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Article

Industrial Decarbonization through Blended Combustion of Natural Gas and Hydrogen

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Abstract: The transition to cleaner energy sources, particularly in hard-to-abate industrial sectors, often requires the gradual integration of new technologies. Hydrogen, crucial for decarbonization, is explored as a fuel in blended combustions. Blending or replacing fuels impacts combustion stability and heat transfer rates due to differing densities. An extensive literature review examines blended combustion, focusing on hydrogen/methane mixtures. While industrial burners claim to accommodate up to 20% hydrogen, theoretical support is lacking. A novel thermodynamic analysis methodology is introduced, evaluating methane/hydrogen combustion using the Wobbe index. The findings highlight practical limitations beyond 25% hydrogen volume, necessitating a shift to "totally hydrogen" combustion. Blended combustion can be proposed as a medium-term strategy, acknowledging hydrogen's limited penetration. Higher percentages require burner and infrastructure redesign.

Keywords: blended combustion; hydrogen/methane mixture; industrial burners; thermodynamic analysis; decarbonization

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1. Introduction

The topic of energy transition is one of the most relevant today. There are many studies and projects addressing this issue, but it is often presented in an overly monothematic way, frequently focusing only on the use of electricity. However, just as energy uses are complex and varied, the solutions to the problem must also encompass a wide spectrum of possibilities. These solutions particularly concern two main areas: civil uses and mobility. A sector that is somewhat underestimated in its potential is industrial energy use. This sector involves significant energy consumption, and since most of the energy used is of fossil origin, it has strong environmental impacts.

Referring to the industrial sector, data from the IEA report indicate that approximately 9 Gigatons of carbon dioxide (CO_2) were emitted by industries, primarily energy-intensive ones [1].

Recent discussions on hydrogen, particularly green hydrogen, have been driven by international directives addressing climate change. Ambitious projects like Europe's Fit for 55 and the European Green Deal position hydrogen centrally in the energy transition. However, the Green Deal remains vague on hydrogen production sources, referring generically to "clean hydrogen". Blue hydrogen (produced from natural gas with CO_2 capture) is identified as a medium-term option, but the Ukraine war in early 2022 pushed Europe to invest in green hydrogen (produced from renewable energy).

Today's perspective on renewable-sourced hydrogen has significantly evolved. Renewables have established themselves in the electricity market with competitive costs. Hydrogen can serve as a valuable vector to transfer green energy to sectors primarily using thermal energy given the infeasibility of complete electrification. Advances in various technologies make hydrogen a more viable option today than two decades ago. However, it is crucial to identify the best paths to pursue, considering the overall energy balance and avoiding a rebound effect where hydrogen integration leads to increased fossil energy use.

The utilization of hydrogen in the industrial sector could play a pivotal role in the energy transition and decarbonization efforts, especially in hard-to-abate sectors. Hydrogen produced through renewable sources holds promise as both a chemical element integrated into industrial processes and as a fuel, either as a partial or complete substitute for natural gas. The adoption of new technologies often hinges on gradual rather than revolutionary shifts, with advancements built upon the existing frameworks. In industries where process temperatures exceed 1500 °C (e.g., steel and glass), fully electric heating is not convenient, and combustion technology will remain essential for industrial heating. Achieving CO_2-neutral industrial heating requires low-emission combustion technologies, with hydrogen combustion being a promising solution. Green hydrogen, produced from renewable energy sources, is recognized as a potential carbon-free fuel for high-temperature industrial processes [2,3].

Hydrogen can be produced from renewable energy sources via electrolysis. Blending renewable hydrogen with conventional fuels supports the integration of renewable energy into the energy mix, enhancing energy security and sustainability [4].

Blending hydrogen with the existing fuels can be a transitional strategy to gradually shift towards a hydrogen-based energy system. It allows the use of the existing infrastructure while reducing the reliance on fossil fuels. One of the methods for introducing hydrogen in these sectors is its use as a fuel. An interesting possibility is the use of hydrogen in blended combustions, for burners, boilers, and furnaces [5–7]. Hydrogen's role as a co-fuel mixed with methane presents distinct challenges due to its differing chemical and physical properties. When combined, hydrogen alters combustion dynamics and flame characteristics, such as increased flame speed, leading to compact, turbulent flames and potential issues with backfire and flashbacks [8]. Adjustments in combustion management become necessary, including air staging to widen the flammability range and mitigate ignition energy requirements. Despite reduced CO_2 emissions, high temperatures can elevate NO_X emissions, prompting recommendations for future burner configurations emphasizing Dry Low NO_X or flameless designs. The development of new combustion technologies is of high interest for natural gas/hydrogen co-fired furnaces and boilers to control source NOx production economically and efficiently [9]. Additionally, hydrogen's small size and chemical reactivity with steel alloys pose challenges in piping and storage, necessitating careful consideration in infrastructure design. Ultimately, these factors highlight the complexity of harnessing hydrogen's potential while ensuring efficient heat release. When blending or replacing one fuel with another, the power range and stability of combustion are influenced. Furthermore, the two gasses are at different densities, which influences the flow rate that passes through the same nozzle and the heat transfer rate. For any combustion system (boiler or furnace), one of the most important parameters is the heat release rate. Similar gas volume flow rates will give very different heat release rates for different gasses. Furthermore, since most systems supply gas through a fixed nozzle, the flow rate varies as a function of density, which in the case of natural gas and hydrogen at atmospheric conditions is an order of magnitude different.

Some papers analyze the possibilities of using hydrogen in hard-to-abate industries (e.g., steel, glass, and paper), focusing on hydrogen as an alternative fuel in burners, a reducing agent, and an energy storage system linked to process electrification and the use of renewable energy [4]. Several contributions provide support through CFD and the Multiphysics modeling of combustion in industrial boilers using hydrogen-rich fuels and the possible integration of catalytic units in hard-to-abate technologies [10]. Low-energy catalytic processes discussed in the recent literature could be applied to optimize the hydrogen/methane combustion processes [11]. For example, catalysts that enhance the efficiency of hydrogen production or the stability of hydrogen/methane blends could significantly improve the feasibility and effectiveness of industrial decarbonization efforts. Other articles try to analyze hydrogen use in specific industries (e.g., steel, glass, and paper), focusing on hydrogen as an alternative fuel in burners, and identifying upper limits for hydrogen blends [12]. Luzzo et al. tested mixtures with 30% and 50% of hydrogen with natural gas in the existing industrial burners and have shown that both can be used, although the burner results are more stable with 30% vol of hydrogen [13]. Glanville et al. highlighted the relevance of using higher hydrogen blends [14]. Leicher et al. studied the impact of hydrogen use on burner performance considering heat transfer rate, efficiency, flame shape, and NOx emissions. They also evaluated the potential effects of advanced measurement and control technologies on ignition speed and excess air ratio [15].

Starting from an extensive review of the existing literature, this study examines the concept of blended combustion, specifically focusing on hydrogen/methane mixtures in different percentages. Notably, numerous industrial burner manufacturers already offer products capable of accommodating such blends, with claims of up to 20% hydrogen by volume sustaining the existing burner technologies. However, the theoretical underpinnings supporting this threshold remain elusive given the distinct thermophysical properties and flammability characteristics of hydrogen and methane.

The paper is structured as follows: After the introductory section, Section 2 delves into the significance of thermal energy use and its importance in global decarbonization efforts. Section 3 provides an overview of blended combustion technology, reviewing current advancements and state-of-the-art practices. Then, a thermodynamic analysis explores the potential of hydrogen as an alternative fuel in burners, focusing on mass and energy balances, employing idealized models of natural gas as methane, and introducing the use of synthetic indicators. The following section evaluates the interchangeability of natural gas/hydrogen blends using synthetic indicators, considering the variations in natural gas composition. The Section 6 summarizes the findings, emphasizing the potential impact of blended combustion on reducing natural gas usage. A final section that outlines the main conclusions drawn from the study is provided as usual.

