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Towards hydrogen transportation in gas transmission pipelines

TESI DI LAUREA MAGISTRALE IN
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Abstract

Hydrogen is becoming a realistic opportunity to carry energy among decarbonization goals and constant energy growth demand.
In this study a first introduction to hydrogen economy through production, application and transport is presented. Hydrogen transport can rely on gas pipelines, pipeline technology assessment is carried out by considering the already well-established gas infrastructure with focus on the gas transmission pipeline, afterwards it is analyzed the possibility to inject hydrogen in the gas network resulting in a hydrogen and natural gas mixture. The paper concludes with the prospect of pure hydrogen pipelines in a widen gas transmission network open to systems power to gas and gas to power.
Throughout the study an Excel model on transmission pipeline was developed to examine pipeline design parameters in three main scenarios; Natural Gas, Blending and Pure hydrogen.
Hydrogen behaves slightly different from methane in many fields and gas transportation is not an exception. Natural gas infrastructure has been shaped and optimized for several decades and introducing hydrogen in it places challenges on both technical and economic aspects. Nevertheless, blending seems to propose a short-medium term option in expectation of hydrogen pipelines that will sustain the promising hydrogen economy.

Key-words: Hydrogen, gas infrastructure, transmission pipelines, blending.

Abstract in lingua italiana

L'idrogeno sta diventando un'opportunità realistica per trasportare energia tra gli obiettivi di decarbonizzazione e la costante crescita della domanda di energia. In questo studio viene presentata una prima introduzione all'economia dell'idrogeno attraverso la produzione, l'applicazione e il trasporto. Il trasporto dell'idrogeno può fare affidamento sui gasdotti, la valutazione della tecnologia del gasdotto viene effettuata considerando l'infrastruttura del gas già consolidata con particolare attenzione al gasdotto di trasporto del gas, successivamente viene analizzata la possibilità di iniettare idrogeno nella rete del gas con conseguente miscela idrogeno e gas naturale. Lo studio si conclude con la prospettiva di gasdotti a idrogeno puro in una rete di trasporto del gas più ampia, aperta ai sistemi power to gas e gas to power. Durante lo studio è stato sviluppato un modello Excel sulla conduttura di trasmissione per esaminare i parametri di progettazione della conduttura in tre scenari principali; Gas naturale, miscelazione e idrogeno puro. L'idrogeno si comporta in modo leggermente diverso dal metano in molti campi e il trasporto del gas non fa eccezione. L'infrastruttura del gas naturale è stata modellata e ottimizzata per diversi decenni e l'introduzione dell'idrogeno al suo interno pone sfide sia sugli aspetti tecnici che economici. Ciononostante, il blending sembra proporre un'interessante opzione a breve-medio termine in attesa di idrogenodotti che sosterranno la promettente economia dell'idrogeno.

Parole chiave: Idrogeno, infrastruttura del gas, condotte, gasdotti, blending.

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Introduction

Hydrogen transportation infrastructure can be developed by taking as a model the Natural Gas infrastructure. The Natural Gas infrastructure consist of an aggregation of networks with the tasks to collect natural gas (raw gas) from production sites and bring it to processing plants, transporting then high quantities of gas at great distances and distribute it among consumers. The last two operations are respectively carried out by gas transmission systems and gas distribution systems and are of particular interest for hydrogen transportation where the same approach to Natural Gas could be applied.

The main focus of this thesis is aimed at analyzing hydrogen transportation through transmission pipelines. Transmission pipelines are the arteries of the gas networks, they consist of pipes with great diameters able to withstand the high pressures needed to push millions of cubic meters of gas each day. Along them compressor stations and other facilities like gas storages are placed for a correct transport and balance.

The natural gas infrastructure has been developed for decades and constructing a new one for hydrogen could require expensive amount of time and costs. For this reason, in short-medium term, the hydrogen injection into the natural gas network is taken as a viable option. The process involved, called blending, could overcome the "Chicken and Egg" problem for hydrogen infrastructure, while waiting for a dedicated hydrogen transport system.

Although hydrogen and methane share similar properties, they are not equal. Among the differences the lower volumetric energy density of hydrogen stands out, a third of methane (the primary component of NG) and this would imply a third of energy transported if same volumes are considered. Moreover, hydrogen is known to weaken and induce faster growth of cracks on steel through a process called "hydrogen embrittlement", this side effect is crucial for transmission pipelines that are made of steel.

The goal of the thesis is to analyze the possibility to employ the already in-use transmission pipelines for hydrogen transport by investigating the opportunities and challenges, the limitations and the steps necessary to move forward. Alongside, an assessment on the operative transmission pipeline parameters, including volumetric and energetic outlook, is carry out with the Gas Pipeline Model (GPM). Through the excel environment the GPM was built based on properties of gases, pipeline features and semi-empirical correlations employed in gas systems to confront natural gas, hydrogen-methane mixtures and pure hydrogen by presenting and comparing possible operative configurations of transmission pipelines.

The hydrogen supply chain is presented at the beginning in order to introduce hydrogen tracing with its current and future applications, the production methods under development and the wide range of methodologies to transport it. Afterward the gas infrastructure, transmission pipelines with their primary components and the relationship with hydrogen, are analyzed leading to the presentation of a standpoint of a hydrogen pipeline. Throughout the evolution of the analysis, three scenarios are in support with numerical frameworks, specifically "Scenario 0" considers the absence of hydrogen in the flow, "Scenario 0.x" considers the hydrogen introduction through blending and "Scenario 1" evaluates pure hydrogen stream.

1. Hydrogen supply chain

1.1 Introduction to hydrogen

Hydrogen is the simplest atom in nature consisting of one proton and one electron, the molecule is a combination of two atoms (H_2). It's the most abundant element in the universe and the propulsive energy for the stars, the ultimate fuel in the universe.

In standard conditions hydrogen comes as a gas having a boiling temperature extremely low (-253 °C) at ambient pressure. Below are listed the main properties of this gas.

Thermophysical properties of Hydrogen								
PM	Density	PCI		PCS		T critic	T boiling	Viscosity
g/mol	*kg/m3*	*MJ/kg*	*MJ/Nm3*	*MJ/kg*	*MJ/Nm3*	*K*	*K*	*µPa·s*
2,016	0,08988	120	10,78	142	12,76	33,15	20,37	9

Table 1 - Hydrogen properties [1]

However, the matter of the abundance in the space does not apply to earth too. Hydrogen, although still essential, isn't at his pure form, only in small traces as gas (50 ppm per volume [2]). Nearly always it is bond with other atoms to form other molecules or organic compounds. Some of them essential to men since the beginning, like water (H_2O), others have seen their rise through the human and technological progress, like hydrocarbons.

The discovery of hydrogen dates back in the 16° century, when the Swiss physician, "Parcelsus", noticed the release of a gas after the reaction between sulphuric acid and iron. Robert Boyle in the 1761 discovered this gas after the interactions between metals and acids, but only Henry Cavendish in 1776 identified it as a distinct element. His name, instead, was named by Antoine Lavasier that took the Greek roots "Hydro" and "Genes" that is born from water [3].

1.2 Applications

Its first application, in the XIX century, had been mainly as a fuel present in a mixture for heating and lighting in buildings and streets. Another employment had been as a gas fill in balloons, the airships had long used it in transportation for people and goods even for transatlantic flights in the '20s and '30s. It is famous the last flight of the airship Hindenburg, ending with a tremendous incident in the 1937, signing the end of the era for the airships and feeding the danger behind the flammability of Hydrogen. Nevertheless, recent studies [4] has confirmed that the flammability of hydrogen was partially the cause, together with poorly equipped ground crew and a hostile weather with the consequently electrostatic charge accumulated in the structural materials causing the hydrogen ignition. Thereafter, hydrogen faced a period restricted as a tool for the space race, used as a propellent to boost the spaceships [5, 6].

Nowadays, Hydrogen is predominantly used in the industrial sector. Since the 1970s more and more processes required the use of hydrogen, in pure form but also mix with other gases. Around 90 million of tons are used in pure form, mainly in the oil refinery and in the production process of ammonia for fertilizers. Another 45 million tons, instead, are used in the industry without a proper separation from other gases [7, 6, 8].

1.2.1 Oil refinery

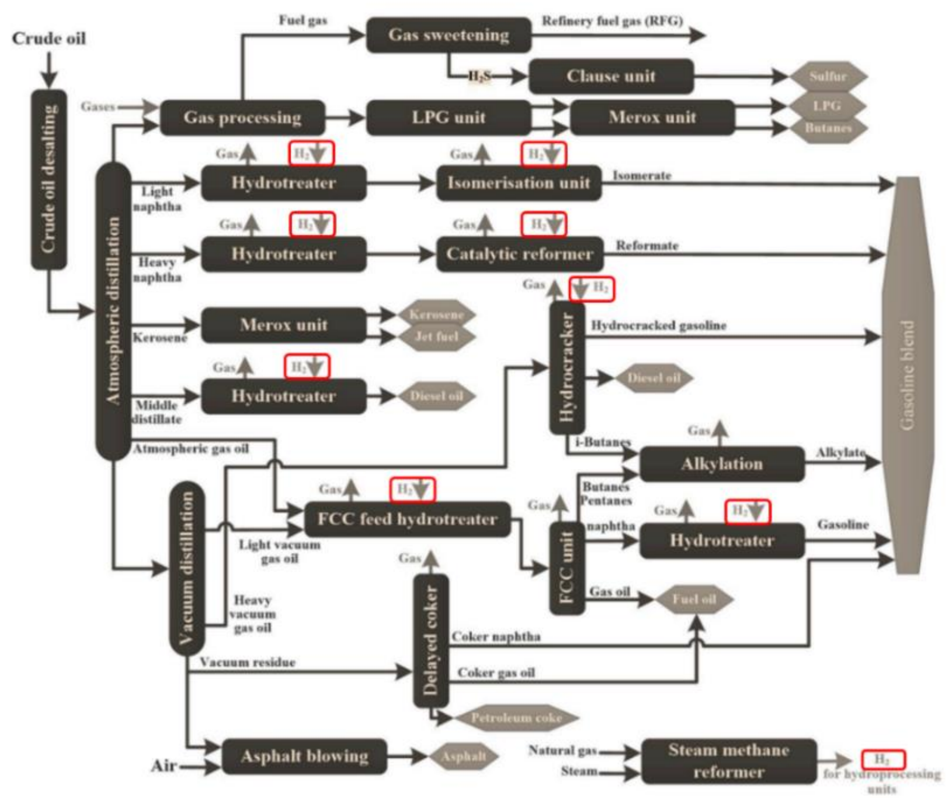


Figure 1 - Schematic overview on oil refinery processes [9]

Oil refinery refers to the whole series of processes aimed at produce petroleum derivatives based on their qualities and properties. By observing the oil refinery scheme, it is possible to notice the multitude of processes that employ hydrogen. These processes are under the chemical-catalytic process category in which the goal is to improve the property of the derivatives in order to reach the standards imposed in the oil market. The main ones are Hydrotreatment and Hydrocracking.

1.2.1.1 Hydrotreatment

Two reactions are the core of this process; the *Hydrogenation* (addition of H_2 in double, triple bonds or aromatic rings) and the *Hydrogenolysis* (break of C-X bonds where C is Carbon and X an element between sulphur, oxygen, nitrogen or a metal).

The aim of these two reactions is to increase the content of hydrogen in the derivatives and the consequent better quality of them and to remove the impurity through hydrogenolysis and saturation of olefins and aromatic bonds.

The reactor and its conditions depend on the substance on treatment, temperatures vary from 300 to 350 °C while pressure is much more dependent on the substance, it can vary from 15-40 bar for gasoline to 100 bar for gas oil. The catalysts most utilized are based on sulphuric metals.

The peculiarity of this treatment is also its usage in the saturation of vegetal oil [9].

1.2.1.2 Hydrocracking

Hydrocracking is the process to convert and break heavy compounds present in the residue of the distillation tower into lighter products. It is a far more onerous process compared to hydrotreatment because beyond the hydrogenation reaction, his function is to break carbon bonds between various hydrocarbons in order to have lighter products like kerosene and naphtha.

Since it is a more severe process also the operative conditions are stricter. Pressures arrive at 200 bar e the employment of hydrogen is far heavier, having to deal with the wastes of the towers and so with large amount of impurities. The metal removal is essential to avoid the poisoning of the catalyst that reacts with sulphuric acid (H_2S).

Hydrocracking shares same catalysts of hydrotreatment, like noble metals, but in addition it can be employ zeolites and silica-allumina.

1.2.1.3 Prospective on refinery sector

From the processes above listed it becomes evident how hydrogen is a fundamental component in almost every petroleum derivatives. The hydrogen quantity used is highly dependent from oil refinery, currently is estimated that 75% of hydrogen produced is destined in this sector. Therefore, the oil demand characterizes and will characterize for a long time to come the hydrogen demand.

According to studies of the International Energy Agency (IEA) and the Organization of the Petroleum Exporting Countries (OPEC) the oil demand will still increase in the next years, according to the World Oil Outlook 2021 from OPEC the peak of the demand will be reach in 2040-2045 (IEA estimates a sooner peak) [10, 11].

Year	*2019*	*2020*	*2025*	*2030*	*2035*	*2040*	*2045*	*Growth 2019-2045*
World (MBD)	*100,0*	*90,6*	*103,6*	*106,6*	*107,9*	*108,1*	*108,2*	*8,2*

Table 2 - Long term oil future demand [10]

This will imply a necessity to further increase hydrogen production and parallel to reduce emissions from oil refinery. Hydrogen will play a key role having the possibility to be produced at low carbon footprint and accordingly reducing the emissions in the processes in which it is involved.

1.2.2 Chemical sector

1.2.2.1 Ammonia production

In the hydrogen demand scenario the ammonia holds the second place for usage. Ammonia (NH_3) comes as a colorless and odorless gas at ambient temperature and pressure, although has the disadvantage to be toxic.

The main method to produce ammonia is the Haber-Bosch process where hydrogen reacts with nitrogen in a ratio 3:1.

$$N_2 + 3H_2 \rightarrow 2NH_3 \quad \Delta H = -92\ kJ/mol \tag{1.1}$$

A preliminary process involves air at high pressures (100 – 150 Bar) and at high temperatures (from 350 to 550 °C) on a metal catalyst to obtain a nitrogen flow (N_2) [7].

The process then involves the nitrogen flow with a hydrogen flow mixed in a reactor still at high pressure (200 Bar) and temperatures around 450 °C, moreover it is necessary the use of iron base catalyst. The distinction of this reaction is the light direction onwards and so a constant tracking of the equilibrium reaction is needed, plus a cycle of heating and cooling for recycling unreacted N_2 and H_2 [12].

Ammonia is predominantly used to produce nitrogen fertilizers, that accounts for 2% of global final energy demand and around 1% of energy-related and process CO2 emissions from the energy sector. Aside from fertilizer applications (70% of total demand), ammonia is used for industrial applications in explosives, synthetic fibers and other specialty materials. As producing 1 ton of ammonia requires 180 kg of hydrogen, total production of 185 Mt in 2020 required 33 Mt H_2 as feedstock, i.e. 65% of total industry hydrogen demand [8].

1.2.2.2 Methanol production

Methanol is the simplest of the alcohol (CH_3OH), also known as methyl alcohol, comes in liquid form at standard conditions colorless and odorless, as ammonia it is toxic. Methanol production is the second-largest consumer of hydrogen in industry, requiring 130 kgH2/t produced commercially from fossil fuels. The 100 Mt of methanol produced globally accounts for 28% of hydrogen demand in the chemical subsector and one-quarter of total industry hydrogen demand. A side effect is the CO2 emission, in fact producing methanol generates, on average, 2,2 kgCO2/kgCH3OH [8].

Although methanol in previous decades was obtained by dry distillation of wood, in recent times the industrial sector adopted almost entirely the catalytic hydrogenation of carbon monoxide and carbon dioxide to produce methanol.

$$CO + 2H_2 \rightarrow CH_3OH \quad \Delta H° = -90.7\ kJ/mol \tag{1.2}$$

$$CO_2 + 3H_2 \rightarrow CH_3OH + H_2O \quad \Delta H° = -49.5\ kJ/mol \tag{1.3}$$

The operative temperature is a trade-off between low temperatures, since the exothermic nature of the reaction, and high temperatures to speed up the reaction itself. Operative conditions, with the nature of the catalyst (usually Copper and Zinc based), influence parasite reactions that can give dimethyl methane ether [13].

Methanol is used in several industrial applications. In the manufacture sector for formaldehyde production and various solvents but also in the oil sector for conversion into light oil derivatives (methanol to olefins, methanol to gasoline and methanol to aromatics) [7].

1.2.3 Steel and iron industry

Metals rarely occur in pure form, they are usually bonded to oxygen, sulphur and infrequently, halogenides. Therefore, metals must be separated from these non-metals by reduction reactions.

Hydrogen plays an important role for the reduction process in the steel production through two different ways; as an auxiliary reducing agent in the *Blast Furnace - Basic Oxygen Furnace route* (BF-BOF) or as the sole reducing agent in a process known as *Direct reduction of iron* (H2-DRI) [14].

DRI is a method for producing steel from iron ore. This process constitutes the fourth-largest single source of hydrogen demand today (4 MtH_2/yr, or around 3% of total hydrogen used in both pure and mixed forms), after oil refining, ammonia and methanol. DRI method accounts only for 7% of primary steel production globally.

It is the BF-BOF route that leads the sector accounting for about 90% of primary steel production globally. The major difference with DRI in the hydrogen chain is the supply of hydrogen, in BF-BOF hydrogen is a by-product of coal use. It is contained in so-called "works-arising gases" (WAG), a mixture of gases containing also carbon monoxide and then used for various purposes on site. The portion utilized in mixed form within the iron and steel sector is estimated at 9 MtH_2/yr [7].

The issue related to the BF-BOF method is the virtual emissions related to all of the hydrogen generated from coal and other fossil fuels. To reduce emissions, efforts are underway to test steel production using hydrogen as the key reduction agent chasing in the mean while the growing demand of steel (+6% by 2030 [7]).

1.2.4 Energy vector

Hydrogen is identified not as an energy source rather a transporter of this last, an energy vector that in a later stage will release part of the energy with whom it was produced in the first place.

1.2.4.1 Hydrogen as a fuel

Hydrogen serves as the base for the combustion process where hydrogen and oxygen react to produce water:

$$Combustion\ with\ pure\ oxygen: H_2 + \frac{1}{2}O_2 \leftrightarrow H_2O \quad \Delta H° = -285{,}5\frac{kJ}{mol} \tag{1.4}$$

$$Comb. with\ air: H_2 + \frac{1}{2}(O_2 + 3.76N_2) \leftrightarrow H_2O + N_2(+\ NO_x)\ \Delta H° = -242\frac{kJ}{mol} \tag{1.5}$$

Since hydrogen is extremely rare in its pure form, in the combustion process it is mainly bond with carbon forming hydrocarbons. This implies an adjustment for the reactant hydrogen in the combustion and therefore an additional product in the reaction, carbon dioxide (complete combustion).

$$Hydrocarbon\ combustion: C_xH_y + (x + \frac{y}{2}) \cdot O_2 \ \leftrightarrow x \cdot CO_2 + \frac{y}{2} \cdot H_2O \tag{1.6}$$

It's useful to compare hydrogen with other kinds of fuel to have an overview of its property in relation with other fuels notwithstanding that when comparing fuels, each of them is used in certain applications. Thus, the flexibility to be used in more possible areas is a key advantage.

Properties	**Hydrogen**	**Methane**	**Gasoline**	**Diesel**	**Propane**	**Methanol**
FORMULA	H2	CH4	-	-	CH3CH2CH3	CH3OH
HHV (MJ/KG)	141,6	55,5	47,3	44,8	50,3	22,7
AUTO-IGNITION TEMPERATURE(°C)	585	360-540	228-501	180-320	450	460
FLAME TEMPERATURE (°C)	2045	1875	2200	2327	1925	1870
FLAMMABILITY LIMITS (% VOLUME)	4-75	5,3-15	1-7,6	0,6 – 5,5	2,1-9,5	6,7-36
MINIMUM IGNITION ENERGY (MJ)	0,02	0,29	0,24	-	0,25	0,14
FLAME PROPAGATION IN AIR (M/S)	2,65	0,4	0,4	0,3	0,3	

DIFFUSION COEFFICIENT IN AIR (CM2/S)	0,61	0,16	0,05	-	0,3	0,16
TOXICITY (PPM)	0	0	500			
VOLUMETRIC ENERGY DENSITY (KWH/M3)	2,99	10,5	7125	6000	6888	4994

Table 3 - Chemical and physical properties of certain fuels [2]

From the table it is possible to have a rapid overview where hydrogen overcomes the other fuels and where it lacks competitiveness. Starting from the calorific value, hydrogen leads the table having double the mean value. Even though HHV is remarkable, a proper comparison has to also include volumetric measures, hydrogen volumetric energy density is very low compared to other fuels.

On safety aspects hydrogen is known for is high flammability, very wide in terms of volume and it needs very low energy to be ignited. The fast propagation in air, though, helps to be safer for small leakages. Toxicity isn't an issue for hydrogen.

From the comparison of values, it comes out that hydrogen requires a volumetric shrinkage and a meticulous safe management to be performant as other fuels.

1.2.4.1.1 Hydrogen in internal combustion engine

Internal Combustion Engine (ICE) the ignition and combustion of the fuel occurs within the engine itself.

ICEs are divided into two main types depending on the ignition process and the relative fuel used; the spark ignition gasoline engine and the compression ignition diesel engine. Thanks to its suitable structural properties, hydrogen can be used as a direct fuel in injection systems of gasoline engines [15].

The automotive industry is the leading sector for usage of the ICEs, but recently this sector is currently undergoing a transformation away from fossil fuels towards sustainable energy carriers. For this hydrogen-based powertrain such as fuel cells and hydrogen internal combustion engines (H_2-ICE) are being taken into consideration as well.

Starting from the benefit of zero carbon direct emissions, hydrogen does provide some other favorable properties compared to regular fuels. In ICE application one of the most important features of internal combustion engines is to increase the efficiency by increasing the compression ratio. Thanks to the high self-ignition temperature of hydrogen, the efficiency of these engines can be increased by reaching higher compression rates [16]. Other aspects can cover the wide range of flammability limits that reflects a large flexibility for ignitable mixture with air providing part loads without having to throttle, which normally drastically lowers the engine efficiency. The higher laminar flame speed of hydrogen shortens combustion durations; hence a higher indicated efficiency is possible [17].

similar to gasoline combustion engine, the H2 ICE has to modify some components to the system to optimize structural properties, otherwise the desired efficiencies will not be obtained [16].

The spread of hydrogen internal combustions was though limited by drawbacks in the combustion process. The main issues are early ignition, knocking and the NOx formation.

- **Early ignition**: Because of the low ignition energy and rapid combustion of hydrogen, early ignition may occur at hot spots in the combustion chamber at the top of the cylinder. This occurs when the new mixture comes into contact with the combustion gases, especially when the suction and exhaust valves remain open together, as a result of the high temperature exhaust gases and the increase in combustion time [16].
- **Knocking**: Although the knocking issue limit only the power for gasoline engine, it remains a drawback also for H2-ICE. The knock can be defined as the spontaneous ignition of the hydrogen-air mixture in front of the flame front after the compression time. This is often referred to as engine knock. Knock formation causes excessive temperature and pressure increase in the cylinder walls. This results in reduced engine power and in increased harmful exhaust emissions. A possible way to reduce the knocking phenomenon could be a more rigorous control of hydrogen injected and an appropriate ignition advance [16].
- **NOx formation**: For the NOx challenge an approach to low hydrogen mixture and low temperature combustion significantly drops the NOx emission for H2-ICE.

1.2.4.1.2 Hydrogen-based fuels

The versatility of hydrogen comes to the possibility to create hydrogen-based fuels. Hydrogen can be combined with CO2 to produce synthetic hydrocarbons such as methane, or synthetic liquid fuels such as methanol, diesel, gasoline and jet fuel. Some of these products have higher energy densities than hydrogen [7]. The conversion can allow to work with synthetic fuels more suitable for specific applications (e.g. aviation, shipping).

1.2.4.2 Fuel cells

A fuel cell is an electrochemical device in which the chemical energy of the fuel is directly converted into electrical energy cleanly and efficiently. If hydrogen is the fuel, the only products are electricity, water, and heat [18, 19].

Although already in 1839 Sir William Robert Grove developed the first hydrogen-powered fuel cell [20], only in recent years this application has regained interest in the scientific and technological world.

Fuel cells work similar to batteries producing electricity and heat, but they are open systems (reactants and products flow through, so they produce as long as fuel is supplied) and thus power is independent from stored energy. A fuel cell consists of two electrodes: a negative electrode (anode) and a positive one (cathode) surrounding by an electrolyte (liquid or solid).

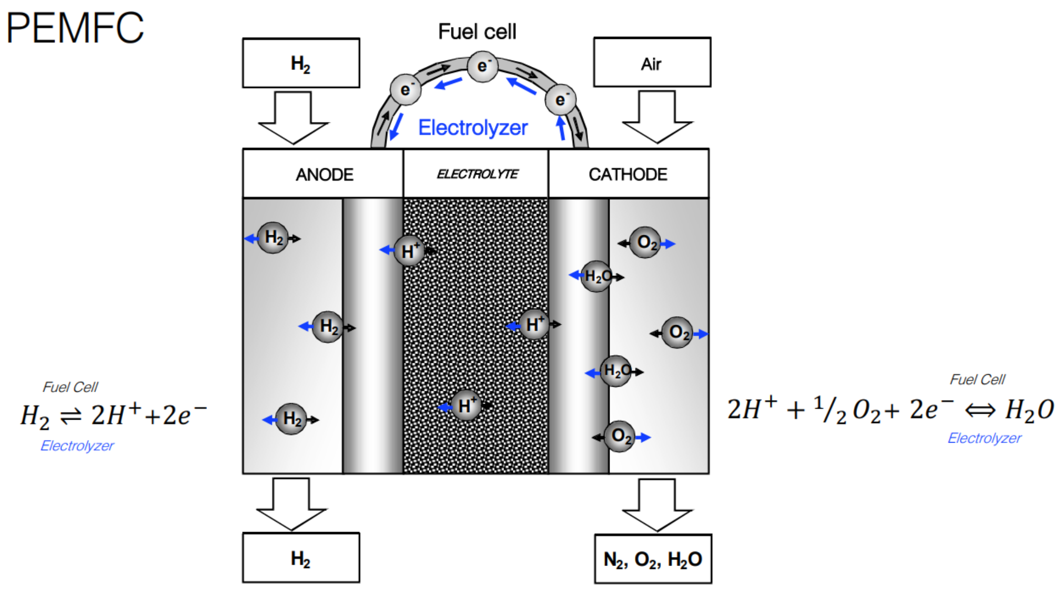


Figure 2 - PEM fuel cell overview

A fuel, such as hydrogen, is fed to the anode, and air is fed to the cathode. In a hydrogen fuel cell, a catalyst at the anode separates hydrogen molecules into protons and electrons, which take different paths to the cathode. The electrons go through an external circuit, creating a flow of electricity. The protons migrate through the electrolyte to the cathode, where they unite with oxygen and the electrons to produce water and heat.

Fuel cells are unique in terms of the variety of their potential applications. They are classified in relation to their electrolytes and fuels used and brings a quite large amount of fuel cell kinds. In the tables below are listed the main features of certain FC.

Characteristics \ FUEL Cells	Operating T (°C)	Electrolyte	Electrodes	Catalyst	Interconnect	Charge carrier
Polymer electrolyte Membrane	40 – 80	Hydrated polymeric ion exchange membrane	Carbon	Platinum	Carbon or metal	H+
Alkaline	65 – 220	Mobilized or immobilized potassium hydroxide in asbestos matrix	Platinum	Platinum	Metal	OH-
Phosphoric acid	205	Immobilized liquid phosphoric acid in SiC Carbon	Carbon	Platinum	Graphite	H+
Molten carbonate	650	Immobilized liquid molten carbonate in LiAlO2	Nickel and Nickel oxide	Electrode material	Stainless steel or nickel	CO3+
Solid oxide	600 - 1000	Perovskite (Ceramics)	Perovskite and with metal cermet	Electrode material	Nickel, ceramic or steel	O-

Table 4 - Fuel cells classification

1.2.5 Hydrogen future demand

Global hydrogen demand was around 90 Mt H_2 in 2020, 70 Mt as pure hydrogen and remaining a mixture with carbon-containing gases, having grown 50% since the turn of the millennium. Annually, refineries consume close to 40 Mt H2 as feedstock and reagents or as a source of energy.

Based on the announced pledges, hydrogen demand will increase the growth in following decades, with an almost 300% in 2050. Even more if the Net Zero conditions will be respected, arriving at more than 500 Mt of H_2, double the value for the one in the current scenario (260 Mt). Such a difference comes from sector like transport, power, synfuels and grid injection where a huge boost is needed to equalize the two scenarios.

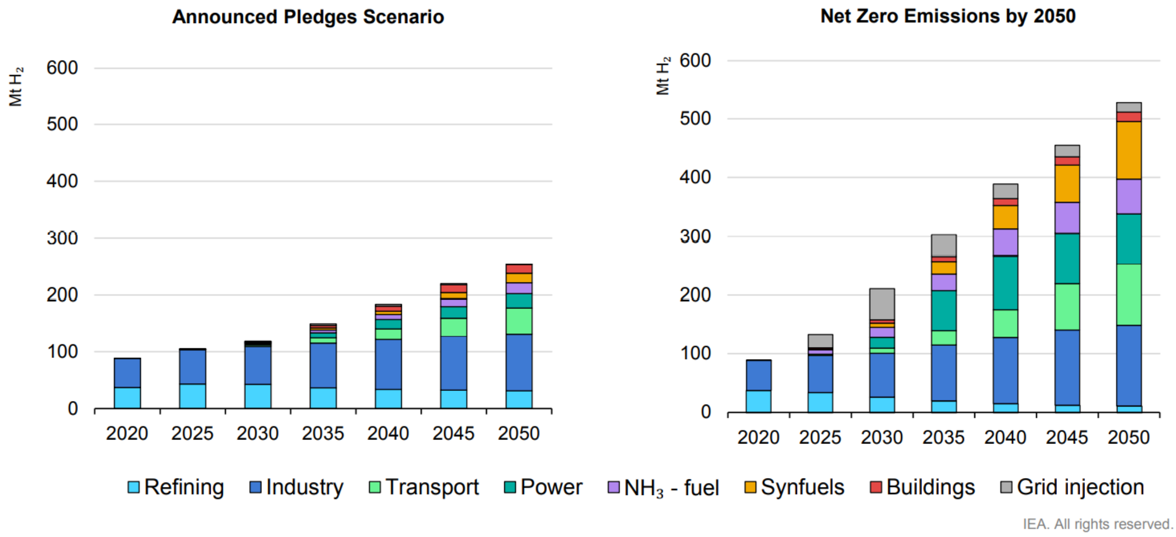


Figure 3 - Hydrogen demand by sector

1.3 Production: hydrogen colors

As previously anticipated, hydrogen in order to be used must first be produced. It is a very versatile fuel that can be produced using all types of energy sources through a very wide variety of technologies with peculiar characteristics.

Even though there is no international agreement on the use of these terms yet, nor have their meanings in this context been clearly defined [8], in recent years, colors have been used to refer to different hydrogen production routes. Despite colors do not represent a full outlook of the production options, to hence a rapid overview on the hydrogen production routes, it has been taken into considerations 5 colors:

- Grey hydrogen from Natural Gas
- Brown hydrogen from coal
- Blue hydrogen, when CCUS unit support fossil fuel sources
- Green hydrogen from renewable sources
- Purple hydrogen from nuclear

Apart from the "color" of the hydrogen that generally reflects the energy source, the common ground flows into the economics. As for every technology, the predominant ones are the cheapest and the most mature ones. An important parameter to summarize the deployment of hydrogen and the technology associated is the LCOH (Levelized Cost Of Hydrogen), similar to LCOE (Levelized Cost Of Energy) used to describe electricity costs. Although they describe different energy vectors, these two parameters are also correlated in a cycle of cause and effect, LCOH can integrate the LCOE, especially when RES are considered.

However in today's times, climate and environmental issues press for being principal actors in the decision making too. This reshuffling of the cards is driven hydrogen investments where a symbiosis relationship between renewables and hydrogen is sought giving a privilege focus on green hydrogen (and low carbon hydrogen) for future applications.

1.3.1 Reforming: grey hydrogen

Currently the largest method to produce hydrogen is through reforming of methane, about 75% of the 90 million tons of hydrogen produced passed via reforming [7]. The large deployment of this method is due to the low LCOH, around 1-1.5 $/kgH2 [8].

Reforming refers to the conversion of gaseous or light liquid hydrocarbons. In particular for hydrogen, methane (CH_4) is the most employed hydrocarbon.

1.3.1.1 Steam (methane) reforming

The steam reforming process consists in a catalytic conversion of hydrocarbon and steam in hydrogen and carbon oxides. The technique utilizes as the principal hydrocarbon methane naming it "steam methane reforming", often it is omitted the specific of methane source being the main technique.

The process involves 3 main key reactions:

$$CH_4 + H_2O \rightarrow CO + 3H_2 \qquad \Delta H = -206{,}1\ kJ/mol \tag{1.7}$$

$$CO + H_2O \rightarrow CO_2 + H_2 \qquad \Delta H = +41{,}1\ kJ/mol \tag{1.8}$$

$$CH_4 + 2H_2O \rightarrow CO_2 + 4H_2 \qquad \Delta H = -165{,}0\ kJ/mol \tag{1.9}$$

The (1.7) is an endothermic reaction that requires energy, it's the main reaction of the process where methane and water produce carbon monoxide and hydrogen, with a molar ratio for hydrogen/methane 3:1.

The (1.8) reaction is an exothermic one, the heat produced is recovered to promote the first reaction through preheating of methane. It is called "*Water Gas Shift*" because carbon monoxide, produced in the first reaction, and water are shifted into carbon dioxide and hydrogen, generating a double advantage, increase the amount of hydrogen produced and convert CO into a lighter pollutant, CO2.

Overall, the ideal conversion consists of one mole of methane and two of water into one of carbon dioxide and four of hydrogen.

On a plant engineering level steam reforming begins with a desulphuration unit (optional in case methane is already devoid of sulphur), a reformer where the conversion of methane starts, one or more reactors for the carbon monoxide conversion, lastly a purification unit used as hydrogen through adsorption (PSA).

1.3.1.2 Alternative processes

Two other processes can be implemented for reforming [21]:

- Partial oxidation, it differs to the direct use of oxygen as the co-reactant in the endothermic reaction. It is necessary a preliminary process to obtain a pure oxygen flow.
- Autothermal reforming, it is a hybrid process involving both steam and pure oxygen.

1.3.2 Coal gasification: brown hydrogen

Gasification is recognized as the process of converting any carbon-based raw material into synthetic gas, a mixture mainly based on carbon monoxide and hydrogen, using air, water vapor or oxygen [22]. Coal gasification is the process of production of syngas from Coal in which hydrogen is manufactured.

Initially coal reacts with oxygen and steam under high pressure and temperature (around 900 °C) to form syngas. The process is usually carried out in coal refineries plants, when the hydrogen is the desired product of the syngas and requiring further refined.

