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Hydrogen–Natural Gas Blending in Distribution Systems—An Energy, Economic, and Environmental Assessment

Adrian Neacsa [1,2,*], Cristian Nicolae Eparu [3] and Doru Bogdan Stoica [3]

[1] Mechanical Engineering Department, Petroleum-Gas University of Ploiesti, 100680 Ploiesti, Romania
[2] School of Advanced Studies of the Romanian Academy (SCOSAAR), 010071 Bucharest, Romania
[3] Well Drilling, Extraction and Transport of Hydrocarbons Department, Petroleum-Gas University of Ploiesti, 100680 Ploiesti, Romania
* Correspondence: adnea@upg-ploiesti.ro or adineacsa@gmail.com

Abstract: Taking into account the international policies in the field of environmental protection in the world in general, and in the European Union in particular, the reduction of greenhouse gas (GHG) emissions, and primarily of carbon dioxide, has become one of the most important objectives. This can be obtained through various renewable energy sources and non-polluting technologies, such as the mixing of hydrogen and natural gas. Combining hydrogen with natural gas is an emerging trend in the energy industry and represents one of the most important changes in the efforts to achieve extensive decarbonisation. The importance of this article consists of carrying out a techno-economic study based on the simulation of annual consumptions regarding the construction and use of production capacities for hydrogen to be used in mixtures with natural gas in various percentages in the distribution network of an important operator in Romania. In order to obtain relevant results, natural gas was treated as a mixture of real gases with a known composition as defined in the chromatographic bulletin. The survey presents a case study for the injection of 5%, 10%, and 20% hydrogen in the natural gas distribution system of Bucharest, the largest city in Romania. In addition to conducting this techno-economic study, the implications for final consumers of this technical solution in reducing greenhouse gas emissions—mainly those of carbon dioxide from combustion—are also presented.

Keywords: sustainability; hydrogen–natural gas mix; energy systems; environment; distribution systems

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1. Introduction

In the transition to a carbon-free energy system, one approach is to use hydrogen as an energy carrier and storage medium for natural gas in order for a wide range of energy consumers to profit from reductions in greenhouse gas emissions.

In order to reduce the increasingly important phenomenon of global warming, which is one of the most urgent challenges facing humanity, it is necessary to reduce greenhouse gas emissions (mainly carbon dioxide and methane). In its sixth assessment report, the Intergovernmental Panel on Climate Change issued a warning about the seriousness of the damage already produced by greenhouse gases in the Earth's atmosphere that will not be reversed without rapid and radical measures. For this reason, research has been done, is being done, and will be done to replace fossil fuels with alternative fuels without carbon emissions.

The successful implementation of hydrogen-based technologies in various industrial sectors of the economy will require a coordinated effort from all stakeholders (community leaders around the world, governments, policy makers, industries, research institutions, and investors). The current study was carried out in the current conditions in the European Union, and specifically in Romania.

This article aims to be an up-to-date study on the methods of mixing hydrogen and natural gas and delivering this mixture to final consumers. Furthermore, it underlines both techno-economic and environmental implications. For a better understanding of the study, a graphical abstract with the most important steps of our enterprise is presented in Figure 1.

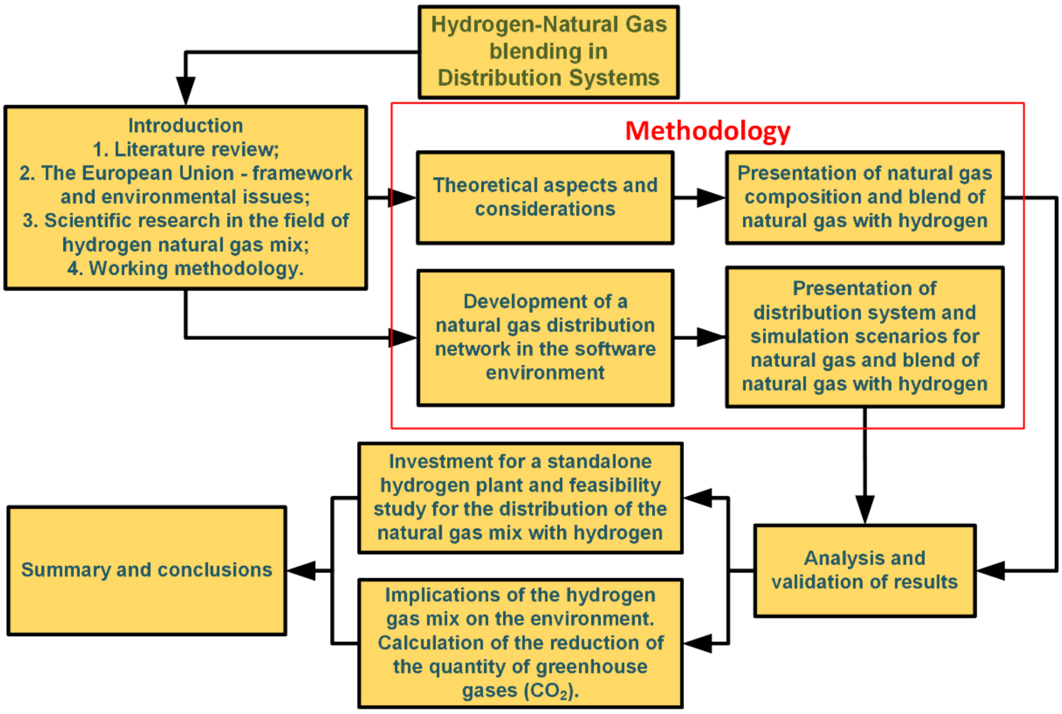


Figure 1. Graphical abstract of the article (source: authors, based on article content).

As stated above, the method of introducing a mixture of natural gas and hydrogen into distribution systems is a topical issue and must be implemented in as many states of the European Union as possible.

At this moment in Romania, the economic agents dealing with the distribution of natural gas to the final consumers have not carried out any applied studies regarding this method, which resulted in the novelty of our article and emphasized the need for the technical and economic treatment of this new technology. Moreover, this technical and economic problem should lead to finding solutions for the distribution of the natural gas and hydrogen mix using the already-existing distribution networks or the implementation of new pipeline constructions dedicated to this application.

At the level of the European Union, with respect to its energy policies, the importance of the mix between natural gas and hydrogen in the existing gas networks is crystallizing more and more intensely. This method will help to achieve environmental objectives by decarbonising with minimal influences on the final consumers [1,2].

Taking into account both the Sustainable Development Goals (SDGs) and the provisions of the Paris Agreement, as well as a recent report on the climate change crisis, a correct response to the current situation consists of a transition to renewable energy or modernized sources, such as the use of natural gas–hydrogen mixtures, and an increase in the efficiency of the methods used to obtain and conserve different types of energy [3].

In order to analyse the most relevant concepts in the field of using natural gas mixed with hydrogen in transmission and distribution networks, a bibliometric analysis was carried out using the scientific articles on the academic platform Web of Science as resources.

Taking into account the results of the studies carried out at the international level that highlighted the benefits of using mixtures of hydrogen and natural gas in various proportions, many countries around the world have supported projects in the field, such as East Neuk Power, HyDeploy, HyNet Northwest, Aberdeen Vision, and HyNTS Hydrogen Flow Loop (UK); GRHYD (France); THyGA (EU); WindGas Falkenhagen and WindGas

Hamburg (Germany); HyP SA, HyP Gladstone, HyP Murry Valley, and Jemena West Sydney (Australia), Fort Saskatchewan and Cummins-Enbridge (Canada); HyBlend and SoCalGas (USA); and others. All these demonstration projects seek optimal solutions from a technical and/or economic point of view to achieve the objective of reducing greenhouse gas emissions (carbon dioxide) in the coming decades.

Therefore, the content of 237 highly cited articles related to this topic was analysed in order to highlight the structure of the scientific field by inspecting the most common keywords and the relationship between them. An empirical analysis showed that the most used words in the full content of the selected articles included "natural", "hydrogen", "mix/blending", "energy", "network", and "environment", as shown in Figure 2.

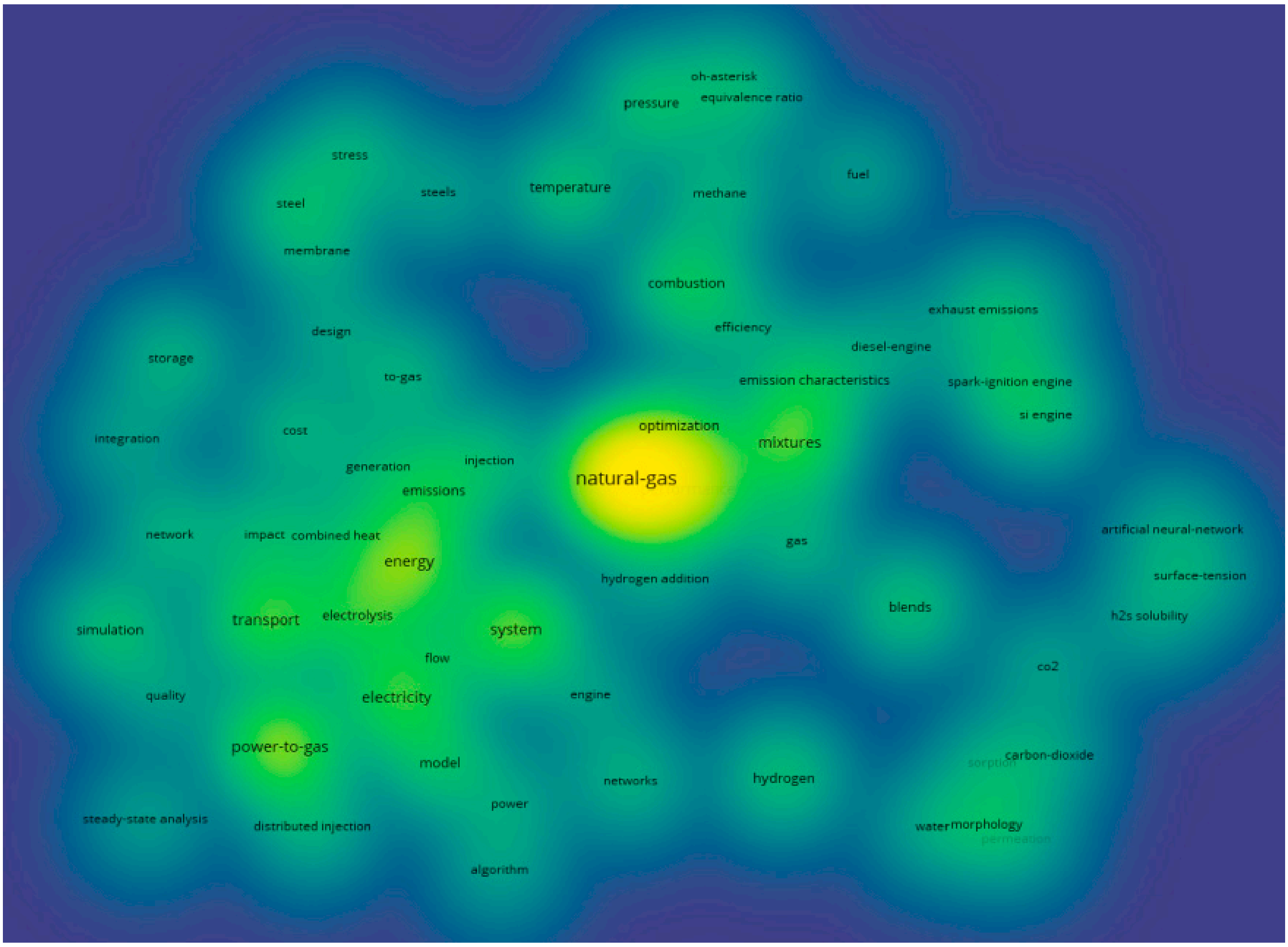


Figure 2. Common words in scientific publications (source: authors, based on articles analysed).