2. Thermal Energy Use and Its Importance for Decarbonization

If we analyze the data related to global energy uses, a rather interesting fact stands out. The main uses of energy worldwide (about 50%) are for thermal energy. In terms of primary energy, the use of electricity is often much lower; in most industrialized countries, it can be traced back to a share of less than 20%. It is rather curious that the bulk of the initiatives related to decarbonization focus on electricity use. As clearly emerges from the data reported in Table 1, if we take into consideration the data relating to the use of energy in the last 40 years at the world level, there has certainly been a significant increase in the use of electricity. However, this has not greatly influenced the percentage of electricity compared to the total energy used, which has only gone from around 10.4% to about 15% [16]. The other energy uses are primarily related to mobility, mainly connected with petroleum, and thermal products, mainly connected to coal and natural gas.

Table 1. Energy consumption in the world and the share of electricity generation during the last 40 years: data rearranged from [16].

Year	Total Energy Use [TWh]	Electricity Generation [TWh]	Share of Electricity Generation [%]
2023	183,320	27,479	0.150
2019	174,458	26,771	0.153
2015	163,146	24,006	0.147
2011	156,261	21,957	0.141
2007	147,434	19,712	0.134
2003	130,139	16,627	0.128
1999	119,843	14,926	0.125
1995	112,842	13,382	0.119
1990	106,656	11,961	0.112
1985	94,876	9886	0.104

The data on global energy use show that electricity accounts for less than 20% of the total energy consumption, as shown in Table 2. Even considering the European Union, which serves as an emblematic example of a continent with strong political momentum towards energy transition, the percentage of electricity use does not significantly increase. Figure 1, which examines the last 40 years, highlights that the increase in electricity use is not substantial considering that a large portion of non-electric energy consumption comes from non-renewable sources. It is, therefore, clear that the ambitious objectives set by international organizations will be unachievable, and not even approachable, if only the contribution of renewable energy in the electrical sector is considered. The path towards energy transition must focus not only on increasing electric uses but, more importantly, on addressing non-electric sectors. This is evident, for example, in the civil and residential sectors, where the penetration of heat pump systems is increasing, effectively transferring thermal uses into electrical ones. The whole topic of ZEBs (Zero Energy Buildings) or n-ZEB (nearly ZEB), which is diffusely discussed in the recent literature [17], revolves around the powering of heat pump systems using renewable energy, usually photovoltaic systems. The topic, although interesting and noteworthy, nevertheless encounters a significant problem: in winter conditions, when there is a greater need for thermal energy to heat buildings, solar radiation is often reduced. Meanwhile, the integration of heat pump systems with photovoltaic systems is certainly an excellent solution for summer cooling. Anyway, the electricity used for air conditioning represents only 10% of the total (2200 TWh on a total of 27,500 TWh as in Table 1).

Table 2. Total energy consumption and the share of electricity generation in Europe (27) in the last 40 years: data rearranged from [16].

Year	Total Energy Use [TWh]	Electricity Generation [TWh]	Share of Electricity Generation [%]
2023	15,662	2773	0.177
2019	17,155	2875	0.168
2015	17,049	2870	0.168
2011	17,745	2908	0.164
2007	18,754	2947	0.157
2003	18,582	2799	0.151
1999	17,877	2587	0.145
1995	17,345	2409	0.139
1990	17,442	2273	0.130
1985	16,793	2023	0.120

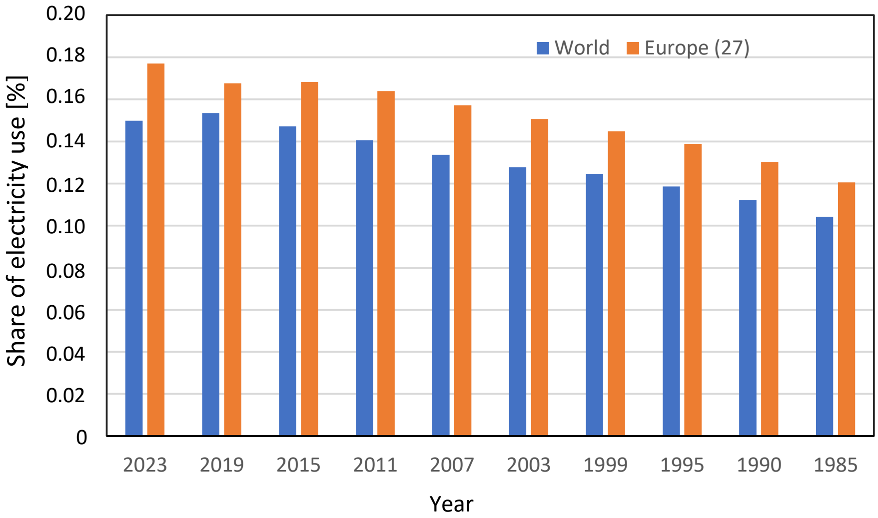

Figure 1. Percentage of electricity with respect to total energy uses: a comparison between the world and Europe (27).

To overcome these structural limits, the recent literature has given much space to the topic of energy storage in its various forms and to the integration of energy users. This theme has taken on various connotations (virtual power plants, microgrids, and energy communities), even if it does not seem to address the real problem, which is the mismatch between energy use and renewable production.

Furthermore, the topic of renewable energy is often trivialized. The assumption that renewable energy resources cost nothing is not true because all forms of energy have a cost. In the case of renewable sources, while it is true that the resource itself has no costs, the installed power does cost a lot, and this affects system costs.

Returning to the use of thermal energy, this is only partly linked to the civil sector. In many cases, energy is used for high-temperature industrial processes, where it is quite difficult to think simply about replacing this energy with renewable energy.

While there are alternatives such as solar for process heat at temperatures below 60 °C, which are nevertheless relevant—as also analyzed by one of the authors of this work in a recent article [18]—the use of solar heating is certainly not conceivable for numerous applications where the temperature exceeds 150–200 °C. This is particularly true in the sectors conventionally referred to as hard-to-abate.

In those sectors, energy transition could only happen by progressively electrifying thermal processes, but this is not always possible due to technological challenges. In certain energy sectors, hydrogen represents the only real alternative to allow renewable energy to penetrate significantly. Therefore, in this decarbonization process, the role of hydrogen produced from renewable sources (green hydrogen) can become very important, particularly its use as a fuel for high-temperature processes. Initially, this could be carried out by mixing it with natural gas, with increasingly higher percentages of hydrogen. Among other things, this approach would have the advantage of allowing a progressive penetration of hydrogen in the thermal energy sector.

3. Blended Combustion of Hydrogen and Natural Gas

The high thermal demands of industrial furnaces, mainly in the various hard-to-abate sectors (steel, chemical and petrochemical, cement, glass, paper, and cardboard among others) are traditionally met by fossil fuels, particularly natural gas. Hydrogen can be used as a fuel to produce thermal energy too.

Almost all the heat high-grade requirements are ($T > 400$ °C), with temperatures reaching up to 1500 °C or more, where any electrification of the heating sources is complex and requires a complete redesign of the equipment with high capital costs. In this case, the burners can be slightly modified to use hydrogen as a fuel at a relatively low capital cost.

Ensuring that hydrogen can meet similar conditions without altering oven characteristics or final product quality is paramount. Transitioning from the existing burners and ovens to gradually incorporate hydrogen blending before fully transitioning to hydrogen is an intriguing strategy. However, the chemical and physical properties of hydrogen (H_2) mixed with CH_4 result in notable changes to flame characteristics compared to using methane alone, particularly as the hydrogen content increases. A simple schematic representation of an air furnace with blended combustion is provided in Figure 2. When planning to implement blending techniques in production line burners, it is essential to anticipate potential changes in heat exchange methods based on the percentage of hydrogen in the mixture. This might require modifications to the furnace design or exhaust recovery pathways. Considering its thermophysical properties [19], the presence of hydrogen alters combustion for several different reasons:

- Hydrogen delivers about 2.5 times more heat per unit mass than CH4 but low density: higher heating value (HHV) and lower heating value (LHV) are 2.4–2.6 times the corresponding of methane.
- Hydrogen's faster flame speed results in shorter, more compact, and turbulent flames.
- Hydrogen raises combustion temperatures, which may exceed oven thermal specifications.

- Hydrogen expands the flammability range of mixtures, increasing reactivity and the risk of flashbacks.

