HIGGS
Hydrogen in Gas Grids

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

D6.1

Considerations on H_2 injection potential to reach EU decarbonisation goals

Date	30th June 2023 (M42)
Grant Number	875091
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Status	Started / Draft / **Consolidated** / Review / Approved / Submitted / Accepted by the EC / Rework [use bold style for current state]

Dissemination level:

PU **Public**

PP Restricted to other programme participants*

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Clean Hydrogen Partnership

This project has received funding from the Fuel Cells and Hydrogen 2 Joint Undertaking (now Clean Hydrogen Partnership) under Grant Agreement No. 875091 'HIGGS'. This Joint Undertaking receives support from the European Union's Horizon 2020 Research and Innovation program, Hydrogen Europe and Hydrogen Europe Research.

Document history

Version	Date	Description
1.0	2023-05-15	First draft
2.0	2023-06-23	Consolidated version
3.0	2023-06-26	First feedback from partners implemented
4.0	2023-07-07	All changes and updates implemented. Consolidated version

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Executive Summary

This deliverable is divided into two complete different parts. The first part of the report, corresponding to section 3, aims to complete the inventory of the pipelines and assets of the European transport natural gas grid already begun in D2.3 of WP2. The second part of the deliverable studies the potential for hydrogen injection in the European grids, estimating the ranges of hydrogen injection potentially required due to future energy trends, and comparing them with the current EU policies. This second part, dealing with the work developed in Task 6.1 of WP6, is detailed in section 5. Sections 1 and 2 correspond to the introduction and list of objectives of this report, while the main conclusion can be read in section 6.

The update of the inventory of the grid has considered two different approaches in section 3. In a first term, up to 59 TSOs operating in Europe have been identified. A deep search in their websites have been performed to collect all relevant information regarding the pipelines and transport facilities forming part of their grids. The information about pipelines has considered relevant design parameters such as diameter, Maximum Operating Pressure (MOP) and installation period. Regarding transport facilities, compressor stations, valve nodes, pressure regulation and/or metering stations and different kind of entry and exit points have been object of study. The results of this detailed research can be seen along section 3.1.

All this huge amount of information has been processed in section 3.2. Firstly, this review has allowed to build national scenarios of the transport grid in section 3.2.1. The total length of transport pipelines in Europe from the information gathered is 258,968.98 km, with approximately 60% of the length having an unknown diameter. The most common nominal diameters are above 20 in, accounting for 6-10% of the pipelines. France, Germany, Italy, and Ukraine have the longest grids, followed by Hungary, Norway, Poland, Romania, Spain, and the UK. The installation period of 73% of European pipes is unknown, with the most common periods being before 1975, between 2001-2005, and between 2016-2020. However, some countries, including France, Germany, and Ukraine, do not provide information on the installation period. The MOP of 83% of European pipes is also unknown. Most grids operate at 70-85 bar, while Romania has an important portion operating at 40 bar. The number and power of compressor stations vary among countries, with Germany and Ukraine having the highest frequency per kilometre of grid length. Other facilities such as valve nodes, pressure regulation and/or metering stations, exit points, and entry points are also present, but the available information is insufficient for conclusive analysis.

In a final step, the data collected at national level have been grouped into five geographic clusters in section 3.2.2. The clusters show that pipes with diameters over 40 in are prevalent, followed by diameters between 14-40 in. Older and newer grids coexist within the same cluster. The MOP of most clusters operates between 70 and 85 bar, except for Eastern Europe, which has a significant length operating at 40 bar. Compressor stations and other transport facilities are also categorized into clusters, with middle Europe having the highest concentration of compressor stations. Western Europe has the most valve nodes and connections to industrial customers, while exit points are primarily located in the Middle Europe cluster. The available data is, however, limited for drawing definitive conclusions.

The inventory of the grid has also considered a second approach to complement the information gathered so far. In this second part of the work, contained in section 3.3, a survey has been shared with the main TSOs and gas associations in Europe asking for specific information about their grids. To the kind of information detailed above adds more specific details, such as pipe and welding material, type of coatings, odorization systems or gas quality control systems. The results are only displayed as geographical clusters to protect sensitive information provided by the companies. Almost one third of the total European grid has been collected. The Middle Europe cluster is the best-defined area, with 63% of the grid characterised thanks to the input received. This fact is extremely important

because this clusters grid contributes with the longest section of grid to the continent. On the other hand, no information could be gathered from TSOs in East Europe.

The survey collected data on approximately 73,000 km of the European transmission gas grid. Steel materials used in the European grid range from API 5L Gr A to Gr X80. The most common steel materials include API 5L Gr B, X42, X52, X60, and X70, with higher steel qualities (over X52) being used more frequently. The usage of steel materials varies across different clusters, with X70 being the most common in Middle Europe and Northern Europe, and X60 being more prevalent in Western Europe. Lower steel qualities (X42 and X52) are common in South, Western, and Middle Europe, but less so in the Northern cluster.

Regarding diameter, more than half of the pipelines in Europe have diameters between 11-30 in. The distribution of diameters is similar across the different clusters, except for Northern Europe, where the majority of pipes have an outer diameter of 11-20 in. The MOP of the pipelines shows variations among the clusters. MOP <59 bar and <80 bar dominate the overall European grid, with Middle Europe leading the tendency due to its significant contribution. However, South Europe has a predominant MOP <80 bar, while Western Europe operates between 70 and 85 bar. Northern Europe also has a dominant MOP <80 bar. Information about welding materials indicates a lack of quantitative data. However, qualitative analysis reveals common materials used in each cluster, with no significant differences from previous reports.

