomes:

$$\frac{100 + b}{100} \cdot TC = p_E \cdot E + p_H \cdot H + B \tag{2}$$

where *b* is the minimum desired benefit (%); p_E is the price of the delivered electricity (EUR/kWh), p_H is the price of the delivered heat (EUR/kWh); *E* is the delivered electricity (kWh); *H* is delivered heat (kWh); *B* are bonuses/incomes from support schemes.

Equation (2) represents the equation of a straight line in p_E and p_H coordinates. In Figure 3 the following notations were used: p_E and p_H are the current prices that can be practiced by the electricity and heat producer; p_{E0} and p_{H0} are the expected prices on the electricity and heat markets; p_{EMax} is the maximum electricity price when p_H = 0 and p_{HMax} is the maximum heat price when p_E = 0.

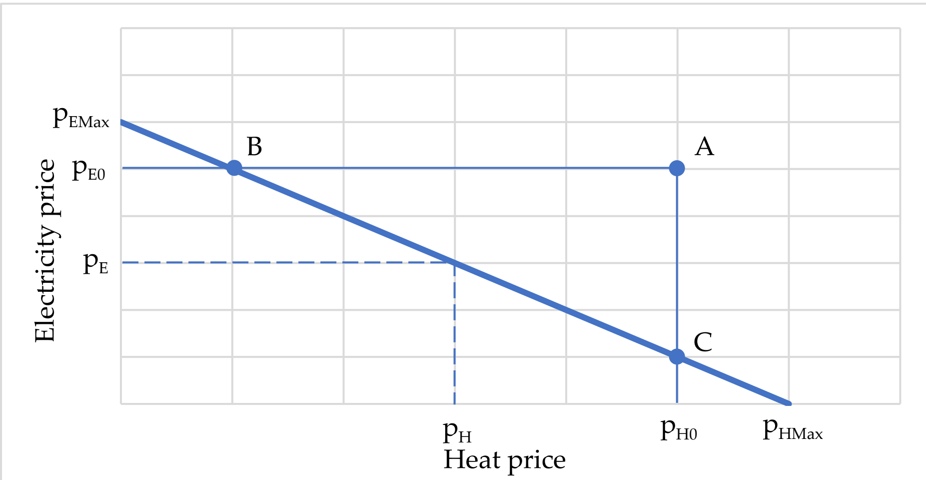

Figure 3. Heat and electricity prices of the combined heat and power (CHP) plant.

The configuration of the cogeneration units varies significantly from site to site. Accordingly, the components of variable cost, as well as the magnitude of each component, are site-specific depending upon the respective configuration. The fuel costs are one of the largest components of variable cost.

The minimum correlated prices below which the heat and electricity producer cannot sell without reducing its profit or/and production costs result from Equation (2):

$$p_{EMin} = \frac{1}{E} \cdot \left(\frac{100 + b}{100} \cdot TC - B \right) - \frac{p_H}{C} \tag{3}$$

$$p_{HMin} = \frac{1}{H} \cdot \left(\frac{100 + b}{100} \cdot TC - B \right) - p_E \cdot C \tag{4}$$

where *C* is the heat to power ratio (*C* = *E*/*H*).

The heat and electricity producer can sell at lower prices than those in the market, provided that the price intersection (p_E and p_H) is inside the ABC triangle. In this case, the heat and electricity producer can fully cover its production costs and can achieve a higher profit or at least equal to the proposed profit. The intersection of the p_{E0} and p_{H0} lines should always be above the straight line between p_{EMax} and p_{HMax}. Otherwise, either the production costs are too high, or the producer has set out to achieve an excessively high profit.

The bonuses come from support schemes for sustaining the production of electricity from renewable energy sources and/or cogeneration. In Romania, the support scheme for the production of renewable electricity started in 2008. The support scheme in operation through green certificates and mandatory annual quotas has been adopted. The number of green certificates depends on the type of technology used. The electricity production from biomass is supported by two green certificates for each MW delivered to the public network. Also, the electricity production in high efficiency cogeneration is additionally supported by a green certificate. The high efficiency cogeneration (HEC) is based on useful heat demand and primary energy saving (PES) compared to alternative options of separate production [34,35]:

$$PES = \left(1 - \frac{1}{QF}\right) \cdot 100(\%) \tag{5}$$

The quality factor QF considers options for the separate production of electricity and heat and can be defined as [36]:

$$QF = \frac{\eta_{h,CHP}}{\eta_{h,Ref}} - \frac{\eta_{e,CHP}}{\eta_{e,Ref} \cdot p_{loss}} \tag{6}$$

where $\eta_{e,CHP}$ is the electricity efficiency of the CHP plant; $\eta_{h,CHP}$ is the heat efficiency of the CHP plant; $\eta_{e,Ref}$ is the reference value of electricity efficiency; $\eta_{h,Ref}$ is the reference value of heat efficiency; p_{loss} is the network loss correction factor.

In reference [37], the reference values for the separate production of heat and electricity that have been reviewed for application after 1 January 2016 are found.

The minimum value of the quality factor for which the electricity production fulfills the requirements of high efficiency cogeneration is QF_{min} = 111.112. This corresponds to the primary energy saving of 10%.

If the quality factor determined with Equation (6) does not respect the minimum condition, the recalculated values of electrical and thermal efficiency that meet QF_{min} are:

$$\eta_{e,HEC} = \eta_{e,CHP} - \frac{QF_{min} - QF}{\frac{100}{\eta_{h,Ref}} - \frac{100}{\eta_{e,Ref} \cdot p_{loss}} \cdot \beta} \cdot \beta \quad [\%] \tag{7}$$

$$\eta_{h,HEC} = \frac{QF_{min} - QF}{\left(\frac{100}{\eta_{h,Ref}} - \frac{100}{\eta_{e,Ref} \cdot p_{loss}} \cdot \beta\right) + \eta_{h,CHP}} \quad [\%] \tag{8}$$

where β is the reduction factor of power for the condensing steam turbine and extraction outlet (β = 0 if the cogeneration unit does not have extraction steam outlet).

The production of electricity considered in high efficiency cogeneration:

$$E_{HEC} = H \cdot C_{ech} \tag{9}$$

where H is the useful heat and C_{ech} is the power to heat equivalent ratio:

$$C_{ech} = \frac{\eta_{e,HEC}}{\eta_{h,HEC}} \tag{10}$$

Based on the above, an algorithm has been proposed for establishing the operating strategies of the cogeneration unit (Figure 4). The economic opportunity costs and revenues are the basis for setting the operating strategies of the CHP plant. It is important to distinguish between the technical potential of cogeneration and its economic and financial potential. An operational strategy is economically viable if the total costs are less than the possible revenues.

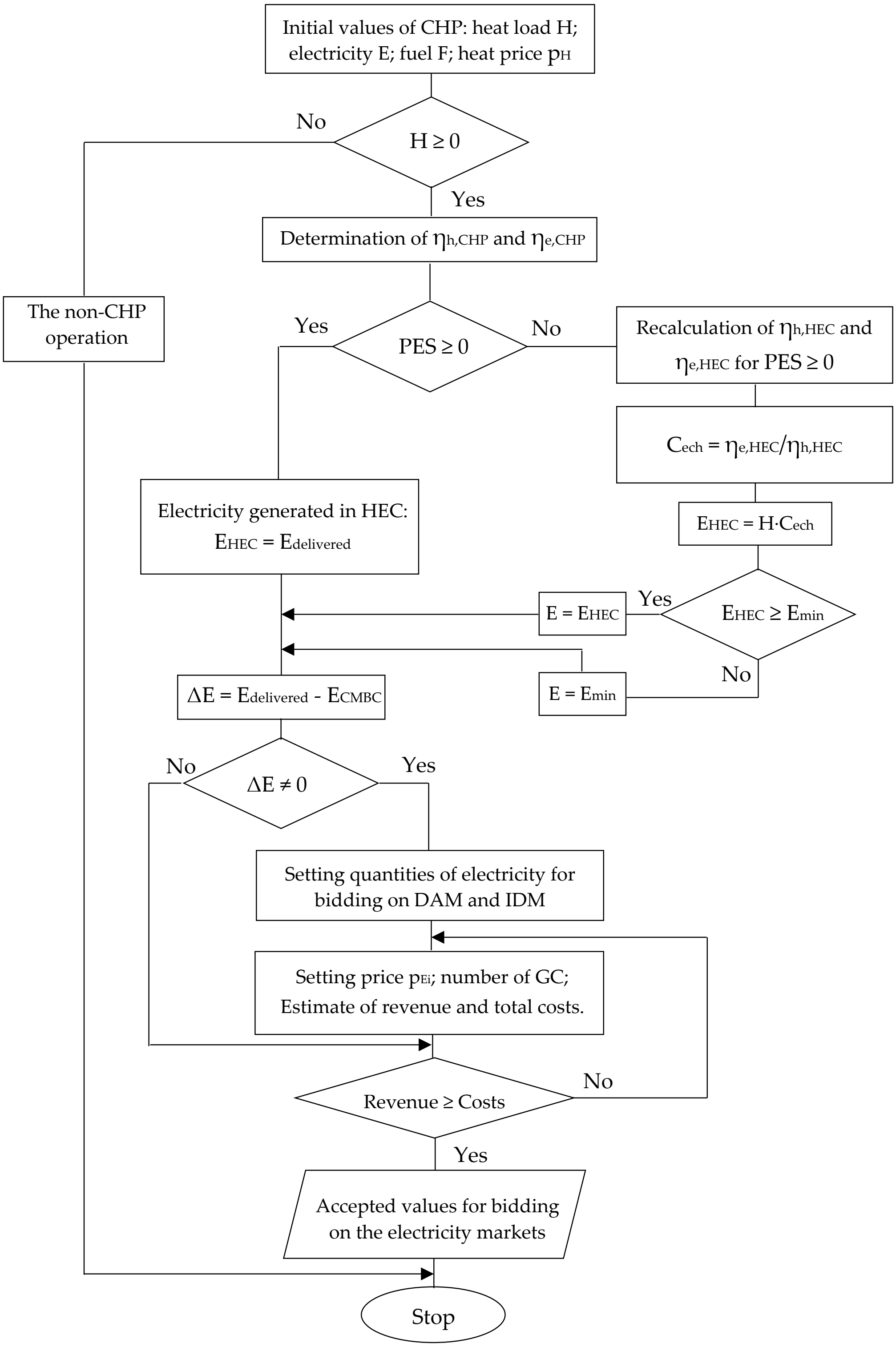

Figure 4. Algorithm for determining the operating strategies of the CHP plant.

The amount of electricity traded on the bilateral contracts market is set according to the demand for useful heat. This quantity will ensure the long-term economic operation of the CHP plant and protecting the heat and electricity producer against price variations on spot markets. The amount of available electricity will be traded on the DAM. The costs due to accidental shutdowns of the CHP plant may be reduced by purchasing electricity on the IDM in the delivery day. Thus, the costs due to the imbalance between the electricity production and the one scheduled on the delivery day can be significantly reduced.

3.2. Optimization Problem Formulation

The objective function is formulated to maximize the profit of the cogeneration plant operation in the new conditions of the power market:

$$Max(Profit) = Revenue - Total\ Costs \tag{11}$$

The algorithm proposed in Figure 4 is used to determine the total costs and revenue according to the operating strategies of the CHP plant. The quantities of electricity to be bidding on the different components of the power market (CMBC, DAM and IDM) are determined by this algorithm. The generated electricity in high efficiency cogeneration and technical possibilities of the CHP plant are considered. The operating strategy of the CHP plant over a specific trading interval or time period can be accepted only if the possible revenue is higher than the costs. Thus, the possible revenues of the cogeneration plant on the energy markets can be expressed with the equation:

$$R(H, E) = \sum_{i=1}^{N} (p_{E,CMBCi} \cdot E_{CMBCi} + p_{E,DAMi} \cdot E_{DAMi} + p_{E,IDMi} \cdot E_{IDMi} + p_{GCi} \cdot n_{GCi} + p_{Hi} \cdot H_i) \tag{12}$$

where $p_{E,CMBCi}$, $p_{E,DAMi}$ and $p_{E,IDMi}$ are the electricity prices on CMBC, DAM and IDM in (EUR/kWh); E_{CMBCi}, E_{DAMi} and E_{IDMi} are the selling electricity on CMBC, DAM and IDM in (kWh); p_{GC} is the green certificates price in (EUR/GC); n_{GC} is the total number of green certificates (GC); p_{Hi} is the delivered heat price in (EUR/kWh); H_i is the delivered heat in (kWh); i is the time interval.

