HIGGS

Hydrogen in Gas Grids

A systematic validation approach at various admixture levels into high-pressure grids

D5.1

Report on baseline, assumptions and scope for techno-economic modelling

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Executive Summary

Introduction

The report "Baseline and case studies definition" aims to develop the basics which are of fundamental importance for the further tasks in Work package 5 of the HIGGS project. The report is divided into three main chapters. The section on **baseline** includes studies on the present and future consumption of natural gas and hydrogen in Europe up to 2050. Furthermore, the current production and use of hydrogen is discussed and how it influences the physical and chemical properties when it is admixed with natural gas.

The first part of the **case studies** section is dedicated to the conceivable blending levels of hydrogen in the natural gas grid, the hydrogen sources, and consumers of hydrogen and/or natural gas blends. In order to protect hydrogen-sensitive customers, hydrogen separation technologies are briefly discussed, and it is explained how they can be integrated into a simulation model. Afterwards, the basic operating strategy of transmission system operators (TSO) and economic aspects of the gas pipeline system are described and brought in context with the case studies. Finally, the current transport system in the European context is discussed and regions are presented that could be suitable for an in-depth analysis.

In the last third of this documentation, the **methodology for network modelling** is discussed. It clarifies the approach of the modelling tasks, where the data on the transmission network and gas consumption comes from and which quality. Also, the boundary conditions of this network analysis task is discussed. In addition, the reader is given a first insight into the scope of our investigations in the further task. The section concludes with the basics of computer-aided network calculations and an analysis of software that can be used for network modelling.

Key findings

Large shares of Europe's natural gas demand of almost 6,200 TWh today comes from the East (Russia, 30 %), via the North Sea (Norway, 26 %), from European producers (20 %) or Southern (Algeria 9 %) and the Arab regions (6 %). The largest consumption markets are in Central Europe, Italy and Spain. It is evident that natural gas consumption has risen steadily worldwide in recent years. In Europe, however, demand has stagnated over the last decade. Future scenarios till 2050 forecast a slight to strong decrease in the demand for gas as an energy source, depending on the degree of electrification. Only few studies predict stable or even higher consumption figures.

Hydrogen, which today in Europe is largely produced from natural gas reforming processes (approx. 370 of 470 TWh), can contribute significantly to the decarbonisation of the gas sector if it is mixed with natural gas, provided that it is produced renewably or with appropriate CCS technology. At a volume share of 20% hydrogen, 6.5% less CO_2 is emitted per kilowatt hour of gas, at 30% H_2 by volume this is already 12% less, and with pure hydrogen no carbon-based gas is produced at all upon combustion. Various studies indicate a future demand for hydrogen in Europe of between 800 and 4,000 TWh and, depending on the scenario (technology diversification or push of renewable production), different technologies will be used for supply.

If hydrogen is mixed with natural gas, which could well be the case in the short and medium term until a hydrogen economy with the necessary sales markets has been established, this will also have an impact on the operation of today's transmission systems. For instance, the transport properties of the gas are changed by H_2 admixture (density, viscosity and compressibility), but also end-user relevant parameters (calorific value and Wobbe Index). The investigation of two operating regimes of TSO with 20 vol.-% H_2 within this study has shown that the pressure drop across a pipeline also increases by almost 20 % if the same amount of energy is to be transported. Conversely, if one wants to keep the pressure drop the same, the pipeline has only 90 % of the capacity as before. In both cases, the required compressor power increases (+15 % and +45 %, respectively) and the required preheating at the inlet of regulator stations decreases by approx. 50 %.

From an economic point of view, the 20 vol.% are also of interest, because it is assumed that the greatest costs are incurred for end-user devices downstream from this blending level onwards, relative to the previously necessary expenditure for adaptation. The reasons for this can be found in the change of the combustion process, which is the basic application of natural gas. Depending on the burner technology used, heating stoves are less sensitive to hydrogen components in the natural gas. Studies show that in many cases 20 % hydrogen admixture is well tolerated by the majority of burners. Gas turbines and especially CNG vehicles are more sensitive. This is not only because of the chemical changes in properties, but also because of regulatory requirements. Sensitive gas customers can be protected from excessive hydrogen content with appropriate separation technologies. Work package 3 investigates various membrane materials that are suitable for separation. The characteristics of the most suitable membranes are included in the case studies in later Deliverables.

In the HIGGS project, cost considerations are only made for the transmission network. Analyses of data on network development projects have shown that pipeline projects cost between 1 and 3.5 M€/km, depending on the size of the diameter. Reducing stations or city gates cost up to 20 M€, depending on the nominal flow rate. Last but not least, compressor stations between 5 and 50 MW capacity cost between 25 and 200 M€. Only marginal shares of these costs are assumed for the adaptation of the grid for hydrogen admixing. With these values, the specific transport costs of hydrogen for defined cases can be calculated in upcoming tasks and compared with other systems. Various studies have calculated values between 1.78 and 5.84 €/MWh_{H2}/1,000 km for pure hydrogen pipelines.

In order to model such a case from the bottom, an appropriate methodology had to be developed. For network models, important core data are geometric information on the pipes (diameter, length, material, number of pipes), information on the infrastructure (number and locations of city gates, compressors, regulating valves) and operating conditions (pressure stage, volume flow and flow direction, ambient temperatures). In addition to the information from the operating companies, publicly available data sets like the reference data set 'LKD-EU' for Germany or the 'IGG gas transmission network data set' for Europe were considered for modelling purposes. This QGIS-based data contains information on pipe diameters and operating pressures, the amount and position of city gates and compressor stations and how pipelines are routed roughly (e.g. single lines or parallel, ring circuits). On the ENTSOG Transparency Platform, information on flow direction, flow quantity and gas quality at border and market crossings is recorded in hourly resolution and was retrieved for certain points. In the LKD-EU set, regional consumption data, subdivided for the household and industrial sectors, are available for the German region in an annual resolution. These can be distributed in hourly resolution by using common load profiles with relative shares depending on the consumer.

The modelling for a selected network section and the calculation of the transport effort requires suitable software. A short evaluation was carried out and documented. In addition to gas quality tracking, the possibility of time-based calculation and import and export options were also considered.

The transmission network in Europe is highly branched and there are transport routes that cross each other. One of these intersections can be identified in southern Germany between the MEGAL (east-west route) and the TENP (north-south route). This route appeared to be interesting as a model basis for the case studies due to the importance to European supply security and availability of data for the two pipelines. The dimensions and the operating pressure of the two transmission lines are different. In addition, natural gas can be exchanged between the two pipelines at the intersection in Mittelbrunn and the TENP also allows a flow reversal. Transporting hydrogen-natural gas mixtures through Italy or Spain are also interesting alternative scenarios. In both cases, the scenario would be hydrogen production in the northern Sahara region and the flow direction from south to north. An advantage could be that these scenarios could be surrounded by imports from LNG stations (or liquid hydrogen injection stations).

Outlook

The model, which was built for the German case (TENP-MEGAL Intersection), has to be increased in detail. One of the challenges is the transfer of the compressor and gas exchange station in Mittelbrunn into the model. Not only the gas exchange, but also the flow reversal of the TENP has to be implemented. Furthermore, it is necessary to verify the consumption quantities and to work out load profiles for the industrial sector. In a later step, it is foreseen to integrate local hydrogen producers. This requires a production profile of surplus renewable electricity that could be available for electrolysis. It is assumed that such surplus energy could come mainly from wind and PV plants. Moreover, the boundary conditions must be implemented and investigated how they will affect the network calculations.

The cases to be investigated, which will be defined in Task 5.2, will accordingly have a blending share of up to 20 or even 30 vol.-% hydrogen and cover different scenarios. In that way, statements can be made on the additional technical and economic costs for the corresponding admixture level. In preparation for T5.3, it is investigated how separation technologies can be realised in the model together with *Tecnalia*. To round off the investigations, the aim is to make comparisons between the transport costs of hydrogen in 100 % H_2 networks, in blends in the existing network and transport in trailers.

1 Objective

The main objective of this Deliverable is to provide the common ground for the techno-economic modelling, which will be carried out within Task 5.2 (M12-31).

The specific objectives of this Deliverable are classified as follows:

- Identifying the baseline and defining the scope of investigations of WP5 (and other work packages) within the HIGGS project.
- Definition of case studies, including definition of generic topologies, structures of HPGN that are relevant in the EU context.
- Analysis on existing software for grid modelling, operation and forecasting, based on the available tools used by stakeholders.

2 Introduction

In the HIGGS project, an experimental R&D platform is being built to conduct tests on the integrity of natural gas transmission network infrastructure under the influence of hydrogen admixture. The testing loop includes state-of-the-art components and materials of gas pipelines and is designed to work up to 80 bar with various blending levels but also pure hydrogen. A hydrogen purification prototype based on membrane technology for the separation of H_2/CH_4 on behalf of different end-use applications is also integrated in the design.

In addition to the construction and commissioning of the plant, as well as carrying out and analysing various tests (e.g. varying the H_2 concentration and using different pipeline steels), further research is carried out with regard to legal, regulatory, technical and economic aspects of the blending of hydrogen into the existing gas grids.

In WP5, *Techno-economic modelling and validation, enablers and interoperability*, the main objective is to develop operational strategies and business cases for grid operators and to illustrate how hydrogen blending in the high-pressure gas grid can contribute to the overall goals of decarbonising the European energy system. Moreover, the influence of higher H_2 fractions on the economics of the gas transport value chain will be assessed in the project and compared to other common methods, considering gas producers, transport companies up to delivery to the gas distribution networks. For this purpose, a numerical model will be compiled for representative cases in Europe in order to describe technical operation and business impacts. The model will allow analysing the different technological adaptions of the grid, which strongly depend on the blending level, as well as the operational strategies for the future grid with hydrogen injection.

This document contains most of the work carried out in Task 5.1, *Baseline and case studies definition*, so far. The Task is led by OST (formerly HSR) and runs from month 7 to 24 of the project lifetime. Project partners participating are TECNALIA, REDEXIS and FHA (sorted by commitment in terms of person months).

Section 3 discusses the baseline. As an introduction, the consumption and trade of gas in Europe is illuminated and quantified on the basis of historical data. This is followed by figures on hydrogen, which explain why it is as important as the energy carrier of the future and how it impacts the current standards. To get a first impression of the development of hydrogen-related technologies, recently published strategies and pathways for a hydrogen-economy are examined.

The essential drivers for the modelling of case studies in Task 5.2 are presented in section 4 and the main parameters to be investigated in detail are described. First, the blending scenarios and separation of H_2/NG blends are discussed. Then the basics of gas transport systems and the influence of hydrogen on their operation will be discussed, before continuing with economic considerations for the transport of H_2. Finally, real-life scenarios of the European grid are described and one case is specifically highlighted.

In a subsequent section, the methodology being followed to deal with the modelling tasks is presented. In addition to the approach and the scope of the modelling, some fundamentals are explained, e.g. for the simulation of networks. This is followed by a description of existing software for grid modelling, operation and forecasting.

3 Baseline

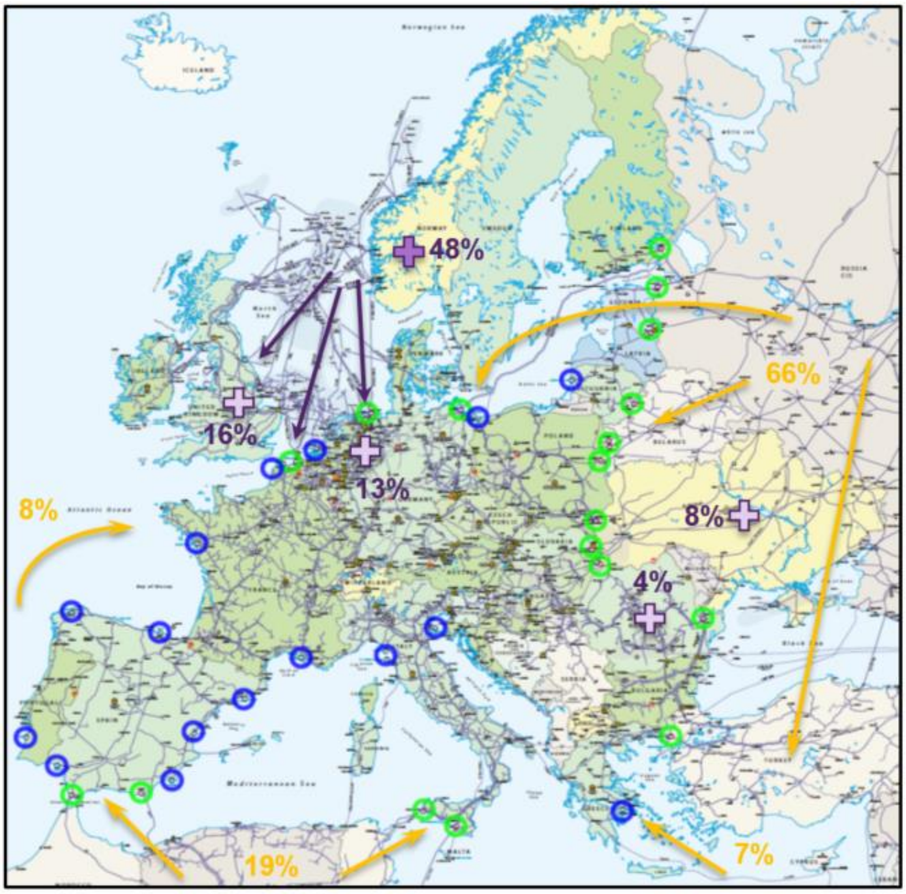
In this section, the baseline for the challenges addressed in HIGGS will be discussed.

3.1 Gas demand of European countries

In order to better quantify energy transition strategies regarding the gas sector and get a sense of the relative amounts of hydrogen described later on, the historical gas consumption in Europe up to the present day is reviewed in the following sections.

3.1.1 The European gas system and trade movements

In the reference year 2018, the total energy consumption of natural gas in Europe (including Ukraine and Turkey) was around 6165 TWh. Almost 40 % (2785 TWh) of this was produced in Europe, mostly by Norway, but also by the UK, the Netherlands, Ukraine and Romania. The other 3380 TWh were transported to Europe via the 26 pipeline interconnection points and 20 % via the 21 LNG terminals. Two thirds of the imports originated from Russia, followed by Algeria (19 %), Qatar (7 %), Nigeria and America (8 %) as major importers [1]. These imports are illustrated in the following figure:



Total consumption:
6'165 TWh

2'785 TWh Production

3'380 TWh Imports:
- *2'705 TWh pipeline*
- *675 TWh LNG*

Figure 1: Production countries, pipeline interconnection points, LNG terminals and import flows of natural gas to Europe and the corresponding amount of energy

The split of consumption between the European states is shown in Figure 2. For the sake of better comparability, the quantities are expressed as TWh (or MWh / kWh) instead of tons or cubic meter.

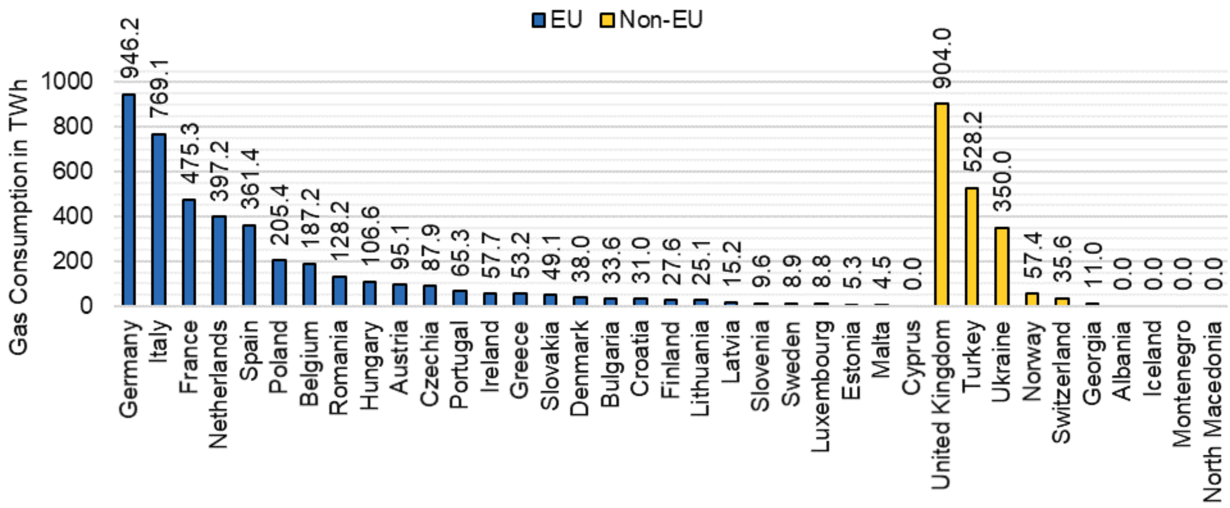


Figure 2: Gas supply of European Countries 2018 [2]

The largest 2018-consumers by far were Germany and Italy in the EU and the United Kingdom (non-EU), followed by France, the Netherlands, Spain, Turkey and Ukraine. A closer look at the trade movements revealed that Italy only obtains a quarter of its demand from North Africa and imports a large part of Russian gas, which is transported through Austria or Switzerland down South. The figures from the statistical review [1] indicate that Germany takes in large surpluses (~200 TWh higher than demand) and distributes Gas to many Countries, also in Central and Western Europe.

3.1.2 Historical data and prognoses on future consumption

Looking at the historical data in Figure 3, it is striking that European gas supply has increased by 50 % since 1990 and is now stabilising at a lower level, while global consumption has roughly doubled to date. According to the various data sources, a tendency towards decreasing demand has been noticeable in Europe for the last ten years.

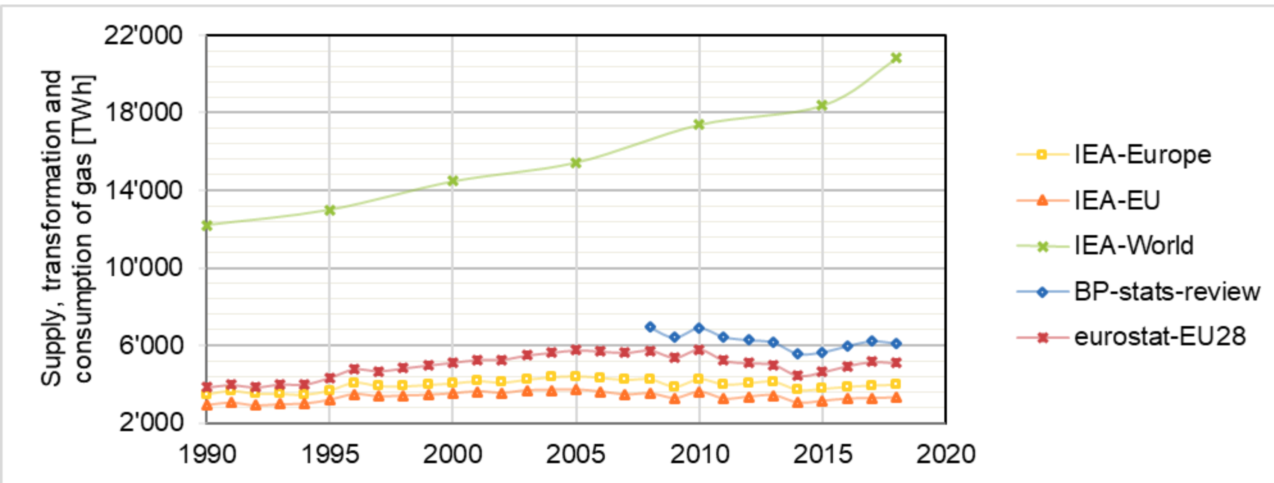


Figure 3: Supply and consumption of natural gas from 1990 to 2018 [1] [2] [3]

The oscillations of the data are very similar, however, they differ in the absolute numbers. BP's figures [1] have been verified with those from the Eurostat database, where data is available only for the EU countries. The source of the IEA's figures could not be replicated.

In order to include future trends in the models, studies on the development of gas demand were considered. Most projections indicate a significant decline in demand for gas by 2040 and 2050 (see Figure 4). Otherwise, it is likely to be stable. The scenarios are usually targeting a reduction of greenhouse gas emissions by at least 80% through different measures (e.g., Energy efficiency measures, electrification, technological developments and behavioural changes at societal level). In certain scenarios, natural gas has a short-term increase in demand, e.g., if electricity generation has to take place via gas-fired power plants due to the phase-out of coal or nuclear power. To cover a wider range of scenarios, it certainly makes sense to consider the techno-economic aspects for unchanged as well as declining gas supply (indicated by the two orange arrows) in the models.

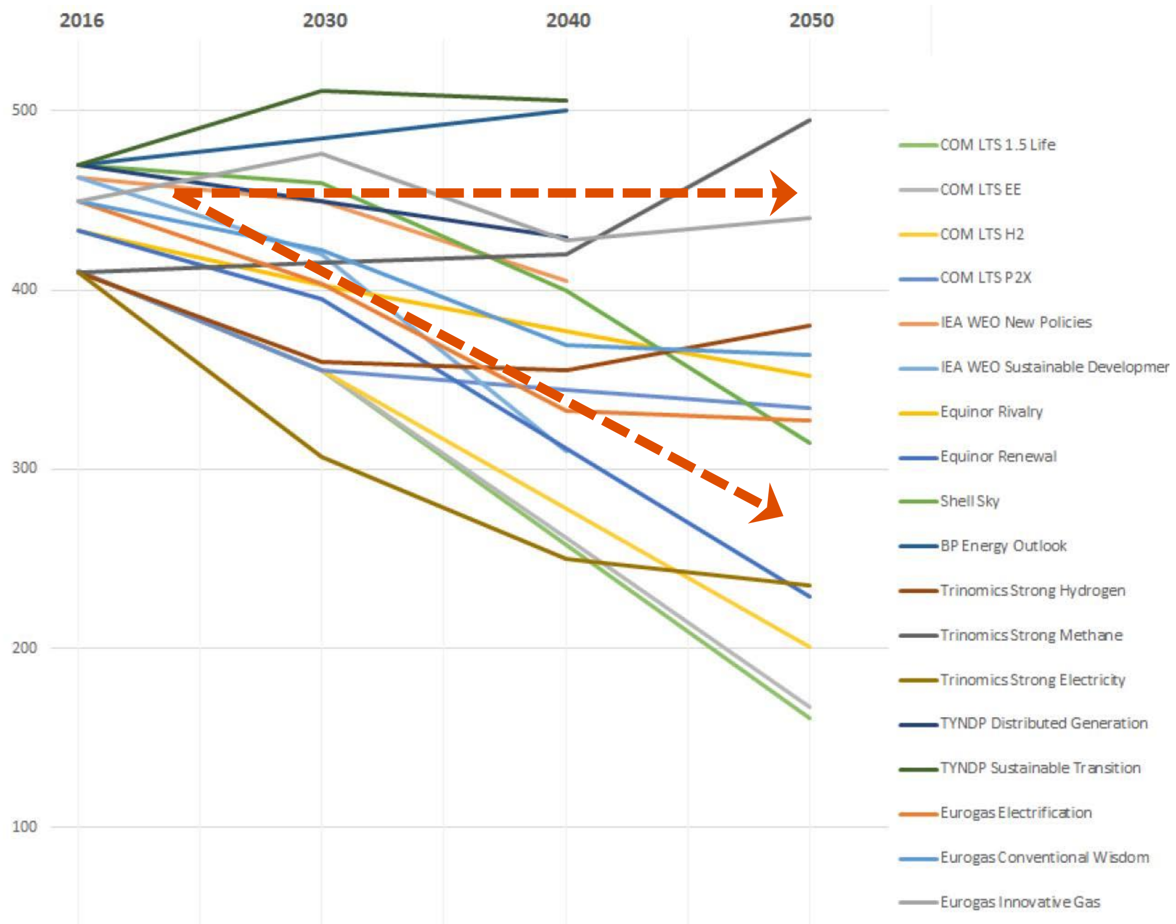


Figure 4: Scenarios on the development of European natural gas demand from 2016 to 2050 [4]

3.2 The role of hydrogen

The decarbonisation of the energy sector can be achieved with renewable energy sources (solar, wind, etc.). However, the electricity surplus generated at the highest production moments need a way to be properly stored, so that this energy can be used when it is actually required. The production of hydrogen via electrolysis can mean an alternative to the use of batteries or immersion heater, not suitable for storing large quantities of electricity. There is a clear commitment in the European Union to produce green hydrogen.

Blending hydrogen with natural gas may contribute to the development of renewable energy facilities since the gas grid can provide large storage quantities for hydrogen, as well as a delivery pathway across a broad range of locations because of its extensive interconnection. Due to the large geographic scope of the existing natural gas infrastructure, even very low blend levels (lower than 5 vol.-%) can absorb huge quantities of excess renewable energy. Blending can also mean a way of delivering hydrogen to the end-users, such as industry, FCEV's or stationary fuel cells. Therefore, it would need an extraction from the natural gas using suitable separation technologies. [5]

Adding hydrogen to the grid can result in a significant reduction of greenhouse gas emissions. According to the THyGA project, an admixture of 20 vol.-% of H_2 into CH_4 can reduce combustion-related CO_2 emissions by about 7 %. Raising the H_2 content to 40 vol.-% in the fuel gas, will lead to a CO_2 reduction of about 17 %, while a hydrogen content of 60 vol.-% will result in a reduction of about 31 % [6]. The evolution of the emission of CO and NO_x is not so clear and depends on the combustion parameters of the specific devices. With an estimated annual natural gas consumption of 5090 TWh, [7] even a low content of hydrogen in the blend can mean an important reduction in CO_2 emissions. The association between hydrogen admixture and normalised CO_2 emissions per kWh is shown in Figure 5 for natural gases and can be derived from the general reaction equation (1) if an ideal combustion process is assumed.

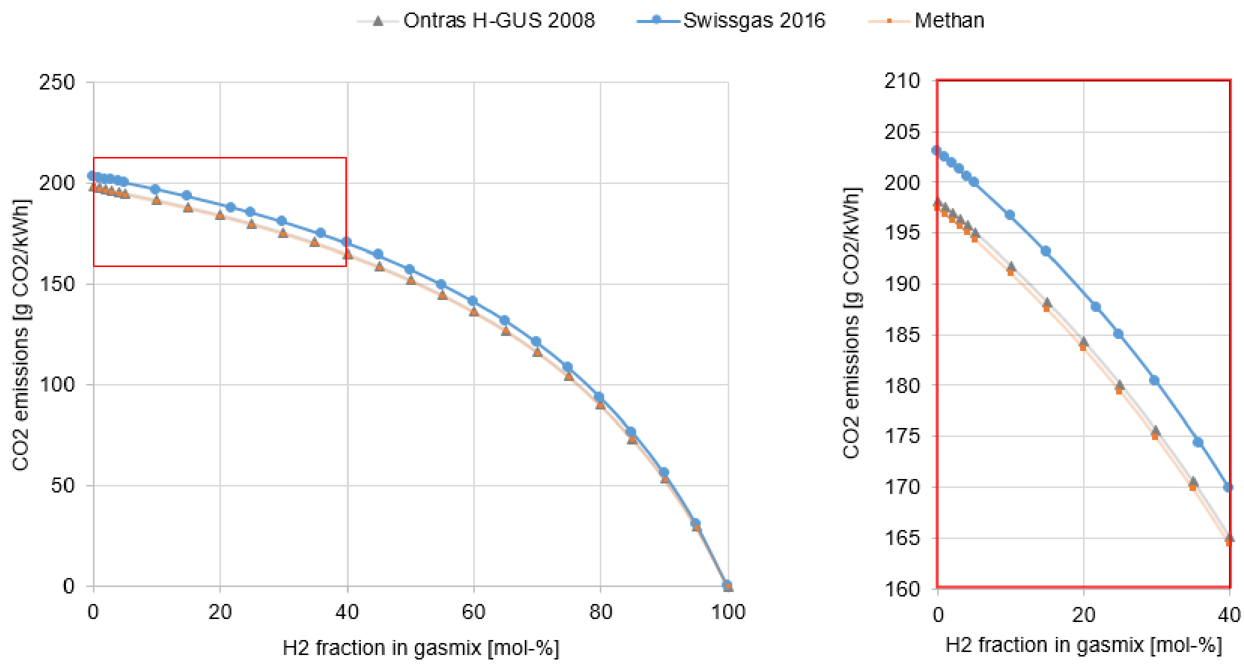


Figure 5: CO_2 emissions of various gasmixes related to volumetric calorific value

$$C_jH_kS_lN_mO_n + \left(j + \frac{k}{4} + c - \frac{n}{2}\right) \cdot O_2 \leftrightarrow j \cdot CO_2 + \frac{k}{2} \cdot H_2O + l \cdot SO_2 + \frac{m}{2} \cdot N_2 \quad (1)$$

Blending natural gas with a limited amount of injected hydrogen can be an effective temporary solution to boost hydrogen production and facilitate the reduction in CO_2 emissions during the 2020's. However, the volumes of hydrogen needed to reach a net-zero emission energy system in 2050 will require a separate regional and national pure hydrogen infrastructure around 2030, as well as trans-EU hydrogen flows around 2040. Such infrastructure can be largely based on existing gas infrastructure, which can be retrofitted cost-effectively (as described in the *Gas for Climate 2019* study). While part of existing gas transmission infrastructure will be retrofitted to carry H_2, part of it will remain in use to transport decreasing volumes of biomethane, some power-to-methane, and remaining volumes of natural gas for blue hydrogen. Gas distribution infrastructure will be used to collect biomethane from farms and other decentral sources and deliver it to buildings. Regulatory and policy developments are needed to support the evolution of gas infrastructure to the future supply and demand of low carbon and decarbonised gases. Current policies are not developed to cope with declining gas volumes and with repurposing assets from natural gas to hydrogen. [8]

Pipeline transport of hydrogen can either take place by blending shares of hydrogen with methane or dedicated hydrogen transport. Blending makes sense when hydrogen volumes are small, especially during the 2020s. When hydrogen volumes increase while transported volumes of natural gas decrease, dedicated hydrogen transport will emerge, initially connecting industrial clusters and later connecting regional and national hydrogen infrastructures. [9]

3.2.1 Current production and use of hydrogen

Production processes of hydrogen can be classified into thermo-chemical/thermal processes, electro-chemical and biological processes. The most relevant thermo-chemical process is the steam reforming of hydrogen from hydrocarbons. Using hydrocarbons like methane and high temperature steam with pressures between 15 and 25 bar results in hydrogen and CO_2. Another possible process is the partial oxidation of natural gas using oxygen and high temperatures and pressures as well as pyrolysis, also referred to as thermal cracking, where hydrocarbons are cracked at high temperatures using catalysts in the absence of oxygen to create hydrogen [10]. There are new developments trying to use plastic waste and create hydrogen with the by-product of carbon dioxide or in a very recent process instead of carbon dioxide, carbon nanotubes (waste-to-hydrogen). [HIGGS D2.3]

A different approach is the electro-chemical separation of water, using (regenerative) electricity to decompose water into its components water and hydrogen. Depending on the temperature of operation low temperature water electrolysis (LTWE) or high temperature steam electrolysis (HTSE) technologies are distinguished. Additionally, depending on the used electrolyte there are three main LTWE technologies: alkaline electrolysers (AEL), proton exchange membrane electrolyser (PEMEL) and those based on Anion Exchange Membranes (AEMEL). Regarding HTSE, electrolysers including solid oxide anionic conducting electrolyte (SOE) or proton conducting electrolyte (PCE) are considered. [HIGGS D2.3]

Nowadays, around 120 Mt/year of hydrogen is produced in the world. Two-thirds of them correspond to pure hydrogen and the other one-third is blended with other gases [11]. This would suppose 4,000 TWh of energy, which is around 4 % of global final energy and non-energy use, according to International Energy Agency (IEA) statistics [12]. Around 95 % of this hydrogen is generated from natural gas and coal, while the other 5 % are generated as a by-product from chlorine production or through electrolysis. This is roughly in line with the assumptions from the IEA report [13], according to which about 70 Mt of dedicated pure hydrogen are produced worldwide per year (2760 TWh, 76 % from natural gas steam reforming and 23 % produced from coal). In the iron and steel industry, coke oven gas also contains a high hydrogen share, some of which is recovered. However, there is currently just minor hydrogen produced via renewable sources [14], for example, electrolysis accounts for about 2 % of today's production [13].