External coating materials primarily include polymers such as polyethylene (PE), polyamide, and polypropylene. PE is the dominant coating material, especially in South and Western Europe. Coal tar and brai are also used in Western Europe. However, information about the external coating material for a significant portion of the Middle Europe cluster is unavailable. For inner coating, epoxy resin is the most common material used, with around 28% of the pipes in Europe being coated internally with epoxy. However, data on 65.7% of the length in Europe is missing. Other materials, such as red led, are occasionally reported in Western Europe.

The installation period of the pipelines shows a distributed pattern over the decades. Around 20% of the grid length has been installed in each decade, except for the 1980-1989 period. South Europe has a relatively new grid, with 78% of the pipes installed after 2009, while Western Europe has a significantly older grid, with 45% of the pipes installed before 1970. Northern Europe falls in between, with 80% of its grid installed between 1980 and 1989. Information on the expected year of renewal of pipelines was insufficient to draw conclusions, except for some percentages in Western Europe, Northern Europe, and Middle Europe.

The report also provides insights into the facilities available in the European transmission grid, including transmission facilities, odorization systems, and gas control systems. The most common facilities are valve nodes, city gates, and compressor stations, with varying frequencies across clusters. Odorization systems primarily use THT (tetrahydro-thiophene) as the most common odorant.

Gas quality control systems in the European transmission gas grid consist of quality control systems and flow control systems. The survey collected data on a total of 445 devices, with a concentration of over 6 devices per 1,000 km of grid. Process gas chromatographs are the most common quality control systems, while electrochemical cells are only found in South Europe. The concentration of quality control systems is higher in South, Western, and Northern Europe compared to Middle Europe. Flow control systems are divided into gas metering systems and gas pressure control systems. Turbine gas meters are the most commonly used devices, followed by rotary gas meters. The technology of some gas meters is undefined, particularly in Western and Middle Europe. Turbine gas meters are prevalent in South and Middle Europe, while Western Europe has a variety of technologies. Data on gas pressure control systems is limited to Western and Middle Europe, with membrane regulators being the most common in Western Europe. The use of flow control systems is more popular in Western Europe compared to other regions. No significant conclusions about the handling of hydrogen content by these devices could be drawn from the survey.

Finally, section 4 provides an overview of the maximum admissible hydrogen concentration in transport gas grids, updating the picture provided in D2.3 in 2021.

The second part of the deliverable considers the potential for hydrogen injection in the European transport grids and its alignment with the current EU policies, which is developed along section 5. Three scenarios have been considered. 2020-23 has been defined as the baseline scenario to settle the capacity of the grid. Forecasts are made afterward for a mid-term scenario (2030) and long-term scenario (2045/50). The first approach of this section involves providing a general overview of the expected trends in Europe as a whole (section 5.1), followed by a detailed review on a country-by-country basis in section 5.2. This review has based on identifying the total gas demand expected up to 2050 and the role of renewable gases, i.e. renewable methane and hydrogen, to meet part of this demand. Relevant studies, such as the hydrogen national strategies, have been considered. A summary of the findings is given in section 5.3.

Countries such as Austria, Belgium, Czech Republic, Denmark, Germany, Italy, Slovakia or Switzerland have shown a clear tendency to postulate as hydrogen importing countries, with rising needs for hydrogen to meet their national gas demand by 2050. On the other side of the board, countries such as Estonia, Finland, Greece, Hungary, Latvia, Norway, Portugal, Romania, Spain, Ukraine and UK are expected to become hydrogen exporters. Countries such as Ireland or The Netherlands may be only capable of exporting hydrogen on the long-term, once the hydrogen production units and/or renewable energy sources are fully developed. There seem to be some countries that may remain neutral, consuming all the hydrogen produced at a local level with no need for importing it and no surplus to export. It is the case of Croatia, France or Luxembourg, for instance. Other countries such as Poland, Slovenia or Sweden are difficult to classify as importers, exporters or neutral, because the tendency changes considerable depending on the source of information consulted.

There are several countries in Europe with a powerful strategy towards renewable methane that needs to be highlighted. It is the case of Bulgaria, Denmark, France, Latvia and Sweden. These countries are developing strong strategies towards the production of biogas and its final upgrade to biomethane and are expected to meet a great part of their future local demand with this gas. This could mean that hydrogen may mainly only be produced for exporting. Portugal is following a completely different strategy, where synthetic methane gains a lot of weight to cover the gas demand. This way, a great production capacity for hydrogen is expected, but to use is as reagent in the synthesis of synthetic methane.

The information collected through this country-by-country review has allowed to build the three case scenarios (2020, 2030 and 2045/50) to study the potential for hydrogen injection in the European gas grid in section 5.4. The baseline scenario is developed in section 5.4.1. This case study considers a hypothetical case to decarbonise the grid blending natural gas with hydrogen. The current gas demand in each European country is considered, and the calculated needs of hydrogen to replace 2 to 5% of the total gas volume are compared with the available merchant hydrogen in 2020. It is important to note that this is not a real case as merchant hydrogen is not prepared for injection, but it serves to demonstrate the existing gap in adding 2-5% and understand the challenge for future scenarios.