Based on the bibliographic references highlighted in Figures 2 and 3, we identified many articles that presented studies that referred directly to:

- The use of the mixture of natural gas with hydrogen in the combustion processes in different industrial fields and for domestic use;
- Transport and distribution of natural gas and energy mixtures through both new and used natural gas networks;
- Identification by chromatography of the natural gas composition;
- Infrastructure costs for hydrogen production, storage, and transportation;
- Environmental impact studies on the combustion of combustible mixtures containing different proportions of hydrogen in mixtures with natural gas a.s.o.

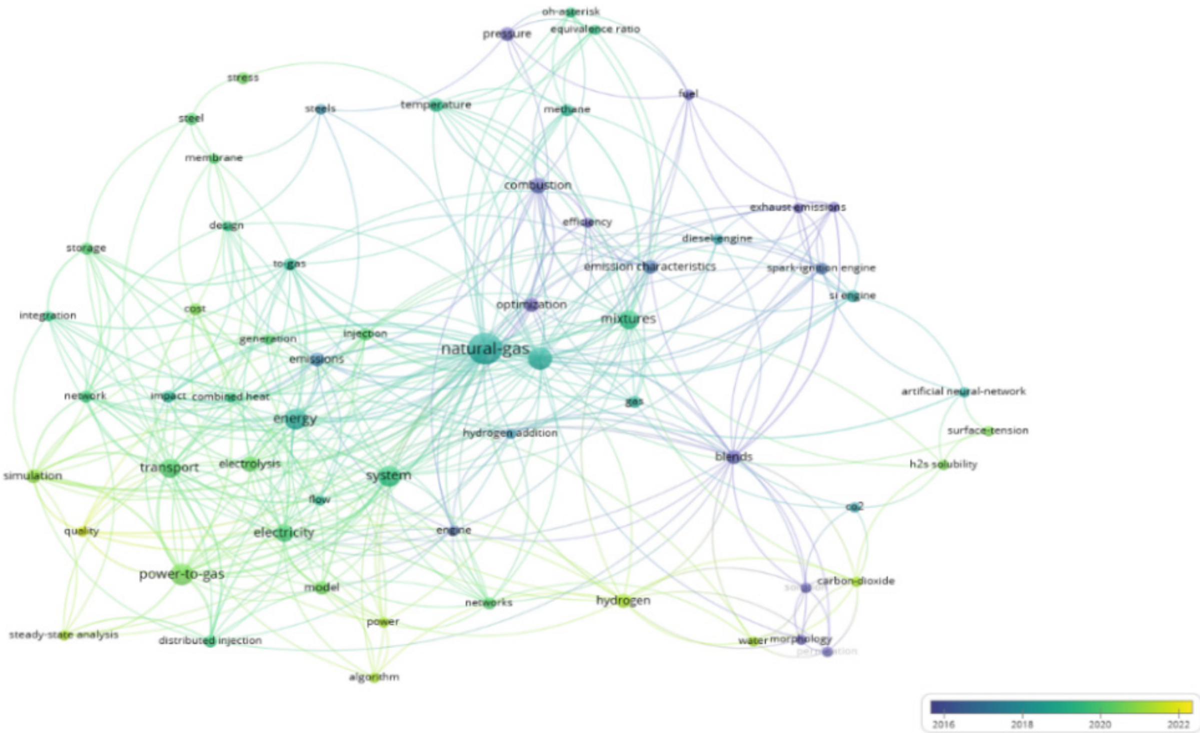


Figure 3. Content of international network scientific publications with references to the transition to the use of natural gas–hydrogen blending (Source: authors, based on articles analysed).

No study/survey included in the numerous articles in this bibliographic analysis brought together all these aspects in order to use them in conducting a techno-economic study of profitability on the opportunity of investment in a hydrogen production capacity in order for it to be injected into the gas distribution network, or provided a presentation of the impact this investment might have on the environment.

A protected climate may be achieved by means of transitioning to the practice of mixing natural gas and hydrogen to be introduced in the current transmission and distribution networks. The increasing use of inter-sectorial flexibility options for different energy sectors should be the starting point of a combined analysis [4].

Sustainability in the field of natural gas transmission and distribution was related to "technology", "impact", "development", "global heating", "sustainable energy", "change", and "future" (Figure 3).

The climate and nature must be fully protected, but this can be achieved only by means of a fair and sustainable transition to modern methods of obtaining different forms of energy.

The articles analysed revealed the existence of many types of behaviours and attitudes related to this field that depended on the type of stakeholder and their means to become involved in such a complex process. The attitude a country towards energy transition depends on its level of economic development. It is known that developing countries mainly use fossil fuels, which have the advantages of availability and low prices.

Taking into account the recent rising trend in natural gas prices (see Figure 4), it can be stated that the problem of replacing a portion of the gas with hydrogen in pipeline systems in optimal conditions, in terms of eliminating technical risks due to depreciation of the components of these systems, is a very important one [1,2].

Natural gas prices have recently continued their upward trend due to the global economic recovery fuelling travel demand [5].

Moreover, expectations of uncomfortably hot weather, as well as concerns over a lack of storage inventories ahead of winter, also buoyed demand for natural gas. Simultaneously, supply of the commodity has tightened recently, further fuelling the price rally [5].

A comparison with the winter of 2020–2021 showed that the natural gas prices in Romania compared to stock exchanges in the region increased by about 400% for traded natural gas both at the level of the main centralized platform in Romania and at the level of Vienna.

Due to the price increase, as can be seen in the graph of their evolution (see Figure 4), estimating or calculating the costs and implications of injecting hydrogen in natural gas transport or distribution systems can materialize in engineering instruments that may diminish the costs and, indirectly, the final prices paid by the above-mentioned final customers [5–7].

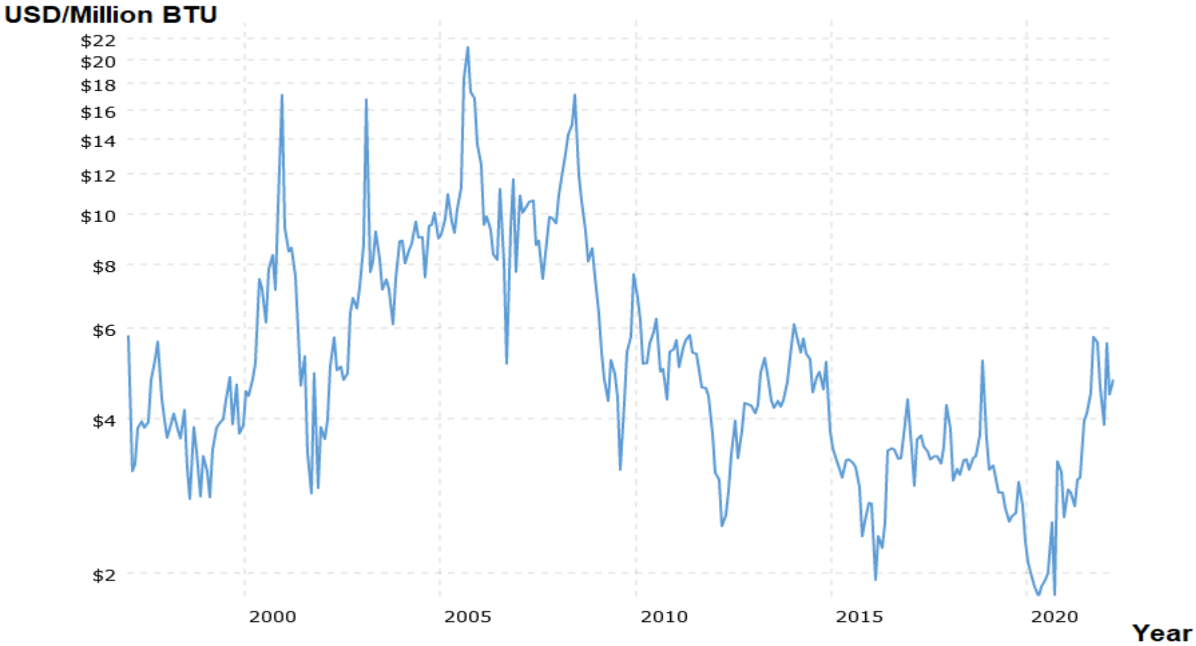


Figure 4. Natural gas prices—historical chart [7] (source: https://www.macrotrends.net/2478/natural-gas-prices-historical-chart, accessed on 15 January 2022).

By conducting such complex studies, maintenance measures can be identified and predictive/preventive/corrective actions can be applied to the elements of natural gas transmission systems, resulting in a significant drop in both operating costs and pollutant emissions that have a negative impact on the environment [6].

Given this context, it can be stated that at the moment, national gas distribution network systems represent a critical infrastructure with an important role in both the energy supply itself and its security, as they can store a large amount of fuel for energy in the long run.

It is hoped that the existing infrastructure may be used for the distribution of natural gas with hydrogen added.

In order to ensure the safety of distributing this mixture, given its high concentration of hydrogen, and to determine the performance of the existing pipeline networks, an effort is required from specialists in the field of pre-normative research. The use of hydrogen-enriched fuels may contribute to alleviating the severe safety issues related to the use of pure hydrogen [8–10].

In view of the above, the European Union aims to develop research and communicate its results in order to better understand the impact of natural gas and hydrogen mixtures on the distribution to final consumers, especially those from the domestic and commercial sectors, as presented in [11] for domestic gas meter durability; [12] for residential and commercial gas appliances; and [13], which focused on the performance, emissions, and safety of the unadjusted equipment. In addition, the presence of hydrogen may have beneficial effects in terms of an increase in the overall combustion stability [14,15].