Four different kind of coal are utilized: lignite, sub-bituminous coal, bituminous coal and anthracites.

While five techniques are carried out [22]:

- Fixed bed gasification

- Moving bed gasification
- Fluidized bed gasification
- Entrained flow gasification
- Plasma gasification

Each of them has its own kind of coal utilized, sized of the samples, reactor configuration and temperature ranges. A comparative parameter is the Cold Gas Efficiency (CGE), most of them present a CGE around 80%, only Plasma gasification can reach values till 90% with 5500 °C. However, it is still a new technology with ongoing researches.

Despite being financially viable, LCOH similar to the SMR process (1-1,5 $/kgH2), it is not often employed due to its high carbon foot print and only countries with large amount of coal are pursuing the Coal gasification routes.

1.3.3 Carbon capture and sequestration: blue hydrogen

When it is placed a carbon capture unit into a hydrogen plant based on reforming or coal gasification in order to reduce and minimize the CO_2 emissions, the hydrogen produced "shift" its color from grey to blue.

The CO2 emission for a SMR plant are around 8-10 kgCO2/kgH_2, while for a gasification process are even higher, around 18-20 kgCO_2 /kgH_2 [8]. This side effect is becoming more relevant each day being in contrast with the aims for a zero-carbon emission future where hydrogen is a leading tool to achieve this important environmental goal.

Nevertheless, hydrogen still needs to be produced at achievable prices where currently only fossil fuel sources can reach. The option to mitigate the emission from these sources by CCS seems to be promising for the short-medium term in expectation of cleaner H2 routes.

1.3.3.1 CO2 capture options

The CO2 removal in general term falls into the process of Acid Gas Removal (AGR), where the processes can be classified as follows [23]:

- **Absorption processes:** they are characterized by a solvent washing process for separation of sour component from the gas. Depending on the type of solvent, the process can be a chemical absorption, a physical absorption or even a combination of both.
- **Adsorption processes:** in this kind of processes the gas meets the adsorbent solid surface, which makes the acid gas removal from the stream, thanks to

chemical bonding interactions between the gas and the solid phases. The adsorbent is characterized by a high surface capacity to improve contact with the gas stream and by high selectivity for acid components to be removed.
- **Other removal processes:** the main acid gas removal processes differing from absorption and adsorption are cryogenic separation and membranes. Contrary to the previous processes, they are not commercially and fully developed technologies and researches are still ongoing.

1.3.3.2 Capture technologies

For high efficiency it is essential to spot the right places to integrate the carbon capture unit into the hydrogen production plants.

Focusing on SMR plant, three main locations are suited to place a Removal CO2 unit:

- PSA inlet
- PSA tail gas
- SMR flue gas

Each of them presents a specific yield on the CO2 removal and based on that only option 1 and 3 are reasonable to investigate. A hypothetical combination of them can increase the overall efficiencies to even values higher than 95% [23].

CO_2 removed from:	CO_2 removed from each stream (%)	Overall $\eta\ CO_2$ (%)
1. PSA INLET (SYNGAS)	100	60
2. PSA TAIL GAS	90	55
3. SMR FLUE GAS	90	90

Figure 4 - Locations of removal CO2 unit

The same technology can be applied into an ATR plant having the advantage, though, that the required heat is produced in the reformer itself. This means that all the CO2 is produced inside the reactor, which allows for higher CO2 recovery rates with respect to SMR plant. ATR also grants capture emissions at lower cost than SMR given the higher partial pressure of Carbon dioxide [7].

1.3.3.3 Impact on economics and environment

The friendly environment treatment comes at a price. Adding CCUS to SMR plants leads, on average, to cost increases of some 50% for CAPEX and some 10% for fuel, with the exact amounts depending on the design. It also leads on average to a doubling of OPEX as a result of CO_2 transport and storage costs. In the most promising regions, however, costs for hydrogen from SMR with CCUS are in the range of 1.5–2 \$/kgH_2, making it one of the lowest cost low-carbon hydrogen production routes [7].

When comparing hydrogen costs with and without the CCS technology it is vital also to consider further fluctuations of pricing CO_2 emissions (e.g. through carbon tariffs). These taxes could further narrow the gap by pushing up the cost of hydrogen produced from fossil fuels. For example, a carbon price of 100 \$/t CO_2 corresponds to a cost increase of 0.90 \$/kgH_2 f or natural gas-based production without CCUS, or 2 \$/kg$H_2$for coal gasification without CCUS enhancing the role of CCS technologies [8].

If for the economics the option of CCS might be a challenge, for an environmental perspective the CCS tries to embrace a low-carbon routes necessary to ease a clean hydrogen economy. But it is important a proper estimation on emission reduction.

Currently the thresholds of CO2 emission from blue hydrogen arrives at 5 kgCO_2/kgH_2, half the value of SMR plant emissions without implementing CCS but still higher of the 3 kgCO_2/kgH_2 established in the RED II at European level to talk about "clean" hydrogen". The road for a clean hydrogen using CCS is developing fast but still a long way to go.

1.3.4 Water electrolysis: green hydrogen

Dedicated electricity generation from renewables or nuclear power offers an alternative to the use of fossil fuels for hydrogen production and therefore an almost zero emission of CO_2.

This path is mainly influenced by the LCOE (from renewable energy sources and from Nuclear plants) and the relative technology behind the process to produce hydrogen: the electrolyzers.

1.3.4.1 Renewable energy sources trends

With declining costs for solar PV and wind generation, building electrolyzers at locations with excellent renewable resource conditions could become a low-cost supply option for hydrogen. Large scale photovoltaic plants and wind farms are prominent to produce more energy [24] .

Hydrogen is seen as a possible medium to smooth the well-known limits of the renewables, in the first places intermittence, unreliability for the electrical grid balance and the possible unwanted energy waste during peak power generation periods.

Hydrogen production from these resources is an alternative solution for ease their implementation. Splitting water into hydrogen and oxygen using electricity generated from one of the many renewable sources seems to be the most promising method to efficiently and cleanly produce hydrogen.

To hold back the green hydrogen spread there are the costs behind the production. As mentioned before, the LCOH can integrate the LCOE in the case of renewables, electricity is costly, resulting in high price of LCOH currently between 3-8,5 €/kgH_2. In fact, Renewable electricity costs can make up 50-90% of total production expenses, depending on both electricity costs and the full-load hours of the renewable electricity supply [8].

1.3.4.2 Principles of an electrolyzer

Electrolyzers are the technology dedicated to produce hydrogen using the electricity provided. An electrolyzers is similar to a fuel cell, it still consists of an anode and a cathode separated by an electrolyte, but it works in the opposite direction, it produces hydrogen and oxygen from water. This process of splitting water into hydrogen and oxygen by supplying electricity is called electrolysis.

Electrolyzers operate in different ways, having different type of electrolyte material and the ionic species involved it results in diverse employment. Three main electrolyzers technologies exist today: alkaline electrolysis, proton exchange membrane electrolysis (PEM), and solid oxide electrolysis cells (SOECs) [25, 26, 18].

1.3.4.2.1 Alkaline Electrolyzers

Alkaline electrolysis is a mature and commercial technology. It has been used since the 1920s, mainly for hydrogen production in the fertilizer and chlorine industries.

These electrolyzers operate at low temperature (60–80 °C) with maximum current density less than 400 mA/cm2, power consumption for H2 production is around 4.5–5.5 kWh/Nm3 with an efficiency of approximately 60%. The electrolyte is an aqueous solution with KOH and/or NaOH and its concentration is 20%–30%.

The operating range of alkaline electrolyzers goes from a minimum load of 10% to full design capacity while the pressure output can achieve maximum 30 Bars. Alkaline electrolysis is characterized by relatively low capital costs compared to other electrolyzers technologies due to the avoidance of precious materials, overall costs for this type of electrolyzer are around 1000-1400 €/kW.

Alkaline electrolyzers are normally used with a steady power input due to the long start-up preparation and a slow loading response making it difficult to adapt alkaline electrolyzers to the variable nature of renewable energy sources.

1.3.4.2.2 PEM Electrolyzer

PEM electrolyzer use pure water as an electrolyte solution avoiding the recovery and recycling of the potassium hydroxide electrolyte solution that is necessary with alkaline electrolyzers. The operating current density of this system is 10.000 mA/cm2, much higher than alkaline technology. They are also able to produce higher compressed hydrogen (20 to 50 Bars). These electrolyzers offer flexible operation, including the capability to provide frequency reserve and other grid services with the possibility to work temporarily till an overload of 160% of design capacity.

The limited spread deployment of PEM is due to the expensive costs from catalyst materials (the catalysts in PEM electrolyzers require 300 kg of platinum and 700 kg of iridium per GW) and membrane and the current shorter lifespan. Overall costs can arrive till 1750 €/kW.

1.3.4.2.3 SOEC

SOECs are the least developed electrolysis technology but they are starting to be commercialized thanks to the promising very high efficiencies (more than 90%). High efficiencies are made possible thanks at high temperature water electrolysis that requires a lower voltage, which means lower energy consumption. The high temperature range goes from 600 °C to even 1000 °C and thus the use of steam for electrolysis. SOECs use ceramics as the electrolyte granting thermal and chemical stability and additionally having low material costs.

In order to achieve the temperature required a heat source is need. If the hydrogen produced were to be used to produce synthetic hydrocarbons (power-to-liquid and power-to-gas), the waste heat from these synthesis processes (e.g. Fischer-Tropsch synthesis, methanation) could be recovered to produce steam for further SOEC electrolysis. Nuclear power plants, solar thermal or geothermal heat systems could also be heat sources for high-temperature electrolysis.

Unlike alkaline and PEM electrolyzers, it is possible to operate an SOEC electrolyzer in reverse mode as a fuel cell, converting hydrogen back into electricity, which means it could provide balancing services to the grid in combination with hydrogen storage facilities. This would increase the overall utilization rate of the equipment. It is also possible to use a SOEC electrolyzer for co-electrolysis of steam and carbon dioxide, producing a gas mixture (carbon monoxide and hydrogen) for subsequent conversion to a synthetic fuel.

One key challenge for the development of SOEC electrolyzers is addressing the degradation of materials that results from the high operating temperatures.

1.3.4.3 The alternative of nuclear power: purple hydrogen

Hydrogen production from Nuclear power plants can be carried out by adding on the electricity generation side an electrolyzer. It has the advantage to facilitate the integration of hydrogen production without changing the plant configuration. Hydrogen can be produced to balance the output power and the grid demand operating at design load without direct interference with the grid which can be under congestion in some periods of time. Additionally, generation of hydrogen during off-peak hours allows for constant load operation at the highest efficiency and lowest electricity production cost.

Ongoing research in new reactor configurations with the main goal to rise the temperature range available are also analyzing technologies to couple electricity and hydrogen production. Thermal cycles, coal gasification and reforming are investigated to better employ part of the thermal energy produced. Moreover, SOEC electrolyzer are suitable to use electricity and steam produced since the electrolysis is carried out at high temperatures [7, 27].

1.3.5 Hydrogen production trends

It is presented a summary diagram on the hydrogen production routes beyond methodologies presented. the primary source and the process also used for alternative production methods to the main ones.

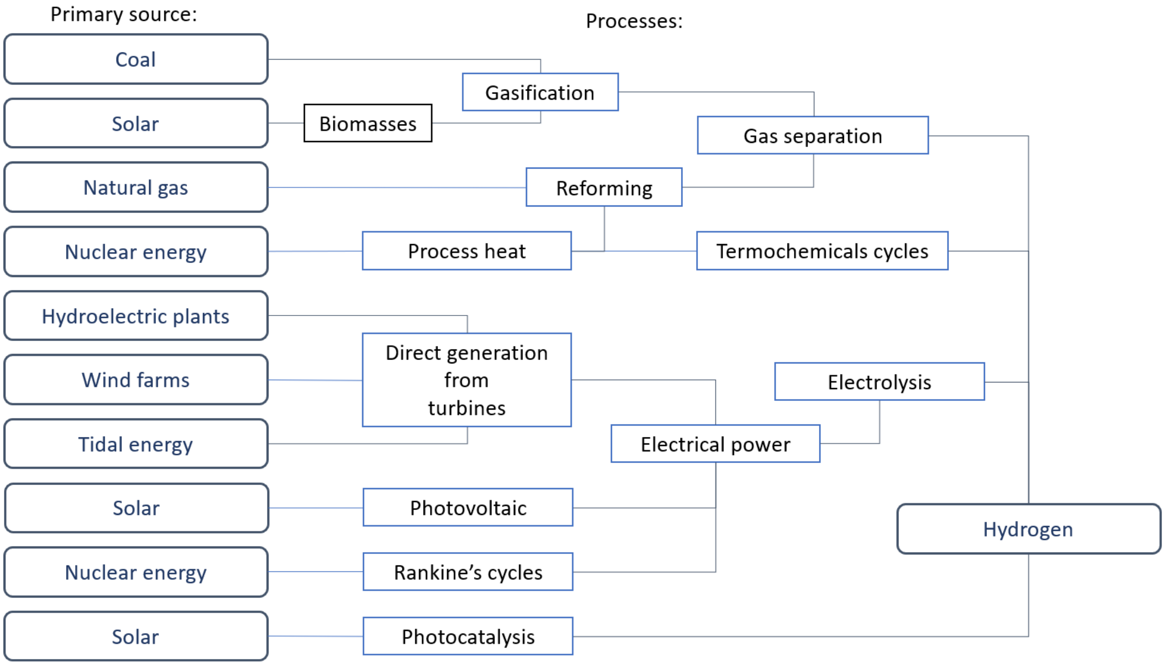


Figure 5 - Overview on hydrogen production routes

Accordingly to the large growth of future hydrogen demand expected it will be needed an equal amount of hydrogen production. Many options to produce hydrogen are under development and optimization, technologies that are currently non feasible might turn as the best option in the future hydrogen production. Steam reforming will remain the first route for a while longer but in long term future (2050) hydrogen from electrolysis is expected to leader the sector with CCUS technologies smoothing emissions from fossil fuel based.

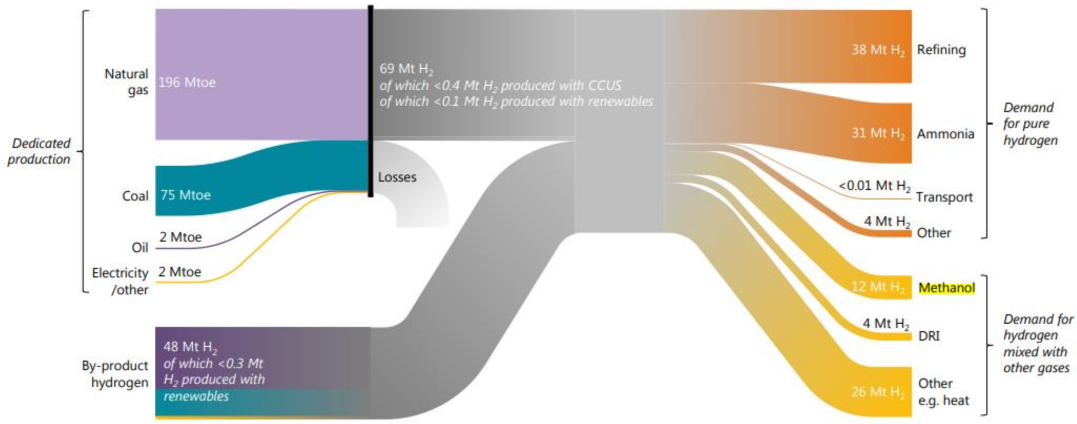


Figure 6 – Today’s hydrogen value chain

1.4 Hydrogen transport

Transportation and storage costs will play a significant role in the competitiveness of hydrogen. Given the wide variety of production method and the final use, hydrogen transportation is affected largely by the supply chain.

In certain cases hydrogen could be used locally, to produce end products or to produce other fuels that could be transported more cost-efficiently.

This configuration rises a certain competition between hydrogen and other energy carrier that might be more attractive for some specific configurations, even more when are direct use as end-products. In other cases, pure hydrogen would be the final product (for use in transport or high-temperature heating) and its transport as pure hydrogen (gaseous or liquefied) or using a hydrogen carrier (ammonia or a liquid organic hydrogen carrier) would depend on the total cost of transport (including conversion/reconversion, storage and transport).

1.4.1 Pure hydrogen

Pure hydrogen transportation relies on the already existing knowledge of gas transportation. To be feasible, compression or liquefaction must be carried on resulting in a transportation of compressed hydrogen (CH2) or liquefied hydrogen (LH2).

Both compressed and liquefied gas can rely on a large transport segment (rails, ships, trucks) implementing tanks, but the compression option relies also on the pipeline option. The liquefied hydrogen has mainly the function to occupy minimal space and in rare cases LH2 is then used directly (e.g. aerospace sector). Trivially, transportation of LH2 is based only on moving storages.

1.4.1.1 Compressed hydrogen

Hydrogen compression is achieved via mechanical or non-mechanical compressors. It has been widely used mechanical options (reciprocating piston, diaphragm, linear motor, liquid piston) in the gas industry, non-mechanical compressor such as electrochemical compressors are under development to overcome the drawbacks of standard compressors. That includes high maintenance cost, acoustic pollution and lower efficiency associated to the hydrogen compression with its high flammability and easy leak out [28].

The compression technology employed is affected to the desire transportation pressure, gas infrastructures and pipelines will face pressures that hardly will exceed 100 bars and that will justify the current employment of mechanical compressors. Hydrogen tanks, on the other hand, are justified to pursue higher pressure given the fix volume available. Currently, tanks are able to maintain pressure till 1000 bar. However these applications are presently restrained for quick refueling station applications, non-stationary applications work around 400 Bar.

1.4.1.2 Liquefied hydrogen

The liquefaction process is a combination of compression, expansion and throttling processes to store the produced gaseous hydrogen in liquid phase. Linde-Hampson cycle is the base for hydrogen liquefaction. The standard procedure behind this cycle includes:

1. Compression of gaseous hydrogen at source temperature
2. Cooling of compressed hydrogen using cooled hydrogen vapor product in a heat exchanger
3. Throttling to further reduce temperature and pressure, falling into the biphase zone
4. LH2 separation from cooled hydrogen vapor and collection of it
5. Hydrogen vapor recycle passing through the heat exchanger

Many other steps could also be added and modified as a variation of this cycle to improve the efficiency of the process [28].

On one hand, the liquefaction of hydrogen leads to almost twice the density than the compressed hydrogen has at 750 bars, therefore requires half of the tank volume to store it. On the other hand, it is much more energy-intensive than compression, if the hydrogen itself were to be used to provide this energy, then it would consume between around 25% and 35% of the initial quantity of hydrogen, considerably more energy also comparing it with natural gas liquefaction, which consumes around 10% of the initial quantity of natural gas [7]. Moreover, it requires a more efficient control, the extremely large temperature gradients (around 270 °C) with external temperatures can lead to significant boil-off losses even with very well insulated storage tanks, presenting safety risks for evaporated hydrogen and cost dependency with the scale.

The challenge between which is the best option depends on the circumstantial conditions, LH2 becomes more attractive than CH2 when there are very long distances and transport via sea is required. Given infrastructures and easier transportation on trucks and rails, CH2 is usually preferred.

1.4.2 Hydrogen carriers

The challenge of hydrogen transportation is not only played by hydrogen alone, but a large number of derivative carriers might overcome the limits of hydrogen. Hydrogen can be incorporated into larger molecules that can be more readily transported as liquids. Therefore, hydrogen does not fit the role of ultimate medium to carry energy from primary sources to end users, but neither any other carrier is the perfect solution. For instance, an ideal thermodynamic energy carrier might be a liquid with a boiling point above 80°C and a solidification point below -40°C, but it might be toxic and more difficult for conversion processes. Every alternative has its own advantages and drawbacks, the best feasibility is under requirements of specific cases, from production site to end use product desired passing through the distances and times of transportation.

1.4.2.1 Synthetic methane

Previously it was discussed steam reforming as the major process used to produce hydrogen. However, it exists also the backward process, by the backward reaction called methanation, where methane is obtained from hydrogen and carbon dioxide, in this case it is referred as synthetic methane.

The synthetic methane presents a unique advantage among the energy carriers, it has an already built infrastructure and well-known technology employed, allowing vehicles, residences, and other customers to indirectly use renewable sources for fuel and heat. Moreover, methane shows better performances as energy carrier compare to hydrogen and like hydrogen can benefit to have an almost zero CO2 emission cycle, this is because the carbon dioxide emitted using methane is the same that was captured to produce methane in the first place. The main drawback is the further conversion to produce it, that consequently lose energy from its primary source rising the related cost with it.

1.4.2.2 Ammonia

In the paragraph 1.2 it was introduced ammonia as a product from nitrogen and hydrogen listing the main uses of this molecule, now it is described NH3 from another point of view. That of a hydrogen carrier or more precisely a derivative energy carrier, opening its use in the energy and transportation sector.

Ammonia is, among hydrogen carriers, the most developed in terms of intercontinental transmission, which relies on chemical and semi-refrigerated liquefied petroleum gas tankers. It is already traded internationally as a chemical product [8].

The conversion process from hydrogen to ammonia requires energy equivalent to between 7% and 18% of the energy value of hydrogen, depending on the size and location of the system. Similarly in case of pure hydrogen needed at its destination, the reconversion process wastes a comparable amount of energy. [7]

Nevertheless, ammonia liquefies at -33°C, a much higher temperature than is the case for hydrogen and contains 1.7 times more hydrogen per cubic meter than liquefied hydrogen, which means it is much cheaper to liquefy and to transport than hydrogen.

Its toxicity with an increase in transport and use may raise safety and public acceptance issues, restricting its handling to professionally trained operators and limiting its use in some end-use sectors. An additional risk might come from uncombusted ammonia, where its accidental release can lead to the formation of particulate matter and acidification [7].

1.4.2.3 Synthetic methanol

Methanol in atmospheric conditions is liquid and has 80% more energy density than liquid hydrogen [7], this advantage makes it very competitive as an energy carrier. Not just as an energy carrier but also as a hydrogen-based fuel, methanol has been demonstrated to be a reliable fuel for the maritime sector and where the technology behind is relatively more mature than hydrogen and ammonia. Given its compatibility with existing maritime engines, methanol could be a near-term solution to reduce shipping emissions. [8]

Non-fossil sources of carbon can produce methanol without leading to greenhouse gas emissions, this may reflect that using hydrogen-based liquid fuels is an important pathway to decarbonize long-distance transport like aviation and shipping.

The path of non-fossil sources relies mainly on electrolytic hydrogen and, as for other carriers, the issue lies in the conversion process where a large amount of energy is lost during the process resulting in the limited employment in the transport sector.

1.4.2.4 Liquid organic hydrogen carrier

Liquid Organic Hydrogen Carriers (LOHCs) are molecule carriers loaded with hydrogen able to transport it and then extracting it again at its destinations. LOHCs have the key advantage of transportation as liquids without a need of pre-cooling process (liquefaction), they have similar properties to crude oil and oil products. The energy costs saved from the cooling process, however, are spent in the conversion and reconversion process involved (purification process might be considered too). The required energy would be equivalent to between 35% and 40% of the hydrogen itself [7].

Although LOHCs are similar to crude oil and diesel resulting in the advantage of hypothetical use of existing oil pipelines, the need to transfer the hydrogen carrier back to its place of origin to be re-loaded with hydrogen, either by truck or a parallel pipeline operating in the opposite direction, makes this a complicated and expensive method of transport. They begin to be competitive for very long-distance transportation (above 1500 km) coupled with transport by ship.

Several different LOHC molecules are under consideration, each with various benefits and drawbacks, to find a competitive supply chain able to overcome (re)conversion processes and infrastructure problems.

1.4.3 Outlook on energy carriers

To give an overview on the energetic requirements for conversion processes of some hydrogen-based fuel it is presented a diagram below.

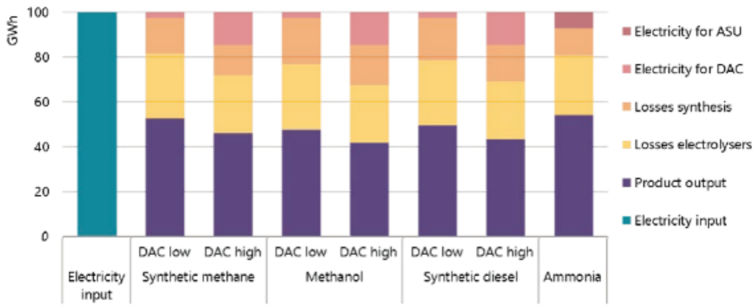
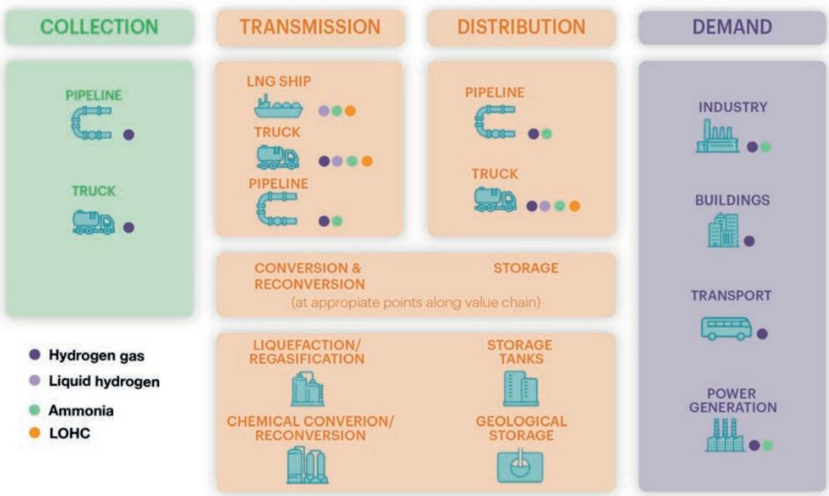


Figure 7 - Efficiencies and losses of different energy carriers

Hydrogen transport via pipeline, together with truck option, stands in all three-sector chain where is needed to move hydrogen. Transmission and distribution today rely mainly on trucks carrying hydrogen either as a gas or liquid, and this is likely to remain the main distribution mechanism over the next decade [7]. Pipelines, on the other hand, are likely to be the most cost-effective for long-term choice in the transmission segment and for local hydrogen distribution if there is sufficiently large, sustained and localized demand.



Note: LOHC = liquid organic hydrogen carrier.
Source: IEA 2019. All rights reserved.

Figure 8 - Transportation value chain

2. Gas pipelines and gas infrastructure

The art of design and construction of piping systems and pipelines dates back to the earliest civilizations. Its progress reflects the steady evolution of cultures around the world, they are an indispensable and the preferred mode of freight transport in many situations. Pipelines perform vital functions, they serve as arteries and veins, bringing life-dependent supplies such as water, petroleum products, and natural gas to consumers through a dense underground network of transmission and distribution lines. [29]

Pipelines are the least understood and least appreciated mode of transport, general public underestimates the importance of such an intricate system and it pays attention to pipeline unless and until a water main leaks, a sewer is clogged, or a natural gas pipeline causes an accident [29]. Pipelines are able to move tremendous amount of goods and wastes minimizing the use of surface land, noise, air pollution, accidents and damage to highways and streets caused by trucks and other vehicles.

The expansion of energy demand places several challenges on the transportation and delivery side of energy networks, that are starting to consider hydrogen and other means as well. Pipeline systems are good candidates to become an efficiency infrastructure for these new energy vectors. But Hydrogen is not the first gas trying to be transported in pipes, natural gas has already an essential role in the energy supply (half of energy is delivered by NG [11]) and a vast infrastructure of pipes has been built over decades. In the world each year 452,2 billion cubic meters of Natural Gas are traded inter-regionally through pipelines and almost the half (211,3 Bm3) are imported in the European network [30]. In order to overthrow (or to complement) the natural gas' role, Hydrogen has first to start conquering the gigantic infrastructure behind the transport of natural gas that can count almost on 3 million kilometers by considering just transmission pipelines [31].

2.1 Gas pipeline system

The history of natural gas transportation in pipes is surprisingly quite old, Chinese in 400 B.C. used bamboo pipes wrapped with waxed cloth to transport natural gas to their capital Beijing for lighting and for boiling sea water to get drinkable water [29, 32].

It is only in the 20th century with effective gas pipelines that the use of Natural gas expanded to home heating and cooking, manufacturing and processing plants, and boilers to generate electricity [32].

Nowadays Natural gas is a vital component of the world's energy supply and NG pipelines infrastructure has become larger, more complex, till capillary extension being capable of transporting energy over long distances with very low losses (0.7% vs. 2 to 6% for electricity) [33]. This energy network is still in expansion, an average of over 20.000 km per year of newly constructed gas pipeline has been completed in the last decades, most of which cross several countries [34]. In Europe, for instance, the Nordstream2 (a large pipeline long 1230 km with 1200 mm of nominal diameter) was inaugurated this year to assist the already operational Nordstream.

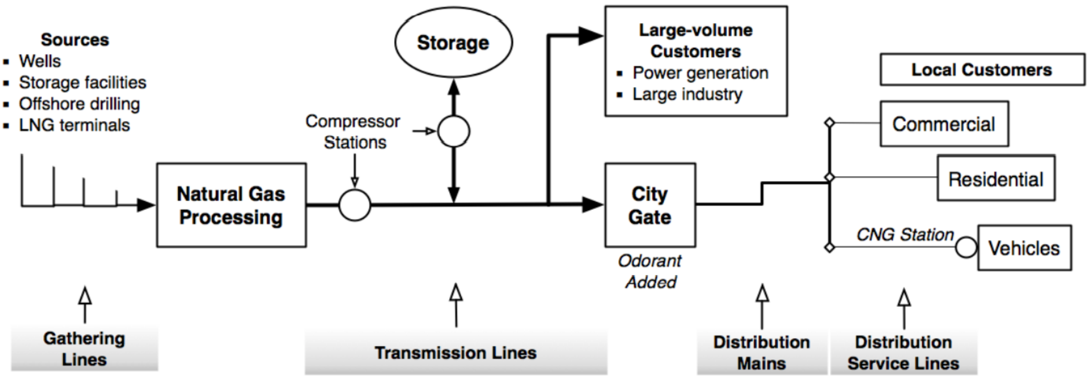


Figure 9 - Elements of a gas system

2.1.1 Gathering system

Gathering systems have the role to collect and transport gas from wells to Gas processing plant or to initial treatment facilities where purification and impurities removal are carried out.

Gathering pipelines tend to be in short length and small diameter with variable pressure ranges in order to minimize the time between the extraction of resources, and the initial processing steps. Operating with almost non treated natural gas requires for gathering pipelines severe regulation for pipeline integrity management.

2.1.2 Transmission system

The transmission pipeline system is the backbone of the gas transport, it involves the conveyance of large volumes of gas at high pressures over long distances from gas production sources (Gas processing plants) to distribution centers.

The pipelines in the transmission system are characterized by large diameters and high pressures. These Gas pipelines are distinguished in ground pipes which the Nominal Diameter ("Diametro Nominale" - DN) reaches 1400 mm with pressures between 24-75 Bar and submarine pipes with smaller DN (500 – 600 mm) but higher achievable pressures, till 115 Bar [35].

2.1.2.1 Rete Nazionale Gas (RNG)

In Italy the gas transmission network called Rete Nazionale Gas (RNG) is managed by SNAM. Moreover, SNAM handles the point of injection of Natural Gas into the RNG that symbolise the start of the transmission network.

The injection points are divided into injection by connection of transnational pipeline and injection by gasification plants where Liquefied Natural Gas (LNG) transported via ships is converted into gaseous form. RNG can rely on eight injection points, five in connection with transnational pipelines and three from regasification plants.

Route	Nominal Diameter (mm)	Length (km)	Pipeline connection
Mazara del Vallo	▪ 1050 ▪ 1200	1500	Sealine Transmediterranee
Gela - Enna	▪ 900	67	Greenstream
Tarvisio – Sergnano	▪ 850 ▪ 1400 ▪ 1400	900	TAG
Gorizia – Flaibano	▪ 650 ▪ 1050	65	Connection with the Slovenian transmission system
Passo Gries – Mortara	▪ 1200	177	Transitgas
Melendugno	▪ 1400	55	TAP

Figure 10 - Pipelines in national connection points

GNL Italia Panigaglia	110 km
Adriatic LNG of Porto Viro	Gas pipeline Cavarzere - Minerbio
OLT di Livorno	36 km

Figure 11 - LNG injection points

Around 38.000 km of pipelines form the RNG where each year, about seventy billion Std cubic meters are moved in the Italian gas transmission network [36]. The function of the RNG is to transfer the gas till the interconnections points with the "Rete Regionale di Trasporto (RRT)", local distribution networks, storage facilities and also to supply large industries and thermal power plants.

2.1.3 Distribution system

The distribution system is the capillary part of the infrastructure with the purpose to branch an extended area and deliver the gas to small consumers. Like transmission pipelines, distribution pipelines have no unique values for pressure and diameter but they usually space between 5 - 0.05 Bar and 400 – 40 mm.

The distribution side has the duty to guarantee the needed amount of gas required by small consumers.

2.1.4 Consumer classification

Consumers then are linked with the gas system to the more suitable network for them. A gas network is developed considering the consumer needs and hence the volume required carried through proper pipelines. Consumers can be classified based on their gas usage and quantity variation:

- Industrial consumer (type A) that consumes from the network the same gas amount regardless of time of the year and time of the day, large volumes are involved.
- Municipal consumers (type B - C) that can have daily variation and/or seasonal cycles where their gas consumption mainly depends on weather and calendar factors, lower volumes of gas per consumer are employed.
- Countries, nations can fit the consumer role when transnational pipelines are planned, it is a combination of the previous consumers and it depends which one is predominant.

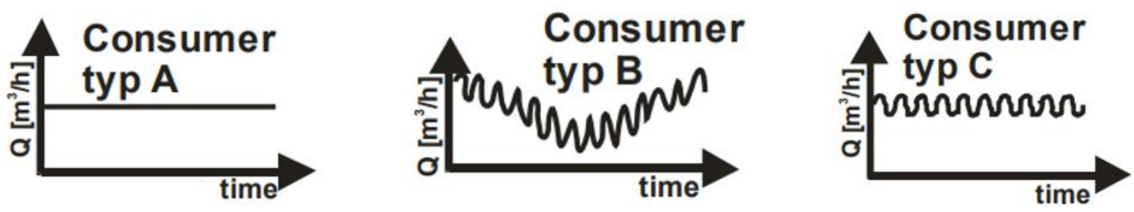


Figure 12 - Types of gas consumer

2.2 Elements of gas pipeline

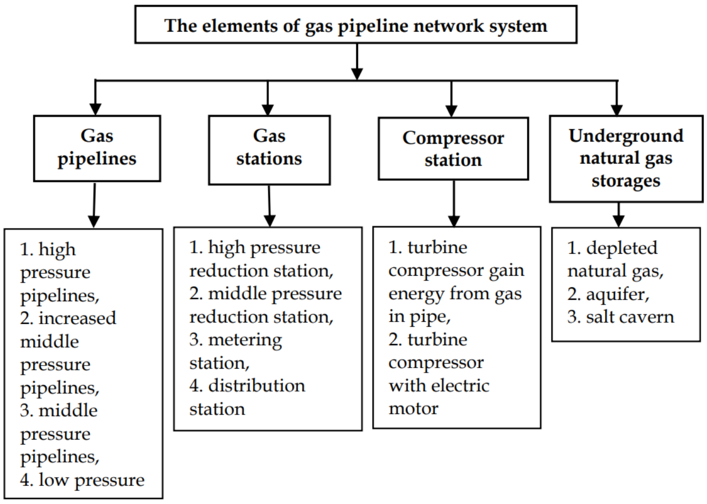


Figure 13 - Technical units of a gas pipeline network [37]

2.2.1 Gas line pipe

Line pipes are essentially the body of the pipelines (the actual pipeline itself), the tubular body. The production of these components strongly depends on several parameters accounting the future gas system designated.

