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Hydrogen Blending in Natural Gas Grid: Energy, Environmental, and Economic Implications in the Residential Sector

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Abstract: The forthcoming implementation of national policies towards hydrogen blending into the natural gas grid will affect the technical and economic parameters that must be taken into account in the design of building heating systems. This study evaluates the implications of using hydrogen-enriched natural gas (H_2NG) blends in condensing boilers and Gas Adsorption Heat Pumps (GAHPs) in a residential building in Rome, Italy. The analysis considers several parameters, including non-renewable primary energy consumption, CO_2 emissions, Levelized Cost of Heat (*LCOH*), and Carbon Abatement Cost (*CAC*). The results show that a 30% hydrogen blend achieves a primary energy consumption reduction of 12.05% and 11.19% in boilers and GAHPs, respectively. The presence of hydrogen in the mixture exerts a more pronounced influence on the reduction in fossil primary energy and CO_2 emissions in condensing boilers, as it enhances combustion efficiency. The GAHP system turns out to be more cost-effective due to its higher efficiency. At current hydrogen costs, the *LCOH* of both technologies increases as the volume fraction of hydrogen increases. The forthcoming cost reduction in hydrogen will reduce the *LCOH* and the decarbonization cost for both technologies. At low hydrogen prices, the *CAC* for boilers is lower than for GAHPs; therefore, replacing boilers with other gas technologies rather than electric heat pumps increases the risk of creating stranded assets. In conclusion, blending hydrogen into the gas grid can be a useful policy to reduce emissions from the overall natural gas consumption during the process of end-use electrification, while stimulating the development of a hydrogen economy.

Keywords: power-to-gas; sector coupling; decarbonization cost; levelized cost of hydrogen; energy efficiency; building refurbishment; hydrogen mixtures; renewable energy; green hydrogen; energy policy

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1. Introduction

As the phenomenon of global warming and its consequences continue to develop, the necessity to reduce greenhouse gas (GHG) emissions is becoming increasingly apparent. Therefore, the implementation of energy systems that integrate renewable energy sources is of paramount importance for the immediate decarbonization of the energy sector. This results in a significant enhancement of the flexibility of energy systems [1]. Electric batteries can play an important role in renewable energy integration. Nevertheless, this technology is not sufficient to address the issue, and more effective storage devices are therefore being sought [2]. Hence, the integration of diverse strategies and the conversion of energy carriers that enhance storage capacities represent suitable solutions for guaranteeing the flexibility of the energy system [3]. In this context, the utilization of hydrogen becomes a crucial factor. Indeed, numerous studies have identified hydrogen as a key vector for facilitating the integration of renewable energy sources at high percentages [4,5]. The European Hydrogen Strategy has the objective of making hydrogen a substantial part of the European energy system. The ambitious targets of the strategy set forth a goal of achieving a minimum production of 10 million tonnes of hydrogen from renewable sources by 2030 along with the installation of 40 GW of electrolyzers. Furthermore, the national gas grid should be employed as a means of distributing hydrogen over long distances, thereby contributing to the development of adequate storage facilities [6]. In order to achieve the 2050 climate neutrality targets, it is necessary to reduce emissions from the hard-to-abate sectors, which are characterized by high energy intensity and a lack of viable electrification solutions [7]. Currently, the chemical and petroleum refining sectors utilize hydrogen as a raw material in the production of basic chemicals such as ammonia and methanol, as well as in a number of refining processes [8]. Accordingly, by 2050, hydrogen carriers should represent at least 13% of the European energy mix in order to achieve the set climate neutrality targets [9]. It is of significant importance to emphasize that the European Hydrogen Strategy has been designed with the intention of facilitating the long-term deployment of renewable hydrogen and the transition to low-carbon hydrogen. Indeed, despite currently accounting for the majority of hydrogen produced [10], hydrogen produced by steam reforming remains excluded from the planning. The objective is therefore to gradually increase the proportion of green hydrogen in industry [11]. A further hard-to-abate sector is transport, in particular heavy [12], public [13] and maritime transport [14]. Nevertheless, in the absence of refueling stations across the country, the production of synthetic natural gas (SNG) [15] or other alternative fuels [16] could be considered potential applications for immediate decarbonization of the transport segment.

The implementation of a hydrogen economy may encounter initial obstacles related to the lack of dedicated storage and distribution infrastructures [17]. In this context, a potential interim solution could be the injection of hydrogen into natural gas (NG) distribution networks [18,19]. It is indeed feasible to employ limited hydrogen volumetric fractions ($f_{H2,vol}$) in hydrogen-enriched natural gas (H_2NG) mixtures in such a way that this blend can be used in end-user devices without necessitating significant operational changes [20]. According to Jones et al. [21] and Schiro et al. [22], the threshold limit for safely running domestic end-user devices without any modifications on commercial versions is equal to 30% vol. of hydrogen content. Based on these studies, the limit value for the volumetric fraction of hydrogen used in the present study was selected. It has been widely demonstrated that the utilization of H_2NG mixtures within end-user devices can result in technical and environmental benefits [23]. In fact, the incorporation of hydrogen fractions within the natural gas (NG) network could potentially reduce GHG emissions from heating systems while simultaneously enhancing combustion efficiency. Indeed, hydrogen has a high flame velocity and a wide flammability range, which would permit more complete combustion in a mixture, thereby reducing pollutants such as CO and nitrogen oxides (NO_x). Furthermore, its higher energy density per unit mass, if compared to natural gas (NG), enables a reduction in the volume of fuel required when used in a blend.

Nevertheless, the integration of hydrogen still presents unresolved problems that are intrinsically linked to the very characteristics of H_2. In addition to the lack of adequate facilities for transport and storage, hydrogen is characterized by high flammability, which could create safety problems, especially in residential applications [24]. Furthermore, hydrogen is characterized by high energy losses related to compression and liquefaction processes, with losses of 10% and 40%, respectively [25]. From a mechanical standpoint, it is also essential to consider the potential for hydrogen embrittlement, which could impact the yield stress and strength of the materials. Consequently, the current design process of transmission networks can only be considered valid for low volumetric fractions of hydrogen in the mixture, due to the low ignition energy of hydrogen, which could cause accidents [26]. Indeed, the thermophysical properties of the mixture are significantly influenced by the proportion of hydrogen utilized. The utilization of H_2NG blends would facilitate a more extensive diffusion of the hydrogen carrier, while also representing an economically viable means of storage and transport [27]. The utilization of these mixtures of H_2NG would also result in an immediate reduction in CO_2 emissions associated with end-user systems, with reductions varying depending on the device considered [28–30]

A number of European countries have already enacted legislation on the introduction of hydrogen into the grid. For instance, France and Spain have imposed a limit of 6% and 5% by volume, respectively. In Germany, the threshold of $f_{H2,\ vol}$ in the mixture is 10%, but only under specific conditions and in designated infrastructure sections. In many European countries, the maximum permitted blending ratio is 4% [31]. Other countries, such as Italy, have not yet enacted legislation to incorporate H_2NG blending into their energy systems. However, their strategy encourages the implementation of such a solution in the next decade [32]. In fact, the employment of this vector would facilitate the achievement of decarbonization objectives in the building heating sector, which are challenging to attain through the implementation of efficiency enhancements or the electrification of end-user systems in isolation [33]. Moreover, the building sector is frequently constrained by spatial limitations and architectural constraints that preclude the installation of large-scale renewable energy systems, thereby complicating the task of reducing emissions [34]. The utilization of mixtures of hydrogen and natural gas in the building sector will result in increased primary fossil energy savings through the deployment of highly efficient gas systems.

