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Techno-economic feasibility assessment of hydrogen blends transport through natural gas pipelines infrastructure

TESI DI LAUREA MAGISTRALE IN
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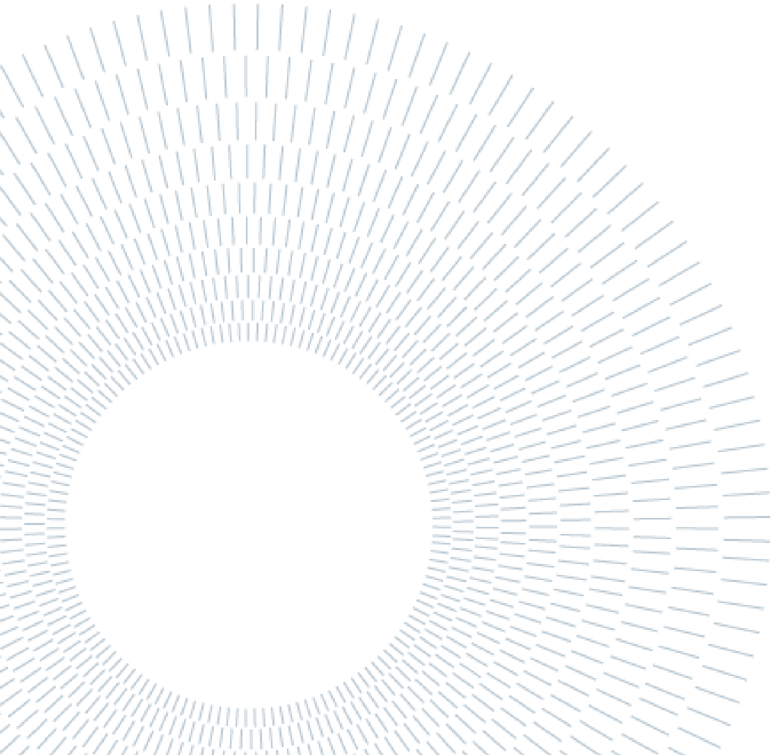

Abstract

Hydrogen is progressively getting protagonism and is adopting the position of being part of the solution to decarbonize fields as energy generation, mobility or heating.

The main problem is the lack of infrastructure to establish an energy market partially based on hydrogen. Green hydrogen generation plants, large scale storage places and transmission networks must be implemented and work together to make this solution feasible.

Among all these topics, this master thesis is focused on analysing the problem of hydrogen transmission at large scale. To solve the problem of hydrogen transmission, natural gas networks can be taken as a reference for the assessment. Apart from pipping, natural gas can be delivered in liquid state, however, liquifying hydrogen is much more challenging and expensive so right now the main solution to deliver hydrogen through great distances at large scale are pipeline systems.

The main question is how to find the optimum way to deliver hydrogen using pipelines. Nowadays there is a huge and sophisticated natural gas transmission network which can be used to deliver hydrogen too. But this solution has two main drawbacks. On the one hand, it depends on the role of hydrogen in the future, because in case of utilizing hydrogen as a pure gas, the fact of mixing it with natural gas and then split them might not be the best alternative from an economical point of view. However, if hydrogen is added into natural gas with the intention of generating a fuel with less environmental impact, this option could turn very interesting. On the other hand, natural gas pipes were not designed considering hydrogen transmission through them, so the problem of hydrogen embrittlement will be a key limiting factor.

After selecting the portion of baseline infrastructure, consequences of blending hydrogen in fluid dynamics and new compression power requirements will be assessed. Then, the issue of hydrogen embrittlement and his impact in the steel will be studied with the purpose of defining a safety limit for hydrogen addition.

Then, an economic analysis will be made by considering hydrogen transmission as a mix with natural gas using the current infrastructure with as less modifications as possible. Investment and operational costs will be calculated for different alternatives, making easier to decide which one would be the best way to afford the problem. Moreover, the case of building new pipes for pure hydrogen transmission will be assessed too.

Finally, both paths will be compared with the intention of establishing which one is the best in case of facing different scenarios.

Key-words: Hydrogen transmission, natural gas-hydrogen blends, pipeline, profitability, infrastructure adaptation, economic assessment

Abstract in italiano

L'idrogeno sta progressivamente ottenendo protagonismo e sta assumendo un ruolo centrale come parte della soluzione per decarbonizzare settori come la generazione di energia, la mobilità e il riscaldamento. Il principale problema è la mancanza di infrastrutture per stabilire un mercato energetico basato in parte sull'idrogeno. È necessario implementare impianti di produzione di idrogeno verde, luoghi di stoccaggio su larga scala e reti di trasmissione che lavorino insieme per rendere questa soluzione praticabile.

Tra tutti questi aspetti, questa tesi magistrale si concentrerà sull'analisi del problema della trasmissione dell'idrogeno su larga scala. Per risolvere il problema della trasmissione dell'idrogeno, è possibile prendere come riferimento le reti di gas naturale per la valutazione. Oltre al trasporto tramite condotte, il gas naturale può essere consegnato in stato liquido; tuttavia, liquefare l'idrogeno è più complesso e costoso, quindi al momento la soluzione principale per trasportare idrogeno su grandi distanze e su larga scala è costituita dai sistemi di gasdotti.

La domanda principale è come trovare il modo ottimale di trasportare l'idrogeno attraverso gasdotti. Attualmente esiste una vasta e sofisticata rete di trasmissione di gas naturale che potrebbe essere utilizzata anche per l'idrogeno. Tuttavia, questa soluzione presenta due principali svantaggi. Da un lato, dipende dal ruolo futuro dell'idrogeno, poiché nel caso in cui si utilizzi idrogeno puro, la possibilità di mescolarlo con gas naturale e poi separarli potrebbe non essere l'alternativa migliore dal punto di vista economico. Tuttavia, se l'idrogeno viene aggiunto al gas naturale con l'intento di generare un combustibile a minore impatto ambientale, questa opzione potrebbe diventare molto interessante. D'altro canto, i gasdotti per il gas naturale non sono stati progettati per la trasmissione di idrogeno, quindi il problema della fragilità dell'idrogeno rappresenterà un fattore limitante fondamentale.

Dopo aver selezionato la porzione di infrastruttura di base, verranno valutate le conseguenze della miscela di idrogeno in termini di dinamica dei fluidi e nuovi requisiti di potenza di compressione. Successivamente, verrà analizzato il problema della fragilità dell'idrogeno e le sue conseguenze sull'acciaio, al fine di definire un limite di sicurezza per l'aggiunta di idrogeno.

In seguito, verrà effettuata un'analisi economica considerando la trasmissione dell'idrogeno come una miscela con gas naturale utilizzando l'infrastruttura attuale con il minor numero possibile di modifiche. I costi di investimento e operativi saranno calcolati per diverse alternative, facilitando la decisione su quale sia la soluzione migliore per affrontare il problema. Inoltre, verrà valutato anche il caso della costruzione di nuovi gasdotti per la trasmissione di idrogeno puro.

Infine, entrambe le soluzioni saranno confrontate con l'intento di stabilire quale sia la migliore per affrontare scenari diversi.

Parole chiave: trasmissione dell'idrogeno, miscele di gas naturale-idrogeno, gasdotti, redditività, adattamento dell'infrastruttura, valutazione economica.

Contents

1 Chapter one. Introduction

Nowadays, the majority of energy needs are still covered by fossil fuels. During the last decade, hydrogen has arisen as a key player when finding solutions to reduce CO_2 emissions. Even it could replace fossil fuels in certain sectors which are more difficult to decarbonize. However, there are two main barriers that make hydrogen unable to compete in the energy market inclusive with grants or penalization to fossil fuels: production cost and infrastructure.

Hydrogen production in 2022 was around 95Mt and only 1Mt was low emission hydrogen, which means 0.7% of the total production. Furthermore, the vast majority was made from fossil fuels with Carbon Capture, Utilization and Storage (CCUS) technologies. The amount of electrolytic hydrogen was even lower, hardly reaching 100kt (0.1% of global production) [1]. Coal or heavy hydrocarbons gasification and natural gas reforming are the cheapest methods to produce hydrogen.

In the short-medium term the scenario is expected to be different and forecasts for electrolysis capacity has been grown exponentially. By the end of 2022, electrolysis capacity deployed was roughly 700MW and this number is supposed to grow until 230GW by 2030 [2], meaning an increase of more than 30000%.

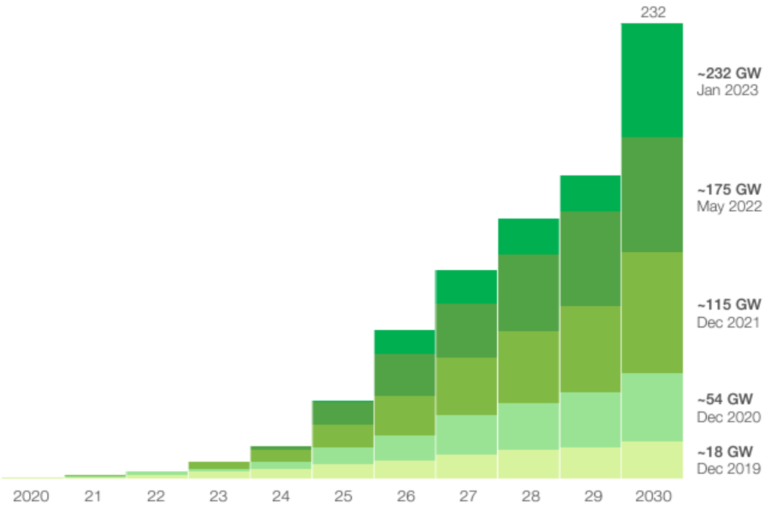

Figure 1.1: Cumulative electrolysis capacity. Installed power announced all over the years including projects in all maturity stages. [2]

The other main issue is the lack of infrastructure dedicated to hydrogen. Besides hydrogen production facilities, others key phases within the supply chain as storage, transportation and distribution need huge investments to make hydrogen competitive in the energy market. The current supply chain process for hydrogen consists in a compression stage, introduction in pressurized vessels, transportation through trailers and storage in high pressure tanks before the end use [3].

This method is useful if hydrogen demand is concentrated in certain points and with moderated volume requirements, for instance, in chemical industry. Nevertheless, logistics and infrastructure must change if hydrogen is forced to play a big role in other areas like mobility, heating, power generation or energy buffer.

1.1. Natural gas and hydrogen transportation overview

Natural gas is an energy source used to satisfy great part of energy requirements in different fields such as mobility, heating, and power generation with gas turbines and combined cycles. All these sectors and other areas are supposed to be partially covered by hydrogen, so it would be important to check the natural gas transmission situation and verify if hydrogen can be transported using similar methods.

Long distance transportation of natural gas can be done by pipelines or shipping. On the one hand, pipelines are widely used as compressed natural gas transmission path in land. On the other hand, after being extracted and treated, natural gas can be converted into liquid state and transported via shipping inside liquefied natural gas (LNG) tanks. When natural gas is liquefied, its volume is reduced in six hundred times. This considerable decrease in volume is a powerful advantage, not only in LNG shipping but also in other fields as mobility sector, where having a fuel with high energy density is crucial.

If applying these technologies to high scale hydrogen transportation, the most suitable option would be pipeline networks. Due to his low density, liquifying hydrogen requires even higher efforts and extreme conditions than with natural gas. Today's technologies spend 11kWh [3] per kg of H_2 in liquefaction, which means the third part of his lower heating value, so there is no profitability in liquifying hydrogen for delivery purposes.

Transporting hydrogen using other materials is under investigation and could be the only solution which can compete with pipelines in the medium term. Liquid organic hydrogen carriers (LOHC) are liquids at ambient temperature which can react with hydrogen generating another liquid compound. Hence, it is a cyclic process based on hydrogenation (exothermic) and dehydrogenation (endothermic) of compounds from hydrocarbon and alcohol families [3]. Figure 1.2 reflects some examples of LOHC release and storage cycle. Moreover, chemical hydrides as methanol or ammonia could be useful for hydrogen delivery.

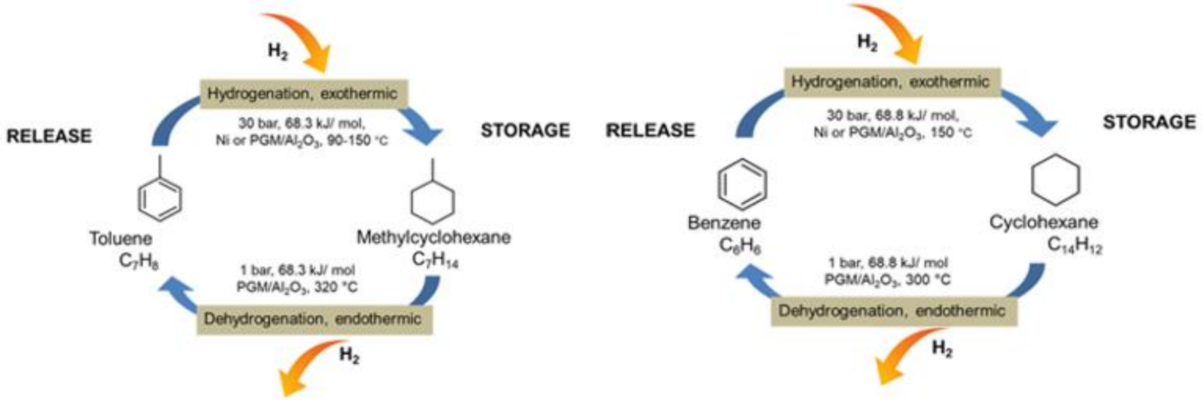

Figure 1.2: Representation of the benzene/cyclohexane (left) and toluene/ methylcyclohexane (right) LOHC system. [4]

The cost of all the process should be computed together and compared with hydrogen transportation using pipelines. Niermann et al. establish that compressed hydrogen transportation via pipelines is a valid transport option if shorter distances, however, they affirm that methanol is not only more economic but also more efficient than pipes for transporting hydrogen over long distances [5]. Others such as dibenzyl toluene or toluene are also interesting in case medium distances.

Despite all these possible advantages, the knowledge in gas and oil pipping delivery is much bigger than in the case of LOHC. In addition, the possibility of blending hydrogen with natural gas without the necessity of making great investments in the short term should be also considered.

An exhaustive comparison between both methods would be interesting and necessary, nevertheless, diving deeper into LOHC technologies is out of this master thesis' scope.

1.2. The European Hydrogen Backbone

European countries are making efforts and investing in research about green hydrogen generation, transmission and storage. The idea is to create a great hydrogen market with the collaboration and participation of the most important transmission system operators (TSO).

The European Hydrogen Backbone is an initiative which involves more than thirty TSO all around Europe, with the objective of building an international transmission network. That infrastructure will interconnect storage and generation sites with the consumption points, enabling the development of a renewable and low-carbon hydrogen market [6]. The goal is to have available the system of the Figure 1.3 by the end of 2040. It will be composed by a mix of existing pipes and new ones.

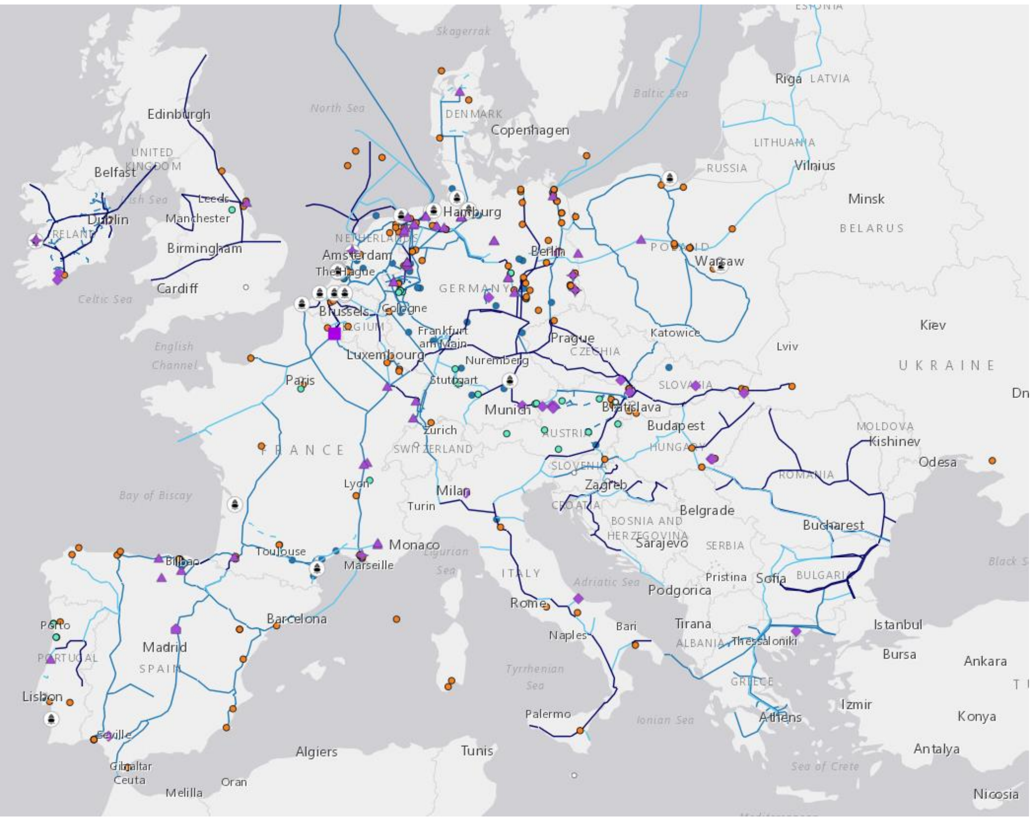

Figure 1.3: Expected European Hydrogen Infrastructure map in 2040. Darkest lines are existing reconverted pipelines, light blue new pipes and dark blue a mix of both. [7]

Within this giant project, H2med is the fraction which connects hydrogen transmission network of Iberian Peninsula with northwestern Europe. The initiative was initially launched by Portugal, Spain and France in December 2022, creating a collaborative space composed by the companies in charge of gas transmission (REN, Enagás, GRTgaz, and Teréga) and the respective governments. In January 2023 Germany and his operator OGE became part of the project too. In addition, GRTgaz's project HY-FEN will be used as a connection between this Iberian corridor and other important networks such as MosaHYc or H2ercules, see Figure 1.4. These four systems are expected to be working together by 2030, becoming the first European infrastructure dedicated to international hydrogen transportation at high scale. Some details about each project will be exposed hereunder.

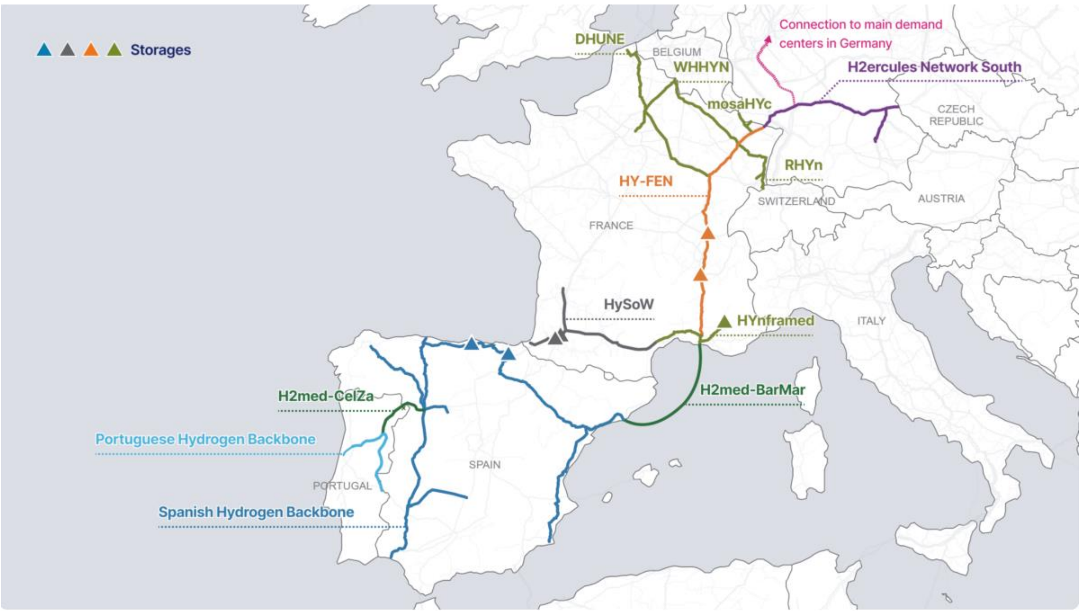

Figure 1.4: Western European hydrogen corridor infrastructure in 2030 as a result of several projects combination. [8]

1.2.1. H2med: CelZa and BarMar

CelZa and BarMar are the two international connections between Spanish future hydrogen infrastructure and Portuguese and French networks, conforming the H2med system. Both are in study phase since 2022 with the intention of starting the construction works in 2026.

CelZa involves the construction of a 250km pipe which connects both Iberian countries through Celorico da Beira and Zamora. This line will be used to export hydrogen produced in Portugal from solar and wind energy. Pipe will be designed to withstand up to 100bar with a compression station of 24.6MW. Pipeline building is responsibility of transmission system operators REN and Enagás, that will cover the works in their respective sections [8].

BarMar will connect Barcelona with Marsella using an offshore path under the Mediterranean Sea, thus, the works will be more expensive and challenging. The intention is to carry the gas 2600m under the sea level at 210bar maximum pressure. This will offer the possibility of delivering hydrogen from Spain and Portugal with France and then export the gas also to hydrogen German network. Table 1.1 wraps up some technical data of both projects.

To make this possible, Enagás has alseady set two main axes to send hydrogen between Spanish regions [9]. The first one is the north line, which covers the Cantabrian Sea and will be extended through the Ebro valley until reaching the Mediterranean Sea station, where the line would be split in two parts to deliver the gas to Barcelona and Cartagena. Moreover, the first axis will include two salt caverns for hydrogen storage in Cantabria and Basque Country.

From Huelva to Gijón, the second axis will ensure linkage between the occidental regions, including the international connection in Zamora, Galicia and also Puertollano. Enagás strategy will be to reconvert part of the current infrastructure to hydrogen transmission and complete the path with construction of new pipelines.

Table 1.1: Technical specification of CelZa and BarMar pipelines [8].

	CelZa	**BarMar**
Length [km]	248	450
Diameter [inch]	28	28 or 42
Maximum pressure [bar]	100	210
Annual capacity [Mt]	0.75	2
Power transmission ratio [MW]	2855	7610
Budget [Million €]	350	2135

1.2.2. HY-FEN and MosaHYc

France has already launched feasibility studies as a starting point for HY-FEN project. His TSO GRTgaz is in charge of building the 1200km line which will be used to connect the Iberian corridor with Germany, passing through Lyon and including linkage with large hydrogen storage projects in the Rhone valley.

The intention of MosaHYc (Moselle-Saar-Hydrogen-Conversion) is to set more than 90km of hydrogen grid to connect French and German networks using nearly 70km of natural gas pipelines to deliver pure hydrogen. Apart from GRTgaz, enterprises involved are CREOS Deutschland and the energy group from Luxemburg Encevo [10].

The main purpose is to supply industrial plants along the border area between Germany, France and Luxemburg [11]. Moreover, it is expected that other sectors as electricity production, mobility or heat generation could take advantage from the infrastructure to operate and transport hydrogen.

However, considering that the maximum capacity is 5.5GWh/day, the infrastructure does not appear to be sized to cover the capacity requirements that a future with certain protagonism of hydrogen would need. To establish a direct comparison with H2med, this capacity is equivalent to say 229MW of power transmission ratio against 7610MW of BarMar pipeline. If looking at annual transmission capacity, MosaHYc is designed to deliver 0.06Mt of hydrogen per year, which is too far from 0.75 or 2Mt of previous lines.

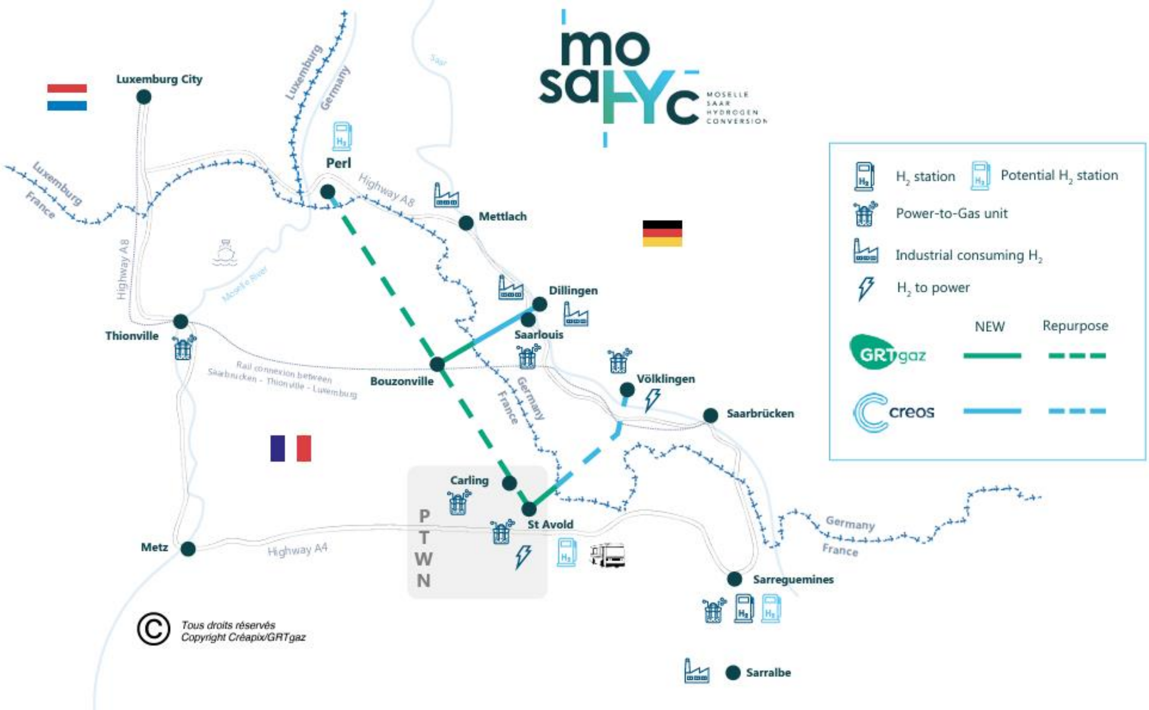

Figure 1.5: Schematic view of MosaHyc pipeline project with hydrogen consumption points, including power to gas units, industrial areas and hydrogen stations [10].