If a 2 mol% of hydrogen concentration would be allowed in the grid, Germany, Spain, The Netherlands and Belgium would reach this level easily and would have up to 7.5 TWh of hydrogen for exports. Spain, however, would have no way of exporting its hydrogen via pipeline at this point. Finland, France or Hungry would also reach this level of blend with their national production, but with little surplus (0.4-1.4 TWh of hydrogen). UK would need to receive hydrogen from the Netherlands.

Poland and Ukraine would need up to 2 TWh of hydrogen that may come from Germany. Finland could meet the demand of their neighbouring countries Sweden and Norway.

If the allowed concentration would rise to 3 mol% hydrogen, once again, Germany, Spain, The Netherlands and Belgium are the countries with the higher surplus (1.8-4.3 TWh), and UK would be the country with the higher hydrogen needs (i.e. 7.1 TWh). A new corridor of hydrogen may appear from Spain to France, because the surplus of Spain could cover the demand in France at this point. To achieve Italy's hydrogen demand of 2.7 TWh, it would require the transportation of hydrogen from Germany via Switzerland and Austria, which would be divided between Poland and Italy.

Finally, if the hydrogen allowance in the grid would be of 5 mol%, countries like Germany or Spain would become new hydrogen-demanding nations. Belgium, the Netherlands, Hungary, and Finland would be the only countries with a surplus of hydrogen available for export. Finland could partially meet the demand of Sweden and Norway, while Belgium and the Netherlands would cover Germany's demand. The majority of European countries would require additional hydrogen sources to meet their demands.

The mid-term scenario forecasted for 2030 is developed in section 5.4.2. The mid-term scenario aims to predict the transit of hydrogen across Europe by 2030, taking into account the total gas demand, hydrogen production and hydrogen demand in different countries at that time, and the part of the demand that can be covered by renewable methane, the main “competitor” of hydrogen in the grid. Two scenarios are considered based on the maximum and minimum production/demand capacities, according to the information gathered in section 5.2.

In the minimum demand scenario, the highest hydrogen-demanding countries would be Switzerland and Germany, importing up to 26 TWh of hydrogen, followed by Belgium, Czech Republic, Hungary, or France that would require up to 11.1 TWh of hydrogen. The major exporting counties would be Finland (55 TWh) and Spain (36 TWh), followed by the Netherlands, UK, Portugal, Norway, and Ukraine. Hydrogen delivery is coherent with some of the corridors defined by the European Hydrogen Backbone.

In the maximum demand scenario, Germany remains the highest in hydrogen needs with 211 TWh, followed by Switzerland at 26 TWh. Countries like Italy and Poland, previously self-sufficient, would now import less than 20 TWh. Import needs would notably increase for Belgium, Bulgaria, Croatia, Czech Republic, Romania, and Slovakia, ranging from 0.5 to 5.5 TWh. Ukraine has the potential to become the top exporter with 286 TWh, but its forecast is uncertain due to ongoing conflict. Spain would lead as the main exporter with 53 TWh, followed by Finland (36 TWh) and Norway (30 TWh). Denmark, Portugal, and Ireland would also contribute significantly to hydrogen exports. Central Europe faces insufficient capacity and requires 140 TWh of extra hydrogen supply from high-producing countries. Italy's demand would be unmet.

The long-term scenario aims to predict the transit of hydrogen across Europe by 2045/50 in section 5.4.3, following the same methodology explained above. In the minimum demand scenario, Belgium, France, and Poland are the countries with the highest hydrogen import needs, totaling 83 TWh, 66 TWh, and 42 TWh, respectively. Other importing countries include Austria, Switzerland, the Netherlands, Czech Republic, Hungary, Italy, and Sweden, with import needs ranging from 10-25 TWh. On the other hand, Spain emerges as the largest producer with an export capacity of up to 209 TWh, followed by Finland, Ukraine, and Denmark. In this scenario, Germany also transitions into an exporting country, capable of supplying hydrogen to France, Austria, Czech Republic, or Poland. Several other countries such as Bulgaria, Greece, Portugal, Romania, and the UK have notable export capacities of around 40 TWh each. Ireland and Norway also have potential as hydrogen-exporting nations.

In the maximum demand scenario, Germany and the UK undergo a significant shift as they become the countries with the highest hydrogen import needs, with respective capacities of 406 TWh and 163 TWh. Other significant importers include Italy, Norway, and Belgium. Ukraine becomes the highest exporting country with a capacity of up to 1,100 TWh, followed by Poland and the Netherlands. Spain, Denmark, Finland, and Ireland also demonstrate substantial exporting potential. Countries like Greece, Portugal, Romania, Estonia, and Sweden become hydrogen-exporting nations with capacities up to 43 TWh.

Delivery routes vary in each scenario. In the minimum demand scenario, the Scandinavian countries deliver hydrogen through the Baltic Sea, Spain supplies France and potentially Italy, and countries like Ukraine, Greece, Bulgaria, and Romania deliver hydrogen to Central European countries. In the maximum demand scenario, Spain and Portugal supply Italy through France, while the Scandinavian countries, Greece, Bulgaria, and Romania deliver hydrogen to Central Europe. The UK's significant hydrogen demand may be partially supplied by Ireland, with the remaining supply potentially coming from the Netherlands or the Scandinavian peninsula.