2.2.1.1 Line pipe material

The material is the core of the line pipe that will have to guarantee specific operational conditions for particular dimensions.

Two main categories of material are identified: plastic polymers and steels. These typologies divide the pipes in small pipes with little diameters and low pressures where flexible materials like Polyethylene can be used.

Plastic like Polyethylene are used when small pipes with little diameters and low pressures are faced granting also a flexibility and a non-corrosion condition that are natural material properties. and plastic pipe. Plastic pipe is commonly installed today for gas distribution systems. Plastic piping requires a copper tracer to be buried with the pipe.

Steels, instead, are the most commonly used for natural gas at medium and large-scale accounting 99% of the material employed in transmission pipeline [38]. Although comparatively expensive to other materials, they hold the advantage of being able to withstand high pressures, being available in more convenient lengths and can also be welded easily, thereby resulting in lower installation and transportation costs. Steel pipes are highly efficient and can even be used in small diameters as needed and are 100% recyclable compared to other materials.

Steel pipes, though, are difficult to fabricate and lack the malleable qualities that other materials have, therefore repairs and replacements of steel pipes are extra difficult. Thermal conductivity is poor but bonding with aluminum or copper increase the property and improve heat transfer steel pipes.

By the term Steel, a large variety of iron alloys with carbon content are considered, it is important to have an overview on the type of steel to better frame which one are suitable for pipes. The four main types of steel are [39]:

- **Carbon steels**: They are the main family and only contain trace amounts of elements besides carbon and iron making them cheaper but strong enough. These are usually divided into low carbon steels (<0.3% carbon), medium carbon steels (0.3-0.6% carbon) and high carbon steels (> 0.6% carbon).
- **Alloys steels**: Alloys with additional elements (e.g. nickel, copper, chromium, aluminium etc.) that increase in strength, ductility, corrosion resistance.
- **Stainless steels**: These alloys contain large amount of chromium (10-20%) with also nickel, silicon, manganese and carbon. The main feature is the high corrosion resistance and weather.

However, several other factors influence the steel performance beyond composition, heating/cooling rate can impact on the strength on a molecular level, so steels with the same element percentage configuration can have different behaviors. Grading systems like the ASTM and SAE have been developed to describe steel properties.

For pipeline the American Petroleum Institute (API) drew up a standard specification for seamless and welded pipes for use in pipeline transportation: the API 5L [40, 41].

Steels in API 5L are recognized by a first letter that identifies specific properties and the followed two-digit number indicate the Minimum Yield Strength (MYS in kpsi) of pipe produced to this grade.

The determination of gas reservoir properties (such as carbon contents, gas specific gravity, gas compressibility factor, gas viscosity, critical temperature and pressure, gas density, etc.) are essential to select a proper grade of the steel pipeline.

Natural gas transmission pipeline systems require high yield strength and tensile strength employing for this reason carbon steels, API 5L grade X65 and higher are the most popular carbon steel material used for high-pressure pipelines. Distribution systems, since operational conditions are less severe, have been constructed from many different materials, including cast iron, steel, copper beyond plastics. [38]

2.2.1.2 Pipe welding

Steel pipes can be either seamless or welded (seamed).

Seamless pipes are cylinders where at very high temperatures (1100 °C) a cold rod is pushed inside forming a hole.

Welding is the process of connection of metal parts, pipe welding refers to the process of connections the two extremities of a laminar sheet. Welded process can be carried out in furnace, mostly for small pipes (DN <100 mm) implementing butt weld or lap weld, for larger diameters that require outside-furnace process welded is carry on by fusion. Fusion welded can employ electric arc technology (single or double joint), this process involves a filler metal while in the cases of electric resistance welding and electric induction welding. [29]

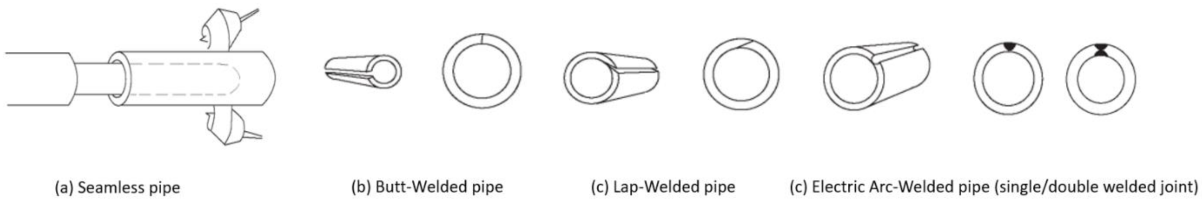


Figure 14 - Types of pipe welding

2.2.1.3 Protection systems

Steel pipes are structurally strong and ductile, they do not fracture easily. However, unless they are coated or lined with an inert material or protected by other means they can be badly corroded.

Corrosion is the second largest cause of pipeline damage. Corrosion is defined as being the gradual damage of pipe due to chemical or electrochemical reactions of pipes with their environment. The environment includes the fluid in the pipe, the soil, water, and atmosphere around the pipe, and other metals attached to or in contact with the pipe.

Unlike the erosion damage to pipe, which is caused by the physical process of abrasion or wear such as encountered by slurry pipelines or pneumatic conveying of solids in pipes, and unlike cavitation, which is caused by vapor pockets in liquids generated by low pressure, corrosion is caused by chemical or electrochemical reaction. Three main types of corrosion can be identified:

- Chemical
- Electrochemical
- Galvanic

2.2.1.3.1 Pipeline coating

Coating is the process of surrounding pipes with special layers that protect pipes from moisture, corrosive soils and construction-induced defects, which cause corrosion and rusting. A pipeline coating is a cost effective and viable solution to maintain pipelines' integrity and it is one of the most reliable corrosion prevention methods used by industries today. [42]

Classification of coating passes through the evaluation of the Coating strength. It refers to the ability of a coating to stick to a surface or substrate. Coating strength allows the engineer to estimate the life of a structure and durability of a coat and therefore occurrence of corrosion. Factors affecting coating strength include [43]:

- Chemistry and physics of surface & coating materials
- Stresses in coating or in substrate
- Application and service environment

Coating applications can be at the pipe exterior, as described above or internal, in this case coating is called *"lining"*.

Lining is the application of a protective coating on the inside surface of pipes, it is intended to reduce corrosion and abrasion of pipes internally. Lining also serves the purpose of forming a smooth pipeline interior, which reduces frictional losses, in fact it provides the following benefits [42]:

- **Improved gas flow** - A smoother surface results in enhanced flow capacity. Various studies have demonstrated that flow capacity of coated pipelines is far better than uncoated ones.
- **Faster inspection and commissioning** - Coated pipework dries faster than uncoated pipes. This means that commissioning can be faster and easier on the

line. Any type of robotic inspection is also simplified with the enhanced mobility of equipment through a coated pipeline.

- **Decreased cost of energy** - This is especially true in terms of compressors and pumping stations. Pipelines that are internally coated could create a vast difference in lowering the costs of compression and pumping over the pipe's lifespan. This can possibly increase financial payback in three to five years, which means significant savings.

Other than these benefits, pipeline lining can also reduce the need for inhibitors and promote clean delivery of the product. Thus, this can serve as a cost-effective and low-maintenance option for corrosion control that offers ample and reliable protection.

A multitude of materials are used for pipe lining and coating based on the surrounding environment, fluid in the pipe and type of material employed. In gas pipelines are Epoxy, polyesters, etc. can be sprayed on and baked to produce a hard-glasslike pipe interior.

2.2.1.3.2 Wrapping

Tape or encasing is applied around a pipe to increase its resistance to corrosion and abrasion. It can be done on pipes with or without coating. Steel pipes are often coated with tar or bitumen and then wrapped with one or more layers of plastic or kraft paper. [29]

2.2.1.3.3 Cathodic protection system

Cathodic protection is an electrical method for combatting corrosion in metal structures, including steel pipes, both on ground and in water. The method requires the use of an electrical current to counter or cancel the current generated by corrosion going between a steel structure and the surrounding ground. By making the protected metal structure a cathode instead of anode, the structure is protected from corrosion.

There are two general methods to provide cathodic protection:

- Impressed current method, where the metal structure becomes a cathode by connecting the negative terminal of the rectifier to it and connecting the positive terminal to the ground through an electrode. This method requires the use of a direct current (DC) source.
- Sacrificial anode, this alternative involves a connection to a zinc or magnesium electrode to the pipe and its environment (ground or water). This will create a galvanic cell where the pipe will become indirectly the cathode of the cell and thus the zinc/magnesium electrode will be the one to be corroded.

2.2.2 Gas storage facilities

Gas storage facilities that are present in the territory to balance supply-demand in the gas network, they can even smooth the gap seasonally for large storages.

In a market deeply dependent on imports and contracts, storage facilities add the flexibility needed to guarantee a safety margin for a proper supply.

Natural gas can be stored in a number of different ways in gas storage facilities, above-ground or underground with specific condition to assure absence of contaminants and proper insulation to avoid leakages. Gas storage facilities can be seen both as fictitious injection points and large delivery points, they contribute to the network by giving an essential back support also for long periods (seasonal time). For large volumes inventory underground under pressure are considered. Three types of facilities exist and each storage type has its own physical characteristics (porosity, permeability, retention capability) and economics (site preparation and maintenance costs, deliverability rates, and cycling capability), which govern its suitability for particular applications. These underground facilities are depleted reservoirs in oil and/or natural gas fields, aquifers, and salt cavern formations [44].

Two important characteristics of an underground storage reservoir are its capacity to hold natural gas for future use and the rate at which gas inventory can be withdrawn (deliverability rate).

- **Depleted oil and natural gas reservoirs** are the most commonly used underground storage sites because of their wide availability. Moreover, conversion of a field from production to storage duty takes advantage of existing wells, gathering systems, and pipeline connections.
- **Natural aquifers** can be converted to natural gas storage reservoirs. A natural requirement to become an underground facility is an impermeable cap rock that overlays the water-bearing sedimentary rock formation. Compared to depleted production fields are less flexible in injecting and withdrawing gas resulting in a less deliverability rate. Presence of an active water drive, which supports the reservoir pressure through the injection and production cycles may enhanced the operability rate.
- **Salt caverns** are formed out of existing salt bed deposits through the leaching process (drilling a well down into the formation and pumping water through the completed well to dissolve the salt which returns to the surface as brine) and geometrical volumes of a few hundred cubic meters can be achieved depending on technical specifications and geological conditions. Depending on the depth (500 to 2000 m), these caverns can be operated with a pressure of up to 200 Bar and thus allow the storage of very high volumes of gas.

Cavern construction is more costly than depleted field conversions, but the walls of the cavern are very resilient against reservoir degradation, base gas requirements are relatively low while derivability rates are high, this configuration well suit for peak loads and short-term trading rather than long term seasonal storage. All these factors make salt cavern an optimum option even if related costs are high.

2.2.2.1 Linepack

Gas pipeline systems also present a fictitious storage that helps to balance the supply-demand equilibrium: the **Linepack**.

The linepack is basically the volume of gas already compressed, injected into the network and stored in a gas pipeline that is available as soon as is required, without the need of immediate response from the supply and storage side. This is possible thanks to the gaseous nature making the system flexible. However, variations of operative parameters like pressure have to be controlled to maintain them at certain level.

2.2.3 Compressor station

Along the pipelines, compression stations are placed with two main goals; recompressing the gas to re-establish the desire pressure in order to push the gas and further purification process in case of residual compounds.

Natural gas is highly pressurized as it travels through pipelines to expedite the flow of gas. To ensure the pressurization condition, compression of the natural gas occurs periodically along the pipes. This is accomplished by compressor stations. The natural gas enters the compressor station, where it is compressed by either a turbine, motor, or engine.

Pressure constraints due to mechanical properties of materials employ, size of the pipe and safety reasons limit the upper pressure resulting in a Maximum Allowable Operating Pressure (**MAOP**), to also assure a proper pressure delivery (usually in the range of 70% of the MAOP) more than a single compression station can be required, which are usually placed at 100-200 km intervals along the pipeline. The specific locations and pressures at which these compressors stations operate are determined by several other factors including compression ratio, power available, environmental and geotechnical factors and quality of the gas.

Large compression stations can include up to 12 compressors (centrifugal or reciprocating). These compressors are typically gas turbine-driven, with a power consumption of as much as 60 MW and with a (desirable) compressor ratio around 1.4 [45]. The energy bill for natural gas transmission is an important account on the transport company's financial statements.

Compressor stations can employ liquids separator, similar to those used to dehydrate natural gas during its processing. The liquid separators at compressor stations ensure that the natural gas in the pipeline is as pure as possible, and usually filter the gas prior to compression employing even scrubbers. [46]

2.2.4 Metering station

Gas stations have the functions to control and measure flow parameters to avoid undesired effects keeping values into certain parameters. Since the quality of gas depends on the origin and further mix in the gas network might change the composition of the gas in specific point, it is important to analyse and assure minimum level of quality of the gas, an important parameter used to classify the quality of a gas is the Wobbe index that relates the High calorific value and the relative density of the gas (compare to air). Acceptable range are between 52.3 and 47,3 MJ/Sm3.

$$I_w = \frac{Higher\ heating\ value}{\sqrt{Specific\ gravity}} = \frac{HHV}{\sqrt{G}} \tag{2.1}$$

Beyond the minimum quality, the gas is even traded with an energetic point of view, different quantity of gas might be treated as same amount.

Metering stations are placed periodically along interstate natural gas pipelines. These stations allow pipeline and local distribution companies to monitor, manage, and account for the natural gas in their pipes. They employ specialized meters to measure the natural gas as it flows through the pipeline without impeding its movement. In essence, the metering station is the company's "cash register". [46]

Even a very small error in flow measurement on large capacity pipelines can result in huge losses to either the owner or customer of gas and thus a very accurate flow measurement in gas pipelines is essential.

The **orifice meter** is the major flow measurement employed in the gas industry, it consists of a flat stell plate that has a concentric machined hole with a sharp edge and positioned inside the pipe

2.2.5 Pressure regulation station

In transmission pipelines there may be a need to reduce the gas pressure at certain values to satisfy some customer requirements. Pressure regulation station, also known as delivery station, has the task to regulate the downstream pressure by reducing the upstream one at the correct value, regardless the pressure on the upstream side of regulators. Delivery stations represent also the passage between the transmission network to the distribution network by protecting the latter from overpressure that may come from the high-pressure pipelines.

An important phenomenon to control in pressure regulation station is the Joule Thomson effect, also known as the throttling effect. The Joule Thomson effect was first observed in an experiment conducted by James Prescott Joule and William Thomson in 1852 and is a thermodynamic process that occurs when a fluid expands from high pressure to low pressure at constant enthalpy [47].

$$JT = \left(\frac{\partial T}{\partial p}\right)_H = -\frac{\left(\frac{\partial H}{\partial p}\right)_T}{\left(\frac{\partial H}{\partial T}\right)_p} = -\frac{1}{C_p}\left(\frac{\partial H}{\partial p}\right)_T = \left[\frac{°C}{Bar}\right] \tag{2.2}$$

The majority of the gases, including methane, in a wide range of temperatures and pressures present a positive JT coefficient, meaning that when pressure reduction occurs, as in the case of delivery stations, the gas cooled down. The cooling effect could bring gas temperature below the safety limits where undesired effect can occur like hydrates blockage.

$$T_2 = T_1 + JT \cdot (P_2 - P_1) = [°C] \tag{2.3}$$

Methane has a JT coefficient around 0.4 °C/Bar and the cooling produced in JT expansion has been a double-edged sword in natural gas engineering, many counter measurements, like heating processes in delivery stations, were employed to prevent the undesired effect.

2.2.6 Supervisory Control And Data Acquisition (SCADA) centres

SCADA systems are sophisticated communications systems that take measurements and collect data along the pipeline (usually in metering or compressor stations and valves) and transmit the data to the centralized control station [46]. To accomplish the task of monitoring and controlling the natural gas that is traveling through the pipeline, centralized gas control stations collect, assimilate, and manage the data received from monitoring city gate stations and compressor stations to evaluate the status of the pipeline at a given moment.

2.2.7 Pipeline inspection gauge (PIG)

Several activities need to carry on by inside the pipeline and so specific devices where develop to operate in already in-service pipelines.

These special devices are called Pipeline Inspection Gauges (PIGs) and are essential to building and maintaining gas pipelines by insertion into them and travelling from one PIG station to the another, propelled by the pressure of the gas. PIGs are cylindrical devices with a main body and radial extension to cover all the diameter of the pipe, their length can range from 2 to 7 meters long and there are different types of PIGs depending on the jobs. Many activities include cleaning, monitoring and maintenance.

A first activity that concerns PIGs is after the pressure test where pipes is flooded with water and a dry process is required, these PIGS take the name of dewatering PIGs ensuring a clean and undamaged pipe.

For operational activities Intelligent PIGs are employed, thanks to high resolution sensors, these PIGs can detect even the slightest irregularities. They are capable of detecting any sign of corrosion and measuring the internal dimensions of the pipelines to detect buckling, their precise position, size, and coordinates. Inspection results form the basis for any remedial measures required to ensure operational safety. [48]

2.2.8 Valves

Valves are installed on pipelines and piping systems working like gateways to isolate sections of piping for maintenance, for directing the fluid from one location to another, shut down flow through pipe sections and for protecting pipe and prevent loss of fluid in the event of rupture. Since the large number of functions, a great number of valves are placed along the entire pipeline length every 5 – 20 km with specific characteristics [46].

The majority of valves are constructed of steel in conformity with specification API or ASME standards. When aggressive environmental conditions exotic materials with special properties may be used.

Pressure rating is of the main parameters to characterize a valve, it sets the internal pressure that the valve can withstand under normal operating conditions. On this criterion, valves are divided in classes with their relative MAOP. Another important aspect is the equivalent length that a valve possesses, it relates the length with the diameter to have a relative size of the component for generic diameters.

2.2.8.1 Types of valve

- Gate valve: It provides a completely shut off fluid flow when closed and in open position allows a full flow, it is not suitable for partial flow and regulating conditions. Gate valves consist of a valve body, seat and disc, a spindle, gland and a wheel for operating valve. It is employed for large pipelines too since it allows pigs to pass in it. A disadvantage is the high resistance also in open condition.

- Ball valve: It is another Open/close valve like the gate valve but the structure is basically a rotating sphere that has a hole in it. It allows the passage of Pigs too but unlike the previous one the flow resistance is moderate and it's fast open – close passage makes the valve safer when emergencies occur.
- Butterfly valve: This type of valve evolves during time with better shut off conditions, and it is employed when space is limited. Due to its built-in structure it is employed for small pipes where inside controls are not required.
- Check valves: As it suggests the word it checks that the gas flows in just one direction.
- Pressure regulator: These types of valves control and regulate the pressure in a certain section of a pipeline system
- Pressure relief valve and blow off valve: They have the function to protect the pipe from over pressure are usually set at a little higher pressure than MAOP.

2.3 Project of a gas pipeline

Gas pipelines projects require meticulous studies and phases with an intricate and partial iterative network between data, authorizations and studies.

The project as a whole is developed in three major stages:

- Feasibility study
- Basic design
- Detail engineering

While the main activities distributed in the above phases are the following:

1. Preliminary planning

After the intention to transport gas, a preliminary investigation is carried out to verify the feasibility and practicability of the pipelines. The analysis examines the origin and the destination of the pipe, the gas quality to be transported, the approximate length, diameter and type of the pipe to be used, the velocity of flow, friction losses, power consumption, capital cost, operating expenses, economics, and many other practical considerations. All the design and calculations done during this stage are preparatory and approximate. This first activity can be considered as the core part of the feasibility study.

2. Route selection

A pipeline route should be selected from, and marked on, both a highway map and a topographical map. Aerial photography and surveys of the pipeline route are undertaken to obtain data needed for the design and preparation of route maps and property plats, which are normally required for right-of-way acquisition. Gas pipelines can cross multiple countries with possible specification national-dependent or even maritime areas. Route selection covers each of the 3 phases since it is strongly correlated with future steps. Usually, an indicative route is assumed in the feasibility study, optimised in the basic design and final approved in the detail engineering.

3. Acquisition of Right-of-Way

It is the process to acquire the right to pass and to operate in a determine area choose to receive the pipeline. The acquisition of the right-of-way for a pipeline can come either through a voluntary process base on negotiation with land owners for the purchase, lease, or easement of their land needed for the passage of the pipeline, or through condemnation, which is an involuntary legal process.

Transmission systems that are usually public-owned or pipelines privately owned that serve the public, the state and federal governments grant the right of eminent domain, which is a legal term for the right to condemn land. Landowners who lose their land through condemnation are normally compensated at a fair market value. Depending on pipe size the RoW sets the area (width) which is place the construction site.

4. Soil borings, testing of soil and other data collection

Once the acquisition of the right-of-way has been completed, the pipeline developer can undertake necessary geotechnical investigations and determine whether groundwater and/or hard rock will be encountered and collect other data along the route that are needed for the design of the pipeline. It can largely affect the route selection since environmental, technological and/or economical constraints may rise in this step. Specific protection systems are considered base on the ground properties collected.

5. Pipeline design

It is carried out since the feasibility study and revised for each steps with more detail or modification, a first calculation methodology will be discussed in next paragraphs.

6. Seek legal permits

Permits from different state and federal agencies may be needed, this activity sometimes is accomplished parallel to route selection and RoW acquisition when several authorities are considered.

7. Executive project and final documentation

The last step includes the approved executive project with the final authorization required and the draw up of the documents needed for starting construction.

2.4 Gas pipeline design

In its logical and temporal development, design consists of a set of activities and phases, coordinated and controlled, undertaken to achieve a target that meets specific requirements including the temporal, resource and economical constraints. [49]

Gas pipeline design is a plan (or process) to show the outlook and the functionality of the project before it is constructed.

A fundamental prerequisite for the phase design is the well understanding of the various standards, codes and regulations with their relative fields of application in order to create a suitable pipeline.

Over the years, the American society of Mechanical Engineers (ASME) has developed a set of calculation codes and standards which are considered as reference standards by other control authorities. Particularly for the gas pipelines ASME has released the section B31.8 that covers gas transmission and distribution systems.

At national level, firms adopt internal legislation (Italy - SNAM) in which are described implementing rules.

Standard parameters are usually set to classify and identify pipelines design into categories.

For instance one classification divide the gas transmission system into three line species in relation with the Design Pressure and the relative Maximum Operative Pressure (MOP) ranging from 10 Bars to 75 Bars.

Nevertheless the codes and the regulations, the design consists mainly of four interrelated areas where they are all geared towards figuring out suitable pipelines that will safely transport the gas [34]:

- **Hydraulic design**; focus on the pressure analysis and the maximum working pressure
- **Mechanical design**; focus on the integrity of conduct
- Geothermal design; focus on the interactions between environment and pipe during its construction phase and operative phase
- **Operating/maintenance design**; focus on the methodologies and devices to implement during the lifetime of the pipeline.

An approximative design with methodology and calculations to apply for a gas pipeline will be presented later in this chapter.

2.5 Gas pipeline construction

1. **RoW preparation**

It is the ground/area preparation that involves clearing a path of a minimum width and removing trees and flattening the path somewhat so that trucks and heavy equipment can be brought in. For large pipelines, this may involve a minimum width of 15 m.

2. **Stringing**

It is the transportation and setting of the pipe in the construction site in a line along one side (internal of the RoW area).

3. **Ditching and trenching**

Use hydraulic backhoes or some other equipment to dig ditches or trenches of rectangular or trapezoidal cross section. The depth of the ditch (trench) should be such that the pipe will be below the frostline or at least 1 m beneath the land surface, whichever is greater. Staying below the frostline prevents damage to the pipe by freezing and thawing of the ground; it is especially important for pipelines that convey water. Even in a non-freezing climate, major pipelines should be at least about 1 metre underground to reduce the chance of damage from human activities, such as plowing and land levelling.

Two problems often encountered in ditching (trenching) are groundwater and hard rock. They should be avoided during the route selection step of the process whenever possible and practical.

Special alternatives to ditching and trenching include:

a. **Boring**

When passing through obstacles such as a highway, railroad, or rivers, boring may be used to get the pipe across the obstacle from underneath. Modern boring machines can bore long holes to install pipes under rivers and other obstacles. Boring methods will be discussed in more detail in Section 12.5

b. **Tunnelling**

When ground elevation and environment are hostile tunnelling is considered, especially for crossing mountains or hills.

c. River crossing

Three methods for river crossing are:

- Ditching: cutting a ditch in riverbed and then burying the pipeline there
- Bridging: building a new bridge or utilizing an existing bridge to carry the pipeline across a river
- Boring: boring a hole underneath the riverbed and then pulling a pipe through.

For wide rivers of shallow water, ditching often proves to be the most economical. However, recent advances in horizontal directional drilling (HDD/TOC) have greatly enhanced the technical and economic feasibility of drilling and boring across rivers to lay pipes. Trenchless methodology will be discussed along the detail description in Trenching

4. Bending

Pipeline bending can be done in the fabrication process, this method is preferred for pipe DN less than 1000 mm and usually induction pipeline bending is employed for its guarantee of high-quality products. For large DN bending process is carried out in the field. [50]

The ratio thickness/Diameter (t/D) and the curve degree define also what's the best technology to use to withstand quality requirements.

Modern machines can be equipped with a fully automated tangent heating systems allowing to heat the straight tangent in the same way as the bend. This way the material properties of the bend and the straight tangents will be comparable. That's an advantage in case transmission pipelines are made of higher X-grades (API5L X-70/80/100) where heating treatment is needed.

5. Welding, coating and wrapping

After the ditch has been prepared, steel pipes of 12m length are welded together to form a long line or string. The welded joints are radiographically inspected, and the pipeline is coated and wrapped with special protective and insulating materials before being laid in the ditch. For pipelines laid underwater, the pipe must be covered with a thick layer of concrete to prevent the pipe from floating

6. Pipe laying

The welded pipeline is lifted and laid into the ditch by a line of side-booms parked along the right of way at approximately equal intervals. Steel pipes normally do not require the use of bedding materials to support the pipes in the ditch. Iron and concrete pipes require that the ditch bottom be covered by a layer of gravel or crushed rock to facilitate drainage and reduce settling. Otherwise, such pipes may be damaged and may leak.

7. Backfill and restoration of land

The pipe in the ditch is then backfilled by earth, the earth is then compacted, and the land surface is restored. After the pipe is backfilled, it is hydrostatically tested with water to meet applicable code and government requirements. Restoration involves cleaning out construction waste materials and planting of grass.

2.5.1 Trenching

A particular attention is given to the trenching activity being the core of the construction process resuming the decision making that implies several project phases.

The execution of the line by laying the pipe in the trench is the priority method of installation to be pursued. The pipeline must be buried in such a way that, considering all possible conditions, prevent any unintended and unaccepted movement.

The laying conditions can influence the general development of the track, in the need to eliminate or minimise interference with critical points of the territory.

The basic design must identify the method of excavation, any consolidation of provisional or definitive works. The depth of the trench is one of the technical and dimensional data required for basic design, it has direct influence on the design procedures of structural calculation and also to the design of active and passive protection systems.

The definition of alternatives underground laying and their implementation must be achieved by an accurate analysis of the territory. The comparative analysis of the different criteria of underground execution must allow the choice between the possible methodologies. In the case of watercourses, the route must also provide, at appropriate points, eventual crossing with sub-bed laying.

In the detail engineering stage, it has to be defined the methods of laying the pipeline, within the framework of the individual choices of implementation, on the basis of findings and detailed surveys, including the possible use of "trenchless" methodologies and the specification of systems protection of the pipe. The coverage to be adopted must be subject to careful assessment (and may be increased) in cases where it takes on the role of piping protection. The project must specify the cases in which it is necessary to implement pipe thickness.

The main aspects of the trench design include:

- the stability of the wall in relation to the inclination of the excavation walls ("shoe") and effects induced by vibrations and dynamic stresses arising from means of enforcement;
- the soil shear resistance characteristics,
- the presence of water in the soil,
- the depth of excavation, the minimum width required at the top and bottom of the trench;
- the influence of the load induced by the means of excavation and of the material deposited along the edge of the excavation;
- the local deepening necessary to reach the laying quotas in correspondence of road, rail, watercourse and other crossings services, and to connect the same with the main ones of the line

the standard section of the digging and laying in trenches is shown in Fig. 4.1, with the following details:

- the slope of the trench walls must be adapted to the nature of the ground, as described above;
- the width of the signalling network depends on the diameter of the pipe;
- the characteristics of the laying bed (bottom of the excavation) if any, and of the hole are;
- the installation of polyphorae in the trench is possible in the absence of interference and protection requirements, without prejudice to specific requirements of a geotechnical nature, or related to duct strength, the minimum depth of burial (or cover) "h" (Fig. 4.1), measured on the Upper generator, is equal to 1.5 meters.

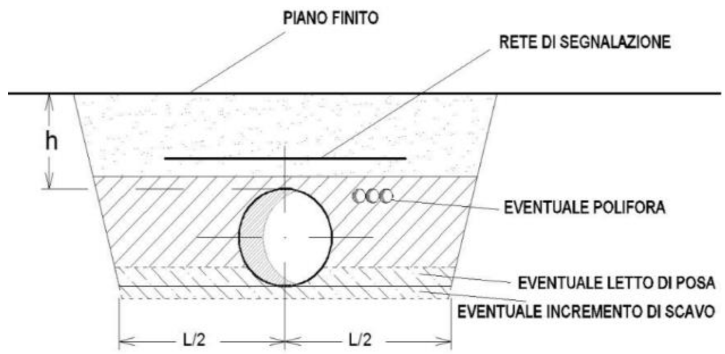


Figure 15 - Trenching section

2.5.1.1 Trenchless methodology

The "trenchless" technologies represent solutions for ground excavation alternatives to the trench, finalized to the laying of the pipe. They allow the realization of the line without direct interference with the surface of the territory; it may, therefore, constitute the solution for crossing areas of particular sensitivity environmental, natural and/or man-made physical obstacles.

These methodologies are based substantially on the realization of underground tunnels, which are constructed by inserting the protective tube, or by direct drilling of soil or rock, within which then the opening of the pipe, with or without protection pipe. The tunnel can be armed during the course of the drilling itself, by advancing the steel protection tube or by prefabricated reinforced concrete rings.

Common advantages are listed below:

- avoid interruptions of functionality, in cases of crossing infrastructure transport;
- allow the route to interfere with waterways without problems linked to the deflection of outflows and to avoid any interference with evolutionary dynamics and with the geomorphological structure of the bed.
- preserve the integrity of existing works;
- limit the interventions aimed at morphological restoration and, therefore, the related costs;
- optimise the route, allowing shorter routes than external routes alternative

Each methodology needs its own project of building, specific machinery and equipment handling spaces. The definition of the most suitable methodology for the implementation of trenchless crossings must be the result of a comparative analysis of alternative solutions through:

- objective factors related to morphological characteristics and level of anthropization:
- factors related to geological, geotechnical and hydrological-hydraulic characteristics
- economic and/or environmental factors:
- availability of suitable areas;
- the geometry of the crossing,
- compatibility with the sub-channel hydrodynamic network;
- the litho-stratigraphic nature of the land.

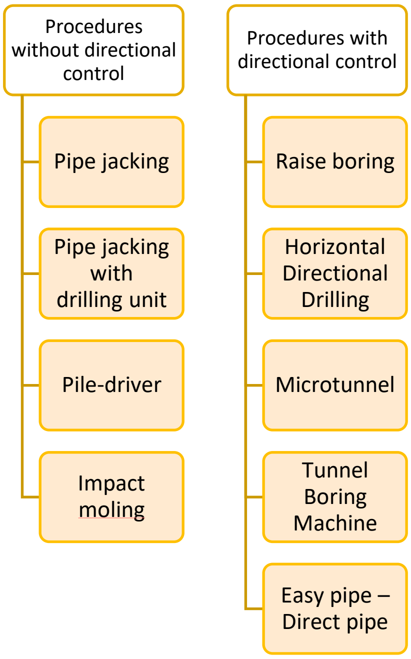


Table 5 - Trenchless methodologies

2.5.1.1.1 Procedures without directional control

The most important limitation in **drilling without direction contro**l is in the exclusive feasibility of straight-axis pipe.

The general propelling method consists in inserting into the ground the protective tube, an open head, for portions progressively welded in place, by means of pressure operated by hydraulic jacks.

In the percussion pusher method ("pile-driver") the head protection tube open (if necessary reinforced to facilitate entry into the ground) is fixed, for progressively welded portions on site, by the pressure exerted in the position of push from appropriate pneumatic swing.

Accentuated differences in height with sub-vertical arrangement or crossing the base of rocky bumps with sub-horizontal drilling or the "Raise Borer" methodology. Regardless of the diameter, the technology of raise boring is suitable for drilling sub-vertical of the order of 300 meters and more, and for sub-horizontal drilling of the order of 200 meters and more.

2.5.1.1.2 Procedures with directional control

Among the trenchless crossing technologies, the **Horizontal Direction Drilling** (H.D.D.) presents the characteristic to allow the laying of the pipe by operating directly from the country floor, without the need for ancillary works such as departure and arrival wells. On the other hand, insufficient geotechnical knowledge of the land

and/or inadequate executive methods may cause disruption. Additional features are essentially attributable to the following aspects:

- the possibility of reaching high depths of exposure, particularly useful for sub-bed crossings;
- variability of the geological conditions of application,
- relatively fast execution times.

The execution technique is divided into three main phases:

- construction of a pilot hole;
- bore hole up to the appropriate diameter;
- pipe laying.

In general, and with particular regard to river crossings, the feasibility of H.D.D. drilling is critical whenever a "Preferential" filtration path of groundwater along the pipeline cutlery.

2.5.2 Additional improvements on a gas pipeline

As anticipated the natural gas network is quite a while around and necessity of improvements might need in some areas depending on fluctuations on the volume decided in pluriannual contracts and market developments.

It might happen that larger gas volumes are required to pass in certain gas corridors. If the amount added is contained, it is possible to operate on the compressor station side to increase the pressure and hence allowing more flow to pass, but if the compressor is already operating at its maximum power or the pressure is already at its maximum (close to MAOP) then a Pipe loop is considered.

2.5.2.1 Looping system

Pipe loop is a piping system where two or more pipes are connected such that the fluid flow splits among the branch pipes and eventually combine downstream into a single pipe. Splitting a segment into branch pipes reduces the pressure drop allowing to remain in the pressure range required but increasing the gas transported.