The main objective of the European Commission and the Joint Undertaking for Fuel Cells and Hydrogen (FCHJU) is the widespread implementation of H_2NG (hydrogen in natural gas) mixture distribution by eliminating the lack of information with respect to the technical impact on supply chains and gas appliances of domestic and commercial final consumers.

The European Commission aims to turn the EU into a pioneer in the use of hydrogen as an energy carrier. In 2020, the Commission presented *A hydrogen strategy for a climate-neutral Europe*, the aim of which was to make the widespread use of hydrogen possible by 2050.

To achieve the "Net Zero" goal of decarbonising industrial processes and carbon neutrality in the atmosphere by 2050, energy experts stressed that the use of hydrogen and energy from green sources is generally the mainstay of this international strategy and especially of EU [16].

A multi-energy and multi-sector model was used for the 2050 Belgium energy modelling system at different mitigation levels of greenhouse gas (GHG) emissions [17]. Because such a model relies on many parameters that can be highly uncertain, especially for long-term planning, a global sensitivity analysis was carried out in order to highlight the influence of the parameters on the total cost of the system.

Studies have shown that the use of hydrogen, mainly as a raw material, is limited to local industrial clusters, but the hypothesis is that it may become a major energy vector because it can be transported over longer distances in Europe and stored for longer periods. Power-to-gas technologies can provide flexibility in electrical networks, as the gas sector has great potential to provide large storage capacity [18].

It follows from the above that although it already contributes to a reduction in carbon dioxide emissions, the blending strategy plays only a transitional role, as the complete decarbonisation of the EU economy requires a volume of hydrogen in the natural gas energy mix that is higher than the level currently accepted in the transport pipeline systems.

A life-cycle inventory analysis with a CO_2 emissions calculation for the entire supply chain of hydrogen in Japan was performed in [19] in order to determine the anticipated environmental benefit under the uncertainty of hydrogen technology progress.

The current questions regard whether and to what extent this role of the hydrogen mix with natural gas should be regulated by combined standards and whether these standards should be harmonized throughout Europe.

A small amount of hydrogen in combination with natural gas does not pose special technical problems in the transport and use of the resulting mixture, although some safety issues may arise due to the combustion characteristics of hydrogen, which differ greatly from those of natural gas. Currently, different countries of the world, including in Europe (see Figure 5), have imposed different limits on the percentage of hydrogen blends with natural gas that may be used in the distribution networks. The feasibility of blending hydrogen into the natural gas network is being intensively investigated [20,21].

Of those EU Member States where hydrogen is allowed to be mixed with natural gas, the graph shows that the highest limits are in Germany (10%, but only if the compressed natural gas stations are not connected to the networks, otherwise the limit is 2%), France (6%), Spain (5%), and Austria (4%). However, many states do not (yet) allow the use of this mix.

If blending is accepted as an intermediate arrangement to smooth the development of the hydrogen sector, at least in its early phases, the steady functioning of the internal energy market will require the introduction of harmonized standards for the maximum allowable hydrogen quota. In setting such limits, three aspects shall be taken into account: the need and costs of redeveloping transmission and distribution networks [22,23], the potential use of the resulting mixture in the industrial and commercial installations of end users, and household appliances and any associated costs.

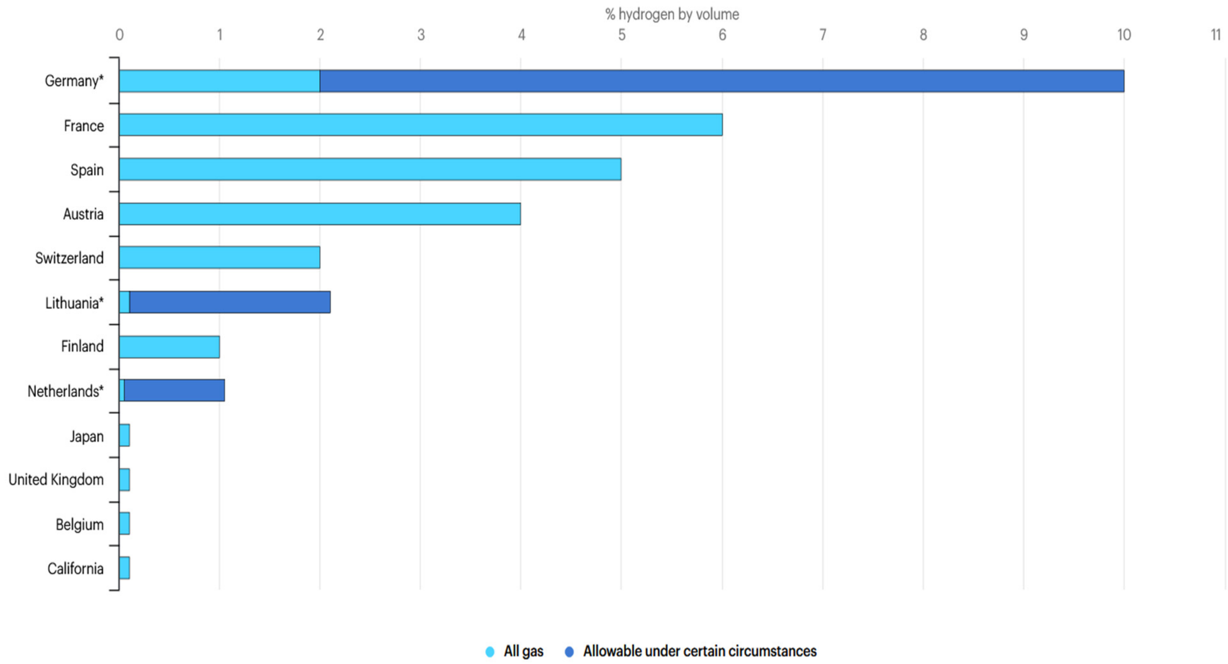


Figure 5. Limits on hydrogen blending in natural gas distribution networks. Note: * higher limit for Germany applies if there are no CNG filling stations connected to the network; higher limit for the Netherlands applies to high-calorific gas; higher limit for Lithuania applies when the pipeline pressure is greater than 16 bar pressure. Source: Current limits on hydrogen blending in natural gas networks and gas demand per capita in selected locations, IEA, Paris (https://www.iea.org/data-and-statistics/charts/current-limits-on-hydrogen-blending-in-natural-gas-networks-and-gas-demand-per-capita-in-selected-locations, accessed on 15 January 2022).

Given the fact that a high percentage of hydrogen mixed with natural gas reduces its calorific value, unitary standards should also be developed for the evaluation of gas mixtures with different levels of hydrogen.

Strong coordination in planning the transition from the initial phase (based on mixing) to a sustainable future (based on the use of pure hydrogen as an energy carrier) will also be imperative. At that time, two types of molecular energy vectors will coexist; namely, hydrogen and renewable gases (biogas, biomethane, and synthetic natural gas). By default, these sources will compete for traffic through existing pipelines (and possibly for any extension). Nevertheless, these sources will no longer be mixed, and as a result, it will be imperative at the EU level to coordinate the use of transmission and distribution infrastructure for the two types of molecular vectors in order to avoid asset failure and to reduce costs for final energy consumers.

Therefore, hydrogen has become a key component of the European Commission's energy development strategy, which was formalized by the European Commission in July 2020 and, at the same time, was marked by the launch of a common European hydrogen strategy.

The evolution from raw material in local clusters to a key energy transporter across the EU will require the development of hydrogen infrastructure along with a regulatory framework, including legislative harmonization through the implementation of common standards.

The current regulatory framework is probably the only area in which the natural gas infrastructure could not be fully taken as an inspiration for the hydrogen approach.

Standardization in this sensitive area will have to cover many aspects, including quality and safety of use. This paper addresses the specific issue of how hydrogen, as an energy carrier, could be safely transported over long-distance pipelines across Europe.

By studying articles on the same topic, we observed that green hydrogen is a priority because renewable electricity is used for its production. However, other production processes; e.g., the use of natural gas as a raw material or other fuels, should also be promoted as a technological alternative.

At the level of the European Union, the hydrogen strategy is being implemented, with premises for achieving various targets such as:

- "The achievement of a carbon-neutral EU by decarbonising sectors that are not accessible to direct electrification";
- "A better integration of wind and solar power with hydrogen as a storage medium";
- "Overcoming the economic damage caused by the COVID-19 lockdown, in particular by providing substantial subsidies for the hydrogen economy from the EU Recovery Deal";
- The real opportunity to create new jobs in the hydrogen production industry;
- "Combating the causes of migration by creating supply chains with countries outside the EU within the framework of the EU's external energy policy" [24].

Based on the European Union's decarbonisation targets through direct electrification and renewable electricity, strategies in the hydrogen industry should support sectors with low decarbonisation levels, such as the construction, transport (road/water/air), and manufacturing industries.

The three objectives of the EU's hydrogen strategy, which are part of the European Environment Pact, are:

- Green hydrogen production should grow to one million tonnes per year by 2024;
- Green hydrogen production should to grow to approximately 10 million tonnes per year by 2030;
- Green hydrogen production between 2030 and 2050 will be on a systemically relevant scale.

The EU hydrogen strategy is supported by countries such as the Netherlands, which—in connection with the end of the natural gas production in the Groningen gas field—is searching for other uses for its current natural gas infrastructure; and Germany, which presented a national hydrogen strategy two years ago.

Moreover, in July 2020 the European Commission presented its strategy for better-integrated energy systems (*Powering a climate-neutral economy: An EU Strategy for Energy Sector Integration*). This approach intends to better integrate energy production and consumption, as well as planning of the electricity and natural gas systems. Instruments include both the expansion of electrification and the use of hydrogen as a transport and storage medium.

The European Commission must present tangible legislative proposals on the hydrogen economy and sector integration. Major preliminary work was conducted with regard to the legislative procedure within the framework of an "own-initiative report on a European hydrogen strategy".

This article addresses a very important topical issue that takes into account technical, technological, economic, and environmental issues and is mainly based on international and European trends in dropping CO_2 emissions by switching from the use of hydrocarbons in producing energy to the use of innovative technologies to obtain energy from renewable sources [1,2].

As the maximum allowed levels of hydrogen in the natural gas distribution systems fluctuate from country to country due to different infrastructure states and regulations [25], simulations were run and the techno-economic and environmental impacts were analysed for different percentages of H_2 in the mix with natural gas.

2. Methodology

At the central level of the European Union, it is recommended as a stringent sustainability requirement for future generations that each member country propose concrete measures to eradicate or diminish carbon dioxide and other emissions. The methane emissions from transmission networks (EU28) transformed into the CO_2 equivalent are estimated at 3.724 kT CO_{2eq} per year [26]. Obviously, these measures need to be adapted in order to meet the national reality within each member state. Currently, Romania registers gaps in the correct assessment of the level of carbon dioxide and pollutants emissions. Thus, the production, transport, storage, and distribution of natural gas have a major impact on the costs paid by the final clients, as well as on the environment, by sizing the levels of polluting emissions.