1.2.3. H2ercules

The initiative was launched in 2022 by OGE and RWE, which are companies dedicated to German gas transmission and energy production respectively. RWE wants to build electrolysers with 1GW capacity and reconvert gas-fired stations of 2GW into hydrogen. H2ercules project will try to connect those electrolysers and reconvert power stations to establish a hydrogen corridor with industrial companies through pipelines along the west line of the country [12]. In addition, the plan involves connections with European routes for green hydrogen.

The majority of the 1500km final grid will be obtained from the conversion of current natural gas pipelines, making the implementation faster and more cost-effective [13].

By 2026 it is expected to establish connections with Norway and Belgium. Two years later there will be few link points with Netherlands, and for 2030 the network will operate with France and also with Czech Republic thanks to an extension in the south of the country.

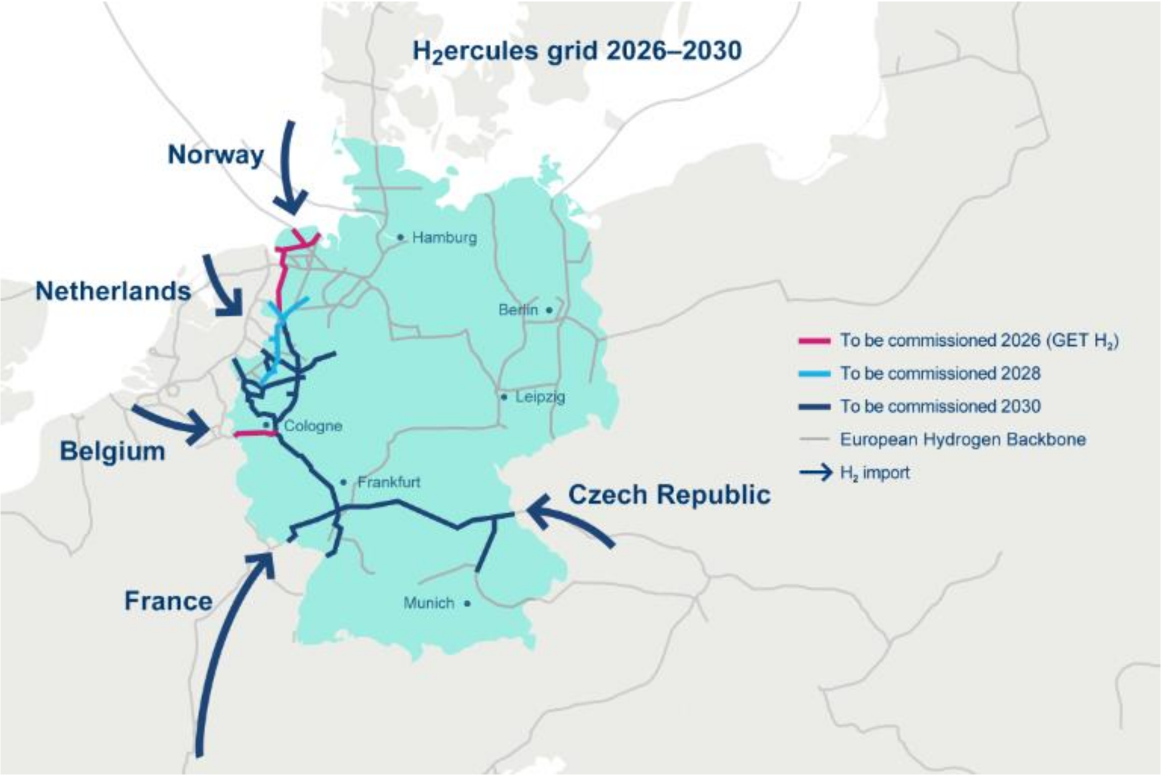

Figure 1.6: H2ercules network layout and evolution from 2026 to 2030. [13]

2 Chapter two. Methodology

The purpose of this project is to establish a defined path to face the problem of transporting hydrogen at high scale through pipelines. There are three main lines of action in which the thesis is going to be focused: Fluid dynamic assessment, pipe material integrity and cost analysis.

In order to be as close to the reality as possible, all this analysis will be based on a real case. The system selected is a portion of the Spanish natural gas network which counts with three pipelines of around 250km each one. This is the starting point for evaluating a possible scenario in the short and medium term, that is to introduce hydrogen in the system and transport the gas as a blend with natural gas. Designing a full dedicated hydrogen pipeline would be the long-term solution, in case hydrogen gain much more protagonism in certain industrial sectors as mobility, power generation or energy storage.

2.1. Fluid dynamics

When adding hydrogen to natural gas, fluid properties change drastically. This change generates variations in volume flow, mass flow, power transmitted, density and consequently pressure losses which affects compression stations set-up. Because all this, there is a necessity to complete an exhaustive assessment on fluid dynamics at different blending levels.

The program used for this analysis was MATLAB, specifically MATLAB basic functions based on discrete properties evaluation. The codes are composed of a first part in which several parameters are defined. Then, using this parameters and properties, other variables were calculated to define the pressure losses each two kilometres. Hence, gas properties are computed 376 times along the whole pipeline.

Variables as mixture's molar mass, net heating value, density, compressibility factor or adiabatic index are given by REFPROP. This software can give all this information for different pressure, temperature and gas composition.

The most important requirement will be to satisfy the same power demand as there is now with natural gas. The problem was tackled from different points of view with the aim to cover distinct possibilities and check the goodness of each one by evaluating data extracted from the code.

2.2. Hydrogen embrittlement and impact in the metal microstructure

Other important issue of introducing hydrogen in the current natural gas infrastructure is hydrogen embrittlement. These pipes were designed without considering important hydrogen presence in the delivered gas. These steels are not prepared to face that situation, and their mechanical performance could decrease dangerously.

Different mechanical properties will be assessed. Firstly, tensile properties as yield strength, ultimate tensile strength, elongation and reduction of area were used to extract conclusions about the ductility of the material and the behaviour in both elastic and plastic region. Then, fragilization was also analysed by gathering data about the material response after testing their fracture toughness and fatigue crack growth. The vast majority of the experiments considered from literature were done by following testing standards.

The assessment of all these properties was necessary to establish certain limits in blending hydrogen. Thanks to all data, it was possible to define a rigorous theoretical threshold. Furthermore, an exhaust verification of pipes preservation level must be done.

2.3. Economic study

Last chapters will be dedicated to make an economic study of two scenarios: natural gas-hydrogen mixture and pure hydrogen transportation. In both cases the pipeline covered is the same. There will be some operational costs and investment cost that should be considered together to conclude which solutions are not only feasible but also optimal.

2.3.1. Natural gas-hydrogen admixtures

For this transportation method the idea is to change the less infrastructure possible investing the minimum quantity of resources. Introduction of electric compressors was also considered as a possibility to save money. That is because there exist penalizations in the industrial sector for companies which emit greenhouse effect gases.

This emissions tax is one of the two operational costs branches. The other one is gas consumption costs, or in case electric compressors, electricity consumption cost. Moreover, three different scenarios are considered for the economic analysis depending on how close the European industry would be to a net zero emission system. Three prices of EU ETS Carbon Permits were selected depending on the market evolution, simulating the trade in the short/medium and long term. Calculations were also made using three prices for hydrogen according to the evolution of hydrogen production costs from electricity mix. Natural gas and electricity prices were assumed constant.

The other part of the economic analysis is the investment cost. This expenditure comes basically from compression station changes that should be made to adapt the system to hydrogen addition.

2.3.2. Pure hydrogen pipeline

If the intention is to design a full hydrogen network, the first step is making an adequate material selection to transport hydrogen in safe conditions. Moreover, the cost of that material must be considered, specifically, a pipeline estimation cost per unit of length.

Once the material is selected the next step is to establish a path to design the system. Pipe sizing depends on the capacity requirements, nominal pressure and diameter. As maximum capacity must be the same, the problem will be tackled by considering the other two variables. Obviously, for different pressures and diameters investment and operational costs will change, so the key is to find a combination which results optimum in the long term.

The investment will be divided into pipe material costs, labour costs, miscellaneous costs and extra compressors acquisition. Operational costs will only consider hydrogen consumption cost with long term prices, since CO_2 emission costs are not applicable in case of 100% hydrogen.

The minimum investment possible will be the reference project. The strategy is to compare it with other diameter-pressure configuration which would result more profitable after a period of time due to lower operational costs.

3 Chapter three. Adaptation assessment in Spanish infrastructure.

As commented, the development of the whole thesis is based on a real infrastructure within the Spanish natural gas network. It is composed by three pipeline sections of approximately 250km each one which connect four compression stations. These compression stations are shown in Figure 3.1. From left to right: Almendralejo, Córdoba, Alcázar de San Juan and Chinchilla.

An assumption will be to consider only three compression stages and converting the fourth as the point where the system changes from transmission to distribution, so the gas condition in this last point will be the one which corresponds to the lower limit pressure value.

Figure 3.1: Spanish natural gas network. [14]

In order to create the model as realistic as possible, the parameters considered were taken directly from Enagás, the company which manages the natural gas network in Spain [15]. Only the last section is considered to have a diameter of 32’’ instead of his real size (36’’). To make initial iterations, the inlet pressure in the compression stations were established by considering a pressure loss of 25% regarding initial pressure.

Table 3.1: API 5L X70 pipeline parameters for assessed Spanish section.

Max. Pressure [bar]	**Min. Pressure [bar]**	**Int. Diameter [inch, mm]**	**Ext. Diameter [inch, mm]**	**Flow rate [Skm^3/h, Nkm^3/h]**	**Power rate [MW]**	**Mass flow rate [kg/s]**
80	60	32	32.90	750	8271.03	167.37
		812.80	835.80	709.50		

The external diameter was not provided by Enagás, so calculations were done to estimate the thickness needed in these pipes. According to ASME B31.8-2022, the thickness must be greater or equal to [16]:

$$t = \frac{P \cdot D}{2000 \cdot S} \cdot \frac{1}{F \cdot E \cdot T} = 11.50\, mm \tag{3.1}$$

Where P means the maximum pressure (8000 kPa), S the minimum yield strength for API 5L X70 (485 MPa), D the external diameter ($D = D_{in} + t$) and F, E, T safety factors for surrounding population degree (0.6 for location class 2), longitudinal weld joint quality factor (1) and temperature correction factor (1 for temperatures below 121 ºC) respectively.

3.1. Fluid properties after blending hydrogen

Natural gas transmission networks are complex systems carefully designed to transport energy with the maximum optimality level. Depending on the place and the extraction process, natural gas could have minor differences between regions. That means not all the outputs in extraction plants can be directly poured into transmission pipes, moreover, gas must have properties inside a certain range for being able to be included in the network [17]. Obviously, if hydrogen starts to play a big role in energy supply at regional scale, additional regulation will be imposed for controlling the properties of the admixture. Some features which are susceptible to suffer changes are: density, dynamic viscosity, Joule-Thompson coefficient, heat capacity, thermal conductivity or compressibility factor.

All these properties are critical to design a pipeline system since they have direct impact in variables like pressure losses, gas speed, compression power needed, temperature evolution, etc. Figure 3.2 shows the trends of some variables to understand the effect of blending hydrogen while keeping the same volume flow and maximum pressure.

3.1.1. Density, mass flow rate and power delivered

Hydrogen is known for his low density beside other gases as methane, the major component of natural gas. The fact of having this low density makes the mass flow fall off if the same volume flow.

The evolution of the power delivered depends on two variables: mass flow rate and the LHV of the blend. On the one hand, the hydrogen makes the average LHV to increase, leading to a higher energy delivery for the same mass of gas. On the other hand, as a consequence of the deep decrease in the quantity of gas transmitted, the power will decrease too. Other third cause is the compression power needed, which is taken from the gas transmitted, however, it will be considered negligible. By taking first two effects, the result remarks the greater influence of the second reasoning. The power delivered goes down from 8271.03 MW in case of natural gas to 2247.63 MW in case full hydrogen, which means 27% of the initial power rate.

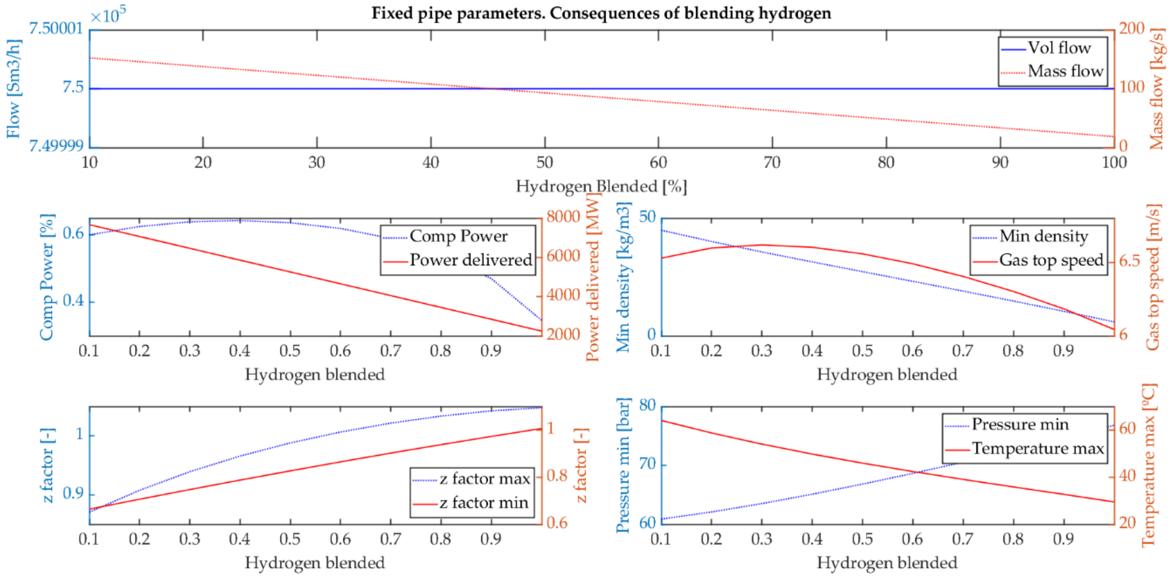

Figure 3.2: Parameters after blending hydrogen at various levels. Fixed compression station number and location, 80bar maximum pressure.

3.1.2. Pressure losses and compression power

Pressure drop is evaluated as shown in Equation (3.4). By decreasing the speed and density, the energy wasted in gas friction with internal pipeline face will be lower. As explained before, density decreases when introducing hydrogen and the speed depends on the quotient between mass flow rate and density (Equation (3.3)) , which remains inside a reduced range of variation. As a result, the pressure drop is lower when hydrogen increases and the minimum pressure at the compressor inlet will be higher. It would be expected the energy compression needs (Equation (3.5)) to decrease, nevertheless, the hydrogen is such a light molecule that needs so much effort to compress it.

Compression power (Equation (3.6)) is obtained by multiplying the energy compression effort times the mass flow. The result is a descending trend while adding hydrogen. Table 3.2 includes a comparison between the energy compression needs in each compression station and power required for different blending levels.

It is useful to express the compression power as a percentage of total power transmitted since this power will be taken from the delivered gas. For low blending values, the ratio increases slowly until 0.4%, from that point on, the percentage decreases faster when introducing more hydrogen.

$$F_m = \frac{F_{Standard}}{3600} \cdot \frac{M_w blend}{22.414} \quad [kg/s] \tag{3.2}$$

$$v = \frac{F_m}{\rho \cdot A} \quad [m/s] \tag{3.3}$$

$$p_{drop} = \frac{f_D(Re) \cdot step}{D} \cdot \frac{\rho}{2} \cdot v^2 \; [Pa] \tag{3.4}$$

$$E_{cmp} = \frac{R}{M_w blend} \cdot z_0 \cdot \frac{T + 273.15}{\theta} \cdot \left(\left(\frac{p_0}{p} \right)^{\theta} - 1 \right) \; [kJ/kg] \tag{3.5}$$

$$TotCmpP = \frac{\sum_{N_{CS}}^{1} \left(E_{cmp} \cdot F_m \right)}{\eta_{Driver} \cdot 1000} \quad [MW] \tag{3.6}$$

Maximum temperature reached in compressor outlet is also an important variable to be considered. This temperature is directly linked with compression effort, so as the compression effort is lower, the temperature follows the same trend.

Table 3.2: Energy compression needs and compression power in each compression station, total compression power for different blending levels.

Hydrogen [vol%]	0%	20%	40%	60%	80%	100%
ECmp [kJ/kg]	35.37	40.70	44.26	46.75	49.03	52.66
CmpP [MW]	46.66	44.18	37.68	28.84	18.76	7.79

Hydrogen [vol%]	0%	20%	40%	60%	80%	100%
TotCmpP [MW]	139.97	132.55	113.05	86.54	56.27	23.69

3.2. Approaches for keeping constant the power delivered

The objective is to progressively include hydrogen in the network to reduce the natural gas consumption and have in the future full hydrogen gas transmission networks.

However, this would be useless in case the system will not be able to carry the same power. Hence, the initial maximum power of 8271 MW is going to be a fixed parameter from now on.

There are several approaches to achieve this target: Maintain the pressure drop and adding new compression stations, keep constant the compression station's location and allow the gas to reach lower pressures alongside the pipeline, or varying the diameter of the pipes with changes neither in compression station location nor minimum pressure.

Volume and mass flow ratio are not dependent on the different approaches previously mentioned. The volume flow will follow an ascendent trend as hydrogen gets higher unlike mass flow, which must be lower with more hydrogen in the blend. On the one hand, Equation (3.7) shows how the required mass flow will decrease due to the ascent in the LHV value of the admixture. On the other hand, Equation (3.8) demonstrate the volume flow will grow because of the lighter weight of hydrogen.

$$F_m = \frac{Power}{LHV_{Blend}} \quad [kg/s] \tag{3.7}$$

$$F_{Standard} = \frac{F_m \cdot 3600 \cdot 22.414}{M_w blend} \quad [Sm^3/h] \tag{3.8}$$

3.2.1. Maintaining the minimum pressure

This proposal consists in avoiding the pressure drop to fall more than established 25% by changing the number and location of compression stations. The tendency is an increase in the number of compression stages while adding hydrogen to overcome the greater pressure losses.

In Figure 3.3, one of the graphs includes information about the evolution of the maximum gas speed before compression. With 100% hydrogen the gas reaches 30m/s (108km/h), which is a great increase compared to the initial 6m/s. This speed is included in the calculation of pressure drop, which becomes bigger with the square of velocity (see Equation (3.4). Pressure losses will unavoidably increase and if the designer wants to maintain the compression ratio, more compression stations must be built alongside the pipeline circuit.

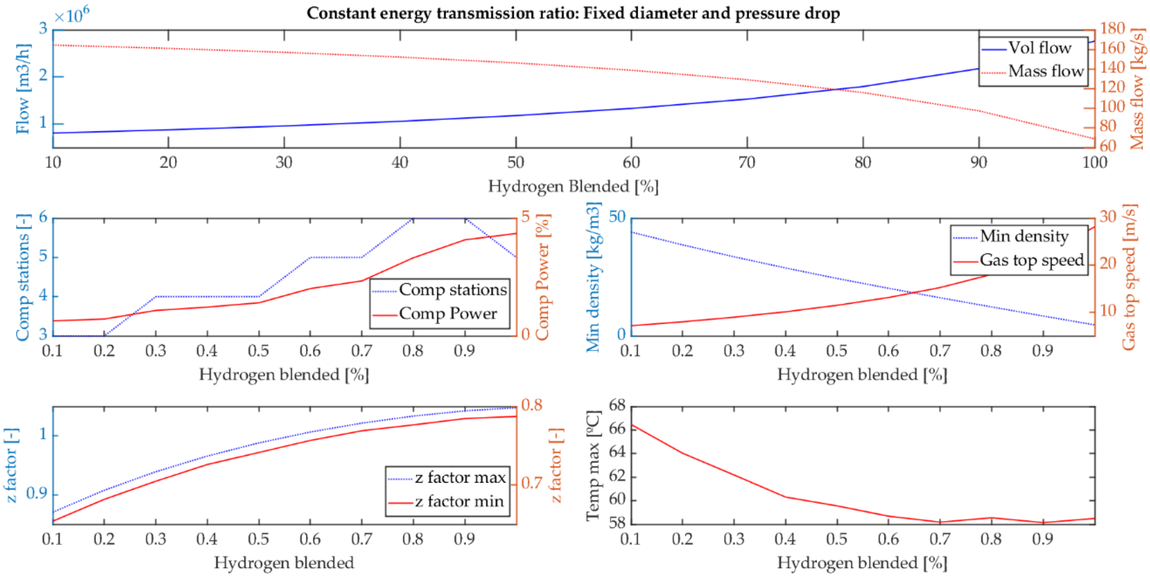

Figure 3.3: Parameters after changing compression station number by keeping the minimum pressure.

However, there is a strange behaviour in the step between 90% and 100% hydrogen. The number of compression stations drops from six to five due to a reduction in pressure losses. To understand this phenomenon, a look in Table 3.3 should be taken.

Table 3.3: Mass fraction, LHV and mass flow needed for different blending levels.

Hydrogen [%]	10%	30%	60%	80%	90%	100%
H_2 mass fraction [%]	1.23	4.58	14.38	30.93	50.19	100
LHV_{Blend} [MJ/kg]	50.29	52.65	59.56	71.24	84.82	120.00
Fm [kg/s]	164.48	157.10	138.86	116.11	97.51	68.95

$$p_{drop} = \frac{f_D(Re) \cdot step}{D} \cdot \frac{1}{2} \cdot \frac{{F_m}^2}{\rho \cdot A^2} \ [Pa] \tag{3.9}$$

Table 3.3 shows the difference between hydrogen presence in terms of mass and volume fractions.

The hydrogen is added considering an increase of 10% in volume ratio, however, if we look at the mass fraction, they differ severely. The greatest change takes place in the step from 90%vol to 100%vol of hydrogen. Looking at mass fractions the number grows up from 50% to 100%.

This huge change in the composition leads to a sudden increase in LHV of the admixture and consequently, the mass flow needed for satisfying the power demand decreases sharply (Equation (3.7)). By substituting the speed, pressure drop can be written as in Equation (3.9. With this other shape, the affectation of the mass flow rate in the pressure losses can be easier appreciated.

Out from this last behaviour, from a macroscopic point of view pressure losses increases with more hydrogen, so the power spent in compression along the line becomes higher when increasing hydrogen in the blend. From 0.64% of power delivered in the gas with 10% hydrogen until 4.35% with 100%.

3.2.2. Without changes in location of compression stations

If the main objective is to make the lowest investment possible this alternative is the best one since there is no change in compression stations and system's configuration. In the previous case, the minimum pressure was regulated by adding compression stations when needed, but now the gas reduces the pressure during the 250km until reaches other compression station.

The main drawback of not compressing the gas after a reasonable threshold is that gas speed continues increasing and consequently pressure losses become unacceptable. Owing to the density reduction, this effect increases quicker when more hydrogen in the blend, achieving values for gas speed higher than 200km/h and compression needs up to 13% of the total power delivered. To smooth that situation one solution might be to increase the pressure. By comparing Figure 3.4 and Figure 3.5, the improvement is evident if the maximum pressure is changed to 90bar.

Obviously, the purpose of these graphs and also the intention of this subsection, is to understand the evolution of gas properties at different blending levels, avoiding regions which are unacceptable or unfeasible. Apart from that, introducing more than 50% hydrogen with the same pipes considering they are made for natural gas transport is not realistic at all.

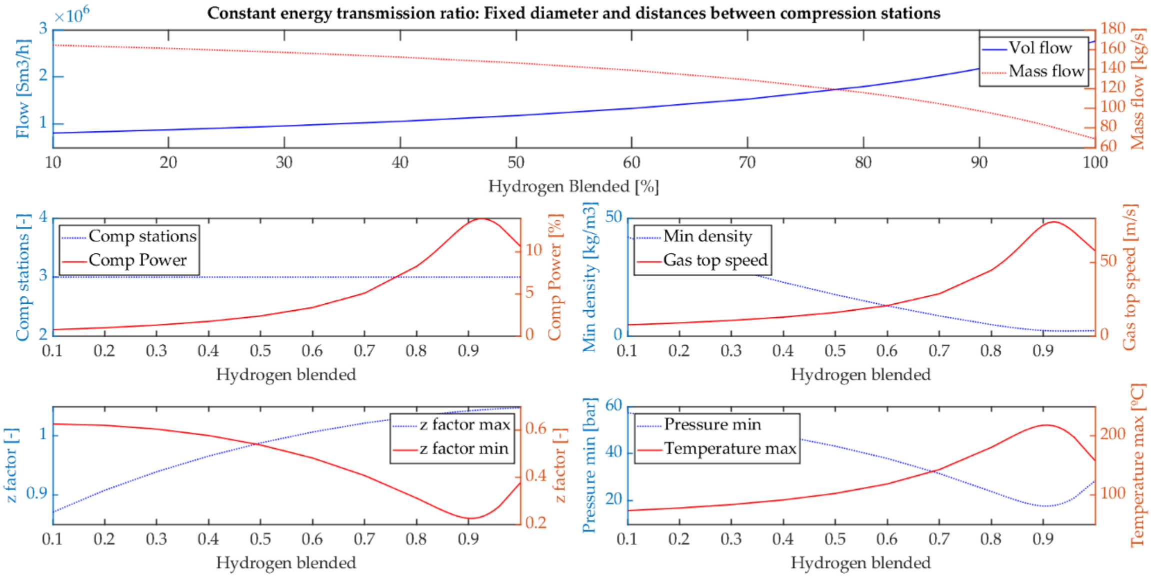

Figure 3.4: Parameters after changing lower limit for pressure and keeping the original location for compression stations with 80bar as maximum pressure.

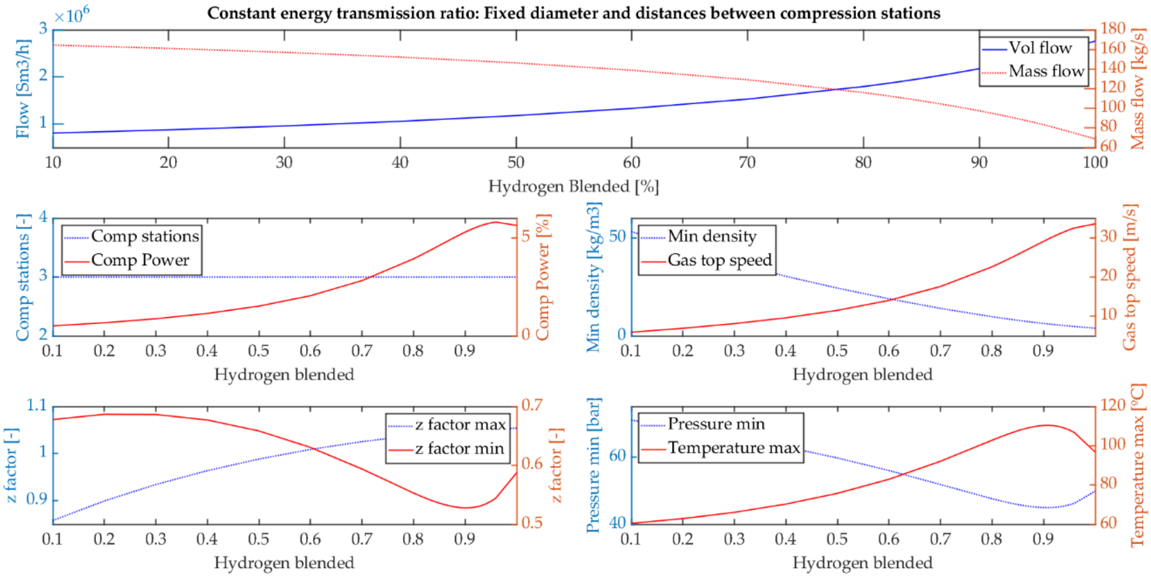

Figure 3.5: Parameters after changing lower limit for pressure and keeping the original location for compression stations with 90bar as maximum pressure.