Two principles are evaluated in loop piping system:

- Conservation of total flow
- Common pressure loss across each parallel pipeline

For a proper functional pipe loop system is important to evaluate the best location for the pipe loop. Three main options are possible:

Pipe loop at the begin of the pipeline section (upstream part), in the middle of the section of at the of the pipeline section (downstream part).

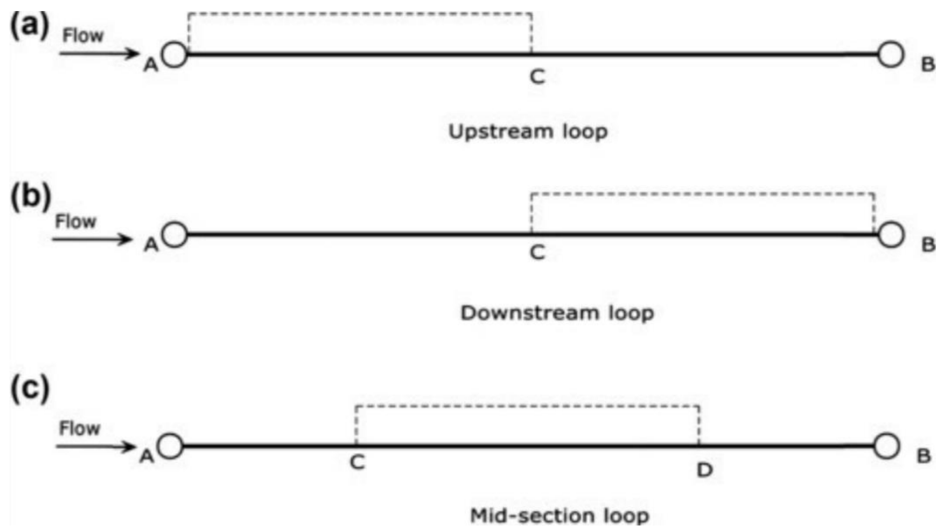


Figure 16 - Different looping scenarios

To determine which is the optimum scenario, we must consider how the pressure drop in the pipeline varies with distance from the pipe inlet to outlet.

The pressure drops at a faster slow rate in the downstream end giving the aspect of the best choice to insert a loop, however if it is considered a heat transfer along the pipeline and the greater gas temperature outside of the compressor (upstream part) due to the compression, the first segment will deliver a larger pressure drop and therefore the pipe loop should be installed in the upstream portion for maximum benefit.

The distance between two compression stations ranges from 100 km–200 km. Looped pipes may extend the distance between compressor stations. Sometimes, the looping is used to create storage capacity, where natural gas can be line-packed as a way to increase deliveries to local customers during peak periods. In addition to delivery pressure modulation and looping, another option for expanding pipeline capacity is the installation of a new compression facility but it would require higher costs [51]

2.6 Economics

The economics have implications on the operative characteristics of the pipeline.

First an economic analysis must be performed for the project taking into account possible scenario of market development considering a reasonable project life of at least 20 years.

After it is important to evaluate cost-capacity profiles; for instance different pipe diameters reflect relative cost-capacity profiles. Using larger diameter pipe will cause a smaller pressure drop and a less power requirement for a given volume flow rate. In terms of cost it will result in a raise of material costs due to the enlargement of the diameter, but it will decrease the compressor capital costs requiring less power.

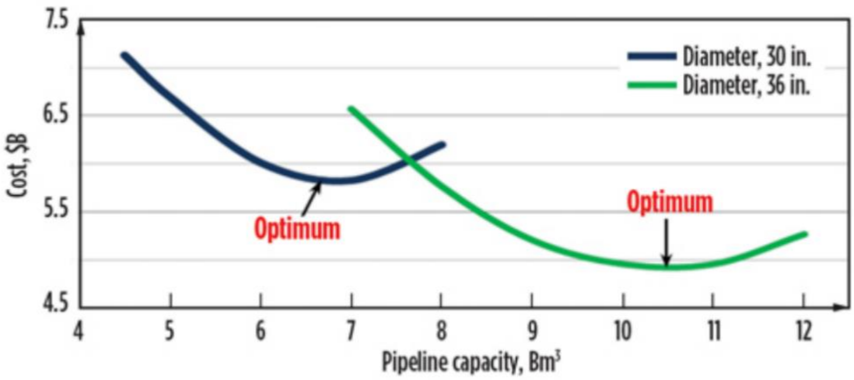


Figure 17 – Economical trade-off between capacity and diameter

In result, pipelines are project significantly affected by economy of scale. A rule of thumb is to build a pipeline system with an overestimation on the pipe diameter and with compressors capacity limited to current needs. This will allow to have an operative range beyond the nominal quantities. However this extra boost is limited since the flow only increases with the square root of pressure drop along the line, while the energy consumption of compressors increases more than proportionally. [52]

When the market grows beyond the nominal capacity and over the compressor range, the new market demand can be met by alternating the looping of an existing line with the addition of new compression stations.

Furthermore, considering pressure constraints, it might happen that the compression ratio for compressors are limited by them. For long pipelines this might imply that more compressors are needed if smaller diameter are employed.

2.6.1 Costs & Expenses

2.6.1.1 Fixed Costs

For pipelines initial investments costs are very expensive, the major capital components of a pipeline system consist of the pipe, compression stations, storage tanks, valves, fittings and meter stations.

Pipelines required a meticulous approach for the calculation costs since they largely depend on the route decided and operative/environmental conditions. Moreover, pipelines are huge projects and the deviation between actual cost and estimated cost increase with the size of the pipeline.

Although it is not possible to detail into expenditures, it is possible to outline the approximate percentage for each phase that make the overall costs of the project based on historical records.

#	Cost items - Budgetary estimation	%
1	Pre-feed studies	1%
2	Feed studies and environment	2%
3	Long lead line pipes, Coating	17%
4	Other long lead items	3%
5	Transportation	3%
6	Compressor station (EPC)	10%
7	EPC*	45%
8	Land Ease agreements**	4%
9	Project management Services	9%
10	Others	6%
Total capex		**100%**

*(excl. Pipes, traps, foc, main valves)

** (RoW + land purchasing)

Table 6 - Budgetary estimation of cost items

Other sources [53] for onshore pipelines feature labor cost and material cost the highest expenditures respectively 40% and 30% of the total cost, some projects can reach up to 80% of the total cost for these two voices. Miscellaneous cost, that are a composite of several low monetary costs including: surveying, engineering, supervision, contingencies, telecommunications equipment, freight, taxes, allowances for funds used during construction, administration and overheads, and regulatory filing fees are in the order of 20% while RoW accounts for an average of 7%.

All data	Average	Material	Labour	Miscellaneous	ROW
		31%	40%	23%	7%
Diameter	4-20 in.	19%	43%	28%	9%
	22 - 30 in.	28%	38%	26%	8%
	34 - 48 in.	34%	40%	20%	6%
Length	0 - 60 mi	28%	41%	24%	7%
	60 - 160 mi	31%	39%	23%	7%
	160 - 713	35%	39%	20%	7%
Region	Central	41%	38%	18%	4%
	Northeast	24%	43%	27%	6%
	Southeast	24%	34%	30%	12%
	Midwest	26%	37%	27%	11%
	Southwest	31%	41%	23%	5%
	Western	32%	48%	13%	8%
	Canada	39%	40%	19%	1%

Table 7 – Shares of pipeline cost components

2.6.1.1.1 Construction cost

Construction cost are related to the manufacture and physical implementation of the project, several voices are contained in this category:

Material costs

An empirical method for first calculation of material cost pass through the calculation of the total weight of the pipeline:

$$Material\ cost = 0.02463L^{*} \cdot (D_{int} + t) \cdot Cpt \tag{2.4}$$

Where Cpt is the unitary material cost per km of pipe per ton of material $\left(\frac{€}{m\ ton}\right)$ that considers the type of steel employed. To consider other expenses related to coating, wrapping, cathodic protection, an extra factor for the cost is added (f_{CWC}) in the formula.

$$Material\ cost^{*} = 0.02463L^{*} \cdot (D_{int} + t) \cdot CPT \cdot f_{CWC} \tag{2.5}$$

Labor cost

Labor cost consists of the cost of pipeline construction labor, similarly to material costs an estimation is performed passing through the unitary cost of labor per km of pipe per size of the Diameters $\left(CU_{labour} = \frac{€}{mm_{DN}\ km_{Length}}\right)$.

$$Labour\ cost = L^{*} \cdot DN \cdot C_{labour} \tag{2.6}$$

Additional component cost

For compressor stations first estimation can be carried on the power required, based on $\left(\frac{€}{kW}\right)$. Since the marginal power of kW is not constant and decrease with the increase of power, it is better to divide the values in certain range depending also on the type of compressor installed (centrifugal, reciprocal).

The costs of the valve mainly depend on the type and the Diameter of the pipe.

Metering stations may be estimated as a lump sum fixed price for a complete site including material and labour cost.

For SCADA systems there are facilities cost for remote monitoring, operation and control of the pipeline from a central control centre. The expenses are very flexible and are affected by the other items. It is usually 2-5% of the total project cost.

Number of crosses

The cost related to crosses depends on the type of cross and the relative trenchless methodology employed. [54]

Since it is an alternative to the classic trench methodology, it doesn't apply the same calculation cost, so the length cost interested in the crosses are calculated separately. This will result in a less size for standard calculation cost of the pipe $L^{*} = L - \sum L_i^{cross}$

It is usually done a lump estimation of the total cost related to the cross.

2.6.1.2 Operative costs

Once the capital is expended, after the pipeline installation and compression station and other facilities built, the pipeline will start to work and annual operating and maintenance cost (O&M) for these facilities will incur.

O&M are related to the operative status of the pipeline, having the task to maintain it or to restore it, and to the normal operations for running the business.

Operative costs have to be pondered together with the capital cost - benefits evaluation. For instance, the trade-off between Diameter and Compressor power involves also different operative expenditures. A larger compressor requires more energy to run and thus more energy expenses related to it.

Maintenance expenses for the cleanness of the pipes, related with the use of PIGs, are crucial and productive in a life of a pipeline. Since the revenues are related to the passage of the gas, a cleaner pipe will be able to allow greater flow amount and thus higher revenues.

2.6.2 Tariffs & Revenues

Initially it is required to determine the revenue stream necessary to amortize the total investment in the pipeline. Roughly, the revenue earned after expenses and taxes plus a percentage for profit divided by the volume transported will give the transportation tariff necessary.

Annualize the capital cost by discount rate and project lifetime, then adding annual operating costs, tax rate, depreciation of asset, profit margin.

The revenue for this operation will be in the form of pipeline tariffs collected from companies that ship products through this pipeline.

Then by dividing per the volume transported with an average load factor you have the tariff.

2.6.2.1 Transmission evaluation tariffs

In the Italian transmission network SNAM on base of the deliberation *114/2019/R/GAS* set the transport fee (T) for continuous transport service on an annual basis for the user with the following formula [55]:

$$T = [(K_e \cdot CP_e) + (K_u \cdot CP_u)] + [(V \cdot CV_u) + (V_{FC} \cdot CV_{FC})] \tag{2.7}$$

The first square bracket represents the fix fee based on the capacity granted to the user. K is the capacity available of cubic meters per day during the year and CP is the unitary cost related $\left(\frac{€}{year\ m^3/day}\right)$. The subscripts are relative to entry point (e) and the exit point (u) of the national pipeline network.

The second square bracket is the variable part and it is based on the consumption of gas taken from the network. V stands for the amount of gas (m^3) and CV the relative unitary cost $\left(\frac{€}{m^3}\right)$. The second term with the subscript FC refers to the gas taken from a network except for points output interconnected with foreign.

The tariff components associated with the unit commitment fees CP_e, CP_u, must be paid regardless of the actual use of the daily capacity provided, while the components relating to the variable fees CV_u and CV_{FC} will be applied to the volume taken at each of the points of exit.

In addition, the CP_u considers the distance with the delivery points, differentiating the values between CP_u with distances less or more than 15 km.

2.7 Introduction to Gas Pipeline Model

For the purpose to support the pipeline analysis a Gas Pipeline Model (GPM) has been built for the design phase and evaluation process. The GPM is based on a general analysis for steady single-phase of a compressible (isothermal) flow in a pipe (pressurized environment). It considers variables and parameters to settle a proper sizing and to estimate operative parameters, a sensitivity analysis also was carried to evaluate a widen outlook.

2.7.1 Gas properties

The starting point is to calculate the gases properties to characterize their behavior in the system. The majority of the properties have to also consider the peculiarity of working with mixture of gases dependent on the volume (molar) fractions. Furthermore, distinctions have to be made for values that are referred to Standard cubic meters and (Sm3) or Normal cubic meters (Nm3), the difference stands in the temperature assumption, respectively at 20 °C and 0°C. The GPM refers to the Sm3.

The main variables to consider are the following:

Molecular weight or molar mass is the weight of 1 mole of the gas (g/mol), for mixtures by considering mole (volume) fractions the molecular apparent weight is:

$$MW_a = \sum MW_i \cdot y_i \tag{2.8}$$

Density:

$$\rho = \frac{P \cdot MW_a}{ZRT} \tag{2.9}$$

Specific gravity
(relative density to air)

$$G = \frac{MW_a}{MW_{air}} \quad ; \; MW_{air} = 28.9625 \frac{g}{mol} \tag{2.10}$$

Specific heat: For these properties it is assumed to work with perfect gases.

$$C_v = \left(\frac{\partial u}{\partial T}\right)_v ; C_p = \left(\frac{\partial h}{\partial T}\right)_p \tag{2.11}$$

Gas viscosity, it is the effect of shear interaction between the wall and the fluid and it is what characterize the shear stress τ.

$$\tau = \mu \frac{du}{dy} \; where\ \mu\ is\ the\ dynamic\ viscosity \tag{2.12}$$

Gas viscosity in mixtures can be calculated by weighting the mole fractions (volume fractions) or by considering also the molecular weight:

$$\mu = \frac{\sum \mu_i \cdot y_i \cdot \sqrt{MW_i}}{\sum y_i \cdot \sqrt{MW_i}} ; \; \mu^* = \frac{\sum \mu_i \cdot y_i}{\sum y_i} \tag{2.13}$$

Lower and higher heating value: Expressed in MJ/Sm3 due to the gaseous phase.

In natural gas industry is wide employed another parameter to evaluate heat combustion of natural gas mixtures: the **Wobbe index.**

It is the ratio between the HHV and the square root of the relative gas density (MJ/Sm3). The Wobbe index, associated to natural gas, has to remain in determined range for interchangeability to ensure safe and satisfactory equipment operations, in Italy it has to be:

$$47{,}31 < \left(I_W = \frac{HHV}{\sqrt{G}}\right) < 52{,}33 \tag{2.14}$$

Critical temperature and **pressure** affect the behavior of the gas, the critical point is described as the end of phase equilibrium curve and beyond that liquefaction cannot be carried out by just one variable (temperature or pressure).

Since pipeline gases are the result of a combination of single gases, the critical conditions have to correspond to these gas mixtures. The calculation of gas mixtures is quite hostile and for simplicity are often calculated pseudo-critical properties that are the sum of the critical values with their percentage volume.

$$T_c = \sum T_{c_i} \cdot x_i \quad ; \; P_c = \sum P_{c_i} \cdot x_i \tag{2.15}$$

Moreover, for Natural gas mixtures empirical methods have been developed to calculate these values from specific gravity.

Critical conditions are often alongside with the reduced parameters, to have a rapid outlook on the relative distance between operative and critical conditions related to gas behaviour, in fact they are the ratio of an operative property and its relative critical value.

$$T_r = \frac{T}{T_c};\ P_r = \frac{P}{P_c} \tag{2.16}$$

Compressibility factor, it is the numerical deviation between the behavior of an ideal gas and a real gas, for an ideal gas this factor is considered to be one. The compressibility coefficient is function of pressure, temperature and gas composition.

$$pv = nRT \ \rightarrow pv = ZnRT \tag{2.17}$$

When natural gas pressures are higher than 8 Bar the gas compressibility factor may not be close to 1.00, so it can be advisable to use a gas compressibility factor especially based on the pressure in the pipe.

Countless methodologies exist to determine the Z factor and are based on the dependence of the reduced parameters. This thanks to the bond between Z factor and reduced state variables that is independent from the nature of the fluid considered.

$$Z \ \rightarrow f(T_r; P_r)$$

In this model it was chosen the calculation through three empirical approaches.

AGA formula calculates the Z factor with the reduced properties. Adequate for pressure till 70 Bars.

$$Z_{AGA} = 1 + 0.257P_r - \frac{0.533P_r}{T_r} \tag{2.18}$$

Papay formula is another method that involves the reduced quantities also in exponential factors. Adequate for pressure till 150 Bars.

$$Z_{Papay} = \ 1 - 3.52P_r \cdot e^{-2.26T_r} + 0.274P_r^2 \cdot e_r^{-1.878T_r} \tag{2.19}$$

The California Natural Gas Association (**CNGA**) provides a method that differs with the variables implemented and it was specifically design for pipeline application. It combines the average pressure in the pipeline, the flowing temperature of the gas and its specific gravity.

$$Z_{CNGA} = f(T_f; P_{avg}; G) = \frac{1}{\left(1 + \frac{344400 P_{avg} \cdot 10^{1.785G}}{T_f^{3.825}}\right)^2} \tag{2.19}$$

For a pure hydrogen stream is suggested to employ a formula specific for hydrogen. The equation by Lemmon [56] is built by considering several empirical coefficients specific for the gas.

$$Z = f(p; T) = \frac{p}{\rho RT} = 1 + \sum_{i=1}^{9} a_i \left(\frac{100K}{T}\right)^{b_i} \left(\frac{p}{1\ MPa}\right)^{c_i} \tag{2.20}$$

i	a_i	b_i	c_i
1	0.0588846	1.325	1
2	-0.06136111	1.87	1
3	-0.002650473	2.5	2
4	0.002731125	2.8	2
5	0.001802374	2.938	2.42
6	-0.001150707	3.14	2.63
7	$0.958852 \cdot 10^{-4}$	3.37	3
8	$-0.110904 \cdot 10^{-6}$	3.75	4
9	$0.1264403 \cdot 10^{-9}$	4	5

Table 8 - Lemmon coefficients for hydrogen compressibility factor

2.7.2 Pipe characteristics

Pipe is essentially a duct where the gas flows under pressure. Its design must consider many types of load including stresses from the interior (internal pressure generated by the flow) and/or exterior (pressure generated by the weight of earth).

For the GPM, considering structural design, the main characteristics with their units are:

- Length [km]
- Diameter (internal and external) and the relative thickness [mm]
- Roughness of the pipe, labelled and diameter dependent [mm]
- Material evaluated considering the yield strength and tensile strength [kPa].

The stress due to internal pressure results on a combination of three different directions:

- Circumferential stress (Hoop stress)
- Longitudinal stress
- Radial stress

The GPM focuses on the circumferential stress since, among the three, it is the most stringent one. For thin-walled cylindrical pipe it is employed the Barlow's equation:

$$S_h = \frac{P \cdot D_{out}}{2t} \tag{2.21}$$

In the above derivation, it was implicitly assumed that the internal pressure is uniform around the circumference of the pipe, the non-uniformity can be neglected for gas application.

The hoop stress is determined by multiplying the (Steel) Minimum Yield Strength (SMYS), expressed in kPa as the pressure, of the pipe material with a utilization factor (design factor). For standard transmission pipeline in class 1 it can be assumed equals to 0.72.

Therefore, the Barlow's equation can be used to calculate the minimum thickness t of the pipe:

$$t_{min} = \frac{P \cdot D_{out}}{2S_h} = \frac{P \cdot D_{out}}{2f_u \cdot SMYS} \tag{2.22}$$

The minimum thickness has to be compared with standard thicknesses available in pipes (in relation with Diameters). Alternatively, it possible as well to calculate the minimum thickness/Diameter ratio to compare pipes from different suppliers.

Alternately Barlow's formula is used to calculate the maximum allowable operative pressure (MAOP) for a given material and pipe:

$$MAOP = \frac{2S_h t}{D_{out}} = \frac{2f_u \cdot SMYS \cdot t}{D_{out}} \tag{2.23}$$

Notwithstanding that pipelines shall be tested at a pressure of at least 150% of MAOP for at least 2 h where water is the preferred medium [41].

For gas pipeline many alloys are suited to be used, environment conditions might lead one option rather than another. In the GPM carbon steel alloys with relative grades have been utilised. The classification is performed with the API 5L (X-grades). The yield strength and the tensile strength are labelled with the grades.

Due to the elevate numbers of metals, for rapid comparisons general parameters are account:

- Carbon Equivalent (**CE**)

$$C.E. = \%C + \frac{\%Mn}{6} + \frac{\%Mo + \%Cr + \%V}{5} + \frac{\%Ni + \%Cu}{15} \quad (2.24)$$

- Composition parameter (**Pcm**): to indicate cracking susceptibility, well suited for steels with lower carbon contents or carbon equivalents.

$$Pcm = \%C + \frac{\%Mn + \%Si + \%Cu + \%Co}{20} + \frac{\%Mo}{15} + \frac{\%V}{10} + \frac{\%Ni}{60} + \%5B \quad (2.24)$$

Long pipelines can interest differences in elevation non negligible even for gas pipelines. To consider these possible situations a length factor for an equivalent length can be calculated through the height elevation (H – express in meter), specific gravity of the gas, compressibility factor and the gas flowing temperature by considering an elevation factor s:

$$L_e = L\frac{(e^s - 1)}{s} \quad where\ s = 0.0684G \cdot \frac{H_2 - H_1}{T_f \cdot Z} \quad (2.25)$$

For a given line pipe it is possible to calculate the linepack for a specific gas mixture:

$$V_b(D_{int}; L; T; P; Z) = \frac{\pi}{4 \cdot 1000} \cdot \left(\frac{T_b}{P_b}\right)\left(\frac{P_{avg}}{Z_{avg}T_f}\right)(D_{int}^2 L) = [Sm3] \quad (2.26)$$

2.7.3 Flow analysis

Fluid flow is under the basic concepts of continuity, momentum and energy equations through Bernoulli’s principle.

$$\rho_1 V_1 A_1 = \rho_2 V_2 A_2 \quad (2.27)$$

$$\frac{V_1^2}{2}+\frac{p_1}{\rho_1}+gz_1=\frac{V_2^2}{2}+\frac{p_2}{\rho_2}+gz_2+(i_2-i_1)+\frac{dQ_m}{dm} \tag{2.28}$$

$$F_x = \rho_2 V_2^2 A_2 cos\theta - \rho_1 V_1^2 A_1 \ ; F_y = \rho_2 V_2^2 A_2 sin\theta \tag{2.29}$$

The velocity of gas stream represents the speed at which the gas molecules move through the pipeline. In a duct the velocity can be seen as the ratio of Mass flow and density per unit of area

$$u=\frac{Q_m}{A\rho} \tag{2.29}$$

Since density is related to pressure and this latter varies along the pipe, consequently gas velocities will vary as well. For simplicity the evaluation is on the mean velocity and local velocities are left out.

It might be considered the variation of velocity as well along pipe due to the development of the flow. Nevertheless, working with pipelines long kms allows to neglect this last effect and assuming it fully developed.

An empirical formula was developed to be used in pipeline sections to calculate the velocity at any given point [51]:

$$u_x = 14.7349\left(\frac{Q_{vol}}{D_{int}^2}\right)\left(\frac{P_b}{T_b}\right)\left(\frac{Z_x T_x}{P_x}\right) \tag{2.30}$$

The velocity in a pipe is also function on the flow regimes. The flow in a pipe may be either laminar or turbulent, depending on the specific dimensionless parameter, the Reynolds number (and the amount of perturbation).

Gas velocities in pipes have to be under certain values to assure the integrity of the pipe. Too high velocities can lead to erosion effects and have to be calculated to assure also with a theorical approach that such velocities are not encountered. The erosional velocity is the speed calculated at which erosion effects take place, it is calculated as follows:

$$u_e=\frac{C}{\sqrt{\rho}}=\frac{C}{\sqrt{\frac{ZRT}{29GP}}} \ where \ C = 100 \ or \ 125 \tag{2.31}$$

C = 100 is employed for continuous services while C = 125 for non-continuous ones. Acceptable velocity limits are in the order of 60% of the erosional velocity [29].

Although not comparable with the risk of high velocities, low velocities can increase risk of sedimentation.

Reynold number has a central role in fluid dynamics. It is the ratio between and viscous forces, the Re value characterizes the flow, ranging from laminar flow when Re is low to turbulent flow when Re is high. The change on the kind of flow is recognized a specific value of Reynolds called the critical Re number that depends on the perturbation of the pipe, roughly for large perturbations Rec is around 2100.

$$Re = \frac{D_{int} \cdot u \cdot \rho}{\mu} \tag{2.32}$$

In pipe the Re can achieve really high number (in the order of millions) and any pipe flow at a high Reynolds number (exceeding ten of million) is highly unstable. Usually in pipeline application is employed a more suitable formula [29]:

$$Re = 0.5134 \cdot \left(\frac{P_b}{T_b}\right)\left(\frac{G \cdot Q_{vol}}{\mu D_{int}}\right) \tag{2.33}$$

2.7.3.1 Empirical formulas for the flow

Over time a several number of flow equations in gas pipelines have been suggested. Most of them share same configurations, considering the operational conditions and the standard conditions. In this study some of these methods were analyzed to comprehend a better sensitivity of the results.

The **General Flow equation** (a.k.a. General Fundamental Isothermal Flow Equation) provides perhaps the most universal method for calculating isothermal flow rates, however it relies on the inclusion of an accurate friction factor f :

$$Q_{vol} = 1.1494 \cdot 10^{-3} \cdot \left(\frac{T_b}{P_b}\right) \cdot \left(\frac{P_1^2 - P_{2^*}^2}{G \cdot T_f \cdot L \cdot Z \cdot f}\right)^{0.5} \cdot D_{int}^{2.5} \tag{2.34}$$

Alternative equations rely on Pipeline Efficiency Factors (E) and include:

Weymouth flow equation:

$$Q_{vol} = 3.7435 \cdot 10^{-3} \cdot E \cdot \left(\frac{T_b}{P_b}\right) \cdot \left(\frac{P_1^2 - P_{2^*}^2}{G \cdot T_f \cdot L \cdot Z}\right)^{0.5} \cdot D_{int}^{2.5} \tag{2.35}$$

Panhandle A equation:

$$Q_{vol} = 4.5965 \cdot 10^{-3} \cdot E \cdot \left(\frac{T_b}{P_b}\right)^{1.0788} \cdot \left(\frac{P_1^2 - P_{2^*}^2}{G^{0.8539} \cdot T_f \cdot L \cdot Z}\right)^{0.5394} \cdot D_{int}^{2.6182} \quad (2.36)$$

Panhandle B equation:

$$Q_{vol} = 1.002 \cdot 10^{-2} \cdot E \cdot \left(\frac{T_b}{P_b}\right)^{1.02} \cdot \left(\frac{P_1^2 - P_{2^*}^2}{G^{0.961} \cdot T_f \cdot L \cdot Z}\right)^{0.5394} \cdot D_{int}^{2.53} \quad (2.37)$$

Where the subscript b stands for the reference conditions (15 °C and 101 kPa).

The Panhandle B formula was introduced to extend the equation at larger Reynolds numbers, Panhandle A is suitable for Re between 4 and 11 million while the Panhandle B reaches 40 million

The efficiency factor is usually labelled and can be used also to evaluate the efficiency for the general flow equation, usually it is applied:

- E = 1 in the absence of field data (also for new straight pipe with no Diameter change)
- E = 0.95 for very good operating conditions (typically through first 12-18 months)
- E = 0.92 for average operating conditions
- E = 0.85 for unfavourable operating conditions

In addition, the efficiency may consider temporal factors such as pipe cleanness through time.

All the equations above consider a flat line pipe with zero elevation, if pipe elevation is not negligible some downstream pressure has to be modified accordingly to the elevation factor:

$$P_{2^*}^2 = (e^s) \cdot P_{2\,Flat}^2 \quad (2.38)$$

2.7.4 Pressure losses

Fluids flow through pipes thanks to a difference in pressures within the piping system. The pressure forces the fluid from high-pressure regions into low pressure regions. Pressure forces have also to overcome any losses along the pipe. The calculations for pressure drop in fluid dynamics problems derive from the First Law of Thermodynamics.

Friction losses depend on several variables:

- Flow rate
- Diameter
- Type of pipe (Roughness)
- Length of pipe (related to Major Losses)
- Number and sizes of fittings and valves (related to Minor Losses)
- Entrance and Exit Losses (related to Minor Losses)

2.7.4.1 Friction and transmission factor:

It exists a large number of methods to calculate friction losses, to be consistent with the flow equations the Darcy-Weisbach equation was chosen with its relative friction factor, the Darcy friction factor. Head loss due to friction:

$$h_f = f \frac{L_e}{D} \frac{V^2}{2g_c} \tag{2.39}$$

In relation with the flow equation the calculation was focused just on the Darcy friction factor (f).

Once the Reynolds number and the relative roughness are calculated, the f factor can be determined by applying one of the following methods. The most common method is to enter the Moody Diagram but empirical formulas have been built. The flow regime affects the friction equations and they might change depending if it's turbulent or not, the flow regime is prior assumed to be turbulent this is consistent with high pressurized pipeline application, Reynolds is in the order of millions.

The first empirical equation is the **Colebrook-White** equation that is an iterative formula.

$$\frac{1}{\sqrt{f}} = -2\log_{10}\left(\frac{e}{3.7D} + \frac{k}{Re \cdot \sqrt{f}}\right) ; k = 2.51 \; or \; 2.825 \tag{2.40}$$

In recent times it has been advised to assume the value k = 2.825 instead of 2.51 for a more conservative approach (a.k.a. Modified Colebrook Equation)

Hofer suggests an explicitation of the Colebrook formula:

$$f = \frac{1}{\left(2\log_{10}\left(\frac{4.518}{Re}\log_{10}\left(\frac{Re}{7}\right)+\frac{e}{3.71D}\right)\right)^{2}} \tag{2.41}$$

While other formulas, like the one employed by the American Gas Association (**AGA**), rely on the transmission factor, that is basically how good the gas flows into the pipe. The relation with the Darcy factor is then presented:

$$F = 4\log_{10}\left(\frac{3.7D}{e}\right);\ \ F = \frac{1}{\sqrt{f}} \tag{2.42}$$

2.7.4.2 Local pressure losses

Local pressure losses refer to components along the pipeline that produce pressure losses in their section, these are typically the case of valves that even when they are fully open produce small discontinuities in the flow.

They are also called minor losses referring that in the majority of the cases their contribution is small considered to losses due to friction, this is specially the case of long pipelines.

Since friction losses distil down to units of meters, conversions have been developed to describe minor losses simply as an equivalent length of straight pipe. A method implies evaluation of valves in number of diameters, although not very precise it helps the conversion for a pipeline with any diameter just by multiplying the number of diameters relative to the local loss with the diameter size, then the extra length to add is found. The relation with the type of valves and relative n° of Diameters is labelled.

$$\mathrm{L_e^{valve}} = \mathrm{N°}_{D_{eq}} \cdot D_{int} \tag{2.43}$$

Another option passes through the analysis of friction factor:

$$L_{e2}^{valve} = \frac{KD_{int}}{f} \tag{2.44}$$

Where K is a resistance coefficient dependent on the type of valve. Although it is a more precise method it was discard since several gas mixtures are considered in the model affecting the friction factor that is not investigated in advance.

2.7.5 Compressor station

To complete the pipeline analysis an energetic point of view for gas compression is assessed through a fictitious compressor station assuming to bring back the downstream pressure to upstream values to simulate the passage to another pipe segment. The compression power required is calculated by multiplying the isentropic head with the volumetric flow (in MSm3/d) and then divided by the adiabatic efficiency of the compressor.

$$Power_{comprex} = Head_{is} \cdot \frac{Q_m}{\eta_{ad}} \left(\frac{10^6}{24 \cdot 3600}\right) = [W] \tag{2.45}$$

$$Power_{comprex} = \left[\frac{R}{MW_{gas}} \cdot \frac{Z_{avg} \cdot T_{in}}{\theta} \cdot \left(\left(\frac{P_{out}}{P_{in}}\right)^{\theta} - 1\right)\right] \cdot \frac{\rho_{Std} \cdot Q_{vol}}{\eta_{ad}} \cdot \left(\frac{10^6}{24 \cdot 3600}\right) \tag{2.46}$$

Given almost the totality of Centrifugal compressor employment in transmission pipelines, it is assumed to work with large centrifugal compressors that usually present adiabatic efficiencies in the order of 80% [57]. For any gas mixture the factor $\theta = \frac{\gamma-1}{\gamma}$ depends on the gas mixture and it is an average of inlet and outlet conditions. The hypothesis of constant adiabatic efficiency might oversimplify the calculation process; however the hereby goal is to compare different power (energy) required for compression.

In the power compression formula it has to be clear that the volumetric flow in the formula it refers to the standard conditions and differs with the actual flow rate at the compressor inlet. For this reason the density is referred to the standard conditions and not the density relative to inlet/outlet pressure. To get the actual volumetric flow at compressor inlet a simplified formula usually employed in gas systems is:

$$Q_{vol}^{actual} = 0.352 \cdot \left(\frac{Z_1 \cdot T_1}{P_1}\right) \cdot Q_{vol}^{Std} \tag{2.47}$$

Where pressure with [kPa] and temperature in [K}

Parallel to the power calculation, pipeline manuals [29, 58] suggest to consider the specific adiabatic work required to compress the gas with the following formula:

$$W_{ad} = \frac{R}{MW_{air}} \cdot \frac{T_1}{G \cdot \theta} \cdot \left(\left(\frac{P_2}{P_1}\right)^{\theta} - 1\right) \cdot 10^3 = \left[\frac{J}{kg}\right] \tag{2.48}$$

2.7.6 CO2 emissions

The GPM emission evaluation relies on several studies [59, 60] that estimates the emission contribution of the supply chain for the specific gas, adding the emission by combustion for methane and emission by production for hydrogen.

Hydrogen emissions depends on which sources is considered, in the GPM several sources are presented, with a possible combination mix among them:

- Steam Methane Reforming with/without CCS
- Renewable electrolysis
- Biomass gasification with/without CCS
- Coal gasification with/without CCS

The emissions calculated are relative to the amount transported in the pipeline the combustion after pipeline transportation based on kgCO2 equivalents, so by calculating the volumetric/energetic flow in the pipe it could be consider the kilograms equivalent of CO2 transported.

2.7.7 Excel environment

The excel model was built with several sheets chain-linked in cascade levels starting from the features of gases that are involved in the several mixtures to the technical and economical pipeline evaluation.