In contrast with the existing case-specific studies, the work presented in [27] proposed a generalized assessment of hydrogen injection into gas distribution networks.

To be able to deliver the same level of energy to customers while substantially reducing carbon dioxide emissions and achieving good results in sustainability, a new technology emerged that consisted of introducing 2–20% hydrogen in natural gas distribution systems by means of modern compressors [28,29]. Consequently, the study in this paper is of specific interest to specialists in the field of production, transport, storage, and distribution of natural gas in terms of sustainability, safety and risks in operation, and environmental issues.

The assumptions of this study were represented by the annual zonal consumption registered by the main distribution operator in Bucharest, the Romanian capital.

For these consumptions, simulations were conducted for the introduction into the distribution network through certain predefined points of the mixture of natural gas and hydrogen in various concentrations (5%, 10%, and 20% hydrogen). This resulted in a seasonal need for hydrogen, which requires an investment in its production capacity.

Based on the consumption history, a feasibility study was carried out both for the achievement of hydrogen production capacity and for the damping period of this technical objective.

In addition to conducting this techno-economic study, the implications of using the natural gas mixture with hydrogen on reducing greenhouse gas emissions were presented.

Based on the graphical abstract (see Figure 1), it is possible to describe the working methodology used to produce this article. In order to make it easier to follow, the following working steps taken will be presented in detail:

1. The selection of the energy solution for the introduction of hydrogen in natural gas networks worldwide;
2. The study of the evolution of natural gas prices in the current socio-political context;
3. Highlighting the calculation hypotheses and producing the working scenario while taking into account: seasonal consumptions of an important regional distributor servicing the Romanian capital during a calendar year, modelling of the distribution network typology, injection points of variable quantities of the energy mix (gas in mixture with 5%, 10%, or 15% hydrogen) in this distribution network, composition of natural gas and the mixture (chromatographic bulletins), calorific power, etc.;
4. Based on data analysis in the considered scenario, including all its assumptions, a feasibility study was carried out regarding the opportunity for an investment in a hydrogen production capacity necessary for the energy mix, as well as calculations on the amortization of this investment, while taking into account the distribution tariffs and the amounts resulting from marketing a hydrogen surplus.
5. Moreover, based on the scenario considered, an analysis of a reduction in greenhouse gas emissions (CO_2) was performed that examined the environmental impact of burning the natural gas energy mix with hydrogen;
6. Discussion of the results obtained;
7. Conclusions and future research directions in this area.

3. Analysis of the Hydrogen–Natural Gas Blend in a Distribution System

In order to further simulate gas networks with different hydrogen concentrations accurately, it was important to consider gas mixture properties. These properties were calculated using the Peng–Robinson EOS (PREOS) for a mixture of any number of compounds. The properties of the gas components were consistent with the literature in the field [30,31]. Chromatographic bulletins related to the delivery points were used to establish the gas composition. The data selected from the bulletins to be used in the processing software are presented in Table 1.

Table 1. Initial gas composition related to chromatographic bulletins.

No.	Component Name	Symbol	Entry 1	Entry 2	Entry 3	Entry 4
0	1	2	3	4	5	6
1.	Methane	CH_4	0.9068	0.8568	0.7568	0.8568
2.	Ethane	C_2H_6	0.021	0.051	0.151	0.051
3.	Propane	C_3H_6	0.0248	0.0348	0.0348	0.0348
4.	ISO-Butane	C_4H_{10}	0.0051	0.0051	0.0051	0.0051
5.	N-Butane	C_4H_{10}	0.0085	0.0085	0.0085	0.0085
6.	ISO-Pentane	C_5H_{12}	0.0022	0.0022	0.0022	0.0022
7.	N-Pentane	C_5H_{12}	0.0018	0.0018	0.0018	0.0018
8.	Hexane+	C_6H_{14}	0.00508318	0.005083	0.005083	0.005083
9.	Carbon dioxide	CO_2	0.01781365	0.027814	0.027814	0.027814
10.	Nitrogen	N_2	0.0069	0.0069	0.0069	0.0069
11.	Hydrogen sulphide	H_2S	0	0	0	0
12.	Water	H_2O	0	0	0	0
13.	Mercaptan	MRC	0	0	0	0
14.	Hydrogen	H_2	0	0	0	0
	TOTAL		100	100	100	100

The mix of hydrogen with natural gas was carried out in two stages due to the availability of hydrogen plants. One type of simulation implied different percentages of H_2 (5, 10, and 20) entering the system via Entry 2, as the hydrogen plant was the first to be functional and had the necessary capacity to deliver. The three H_2 percentages used in the simulations were a result of discussions held by the Parliament Special Commission for Hydrogen on the implementation stages in the gas distribution systems in Romania, the percentages of which will be included in the next regulatory framework. The other components were reduced accordingly (Table 2).

The other type of simulation used different percentages of H_2 (5, 10, and 20) entering the system through all four entries, as the hydrogen plants will be functional in the near future. The results of this type of simulation will be presented in a future article.

The effect of increasing the hydrogen percentage can be seen in Figure 6 in terms of the higher heating value (HHV) entering the system through the Entry 2, a parameter that, after some time, impacted the energy delivered to the clients [32,33].

Table 2. Gas composition from Entry 2—different H_2 percentages.

No.	Component Name	Symbol	Initial	5% H_2	10% H_2	20% H_2
0	1	2	3	4	5	6
1.	Methane	CH_4	0.8568	0.81396	0.77112	0.68544
2.	Ethane	C_2H_6	0.051	0.04845	0.0459	0.0408
3.	Propane	C_3H_6	0.0348	0.03306	0.03132	0.02784
4.	ISO-Butane	C_4H_{10}	0.0051	0.004845	0.00459	0.00408
5.	N-Butane	C_4H_{10}	0.0085	0.008075	0.00765	0.0068
6.	ISO-Pentane	C_5H_{12}	0.0022	0.00209	0.00198	0.00176
7.	N-Pentane	C_5H_{12}	0.0018	0.00171	0.00162	0.00144
8.	Hexane+	C_6H_{14}	0.005083	0.004829021	0.004574862	0.004066544
9.	Carbon dioxide	CO_2	0.027814	0.026422968	0.025032285	0.02225092
10.	Nitrogen	N_2	0.0069	0.006555	0.00621	0.00552
11.	Hydrogen sulphide	H_2S	0	0	0	0
12.	Water	H_2O	0	0	0	0
13.	Mercaptan	MRC	0	0	0	0
14.	Hydrogen	H_2	0	0.05	0.1	0.2
	TOTAL		100	100	100	100

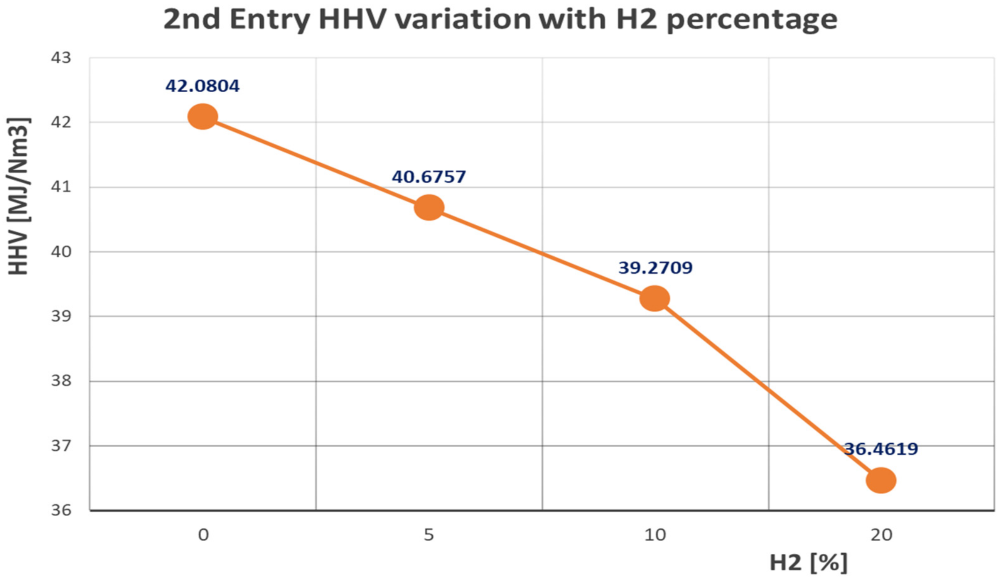


Figure 6. HHV variation for different H_2 percentages (source: authors, based on case study).

3.1. Presentation of the Distribution System

As already mentioned, our study presents a simulation of the natural gas medium-pressure distribution network in Bucharest, the largest city in Romania.

As this is part of the strategic networks of Romania, the names or locations of the equipment cannot be made public, but the configuration was similar to the real one in terms of connections and the length and diameters of the pipes. The medium-pressure distribution network, which consisted of a circular network supplied by four entry points, was designed in a hydrogen-enriched natural gas network simulator. The gas mix went to three delivery points directly and to the other five through two major measuring regulation stations (MRSs) (see Figure 7). One of these delivery points was closed due to maintenance, and as a result, the flow was 0 throughout the simulation.

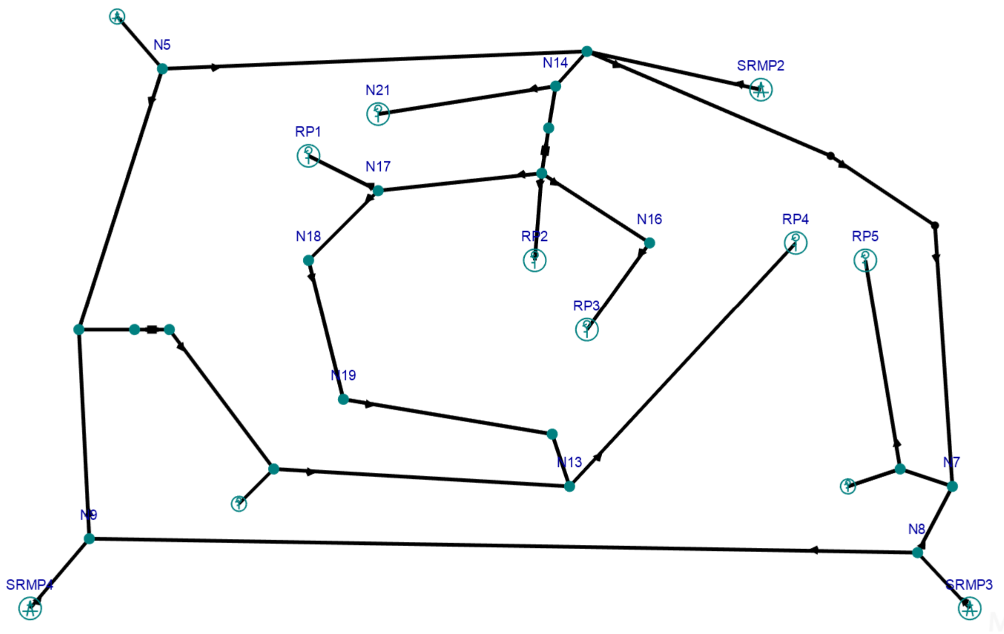


Figure 7. Natural gas medium-pressure distribution network (source: authors, based on case study). SRMPs (MRSs)—Measuring Regulation Stations; RPs—Regulation Points; Ns—network nodes.