The total number of green certificates is as follows:

$$n_{GC} = n_{GC,RES} \cdot E_{delivered} + n_{GC,HEC} \cdot E_{GC,HEC} \tag{13}$$

where $n_{GC,RES}$ is the number of green certificates allocated depending on the technology used for harnessing renewable energy sources in (GC/MWh); $E_{delivered}$ is the delivered electricity to the public network in (MWh); $n_{GC,HEC}$ is the number of green certificates allocated for electricity generated in high efficiency cogeneration in (GC/MWh); E_{HEC} is the electricity generated in the high efficiency cogeneration in (MWh);

The total costs from Equation (1) can be expressed in terms of electricity and heat production by the following [38,39]:

$$TC\ (H, P) = \sum_{i=1}^{N} \left(a + b \cdot P_i + c \cdot P_i^2 + d \cdot H_i + e \cdot H_i^2 + f \cdot P_i \cdot H_i \right) \cdot t_{hi} \tag{14}$$

where H_i and P_i are the heat and electrical power output of the cogeneration unit in (kW); a, b, c, d, e, and f are the cost coefficients of CHP unit in (EUR/h) or (EUR/kW/h) or (EUR/kW^2/h), as the case may be; t_{hi} is the operating time of the cogeneration plant in that regime in (hours).

The optimal operation of the CHP unit is determined by fulfilling the following set of constraints:

$$P_i^{Min} \leq P_i \leq P_i^{Max} \tag{15}$$

$$0 \leq H_i \leq H_i^{Max} \tag{16}$$

$$E_{CMBCi} + E_{DAMi} + E_{IDMi} = E_{delivered,i} \tag{17}$$

$$p_{Ei}^{Min} \leq p_{E,CMBCi} \leq p_{E,CMBCi}^{Max} \tag{18}$$

$$p_{Ei}^{Min} \le p_{E,DAMi} \le p_{E,DAMi}^{Max} \tag{19}$$

$$p_{Ei}^{Min} \le p_{E,IDMi} \le p_{E,IDMi}^{Max} \tag{20}$$

$$p_{Hi}^{Min} \le p_{Hi} \le p_{Hi}^{Max} \tag{21}$$

$$p_{GCi}^{Min} \le p_{GCi} \le p_{GCi}^{Max} \tag{22}$$

$$E_{GC,HEC} = Min(E_{deivered}; E_{HEC}) \tag{23}$$

The optimization problem of CHP plant was defined as a linear mixed-integer problem (MILP), divided into two subproblems: maximizing revenue and minimizing costs. Mathematically, this can be easily solved by classical mathematical techniques. The Excel Solver program was used to solve the optimization problem.

4. Case Study

A CHP plant based on Organic Rankine Cycle (ORC) is studied in this section. The CHP plant became operational in the year 2015. The nominal technical specifications of the CHP are: electrical output 1278 kWe and heat output 5380 kWth. The own consumption of electricity is 265 kW. The schematic diagram of the CHP plant is shown in Figure 5. The CHP plant uses biomass from various sources: wastes from the forestry and related industries (wood chips, wood debris, bark, sawdust); wastes from agriculture (straw, stems, branches, leaves, husks, seeds). The delivered heat by the CHP plant is in the form of hot water at 90 °C. The heat is used for technological purposes in the primary woodworking process.

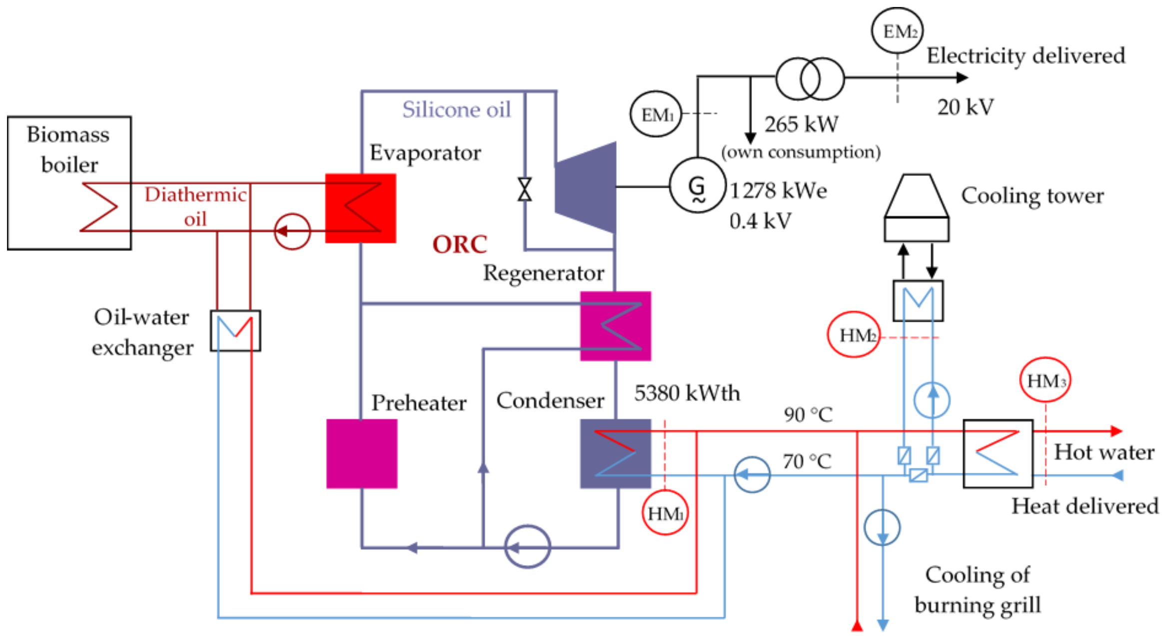

Figure 5. The schematic diagram of the CHP plant with the Organic Rankine Cycle (ORC) technology and biomass fuel.

The heat consumers are powered from the following sources: the ORC condenser (cogeneration regime), the cooling plant of the burning grill and the oil-water heat exchanger (non-cogeneration regime). The useful heat is considered only heat generated in cogeneration regime. The oil-water exchanger is kept warm for safety reasons. This exchanger provides evacuation of the main flow of heat to emergency stops of the cogeneration group. Also, the consumers are supplied with heat in this way in situations where the ORC module is shut down for maintenance. The amounts of heat associated with the non-cogeneration regimes in which the electric generator is disconnected of the public network must be excluded from the amount of useful heat delivered to consumers. In order to identify the useful heat delivered from the CHP plant, the following measurement groups are used: the electricity generated (EM1); the delivered electricity to the public network (EM2); the heat generated by the ORC cogeneration unit (HM1); the heat transferred to the cooling tower (HM2), and the heat delivered to consumers (HM3).

Figure 6 shows the regime diagrams of the CHP unit: fuel consumption diagram and heat to power ratio. These diagrams are useful for analyzing the operation of the CHP plant at partial loads.

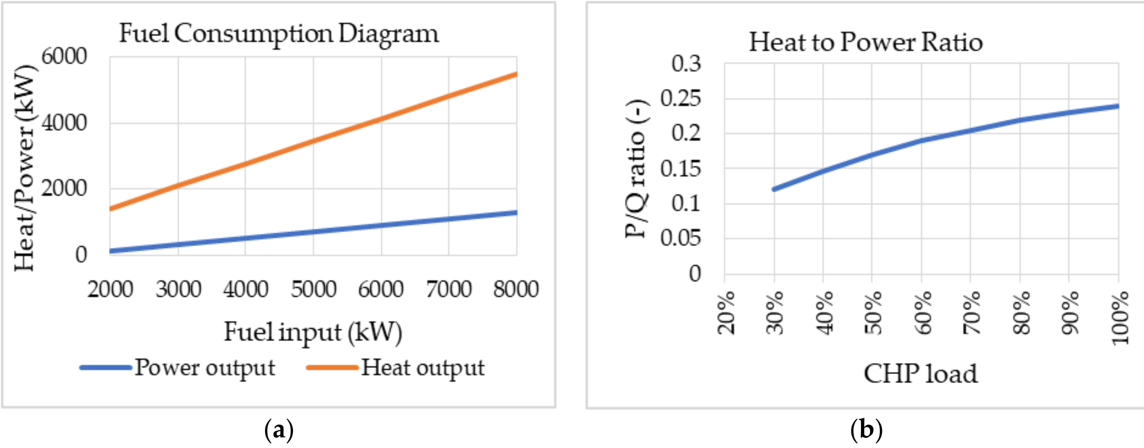

Figure 6. Regime diagrams of the CHP unit: (**a**) Fuel consumption diagram; (**b**) Heat to power ratio.

The establishment of the operating strategies of the CHP plant is based on the forecast heat demand of the consumers. Five cases were analyzed and compared.

4.1. Case 1: Full Cogeneration Regime (100% Heat Demand)

The CHP plant is loaded to the nominal design values. The useful heat consumption of the CHP plant is maximum. All the delivered electricity is generated in high efficiency cogeneration, so it benefits from the green certificates support scheme. The delivered electricity is traded on the centralized market of bilateral contracts.

4.2. Case 2: Cogeneration Regime (76% Heat Demand)

The electrical load of the CHP plant has its nominal value. The useful heat consumption of the CHP plant is reduced to the minimum value for which the primary energy saving is positive (PES > 0). Therefore, all the delivered electricity is considered to be generated in high efficiency cogeneration and benefits from the green certificates support scheme. The delivered electricity is traded on the centralized market of bilateral contracts.

4.3. Case 3: Non-Cogeneration Regime (0% Heat Demand)

The CHP plant works in condensation mode. The useful heat consumption of the CHP plant is missing. The heat generated by the cogeneration unit is ceded to the cooling tower.

4.4. Case 4: Cogeneration Regime at Partial Load (30% Heat Demand)

The electrical load of the CHP plant has its nominal value. The useful heat consumption of the CHP plant is low (30% heat demand). The 70% remaining difference is transferred to the cooling tower.

4.5. Case 5: Optimized Cogeneration Regime at Partial Load (30% Heat Demand)

This case is the same as Case 4 in terms of useful heat demand but the electric load of the CHP plant is reduced so that the possible revenues are higher than the costs. Only the amount of electricity

generated in high efficiency cogeneration is traded on the bilateral contracts market. The CHP plant has an electrical load reserve. This amount of available electricity can be traded on the spot markets (DAM and IDM) when the electricity price is convenient.

An example of calculating revenue for a typical day of operation of the CHP plant at partial loads is presented in Table 1.

Table 1. An example of calculating revenue for the CHP plant operation at partial loads.

Hour	CMBC		DAM		Electricity Dlivered	HEC Electricity	Green Certificates		Heat Delivered		Revenue
	kWh	EUR/kWh	kWh	EUR/kWh	kWh	kWh	Number	EUR/GC	kWh	EUR/kWh	EUR
1	620	0.039	330	0.029	950	536	2.44	29	2152	0.04	120
2	620	0.039	330	0.022	950	511	2.41	29	2044	0.04	113
3	620	0.039	330	0.021	950	524	2.42	29	2098	0.04	115
4	620	0.039	330	0.043	950	524	2.42	29	2098	0.04	122
5	620	0.039	340	0.051	960	530	2.45	29	2125	0.04	127
6	620	0.045	340	0.051	960	534	2.45	29	2141	0.04	131
7	620	0.045	340	0.069	960	537	2.46	29	2152	0.04	138
8	620	0.045	340	0.083	960	537	2.46	29	2152	0.04	142
9	620	0.045	340	0.094	960	537	2.46	29	2152	0.04	146
10	620	0.045	340	0.089	960	537	2.46	29	2152	0.04	144
11	620	0.045	340	0.045	960	537	2.46	29	2152	0.04	129
12	620	0.045	340	0.042	960	537	2.46	29	2152	0.04	128
13	620	0.045	340	0.079	960	537	2.46	29	2152	0.04	141
14	620	0.045	340	0.062	960	537	2.46	29	2152	0.04	135
15	620	0.045	340	0.055	960	537	2.46	29	2152	0.04	133
16	620	0.045	340	0.092	960	537	2.46	29	2152	0.04	145
17	620	0.045	340	0.096	960	537	2.46	29	2152	0.04	147
18	620	0.045	340	0.095	960	537	2.46	29	2152	0.04	146
19	620	0.045	340	0.097	960	537	2.46	29	2152	0.04	147
20	620	0.045	340	0.108	960	537	2.46	29	2152	0.04	151
21	620	0.045	340	0.102	960	535	2.46	29	2147	0.04	149
22	620	0.045	340	0.077	960	534	2.45	29	2141	0.04	140
23	620	0.039	340	0.036	960	535	2.46	29	2147	0.04	122
24	620	0.039	340	0.032	960	537	2.46	29	2152	0.04	121
Total day	14,880	0.043	8120	0.066	23,000	12,816	59	29	51,374	0.04	3233

The main characteristics of the analyzed cases (average hourly values of useful heat, electricity and fuel) are presented in Table 2. Figure 7 shows the costs, revenue, and profit in the analyzed cases. The following values as input data were considered: 20 EUR/MWh the cost of fuel; 4,765,200 EUR the investment cost of the CHP; 40 EUR/MWh the delivered heat price; 45 EUR/MWh the CMBC electricity price; 55 EUR/MWh the DAM electricity price; 29 EUR/GC the green certificate price and 8000 hours/year the scheduled operating time of the CHP.

Table 2. The main characteristics of the analyzed cases (average hourly values).