3.2.3. Varying the diameter and keeping the same compression stations and minimum pressure

This last approach consists of estimating the diameter needed to send the same energy ratio at the same time the original position of compression stations and the pressure drop between them are preserved.

For the initial distances between compression stations the speed increases considerably for rich hydrogen blends, causing more pressure drop and consequently pressures in the inlet of compression stations so far from the optimum.

The idea now is to maintain both the pressure drop and compression stations constant. Solution involves calculation of diameter needed to reduce the speed of the gas and so the pressure losses. The method applied was to fix the distance between compression stations and calculate the pressure drop takin an initial section of the pipeline. Comparing this value with the pressure wanted, we know if the diameter needs to be increased until reach the objective pressure.

Diameter values are plotted in Figure 3.6. We can see how the number of the compression stations and minimum pressure are both constant.

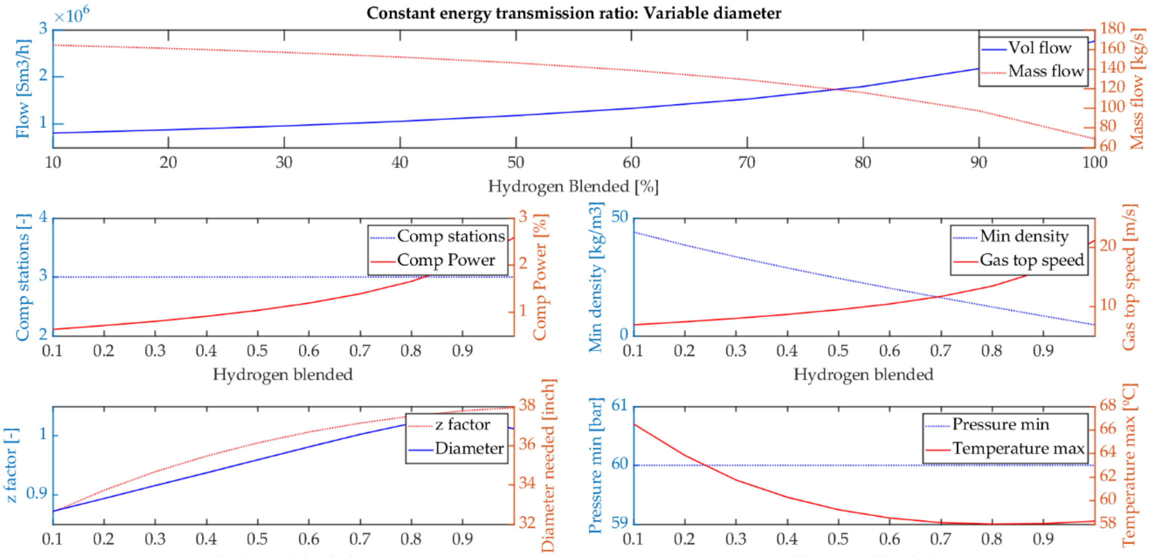

Figure 3.6: Parameters after modifying internal diameters and maintain both minimum pressure and compression station's location.

This graph contains the lowest values for gas speed. The flow ratio is the same as in the other cases for each gas composition, however the diameter of the pipe is being increased while adding hydrogen to the blend. That is the main difference that made the gas velocity lower.

This way of establishing the pipeline system gives us the best values in terms of power spent in gas compression along the pipeline. This method might be the best way to deliver hydrogen in terms of transport yield if the main target is to preserve the same energy transmission ratio. The problem in comparison to the alternative explained in 3.3, is the investment needed to change the pipe by allocating other with different diameter.

Without any doubt, the most unexpensive option to face the inconveniences arisen from blending hydrogen is the one explained in 3.3. There is no necessity for investing in changing the whole pipeline or building new compression stations. However, the increase in power required in compression stations is a common issue for all the alternatives proposed. That means the installed power in each compression station must be higher.

In Table 3.4 there is a comparison between the different alternatives in case the percentage of hydrogen is 30%. This exposed data demonstrates that, for low blending levels critical parameters as speed, density or compression power required do not cross undesirable ranges.

Table 3.4: Comparison between relevant parameters for the current natural gas system and after applying different changes with 30% hydrogen.

	Max P. (bar)	**Max speed (m/s)**	**Max T. (ºC)**	**Min P. (bar)**	**Vol flow (kSm3/s)**	**Mass flow (kg/s)**	**Comp. Power (%)**	**Comp. station (Nº)**
Current Pipeline	80	6.9	63.9	60	750	167.35	0.48	3
Same diameter Same press. drop Different CS number (30% H2)	80	8.97	62.18	60	960	161.11	1.08	4
Same diameter Same CS number Different press. drop (30% H2)	80	10.6	83.4	51.2	960	161.11	1.29	3
Same diameter Same CS number Different press. drop (30% H2)	90	8.1	66.1	65.9	960	161.11	0.87	3

Same CS number Same press. drop Different diameter (30% H2)	80	8.0	62.18	60	960	161.11	0.81	3

3.3. Hydrogen embrittlement and blending limits

When adding hydrogen not only is important to assess the changes in gas properties and their impact in fluid dynamics, but also an analysis of the impact in the structure is mandatory.

Hydrogen is known for his impact in steels and other structural materials. Apart from avoiding certain behaviours as a fluid, hydrogen embrittlement will be other issue to be assessed deeply in order to know the blending limits for the current infrastructure.

3.3.1. Hydrogen embrittlement theory

The vast majority of materials used in industrial applications are exposed to hydrogen embrittlement effects. Materials that are not directly dealing with high hydrogen presence environments, suffer from hydrogen embrittlement after corrosion reactions. This chemical mechanism produces this gas as a product and then it comes into the material lattice structure.

For structures which are exposed to environments with high hydrogen presence, the risk of having structural failures as a consequence of this phenomenon grows up considerably.

Hydrogen is the lightest molecule and that makes easier his permeation through materials. Liu and Atrens affirm that interaction between solid and gas involves three different phases: Physisorption, chemisorption and dissolution [18]. Physical adsorption reaches the equilibrium faster, is reversible and involves hydrogen as a molecule. Chemical absorption often occurs after this first phenomenon. Chemisorption is slow compared to physical absorption because the hydrogen dissociation and metal absorption energies are considerably higher. That is the reason why the completion of this second phase is more frequent when the surround environment is more aggressive in terms of temperature and pressure conditions. Once chemisorption is completed, hydrogen dissolution starts. The single atoms permeate into the material according to hydrogen concentration gradient and Sieverts' law for gases with high pressure hydrogen [19]:

$$C_H = S \cdot \sqrt{P_{H_2}} \tag{3.10}$$

where C_H is hydrogen concentration, S a solubility constant and P_{H_2} hydrogen partial pressure.

Size of hydrogen atom makes feasible the diffusion mechanism. His 53 pm radius is similar to the size of interstitial spaces in body centered cubic (BCC) and face centered cubic (FCC) crystalline structures. Sizes of interstices for the two different crystalline structures are exposed in the Table 3.5 [20], where r means the radius of the element which forms the lattice.

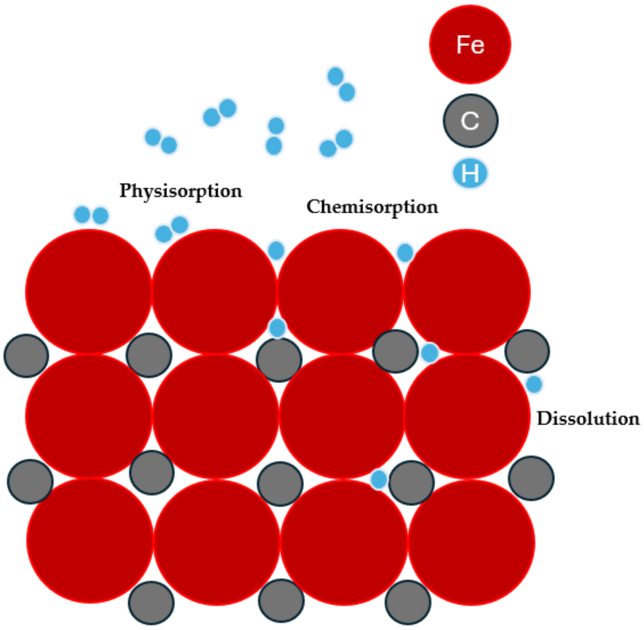

Figure 3.7: Hydrogen entry process.

Table 3.5: Interstitial radius for BCC and FCC structures.

	Minor interstitial radius	Major interstitial radius
BCC	0.155r	0.291r
FCC	0.225r	0.410r

Ferritic steels, which have a body-centered cubic (BCC) crystal structure, make it more difficult for hydrogen atoms to be accommodated within their crystal lattice. In contrast, austenitic steels, with their face-centered cubic (FCC) structure, are more susceptible to hydrogen embrittlement from this point of view.

3.3.2. Consequences in mechanical properties.

According to a report published by the US Department of Energy [21], 99.73% of natural gas transmission pipelines alongside the United States are made of carbon steel materials. This kind of steels are very common in these structures due to the facilities and good behaviour they present when subjected to welding or hot rolling processes.

Particularly, API 5L high strength carbon steels contain elements as Vanadium or Niobium which increase their mechanical performance. Depending on these mechanical requirements of the pipe, different grades could be selected from X42 to X80. Higher grades (X70 and X80) are commonly used in pipes for transporting highly pressurized gas. However, they prone to suffer against corrosive environment or hydrogen presence, especially when high pressure conditions are present. Hence, it is mandatory to study and dive deeper into this phenomenon and assess if it is possible to be close to the same operating conditions than with natural gas or changes within the pipelines must be implemented.

Significant effort has been made to study the response of these materials against hydrogen by performing tests under different conditions. Literature reflects that, properties as fracture toughness, fatigue crack growth or notch tensile strength are the ones which decrease the most. Nevertheless, effects in others like smooth tensile strength or yield strength can be considered negligible. Consequences of hydrogen in all these properties will be studied in more detail down below.

3.3.2.1. Smooth tensile properties

When testing with smooth specimens of carbon steel, there are no significant changes both in yield and ultimate tensile strength. Difference arises when looking at the fracture mechanism. Some properties as reduction of area or elongations give information about the behaviour of the material within the plastic region. In case of hydrogen presence, the reduction of area and elongations are lower than if contact with simple air, demonstrating worsening of ductility.

There are several studies focused on studying API 5L steels. Nguyen and Park developed punch tests with API 5L X70 specimens under various natural gas and hydrogen admixtures [22]. The different gas blends were at 0.1, 0.5, 1, 3, 5 vol% hydrogen at typical pipelines pressure levels (5, 7 and 10 MPa). The objective was to assess the response of the specimen in a low hydrogen admixture, however, they also performed tests using 100% hydrogen to check and compare the results obtained with pure hydrogen conditions.

Figure 3.8 reflects the differences between the whole range of blending levels at 7 and 10 MPa. The first part of both curves corresponds to the elastic region of the material, where the specimen gave the same performance regardless of the hydrogen percentage. When entering the plastic region, the material performance changes. As the level of hydrogen gets higher, ductility decreases. For lowest admixture levels changes are not critical, but for higher than 1% hydrogen the loss of ductility is not negligible. The inclusion of a test with full hydrogen at 10 MPa was useful to conclude there is certain point close to 5% where the deterioration of ductility becomes less dependent of hydrogen partial pressure. This plateau in tensile properties can be also recognized in next test results (tables 3.6 to 3.8).

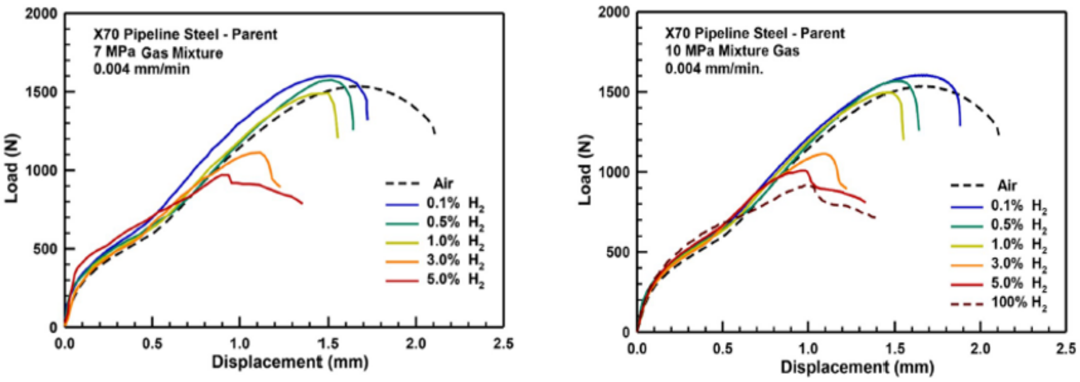

Figure 3.8: Load-Displacement curves of punch test with different hydrogen blending levels at 7 and 10 MPa. [22]

Although load-displacement curves can give us useful extra information, it is always advisable to use stress-strain plots to properly study the mechanical response of the material.

Nguyen et al. [23] complete a study where they analysed the differences between performance of certain steels under the same conditions. The trial involves grades X42, X65 and X70 of API 5L micro alloyed carbon steels. The stress-strain curves are all together in Figure 3.9 Here can be appreciated the fact that tensile properties barely change in case of smooth specimens, even for 100% hydrogen. This second test conclusion are entirely compatible with the previous one. Deterioration of mechanical performance occurs in the plastic region, and it is more severe as the level of hydrogen is increased. Using these curves, the transition between the elastic and plastic regions becomes easier to identify. Hydrogen embrittlement effects arise deeply inside the plastic region, when the stress is in his maximum point. Once the tensile strength is reached and microstructural dislocations are important owing to deformation, the material falls down.

Results also offer valuable information about how the steels with higher grades suffer more with hydrogen. By keeping constant the hydrogen percentage of the admixture, the reduction of ductility in X70 grade is considerably higher than X65 and X42 grades.

While these two last steels become unstable after 21% strain, grade X70 do the same just after 15%.

As a summary of collected data, Table 3.6, **Error! Reference source not found.**, and Table 3.8 contain some numbers about yield strength, tensile strength, elongation and reduction of area.

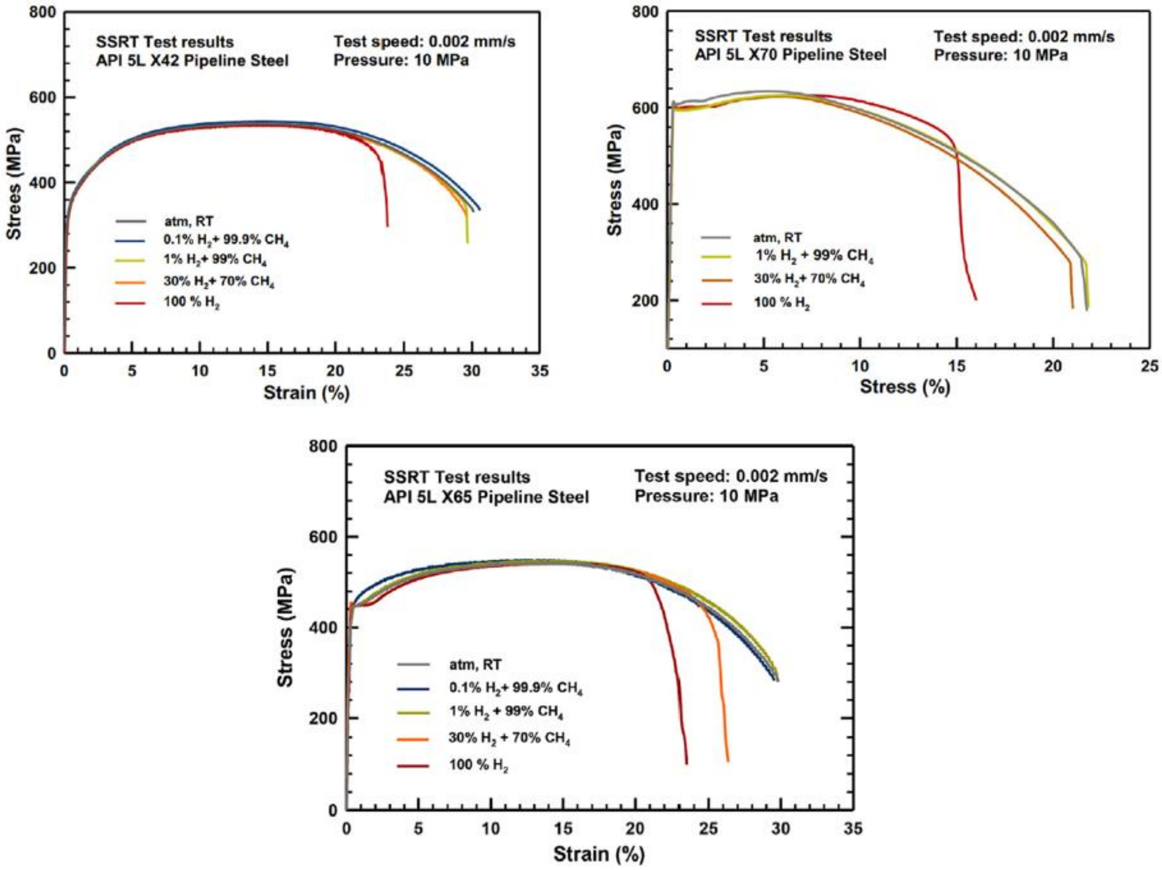

Figure 3.9: Comparison of stress-strain curves under different environment conditions for X42, X65, and X70 pipelines. [23]

Table 3.6: Tensile properties for different hydrogen blending levels at 10MPa. API 5L X42. [23]

	Yield Strength [MPa]	Ultimate Strength [MPa]	Elongation at fracture [%]	Reduction of area [%]
Ambient air	332.0	545.2	32.3	77.1
1% H_2	330.0	535.2	31.2	74.2
30% H_2	328.0	536.7	31.0	68.4
100% H_2	325.0	536.2	25.3	41.9

Table 3.7: Tensile properties for different hydrogen blending levels at 10MPa. API 5L X65. [23]

	Yield Strength [MPa]	Ultimate Strength [MPa]	Elongation at fracture [%]	Reduction of area [%]
Ambient air	448.0	546.9	29.3	79.3
1% H_2	452.0	548.8	29.5	73.3
30% H_2	459.0	542.2	25.5	55.5
100% H_2	450.0	541.5	23.4	43.5

Table 3.8: Tensile properties for different hydrogen blending levels at 10MPa. API 5L X70. [23]

	Yield Strength [MPa]	Ultimate Strength [MPa]	Elongation at fracture [%]	Reduction of area [%]
Ambient air	607.0	632.0	24.56	82.3
1% H_2	605.0	624.0	22.4	81.7
30% H_2	604.0	627.0	21.7	81.5
100% H_2	602.5	628.0	17.6	40.2

3.3.2.2. Notch tensile properties

Notch tensile strength is defined as the quotient between the maximum load (F_{max}) and the initial minimum cross section area of the notch (S_{min}) [24]:

$$\sigma_N = \frac{F_{max}}{S_{min}} \tag{3.11}$$

San Marchi and Somerday [25] affirm that differences between elongation and reduction of area with hydrogen presence compared to air became bigger in case of notch pieces than with smooth samples. They carried out several tests to compare some properties under 6.9 MPa hydrogen or air with notch and smooth specimens.

For instance, reduction of area in an API 5L X70 smooth specimen were 77% and 37% within air and hydrogen respectively. When they included a notch, the values were 45% and 8.7%, in other words, the relative reduction of area pass from 48% to 19%.

Table 3.9: Smooth and notch tensile properties for API 5L X70 steel at room temperature. [25]

	Ultimate Strength [MPa]	Notch Tensile Strength [MPa]	Reduction of area [%]	Notch reduction of area [%]
Ambient air	693	946	77	45
100% H_2	653	845	37	8.7
Relative reduction [%]	94.22	89.32	48	19

There is also an interesting experiment where the effect of hydrogen embrittlement in X80 pipeline steel was assessed [24]. This study was particularly focused on natural gas and hydrogen mixtures at 12 MPa. Trials was at 5, 10, 20 and 50 vol% hydrogen.

As it is deduced from Table 3.9, when a notch is included in a specimen, the notch tensile strength reduction ratio before the plateau decreases with more pace than ultimate strength in smooth ones. The same happens with reduction of area.

By looking at Figure 3.10 and Figure 3.11, we can see how this trend is extended for all tensile properties. Furthermore, the presence of a plateau in tensile properties when entering in regions with high hydrogen presence, turns irrefutable.

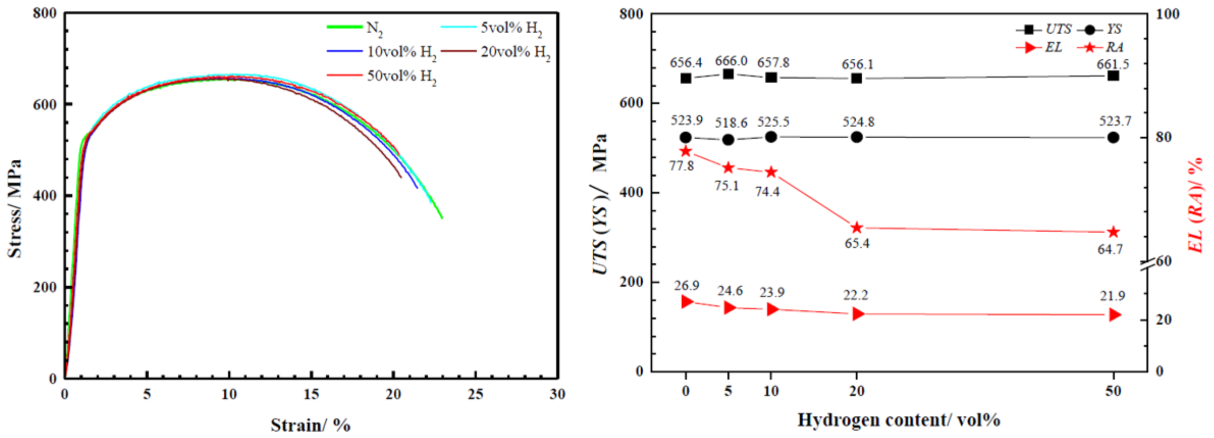

Figure 3.10: Influence of adding hydrogen in stress-strain curve for X80 smooth specimen (left) and tensile data (right). [24]

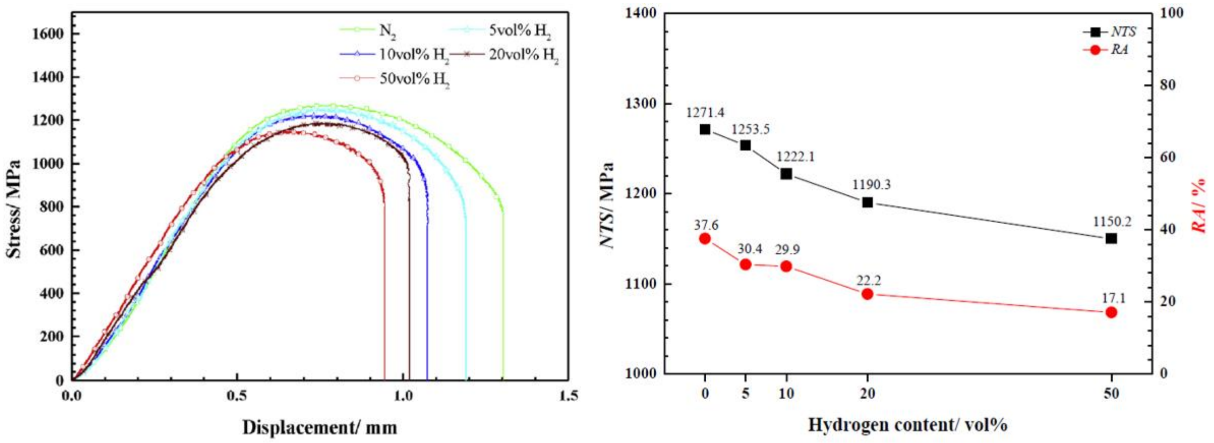

Figure 3.11: Influence of adding hydrogen in stress-displacement curve for X80 notch specimen (left) and tensile data (right). [24]

3.3.2.3. Fracture toughness

Fracture toughness is the value of the stress intensity factor in which the crack propagation becomes uncontrolled [26]. That single value is a property of the material (like yield strength or tensile strength) , and it is called critical stress intensity factor in mode I (K_{Ic}).

Stress intensity factor (K_I) is an important parameter that gives information about the stress situation in the deeper part of a crack. It depends on a crack geometry parameter, α; remote applied stress, σ; and the square root of crack length, a. For a single crack with certain length and geometry, in a specimen made of a specific material, σ_c is the critical stress which determines K_{Ic}.

$$K_I = \alpha \cdot \sigma \cdot \sqrt{\pi \cdot a} \quad [MPa \cdot m^{1/2}] \tag{3.12}$$

$$K_{Ic} = \alpha \cdot \sigma_c \cdot \sqrt{\pi \cdot a} \quad [MPa \cdot m^{1/2}] \tag{3.13}$$

According to Equation (3.13) and the definition, in case of two specimens with different crack length, geometries or remote tension but the same material, the value of critical stress intensity factor will be the same when the crack growth becomes unstable.

Fracture toughness was primarily applied for fragile materials. However, as plastic region around a crack in many metals is quite small compared to the crack length or the element thickness, that theory can be extended to all these materials. Particularly in metals, it is known how fracture toughness is variable for the same material depending on the specimen thickness. There is a threshold where the designer is forced to consider plain strain instead of plain stress conditions. For great thickness, stresses in the third dimension cannot be considered negligible (plain strain behaviour) and fracture toughness reaches his lowest value . See Figure 3.12.