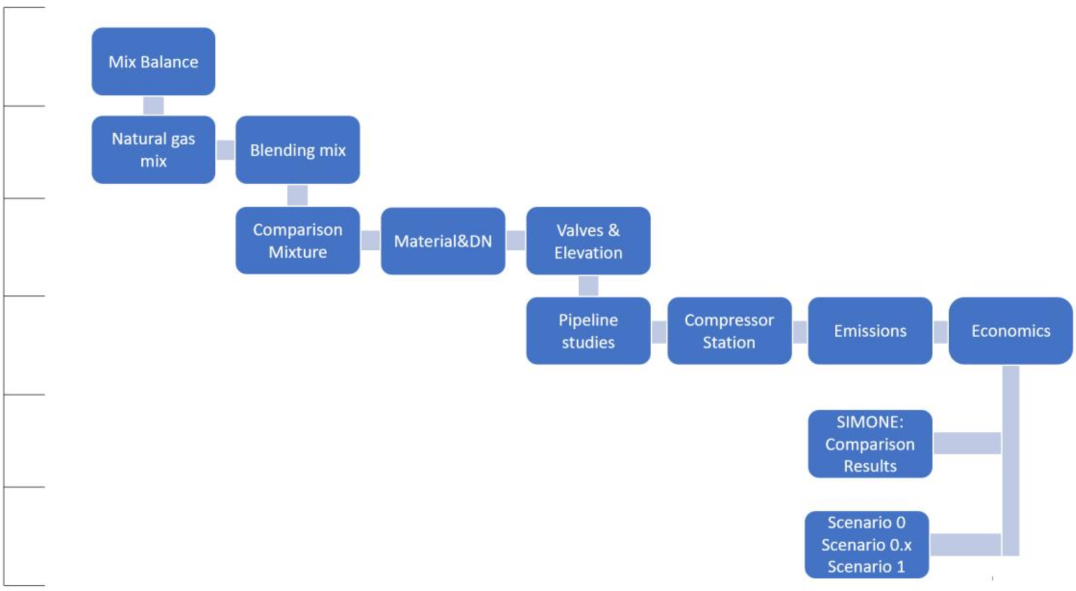


Figure 18 - Excel flow diagram

The model has been developed with the support of the VBA language to build appropriate functions including any iterative loops needed [appendix A]. Since several equation methods are available, in some functions it is mandatory to express the method used for the relative variable (e.g. MFlow, Mfriction, MZ).

Requirements are usually set with delivery pressure. Working in a transmission gas system (high pressure pipelines) the value are in the order of few megapascal.

Constraints are related to the MAOP (MOP), minimum thickness and the erosional pressure, the latter, since it is related to the erosional velocity, is replaced with the erosional velocity factor and compared with the velocities in the pipe (since the pressure has its highest at the begin and the lowest at the end, the last part will face higher velocities and hence a calculation on that point will be calculated).

A fictitious MAOP can be set by considering the Barlow's equation having the relation between thickness and diameter and knowing the pipe material (steel) employed.

$$MAOP = 2SEf_uT \cdot \frac{t}{D} \tag{2.49}$$

Where:

S = SMYS of pipe material
E = Seam joint factor (E = 1 for seamless pipes)
f_u = utilization factor (design factor)
T = temperature deration factor (T = 1 below 120 °C)

If onshore pipelines are considered, rarely the MAOP goes beyond 7500 kPa (75 Bar) so for general applications this value will be considered.

The main core of the excel is the "Pipe" sheet where flow is analyzed:

Inside it is present a table composed of the General parameters with variables to set, such as the delivery pressure (downstream pressure) and a recap of the previous chosen parameters.

General Parameters		
L equivalent	202,0	*km*
	125	mi
Segment	1	km
# seg.	10	-
Dext	1062,6	*mm*
	41,8	in
t	***12***	*mm*
Dint	1038,6	mm
	40,9	in
rel rough	1,2E-05	-
Tb	288	K
Tf	***288,15***	*K*
Pb	101	kPa
P_delivery	***5000***	*kpa*

Figure 19 - List of the general parameters

Moving on, "Pipe" sheet contains all the "studies" evaluated, each of them with the following structure:

Study 1: Given the volumetric flow, pressure delivered and pipe parammeters find **Inlet pressure**					
Parameters	**Natural Gas**	**Methane**	**Blending 10%**	**Hydrogen**	**Units**
Re	43.840.133	38.644.950	35.660.043	5.188.721	-
f	8,49E-03	8,52E-03	8,54E-03	9,63E-03	-
G	0,61	0,53	0,48	0,07	-
Zavg	0,85	0,88	0,91	1,81	-
P1	6372,5	6244,8	6181,6	5232,7	kpa
ΔP	1373	1245	1182	233	kpa
Pavg	5714	5645	5612	5117	kpa
u1	7,27922	7,69318	8,1	19,1	m/s
u2	9,6	9,8	10,0	20,0	m/s
ue	18,6	20,3	21,6	80,0	m/s
Qe	437.522.997	419.382.296	390.870.647	134.265.809	*kWh/d*
	1.492.890	1.430.992	1.333.706	458.134	MMBtu/d
	100%	96%	89%	31%	-
Qmass	31.380.282	27.190.565	24.812.332	3.364	kg/d
	100%	87%	79%	0%	-
Linepack	5.615.824	5.379.852	5.182.375	2.371.434	Sm3
Energy content	61.426	56.405	50.641	7.960	Mwh

Case specific parameter		
Q_nom	*40.000.000*	*Sm3/d*
	1.413	MMft3/d

Parameter	Method
Friction	ColeWhite
Flow	General
Z GN	Papay
Z H2	AGA
Efficiency	0,92

Figure 20 - Example of pipeline study

The distinction in studies was carried out to evaluate, in different conditions, upstream/downstream pressure, volumetric and energetic flow, internal diameter and the pipe length. The variable of the case study the highlighted one.

Such different conditions refer to the "Case specific parameter(s)" including setting a volumetric, energetic and mass flow and pressure conditions. In details the following table presenting the variable of the case as a function of the specific parameters:

Structural pipeline parameters as diameter and length where set also as variables, this to indirect confirm the results found with the other studies but also to evaluate physical requirements and possible outcomes especially for specific hydrogen pipelines. The diameter is useful to calculate maximum volumes achievable with the constraints of pressure range. While the length indirectly set the possible position of the compression stations.

Since several methods exist for empirical formulas, each study is equipped with a drop-down menu below the Specific parameters to choose the suitable method.

Parameter	Method
Friction	Hofer
Flow	PanhandleB
Z GN	General Weymouth
Z H2	PanhandleA
Efficiency	PanhandleB

Figure 21 - Menu for methodology parameter option

2.7.8 "SIMulation and Optimization on NEtworks"

Thanks to SNAM colleagues it was possible to compare the results calculated in the Excel model with a more proper software able to analyse more complex pipeline systems: "SIMulation and Optimization on NEtworks" (a.k.a. SIMONE).

SIMONE is a software package by Liwacom that able to simulate real conditions for a gas network, offering the possibility to analyse all the possible process.

For the comparison analysis, simplified scenarios were set to not overcomplex the differences between Excel model and SIMONE. the basic equations and methods being used in SIMONE to model the behavior of the gas, flows, and equipment in a pipeline system are chose on the basis of the same methodologies that the Excel model was built.

This means that same equations where used in both the simulation environments:

- **Papay** formula for Compressibility factor
- **Hofer** formula for friction factor
- **General flow equation**

It is important also to point out the simplification carried out in the SIMONE environment lead to an extra error and thus an additional comparison is useful.

The primary limit for the excel model is to assume isothermal flow. SIMONE helps to quantify the hypothesis' weight on the scenario simulating both isothermal and non-isothermal flow. In addition, the thermal hydraulic depends also on the season reference resulting in a ground temperature variation, usually from winter to summer a delta temperature of 10 °C is considered (Summer 20 °C and winter 10 °C).

In the isothermal flow assumption the ground temperature is set at 15 °C (288 K), this value being the same as the flowing gas has an added factor. The Joule Thomson effect cools the gas and contrary the thermal exchange between gas-pipe-ground heat the gas as soon as the gas temperature drops. The combination will smooth the variation temperature and partially balance.

Base on the level of accuracy possible to reach it was chosen to operate with Colebrook-White approach and a Weymouth comparison for the efficiency factor, the panhandle equations were discarded since too optimistic results might come to underestimates pipe.

Gas composition	Variable calculated	Error%
NG	Pressure - Flow	0.01 – 0.009 % / 0.25 – 0.6%

Methane	Pressure - Flow	0.01 – 0.02 % / 0.2 – 0.5%
Hydrogen	Pressure - Flow	0.03 – 0.04 % / 0.3 – 0.5%
5% H2	Pressure - Flow	0.2 – 0.4 % / 0.5 – 0.8%
15% H2	Pressure - Flow	0.4 – 0.8 % / 0.5 – 0.9%
20% H2	Pressure - Flow	0.4 – 1 % / 1 – 2%

Figure 22 - Error with respect to SIMONE results

Comparing with SIMONE, the errors in the studies between the GPM and SIMONE were in the order of 1%.

2.8 Scenario "0"

The first scenario, Scenario 0 ("Zero") refers to the absence of hydrogen in the gas composition and hence is a scenario suited to analyse common natural gas. Composition data are from already existed type of natural gas.

Natural gas composition is usually defined by its origin and for a transmission system point of view it depends from which entry point is considered. Thus, with the help of SNAM colleagues, several entry points were analysed and each of them with their proper gas composition. The percentage of methane varies in the range of 85% - 99%.

Afterwards, a gas mixture from the Sicilian entry point "Gela" was carried on for flow analysis. This gas mixture is the result of Lybian importation that features a relatively low methane concentration (ca. 87%) with important heavier hydrocarbons presence, such conditions nominate the gas as "Wet Natural Gas". The choice has originated from a decision to widen the comparison with pure methane stream and thus choosing a gas mixture with farer methane concentration.

The HHV value falls perfectly within the allowable range with ca. 49-50 KJ/Sm3.

Since the environment of the model analysis focuses on transmission pipelines, high volumes (in the order of tens of millions) and large diameters (DN 700 – 1400 mm, 27 – 54 in) are considered.

The first studies were focused on the evaluation of the inlet pressure by setting the gas properties and pipeline parameter. This approach it is called "fast track" as it is applied to engineering projects in which design is taking place before all the information is available and one of the first efforts in a piping project is just to calculate pressure drops. [58]

For the outlet pressure (also called the delivery pressure) the values were set between 3500 and 5500 kPa in conformity of the general delivery contract points that the Italian transmission system operates [49].

2.8.1 Numerical framework

To give an overview on the values for a generic pipeline, we start considering some cases to give a basis from which to begin:

Parameters	Case1	Case2	Case3	Case4	Case5	Unit
L	100	200	200	300	350	km
DN	750	750	900	1050	1400	mm
P2	5000	5000	5000	5000	5000	kPa
Q	15	15	18	21	50	MSm3/d
P1	***6162.5***	***7121.0***	***6246.4***	***6087.1***	***6572.0***	***kPa***

Table 9 - Pipelines numerical outlook

While below in details the parameters outlook for case 2:

Parameters	Values	Unit
L	200	Km
D	733.4	mm
Re	20 577 876	-
f	9.78E-03	-
Roughness	0.02	mm
Zavg	0.877	-
Tf	288.15	K
P2	5000	kPa
Q	15	MSm3/d
P1	***7121.0***	***kPa***

Table 10 - Case 2 extended numerical outlook

Velocities along the pipeline are function of the flow and pressure variation, for the Bernoulli's principles upstream sections with highest pressures present lowest velocities and vice versa for downstream conditions.

Assuming a pipeline length of 200 km with a DN 900 the interested parameters are:

Parameters	Upstream conditions	Downstream conditions
Volumetric flow (MSm3/d)	20	20
Pressure (kPa)	6492	5000
Velocity (m/s)	5,1	6,7

Table 11 - Velocities at given pressure

After 200 km with a pressure reduction of almost 15 bars, the velocity increase about 1.5 m/s. The main analysis when assessing velocities is to compare them with the erosional velocity, that in the previous case the erosional velocity is 20.3 m/s, being more than three times the downstream velocity that is an acceptable ratio.

2.8.2 Sensitivity analysis by methodology employed

Given the wide possibility to calculate the operative pipeline parameters, it is carried out a sensitivity analysis on the possible methodologies to be employed.

Pressure evolution

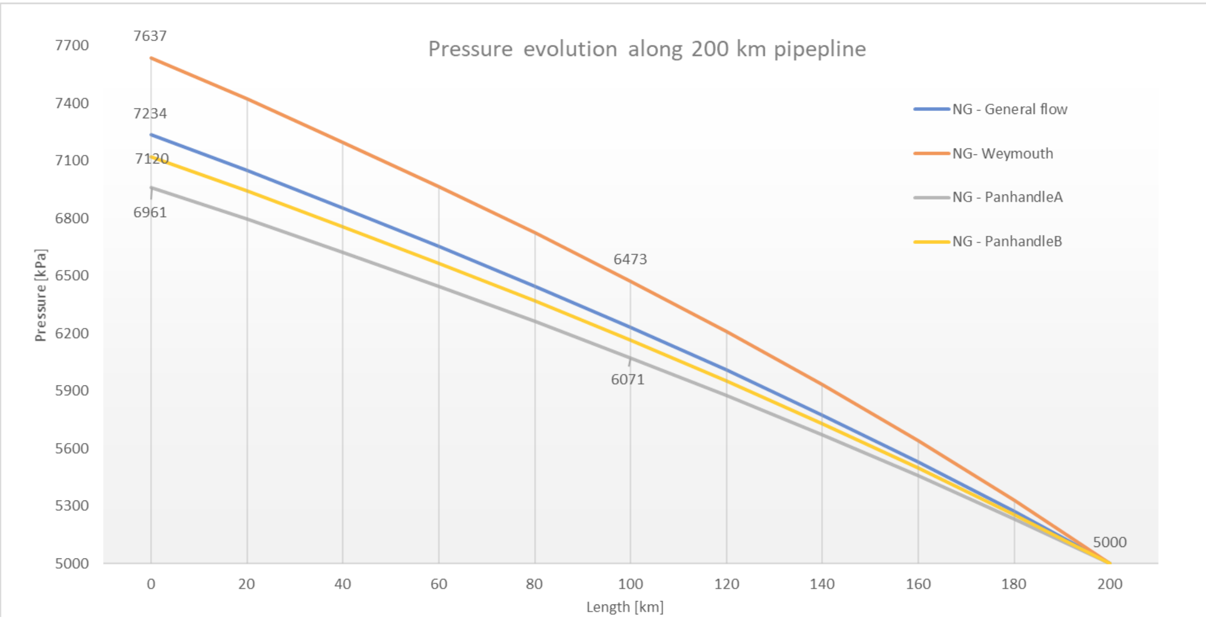


Figure 23 - Pressure evolution (L=200 km - DN = 900 mm - Qvol = 24 MSm3/d)

From the graph it possible to notice the difference between the possible methods, where the Weymouth is the most optimistic while the PanhandleA is the most conservative. The delta pressure at inlet conditions spaces for a 10% percent of the nominal value (ca. 7100 kPa),

Diameter and length variation

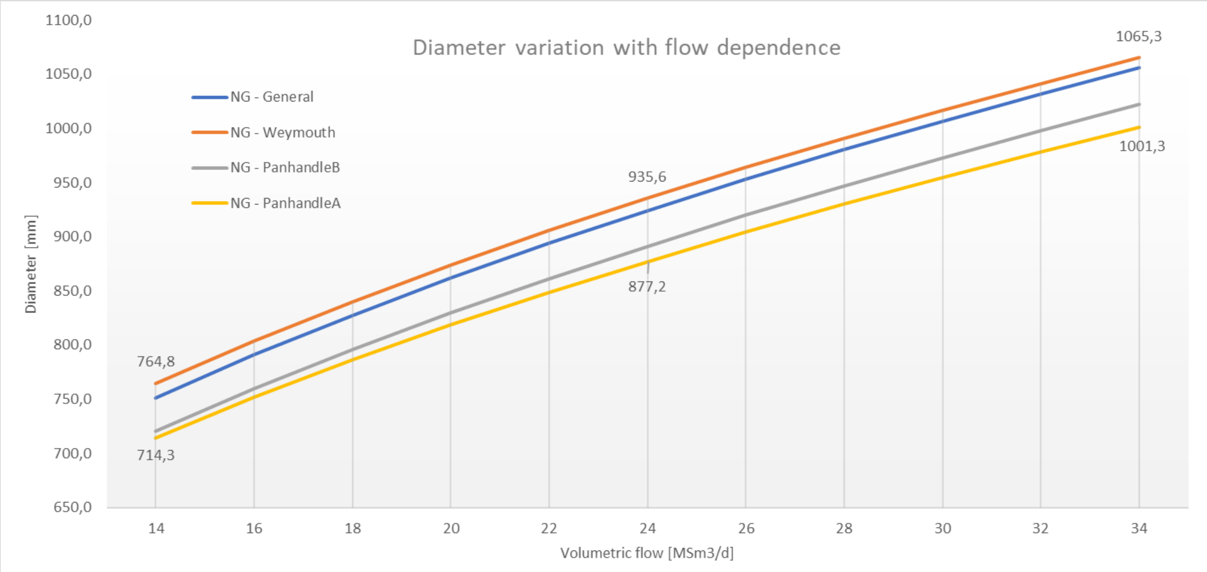


Figure 24 - Diameter trends

The process was carried out also for the pipeline length to evaluate possible distances with the delivery point or between compressor stations.

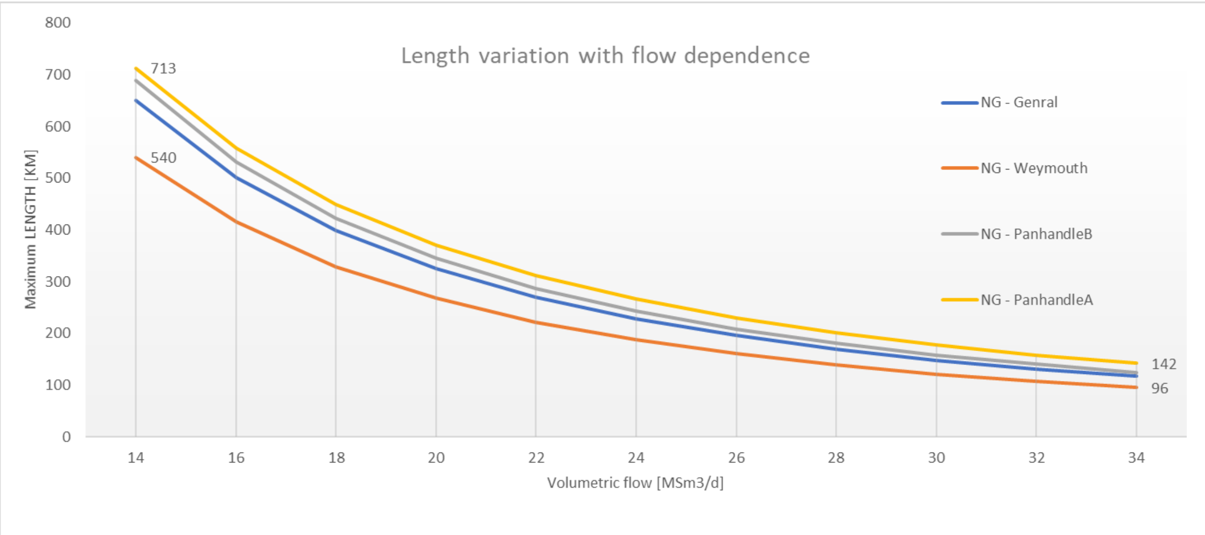


Figure 25 - Pipeline length with volumetric flow variation (DN = 900 mm)

Comparing the equations with same parameters it turns out that the most precautionary is the Weymouth equation, the Colebrook-White lies in the middle and the Panhandle B is the most optimistic one.

Furthermore considering a decrease in the Efficiency parameter (to address temporal perspectives also on the degradation of the pipe) sets initially at 0.92, trends would decrease (except for General method that involves the efficiency factor) are expected and affect the result.

On the Scenario "0" calculation and evaluation parameters have considered just Natural gas (and some possible composition). Moving over, in the next scenarios the calculation methods will be based on the General Flow equation with Colebrook-White friction factor relation since it gives mean values for the variables calculated and it considers the roughness of the pipes.

3. Transition: Natural gas to Hydrogen

One of the main barriers to moving towards a hydrogen economy is the difficulty of developing a reliable and cost-effective hydrogen transportation and delivery system [61]. A gaseous hydrogen delivery pathway includes many components that are already implemented on the Natural gas infrastructure. Hydrogen can take advantage on this infrastructure by being injected into it, the process that involves the mixture of Hydrogen with Natural Gas in a single flow is called "Blending".

Blending hydrogen and methane into pipelines has a long history, dating back even to the origins of today's natural gas system when manufactured gas produced from coal was first piped during the Gaslight era to streetlamps, commercial buildings, and households in the early and mid-1800s. Commonly referred to as "town gas" it typically contained 30% to 50% hydrogen and could be produced from coal, petroleum products and pitch [38].

3.1 Blending: Opportunities and challenges

3.1.1 Facilitating the transition to a hydrogen economy

The 3 million kilometers of natural gas transmission pipelines around the world (with almost 400 *Bcm* of underground storage capacity) could provide a major boost to the development of hydrogen if some of this infrastructure could be used to transport and use hydrogen. Blending just 3% hydrogen in natural gas global demand (around 3900 bcm in 2018) would result in a 12 MtH2 implementation [26].

The blending process would avoid the significant capital costs involved in developing new transmission and distribution infrastructure and it could be a great near-term opportunity spacing many sectors.

The International Energy Agency estimates in 2030 up to 4 Mt of potential hydrogen use for heating buildings that could come from low concentration blending. If low carbon, it could help to reduce emissions [3], with a higher potential in multifamily and commercial buildings particularly in dense cities, where conversion to heat pumps is more challenging than elsewhere. Longer term prospects, instead, will depend on infrastructure upgrades and on measures to address safety concerns and provide public reassurance relying on the use of hydrogen in boilers and fuel cells.

3.1.2 Scalability for green hydrogen demand

Current hydrogen strategies focus on the possibility to storing and delivering renewable energy to markets by blending low concentrations of hydrogen (5%-15%). [38]

Renewable energy sources such as solar, biomass, wind have the potential to significantly reduce greenhouse gas emissions related to the passage from natural gas to blending mixtures. Any social or environmental benefits associated with sustainable hydrogen pathways could arguably be attributed to natural gas with a hydrogen blend component in proportion to the hydrogen concentration [38]. Moreover, the bond between low-carbon hydrogen production and the possibility of blending can carry a drop down on capital costs of these technologies.

3.1.3 Flexibility in hydrogen production and injection

Hydrogen production would be enhanced by the possibility of injecting energy on an already built infrastructure, allowing to deliver surplus energy without onerous storages.

Decentralization h2 production

Decentralized hydrogen production could overcome many of the infrastructural barriers facing a transition to hydrogen, many studies [33, 38] are on support to this with decentralized hydrogen production that could encompasses the on-site production of hydrogen by means of reforming or electrolysis, or the on-board production of hydrogen in fuel cell vehicles. The existing natural-gas and electricity infrastructures can then be used to power the hydrogen production units.

3.1.4 Lower volumetric energy density

One of the most criticized features to overcome when comparing hydrogen and methane is the volumetric energy density, where hydrogen energy density is about a third of that of natural gas (3.4 kWh/Sm3 and 10.5 kWh/Sm3 respectively). Therefore, a blend of the two gases reduces the energy content of the delivered gas mixture. End users would need to use greater gas volumes to meet the same energy need.

Nevertheless, it is important to distinguish percentage in relation with respect to volume or energy content, blending usually refers to H2 volumetric values that result in a less energy percentages (e.g. 15% of H2 volume represents 10% less energy for the delivered gas).

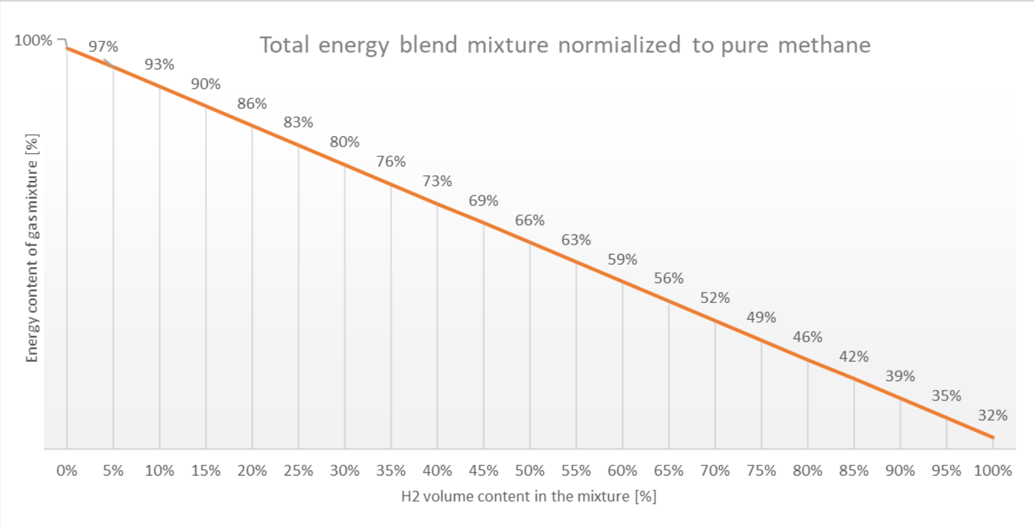


Figure 26 - Energy content vs Volumetric content of blending mixtures

3.1.5 Development of legislations and specific markets

Currently the blending permitted in many jurisdictions is very low and it differs from area to area resulting even more difficult where cross-border pipelines exist. The situation clearly set an essential role on standards for the tolerance of appliances and equipment to different blending levels [26].

Policies, even for low blending levels, should support and stimulate a development from gas suppliers to encourage hydrogen equipment production and infrastructure use. Gas Infrastructure Europe (GIE) believes that the future hydrogen regulatory framework, being inspired from the principles underpinning the Internal Energy Market for gas and electricity, should also take into account the development stages and particularities of the hydrogen market [62].

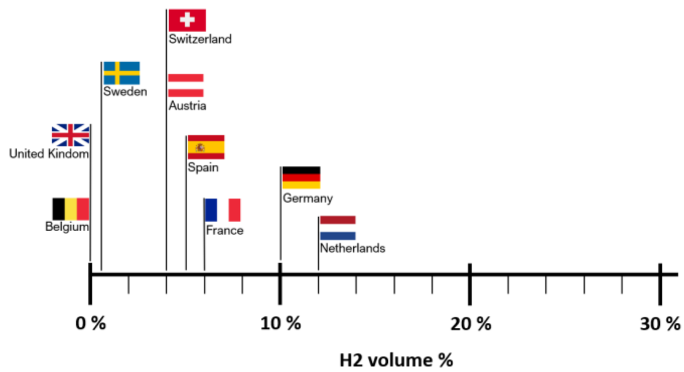


Figure 27 – Limits allowed of hydrogen blending in national gas grids

Blending, in order to become a dependable source of low-carbon hydrogen demand, could be enhanced by setting quotas, emission targets or blend levels for low-carbon gases without neglecting the consumer side that might be affected by the additional costs of the mixing process [26]. Conceivably, a credit trading system in the gas market could apply to natural gas with a specified blend content of green hydrogen, paralleling the renewable energy credit system used in the electricity sector. Economic incentives may rise for converting otherwise curtailed renewable energy to hydrogen, increasing the energy provided from existing renewable energy production facilities, and enhancing the sustainability of the natural gas supply system [38].

A European regulatory framework should be guided by these opportunities to start over a new gas market, with the experience from natural gas sector, setting reference to develop a functioning hydrogen market. Such references include third-party access, unbundling from vertically integrated activities, non-discrimination and transparency rules to guarantee a fair and open competition among all market users. This emerging market could help into building-up the hydrogen infrastructure with a system of regulated tariffs for hydrogen transmission and storage facilities. [62]

3.2 Analysis of methane pipeline preparation for hydrogen transport

Transmission and distribution pipelines were built to optimize the transport of Natural Gas that can vary in a very narrow range of other hydrocarbons and contaminants. In the previous chapter it was illustrated the Natural gas infrastructure with the main focus on transmission pipelines. In this chapter it is illustrated the possibility to widen the implementation of hydrogen along with Natural gas by evaluating the effects on the main components of a transmission network.

The upper limit for hydrogen blending in the grid depends on the equipment connected to it and this would need to be evaluated on a case-by-case basis. **The component with the lowest tolerance will define the tolerance of the overall network** [26].

3.2.1 Structural pipeline integrity

In terms of impact on structural integrity hydrogen can accelerate pipe degradation through a process known as hydrogen embrittlement, whereby hydrogen induces cracks in the steel and reduce ductility. Studies show that hydrogen embrittlement, by accelerating propagation of cracks, shorten the pipeline's service life by 20% to 50% [63]. Nevertheless, this problem of hydrogen is mainly constrained due to its atomic form. Atomic hydrogen can enter the pipe crystalline structure and combine with carbons to form pockets of hydrocarbons creating internal stresses in the material that cause fractures or cracks. The atomization process, together with the ionization process, is carried out through chemical reactions that occur when hydrogen is exposed to natural gas contaminants such as water and/or phosphorous.

It should be considered that hydrogen atomization, together with the presence of high contaminants percentage, are not the only factor that have to occur simultaneously to trigger hydrogen embrittlement. In fact, pipeline has to already present some fractures in order to accelerate the process and that is also subjected to dynamic stresses due to fluctuating internal pressures, while is less likely to have high load variation, especially for transmission pipelines [63].

The majority of transmission pipelines are made of steel but not every type of steel reacts equally on the embrittlement process. High strength steels are more susceptible to failures, considering the API 5L, the grades X60 and above are considered more vulnerable to hydrogen. ASME B31.12, the code relative to hydrogen pipelines, set thickness penalties on high strength steels but usually low carbon steel alloys are employed in the majority of transmission pipelines where hydrogen embrittlement might be contained.

If not the case, a range of solutions already tested to combat H2 embrittlement include [64]:

- Applying inner coating to chemically protect the steel layer;
- Pigging (monitoring) of pipes to regularly check crack widths;
- Operational strategies such as keeping pressures steady to prevent initial crack formation;
- Using lower-grade steel (more ductile steel) by replacing strategic pipes.

The optimal solution varies per pipeline as it depends on transport capacity requirements, status of existing pipelines, and trade-offs between capital and operating expenditure. In addition to the sensitivity of hydrogen embrittlement depending on steel types, other factors that affect the process are [33]:

- Diameter: the regional networks with smaller steel diameters with a low yield strength are, on initial examination, less sensitive to hydrogen embrittlement than some large transmission backbones, which may be made of technologically advanced steels;
- The year and the method of the tube's manufacture;
- The purity of the steels in which sulphur/phosphor compounds are present;

- Features arising from welding procedures (affecting also hydrogen permeation);
- The composition of the gas (in storage, the gas may contain hydrogen sulphide or water in places);
- Operating conditions, especially high pressure, strain amplitude and pressure variation frequency

In any case pipeline repairs should be avoided when hydrogen mixtures are present, generally no cold working of piping exposed to hydrogen should be carried out [65].

3.2.2 Permeation in pipelines

Hydrogen is more mobile than methane in steel and also in many polymer materials.

Fugitive emissions by leakage strongly depend on the pipe material employed. Considering leakages in steel and ductile iron systems, they mainly occur through threads or mechanical joints while for polyethylene (PE) most gas loss would occur through the pipe wall, rather than through joints. The assessment has also to contextualized with the bond between materials and their applications that affect pipe characteristics (Diameter, thickness and joints position).

Gas Technology Institute (GTI) suggest that for steel and ductile iron gas distribution systems (including seals and joints) the volume leakage rate for hydrogen is about a triple than that for natural gas for transmission, further increase in leakages rate are present in distribution networks where plastic materials are used [38].

For blending mixtures, however, a complex relation links the fugitive rate percentages between hydrogen and methane, where hydrogen is likely to present higher leakage rate [66]. Calculations carried out by National Renewable Energy Laboratory (NREL) estimates that, for a 20% blending in PE pipes, 60% of the losses would be from hydrogen and 40% from natural gas.

In absolute quantities hydrogen blends would slightly reduce natural gas leakage due to the higher mobility of hydrogen molecules, resulting in a net reduction in the greenhouse gas impact due to leakage. It remains crucial, though, that further investigation and additional empirical data would be provided for more accurate gas loss estimates associated with hydrogen blends.

3.2.3 Blending measurements through the network

The introduction of blending would have an impact on the equipment of the gas network too. If the integrity of the components could be guaranteed the same does not apply automatically to the measurement and the quality of the gas. Injecting a relative huge amount of a new component in the natural gas mixture might affect how quantity and quality measurements are carried out. Taking as example the most employed method, the orifice meter, there might be some problems due to the low density and high sound speed of hydrogen that would require smaller diameter ratios (large area change) to be effective [65].

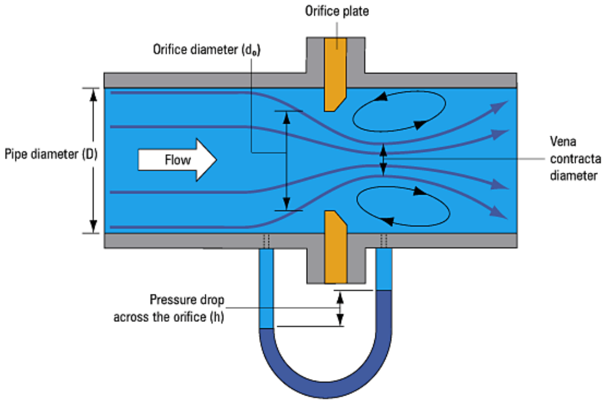


Figure 28 - Orifice meter

3.2.4 Risk assessment

Failures in high pressure pipelines often result in large jets in open air: Hydrogen can spontaneously combust or auto-ignite at pipeline conditions [65]. Moreover hydrogen burns much faster than methane. This increases the risk of flames spreading. A hydrogen flame is also not very bright when burning [26]. New flame detectors and safer fire protection would probably be needed for high-blending ratios.

On the basis of occurring accidences, when natural gas leaks result in explosions, inclusion of 20% or less hydrogen would result in minor increases in the severity of the explosion.

3.2.4.1 Risk from transmission pipelines

$$Risk = Pipeline\ failure\ frequency\ \cdot Ignition\ probability \cdot Fire\ consequence \qquad (3.1)$$

This risk can be estimated on an individual or societal basis. When defined as an individual risk, the result is the likelihood of a person becoming a fatality in a year. Historically for transmission pipelines, the risk factor is dominated by the rupture of the pipeline [67].

Compared to natural gas transmission pipeline explosions, there is a consistent tendency for the severity of the risk with hydrogen mixtures to shift spatially, increasing closer to the point of explosion and decreasing further from the point of explosion. The risk associated with explosion of a natural gas pipeline drops to zero at just over 400 m from the pipeline. However, adding 25% hydrogen decreases this distance by about 25 m while slightly increasing risk closer to the pipeline.

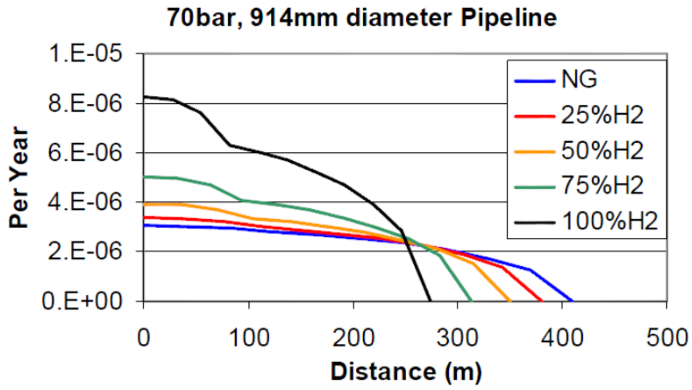


Figure 29 - Risk to an individual per year as a function of distance from the pipeline

3.2.5 Injection points and pipelines requirements

Blending process should be followed by a meticulous control of the pipeline exposed to hydrogen, in particular focusing on injection and extraction points of hydrogen where physically are the strategic points that control the maximum allowable hydrogen percentage.