Energy Type	Case 1	Case 2	Case 3	Case 4	Case 5
Electricity delivered (kWh)	980	980	980	980	490
Electricity HEC (kWh)	980	980	0	294	294
Heat delivered to consumers (kWh)	5380	4089	0	1614	1614
Useful heat (%)	100	76	0	30	30
Fuel (kWh)	7970	7970	7970	7970	5029

The payback period of the investment depending on the heat demand (in percentage of rated load) and the annual operating time is shown in Figure 8. The investment is recovered within a reasonable time (less than 20 years) for an annual operating time of 8000 h if the heat demand is higher than 40%. For an annual operating time of 4500 h, the heat demand must be greater than 50%. The operation of the CHP plant at low thermal loads (Case 2 and Case 5) can be accepted if the revenues obtained are higher than the operating costs. However, it is found that the annual heat demand must be higher than 40% so that the investment is recovered in a maximum acceptable payback period. The annual heat demand should increase if the plant's annual operating time is reduced.

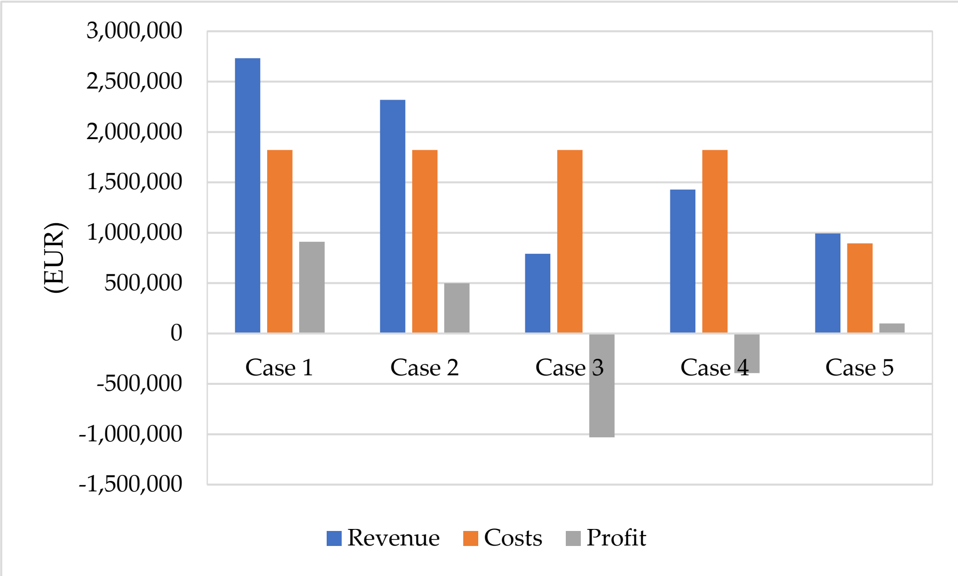

Figure 7. The costs, revenue and profit of the CHP plant.

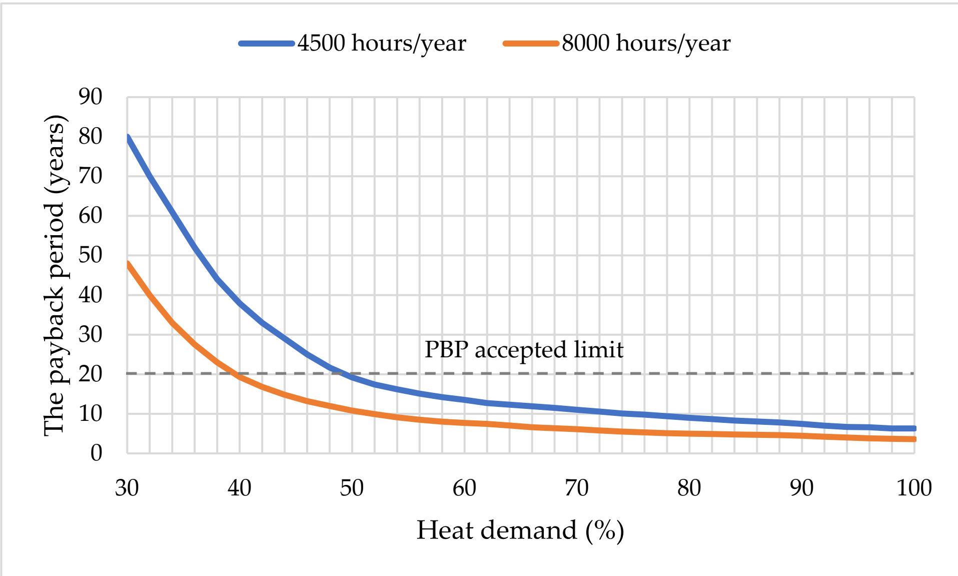

Figure 8. The payback period depending on the heat demand.

When estimating the market prices for heat and electricity generated in the CHP plant, the basic principle of cogeneration should be considered: the costs of heat and electricity generated in cogeneration must not be higher than in the case of separate electricity and heat generation. As a general rule, in the case of cogeneration plants, heat consumers are captive and the heat market has a monopoly character in which competition is missing. However, the alternative options for separate heat generation must be considered. Therefore, the price of heat in cogeneration should not be higher than the heat produced separately with alternative technologies that would use the same type of fuel.

Figure 9 shows the economic characteristics of the CHP plant operation in the five cases. Equation (2) has been customized for each case.

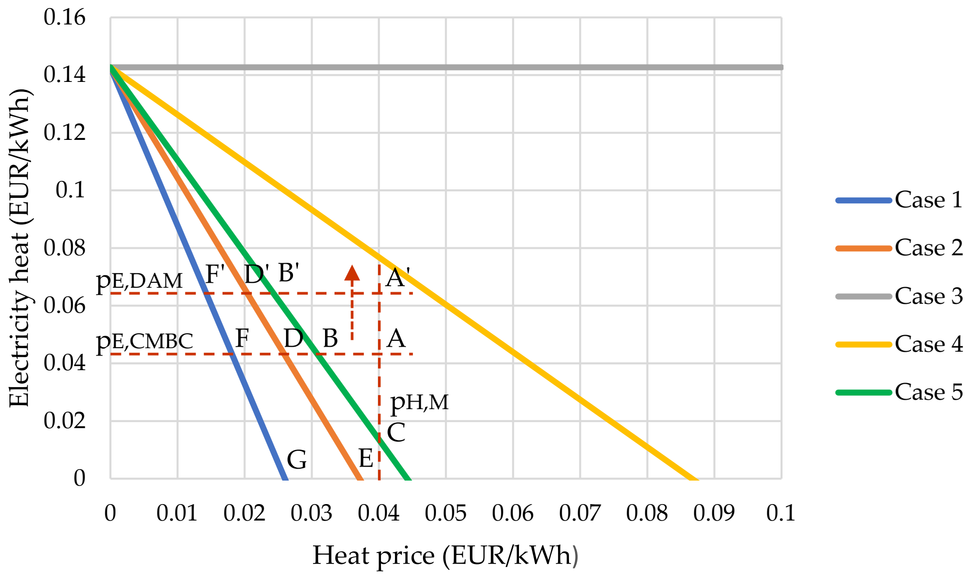

Figure 9. The economic characteristics of the CHP plant operation.

The main goal of the proposed algorithm is to establish the operating strategies of the cogeneration plant according to revenue potentials in the different markets. Case 1 is the reference case in which the CHP plant can achieve the highest revenue. The operating costs are the same in Cases 2–4 as in Case 1 but possible revenues are lower due to reduced consumption of useful heat. The operation of the CHP plant in Cases 3 and 4 is uneconomical, the possible revenues are lower than the operating costs. The heat demand is missing in Case 3 and the revenues obtained only from the sale of electricity are insufficient. The same finding is also observed in Case 4 because the heat demand is reduced. This situation can be corrected by choosing an appropriate mode of operation. Case 5 is the same as Case 4 in terms of the useful heat demand (30% heat demand) but the electric load of the CHP plant is reduced so that the possible revenues are higher than the costs. The profit in Case 5 increased to 11% compared to Case 4 where the operation of the CHP plant is uneconomic with a negative profit (−21%).

Figure 8 shows that the prices of heat and electricity in the market do not cross the economic operating characteristics in Cases 3 and 4. The operation of the CHP plant in these cases is uneconomical. In Case 1, the intersection points of the correlated prices should lie within the ABDFGE area above the economic characteristic. The area can be extended to A'B'D'F' points if a part of the electricity is traded on the DAM. Similarly, in Case 2 intersection points should be inside the ABDE area and respectively inside the ABC area in Case 5.

The correlated prices of heat and electricity generated in cogeneration can be suited to market conditions to achieve maximum revenue.

The useful heat demand directly influences the production of electricity in high efficiency cogeneration. The minimum value of the useful heat demand is identified by the proposed algorithm and the optimization problem formulated in Section 3.2. Figure 10 shows the feasible operating area for heat and electricity production in the CHP plant. The feasible operation area of the CHP plant increased in the case of the optimized regime. The minimum heat demand for which the CHP plant starts to have a profit is 26% compared to a useful heat demand of over 80% in the reference case. However, the revenue generated by such a reduced heat demand is not sufficient to recover the investment. In the current conditions of the power market, the annual heat demand must be higher than 40% so that the investment is recovered in a maximum acceptable payback period (Figure 8). Therefore, the CHP plant can be economically operated at a thermal load of at least 40% when the operating strategies are applied.

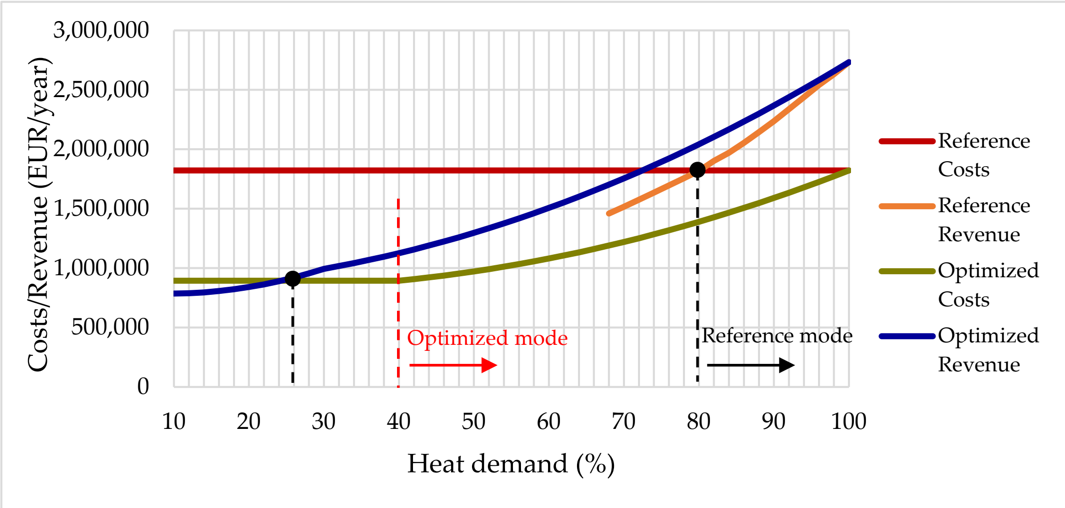

Figure 10. Optimizing the operation of the CHP plant.

5. Conclusions

Currently, there is a trend towards generating useful energy (electricity, heating, and cooling) as close to the place of consumption as possible. The increasing installed capacity of small CHP plants is accompanied with several new challenges in the planning and operation of CHP plants on power markets.

The daily variations of the electric load in the case of a small cogeneration unit do not essentially affect the structure of the power system. However, the expansion of distributed generation will be a challenge for both the electricity distribution network operator and the small cogeneration producers in terms of ensuring a balance between the physical notification and achieved production. These imbalances can be avoided by the realistic programming of production depending on the operating regimes and the technical state of the cogeneration units as close as possible to the moment of dispatch (day of electricity delivery).

An algorithm for determining the operating strategies of the CHP plant is proposed in this paper. The solution to the problem of economic dispatch is based on the amount of electricity generated in high efficiency cogeneration and the correlated prices of heat and electricity. This approach is the main contribution of this paper compared to optimization algorithms existing in literature. The algorithm can be used to identify the opportunities on the liberalized power markets for the increasing flexibility in the operation of the cogeneration plant. The price coupling of regions is the new change in the liberalized power markets and the usefulness of the proposed algorithm is viable in this context.

The results show that the operating strategies of cogeneration plants have a significant impact on their operating costs and profitability. The minimum heat demand of 40% is identified for which the CHP plant can be economically operated under the current conditions of power markets. Obviously, the profit of the cogeneration plant increases if the useful heat demand is higher than this value. The average prices recorded in the power markets were used to solve the optimization problem. The proposed model could be improved in future research by using an algorithm in which predicted prices are used. The main purpose of presenting the paper in this form is highlighting the operating strategies of the CHP plants. Starting from these possibilities of operation of the CHP plants in the new conditions of the power markets, different optimization algorithms can be used to solve the practical needs of the cogeneration producers.

The main goal of the operating strategies is to achieve revenues over expenses in the operation of the cogeneration plant. The fact that fuel and electricity prices may be volatile can create not only risks, but also opportunities for the cogeneration plant owners to incur profits.

Funding: This research received no external funding.

Conflicts of Interest: The author declares no conflict of interest.