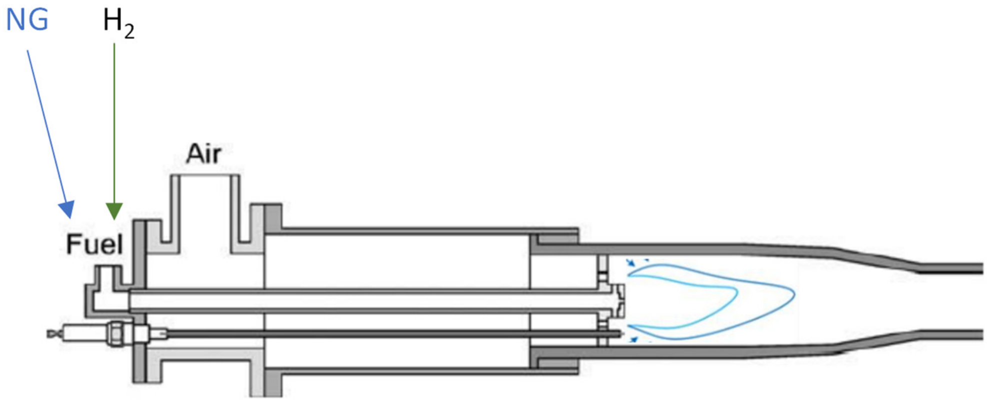

Figure 2. Air furnaces with premixed blended combustion (a synthetic and schematic view).

Burner manufacturers currently report the feasibility of blending with up to 20% H_2 by volume without requiring changes to burner technology or operating conditions at temperatures exceeding 750 °C despite changes in combustion properties.

There are various types of boilers available on the market that allow hydrogen to be used even partially as a fuel. In detail, there are boilers (or furnaces) that can be converted from natural gas to hydrogen, partially converted boilers that can operate with a mixture of natural gas and hydrogen (generally up to 20%), and 100% hydrogen-ready boilers that can operate exclusively with hydrogen gas. To date, the actual use of boilers designed for hydrogen is rather limited, also due to the reduced availability of infrastructure for the production and transport of hydrogen; however, it is likely that this sector will be strongly developed in the coming years. Fuel-switching considerations are crucial when transitioning to hydrogen. A thorough evaluation of the entire system (boiler or furnace) is necessary to ensure a seamless and effective integration.

This involves assessing the compatibility of the existing infrastructure with hydrogen, examining the combustion characteristics, and identifying any required modifications or upgrades. Factors such as burner design, fuel delivery systems, and safety measures must be carefully analyzed. Additionally, the impact on overall system efficiency, emissions, and operational costs needs to be considered. A comprehensive approach ensures that the shift to hydrogen not only supports decarbonization goals but also maintains the reliability and performance of the combustion system.

Tables 3 and 4 show some boilers (Table 3) and burners (Table 4) which allow the use of the blends of natural gas/hydrogen up to 100% H_2, respectively. As can be seen by observing the data reported in Tables 3 and 4, two points of view are being compared: that of creating blended combustion with hydrogen fractions lower than 20% and that of commercialized systems capable of operating with 100% hydrogen. The first type tries to modify the existing systems as little as possible and guarantees a certain versatility of use, while the second type still requires a complete modification of the thermal generation system. Burner manufacturers generally indicate that up to 20% hydrogen by volume can be mixed with methane while maintaining the same burner technology, provided the process parameters meet the product specifications. In applications where direct flame contact with the product is necessary, such as many processes in the steel industry, the presence of hydrogen increases the flame temperature. This can result in the output product reaching excessively high temperatures, potentially causing mechanical issues. Additionally, hydrogen in the mixture results in shorter flames and expands the flammability range, increasing reactivity, diffusivity, and reaction speed compared to pure methane.

Table 3. Examples of "H_2 ready" boilers currently available on the market.

Manufacturer	Series	Typology	Power [MW]	Max H_2 Allowed
Viessman	VITOMAX	Boilers-Hot water	0.65–22	100%
Bosch industrial	UNIMAT	Boilers-Hot water	0.65–38	100%
UNICAL	MODULEX	Boilers-Hot water	<1.5	20%

Table 4. Examples of "H_2 ready" burners currently available on the market.

Manufacturer	Series	Typology	Power [MW]	Max H_2 Allowed
MACCHI ABS	-	Gas burners	35	100%
SAAKE	TERMINOX	Gas burners	3–28	20%
SAAKE	ATONOX	Gas burners	7–100	20%
SAAKE	SKVG	Gas burners	1–55	100%
SAAKE	SSBG	Gas burners	1.5–90	100%
Bloom Engineering		Premix burners	0.073–41	8%
Bloom Engineering		HTR burners	0.012–1.3	100%
Bloom Engineering		Regenerative burners	0.7–15	100%
Bloom Engineering		Radiant tube burners	n.a.	100%
Bloom Engineering		Baffle burners	0.075–117	100%
Bloom Engineering		Air Stage burners	0.050–10	100%
GF-ELTI	H2BURN	Auto-recuperative burners	0.1	100%
GF-ELTI	H2BURN	Regenerative burners	0.3	100%

Hydrogen burners are still in the research phase, as a complete replacement with hydrogen requires new gas lines, control systems, and technology that are very different from the traditional ones, involving some relevant additional problems, as evidenced in Table 5. Combustion management is difficult and still under study, but as has happened in the past when faced with the use of new fuels, various analyses are necessary for the complete knowledge of the fuel.

Table 5. Problems connected to totally hydrogen combustion and possible solutions.

Cause/Problem	Effect	Solution
High flame speed	Flashback, flame detachment problems, and overheating burner surface	Higher gas injection pressure
High flame temperature	Increase in thermal NOx and difficult to keep below the minimum emission limits	Special materials in the construction of burner or furnace
Extremely flammable	Risks of leaks and explosions	Significant design modifications and advanced safety protocols
Short and compact flame shape	Higher temperatures in localized areas: heat distribution throughout the boiler or furnace may be difficult	Enhanced combustion control systems and the use of flame stabilizers and spreaders
The flame is not bright	Incomplete combustion, less radiative heat transfer, but higher convective heat transfer	Optimize air/fuel ratio, use flame retention heads, and install flame stabilizers
The small size of the H_2 molecule	Hydrogen embrittlement	Special materials less sensitive to hydrogen embrittlement
Hydrogen combustion has a high noise intensity	High noise intensity	Sound insulation and dampening and the use of acoustic enclosures

A relevant obstacle to the diffusion of totally hydrogen energy conversion systems may be represented by the cost of H_2-ready boilers which can be higher than traditional natural gas boilers and furnaces. Furthermore, we should not ignore the fact that in the case of devices totally powered by hydrogen, there is a risk of losing flexibility and the supply of green hydrogen is certainly not simple if we consider the average power of industrial furnaces.

As discussed before and reminded in Table 5, one of the primary technical challenges in hydrogen/methane combustion is maintaining flame stability. Recent advancements in burner design, such as the development of premixed burners, ensuring a more uniform fuel/air mixture, have shown promise in enhancing flame stability, reducing the occurrence of hotspots, and improving combustion efficiency [20].

Backfire risks are critical concerns too. Backfires can cause significant damage to combustion systems and pose safety hazards. To mitigate these risks, modern combustion systems are incorporating advanced control systems that can dynamically adjust fuel flow and air intake to prevent conditions that lead to backfire [21].

Operational adjustments, such as optimizing the fuel/air ratio and maintaining appropriate operating temperatures, are also crucial in addressing these challenges [22]. The regular maintenance and monitoring of combustion systems can help detect and rectify potential issues before they escalate. By integrating these technological advancements and operational adjustments, it is possible to mitigate the technical challenges associated with hydrogen/methane combustion, thereby enhancing the feasibility and safety of using hydrogen as a transitional fuel.

Although evaluating the effectiveness of the two strategies (blended combustion or totally hydrogen combustion) must consider the specific application context, the next section aims to provide a more detailed analysis of the decarbonization potential of the blended combustion strategy.

4. Thermodynamic Analysis of Hydrogen as an Alternative Fuel in Burners

The unique physical/chemical properties of hydrogen (higher diffusivity, larger flame speed, higher adiabatic flame temperature, $T_{ad,f}$, etc.) compared to hydrocarbon fuels present significant challenges for its use in burners and combustors [23].