This work aims to evaluate the H_2NG effects on technical, economic, and environmental parameters of two different plant configurations: condensing boilers and Gas Adsorption Heat Pumps (GAHPs). Some experimental investigations have already analyzed the effects of using H_2NG mixtures on condensing boilers, while there are still few studies on GAHPs. Lamioni et al. [35] numerically simulated the use of H_2NG mixtures on condensing boilers. Their study showed that the use of hydrogen causes the flame front to advance towards the burner, causing the risk of flashback, but at the same time, it prevents temperature rise due to the dilution phenomenon. The temperature reduction observed has a positive effect on the reduction in NO_x emissions. In their study of a condensing boiler, Yang et al. [36] showed how the use of 100% hydrogen as a fuel leads to an increase in the efficiency of the appliance of 8.8 percentage points. It was also shown that the boiler condenser can adequately meet the heat transfer demand when using H_2NG blends, demonstrating the feasibility of this energy-saving approach. Furthermore, with an 80% hydrogen content, the CO_2 emission intensity could be reduced by 55.4%, demonstrating the positive environmental impact of using H_2NG blends. Sforzini et al. [37] focused on developing and validating a mathematical model for a GAHP running on unconventional gaseous fuels, specifically hydrogen-enriched natural gas blends. The study revealed that from an energetic point of view, the hydrogen addition does not visibly influence the machine's performance. This is due to the fact that the tested GAHP heat recovery architecture is not able to exploit latent heat by condensing out the exhaust gas water content.

Some works analyzed the combustion effects of blending hydrogen in gas-driven end-user systems. Other works analyzed the technical and economic aspects of feeding gas-fired heating systems in residential buildings. However, to the best of the authors' knowledge, there is a gap in the literature regarding the broader analysis of the energy, environmental, and economic effects of implementing hydrogen blending policies in gas-based countries. The present work aims to fill this gap by investigating such aspects from the point of view of the end-users, who see variations in the quality of the gas mixture consumed, with consequent implications for primary energy, plant efficiency, emissions, and costs associated with their heat requirements.

In this scenario, the aim is to make a comparison between two different heat generation systems, one traditional and widely used, such as gas boilers, and one innovative, such as GAHPs, and to assess how the use of H_2NG blends can affect several technical and environmental parameters. Different parameters were assessed at variable H_2 volumetric fractions of the blend. Due to the effects of hydrogen on technical, environmental, and economic parameters, different fractions of hydrogen ranging between 0% and 30% were assessed. Finally, the economic parameters were evaluated at different hydrogen and natural gas costs, respectively, by means of two sensitivity analyses.

Similar analyses have been implemented for other H_2NG end-uses, such as internal combustion engines [38,39], household appliances [40,41], industrial burners [42,43], and CHPs [44,45].

2. Materials and Methods

The purpose of this study is to evaluate the efficiency and cost-effectiveness of two heating systems applied to a building. To conduct this evaluation, a methodology was developed for assessing the energy, environmental, and economic performances of a condensing boiler and a GAHP. The proposed scenarios have been dynamically implemented in MATLAB/SIMULINK to determine the power required to fulfill the heating demand of the building. Several energy, environmental, and economic parameters related to boiler operation were then evaluated. The latter is considered the reference case when supplied with natural gas. The second system envisages the replacement of the boiler with a GAHP. Subsequently, the operation of the two systems has been evaluated by powering them with hydrogen fractions varying between 0 and 30% by volume, with a gradual increase of 10%. Next, many sensitivity analyses were conducted to ascertain how the impact of variations in the costs of the two energy vectors employed and the fraction of hydrogen replaced in the mixture affects the economic viability of the proposed interventions.

2.1. Case Study

The residential building considered as a case study is situated within a renewable energy community in Rome. Such a case study has already been analyzed and described in Ref. [46]. Four distinct housing types have been identified within the building by the study by Mancini et al. [47], whose characteristics, electrical consumptions, and heating demands are presented in Table 1. All values in Table 1 are taken from Ref. [46]. The total surface of the building was calculated as equal to 1990 m^2. The study enabled the estimation of the thermal demand to be carried out, starting from the definition of average energy performance indicators for a residential complex located in Rome. The energy performance indicator for the heating phase is considered equal to 70.3 kWh/m^2 yr. The hourly profiles related to the heating demand were evaluated from data obtained from the Hotmaps Project [48]. In order to determine the annual thermal energy demand of the entire building, the demands of the individual apartments, related to the m^2 of each housing unit, and the number of housing units within the structure were considered. The annual heating demand was thus determined to be 139.9 MWh/yr as seen in Figure 1. Therefore, for each type of dwelling, the total heat load was determined by considering five dwelling units, while the surfaces are referred to as a single unit.

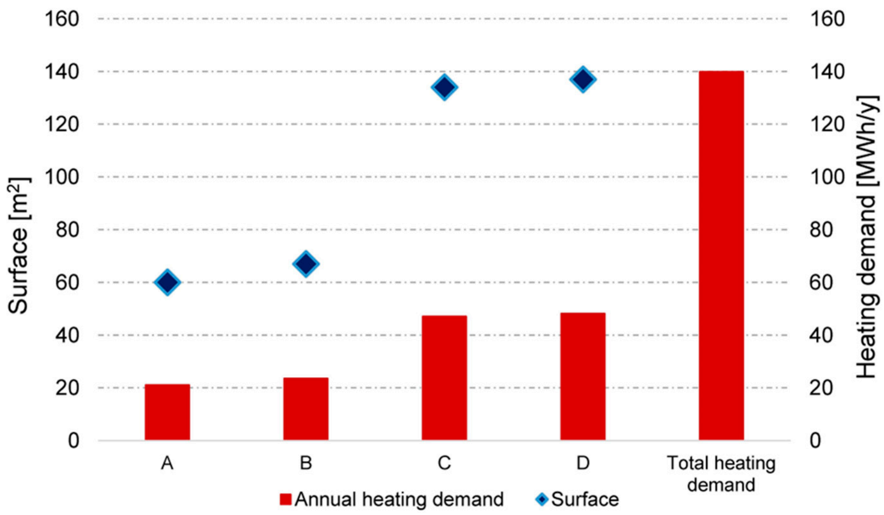

Figure 1. Annual heating demand for the different dwellings, surface of each dwelling, and total heating demand.

Table 1. Dwelling characteristics and heating demand [46].

Dwelling Typology/Building	Number of Dwellings	Surface (m^2)	Annual Heating Demand (MWh/yr)	Annual Electrical Consumption (MWh/yr)	INHABITANTS (n° of People)
A	5	60	4.22	4.75	2
B	5	67	4.71	9.55	3
C	5	134	9.42	12.65	4
D	5	137	9.63	12.5	3
Building	20	1990	139.9	39.45	60

2.2. Energy, Economic, and Environmental Model for Simulation

To be able to evaluate the energy, environmental, and economic performances of the boiler and GAHP systems, several parameters were considered such as non-renewable primary energy consumption ($EP_{nr,t}$), CO_2 emissions, Levelized Cost of Heat (*LCOH*), and Carbon Abatement Cost (*CAC*).