The FCH JU estimated the 2015 hydrogen demand in the EU at 339 TWh, which corresponds to about 5 % of the energy supply with natural gas [15]. The total hydrogen production in Europe in 2019 was 12.2 Mt according to the FCHO database [16], involving merchant hydrogen (1.5 Mt), captive hydrogen (7.6 Mt) and hydrogen as by-product of other processes (3.0 Mt).

As depicted in Figure 6, most part of the captive hydrogen is produced via reforming, with over 7.5 Mt/year. Hydrogen as by-product is obtained mainly in coke oven gas processes (over 1.6 Mt/year), followed by reforming processes and those using ethylene as feedstock (649 and 403 kt/year, respectively). Regarding merchant hydrogen, the production in 2019 was mainly achieved by reforming processes (1245 kt/year) and was quite poor using green power, such as water electrolysis (15 kt/year). These figures are allocated to the European countries in Figure 7. Some sources state that in the next decades, an increase to nearly 550 Mt/year (21,750 TWh/year) is expected until 2050 because of the increasing need of carbon-neutral energy supply throughout the EU [10].

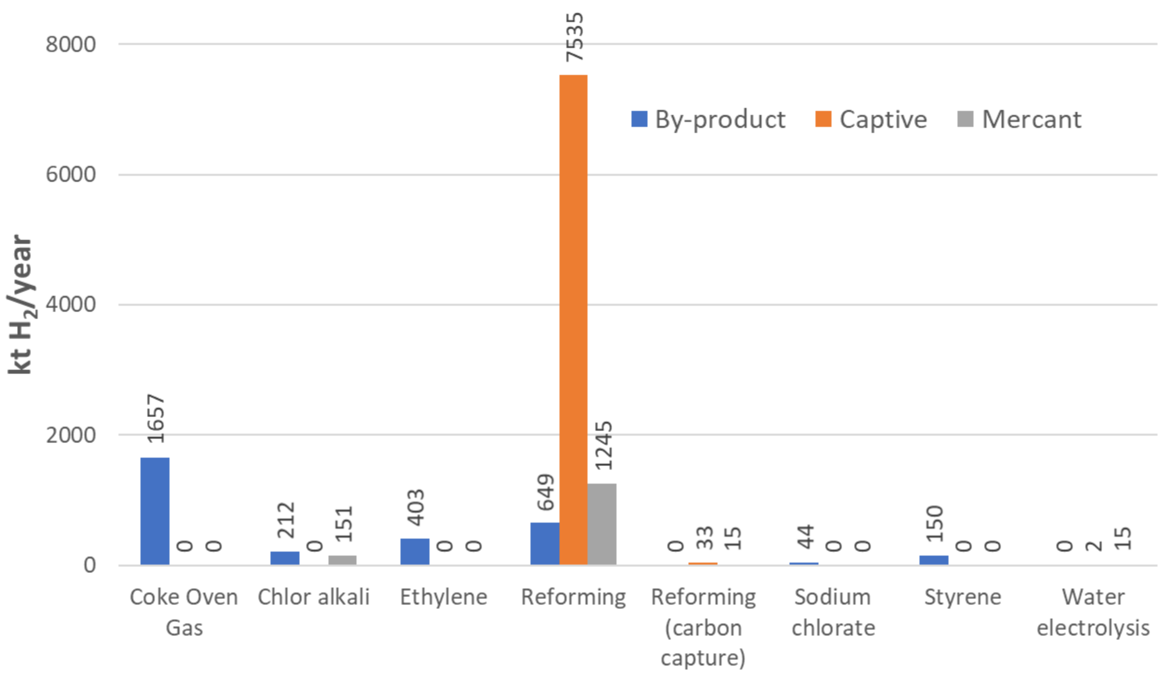
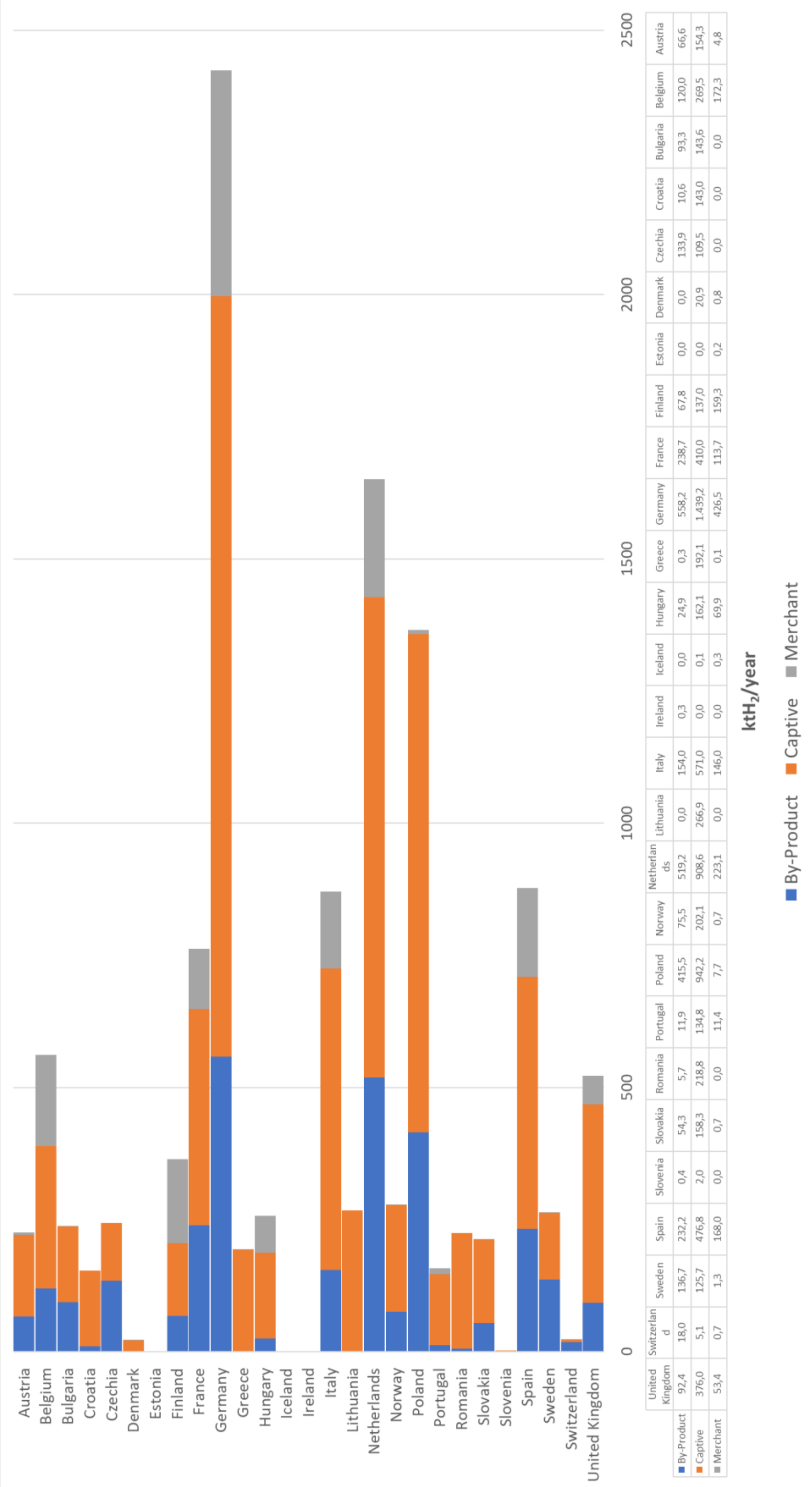


Figure 6: Hydrogen production with different feedstock and technologies [16]



	United Kingdom	Switzerland	Sweden	Spain	Slovenia	Slovakia	Romania	Portugal	Poland	Norway	Netherlands	Lithuania	Italy	Ireland	Iceland	Hungary	Greece	Germany	France	Finland	Estonia	Denmark	Czechia	Croatia	Bulgaria	Belgium	Austria
By-Product	92,4	18,0	136,7	232,2	0,4	54,3	5,7	11,9	415,5	75,5	519,2	0,0	154,0	0,3	0,0	24,9	0,3	558,2	238,7	67,8	0,0	0,0	133,9	10,6	93,3	120,0	66,6
Captive	376,0	5,1	125,7	476,8	2,0	158,3	218,8	134,8	942,2	202,1	908,6	266,9	571,0	0,0	0,1	162,1	192,1	1.439,2	410,0	137,0	0,0	20,9	109,5	143,0	143,6	269,5	154,3
Merchant	53,4	0,7	1,3	168,0	0,0	0,7	0,0	11,4	7,7	0,7	223,1	0,0	146,0	0,0	0,3	69,9	0,1	426,5	113,7	159,3	0,2	0,8	0,0	0,0	0,0	172,3	4,8

Figure 7: Hydrogen production in Europe in 2019 [16]

3.2.2 Gas properties of NG-hydrogen blends

In this section, the impact of hydrogen admixture on the properties of the gas to be transported is discussed. Primarily, parameters of gases that are relevant for techno-economic modelling in HIGGS, i.e. transport and energetic properties, are investigated. Finally, the influence on the combustion process of H_2/NG mixtures is briefly mentioned, as this will be important for the economic considerations.

3.2.2.1 Comparison of pure gas properties

For the computations, the two main natural gases from Russia and extracted from the North Sea (Norwegian gas) are taken into account. As explained in chapter 3.1, those are most imported ones in the European gas mix. The gas properties and compositions are listed in Table 1 below and the corresponding footnotes (1, 2), respectively.

Table 1: Relevant gas properties of two NG-types compared with hydrogen

Parameter	Unit	H-Gas Russia[1] [17]	H-Gas Northsea[2] [17]	Hydrogen
Density [ρ_n]	kg/m³	0.74	0.81	0.09
Gross calorific value [H_S]	kWh/m³	11.19	11.64	3.54
Wobbe Index [W_S]	kWh/m³	14.75	14.69	13.43
Heat capacity [c_p]	kJ/kg/K	2.13	2.02	14.20
Dynamic viscosity [η]	µPa*s	10.25	10.20	8.38
Speed of sound	m/s	422.7	401.9	1261.1

3.2.2.2 Transport properties

Indicators of the transport properties of gases are the density and viscosity, which corresponds to the transfer of momentum. The change in the two parameters with increased hydrogen blending into Russian H-Gas is shown in Figure 8 below.

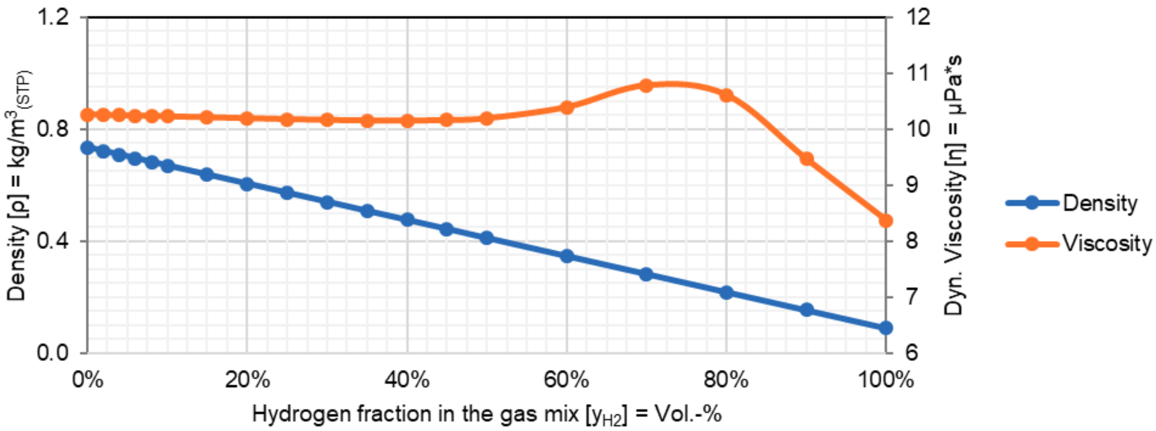


Figure 8: Change in density and viscosity with increasing H_2 ratio in Russian H-Gas @ STP

[1] Molar composition: 96.96 % CH_4, 0.86 % N_2, 0.18 % CO_2, 1.37 % C_2H_6, 0.45 % C_3H_8, 0.15 % C_4H_{10}, 0.02 % C_5H_{12}
[2] Molar composition: 88.71 % CH_4, 0.82 % N_2, 1.94 % CO_2, 6.93 % C_2H_6, 1.25 % C_3H_8, 0.28 % C_4H_{10}, 0.05 % C_5H_{12}

All fluids have a viscosity, which is a type of internal friction. To keep a fluid in motion, a continuous application of force is required. Considering the case of gas being transported through a pipe. A pressure difference (Δp) must be maintained between both ends of the pipe for the gas to flow, in the case of gas transmission network that is the compressor. The resulting flow rate is proportional to Δp and inversely proportional to viscosity (η), since the friction that counteracts the flow grows as η increases. It also depends on the geometry of the pipe, however, this effect is not considered here.

3.2.2.3 Real gas factor

Real gases only behave approx. ideally at low pressures and high temperatures, i.e. according to the equation of state (2) for ideal gases with a real gas factor [Z] (or compressibility factor) of one. At higher pressures, gases sometimes deviate considerably from ideal behaviour, as both attractive and repulsive forces between the particles become noticeable. Therefore, the real gas factor depends on the pressure and temperature of the gas (the molar volume in turn depends on the temperature alone). A real gas is generally harder to compress at high-pressure than an ideal gas, which corresponds to a real gas factor greater than one.

$$Z = \frac{p \cdot V}{R \cdot T \cdot n} \tag{2}$$

The real gas factor is a substance-specific variable that depends on pressure and temperature and must be taken into account particularly in the planning and calculation of high-pressure gas pipelines. Figure 9 shows the change in the real gas factor of H-gas under different hydrogen admixtures and different pressures. The calculations were carried out in *RefProp*. [17] Shows empirical approaches for the calculation of this parameter for natural gases.

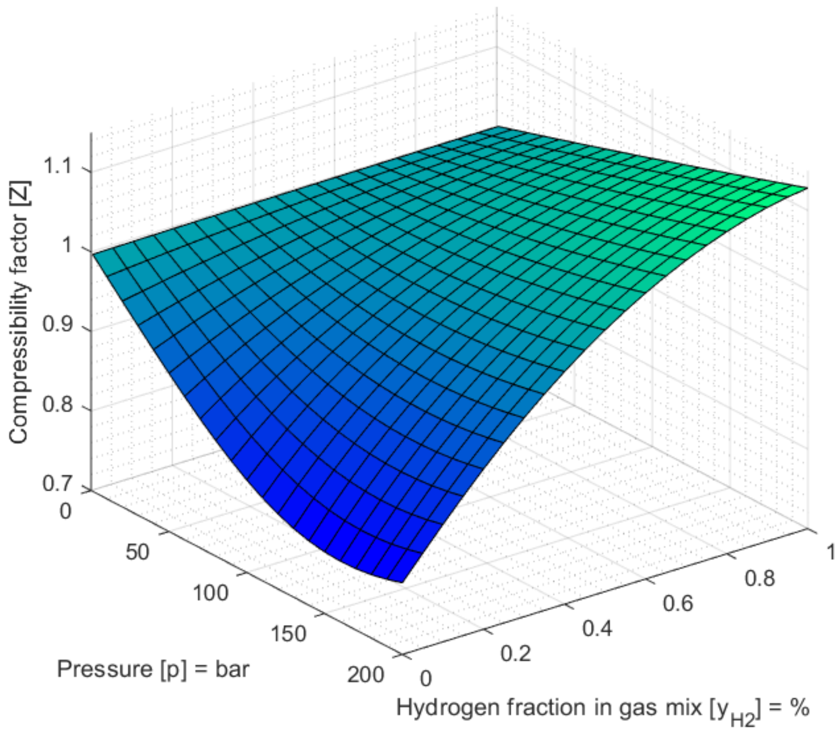


Figure 9: Compressibility factor of H-Gas (T=15 °C) for different H_2 admixtures and pressures

3.2.2.4 Wobbe vs. GCV

The gross calorific value (GCV) describes the energy content of the gas and is important for billing. According to DIN EN ISO 6976, the value of a gas is given by the negative value of the reaction enthalpy that occurs when the gas burns under constant pressure. It is assumed that the temperature of the reaction product after a completed combustion process is equal to the temperature before combustion. The Wobbe Index is a characteristic value for the interchangeability of gases with regard to the heat load of gas burners and is a very important combustion-related parameter, especially for gas boilers. Fuel gases of different compositions show approximately the same heat load (capacity) at the same Wobbe and under the same pressure at the burner. Certain fluctuations can be tolerated, but if they fall below or exceed them, disturbances of the combustion process can occur and, for example, high carbon monoxide emissions and/or overheating can occur [17]. The Wobbe Index and the gross calorific value are related as follows:

$$W_S = \frac{H_S}{\sqrt{\rho_{n,NG}/\rho_{n,Air}}} = \frac{H_S}{\sqrt{\rho_{rel.}}} \tag{3}$$

Figure 10 shows feed-in limitations of different countries with regard to the two parameters and how hydrogen admixture in different gases affects them. It can be seen that the gas properties with increasing H_2 contents fall out of bounds very quickly.

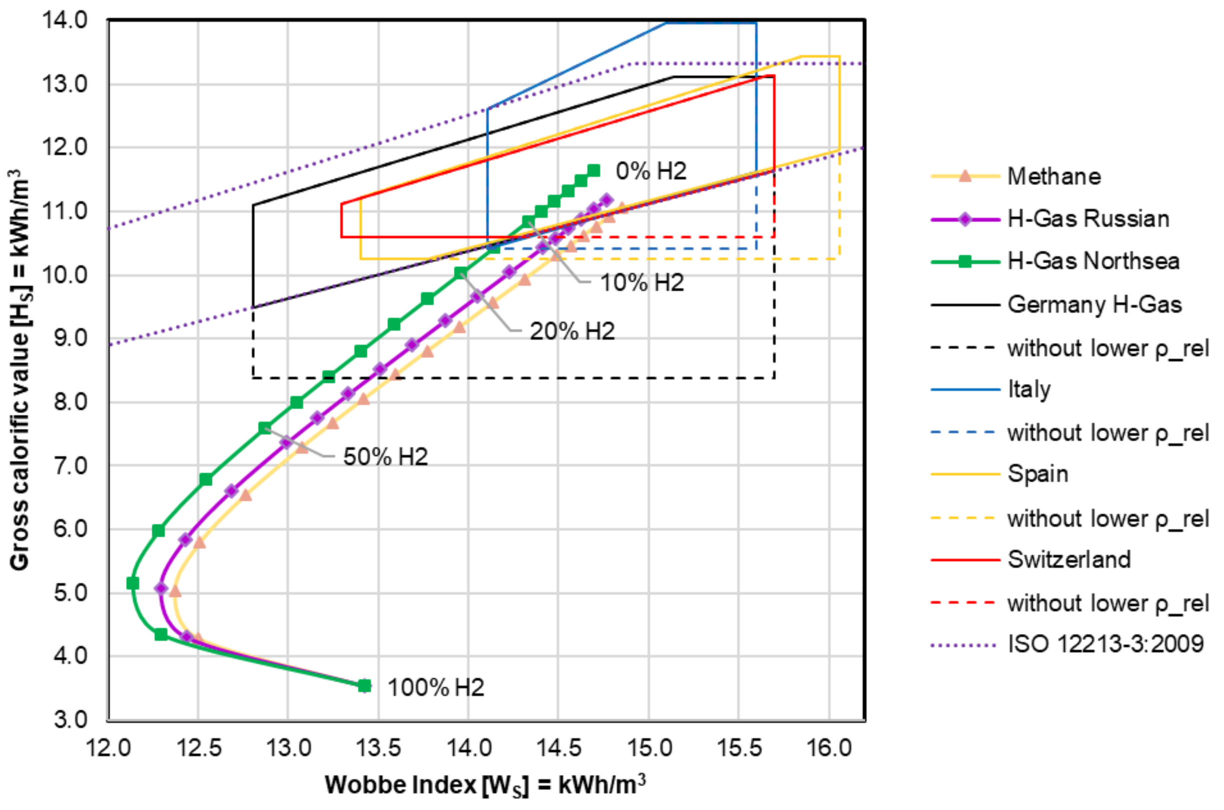


Figure 10: Change of Wobbe and GCV for raised hydrogen contents in natural gas (Russia and North Sea) and methane as well as injection restrictions of some countries regarding those two

However, this is mainly due to the limitation of the lower relative density imposed by the scope of the EN ISO 12213 standard. This provides for the density of pure methane as a minimum and would have to be amended in the case of permission to inject higher H_2 concentrations. Particularly since only 10 mole-% hydrogen in the gas is currently permitted according to the standard [18].

If an injection were not to be limited by the lower relative density [$\rho_{rel.}$], but only by the Wobbe Index and the gross calorific value, larger amounts of added hydrogen would be possible, especially in Germany, where the lower bound for the GCV is restricted to ~8.4 kWh/m^3. This assumption is indicated in Figure 10 for all countries with a dashed line.

3.2.2.5 Volumetric energy density

Assuming that the 480 TWh of today's hydrogen use (resulting from 12.2 Mt mentioned in section 3.2.1) would be a homogeneously mixed natural gas, regardless of time shift in supply and demand, this would amount to an energy share of ~8 % from the total used energy (6165 TWh). The volume share of H_2, on the other hand, would be significantly higher. Namely 21.6 vol.-% in this case. The correlation between those values results from the fact that the energy content of hydrogen (3.54 kWh/m$^3_{(STP)}$) is about three times smaller than that of natural gas (>11 kWh/m$^3_{(STP)}$). Figure 11 shows the relation between energy and volume share of hydrogen in natural gas, as well as the linear increase in volume of the gas mix, when a constant amount of energy is assumed.

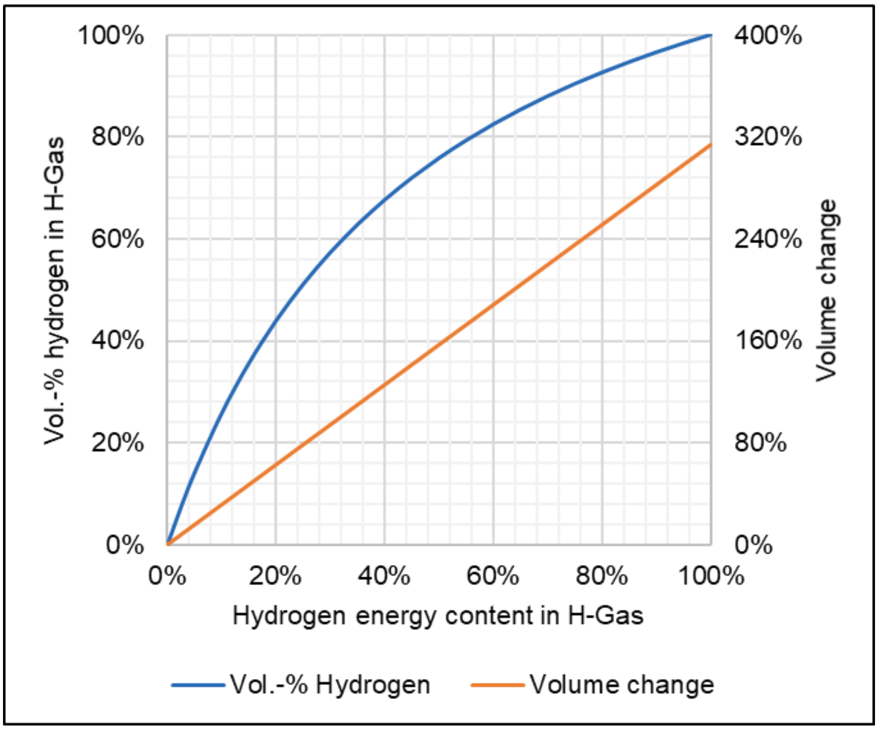


Figure 11: Relationship between energy and volume shares of H_2 in natural gas as well as the increase of volume assuming constant energy (calculation with Russian H-gas @ STP)

This figure intends to illustrate the connection that it is important to be careful when referring to hydrogen fractions in the gas, as energy and volume fractions differ significantly from each other.

3.2.2.6 Impacts on combustions processes

The topic of combustion processes for H_2/NG blends is not part of this study. Nevertheless, the topic should be briefly addressed in order to be clear about the challenges facing consumers of hydrogen or natural gas fuels. The change in gas properties due to hydrogen admixture can lead to excess of oxygen in combustion processes if the air and fuel supply is not controlled. Together with higher flame temperatures occurring, this favours the formation of more NO_X which is a serious challenge for e.g. incinerator operating companies. They are required by law to minimise emissions of environmentally harmful substances and can be fined for that. The study also shows that more water vapour will be formed in the exhaust gas. This can also be anticipated from the chemical reaction equations. This means that changes can also be expected in downstream plant components, e.g. heat exchangers. In summary, this can lead to many end-user devices having to be adapted or replaced above a certain admixture concentration, which would result in substantial costs. Annex IV provides more details on how the combustion process is influenced by the gas properties of H_2/NG blends.

3.2.3 Future scenarios

This section is supposed to give a short overview of what share of the energy mix hydrogen can achieve in the medium and long term. For this purpose, both European models and the hydrogen strategies of individual countries are outlined.

3.2.3.1 Models on European level

Figure 12 shows the energy consumption by gas as a source in different EU-models for 2050. The total consumption consists of the shares of natural gas, carbon-free gases and hydrogen. Applying the same assumption as in section 3.2.2.5 to the different future scenarios would result in even higher hydrogen levels in the natural gas grid. The strong electrification (EE, CIRC, ELEC) and P2X scenarios each result in a share of about 20 vol.-% H_2. For the 1.5 °C scenarios (last three from the right), the share is between 40 and 60 vol.-%. It is highest in the H_2 scenario, at around 70%. These numbers are indexed with triangles in the graph.