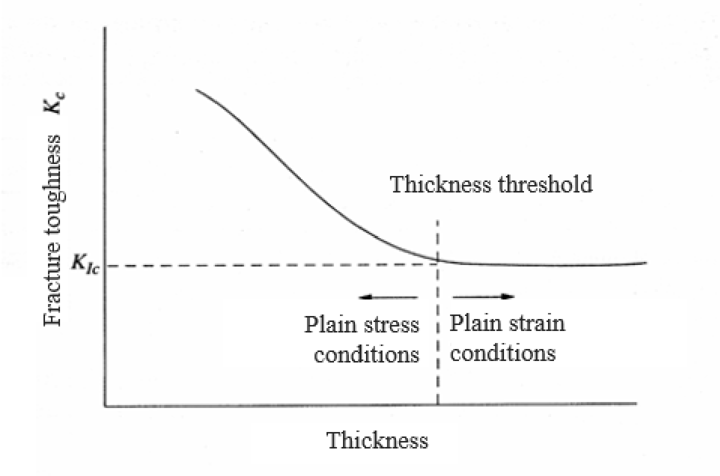

Figure 3.12: Variation of fracture toughness as a function of thickness. [26]

There is other property to assess this fragilization behaviour: Integral J. It represents the quantity of energy released while a crack propagates per unit of crack area. Similar to stress intensity factor, there is a limit for integral J (J_c) when the fracture occurs.

When hydrogen gets into the metal microstructure, it tends to accumulate in the areas with more energy, that is to say, with more stress. Hence, hydrogen normally goes around crack edges and other defects, making more fragile the material around the fracture. That is the mechanisms that explains why fracture toughness is critically worsened when the material is immersed in a rich hydrogen environment.

J. Shang, J.Z. Wang, W.F. Chen et al. investigated the fracture toughness evolution in a X80 transmission pipeline at 10 MPa total pressure under 0, 30, and 100 vol% hydrogen [27]. They used the integral J as the variable to measure hydrogen embrittlement. After making some trials with the different admixture levels and collect some data, they plotted two representative graphs showed in Figure 3.13.

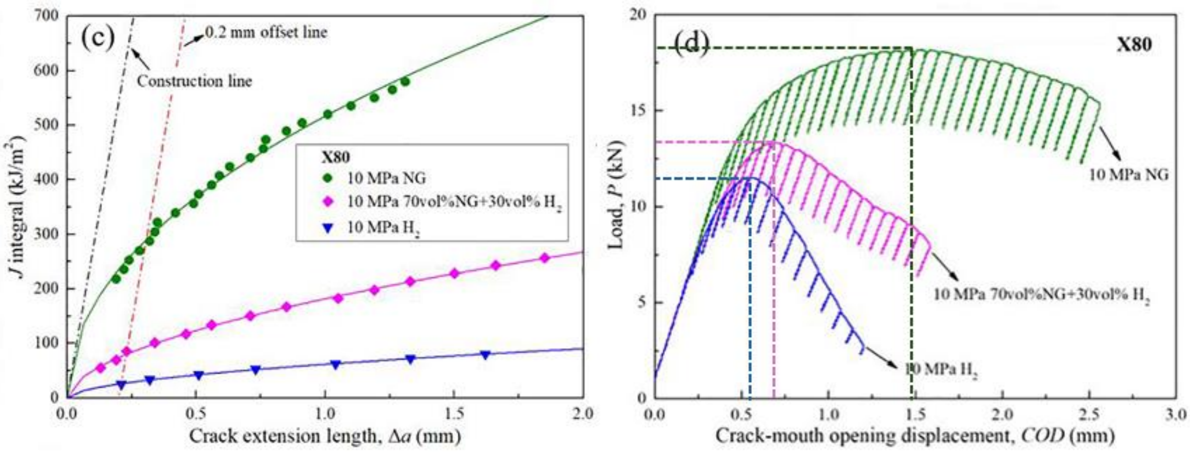

Figure 3.13: J integral-crack extension (left) and load-crack mouth opening displacement (right) curves. [27]

Both images perfectly represent the loss of ductility of low alloyed carbon steels when in contact with hydrogen. Green line reflects the common ductile response of the steel when only natural gas is around the specimen. With 30% hydrogen energy required for increase the crack extension suddenly drops until reach the blue line in case 100% hydrogen. This last one is much flatter compared to the starting green line.

If looking at the load vs crack-mouth opening displacement diagram, different interpretation could be done but achieving the same conclusion. Without hydrogen the maximum load is 18 kN with a displacement of 1.5 mm. The line which represents 30% hydrogen starts the decaying trend at 13 kN with only 0.7 mm as opening displacement. For 100% hydrogen the numbers are still worse, with nearly 12 kN and 0.55 mm. As a conclusion, with more hydrogen the specimen is less able to withstand certain level of stress and opening displacement, that means, a severe fragilization. Same conclusions can be extracted from other studies, for instance, the already mentioned San Marchi and Somerday's report [25].

Furthermore, according to a report published by the National Renewable Energy Laboratory (NREL) [28], steel's quality seems to be an important variable to be taken into consideration. Generally, the higher the quality of steel, the higher the fracture toughness. Nevertheless, the behaviour under hydrogen turns opposite. Although the available data regarding this type of test in hydrogen environments is not wide, it appears that the higher the quality of the steel, the lower the fracture toughness. See Figure 3.14.

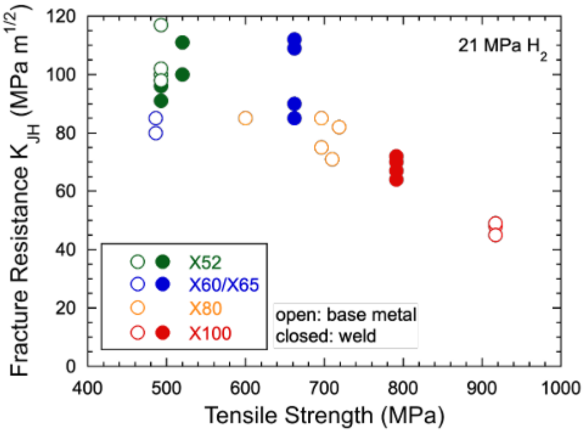

Figure 3.14: Fracture resistance of base metal and weld fusion zones of a range of API-grade pipeline steels in gaseous hydrogen at pressure of 21 MPa. [28]

3.3.2.4. Fatigue crack growth

Fatigue crack growth (FCG) diagrams offer data about how fast a crack can become greater after cycling loads. Pipelines are structures which are often dealing with changes in pressure, causing this kind of stress. Unless the frequence of these cycles are not as high as in other engineering fields like aviation, fatigue crack growth must be analysed, especially when hydrogen embrittlement phenomenon could affect the material response.

Ronevich and San Marchi offered a conference about material compatibilities for transporting and storage of natural gas and hydrogen blends [29]. Most of the discussion was about effect of hydrogen in fatigue crack growth in ferritic steels. In a previous report [30], they defined a master curve for ferritic steels and distinguish three regions depending on the stress intensity factor range, in which hydrogen plays different roles. See Figure 3.15. The general equation is:

$$\frac{da}{dN}[m/cylce] = C\left(\frac{1+C_H R}{1-R}\right)\Delta K^m \left(\frac{f}{f_{ref}}\right)^{1/2} \tag{3.14}$$

where C, C_H, m are constants, R means the load ratio (between the minimum and maximum load), f is the fugacity of hydrogen at certain pressure and f_{ref} is the fugacity at a reference pressure.

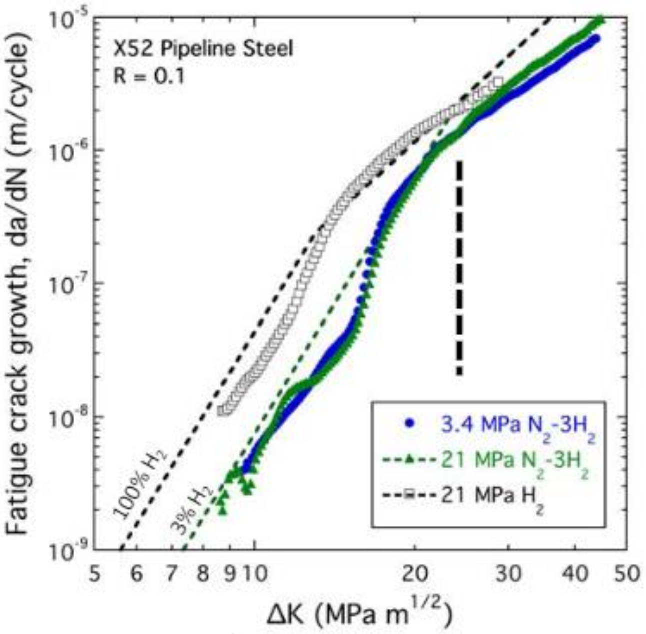

Figure 3.15: Fatigue crack growth vs stress intensity factor range for different pressures and mixture levels in carbon steel grade X52. [29]

For low stress intensity factors ($\Delta K < 5$), the crack growth is so low ($\frac{da}{dN} < 10^{-9}$) that hydrogen presence is not consider as an important factor.

For intermediate stress intensity factors ($\Delta K < \Delta K_C$), FCG does depend on the hydrogen partial pressure. With the corresponding parameters the equation results as follows:

$$\frac{da}{dN}[m/cylce] = 3.5 \times 10^{-14} \left(\frac{1 + 0.43R}{1 - R}\right) \Delta K^{6.5} \left(\frac{f}{f_{ref}}\right)^{1/2} \tag{3.15}$$

Figure 3.15 includes three different hydrogen partial pressures. Blue dots are 0.1 MPa, green dots 0.6 MPa and white dots 21 MPa. Moreover, they drew some lines to assess the FCG trend when 3 and 100 vol% hydrogen. Results are clear and influence of hydrogen between the specified range of stress intensity factor is incontestable.

In case high stress intensity factor range ($\Delta K > \Delta K_C$), all lines converge so the hydrogen partial pressure and the blending level do not affect the crack growth. The mathematical expression becomes:

$$\frac{da}{dN}[m/cylce] = 1.5 \times 10^{-11} \left(\frac{1 + 2R}{1 - R}\right) \Delta K^{3.66} \tag{3.16}$$

Regarding the role the steel quality could have in FCG, conclusions are different than with fracture toughness. In this case, grade of the steel seems to be completely independent. Ronevich, San Marchi et al., included this question in their report too. Figure 3.16 shows results in two different pressure conditions with 100 vol% hydrogen. For both 5.5 MPa and 21 MPa there are no significant differences between steels behaviour for each stress intensity factor range.

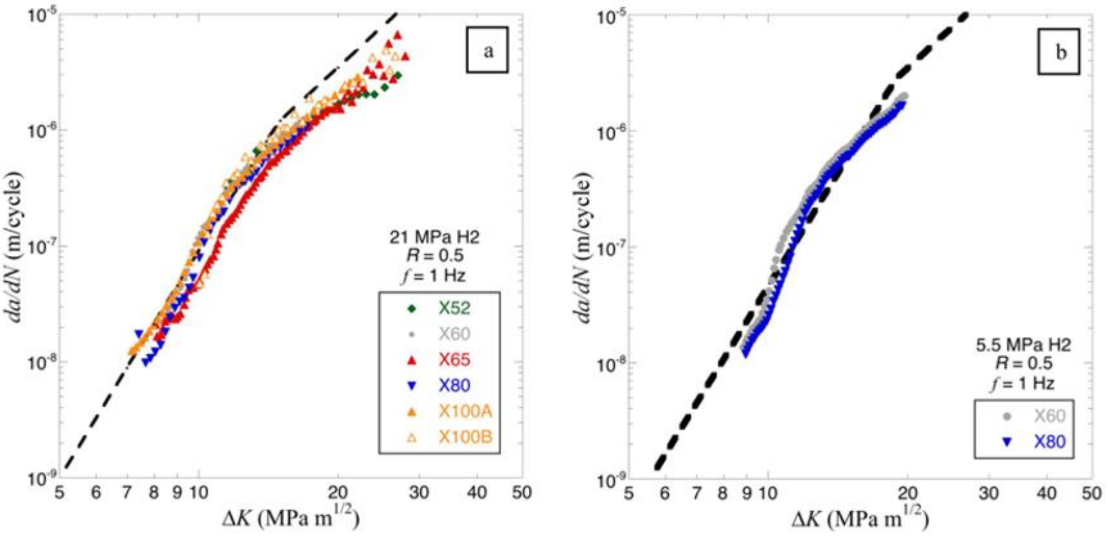

Figure 3.16: Fatigue crack growth rates of pipeline steels with R = 0.5 at pressure of (a) 21 MPa and (b) 5.5 MPa. Dashed lines are derived from the master curves for pressure vessel steels for the specific load ratio (R = 0.5) and pressure of these data sets. [30]

3.3.3. Blending limits for current infrastructure

After studying the effects of hydrogen in the material normally used in transmission pipelines, it is time to establish a limiting criterion for hydrogen addition in natural gas.

The results reflect that hydrogen worsen certain characteristics of low carbon steels with more emphasis than others. Yield strength is the most widely used property to size pipeline structures according to industrial standards ASME B31.8, ASME B31.12 or UNE-EN 15001 among others. The first one was used in Equation (3.1) to estimate the thickness of the current pipeline, because with UNE-EN 15001, both are the main rules for designing natural gas pipes.

Tensile strength and especially yield strength do not suffer serious damage in hydrogen environments. Nevertheless, other properties as fracture toughness and fatigue crack growth, are strongly affected in case of fragile behaviour. Although these properties related with fracture dynamics are not directly used to design the pipe, they become crucial when talking about old systems. These pipelines are designed to have long lifetime, and the vast majority of them are now more than 20 years old.

Even though pipelines are coated in order to prevent corrosion and crack openings, any structural material should be considered as immune against these phenomena. Moreover, initial cracks can be induced as a consequence of fatigue or unexpected loads. Obviously, old structures are prone to have this kind of flaws.

When analysing hydrogen impact in metals, one way for assessing the level of risk is evaluating the hydrogen environmental embrittlement (HEE). There are different ways to compute this parameter, but always taking properties which refer to the fragile behaviour of the material. The most common ones are reduction of area, elongation or notch tensile strength [24] [31].

Notch tensile strength is the parameter used by J. A. Lee in a Nasa report about hydrogen embrittlement [32]. They set the Table 3.10 as an orientation to consider how far a material is affected by hydrogen embrittlement.

Table 3.10: Material screening for hydrogen embrittlement based on HEE Index from NTS ratio. [32]

H Embrittlement Category	HEE Index (NTS ratio)	Material Screening Notes *
Negligible	1.0 – 0.97	Materials can be used in the specified hydrogen pressure & temperature range with fracture mechanics & crack growth analysis in hydrogen.
Small	0.96 – 0.90	
High	0.89 – 0.70	Cautiously use only for limited applications with detailed fracture mechanics & crack growth analysis in hydrogen.
Severe	0.69 – 0.50	Not recommended for usage at specific pressure and temperature where the HEE Index is measured.
Extreme	0.49 – 0.0	

*Based on application at specific hydrogen pressure and temperature, where HEE Index is measured. In all categories, additional testing and fracture analysis must be performed beyond the material screening phase.

Using the notch tensile strength, they defined the HEE index as follows:

$$HEE = \frac{NTS\ in\ hydrogen}{NTS\ in\ air\ or\ helium} \tag{3.17}$$

With data provided in Figure 3.11 it is possible to evaluate the HEE index for different blending levels. Figure 3.17 collects not only the values for notch tensile strength at different hydrogen percentage, but also the HEE index computed considering these values. Notch tensile strength value at 0 vol% hydrogen was taken as the reference in pure air. For more clearance, exact values are gathered in Table 3.11.

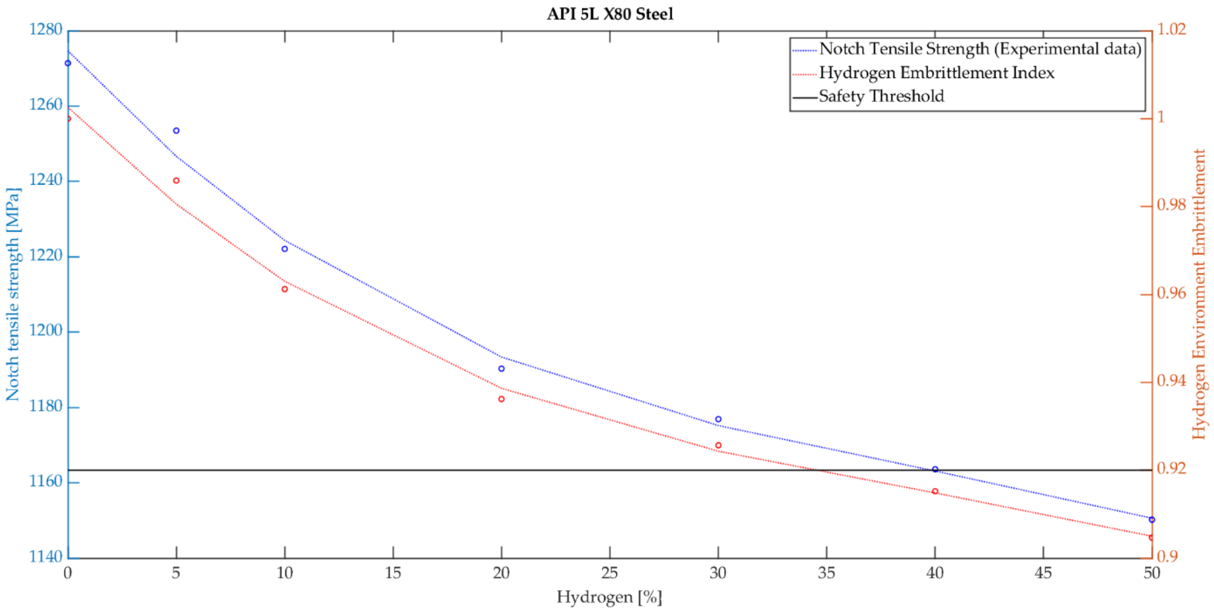

Figure 3.17: Notch tensile strength [24] and HEE index evolution at different blending levels. Safety threshold considered.

The ideal situation would be to keep the HEE index value inside negligible region. From 10 to 50 vol% hydrogen, HEE index falls within small affectation range. Of course, 0.90 is a barrier which designer must not cross, so admixtures with more than 50 vol% hydrogen cannot be considered any more. Indeed, being in the small impact category should not be a problem, however, this kind of system force to the designer to be conservative. The intention is to avoid the last third interval of this region in order not to be close to 0.90.

Other important point to be taken into account is the fact that numbers used to calculate HEE index were taken from trials with X80 grade steel at 12 MPa, while the real pipeline is made by X70 steel at 80 MPa instead. By taking this data as the reference for calculations, the assessment is even more conservative. On the one hand, pressure is less; on the other hand, as it was commented before, the higher the grade of the steel the poorer performance in hydrogen presence.

Final decision is to consider as plausible only values of HEE index greater than 0.92 vol%. This means that, if the idea is to use the same pipeline, hydrogen could be included with a maximum blending level of 30 vol%.

Needless to say, it will be necessary to inspect the pipeline material state after taking the decision of introducing hydrogen and more maintenance and inspection labours should be done.

Table 3.11: Notch tensile strength values [24] and HEE index at different hydrogen blending levels.

	0 vol%	**5 vol%**	**10 vol%**	**20 vol%**	**30 vol%**	**40 vol%**
NTS [MPa]	1271.4	1253.5	1222.1	1190.3	1176.9	1163.6
HEE	1	0.986	0.961	0.936	0.924	0.915

4 Chapter four. Cost modelling. Previous considerations.

Before starting with an economic analysis some previous aspects should be considered. In this chapter, the intention is to evaluate possible future scenarios and adjust some costs which for sure will drastically change during next years.

Moreover, it is necessary to distinguish between two situations when sizing a system such as gas networks: Operation at maximum capacity and the seasonality all over the year.

4.1. Future scenarios: Hydrogen admixtures and full hydrogen transmission systems

Hydrogen has been studied over many years as an energy source in many different areas of engineering. Previous years, popularity inside engineering field about the possibility of using hydrogen as an energy vector to take a step through a net zero emission energy system has been increased. Although many countries and organisms as European Union foster projects which involves hydrogen, the fact that the solution will be hydrogen is not clear enough. Nevertheless, hydrogen seems to be, at least, an alternative in the short-medium term.

Nowadays, transmission systems are adapted for transporting oil and gas. If the demand of hydrogen increases, the gas must be transported to different places alongside national territories. Here is when the question of how hydrogen should be transported arises: by creating an infrastructure dedicated only to hydrogen or using the current natural gas pipelines to transport gas mix?

In the previous section, an exhaustive evaluation of the impact hydrogen might have in the infrastructure was completed. It was clear this is not going to be as optimum as if building a system dedicated exclusively for hydrogen, but the current hydrogen situation is not reliable enough for nations and investors to go on with such a huge expenditure. Nonetheless, if hydrogen is consolidated in the long term, change to a full hydrogen system would be worth it.

The idea is to cover both scenarios and set a path to evaluate associated costs and how they change if choosing one alternative or the other.

4.2. Expenses estimation

In every industrial project there are two different types of expenses: investment cost and operational costs. On the one hand, investment cost is linked with the equity needed to purchase the necessary thigs to carry out the project. On the other hand, operational cost is the money the company will need once the system is functioning. These two concepts are commonly called as capital expenditures (CAPEX) and operating expenses (OPEX), and they are completely applicable to this case study. As the purpose is to establish comparisons, concepts which are going to be contemplated are the ones which makes differences between different scenarios. They are listed in Table 4.1 OPEX could have been evaluated in several ways (€/kg, €/s, €/Sm^3…), however, if talking about pipelines and gas transmission system €/MWh is the most useful and frequent unit to express them.

Table 4.1: CAPEX and OPEX of the economic analysis.

Capital Expenditures (CAPEX) [€]	**Operating Expenses (OPEX) [€/MWh]**
Pipeline Costs Compression station costs	Fuel consumption costs CO_2 emission taxes

4.2.1. Investment costs

4.2.1.1. Pipeline costs

As it was explained at the beginning of Chapter 3, the line considered is 750km long so if pipeline is modified this cost will be a considerable part of the investment. In order to save as much money as possible pipeline change will be avoided. However, if the project consists of changing the system to convert it to a full hydrogen one, these costs must be computed as an important part of the investment. Annex I provide additional information about suitable materials for pipelines in hydrogen environments and economic comparison between them.

To set the cost of changing pipes as accurate as possible, Q. Yu et al, considered a distribution of different aspects which contributes with distinct weights to the overall cost of a project [33]. Based on that assessment, this work will consider material cost, labour cost and miscellaneous cost.

Table 4.2: Cost distribution for pipeline engineering.

Material Cost [%]	Labour Cost [%]	Miscellaneous Cost [%]
30.4	41.3	28.3

Q. Yu et al took as a reference price for API 5L X52 steel 1.022$/kg, which converted to euros become 0.92€/kg approximately. Once the price for material cost is established, the other subdivisions contributions are determined by the weight relationship of Table 4.2. All these subdivisions together constitute the total pipeline costs.

4.2.1.2. Compression station costs

Apart from pipelines, compression station is the other factor considered within investment costs. In Chapter 3, it was exposed that compression power grows while adding hydrogen. Independently of compression stations number, more compressors will be needed to increase the installed capacity according to the requirements in each case.

The possibility of replacing the gas turbines with electric motors as new drivers or adding these electric motors as the drivers for the new compressors needed is also contemplated in the thesis. The main advantage of incorporating electric compressors is the reduction of operational costs, which are going to be explained hereafter.

There is a public report about the substitution of a turbo-compressor unit with a moto-compressor unit in Almendralejo compression station [34], where valuable information about the cost of the entire substitution is provided. In Table 4.3 there is the data used for evaluating the costs when modifying the compression stations within the system. Costs are divided in fixed and variable terms. Fixed term is further divided into two categories: if the installation is for a new extra compressor, or if the installation is for substituting an existing one.

Table 4.3: Fixed and variable costs for compression stations necessary modifications.

	New installation	Substitution	Variable term
Fixed Cost [€]	12.000.000	4.000.000	-
Variable Cost [€/kW]	-	-	605

4.2.2. Operational costs

4.2.2.1. Fuel consumption costs

Compression stations are composed by two different machines. Drivers, which give the power to the compressors, and that compressors which use this power to compress the gas from the inlet to the outlet maximum pressure.

The vast majority of the natural gas compressors has gas turbines as drivers. One of the strengths of this option is the simplicity in logistics and infrastructures to supply with fuel the gas turbine. As it is draw in **Error! Reference source not found.**, natural g as transported is used as the fuel of the turbines, so there is only needed an extra thin pipe which connects the pipeline with the gas turbine's combustion chamber. There is also the alternative of installing electric motors to move compressors using electric power. See Figure 4.2.

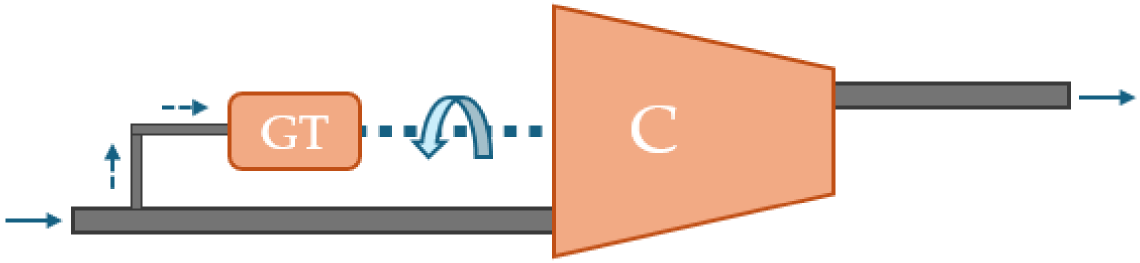

Figure 4.1: Compression system schematic based on gas turbines.

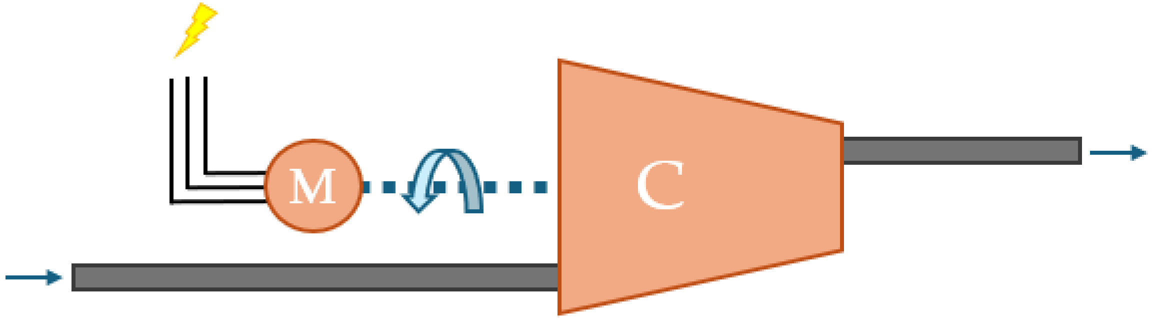

Figure 4.2: Compression system schematic based on electric motors.