Regarding the capacity of the grid to transport hydrogen, in the mid-term case of study (2030), all countries could inject enough hydrogen into their grids to meet the total hydrogen demand via pipelines in the minimum demand scenario, except for Norway, Switzerland, and Sweden, which would require additional grid capacity of 0.5-9 TWh. The replacement of natural gas with hydrogen would range from 5-25% of the gas energy, with higher values in Ireland (33%), Greece (33%), and Finland (67%) due to grid size and high production of renewable methane. However, these assumptions come from different sources, leading to potential imbalances. In the high-demand scenario, Denmark, Finland, Norway, and Sweden would require grid expansions, with Switzerland needing 9 TWh of extra capacity. The percentage of natural gas replaced by hydrogen remains the same as in the minimum demand case.

When having a look into the long-term case of study (2045/50), several countries, including Bulgaria, Finland, Greece, Latvia, Norway, Poland, Portugal, Romania, Slovenia, and Sweden, have a significant potential for renewable methane. These countries could meet their national gas demand solely with renewable methane and may even have a surplus for export to neighbouring countries. Fortunately, these countries have sufficient grid capacity to accommodate both renewable methane and hydrogen demand, except for the Czech Republic, which would need to increase its grid capacity by 28 TWh. Countries like France, Germany, Poland, the Netherlands, Ukraine, and the UK have oversized grids capable of transporting all renewable gases. While Austria, Belgium, Estonia, Norway, and Slovenia have slightly more limited grid capacity, they still have enough to meet the transport needs. Notably, Norway's grid capacity is critical due to its expected role as a major hydrogen exporter to Central Europe, necessitating potential future increases in grid capacity for hydrogen transport unless renewable methane is consumed off-grid. The outlook of this study is consistent with the Vision 2050 developed in D5.4 of WP5.

The Hydrogen and decarbonised gas market package, including the EU Gas Directive and TEN-E regulation, establishes the framework for injecting hydrogen into gas grids. Ongoing interinstitutional negotiations may lead to important changes in the EU Gas Directive. Currently, the directive allows a maximum of 2% hydrogen blending in cross-border gas transport, suggesting limited blending above this threshold. Consequently, it is anticipated that dedicated and repurposed lines will be developed to deliver 100% hydrogen at transport pressure levels. However, a comprehensive analysis cannot be provided at this stage due to the evolving nature of the regulations. Further updates on EC policies and identification of potential gaps will be covered in Deliverable D6.3.

Finally, section 5.5 contains the feedback received from WP5 regarding the expected the characterisation of future transport grids. Four scenarios considering 2 vol% H_2 blends, 30 vol% H_2 blends and the transport of 100 $\%H_2$ are explained. The use or not of separation technologies with the highest blends is also considered.

1 Objective

The main goal of D6.1 is completing the work already started in WP2 about the state-of-art of the European transport grid infrastructure, as well as reporting the main achievements of task 6.1 in WP6, where the potential for hydrogen injection in the European grid is studied, forecasting future trends up to 2050 and their alignment with the EU policies. More specifically, the following objectives have been considered:

- Completing the inventory of the European transport grid with public information available from TSOs as well as from direct their direct contribution to HIGGS via a dedicated survey, providing an update of the overview already shown in D2.3 (WP2).
- Estimating the ranges of hydrogen injection which are potentially required due to future energy trends.
- Defining a baseline scenario for hydrogen injection in the European counties and forecasting future trends in the mid-term (by 2030) and long-term (by 2050), including possible flows of hydrogen among countries.
- Comparing the hydrogen injection potential with the current EU policies to identify the regulation missing and other kind of barriers.
- Studying the alignment of the Task 6.1 outputs with those of WP4: Systematic and experimental validation of components and WP5: Techno-economic modelling and validation, enablers and interoperability

2 Introduction

This deliverable considers an update of the inventory of the grid already tackled in WP2 (D2.3). The same survey methodology has been followed to gather information about pipelines and assets of relevant TSOs. This information has been completed with public information available at TSOs' web-sites to provide a picture of the European grid as complete as possible.

Within the scope of WP6, the potential for hydrogen injection has been analyzed, using as starting point the expected demand and production of hydrogen, as well as that of renewable methane, which can help to meet part of the total gas demand and therefore replace some of the "space in the grid" available for hydrogen. Three scenarios have represented the framework of the study, the baseline (2020), and the estimated 2030 and 2045/2050. The conclusions reached with this analysis are aligned with the outputs of WP2, where the current EU policies related to hydrogen injection in the gas network are studied, which have besides been updated in this report.

3 The European transmission grid

This section outlines an update on the state-of-art of the European high-pressure natural gas grid provided in D2.3. An evaluation of the gas network's state based on public information available on the European TSOs' official websites is given in section 3.1. Each TSO has been researched and an exhaustive description of their grids is provided for each country. In section 3.2, numerical data are displayed in the form of graphs, where the main aspects of the pipes (length, diameter, installation period and MOP) and transport facilities are discussed at national level. The same aspects are considered in section 3.3, but this time the information is gathered into geographic clusters. Finally, this review is complemented in section 3.4 with confidential information provided by some TSOs about their own grid. This information has been gathered with a survey where specific details about pipelines and transport facilities was requested.

3.1 Review of the infrastructure of European TSOs based on publicly available information

This section provides a review of the infrastructure of the main European TSOs (see Table 1). The data have been collected by performing a deep search in the TSO's official websites, where specific information about their own infrastructure is provided in greater or lesser detail depending on the case. A review country by country is shown in the following subsections.