3.2. Simulation Type

In order to reach a full understanding of the H_2 injection's influence on the distribution network and on the final consumers, three types of simulations were run. We used two numerical simulators for verification purposes: Simone by Liwacom [34] and Admodunet by NetGas [35]. All the simulations were dynamic for 24 h in order to observe how the mixed gas was flowing through the distribution network and to be able to determine the daily gas balance [32,33]. In the simulations of the four entry points, three of them were in a flowrate condition and one in a pressure condition (the flowrate was calculated by the simulator). All the exit points were in a flowrate condition, as the requested volume of gas had to be delivered. The second measuring and regulation station was in an output pressure condition.

The first simulation was without H_2 in the system and was used as a benchmark. A picture of the pressures in the network in the final hour of the simulation is presented in Figure 8, which should be interpreted based on the colour code on the right of the figure.

The next types of simulations were for summer and winter; in the cold season, the consumed volume was 10 times higher. For the two cases, simulations and analyses were performed for three types of scenarios (the varied H_2 percentage of the mix). Simulations were conducted for 5%, 10%, and 20% H_2 injected into the network.

All the above-mentioned simulations were conducted for the first-stage situation (Entry 1), with the possibility of introducing hydrogen in the network (Entry 2).

The purpose of this simulation was to determine the impact of the energy delivered to final customers in different parts of the city.

As will be further presented, the energy delivered decreased with the percentage of hydrogen introduced in the network, but only for the areas affected by the mix of hydrogen with natural gas. For the case of 20% H_2 injected in the distribution network, simulations were performed to see how much the gas needed to be increased in order to deliver the same energy to affected customers.

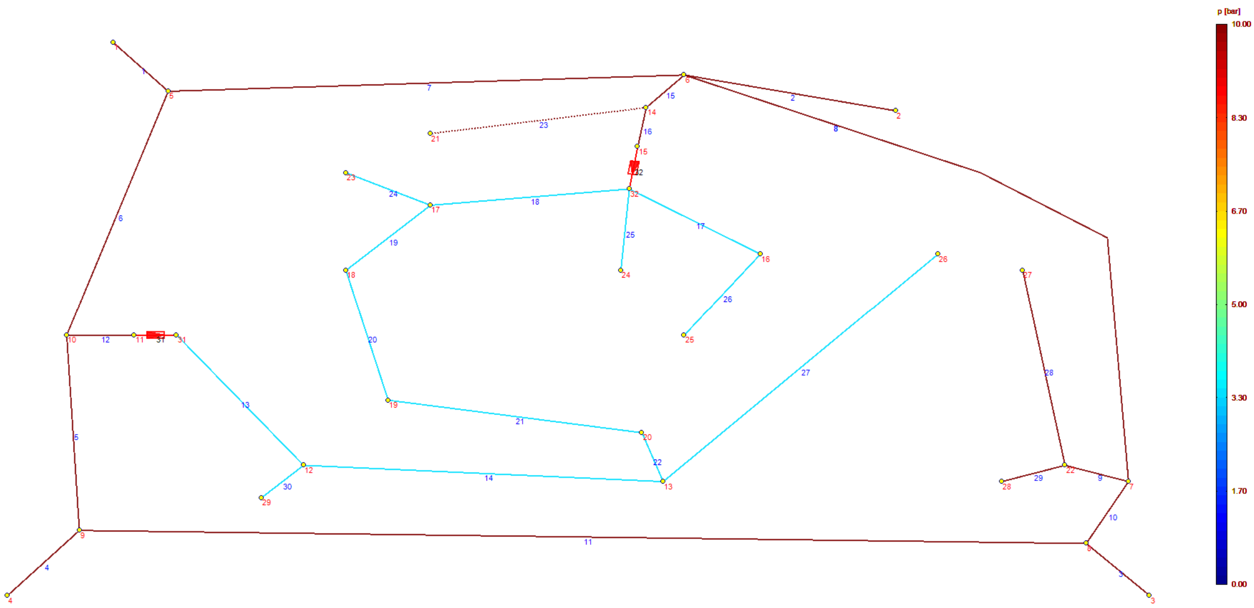


Figure 8. Natural gas medium-pressure distribution network—initial simulation results (source: authors, based on case study).

3.3. Results of the Numerical Simulation

As stated before, the initial case in which no H_2 was introduced yet is used as a benchmark. Table 3 presents the flowrates, high heating values, and energy entering and leaving the distribution network under analysis in the summer scenario.

Table 3. Gas parameters—initial scenario.

Input					Output				
Node	Name	Flowrate Nm^3/h	HHV MJ/Nm^3	Energy MWh	Node	Name	Flowrate Nm^3/h	HHV MJ/Nm^3	Energy MWh
0	1	2	3	4	5	6	7	8	9
1	SRMP1	4708.68	41.03485	1289.66	23	RP1	6121.284	41.37577	1690.488
2	SRMP2	7651.605	42.08037	2149.094	24	RP2	3060.642	41.707	852.0102
3	SRMP3	7063.02	44.94874	2119.002	25	RP3	3884.661	41.707	1081.398
4	SRMP4	7063.02	42.08037	1983.779	26	RP4	706.302	42.08037	198.3779
					27	RP5	5650.416	43.70217	1648.188
					28	RP6	6121.284	43.70217	1785.537
					29	RP7	941.736	42.08037	264.5039
	Total	26,486.33	170.1443	7541.535			26,486.33	296.3548	7520.502

In this scenario, there were no large differences in the HHV for different parts of the city. This problem appeared and increases along with the introduction of hydrogen.

In the summer scenario, which had only one entry point with a hydrogen–natural gas mix, due to different mixing and flowrates in the distribution network, some parts of the city were more affected by the energy decrease. As shown in Figure 9, Exit Points 4 and 7 were the only ones unaffected by the decrease in HHV, whereas the largest impact was on Exit Points 2 and 3. The advantage for these areas was that there is a substantial reduction in the carbon footprint.

For a winter scenario, as winter flowrates were approximately 10 times larger and the HHV entry was the same, similar trends and values were obtained that depended only on the mixing of the gas flows. A comparison of summer and winter HHV for one of the delivery points is presented in Figure 10. The difference between the summer and winter scenarios was between 0.1% at benchmark and 0.14% at 20% H_2 in the mixed gas.

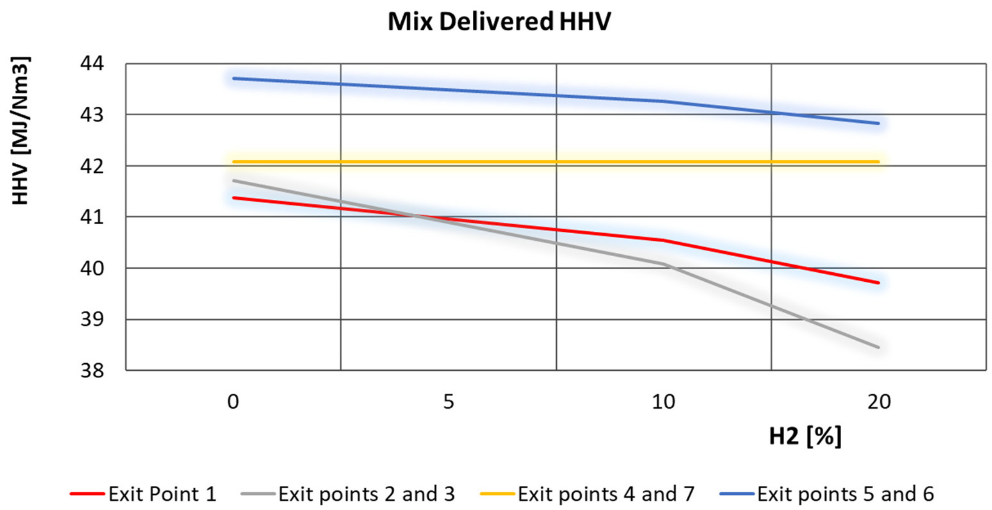


Figure 9. HHV variation by area for different H_2 percentages in the mixed gases—summer (source: authors, based on case study).

In order to deliver the same amount of energy to the customers, the flows must be increased in order to compensate for the HHV decrease due to the presence of hydrogen. We observed that the sum of the entry points' volume or energy was not similar to the sum of the exit points due to the dynamic of the gas in the network. In this paper, the hourly behaviours of the gas quality in the network and the gas balance were not analysed, as the research focused only on the quality of the stabilized gas at the end of the day [36]. Due to the network size and gas dynamic, there was a difference of 232 MWh between the entry points and exit points, which was energy that was accumulated in the gas existing in the network.

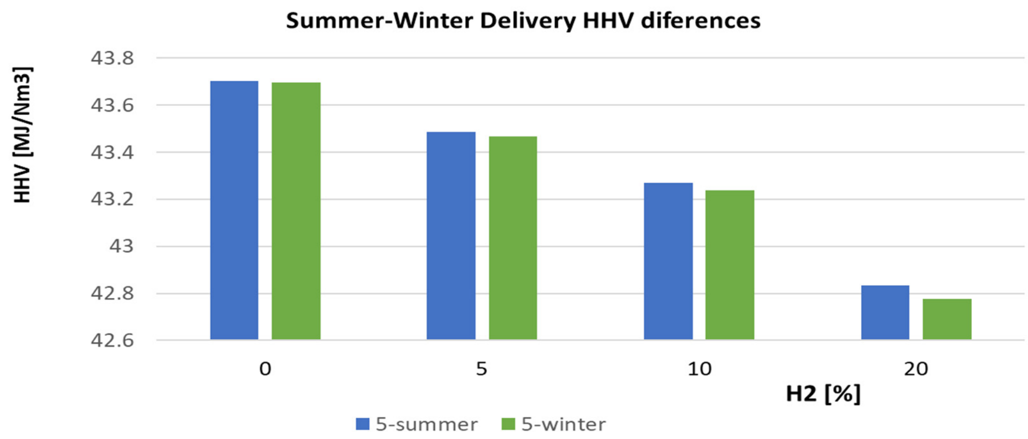


Figure 10. HHV variation for Area no. 5 (Source: authors, based on case study).