In order to verify the viability of the proposed scenarios, they were dynamically implemented in the MATLAB/SIMULINK environment and simulated on an hourly basis over a full year. Initially, the fuel utilized was only natural gas (NG), followed by a transition to H_2NG blends. Specifically, knowing the power required to fulfill the heating demand of the building, the thermal power related to the different mixtures can be obtained from Equations (1) and (2) for the boiler and GAHP, respectively. The quantity of NG varies according to the hydrogen fractions considered for the mixture.

$$P_{H2NG,boiler}(t) = \frac{P_{th,D}(t)}{\eta_{boiler}(t)} \tag{1}$$

$$P_{H2NG,GAHP}(t) = \frac{P_{th,D}(t)}{\eta_{GAHP}(t)} \tag{2}$$

It should be noted that when a change is made to the composition of the mixture, the power supplied to the end-user remains constant. Consequently, the power supplied is dependent upon the efficiency of the system under consideration. Once the supply of thermal power was established, it was therefore possible to determine the amount of energy produced as the mixture under consideration varied, using the following equation:

$$E_{H2NG} = \int_t P_{H2NG} \tag{3}$$

The fraction of energy derived from hydrogen can be quantified by multiplying the energy content of the mixture by the hydrogen fraction applied.

$$E_{fH2} = E_{H2NG} \cdot f_{H2,vol} \cdot \frac{LHV_{H2,vol}}{LHV_{H2NG,vol}} \tag{4}$$

The efficiency of the GAHP system was considered constant and equal to 1.4, while the efficiency of the boiler was considered variable as the fraction of H_2 varied. As Ref. [49] points out, the indirect method, which is also certified by UNI 10389 [50] in Italy, allows for the assessment of combustion efficiency from sensible heat losses using temperature probes and a gas analyzer. The combustion efficiency for a condensing boiler can be determined using the following equation:

$$\eta_C = 1 - \frac{P_{loss,sens}}{P_{fuel}} + EFC \tag{5}$$

where Energy Fraction of Condensation (*EFC*) indicates the fraction of latent heat resulting from water vapor condensation relative to the energy absorbed by the boiler. It should be noted that both the water dew point temperature and the flue gas temperature at the stack can be used to calculate the mass of water, the actual latent heat recovered, and the EFC factor.

$$EFC = \frac{P_{latent}}{P_{fuel}} \tag{6}$$

In order to evaluate the efficiency variation due to different H_2NG mixtures burned in the boiler, certain parameters were defined including the flue gas outlet temperature equal to 45 °C and an external ambient temperature of 0 °C [51]. The percentage of sensible heat loss to the stack can be determined using Equation (7).

$$\frac{P_{loss,sens}}{P_{fuel}} = \left(\frac{K_1}{20.9 - O_2} + K_2\right) \cdot \Delta T \tag{7}$$

ΔT is determined by the difference in flue gas outlet temperature and the external ambient temperature. The oxygen content in the flue gas outlet was considered to be equal to 4%. The values of the K_1 and K_2 coefficients as the H_2NG mixture varies are provided in Table 2. The EFC factor can be determined using Equation (8).

$$EFC = (HVR - 1) \cdot \eta_{cond} \tag{8}$$

Here, HVR is the Heating Value Ratio and is defined as the ratio between the HHV (higher heating value) and the LHV (lower heating value) of the considered mixtures. The other component in the equation is the condensation efficiency (η_{cond}), which is defined as the ratio between the actual condensed water mass and the maximum condensable mass. The HVR and η_{cond} values, obtained from Ref. [49], are based on the varying fraction of applied hydrogen, as shown in Table 2.

Table 2. Parameter calculation required with changes in hydrogen fraction [49].

f_{H2} (% vol.)	K_1	K_2	HVR	η_{cond}
0	0.007852	2.27425×10^{-5}	1.1062	0.549
10	0.007808	2.23817×10^{-5}	1.1084	0.565
20	0.007756	2.19601×10^{-5}	1.1109	0.581
30	0.007695	2.14608×10^{-5}	1.1139	0.597

The values of the combustion efficiency obtained for different H_2NG mixtures are shown in Table 3.

Table 3. Boiler's combustion efficiency with changes in hydrogen fraction.

f_{H2} (% vol.)	η_c
0	1.04034
10	1.04340
20	1.04671
30	1.05043

The non-renewable primary energy consumption and the CO_2 emissions were calculated using factors determined by Ref. [52] as the H_2NG mixture used in the two systems varied. $EP_{nr,t}$ for the reference year was calculated using Equation (9).

$$EP_{nr} = \left(E_{H2NG} - E_{fH2}\right) \cdot f_{nr,NG} \tag{9}$$

In this equation, $f_{nr,NG}$ is the factor for non-renewable primary energy related to NG. In order to consider the annual equivalent CO_2 emissions of the two systems, it is necessary to establish the following relationship (10):

$$CO_{2,\mathrm{eq}} = \left(E_{H2NG} - E_{fH2}\right)\cdot f_{e,NG} \tag{10}$$

In this equation, $f_{e,NG}$ is the factor required to calculate the emissions associated with NG.

2.2.1. Levelized Cost of Heat

The Levelized Cost of Heat is an economic parameter that assesses the costs of heat produced by a defined system and helps to compare the various technologies for process heating and power generation [53]. The *LCOH* was calculated as the sum of the annual costs divided by the energy supplied annually, in accordance with Ref. [54].

$$LCOH = \frac{\mathrm{P}\cdot CAPEX\cdot crf + C_{O\&M} + C_{FUEL}}{E_{th}} \tag{11}$$

The dimensions of the two devices were determined from the rated power (P) of the entire building, which was calculated to be 88 kW [46]. The annual costs were calculated on the basis of an initial installation cost (*CAPEX*) in EUR/kW for each of the two devices, with the cost varying according to the technology implemented. In order to evaluate the part of the installation costs related to each year of the useful life of the plant, a capital recovery factor (*crf*) was considered. This is defined from Equation (12) as the ratio of the present value of the net cash inflows to the initial investment [55].

$$crf = \frac{i\cdot(1+i)^t}{(1+i)^t - 1} \tag{12}$$

In Equation (12), i stands for the interest rate applied and t is the lifetime of the plant considered. The data provided by the Danish Energy Agency enabled the estimation of the percentage of costs required to operate and maintain the plants [56]. The annual fuel purchase cost was then estimated, varying according to the efficiency of the device and the mixture of hydrogen and methane considered. This cost is calculated according to the following relationship (13):

$$C_{FUEL} = E_{th}\cdot\eta\cdot P_{H2NG,E} \tag{13}$$

where E_{th} is the total heat demand of the whole building, η is the efficiency of the device used, and ($P_{\mathrm{H2NG,E}}$) is the calculated price for the mixture. The efficiency of the GAHP was considered to be constant, whereas for the condensing boiler, the variation in efficiency due to the use of mixtures with different hydrogen fractions inside was taken into account. The efficiency values when varying the volumetric fraction of hydrogen used are presented in Table 1. The price of the mixture was then evaluated through the following relationship (14) [57]:

$$P_{H2NG,E} = f_{H2,vol}\cdot\frac{P_{H2}}{LHV_{H2,mass}}\cdot\frac{LHV_{H2,vol}}{LHV_{H2NG,vol}} + P_{NG}\cdot(1 - f_{H2,vol})\cdot\frac{LHV_{NG,vol}}{LHV_{H2NG,vol}} \tag{14}$$

The relationship allows the cost per unit of energy of the mixture to be assessed. It is a function of the price of hydrogen considered in EUR/kg, the price of natural gas in EUR/MWh, the lower heating value (LHV) of natural gas in MJ/Nm^3, the LHV of hydrogen in mass and volume, in MJ/kg and MJ/Nm^3, respectively, and the LHV of the mixture depending on the volumetric percentage of H2 involved.