These possibilities bring different operational expenses that must be computed to establish a comparison between them. In addition, it is important the fact that prices of some products are changeable in the medium and long term with respect the current situation. In the assessment there will be three different scenarios depending on the variable price of hydrogen. Natural gas and electricity market value are going to be considered fixed . Table 4.4 wraps up all the values considered.

Table 4.4: Prices for hydrogen, natural gas and electricity in current, near future and long-term scenarios.

	Current	**Short/ Medium term**	**Long term**
Hydrogen (€/kg)	10	6.5	3
Natural Gas (€/MWh)	30	30	30
Electricity (€/MWh)	100	100	100

Natural gas price was taken from MIBGAS computing the average cost in 2024 until July [35]. Electricity cost of 100 €/MWh is the average of prices in 2023 [36]. Hydrogen cost was estimated considering a production based on grid electricity [37].

4.2.2.2. CO_2 emission taxes

Every company in the industrial sector which emits carbon dioxide to the atmosphere is forced to acquire certain quantity of emission rights depending on the CO_2 discharged.

Each enterprise is assigned with certain emission rights that allow them to emit greenhouse effect gases under a fixed threshold. In case a company reduces their CO_2 emissions, they could sell part of their emission rights. At the contrary, if others are expecting their emissions to increase, they must acquire extra emission rights. This is a free market which is characterized by having a system based on regulated offer. Each year, the European Commission reduces the number of permissions available. Consequently, the prices of the emission rights increases, penalizing the companies which emit the most. With this method called EU Emissions Trading System (EU ETS), European Union is trying to force big emitters to reduce the generation of polluting gases.

In Figure 4.3 is represented the evolution of prices during last year. Numbers refers to € per CO_2 tonne emitted. The average in this time period is around 70 €/tonCO_2.

source: tradingeconomics.com

Figure 4.3: EU ETS Carbon Permits price evolution last year.

Trading Economics provides information about this market since 2005, so it is possible to roughly estimate the evolution of Carbon Permits value in the following years. Table 4.5 gather the trend considered in the short/medium and long term.

Table 4.5: Forecast for EU ETS Carbon Permits' prices the following years.

	Current	**Short/ Medium term**	**Long term**
Emission taxes (€/tonCO_2)	68	100	150

4.3. Seasonality

Natural gas pipelines are not always working at maximum capacity. Typically, during winter transport demand is higher such that the system could reach flows close to the maximum, however, there are other periods when the demand is even lower than half of the rated value.

This seasonality is crucial not only for properly design the infrastructures, but also for correctly evaluating the operational costs over an entire year. System must be prepared to deal with the maximum capacity, so pipes and compression stations will be sized according to this maximum. Nevertheless, for assessing the operational costs which includes the compression stations consumption and the emission taxes, an average taking into account that seasonality will be considered.

To estimate this seasonality, data from international connection in Sicily pipelines was used [38]. This connection has three different pipes with 48inch as nominal diameter. Although the capacity of this connection is higher than the analysed case, the data can be also used to estimate natural gas transport demand changes in the Spanish system. After some data treatment results are in Figure 4.4. Blue line refers to the capacity evolution and the red one the average of the whole year.

The average is 48.98% and will multiply the power needed to be deliver. Hence, there will be two values: the maximum power to calculate the infrastructure requirements, and the average power to estimate the operational costs. Remark that from this value of power requirements, other variables as mass flow rate and standard volume flow are computed. See Equation (3.7) and Equation (3.8).

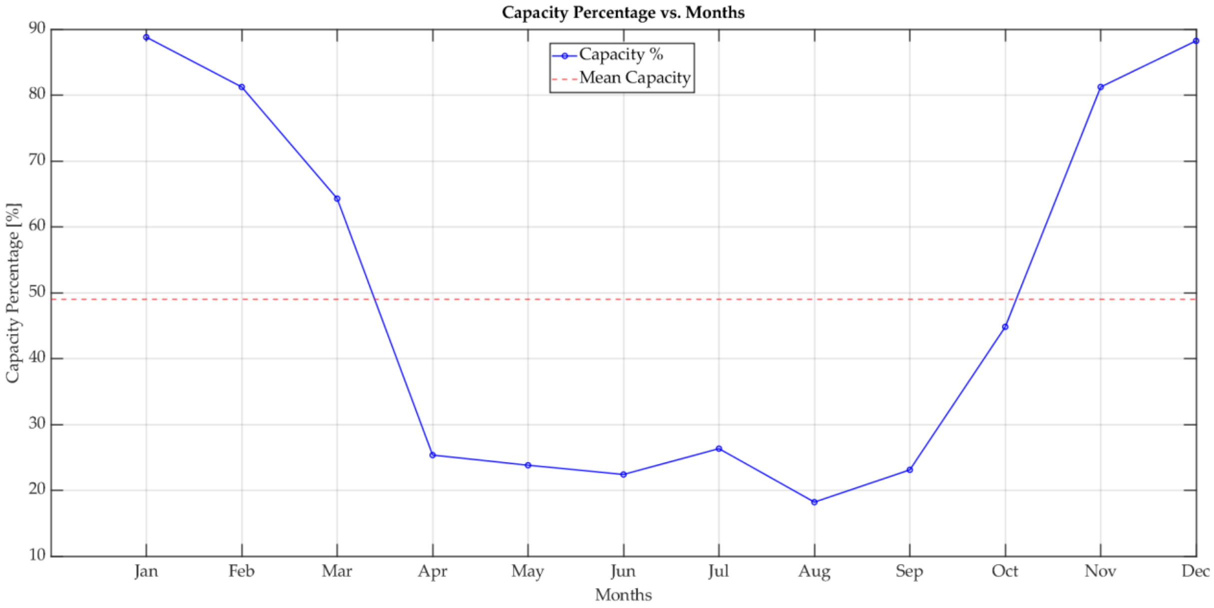

Figure 4.4: Seasonality estimation for capacity usage in natural gas transport.

5 Chapter five. Economic analysis for natural gas-hydrogen admixtures.

Previous chapter offered information about some changes engineers are forced to implement in case the choice is to deliver hydrogen as a blend with natural gas trough current pipeline network. In this fourth chapter the main goal is to carry out an economic study in order to identify the best path to make this transport as optimum as possible.

There were three proposals for transporting hydrogen with natural gas system: Keeping the minimum pressure of 60bar by adding new compressor stations depending on pressure losses, keeping the number of compression stations by allowing the gas to drop below the established minimum pressure, or keeping both compression station location and minimum pressure by changing the pipeline diameter.

Chapter four assessment will cover the first two cases. The last idea may result useful from the physics point of view, however, installing a new pipeline to deliver natural gas-hydrogen blends is not a convenient investment. Especially if considering the possibility of building new pipelines for transporting full hydrogen certain years later. In case of starting such a project, the best option would be to design the pipeline considering full hydrogen transportation and introducing blends until hydrogen technologies are rooted enough.

5.1. Keeping the minimum pressure and changing compression station number

Each alternative will be evaluated taking into account operational and investment costs. There will be also four different scenarios:

1. Black line. Gas turbines as compressor drivers with current prices for hydrogen and ETS Carbon Permits.
2. Blue line. Gas turbines as compressor drivers considering medium term prices for hydrogen and ETS Carbon Permits.
3. Pink line. Gas turbines as compressor drivers considering long term prices for hydrogen and ETS Carbon Permits.

4. Green line. Electric motors as drivers considering electricity price for computing operational costs.

5.1.1. Operational costs

Figure 5.1 includes the evolution for gas transportation efficiency, gas emission costs (GEC) and gas consumption costs (GCC).

Gas transportation efficiency refers to the quantity of transported gas (mass flow) required to generate the necessary power to compress the gas from the lower to the upper pressure. As the compression power needed incresases when adding hydrogen, the gas transportation efficiency reduces his value. It is calculated as follows:

$$\begin{cases} G_{ef} = \dfrac{\overline{F_m} - q_f}{\overline{F_m}} \cdot 100, \\ q_f = \dfrac{\overline{TotCmpP}}{LHV_{Blend}}. \end{cases} \tag{4.1}$$

Where $\overline{TotCmpP}$ is the total compression power needed to recompress the gas along all the pipeline, q_f the fuel needed, and $\overline{F_m}$ the average mass flow in a year. Remenber that all this values for operational costs are considering the average capacity in an entire year.

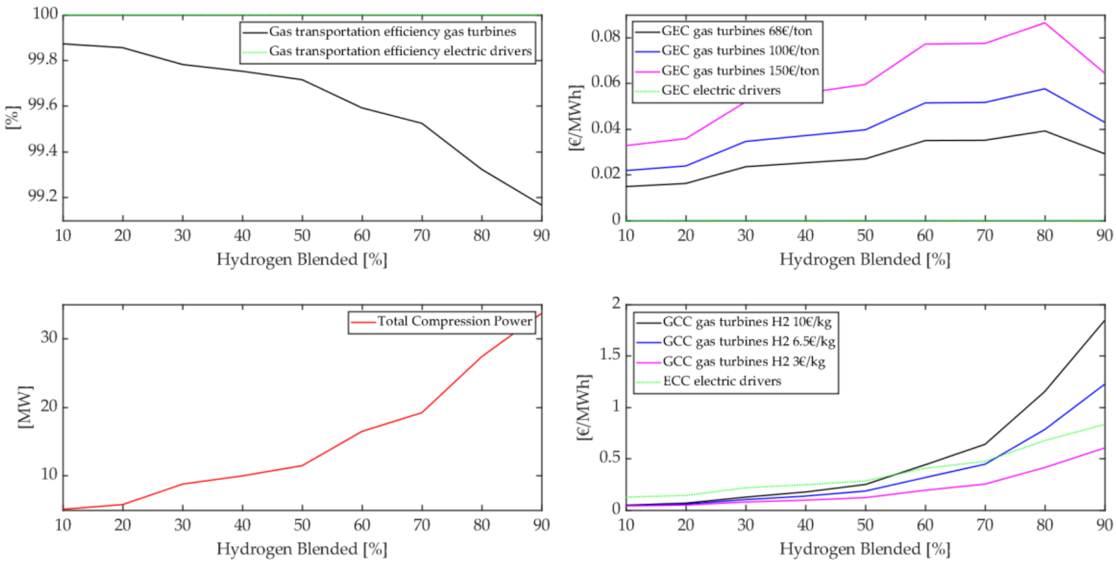

Figure 5.1: Gas transportation efficiency, emission and consumption costs evolution while adding more hydrogen. In case keeping the minimum pressure and increasing compression station number.

Nowadays, EU ETS Carbon Permits price is lower than in the future. If the industry is closer to the net zero emissions target, prices per ton emitted will increase. The trend of gas emission costs is the result of combining the increase in total compression energy requirements, and the natural gas reduction in the blend. In the admixture, only natural gas produces carbon dioxide in the combustion and that is the reason why although the compression power needed is higher, from 80% to 100% hydrogen GEC reduces his value until zero.

In these last two graphs the case of electric compressor did not play because if the driver is an electric motor, it will not consume gas so efficiency is the maximum possible, and will not emit CO_2, so the GEC are zero.

In case of power consumption in compression stations, electric costs increase according to the growth in compression power needs. In case of gas turbines, apart from this, hydrogen price must be added. When hydrogen has greater presence the cost of gas consumption increases quicker than if there were only natural gas. This slope depends on price of hydrogen. Now hydrogen is more expensive than natural gas or electricity, but in several years it is expected to be cheaper. To establish an easier comparison, Table 5.1 have the prices of how much energy costs depending on the source. Hydrogen presence in lower blends is not enough to make hydrogen price the dominant factor, nevertheless, when hydrogen presence is bigger, we can see how lines diverge with more difference.

Table 5.1: Costs per MWh of energy obtained from natural gas, electricity or hydrogen in different scenarios.

	Natural Gas	**Electricity**	**Hydrogen 10€/kg; 6.5€/kg; 3€/kg**
Energy cost (€/MWh)	30.17	100	300; 195; 90

Electricity is cheaper only when admixtures are rich in hydrogen and only in the cases when this gas is more expensive. If considering current situation electricity is worth it with more than 55vol% H_2, and if moving to medium term from 72vol% H_2 on. According with the graph and Table 5.1, if 3€/kg is taken as hydrogen price, it will be cheaper to produce energy even with 100vol% H_2 rather than with electricity from the net.

All these considerations about operational costs are considered together in Figure 5.2. From total operational cost (TOC) point of view, it is better to take the compression energy from the gas than from the electricity for low admixtures.

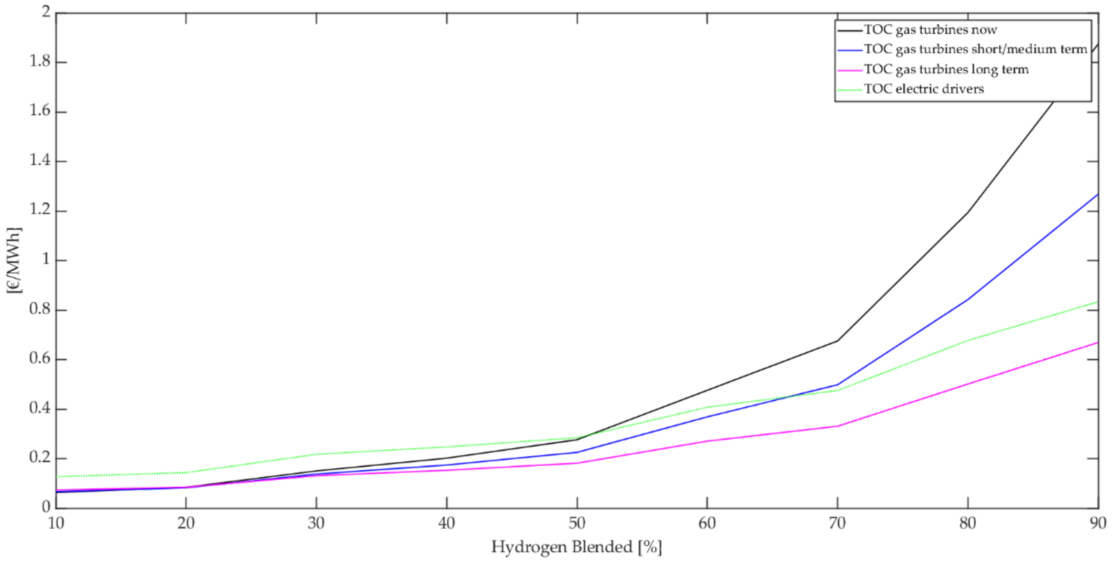

Figure 5.2: Total operational cost evolution in case keeping the minimum pressure and increasing compression station number.

5.1.2. Investment costs

In this particular case we have to consider variable compression station number and calculate the compressors which should be installed in each one to satisfy the compression power demand operating at maximum capacity. In addition to information provided in Figure 5.3, Table 5.2 gathers some data about the evolution of compression power needs and compressors that must be present in each station.

Table 5.2: Compression power required at maximum capacity, compression station number and compressors in each station for different blending levels. In case keeping minimum pressure.

H_2 [vol%]	Compression power [MW]	Compression station number	Compressors in each station
10	52.92	3	5
30	89.61	4	5
50	116.40	4	7
70	193.22	5	9

H_2 [vol%]	Compression power [MW]	Compression station number	Compressors in each station
90	337.50	6	13

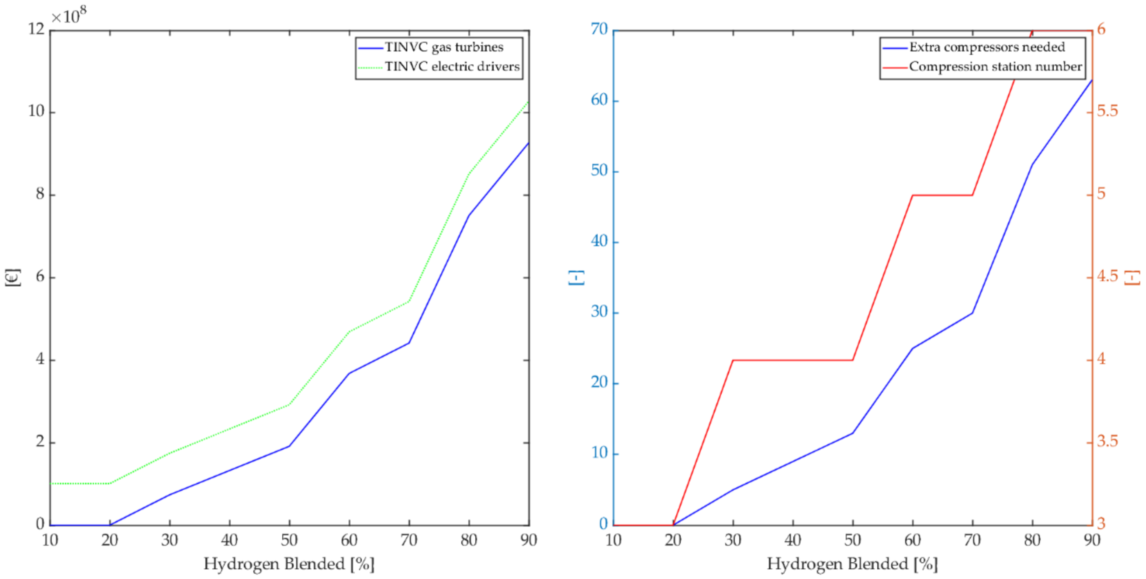

Figure 5.3: Total investment costs in case gas turbines and electric compressors (left) and number of total compression stations and extra compressors needed (right). In case keeping the minimum pressure and increasing compression station number.

If electric compressors were implemented, the extra cost of changing the current compressors with gas turbines as drivers must be added. That value is 100.8 million€ and makes the difference between the green and blue line. Remember that for new extra compressors the cost is considered the same independently of the driver type.

5.2. Keeping compression station location and changing minimum pressures

The assessed data will be the same as before but considering now compression stations fixed and allowing the gas to lose pressure without establishing lower limits.

5.2.1. Operational costs

Analysis of chapter 2 demonstrated that the main drawback of this alternative was the high pressure loses. Hence, this pipeline configuration is expected to have bigger operational costs than the previous one.

If comparing Figure 5.4 and Figure 5.1 it can be shown the increase in both gas emission and gas consumption costs. The difference between compression power needs is not very high because they are computed considering the average capacity instead of the maximum one. Power spent in compression stations increases roughly 8.5%. That makes the total operational costs increase also around 8.5% respect the case before. In case electric compressors they are also affected by the increase in consumption costs, however, operational cost does not suffer from the growth in gas emission cost. That changes the crossover points respect the previous case. As the operational cost rise in case gas turbines is more pronounced, that points are at 51vol% and 66vol% H2 instead of 55vol% and 75vol% H_2. See Figure 5.5 and Table 5.3.

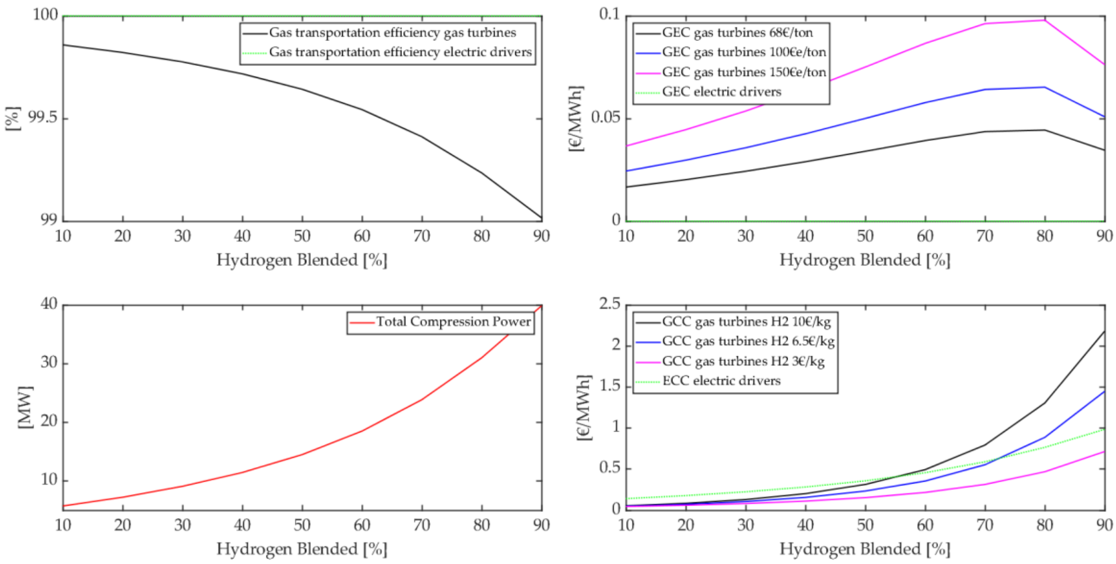

Figure 5.4: Gas transportation efficiency, emission and consumption costs evolution while adding more hydrogen. In case keeping compression station number and releasing minimum pressure.

Table 5.3: Comparison between compression power required (considering seasonality) and operational costs for the two cases. Keeping the minimum pressure on the left and keeping compression stations on the right.

	Avg. compression power [MW]	**TOC [€/MWh]**	**TOCe [€/MWh]**
10	5.12; 5.72	0.063; 0.070	0.13; 0.14
30	8.79; 9.08	0.15; 0.16	0.22; 0.23
50	11.49; 14.48	0.27; 0.35	0.28; 0.36
70	19.21; 23.85	0.68; 0.84	0.48; 0.59
90	33.71; 39.85	1.87; 2.22	0.83; 0.99

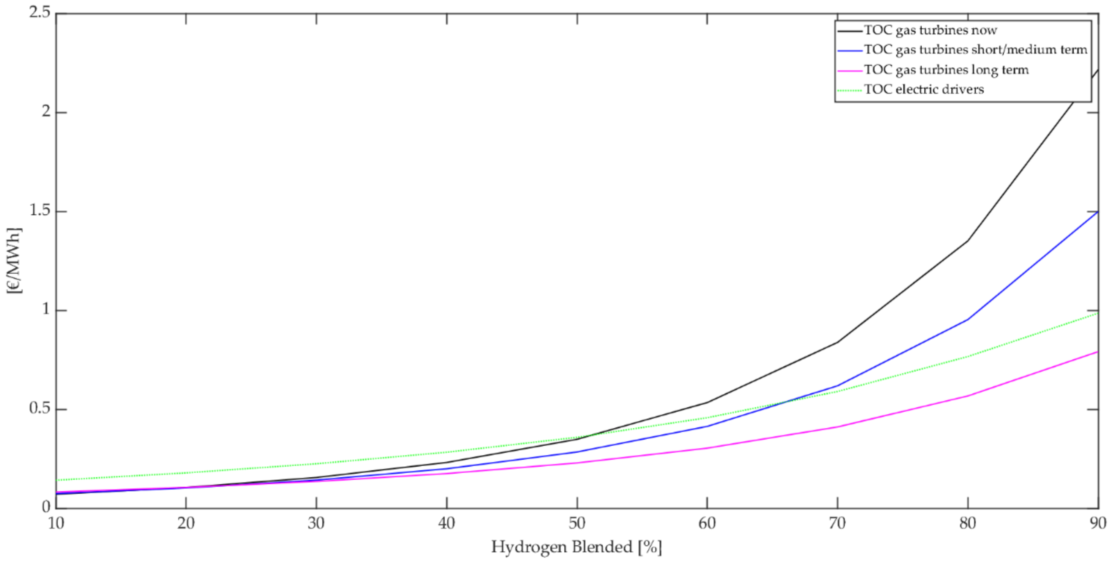

Figure 5.5: Total operational cost evolution in case keeping compression station number and releasing minimum pressure.

5.2.2. Investment costs

When calculating the operational costs difference between configurations were small. In this case, the capacity considered for sizing the new system is the maximum one and that differences increase considerably. Table 5.4 compares compression power necessities in both configurations. When dealing with low hydrogen the growth is not severe, but when surpassing 50vol% H_2 that growth turns critical until reaching 231% for 90vol% H_2.

Obviously the problem is the increase in installed power the system should have in each compression station. Again, the situation is not serious for low hydrogen blends, but when having higher percentages of hydrogen, values became irrational. For instance, with 70vol% H_2 32 compressors would be needed in each station, making the company to acquire 81 new compressors, which is unfeasible from the economic perspective.

Table 5.4: Compression power required at maximum capacity, compression power rise respect keeping minimum pressure case and compressors number in each station for different blending levels. In case keeping compression station number.

H_2 [vol%]	Compression power [MW]	Compression power rise	Compressors in each station
10	61.68	16.5%	5
30	107.12	19.5%	8
50	197.00	69.2%	15
70	421.53	118%	32
90	1118.4	231%	83

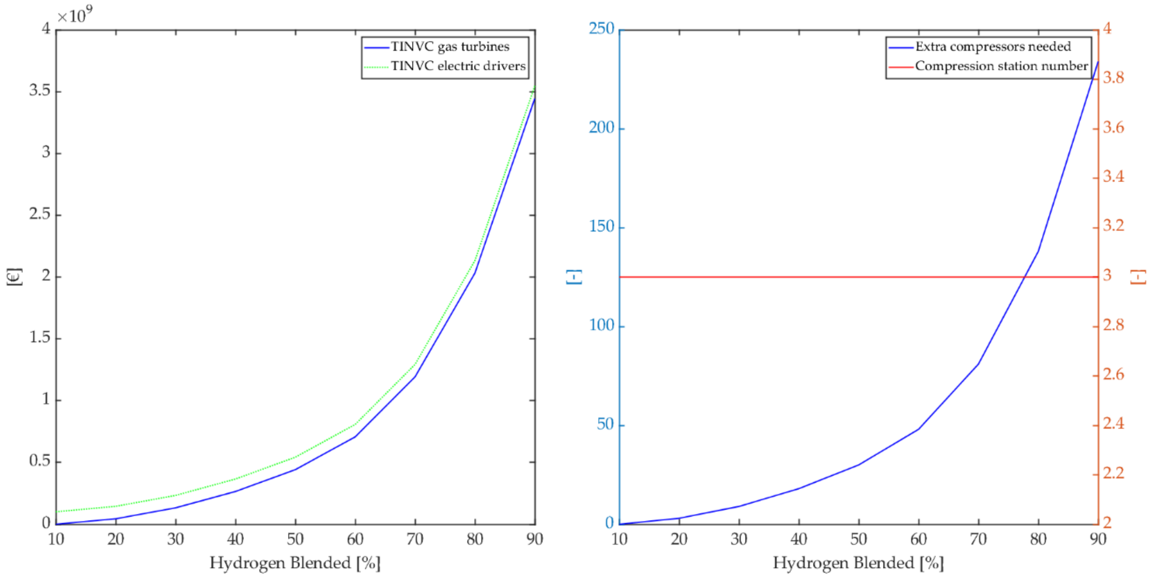

Figure 5.6: Total investment costs in case gas turbines and electric compressors (left) and number of total compression stations and extra compressors needed (right). In case keeping compression station number and releasing minimum pressure.