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Choosing the Energy Sources Needed for Utilities in the Design and Refurbishment of Buildings

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Received: 22 February 2018; Accepted: 27 March 2018; Published: 30 March 2018

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Abstract: This paper presents a method for choosing the energy sources that are needed for the following building utilities following building: lighting, domestic hot water, heating, ventilation, and air conditioning. The novelty of this paper consists of applying the concept of the energy hub and considering the cost of carbon dioxide emissions when selecting the available energy sources in the building's location. The criterion for selecting the energy sources is the minimum overall cost of all forms of energy that are consumed in the building over its estimated lifetime. In order to estimate the overall costs, it is necessary to know the power that is installed and provided by the energy production technologies that are inside the building, as well as the capacity of energy that is required from outside energy sources. An office building that was proposed for refurbishment has been investigated as a case study. In the paper, we have analysed four scenarios. The results indicate that more favourable alternative solutions can be obtained compared to the traditional scenario (Scenario 4—heat and electricity by public utility networks). The overall costs are 46.17% (212,671 EUR) lower in Scenario 1, 25.35% (116,770 EUR) lower in Scenario 2, and 10.89% (50,150 EUR) lower in Scenario 3. Additionally, the carbon dioxide emissions are 22.98% (49 tonnes CO_2/year) lower in Scenario 1 and 8.91% (19 tonnes CO_2/year) lower in Scenario 2. Thus, renewable energy sources can occupy a growing share of the total energy consumption of the building. The proposed algorithm can be used for both the refurbishment of existing buildings and the design of new buildings.

Keywords: energy audit of buildings; energy sources; building refurbishment; energy hub; multiple energy carriers; energy performance of buildings

1. Introduction

In the European Union, the energy consumption of buildings accounts for around 40% of the final energy consumption, and about 75% of existing buildings are considered to be energy inefficient.

The energy performance of buildings in the European Union is regulated by Directive 2010/31 [1]. Both new buildings and rehabilitated buildings must meet the minimum energy performance requirements, which are set according to climatic and local conditions. There are also recommendations for the reduction of carbon dioxide emissions and for increasing the share of the energy provided by renewable energy sources [2,3]. In line with the requirements for new buildings, support policies are recommended to shift the refurbishment of existing buildings towards nearly zero-energy buildings (nZEBs) [4]. The nearly zero—or very low amount of—energy that is required should be covered to a significant extent by renewable energy sources that are produced on-site or nearby. Authors in [5] analyse the construction features of a set of nZEBs that were collected from 17 European countries. An increasing amount of papers that have been published in recent years consider the nZEB concept [6–8].

Reducing the energy consumption—and hence the carbon dioxide emissions—of buildings is an important way to minimize the environmental impact. Thus, the need to refurbish existing buildings provides an opportunity to improve the energy performance of buildings.

An energy audit—with the aim of identifying optimal solutions in order to increase the energy performance—is required for the refurbishment of a building. The audit is necessary in order to identify optimal energy efficiency solutions. The refurbishment project must take into account both the envelope and the building's services [9–11]. The cost–benefit analysis is generally used for the evaluation of the rehabilitation measures [12,13]. However, it is also recommended to consider the carbon dioxide emissions [14].

In most cases, a building's energy sources are considered and analysed individually. A joint examination (as opposed to an individual examination) can lead to numerous benefits, such as continuity in energy supply, supply flexibility, and optimization potential.

Given that several sources of energy can be used to meet the energy demand of the building's utilities, the availability of energy for the required loads (electricity, heat, and cooling) is no longer dependent on a single infrastructure. The increased flexibility in energy supply is because of the redundant ways of covering the load curve, in which some degree of freedom is provided.

The optimization potential stems from the fact that several sources of energy, and various combinations thereof, can be used to meet the requirements of consumers at a lower cost.

Typically, the optimization methods are used on systems with a single form of energy, such as electricity, natural gas, or district heating. The energy hub concept allows for the determination of an optimal interface between certain energy infrastructures and loads. An integrated system of the energy sources can make use of multiple paths to deliver different forms of energy. Recently, there has been an increased interest in concerns surrounding the modelling and combined analysis of multi-carrier energy systems [15–18]. The energy sources that are used can be characterized by the different costs, related emissions, availability, and other criteria [19–22]. Nižetić et al. [23] present different hybrid energy scenarios for application in small or medium-sized residential building facilities in typical Mediterranean climate conditions. The concept of levelized cost of electricity (LCOE) is used to compare the cost of energy that is provided by different sources.

The correct determination of the consumption curves of the building is of great importance for the choice of energy sources [24–26]. The consumption curve, or load profile, is a chart that illustrates the variation in the demand for energy over a specific period of time. The load duration curve is derived from the chronological load curve. An example of deriving the load duration curve for one day is presented in Figure 1. The analysis period may be extended to either one week, one month, or one year. The information is the same in each case, but it is presented in different forms. These curves are useful in the selection of generation technologies, in order to plan how much power they will need to generate at any given time.

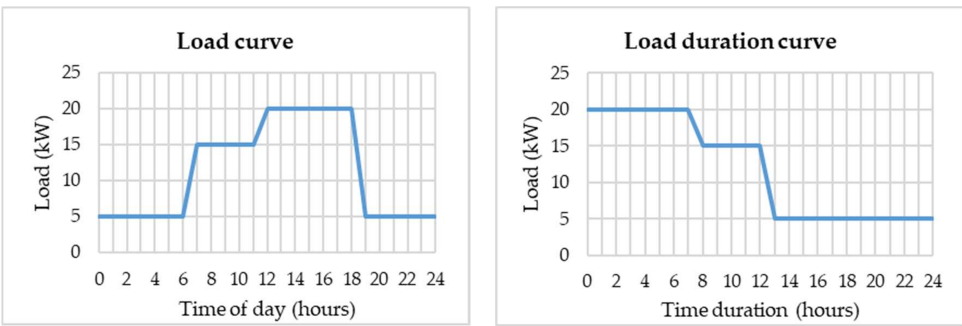

Figure 1. The chronological load curve and the derived load duration curve.

In this paper, a method of choosing the energy sources that are required for the building's utilities (electricity, heat, and cooling) is developed. In Section 2, the mathematical model that was used—based on the concept of the energy hub—is presented. The details of the proposed optimization framework are described in Section 3. The case study is then introduced and described, along with the assumptions and input data for a non-residential building (office building). The evaluation of energy use and the economic analysis for each of the scenarios for the target building are then carried out. Finally, in Section 4, the conclusions are presented.

The main objective of this paper is to select the energy sources (electricity, heat, and cooling) that are required for the following building utilities: lighting, appliances, domestic hot water, heating, ventilation, and air conditioning.

2. The Mathematical Model that Was Used

The energy that is required for a building's utilities (lighting, domestic hot water, heating, ventilation, and air conditioning) is provided by energy carriers from various sources—either directly or through conversion systems that convert energy from one form into another. An energy carrier is an energy form that can be converted to other forms at a later stage, such as mechanical work, electricity, heat, or cold. An energy carrier corresponds only to an energy form (and not to an energy system) of energy input that is required by the building's utilities. The economic analysis of the application of the various power supply solutions of a building involves the determination of the net present value of the overall costs that are involved in making investments and operating the building's services over the life of the investment, as well as the quantification of the carbon dioxide emissions.

The objective function is described as the overall cost of all of the forms of energy that are consumed in the building at the net present value as follows:

$$Min\ C_g(t) = C_0 + \sum_{k=1}^{S} C_{Ek} \sum_{t=1}^{N} \left(\frac{1+f_k}{1+i}\right)^t + C_M \sum_{t=1}^{N} \left(\frac{1}{1+i}\right)^t + C_{CO2} \sum_{t=1}^{N} \left(\frac{1}{1+i}\right)^t \quad (1)$$

where:

C_0 represents the initial investment costs (EUR);
C_E is the annual cost of energy that is consumed at the reference year level (EUR/year);
C_M is the annual operating and maintenance (O&M) cost (EUR/year);
C_{CO2} is the annual cost of carbon dioxide emissions (EUR/year);
f is the annual rate of increase in the cost of energy;
i is the discount rate;
k is index corresponding to the energy source that is used;
N is the calculation period.

To estimate the overall costs, it is necessary to know the power that is installed and provided by the energy production technologies that are inside the building, as well as the required capacity from outside energy sources. The interactions between these energy systems were considered based on the concept of the energy hub [27]. Mathematically, this is a mixed-integer linear problem (MILP), which can be easily solved using classic mathematical techniques. An energy hub is the interface between the transport infrastructure (networks), local sources, and energy consumption (loads) in the building.

For example, the electricity that is required by consumers in the building can either be provided by the public electricity grid, produced locally in a cogeneration plant, or produced using renewable energy sources (solar, wind). Similarly, different feed solutions can be considered for the other utilities that are used in the building (heating, cooling) (Figure 2). Thus, the energy requirement in the building can either be secured directly from the appropriate entrance or may be generated partially or totally within the energy hub. By using such an approach, an unattractive energy carrier (for example, one with a high cost or high carbon dioxide emissions) can be substituted or even eliminated.

The multi-carrier energy system can be described by the following matrix equation [27,28]:

$$\underbrace{\begin{bmatrix} L_\alpha \\ L_\beta \\ \vdots \\ L_\omega \end{bmatrix}}_{L} = \underbrace{\begin{bmatrix} c_{\alpha\alpha} & c_{\beta\alpha} & \cdots & c_{\omega\alpha} \\ c_{\alpha\beta} & c_{\beta\beta} & \cdots & c_{\omega\beta} \\ \vdots & \vdots & \ddots & \vdots \\ c_{\alpha\omega} & c_{\beta\omega} & \cdots & c_{\omega\omega} \end{bmatrix}}_{C} \cdot \underbrace{\begin{bmatrix} P_\alpha \\ P_\beta \\ \vdots \\ P_\omega \end{bmatrix}}_{P}, \tag{2}$$

where:

$\alpha, \beta, \ldots, \omega$ are the different energy carriers;
L is the load matrix (the energy consumption of the building);
P is the power matrix of the energy carriers that enter the hub;
C is the converter coupling matrix.

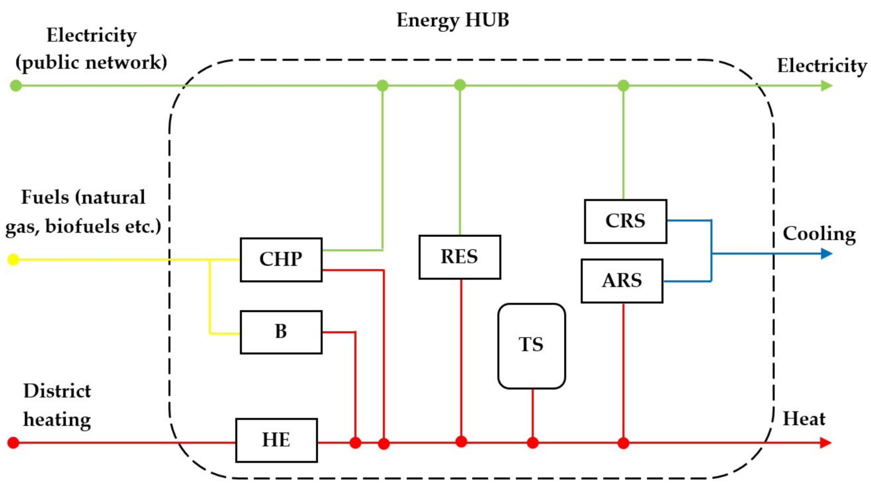

Figure 2. Structure of the energy hub that contains typical elements: CHP—combined heat and power plant; B—boiler; HE—heat exchanger; RES—renewable energy sources (photovoltaic panels, solar thermal panels, heat pump, etc.); TS—thermal storage; CRS—compression refrigeration system; ARS—absorption refrigeration system.

Thus, after applying Equation (2), the power balance equation can be reformulated as follows:

$$\begin{aligned} L_\alpha &= c_{\alpha\alpha} \cdot P_\alpha + c_{\beta\alpha} \cdot P_\beta + \cdots + c_{\omega\alpha} \cdot P_\omega, \\ L_\beta &= c_{\alpha\beta} \cdot P_\alpha + c_{\beta\beta} \cdot P_\beta + \cdots + c_{\omega\beta} \cdot P_\omega, \\ &\vdots \\ L_\omega &= c_{\alpha\omega} \cdot P_\alpha + c_{\beta\omega} \cdot P_\beta + \cdots + c_{\omega\omega} \cdot P_\omega. \end{aligned} \tag{3}$$

The coupling coefficients characterize the energy efficiency of conversion as follows:

$$c_{ij} = \sum_{k \in C} \nu_i^k \cdot \eta_{ij}^k \qquad 0 \le c_{ij} \le 1 \qquad \forall\,(i,\ j) \in\ C, \tag{4}$$

where ν_i^k is the dispatch factor that represents the percentage of input power P_i and η_{ij}^k is the conversion efficiency of energy carrier i.

The constraints for the dispatch factors are as follows:

$$0 \leq \nu_i^k \leq 1 \quad \text{and} \quad \sum\nolimits_{k \in C_i} \nu_i^k = 1. \tag{5}$$

The coupling matrix between the energy carriers reflects the degrees of freedom that can be used to optimize the energy requirement in the building.