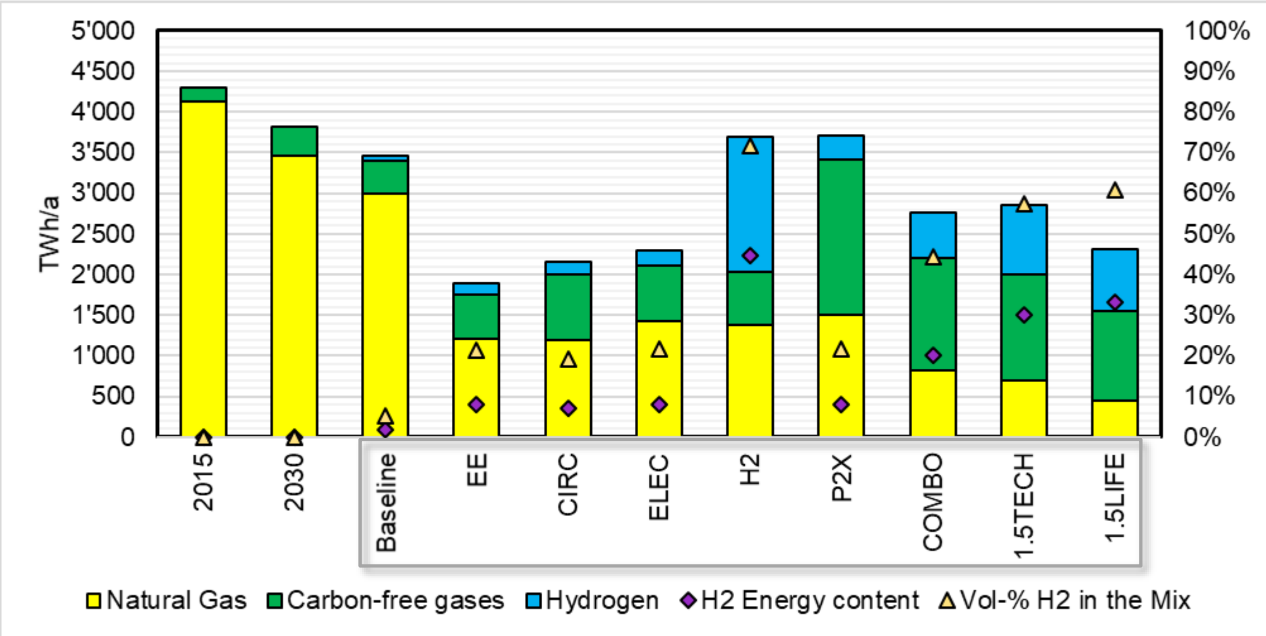


Figure 12: Different scenarios 2050 with the respective shares of natural gas, renewable gases and hydrogen modelled by the EC [19]

The Gas for Climate study *Gas Decarbonisation Pathways 2020 to 2050 [8],* likewise, states that 1700 TWh of hydrogen could be produced within the EU by 2050. Even further, the EC's hydrogen strategy for a climate-neutral Europe predicts a consumption of up to 2250 TWh if ambitious measures are taken. Thereby, in the next ten years, the hydrogen demand is expected to double, compared to the current level. The corresponding data is listed in Table 2. In order to achieve this successfully, electrolysis plants with a total capacity of 6 to 40 GW shall be able to supply renewable hydrogen in Europe in mid-term [20]. According to *Fuel Cells and Hydrogen Joint Undertaking*, the electricity need for generating 2250 TWh of hydrogen in Europe in 2050, represents roughly a quarter of the EU's total energy demand [15].

Table 2: Projected hydrogen demand in EU for 2030 and 2050 [15]

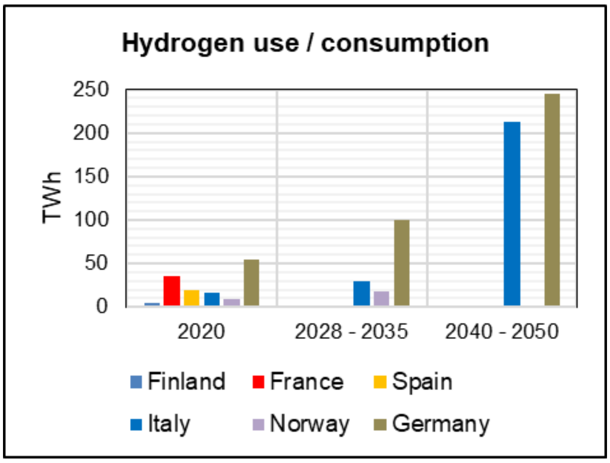
	2030	2050
Business as usual	~500 TWh	778 TWh
More ambitious scenario	657 TWh	2252 TWh

3.2.3.2 European hydrogen strategies

The fact that the share of hydrogen of the gas mix will ultimately be between 20 and 70 vol.-% is also in line with the most recent international hydrogen strategies of the individual countries. An overview of which European countries have published a hydrogen strategy and which national legal frameworks apply can be found in Deliverable 2.3 of the HIGGS project. These strategies have also been compiled very comprehensively in a document by *Ludwig-Bölkow-Systemtechnik* [21] last year and give a good impression in which sectors the individual countries may focus on the development of hydrogen. The individual sectors will be discussed in detail in later sections. In this section, only a few figures are given to help establish a practical admixture scenario for European gas grids.

3.2.3.2.1 Europe's prime gas consumers

In Figure 13, estimates of short-, medium- and long-term consumption and production for certain European countries, especially the largest consumers, have been summarised and presented. Taking Italy and Germany as an example, one can see that both predict approximately a quarter of their current energy consumption by gas to come from hydrogen in 2050. Depending on how the total demand of the two countries evolves, assuming that it drops by 30 to 40 %, a share of >50 vol.-% of hydrogen can be expected.



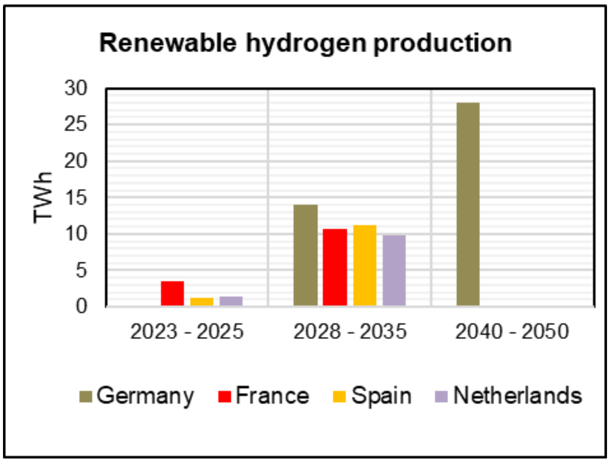


Figure 13: Outlook on the H_2 use and production of large gas consumers in Europe [21]

3.2.3.2.2 Europe's main suppliers

Information on selected countries that are responsible for a relatively large amount of Europe's gas supply is compiled below.

3.2.3.2.2.1 Russia

Hydrogen should play an important role in Russia's energy policy in the medium and long term. The production of hydrogen and H_2/NG blends by various sources, as well as international cooperation for easier access to the hydrogen market, are to be intensified. By 2035, approximately 80 TWh of hydrogen should be available annually for export, which corresponds to about 4 % of the gas volume supplied by Russia to Europe in 2018 [21]. Russia is receiving a lot of attention in the public debate, although it is more likely to be interested in exporting grey and blue hydrogen in the short and medium term. The production costs for green hydrogen are foreseeably higher in Russia than in global best locations due to higher prime costs for renewable electricity as can be seen in Figure 14. [22]

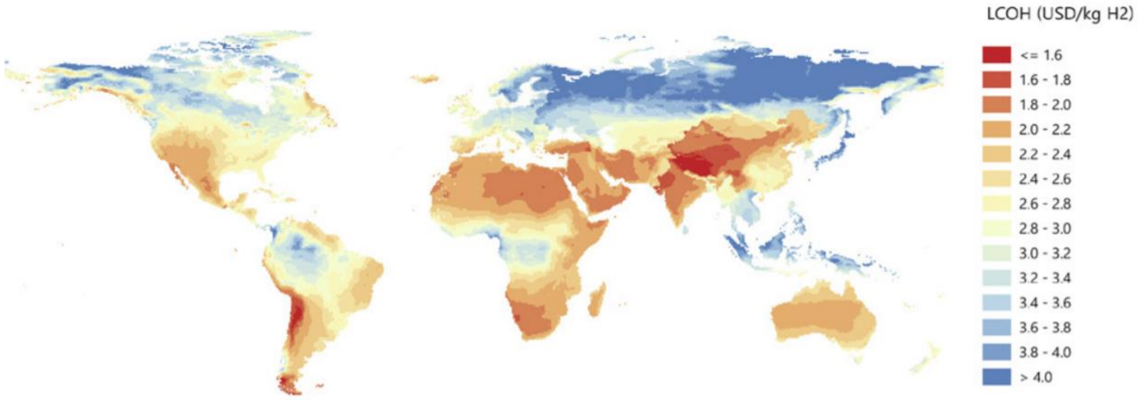


Figure 14: Production costs of green hydrogen from wind and PV plants in 2050 [22]

3.2.3.2.2.2 Norway

Funding of half a billion NOK has been provided through the ENERGIX energy research programme by the Norwegian government for the development of blue hydrogen technology, which appears to be a key element of Norway's strategy. The production of blue hydrogen promises to be cheaper in the short term than using electrolysis (green hydrogen). In a meta-study, on the other hand, the costs for green hydrogen imported via pipeline from Norway are given as 0.14 €/kWhH_2 for 2050, which is only slightly above the average of 0.12 €/kWhH_2 [22]. This pathway is understood to have a specifically Norwegian value also for future technology export to other European countries, both adding value through technology leadership and by offering CO_2 storage capacity (currently two facilities with a capacity of 1.7 MtCO_2/a) in old oil and gas fields under the North Sea. However, direct export from Norway as blue hydrogen is not foreseen [21].

3.2.3.2.2.3 Ukraine

Ukraine's energy infrastructure is characterised by low efficiency and high dependence on imported energy sources. Alternative energy sources would play an important role in achieving energy independence. Recent developments such as the current activities of the Ukrainian Hydrogen Council show that hydrogen is gaining importance in Ukraine. Thanks to the large wind and biomass resources that could be used for renewable hydrogen production, Ukraine has enormous potential for large-scale hydrogen production near major power generation plants. The export potential to the EU is about 118 TWh per year by 2030, which can be transported via dedicated pipelines. [21]

4 Case studies definition

This section should form the basis for the case studies in WP5 and address all relevant domains.

4.1 Hydrogen blending scenarios

The injection of hydrogen into the natural gas grid depends on various factors. On the one hand, it is important to determine which levels the existing infrastructure can withstand or are permitted to inject. But also the source and the end user of hydrogen have to be considered when it comes to supply and demand.

4.1.1 Admixture levels

A H_2/NG blend can be prepared in whatever range from pure natural gas to pure methane and the transmission grid seems ready to transport high hydrogen contents after more R&D is conducted and proper adaptations are adopted [23]. However, according to direct contact made with several stakeholders (TSOs, DSOs, similar projects to HIGGS, etc.), the amount of hydrogen to be blended with natural gas in the future is not expected to raise over 20 vol.-%, at distribution level and 20-30 % at transmission level. This fact is due to the limitations in the maximum amount of hydrogen that end-users can allocate.

As explained in previous sections, hydrogen and natural gas possess completely different physical and chemical properties. For example, the addition of hydrogen to natural gas leads to the reduction of the calorific value and Wobbe index of the blend. The more hydrogen the blend contains, the more different it becomes from natural gas. Once a threshold is surpassed, the properties of the blend are so different to those of either hydrogen or natural gas, that it becomes easier to change to pure hydrogen transport instead to adapting the components of the grid to the new conditions.

The range noted as acceptable for end-use systems fall within 5–20 vol.-% of hydrogen. Some CEN TCs are currently working on H_2 certification programs to state if appliances are ready for a) 20 % H_2, b) >20% H_2 or c) pure hydrogen. The injection of hydrogen will likely begin at very low concentrations and then increase gradually over as required modifications for higher concentrations are addressed. These are maximum hydrogen blend levels at which no or minor modifications would be needed for end-use systems, including appliances such as household boilers or stoves, industries and power generation [5]. Nevertheless, there are end-users which are particularly sensitive to even the lowest hydrogen contents, such as GNC stations and chemical industry using natural gas as feedstock, and can only accommodate 2 vol.-% of hydrogen in natural gas. Mitigation techniques, such as membrane technology, will be necessary in these cases to reduce the hydrogen concentration in the gas grid under the tolerated limits [23]. This will be the topic of chapter 4.2.

Another aspect for limiting the hydrogen content in the blend is the capacity of the compressor stations in the transmission grid. Since the energy density of hydrogen is three times lower than that of natural gas, the volume of hydrogen transported must be greater accordingly than in the case of natural gas to provide the same energetic content. Some studies suggest that the current compressor stations may not be fit for high hydrogen volumes [24].

Current research shows that most applications, except industry using methane as a raw material, could be adapted to work with hydrogen-methane blends from 15 to 20 % of hydrogen. Beyond those limits, the gas quality variability may increase significantly, possibly leading to suboptimal use of applications or imposing the need to store hydrogen in dedicated tanks as a buffer at nearby P2G facilities to handle this issue. While certain applications may handle variable concentrations of hydrogen better in the future, thanks to automatic combustion control, with every increase in hydrogen concentration, the infrastructure and end user applications may require retrofitting and/or replacement. In addition, fluctuations in the gas quality could impede the billing process, although digitalisation may offer solutions in this regard. End-user sensitivity may require grid operators to control gas quality either by injecting greater amounts of (bio-) methane, methanation or storing hydrogen to avoid curtailing production. Alternatively, where certain customers – typically within the industrial segments – remain especially sensitive to hydrogen-rich biomethane, the grid may need to utilise, for example, a membrane filter technology close to the point of supply to remove excess hydrogen and redirect it to supply hydrogen applications. [25]

The EU gas quality standard (EN16726) including renewable gases will be an important element for the hydrogen-methane blends pathway, provided that the application will follow the flexible approach as foreseen in the initial CEN concept presented at the Madrid Forum in June 2019. A coordinated EU approach for managing the changes and possibly fluctuating gas compositions across Europe should set the basis for the revision of gas quality standards and for end-user appliances, including CNG vehicles. [25]

For all the above-mentioned reasons, it might not be feasible to gradually increase the hydrogen fraction in gas networks from 0 to 100 %. Instead, once a certain “tipping point” is reached that makes a full transition to hydrogen more economical, it might be recommendable to do so, rather than increasing hydrogen concentration in a methane/hydrogen blend in several incremental steps, each of them requiring adjustment and replacement of equipment at grid or end user level. For those cases, blending would be only a transitional solution before a switch to a hydrogen only configuration. However, blending hydrogen up to a reasonable threshold for appliances can be considered as a long-term, cost-efficient solution for cases where the potential for biomethane or abated methane is high. [25]

In many cases, grid injection will take place in low or medium pressure distribution grids, simply because biomethane plants will want to inject into the nearest possible gas pipeline, which will often be distribution grids. If relatively large biomethane plants feed into small gas distribution pipes in areas with little local gas demand, there will be a need to ensure that biomethane can flow upwards towards medium or even high-pressure grids using reverse flow technology. This is a marked change compared to current flows, which are always from high to medium to low pressure grids. Reverse flow is in the process of being implemented today and requires limited investments. [8]

Looking further to the future, and when the injection sector develops, research work advances, and network and downstream equipment is adapted for hydrogen, the gas specifications will be updated in coordination with State services–to 10 % initially, rising to 20 %. Specific local contexts aside, this 20 % threshold seems to be the upper limit above which significant investment will be needed, in particular for downstream uses. This point is clarified in the section on technical-economic conditions blend [26].

4.1.2 Sources of hydrogen production

Domestic hydrogen production can be based on solar PV, e.g. in Spain and Italy or based on offshore wind, e.g. on the north and Baltic seas. Domestic hydrogen production can also be blue hydrogen produced at locations (likely industrial clusters) with good transport links to carbon storage locations. In addition to EU domestic production, there is also a promising outlook of largescale imports of (mainly renewable) hydrogen from countries outside the European Union. In its Hydrogen Strategy, the Commission expects that hydrogen supply will be developed within Europe but also sees an important role for international trade, in particular with the EU's neighbouring countries in Eastern Europe and in the Southern and Eastern Mediterranean countries. The Commission also highlights that hydrogen supply ultimately mainly consist of renewable green hydrogen, yet that low carbon blue hydrogen has a role to play in the short to medium term [9]. The production sequences of these two groups are shown in Figure 15.

Green hydrogen production is virtually non-existent today, although an impressive number of pilot projects are ongoing and in development. The first large-scale blue hydrogen projects are under development and can be expected during the next 5 years. [8]

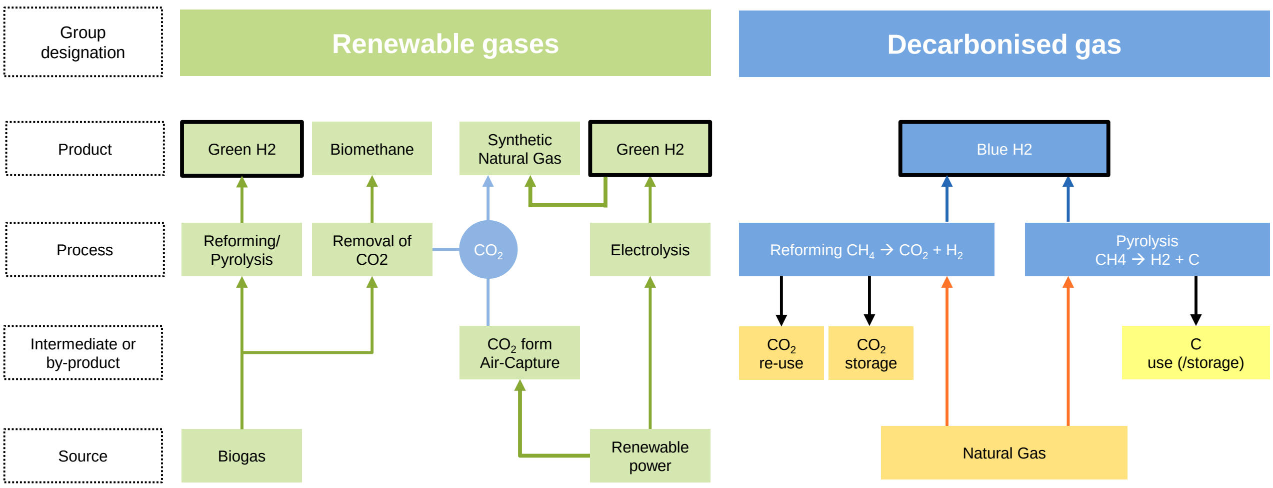


Figure 15: Process chains of green and blue hydrogen [27]

Hydrogen production could take place on-site close to where it is used. However, this is not always the most efficient supply option. For instance, in cases where hydrogen consumers are located away from large supply of renewable electricity or CCS locations and have access to existing gas grids, it will be cost-effective to receive hydrogen through gas grids. [9]

According to the *two Hydrogen for Europe* pathways, European hydrogen production will increase significantly over the next three decades and will rely on a varied production mix that includes renewable and low-carbon technologies. The pathways show the diversity of hydrogen production technologies and the complementarity between renewable and low-carbon technologies. While low-carbon hydrogen plays a crucial role in building a hydrogen economy in the first half of the forecast period, renewable hydrogen develops mainly in the second half of the forecast period and covers most of the additional demand growth. On the technology diversification pathway, the production mix is balanced in 2050, with renewable and low-carbon sources each supplying about half of Europe's production. On the Renewable Push pathway, supported by higher policy targets for renewable deployment, renewable hydropower takes the lead in the late 2030s and becomes the main source of hydrogen production (via electrolysers) by 2040. As with the other pathways, low-carbon hydrogen plays an important role in establishing the hydrogen economy: it covers most of the demand in the first half of the forecast period. [28]

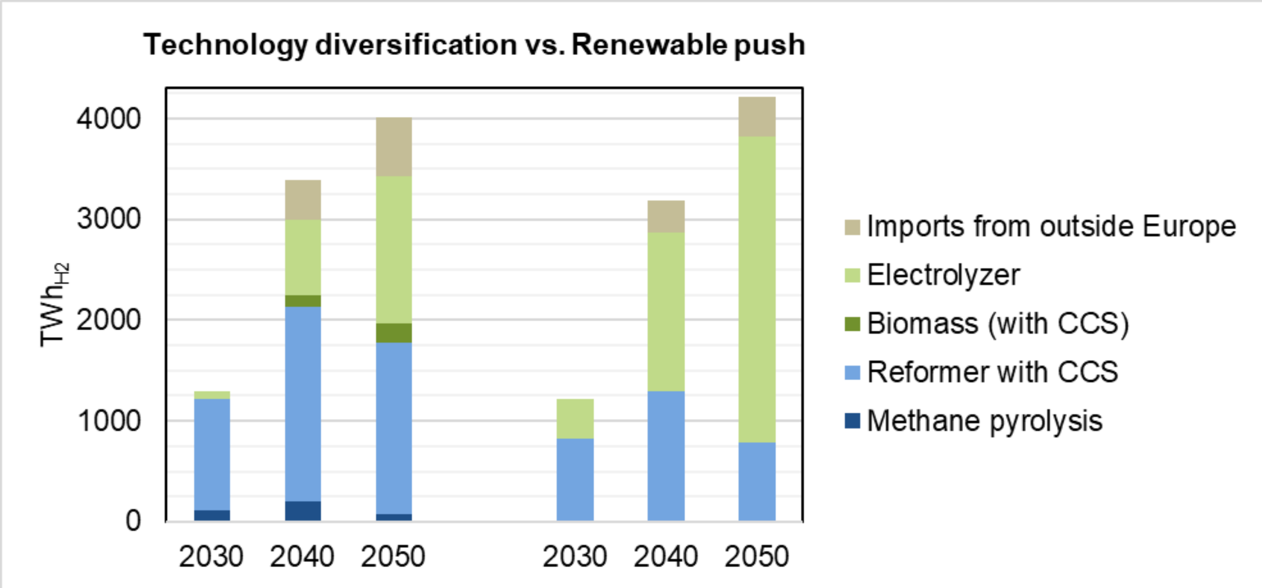


Figure 16: European hydrogen supply model within the two trajectories of technology diversification and renewable push from 2030 to 2050 [28]

4.1.3 Producers injecting hydrogen

The International Energy Agency (IEA) has published a database where existing projects in Europe that are currently injecting hydrogen in the natural gas grid are reported. Future injection projects can also be consulted [29]. Table 18 and Table 19 in the Annex I summarize the information gathered from this data base. It can be seen how most of the projects in operation are demo sites that consider injection of hydrogen at distribution level. Currently, over 3,600 Nm3/h of hydrogen are being injected in the gas grid in Europe. This amount is expected to rise hugely over 4 Mio. Nm^3/h by 2030, specially thanks to really ambitious projects, such as *SilverFrog* [30] in Italy, Green H_2UB [31] in The Netherlands, the installation in Zeebrugge (Belgium) or the Centurion project in UK.

The main barrier to inject hydrogen in the gas grid is the current maximum hydrogen injection concentration allowed, which is different for each European country, hindering the flow of gas through cross-border interconnection points. Figure 17 shows the currently allowed hydrogen concentrations in blending with natural gas in the different EU member states. It can be seen, that in 14 countries it is possible to have hydrogen in the transmission natural gas grid. On the other hand, the allowed concentrations in some of these countries are very low. Countries like Germany, Austria, France, and Spain have allowed concentrations between 5 to 10 vol-% and in some of these countries further adjustments to raise this limit to up to 20 Vol-% are ongoing. In other countries there is no opportunity for the injection or the transport of hydrogen reported at all. [HIGGS D2.3]

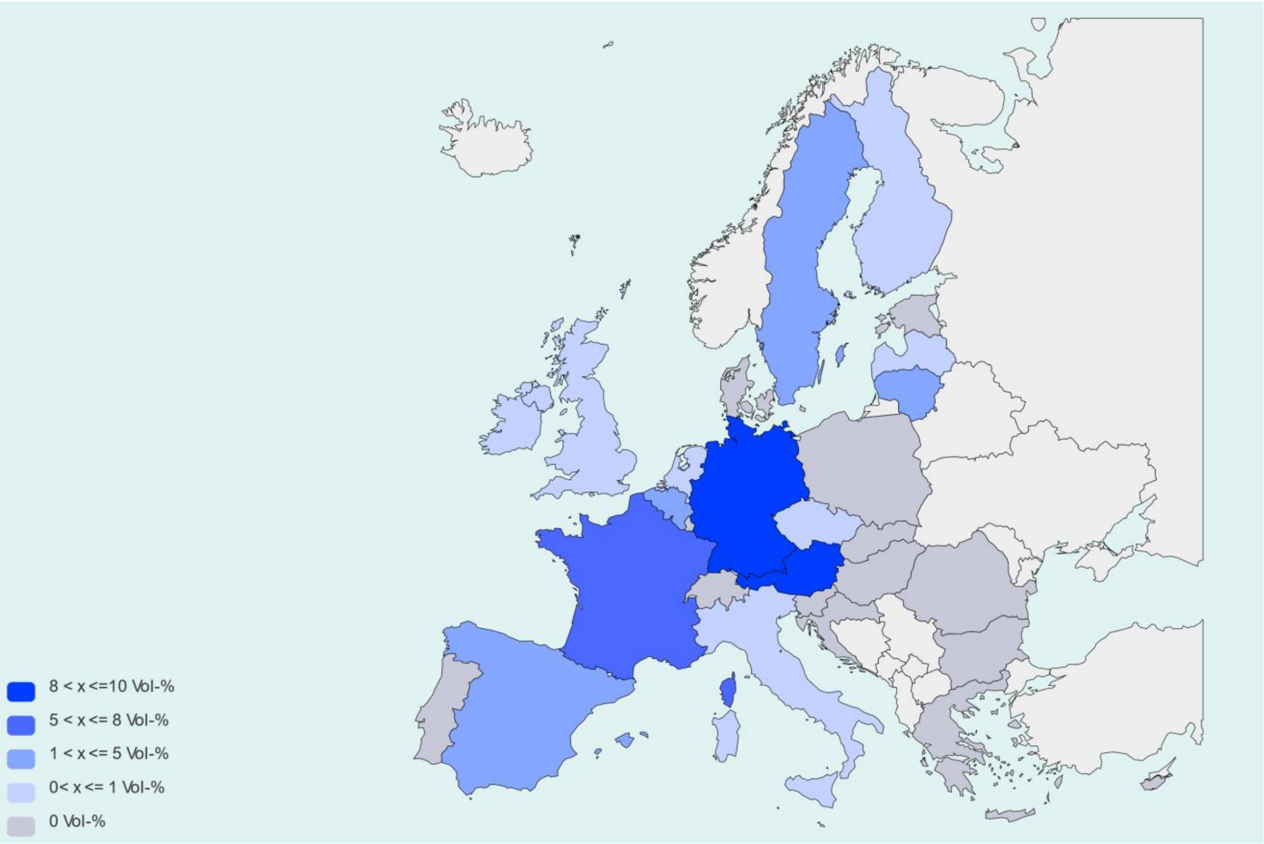


Figure 17: Allowed hydrogen concentration for blending with natural gas in the transmission gas grid of the European member states [HIGGS D2.3]

4.1.4 Gas buyers

Hydrogen can be used for many applications, from high temperature industrial heat, the production of dispatch able electricity or to provide transport fuel and heat in the buildings sector. Delivering hydrogen to all these demand sectors also involves distribution grids. [9]

Many end users can operate with hydrogen/natural gas blends without significant problems. For example, modern domestic utilisations are certified according to *Gas Appliance Regulation* (GAR) using G222 (a gas containing 23 vol.-% H_2) as test gas [32]. Besides, several research projects in Europe, such as *HyDeploy* [33] or *Thyga* [34] have proved the safe operation of appliances with up to 20 vol.-% of hydrogen in natural gas. The use of higher hydrogen content is under research and 30 vol.-% seems also acceptable.

Adding hydrogen to natural gas has a direct influence on some gas properties that are vital for end-users (density, Calorific Value, Wobbe Index, combustion air requirement, Methane Number etc.). The impact on each property is also different with hydrogen content. For example, density or calorific values are much more affected by increased concentrations of hydrogen than Wobbe Index. The parameters of interest also differ according to the end user. Normally, Wobbe Index is the reference parameter for domestic applications, while others such as calorific values gain importance for industrial applications, or methane number for gas engines [35].