Table 6, drawn up by the authors on the basis of various sources available in the literature, highlights, albeit in a fairly qualitative manner, some relevant differences between the two fuels, from which the relevant quantitative differences between some parameters, such as Minimum Energy required for Ignition (MEI), flame velocity in air, and diffusion coefficient in air, can also be highlighted, which will obviously have an influence on the phenomenon of combustion.

Table 6. Properties of the two fuels (hydrogen and methane) considered in blended combustion (at p = 1 bar and T = 298 K).

Fuel	LHV [MJ/kg]	HHV [MJ/kg]	LHV [MJ/m^3]	Density (ρ) [kg/m^3]	$T_{ad,f}$ [K]	Min. Energy for Ignition [mJ]	Flame Velocity in Air [m/s]	Diffusion Coefficient in Air [cm^2/s]
Methane (CH_4)	50	55.8	32.289	0.646	2220	0.29	0.4	0.16
Hydrogen (H_2)	120	144	9.687	0.08076	2400	0.02	3.2	0.61

A lot of research activity has been conducted on this topic, providing experimental data and knowledge for the design of hydrogen-fueled burners and combustors, focusing mainly on the analysis of premixed hydrogen/air combustion in swirl burners. The key areas of investigation include the effects of swirl level and fuel injector configuration on flame structure and combustion stability (flashback and blow-off), and NOx emissions. The experimental studies of H_2 combustion in premixed and non-premixed atmospheric swirl burners have been conducted too. It is also possible to find several modeling activities of domestic and industrial boilers, including CFD analysis. The enrichment of green fuels with hydrogen in variable fractions to assess the performance and emissions of small-scale energy systems for stationary use have been investigated too. But the first relevant evaluation concerns energy balance. For this reason, assimilating natural gas with methane, the equivalent composition of the fuel blend can be identified as a function of hydrogen percentage by mole or weight. Assuming an ideal combustion by using the properties of components in Table 6, a model of combustion can be developed.

The analysis of hydrogen blends can be conducted based on a preliminary energy analysis based on a thermodynamic model. For a well-defined combustion device, the idea is to achieve equivalent thermal input in the burners [19]. Hydrogen and methane (the primary component of natural gas) not only have significantly different lower heating values (LHV) which are approximately 10 MJ/Nm^3 for hydrogen versus 33 MJ/Nm^3 for methane), but they also require different amounts of oxygen for complete combustion due to their different molecular weight and combustion characteristics.

According to the basic oxidation reaction, considering combustion with air, the following stoichiometric equation can be considered. From the mass balance, it means that for 1 mole of methane, 2 mole of oxygen is required (approximately 9.52 moles of air):

$$CH_4 + 2\ (O_2 + 3.76\ N_2) ==> CO_2 + 2\ H_2O + (7.52)\ N_2 \tag{1}$$

From the balance expressed by Equation (1), it is possible to observe the equivalence between the molar production of CO_2 with respect to the molar use of CH_4. Considering that the ratio between the molar weight is 2.75 (44 for CO_2 and 16 for CH_4), this means that for each kg of methane burned, 2.75 kg of CO_2 is produced and consequently emitted because of the oxidation process. For this reason, we can appreciate how for each unit of energy saved, 2.75 units of CO_2 are emitted, so each reduction in mass flow rate of natural gas corresponds to a reduction in carbon dioxide emissions.

Another relevant difference connected to the different combustion temperatures is represented by the changes in flue gas composition with a reduction in the flue gas flow. The change in flue gas composition and flame temperature can affect the radiation flux for two relevant reasons. This topic is extensively discussed in various articles in the literature, highlighting the critical impact of combustion temperature on flue gas composition and radiation flux, such as [24,25]. The topic is certainly well explored in the literature, but it can also be understood fairly easily from some theoretical considerations. The heat radiation varies according to the following law:

$$q_{flame\ radiation} = \varepsilon_{flame} \cdot \sigma \cdot T^4_{flame} \tag{2}$$

The combustion of a blended mixture of methane and hydrogen determines a variation in the temperature of the flame, T_{flame}, and in the emission coefficient (ε_{flame}) of the flame gasses which depend upon the partial pressures of the gas composition (it mainly depends on the quantity of carbon dioxide and water, on the absorption path length, and on the temperature.

$$\varepsilon_{flame} = \varepsilon_{CO} + \varepsilon_{H2O} - \Delta\varepsilon_{overlap} \tag{3}$$

The emissivity of the two substances, including pressure and overlap functions, can be obtained from empirical relations derived from spectral data.

The flame temperature increases with increasing hydrogen content, the water fraction increases, and the CO_2 fraction in flue gas decreases with increasing hydrogen content. As a result, the estimated net radiation flux from the flame increases with increasing hydrogen content. As we have said and as can be appreciated by analyzing some of the characteristic parameters of the two fuels, the problem cannot be analyzed only from the point of view of mass and energy balances while recognizing this as a relevant assumption.

A preliminary analysis of the combustion of methane/hydrogen mixtures can be carried out using synthetic indicators. The concept of gas interchangeability using empirical indicators was developed before the Second World War [26]. Gas interchangeability can be defined as the degree of change in the performance of a combustion device when the fuel is varied. Two fuels can be considered interchangeable when they can be used in the same combustion device without the operating conditions and other operating parameters relating to both combustion performance and safety varying significantly. The concept of interchangeability has been extended since the early 1950s focusing the attention on flame stability, analyzing the tendency to release carbon monoxide or soot; however, these analyses have not undergone major evolutions over time [27,28].

Meeting gas interchangeability criteria ensures that any gas-fired equipment using a replacement gas continues to meet the performance standards for which it was originally approved [29]. However, the approach based on the use of synthetic indicators appears to be closely linked to a commercial approach to the combustion problem. However, some of the indicators found in the literature appear rather interesting and worthy of consideration.

Among the others, for example, is the Wobbe index (WI), a parameter for defining fuel interchangeability. The Wobbe index was introduced as an important gas quality criterion when interchanging gaseous fuels for engines just in the late years of the last century [30].

For some years, it has also been proposed for possible use in combustions that involve the progressive replacement of natural gas with hydrogen [31].

This indicator considers the idea that gasses with similar Wobbe numbers produce equivalent heat release rates, facilitating comparisons and optimizing burner performance. According to the vision diffused in the literature, this preliminary analysis becomes crucial for ensuring optimal burner performance, including factors such as flashback prevention, flame propagation, and heat transfer capacity [8]. Wobbe index, which serves as a metric for fuel interchangeability [8], can be defined for a specific fuel, such as natural gas, as follows:

$$WI = \frac{HHV}{\sqrt{\frac{\rho_{NG}}{\rho_{air}}}} = \frac{HHV}{\sqrt{RD}} \tag{4}$$

where RD is the ratio between the density of natural gas, ρ_{NG} and air, ρ_{air}. If the same concept is applied to a mixture of hydrogen and natural gas, the Wobbe index can be defined as follows:

$$WI_{Mix} = \frac{HHV_{Mix}}{\sqrt{\frac{(1-x\%)\rho_{NG}+x\%\rho_{H_2}}{\rho_{air}}}} \tag{5}$$

$$HHV_{Mix} = (1-x\%)HHV_{NG} + x\%HHV_{H_2} \tag{6}$$

where for each fuel, HHV is the higher heating value, ρ is density, and x is the volumetric fraction. The basic concept for blended combustion is that gasses with similar Wobbe index will produce the same heat release in a furnace through the same nozzle at a pressure of similar power supply. Calculating the WI of the hydrogen/methane mixture shows that it is not profitable to increase too much hydrogen percentage [8].