Table 1. List of European TSOs studied in this report

Country	TSO
Austria	Gas Connect Austria GmbH
	Trans Austria Gasleitung GmbH
Belgium	Fluxys Belgium SA
Bulgaria	Bulgartransgaz EAD
	ICGB AD Interconector
Croatia	Plinacro
Czech Republic	Net4Gas
Denmark	Energinet
Estonia	Elering
Finland	Gasgrid Finland Oy
France	GRTGaz
	Teréga
Germany	Bayernets GmbH
	GASCADE Gastransport GmbH

	Fluxys TENP GmbH
	Fluxys Deutschland
	ONTRAS
	Gastransport Nord GmbH
	Gasunie Deutschland Transport Services GmbH
	Open Grid Europe GmbH
	Thyssengas
	Terranets bw GmbH
	GRTGaz Deutchland
	Nowega
	OPAL and Lubmin-Brandov Gastransport Gastransport
	Ferngas
Greece	DESFA SA
Hungary	FGSZ Földgázszállító Zrt
Ireland	Gas Networks Ireland
Italy	Snam Rete Gas S.p.A.
	Società Gasdotti Italia S.p.A.
Latvia	Conexus Baltic Grid
Lithuania	AB Amber Grid
Luxembourg	Creos Luxembourg S.A.
Netherlands	Gasunie Transport Services B.V.
	BBL Company V.O.F.
Norway	Gassco
Poland	GAZ-SYSTEM S.A.
Portugal	REN - Gasodutos, S.A.
Romania	Transgaz S.A.
Serbia	Srbijagas
Slovakia	eustream, a.s.
Slovenia	PLINOVODI d.o.o.

Spain	ENAGAS TRANSPORTE S.A.U
	Medgaz
	Redexis
Sweden	Swedegas AB
Switzerland	Swissgas
	Transitgas AG
	Gasverbund Mittelland
	Erdgas Ostschweiz AG
	GAZNAT SA
Ukraine	NaftoGaz
	UkrTransGaz
UK	National grid
	GNI(UK), Premier Transmission Limited ("PTL"), Belfast Gas Transmission Limited ("BGTL") and West Transmission Limited ("WTL")

3.1.1 Austria

➢ Gas Connect Austria GmbH [1]

This TSO reports seven different lines that are operated by them in Austria:

1- *West-Austria-Gasleitung (WAG)*: It is a system commissioned in 1980 consisting in two parallel pipelines with nominal diameter (refer in mm) of DN800 (245 km) and DN1200 (140 km) and its auxiliary equipment (metering and control stations, slide gate valve stations, etc.). The system runs from Baumgarten an der March on the Austrian-Slovak border, through Lower Austria and Upper Austria to Oberkappel on the border with Germany. The pipelines can be operated bi-directionally.

2- *Penta-West (PW)*: 95 km of a DN700 pipeline and associated auxiliary equipment. It was commissioned in 1999 and the pipeline can be operated bi-directionally.

3- *Hungaria-Austria pipeline (HAG)*: It is a DN700 pipeline with its auxiliary equipment running from Baumgarten an der March through Lower Austria and Burgenland to Deutsch-Jahrndorf on the border with Hungary. It was commissioned in 1996.

4- *Kittsee-Petrzalka-Gasleitung (KIP)*: 4 km pipeline of DN500 running from Berg/Kittsee to the Slovak border. It supplies gas to Slovakia and was commissioned in 2009.

5- *Süd-Ost-Leitung (SOL)*: One 26 km long DN500 pipeline with its auxiliary equipment running from Weitendorf in Styria to Murfeld to the Austrian-Slovenian border. It was commissioned in 1978 and supplies gas to Slovenia and Croatia.

6- *Primary distribution system (PDS)*: It is a pipe system made of 40 pipelines DN100 to DN1200, and the associated auxiliary equipment. It was commissioned in 1942.The primary distribution system is made up of around 40 pipelines with nominal diameters of between 100 and DN1200, and the associated auxiliary equipment. The system runs through eastern Lower Austria, and there is a small section in Vienna and it is 315 km long.

7- *March-Baumgarten-Gasleitung (MAB)*: It is a 2.5 km long DN500 pipeline running from the Austrian-Slovak border to Baumgarten an der March that was commissioned in 1997.

The largest import and entry station for natural gas in Austria is located in Baumgarten, Lower Austria, dating from 1959. Gas Connect Austria also operates five compressor stations. The VS OGG compressor station for the PVS primary distribution pipeline system (operated 100% electrically), the VS WAG compressor station (partial electrical operation), Kirchberg (2008), Reinbach (2008) and Neustift/Oberkappel.

➢ Trans Austria Gasleitung GmbH [2]

The TAG Pipeline System is a network of pipelines with a total length of about 1,140 km and diameters ranging from 36 to 42 inches. It has a pressure of up to 70 bar and consists of three lines, five compressor stations, and auxiliary equipment. The total installed power of the compressor stations is approximately 480 MW. The Pipeline leads from the Slovakian - Austrian border near Baumgarten an der March to the Austrian - Italian border near Arnoldstein.

The system is used to supply natural gas to domestic customers in Austria as well as for the transit of gas to Italy. Transit to Slovenia is also possible via the SOL Pipeline System (Süd - Ost - Leitung) of Gas Connect Austria GmbH, which diverges at Weitendorf from the TAG Pipeline System. The system has two entry points and one exit point.