5.3. Economic analysis until 30vol% H_2

A brief study was made to check the behaviour of the costs considering blends from 10 to 90vol% H_2. However, conclusion of chapter 2 set at 30vol% H_2 the safety limit for hydrogen addition without changing the pipes. Now the assessment is going to be focused on the allowed interval.

Before going to more details, the first discard will be not to consider electric compressors as a cost-effective option. Changing current gas turbines is a non-profitable investment considering that for blends rich in natural gas, the operational cost results cheaper, even with the emission penalization extra cost.

Both configurations are going to be analysed in the medium term to find the optimum solution depending on the quantity of hydrogen in the mixture.

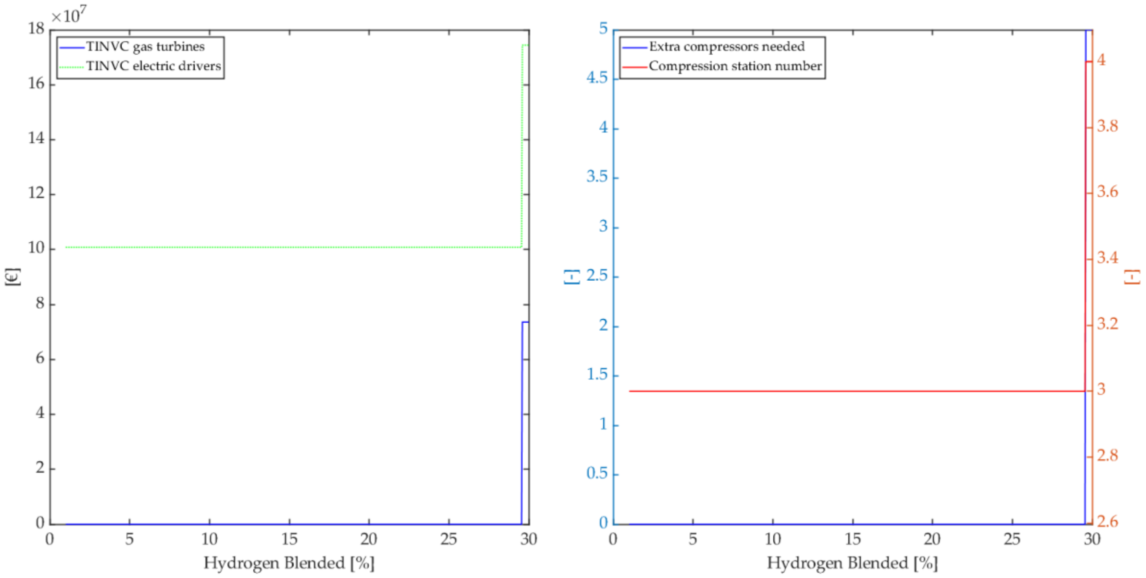

Figure 5.7: Total investment costs in case fixed minimum pressure for hydrogen levels between 0 and 30vol%.

In terms of investment, it would be interesting to evaluate the alternative of keeping constant the minimum pressure. Until reaching 29vol% H_2 no investment in new compressors must be made. In addition, this configuration is better from the operational cost point of view (see Figure 5.9 and Figure 5.10). Table 5.5 shows the savings obtained in a period of five years with respect to configuration with variable minimum pressure and fixed compression stations location.

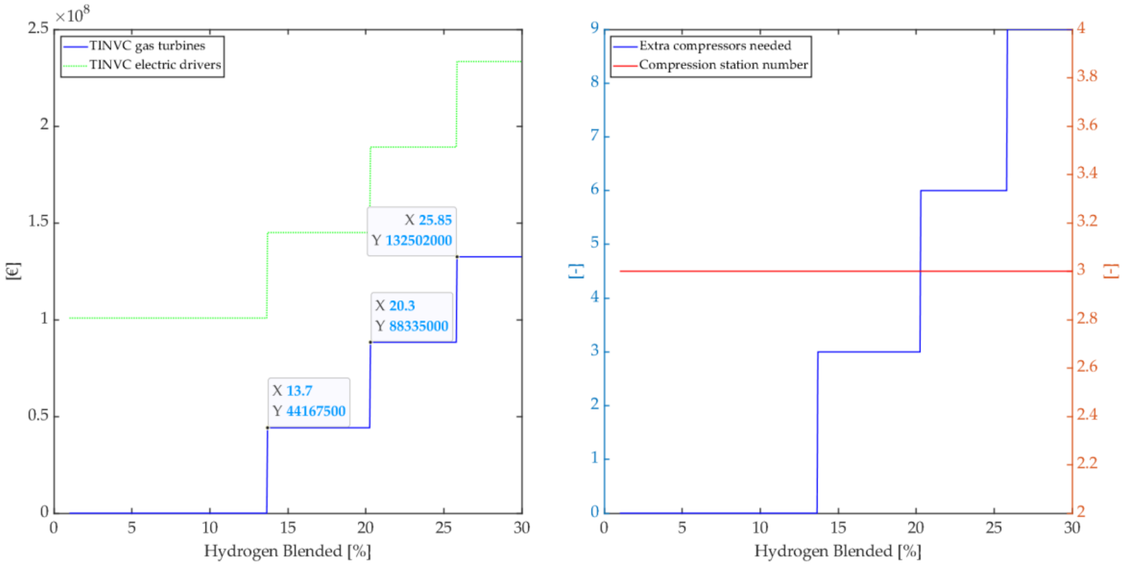

Figure 5.8: Total investment costs in case fixed compression station location for hydrogen levels between 0 and 30vol%.

Table 5.5: Savings of fixed minimum pressure alternative with respect fixed compression stations for different blending levels. Calculation all over five years with 2.37% as discount rate. The scenario considered was in the medium term (blue line).

	10vol%H_2	**15 vol%H_2**	**20 vol%H_2**	**25 vol%H_2**	**29 vol%H_2**
Savings [Million €/ year]	1.27	2.19	3.31	4.64	6.07

The problem here is that compression stations must be moved to other places depending on the blending level. Because of hydrogen addition, the pressure losses are higher and distance between stations should be reduced to recompress the gas when needed. For instance, distances between compression stations should be 224 and 204km in case 10 and 20vol% H_2 respectively. This translation cost should be calculated and compared with investments needed in case compressors acquisition when dealing with the alternative of keeping the compression stations location.

Moreover, it is important to remark that the last section of pipe in case changing compression station's location is going to be larger and there will be more pressure losses. As the final pipe section ends in a point where the transmission changes to distribution, the fact of having less pressure might not be a problem. Remember that system configuration is designed considering maximum capacity conditions, which is not the normal system operation mode, so this situation will occur in few months within the whole year. To clarify how these configurations would result the schemes of Figure 5.11 and Figure 5.12 were added.

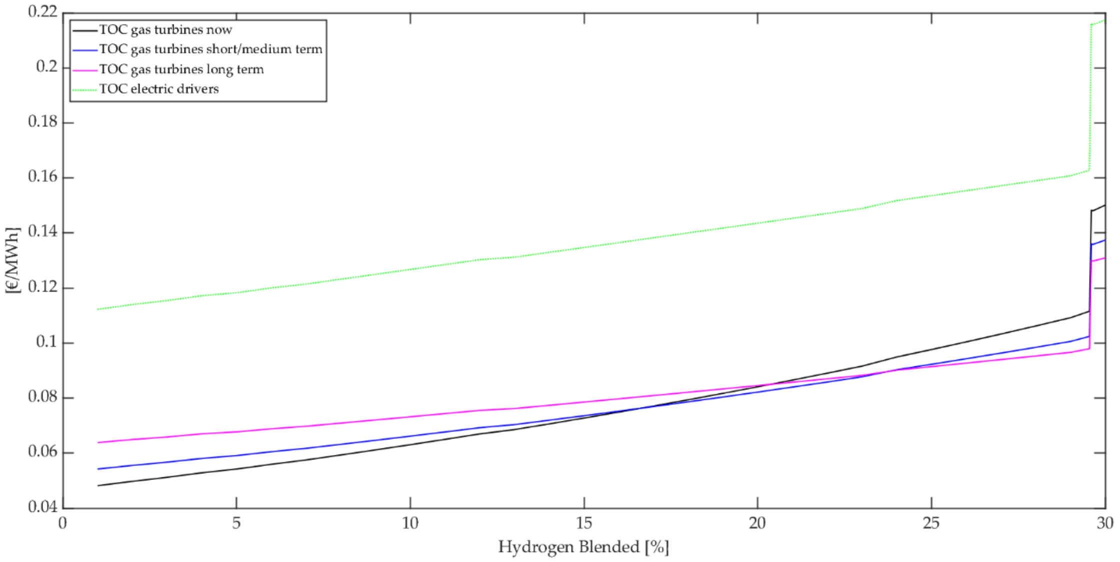

Figure 5.9: Total operational costs in case fixed minimum pressure for hydrogen levels between 0 and 30vol%.

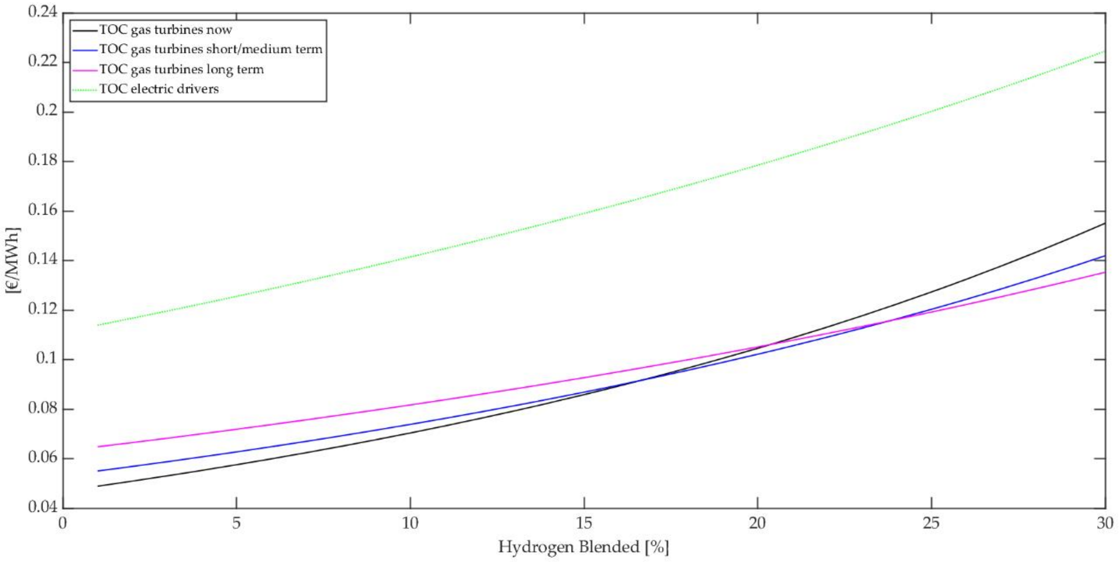

Figure 5.10: Total operational costs in case fixed compression station location for hydrogen levels between 0 and 30vol%.

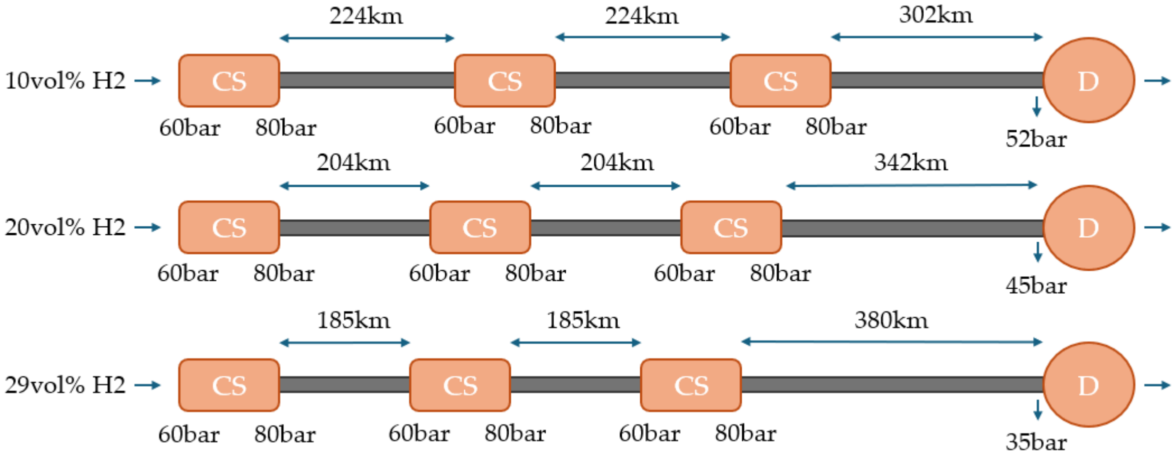

Figure 5.11: Diagram for configurations with the same minimum pressure by changing compression station location. Cases for 10, 20 and 29vol% H_2. CS means compression stations and D the starting point for gas distribution system.

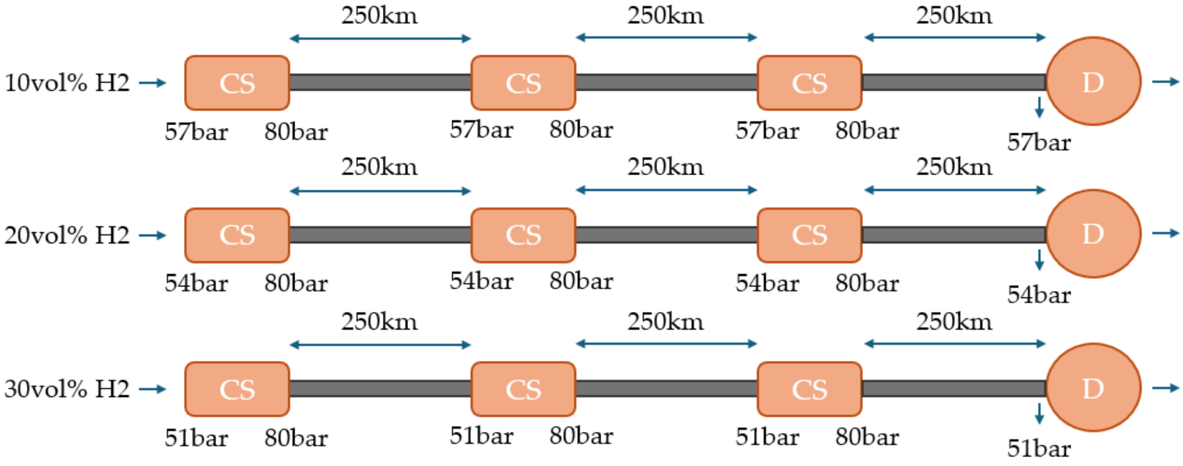

Figure 5.12: Diagram for configurations with the same compression station location by changing minimum pressures. Cases for 10, 20 and 30vol% H_2. CS means compression stations and D the starting point for gas distribution system.

Considering that in case of Figure 5.11 the configuration will be different for each hydrogen percentage, the best way to afford the problem is to take the configuration for 29% hydrogen which is the worst case. In case poorer admixtures were added using this last configuration, pressure losses and power spent in compression are going to be lower.

It is difficult to establish a conclusion without information about the cost that moving compression stations will take. However, there is a region in which the actuation is clear. On the one hand, if hydrogen expected to be added is less than 13.5vol%, the best option is to continue with the current compression station's location without investing money since it was demonstrated that with the current installed power, extra pressure losses could be overcome.

On the other hand, if hydrogen is higher than 14vol% and it is expected to reach levels as 29-30vol% H_2, the best way seems to be by changing the compression station's location which should be cheaper than the investment in new compressors. Nevertheless, this is a special case in which we are considering the end of the transmission line. For general cases the only way possible would be to maintain the compression stations in the same place, making investments according to Figure 5.8 by buying new compressors depending on the power demand.

6 Chapter six. Economic analysis for full hydrogen conversion.

In this chapter the idea of a conversion into a full hydrogen system is developed. There is a possible future scenario when hydrogen may take more protagonism and projects for adapting the natural gas network to hydrogen would turn into a full network conversion.

For assessing this transformation two main steps will be followed. The first one includes pipeline and compression stations design. After the design stage an economic study will be done in order to compare the possible alternatives and try to select the best ones.

6.1. Study of possible suitable materials

Some of the materials typically considered for hydrogen purposes are aluminium alloys, copper alloys, titanium alloys, austenitic stainless steel and carbon steels. When making the study about possible useful materials for pipeline usage, two main aspects should be considered: material will suffer from high stress conditions and material volume needed will be huge. Hence, the key is to find good balance between performance and material cost.

6.1.1. Carbon steels

Low alloy steels have been widely used in pipeline engineering since the first constructions because of their good mechanical properties and unexpensive cost. It is important to consider that materials with high yield strength allows de designers to build thinner structures and consequently save a lot of money. From this point of view, API grades X70 or X80 are the best option.

However, if the purpose of the pipeline is to transport hydrogen the situation is different. As it was explained before, these high strength steels are prone to struggle in hydrogen presence. The European Industrial Gases Association (EIGA) wrote a repot about hydrogen pipeline system where remarks the importance of selecting materials with tensile strength lower than 800 MPa [39].

In that document EIGA recommends API 5L steel with grade X52, which has been used with hydrogen without reporting important problems. This grade of carbon steel is characterized for having lower tensile strength and better behaviour against fragile fracture mechanisms. Furthermore, they specify their preference with PSL 2, which is a product specification level that includes requirements as maximums for yield and tensile strength, better control of elements involved and a maximum value of carbon equivalent. This control in properties is crucial when designing for hydrogen. The standard ASME B31.12 [40] says that apart from the minimum for structural purposes, also the maximum yield strength information should be provided to manage HE.

In addition, there is an internal safety standard for hydrogen systems in NASA where, among others, carbon steels are advisable for hydrogen pipping [41].

Following the recommendations from institutions as ASME, EIGA and NASA grades X52 and X42 will be both considered.

6.1.2. Stainless steels

6.1.2.1. Austenitic stainless steel

Austenitic steels are alloys with high content of nickel which perform well in corrosive environments and offer high tenacity. They present grain corrosion issues when surpassing 400ºC [20], which is important in welding processes, however, during pipeline lifetime the steel will never reach such a high temperature.

There are different grades depending on nickel content and other elements like molybdenum or titanium. In addition, carbon content could be variable. Two of the most used austenitic steels are 304/304L or 316/316L. The second one has more resistance against intergranular corrosion after welding and also against aggressive environments. NASA recommends these alloys against carbon steels specially when hydrogen is transported as a liquid at cryogenic temperatures.

Other key aspect in austenitic stainless steels is the tendency towards martensitic conversion. There are alloys where austenitic phase is not stable enough and becomes martensitic with high stresses at low temperatures, reducing the ductility of the steel [41]. According to this, 316L is the most stable one.

When the L is included in the grade means that the carbon content is reduced. While 304 and 316 steels have 0.08%C, 304L and 316L have around 0.02%C. First ones, with more carbon in the microstructure, offer better mechanical performance (higher yield strength), however, they are more prone to suffer intergranular corrosion.

Considering all this, 316 and 316L seems to be the two best options for hydrogen pipelines, being 316L slightly better.

6.1.2.2. Other alloys

Copper alloys are also suitable for dry hydrogen. The problem is that it is necessary to ensure there are no oxygen or copper oxide inside the metal. Hydrogen would go through the crystalline structure and react with oxygen, generating water. If temperature is considerably high (370ºC) gas pressure will be enough to generate cracks [39] [32]. This is not the case of gas transmission pipelines, and even in case it was, these alloys can be easily deoxidized. The main drawback of copper alloys is his poor yield strength respect carbon steels, which makes them not suitable for high pressure conditions. This problem is even worse in case aluminium alloys.

Nickel and his alloys must be avoided. Apart from being very expensive, they are severely embrittle by hydrogen.

As a conclusion, the possibilities are reduced to austenitic or carbon steels. Table 6.1 recaps some data about tensile properties of both steels. The pipeline will be sized according to ASME 3.12 guidelines, that means, taking the yield strength of the material as the reference value. The expression is very similar to Equation (3.1:

$$t = \frac{P \cdot D}{2 \cdot S} \cdot \frac{1}{F \cdot E \cdot T \cdot H_f} \tag{6.1}$$

The only difference is the introduction of the coefficient H_f, which represents a performance factor considering the adverse effects of hydrogen in the mechanical properties of carbon steels (in austenitic steels is considered 1). For grades X52 and X42 with design pressures under 2000psig (140bar) H_f is considered 1. See Figure 6.1.

Table 6.1: Yield and tensile strength comparison between some austenitic and carbon steels. [40]

Austenitic steels	**304, 316**	**304L, 316L**
Yield Strength [ksi (MPa)]	30 (207)	25 (172)
Tensile Strength [ksi (MPa)]	75 (517)	70 (482)
Carbon steels	**API 5L X52**	**API 5L X42**
Yield Strength [ksi (MPa)]	52 (359)	42 (290)
Tensile Strength [ksi (MPa)]	66 (455)	60 (414)

Equation (6.1 reveals the main disadvantage of austenitic steels respect carbon steels. Their lower yield strength implies much more thickness for the same design pressure than if the pipe is made of carbon steel. Moreover, data provided directly from the

Stainless Steel Development Association CEDINOX reveals that the cost of austenitic stainless steel is much higher than carbon steels. Table 6.2 contains some calculations about cost of pipe material.

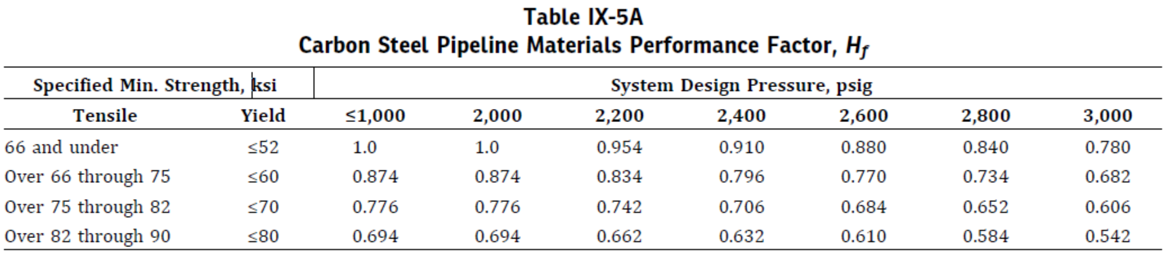

Table IX-5A
Carbon Steel Pipeline Materials Performance Factor, H_f

Specified Min. Strength, ksi		System Design Pressure, psig						
Tensile	Yield	≤1,000	2,000	2,200	2,400	2,600	2,800	3,000
66 and under	≤52	1.0	1.0	0.954	0.910	0.880	0.840	0.780
Over 66 through 75	≤60	0.874	0.874	0.834	0.796	0.770	0.734	0.682
Over 75 through 82	≤70	0.776	0.776	0.742	0.706	0.684	0.652	0.606
Over 82 through 90	≤80	0.694	0.694	0.662	0.632	0.610	0.584	0.542

Figure 6.1: Material performance factor for carbon steel pipeline systems based on the specified minimum yield strength. [40]

Results reflect austenitic stainless steel is not an option in this case, where pipes have big diameters and are forced to withstand high pressures. The combination of these two factors, make them over ten times more expensive. In case size and stress requirements were lower, this type of steel could be more useful. Thus, the final decision will be considering API 5L X52 as base material to build the pipeline.

Table 6.2: Thickness according ASME B31.12 and costs for each steel at 120bar maximum pressure and 30inch internal diameter.

	316 **X5CrNiMo17-12-2**	**316L** **X2CrNiMo17-12-2**	**316L** **X2CrNiMo18-14-3**	**X52**	**X42**
Thickness [mm]	47	57	57	26	33
Density [kg/m³]	8000	8000	8000	7850	7850
Material cost [€/ton]	4560*	4610*	6380*	920**	920**
Pipe cost [€/m]	4345	5421	7502	471	593

*Data obtained directly from CEDINOX (Asociación para la Investigación y Desarrollo del Acero Inoxidable en España)

**Data extracted from [33]

6.2. Pipeline sizing

6.2.1. Design parameters: Diameter and maximum pressure

Once we know the gas which will be delivered, when beginning the study for building a pipeline there are four basic parameters or variables in which all the others are based on. These are the maximum pressure, pipe diameter, temperature and the energy ratio or power needed to be transferred.

Last two are already known. On the one hand, temperature is always considered 25ºC, on the other hand, power requirements are the same than in case natural gas, because, as it was mentioned, the main requirement is not to reduce the maximum power capacity. This power establishes the mass flow needed and, what is the same, the volume flow. With this last two and knowing the density from temperature and pressure, there is all the information for pressure drop calculation and consequently the operational costs.

The design problem is then reduced to two variables: maximum pressure and pipe diameter. As it was already demonstrated in Equation (3.1 and Equation (6.1, design pressure and pipeline diameter are both correlated and these two determine the pipe thickness.

Great part of the investment costs will come from pipe engineering, so determining the best combination of diameter and pressure is absolutely crucial to optimize costs. Having all this clear, the best way to continue is to check the trend of investment cost and operational costs depending on this pair of variables.

6.2.2. Investment and operational costs variation

As explained in the previous chapter, pipeline cost is considered the sum of three branches: material cost, labour cost and miscellaneous cost, and the last two are proportionally related with material costs (see Table 4.2). Thus, it is enough to assess material cost (MC) behaviour. These material costs are computed as shown in Equation (6.2.

$$MC = \pi \cdot \frac{{D_{out}}^2 - {D_{in}}^2}{4} \cdot L \tag{6.2}$$

Where D_{out} is the external diameter, D_{in} the internal diameter and L the pipeline length.