2.2.2. Carbon Abatement Cost

The Carbon Abatement Cost (*CAC*) is an economic parameter expressed in EUR/tonne of CO_2 avoided [58]. This parameter refers to the cost associated with the implementation of measures or technologies aimed at reducing carbon dioxide emissions when compared with a reference scenario in which no such measures are taken. In simpler terms, *CAC* represents the cost of avoiding the emission of one ton of CO_2. It is evident that the Carbon Abatement Cost (*CAC*) may fluctuate considerably in accordance with the technologies employed, the geographical and economic context, and specific local conditions [59]. Consequently, the utilization of this metric, as observed in this paper, is a prevalent methodology employed for the assessment of the cost-effectiveness of measures designed to reduce carbon emissions. Additionally, this approach enables an evaluation of the efficacy of these strategies in terms of climate change mitigation. Furthermore, it can be observed that this value, in addition to the *LCOH* described above, is also affected by the quantity of hydrogen utilized in the H_2NG mixture. The Carbon Abatement Cost is thus defined as the ratio of the difference between the investment and O&M costs for the technology under consideration and the CO_2 emissions avoided with the use of this technology [57], as shown in Equation (15).

$$CAC = \frac{\left(CAPEX_i \cdot crf_i + C_{O\&M,i} + C_{fuel,i,fH2}\right) - \left(CAPEX_{boiler} \cdot crf_{boiler} + C_{O\&M,boiler} + C_{fuel,boiler,0\%}\right)}{CO_{2,\ i,\ fH2} - CO_{2,\ boiler,0\%}} \tag{15}$$

2.3. Techno-Economic Assumptions

In order to determine the different parameters, some techno-economic assumptions are needed. To proceed with the calculation of EP_{nr} and the assessment of CO_2 emissions, two different factors were defined. From Ref. [52], it was possible to determine the value of the factor $f_{nr,NG}$ to be equal to 1.05, while the factor $f_{e,NG}$ was considered equal to 201.4 kg_{CO2}/MWh. Table 4 shows the values of the lower heating value (LHV) and the density of the H_2NG mixture. The LHV mass for hydrogen is defined as 120 MJ/kg and the density ρ of H_2 as 0.0899 kg/Nm^3, as a function of the fraction of hydrogen within the H_2NG mixture. All values in Table 4 are taken from Ref. [49].

Table 4. Density and LHV values for H_2NG mixtures [49].

f_{H2} (% vol.)	ρ_n (kg/Nm^3)	$LHV_{H2NG,mass}$ (MJ/kg)	$LHV_{H2NG,vol}$ (MJ/Nm^3)
0	0.717	49.98	35.857
10	0.655	50.99	33.3822
20	0.592	52.22	30.9074
30	0.529	53.73	28.4326

The price of the mixture was evaluated considering a natural gas price of 93 EUR/MWh [60] and an estimated hydrogen price of 5 EUR/kg [61]. In order to annualize the investment costs, it was necessary to estimate an interest rate of 3% and determine the life cycle of the devices considered. The main techno-economic assumptions related to the two systems used are shown in Table 5.

Table 5. Techno-economic assumptions for the condensing boiler and GAHP systems [46,56,62].

Technology	CAPEX (EUR/kW)	O&M Costs (% of CAPEX)	Lifetime (y)	Ref.
Boiler	228	4.9	15	[46,56,62]
GAHP	429	4.9	20	[56,62,63]

3. Results

In this section, the outcomes of the work are presented and discussed.

3.1. Environmental Effects of H_2 Addition on Boiler and GAHP Systems

In order to verify the impact of H_2NG on the boiler and GAHP, it is first necessary to consider the annual non-renewable primary energy consumption and the CO_2 emissions for both systems.

As illustrated in Figure 2, the utilization of the GAHP results in a reduction in primary energy consumption, even when only NG is burned in the system. This reduction is attributed to the enhanced efficiency of the GAHP system. Indeed, in the NG fuel case, there is a 25.69% reduction in the $EP_{nr,t}$ between the boiler and GAHP, with a value of non-renewable primary energy consumed of 104.93 MWh/y. However, when the H_2NG mixture is employed, a linear decrease in non-renewable primary energy consumption can be observed, reaching 124.19 MWh/y and 93.18 MWh/y for the boiler and the GAHP, respectively, with a 30% volume fraction of hydrogen in the mixture. This phenomenon can be attributed to the progressive increase in the hydrogen volumetric fraction, which consequently results in a reduction in natural gas consumption. Furthermore, it can be observed that as the hydrogen fraction increases, the reduction is marginally greater in the boiler than in the GAHP, due to enhanced boiler efficiency by increasing $f_{H2,vol}$. Indeed, a reduction in $EP_{nr,t}$ of 12.05% and 11.19% for the boiler and GAHP, respectively, is achieved when 30% hydrogen is implemented in the mixture.

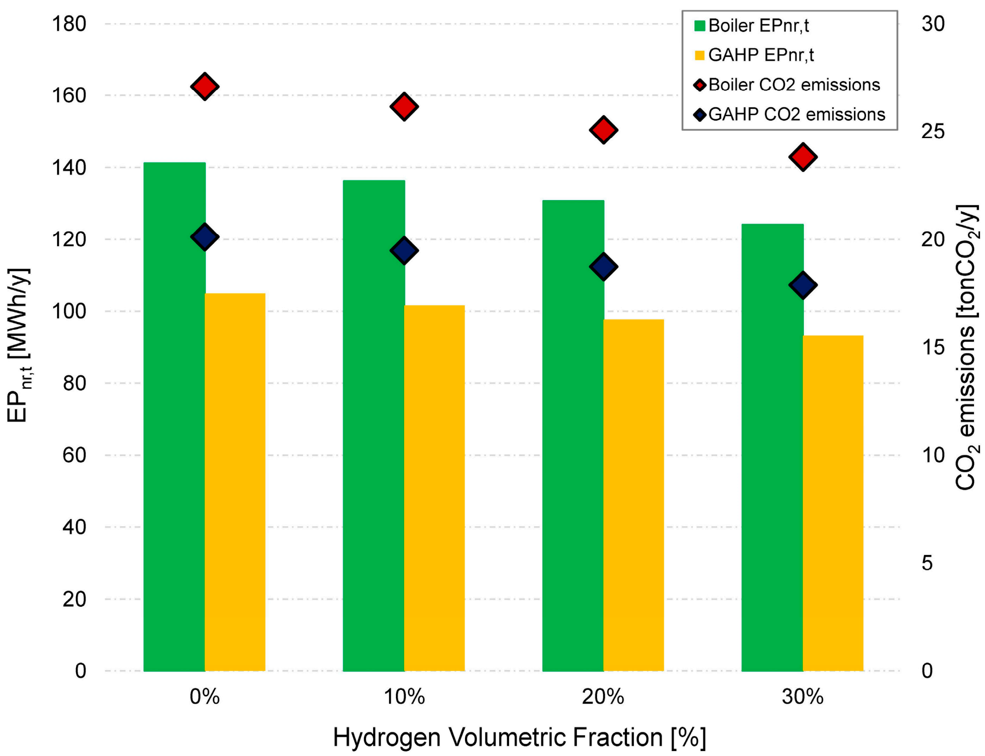

Figure 2. Non-renewable primary energy consumption and CO_2 emissions for the boiler and GAHP systems with changes in hydrogen fraction.