3.1.2 Belgium

➢ Fluxys Belgium SA [3]

Fluxys Belgium's transmission network spans over 4,000 km and is well-connected to all available natural gas sources in the European market. The system allows for gas flows in both directions with all adjacent markets, including the UK, France, The Netherlands, Germany, and Luxembourg.

The grid also offers customers the versatility to use it for their supplies into Belgium as well as for border-to-border transmission to supply other markets in Northwest Europe. The network has interconnection points with all adjacent markets and connections with 17 DSOs and 230 industrial sites and gas-fired power stations in Belgium.

The gas system in Belgium is composed of two separate networks: one for high-calorific gas (H-gas) and one for low-calorific gas (L-gas). The L gas grid is sourced from the Groningen field in the Netherlands and its exports will be phased out progressively between 2024 and 2030. Fluxys Belgium and the DSOs are proactively switching end-users of L-gas to H-gas, and the completion of the network conversion is planned for 2024.

In terms of infrastructure, the Fluxys Belgium network has four compressor stations located at Berneau, Weelde, Winksele, and Zelzate.

3.1.3 Bulgaria

➢ Bulgartransgaz EAD [4]

This TSO operates a 3,276 km long grid, including 11 compressor stations and 240 domestic connection points. The Bulgarian grid is connected to Romania, Turkey, Greece, North Macedonia and Serbia through 8 cross-border interconnection points. Bulgartransgaz reports a total storage capacity of around 5,813,500 MWh in their underground storages.

➢ ICGB AD Interconector [5]

The gas interconnector Greece – Bulgaria (project IGB) is a pipeline system that connects the natural gas transmission network of Greece near the town of Komotini with the Bulgarian transmission network near the town of Stara Zagora. The interconnector spans an overall length of 182 km, it has a technical capacity of 3 billion cubic meters (bcm) per year and it is built in 151BG / 31GR steel.

The pipeline also has an option to increase its transmission capacity up to 5 bcm per year with the construction of a compressor station on Greek territory that would also allow for reverse flow. This will enable natural gas to flow in both directions between Greece and Bulgaria, giving both countries more flexibility in terms of supply and demand. Since February 2022, the ICGB has been certified as an independent TSO.

3.1.4 Croatia

➢ Plinacro [6]

Plinacro is responsible for operating and maintaining over 2,544.43 km of high-pressure gas pipelines that transported 31.712 GWh in 2021. The grid operates at pressures between 50 and 75 bar and has 5 entry measuring stations, one compressor station, 156 exit measuring-reduction stations, over 450 of overhead facilities of the transmission system and a National Dispatching Centre. The gas transmission system in Croatia is divided into five regions: Gas Transmission Region Central Croatia, Gas Transmission Region Northern Croatia, Gas Transmission Region Eastern Croatia, Gas Transmission Region Western and Southern Croatia, and the Transmission System Maintenance and Storage Department.

Approximately 1,100km of new gas pipelines were constructed in the first decade of the 21st century within the gas pipeline system of Pula – Karlovac, Lika and Dalmatia, as well as central and eastern Croatia. This enabled the import of gas from Hungary in 2011. The first compressor station was constructed in 2020 to enable bi-directional gas flow and transmission of large volumes of gas at the interconnection with Hungary. The reconstruction of the main gas pipeline Rogatec – Zabok allowed for bi-directional gas flow with Slovenia as well. The Zlobin - Omišalj evacuation gas pipeline and the LNG terminal on the island of Krk were constructed at the beginning of 2021 to enhance the security and stability of gas supply to Croatia. Bi-directional interconnections with Hungary and Slovenia have also enhanced the security and stability of gas supply to central and southeast Europe.

Underground Gas Storage Okoli, which has an operating storage volume of 553 mil. m3, was put into trial run at the end of 1987, and the first cycle of gas injection began in April 1988. Plinacro acquired a 100% share in the company Podzemno skladište plina d.o.o. in 2009, which is responsible for natural gas storage, management, maintenance, and development of a safe, reliable, and efficient gas storage system. The company's future plans include the modernization and expansion of the compressor of the existing storage facility in Okoli and the construction of a peak gas storage facility in Grubišno Polje, as well as a future strategic underground gas storage facility.

3.1.5 Czech Republic

➢ Net4Gas [7]

NET4GAS operates a natural gas transmission system consisting of pipelines with a total length of 3,973 km. These pipelines are used for both international transit and national transmission of natural gas. The nominal diameters of the pipelines range from DN80 to DN1400, while the nominal pressures range from 40 to 85 bar.

Compressor stations located at Břeclav, Kouřim, Kralice nad Oslavou, Otvice and Veselí nad Lužicí are responsible for providing the required gas pressure in the pipelines. The total installed capacity of these six compressor stations is 281 MW of mechanical capacity. Natural gas is then transferred from the transmission system via 100 transfer stations at the interface with domestic gas distribution, directly connected customers and underground gas storage facilities. At all of these transfer stations, the commercial metering of gas quantities is installed.

3.1.6 Denmark

➢ Energinet [8]

Energinet operates a 900 km long network. Most of the Danish gas system was established in the 1980s and the basic life span of most of the physical assets is 30-50 years.