The most challenging issues regarding utilization are industrial processes that use natural gas either as a feedstock for chemical processes (e.g. production of hydrogen or ammonia) or as a fuel to provide process heat in manufacturing processes [35]. The operational requirements of these processes are very challenging in terms of efficiency, product quality and emissions regulations and adding even small amounts of hydrogen to natural gas affects the gas quality in a significant way. Gas engines are also really sensitive to the hydrogen content in natural gas, with a direct impact in GNC stations. Contents of hydrogen above 2-5 mole-%, depending on the source of natural gas, can lead to a higher knocking propensity of the fuel and is therefore not recommended. In any event, the H_2 content in CNG is limited to 2 vol.-%, if the tank cylinders are manufactured from steel with an ultimate tensile strength exceeding 950 MPa. [36]

Finally, gas turbines are also sensitive applications to the presence of hydrogen in natural gas since they are highly affected by fluctuations in fuel properties. Traditionally, a maximum value of 5 vol.-% of hydrogen has been recommended, but some manufacturers have developed new devices that can handle up to 30 vol.-% H_2 and they are currently targeting higher levels. [37]

4.2 Hydrogen separation

From the information in section 4.1.4 it can be concluded that separation technology is needed for certain consumers of natural gas when hydrogen has been blended. There are various technologies available, each of them with certain advantages and disadvantages. The technologies are at different stages of development and can also be combined if necessary. In [38] and [39], a variety of separation processes were investigated and assessed according to technical and economic criteria. For this purpose, three protective scenarios were developed, which require a reduction of the hydrogen concentration in the natural gas. Based on a hydrogen volume content of 10 %, case studies were carried out for the protection of a natural gas filling station, an industrial user (glass factory) and a gas turbine. In addition, two transport scenarios were examined in which the hydrogen serves as a product. In this case, the natural gas grid served as a transport route for a fuel cell and an industrial consumer with different hydrogen volumes. In the study, membrane processes showed very good separation properties. However, there are still open points or little experience with streams with low hydrogen concentrations. Nevertheless, the membrane technology is the one being investigated in experiments within HIGGS and is briefly presented in the next section. In addition, other available separation processes will be presented afterwards.

4.2.1 Membranes developed in HIGGS

Three different types of membranes have been developed within WP3:

- Hollow fibre membranes based on polymers (e.g. polyamides) by spinning technique
- Thin carbon molecular sieve membranes by dip coating on porous tubular supports
- Thin Pd-based membranes by electroless plating technique onto porous supports.

The hydrogen separation properties of the different membrane types are being tested in a laboratory-scale permeation plant at Tecnalia. The current facility will be upgraded to allow flexible operation when testing the different membranes. Gas admixtures up to 15 vol.-% of hydrogen can pass through at pressures up to 80 bar and temperatures between 400 and 500 ºC. The hydrogen permeate stream and the total flux as well as the purity of the retentate are measured with a flow meter and a gas chromatograph, respectively. More details are presented in Deliverable 3.3. The results obtained will be processed for the techno-economic analysis in WP5.

4.2.2 Technology overview

As mentioned in the introductory part, there are other technologies besides the membranes that could be used to provide protection for gas consumers from excessive H_2 fractions or extract pure hydrogen from the mixture. These are listed in Table 3 and their capability for protection and transport at transmission level is indicated. The latter refers to the possibility of transporting both substances, i.e. that both are still present after separation and that one of them is not being converted, for example. The protection function refers to the suitability for individual end users.

Table 3: Procedures for end users to receive pure substances from H_2/NG mixtures and their suitability for protection and transportation of both gases [39]

	Membrane	Adsorption	Cryogenic	Methanation	Oxidation
Protection	+	-	+	+	+
Transport	+	-	+	-	-

** H_2 separation from low H_2 content streams*

Adsorption processes are not practical for hydrogen volume fractions between 10 % and 30 % from an economical point of view. Methanation systems (power-to-gas process) can also be used to protect consumers, converting the hydrogen to methane. This would require the presence of a CO_2 source. Oxidation (reaction of hydrogen with oxygen to form water) is another method of reducing the H_2 concentration. Cryogenic separation processes are technically possible, but are only suitable if LNG is needed at the same time.

4.2.3 Model integration of separation technology

The possibility of integrating such separation processes into network modelling tools has already been discussed with software providers. There seems to be the possibility to create mathematical relationships to certain input parameters such as temperature, pressure and volume fractions in so-called master and control scripts, which provide the desired output in the simulation. In this way, the membranes developed in HIGGS can integrated in an actual network model from which operators of gas grids in particular would benefit in a hydrogen admixture scenario.

The mathematical relationships are to be derived from the high-pressure membrane tests in WP3 by TECNALIA with their in-house membrane separation simulation tool and provided as an input for the network modelling task in this Work package. The results can be expected in the Deliverables 5.3 (M27) and 5.4 (M33).

4.3 Operation strategies of TSO's

A specific objective of this work package is to look at case studies such as the operator of an HPGN, gas buyers or producers injecting hydrogen and to develop possible operating strategies. For this purpose, the basics of gas transport are described at the beginning of this section and analysed using model computations.

4.3.1 Transmission grid

The transmission grids are complex infrastructures connecting the System entry points (local production facilities (wells), LNG terminals within territory or pipeline connections to outer producing countries) with the exit points (regional networks, storage infrastructures and key consumer areas), that are typically located away from the former.

The classic gas transport facility between two points is the pipeline, either buried under the ground or on top of the surface often also at the bottom of the sea. The carrying capacity of the pipelines depend on the pressure difference between their ends and their diameter (larger diameter involves greater carrying capacity). The transmission pipelines are a high-pressure pipes (up to 85 bar onshore, and up to 225 bar for some offshore applications) with large-diameters (up to 60 in.) running long distances. They are designed to handle large volumes of gas.

This design is carried out taking into consideration different parameters such as the largest amount of energy that is expected to be transported by each installation and its maximum operating pressure (MOP), establishing limitations such as the maximum speed allowed for the gas flow (usually up to 30 m/s in Europe). Deviations in the composition of the gas can lead to changes in its physical properties (density, heating value, etc.), which in turn can lead to changes in the energy transport capacity of that installation, and therefore, changes in the way the system has to be operated.

Natural gas flowing through transmission lines is subject to pressure losses due to friction. To circulate the gas through the pipelines it is necessary to increase the pressure of the gas at certain points of the grid. This action is carried out in compression stations, which ensure the correct circulation of gas flows and the maintenance of system capacity.

The pressure and the flow of the gas circulating through the transmission grid is measured in valves nodes and metering stations located throughout the network, these parameters are measured also in the pressure reduction stations and in the city gates, in which pressure is adjusted to suit the conditions of the downstream networks.

Gas flows are controlled from facilities of the gas network operators. They receive pressure measurements, temperatures, flow rates and other physical and chemical gas parameters (heating value, composition, etc.), called control centres.

4.3.2 Basic network operation

A country's basic network is understood to be defined and operated in a way to guarantee the supply of natural gas even in peak demand situations. The basic network consists of:

- The liquefied natural gas regasification plants that can supply the gas system and the natural gas liquefaction plants.

- Basic natural gas storage that can supply the gas system.
- International connections that allow the flow of gas across borders.
- The primary transportation gas pipelines that connect these elements to each other, and allow the gas to be conducted to the main consumption points.

There is a body, namely the network manager, in charge of the operation of the basic network in each country. It may be associated with the main TSO operating in that country, or it may be an independent one, in any case always under the control and supervision of the public administration.

The network manager continuously receives operating data from plants and warehouses, international connections, and transport networks, and controls and monitors the state of the network on a permanent basis. The information to be exchanged, its periodicity and detail, the communication protocols, etc., are set out in specific rules and regulations, and could be summarized as:

- Information on regasification plants:
    - Data on the quantity and quality of the liquefied natural gas received in LNG tankers as well as of the natural gas injected into the network.
    - Forecast of arrival of deliveries and availability of injection.

- Information on natural gas liquefaction plants:
    - Data on quantity and quality of liquefied natural gas.
    - Forecast demand for liquefied natural gas.

- Basic storage information:
    - Data on the quantity and quality of stored natural gas.
    - Remaining natural gas storage capacity and injection availability in storage.
    - Capacity and availability of natural gas re-injection from storage to the grid.

- Information on international pipeline connection facilities:
    - Data on the quantity and quality of the natural gas that circulates in both directions of the interconnection.
    - Capacity and availability of gas vehicles in both directions.

- Information on the natural gas transportation networks (gas pipelines), both the basic network and the secondary network derived from it:
    - Data on gas flows and pressures at the end points of the network (delivery points between transport operators, and between transport and distribution operators).
    - Energy balances, through which data on the gas introduced and emitted in each gas pipeline of the network are provided during a set period of time, forecasts of demand for the coming days are established, and it is communicated how the emission of the day of gas versus anticipated.
    - Capacity and availability of the transport network.

For all these facilities, information is also provided on any action to be carried out by any of the parties that could affect the gas system, such as the commissioning of new facilities, maintenance shutdowns or the increase in injection capacity or issuance in response to variations in demand, or information on emergency situations, such as breakdowns, or others that could condition the operation or capacity of the facilities.

With the information received, the forecasts and historical data on the evolution of the behaviour of the network, the manager can verify and control the behaviour of the basic network, and make decisions that allow the system to operate properly, managing the gas inputs and outputs to the system, like the storage of natural gas or the pressure at which each sector of the network is operated through the compression stations, that are part of the primary gas pipeline network. In this way, the system can guarantee energy flows, anticipating changes in demand and exceptional situations by acting in the face of unforeseen events that could condition its operation.

4.3.3 Operation of transmission systems

The gas transmission system consist of the pipelines that transport the natural gas and the auxiliary facilities that allow the entry and exit of gas to the system and its operation.

In addition to the exchange of information with the system operator of the country in which it operates, as mentioned in the previous section, the TSO that owns the transmission system owns both the primary gas pipelines that are part of the basic network and the less important pipelines. The entity that connects this basic network with the distribution networks and consumption points, directly or through other gas pipelines, will carry out the following operating tasks:

- Supervise the operation of the gas pipeline, collecting information in real time on pressures, temperatures, etc. The information is sent instantly to the TSO control centres, where:
    - The evolution of demand at the gas pipeline outlets (delivery points to other transmission or distribution networks or to large customers directly connected to the transport pipeline) is analysed.
    - At the points of entry where the measurement stations or the regulation and measurement stations correspond to the TSO that owns the gas pipeline, their operation is controlled, the pressure and flow of gas delivered and its evolution are analysed, ordering in In the case of regulated stations, the modification of the inlet pressures in accordance with the demand forecasts, or requesting, in the case of metering stations, the TSO owner of the installation to which the gas pipeline is connected for this modification.
    - At the entry points where the measurement stations or the regulation and measurement stations correspond to the TSO owner of the installation to which the gas pipeline is connected, the gas pipeline pressure and the flow reported by the TSO of that pipeline are analysed. Installation and its evolution, requesting the modification of the inlet pressures in accordance with the demand forecasts.
    - At the exit points, the operation of the measurement stations, the regulation and measurement stations, and the city gates is controlled, depending on the evolution of demand, ordering in the case of regulated stations, the modification of supply pressures according to demand forecasts.

- In those primary gas pipelines that include compressor stations, increase the pressure of the gas that circulates through the installation in accordance with the indications of the network managing body.

- By having the information available in real time, detect any incident by mobilizing the necessary personnel to solve it, or acting remotely on components of the installation, thus guaranteeing or recovering the correct operation of the gas pipeline in the event of any unusual behaviour, and minimizing the times of putting in security in case of incident.

- Carry out the necessary preventive and corrective maintenance tasks to guarantee the correct operation of the system.

4.3.4 System and network design aspects of H_2 injection into natural gas grids

As described previously, natural gas supply systems are basically composed of the elements pipeline, compressor as well as measurement / control systems. Combined with the knowledge from section 3.2.2 on the effects of hydrogen on the properties of natural gas, the influence of the mixed gas behaviour can now be illustrated in connection with the calculation and design of system components. In a further step, this can be used to assess the impact on existing infrastructures.

4.3.4.1 Design and calculation of natural gas supply system components

In the following sections, the principles for the design of system components are discussed. The focus here is on pipelines, compressors and preheating systems of regulator stations, whose magnitudes are calculated considering real gas factors [17].

4.3.4.1.1 The capacity of a pipeline

To determine the capacity of a natural gas pipeline, formula (4), which is derived from the differential equation of *Darcy-Weisbach*[3] can be used (description of the variables in Table 4). It describes a parabolic (quadratic) pressure drop during high-pressure pipeline transport as a function of displacement. Since the pressure drop occurring during the flow process leads to an increase in the volume flow, this inevitably also results in an acceleration of the gas. From section 4.3.1 it is known that the speed usually is limited at approx. 30 m/s and may be surpassed depending on the hydrogen content in the gas. The average fluid temperature for high-pressure pipes can be assumed to be the ground temperature at the installation depth.

$$p_1{}^2 - p_2{}^2 = \frac{16}{\pi^2} \cdot \lambda \cdot \frac{\rho_n \cdot p_n}{T_n} \cdot \frac{T}{d^5} \cdot K \cdot \dot{V}_n{}^2 \tag{4}$$

If the pressures at the inlet (e.g. through the compressor station) and outlet (e.g. at a city gate) are known or fixed, the equation can be modified according to the volume flow and calculated for different hydrogen admixture rates. The density and the compressibility number must be determined again for each mixture. The latter is defined as the quotient from the real gas factors present and in standard conditions according to the following equation:

$$K = \frac{Z_x(p_x, T_x)}{Z_n(p_n, T_n)} \tag{5}$$

Table 4: Description of variables in equation (4)

p	Pressure at the inlet (1) / outlet (2)	(bar)
λ	Friction number of the pipe material	(-)
d / L	Pipeline diameter / length	(m)
K	Compressibility number	(-)
$\dot{V}_n$	Volume flow at standard conditions	(m^3/h)

[3] In this equation, the differential pressure loss for a horizontally placed pipe is assumed to be proportional to the density of the kinetic energy of the fluid and a stationary flow condition is assumed, which is a reasonable approximation for capacity calculations. [17].

4.3.4.1.2 Compressors for natural gas

The compressor stations are active elements of a gas supply system. Their task is to compensate for the pressure loss caused by friction effects during gas transport in pipelines by means of compression. A compressor's driving force can be provided by a gas turbine or an electric motor. Depending on the case, they are combined with piston or turbo compressors.

In the case of transport compressors, the provision or extraction of the drive energy from the transported natural gas has proven to be the optimal solution, both from an economic and supply point of view. The redundancy principle requires at least one unit per station to be kept as backup, namely the engine with the highest output.

The specific work performed by a compressor on a gas can be calculated in the isentropic case using the approach in equation (6). Here, internal friction losses are neglected and the change of state is considered adiabatic and reversible. The isentropic exponent required for this is a strongly temperature-dependent material property and can be calculated in a simplified way from the division of the specific heat capacities at constant pressure to constant volume.

$$\Delta h_s = \frac{k}{k-1} \cdot Z_1 \cdot R_s \cdot T_1 \cdot \left[\pi^{\frac{k-1}{k}} - 1\right] \tag{6}$$

Table 5: Description of variables in equation (6)

Δh_s	Specific compression work	(J/kg)
k	Isentropic coefficient	(-)
R_s	Specific gas constant	(J/kgK)
Z_1	Real gas factor at inlet	(-)
π	Pressure hub p_2/p_1	(-)

Since both the first term on the right-hand side of the equation and the real gas factor rise with increasing hydrogen content in the natural gas, the required compression work also increases.

4.3.4.1.3 Regulator stations

Measuring and regulation facilities are indispensable elements of the gas supply systems, which include the following components:

- Shut-off and control devices
- Filters and safety valves
- Preheater
- Flow meters as well as temperature and pressure sensors
- Odorisation systems

For the correct billing of the customers, the gas quality is measured in most cases. Today, this is primarily done using process gas chromatographs, which have a high accuracy at comparatively low investment costs.

The regulation of the gas flows at these stations serves, on the one hand, to separate systems of different pressure levels and, on the other hand, to record and control the flow rate. At the throttle valve, which is used to regulate the pressure, the Joule-Thompson effect causes the natural gas to cool down quickly, potentially leading to the formation of condensate and hydrate.

In order to avoid malfunctions in the regulating elements due to this effect during natural gas expansion in regulating systems and to prevent embrittlement of the pipeline material in the downstream network, a sufficient amount of heat according to equation (7) must be added to the gas flow previously in order to absorb the forthcoming temperature reduction.

$$\dot{Q} = \dot{V}_n \cdot \left[\int_{p_1}^{p_2} \left[\frac{\partial T}{\partial p}\right]_h dp + (T_2 - T_1) \right] \tag{7}$$

Table 6: Description of variables in equation (7)

T	Temperature at inlet (1) / outlet (2)	(K)
$\dot{Q}$	Thermal power	(kW)
$\dot{V}_n$	Volume flow at standard conditions	(m^3/s)

Whereby the coefficient of the differential throttle effect can generally be calculated according to formula (8). In *FluidProp*, the temperature can easily be calculated using the pressure and the specific enthalpy of the gas before throttling. The difference of the both temperatures at the in- and outlet multiplied by the mean heat capacity equals the same expression.

$$\left[\frac{\partial T}{\partial p}\right]_h = \frac{1}{c_p} \cdot \left[T \cdot \left[\frac{\partial V}{\partial T}\right]_p - V \right] \tag{8}$$

4.3.4.2 Influence of the hydrogen admixture on transmission system operation

In this section, the calculations from the previous chapters were carried out for a practical example. In terms of dimensions according to Table 7, this corresponds roughly to the pipeline section of the TENP between Stolberg and Mittelbrunn. The *FluidProp* software was used for the calculations of the gas properties, as it is suitable for the calculation of H_2/NG mixtures using the algorithms from the *RefProp* model add-in.

Table 7: Basis for the calculations of the impact of hydrogen on the operation of a natural gas transmission pipeline

Parameter	Unit	Value
Average energy flow (ENTSOG 2019)	MWh/h	7847.4
Mean gas temperature below ground	°C	15.0
Pressure at the pipeline inlet (abs.)	bar	68.5
Pipeline length	km	180.0
Pipeline diameter (inner)	mm	900.0
Friction coefficient	-	0.005

The sample computation was aimed at obtaining information on how certain operating parameters behave with the admixture of hydrogen and what effects and trends could be expected for a state-of-the-art gas transport system. Thus, the following five operating parameters were evaluated:

1. **Flow rate of chemical energy:**
   Formed from the product of the volume flow and the calorific value of the gas.
2. **Compression work:**
   Ideal compression work required to bring the pressure of the gas from the pressure occurring at the end of the pipe back to the initial state (isentropic, adiabatic and reversible).
3. **Pressure drop:**
   Pressure drop across the pipeline length according to equation (4).
4. **Speed of gas flow:**
   Speed of the gas flow at the pipeline end.
5. **Preheating in regulator station:**
   Amount of energy required to preheat the gas in a regulating station before expansion to 16 bar in order that no condensate nor nitrate formation occurs due to the *Joule-Thompson* effect. Therefore, it was assumed that the temperature should not fall below 7 °C.

4.3.4.2.1 Behaviour of transmission pipe operation with constant transported energy flow

First, an operating regime is considered in which a constant amount of energy independent of the gas quality has to be transported to the customers. With regard to the hydrogen admixture, this means that the mass flow has to be increased accordingly. Thus, the pressure losses in the pipe as well as the compression capacity will increase as well. Only in the case of preheating the gas before expansion at regulator stations the needed effort is reduced by the inverse *Joule-Thompson* effect. The increase or decrease of the individual parameters is shown in Figure 18.

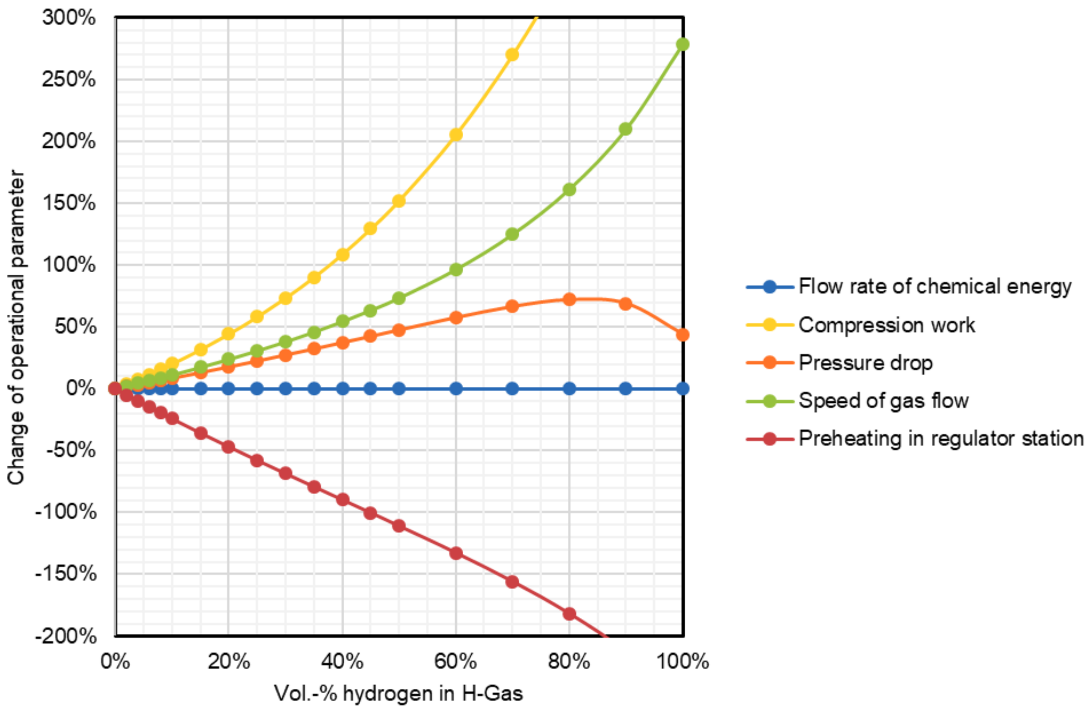


Figure 18: Change of operational parameters of gas transmission systems as a function of H_2 blending rates in Natural Gas (Russian H-Gas) assuming constant energy flow

4.3.4.2.2 Behaviour of transmission pipe operation at constant pressure drop across the line

Henceforth, in contrast to the previous case, an operating strategy where the pressure at the end of the selected pipeline system should kept constant is investigated. In this case, the pressure drop along the pipe is fixed, so that the conditions for consumers at the end of the pipeline match those that are specified in their supply contracts. For this purpose, the mass flow must be adjusted according to the changes in the gas properties and the chemical energy flow decreases in dependence on the hydrogen fraction in the natural gas. The changes of all parameters are illustrated in Figure 19.

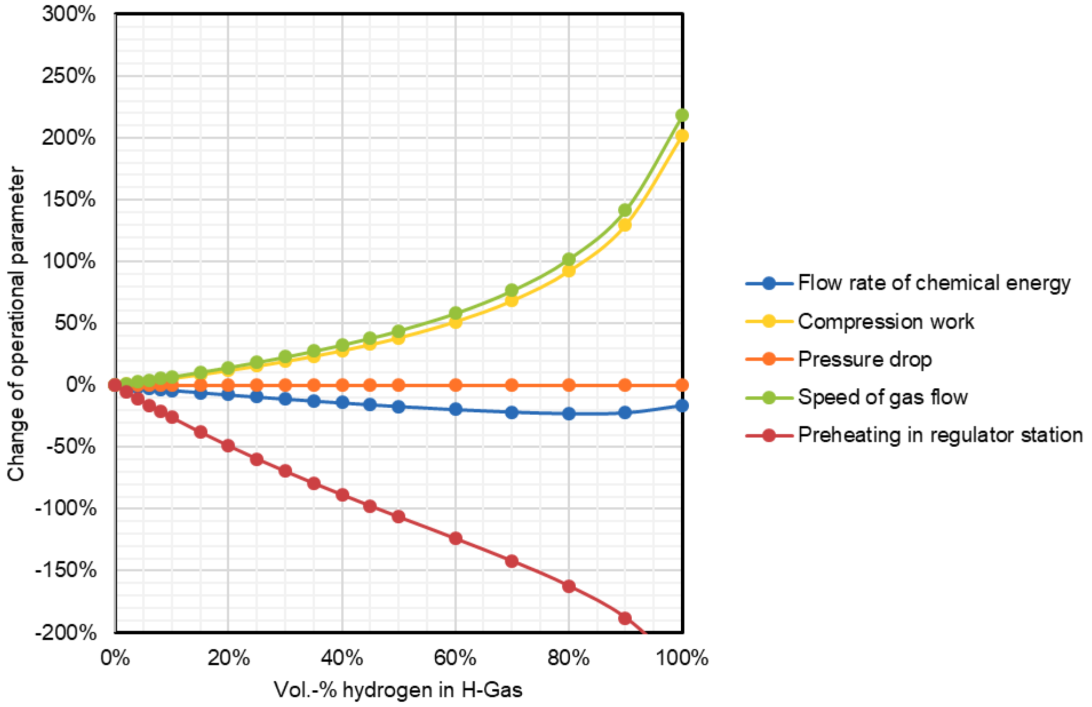


Figure 19: Change of operational parameters of gas transmission systems as a function of H_2 blending rates in Natural Gas (Russian H-Gas) assuming <u>constant pressure drop</u>

4.4 Economic aspects

This section explains the economic considerations in work package 5. In principle, the following two questions ought to be answered:

- What is the impact of the consumption of H_2/NG mixtures for end-users and TSOs?
- Does the transport of H_2 in existing gas grids have advantages for end users of pure hydrogen compared to other delivery pathways?

To answer these questions, various figures on the transport costs of hydrogen in pipeline systems will be taken into account. Afterwards, the considerations for the case of blending into the existing gas grid are explained and what is used for the comparison after all.

4.4.1 Transport costs of hydrogen

The investigations in the HIGGS project are mainly focusing on the question of whether and in what cases it is feasible to feed hydrogen into the existing natural gas grid. The system boundary of the economic considerations should therefore, in contrast to technical aspects from other sections, be limited mainly to the transport of the energy carrier hydrogen.

James et al. carried out an analysis on long-distance energy transmission in general. The aim was to compare the costs of long-distance transport, bulk transport of electrical or chemical energy, independent of the production method or the end users. The calculations were normalised to a transmission of 1,000 miles and performed for pipeline systems of various liquids and gases, as well as high-voltage electrical lines. The models include general losses (i.e. line or machine losses), as well as CAPEX and OPEX of the systems, but neglect the respective production and conversion costs. The results of the specific amortised transmission costs are shown in Figure 20 below. [40]

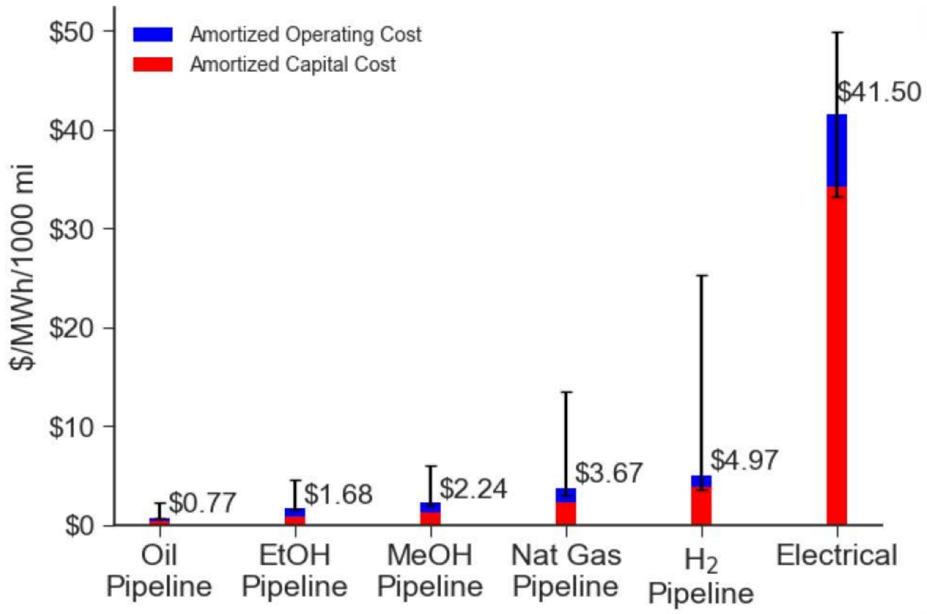


Figure 20: Amortized transmission costs of different pipeline systems for liquids and gas as well as electricity [40]

It can be seen that the transport costs for pure hydrogen are about 35 % higher than for natural gas. However, this is not directly linked to the fact that the material and labour costs for a hydrogen pipeline are higher (approx. + 8 % accounting to greater steel thickness and welding differences). For the same pipeline diameter and transport speed, the total system costs are actually almost 20 % cheaper per mile because smaller compressors are possible. The decisive factor again lies in the capacity, which is nearly only half the size with the chosen parameters [40]. Converted into metric units and European currency, the hydrogen transport costs amount to **2.64 €/MWh/1,000km**.