A similar trend and percentage reduction can be observed for CO_2 emissions since they are directly related to the NG consumption recorded for the system. In fact, if we consider the boiler, we can observe a reduction in CO_2 emissions from 27.08 to 23.82 tons per year. Similarly, for the GAHP, we can see a reduction from 20.13 to 17.87 tons per year. This reduction is achieved by increasing the hydrogen fraction within the mixture from 0% vol. to 30% vol. The GAHP is more cost-effective when fueled with natural gas (NG) due to its higher efficiency, which enables it to consume smaller quantities of fuel and consequently produce less carbon dioxide. Even when the two systems are fed the H_2NG mixture with different H_2 volumetric fractions, the GAHP remains a more cost-effective option, with lower CO_2 emissions and a lower consumption of non-renewable primary energy. The results demonstrate that the GAHP is a technology that can reduce emissions by more than 25%. This potential can be further enhanced by implementing policies pertaining to hydrogen injection and by encouraging the decarbonization of the gas grid in the future.

3.2. Levelized Cost of Heat

The *LCOH* parameter is used to evaluate the cost of heat production in the different heating system configurations and hydrogen fraction scenarios. Figure 3 illustrates the variation in the cost of the H_2NG mixture as the $f_{H2,vol}$ changes considering an NG price equal to 93 EUR/MWh. Also, two maximum and minimum values for the price of natural gas were then evaluated according to the data collected in Ref. [60] for residential consumption over the last four years, equal to 121 EUR/MWh and 63 EUR/MWh, respectively. The cost of the H_2NG mixture increases as the $f_{H2,vol}$ increases, due to the higher cost of hydrogen compared to natural gas when considering a price of 5 EUR/kg for the purchase of hydrogen [61]. At $f_{H2,vol}$ of 30%, the fuel price increases by 6.88% when a price for the NG equal to 93 EUR/MWh is considered.

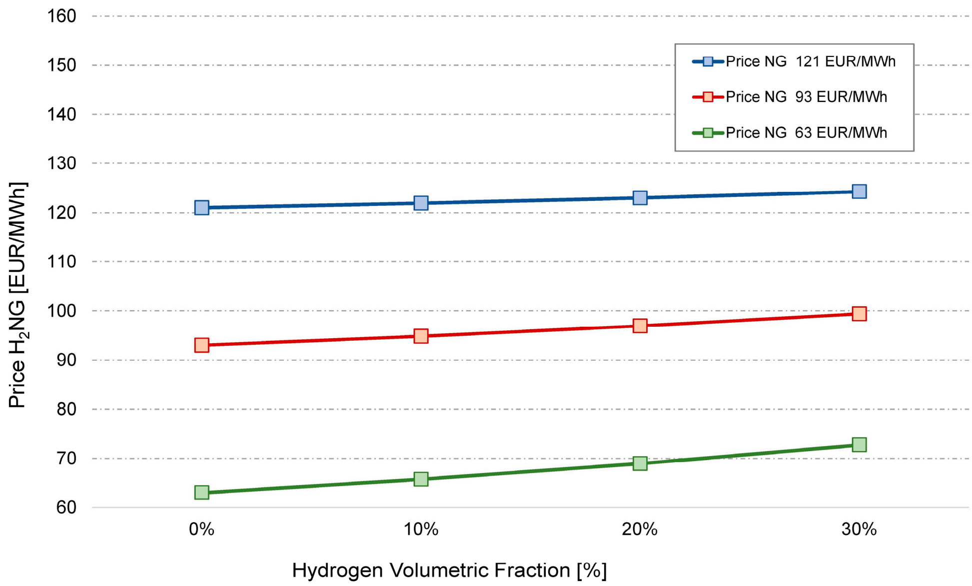

Figure 3. Price variation in the H_2NG mixture with changes in hydrogen fraction and NG price.

In Figure 4, the *LCOH* of the GAHP and boiler systems supplied by different H_2NG blends are depicted. The *LCOH* of the GAHP fed by NG is equal to around 102 EUR/MWh. This cost is lower than the NG boiler due to the higher efficiency of the GAHP system, which allows a lower amount of fuel to be purchased for the same amount of energy produced. Such an efficiency increase allows offsetting of the higher investment cost. As the proportion of hydrogen in the mixture increases, the *LCOH* rises due to the higher cost of hydrogen compared to natural gas. A 30% hydrogen volume fraction for the GAHP results in an increase in the *LCOH* of 4.47% compared to the case with NG alone. In the case of the boiler, the *LCOH* also demonstrates an increasing trend, with an increase of 4.93% observed when an H_2NG mixture with a 30% vol. H_2 content is employed.

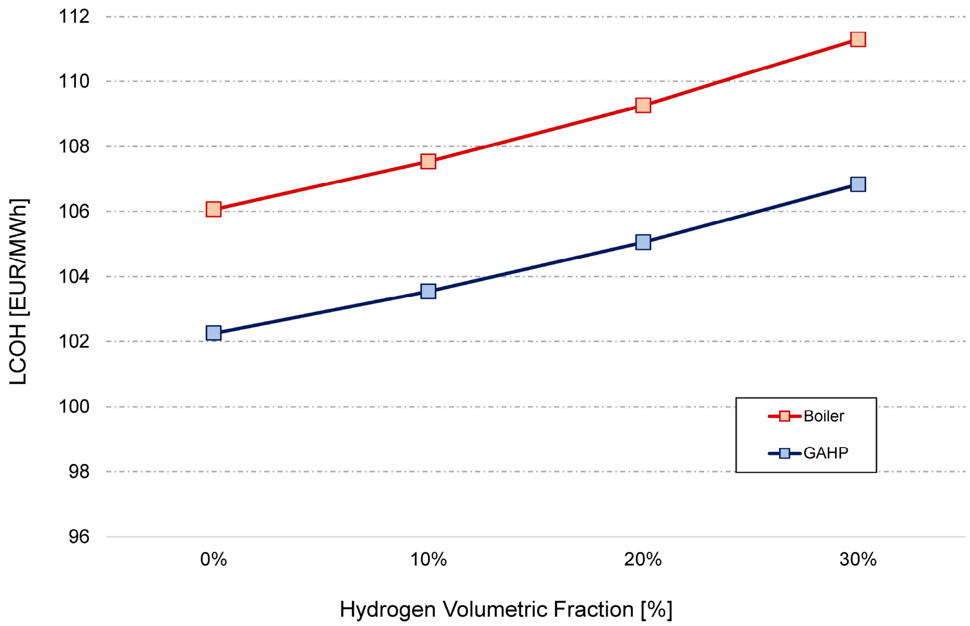

Figure 4. Levelized Cost of Heat for the boiler and GAHP systems with changes in hydrogen fraction.

3.3. Carbon Abatement Cost

Figure 5 shows the *CAC* trend for the two devices as the $f_{\mathrm{H2,vol}}$ varies. The change in boiler efficiency when the $f_{\mathrm{H2,vol}}$ in the H_2NG mixture varies affects this parameter. An increase in efficiency of 0.96% is achieved by using a 30% volumetric hydrogen fraction, resulting in a 27.7% reduction in *CAC* compared to the base case. The decarbonization cost has been calculated with respect to the reference scenario involving the NG boiler. The GAHP can reduce the overall cost of heat production; therefore, the *CAC* achieves negative values representing cost-effectiveness in its use. Furthermore, even when $f_{\mathrm{H2,vol}}$ values up to 20% are considered, the *CAC* of the GAHP is negative. Taking into consideration a $f_{\mathrm{H2,vol}}$ of 30%, the *CAC* is nevertheless very low. From this trend, it can be inferred that the economic advantage of the GAHP is reduced as the volumetric fraction of H2 used increases, due to the higher cost of fuel purchasing. Nevertheless, it is important to note that while the hydrogen price causes costs to rise, the increased quantity of hydrogen used in the heating process helps to reduce CO_2 emissions. In contrast, different considerations must be made about the boiler, as the *CAC* in these scenarios is linked only to the hydrogen blending in the gas grid. Therefore, the emission reduction as well as the increase in blend price is due to the increase in $f_{\mathrm{H2,vol}}$. The current hydrogen prices are correlated with high values of *CAC*, approximately 220 EUR/$\mathrm{kg_{CO2,avd}}$. Such value is correlated to the difference in the purchase cost of the two energy vectors. Furthermore, a slight variation in the *CAC* is observed in the case of the boiler as the fraction of hydrogen involved increases, which is due to the aforementioned increase in efficiency.