The input power of the converter is given as follows:

$$P_i^k = \nu_i^k \cdot P_i\,. \tag{6}$$

The energy storage can be modeled similarly to that of a converter device. The energy that is stored after a certain operating period T equals the initial storage content plus the time integral of the power:

$$E_{ES}(T) = E_{ES}(0) + e_{ES} \int_0^T E_{ES}(t)dt. \tag{7}$$

The factor e_{ES} is considered to be the charge/discharge efficiency and depends on the direction of the power flow:

$$e_{ES} = \begin{cases} \eta_{ES} & \text{if} \quad E_{ES} \geq 0 \quad \text{(charging/standby)} \\ \frac{1}{\eta_{ES}} & \text{else} \qquad\qquad\quad \text{(discharging)} \end{cases}. \tag{8}$$

Different mathematical constraints can be identified in the proposed model: the conversion capacity; the storage capacity; the minimum production from renewable energy sources; and the energy content at the initial time period (t = 0) must be equal to the energy content at the last time period (T):

$$P_i^{min} \leq P_i(t) \leq P_i^{max}, \tag{9}$$

$$E_{ES}(t) \leq E_{ES}^{max}, \tag{10}$$

$$P_{RES}(t) \geq P_{RES}^{min}, \tag{11}$$

$$E_0 = E_T. \tag{12}$$

Therefore, the objective function (1) is associated with two types of constraints, namely, equality constraints corresponding to energy balance equations and inequality constraints corresponding to the limits of the conversion systems and the energy carriers that are entering the hub.

3. Example Application

A non-residential building (office building) that was proposed for refurbishment—with four floors (each 3 m in height) with an S/V ratio of 0.31 and a total useful floor area of 4680 m^2—was investigated. The building is located in the northeastern part of Romania. The annual energy demands (heat, electricity, and cooling) resulting from interventions to the building envelope (external wall thermal insulation, thermal insulation of the upper and lower floors, and the replacement of existing windows and doors) is shown in Figure 3. The mean U value of the envelope is 0.39 W/m^{2}K (the U-value of the wall is 0.41 W/m^{2}K; the U-value of the roof is 0.20 W/m^{2}K; the U-value of the basement is 0.24 W/m^{2}K; and the U-value of the glass is 1.30 W/m^{2}K).

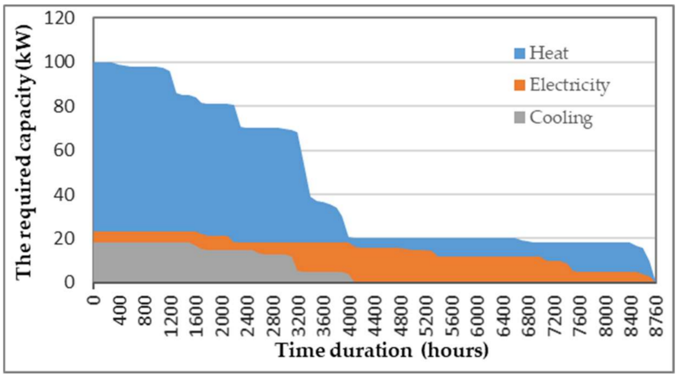

Figure 3. The load duration curves of the building (heat, electricity, and cooling).

The energy loads that are presented in Figure 3 (electricity, heat, and cooling) include all of the energy requirements of the building, namely lighting, domestic hot water, heating, ventilation, and air conditioning.

The following scenarios were considered in order to ensure that the energy demands (heat, electricity, and cooling) are met in the case of the analysed building:

1. Scenario 1 (Figure 4) includes the following energy sources: the electricity supply from the public network; two combined heat and power plants (CHPs) on natural gas fuel; a heat pump; a heat storage system; a compression refrigeration system; and an absorption refrigeration system.
2. Scenario 2 (Figure 5) includes the following energy sources: the electricity supply from the public network; a combined heat and power plant (CHP) on natural gas fuel; a natural gas boiler (as a peak source); a system of photovoltaic panels; a system of solar thermal panels; a heat storage system; and an absorption refrigeration system.
3. Scenario 3 (Figure 6) includes the following energy sources: the electricity supply from the public network; a heat pump; a natural gas boiler (as a peak source); a system of photovoltaic panels; a system of solar thermal panels; a heat storage system; and a compression refrigeration system.
4. Scenario 4 (Figure 7) includes the following energy sources: the electricity supply from the public network; the heat supply from the district heating system and a compression refrigeration system.

In Scenario 1 (Figure 4), the demand for electricity will be fulfilled by the cogeneration plants and the public electricity network. The cold demand will be fulfilled by the absorption refrigeration system or the compression refrigeration system (depending on the heat that is available from the cogeneration plants). The demand for heat in the building is fulfilled by the heat pump and the cogeneration plants. The type and size of the cogeneration plants is chosen according to the level of heat consumption. The electricity differences between local consumption and production are compensated for—without technical difficulty—by the public electricity network. The absorption refrigeration system can consume the available heat that is produced in the cogeneration plants, and consequently increases the efficiency of the cogeneration solution. The heat storage system will be used to compensate for the load variations and to increase the flexibility of the cogeneration plants.

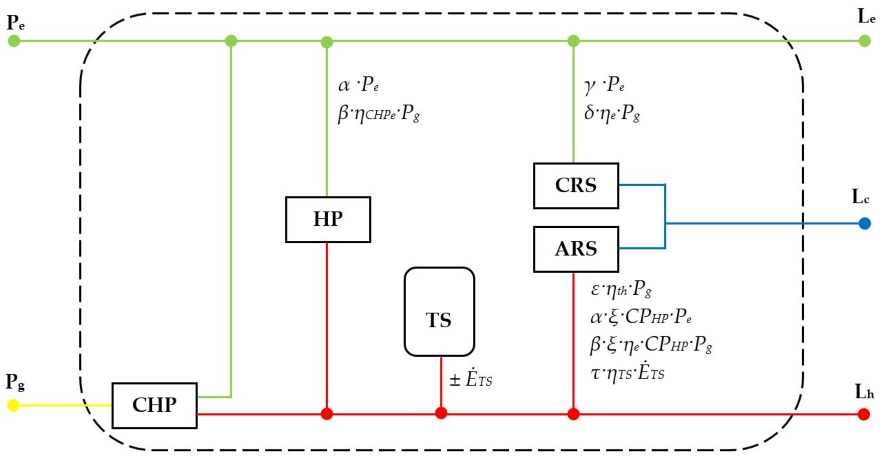

Figure 4. Scenario 1: CHP—combined heat and power plant; HP—heat pump; TS—thermal storage; CRS—compression refrigeration system; ARS—absorption refrigeration system.

Equation (2) customized for Scenario 1:

$$\begin{bmatrix} L_e \\ L_c \\ L_h \end{bmatrix} = \begin{bmatrix} (1-\alpha-\gamma) & (1-\beta-\delta)\cdot\eta_e & 0 \\ \gamma\cdot CP_{CR} + \alpha\cdot\xi\cdot CP_{HP} & \delta\cdot\eta_e\cdot CP_{CR} + (\varepsilon\cdot\eta_{th} + \beta\cdot\xi\cdot\eta_e\cdot CP_{HP})\cdot CP_{AR} & \tau\cdot e_{TS}\cdot CP_{AR} \\ (1-\xi)\cdot \propto \cdot CP_{HP}\cdot P_e & (1-\varepsilon)\cdot\eta_{th} + (CP_{HP}-1)\cdot\beta\cdot\eta_e & (1-\tau)\cdot e_{TS} \end{bmatrix} \cdot \begin{bmatrix} P_e \\ P_g \\ \pm E_{TS} \end{bmatrix}, \quad (13)$$

where α, β, γ, δ, ε, ξ, and τ are the dispatch factors:

α is the share of electricity to supply the heat pump;
β is the share of natural gas that is converted into electricity to supply the heat pump;
γ is the share of electricity to supply the compression refrigeration system;
δ is the share of natural gas that is converted into electricity for the compression refrigeration system;
system;
ε is the share of natural gas that is converted into heat for the absorption refrigeration system;
ξ is the share of heat from the heat pump for the absorption refrigeration system;
τ is the share of heat that is stored to supply the absorption refrigeration system.

and the efficiencies of the converters are as follows:

η_e is the efficiency of electricity generation in cogeneration;
$\eta_{th}$is the efficiency of heat generation in cogeneration;
CP_{HP} is the coefficient of the performance of the heat pump;
CP_{CR} is the coefficient of the performance of the compression refrigeration system;
CP_{AR} is the coefficient of the performance of the absorption refrigeration system;
e_{TS} is the storage efficiency of thermal energy—Equation (8).

The performances of the different energy sources that were considered in Scenario 1 are presented in Table 1 [29–31].

Table 1. The performances of the different energy sources in Scenario 1 [29–31].

Type of Technology	Nominal Power/Energy	Specific Investment	O&M costs (% of Investment/Year)	Conversion Efficiency
CHP	18 kWe36 kWth	1500 EUR/kWe	5.0%	η_e = 30%η_{th} = 55%
HP	65 kW (heat)	1200 EUR/kW	3.2%	CP_{HP} = 4
TS	200 kWh	20 EUR/kWh	2.0%	η_{TS} = 90%
CRS	18 kW (cool)	110 EUR/kW	1.2%	CP_{CR} = 3
ARS	18 kW (cool)	600 EUR/kW	2.5%	CP_{AR} = 0.75

In Scenario 2 (Figure 5), the demand for electricity will be fulfilled by the system of photovoltaic panels, the cogeneration plant, and the public electricity network. Given the available heat in this configuration, the cold demand will be fulfilled by the absorption refrigeration system.

The demand for heat in the building will be fulfilled—with priority—by the system of solar thermal panels and the cogeneration plant. The boiler is used as a backup and peak source. The heat storage system will be used to compensate for the load variations and to increase the flexibility of the cogeneration plant. The size of the storage capacity is determined according to the maximum usage load. The production of energy from renewable energy sources—namely, photovoltaic panels (PV) and solar thermal panels (SP)—was considered in relation to the conditions in the northern area of Romania (the nominal capacity utilization factor was 0.16).

Equation (2) customized for Scenario 2:

$$\begin{bmatrix} L_e \\ L_c \\ L_h \end{bmatrix} = \begin{bmatrix} 1 & \alpha \cdot CF_{PV} & \gamma \cdot \eta_e & 0 \\ 0 & \alpha \cdot CF_{SP} \cdot CP_{AR} & (\varepsilon \cdot \eta_{th} + \beta \cdot \eta_B) \cdot CP_{AR} & \tau \cdot e_{TS} \cdot CP_{AR} \\ 0 & (1-\alpha) \cdot CF_{SP} & (1-\varepsilon) \cdot \eta_{th} + (1-\beta) \cdot \eta_B & (1-\tau) \cdot e_{TS} \end{bmatrix} \cdot \begin{bmatrix} P_e \\ P_{RES} \\ P_g \\ \pm E_{TS} \end{bmatrix}, \quad (14)$$

where α, β, γ, ε, ν, and τ are the dispatch factors:

α is the share of electricity from renewable energy sources;
β is the share of heat from the boiler to supply the absorption refrigeration system;
γ is the share of gas that is converted into electricity in CHP;
ε is the share of gas that is converted into heat in CHP for the absorption refrigeration system;
τ is the share of heat that is stored.

and the efficiencies of the converters are as follows:

η_e is the efficiency of electricity generation in cogeneration;
η_{th} is the efficiency of heat generation in cogeneration;
CF_{PV} is the nominal capacity utilization factor for the photovoltaic panels;
CF_{SP} is the nominal capacity utilization factor for the solar thermal panels;
CP_{AR} is the coefficient of the performance of the absorption refrigeration system;
η_B is the boiler efficiency;
e_{TS} is the storage efficiency of thermal energy—Equation (8).

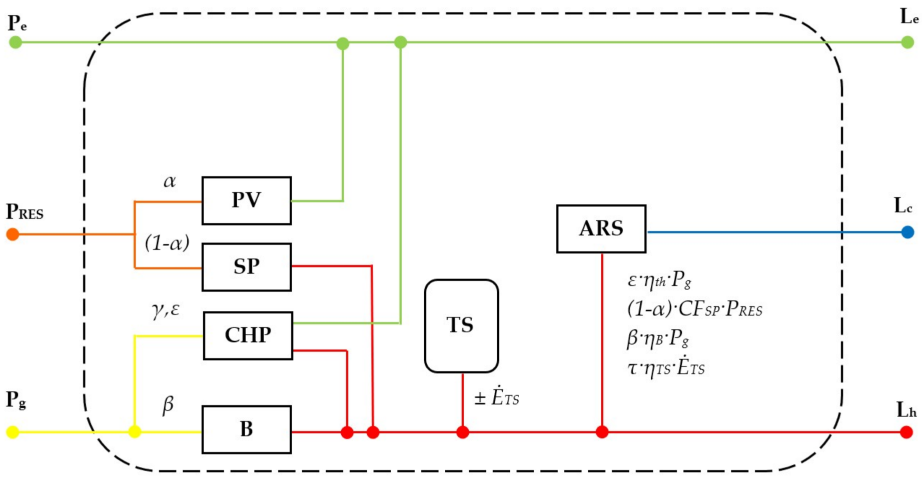

Figure 5. Scenario 2: CHP—combined heat and power plant; B—boiler; TS—thermal storage; PV—photovoltaic panels; SP—solar thermal panels; ARS—absorption refrigeration system.