In the *European Hydrogen Backbone* (EHB) Study, similar calculations were made for different scenarios. Here, not only the costs of transport through a newly built system were estimated, but also a retrofitting of existing infrastructure for three different CAPEX/OPEX models. The results are presented in Table 8 for comparison. It can be seen that transport costs for a new hydrogen infrastructure differ significantly compared to the first analysis. The costs calculated from James et al. are more in line with those for a retrofitted system from EHB. [9]

Table 8: Estimated levelised costs of hydrogen through pipeline infrastructure with different new-build rates and varying CAPEX/OPEX configurations [9]

Levelised costs (€/MWh/1000km)	Low	Medium	High
100 % new infrastructure	4.06	5.08	5.84
100 % retrofitted infrastructure	1.78	2.79	3.81
75 % retrofitted infrastructure	2.29	3.30	4.32

In the end, transportation accounts only for a small share of the total costs, even if very favourable future production costs for green and blue hydrogen of between 25-50 €/MWh are assumed. [9]

As already mentioned, these studies assume pure hydrogen systems. However, many pathway strategies towards a H_2 economy also show the potential for blending hydrogen with natural gas. In some countries, this can also be considered as a transitional phase for certain periods of time or even as a permanent solution beside parallel hydrogen networks as described in chapter 4.1.1. For this reason, the economic aspects in WP5 for blending scenarios up to 30 % vol.-% H_2 into the existing natural gas grid will be considered and compared with those already available for pure hydrogen systems.

4.4.2 Cost assumptions

In this section, the components that are taken into account for the economic considerations in HIGGS are briefly outlined. First, the basis for CAPEX assumptions of hydrogen blending is laid and the impact on operational costs from section 4.3.4.2 is recapitulated.

In order to be able to reproduce comparative figures for hydrogen admixture, the model parameters for cost estimation from other studies analysing a similar system are listed below. Afterwards, the relevant elements for the modelling in HIGGS will be addressed and monetary incentives for gas consumers to benefit from H_2 blending are shown.

4.4.2.1 Investment costs (CAPEX)

For the considerations in HIGGS, the replacement and retrofitting of the following system components are considered:

- Pipeline systems
- Compressor stations
- Pressure regulation and measurement systems

According to current knowledge, only minor adjustments are required to be able to feed 6 vol.-% hydrogen into the grids. The real initial investment threshold has been set at around 10 vol.-%. The key threshold lies at 20 vol.-%, especially if one considers that downstream applications will need adaptations beyond this value [41]. The relative weight of gross CAPEX at each threshold crossing is shown in Figure 21.

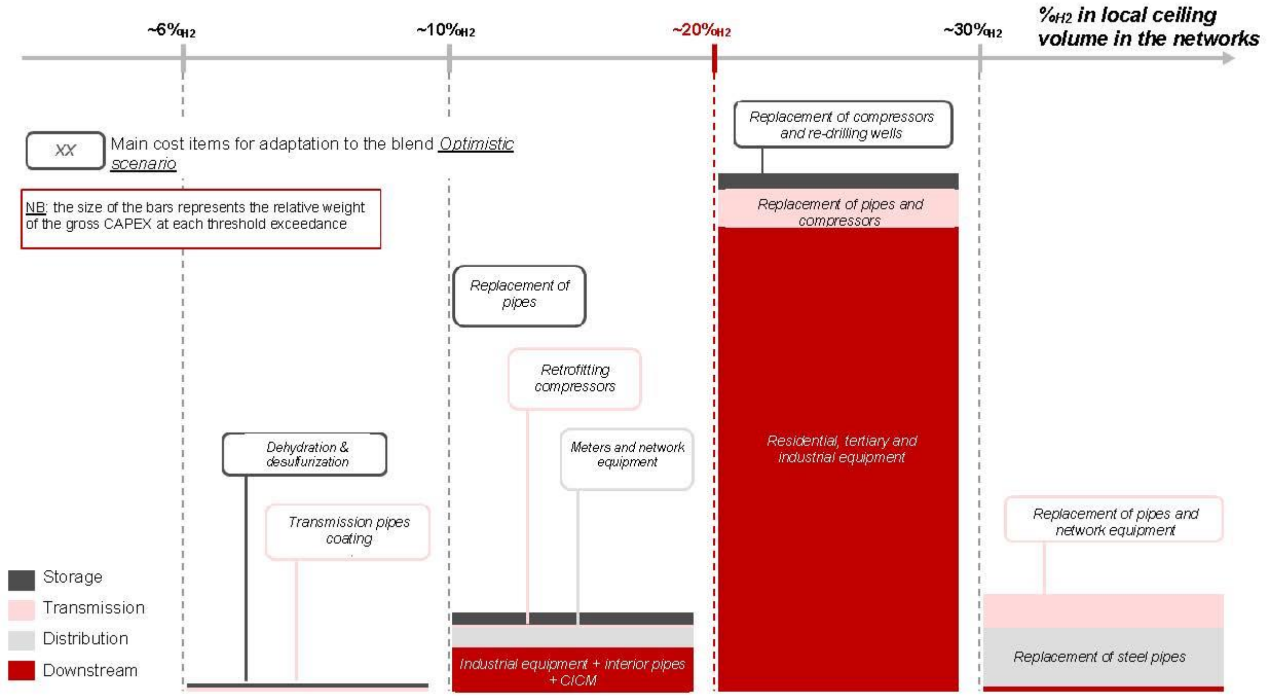


Figure 21: Adaptation costs for gas infrastructures at different hydrogen admixture levels [41]

Furthermore, the separation technology for H_2/NG mixtures is to be included in the case of HIGGS. This will be elaborated in detail by TECNALIA and published in later deliverables (D5.3 or 5.4).

While the retrofitting of existing natural gas pipelines to pure hydrogen pipelines is assumed to cost approx. between 10-25 % of the costs for a new construction as estimates show in chapter 4.4.2.4, this value is likely to be reduced somewhat for medium blending levels. Figure 22 shows the specific pipeline costs of German natural gas grid expansion projects as a function of the pipeline diameter (adjusted from outliers). The average value amounts to 2.07 M€/km with a standard deviation of 0.81. This refers only to NG transmission grids in Germany built today.

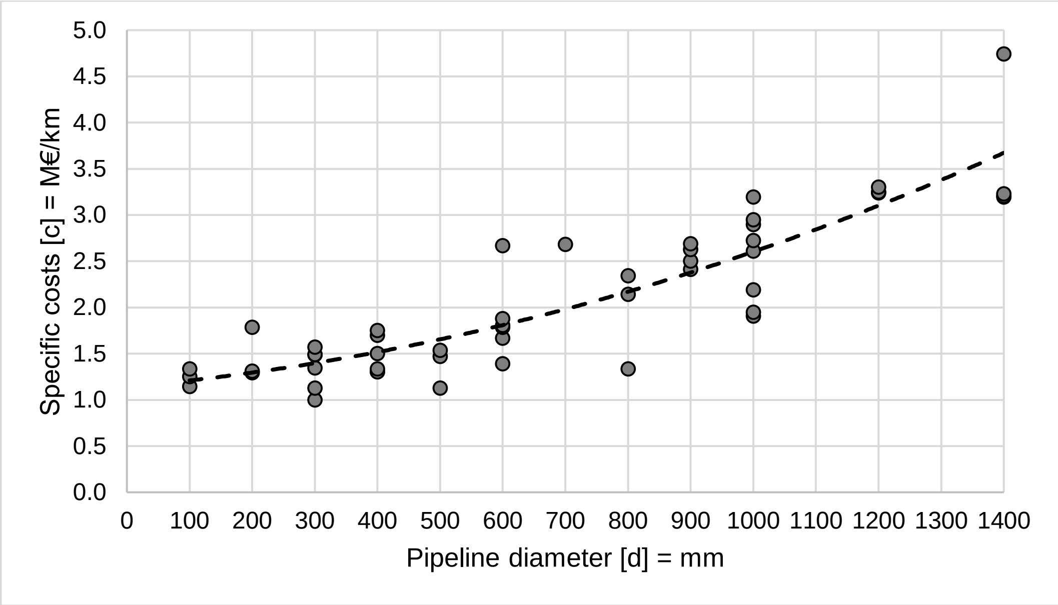


Figure 22: Pipeline costs of German grid expansion projects as a function of the diameter [42]

A smaller value should also be possible for compressor stations, where the same new construction and conversion price is assumed for pure hydrogen systems. Total cost of compressor stations depending on their capacity are shown in Figure 23.

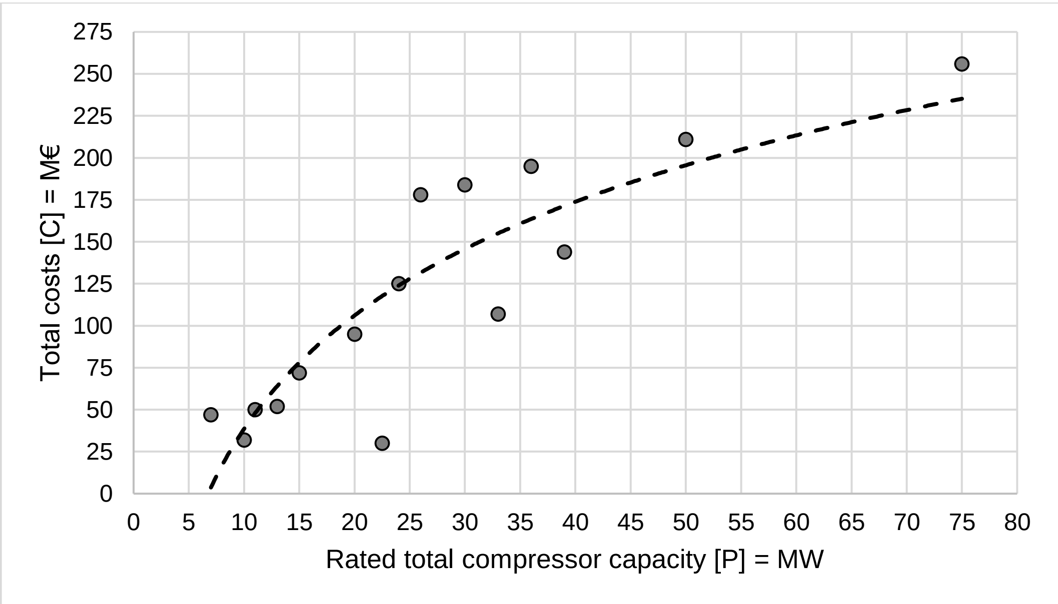


Figure 23: Investment costs of compressor stations in relation to their capacity [42]

For billing purposes, the gas quality is always measured at the pressure regulator stations. Since the devices in use today are only accurate enough up to approx. 10 % hydrogen by volume, they would have to be replaced at higher admixture levels. The share of these devices in the total costs of such a facility has to be estimated for the economic part of the model. The total costs as a function of the nominal transmittable volumetric flow of a regulator station can be seen in Figure 24. Furthermore, it is already known from section 4.3.4.2 that up to a hydrogen content of 40 vol.-%, less preheating capacity would be required and after that it would even be necessary to switch from preheating to cooling of the gas.

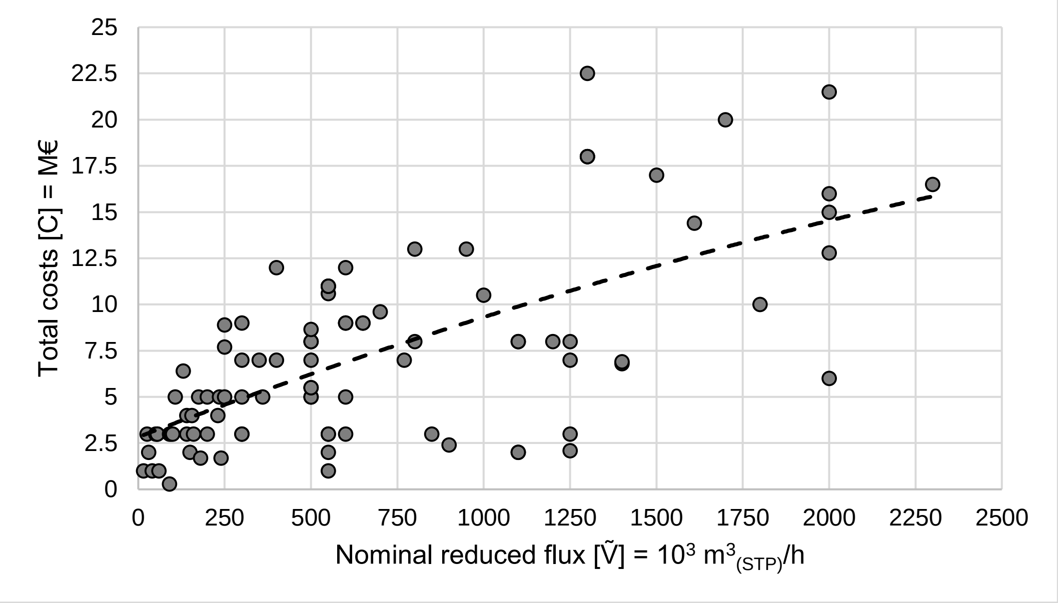


Figure 24: Total costs of pressure regulation and measurement facilities depending on the nominal flow which can be adjusted to the lower pressure level [42]

4.4.2.2 Operational and maintenance costs (OPEX)

The expected effects of hydrogen blends in the existing natural gas system on various operational parameters and therefore the OPEX have already been discussed in section 4.3.4 and are summarised again in the following table:

Table 9: Expected impact of various operating parameters on OPEX costs

Operational parameter	Expected impact on OPEX
Pipeline capacity	-
Compression work	+
Preheating in regulator stations	-

These are taken into account in the techno-economic model as far as it is reasonable.

4.4.2.3 Benefits from hydrogen blending

Blending with natural gas helps, in particular, to reduce emissions in the buildings sector and in industry, which can also result in monetary benefits for gas consumers. In the long term, especially from 2040 onwards, the level of the European trading system (ETS) price increases significantly (see Figure 25). This is the result of a decreasing supply of allowances in line with the annual linear reduction factor, which significantly reduces the cap over time, and a combination of energy supply factors (European Commission 2016) [43].

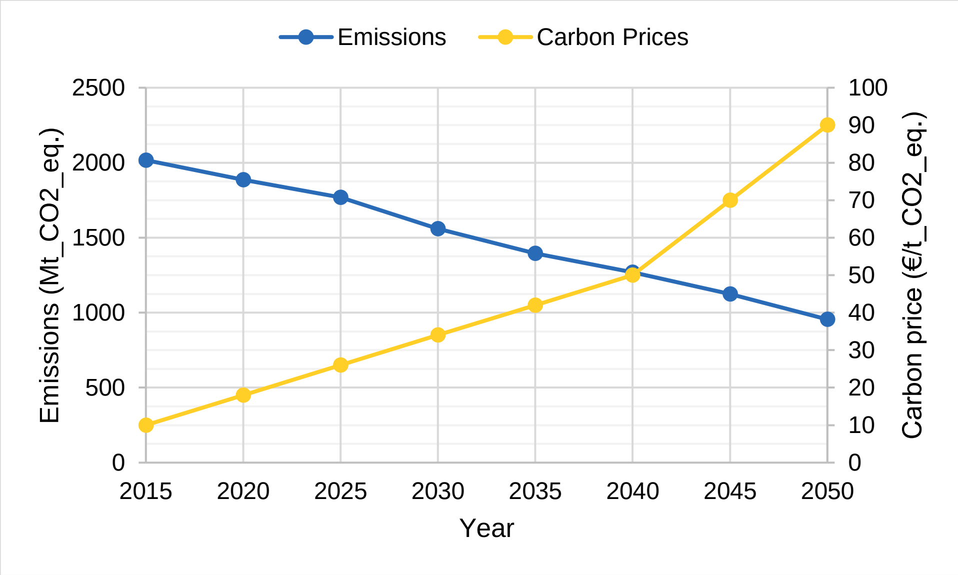


Figure 25: Development of emissions and carbon prices [43]

4.4.2.4 Reference cost parameters

In Table 10 there is an overview of cost parameters from three different studies investigating pipeline transmission of pure hydrogen. These represent the basis for the comparison tasks.

Table 10: Model parameter assumptions of different for cost calculation of H_2 pipeline transport

Cost parameter	Unit	EHB [9]	GASUNIE [44]	James et al [40]
Pipeline new (CAPEX)	M€/km	2.5 – 3.36	2.75	0.73
Compressor station new (CAPEX)	M€/MW	2.2 – 6.7	4.54[4]	N/A[5]
Pipeline retrofit (CAPEX)	M€/km	0.25 – 0.64	0.69	-
Compressor station retrofit (CAPEX)	M€/MW	2.2 – 6.7	N/A	-
Electricity price	€/MWh	40 – 90	114.2	42.7
Load factor of compressors	h/year	5000	8760	5260
Operating & maintenance costs	% of CAPEX	0.8 – 1.7	2	11.94[6]
Interest rates	%	5 – 7	N/A	8 12, 26.6[7]
Amortisation period	Years	15 – 33 30 – 55	N/A	33

[4] No specific values are given in the report. https://www.nep-gas-datenbank.de/app/#!/ausbaumassnahmen gives an average value of 4.50 M€/MW for new compressor station construction projects.
[5] A value of 87.6 €/(km*MW) is noted
[6] Includes compression cost: 1.94 % of rated capacity
[7] Capital recovery factor, Corporate tax rate

4.4.3 Comparison with different hydrogen transport pathways

In Task 5.2, a representative case is examined, for which a model of a real network topology is to be used. The methodology for this is described in detail in the following sections. The main objective of the case study is to simulate the transport of hydrogen over several hundred kilometres of transmission lines in the natural gas grid and to show the cost differences compared to alternative transport routes, specifically a newly or retrofitted hydrogen pipeline and transportation with trucks in gas cylinders[8].

4.5 Gas transmission network and gas flows within the EU

The European transport gas network is highly interconnected, especially in Central Europe. It includes large interregional and international transit pipelines. The gas deliveries are made through large offshore pipelines in the North Sea (Norway, Netherlands, Great Britain) and Mediterranean Sea (North Africa respectively Algeria), rural pipelines in the East (Russia) or through the liquefied natural gas transports from Arabia or overseas via the corresponding LNG ports.

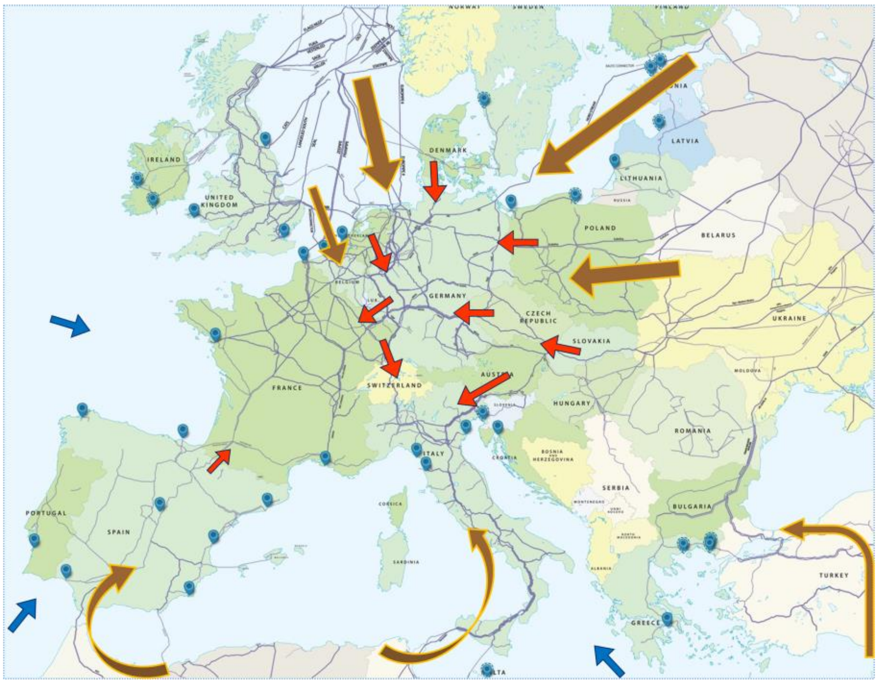


Figure 26: Map of the european gas transmission network including LNG Ports and important gas transport routes [46]

As a refresher to the gas flows within Europe presented in Section 3.1.1, Figure 27 shows that in 2015 the largest suppliers of natural gas are Russia 30 %, followed by Norway 26 %, Algeria 9 % and Qatar 6 %. Of the total consumption, about 20% is produced within Europe itself. The rest, around 9 %, comes from other sources. It is obvious that the southern European countries, especially Spain and Portugal, but also Italy and France, have a larger share of African gas. In the Central

[8] The technology data for energy transport from *Energienet* are primarily used for the estimation of transport costs [45].

European countries (Germany, Benelux countries and British Islands), Russia, Norway and domestic markets dominate as gas sources as can be seen in the following (Figure 27):

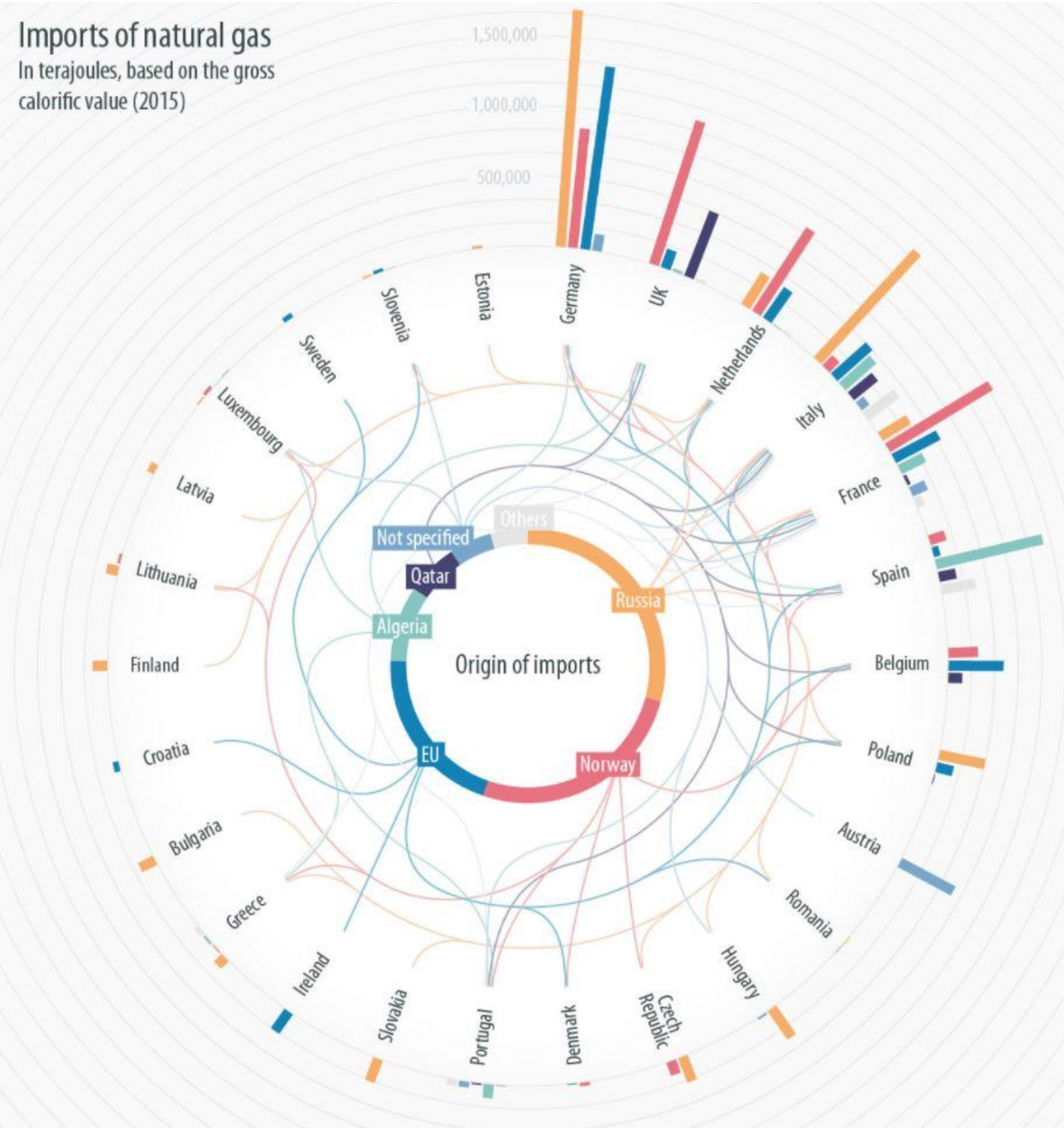


Figure 27: Infographic on the origin of natural gas in the individual EU countries [47]

Some key figures on the gas network in Europe and the six countries with the largest gas network in 2013 is shown in Table 11. Almost 30 % of the EU network was on German soil. Germany is also the most developed country in terms of the number of storage facilities and storage capacity. Spain has a significant number of LNG terminals running, seven of them, with more planned on the island groups of the Canary and Balearic Islands. Italy has a high number of city gates and the highest number of customers.

Table 11: Specific facts of the European gas transmission network (TN) and facilities

Parameter	Unit	Total	DE	FR	IT	ES	NL	BE
TN-length[9]	[10^3 km]	217.7	62.5	37.2	34.4	13.0	11.9	4.1
TN-compressor station[9]	[#]	171	28	31	11	18	13	5
TN-pressure reduction st.[9]	[#]	3'478	N/A	874	638	N/A	82	190
City gate[9]	[#]	19'855	N/A	3'731	7'000	N/A	1'009	190
LNG terminals[10]	[#]	31	0	4	3	7	1	1
Underground gas storage[11]	[#]	106	60	16	13	4	5	1
Total technical working capacity of UGS[11]	[Gcm]	74	22.3	12.7	13.5	2.3	0.0	0.7

Figure 28 shows the traded gas volumes and the ratio between import and export volumes of the individual European countries. Germany imports more than twice as much natural gas as other European countries, but exports about half of it. It can therefore be seen as both a consumer and an export country. Poland, Belgium, Portugal, Hungary, Switzerland, and the Czech Republic can be assigned to the same group. Italy imports the second most natural gas after Germany, but exports hardly any and consequently need the gas for own purposes. France, Spain, and Finland stand out in a similar way to Italy. Norway is the largest exporter of natural gas in Europe in terms of volume. They do not need the natural gas for their own purposes and can cover their energy needs with the immense domestic hydropower. Denmark, Romania, and Slovakia are also strong exporters in terms of share. However, they import natural gas from their neighbouring countries and can therefore be regarded as transit countries.

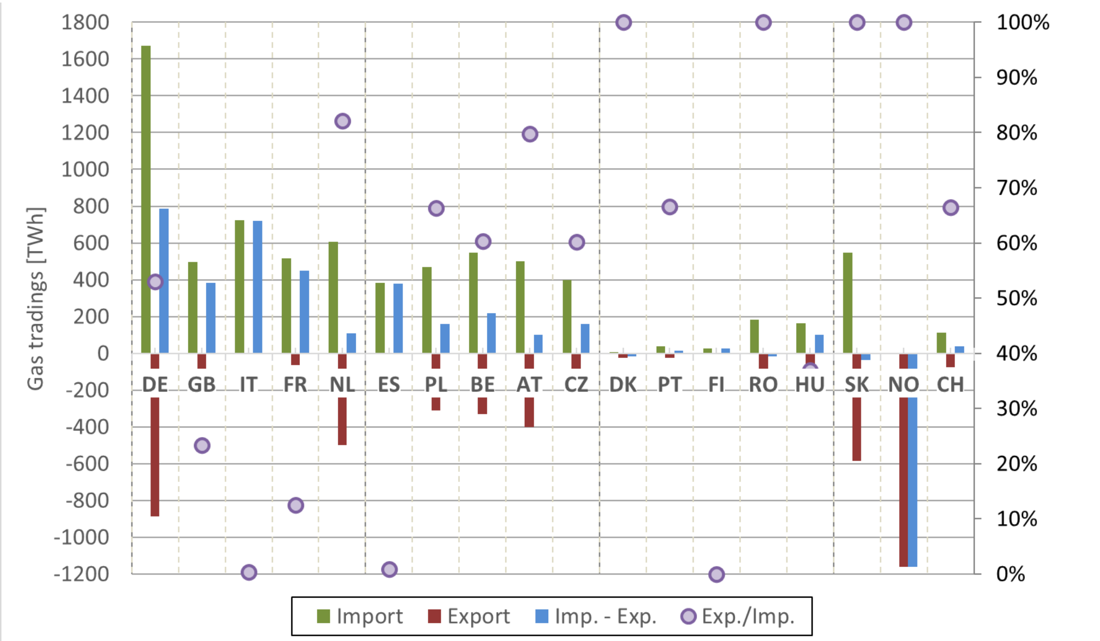


Figure 28: Total gas import and export volumes of european countries in 2017 [3]

[9] Marcogaz 2013 [7].
[10] LNG Terminals information collected in HIGGS Deliverable D2.3
[11] UGS information collected from GIE Storage Map 2021

4.6 Network sections that are particularly suitable for modelling

The discussed data in section 4.5 above may be a few years old. But, as it can be seen in the Table 24 of Deliverable 2.3, the European transmission network is experiencing only slow changes and that similar conditions still prevail today. Due to its important position within the EU in terms of gas transport, trade, storage, and interconnectedness, but also the availability of accessible data, Germany is the area of choice for modelling the transport network for an investigation of hydrogen blending in the transmission gas network.