Simulations were conducted in order to analyse the necessary volumes for the 20% hydrogen–natural gas mix in winter at one injection point.

It was only at Entry 2 for hydrogen that the energy decrease was similar for the entry and exit points: 2869.43 MWh, or approximately 3.8% (see Table 4). In order to deliver the same energy (75,182.52 MWh), the flow had to be increased by 12.38% at Entry 2, from 76,516 Nm^3/h to 87,334 Nm^3/h. The final imbalance of the network based on the exit point energies (see Table 5) was 253.14 MWh, similar to the benchmark.

If the mix of hydrogen and natural gas was introduced at all entry points, the energy decrease was not similar for both the entry and exit points due to the dynamic flow in the distribution network. However, this is an issue that will be analysed in a future paper.

Table 4. Energy comparison—entry points.

Entry Points				
Node	**Name**	**Initial Energy, MWh**	**20% H_2 Mix Energy, MWh**	**20% H_2 Mix Initial Energy, MWh**
0	**1**	**2**	**3**	**4**
1	SRMP1	12,896.6040	12,896.6040	12,896.6040
2	SRMP2	21,490.9403	18,621.5066	21,254.3012
3	SRMP3	21,190.0161	21,190.0161	21,190.0161
4	SRMP4	19,837.7911	19,837.7911	19,837.7911
Total		75,415.3514	72,545.9177	75,178.7122

Table 5. Energy comparison—exit points.

Exit Points				
Node	**Name**	**Initial Energy, MWh**	**20% H_2 Mix Energy, MWh**	**20% H_2 Mix Initial Energy, MWh**
0	**1**	**2**	**3**	**4**
23	RP1	16,889.4834	16,274.8687	16,869.4874
24	RP2	8519.0350	7843.4617	8472.9416
25	RP3	10,812.6213	9955.1629	10,753.1950
26	RP4	1983.7791	1983.7791	1983.7791
27	RP5	16,479.6309	16,133.1518	16,417.6984
28	RP6	17,852.9335	17,477.5811	17,787.2351
29	RP7	2645.0388	2645.0388	2645.0388
Total		75,182.5220	72,313.0443	74,929.3755

3.4. Feasibility Study

Based on the simulations performed in the previous section, a case study was carried out on the amortization of an investment for the hydrogen production capacity required for an existing natural gas distribution network of approximately 40 km (39.76 km with a 20-inch diameter) with a mixture consumption of 6,000,000 m^3/day in winter and 636,000 m^3/day in summer.

Three scenarios were considered in this case study; i.e., with percentages of hydrogen injection mixed with natural gas of 5%, 10%, and 20%. The considered percentages for this scenario imply investments in hydrogen production capacities of 300,000/31,800 m^3 $H_{2,OUT}$/day, 600,000/63,600 m^3 $H_{2,OUT}$/day, or 1,200,000/127,200 m^3 $H_{2,OUT}$/day. When transforming the necessary volume of hydrogen to inject m^3 into MWh $H_{2,OUT,}$ it was observed that capacities included in the following daily production limits were needed, depending on the periods of the year, as follows: 35/3.75 MWh $H_{2,OUT}$, 70/7.5 MWh $H_{2,OUT}$, and 140/15 MWh $H_{2,OUT}$.

In order to better understand the phenomenon of hydrogen production, both the methods of conducting it, as well as the type of hydrogen resulting, are presented below. A colour code is used to indicate the method for obtaining the hydrogen (Table 6). The table summarizes the type of hydrogen and the methods used to obtain it, and where there are more sources of production, the first listed is the most common. Although the use of colour codes is not standardized, this presentation is very clear.

Currently, the most widely used methods of hydrogen production are by the reforming of methane using steam or by the gasification of coal (which is not widespread in the EU), both of which are methods with significant carbon emissions. There are other alternative methods of hydrogen production at different stages of R&D at the technology readiness level (TRL). In this section, the research focuses primarily on the most common electrolytic methods for hydrogen generation; namely, alkaline electrolysis (ALK), polymeric electrolysis membrane (PEM), and solid oxide (SOEC). Furthermore, the most common methods of producing hydrogen based on the use of fossil fuels in direct connection with carbon capture, storage, and use (CCUS) technologies will be investigated. The two technologies mentioned above are the methods of reforming methane with steam (SMR + CCUS) and the autothermal one (ATR + CCUS).

Table 6. The colour codes for different types of hydrogen and production sources.

Colour Code	Production Source	Method
Green	Renewable energy and electricity	Water electrolysis
Turquoise	Hydrogen unstable storage; thermal splitting of methane	Methane pyrolysis
Blue	Hydrogen storage, see surface chemistry; hydrocarbons with carbon capture and storage	CCS networks required
Gray	Fossil hydrocarbons, mainly steam reforming of natural gas	
Brown or Black	Hydrogen minimum, coal	
Purple or Pink or Red	Hydrogen storages; nuclear power	Without electrolysis of water
Yellow	Low level hydrogen in solar powers	Via photovoltaic [37,38]
Gold	Natural hydrogen in the earth's crust	Obtained by mining
White	Medical hydrogen	Refers to naturally occurring hydrogen

There have been several studies at the EU level that led to the identification of investment costs involved in hydrogen production. Figures found in public sources differ in scope and reported units, so they often lack the rigour needed for direct comparison. The methodology and units used in this section are specified below. The data were normalized to standard units.

As mentioned above, there are different technological options for hydrogen production methods. Studies have revealed that most of the amount of hydrogen in the EU is produced on site (of the total production capacity, about 64% is hydrogen captive), usually in large industrial environments, and the remaining hydrogen is generated as a byproduct of industrial processes (21% of total production capacity is secondary hydrogen) or as a main product and delivered to demand points (15% of total production capacity is commercial hydrogen).

Currently, 95% of hydrogen production in the EU is achieved mainly by steam methane reforming (SMR), and a smaller amount by autothermal reforming (ATR), with both processes presenting very high carbon emissions [39]. In order to increase the performances of the processes, a few ongoing studies are seeking to improve the modelling of sorption-enhanced steam methane reforming (SE-SMR) [40] or are using a packed bed reactor embedded with a Ni/Al_2O_3 catalyst [41]. In the European Commission strategy, these continuous production methods that use fossil fuels are commonly referred to as "gray hydrogen production methods" and are defined as producing "fossil hydrogen". However, both SMR and ATR could be coupled with carbon capture, use, and storage (CCUS) systems with different CO_2 capture rates and their reintroduction into technological processes for reuse. In the hydrogen production and use strategy, such production is commonly referred to as "blue hydrogen" or is defined as "carbon-based fossil hydrogen" [39].

Most of the remaining 5% is produced in the chemical industry as a byproduct in the chlor-alkali processes.

To conclude the study in this article, we emphasize that the use of electrolysis for hydrogen production should be preceded by a substantial expansion of the manufacturing capacity of the electrolyser. Without considering the costs for manufacturing the electrolyser, the overhead costs will be estimated on the basis of data provided by the manufacturers of hydrogen production capacity (see Tables 7 and 8), with these investment costs being expressed in millions of EUR per MW $H_{2,OUT}$ [39].

Table 7. Investment cost for green hydrogen production technologies (2020).

Production Method	Initial Investment Costs (mil. Euro/MW $H_{2,OUT}$)
Alkaline electrolyser (ALK)	0.6–2.8
Polymer electrolyte membrane (PEM)	1.25–3.6
Solid oxide electrolyser (SOEC)	1.1–3.7

Table 8. Investment cost for blue hydrogen production technologies (2020).

Production Method	Initial Investment Costs (mil. Euro/MW $H_{2,OUT}$)
Steam methane reforming (SMR retrofit with CCUS)	0.7
Steam methane reforming (SMR new with CCUS)	0.75–1.7
Autothermal reforming (ATR retrofit with CCUS)	0.7
Autothermal reforming (ATR new with CCUS)	0.9–1.5

Studies have shown that companies in the field often declare a capital expenditure (CAPEX) as a total investment in the hydrogen production unit (electrolyser, reformer). However, it is not clear whether these costs refer only to the investment cost for the unit itself or also include the factory balance (BoP) and possibly the cost of the system integration and the cost of capital. For current electrolyser variants, BoP and system integration together can exceed the cost of the electrolyser unit, so their inclusion or omission matters greatly.

The case studies considered the total installed cost, which included the CAPEX for the hydrogen production unit, BoP, and the cost of system integration (the cost of capital was excluded, because the studies did not report it separately).

Regarding production capacity, there are specialized studies containing reports that provide various investment figures in terms of production capacity. There are two definitions of production capacity:

- Input capacity in terms of electricity or methane;
- Output capacity in terms of hydrogen produced.

This is sometimes confusing, as production capacity is often reported in kW/MW (or Nm^3/h) without specifying whether the units refer to input or output capacities.

In the case study, the output production capacities in kW $H_{2,out}$ or kg $H_{2,out}$ were reported.

The concept of energy efficiency is directly dependent on cost and production capacity. In the process of obtaining hydrogen using electrolysis, the energy efficiencies of the stack and of the system are often reported inter-dependently of each other. Moreover, energy efficiency is reported for both lower heating values (LHVs) and higher heating values (HHVs), a situation that leads to inaccuracies upon comparison.

In the case of obtaining hydrogen by means of electrolysis, the determination of the energy efficiency of the system was conducted for the lower thermal power (see Table 9) [39].

Table 9. Electrolyser efficiency and stack lifetime (2021).

Alkaline (ALK)		**Polymer Electrolyte Membrane (PEM)**		**Solid Oxide (SOEC)**	
Efficiency (LHV)	Stack lifetime (years)	Efficiency (LHV)	Stack lifetime (years)	Efficiency (LHV)	Stack lifetime (years)
63–70%	5–10	56–63%	3.5–10	74–81%	1–3.5

In the case of obtaining hydrogen by methane reforming, the determination of the energy efficiency of the SMR process was also conducted at the lower thermal power value.

OPEX represents operating costs, while REPEX represents replacement costs. OPEX and REPEX are important components of costs when comparing different methods of hydrogen production.

In the case of obtaining hydrogen using electrolysis, the main difference was the lifespan of the stack.

For the SMR + CCUS method, an illustrative breakdown of the raw materials (natural gas), electricity (mainly for CCUS processes), and OPEX of the plant are shown in Table 10 [39]. It should be noted that these mature productions have long lifespans (25+ years).

Table 10. SMR coupled with CCUS plant efficiency and illustrative OPEX breakdown [42].

Variable	**Value**
Plant efficiency	65% (including energy demand for CCUS)
Natural gas	70% share of total OPEX costs
System OPEX	15% share of total OPEX costs
Electricity	13% share of total OPEX costs
CCUS system OPEX	Less than 0.1% share of total OPEX costs

In order to carry out the scenarios proposed in this case study, the energy production unit was evaluated at a 65% energy efficiency, which led to a differentiated hydrogen requirement, as shown in the following table. Moreover, the working hypothesis was an investment cost in the year 2020 of approximately EUR 105,000/MWh $H_{2,out}$.