Hydrogen should be compressed at compatible pressure with NG pipelines before being injected. PEM electrolyzers could be an advantageous production method to couple since allow higher pressures output.

Nevertheless, it has to be considered that hydrogen injection is not feasible if a proper pre-mixing process with natural gas is not carried out first. Ongoing research is focusing on the development of suitable reactors that will be able to handle different hydrogen quantities but keeping constant the desired hydrogen blending percentage in the pipeline, minimizing pipeline integrity risks.

Hydrogen injection is also delicate in relation with mercaptans, the odorants employed in natural gas and analysis on the allowable odorant percentage should be performed especially before entering into the distribution network [38].

3.2.6 Compressor station

Compressor station represent one of the challenges for hydrogen transport. Changes in the transported medium affect compression system parameters such as compressor capacity and distance between stations.

Since the volumetric energy density of hydrogen is a factor of three times lower than that of natural gas, to provide the same energetic content, the volume of hydrogen transported must be three times greater and therefore increasing threefold the compressor capacity. Moreover, due to its lower molar mass (larger volume flow) greater efforts for compression are to be expected with hydrogen. Impacts of the suitability of existing compressor types varies amongst transmission system operators and compressor design [64].

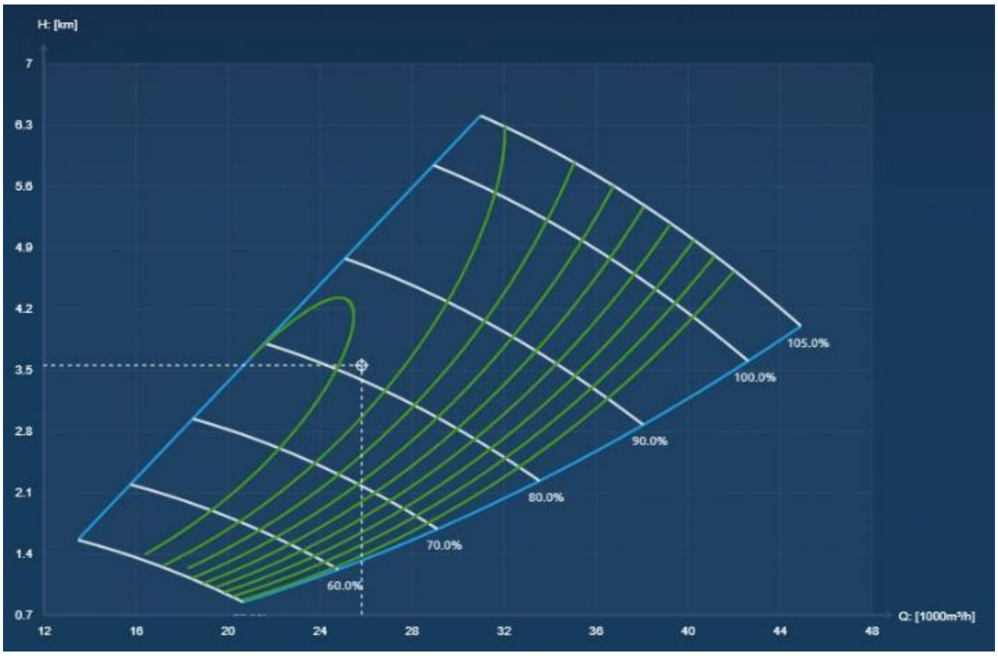


Figure 30 - Typical operative point for a transmission compressor

Compressor design from natural gas transmission pipelines can easily cover cases with hydrogen up to 20%, if the pipeline is operated at constant standard flow rates. Consequently, existing compression equipment can cope with new mixture without any modification.

If it is kept constant energy flow the increase of hydrogen in the mixture would result in out of scale operative points. At 10% hydrogen content, the operative point has already moved outside the compressor map. Performance trends show that for a constant volumetric energy capacity the relative power should increase by a factor of 1.7 for a 20% blend hydrogen [68].

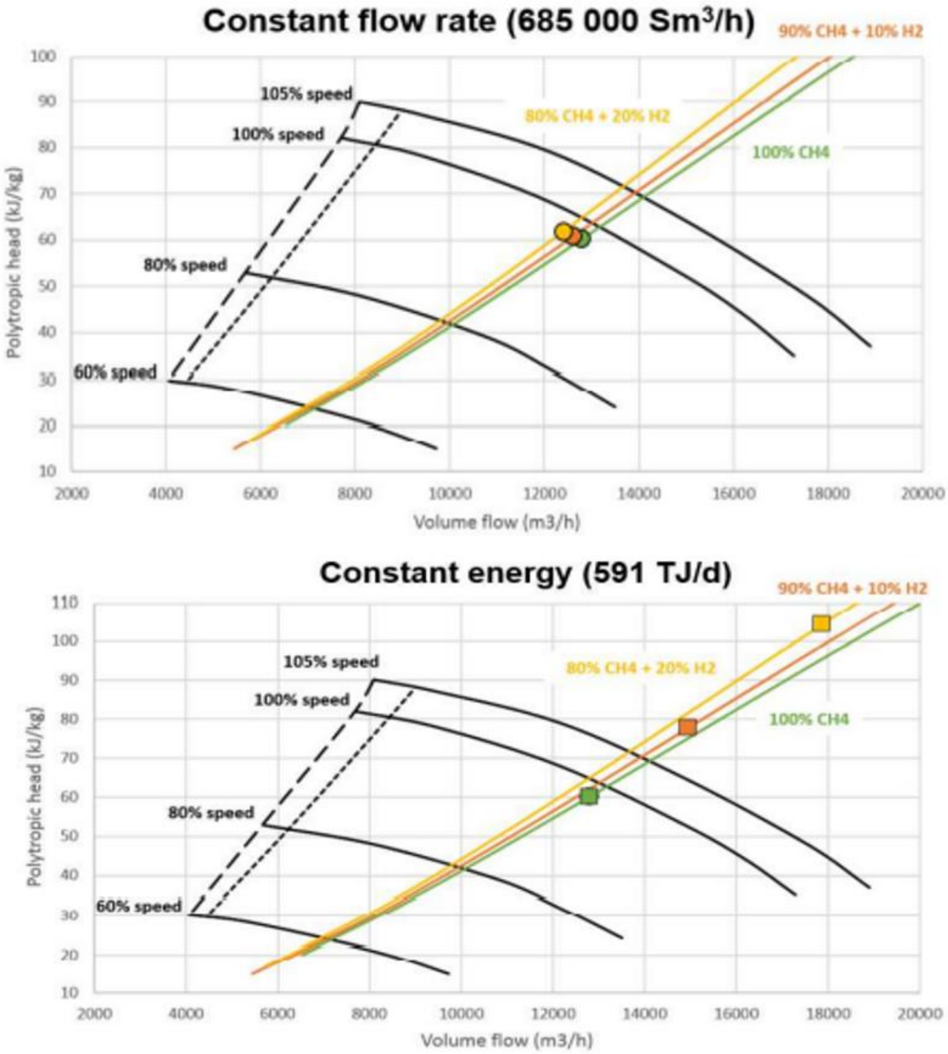


Figure 31 - Operative point for different hydrogen blending mixtures

Prospective on compressor stations will depend on the intention of the gas operator whatever is the injected content of hydrogen: constant gas flow rate or constant energy capacity or a trade-off between them.

3.2.6.1 Energy consumption: Turbines

Most existing gas turbine designs can already handle a hydrogen share of 3–5% and some can handle shares of 30% or higher [26]. The industry sector is confident that it will be able to provide standard turbines that are able to run entirely on hydrogen by 2030 [69].

Recently Baker Hughes, in collaboration with SNAM, successfully tested the first "hybrid" turbine for gas transmission applications, the "NovaLT12" is a gas turbine with 17.5 MW at the shaft and it is able to operate with 10% of hydrogen blending [70].

3.2.6.2 Seals and materials

Due to the hydrogen lower size, seals and materials might be source of hydrogen leakages but it largely depends on the blending percentages [65]:

- Dry gas seals are typically compatible with up to 20% hydrogen blends, even though O&M varication are still recommended
- O-rings are typically made of hydrogen compatible materials such as FKM (Viton)
- Shaft seals made of PEEK or PTFE are usually compatible with hydrogen

API 717 recommended the employment of materials with a maximum of 827 MPa for use in H2 gas transmission service with a high percentage of blend where is more likely the partial pressure of hydrogen exceeds 0,689 MPa. Impeller and shaft are usually made of low yield strength carbon steel and low hydrogen concentrations (or at low pressures) may not be a concern.

3.2.7 Storage facilities

As discussed in the previous chapter, storage facilities are an essential part for a gas transmission network, understanding if blending mixtures are suitable for gas network storage is vital for the future deployment of hydrogen. Possibility to implement gas storage facilities with hydrogen usage represents a key-enabler that will allow to store large quantities of energy from different energy sources thanks to power to gas systems minimizing energy losses during storage.

Hydrogen storage assets will facilitate the interlinkage between electricity and hydrogen markets and provide the flexibility needed to balance the entire energy system on short-term and seasonal timescales. Blending hydrogen and NG into storage facilities of transmission networks would help to achieve flexibility sooner. Gas storages can contribute to short-term flexibility needs that will increase in the coming decades and could have a theoretical storage capacity potential of 60 TWh hydrogen already today [71].

In order to evaluate storage facilities the assessment has to be based on the type of storage; depleted gas fields, aquifers and salt caverns.

For depleted gas fields blending mixtures up to 10% of hydrogen has already been successfully tested on existing facilities without any negative influence on safety [72].

For Saline Aquifer studies show that one well can inject and reproduce enough hydrogen in a saline aquifer, porous rock storage sites and aquifers can be retrofitted to blend hydrogen with natural gas, however limitation in blending percentage could limit the employment of this storage type due to stability and integrity of the overlying seal and the reactivity of the hydrogen with aquifer components [73]. Additionally, cushion gas plays an important role and its injection in saline aquifers that is dominated by brine displacement and accompanied by high pressures.

While hydrogen storage in porous rocks (aquifers and gas fields) is subject to additional research and pilot projects are currently investigated by storage operators [62], Hydrogen storage in salt caverns is already a proven technology with several sites in the North of England and in the United States [74, 75].

In the European Union around 50 salt caverns are currently used for natural gas storage with a storage volume of more than 180 TWh [62]. For the underground storage of chemical energy carriers such as hydrogen, salt caverns offer the most hopeful option owing to their low investment cost, high sealing potential and low cushion gas requirement [44]. The viscoelastic properties of evaporitic rocks ensure the seal and mechanical stability of the salt caverns, making the operation (injection-extraction) flexible and appropriated for medium and even short-term storage.

Moreover, the high saline environment prevents the icrobial consumption of H2. However, salt caverns are relatively small, up to few millions of m3, and are not as wide spread as porous formations, at least those formations with sufficient thickness. [73]

It is not be underestimated, though, the consequences of the hydrogen admixture on the integrity equipment of the storage facilities (e.g. seals and components installed, compatibility of identified materials) that should be carefully assessed before injection.

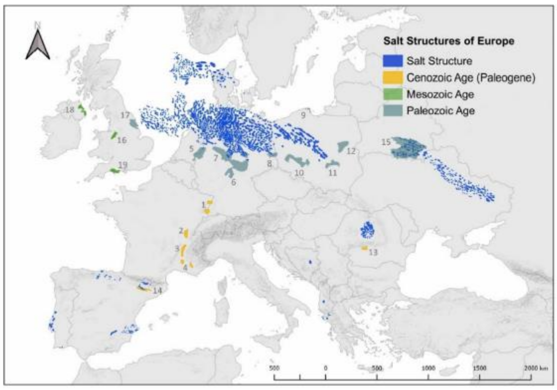


Figure 32 - Salt cavern locations in Europe

3.2.7.1 Pipeline storage of hydrogen

Energy stored in hydrogen form could have the advantage to be injected directly into the natural gas pipelines without the underground storage. The NG network plays the role not only as the transporting system but also as a permanent storage of a fixed mass of hydrogen. So the linepack from NG to hydrogen is largely affected by the low hydrogen volumetric energy density and the ratio of the two linepack is given just by the ratio of the two volumetric energy density resulting in one third for the hydrogen linepack.

3.2.8 Valves

Transmission pipelines include many valves along their length. These valve placements depend on location and spacing typically range from 8-30 km [64]. For gateways valves the correct operation is affected by seals and materials in relation with hydrogen while blowdown valves may present issues with their silencer. Higher flow velocities implied by hydrogen injection might induce inadequacy in the nominal perform of blowdown systems due to relative undersize. Furthermore, blowdown time tends to decrease when operating with lighter gas. [65]

3.2.9 Inspections and pipeline pigging

There are two requirements for inspection. The first is to assess the current integrity o f a line in readiness for hydrogen and the second is to inspect while in service.

Pigging will play a crucial role for blending process. They will have the function to assure a "readiness" and a proper suitability for pipelines and analysed eventual unpleasant condition that might compromise blending and pipeline integrity. It will be more crucial that each pipeline will be subjected specific risk assessments to identify potential hazards and to have the necessary mitigations in place prior to commencement of pigging operation.

For such services, pipelines rely on In-Line Inspection (ILI) technologies [76]. Nowadays it exists a large variety of them and these can be group into the following;

- High resolution deformation (DEF) - Provides a measurement of the changes of the inner pipeline bore for dents, wrinkles, ripples, expansions.
- High field axial magnetic flux leakage (MFL) - Detects volumetric metal loss, mill anomalies and extra metal, and has a strength in detecting wide features.
- Low field axial magnetic flux leakage (LFM) - Identifies magnetic permeability changes in the steel microstructure due to mechanical working and heating /cooling.

- Helical/spiral magnetic flux leakage (SMFL) - Provides inspection of the longitudinal pipe axis, including weld seams, and detection of other longitudinally oriented anomalies.
- Electromagnetic acoustic transducer (EMAT) - Identifies cracks.
- Ultrasonic wall measurement. (UTWM) - Identifies wall loss and other mid-wall defects (e.g. laminations). It requires a liquid product.
- Ultrasonic crack detection (UTCD) - Identifies cracks features and requires a liquid product.
- XYZ mapping using an inertial measurement unit (IMU). Provides high resolution pipe centreline trajectory as well as intentional bends as well as strain and line movement.

To minimize the number of runs, to ensure the best alignment and to benefit from assessing interacting threats, a single tool would be preferred referring to it as a multiple dataset (MDS) tool. For a gas line conversion, a combination of DEF, MFL, LFM, SMFL and XYZ can be achieved and then contrasted with EMAT. By combining the two tools, it is possible to better characterize true cracks from crack-like features and hence better prioritize any defects for remedial action prior to hydrogen service.

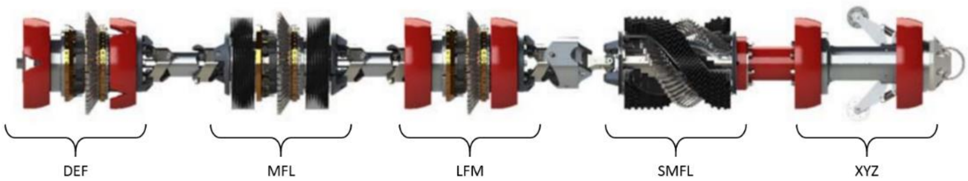


Figure 33 - Combination tool for gas line conversion

Figure 34 - EMAT tool for detection of cracks

Once the pipeline enters in service, conditions for inspection tools change when hydrogen is used. Since ILI tools will have more components exposed to the inner environment of the pipeline, PIGs should be equipped with "hydrogen-friendly" materials or redesign of new material assemblies to prevent hydrogen intrusion. Magnetic components are extremely sensitive to hydrogen and an exposure could mean the disruption of the material [76].

Figure 35 - Magnetic components before and after exposure to hydrogen

EIGA suggests a selection of pig type, including foam, disc, cup, wire brush, scraper and gauging, and states that, in general, pigs will be fabricated from materials that are compatible with hydrogen [77].

It is clear there are some issues with current pigs, but they are not unsurmountable. Simple changes can be made to use current technology without a huge investment.

3.2.10 Gas analysis and Metering station

In metering station, gas chromatography is the most common method for gas analysis in pipeline networks.

Gas chromatograph (GC) provide an analysis of the flowing gas and calculating the physical properties used for the flow calculations and for custody transfer. It is an analytical instrument that measures the content of various components in a sample by utilizing helium as inert gas [78]. When blending is taking into account, inert gases such as nitrogen and Argon are considered a more reliable option Orifice and Coriolis are less likely to lose accuracy if hydrogen concentration fluctuates. [65]

Other components, such as ultrasonic meter sensors, could be threatened by hydrogen due to their employment of high hardness material (e.g. titanium), lubricants and sealants [65].

3.2.10.1 Pressure regulation station

In pressure regulation station it should be considered the impact on the Joule Thomson coefficient when hydrogen is introduced.

Contrary on methane, hydrogen has a negative Joule-Thomson coefficient, about -0.035 Bar/°C, in the operative range considered. Therefore, blended hydrogen can exert major impacts on the Joule–Thomson (J–T) effect of natural gas.

Recent studies [79] show that the J–T coefficient of the natural gas–hydrogen mixture decreases approximately linearly with the increase of the hydrogen blending ratio, the analysis were carried out till blending concentrations of 30%, consisting of the fact that higher hydrogen percentage are not consider feasible yet.

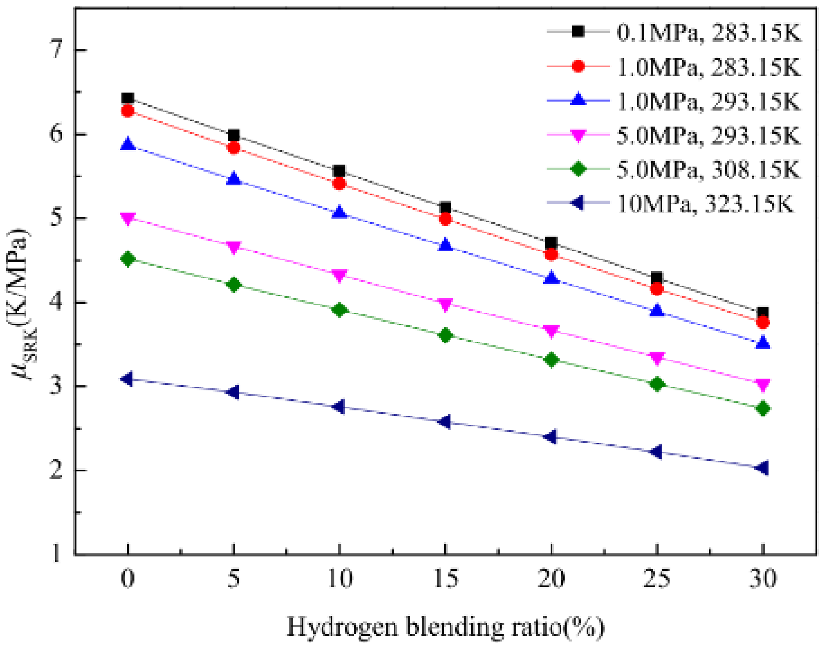


Figure 36 - Variation in the JT coefficient for different blending mixtures

Pressure regulation will require a stringent control and simultaneous calibration on the heating process involved.

3.3 Capacity % executed in gas networks

The maximum allowable hydrogen concentration depends mainly on pressure fluctuations, structure and existing defects. However, widespread knowledge to date indicates that, for some grid sections, certain blending percentages (e.g. 2%–10% in volumetric terms) are technically feasible with few adaptations in some Member States.

At the end of 2019 SNAM carried out a successful hydrogen injection of 10% inside the gas grid. Several studies were investigated to safely carry the experiment also in relation with the absence of hydrogen in the Italian Decree for Natural gas Transmission. This led to the evaluation on relative density and Wobbe index to ensure compliance with the Decree. The operation involved a decompression to few bars to mix hydrogen and NG, initially the experiment have involved at 5% hydrogen mixture and then it was successfully tested 10%.

For upper percentages additional tests are needed, some operators consider 20% the upper bound due in particular to the requirements for downstream users to be adapted beyond this value. [74]

3.4 Hydrogen deblending

Hydrogen deblending is the reverse process of blending and allows to extract pure hydrogen for dedicated uses (e.g. hydrogen fuel cells, feedstock) and simultaneously hydrogen-free Natural Gas.

Most of the deblending technologies are currently under development and still in R&D analysis. Nevertheless, different methodologies exist to carry out the process, pressure swing adsorption, membranes and sieves are the most encouraging ones. The deblending effectiveness depends on the hydrogen concentration in methane but several other important factors have to be considered when choosing the most suitable technology, such as permeability, selectivity, stability of the membrane material, effects of discontinuous operation on the operation, design of the membrane plant, effects of different hydrogen concentration on the separation process [74].

3.4.1 Methane-Hydrogen separation technologies

	PSA	**Membranes (organic)**	**Cryogenic separation**
Produced H2			
Purity (%vol.)	Up to 99.9999%	Up to 99.9%	Up to 99%
Hydrogen flow rate (Nm3/h)	100 - 100 000	100 - 100 000	5000 – 110 000
Possibility to increase capacity	Possible	Easy	Possible
Feed gas			
Min. H2 content (% vol.)	50	15	15
Operative pressure (bar)	5 - 45	Up to 150	10 - up to 120
Performances			
H2 recovery field (%)	50 - 95	Up to 98	Up to 98
Yield dependence to tail gas pressure	High	No	Some
Pressure drop between feed and H2	< 1 bar	High	2 bar

Table 12 - Deblending technologies [77]

3.4.1.1 Pressure Swing Adsorption (PSA)

Pressure swing adsorption (PSA) is an adsorption-based process used to separate gas species from a mixture of gases under pressure according to the species' molecular characteristics and affinity for an adsorbent material. It has been used for various gas separation and purification purposes where its performance depends on the ability and selectivity of the adsorbents.

PSA units are already employed in Steam Reforming, but their usage could be wide to hydrogen deblending processes. PSA unit's operation at low hydrogen concentrations, such as 20% mixtures, are feasible but are liable to impurities in the gas. With low hydrogen concentrations, the PSA units become very large. PSA units appear to be economically practical only at pipeline pressure regulation stations where the pressure drop is synergistic with hydrogen separation. Without this dropin pressure, uneconomically large amounts of compression energy and compressor capital would be needed to reinject hydrogen-depleted gas back into a pipeline [38].

3.4.1.2 Membrane technology

Membrane technology seems to be more suitable for transmission pipelines since high pressure would enhance the separation with a sufficient driving force for hydrogen extraction. Moreover, in such systems, the bulk of the process gas retains its pressure and only a small amount of re-pressurization would be required to compensate for any device pressure drop [38]. Two kind of membranes are currently large investigated:

Palladium membranes

Palladium membranes are the most used technology to recover hydrogen from gas streams with a low hydrogen concentration (<30%). Palladium membranes can achieve very high hydrogen selectivity (Pd membrane technologies can achieve hydrogen at 99.9999999% purity [38]) but in order for these membranes to function efficiently, the entire gas feed stream must be heated to temperatures higher than 350 °C. This temperature requirement increases the cost and energy input. Possible future employments would hardly pair with transmission networks.

Carbon-based membranes

Carbon-based membranes are able to separate hydrogen at lower or ambient temperature, however the efficiency with respect to flux and selectivity vary depending on temperature and pressure.

Carbon molecular sieves are formed by carbonization (pyrolysis) of a polymeric precursor at temperatures between 400 and 800 °C. This is usually preformed under vacuum or an inert gas such as nitrogen using cellulose derived from plentiful wood pulp which is cheap and abundant. Periodical regeneration of carbon membranes can recover hydrogen permeation properties and is beneficial to improve long-term performance of the membranes. A regeneration technique that can be applied on-stream while the membrane is in operation has been developed. Results from NREL [38] indicate that the CMS sieves can effectively recover hydrogen from the pipeline networks that transport hydrogen/natural gas blends providing greater permeability and better selectivity (up to 98%) than conventional polymer membranes with more affordable operative temperatures (30-90 °C).

3.5 Blending economics

Injecting hydrogen into natural gas grid avoids costs for a new pipeline infrastructure but consequently introduces costs on the retrofitting process, necessary to assure and optimize a proper operative gas mixture. On the consumer side, clients would face a new gas mixture with a less quality on the energy side that might rise consumer costs.

Blending hydrogen can create dependable demand for hydrogen through its early deployment phase but managing the cost impacts is a key challenge for policy makers. Re-using natural gas infrastructure is a more economical alternative but not costless and neither without any risk. Governments could play a supporting role by mitigating risk [26], as they could reduce the risks associated with investment in new hydrogen supplies for blending into the gas grid by clarifying market and technical conditions. The issues that need clarifying include conditions relating to third-party access, regulated returns for system operators, and consumer protection. Tariffs on the transmission line should be developed assuring feasible investments on injecting hydrogen into the infrastructure. Moreover, in the last quarter of 2021, gas prices in Europe have been at the center of many attention due to their high volatility, blending natural gas with hydrogen produced locally could smooth price fluctuation of Natural Gas.

Gas tariffs with hydrogen percentages might have environmental incentives and thus reducing costs by avoiding emissions. Contrary it would be counterproductive if low-carbon hydrogen production methods are not implemented. Currently hydrogen is mainly produced by steam reforming, that is methane and blending grey hydrogen with methane would result in higher pollutant mixture.

On the other hand tariffs should account higher operational costs due to, for example, from compressor station where higher pressure gaps and/or larger flow capacity would rise fixed and variable (electricity) costs.

If it is estimated an overall increase in costs by around 0.3-04 $/kgH2 by hydrogen blending, it has to consider that consequently a scale-up process would occur. If the majority of hydrogen would come from electrolyzers, it could deliver around a significant reduction in the capital cost of electrolyzers and thus a reduction of hydrogen cost. [26]

On the consumer side, however, this could potentially have a major impact on the costs of hydrogen supply technologies in the short term that would add around 3–15% to natural gas consumer costs [26]. Many markets are currently close to the tipping point between gas and electricity prices that could trigger a switch to higher-performance heat pump technologies. Increases in gas prices resulting from blending mandates or incentives would risk losing gas customers, something to be considered in policy design.

Hydrogen deblending

The cost of these technologies and the need to recompress natural gas once the hydrogen is extracted currently makes deblending a relatively expensive process. In addition, the contest has to be widened since higher costs come from the blending process in the first place. Technical and economic factors seem to assess the deblending option as a path to take in a long term prospective.

The whole trade-off is subordinate on the percentage of blending hydrogen. Every main aspect, such as technical, economic and environmental are dependent on the hydrogen percentage.

The cost-optimal solution will differ across regions as a result of varying levels of pipeline availability, compression needs, geographical distribution of injection points, internal coating and pressure regulation strategies, parallel piping approach, and regulatory cost recovery frameworks amongst other factors [64]

3.5.1 Prospective

Injection of hydrogen should be assessed by dividing blending mixtures into ranges of hydrogen percentage based on a technical, economical but also temporal evaluation.

European gas operators suggest distinguishing between the following steps with their relative cost predictions:

- 0% to 6% of hydrogen injection; where tests and verification (pipeline integrity through intelligent PIGs) are carried out.
- 6 to 10%; process of contaminants removal should be more severe along with possible internal coating, for this percentage it is required the determination of operative compressor framework
- 10 to 20%; Implements on more sophisticated metering equipment (or less sensitive to hydrogen), and retrofitting on compressors
- 20% and above; replacements equipment for end consumers, both residential and industrial consumer and total replacement of compressors

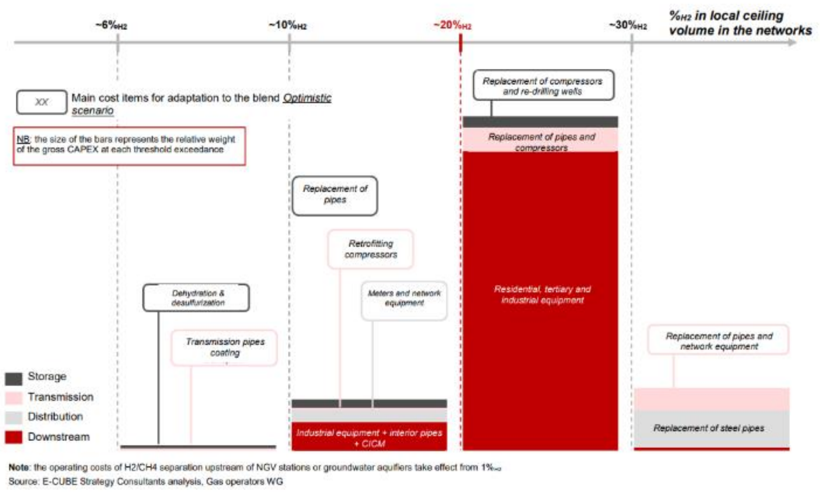


Figure 37 – Summary of the adaptation steps with their Capex [33]

3.6 Scenario “0.x”

In the Scenario 0.x a mixture of hydrogen and methane is assessed to analyse the flow in a pipeline. Considering the topics discussed above it was preferred to narrow the blending analysis till 20% of hydrogen injection. Furthermore, due to the almost absence of testing validation of calculated H2-NG mixture properties that include heavier hydrocarbons and contaminants [65], the blending analysis has been focus on H2-CH4 mixtures and consequently the (pseudo) properties calculated.

3.6.1 Gas properties variation

Thanks to the Webbook Chemistry tool it was possible to evaluate hydrogen and methane properties in the interest range of pressure (4 – 8 MPa at T = 15 °C).

First it is useful to evaluate blending Wobbe Index and HHV in comparison with allowable ranges of these properties.

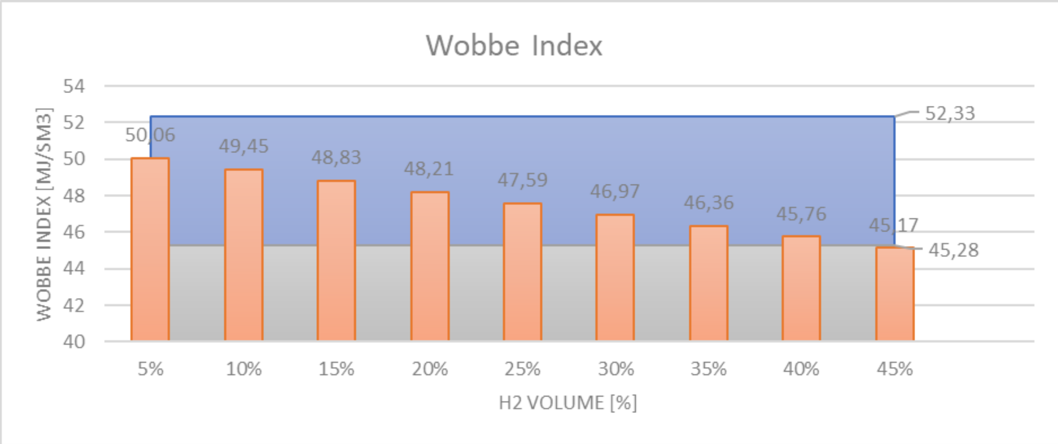


Figure 38 - Wobbe index variation for different blending mixtures

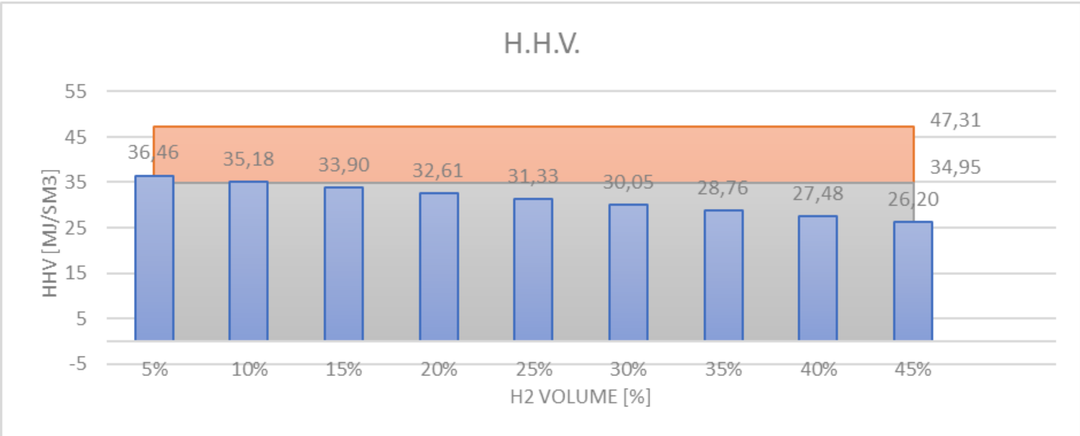


Figure 39 - HHV variation for different blending mixtures

Considering the two parameters, the HHV falls below the range very quickly, after 10% of blending while Wobbe index can count on wider range arriving till 45%.

3.6.2 Pressure evolution

It is calculated how the pressure varies along the pipeline by considering Methane and blending till 30% of hydrogen.

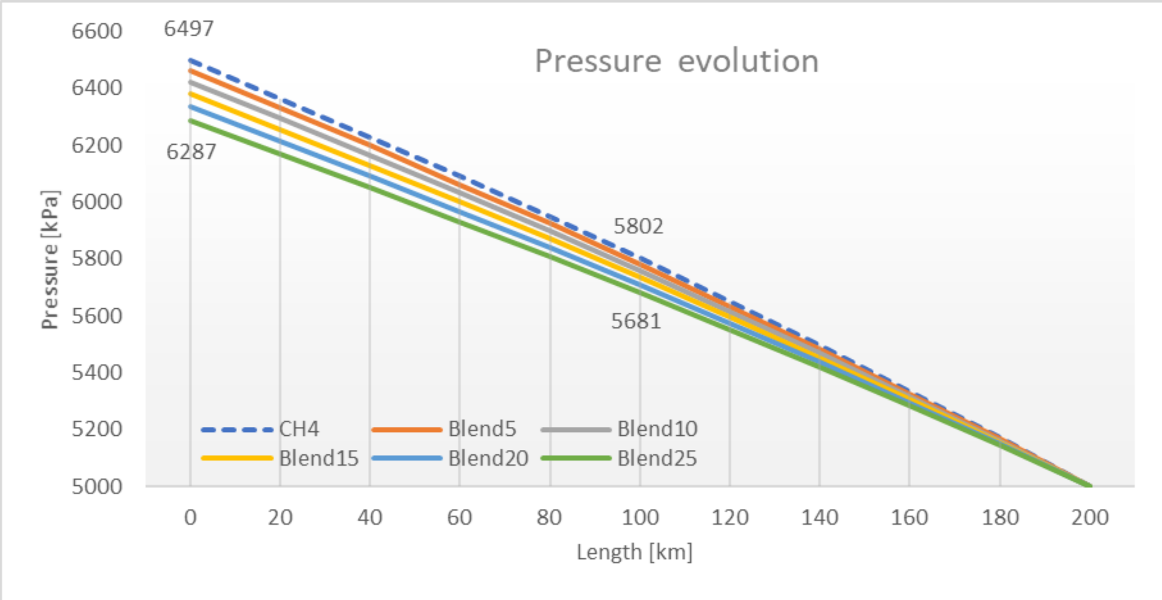


Figure 40 - Pressure evolution Q = 20 Sm3/d DN = 900 mm

For a 5000 kPa of delivery pressure at the same conditions (L = 200 km, DN = 900 mm, Qvol = 20 MScm/d, Tf = 15 °C), introducing a 30% of hydrogen in the gas stream implies a decrease in the upstream pressure of about 200 kPa (ca. 2,5 Bar) from 6497 kPa with a ratio drop of 3.3%.