4.6.1 Germany: TENP-MEGAL intersection

For a technical-economic analysis, the TENP pipeline from the Dutch (Bocholtz) to the Swiss (Wallbach) border and the MEGAL pipeline from Rimpar to the French border (Obergailbach), which is crossed and connected in Mittelbrunn, seem very interesting. Both transport systems have two pipelines running in parallel, are highly relevant for the security of supply in Europe and also part of the European Hydrogen Backbone Study. The TENP transports natural gas from the Netherlands to Switzerland and further to Italy. Moreover, the pipeline system is used for gas transports to and from Belgium as well as for supply within Germany. With the reversibility of the gas flow direction, TENP is also prepared for any future oversupply from Italy. The MEGAL is a pipeline system from the Czech (MEGAL North) and Austria (MEGAL South) to the French border is one of the most important transit pipelines for natural gas in Germany and France. The East-West axis was put into operation in 1980. In 2012, MEGAL South was extended with a parallel line to further secure the supply to Eastern Europe. Further details concerning are given in Table 12.

Table 12: TENP and MEGAL pipeline information [48] [49] [50]

Information	TENP	MEGAL Nord
		
Parent Company (-)	OGE (51%), Fluxys (49%)	OGE (51%), GRTgaz (49%)
Operator (-)	TENP GmbH & Co. KG	MEGAL GmbH & Co. KG
Parallel lines (-)	2	2
Length (km)	2 x ~500	459, 449
Diameter (inch)	(36 – 38), 40	35, 47
Pressure level (bar)	68	80
Compressor Stations	4	6
Main flow direction	North → South	East → West
Capacity (TWh/a)	180.4[12]	246.2[13]
Reverse flow (TWh/a)	52.8	–
Entry / Exit points	4 / 22	5 / 15

[12] Calculated with GCV of Russian H-Gas of 11.19 kWh/m³

[13] Calculated with GCV of North sea H-Gas of 11.64 kWh/m³

Figure 29 shows the generic topology of the TENP/MEGAL case study built with the open source software QGIS and the reference data set of 'LKD-EU' [51]. The boarders of the NUTS regions, from which the data of the consumption figures can be retrieved, and which are assigned to the individual exit points (nodes), are displayed.

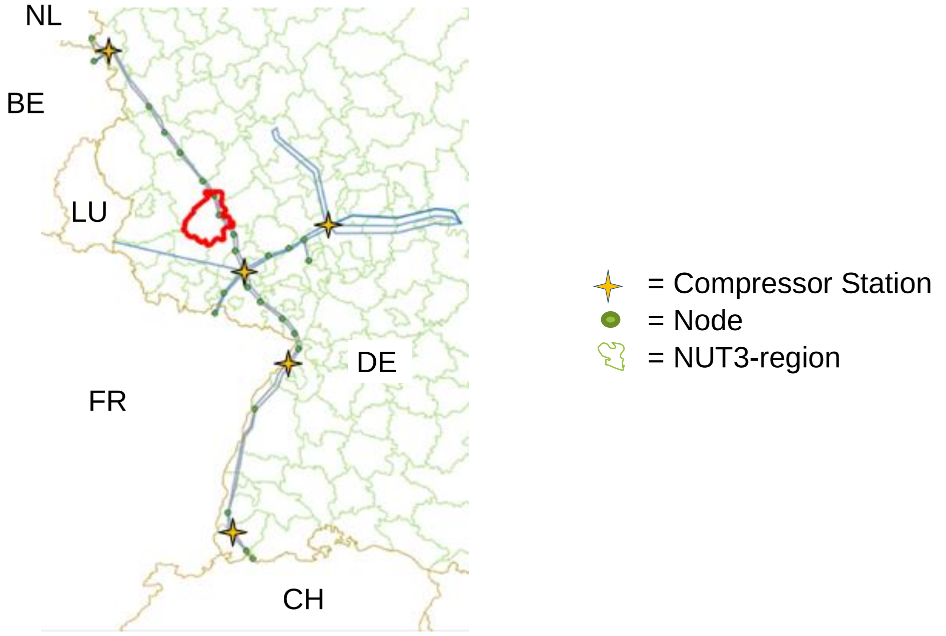


Figure 29: Network modelling of TENP and MEGAL pipeline sections in QGIS

In order to complete the build-up of the network simulation in Task 5.2, more in-depth information is required on the two pipeline sections, in particular on the functioning of the compressor and gas exchange stations in Mittelbrunn and Gernsheim. In addition, further information on the transport infrastructure (materials, efficiency and operation mode), the transported medium itself (gas flow characteristics, gas qualities) and the surroundings (geodetic altitude, gas producers and consumers, storage facilities, etc.) must be obtained.

Table 13 shows the hydrogen production projects close to the TENP-MEGAL intersection. In order to complete the data gathered from databases, direct contact with the project owners was accomplish. Not much information could be obtained but is shown in any event.

Table 13. Local hydrogen production near the TENP and MEGAL pipeline

Production site location	Country	Source	Production	Injecting (Y/N)	Hydrogen customer
Audun-le-Roman / MHYRABEL	FRA	Electrolysis		Y	
Grandrange / H_2V	FRA	Electrolysis		Y	
Metz / John Cockerill et UEM	FRA	Electrolysis			
GazelEnergie - site Emile Huchet, Centrale	FRA	Electrolysis		Y	
Haute-Vigneulles / Hy-Bus	FRA	Electrolysis			
Saint-Avold / H_2V Saint-Avold	FRA	Electrolysis			
Strasbourg / R-HYNOCA	FRA	Biomass gasi-fication			
Mulhouse / MulH_2ouse	FRA				
Völklingen, Perl (Sarre), Bouzonville et Carling (Moselle) / mo-saHYc	FRA			Y (100% H_2 pipeline)	
PVFCSYS Agrate	ITA	Solar - Alkaline	0.7 Nm3/h	N	
Remote Ginostra Italy	ITA				
Wind-H_2 stand-alone system ENEA	ITA				
SAPHYS, ENEA	ITA				
Store&Go, Troia Italy	ITA				
Greenhouse heating, solar-H_2	ITA				
H_2 from the sun, Brunate	ITA				
REFLEX	ITA				
Giovanola SA, Monthey	CH		760 Nm³/h	N	Synthetic stone pro-duction
CABB AG, Pratteln	CH		1400 t/year		
Dietikon, Limeco	CH			Y (methane)	Methana-tion

4.6.2 Italy

Natural gas is also a cornerstone of energy supply in Italy and has grown historically. Since 1950, the natural gas network has extended from northern Italy across the entire boot to the south. With over 23 million consumers, it is ranked number one in Europe. There are three supply points on-shore in the northern part of the country (interconnection with Switzerland, Austria and Slovenia) and three LNG ports at the coats. In the south, Italy is connected with Tunisia, Libya and recently over Albania via off-shore pipelines to the gas producers in North Africa and Eastern Europe (Azerbaijan).

From Sicily to the Austrian border, ten compressor stations are arranged in a line. Another compressor is located north of Milan before the ascent towards Griespass in Switzerland. Some of the pipeline sections consist of meshes, other sections are built parallel. Italy is highly dependent on imports and consumes this gas mainly for their own needs. In scenarios where hydrogen would be produced in the Northern Sahara or in the Arabian region, these offshore pipelines are very likely to become important transport routes for the renewable gas towards Europe.

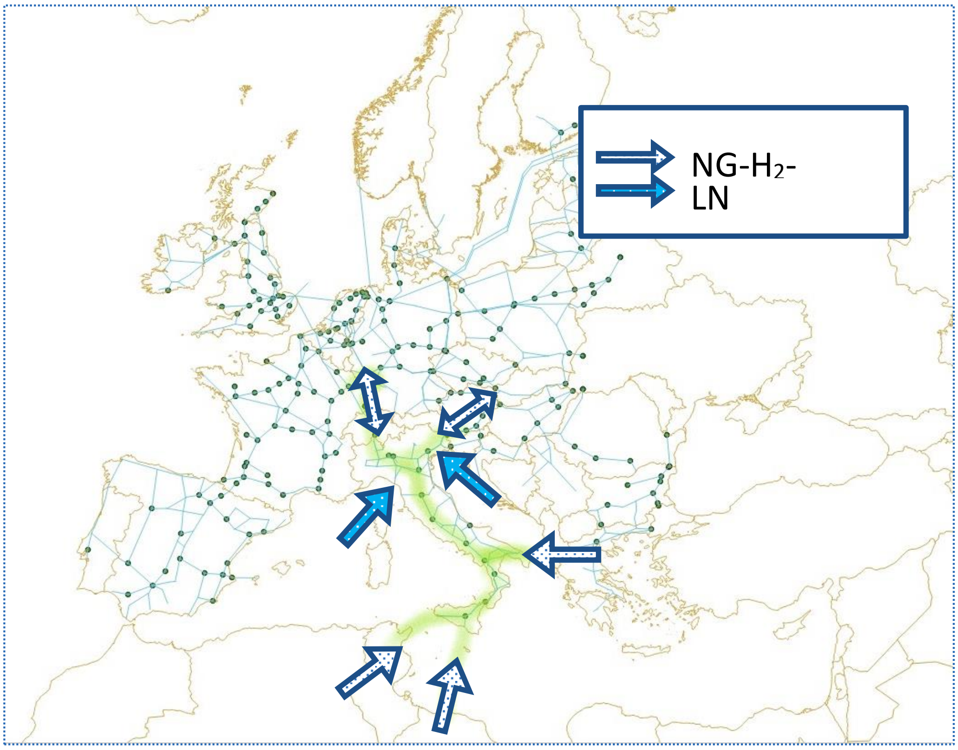


Figure 30: Illustration of possible Case "Italy"

The possibilities in the design of the case could be a combination of several entry points of NG-H_2 blends, primarily in the south. United in the south, the future gas could be transported along the national transport route to the north and distributed to the European market via the Alps (see Figure 30). Deliveries at the LNG ports with natural gas or also of liquid hydrogen would also be conceivable. It was not possible at this point to obtain detailed information on the described pipeline sections.

4.6.3 Spain-France

Another natural gas supply route may be the Iberian Peninsula. Spain has connections to Morocco and Algeria via two sea pipelines, as well as some larger and two smaller LNG ports. There are two connections to France via border interconnections at San Sebastian and Pamplona, where natural gas can be exchanged. Spain, like Italy, has a very high self-consumption rate and consumes practically all imported natural gas itself. This could change in the future if efforts are made to produce hydrogen in the region of northwest Sahara. Then a route via the two sea pipelines across the Spanish and French mainland to the borders of Belgium and Germany would be a realistic scenario (Figure 31). The topology of the transport route would be similar to the Italian case, where two offshore supply lines meet on land, lead together to the north and there split into two lines again.

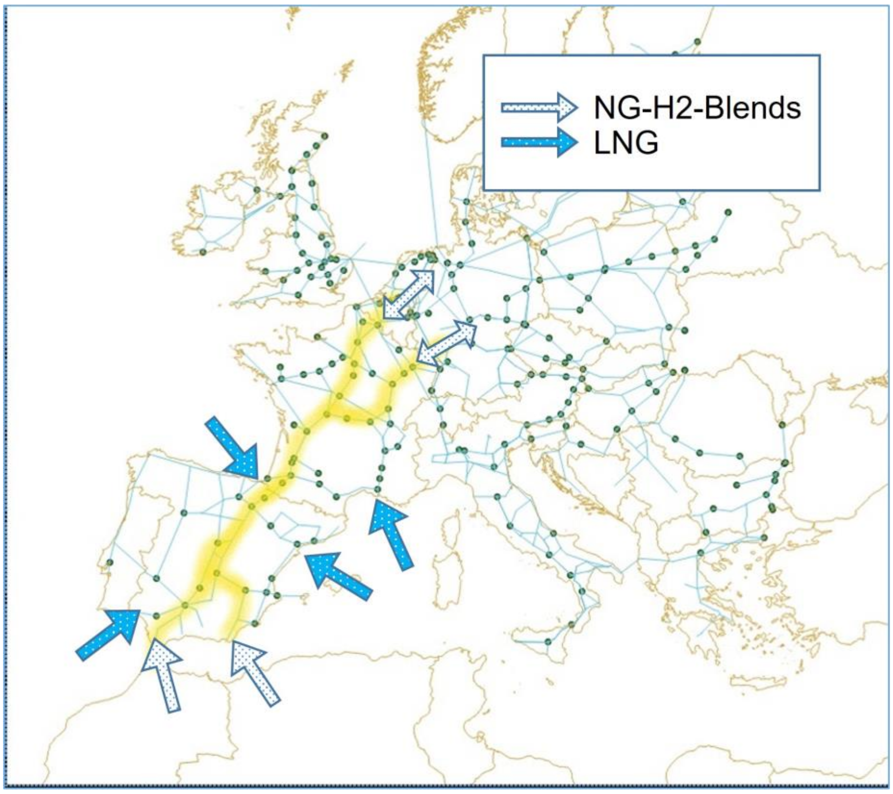


Figure 31: Illustration of possible Case "Spain-France"

4.6.4 Other potential routes

Other future supply routes of hydrogen or hydrogen natural gas in Europe could be via LNG ports and offshore pipelines from the North Sea or via the eastern routes from Ukraine via Slovakia or Poland. These two options were not considered further in depth. As mentioned before, the accessibility of the corresponding pipe network data is crucial. In the authors' opinion, the gathering of data becomes more difficult the more regions or countries the transport pipeline crosses.

Another, more general, case could be the local injection of hydrogen into the secondary gas grid. This would correspond to a decentralised gas supply and many small hydrogen production plants. In such a case, blending into the transmission network would be associated with the retrofitting of pressure reducing stations at the interface. For a gas flow reversal to take place, compressors and corresponding auxiliary aggregates have to be installed there. This inevitably requires a high financial expenditures.

A more realistic scenario, as already described in chapter 4.1.1, is for the hydrogen to be injected into the secondary gas grid and distributed to lower pressure levels. The transmission network would be unaffected by local producers and only dependent on the large and centralised production sites of hydrogen. On the secondary grid level, the H_2-content in the blend would be dependent on the consumption of the customers, the local hydrogen injection rate and the H_2 level coming from the gas in the transmission system.

5 Modelling methodology

The aim of this chapter is to describe the developed methodology for modelling a representative case of hydrogen blending in the existing gas grid.

5.1 Approach and scope

In this section the modelling processes will be described, from the setup of the network topology in QGIS to the import into an appropriate software and the integration of the boundary conditions. Moreover, the system boundaries and the scope under investigation will be explained.

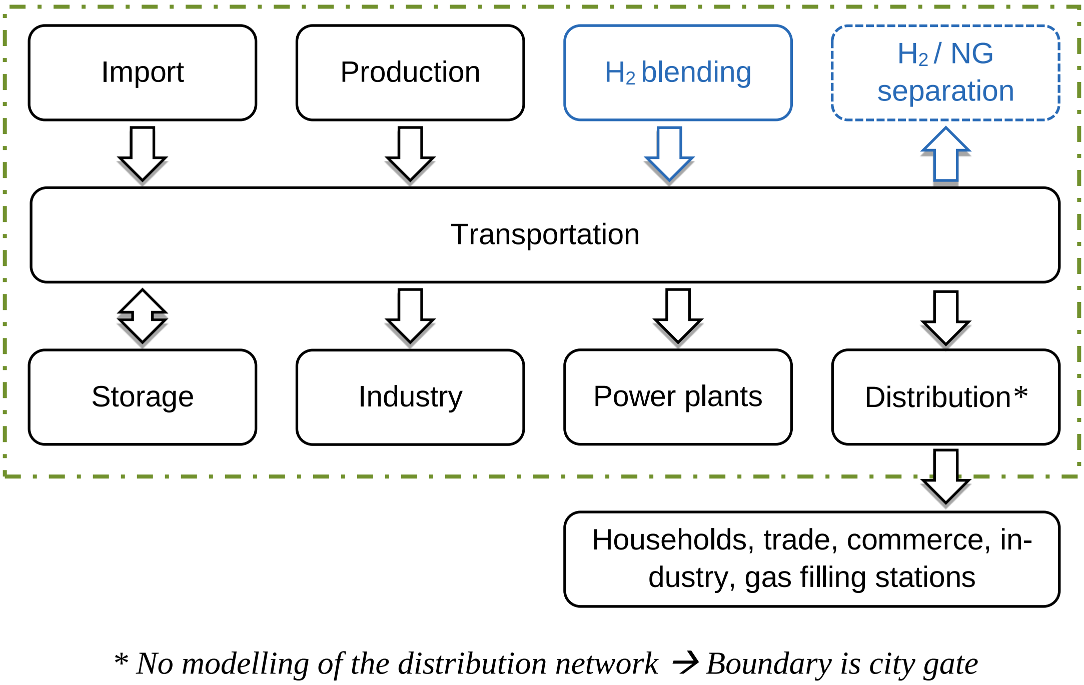


Figure 32: Scope of the modelling part

5.1.1 Data sets for QGIS

Quantum-GIS (QGIS) is a free and open-source cross-platform desktop geographic information system (GIS) application that supports viewing, editing, and analysis of geospatial data. For over a decade, public datasets have been continuously published for QGIS. This is also the case for many scientific projects, from which our used data originate. The following subsections contain a brief description of the two data sets relevant to HIGGS.

5.1.1.1 Reference data set 'LKD-EU' [51]

The project was funded by the German Federal Ministry for Economic Affairs and Energy through the grant 'LKD-EU' and provides a data set of the German electricity, heat and natural gas sectors. The data is from the year 2015 and includes:

- Consumption figures for regional gas consumption at the NUTS3[14] level resolution.
- Breakdown of the gas consumption into household and industrial
- Positioning of exit nodes, industrial consumers, production and storage
- Geographical (position) and technical (length, diameter, operating pressures) information on the transport pipelines

The original sources of the data used in this reference set are described in the accompanying document. An excerpt for the most important sources concerning the transmission gas network is shown in Table 14.

Table 14. Data sources for the gas sector in the reference Data set 'LKD-EU'

Source	Type of data
Entsog	Time series (TS) on: Transmission capacity map Europe, Tariffs and Interruptions
GIE	Gas storage maps Europe since 2011 (gse) LNG maps Europe since 2011 (gle)
AGSI	TS on: withdrawn and injection capacity, working gas volume, injection and withdrawn rates
EUROGAS	Annual gas demand and annual gas supply statistic
FNB	tech. and geographical information on TN
BnetzA	General Information and further extension of the TN, Power Plant list
BAFA	TS on import prices and exploration and exports of NG
DWD	TS on temperature data
BVEG	tech. and economic Data on NG production and extraction
BDEW	Aggregated data on NG-demand, use as fuel and security of supply
Open Street Map	Geographical pipeline information (poor quality)
Open Power System Data	Geographical data on NG-Power plants

5.1.1.2 IGG gas transmission network data set [52] [53] [54]

In the SciGRID_gas project, methods were developed to create an automated process that generates a gas network dataset for Europe. The focus of SciGRID_gas is on the European gas transmission network. The data required for such models are the gas facilities, such as compressor stations, LNG terminals, pipelines, etc. with their specific attributes. Most of these data are not freely available. Within the SciGRID_gas project, a combined dataset from OpenStreetMap (OSM) and non-OSM is described, called the "IGG" dataset. It was generated by combining the following data sources:

- Internet Data Dataset (INET) [DPM20c].
- Gas Infrastructure Europe (GIE) dataset [DPM20c].
- Gas Storage Europe (GSE) dataset [GasSEurop20].

[14] https://en.wikipedia.org/wiki/Nomenclature_of_Territorial_Units_for_Statistics

The IGG data set provides basic information on the European gas transmission network:

- Structure and layout of the European network in simple representation.
- Attributes of the network sections such as diameter, gas flow reversal, gas quality (H- or L-gas), pipeline length, maximum pressure rating and capacity, age.
- EU-Entry and intra-European cross-border points
- LNG ports
- Storages (Store- and withdrawal capacities, working gas capacity, age and gas quality)

5.1.2 Entsog Transparency Map

ENTSO-G was created in 2009 as part of the third EU energy package adopted in 2007 to liberalise and open up the electricity and gas markets in Europe. Its tasks are partly defined in the EC Regulation No. 715/2009 on conditions for access to the natural gas transmission networks. Derived from this, ENTSO-G is responsible for:

- Standardisation, allocation and administration of network codes
- Developing an EU-wide ten-year plan for the development of the gas network
- Improving the flow of information from TSOs to market participants
- Creating common working tools to coordinate the operation of the network

One of these common working tools is the operation of a transparency map. On this platform, the transmission system operators can upload information on the operation of their network. The focus here is on the market concerning data and actual gas flows and qualities. Since the restructuring of the portal in 2014, it has also been possible to upload hourly measured values.

The transparency map also offers the possibility of obtaining data directly via API calls. The API calls can be obtained and processed automatically. For the modelling tasks in HIGGS, a Matlab program was developed to query required data from corresponding interconnection points. Figure 33 shows plots of automatically processed flow and calorific data from an API call at the interconnection points Obergailbach (GER/FRA border) and Wallbach (GER/CH border) in the year 2017.

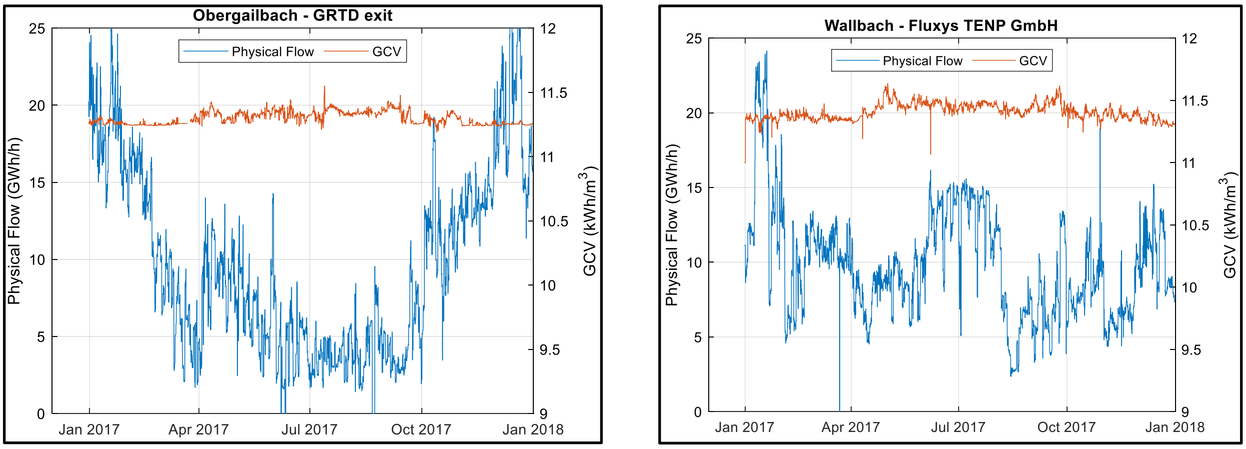


Figure 33: Data plot of API calls from the ENTSOG transparency platform

5.1.3 Transport network

This section describes the various elements of the high-pressure natural gas grid modelled.

5.1.3.1 Exit points

Exit points can be the end one pipeline section where, gas leaves the modelled network. As already mentioned, these can be downstream networks or direct consumers in so-called city gates. As described in section 4.3, at those points the metering and pressure-reduction takes place and the gas is transferred from a high-pressure network to a low or medium pressure distribution system.

In case of the HIGGS project, also, the city gate describes the transfer point where gas is taken out of the transmission network to the interregional or regional high-pressure distribution networks. The rural regions, cities and industrial zones surrounding the transport pipeline are bundled in the corresponding city gate. It is not foreseen that gas can be injected into the transmission network from a city gate. The initial study has been carried on the intersection of the TENP and MEGAL pipelines, where ten, respectively three city gates were modelled in a first approach.

The annual consumption for the household and industry departments were considered for each individual district from the data from the reference data [51]. However, the distribution network is not divided into districts, nor are the transport pipelines assigned to a district as a consumer. The consumption data must therefore be allocated to the individual exit points of the transport pipeline in the most adequate way possible. The allocation of the consumption regions to the exit points was done to the best of knowledge and can be checked in Annex II. Figure 34 shows the consumption for the individual city gates determined for HIGGS, broken down by industry and households.

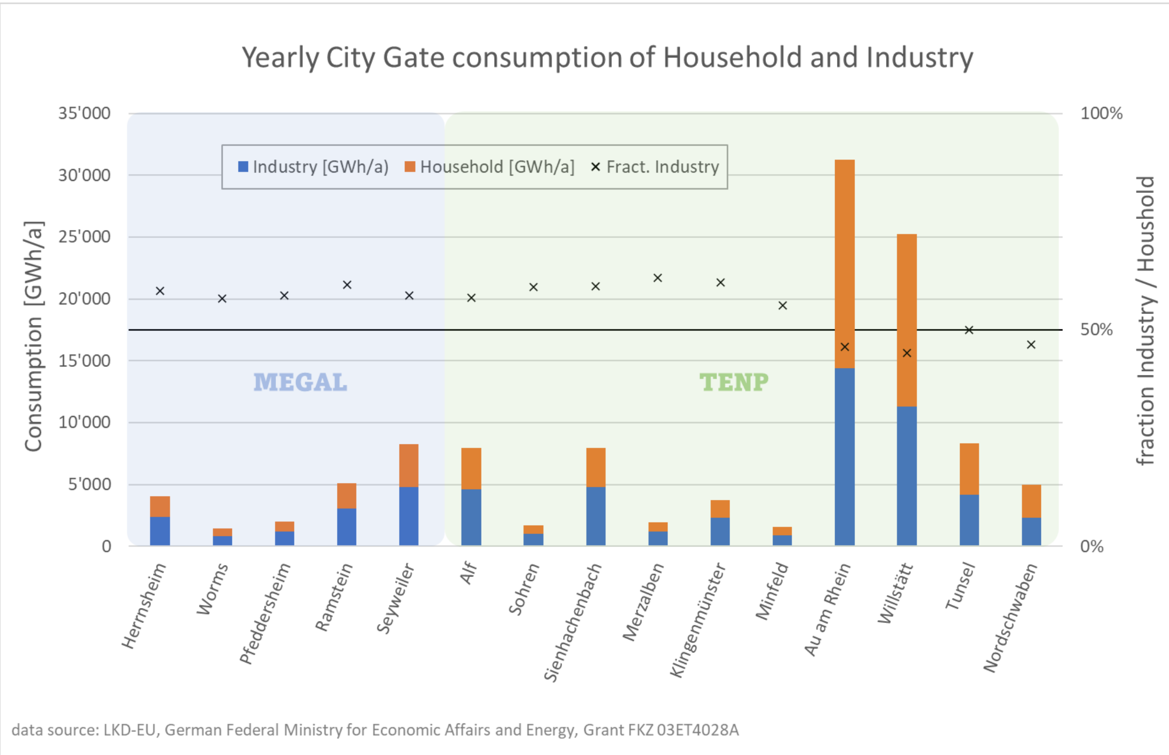


Figure 34: Annual gas consumption of the city gates modelled in HIGGS

Load profiles are used to distribute the annual gas consumption of the city gates. For the household sector two load profiles are derived from hourly measurement data of typical Central European households[15]. One of the profiles describes a rural consumer mix (smaller household buildings), the other one defines a composition that tends to be urban (larger commercial buildings). Table 15 shows in detail how the building stock of the two profiles is composed. These can be individually assigned to the individual city gates in the model.

Table 15: Creation of load profiles for households modelled in HIGGS

Distrubtion of Building type and Energy Consumption [P]	Rural		Urban	
	frac #	*frac ∑P*		*frac ∑P*
one family house	48%	*20%*	11%	*2%*
Apartment building				
-small	19%	12%	6%	1%
-medium	19%	42%	22%	16%
-large	3%	10%	11%	13%
Commercial				
-small	8%	4%	22%	4%
-medium	3%	6%	6%	4%
-large	0%	0%	6%	34%
Restaurant	1%	5%	17%	27%

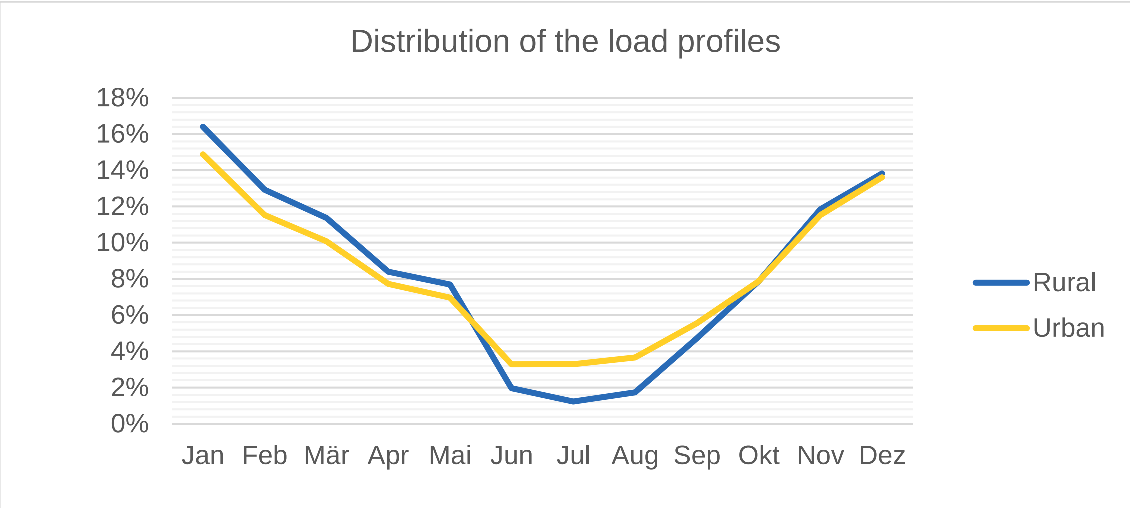


Figure 35: load profiles of a typical household consumption curve for rural and urban regions

The max./min.-ratio of the monthly rural load profile amounts to 13.3 (max 16.4 % in January, min. 1.2 % in July) and for the urban load profile it is profile 4.5 (max 14.9 % in January, min. 3.3 % in June). While the demand for thermal energy among businesses and households resembles the classic annual consumption curve. The one of the industries has a lower fluctuating gas demand. We

[15] The data was provided by a local energy supply company of an average village (530 a.s.l.) in the Zurich region.

have relative data from three South German direct purchasers from the medium-pressure grid, which we will use for the load profile for the industrial sector.