3.4. Sensitivity Analysis

The values of the *LCOH* and *CAC* are closely related to the assumptions made about the cost of hydrogen and the cost of NG. In order to assess how the future cost of hydrogen production affects the techno-economic parameters used in this paper, a sensitivity analysis was carried out. The *LCOH* and *CAC* values were evaluated by changing the hydrogen price. The latter can be identified as the Levelized Cost of Hydrogen ($LCOH_2$) production, transmission, and distribution, which represents the total cost of hydrogen distributed evenly over the lifetime of the production plant. In the reference scenario, such cost was considered equal to 5 EUR/kg in order to take into consideration current hydrogen production costs. In the sensitivity analysis, a decrease of up to 1 EUR/kg was considered. This assessment is based on the assumption of a high future market penetration of the hydrogen vector, which would lead to a reduction in purchase costs. As with all scale economies, the increase in hydrogen production would reduce production costs through process optimization and increased efficiency. Achieving such a low price threshold for the purchase of hydrogen would, in fact, allow a much greater penetration of this vector within the energy system.

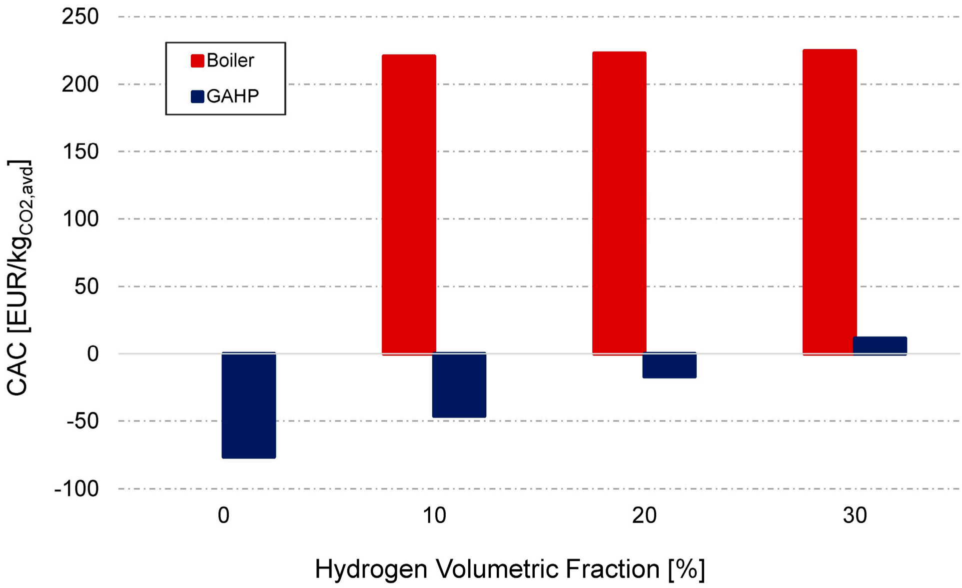

Figure 5. Carbon Abatement Cost for the boiler and GAHP systems with changes in hydrogen fraction.

Figure 6 illustrates the trend of the *LCOH* as the $LCOH_2$ varies. The forthcoming hydrogen price reduction allows the *LCOH* to be substantially reduced in the different scenarios. The two lines representing mixtures with $f_{\mathrm{H2,vol}}$ of 30% exhibit a steeper slope than those representing mixtures with 10% volume fraction. The graph illustrates that, at the same $LCOH_2$, the use of the GAHP is less expensive than the configuration with the boiler. However, this difference decreases as the price of hydrogen decreases. Moreover, it can be observed that, for a given $f_{\mathrm{H2,vol}}$, the GAHP consistently exhibits a lower *LCOH*. In detail, when the $LCOH_2$ is equal to 1 EUR/kg, the most advantageous configuration is that which involves the GAHP fed by a 30% $f_{H2,vol}$ mixture. As shown in Figure 6, the threshold values between the GAHP (10%) and GAHP (30%) lines and between the Boiler (10%) and Boiler (30%) lines, respectively, represent the point at which the purchase cost of hydrogen equals the purchase cost of natural gas. At higher hydrogen prices, blending within the system is no longer cost-effective. The $LCOH_2$ values resulting from the intersection of the aforementioned straight lines are 3.17 EUR/kg and 3.38 EUR/kg for the GAHP and boiler, respectively. The meeting point of the two straight lines for boiler technology is slightly displaced to the right. This phenomenon can be attributed to the variation in the efficiency of the device as the percentage of hydrogen used changes, which therefore balances out the purchase price even for a slightly higher cost.

Figure 7 illustrates the *CAC* trend as a function of the $LCOH_2$ value. The configuration characterized by the boiler is more susceptible to fluctuations in the $LCOH_2$ since the only variable is the fuel cost. Conversely, for the GAHP configuration, there are fixed installation and maintenance costs that are constant beyond the fuel, thus reducing the significance of the variation linked to the $LCOH_2$. The *CAC* values linked to the GAHP system are consistently negative, indicating that the intervention is advantageous across the entire $LCOH_2$ range under consideration, with the exception of the final point on the GAHP straight line (30%), which becomes marginally positive. It can be observed that up to an $LCOH_2$ of 3 EUR/kg, the boiler configuration is more convenient than the GAHP, as no expenditure is required to replace the existing system. Consequently, while Figure 7 indicates that the GAHP configuration is cost-effective for low hydrogen purchase values, Figure 8 indicates that the boiler configuration is more cost-effective.

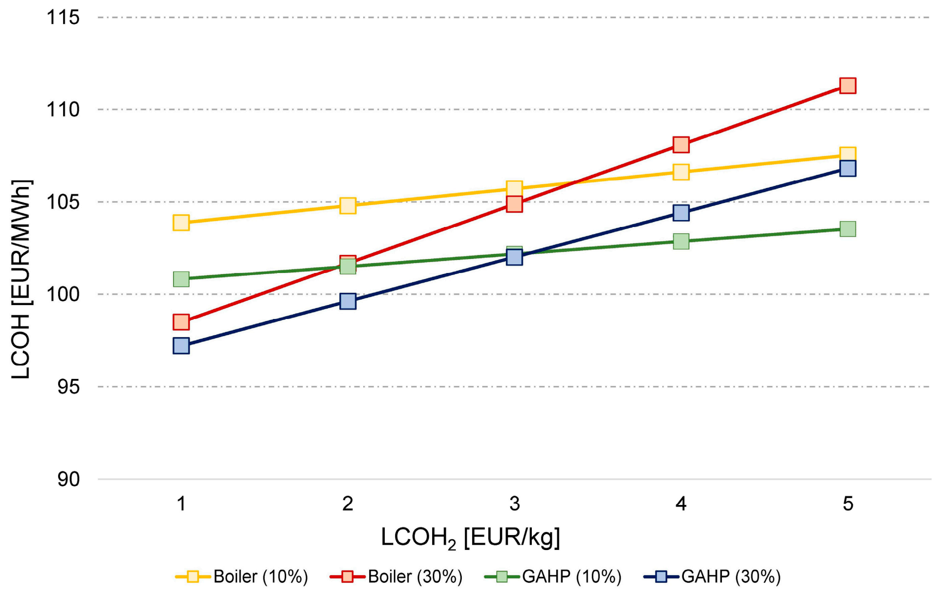

Figure 6. Sensitivity analysis of the *LCOH* for the boiler and GAHP systems with changes in hydrogen fraction and hydrogen price.