The performances of the different energy sources that were considered in Scenario 2 are presented in Table 2 [29–31].

Table 2. The performances of the different energy sources in Scenario 2 [29–31].

Type of Technology	Nominal Power/Energy	Specific Investment	O&M costs (% of Investment/Year)	Conversion Efficiency
CHP	18 kWe36 kWth	1500 EUR/kWe	5.0%	η_e = 30% η_{th} = 55%
B	75 kWth	127 EUR/kWth	2.5%	η_B = 94%
PV	15 kW	2500 EUR/kW	1.0%	CF_{PV} = 16%
SP	60 kW	300 EUR/kW	1.0%	CF_{SP} = 16%
TS	200 kWh	20 EUR/kWh	2.0%	η_{TS} = 90%
ARS	18 kW (cool)	600 EUR/kW	2.5%	CP_{AR} = 0.75

In Scenario 3 (Figure 6), the demand for electricity will be fulfilled by the system of photovoltaic panels, the cogeneration plant, and the public electricity network. Electricity is used to supply the heat pump and the compression refrigeration system. The cold demand will be fulfilled by the compression refrigeration system.

The demand for heat will be fulfilled—with priority—by the system of solar thermal panels and the heat pump. The natural gas boiler is used as a backup and peak source.

The heat storage system is also used in this scenario, taking into account the intermittent heat that is generated by the solar thermal panels. The size of the storage capacity is determined according to the maximum usage load.

The performances of the different energy sources that were considered in Scenario 3 are presented in Table 3 [29–31].

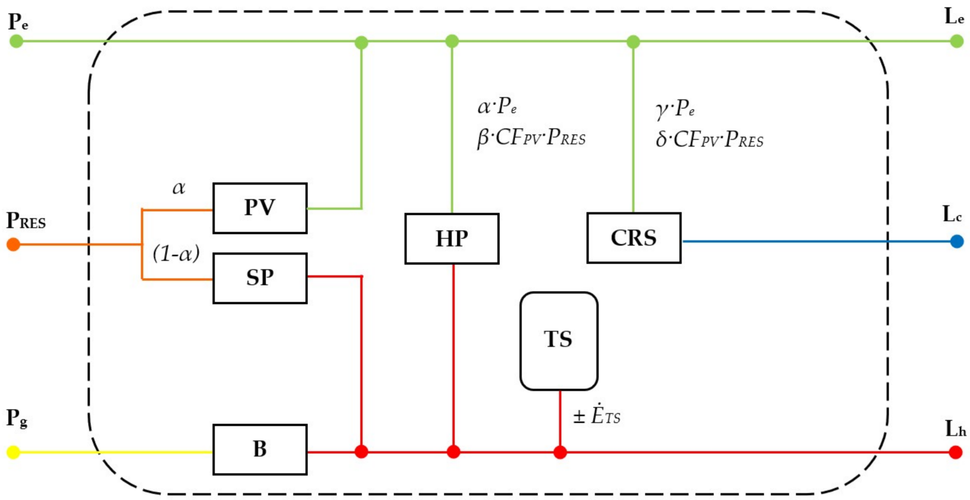

Figure 6. Scenario 3: PV—photovoltaic panels; SP—solar thermal panels; HP—heat pump; B—boiler; TS—thermal storage; CRS—compression refrigeration system.

Equation (2) customized for Scenario 3:

$$\begin{bmatrix} L_e \\ L_c \\ L_h \end{bmatrix} = \begin{bmatrix} 1-\alpha-\gamma & (\nu-\beta-\delta)\cdot CF_{PV} & 0 & 0 \\ \gamma\cdot CP_{CR} & \delta\cdot CF_{PV}\cdot CP_{CR} & 0 & 0 \\ \alpha\cdot CP_{HP} & \beta\cdot CF_{PV}\cdot CP_{HP}+(1-\alpha)\cdot CF_{SP} & \eta_B & \tau\cdot e_{TS} \end{bmatrix} \cdot \begin{bmatrix} P_e \\ P_{RES} \\ P_g \\ \pm E_{TS} \end{bmatrix}, \quad (15)$$

where α, β, γ, δ, ν, and τ are the dispatch factors:

α is the share of electricity from renewable energy sources;
β is the share of electricity from the photovoltaic panels to supply the heat pump;
γ is the share of electricity from the public network for the compression refrigeration system;
δ is the share of electricity from the photovoltaic panels for the compression refrigeration system;
τ is the share of heat that is stored to supply the absorption refrigeration system.

and the efficiencies of the converters are as follows:

CP_{HP} is the coefficient of the performance of the heat pump;
CP_{CR} is the coefficient of the performance of the compression refrigeration system;
CF_{PV} is the nominal capacity utilization factor for the photovoltaic panels;
CF_{SP} is the nominal capacity utilization factor for the solar thermal panels;
η_B is the boiler efficiency;
e_{TS} is the storage efficiency of thermal energy—Equation (8).

Table 3. The performances of the different energy sources in Scenario 3 [29–31].

Type of Technology	Nominal Power/Energy	Specific Investment	O&M costs (% of Investment/Year)	Conversion Efficiency
HP	65 kW (heat)	1200 EUR/kW	3.2%	$CP_{HP} = 4$
B	75 kWth	127 EUR/kW	2.5%	$\eta_B = 94\%$
PV	15 kW	2500 EUR/kW	1.0%	$CF_{PV} = 16\%$
SP	60 kW	300 EUR/kW	1.0%	$CF_{SP} = 16\%$
TS	200 kWh	10 EUR/kWh	2.0%	$\eta_{TS} = 90\%$
CRS	18 kW (cool)	110 EUR/kW	1.2%	$CP_{CR} = 3$

In Scenario 4 (Figure 7), the energy demand for the building is fulfilled by public utilities networks (electricity and heat) without other local energy sources. A compression refrigeration system is used to produce the cold demand.

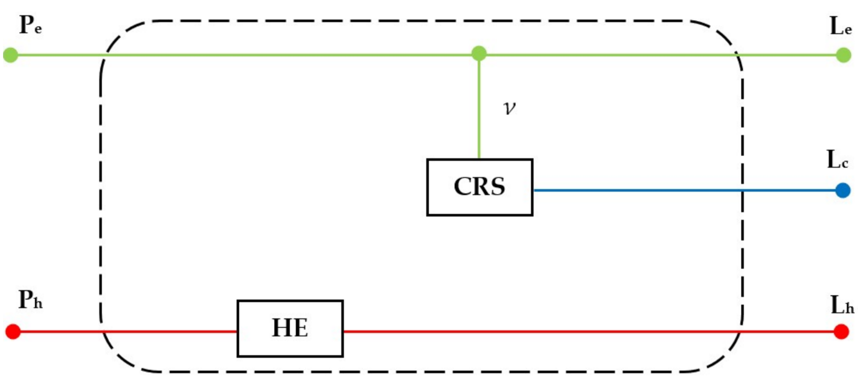

Figure 7. Scenario 4: HE—heat exchanger; CRS—compression refrigeration system.

Equation (2) customized for Scenario 4:

$$\begin{bmatrix} L_e \\ L_c \\ L_h \end{bmatrix} = \begin{bmatrix} 1-\nu & 0 \\ \nu \cdot CP_{CR} & 0 \\ 0 & \eta_{HE} \end{bmatrix} \cdot \begin{bmatrix} P_e \\ P_h \end{bmatrix}, \quad (16)$$

where ν is the dispatch factor (the share of electricity that is used to supply the compression refrigeration system) and the efficiencies of the converters are as follows:

CP_{CR} is the coefficient of the performance of the compression refrigeration system;
η_{HE} is the efficiency of the heat exchanger.

The performances of the different energy sources that were considered in Scenario 4 are presented in Table 4 [29–31].

Table 4. The performances of the different energy sources in Scenario 4 [29–31].

Type of Technology	Nominal Power/Energy	Specific Investment	O&M costs (% of Investment/Year)	Conversion Efficiency
HE	100 kW (heat)	10 EUR/kW	1.0%	η_{HE} = 98%
CRS	18 kW (cool)	110 EUR/kW	1.2%	CP_{CR} = 3

The tariffs for the energy that is consumed from the public networks are indicated in Table 5 [32]. The prices that are taken into account exclude all of the applicable taxes (value-added tax—VAT, charges, and subsidies). Additionally, in Equation (1), the value of the annual rate of increase in the cost of energy is 0.1% and the value of the discount rate is 3%. The calculation period is 20 years.

Table 5. The tariffs for energy consumed from public networks.

Electricity (EUR/kW)	Natural Gas (EUR/kW)	Heat (EUR/kW)
0.105	0.027	0.045

Regarding the carbon dioxide emissions, for macroeconomic calculations, the European Commission recommends using a price per tonne of carbon dioxide (CO_2) of EUR 20 until 2025, of EUR 35 until 2030, and of EUR 50 beyond 2030. The cost of the carbon dioxide emissions refers to the monetary value of the environmental damage caused by the carbon dioxide emissions that are related to the energy consumption in buildings [33].

The comparison and combination of various energy efficient and renewable energy technologies were carried out within the four scenarios. In each scenario, the efficiency measures that are cost-effective may allow for the inclusion of other measures that are not yet cost-effective, but which could substantially add to the primary energy usage and carbon dioxide emissions.

The mandatory condition is that the overall package needs to offer more benefits than costs over the lifetime of the building.

The overall costs (represented by the net present value) for each of the analysed scenarios are presented in Table 6 and Figure 8. Additionally, the carbon dioxide emissions are presented in Figure 8. In terms of the load profiles of the analysed building, the minimum overall costs are observed in Scenario 1 and the maximum overall costs are observed in Scenario 4.

Table 6. Structure of the overall costs.

Structure of the Cost	Scenario 1	Scenario 2	Scenario 3	Scenario 4
The overall costs (EUR)	295,188	399,217	478,707	549,425
of which:				
The investment costs	41.26%	38.76%	43.34%	2.28%
The cost of energy consumed	37.93%	42.28%	39.72%	87.55%
The operating and maintenance costs	7.55%	6.77%	5.54%	0.41%
The cost of carbon dioxide emissions	13.26%	12.19%	11.39%	9.76%

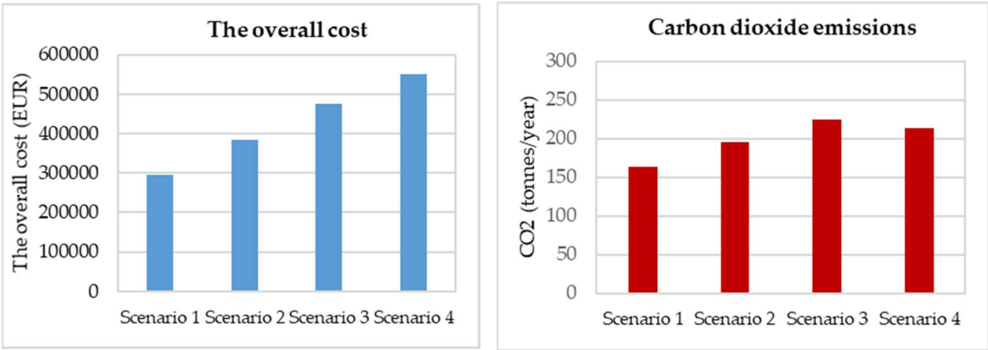

Figure 8. The overall cost and carbon dioxide emissions.

Out of the three forms of energy that are consumed in the building (electricity, heat, and cooling), the heat demand occupies the largest share of the total energy consumption of the building (see Figure 3). Heat is required in both the HVAC system (heating, ventilation, and air conditioning) and the domestic hot water. Therefore, the energy sources that provide heat will have a major influence on the carbon dioxide emissions. Scenario 4 is considered to be the reference (traditional) scenario, in which heat and electricity are provided by public utility networks (the district heating system and the public electricity network). In Scenarios 1, 2, and 3, part of the energy that is required for the building is produced locally (including the energy that is produced by renewable energy sources). The carbon dioxide emissions are lower in Scenario 1 because of the heat pump, which provides a significant portion of the annual heat requirement. The carbon dioxide emissions are higher in Scenario 2 and Scenario 3 because of the heat that is generated by the boiler, even with the production of energy from renewable sources. It is clear that a larger production from renewable energy sources will lead to the reduction of the carbon dioxide emissions. However, such investments must be backed by support schemes.

One can notice that a new category of costs—namely the cost of carbon dioxide emissions—was included in the determination of the overall cost. These costs shall reflect the quantified, monetised, and discounted operational costs of CO_2 that result from the carbon dioxide emissions—in tonnes of CO_2 equivalent—over the calculation period.

The calculations that are required for selecting the energy sources according to the global costs have shown that there is significant potential for the achievement of cost-effective energy savings.