5.1.3.2 Interconnection point

An interconnection point is usually defined as a transfer station to another transmission service operator (TSO), i.e. when a pipeline crosses a country border. Flow direction is determined for some, flow reversal is possible for others. Gas flow metering stations are placed on all interconnection points.

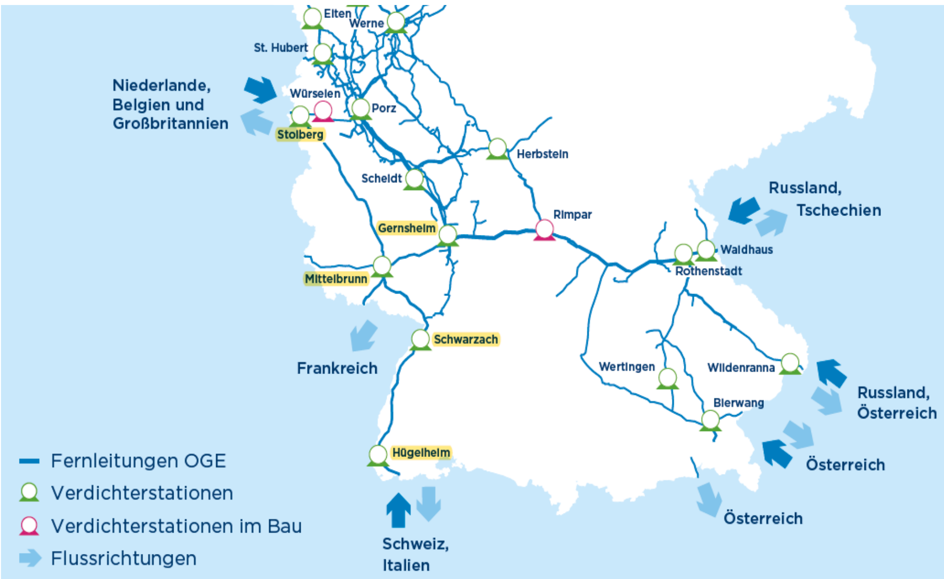
5.1.3.3 Intersection point

Intersections or junctions/combinations of transport pipelines describe points where gas exchange between pipelines take place. In detail, the gas leaves the previous line at this point in order to be added to the new line. This is often done via gas pressure regulating valves or compression systems in order to adjust the gas to be exchanged to the newly added line.

In the TENP-MEGAL case, there are two intersections. One is the gas detection point between the two lines and the other is the branch in the direction of Remich (LU). How the two intersections are structured and are operated must be examined in T5.2.

5.1.3.4 Compressor Station

As described in detail in section 3.2.2.2 the driving force in the gas network are the gas compressors. They are located between 100 and 200 km apart so that they can compensate for the pressure losses that occur in line between them. Figure 36 shows a map of the involved compressor station and corresponding capacity from those of the TENP-MEGAL case. The approach is to model the compressor stations as close as possible to the reality. Therefore, more in-depth clarifications of the installed technology is needed in further tasks.



<u>Engine power:</u>

Stolberg:	46.8 MW
Gernsheim:	60.4 MW
Mittelbrunn 1:	54.5 MW
Mittelbrunn 2:	50.2 MW
Schwarzach:	42.4 MW
Hügelheim:	34.7 MW

Figure 36: Compressor stations and installed engine power of the TENP-MEGAL case [55]

5.1.3.5 Regulator station

The main components and the technical challenges in regulator stations are described in section 4.3.4.1.3. In the model, the functioning of the valves with regards to the maximum allowable flow rate shall be reproduced as far as possible. The required preheater capacity will be taken into account as well.

5.1.4 Boundary Conditions

Since the modelling only involves sections of the transport network and also not everything can be taken into account, certain initial conditions must be assumed and boundary conditions set that must not be violated. These are discussed in the following sections.

5.1.4.1 Pressure

It is well known that gas pressure is the driving force for the flow of gas. The maximum achievable pressure level of the involved compressor stations are therefore a limiting variable in the modelling of a gas network. It is not possible for the system to have a higher pressure at one point than the compressors are able to build up. Furthermore, a lower bound for the pressure must be set in order to keep system working.

5.1.4.2 Maximum gas flow velocity

In order to the cost for transportation low, pipelines with smaller diameter and therefore cheaper in construction can be chosen for a system. This, in contrast, would rise the operating costs due to the higher pressure losses. With a small diameter, the flow rate of the gas increases accordingly in order to be able to transport the same amount of gas or energy. The flow rate, in turn, contributes to the pressure loss to the second power, which results in a higher required compression power and consequently higher operating costs. Furthermore, high volume flows can also lead to undesirable noise. As it is mentioned in section 4.3.1 the flow velocity in the transport pipelines usually does not exceed 30 m/s. Therefore, this value should also be maintained in the future and is therefore set as a boundary condition.

5.1.4.3 Pipeline path and material

When modelling pipelines, several factors affect the local pressure losses. On the one hand, the path of the pipeline (including geodetic height and curves) has an impact, on the other hand, the roughness of the material also plays a role. While in GIS systems one can simply specify the nodes with an elevation value, one has to assume an efficiency factor instead of the precise course for the sake of simplicity. Since the exact roughness of the pipeline is usually not known either, it is best to use literature values.

5.1.5 Scope of investigation

As proposed in Table 16, the first step to tackle in task 5.2 is to set up the initial case study (TENP-MEGAL) correctly. The simulation model should be able to calculate a feasible solution which is in line with data obtained from ENTSOG transparency platform. This requires technical clarifications with the operators of the transport pipeline involved, especially for modelling of the compressor stations at the intersection point in *Mittelbrunn*.

Once the model has been set up correctly with the as-is infrastructure (T5.2.1), admixture scenarios can be implemented, which is the main part of task 5.2.2. This will be based on the future demand for natural gas and hydrogen described in section 3.1.2 and the blending scenarios described in section 3.2.2.6 considering different sources and producers of hydrogen. First, the focus will be on different estimated consumer flows and blending scenarios centralised hydrogen production. In this phase of the simulation, changes in pressure losses are calculated and corresponding additional compression work and other required outputs will be determined.

In a third stage of the model, influences from decentralised hydrogen production will be included. Hydrogen produced by wind power in the north and solar power in the south will be fed into the high-pressure grid. The focus here is on the course of the concentrations and how the hydrogen is distributed over the section of the transport network.

In the last stage of the model, the goal is to implement individual exit points that either want to consume pure hydrogen and those that allow a maximum of 2 vol.-% hydrogen content (e.g., CNG-refilling stations or NG-turbines). The corresponding technology must be simulated at the respective exit points. At the exit points where pure hydrogen is required, this could be, for example, a steam reforming unit that splits methane into hydrogen and CO_2. At the hydrogen-critical exit points, this will be the membrane technology. Finally, it should be possible to draw conclusions on how much technical and financial effort is needed for the corresponding system.

Table 16: Scope of investigation for the techno-economic analysis in WP5

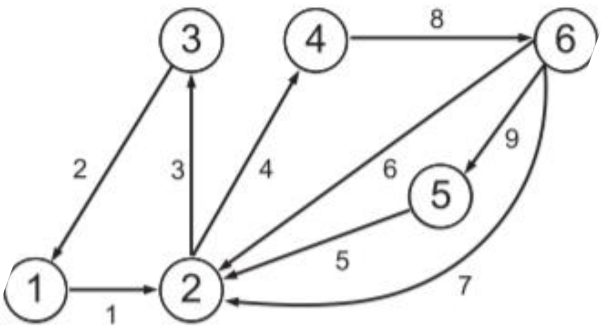
	Modell Phase & Scope	Inputs required	Source[16]	Type	Output
#1	build up Modell Case Germany	Design and operation of the Mittelbrunn station	1, 2	s	Data of today's compression performance
	implement actual gas market in the area of the case	Flow Data and City Gate consumption	3, 4	s	Direction and amount of today's gas flow, pressure losses
#2	Scenarios with higher H_2-Levels (up to 30 vol.-%) in imported gas streams	Clearly defined scenarios based on future demand and blending scenarios	WP5.2	s	Changes of Performance compared to the state without H_2 in #1.
#3	Local H_2 production and injection into the model based on renewable energy (PV, Wind) and location	Energy production curve for PV and wind at different locations	5	t	Max H_2 concentration and amount in the modelled grid over the period of one year
#4	Implement technology to ensure actual regulations in gas quality	Key Performance Indicators (KPI) of existing or new Technology	WP2, WP4	t	Proof of concept, investment and operational cost for additional technology
	Implement additional business case like 100% H_2 consumers	Definition of new business cases and KPI of corresponding Technology, consumption curve of new customers	WP4, WP5.2	t	Proof of concept, investment and operational cost for additional technology

[16] Sources: 1) Fluxys, 2) OGE, 3) ENTSOG Transparency Database, 4) reference Data set 'LKD-EU', 5) Renewables.ninjas database, WPx) HIGGS work packages, Simulation type: **s** = steady state, **t** = transient

5.2 Fundamentals of network computation

In a mathematical sense, gas networks are planar graphs for which certain relationships between the lines and consumers (nodes) apply. According to graph theory, a graph consists of n nodes and k edges. The ratio of the number of nodes and edges can differ in such a way that qualitative jumps occur. If the number of edges is smaller than the number of nodes minus one ($k < n - 1$), it will not be possible to connect all nodes and edges in such a way that every node can be reached from any other node of the network. If, on the other hand, $k = n - 1$, you can connect them all, i.e. you can reach any other node of the network from any other node and the gas can flow from the entry point to the consumer via exactly one path. If the condition that $k > n - 1$ applies, there will be meshes (m) in the network through which certain nodes can be reached via several routes. The larger the network is meshed ($m = k + 2 - n$), the higher the possibility that the gas can flow from the entry point to the consumer via different paths. [17]

In network calculation tools, these transfer possibilities are evaluated in so-called adjacency and incidence matrices. The relationships between nodes and lines (adjacent = neighbour, $n \times k$ matrix), as well as between lines and meshes (incident = belonging, $k \times m$ matrix) are therefore determined in this process. The elements of the matrix are either 0 or 1, depending on whether the parts under consideration belong together or not. If one wants to give the gas lines a certain direction, i.e. create a directed graph, the matrix elements receive a + or - sign. In the case of the incidence matrix, a distinction is made between whether a line meets the circular direction of a mesh. Whereas with the adjacency matrix, the sign corresponds to whether the node receives (-) or transmits (+) gas for a connected line. This relationship is shown schematically in Figure 37.



$$\underline{A} = \begin{pmatrix} 0 & 1 & 1 & 0 & 0 & 0 \\ 1 & 0 & 1 & 1 & 1 & 1 \\ 1 & 1 & 0 & 0 & 0 & 0 \\ 0 & 1 & 0 & 0 & 0 & 1 \\ 0 & 1 & 0 & 0 & 0 & 1 \\ 0 & 1 & 0 & 1 & 1 & 0 \end{pmatrix}$$

$$\underline{I} = \begin{pmatrix} +1 & -1 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ -1 & 0 & +1 & +1 & -1 & -1 & -1 & 0 & 0 \\ 0 & +1 & -1 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & -1 & 0 & 0 & 0 & +1 & 0 \\ 0 & 0 & 0 & 0 & +1 & 0 & 0 & 0 & -1 \\ 0 & 0 & 0 & 0 & 0 & +1 & +1 & -1 & +1 \end{pmatrix}$$

Figure 37: Example network with corresponding adjacency and incidence matrix [56]

Analogies between electricity and gas networks are only of limited validity. The reason for this are the existing non-linearities, which can be divided into two main groups. One of them is the pipe friction, which depends on the pipe parameters and the Reynolds number (Re). This in turn is a function of the volume flow. Another difficulty results from the fact that some of the governing equations, such as the equation of *Prandtl* and *Karmann* and the equation of *Prandtl* and *Colebrook*, cannot be solved explicitly and the solutions can only be determined iteratively. The non-linearity with the most severe impact on the gas network calculation results from *Darcy's* pressure loss equation (equation (4)), which corresponds to Ohm's law in electrical networks. The decisive difference between electrical engineering and fluid mechanics is the quadratic dependence of the pressure loss on the volume flow. [56]

In principle, the distribution of the fluid in a network is computed according to *Kirchhoff's laws* for nodes and meshes [17]. The algebraic sum of all in- and outflows in all nodes equals zero:

$$\sum_{p=1}^{n} \dot{V}_p = 0 \tag{9}$$

And the sum of all pressure drops in a closed mesh equals zero:

$$\sum_{k=1}^{m} \Delta p_k = 0 \tag{10}$$

Depending on the complexity, the flow distribution and pressure loss relationships in a meshed network can only be calculated iteratively with a very high computing effort. This is why network calculation only became a solvable task for network operators with the invention of electronic computing technology. The commercially available programmes differ in user-friendliness, input and output, but often have the same mathematical core. If you go beyond steady-state calculations and want to carry out transient simulations, you need a high degree of specifications or known parameters to solve the non-linear, partial differential equations. Not all programmes are capable of this yet.

5.3 Analysis on existing software for grid modelling

This section introduces the various software products that can be used for network modelling tasks. During the validation process, the attention was focused on the relevant factors according to the tasks to be carried out in the Grant Agreement. These were appointed as follows:

- Can H_2 be simulated and what is the basis for the calculation of fluid properties?
- What are the inputs required and the corresponding results?
- How can the result's accuracy be assessed?
- What grid components can be simulated? (Pipelines, compressors, metering stations, storage, network pressure level, network complexity, number of injection and extraction points…)
- What are the current uses cases and references?

In the following subsections, six commercially available products are described and afterwards compared in tabular form. However, these are by no means the end of the story, there are a lot of other products, but by reputation of some of them seem to be more suitable for networks on distribution level and were therefore not inquired in the first place.

5.3.1 SmartSim[17]

The software *SmartSim* is a tool for gas quality tracking which enables gas grid operators selective invoicing of customers when different gas qualities (natural gas, biogas, hydrogen) are injected into the grid. The chemical properties are calculated with *GasCalc*, which has already been used by OST as an autonomous software in another project. GERG 2008 Guidelines mentioned: OIML R 140 / DIN EN ISO 15112

Contact: *SmartSim GmbH*, 45130 Essen, info@smartsim.energy

5.3.2 Simone[18]

Simone is a software for the simulation and optimization of gas pipelines, which TSO's may use to monitor their operation. Transmission networks as well as distribution networks can be simulated and further useful features like energy billing, compressor fuel optimization, leak detection and real-time operation are implemented. What makes this software particularly interesting is the fact that both steady state and dynamic flow scenarios can be simulated and the whole hydraulic modelling can be done for large-scale, complex gas systems (pipelines, valves, compressor stations, storages, resistances, and nodes).

Contact: *LIWACOM Informationstechnik GmbH*, 45024 Essen, +49 (201) 17038 0

5.3.3 PSIganesi[19]

The *PSIganesi* is an extension to any control system of network operators who would like to rely on applications such as network simulation, forecasts, transport management and gas property tracking. The planning application is interesting, as it allows the analysis of the effects of new supply, transport and storage situations, as well as the planning of new network sections and stations for the injection of hydrogen and other gases.

Contact: *PSI Software AG*, 10178 Berlin, +49 30 2801-1504, gasandoil@psi.de

5.3.4 Neplan[20]

With this software, natural gas networks of any complexity including equipment can be modelled. For the calculation of the gas properties a separate library seems to be necessary. The user is allowed to simulate time-dependent processes by assigning synthetic profiles or measurements of consuming and supplying elements.

Contact: *Neplan AG*, CH-8700 Küsnacht, +41 (0)44 914 36 66, info@neplan.ch

[17] https://www.smartsim.energy/en/
[18] https://www.liwacom.de/
[19] https://www.psigasandoil.com/en/software/gas-management
[20] https://www.neplan.ch/neplanproduct/gas-water-heating-4/

5.3.5 Synergi Gas[21]

Software for optimization and simulation of gas distribution and transmission networks. In addition to pressure and flow calculations, Synergi Gas has extensive gas component, gas property, and thermal tracing features as well as hydraulic modelling, i.e. networks of pipes, regulators, valves, compressors, storage fields, and production wells.

Contact: *DNV GL Limited*, +447936338230, andrew.wilde@dnv.com

5.3.6 Irene Pro[22]

Analysis tool for designing gas networks, performing calculations and determining the level of risk or delivery reliability. The basic function in IRENE Pro is capacity calculation. However, extra modules can be added as required in order to extend the functionality. With that, one is able to calculate all types of gas, so not just natural gas, but also bio gas, green gas, hydrogen and CO_2. Also the optimum design of the network and pressure profile can be determined.

Contact: *Kiwa N.V.*, +31 (0)88 998 44 00, info@kiwa.nl

5.3.7 Evaluation of software scouting

Specific details on the individual products are listed below in Table 17. *Neplan* was no longer considered in detail, as it was not (yet) possible to track calorific values in its module. In the case of hydrogen injection, however, this is indispensable and therefore represents the main criterion for investigations in the HIGGS project. With Irene Pro, the property values of gases can also only be entered statically and would therefore also only result for one admixture level. The other products all seem to be quite equivalent in terms of handling and the possibilities to calculate hydrogen admixtures. The aim is to test one or two of these products and use them for modelling purposes in T5.2.

[21] https://www.dnvgl.com/services/hydraulic-modelling-and-simulation-software-synergi-gas-3894
[22] https://www.kiwa.com/en/service/irene-pro-network-calculation/

Table 17: Evaluation of software scouting

	SmartSim	Simone	PSI Gas	Synergi Gas	Irene Pro
Applications and references?	Gas Quality Tracking in order to ensure correct billing when different gases are injected into the grid. An additional module for grid planning is currently being developed.	Product for planning purposes. Integrated as state estimation and leak detection tool. Computing high- and low-pressure networks as well as for transportation- and distribution structures.	Planning of new gas networks, entry and exit flows, new customer exits, transport of hydrogen or bio gas through networks	Recently awarded the contract to assess the feasibility of transporting Hydrogen in the Italian transmission system; Used in 90% of all gas distribution companies in the US, 100% in UK as a network design and planning tool and for optimization / forecasting.	Used to calculate the Dutch natural gas distribution networks since the seventies up to now and is used by most Dutch DSO's
H_2 computable as part of a mixture?	Yes, hydrogen can be tracked. Also any other components that may be expected in natural gas grid can be considered.	Can be used also for gases containing a considerable content of hydrogen.	Gas compositions are according AGA8-92DC (21 gas components including hydrogen)	Proven Hydrogen modelling capabilities and any gas using multiple gas compositions simultaneously allowing you to trace any component through the network	Following properties define the fluid: density, dyn. viscosity, calorific value, relative compressibility, these values must be given for the mixture.
Simulation: - Network modelling (i.e. GIS) - Thermodynamic model used - **Time resolution of balance / DE** - Input data to be generated or modified	Topology taken from GIS or other software for grid calculation. For conversion of data formats, interface that can be adjusted in a very flexible way. **Kernel** in-house development based on high accurate thermodynamic functions. Further reference (ISBN: 978-3-18-350507-4). The calculation is performed on an hourly basis. Higher time resolution would not increase accuracy of results.	Due to the implementation of various state equations (**GERG2004**, **AGA8DC92**, **BWR**, etc.) it be can be used also for gases containing a considerable content of hydrogen. For hydrogen planned to extend the list of EOS with **GERG2008** by the end of 2020; Standard API which allows transferring data from and to SIMONE within a programming environment. Offered implementations for Java,	GIS import not available. Networks edited via topography editor; Thermodynamics based on Helmholtz free energy. **SGERG-88** and **AGA892DC** for calculation of real gas deviation is available. **GERG 2008, SRK, PR, LKP and BWRS** addable; Solution of DE via implicit finite difference method. The time step range of 1 to 3600 s. No strong relation between time steps and	Networks drawn freehand or from AutoCAD import, Shape / Layer / Coverage files, Geodatabases or live SDE connection to GIS; Calculates gas characteristics from inbuilt code (GasVLE), including HHV, LHV, spec. gravity, viscosity, density etc.; Analysis of a 200,000 pipe network in 1 min. (steady state). Transient a lot longer depending on time period, step size and wave speed.	Network can be drawn freely, but it is also possible to import existing GIS data via XML. Exchanging data with a GIS system is common; The gas properties are not calculated, but have to be defined by the user. We calculate pressure loss using the extended ideal gas law; For both input and output XML (GML based) is used - output data to Excel, ESRI-Shapefiles and DXF. Other

- Corr. output - Dynamic and steady-state - Guidelines / Regulations	All common data interfaces like e. g. csv, txt, XML, MSCONS. Both conditions can be simulated and evaluated.	JavaScript, LUA, C, C# and C++	space. Input in dialogs for entry and exit flows. Export and import possible via clipboard (to MS-Excel); Steady-state normally starting condition for dynamic simulation;	Data can be im- and exported to text file, CSV, MS Excel & Access or spatially to Shape file; Also display background mapping from the above GIS data types but also TIF, BMP, and JPG.	options are: generating a report in PDF format or export views as image.
Equipment: - Pipelines - Compressors - Metering - Storage - Pressure level - Network complexity (i.e. # injection / extraction points	Yes Currently not Storage: Currently not, Metering stations: yes, Valves with zeta-value: currently not directly (valves with zeta-value can be mapped with a corresponding pipe and a valve). There is no mathematical limit except computation time. Currently, grids with more than 8000 nodes are being well-simulated.	Features like quality- and temperature tracking, compressor modelling can be licensed optionally to extend the functionality. Designing and modifying the topology with a network editor, but topologies can also be created by using a topology API. This approach is used to automize the process in fully integrated environments.	Input dialog for length, diameter & roughness; Input dialog for compressor map data points for flow vs. pressure ratio/head and efficiency; No storage available, modeled as entry and exit nodes. Metering stations not available for planning. Valves can be closed or opened; No practical limits (memory and storage limit, execution time increases with network complexity);	Pipes attributes include flow equation, diameter, material, roughness and efficiency factor; Numerous compressor models available (simplest theoretical compressor to full mapped compressors or types of centrifugal and reciprocating compressors); Storage devices, regulator stations, processing plants, valves can be added to the model with all their attributes. Dynamic models are limited to about 20,000 nodes. Number of supply points and demand points is not limited.	Dimensions and roughness to be defined by user. At request, we can supply template files with predefined pipe materials and roughness; Storage is not available, metering stations can be applied (and governers can be defined), valves are only used to close-off a pipeline (a zeta-Value is not taken into account); For the software there are practically no limits to the number of networks, pipelines, nodes, and injection or extraction points.
Planner license available or even academic use? Fees?	For commercial use, usually a license and service contract is filed. An academic license is something to be discussed.		Different fees for software, depending on number of installations, users and nodes.	We do have academic licenses available, however they are only to be used for non-commercial purposes.	Demo version is freely available and can be used for one network containing up to 50 pipe segments and one supply point. The license and service fees are based on the maximum size of the network.

6 Conclusions and Outlook

In this report, the basis for the techno-economic analysis of hydrogen blending into the existing natural gas grid in Europe was established. As an introduction, the consumption and import figures of natural gas in the European states have been examined, in order to put the role of hydrogen in relation to this on the grounds of various studies and strategies. The resulting projected shares of hydrogen in the total future gas mix confirm that the potential exists in the short and medium term to achieve a volume share of up to 20 % hydrogen in natural gas. This value is considered the upper limit in some studies, because at higher concentrations many end-use devices would have to be modified or replaced, which would lead to substantial expenses for infrastructure. Therefore, the general consensus is that a pure hydrogen network should be built in parallel and that blending should serve as a transitional phase to allow the hydrogen economy to become established and competitive with the necessary quantities.

In addition, the effects of the H_2 admixture on the gas properties were analysed from a thermodynamic and fluid-dynamic point of view, and a preliminary study was made with the generated knowledge of how the different operating regimes of TSO behave when there is a varying hydrogen presence in the gas. Initial findings showed that the effort required to transport the gas mixture will generally increase, mainly due to the increase in compressor work. At certain points in the gas transport system, however, it is also advantageous if the H_2 content is increased, e.g. at reduction stations where the gas is expanded to a lower pressure level. There, the reverse Joule-Thompson effect that occurs with H_2 could save energy to preheat the gas accordingly and protect the infrastructure from condensate and nitrate formation.

For the economic part of the model, literature research was conducted on studies dealing with the costs of pure H_2 pipeline systems. In order to understand their assumptions, comparative values were defined, which are to be calculated and compared with the modelling in HIGGS. Since the admixture would involve less new construction and the transport system would have to be rebuilt, data from grid development projects in Germany were analysed, which serve as a basis for the subsequent calculations. The three most important system components were explicitly considered: Transmission pipelines, compressor stations and regulator stations. The aim of these investigations is to compare the transport costs of hydrogen in the natural gas grid with other systems, in this case the transport via pure H_2-pipelines or road transport in gas cylinders.

All these findings converge in Task 5.2 in such a way that a representative transport network topology will modelled and simulations carried out with different H_2/NG mixtures. This will be done using one of the five software packages developed for network calculations which were evaluated within this task (T5.1). The methodology of how such a model is erected and which data sources are used has been described as an example in the last chapter. First, the selected example model of the TENP and MEGAL intersection will be finalised and described in the confidential Deliverable 5.2. Public results follow in Deliverables 5.3 and 5.4, where techno-economic evaluations of separation processes are also given, in particular of the high-pressure membrane systems tested in work package 3. Depending on the time frame and if it proves to be reasonable, further use cases will be investigated, which were presented in chapter 4.6. These can be possible transport routes via Spain and France or Italy, which are considered to have great potential in the future to bring renewable hydrogen from North Africa to Central Europe.