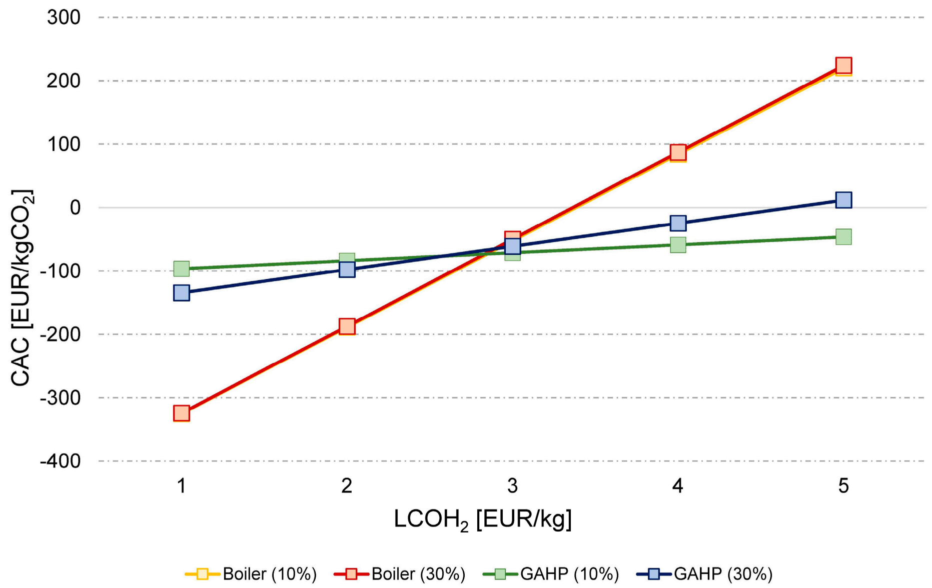

Figure 7. Sensitivity analysis of the *CAC* for the boiler and GAHP systems with changes in hydrogen fraction and hydrogen price.

Figures 8 and 9, on the other hand, show the variation in the *LCOH* and *CAC* as a function of both the price of natural gas and the $LCOH_2$. The NG price was considered to be equal to two values representing the maximum and minimum observed in Ref. [60], equal to 121 EUR/MWh and 63 EUR/MWh, respectively. This analysis allows us to assess how the variation in the cost of the two fuels, taking into account a 30% hydrogen content in the blend, affects the cost of heat production and the reduction in emissions.

As demonstrated in the sensitivity analysis above, an increase in the $LCOH_2$ results in an increase in the *LCOH*. However, Figure 8 shows that the *LCOH* is more influenced by the NG price than by the hydrogen price, as evidenced by the gentle slopes of the straight lines. This is undoubtedly related to the fact that NG still represents the largest volumetric share in the mixture, 70% volumetric in this case, and to the considerable price variations assessed for natural gas. In fact, considering an initial configuration characterized by an NG price of 93 EUR/MWh and a hydrogen price of 5 EUR/kg, the increase that occurs with an NG price of 121 EUR/MWh is 21.27% for the boiler and 16.63% for the GAHP, whereas with a price of 63 EUR/MWh, there is a decrease of 22.79% and 17.81% respectively, for the boiler and the GAHP. This analysis demonstrates that at a low natural gas (NG) cost, the boiler is more cost-effective than the gas absorption heat pump (GAHP), regardless of the Levelized Cost of Heat, despite the GAHP's superior efficiency. This is due to the higher installation cost of the GAHP, which is not offset by the lower cost of NG. On the other hand, a higher NG price demonstrates the advantage of using the GAHP system, which has a higher efficiency.

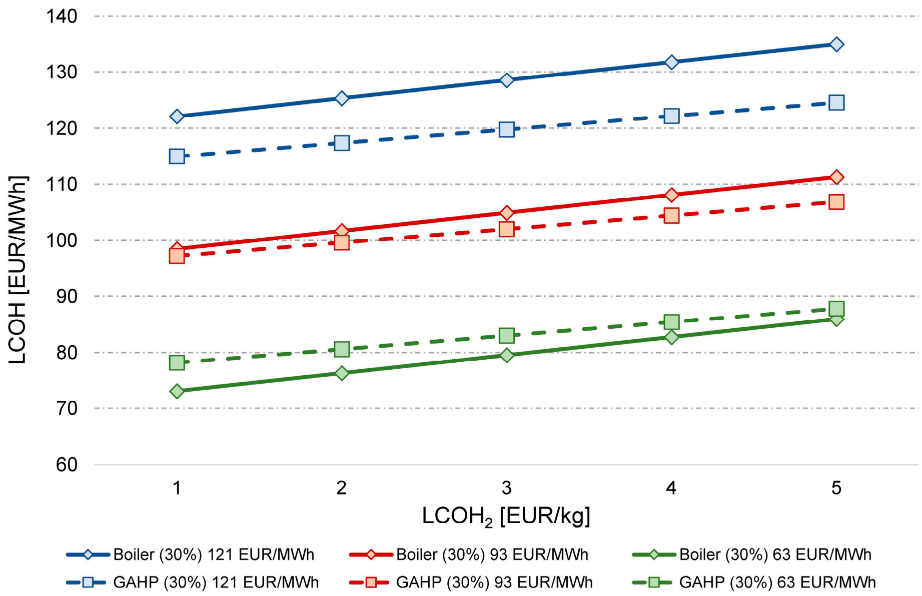

Figure 8. Sensitivity analysis of the *LCOH* for the boiler and GAHP systems with changes in NG and hydrogen prices with fixed H_2 volumetric fraction.

Figure 9 illustrates the variation in the *CAC* as the price of NG and H2 fluctuates, with a constant 30% by volume hydrogen mixture. Upon examination of the boiler and the GAHP individually, it becomes evident that as the cost of natural gas increases, the corresponding values for the Carbon Abatement Cost also increase. For each of the three values considered for the price of NG, it can be observed that for an $LCOH_2$ of 3 EUR/kg, the two technologies are equivalent. This hydrogen price is, therefore, the one that compensates for the purchase difference between the two analyzed energy sources. With an NG price of 121 EUR/MWh, it is evident that an $LCOH_2$ of 4 EUR/kg is sufficient to eliminate the *CAC* and thus the cost of reducing emissions. On the other hand, for a lower NG price of 63 EUR/MWh, an $LCOH_2$ value of around 2 EUR/kg is required to make the use of hydrogen for the boiler economically viable. In contrast, when considering the system with the GAHP, it can be observed that at low NG prices, the *CAC* remains positive for any H2 cost considered, making the system unprofitable.

In summary, the integration of hydrogen carriers into the natural gas infrastructure can help reduce consumption and emissions from heating systems. However, the ultimate goal for decarbonizing the residential sector lies in the electrification of low-temperature heat demand. While GAHPs can reduce emissions in the short term, further investment in natural gas technologies could lead to the risk of creating stranded assets.