Another metric for fuel interchangeability is the Heat Rate Ratio (HRR) that is defined as the ratio between the Wobbe index of a gas selected for the substitution (for example a mixture of natural gas/hydrogen) and the Wobbe index of the natural gas (to replace).

$$HRR = WI_{Mix}/WI_{NG} \tag{7}$$

The Wobbe index, although widely accepted as an indicator, is a highly qualitative parameter. Moreover, there are other similar indicators available. The Wobbe index is a parameter that is difficult to use practically in its basic form as described by the equations above, because we cannot generally consider having a mixture of just two gasses. Natural gas is a multi-component fuel, in which methane is certainly the major component, but the fraction of other gasses is also significant. Shkarovskiy et al. 2022 [32] suggested that two gasses can be considered interchangeable when the HHR is within the range 0.95–1.05 while a greater deviation is considered inadmissible as it implies a reduction in combustion efficiency and a loss of combustion stability. Other metrics for fuel interchangeability require the volumetric composition of the gas mixtures.

Another relevant indicator used to appreciate the modification in combustion is the Maximum Combustion Potential (MCP). This is an index of the theoretical burning rate of a mixture of gasses based on the burning rate of hydrogen and is defined as follows:

$$MCP = \frac{H_2 + 0.6(CO + C_mH_n) + 0.3CH_4}{\sqrt{RD_{gas}}} \tag{8}$$

In the MCP indicator, the volumetric fractions of hydrogen (H_2), carbon monoxide (CO), and hydrocarbons are considered in detail; in C_mH_n, the fractions of all the hydrocarbons are included except CH_4 which is considered separately.

Lin et al., 2018 [33] suggested that two gasses can be considered interchangeable when the variation in MCP remains below ±10%. Several risks are impacted by the use of this indicator and the results obtained are influenced by the presence of unburned gas, combustion process, and combustion products.

Although the use of indicators such as WI and MCP appears to be prevalent in the literature, this approach tends to be quite qualitative and does not adequately address the problem from an energy and reduction in pollutant emissions perspective. The Wobbe index, while useful for certain comparisons, falls short of providing a comprehensive energy analysis of blended combustion. Therefore, let us delve deeper into the issue from an energy standpoint to gain a more accurate understanding. A mass and energy balance of the combustion systems appears to be essential. In the case of blended combustion, it is essential to maintain the required thermal power input to the system. Therefore, when transitioning from pure natural gas to a mixture of natural gas and hydrogen, increasing the hydrogen fraction necessitates an increase in the inlet volumetric flow rate due to hydrogen's lower energy density. Moreover, considering that in general, the combustion processes are at high temperatures, it is better to consider LHV instead of HHV.

In this way, the equivalent calorific value of the fuel mix, LHV_{MIX}, can be estimated by the weighted average of the heating values of the fuels present in the blend according to the following model, in which x is the fraction (in mass or volumetric) considered:

$$LHV_{MIX} = x \cdot LHV_{H_2} + (1 - x) \cdot LHV_{CH_4} \tag{9}$$

In general, the volumetric fraction can be considered so that for a given input power in the burner, P_{burner}, the volumetric flow rate of fuel, q_{MIX} in m^3/s, can be estimated as follows:

$$q_{MIX} = \frac{P_{burner}}{LHV_{MIX}} \tag{10}$$

The volumetric flow rate of hydrogen can be estimated as follows:

$$q_{H_2} = x \cdot q_{MIX} \tag{11}$$

while the volumetric flow rate of methane results in the following:

$$q_{CH_4} = q_{MIX} - q_{H_2} \tag{12}$$

When increasing the fraction of hydrogen in the fuel, the volumetric flow rate q_{MIX} increases. Table 7 provides a trend in volumetric flow rates for a reference burner with an input power of 1 MW. When increasing the fraction of hydrogen in the fuel, the volumetric flow rate q_{MIX} increases. Table 8, instead, starting from the volumetric percentage of hydrogen in the mixture, shows the corresponding variations in the mass flow rates of the two fuels and an evaluation of the potential reduction in carbon dioxide emissions.

Analyzing the results in Table 8, it is evident that the commercially utilized levels of blended combustion (around 20% hydrogen by volume) are not particularly effective from a decarbonization perspective. A 20% hydrogen blend results in an estimated specific CO_2 emissions reduction of only about 7%, while increasing the blend to 30% barely surpasses a 10% reduction (11.3%) in CO_2 emissions (Figure 3).

In this section, we have examined the issue of hydrogen/natural gas blended combustion, starting with the idealization of natural gas as methane. In practice, however, natural gas has a composition that is quite different from methane and can vary significantly from case to case. This variability complicates the situation further, making it more challenging to address the problem of blended combustion. In the next section, we will explore the potential effects of these variations.

Table 7. Volumetric flow rates (V) in blended combustion for various amounts of hydrogen in a burner of 1 MW power thermal power.

x H_2 [% vol]	LHV_{MIX} [MJ/m^3]	V_{H2} [m^3/s]	V_{CH4} [m^3/s]
0	32.289	0	0.0309
5	31.159	0.0016	0.0305
10	30.029	0.0033	0.0300
15	28.899	0.0052	0.0294
20	27.769	0.0072	0.0288
25	26.639	0.0094	0.0281
30	25.509	0.0118	0.0274
50	20.988	0.0238	0.0238
70	16.468	0.0425	0.0182
100	9.687	0.1032	0

Table 8. Mass flow rates in blended combustion (m) for various amounts of hydrogen in a burner of thermal power (Q_{th}) 1 MW power.

x H_2 [% vol]	m (CH_4) [kg/s]	m (H_2) [kg/s]	Q_{th} (CH_4) [MW]	Q_{th} (H_2) [MW]	CO_2 Emitted [kg/s MW]	%CO_2 Reduction
0	0.02	0	1	0	0.055	0
5	0.0197	0.000129	0.984456	0.015544	0.054145	0.015544
10	0.0194	0.000269	0.967742	0.032258	0.053226	0.032258
15	0.0190	0.000419	0.94972	0.05028	0.052235	0.05028
20	0.0186	0.000581	0.930233	0.069767	0.051163	0.069767
25	0.0182	0.000757	0.909091	0.090909	0.05	0.090909
30	0.0177	0.000949	0.886076	0.113924	0.048734	0.113924
50	0.01538	0.001923	0.769231	0.230769	0.042308	0.230769
70	0.01177	0.003431	0.588235	0.411765	0.032353	0.411765
100	0	0.008333	0	1	0	1

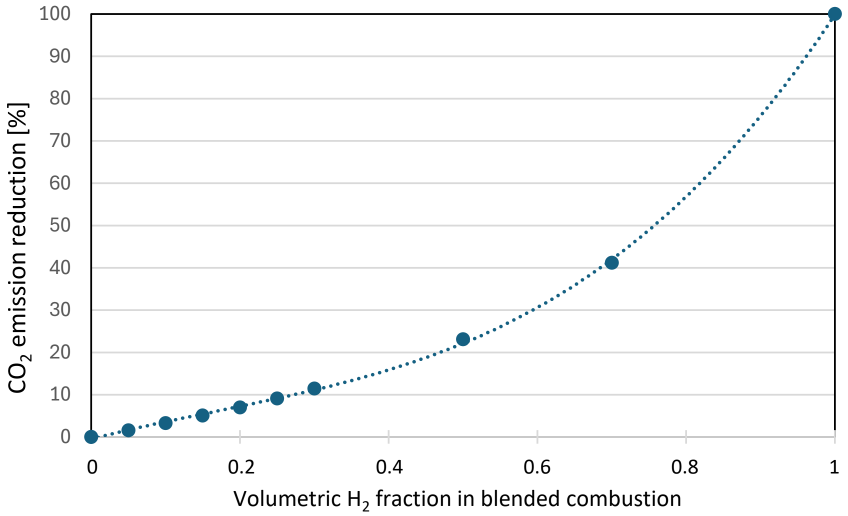

Figure 3. Potential emission reduction as a function of hydrogen volumetric fraction in the fuel.

5. Results of Interchangeability Metrics for Natural Gas/Hydrogen Blends Using Synthetic Indicators

From a conceptual standpoint, the problem of blended combustion of natural gas with hydrogen is relatively straightforward. However, there are two approaches to address the issue: purchasing boilers or furnaces specifically designed for pure hydrogen use or assessing the limits of hydrogen utilization in conventional systems. The latter appears to be the simpler and more intermediate approach. However, identifying the upper limits of hydrogen usage is not always easy. It is crucial to keep in mind that the composition of natural gas varies significantly depending on the region of the world from which it originates. In the previous section, we have already discussed the topic of blended combustion from an energy point of view, seeing how the problem could be addressed by combining the use of synthetic parameters such as WI and MCP and the use of mass and energy balances. This approach turns out to be quite simple in the case of a methane/hydrogen mixture; however, it must be considered that natural gas has an often-variable composition in terms of chemical composition. This complicates the perspective a bit and makes it more difficult to control the properties of the mixture as a function of the percentage fraction of hydrogen because natural gas may contain small percentages of hydrogen too.