The plans for the expansion of the natural gas infrastructure in the Baltic region include several key points in the “Baltic Pipeline” project. Firstly, a new offshore gas pipeline from Norway's pipeline Europipe II in the North Sea to a receiving terminal, with a length of 105-110 kilometres, will be constructed. Additionally, the Danish transmission system will be expanded with a new gas pipeline that will be approximately 210 kilometres long. A compressor station will be built in Zeland to increase the pressure of the gas in the pipeline in the Baltic Sea. GAZ-SYSTEM (Poland) is responsible for establishing a gas pipeline between Denmark and Poland, which will be located in the Baltic Sea and will have a length of 260-310 kilometres. The transmission system in Poland will also be expanded. The ultimate goal of these projects is to transport up to 10 billion Nm^3 of gas per year from Norway to Poland via Denmark. These ambitious plans demonstrate a commitment to improving the energy infrastructure in the region, which will lead to increased energy security and economic growth. Energinet is in charge of establishing the first three components, while GAZ-SYSTEM is responsible for the pipeline in the Baltic Sea and expansions in Poland.

3.1.7 Estonia

➢ Elering [9, 10]

The Estonian gas transmission network comprises 977 km of pipelines (between 10-28 in OD), 36 gas distribution stations, three gas-metering stations, two compressor stations and one gas regulation station. Most of the grid operates below 60 bar, but there are almost 40 km operating at 80 bar.

3.1.8 Finland

➢ Gasgrid Finland Oy [11]

Finland has a high-pressure transport grid that spans 1,150 km. The pipelines are built in steel and coated with polyethylene plastic to protect against corrosion. Cathodic protection supplements the pipeline coating's corrosion resistance. The transmission pipeline system has been in service since 1974 and includes pipes with diameters ranging from DN100 to DN1000. Internal inspection is possible for 80% of the pipelines. Besides, a 77 km offshore pipeline connects Paldiski, Estonia, to Inkoo, Finland. This steel pipeline has a diameter of DN500 and a design pressure of 80 bar. The pipeline is a joint venture between the Finnish transmission system operator and their Estonian counterpart, Elering. It can operate in both directions.

Finland's gas transmission network also includes renewable biogas from four separate biogas plants in Espoo, Kouvola, Lahti, and Riihimäki. Furthermore, a Hamina-based biogas plant is connected to the distribution network.

Three compressor stations are operated by Gasgrid Finland, located in Imatra, Kouvola and Mäntsälä. This means a total of 8 gas turbine-operated compressor units with a total combined shaft power of 54 MW. In addition to these, Gasgrid Finland operates the Ingå compressor unit driven by an electric motor and with capacity of 6.4 MW.

Finally, valve nodes can be found every 8–32 km. The total number of valve stations is 166, and 40 of these are remotely controlled.

3.1.9 France

➢ GRTGaz [12, 13]

GRTgaz is a major player in the transportation of natural gas in France, with a vast underground gas transmission network that spans over 32,500 km. The network is made up of gas pipelines that range up to DN1200. The company has 26 compressor stations located at regular intervals of approximately 200 km along the main network. In addition to its expansive grid within France, GRTgaz is also linked to several international networks, including those in Norway, Belgium, Germany, Spain (via the Teréga network), Switzerland, and Italy (via Switzerland). The company is also connected to 14 underground storage units and 4 LNG terminals along the French seaboard and reports 716 connections to industrial customers.

In 2021, GRTGaz transported 630 TWh of natural gas, with 6.4 TWh/year of connected capacity for injection of renewable gases into networks. A total of 46 producers of biomethane inject their output into the GRTgaz network. Nineteen different DSOs are connected to the GRTgaz grid, which has seven interconnection points, including five international and two national connections (Teréga grid). The company is also connected to four LNG terminals.

➢ Teréga [14]

With 5,115 km of grid, Teréga covers 15.7% of the French transport grid. The pipeline diameters range from DN5 to DN900 and the operating pressure of the grid varies between 8-85 bar. Teréga's monitoring and maintenance program includes continuous remote monitoring of the pipeline 24/7, aerial surveys of pipelines at least 10 times a year, a survey of the pipeline route on foot or by vehicle every 2 years, and an inspection of the pipeline at least every 10 years. Besides, Teréga's grid currently has 4 connections for the injection of 78 GWh of biomethane, and 7 more are on the way.

Regarding its transport facilities, Teréga report up to 700 shut off valve nodes, 6 compressor stations (with a total power of 85 MW), 325 public distribution supply points, 112 connections to industrial customers and 3 cross border interconnection points.

3.1.10 Germany

➢ Bayernets GmbH [15]

The Bayernets network area is located in southern Bavaria and covers an area of approximately 35,500 km². It provides the necessary gas infrastructure for Bavaria, the neighbouring federal states and Austria to supply gas to connected network customers such as municipal utilities, power plants, storage facilities, industry and neighbouring national and international transmission system operators. The network has a total length of 1,664.4 km with 189 exit points and a total annual withdrawal of 153,656,217,613 kWh.

➢ GASCADE Gastransport GmbH [16]

Gascade operates a transmission network in Germany with a total length of approximately 3,236 km and 74 exit points. It is of crucial importance for gas imports in Europe and has seven border crossing points. It includes the MIDAL, RHG, WEDAL, JAGAL, STEGAL, ERM and EUGAL pipelines, among others:

1- The *STEGAL* is a pipeline that is 314 km long and has a DN800 diameter. It was commissioned in 1990 and connects the Czech and Slovakian pipeline systems for Russian natural gas to the MIDAL. In 2006, an additional 97 km DN 1000 pipe was constructed.