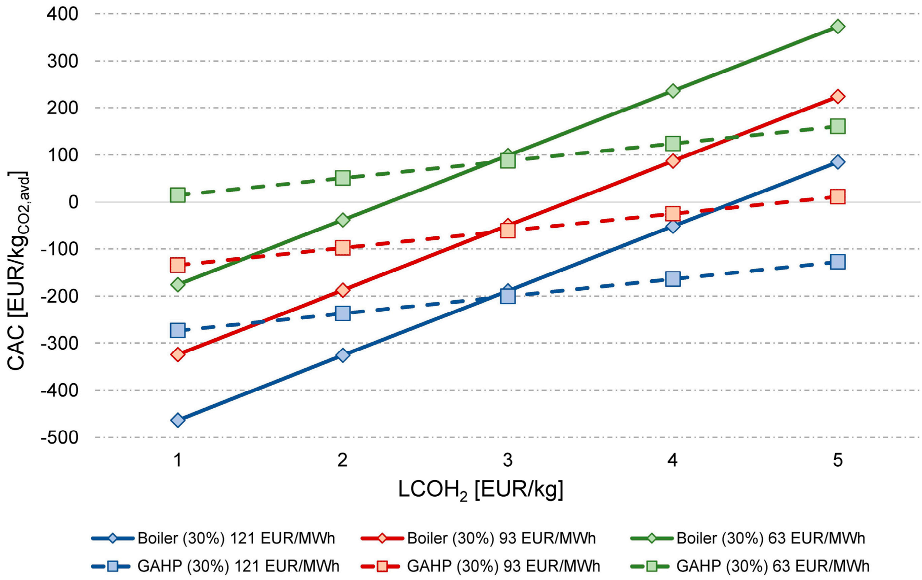

Figure 9. Sensitivity analysis of the *CAC* for the boiler and GAHP systems with changes in NG and hydrogen prices with fixed H_2 volumetric fraction.

This research shows that the costs of decarbonization remain lower when hydrogen prices are below 3 EUR/kg, without the necessity to replace boilers with GAHPs. Consequently, the use of H_2NG blends can effectively reduce the emissions associated with natural gas, with no need for further investments in gas infrastructure. This strategy allows to reduce carbon emissions without disrupting the shift towards electrification of energy consumption. A complete overhaul of heating systems is desirable, but this would be challenging to realize in the short–medium term. Hydrogen blending can contribute to the decarbonization of the not-yet electrified heating demand and in the meantime boost the deployment of hydrogen technologies. Therefore, the implementation of national hydrogen policies should not delay the process of end-use electrification. This approach can be suitable, especially for countries such as Italy, where the heating sector is heavily reliant on natural gas.

In addition, the potential interrelationships and synergies between gas-based and electrification-based decarbonization strategies in the energy transition are issues that can be further explored in future developments of this work.

4. Conclusions

This work aims to assess the technical, economic, and environmental impacts of hydrogen blending on the condensing boiler and GAHP systems in a building. Furthermore, a detailed sensitivity analysis was carried out to evaluate the impact of varying hydrogen and natural gas costs.

The main findings of this study can be summarized as follows:

- The use of the GAHP results in a reduced non-renewable primary energy consumption compared with the boiler of up to 25.69%. The GAHP records an $EP_{nr,t}$ of 93.18 MWh/y when fueled with 30% vol. of H_2.
- At a hydrogen volumetric fraction of 30%, the CO_2 emissions reductions recorded for the condensing boiler and the GAHP are 12.05% and 11.19%, respectively.
- The GAHP records a lower *LCOH* than NG boilers (102.26 EUR/MWh vs. 106.06 EUR/MWh) due to its higher efficiency. The greater the hydrogen rate in the blend, the greater the *LCOH*.
- Due to its reduction in the overall cost of heat production, the GAHP shows negative values of *CAC* at $f_{H2,vol}$ values ranging between 0 and 20%. The economic advantage of the GAHP is reduced as the volumetric fraction of H_2 used increases, which is due

to the higher cost of fuel purchasing. The current hydrogen prices are correlated with high values of *CAC*, which are approximately 220 EUR/$kg_{CO2,avd}$.
- The forthcoming cost reduction in hydrogen will reduce the Levelized Cost of Heat and the decarbonization cost for both technologies. At a hydrogen cost of 1 EUR/kg, the *LCOH* for the boiler and GAHP systems are 98.49 EUR/MWh and 97.22 EUR/MWh, respectively, with a 30% vol. of hydrogen in the mixture.

In conclusion, hydrogen blending in the NG grid allows an immediate reduction in final heating consumption. Nevertheless, H_2NG represents merely a bridging energy carrier toward decarbonization. In the long term, the main solution to decarbonize the building stock is the electrification of the low-temperature heat demand. Therefore, while the GAHP may reduce emissions in the short term, there is a risk of developing stranded assets by investing in additional natural gas-related technologies.

Furthermore, as shown in this article, the overall cost of decarbonization for hydrogen prices below 3 EUR/kg is lower without considering the replacement of the boiler with the GAHP. Therefore, although gas-fired boilers with high volume fractions of hydrogen lead to an increase in overall heating costs, replacement with other gas-fired heating systems may not be the best strategy in the long run. Therefore, blending hydrogen into the gas grid can be a useful policy to reduce emissions from the overall natural gas consumption, including the building sector, without contradicting the process of electrification of energy end-uses.

This policy may have a particular impact in NG-based countries, such as Italy, which has an extensive capillary gas network and where the building stock is mostly supplied by gas boilers. It is challenging to envision a complete replacement of heating systems within the next few years. Consequently, in the near future, hydrogen blending represents an intriguing approach to supporting the decarbonization process while stimulating the development of an industrial hydrogen technology supply chain.

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Data Availability Statement: The raw data supporting the conclusions of this article will be made available by the authors on request.

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

Abbreviations

Nomenclature

C	Costs (EUR/yr)
CAPEX	Initial Capital Expenditure (EUR)
$CO_{2,eq}$	Annual CO_2 equivalent emissions (tCO_2/yr)
E_{th}	Thermal energy required (MWh/yr)
E_{H2NG}	Thermal energy from fuel (MWh/yr)
E_{fH2}	Thermal energy from hydrogen fraction (MWh/yr)
EP	Primary energy consumption (MWh/yr)
$f_{H2,vol}$	Hydrogen volumetric fraction
$f_{e,NG}$	Emission factor (kg_{CO2}/MWh)
$f_{nr,NG}$	Non-renewable primary energy factor

i	interest rate (%)
P	Thermal power (kW)
P_{H2NG}	Thermal power from fuel (MW)
P_{H2}	Price of hydrogen (EUR/kg)
P_{NG}	Price of natural gas (EUR/MWh)
t	Lifetime (yr)
$y_{i,H2}$	Hydrogen Mass Fraction
ΔT	Temperature difference between exhaust gas and external air (°C)
η_{boiler}	Boiler efficiency
η_{GAHP}	Gas Adsorption Heat Pump efficiency
η_{cond}	Condensation efficiency
η_c	Combustion efficiency
Subscripts	
D	Demand
fuel	Fossil fuel
latent	Latent heat losses
loss, sens	Sensible heat losses
nr	Non-renewable energy
O&M	Operation and maintenance
th	Thermal
Abbreviations and Acronyms	
CAC	Carbon Abatement Cost
crf	Capital recovery factor
EFC	Energy Fraction of Condensation
GAHP	Gas Adsorption Heat Pump
GHG	Greenhouse gas
H_2NG	Hydrogen-enriched natural gas blends
HHV	Higher heating value
HVR	Heating Value Ratio
LCOH	Levelized Cost of Heat
$LCOH_2$	Levelized Cost of Hydrogen
LHV	Lower heating value
NG	Natural gas
SNG	Synthetic natural gas

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