4. Conclusions

The energy audit of a building identifies refurbishment and upgrading solutions for the building to meet the minimum energy performance requirements. In the energy audit, both the envelope and the building's services are analysed. In the audit, the energy auditor recommends additional possible scenarios. Together with the building owner, the designer will choose the optimal solution package depending on the financial resources that are available, the legislative restrictions on the minimum energy performance requirements, and the environmental impact.

The refurbishment of existing buildings offers the possibility of an intervention to the building's services in order to efficiently make use of the energy in the building. The energy sources for utilities and building services can be analysed in order to increase the energy performance of the building. The energy demand of the building is satisfied by means of specific energy carriers (heat, electricity, and cooling) for the building's utilities, namely: heating, cooling, ventilation, domestic hot water, lighting, appliances, etc.

The selection of energy sources for the building's utilities (heating, electricity, and cooling) was based on the concept of the energy hub. Through the use of this approach, various optimization issues with the use of energy in buildings can be identified.

In this paper, we analysed four scenarios. Scenario 4 is considered to be the reference (traditional) scenario. In this case, heat and electricity are provided by public utility networks (the district heating system and the public electricity network). Scenarios 1, 2, and 3 resulted from the selection of various energy sources that are available in the location of the building. The consideration of the carbon dioxide emissions penalties (the cost of carbon dioxide emissions) or the support schemes may lead to more favourable alternative solutions as opposed to the traditional scenario (heat and electricity provided by public utility networks). Thus, the renewable energy sources can occupy a growing share of the total energy consumption of the building.

When there are numerous ways to produce the same form of energy, various optimization issues can be identified in the operation of the building's services—considering that energy demands are not constant throughout the year.

The results that were obtained characterize the load profiles of the building under consideration. It is evident that the energy demands can be fulfilled by the selection of various energy sources that are available in the building's location. These energy sources can be renewable energy sources (e.g., biomass, biogas, solar energy, geothermal energy, and wind energy) or public utility networks (natural gas, the district heating system, and the public electricity network). A higher share of renewable energy sources—while keeping the overall costs as low as possible—should be the target in the selection of energy sources.

When selecting energy sources, restrictions on the production of energy from renewable sources and the carbon dioxide emissions penalties should be considered.

The overall costs associated with meeting the minimum energy performance requirements (investment costs, maintenance and operating costs, costs of carbon dioxide emissions, and legislative restrictions on the production of energy from renewable sources) must be minimized over the estimated lifetime of the building. The proposed algorithm can also be used for new buildings. A joint examination of the energy sources and various technologies for the building's services will demonstrate the effectiveness of the method that is used.

Author Contributions: Both authors contributed equally in the writing of this paper.

Conflicts of Interest: The authors declare no conflict of interest.

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Procedia Manufacturing 22 (2018) 651–658

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11th International Conference Interdisciplinarity in Engineering, INTER-ENG 2017, 5-6 October 2017, Tirgu-Mures, Romania

Factors which influence the qualification of the electricity production in high efficiency cogeneration for biomass combined heat and power plants

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Abstract

The high efficiency cogeneration is promoted across European Union by support schemes that are applied in order to achieve energy policy goals of sustainability, security of supply and improved competitiveness. The paper presents an analysis of the factors which influence the qualification of the electricity production in high efficiency cogeneration for the biomass combined heat and power plants. The correct identification of the energy from the consumed biomass and the delivered useful heat, it is decisive for the high efficiency cogeneration.

Peer-review under responsibility of the scientific committee of the 11th International Conference Interdisciplinarity in Engineering.

Keywords: High efficiency cogeneration; support schemes; green certificates; renewable energy sources (RES); organic Rankine cycle (ORC).

1. Introduction

Combined heat and power (CHP) production or cogeneration is significantly more efficient than separate production. Cogeneration greatly reduces overall fuel use, leading to lower emissions. There are various market instruments used by governments of EU Member States to support electricity production from renewable energy sources and high efficiency cogeneration [1,2].

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Peer-review under responsibility of the scientific committee of the 11th International Conference Interdisciplinarity in Engineering.
10.1016/j.promfg.2018.03.094

The simultaneous conversion into heat and electricity of energy from renewable sources or the waste heat from different industrial processes is a solution to reduce greenhouse gas emissions [3]. If the primary energy source has a lower thermal potential, as is the case renewable energy sources [4,5], can be used organic Rankine cycle (ORC), for cogeneration both useful forms of energy: electricity and heat.

The support scheme of electricity production from the renewable energy sources (RES-E) in Romania, combines the mandatory quotas with the trading of green certificates (GC). Directive 2004/08/EC on the promotion of cogeneration and Directive 2012/27/EU on energy efficiency, established the political framework that allows the expansion of the cogeneration implementation in the Member States (Directive 2012/27/EU; Directive 2004/8/EC).

Currently, there are different support instruments in the EU to stimulate the production of electricity from renewable energy sources. Romania has opted for mandatory quota system and green certificates (GC). In the case of biomass, the support scheme provides 2 GC for each MWh delivered to the public network and additional 1 GC if the electricity is produced in high efficiency cogeneration.

2. Analysis of a cogeneration plant with ORC technology and biomass fuel

The principle thermal scheme of the cogeneration plant with organic Rankine cycle (ORC) and biomass fuel is shown in Figure 1. The technical characteristics in the nominal conditions of the biomass CHP are: electrical power 1.3 MWe and thermal power 5.4 MWth.

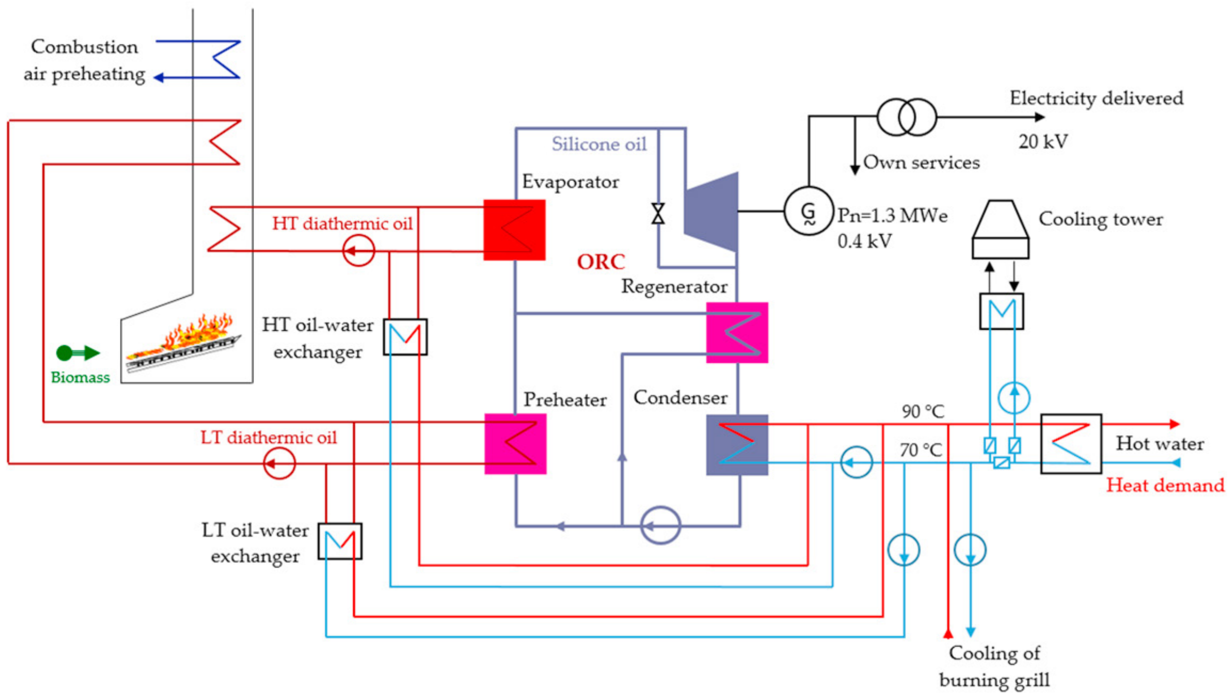

Fig. 1. The principle thermal scheme of the CHP unit with ORC technology.

The main fuel is the biomass (without burning fuel support) and it comes from the primary wood industrialization (wood chips, bark, sawdust) and biomass from agriculture (straw). Heat delivered by the cogeneration plant is mainly used for industrial purposes (dryers for wood) and a small part for heating administrative buildings and production.

The qualification of electricity production in high efficiency cogeneration for a cogeneration unit is based on the primary energy saving compared to separate production with alternative technologies in similar conditions and the same amounts of useful heat and electricity [6]:

$$PES = \left(1 - \frac{1}{\dfrac{\eta_{h,CHP}}{\eta_{h,Ref}} + \dfrac{\eta_{e,CHP}}{\eta_{e,Ref} \cdot p_{loss}}} \right) \cdot 100 \ \ [\%] \tag{1}$$

where:

$\eta_{h,CHP}$ is the heat efficiency of the cogeneration production;
$\eta_{e,CHP}$ is the electrical efficiency of the cogeneration production;
$\eta_{h,Ref}$ is the efficiency reference value for separate production of heat ($\eta_{h,Ref} = 86\%$ for biomass) [7];
$\eta_{e,Ref}$ is the efficiency reference value for separate production of electricity ($\eta_{e,Ref} = 33\%$ for biomass) [7];
p_{loss} is the correction factor for avoided grid losses ($p_{loss} = 0.935$ for connection voltage level 20kV) [7].

The electrical efficiency and the heat efficiency of the cogeneration production:

$$\eta_{e,CHP} = \frac{Electricity \ \ (E)}{Fuel \ \ (F)} \tag{2}$$

$$\eta_{h,CHP} = \frac{Useful\ Heat(H)}{Fuel(F)} \tag{3}$$

For calculating useful heat the following two components are considered:

$$H = H_{output} + H_{own} \tag{4}$$

where:

H_{output} is the useful heat delivered to the heat consumers outside the cogeneration unit;
H_{own} is internal services thermal consumption for heating fuel and heating office buildings.

2.1. The determination of fuel energy

The supply biomass is stored in the biomass storage near the power plant by category. The deposit allows mechanical homogenization of the biomass for each category of fuel material: wood fuel and agricultural biomass, respectively.

The biomass for the boiler is weighed with the help of a car charger. The record of biomass quantities is done in *LUTRO* and *ATRO*. The equation is:

$$ATRO = \frac{100 - w(\%)}{100} \cdot LUTRO \tag{5}$$

where:

ATRO is the amount of biomass without moisture (kg);
LUTRO is the amount of biomass with moisture (kg);
w is the humidity from biomass (%).

The biomass quality is verified by two types of laboratory samples: daily measurements of moisture content and biannual determinations of lower calorific values. Correction of net calorific value with humidity is done with the following equation:

$$NCV_{(i)} = NCV_{anhydrous(i)} \cdot \left(\frac{100 - w(\%)}{100} \right) - 0.00639 \cdot w_i(\%) \tag{6}$$

where:

$NCV_{anhydrous(i)}$ is the net calorific value of dry biomass (without water) for the quantity i of consumed biomass (kWh/kg);
w_i is the moisture content for the quantity i of consumed biomass (%);
0.00639 is constant for the latent heat of water vaporization.

The energy contained in consumed biomass *F (MWh)*:

$$F = \frac{LUTRO \cdot NCV_{(i)}}{1000} \tag{7}$$

The monthly quantities of biomass, the average moisture and net calorific values is shown in Table 1. Figure 2 shows the evolution of biomass quantities and moisture in 2016 year.

Table 1. The monthly quantities of biomass, the average moisture and net calorific values.

Month	LUTRO (tons)	ATRO (tons)	Moisture (%)	NCV (kWh/kg)	NCVanhydrous (kWh/kg)	Biomass energy (MWh)
January	2099.86	1263.97	39.81	2.782	5.044	5841.90
February	1994.48	1176.60	41.01	2.714	5.044	5412.67
March	1086.04	674.09	37.93	2.878	5.028	3125.91
April	963.34	496.33	48.48	2.281	5.028	2197.00
May	2337.40	1306.46	44.11	2.528	5.028	5909.83
June	2033.20	1216.17	40.18	2.751	5.028	5592.53
July	1795.74	1267.86	29.40	3.284	4.917	5896.40
August	1854.48	1263.39	31.87	3.174	4.957	5885.40
September	1869.00	1240.29	33.64	3.054	4.927	5708.55
October	1371.61	827.55	39.67	2.713	4.916	3720.78
November	2152.84	1121.78	47.89	2.246	4.898	4835.60
December	2692.04	1377.91	48.82	2.202	4.912	5928.50

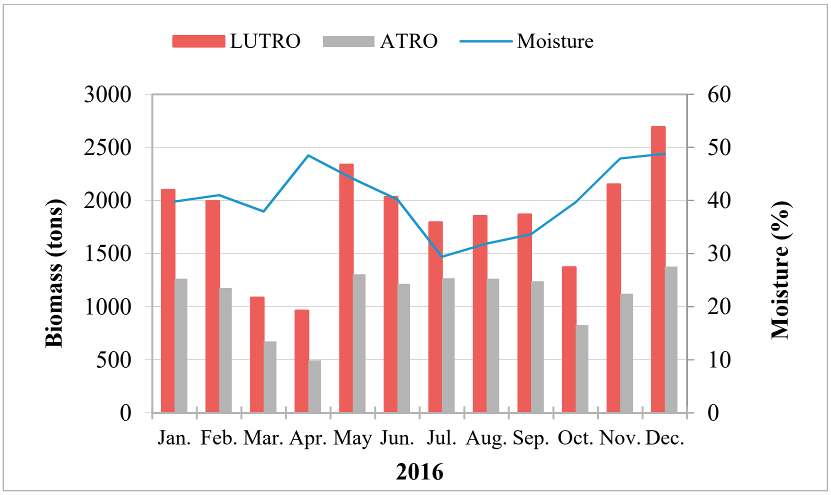

Fig. 2. The monthly quantities of biomass and moisture content.