External diameter can be substituted using Equation (6.3 and thickness using Equation (6.4. By joining all these equations, the final expression of material costs will depend only on internal diameter and design pressure.

$$D_{out} = D_{in} + 2t \tag{6.3}$$

$$t = \frac{D_{in} \cdot P}{2 \cdot S \cdot F \cdot E \cdot T \cdot H_f - P} \tag{6.4}$$

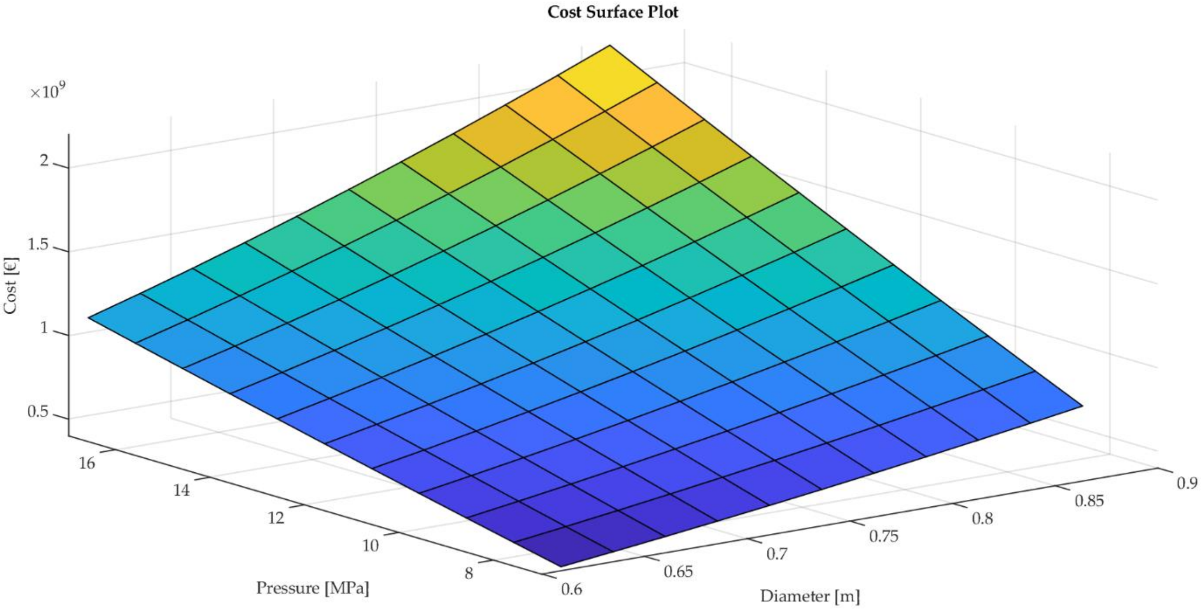

Figure 6.2: Pipe material cost for different design pressures and diameters.

In Figure 6.2 material cost is plotted for diameters from 24 to 34inches and a pressure range from 7 to 17MPa. Conclusions are clear, if only attending to pipeline costs, the optimum configurations are the ones with less diameter and pressure. However, as demonstrated in chapter 3, decreasing pressure and diameter will lead to a great increase in speed and pressure losses. That means not only to spend more resources in gas compression, but also to install more compressors in each compression stations. A clear conflict arises between pipe cost and compression costs so, in order to correctly evaluate the situation, these other expenses should be analysed too.

Although they are related, it is important to remember that operational costs due to fuel consumption and extra compressors installation are evaluated at different conditions. As operational costs will later be computed all over the year, they were calculated with an average capacity taking into account seasonality. Compression stations sizing must be calculated considering the maximum capacity, even if there are some parts of the year in which some equipment is not working due to a lower energy demand.

A clarification about compression stations should be made. In case pure hydrogen transportation, 3€/kg will be considered as hydrogen price. This low price makes possible to generate cheaper power than with electric compressors. The other advantage of including electric compressors instead of gas turbines was to avoid the gas emission taxes, however, with a full hydrogen system the main product of combustion reaction is going to be water and not CO_2 so there will be no need to pay any penalization. If there is no gain in terms of operational costs, electric compressors are not as worth it as before, because changing the installation to prepare the system to work with electric motors has an implicit extra investment cost. For all this, electric compressors will not be considered in this Chapter 6.

After showing some graphs, it is important to remark that there were some cases in which the pressure was not high enough to maintain the gas density within feasible limits. These combinations carried huge energy consumption and could have not been taken into consideration. The decision was to eliminate these combinations so to reduce the computational cost of the code.

Initially, compression stations include 4+1 compressors of 4.5MW each, so the installed capacity in each station and in the whole line is 22.5MW and 67.5MW. This reference will be used to calculate the necessary compressors for each case. Table 6.3 shows the power and additional compressors needed to achieve the compression necessities with higher diameters and pressures. To know about the results in all the feasible combinations see Appendix A. In addition, Figure 6.3 offers a more visual picture about the evolution of power consumption in all the feasible domain. It is clear that the higher the diameter and pressure, the lower the power spent in gas compression due to the reduction in pressure losses.

Table 6.3: Compression power [MW] and extra compressors needed for each feasible combination diameter-pressure.

Diameters [inch] **Pressure [bar]**	**34**	**33**	**32**	**31**	**30**
120	130.5; 15	156.8; 21	191.2; 30	237.8; 39	304.3; 54
130	108.9; 12	129.9; 15	156.9; 21	192.5; 30	241.3; 39
140	92.7; 6	110.0; 12	132.0; 15	160.4; 21	198.4; 30
150	80.1; 3	94.7; 9	131.9; 12	136.5; 18	167.3; 24
160	70.2; 3	82.7; 6	98.3; 9	118.1; 12	143.8; 18

Diameters [inch] **Pressure [bar]**	**34**	**33**	**32**	**31**	**30**
170	62.1; 0	73.0; 3	86.6; 6	103.6; 9	125.4; 15

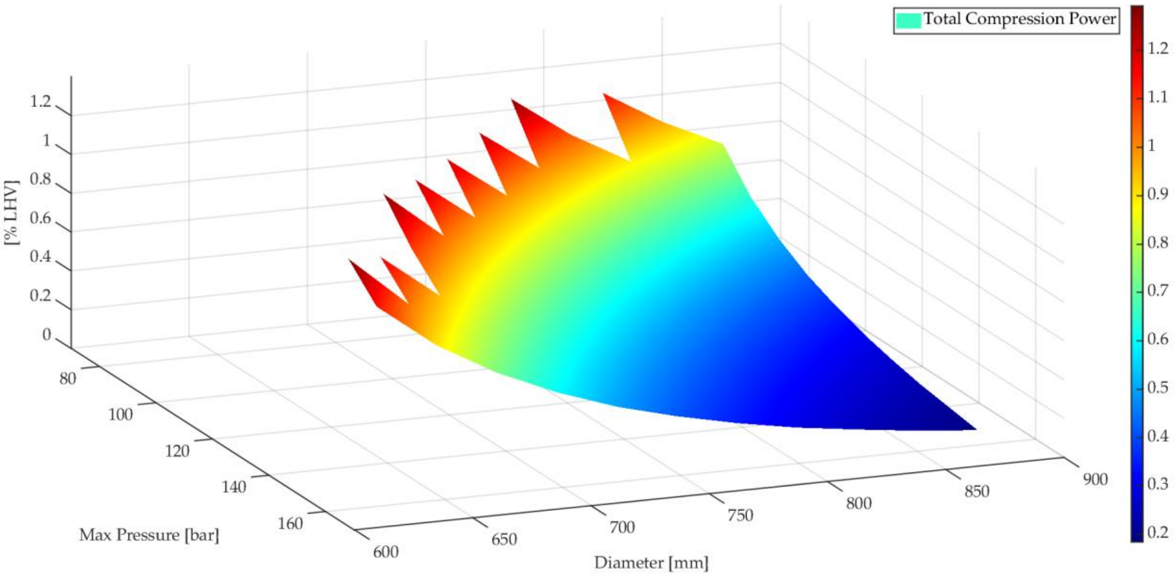

Figure 6.3: Total compression power depending on diameter and pressure.

For even better understanding, some 2D plots will be added. On the one hand, Figure 6.4 contains data about variation of compression power needs vs diameter when pressures are fixed. On the other hand, in Figure 6.5 maximum pressure is the variable in x axis and isolines are organised by diameters.

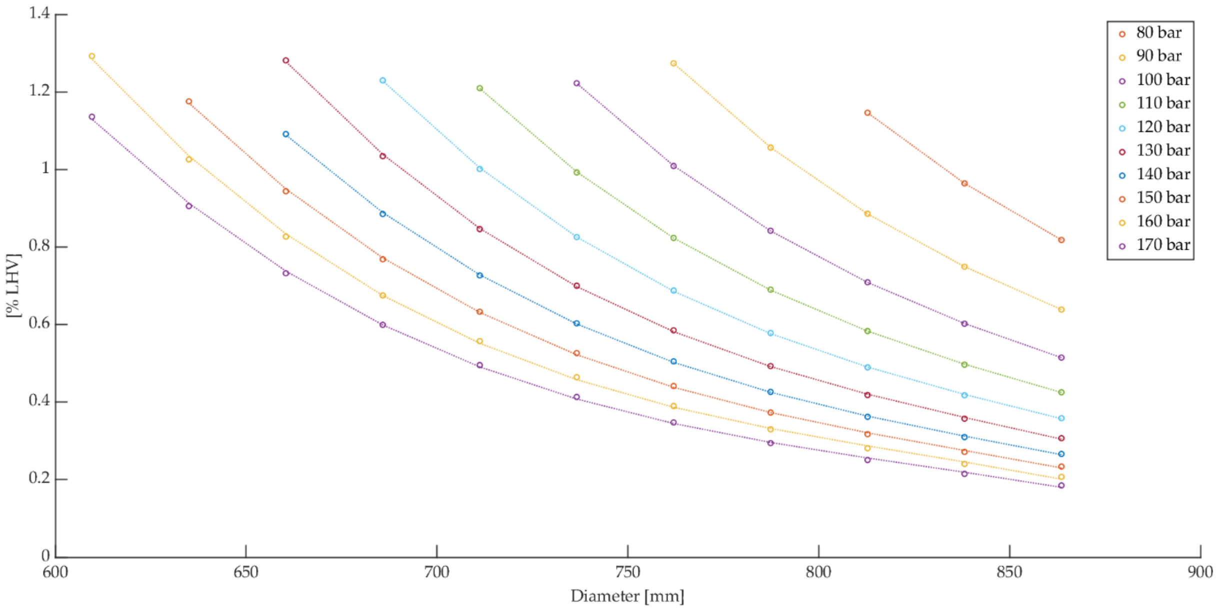

Figure 6.4: Compression needs vs internal diameter with maximum pressure as isolines.

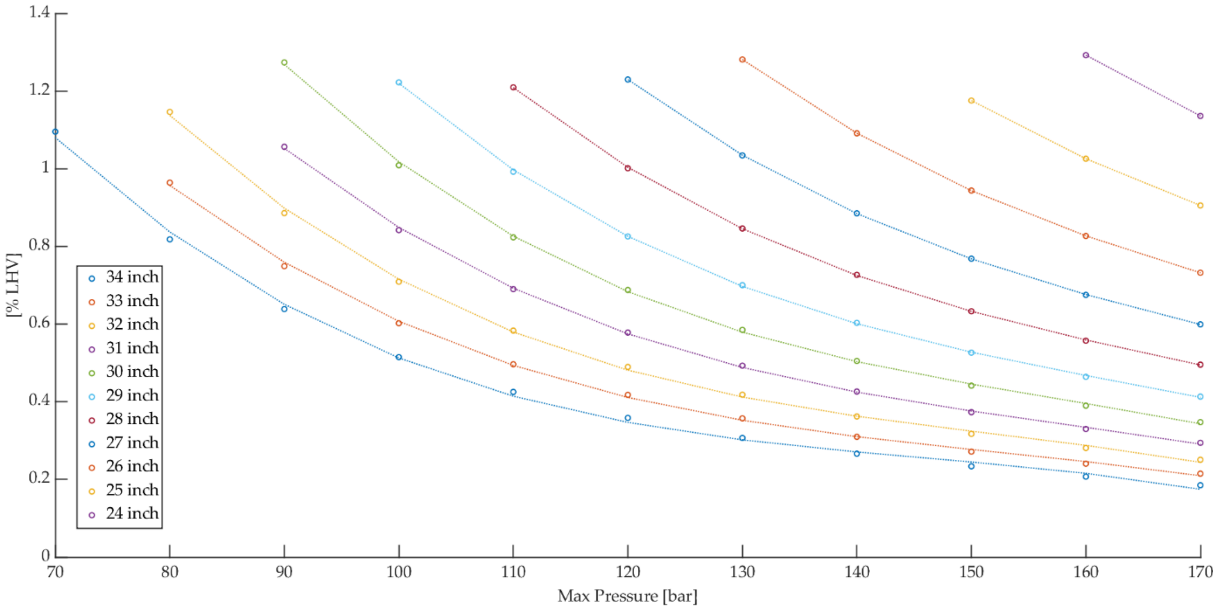

Figure 6.5: Compression needs vs maximum pressure with internal diameter as isolines.

All these extra compressors have certain cost that must be added to pipeline expenses. As these two expenditures have opposite behaviour, the final surface (Figure 6.6) has a minimum value for investment. Remember that compressors cost evaluation was considering the values established in Table 4.3.

From the minimum to the left, pressures and diameter decreases and compression station costs grows severely. From the minimum to the right, pressures and diameter increases, so in this case pipeline cost make the surface to grow up. To be fair in the comparison, in this case pipeline costs was computed not only by considering material costs, but also including labour and miscellaneous costs associated.

Figure 6.9 displays different graphs to have a good overview of different trends and how they affect to global operational and investment costs.

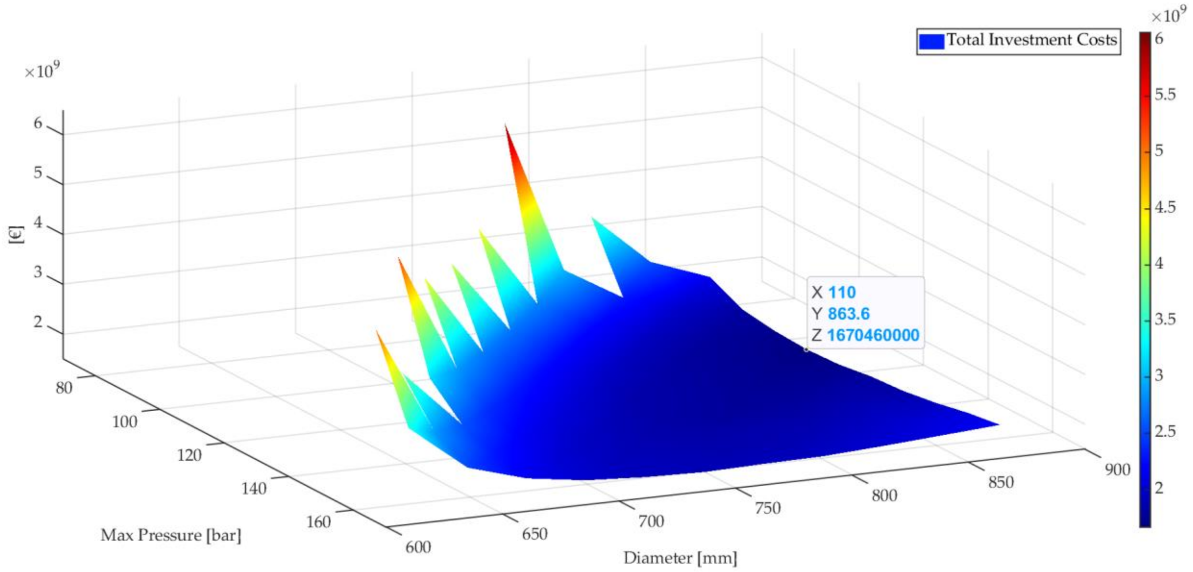

Figure 6.6: Total investment costs depending on diameter and pressure.

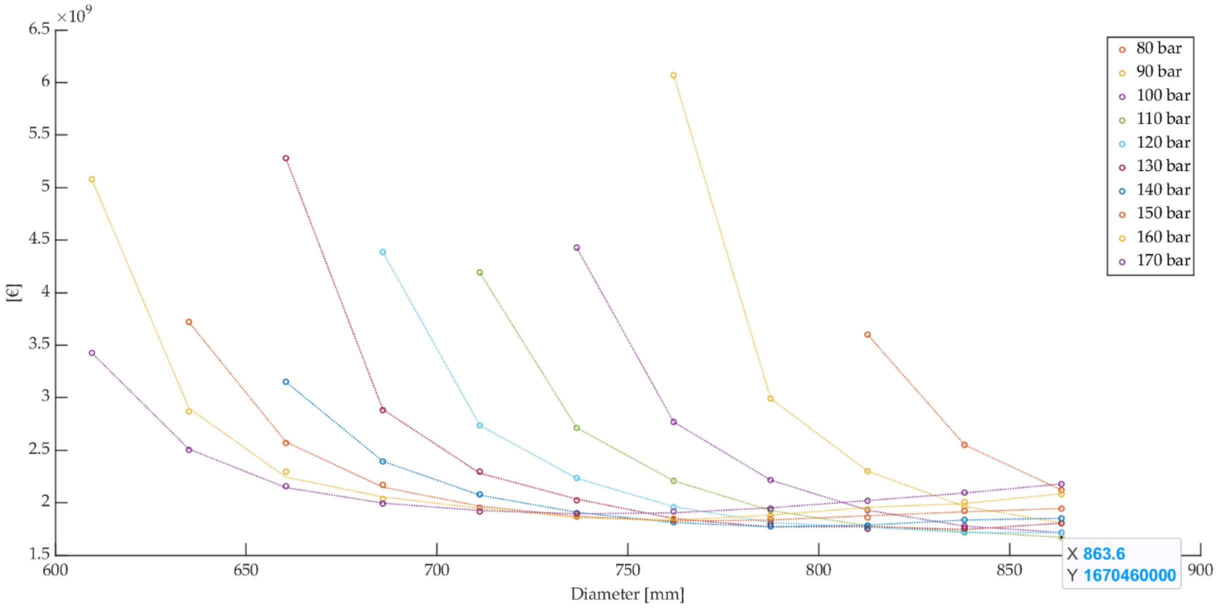

Figure 6.7: Total investment cost vs internal diameter with maximum pressure as isolines.

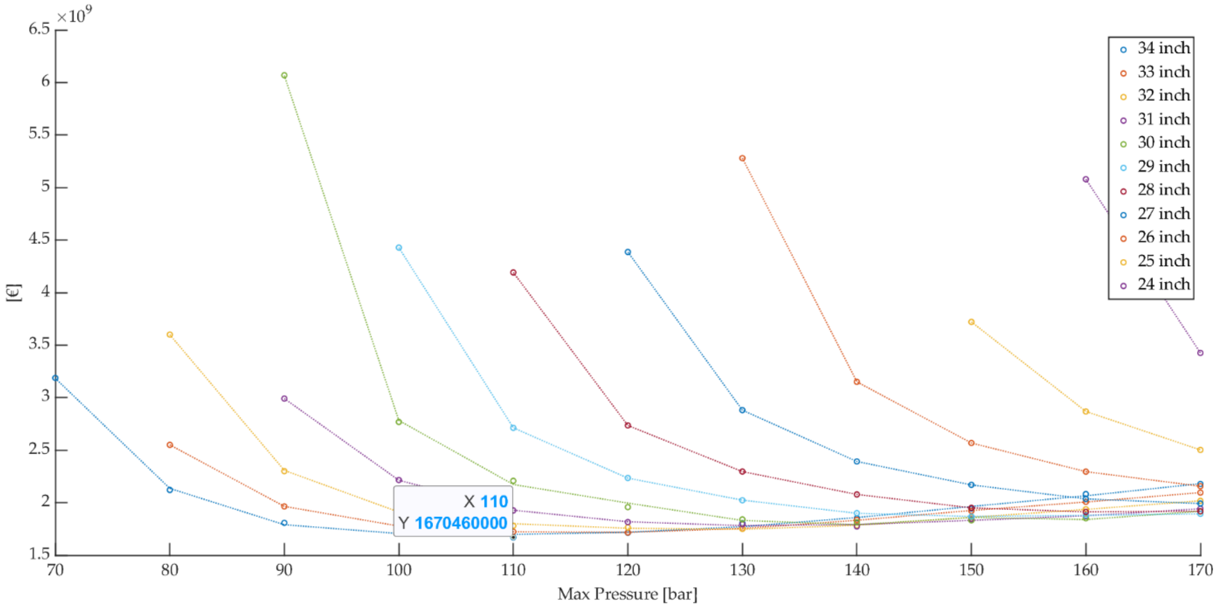

Figure 6.8: Total investment cost vs maximum pressure with internal diameter as isolines.

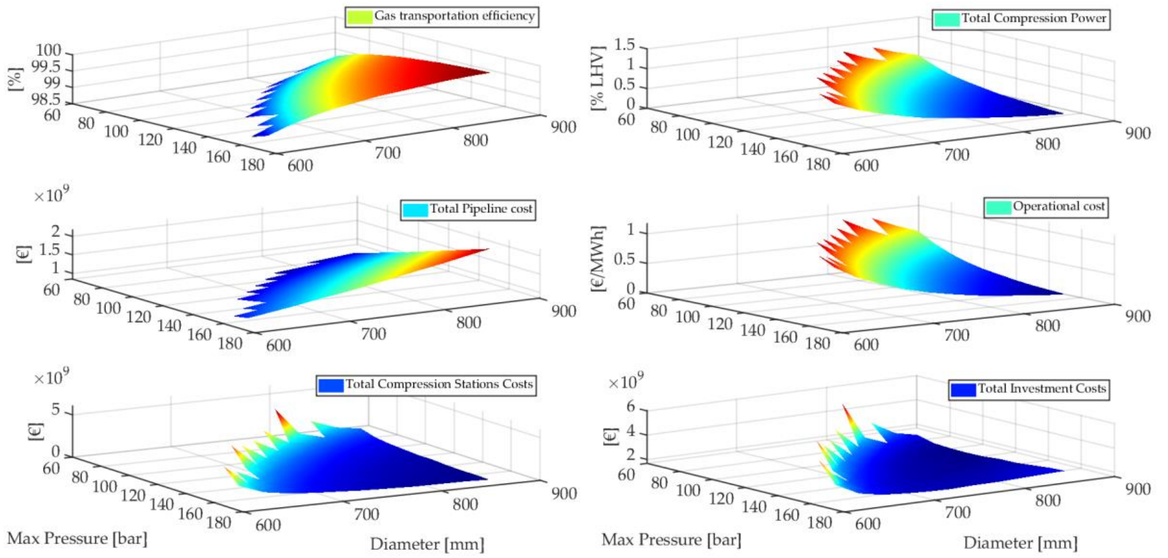

Figure 6.9: Overview of transport efficiency, compression needs, investment and operational costs trends for different diameters and pressures.

6.2.3. Optimum investment selection

Total investment costs and operational costs have different behaviour that forced the designer to correctly evaluate both cases to choose the bests alternatives. As it was already commented, around the minimum value for investment there are two ascending trends. One of them, the one with higher diameters and pressures, leads to lower operational costs while the other implies spending more money in compression. Obviously, there is no sense in selecting options with higher investment at the same time they will have more operational costs. However, it could be interesting to evaluate the region on the right. Here, the fact of having less operational costs, can make a bigger investment worth it all over the years.

Nowadays, the medium age of the Spanish natural gas pipeline system is around 25 years, and the oldest pipes are 50 years old. With these amortization period it is convenient to study the investment in the medium-long term and not just considering saving money in the short term.

The idea is to take the lower investment possible as a reference, and then calculate the crossover point respect other possible investments that have higher initial cost but lower operational expenses. This point could be considered a kind of breakeven. The equations used for calculating that point is:

$$0 = AddCost - \sum_{year=1}^{crossover} \frac{Savings}{(1+0.0237)^{year}} \tag{6.5}$$

$$AddCost = TINVC_i - TINVC_{ref} \quad [€] \tag{6.6}$$

$$Savings = \ (TOC_{ref} - TOC_i) \cdot 365 \cdot 24 \cdot \bar{P} \quad [€/year] \tag{6.7}$$

Where $TINVC_i$ and TOC_i are the total investment ant operational costs of the diameter-pressure combination i, $TINVC_{ref}$ and TOC_{ref} are the investment and operational costs for case 110bar and 34inch, and $\bar{P}$ the average power delivered in a year. In order to compute the energy delivered in an entire year ($MWh/year$), that $\bar{P}$ is multiplied by the number of days per year and hours of a day.

Equation (6.5 is an iterative process in which every year the savings in terms of operational cost are subtracted from the additional cost respect the reference case. Breakeven is achieved when the accumulation of savings is enough to equal the additional costs. Savings should be divided by a discount term to take into account the inflation over the years. INE (Instituto Nacional de Estadística) establish an IPC (Índice de Precios al Consumo) variation of 2.37% during last decade, so that average value was the one considered as annual inflation [42]. An assumption will be the absence of interests, considering the government does not finance the project with any loan.

To make the computational cost lighter, when the variable year reached 150 the solution was discarded. There were only four cases with crossover before 150 years: with 34inch as internal diameter and 120, 130 or 140bar as design pressure, and 33inch as internal diameter and 130bar as design pressure.

Table 6.4: Amortization period for different investments respect 34inch and 110bar case.

Pressure [bar] Diameters [inch]	110	120	130	140
34	Ref	28	77	78
33	-	-	102	-

There is only one affordable solution with 28 years for crossover. Considering pipe lifetime, alternatives with more than 50 years as amortization period are not convenient. Figure 6.10 displays the cost evolution of the two possible solutions, evaluating the situation after 10, 25, and 35 years. The average growth rate of the red line in 25 years is slightly higher than 1 million€/year, which are the average operational costs saved during a year. If the lifetime expected is more than 28 years, the best design will be the second. For instance, if lifetime expected is up to 35 years, the investment is worth it in nearly 6.5 million€.