Decreasing the delivery pressure for about 1000 kPa (New downstream pressure 4000 kPa), involves an greater enlargement in the Delta upstream pressure, of about 253 kPa for a 4.6% (upstream) pressure drop, between methane stream and blend at 25%.

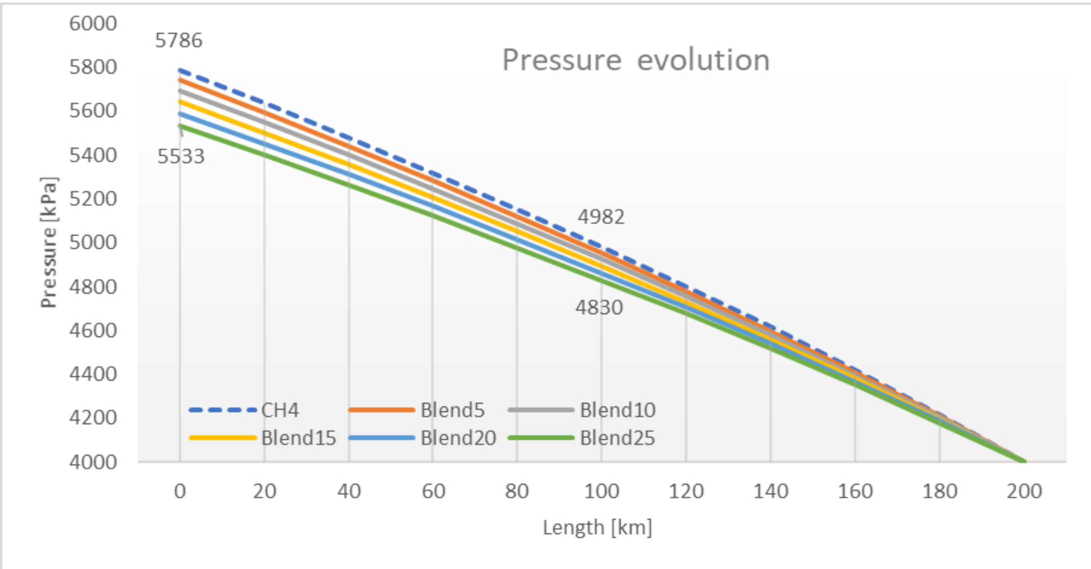


Figure 41 - Pressure evolution at lower downstream pressure

The opposite situation happens if an energetic flow is considered rather than a volumetric one:

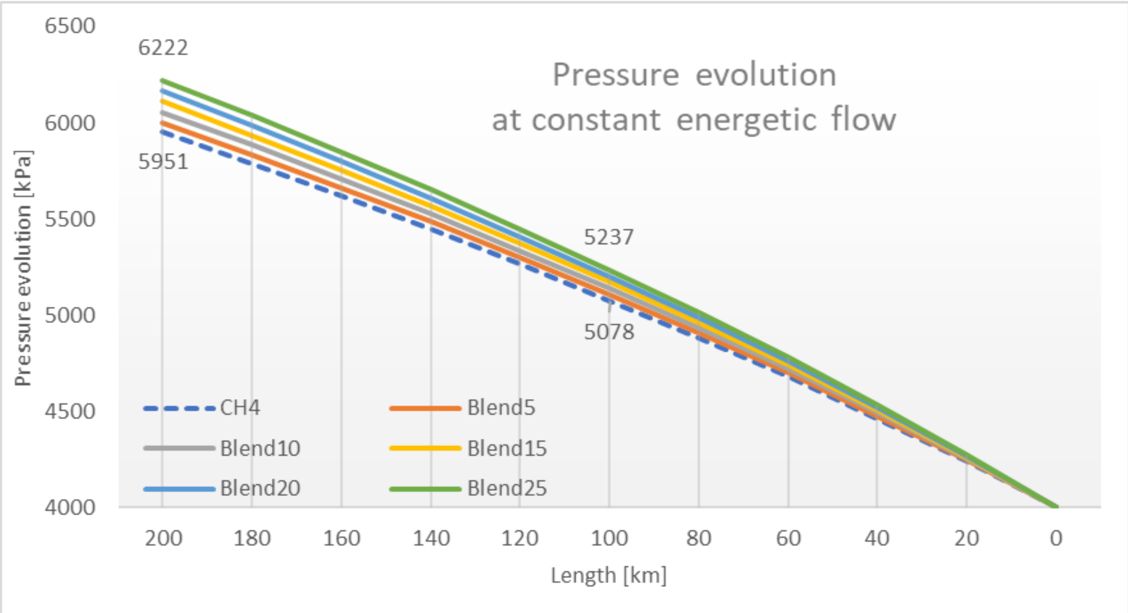


Figure 42 - Pressure evolution at constant energy flow [218 GWh/d]

For the same conditions, except imposing an energetic flow of 218 GWh/d (ca. 746,5 MMBtu – 20 MScmCH4/d), injecting hydrogen into a gas pipelines shifts up the pressure trends, from 5951 kPa to 6222 kPa (increase of 271 kPa - 4.4%). As expected from hydrogen that having a lower volumetric energy density require more pressure to flow the same amount of energy.

Same behavior would have lowering the downstream pressure with the enlargement of the gap.

3.6.3 Volumetric & Energetic flow

Another approach to estimate operational variation with the same technical conditions would be to evaluate the energy stream variation for the same hypothetical pressure gap between upstream and downstream, in the following graph several delta-pressure, ranging from 250 kPa to 2750 kPa, were implemented to evaluate the "energy loss" that would occur if hydrogen is injected.

Considering the standard delta pressure (P1 = 7500 kPa – P2 = 5000 kPa), methane stream would carry 240519 MWh/d while a mixture of 85% methane and 15% hydrogen 222583 MWh/d. This imply that at the same pressure conditions blending lose 7.5% of energy carried by a pure methane stream. The energy ratio also results similar to the other delta pressures calculated attesting itself to 7.6%.

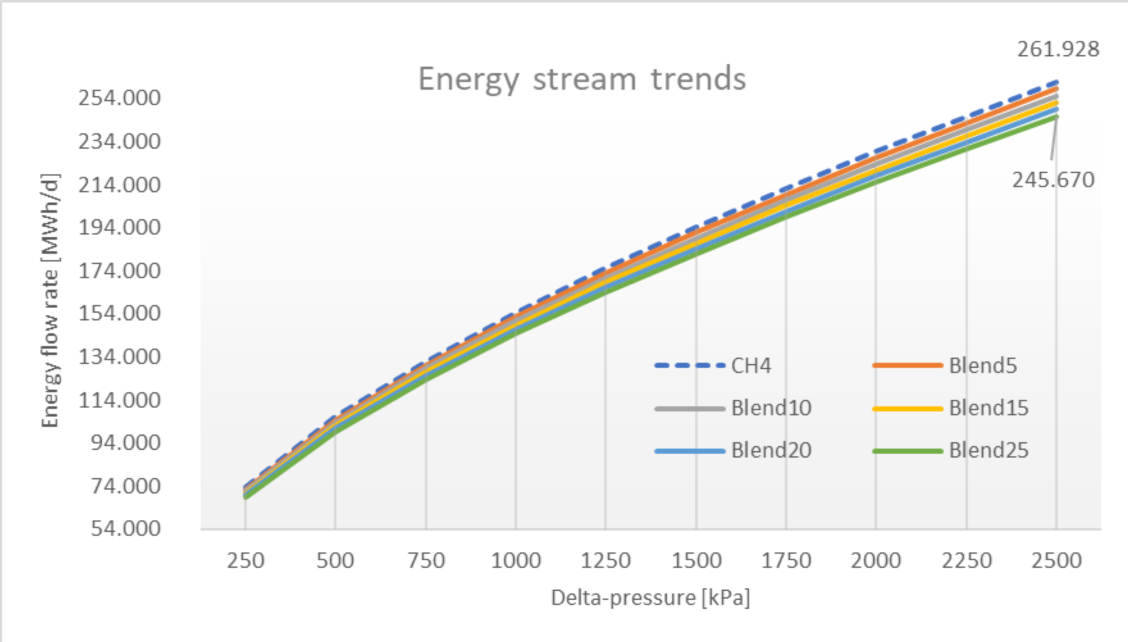


Figure 43 - Energy flow rate with different delta pressure

The following case analyse the energy stream trends again but varying the downstream pressure with a hypothetical constant pressure drop of 2000 kPa.

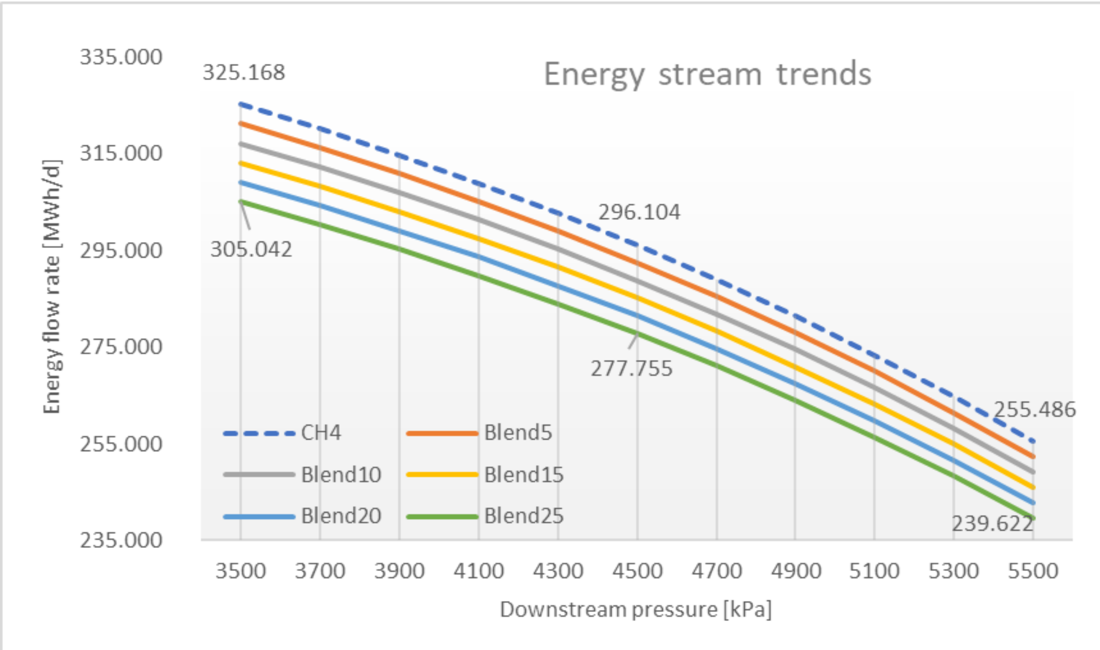


Figure 44 - Energy stream trends varying downstream pressure

The energy loss, resulted in the injection of hydrogen, are approximately in the range of 20 thousand MWh/d (305 GWh/d for the lowest downstream pressure and 240

GWh/d for the highest upstream pressure), the energy loss ratio remains constant across the delivery pressure range considered, about 7.5%.

3.6.4 Velocity calculation for pipeline integrity

In relation with the pipeline integrity, velocity is assessed in the least conservative point, at the outlet of the pipe with respect to the erosional velocity. Since varying the gas properties would result in modifying the erosional velocity itself, initially the reference for erosional velocity is considered with pure methane, hydrogen injection would increase the erosional velocity so considering pure methane for erosional velocity reference is a more conservative scenario.

Erosional velocity analysis	
L	200 km
DN	900 mm
Up. – Downstream pressure	6630 – 5000 kPa
Volumetric flow	20,3 M/d
Erosional velocity	17.6 m/s

Table 13 - Erosional velocity

The erosional velocity (and the highest velocity) depends only on downstream condition, therefore considering variable upstream pressure resulting from hydrogen injection would not affect the comparison.

The table below shows the, for delivery pressures range, the velocities at the downstream. The third column represent the increasement of blending velocities with respect to the nominal velocities of methane in which values are in the range of 7% to 9%. Considering the limits of the erosional velocities, hydrogen accelerates the flow remaining still in acceptable range comparing with the erosional velocities (maximum of 41.4% velocity ratio).

P2	u_e	u_{CH_4}	u 30% H2	Increasement%	$u_{blend}/u_e\%$
3750	23.6	9.1	9.8	6.9%	41.4%
4000	22.8	8.5	9.2	7.1%	40.1%
4250	22.1	8.0	8.6	7.4%	38.9%
4500	21.4	7.5	8.1	7.7%	37.9%
4750	20.8	7.1	7.7	8.0%	36.9%
5000	20.3	6.7	7.3	8.2%	36.0%
5250	19.7	6.4	6.9	8.5%	35.2%
5500	19.2	6.1	6.6	8.8%	34.4%

Table 14 - Erosional velocities for different downstream pressures

3.6.5 Linepack

Linepack analysis passes through the numerical calculation and comparison between Natural Gas, pure methane and blending mixtures. In the linepack formula (2.26) only the compressibility factor is function of the gas employed. Since hydrogen present higher compressibility factor, the volume stored for blending mixtures will be lower at the same operative conditions.

For a pipeline long 200 km with a nominal diameter of 900 mm it is found:

Parameters	Natural Gas	Methane	5% H2	15% H2	25% H2	Units
Pavg	6000	6000	6000	6000	6000	kPa
Zavg	0.87	0.90	0.91	0.92	0.94	-
Linepack	8 452 871	8 136 426	8 064 206	7 938 717	7 834 842	Sm3
Linepack ratio	100%	96%	95%	94%	93%	-
Energy content	92 458	85 307	81 676	74 746	68 183	MWh
Energy content ratio	100%	92%	88%	81%	74%	-

Table 15 - Linepack calculation for different blending mixtures

As expected, the hydrogen introduction into the line pipe reduces the gas stored in it, the 25% hydrogen blending brings a volumetric loss of 7%. Furthermore if it is considered the energy content stored, blending further reduces the energy content due to the low hydrogen volumetric energy density, losing about 25% of energy with the mixture 25% H2 – 75% CH4.

If on one hand it is true that blending implies reducing the energy stored, on the other hand it has to be seen has an opportunity to energy storage through hydrogen injection into the pipelines. For this reason it is in the interest to calculate the energy content of a blending by differentiating the contribution of Hydrogen and Methane.

Given the same pipeline characteristics:

Blending 5%	**Linepack [Sm3]**	**Energy content [MWh]**	**%**
CH4	7 660 996	80 322.15	98,3%
H2	403 210	***13 53.43***	1,7%
TOT.	8 064 206	81 675.58	100%
Blending 15%	**Linepack [Sm3]**	**Energy content [MWh]**	**%**
CH4	6 747 910	70 748. 85	94,7%
H2	1 190 808	***3 997.12***	5,3%
TOT.	7 938 717	74 745.97	100%
Blending 25%	Linepack [Sm3]	Energy content [MWh]	%
CH4	5 876 132	61 608.64	90,4%
H2	1 958 711	***6 574.70***	9,6%
TOT.	7 834 842	68 183.34	100%

Table 16 - Linepack analysis for different blending mixtures

The linepack, with 25% blending of hydrogen at 60 Bar and a pipeline of 200 km with 900 Diameter, results in storing about 6.5 GWh of hydrogen energy.

If the pipeline length is halved (100 km) and the average pressure reduced to 40 Bar, still considerable energy storages are present, with a reduction to one third of the previous case:

Blending	**Gas**	**Linepack blend [Sm3]**	**Energy content [MWh]**
5% H2	H2	130 423	438
15% H2	H2	387 051	1 299
25% H2	H2	639 267	2 146

Table 17 - Linepack comparison for different blending

Even though the process to inject and extract hydrogen leads to energy losses, the potential of hydrogen storage through linepack should not be underestimated but on the opposite, it should be encouraged.

3.6.6 Equivalents CO2 kilograms transported

The introduction of hydrogen in a Natural Gas stream has implicitly the goal to reduce the emissions transported and emitted with combustion.

The fossil-based production route without applying carbon capture (grey hydrogen) is an emissions-intensive process. Depending on the specifics of the supply chain, the total GHG emissions for grey hydrogen have been estimated 230 - 318 gCO2eq/kWh [59], higher than the estimated total emission of the natural gas supply chain, 220 - 230 gCO2eq/kWh (ca. 20-40% of the total emissions from the supply chain and the rest from combustion).

Therefore, hydrogen blending is reasonable if low-carbon hydrogen production methods are considered.

Implementation of carbon capture technologies can support steam reforming allowing to fall below the threshold of natural gas CO2 emissions. Blue hydrogen total emissions are estimated in the range of 23 – 150 gCO2eq/kWh [59].

Hydrogen production through water electrolysis by renewable resources is certainly an advantage for CO2 emission reduction. Nevertheless, considering the whole supply chain behind green hydrogen, total emissions are similar to high-efficiency steam reforming processes with carbon capture implementation ranging in 20 – 150 gCO2eq/kWh [59].

A possible evolution of emissions intensity of different blended percentage considering various hydrogen production method (with their relative emissions) might be:

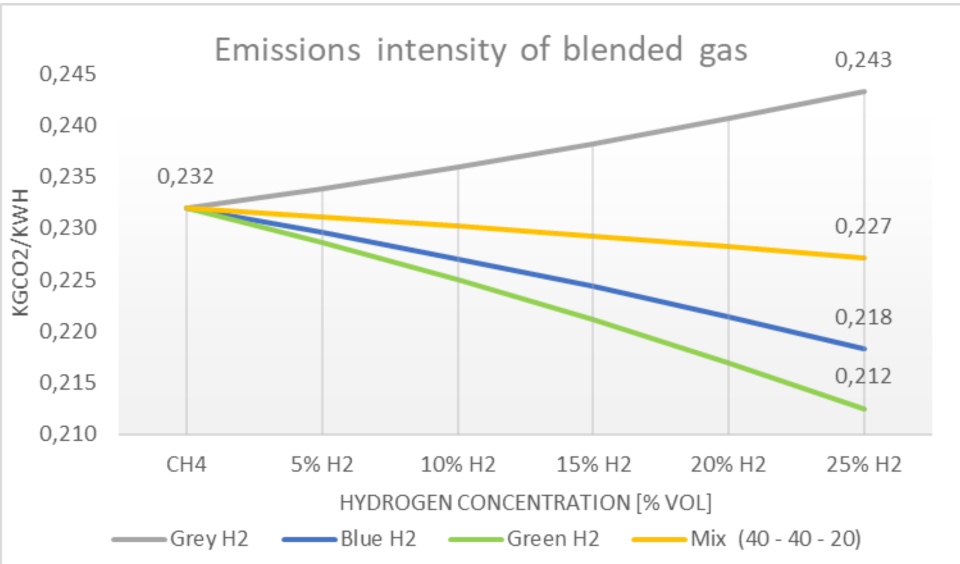


Figure 45 - Emission intensity of blended gas

The reduction of specific energy emission might seem trivial but on absolute quantities, transported by a generic pipeline (L = 200 km – DN 900), the difference is more pronounced.

Emission intensity on absolute values							
Parameters	CH4	5% H2	10% H2	15% H2	20% H2	25% H2	Units
Qvol	19,1	19,7	20,5	21,2	22,1	23,0	MSm3/d
Qe	200	200	200	200	200	200	GWh/d
Emission intensity	0,232	0,230	0,227	0,224	0,221	0,218	kgCO2/kWh
Emission	46,4	45,9	45,4	44,9	44,3	43,6	tCO2/d
Emis. reduction	0,0	-0,5	-1,0	-1,5	-2,1	-2,7	tCO2/d

Table 18 - Emission intensity on absolute values

4. Hydrogen pipelines

Hydrogen pipeline refers to a pure hydrogen stream in pipes along with compressor stations, storage facilities, metering stations and auxiliary components suitable to work with 100% hydrogen. In the medium to long term, the conversion or construction of hydrogen pipelines could be an opportunity to definitely scale up a hydrogen economy delivering decarbonized hydrogen to industrial consumers, business districts, refueling stations and storage facilities.

4.1 Existing infrastructure

The first hydrogen pipeline is thought to have been constructed in the 1930's in Germany [80]. Currently hydrogen pipelines cover a total length of 4542 km in the world with the majority in US and Europe [80].

The majority of them are small pipelines with an average of Diameter of 200 mm (8 in), operated by industrial hydrogen producers and mainly used to deliver hydrogen to chemical and refinery facilities. Therefore, size, pressure range and length comparison for a possible hydrogen gas transmission pipeline are restricted to few pipelines from Air Liquide and Praxair [77].

Location	Pipe material	Years of operation	Diameter (mm)	Length (km)	Service pressure (MPa) and hydrogen purity (%)	Satus
AGEC, Alberta, Canada	Gr.290 (5LX X42)	Since1987	273 (Thickness: 4.8)	3.7	(99.9%)	Operational
Air Liquide, Texas/Louisiana, USA	X52, X60 and other	?	76 - 356	390	5.1	Operational
Air Liquide, France, Belgium, Netherlands	Seamless Carbon steel	Since1966	Up to 304.8	879	[illegible] (pure and raw H2)	Operational
Air Products, Houston, USA	-	Since1969	114.3 – 324		0.345 – 5.516 (pure H2)	Operational
Air Products, Louisiana	ASTM 106	?	101.3 – 304.8	48.3	3.447	Operational
Air Products, Sarnia	-	-	-	~3	-	Operational
Air Products, Texas	Standard natural gas line pipe (steel)	>10	114.3	8	5.5 (pure H2)	Operational
Air Products, Texas	steel, Schedule 40	>8	219	19	1.4 (pure H2)	Operational
Air Products, Netherlands	-	-	-	45	(flow rate : 50 t/day)	Operational
South Africa	-	-	-	80	-	-
Chemische Werke Huis AG, Ruhr, Germany	Seamless equipment to SAE 1016 steel	Since1938	168-273	215	Up to 2.5 (pure H2)	Operational
Cominco B.C., Canada	Carbon Steel (ASTM 210 seamless)	Since1964	5 (Thickness: 0.8)	6	>30 (62-100 %)	Stand-by
Gulf Petroleum Cnd, Petromont – Varrnes	Carbon Steel, seamless, Schedule 40	-	168	16	93.5% H2-7.5% CH4	Operational
Hawkeye Chemical, Iowa	ASTM A53 Gr. B	3	152.4	3.2	2.8	Operational
ICI Billingham, UK	Carbon Steel	-	-	15	30 (pure H2)	-
LASL, New Mexico	ASME A357 Gr. 5	-	25.4	6.4	13.8	Abandoned
Los Alamos, New Mexico	5Cr-Mo (ASME A357 Gr. 5)	>8	30	6	13.8 (pure H2)	Abandoned
Linde, Germany	-	-	-	1.6 – 3.2	-	-
NASA-KSC, Florida	Stainless steel 316 (austenitic)	>16	50	1.6-2	42	Operational
NSA-MSFC, Alabama	ASTM A106-B	-	76.2	0.091	34.5	Abandoned
Philips Petroleum	ASTM A524	4	203.2	20.9	12.1 – 12.8	Operational
Praxair, Golf Coast, Texas, Indiana, California, Alabama, Louisiana, Michigan	Carbon Steel	-	-	450	H2 commercial grade (14 M Nm3/day)	Operational
Rockwell International S.	Stainless steel -116	>10	250	-	>100 (ultra pure H2)	-

Figure 46 - Main feature of existing hydrogen pipeline

4.2 Repurposing gas pipelines - Retrofitting

Existing high-pressure natural gas transmission pipes could be converted to deliver pure hydrogen in the future especially if they are no longer used for natural gas. To shift towards total hydrogen gas pipeline retrofitting process has to be substantial. Previous hydrogen pipelines were built in accordance with specific hydrogen codes, which tend to be much more restrictive in terms of material properties than their natural gas equivalents. This in turn means that the conversion of natural gas pipelines made from "standard" grades can be challenging [80].

The idea of reusing NG pipelines born from economic factors, it would be cheaper than a new infrastructure, it would take the advantage of already studied "strategic lines" for gas transport and the possibility to couple with necessary improvements, necessary for hydrogen transportation.

For the European Hydrogen Backbone [81] the relative ease of conversion from a technical standpoint and the modest repurposing costs are two key enablers.

The main challenge would remain on compressor station that should be rethink in order to operate at higher capacities (higher power required) due to the requirement of transporting similar amount of energy, so repurpose of the current compressor station for pure H2 stream could be very limited.

4.2.1 Line pipe

Additionally to "H2 Blending ready", pure hydrogen stream would require additional investigations on the current integrity of the pipe, existing codes [82, 80] recommend destructive testing of material samples at a minimum frequency of one sample per 1.5 km even for pipes with material able to withstand high concentration of hydrogen (low X-grades API 5L).

Ongoing studies [80] are focused to characterize the "Pipeline DNA" to allow more robust assessments of the pipeline and its suitability for hydrogen service by constructing integrity framework. "Pipeline DNA" approach might enable a step-change in the approach to assess materials for their suitability for hydrogen service thorugh Pipe Grade Sensor (PGS) technology and the Distributed Modular system hard spot technology with the aim of supporting operators through the processes of material verification [83].

Other studies [38, 8] are studying the possibility of specific internal layer coating (lining) that could be applied on pipes with materials more liable to hydrogen embrittlement. Lining technology could additionally extend the possibility to withstand similar pressure ranges of NG pipelines.

4.2.2 Gas metering station

For gas metering, precautions for retrofitting should be focus on:

- Liable material components
- Safety measurements
- Meters calibration to work with low density gas for high precision.

Components that employs noble metals (e.g. titanium for ultrasonic sensors) that are very sensitive in hydrogen environments should be replaced with other appropriate tools. Electro-hydraulic and electric valve actuators shall be used instead of gas-hydraulic actuators along with replacement of generic valves with extend operational time for the same reason.

4.2.3 Storage facilities

Pure hydrogen in storage facilities from gas infrastructure is a further step to completely convert the gas infrastructure.

Among the three option previously discussed salt caverns are the most suitable candidates even for pure hydrogen. They are considered the best way to ensure hydrogen purity and hermetic storage but some arrangements are needed as well.

The high hydrogen diffusivity and bacterial activity can disturb the cavern impermeability and the purity of the stored gas. In the presence of sulfates and carbonates, bacteria consume hydrogen and produce H2S and/or methane which leads to gas pollution. Furthermore the effect is aggravated by water evaporation to gas and by thermal convection in gas that accelerate gaseous mixing.

4.2.3.1 Linepack

Hydrogen linepack could lose its performance of fast balance in the gas grid, considering the loss in energy content that hydrogen has with respect to methane. However, linepack with the perspective of hydrogen pipelines will still play an important considering also power to gas systems link with the electric grid.

4.2.4 Safety concerns

In transmission pipelines, the use of pure H2 stream is less stringent compare to distribution networks due to the lower population density in surrounding areas but still some arrangements are needed, working with hydrogen instead of NG would imply to move from the explosion group IIA to the IIC and consequently will affect all electrical equipment and instrumentation installed in the relative hazardous area. The easier hydrogen inflammation will require venting to be collected and routed to a single stationary or mobile venting point at the safe location within the station fence with possible impacts on the plot size of the block valve stations. Other elements include leak testing of (hydrogen) valves, fire and gas detection at block valve stations in hydrogen pipelines [84].

4.3 Ex-novo construction

New pipeline construction would involve assessing the classical methodology study and design for a transmission pipeline plus extra evaluation parameters that are related to the change of the gas transported. Researches and lessons learned from first hydrogen projects by European gas TSOs show that dedicated hydrogen pipelines do not differ significantly from natural gas pipelines [81].

Moreover, building new pipelines might give more degree of freedom to optimize the pipelines just for hydrogen by investigating even the smallest details.

4.3.1 New line pipe

For line pipe material, constructors shall consider code requirements for pure hydrogen pipelines. The most common design codes for hydrogen pipelines are ASME B31.12 and the AIGA / EIGA guidelines.

ASME recommend low carbon steel with thickness penalties to apply for hydrogen pipelines. However currently researches are lowering the thickness needed (or alternatively increasing the MAOP) thanks to steel improvements. Case studies [85] have seen possible replacement of X52 steel with X72 that allow to build pipeline with DN 900 at 100 Bar.

Since the first hydrogen permeation sources are from welds, the number of them shall be decreased comparing to a natural gas pipeline. Therefore, as well as due to further technical considerations, longitudinal welded pipes may be preferred. Likewise the number of flanged connections shall be reduced as far as practically possible to avoid the leak of hydrogen [84].

4.3.1.1 Line pipe preparation

The first gas injection process implies the introduction of hydrogen into the pipeline after the last steps of cleaning. The European Industrial Gases Association (EIGA) has a recommended procedure for Natural Gas for post installation cleaning using compressed (dry and oil-free) air or nitrogen. EIGA also has a sequence for dewatering, drying, and final drying using nitrogen or vacuum to the desired dew point [77].

In the hydrogen case, as pipelines are gassed up, hydrogen will mix with air, which is heavier, and may result in an explosive mixture during breaking containment (i.e., opening a closure). This will require great care in inerting procedures and personnel training [76, 77]. Nitrogen purging of the trap will also reduce the risks.

4.3.2 Compressor station

The lightness of hydrogen is paid at high prices in compressor design.

Centrifugal compressor in order to guarantee similar pressure ratio as in the case of NG should be design with high head impeller type, greater number of stages or higher impeller tip speed [45]. Generally, the limits in increasing the rotating speed is given by mechanical stress of the impellers, rotodynamic criticalities and the loss of interference between impeller and shaft.

To withstand high tip velocities usually high-strength steels and titanium alloys materials are employed but they may fall under the hydrogen embrittlement phenomenon. For this reason compressor firms are rethinking the compressor design.

Baker and Hughes recently a new type of centrifugal compressor design called High Pressure Ratio Compressor (HPRC) that allows the installation of more impellers in a raw [45].

Other studies [38] are focusing on the possibility to employ eelectrochemical compressors, but this type of technology will unlikely be used in transmission systems where high capacities are needed.

4.3.2.1 Re-compression distance

Distance between compression station is largely affected by the relation of MAOP and pipeline integrity and the pressure drop related to volumetric flow and gas properties. Comparing with methane, for the same amount of volume transported and pressure drop hydrogen is able to travel for more distance. This thanks to hydrogen that shows a minor pressure drop due to less friction factor induced by lower Reynolds number.

By considering the Reynolds formula employed in pipelines:

$$Re = 0.5134 \cdot \left(\frac{P_b}{T_b}\right)\left(\frac{G \cdot Q}{\mu \cdot D}\right)$$

For same operative conditions (Equals Diameter and flow) Reynolds depends on the ratio of Specific gravity and viscosity, that results seven times higher for Methane compare to Hydrogen.

Gas	Specific gravity	Viscosity (μPas)	G/mu	%
Hydrogen	0.066	8.389	0.0079	100%
Methane	0.5	9.4	0.0557	709%

Table 19 - Reynolds coefficient evaluation

The extra distance gained by less friction, however, has to compensate possible lower pressure ranges (due to pipeline integrity) and more important lower energy flow for the same volume transported.

Particularly the latter aspect, if it is considered the same amount of energy to be transported (with same operative conditions), hydrogen needs to be recompressed at shorter distance and it'll result higher energy consumption for compressor station.

4.4 Production side connection

Connection between hydrogen pipelines and production site will play a key role to justify hydrogen pipelines in order to transport huge hydrogen volumes. Centralization of hydrogen production

In the overview of energy transport, the quantities transported will define which energy mean will be implemented.

If for blending process the decentralization hydrogen production is an accelerator, for pure hydrogen stream this might not be enough, for hydrogen pipelines it will be essential to concentrate enough hydrogen production. By recalling the values used in scenario 0, if same volumes of natural gas (20 Sm3/d) would be transported from hydrogen, 1700 tons of hydrogen should be produced each day.

Currently no method can guarantee such hydrogen volumes but Gas operators with energy coalition like European hydrogen backbone are moving on to make it possible.

4.4.1 FER Electrolyzers and SMR

Steam methane reforming is at the moment the largest method employed to produce hydrogen. SMR plants already produced large amount of hydrogen that would result in sufficient volume to transport via (small) pipelines. Air Liquide plants are able to produce hydrogen stream capacities in the order of hundred thousand per hour [86]. With the implementation of CCS technology, blue hydrogen could play an important role in the hydrogen infrastructure supplying enough volumes with relative low carbon emissions.

Simultaneously, large Wind and Solar plants would be great possible departure point for hydrogen pipelines when massive scale of RES will occur. Electrolyser should face an important scale up in terms of power, currently Air Liquide is setting future standard to reach sizes of 100 MW and in 2021 has already presented a project regarding a PEM electrolyzer of 20 MW.

4.5 End consumers

End consumers can be identified depending on which gas network side are connected,

A first distinction has to be made between consumers that will directly use hydrogen and those who will use it as a mean of energy transport or energy storage.

Delivery a pure hydrogen stream will selectively choose the end consumers, current applications of pure hydrogen are restricted to narrow industrial sectors leading by ammonia production. Gas turbines are currently pushing forward blending limits and many ongoing projects see hydrogen in trucks and on rails.