As shown in the simulation, an injection point was considered in order to analyse the volumes needed for a mixture of 20% hydrogen and natural gas during winter. The entry point for the specified mix was SRMP 2. In order to deliver the same energy requirement (75,182.52 MWh), the flow must be increased by 12.38% at Entry 2, from 76,516 Nm^3/h to 87,334 Nm^3/h.

The energy requirement was 21,490.94 MWh, which implied 4298.19 MWh of hydrogen in the mixture with natural gas (see Table 11).

Table 11. Hydrogen requirement for the winter or summer period and a 65% energy efficiency.

Scenario	Winter Requirement, MWh $H_{2,OUT}$	Summer Requirement, MWh $H_{2,OUT}$
NG mix with 5% H_2	1074.55	11.39
NG mix with 10% H_2	2149.09	22.78
NG mix with 20% H_2	4298.19	45.56

The investment costs were assessed in accordance with the requirements for each season (summer and winter) associated with the minimum and maximum limits; for spring and autumn, an average value of consumption was used that implied the costs related to these values. Therefore, depending on the default scenario for hydrogen demand, the costs of investing in such a production capacity were as shown in Table 12.

Table 12. Investment cost for hydrogen production capacity.

Scenario	Investment Requirement Costs, mil. EUR/Scenario
NG mix with 5% H_2	112.83
NG mix with 10% H_2	225.65
NG mix with 20% H_2	451.31

Hydrogen can be produced near the source of electricity/natural gas or close to the point of consumption. The case study found that hydrogen production capacity was decentralized (near the metering and adjustment station (MAS)) and was intended for a large group of consumers, requiring only a relatively minimal infrastructure for local storage and distribution.

The case study considered the availability of hydrogen to achieve the mix of natural gas in significant volumes that will have to be transported over short distances through pipelines at a relatively low cost. Apart from pipelines, compressors are the second main component of the costs of the gas transmission network. Both components (pipelines and compressors) can be reported as costs for new infrastructure or costs for the renovation of the existing affected infrastructure (usually for pipelines) [42–44].

The investment costs for transporting hydrogen and the mix between hydrogen and natural gas took into account the modernized pipelines (the total cost of renovating the pipeline network is usually divided by the total number of kilometres), a new dedicated pipe (as CAPEX costs), and the compressor station (Table 13); these were evaluated in millions of EUR/km [39].

Table 13. Costs of hydrogen transmission.

Part of the System	Units	Value	Cost/Unit, mil EUR/Unit	Investment Cost, mil EUR
New dedicated hydrogen pipelines	km	0.750	1.50	1.12
Refurbishment of natural gas pipelines	km	39.76	0.57	22.66
New dedicated compression	Installed compression power, MWh	1500	0.65	97.50
	Total costs of hydrogen transmission			121.28

The total investment costs in the case study, which were approximately EUR 1705 mil., accommodated the maximum necessary distribution capacity while considering the sizing of the network and the composition of most elements in the case of a mix of 20% hydrogen and 80% natural gas.

The rest of the investment to modernize the network was also the responsibility of the distributors.

The study on the return on investment was conducted using the working hypothesis that the operating period for the considered system was 25 years.

For all natural gas distributors, there are regulated tariffs for the provision of natural gas distribution services to different categories of final customers (consumers). Based on a documentary study conducted in 2021, the following categories were found for final consumers, for which differentiated tariffs were applied for the provision of the distribution service, depending on consumption and the distribution company (see Table 14). Based on this tariff for distribution services and annual consumption, a study was carried out on the amortization of investment costs for a hydrogen production station and the injection of hydrogen into a mix with natural gas in a section of the distribution network.

Table 14. Consumption by consumer categories and distribution service tariff limits.

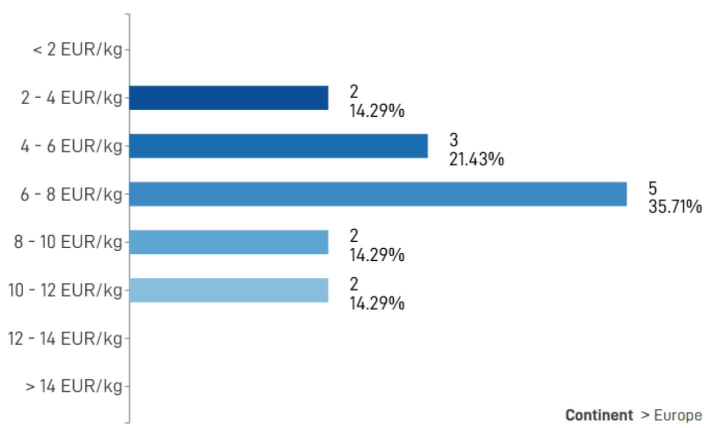
Customer Category	Minimum Annual Consumption, MWh	Maximum Annual Consumption, MWh	Distribution Service Tariff Limits, EUR/MWh
C.1.	-	≤280	2.18–13.12
C.2.	>280	≤2800	0–8.57
C.3.	>2800	≤28,000	0–8.18
C.4.	>28,000	≤280,000	0–6.84
C.5.	>280,000	-	0–4.58
C.6.	Customers who benefit from the proximity distribution tariff		0
C.7.	Transit tariff		0–0.79

Based on the consumption history of the network considered in order to carry out the case study, a quantitative assessment of seasonal consumption by types of consumers and a weighted average of distribution service tariffs were taken into account according to these percentages (see Table 15). For the considered company, the amortization was made according to the distribution tariff for the natural gas partner for the entire network.

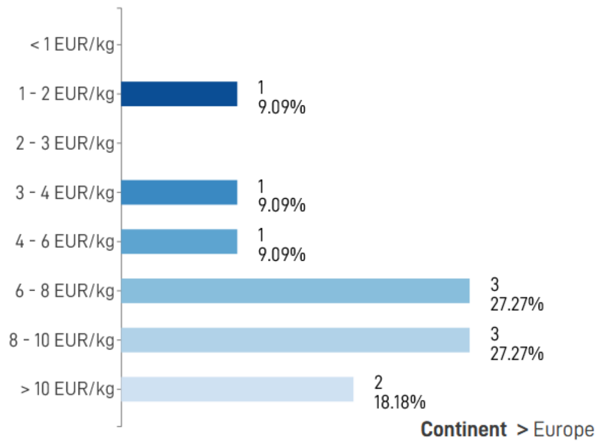
Table 15. Seasonal consumption of mix (natural gas with hydrogen) for two categories of consumers (households and companies) and the total values of the distribution tariffs collected.

No	Season	Number of Months	Household Consumption/Tariff, %/EUR/MWh	Consumption of Companies/Tariff, %/EUR/MWh	Amount of Household Consumption, MWh	Amount of Commercial Consumption, MWh	Household Consumption Value, EUR/Season	Commercial Consumption Value, EUR/Season
1	Winter	3	60/6.03	40/4.18	45,249.21	30,166.14	24,556,746.72	11,348,502.08
2	Spring	2	50/6.03	50/4.18	15,711.53	15,711.53	5,684,432.11	3,940,452.11
3	Summer	5	40/6.03	60/4.18	3197.611	4796.416	1,156,895.62	1,202,941.22
4	Autumn	2	50/6.03	50/4.18	15,711.53	15,711.53	5,684,432.11	3,940,452.11
							37,082,506.57	20,432,347.52
			Total annual value				EUR 57,514,854.09/year	

The market value was estimated based on both the costs of obtaining hydrogen and the selling prices in the European Union (see Figure 11). This analysis provided an overview of the hydrogen cost and sales price of hydrogen valleys in EUR/kg of H_2.



(**a**)



(**b**)

Figure 11. Hydrogen cost and sales prices (source: https://www.h2v.eu/analysis/statistics/financing/hydrogen-cost-and-sales-prices, accessed on 15 January 2022). (**a**) EU average cost of green hydrogen (number (share) of valleys); (**b**) EU external sales price of hydrogen (number (share) of valleys).

Furthermore, as shown in Table 16, it was specified that the excess hydrogen from the monthly production was sold on the free market to emerging industries at 80 EUR/MWh H_2, a value that was added to the amortization of the investment.

Table 16. Seasonal and total values resulting from the sale of hydrogen surplus to emerging industries.

No	Season	Number of Months	Amount of Hydrogen Sold, MWh/Season	Total Value per Season, EUR/Season
1	Winter	3	338.48	27,078.60
2	Spring	2	1790.91	286,546.00
3	Summer	5	13,484.26	182,243.26
4	Autumn	2	1790.91	286,546.00
	Total annual value			782,413.86

The period of adequate operation of a hydrogen production plant is considered to be 25 years at a linear damping rate. It was mentioned that at the level of the European Union, this amortization model, as well as the size of the period, were specified for the amortization of the investments made to reach the objectives in the energy field.

It was also mentioned that the analysis of the investment amortization was conducted using the current estimates, a fluctuation in the distribution tariffs of 5%, and with constant revenues updated with an inflation rate of 5%. Any crisis situation could affect this study by influencing the payback period of the investment.

3.5. Results of the Feasibility Study

Taking into account the values specified in the previous paragraphs, Figure 12 shows the results of the linear depreciation method applied to the necessary investment by the natural gas distributor.

As we noticed, if there was no crisis or economic uncertainty, the investment would pay off in the eighth year of operation.

ERR	or	RIRE	13.41%	(>5.5%)
ENPV	or	VANE	EUR 1298 mil.	(>0)

Apart from the economic and financial advantages, the most important gain was the environmental factor because the presence of hydrogen in the natural gas mix reduced the emission of greenhouse gases, and as a result, the processes employed were much more environmentally friendly.