For example, the natural gas injected into the Italian national distribution network is imported from various countries. In 2021, Italy has imported natural gas mainly from (data published by the Italian Ministry of Ecological Transition) Russia (40.0%), Algeria (30.8%), Azerbaijan (9.9%), Qatar (9.4%), Libia (4.4%), Norway (2.7%), USA (1.5%), the Netherlands (0.4%), Nigeria (0.4%), Egypt (0.3%), and Spain (0.1%). The percentages have changed drastically since 2022 following the outbreak of the Russia/Ukraine war. Although the main element is methane (CH_4), natural gas is also composed of secondary elements such as ethane, propane, and butane. Depending on the origin of extraction, natural gas can be characterized by a specific wellhead composition. Consequently, the values of higher heating value (HHV), Wobbe index (WI), and relative density (RD) cannot be considered invariable. Average values are frequently used; however, depending on the type of investigation, it may be more correct to consider the actual variability of these characteristics. Table 9 shows the main characteristics of the natural gas injected into the national distribution network for some countries of origin. At a national level, each country establishes the acceptability ranges of LHV and HHV, chemical composition ranges, and relative density (density of the gas compared to that of the air) that must be satisfied by the natural gas injected into the distribution network. In Italy, these requirements (Table 10) are indicated in [34].

Table 9. Characteristics of natural gas from some countries of origin.

Region of Origin of Natural Gas	HHV (MJ/Sm^3)	Density (kg/Sm^3)	Wobbe Index (MJ/Sm^3)
Italy	37.70	0.682	50.53
The Netherlands	37.12	0.752	47.38
Russia	39.21	0.742	50.38
Algeria	39.35	0.790	49.00
Libia	40.61	0.778	50.96

Table 10. Acceptability ranges required on Italian territory, for natural gas/hydrogen blend.

Properties/Index	Acceptability Range	Unit
Higher Heating Value (HHV)	34.95–45.28	MJ/Sm^3
Wobbe Index (WI)	47.31–52.33	MJ/Sm^3
Relative Density (RD)	0.56–0.8	-

Considering the limit values reported in [30], the results of the Wobbe index (WI) for natural gas/hydrogen blends are shown in different cases and compositions. The analyzed mixtures were obtained considering the different properties of the natural gas injected into the Italian national distribution network (Table 9) and volumetric fractions of hydrogen increasing from 0% to 100%. In Figure 4 is shown the variation in WI with the percentage by volume of hydrogen for natural gas extracted in Russia, the Netherlands, Algeria, and Libia, while with a dotted red line is represented the lower limit level of the Wobbe index (WI = 45.7 MJ/Sm^3, as described in Section 3).

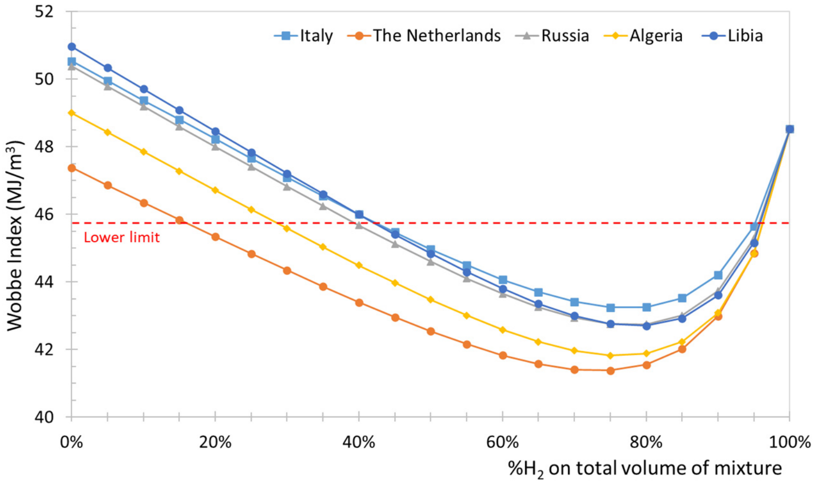

Figure 4. Variation in WI of NG-H_2 blends in relation to the % by volume of hydrogen for natural gasses with different origins.

From the obtained results, it is possible to observe that the percentage of hydrogen that can be considered acceptable (i.e., which corresponds to a Wobbe index of at least 45.7 MJ/Sm^3) varies significantly depending on the origin of the natural gas. In detail, for the gas extracted in Italy, Russia, and Libia, hydrogen volume concentrations up to 45% can be accepted, while for the gas coming from Holland and Algeria, the percentage of acceptable hydrogen is lower and equal to approximately 15% and 30%. In all the cases, in relation to the WI, natural gas/hydrogen blends with a volumetric percentage of hydrogen greater than 95% are permitted. Considering the wide variability of the characteristics of natural gas and the acceptability ranges required on Italian territory, natural gas/hydrogen blends were studied assuming different types of natural gas created using the HHV and RD limit values reported in Table 10. In detail, the following gasses were hypothesized: a natural gas characterized by values maximums of both HHV and RD (NG1), a natural gas with the minimum values of both HHV and RD (NG4), and gasses with the maximum of HHV and the minimum of RD and vice versa (NG2 and NG3).

Finally, an "average" natural gas characterized by the average of the acceptable limit values of HHV and RD (NG5) was assumed. The characteristics of the studied natural gasses are shown in Table 11. Figure 5 shows the variations in the WI as the percentage (by volume) of hydrogen varies for different natural gasses and for the pure methane/hydrogen blends. In Figure 5, the lower and upper limits of the Wobbe index for boilers in accordance with the EN 437 standard are also represented with horizontal dotted lines. From the results reported in Figure 5, for a pure methane/hydrogen blend, it is possible to reach up to 50% hydrogen by volume. As regards NG5 (average HHV and average RD) natural gas, it is possible to introduce up to approximately 25% by volume of hydrogen, while for NG4 (minimum acceptable HHV and minimum acceptable RD), only 10% by volume is permitted. Finally, the NG3 (minimum acceptable HHV and maximum acceptable RD) does not allow mixing with hydrogen because WI is always lower than the minimum required. The same natural gasses used for the evaluation of WI as a function of the percentage of hydrogen were used to analyze HRR. In Figure 6, the results of HHR and the lower and upper acceptability limits (according to [34] for the specific case of Italian Market) corresponding to a variation of ± 5% (two dashed red lines) are represented too. From the results of Figures 5 and 6, it is evident that a maximum volume percentage of hydrogen of between 20% and 30% is admitted depending on the type of natural gas, but some relevant variations can be appreciated. The result is consistent with what was stated by the manufacturers and documented in Section 3, as well as with findings from some recent experimental studies on the topic [3], even if some recent experimental investigations show that a higher volumetric share of hydrogen is possible [35,36].

Table 11. Characteristics of natural gasses used for the study of hydrogen/natural gasses blends based on HHV (at atmospheric pressure).

Name	Description	HHV (MJ/Sm^3)	RD	Density (kg/Sm^3)
H_2	Hydrogen	12.5	-	0.081
CH_4	Pure methane	37.8	-	0.648
NG1	Max. acceptable HHV and RD	45.28	0.80	0.98
NG2	Max. acceptable HHV and min. RD	45.28	0.555	0.68
NG3	Min. acceptable HHV and max. RD	34.95	0.80	0.98
NG4	Min. acceptable HHV and min. RD	34.95	0.555	0.68
NG5	Average HHV * and averaged *	40.11	0.677	0.83

(*) mean value between maximum and minimum acceptable values.