4.6 Hydrogen between Electricity and Gas grid

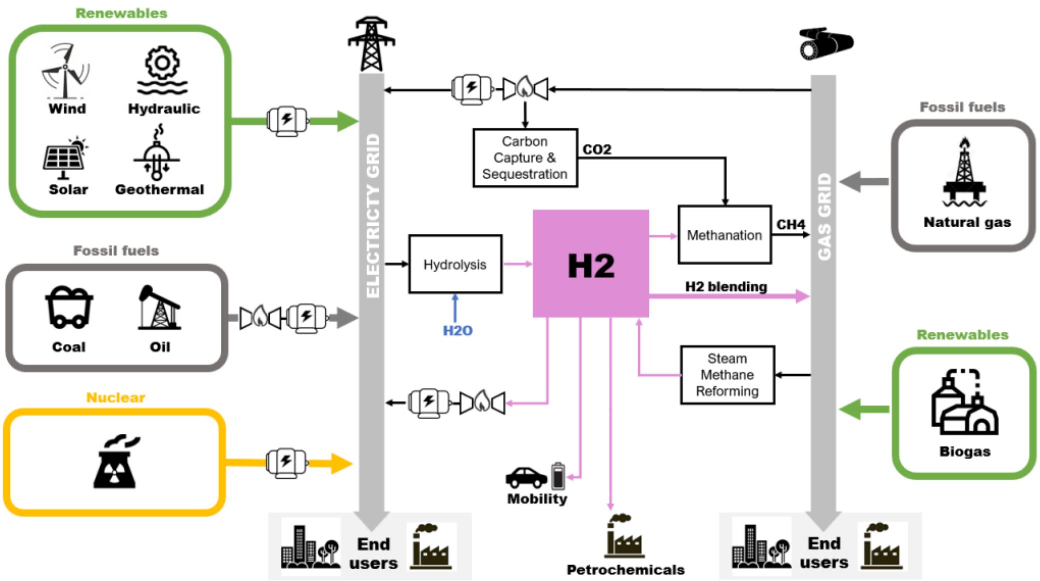


Figure 47 - Role of hydrogen in gas and electricity gird

With higher electrification rates and increasing deployment of renewable energy, large-scale storages will be essential to manage system balancing on short-term and seasonal timescales. In the coming decades, the electricity network will cope with much larger seasonal peaks and daily fluctuations in demand and supply. To address this issue and prevent blackouts caused by an overload, renewable electricity will need to be complemented with dispatchable energy sources such as large-scale storage of hydrogen. For example, in Austria, if 100% of the electricity generated would come from renewable sources, storage with capacity over 100 times greater than the potential offered by pumped storage will be needed [87] [74]

4.7 Economics

Due to the absence of already built hydrogen pipelines the cost estimation is highly approximative. Current estimations and empirical evidence from TSOs indicate that the capital cost of a newly built dedicated hydrogen pipeline will be 10-50% more expensive than its natural gas counterpart though region-specific factors such as typical dimensioning of pipes affect this range [81].

Most of the investigations [81, 88, 64, 89, 90] are estimating the capex for repurposing of gas pipelines in relation to build a new infrastructure, 10 to 30% is the cost factor for total retrofitting of a natural gas pipelines compare to a new hydrogen pipelines.

On a cost per kilometers basis, instead, some evaluations set the repurposing costs of typical transmission pipelines around 0.2 and 0.6 M€/km [74].

The total capex would also affect the cost of transporting hydrogen, the European Hydrogen Backbone estimates that for a thousand km distance the average cost of hydrogen would be in the order of 0.1-0.2 of €/kgH2 transported, with €0.16 per kg for the central case.

On the Opex estimation energy requirements from compressor stations will have a predominant role in combination of higher powers and new design compressors.

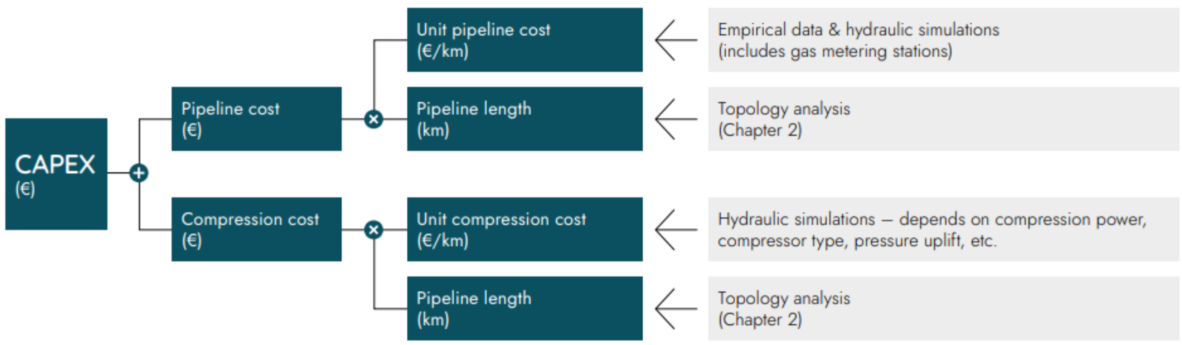


Figura 1 – Costs flow diagram [81]

4.8 Scenario “1”

In the scenario “1”, it is evaluated a pure hydrogen stream through pipeline. For comparison NG stream and a blending of 20% Hydrogen-Methane are assessed.

For hydrogen compressibility factor it is used the Lemmon equation that is more suitable for pure hydrogen stream. At high pressure, H2 Lemmon factor deviates from the ideal behavior by increasing a few centesimal points. For given thermodynamic conditions the compressibility factors are:

Thermodynamic conditions	
Temperature	288.15 K
Pressure	5500 kPa
Compressibility factor	
Z Lemmon	1.0334
Z CNGA	0.9851
Z AGA	1.8127
Z Papay	1.0000

Table 20 - Compressibility factor for different methods

4.8.1 Operative framework

Parameters	
DN	900 mm
L	200 km
Qnom	20 MScm/d
P2	5000 kPa

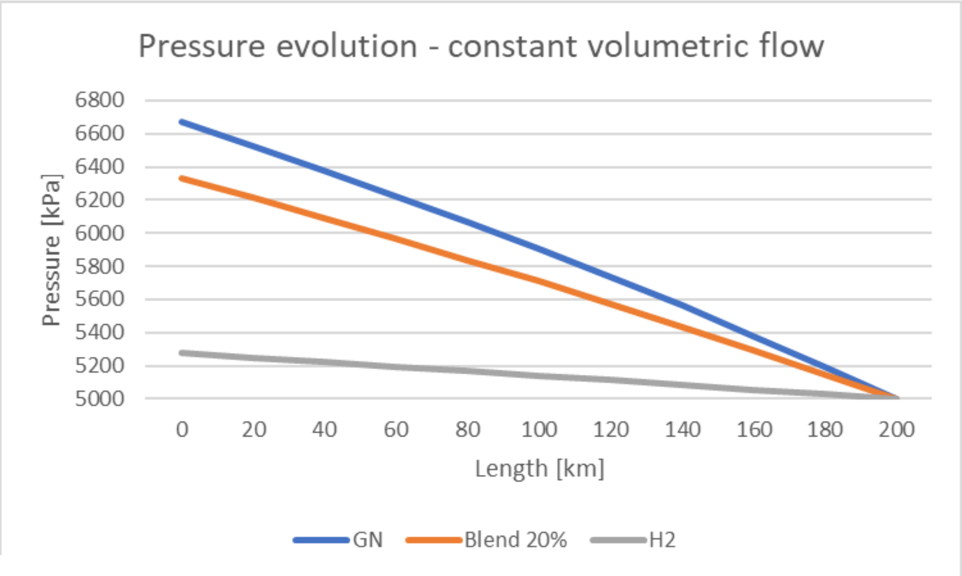


Table 21 - Data & pressure evolution with constant volumetric flow

Parameters	
DN	900 mm
L	200 km
QE	200 GWh/d
P2	5000 kPa

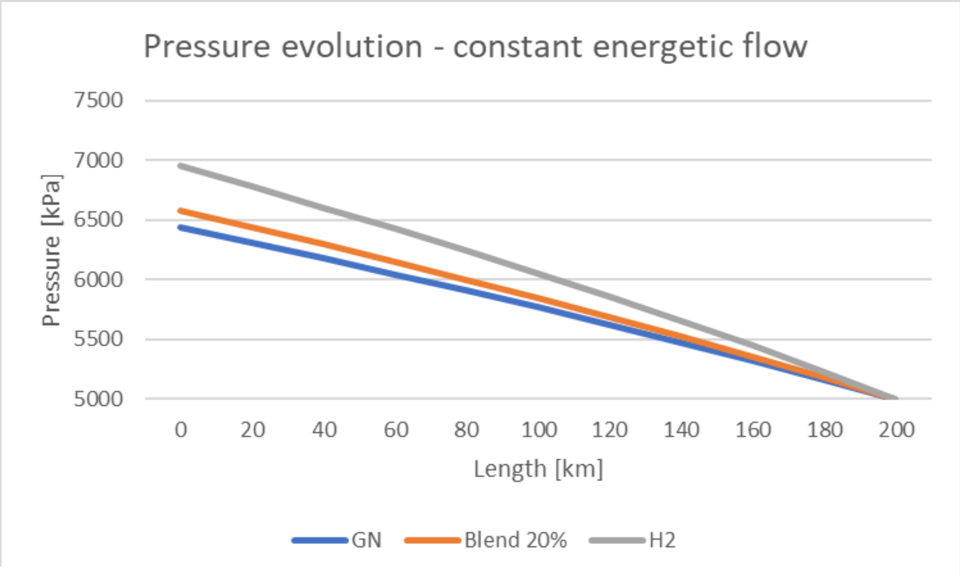


Table 22 - Data & Pressure evoluton - Constant volumetric flow

4.8.1.1 Volumetric/Energetic flow

An interesting configuration is by evaluating the flow rates with same upstream and downstream pressures.

Parameters	NG	H2
P1 – P2 [kPa]	7000 – 5000	7000 - 5000
Qvol [MSm3/d]	22.5	60.5
Qvol%	100%	270%
Qe [GWh/d]	245.5	203.0
Qe%	100%	82.7%

Table 23 - Flow comparison at same pressure range

At the same pressure range hydrogen is able to carry almost triple the volumes of natural gas, comparing the energy content instead the higher flow rate partially compensate the lower volumetric energy density resulting in transporting 82.7% the energy content of the natural gas stream.

Flow analysis considers the variation on the quantities transported

Given the integrity concerns on pure hydrogen stream in pipelines, it is useful also to compare possible energetic flows when H2 pipelines are pressure limited. The following case compare Hydrogen and natural gas in which for the first gas pressure ranges are decreased.

Parameter	GN	H2'	H2''	Unit
L	200	200	200	km
DN	750	750	750	mm
P1	7500	*7000*	*6500*	kPa
P2	5000	*4500*	*4000*	kPa
Qvol	15.591.305	40.512.252	38.717.875	Sm3/d
QE	170.538.859	135.985.258	129.962.171	kWh/d
QE%	100%	80%	76%	-

Table 24 - Comparison pipeline parameters

With the same pressure conditions hydrogen is able to carry more than double the quantities of Natural Gas, however the increase volumes do not cover the gap created in the energy comparison. Around 20% of possible energy transported (by natural gas) is loss for hydrogen pipelines. If it is considered the second case that operates with a reduction of 10 Bars in upstream and downstream conditions, the energy "loss" arrive at 25%.

4.8.2 Pipeline integrity

4.8.2.1 MAOP

For hydrogen pipelines it is meaningful to give an outlook on the possible upstream pressure based on the type of steel employed, considering the series API 5L series X.

As introduced in chapter two, a possible method to calculate the MAOP relies on the Barlow's equation but it is necessary to know the thickness – diameter ratio and it may change depending on constructors, Gas TSOs' choices and if thickness penalties, like ASME recommend, are present.

Nevertheless, using the Barlow's equation to calculate the MAOP highlights which variables leads to changes and on which parameters is possible to work on, the table below shows the MAOP variation with respect to the nominal case that assumes DN 600 and steel grades X70:

DN\Grade	X42	X46	X52	X56	X60	X65	X70
DN 600	60%	66%	74%	80%	86%	93%	100%
DN 650	57%	63%	71%	77%	82%	89%	96%
DN 750	63%	69%	78%	84%	90%	97%	105%
DN 850	49%	54%	61%	66%	70%	76%	82%
DN 900	48%	53%	60%	65%	69%	75%	81%
DN 1050	44%	49%	55%	59%	63%	69%	74%
DN 1200	48%	53%	59%	64%	69%	74%	80%
DN 1400	52%	57%	64%	69%	74%	80%	87%

Table 25 - Hypothetical MAOP variation for different Diameters and steel grades

Low Xgrades, suitable for hydrogen environment, with large diameter might result in a disadvantage combination on which it might be necessary to work with lower MAOP. Hydrogen transmission pipelines are likely that will operate at little less pressure than NG pipelines to ensure safety margins.

4.8.2.2 Erosional velocities

For hydrogen pipelines erosional velocities will be calculated based on hydrogen properties, resulting in higher values. The problem on assuming higher allowable velocities it is the possible presence of contaminants that might harm the pipe, so with the increase of velocities purification processes will be essential.

The table below shows how velocities would increase if the same gas pipeline would be a hydrogen pipeline. Erosional velocity isn't affected by the flow rate variation, while for NG comparison it is assessed both the condition of constant volumetric and energetic flow rate.

	Methane		Hydrogen		
Qvol (MSm3/d)	20		20	65.2	
Qe	218.8		67.1	218.8	
P2	$u_e\ CH_4$	$u_2\ CH_4$	$u_2\ H_2$	$2\ H_2$	$u_e\ H_2$
3750	22	9	10	34	71
4000	21	8	10	32	69
4250	20	8	9	30	67
4500	20	7	9	28	65
4750	19	7	8	27	64

5000	*19*	7	8	26	62
5250	*18*	6	7	24	61
5500	*18*	6	7	23	59

Table 26 - Comparison on different velocities

4.8.3 Energy and power required for transportation

In the previous paragraph it was highlighted the role of the compressor station when the working gas has hydrogen in it. From an energetic point of view, by the formula introduced in Chapter two for the power required to compress gas, it is possible to compare the difference between NG, Methane, blending at 20% and pure hydrogen.

$$Power_{comp.} = \left[\frac{R}{MW} \cdot \frac{Z_{avg} \cdot T_{in}}{\theta} \cdot \left(\left(\frac{P_{out}}{P_{in}}\right)^{\theta} - 1\right)\right] \cdot \frac{\rho_{std} Q_{vol}}{\eta_{ad}} \cdot \left(\frac{10^6}{24 \cdot 3600}\right) = [W] \qquad (2.46)$$

First it is useful to assess the formula considering how gas properties affect the results:

$$\theta_{GN} < \theta_{CH4} < \theta_{Blend} < \theta_{H_2} \rightarrow Power_{H_2} > Power_{GN} \qquad (4.1)$$

$$Z_{GN} < Z_{CH4} < Z_{Blend} < Z_{H_2} \rightarrow Power_{H_2} > Power_{GN} \qquad (4.2)$$

$$\rho_{GN} > \rho_{CH_4} > \rho_{Blend} > \rho_{H_2} \rightarrow Power_{H_2} < Power_{GN} \qquad (4.3)$$

$$MW_{GN} > MW_{CH_4} > MW_{Blend} > MW_{H_2} \rightarrow Power_{H_2} > Power_{GN} \qquad (4.4)$$

Hydrogen, just considering gas properties, will require more power (energy) to operate between the same pressure range with the same volumetric flow rate. The following graph shows the power required for compression normalized to pure methane with a constant volumetric flow of 20 MSm3/d.

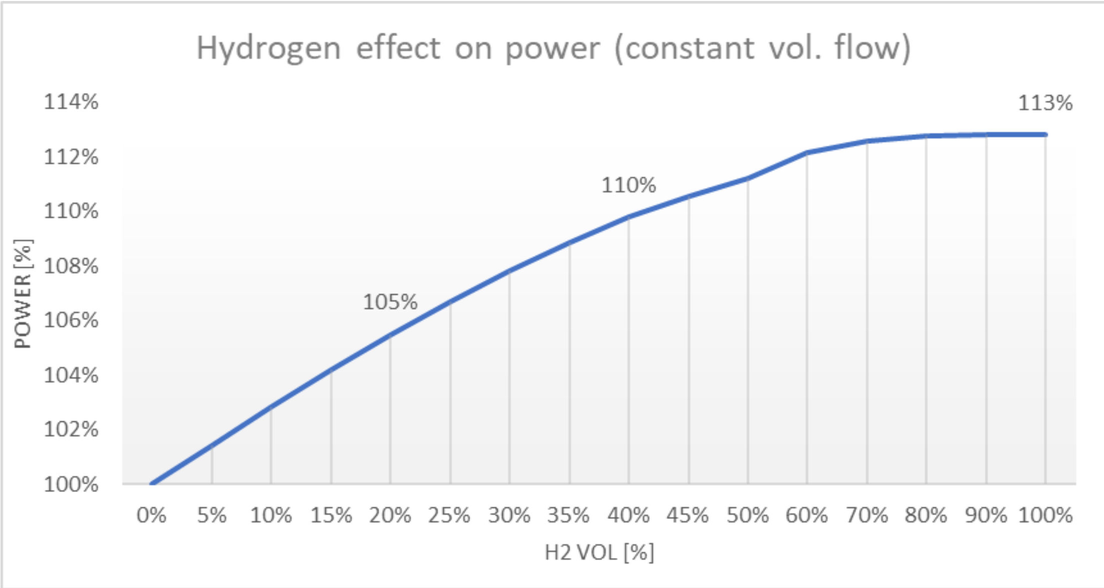


Figure 48 - Compressor power evolution for different H2 %

If it is considered a constant energetic flow rate (200 GWh/d) at the same operative conditions, the situation becomes more critic.

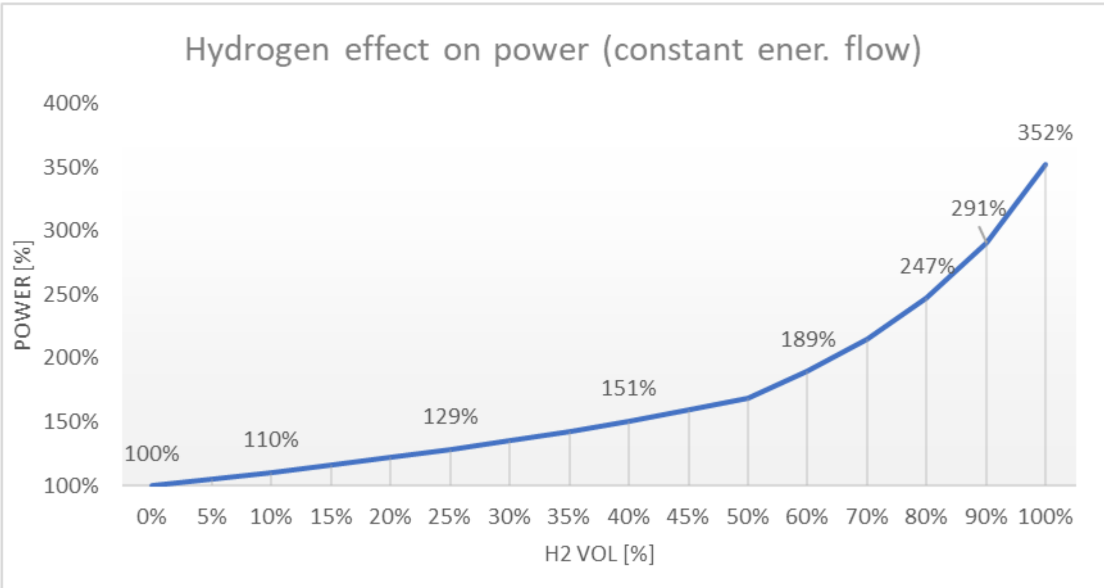


Figure 49 - Compressor power evolution 2 for different H2 %

For a pure hydrogen stream, assuming the same energetic flow rate as methane stream, the compression power required increase more than triple.

4.8.4 Linepack

Considering the HHV ratio between hydrogen and natural gas is around a 30%, the same ratio can be expected from linepacks. Moreover, as in the case of compression power required, the hydrogen compressibility factor reduces further the ratio.

Recovering the same conditions from Scenario 0.x (L=200 km; DN900), it is calculated additionally the pure hydrogen case:

Parameters	Natural Gas	Blending 20%	H2	Units
Pavg	6000	6000	6000	kPa
Zavg	0.87	0,93	1,04	-
Linepack	8 452 871	7 884 327	7 077 440	Sm3
Linepack ratio	100%	93,3%	84%	-
Energy content	92 458	71 424	23 756	MWh
Energy content ratio	100%	77%	26%	-

Figure 50 - Hydrogen linepack

As expected, the hydrogen linepack can store less cubic meters of gas, and its related energy content is reduced to one quarter of the Natural Gas energy content, around 24 GWh.

Further reduction should be considered if the hydrogen pipelines would operate at lower pressure, for an average pressure along the line of 5000 kPa the energy content would lose 4 GWh with a total of 20 GWh.

4.8.5 Gas pipelines comparison

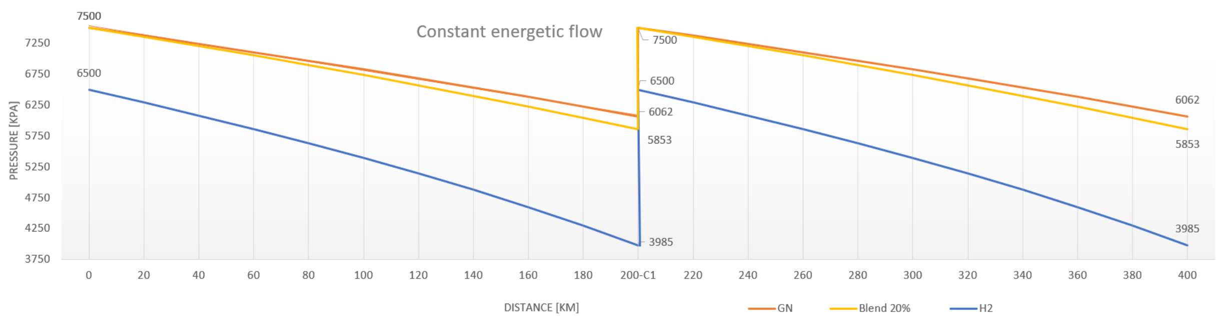


Figure 51 - Gas pipelines 1

Since compressor stations usually work with maximum of 1.4 of pressure ratio, it is evaluated a hydrogen pipeline with the pressure ranges between 6500 – 4600 kPa (Pratio ca. 1.4) along with natural gas pipeline:

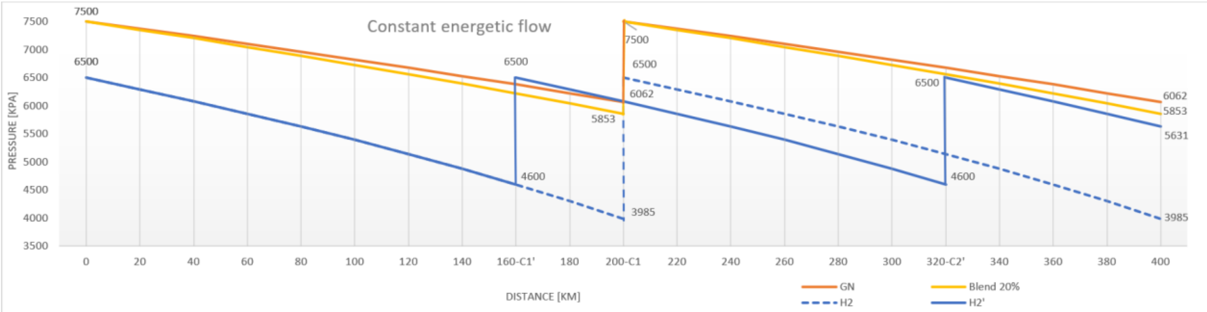


Figure 52 - Gas pipelines 2

For 400 km of pipeline, transporting the same amount of energy, would require two compressor stations in order to respect pressure range limit.

At first look, working with multiple compressor stations implies an increase in power output due to more stringent ranges.

Gas	Power [MW]	Pressure range [kPa]	P ratio	Power%
GN	3	6381 – 7500	1.2	100%
H2	34.8	4123 – 6500	1.6	1177%
H2’	24.5 + 24.5	4693 - 6500	1.4	1660%

Figure 53 - Power compressor stations

Besides the expected increase of the power output due to an additional station for hydrogen, it emerges the enormous power ratios between hydrogen and methane. The result is a combination of several factors that include; unfavorable gas properties, necessity to carry more higher volumetric quantities and lower pressure ranges. However, the comparison has to be contextualized in the fact that it has been stretched in the optic to carry the same energy and it hasn’t been optimized for hydrogen where certainly less strict energy requirement would benefit the hydrogen pipeline. A more favorable comparison would pass by assessing gas pipelines with the same pressure range as previously presented in this Scenario.

It is interesting also to evaluate a third configuration for hydrogen when three compressor stations at 100 km distances between them are employed.

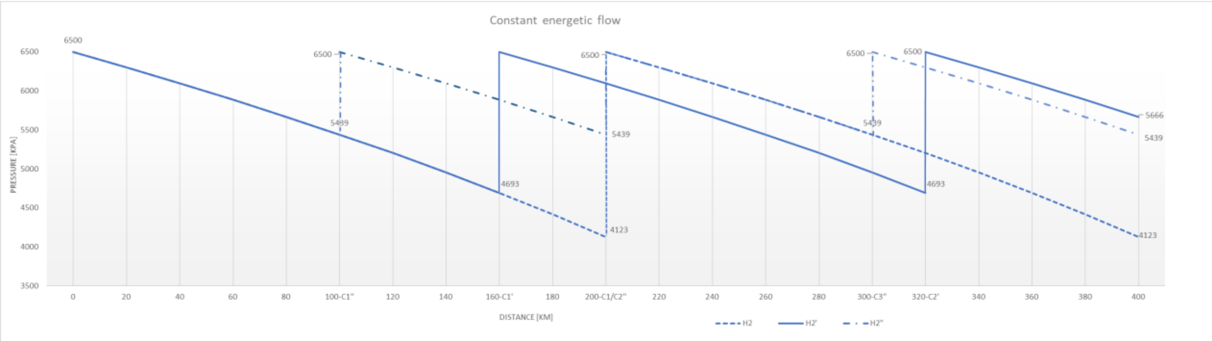


Figure 54 - Hydrogen pipelines with different compressor station configurations

Gas	Power [MW]	Pressure range [kPa]	P ratio	Power%
H2	34.8	4123 – 6500	1.6	100%
H2’	24.5 + 24.5	4693 - 6500	1.4	141%
H2’’	13.2 + 13.2 + 13.2	5439 – 6500	1.2	114%

Table 55 - Hydrogen compressor stations

Contrary on the expectations, adding a third compressor station would benefit the compression power allowing even lower pressure ratios.

Another approach would be increasing the Diameter that reduces the pressure drop, in the next graph it is presented a pressure evolution for hydrogen and natural gas with the same energy transported but for hydrogen it used a large diameter (DN 1050):

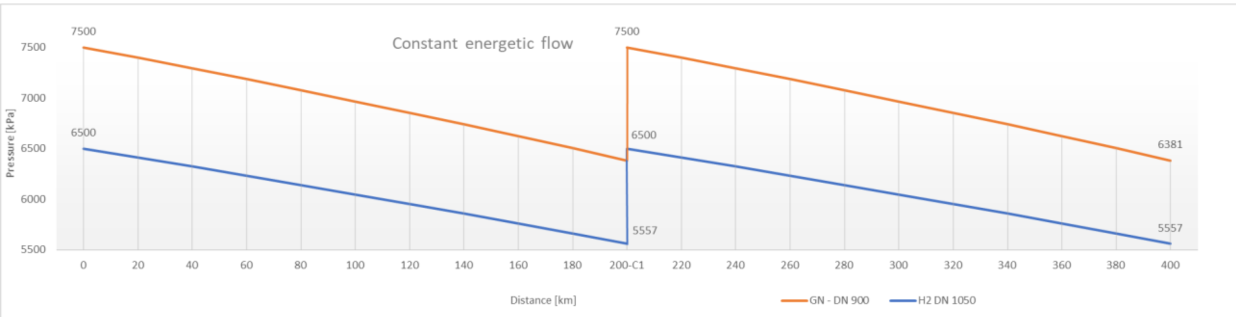


Figure 56 - Gas pipelines 3

Gas	Power [MW]	Pressure range [kPa]	P ratio	Power%
GN	3	6381 - 7500	1.2	100%
H2	11.6	5557 - 6500	1.2	392%

Table 57 - Power compressor stations 2

The employment of a larger diameter will largely affect positively the hydrogen pipeline and the power related to the compression station, but it will rise the costs related to it.

If it is considered the formula used to calculate the material costs:

	Pipeline material cost	%
H2 DN 900	160 092 177 €	100%
H2 DN 1050	199 742 988 €	125%

Table 58 - Hydrogen pipeline material cost for different Diameters

Using a larger diameter will result in 25% increase in costs. Nevertheless, cost-saving would be from the lower power required for compression. Normalizing with the same conditions, the two hydrogen pipelines with DN 900 and DN 1050 would require:

	Power required [MW]	%
H2 DN 900	34.8	300%
H2 DN 1050	11.6	100%

Table 59 - Hydrogen compressor stations 2

The 300% increase in power would require a huge expensive in compressor costs that will likely surpass the costs related for a large diameter.

Assuming 2 M€/MW for compressor station, the situation would be:

	Power required [MW]	Compressor cost [€/MW]	Total compression Station cost	Total material cost	Total Cost
H2 DN 900	34.8	2 M€	70 M€	160 M€	230M€
H2 DN 1050	11.6	2 M€	23 M€	200 M€	223 M€

Table 60 - Cost evaluation for different pipeline configurations

The logistic of compressor station locations, along with diameter choice is a complex study that incorporates hydraulic balances compressor power and as well economical and legislative permission.

5. Conclusion and future development

In the next years hydrogen is likely to experience a relevant growth in each aspect of its supply chain, both in new and well establish employments. A hydrogen economy will have to rely on a suitable infrastructure to cover the wide versatility of production and application methods. On the race for excelling as an energy vector, hydrogen will have to develop a substantial and capillary network for energy transport.

The remarkable gas infrastructure, with its extensive networks and systems, is a model to aspire. The core of gas transportation are pipelines, where enormous quantities of energy flows under the form of Natural Gas. Natural gas, though, is constituted of hydrocarbons that are harmful for the environment and thus other energy transportation are taken into consideration. On this ground hydrogen, being able to be produced at lower carbon footprint, has begun to challenge the domain of natural gas.

The deployment for a hydrogen gas infrastructure like the one of natural gas would require tremendous effort, not feasible with the current energy outlook requirements. The blending option seems to be a viable solution to undertaken. Blending could allow to scale up the whole supply chain of hydrogen resulting also as an advantage for renewable sources that could rely on its flexibility.

However, the current gas infrastructure is a result of decades of optimization processes and investments that has led to specific NG operations. Hydrogen and methane can cooperate as a gas mixture in gas systems but hydrogen implies different effects to be managed.

Different blending mixtures perform and act differently on transmission pipelines. The current focus is to investigate which component of transmission pipelines is more sensitive to hydrogen injection to establish the correct limits for hydrogen percentage.

Impact of hydrogen embrittlement in transmission pipelines depends largely on the type of steel employed (low carbon steels are more resilient). Pipeline inspections, through apposite PIGs, are crucial to investigate and track pipeline integrity.

Gas storage facilities are already proven option for blending mixtures, allowing to store considerable amounts of hydrogen. Moreover, salt caverns can extend their usage till pure hydrogen.

The reduction in energy content of the flowing gas, instead, is a limitation that unlikely will be overcome in a short term scenario. The main restriction comes from compressor capacity. Transmission compressors can cope with relative high blending percentage (20% H2), but the goal to keep working at constant energy flow rate while increasing hydrogen in the blending mixtures is possible only for small percentage (5% H2). If higher hydrogen percentages will be considered on the transmission level, the coordination among gas operators, end consumers and international institutions will be required for trading the gas at lower energy rates.

Linepack is the first line of gas peak shaving and hydrogen could limit its performance when it is present into the pipeline. Nevertheless, on the scenario 0.x it has been proven that energy reductions are contained and valuable energy quantities can be stored under hydrogen form already at low blending concentration. This aspect should be also coupled with the technologies of deblending processes.

Hydrogen transmission pipelines will require centralized production of hydrogen in order to operate at the appropriate flow rate. Energy transport could be limited by compressor capacities and pipeline materials.

To conclude, hydrogen is less competitive than Natural Gas on absolute performances in gas systems and transmission pipelines. Apart from the technical requirements, hydrogen mainly suffers from its lower volumetric energy density. However, hydrogen has to be contextualized in a wider range, having an intermediary role between different energy networks. Presently, hydrogen is the most suitable gas to start challenging methane, but still a long cooperation will occur between them.

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A. Appendix A

VBA functions built in the Gas Pipeline Model, iterative cycles are set with an allowance of 10^{-6}.

Parameter	Function	Var	Notes
Velocity **(at any point)**	**u**(Qb, D, Pb, Tb, Tf, Z, P)	6	Local pressure dependent
Erosional velocity	**ue**(G,P,Z,T)	4	Assuming k = 100 (more conservative)
Reynolds	**Re**(Pb ,Tb ,G ,Q ,mu ,D)	5	
Friction factor	**ff**(Mfriction ,Re ,rel_rough)	3	Iterative methods Calculated only for turbulent flow
Compressibility factor	**Z**(MZ,P1,P2,Pc,Tf,Tc,G)	6	
Pressure inlet **Pressure outlet**	**Pressure1**(MFLow,MZ,Q,D,L,Tb,Tf,Pb,P2,G,Pc,Tc,f,E) **Pressure2**(MFLow,MZ,Q,D,L,Tb,Tf,Pb,P2,G,Pc,Tc,f,E)	14	For Z iterative calculation: (P1 -> Pavg -> Z)
Volumetric Flow	**Flow**(MFLow,Mfriction,Tb,Pb,P1,P2,G,Tf,L,Z,D,mu,rel_rough,E)	14	For ff iterative calculation: (Q -> Re -> ff)
Internal Diameter	**D**(MFLow, Mfriction, Q, Tb, Pb, P1, P2, G, Tf, L, Z, mu, roughness, E)	14	For ff iterative method: (D -> Re -> ff)
Pipe length	**L**(MFLow, Q, Tb, Pb, P1, P2, G, Tf, L, D, Z, f, mu, roughness, E)	15	-

Compressor power	**Power_comprex**(Qvol, Tin, Pin, Pout, Zin, Zout, gamma, eta_ad, MW,Rho)	8	
Adiabatic work	**W_ad**(T1, P1, P2, G, gamma)	5	
Linepack	**Linepack**(Tb, Tf, Pb, Pavg, Zavg, D, L)	7	
Equivalent length Factor	**Elev_factor**(H1,H2,Tf,G,Z)	5	To multiply with the length to get the equivalent length
Gas properties NIST	**Interpolation**(Gas, property, pressure)	3	By NIST data collected it is possible to estimate a specific gas property in relation to pressure

Studies	$\boldsymbol{Output(input)}$	Note
$\boldsymbol{Study1}$	$P_1(Q_{vol}^{Gas})$	
$\boldsymbol{Study2}$	$P_1(Q_E^{Gas})$	
$\boldsymbol{Study3}$	$Q_{vol}^{Gases}(P_1)$	Consequently Q_E^{Gases}
$\boldsymbol{Study4}$	$P_1(Q_{Mass}^{H_2})$	From $Q_{Mass}^{H_2} \rightarrow Q_E^{Gases}$
$\boldsymbol{Study5}$	$D_{int}\ (Q_{Mass}^{H_2})$	From $Q_{Mass}^{H_2} \rightarrow Q_E^{Gases}$
$\boldsymbol{Study6}$	$D_{int}\ (P_1; Q_{vol}^{Gas})$	
$\boldsymbol{Study7}$	$D_{int}\ (P_1; Q_E^{Gas})$	
$\boldsymbol{Study8}$	$Q_{vol}^{Gases}(P_1; P_2)$	Consequently Q_E^{Gases}
Study9	$L(P_1; P_2; Q_{vol}^{Gas})$	
Study10	$L(P_1; P_2; Q_E^{Gas})$	
$\boldsymbol{Study11}$	$P_2(Q_E^{Gas})$	
Study12	$P_2(Q_{vol}^{Gas})$	

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