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Annex I: Planned and operational projects in Europe injecting hydrogen in the gas grid

Table 18. Operational projects in Europe injecting hydrogen in the gas grid

Project name	Country	Start date	Technol-ogy	Installed capacity	
				MW_{el}	Nom. flow (Nm^3 H_2/h)
HyDeploy	UK	2019	PEM	0.5	106
Rozenburg Power2Gas Phase 2	NLD	2019	PEM	0.007	1
Jupiter 1000	FRA	2018	AEL PEM	1	200
GRHYD	FRA	2018	PEM	0.047	10.0
Hassfurt	GER	2016	PEM	1.25	266
HPEM2GAS (R&D)	GER	2016	PEM	0.2	43
Energiepark Mainz	GER	2015	PEM	6	1.28
Regio Energie Solothurn/Aarmat hybrid plant	CHE	2015	PEM	0.282	60.0
H_2BER (Berlin airport)	GER	2014	AEL	0.5	108.7
Hanau. Wolfgang Industrial Park	GER	2014	PEM	0.03	4.00
HYPOS (Leipzig)	GER	2013	AEL PEM SOEC	1.25	277.8
RWE PtG plant Ibbenbüren	GER	2013	PEM	0.15	32
PtG plant Hamburg-Reitbrook	GER	2013	PEM	1.5	319
Uniper/E-ON WindGas Falken-hagen Hydrogen Pilot Project	GER	2013	AEL	2	360.0
P2G plant Erdgas Schwaben	GER	2013	PEM	1	212.8
INGRID	ITA	2012	AEL	1.15	240.0
Cotbus	GER	2012	AEL	0.12	30.0

Project name	Country	Start date	Technol-ogy	Installed capacity	
				MW_{el}	Nom. flow (Nm^3 H_2/h)
Hydrogen mini grid system Yorkshire (Rotherham)	UK	2012	AEL	0.03	6.5
Hybrid Power Plant Enertrag. Prenzlau	UK	2011	AEL	0.5	108.7

Table 19. Planned projects in Europe injecting hydrogen in the gas grid

Project name	Country	Stated start date	Technol-ogy	Planned capacity	
				MW_{el}	Nom. flow (Nm^3 H_2/h)
Drax Humber cluster completion	UK	2040	ATR / CCS		
H_2morrow	NOR GER	2030	SMR / CCS		328'000
Hyoffwind Zeebrugge, 3rd phase	BEL	2030	Unknown PtX	975	216'667
SilverFrog	ITA	2030	PEM	10'000	2'127'660
GreenH_2UB (9 hubs of 3-10MW)	NLD	2030	Unknown PtX	97	21'087
$H_2$1 North of England	UK	2028	ATR+CCS		4'055'407
NorthH_2 green hydrogen	NLD	2027	Unknown PtX	3'000	666'667
Hygreen Provence 3rd phase	FRA	2027	Unknown PtX	305	677'778
Hynet Northwest	UK	2025	ATR / CCS		
Hygreen Provence 2nd phase	FRA	2025	Unknown PtX	113	25'111
Westkuste 100	GER	2025	Unknown PtX	30	6'383

Project name	**Country**	**Stated start date**	**Technol-ogy**	**Planned capacity**	
				MW_{el}	**Nom. flow (Nm^3 H_2/h)**
Drax Humber cluster demon-strator	UK	2025	ATR / CCS		
Acorn Aberdeenshire	UK	2024	ATR / CCS		
Hyoffwind Zeebrugge, 2n phase	BEL	2023	Unknown PtX	24	5'333
Hybridge	GER	2023	AEL PEM	100	22'222
Hygreen Provence, 1st Phase	FRA	2023	Unknown PtX	17	37'778
HyNetherlands, 1st phase	NLD	2023	Unknown PtX	100	22'222
H_2V Normandy, 2nd phase	FRA	2023	AEL	100	21'739
H_2V59, 2nd phase	FRA	2023	AEL	100	21'739
Element One (Element Eins)	GER	2022	Unknown PtX	100	22'222
Bad Lauchstädt energy park	GER	2022	Unknown PtX	35	7'778
H_2V Normandy, 1st phase	FRA	2022	AEL	100	21'739
H_2V59, 1st phase	FRA	2022	AEL	100	21'739
Power to Green H_2 Mallorca - Phase 2	SPA	2022	Unknown PtX	7,5	1'667
PGNiG - INGRID	POL	2022	Unknown PtX		
Power to Green H_2 Mallorca - Phase 1	SPA	2021	Unknown PtX	2.5	556
GreenH_2UB (1st hub, Noord Brabant)	NLD	2021	Unknown PtX	3	652

Project name	Country	Stated start date	Technol-ogy	Planned capacity	
				MW_{el}	Nom. flow (Nm^3 H_2/h)
Hyoffwind Zeebrugge, 1st phase	BEL	2020	Unknown PtX	1	222
PtG-Fehndorf	GER	2020	Unknown PtX	2	444
Wind2Hydrogen, HyCentA	AUT	2014	PEM	0.1	21.28
Thüga PtG plant Frankfurt/Main	GER	2013	PEM	0.3	63.83
Ameland	NLD	2008	PEM		
Etzel, Salt caverns	GER	2007	Unknown PtX		
Get H_2 Lingen	GER		Unknown PtX	105	22'826
Green Spider, Castilla y Leon Hub	SPA		Unknown PtX	100	21'739
Green Spider, Asturias Hub	SPA		Unknown PtX	100	21'739
Centurion	UK		PEM	100	21,276
Green Spider, Aragon Hub	SPA		Unknown PtX	50	10'870
H_2-based residential area in Van der Veen	NLD		Unknown PtX		
H_2Gas	SPA		Unknown PtX		
Westkuste 100	GER		Unknown PtX	30	6'667
Hemweg hub Amsterdam	NLD		Unknown PtX	100	21'739
H_2 Air Base Leeuwarden	NLD		Unknown PtX	5	1'087

Annex II: Allocation of country consumption and city gates

Name, ID	Operator	NUTS		Location-Name	Household GWh/a	Industry GWh/a	Sum GWh/a
Herrnsheim, 807001	Gas-union				2380	1651	4031
		DEB3B	50%	Alzey-Worms	899	649	
		DEB3J	50%	Mainz-Bingen	1481	1002	
Worms, 807002	EWR Netz				818	609	1427
		DEB39	75%	Worms	818	609	
Pfeddersheim, 807003	Creos				1172	852	2024
		DEB39	25%	Worms	273	203	
		DEB3B	50%	Alzey-Worms	899	649	
Ramstein, 807004	Creos				3078	2017	5095
		DEB3A	30%	Zweibrücken	153	97	
		DEB37	30%	Pirmasens	186	105	
		DEC05	70%	Saarpfalz-Kreis	1416	924	
		DEC03	70%	Neunkirchen	1323	891	
Alf, 807009	Creos				4580	3403	7983
		deb22	95%	Bernkastel-Wittlich	1526	1184	
		deb21	100%	Trier Stadt	1289	971	
		deb25	50%	Trier-Saarburg	1049	733	
		deb23	50%	Eifelkreis Bitburg-Prüum	716	515	
		deb16	0%	Cochem-ZELL (evt. auch DEB1C)	0	0	
Sohren, 807010	Thyssengas				1032	692	1724
		DEB15	30%	Birkenfeld	374	242	
		DEB14	30%	Bad Kreuznach	658	450	
Sienhachen-bach, 807011	Creos				4966	3307	8273
		DEB3G	100%	Kusel	1106	726	
		DEC06	100%	St. Wendel	1267	831	
		DEB15	70%	Birkenfeld	872	565	
		DEB14	70%	Bad Kreuznach	1536	1050	
		DEB22	5%	Bernkastel-Wittlich	80	62	
		DEB25	5%	Trier-Saarburg	105	73	
Merzalben, 807013	Creos				1206	740	1946
		DEB37	70%	Pirmasens	433	245	
		deb3k	50%	Südwestpfalz	773	495	
Klingenmüns-ter, 807014	Creos				2288	1463	3751
		DEB33	100%	Landau	644	393	
		DEB3H	100%	Südliche Weinstrasse	1644	1070	
Minfeld, 807015	Thüga AG				#N/A	#N/A	#N/A

		DEB3E	50%	Germersheim	863	686	
		DE142	20%	Tübingen	360	380	
		DE141	25%	Reutlingen	572	785	
		DE124	70%	Rastatt	1474	1828	
		DE121	50%	Baden-Baden Stadt	296	250	
		DE123	100%	Karlsruhe Land	3955	4412	
		DE129	100%	Pforzheim	909	1217	
		DE12B	50%	Enzkreis	862	1116	
		DE122	50%	Karlsruhe Stadt	1306	1301	
		DE113	33%	Esslingen	1437	1842	
		DE111	33%	Stuttgart	1702	1738	
		DE112	50%	Böblingen	1555	1990	
Tunsel, 808012	terranets bw				4867	5029	9896
		DE132	100%	Breisgau Hoch-schwarzwald	2342	2532	
		DE131	100%	Freiburg im Breisgau, Stadt	1817	1633	
		DE133	50%	Emmendingen	708	864	
Nordschwa-ben, 808013	terranets bw				659	742	1401
		DE139	30%	Lörrach	659	742	
Willstätt, 808019	terranets bw				13071	16442	29513
		DE134	100%	Ortenau	3789	4820	
		DE133	50%	Emmendingen	708	864	
		DE137	80%	Tuttlingen	991	1406	
		DE138	66%	Konstanz	1664	1834	
		DE135	100%	Rottweil	1278	1680	
		DE143	80%	Zollernalbkreis	1365	1805	
		DE12C	100%	Freudenstatt	1056	1454	
		DE142	40%	Tübingen	720	761	
		DE141	25%	Reutlingen	572	785	
		DE124	30%	Rastatt	632	783	
		DE121	50%	Baden-Baden Stadt	296	250	
Seyweiler, 810001	creos			#N/A	4810	3476	8286
		DEB3A	70%	Zweibrücken	356	225	
		DEC05	30%	Saarpfalz-Kreis	607	396	
		DEC03	0%	Neunkirchen	0	0	
		DEC01	100%	Regionalverband Saarbrücken	3847	2855	

Annex III: Preliminary status of the modelling of a natural gas transport system in Europe

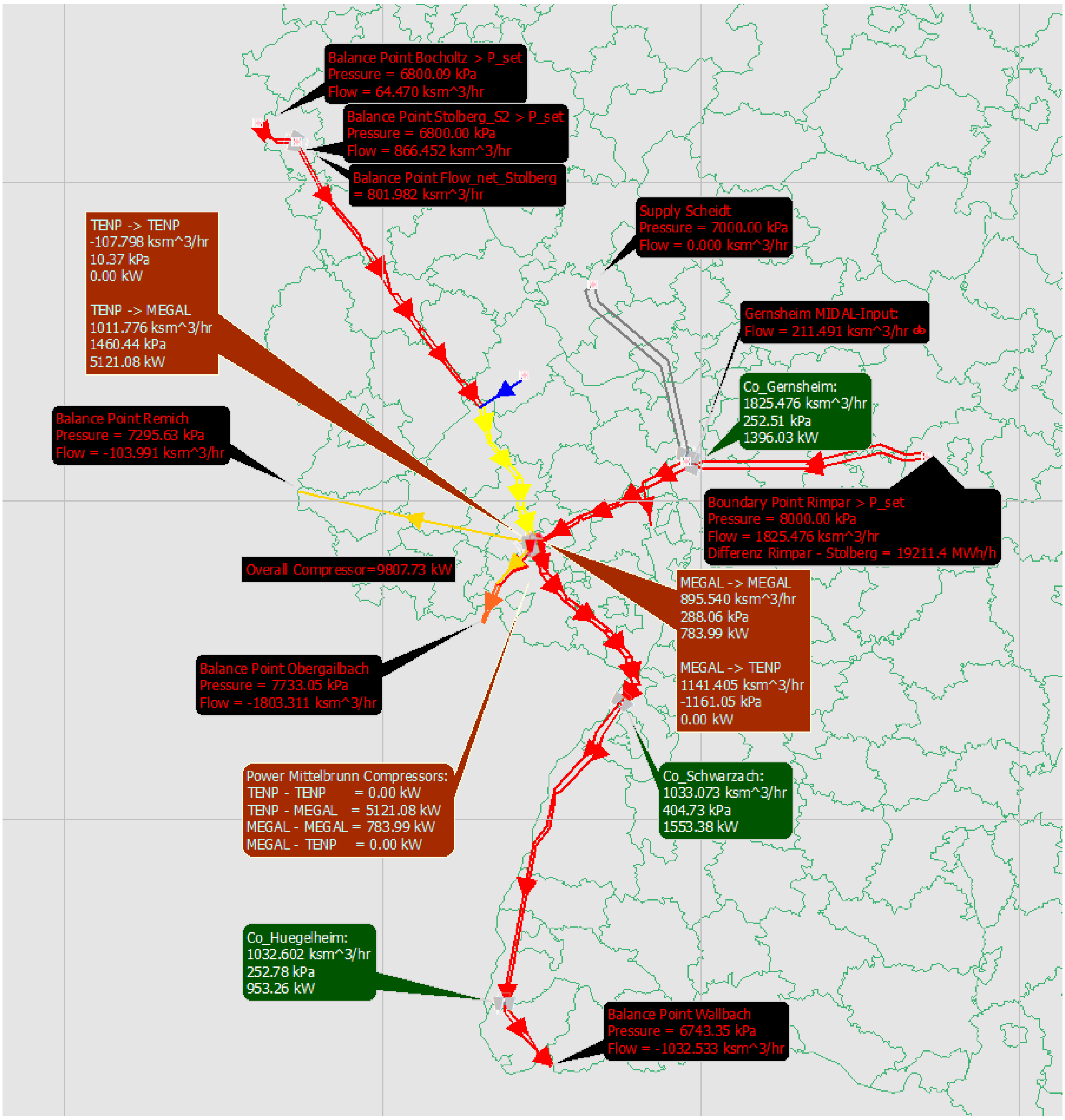

Figure 38: Network modelling of TENP and MEGAL pipeline sections. Pipeline colour corresponds to the hydrogen share in the corresponding section.

Annex IV: Changes in the combustion process

Not only in terms of energy content, but also with regard to the processes in the incineration process itself, hydrogen has very different properties from methane. Table 20 gives a brief overview of the key data of the two components. It can be strongly assumed that there will also be changes in the entire combustion process from the fuel gas mixture, ignition, flame formation and exhaust gases.

Table 20: Relevant combustion properties of hydrogen compared with methane

Combustion properties		Methane	Hydrogen
Lower explosion value[23]	[Vol.-%]	4.4	4
Higher explosion value[23]	[Vol.-%]	16.5	77
Minimum ignition energy[24]	[mJ]	0.28	0.016
Ignition temperature in air[25]	[°C]	645	530
Flame temperature in air[25]	[°C]	1922	2086
Maximum flame speed[25]	[cm/s]	43	346
CO_2-emissions[26]	[g CO_2/kWh]	197.4	0.0
Air demand (λ=1)[25]	[m^3_{Air}/m^3_{Fuel}]	9.52	2.39

In the report of the International Flame Research Foundation (IFRF) on the effects of hydrogen-natural gas mixtures for firing processes, the various problems that arise for thermos-processing plants are discussed in detail. [57] In addition to the changes in physical properties known from section 3.2.2, considerable influences on ignition delay times, auto-ignition behaviour, adiabatic flame temperature or laminar flame speed are documented.

<u>Air demand and mixing of the fuel</u>

Due to the chemical combustion stoichiometry, the oxidation of one mole of hydrogen requires about ¼ of the amount of oxygen as when one mole of methane is burnt. This is why the air requirement per m³ of fuel also varies to a similar extent.

$$H_2 + \frac{1}{2}O_2 \rightarrow H_2O \qquad \Delta_r H^0 = -571.6 kJ/mole \tag{11}$$

$$CH_4 + 2\,O_2 \rightarrow CO_2 + 2\,H_2O \qquad \Delta_r H^0 = -802.4 kJ/mole \tag{12}$$

If the volumetric calorific value H_s of the two substances is taken into account, the difference in air demand per unit of energy is smaller. Hydrogen then requires about 22 % less oxygen per kilowatt hour than methane (6.29 mole/kWh H_2 compared to 8.08 mole/kWh CH_4). If the air supply is not adjusted, combustion can quickly become hyper-stoichiometric if the gas quality changes due to

23 Safety parameters, SUVA (Suisse work accident-insurance)
24 Physical Technical Federal Institute Braunschweig retrieved via vbg.de
25 Grundlagen der Gastechnik. Günther Cerbe. 6th edition, 2004
26 Own calculation with the software GasCalc @25 °C and 1 atm, HHV

increased H_2 content and if the air volume is not adjusted. Depending on the process, this is undesirable and can have negative effects on the burner and combustion chamber. [57]

The mixing of fuels with atmospheric oxygen has an influence on the ignitability. In addition to the fuel quantity, gas temperature and burner geometry, it is also a decisive factor whether a mixture burns, explodes, detonates, or does not burn. The technical design of the gas mixture can be designed in different ways. The strong physical differences such as density, sonic velocity or viscosity can lead to changes in the mixing of the fuel-air mixture.

Ignition

At 0.02 mJ, the minimum ignition energy of H_2 is about 18 times lower than that of methane. In absolute terms, the minimum ignition energy for all hydrocarbon gases is in the mJ range and thus low. Electrostatic discharges from ungrounded objects usually contain sufficient energy to ignite both pure hydrogen and natural gas mixtures [58]. The reduction of the ignition delay time at 10 %-H_2 from about 46ms to 15ms is particularly pronounced Especially in premix burners in the partial load range, this can lead to problems with flame flashbacks, which can cause a burner to wear out more quickly.

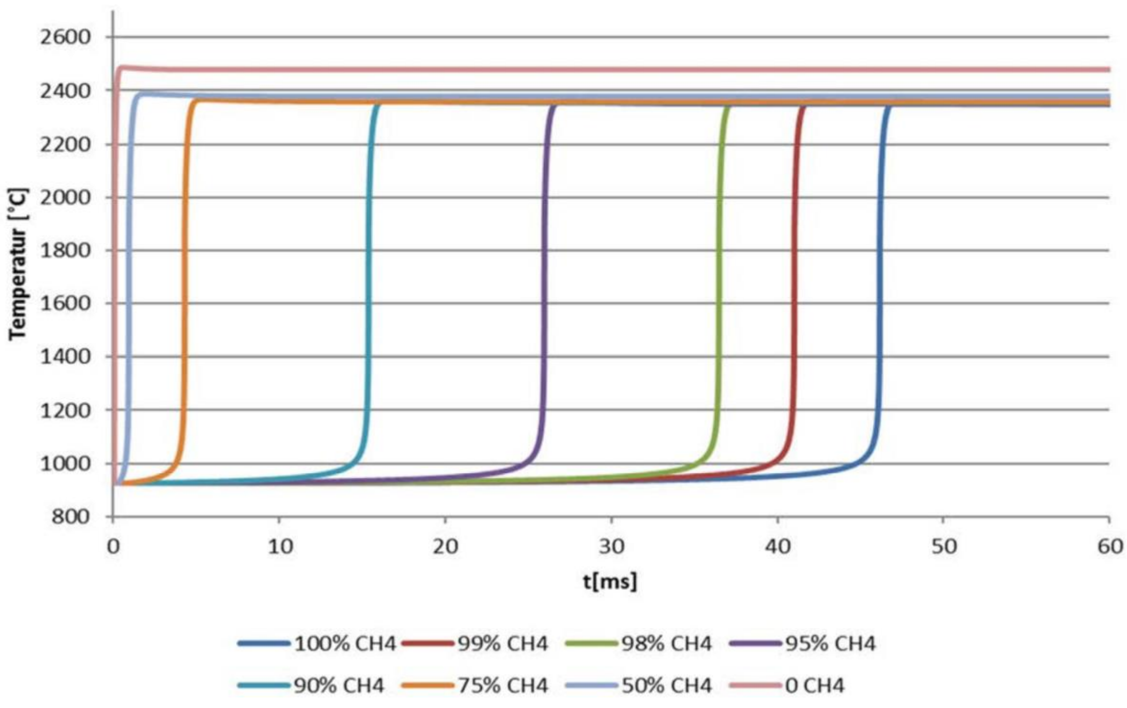

Figure 39: Ignition delay times of methane/hydrogen mixtures at Lambda = 1, p = 1bar and T_{in} = 1200 K. [57]

Flame characteristics

Triggered by changes in the impulse ratios, the flame geometry changes to thinner and shorter flames. The generally higher flame speed is one reason why more oxygen is available for the oxidation of the fuel if the burner technology is not adapted. The hydrogen flame burns more in blue and rather invisible, which is why the radiation intensity of the hydrogen flame decreases, but the flame itself burns hotter. Consequently, there are changes in the heat energy distribution within the burner.

The easiest parameters to control during combustion is the regulation of the supply of fuel and atmospheric oxygen to the burner system. Figure 40 shows that by controlling the gas supply, it is possible to keep the shape of the flame in a similar range to that of a pure natural gas flame. Nevertheless, temperature differences are to be expected.

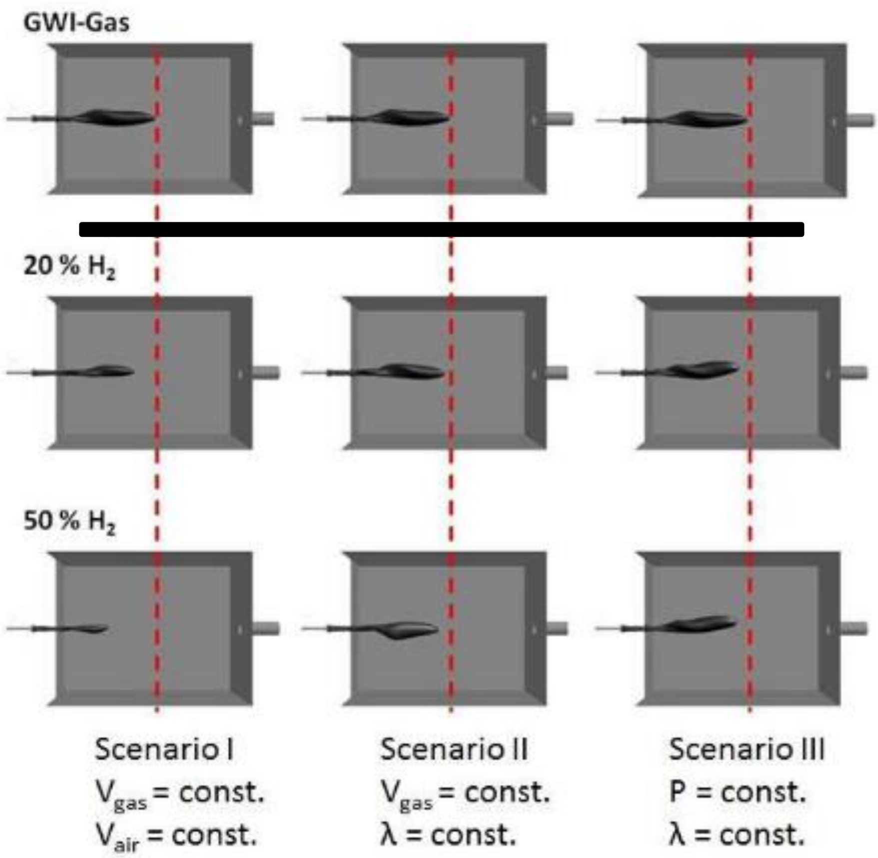

Figure 40: Illustration of the flame geometrics of H_2-NG-Blends [57]

Characteristics of the exhaust gases

The reduction of greenhouse gases, mainly CO_2 in the exhaust gases, has already been addressed in 3.2. Due to the reduced carbon compounds (CO, CO_2), the radiation intensity decreases in the exhaust gas as well as in the flame. With higher Hydrogen admixture levels, more water molecules will be produced per unit of energy. Water vapour has a heat capacity that is about twice as high (at 1000°C, 1bar) than CO_2. Furthermore, water vapour has a lower density (-60 %) and higher thermal conductivity (+65 %). Therefore, altered heat transfer properties may be expected in downstream heat exchangers.

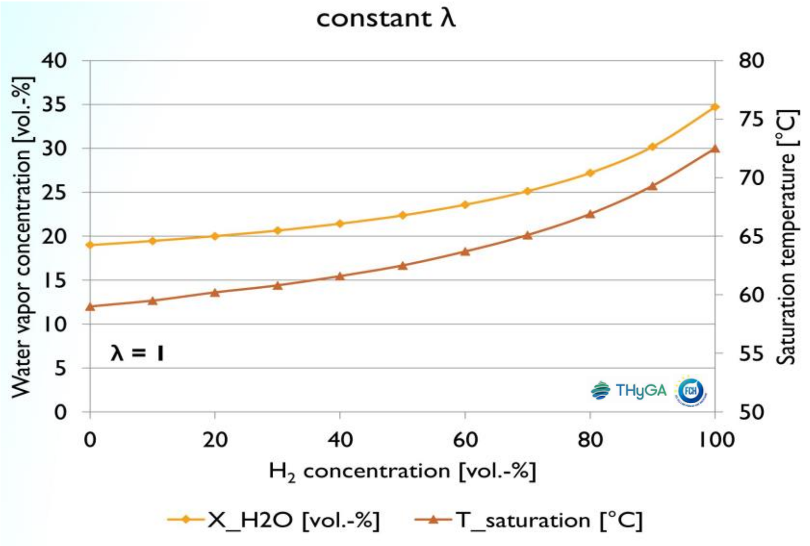

Figure 41: Water vapour concentration in the exhaust of a burning process in function of H_2-admixture level in NG [6]

Figure 42 and Figure 43 illustrate the statements below made in *THyGa* project D2.2 regarding the formation of nitrogen oxides:

"The thermal NO_X formation process is closely linked to temperatures and the availability of oxygen in the hot reaction zone. The admixture of hydrogen leads to higher combustion temperatures and higher air excess, hence more oxygen is available in the reaction zone (if there is no Air excess controller in the burner system). However, residential heating appliances are commonly operated at rather high air excess ratios. A further increase of λ due to the changing fuel composition will lead to a considerable reduction of local temperatures. The net effect is a reduction of NO_X emission when adding hydrogen, if the stoichiometry change is allowed to happen. In the case of a system operated at low air excess (λ < 1.2) or a system which uses some kind of combustion control to keep air excess ratios constant, higher NO_X emissions are to be expected, however, due to an increase in local temperatures. This would be similar to non-premixed burners, e.g. in industrial applications, where the main combustion processes always occurs at near stoichiometric conditions in the flame front, independent of the global air excess ratio of the process." [6]

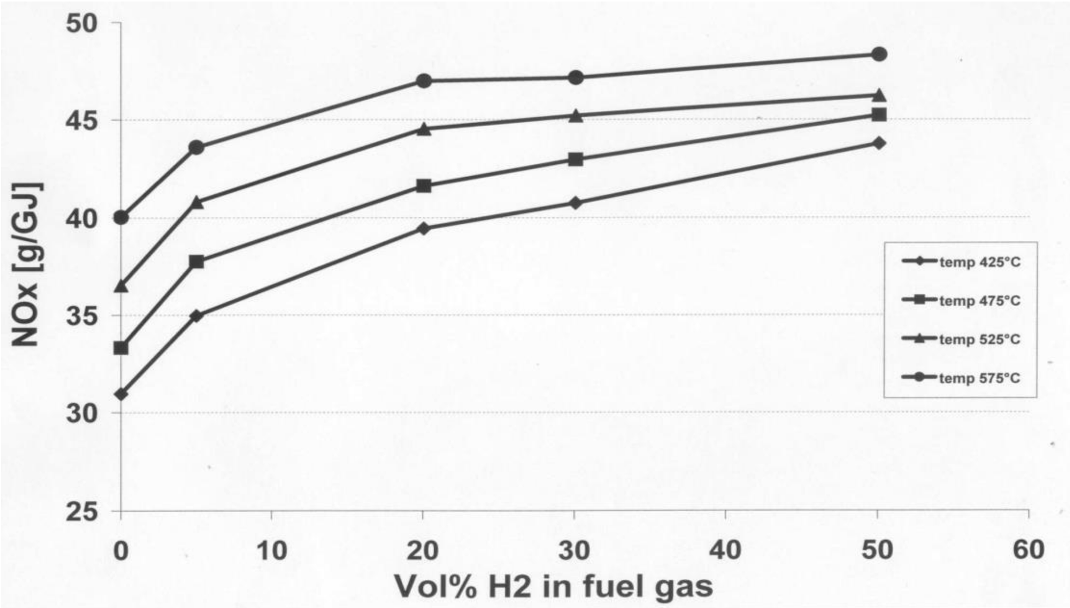

Figure 42: Experimentally determined NOx emissions as a function of the hydrogen content in natural gas at different furnace temperatures. [57]

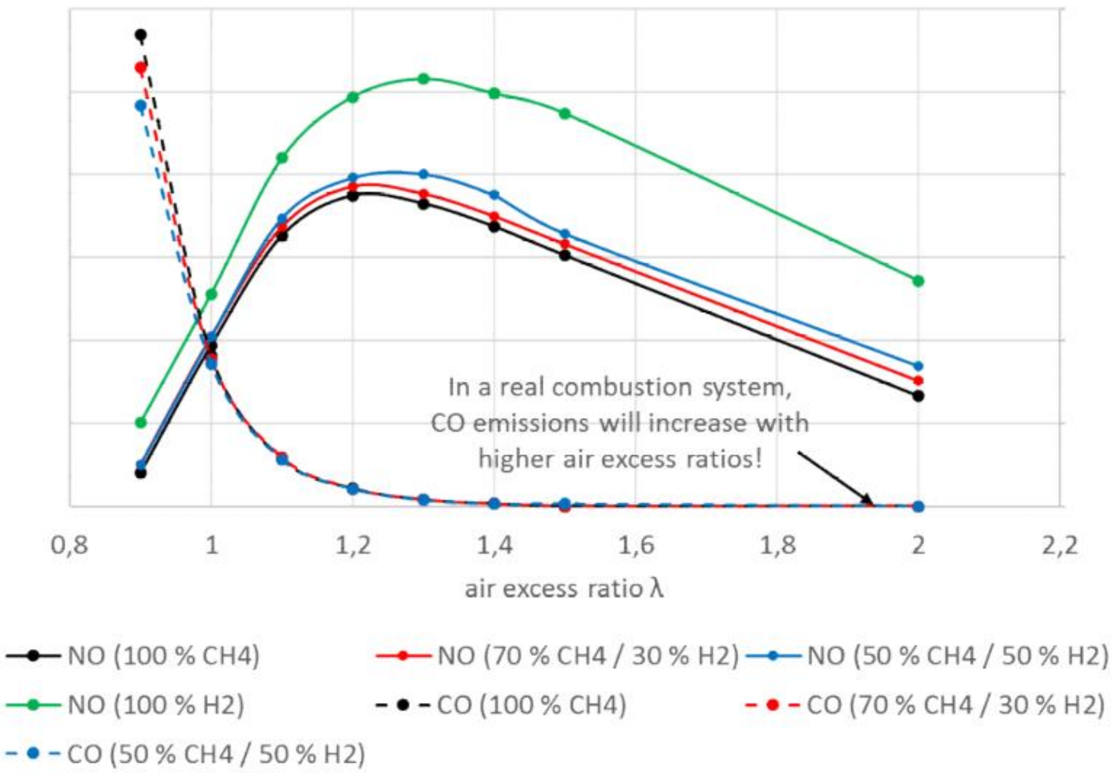

Figure 43: calculated CO and NO emissions as a function of the air excess ratio for methane, hydrogen and blends of them. [59]

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FUEL CELLS AND HYDROGEN JOINT UNDERTAKING