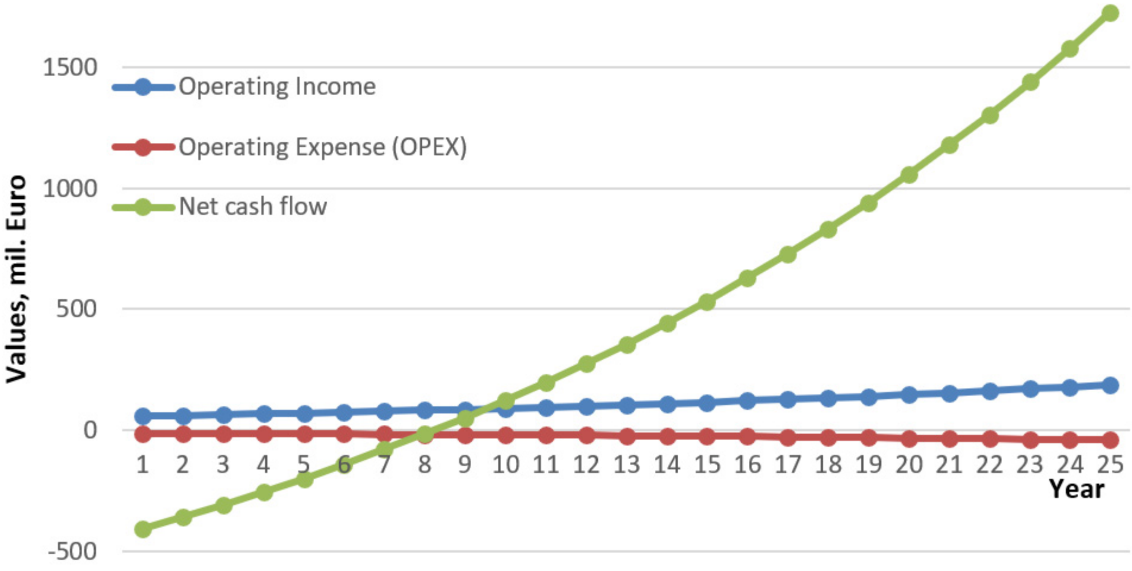


Figure 12. The straight-line method of depreciation for the investment considered (source: authors, based on the considered data).

3.6. Environmental Impact—CO_2 Reduction

In order to analyse the impact that injected hydrogen in gas distribution systems will have on the environment on one hand and on final customers on the other, an estimate was made for the CO_2 reduction when the hydrogen–natural gas mix was burned.

Since one important reason for adding hydrogen to natural gas is to reduce the emissions of CO_2, it is perhaps extremely motivating to consider the amount of this reduction.

We began by calculating the quantity of CO_2 that resulted from the process of burning the natural gas that enters the distribution system through the Entry 2, as in the simulation case this represented the benchmark. From this point, the composition was changed to 5%, 10%, or 20% H_2 and the amount of CO_2 produced was recalculated.

As shown in Figure 13, the quantity of CO_2/kg of mixed gas that was burned decreased with an increase in H_2 in the mix.

To summarize, the reduction in CO_2 was 2.5636% for 5% H_2, 5.262% for 10% H_2, and 11.1127% for 20% H_2 in the mix.

In terms of quantities, there was a reduction of 614.15 kg/h for 5% H_2 and 2466.7 kg/h for 20% H_2 in the mix. If the H_2 maximum remained at 20% in the gas mix, then the CO_2 reduction for a year measured 21.61 kt.

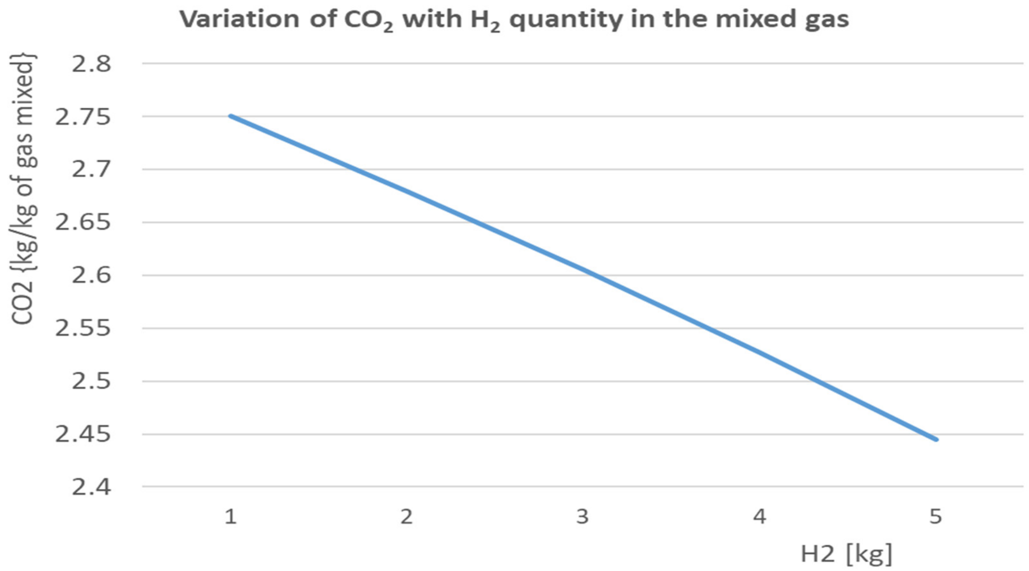


Figure 13. CO_2 produced with quantity of H_2 in the mixed gas (source: authors, based on case study).

4. Discussions

In light of the experience gained in the projects developed in European countries, the transportation of hydrogen and natural gas mixtures will not require significant changes in the standard equipment, which makes for a promising method of using hydrogen together with natural gas. Supporting demo projects such as WindGas Hamburg, HyDeploy, HyP Murry Valley, HyNet Northwest, GRHYD, THyGA, HyBlend, HyP SA, SoCalGas, Jemena West Sydney, and many others are seeking a cost-effective pathway to meet carbon-reduction goals in the coming years.

This research can serve as the basis of future feasibility studies for investments in the field of H_2 and natural gas mix in Romania.

The study arose from the need to implement these modifications quickly and thus used only a part of the existing gas distribution network of a major city in Romania. For this reason, the simulation worked on a hypothesis of introducing hydrogen through one single point in the network. As regulations are yet forthcoming, the simulations were run for different percentages of hydrogen in the natural gas mix. The study was conducted following the seasonal consumption for two categories of consumers (94% households and 6% industry).

Gas network management is based on parameters such as pipeline pressure drop, flowrate, or velocity. In the analysed case of hydrogen introduction into the natural gas distribution network, the most important parameters proved to be composition and HHV.

In addition, for these scenarios, an economic study was conducted for seasonal real consumptions that revealed the profitability of the investment.

Our plan is to further study the effects of hydrogen introduction into the network through all four entry points and the impact on environment, especially on CO_2 reduction, as well as the economic impact.

A future energy cost analysis in each scenario, along with a life-cycle assessment of the environmental impact, are needed to provide a wider perspective on which of the directions better suit Romanian distributors and which assure the lowest harmful emissions.

Another direction to follow would be a risk-management analysis related to the introduction of hydrogen into existing gas distribution pipelines.

Two new projects financed through European funds are currently in the development phase in the south of Romania; their aim is to build new distribution systems that will allow a mix of hydrogen and natural gas to be used. A further step will be to analyse all the above issues in these real distribution systems. This analysis will provide us with a better image of all the implications for the final consumers that now, according to the literature, are minimal.

The construction of new generating capacities operating on hydrogen will require large capital investments and must be combined with measures to reduce greenhouse gas emissions.

5. Conclusions

Hydrogen injection into natural gas systems decreases the emissions of unburned hydrocarbons and CO but increases the NO_x emissions. It is common to argue that introducing 10% hydrogen into natural gas would reduce the CO_2 emissions by the same percentage. However, the results proved otherwise: replacing 10% of natural gas with hydrogen diminished the CO_2 emissions by only 5%. The CO_2 reduction could be increased to 30% if the hydrogen added was around 50%.

As can be seen, the costs of CO_2 reduction by adding hydrogen in the natural gas are quite high, but the long-term operational costs are much lower.

The adaptation/modification costs for consumer appliances are high and largely contribute to the costs of a hydrogen blending scenario.

Flame stability and the negative environmental impact caused by NO_x emissions along with possible problems of hydrogen embrittlement will increase safety risks. On the other hand, the potential benefits of reductions in greenhouse emissions due to using a mix of natural gas and hydrogen must be considered.

A negative effect of introducing hydrogen into the natural gas is the reduction in the HHV, which further leads to a lower energy delivered to the customers and can be compensated only by higher gas flowrates. Another negative impact that derives from this is the capacity problem, which exists when the system is already at its upper limit. Almost all the distribution systems should be able to use a hydrogen–natural gas blend without any changes in pipes, valves, or fittings at low percentages of H_2.

The need for variability in hydrogen production in terms of nominations depending on gas demand (as well as the network and the operations made) can be an obstacle to the introduction of higher percentages of hydrogen in the natural gas.

In Romania, due to many different distribution systems built throughout the years, it is necessary to study and assess the maximal hydrogen concentrations that require no or minor appliance adjustments.

Another issue that must be addressed, as it plays a key role in the economic life, is standardization. A better incorporation of the environmental aspects into standardization is necessary.

However, as hydrogen is produced, due to the diminishing gas resources at the international level and to high gas prices, given Europe's dependence on Russian gas and the Ukraine–Russia conflict, the injection into the gas network pipelines can provide an economic solution for the storage and transport of this energy type.

The injection of H_2 in the gas distribution networks makes the effort of balancing the supply and demand across large networks very challenging. If we take into account the increases in production from renewable sources and the unpredictable nature that comes with them, difficult operating scenarios will appear in the near future.

Taking into account the scenario used and its assumptions, and if no disruptive socio-economic factors arise from the feasibility study carried out, we concluded that investing in a hydrogen production capacity in order to mix with natural gas and sell the surplus on the open market will pay for itself in the eighth year of operation. It is also possible to identify a technical solution that is even more environmentally friendly that uses electricity from sustainable, green sources (photovoltaic panels, windmills, etc.) for the technological process.

As we move to decarbonise our energy systems, a new topic has arisen: an estimate of the real cost of hydrogen–natural gas mix delivery. The critical factors affecting the viability of the solution are: a regulatory framework, the investment position and dimensioning, hydrogen prices, and electricity costs.

The implications of the war between Russia and Ukraine, especially regarding fossil fuel prices, should motivate the entire European space, including Romanian authorities, to take urgent measures and modify their long-term strategies regarding energy sources and their uses. This means that we need to diminish the dependence on these limited resources and increase the usability of renewable energy resources.

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Nomenclature

ALK	Alkaline electrolysis
ATR	Autothermal reforming
BoP	Balance of plant
CAPEX	Capital expenditure
CCUS	Carbon capture, storage, and use
CH_4	Methane
CO_2	Carbon dioxide
CO_{2eq}	Equivalent carbon dioxide
ENPV (VANE)	Economic net present value
EOS	Equation of state
ERR (RIRE)	Economic rates of return
EU (EU28)	European Union
FCHJU	Fuel Cells and Hydrogen Joint Undertaking
GHG	Greenhouse gas
H_2	Hydrogen
H_2NG	Hydrogen in natural gas
HHV	Higher heating value
LHV	Lower heating values
MAS	Metering and adjustment station
MRS	Measuring regulation station
MWh	Megawatt hour
OPEX	Operating expenditure (or expense)
PEM	Polymer electrolyte membrane
PREOS	Peng–Robinson equation of state
REPEX	Replacement expenditure
SDGs	Sustainable development goals
SMR	Steam methane reforming
SOEC	Solid oxide electrolyser cell
TRL	Technology readiness level

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