The moisture of biomass consumed shows higher values in the cold season against the warm season. In March-April and October the amounts of biomass were lower due to the shutdown of the cogeneration unit for maintenance.

2.2. Determination of useful heat delivered

According with [8], "useful heat" shall mean heat produced in a cogeneration process to satisfy an economically justifiable demand for heat or cooling.
From Figure 1 it can see heat sources which contributes to the supply of heat consumers:

- the condenser of the ORC module;
- the heat exchangers HT (high temperature) and LT (low temperature);
- the recovered heat from the cooling circuit of the boiler burning grill.

The heat diathermic oil-water exchangers allow the evacuation of the main heat flow from the biomass boiler when the cogeneration unit is switched off. Also, it can provide heat supply to consumers in case of failure of ORC cogeneration unit for a period longer time.

It is necessary to highlight the heat generated in non-cogeneration and its exclusion from the total amount of heat delivered to consumers [9,10]. The amount of heat generated in non-cogeneration mode resulting from the equation of energy balance:

$$H_{non-CHP} = H_{HC} + H_{CT} - H_{ORC} \tag{8}$$

where:

H_{HC} is the delivered heat to consumers;
H_{CT} is the lost heat to the cooling source (tower);
H_{ORC} is the heat generated of the ORC module.

In transitional situations (ORC turbine-generator unit stopped), is opened the bypass connection of turbine for silicone oil recirculation in the ORC circuit, and the evacuation of the main flow of heat from the biomass boiler is achieved by coupling direct of HT and LT heat exchangers. It is ensured so, continuous supply of heat consumers without operation of the ORC cogeneration unit. For such situations and for cases where is supplied directly of heat consumers from the biomass boiler by means of exchangers HT and LT, amounts of heat associated the operating modes for the null values of electricity generated are excluded. These amounts of heat are excluded of the monthly amounts recorded all three groups of heat metering.

For determining the amount of useful heat delivered from the cogeneration unit, two reports are used by records of the metering groups (a report with hourly records and a report records per minute). By means of these records can be easily identified both categories of operating modes: electric generator coupled to the network and respectively the electric generator is disconnected from the network. Both reports with records of the metering groups are taken from SCADA system (supervisory control and data acquisition) of the cogeneration unit.

3. Analysis of the factors which influence the qualification of the electricity production in high efficiency cogeneration

According with [11], each cogeneration unit shall be compared with the best available and economically justifiable technology for separate production of heat and electricity on the market in the year of construction of the cogeneration unit.

The analysis of the equation (1) allows an identification of the factors which influence the qualification of the electricity production in high efficiency cogeneration. Thus, in the case of an existing cogeneration plant, in conditions of constant maintaining of electricity production, correct determination of energy from the consumed biomass and correct identification of useful heat consumption are the essential factors in the qualification of the electricity production in high efficiency cogeneration.

Determination of energy from fuel requires permanent weighing of the consumed biomass and determining moisture and net calorific power. The variation of net calorific power with moisture for different types of biomass is shown in Figure 3. In case of high moisture in consumed biomass an important amount of energy from fuel is consumed to vaporize the water. Thus, the performance of the boiler on biomass is affected and keeping the parameters in economic limits at entry into the ORC cycle it is done with difficulty.

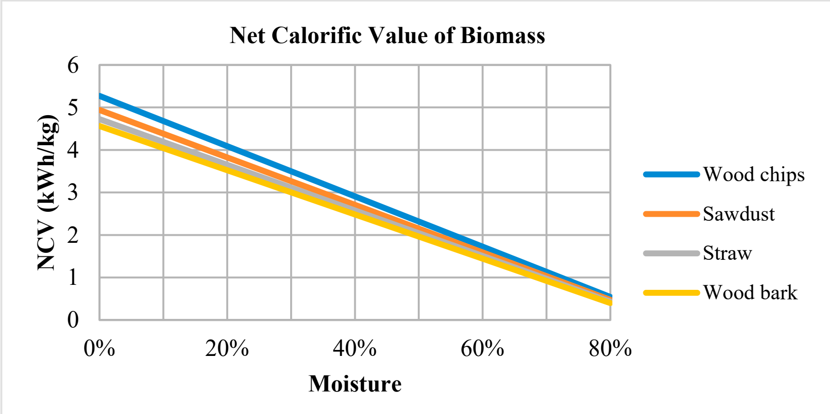

Fig. 3. The variation of net calorific power with moisture.

From relationship (4) it is observed that drying of the biomass before entering the boiler it is considered useful heat. By drying biomass before to be introduced into the boiler it can avoid increasing the amount of consumed fuel. The drying can be done in advance using waste heat evacuated from the ORC module after the electricity was generated and not before. Also by increasing the amount of useful heat it is improving and the heat efficiency of the cogeneration production and implicitly the primary energy economy of the CHP unit.

The charging of the CHP unit to cover the demand for thermal energy it is shown in Figure 4. The load duration curve analysis of the heat delivered from the CHP unit highlights besides the reduced heat demand of consumers and a component of thermal energy which is not produced in cogeneration.

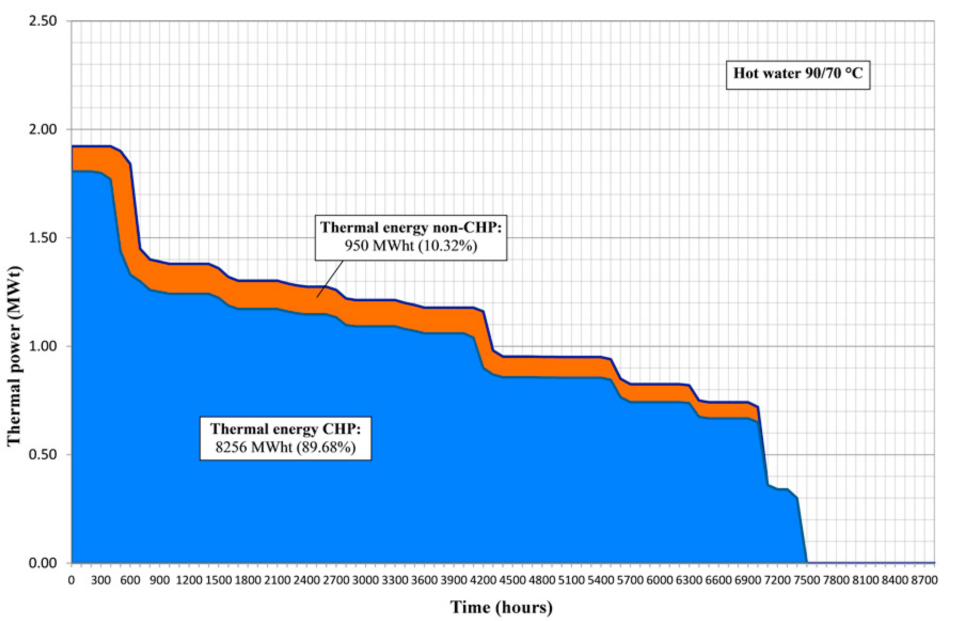

Fig. 4. The load duration curve of the heat delivered from the CHP unit

High efficiency cogeneration is defined by the primary energy savings compared with separate production by alternative technologies of heat and electricity. Higher values of 10% for the primary energy savings justifies the use of the expression "high efficiency cogeneration". Figure 5 shows the primary energy economy depending on the useful heat load delivered from the CHP unit with ORC technology.

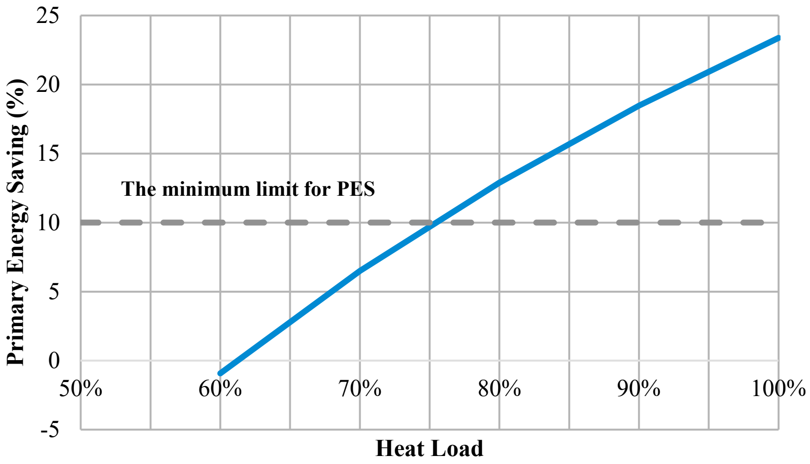

Fig. 5. The primary energy economy depending on the useful heat load delivered from the CHP unit

To qualify the entire production of electricity delivered it is necessary that useful heat load to be more than 75% in the case of the CHP unit with ORC technology.

Evolution of the qualified electricity amount in high efficiency cogeneration between January 2016 and December 2016 is shown in Figure 6. It can be noted a minimum of 12.27% in March and a maximum of 48.46% in November.

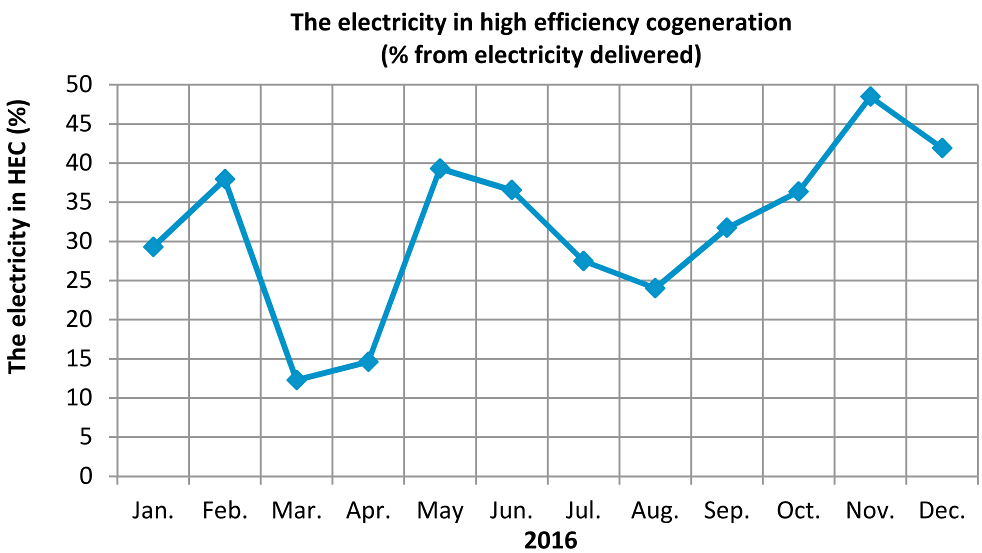

Fig. 6. Evolution of the qualified electricity amount in high efficiency cogeneration.

For the January-December 2016 operating period it was found that only 32.82% of the amount of electricity delivered has been qualified as being generated in high efficiency cogeneration. From the nominal power delivered of the CHP unit of 1.06 MWe (the rated power of 1.30 MWe and the power consumed by its own services of 0,24 MWe), based on the demand for useful heat it is qualifies in high efficiency cogeneration only a power of de 0.34 MWe.

4. Conclusions

The correct identification of the energy from the consumed biomass and the delivered useful heat, it is decisive for the high efficiency cogeneration. To maximize the primary energy savings a detailed analysis of the specific operating conditions of the combined heat and power plant is required.

In the case of the analysed cogeneration unit result in a potential heat available which can be made available to new consumers. The drying of biomass before use may be a first option. Connection of new consumers heat requires consideration the particularities of the existing district heating network in terms of heat flow rate and the tour-return temperatures which may be available without disturbing existing consumers.

Also, thorough analysis of existing operating modes allows identification and reduction of the thermal energy quantity generated in non-cogeneration.

The demand for variable heat of existing consumers can be offset by integrating a storage system of heat in the district heating. The addition of a heat storage system will increase the flexibility of the cogeneration unit with beneficial effects on the primary energy saving.

Acknowledgements

This work was supported by a grant of the Romanian National Authority for Scientific Research and Innovation, CNCS/CCCDI - UEFISCDI, project number PN-III-P2-2.1-BG-2016-0038, within PNCDI III.

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