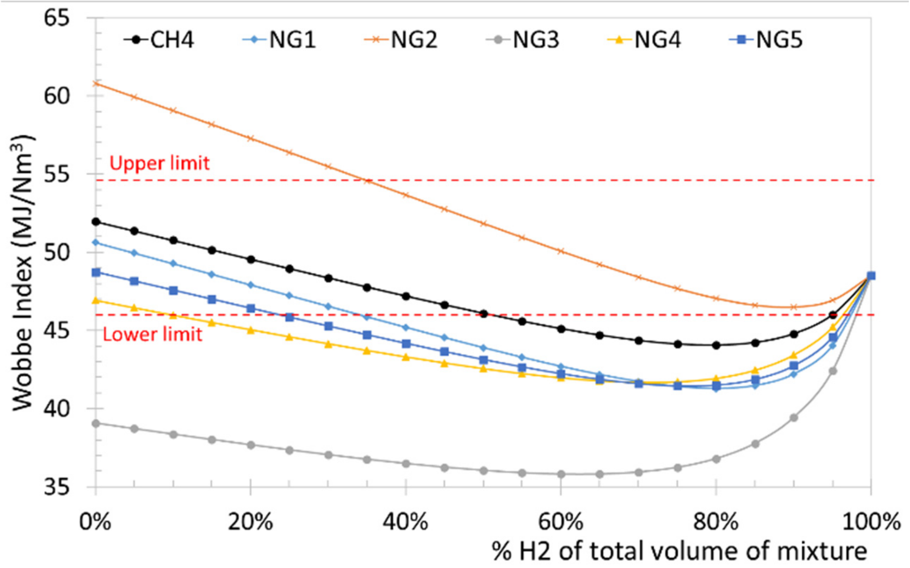

Figure 5. Variation in WI of NG-H_2 blends in relation to different natural gas compositions and different volume percentages of hydrogen in the fuel mixture.

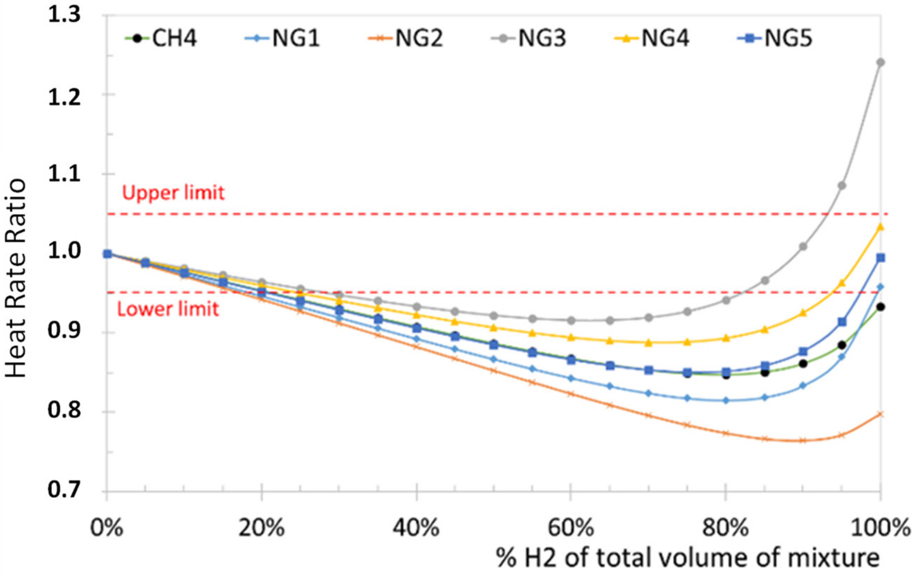

Figure 6. Variation in HHR of NG-H_2 blends in relation to different natural gas compositions and different volume percentages of hydrogen in the fuel mixture.

To analyze the behavior of a different index like MCP for evaluating the interchangeability of gasses, it is necessary to know the volumetric composition of the gas mixtures. While, on the one hand, the density and higher calorific value values are available, the volumetric compositions are more difficult to obtain. The data presented in this section have been obtained considering the typical composition of natural gas, as indicated in [34] and within [37] and reported in Table 12. The variation in MCP as a function of the volumetric percentage of hydrogen in the natural gas/hydrogen blend is represented in Figure 7. This trend is always increasing as the hydrogen percentage increases. Currently, no specific limit values for this index are recognized, so the analysis is limited to evaluating the variation in the index in comparison to its reference value (natural gas only).

Table 12. A typical natural gas composition by volume [37].

Component	Symbol	% Vol.
Methane	CH_4	88.10
Ethane	C_2H_6	4.20
Propane	C_3H_8	1.36
Butane	C_4H_{10}	0.30
Pentane	C_5H_{12}	0.06
Carbon Dioxide	CO_2	0.78
Nitrogen	N_2	5.20

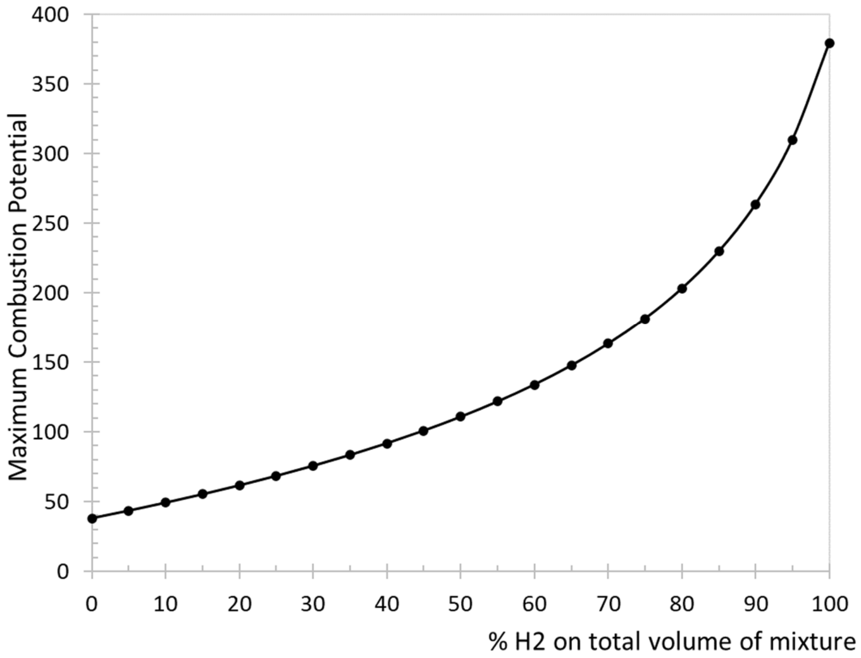

Figure 7. Variation in MCP in relation to the % of H_2 in hydrogen/natural gas mixtures.

In this sense, the indicator requires a careful interpretation. For example, it can be observed that MCP varies even for small percentages of hydrogen. A percentage of hydrogen of 5% corresponds to an increase in MCP of approximately 15%, while it is doubled for a percentage of hydrogen of 30%. Anyway, the usage limits of this indicator are not actually clear.

6. Discussion

The behavior of hydrogen as a fuel is well known, and resorting to systems with blended combustion can represent one of the first steps towards decarbonization before considering the systematic use of hydrogen as a pure fuel. While blended combustion is not a long-term strategy, gradually increasing hydrogen content in mixtures should not be underestimated as a transitional measure. The study of gas interchangeability in the context of natural gas/hydrogen blends is extremely relevant, especially considering future developments in the transition to cleaner energy sources.

Implementing hydrogen blending requires addressing several technical challenges connected to the differences introduced by hydrogen in terms of lower volumetric heating value (10 MJ/Nm^3), higher flame temperature, shorter flame length, broader flammability range, and higher reactivity. It will be crucial to analyze the specific emission characteristics, including NOx formation, to optimize blend ratios for minimal environmental impact.

These differences necessitate careful consideration when blending hydrogen with natural gas to ensure compatibility and efficiency in combustion systems. In particular, in order to advance the understanding and implementation of hydrogen/methane blends in industrial applications, several key knowledge gaps need to be addressed. Future research should surely focus on combustion dynamics in order to investigate the detailed combustion behavior and flame stability of hydrogen/methane blends under various industrial conditions. Attention must be given to material compatibility, studying the long-term effects of hydrogen on materials used in the existing infrastructure to ensure safety and durability. Addressing all these gaps will be crucial for the successful integration of hydrogen/methane blends in industrial processes.