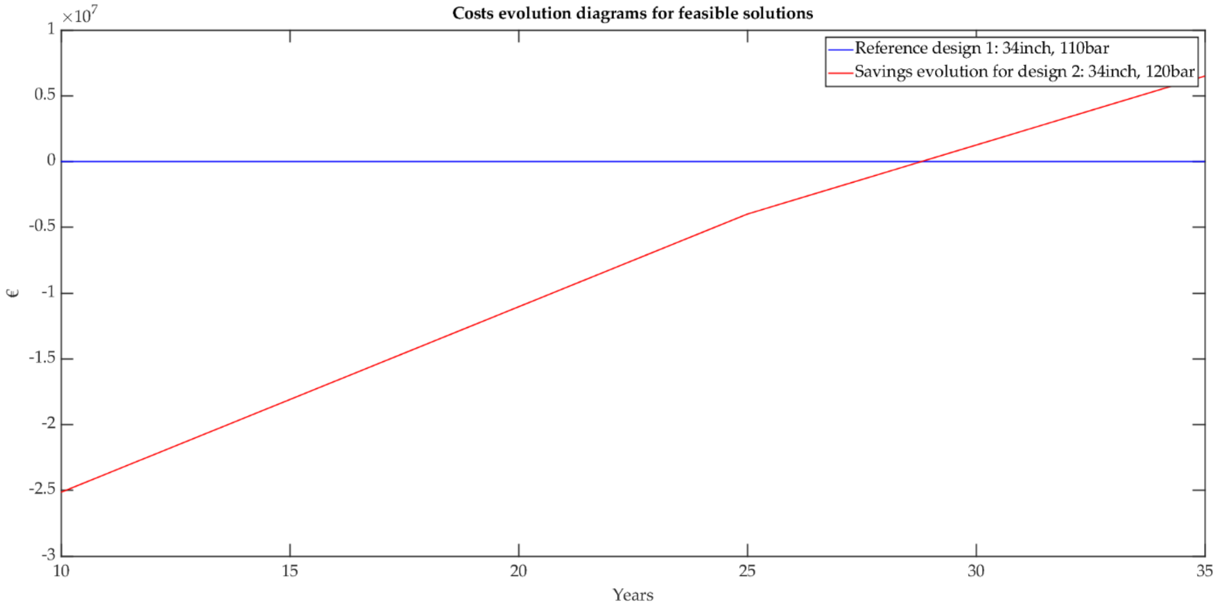

Figure 6.10: Cost evolution diagram for two optimal solutions.

7 Chapter seven. Conclusions and future directions.

7.1. Conclusions

The alternatives this project has studied involves sending hydrogen together with natural gas by adapting current pipeline systems, and the construction of a new infrastructure for transporting pure hydrogen. For natural gas-hydrogen admixtures the safety limit was defined in 30%vol H_2 in order to avoid pipe damage as a consequence of hydrogen embrittlement.

There are two scenarios for hydrogen usage which might define the most suitable way for transporting hydrogen. On the one hand, hydrogen could be used as an additive component for natural gas. This fuel can be useful in the vast majority of processes in which natural gas is involved. According to a report presented by Naturgy [43] about natural gas numbers in Spain, the total natural gas consumption in 2022 was 364.4TWh. That represents the 24% of the national primary energy consumption [44]. That energy was consumed basically in : Commercial-residential purposes (16%), industrial consumption (49%) and generation (35%). The advantage of using this natural gas-hydrogen admixture is the reduction of carbon presence in combustion process, thus, the total emissions of particles and greenhouse gases would decrease considerably. Table 7.2 demonstrates that it would be possible to cover more than 10% of the demand with a blend with 30% volH_2.

Considering that machinery can deal with hydrogen up to 30% with only few modifications, in the short-medium term this can be the solution to make a transition to a future in which hydrogen would replace natural gas completely. Comparing the economic analysis for adapting the infrastructure for blends and building new pipelines, the investments in the first case are much cheaper (See Table 7.1). Furthermore, the strategy of keeping the compression stations in the same place and adapting the power capacity to the requirements offers a lot of flexibility. Compression stations will be able to increase the installed power progressively at the same time the hydrogen acquire protagonism in the following years. In 2030, Spanish government aims to have an installed power of 4GW in electrolytic plants to produce 70.000 annual tonnes of green hydrogen. That quantity means 2.3TWh of hydrogen, which could be easily delivered as a combination with natural gas. Table 7.2 collects some numbers about the energy which could be transmitted in form of hydrogen using that method.

Data exposed demonstrates this quantity of hydrogen could be covered in an 80% only by this pipe section if considering a blend of 30%volH_2. It is important to take into account that, in order to be closer to the reality, seasonality was considered to compute the annual capacity absorbed by hydrogen.

Table 7.1: Investment costs comparison between blending hydrogen with NG using fixed compression station location approach and building a new infrastructure for pure hydrogen delivery.

Hydrogen presence	10vol% H_2	20vol% H_2	30vol% H_2	100vol% H_2
Adaptation for NG-H_2	0 M€	44.17 M€	132.5 M€	-
New pipeline for pure H_2	-	-	-	1670.5 M€

Table 7.2: Hydrogen role in power transmission ratio, annual energy capacity and percentage of hydrogen contribution respect the total capacity.

Hydrogen presence	10vol% H_2	20vol% H_2	30vol% H_2
Power ratio [MW]	242.5	526.4	863.1
Annual capacity absorbed by H_2 [TWh]	0.51	1.11	1.81
Couverture [%]	2.93	6.36	10.44

In case hydrogen will be used alone with high purity level, the optimum way for transporting hydrogen might change. Ideally, an assessment including the cost of removing hydrogen from the natural gas blends would be needed. Purity levels around 99.999% is required for fuel cell usages, so it would be challenging and expensive.

If electrolysers and fuel cells are sufficiently developed and hydrogen is produced and transported to spend it directly in power-to-power applications or mobility, the best way for delivering hydrogen is without making mixtures with natural gas. It is not profitable at all to produce huge amounts of hydrogen, blend it with other gas, and then split them with expensive processes to use hydrogen separately.

This last one is the suitable scenario for the second alternative exposed, which is building an infrastructure dedicated exclusively to carry hydrogen. The main drawback is the cost needed for this kind of projects, as it was shown in Table 7.1. Instead of taking about tens or hundred million euros, numbers are now around several thousand million. There is an important consequence to consider when companies materialize this kind of investments. Part of the price citizens pay for energy is dedicated to cover the expenses of transportation. This price will be higher the years after the investment to cover also construction costs. In the table below there are some estimations for extra price per Megawatt-hour in case it would come from hydrogen. Numbers were calculated taking the budgets of this master thesis case study and H2med-BarMar project.

Table 7.3: Money to be included in hydrogen energy final price due to investments amortization. Cases of Spanish infrastructure section and H2med-BarMar project.

Amortization years	**3**	**4**	**5**
Extra price* [€/MWh]	15.69	11.77	9.41
Extra price [€/MWh]**	21.80	16.35	13.08

*Considering this master thesis case study: 35,49TWh/year (including 48.98% seasonality); investment of 1670.5M€; 750km

**Considering H2med-BarMar project : 32.65TWh/year; budget of 2135M€; 450km

All these are only few of many factors to be considered when making such a step as basing great part of the energy field in other new compound. The idea would be to increase the hydrogen presence in the market by mixing it with natural gas progressively until reaching safety limits for current pipelines. If, after some years, hydrogen is eventually considered able to be used as a feasible energy vector, construction works for natural gas network substitution could be carried out in parallel. Surprisingly, the trend seems to be other, and particularly European governments are investing huge quantities of money to make this transition as short as possible.

7.2. Future directions

There are some key aspects that can be assessed deeper to improve the accuracy of calculations or complement the thisis done.

7.2.1. Aspects to improve the accuracy of the model

An important aspect would be to evaluate the cost of gas turbines adaptation to natural gas-hydrogen consumption. Machinery in compression stations was considered capable of working with certain quantity of hydrogen without any modification and cost. It would be true for lower blending levels, but in case of values higher than 10vol% H_2 the assumption could be too optimistic.

When increasing the compression stations' capacity there was not consider the cost of extra terrain needed and additional material acquisition apart from compressors. Moreover, cost of new compressors was equal to the initial ones, without taking into account economy of cale or the possibility of making optimal combinations with bigger compressors to satisfy certain demand and using the others with lower capacity as backup. This strategy would have resulted in a lower procurement cost, so can compensate the other expenditures previously mentioned.

7.2.2. Ideas to extend the scope of the thesis

Utilization of electric compressors was demonstrated not to be a profitable alternative to natural gas turbines if taking the electric power from the network. Nevertheless, it would be very interesting to evaluate the possibility of solar plants installation to satisfy the compression stations power requirements. These plants must be designed to cover the power needs under maximum capacity. The majority of the season they will produce much more energy than needed, but in tat cases it can be poured into the net. Those systems could be more efficient and probably more worth it in the long term than gas turbines.

As it was mentioned before, including costs of plants dedicated to remove hydrogen from natural gas would help us to consider the possibility of keeping the idea of mixing the hydrogen with natural gas even with higher percentages. If this system results profitable, playing with two different usages of hydrogen would be possible using blending tarnsportation method.

This master thesis was based on a portion of the Spanish natural gas network. However, the study can be more useful if extrapolating the results in order to calculate the costs of changing an entire network and the quantity of hydrogen that could be transported at national scale.

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A Appendix A

This appendix is dedicated to collect some extra information about the results obtained for the design of the pipeline for transporting pure hydrogen.

A.1. Tables

Table A.1: Total compression power needed [MW] for each feasible combination diameter-pressure. Considering medium capacity over the year by applying 0.4898 seasonality factor.

Diameters [inch] **Pressure [bar]**	**34**	**33**	**32**	**31**	**30**	**29**	**28**	**27**	**26**	**25**	**24**
70	44,4	-	-	-	-	-	-	-	-	-	-
80	33,1	39,1	46,4	-	-	-	-	-	-	-	-
90	25,9	30,4	35,9	42,8	51,6	-	-	-	-	-	-
100	20,9	24,4	28,7	34,1	40,9	49,5	-	-	-	-	-
110	17,2	20,1	23,6	28,0	33,4	40,2	49,0	-	-	-	-
120	14,5	16,9	19,8	23,4	27,9	33,4	40,6	49,8	-	-	-
130	12,4	14,5	16,9	20,0	23,7	28,4	34,3	41,9	51,9	-	-
140	10,8	12,5	14,7	17,3	20,5	24,4	29,4	35,9	44,2	-	-
150	9,5	11,0	12,9	15,1	17,9	21,3	25,6	31,1	38,2	47,6	-
160	8,4	9,7	11,4	13,4	15,8	18,8	22,6	27,4	33,5	41,6	52,4
170	7,5	8,7	10,2	11,9	14,1	16,7	20,1	24,3	29,7	36,7	46,0

Table A.2: Total compression power needed [GW] for each feasible combination diameter-pressure. Considering maximum capacity.

Diameters [inch] **Pressure [bar]**	**34**	**33**	**32**	**31**	**30**	**29**	**28**	**27**	**26**	**25**	**24**
70	0,78	-	-	-	-	-	-	-	-	-	-
80	0,41	0,56	0,90	-	-	-	-	-	-	-	-
90	0,27	0,35	0,47	0,69	1,66	-	-	-	-	-	-
100	0,20	0,25	0,32	0,42	0,61	1,14	-	-	-	-	-
110	0,16	0,19	0,24	0,31	0,41	0,58	1,06	-	-	-	-
120	0,13	0,16	0,19	0,24	0,30	0,41	0,59	1,12	-	-	-
130	0,11	0,13	0,16	0,19	0,24	0,31	0,42	0,63	1,39	-	-
140	0,93	0,11	0,13	0,16	0,20	0,25	0,33	0,46	0,71	-	-
150	0,80	0,95	0,11	0,14	0,17	0,21	0,27	0,36	0,51	0,88	-
160	0,70	0,83	0,98	0,12	0,14	0,18	0,22	0,29	0,40	0,60	1,30
170	0,62	0,73	0,87	0,10	0,13	0,15	0,19	0,25	0,33	0,47	0,77

Table A.3: Total extra compressors [-] needed for each feasible combination diameter-pressure.

Diameters [inch] **Pressure [bar]**	**34**	**33**	**32**	**31**	**30**	**29**	**28**	**27**	**26**	**25**	**24**
70	159	-	-	-	-	-	-	-	-	-	-
80	78	111	186	-	-	-	-	-	-	-	-
90	48	63	90	141	354	-	-	-	-	-	-
100	33	42	57	81	123	240	-	-	-	-	-
110	21	30	39	54	78	117	222	-	-	-	-
120	15	21	30	39	54	78	117	234	-	-	-

Diameters [inch] Pressure [bar]	34	33	32	31	30	29	28	27	26	25	24
130	12	15	21	30	39	57	81	126	294	-	-
140	6	12	15	21	30	42	60	87	144	-	-
150	3	9	12	18	24	33	45	66	99	183	-
160	3	6	9	12	18	27	36	51	75	120	276
170	0	3	6	9	15	21	30	42	60	90	159

A.2. Figures

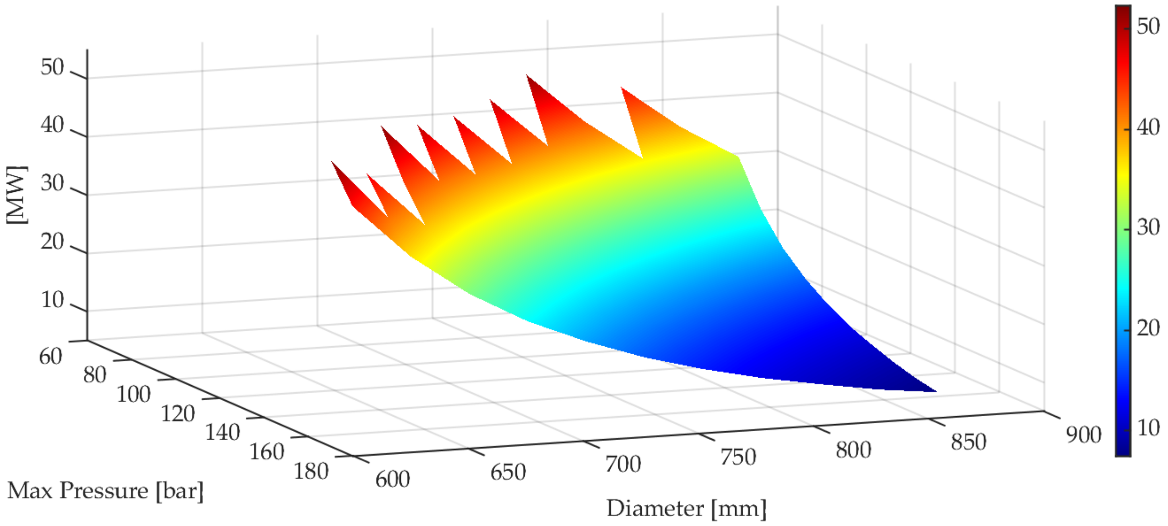

Figure A.1: Total compression power needed for each feasible combination diameter-pressure. Considering medium capacity over the year by applying 0.4898 seasonality factor.

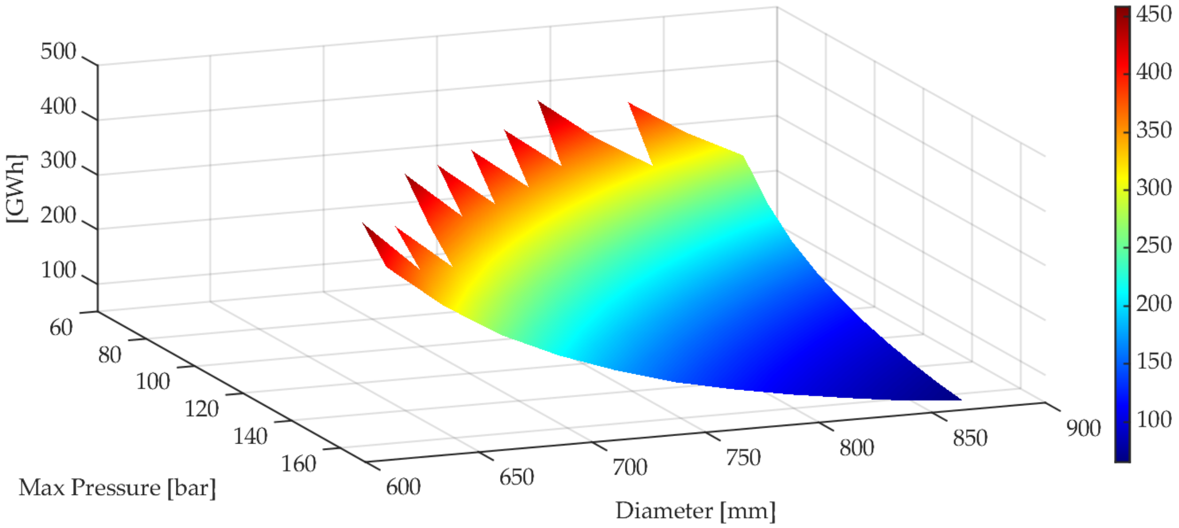

Figure A.2: Annual energy spent in compression station. Total energy delivered in a year: 35.49TWh.

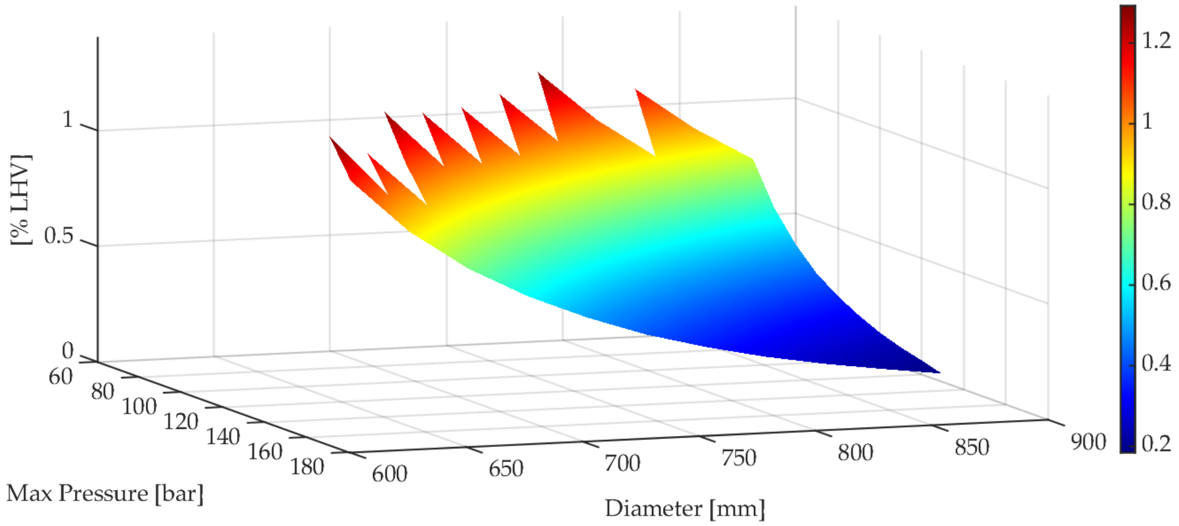

Figure A.3: Total compression power needed for each feasible combination diameter-pressure. Considering medium capacity over the year by applying 0.4898 seasonality factor. Percentage of total power delivered.

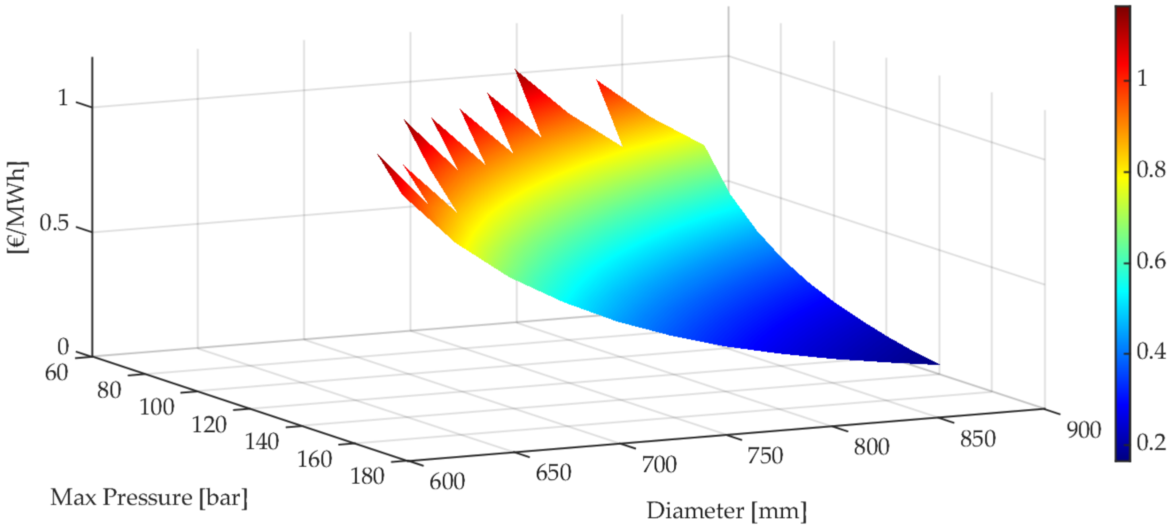

Figure A.4: Total operational costs considering medium capacity over the year by applying 0.4898 seasonality factor.

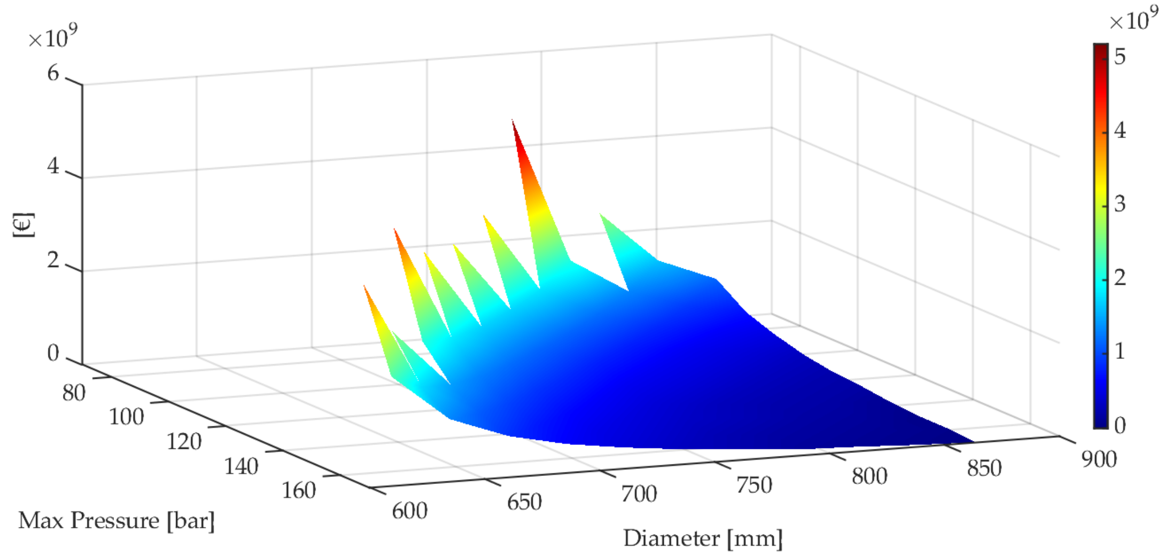

Figure A.5: Investment cost spent in extra compressors for compression stations.

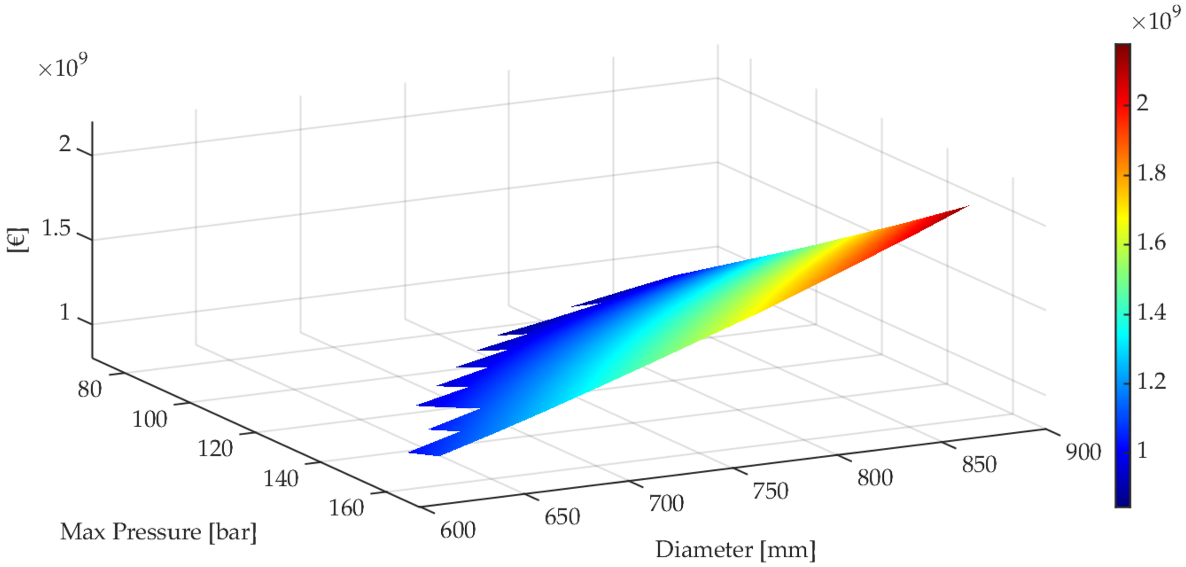

Figure A.6: Investment cost spent in pipeline construction, including labor, miscellaneous and material costs.

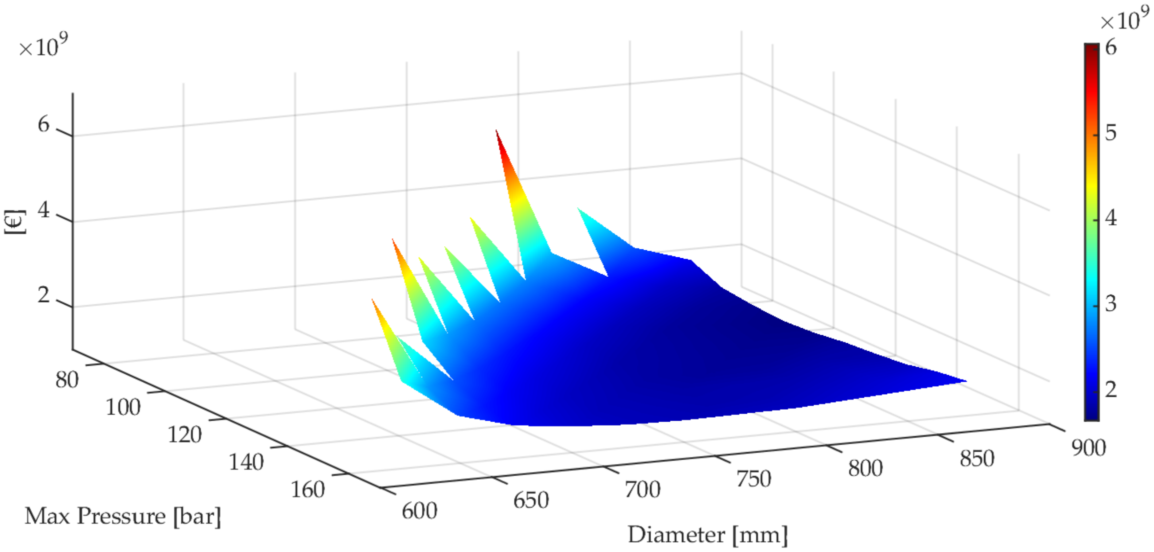

Figure A.7: Total investment costs. Result of summing pipeline construction costs and investment in extra compressors needed.

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