Moreover, we should assess the cost implications and economic feasibility of large-scale adoption of hydrogen/methane blends in industrial settings and develop guidelines for modifying the existing infrastructure to accommodate higher hydrogen concentrations safely and efficiently.

While a blending level of up to 20% by volume is technically achievable, the feasibility of different blending levels depends on factors such as the origin of the natural gas to be blended with hydrogen. Additionally, uncertainties remain regarding the long-term material sensitivities (e.g., pipes and devices) and potential reductions in lifespan due to hydrogen presence, necessitating further investigation. The natural gas distributed in the national network does not have constant characteristics and can vary significantly depending on its origin. Nationally, acceptability ranges are provided for some characteristics of natural gas, such as relative density or higher calorific value; however, these ranges are quite wide and allow for gaseous mixtures with different characteristics. This variability must be considered when evaluating the possibility of mixing natural gas with hydrogen, as the properties of these mixtures can vary significantly based on the percentage of hydrogen introduced and the initial characteristics of the natural gas.

The technical effort required to blend hydrogen into the natural gas supply is substantial, particularly when substituting 20% by volume of natural gas with green hydrogen. This process demands significant modifications to infrastructure, including adjustments to pipelines, storage facilities, and end-user equipment to accommodate the different properties of hydrogen. Hydrogen has a lower heating value compared to natural gas, meaning that, energy-wise, 20% hydrogen by volume contributes less energy than the equivalent volume of natural gas. Despite this considerable technical undertaking, the substitution of 20% natural gas with green hydrogen results in relatively modest greenhouse gas (GHG) savings—approximately 6 to 7%. This modest reduction is due to hydrogen's lower energy density, which requires more hydrogen to achieve the same energy output as natural gas. Consequently, while hydrogen blending is a step towards reducing GHG emissions, its impact is limited unless coupled with other decarbonization measures. The pursuit of hydrogen blending should be seen as part of a broader strategy to start the decarbonization of thermal energy uses, reducing the economic impact on the complete subsystem.

Considering that natural gas consumption at a global level is still growing, as is clearly demonstrated in Figure 8, and that this corresponds to about 40,000 TWh globally, about 21–22% of the total energy use, as discussed in Section 2, even if a reduction of a few percentage points, could have a positive effect in terms of decarbonization [38].

Despite the fact that the use of blended natural gas/hydrogen combustion does not appear to be very relevant, it is also true that on a general level, even the penetration of a few percentage points of hydrogen use, in the event that this is produced by renewable energy, could still produce a non-negligible medium-term impact, both in terms of the penetration of renewable sources and in terms of potential decarbonization.

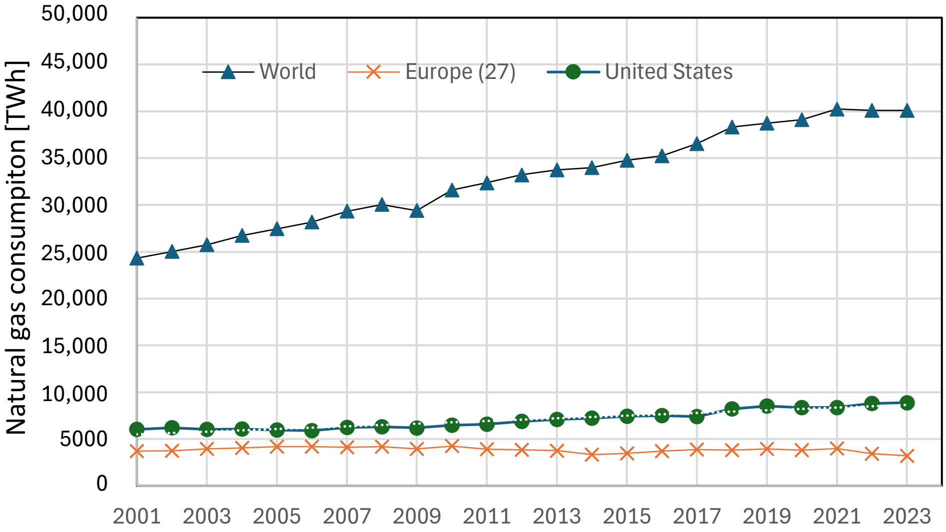

Figure 8. Natural gas consumption in the current century: comparison among the world, Europe (27) and the United States (data rearranged from [38]).

The transition to hydrogen/methane blends as a decarbonization strategy involves significant economic considerations too. Transitioning to hydrogen/methane blends surely requires modifications to the existing infrastructure, including storage, transportation, and combustion systems. The initial investment for these upgrades can be substantial. Moreover, green hydrogen remains costly due to the energy-intensive nature of electrolysis. Advances in technology and economies of scale are expected to reduce these costs over time but not so much. Anyway, blending hydrogen with methane can reduce the overall fuel cost compared to using pure hydrogen, making it a more economically viable transitional solution.

7. Conclusions

In this paper, we have analyzed the potential use of hydrogen as a co-combustible in industrial burners and furnaces. Our study examined the feasibility and effectiveness of hydrogen/natural gas blended combustion in industrial furnaces, beginning with a general energy analysis and incorporating the use of various indicators. From the analysis, it becomes clear that while blended combustion may seem like a practical short- to medium-term strategy for achieving decarbonization, its long-term impact is limited. Industrial practices suggest that blends containing up to 20–30% hydrogen by volume are feasible, but the theoretical limitations of such blends become apparent beyond the 25% threshold. A hydrogen/methane blend with 20% hydrogen by volume results in a CO_2 emissions reduction of approximately 7%. Increasing the hydrogen content to 30% yields a reduction of just over 10%.

Furthermore, the natural gas circulating in the network often contains variable percentages of hydrogen, typically around 2%, which further limits the potential for additional hydrogen blending. This variability complicates the application of blended combustion in real-world industrial scenarios, where the composition of natural gas can vary significantly depending on its origin. The power range and combustion stability are influenced by the change in fuel, necessitating design calculations and experiments at each stage to efficiently utilize the burners and achieve greater controllability while minimizing pollutant emissions. This can be addressed either on an energy basis or by employing synthetic indicators.

The interchangeability of fuels was analyzed using both energy balance methods and synthetic indicators. Various indices are present in the literature; however, there is no international consensus on which indices and related limit values should be used. In certain cases, the evaluation is limited to comparing the value of the index obtained with the new mixture to the value obtained for the original mixture. The Wobbe index is the most used indicator as it requires less data and is easier to calculate. However, it does not consider the volumetric composition of the mixture. The heat release rate (HRR) is another easy-to-use index, but it only provides relative information by considering the variation in the Wobbe index compared to its initial value.

The findings underscore the thermodynamic complexities associated with high hydrogen concentrations in blended combustion. Beyond a certain threshold, transitioning directly to pure hydrogen combustion appears more advantageous, indicating a paradigm shift in burner design and operation.

In conclusion, while blended combustion can be a viable medium-term strategy, the penetration of hydrogen is limited to relatively low mass fractions, resulting in modest CO_2 emission reductions. Therefore, the transition to pure hydrogen combustion appears to be more expensive and far from being realized due to the required technological changes. For this reason, the use of hydrogen in blended combustion in the industrial sector, mainly in the hard-to-abate sectors, appears to be an important step. Another advantage of blended combustion systems is that they allow for the maintenance of the existing infrastructure. This approach also offers the flexibility to operate the facilities even in the absence of hydrogen, which is not possible with systems designed exclusively for hydrogen combustion. By integrating hydrogen into the existing natural gas framework, industries can gradually transition to cleaner energy sources without the immediate need for extensive and costly infrastructure upgrades. This dual capability ensures continuous operation and energy supply reliability, making blended combustion a practical interim solution during the transition to a fully hydrogen-based energy system.

To implement blended combustion in industrial settings, industry stakeholders should focus attention on practical applications and the acquisition of performance data. They should invest in R&D to address technical challenges and optimize burner designs. Policymakers can support this transition by offering financial incentives, such as grants for technology adoption and infrastructure upgrades. Additionally, establishing standardized testing protocols and fostering industry collaboration will ensure consistency and accelerate progress. These measures will help industries integrate blended combustion effectively.

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

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

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