2- The *MIDAL*, or *Mitte-Deutschland-Anbindungsleitung*, is the central element of the gas pipeline system and is 679 km long on the north-south axis. The northern section of the MIDAL has a diameter of DN900 and runs from Bunde and Rysum to Rehden. The middle section of the MIDAL connects Rehden with Reckrod and has a diameter of DN1000. From there, the pipeline continues for 210 km to Ludwigshafen with a nominal diameter of DN800. MIDAL-ERM was put into operation in April 1964. The DN400 pipeline is 57 km long and connects Jockgrim with Ludwigshafen. Other pipelines such as STEGAL, WEDAL, and RHG branch off from the MIDAL. Construction of the MIDAL started in May 1992, and since the end of 1993, they connect the landing point for natural gas from Northwest European supply sources with the German consumer centres.

3- The *RHG (Rehden-Hamburg-Gasleitung, Rehden-Hamburg-gas pipeline)* is a pipeline used to transport natural gas in Greater Hamburg. It is a branch of the MIDAL and was built in a joint project by GASCADE and E.ON Hanse. The RHG is 132 km long, has a diameter of DN800, and runs from the gas storage in Rehden to northeast. It has been in operation since June 1994.

4- The *WEDAL*, which stands for *Westdeutschland-Anbindungsleitung*, consists of two sections that were commissioned between June 1996 and October 1998. Its purpose is to connect the MIDAL to the Belgian pipeline network, allowing for the transportation of natural gas from both northwestern Europe and Russia. The first section of the WEDAL starts at Bad Salzuflen and extends to Soest in Westphalia, with a diameter of DN800. In October 1998, the second section of the pipeline was connected to the grid, making it possible to transport natural gas from Soest all the way to the Belgian border at Aachen, across the state of North Rhine Westphalia. The construction of an underwater pipeline that spans the River Rhine at Cologne was particularly challenging, but it was also part of the WEDAL. This 410-meter-long pipeline, which lies 3.5 meters below the riverbed, connects the sections on the right and left banks of the Rhine.

5- GASCADE's pipeline network is connected to the Yamal-Europe gas pipeline through *JAGAL* (*Jamal Gas Link*). JAGAL stretches from the Polish-German border near Mallnow to Rückersdorf in Thuringia, where it connects with STEGAL since 1999. Construction of this 338 km long pipeline began in September 1995 with a challenging task of tunnelling under the River Oder. JAGAL was completed in September 1999, with a similar technical challenge of tunnelling under the River Elbe. The first 11 km of JAGAL I run from the Polish border on the River Oder to Mallnow, with a diameter of DN1400, and were commissioned in late 1996. The second part of JAGAL I, with a diameter of DN1200, covers the 97 km from Mallnow to Baruth in Brandenburg and was completed in 1997. JAGAL II covers the 230 km from Baruth to Rückersdorf in Thuringia, where it meets STEGAL. Construction work on JAGAL II started in February 1999, and the DN1200 diameter gas pipeline was commissioned in the fall of the same year.

6- *NOWAL* is a 26-kilometer-long pipeline with a diameter of DN1000 that connects the GASCADE infrastructure near Rehden with the OGE network in Drohne, Westphalia. This connection significantly increases the transportation capacity between the entry points in Northern and Eastern Germany and the consumption centres in Western and Southern Germany. NOWAL's relevance is particularly due to the L/H gas conversion in Western Germany.

7- *EUGAL* is a 480-km-long pipeline that strengthens the supply of natural gas to Germany and Europe. The pipeline runs in two strings from the Baltic Sea through Mecklenburg-Western Pomerania and Brandenburg, and in one string through Saxony and over the border to the Czech Republic. The Radeland 2 compressor station in Brandenburg increases the gas pressure to transport it reliably. EUGAL started transporting natural gas on January 1, 2020, after a construction period of over two and a half years, and has been operating at its full capacity of up to 55 billion m³ of natural gas per year since April 1, 2021.

GASADE's grid has a total of 105 entry and exit points and 10 compressors stations in various locations, including Bunde, Eischleben, Lippe, Mallnow, Olbernhau, Radeland, Reckrod, Rehden, Rückersdorf, and Weisweiler.

- The Bunde compressor station has two compressors with a rating of 12.8 MW (2 x 6.4 MW), and a maximum working pressure of 90 bar. The propulsion type is an electromotor. The Eischleben compressor station has three compressors with a rating of 85.6 MW (2 x 30.1 MW, 1 x 25.4 MW), and a maximum working pressure of 90 bar. The propulsion type is a gas turbine.

- The Lippe compressor station has three compressors with a rating of 40.8 MW (2 x 12.9 MW, 1 x 15 MW), and a maximum working pressure of 100 bar. The propulsion type is a gas turbine.

- The Mallnow compressor station has four compressors with a rating of 96.2 MW (3 x 25.4 MW, 1 x 20 MW), and a maximum working pressure of 100 bar. The propulsion type is three gas turbines and one steam turbine.

- The Olbernhau compressor station has three compressors with a rating of 31.8 MW (2 x 9.45 MW and 1 x 12.9 MW), and a maximum working pressure of 90 bar. The propulsion type is a gas turbine.

- The Radeland compressor station has three compressors with a rating of 66.3 MW (3 x 22.1 MW), and a maximum working pressure of 100 bar. The propulsion type is a gas turbine.
- The Reckrod compressor station has five compressors with a rating of 75.8 MW (4 x 12.6 MW, 1 x 25.4 MW), and a maximum working pressure of 90 bar. The propulsion type is a gas turbine.
- The Rehden compressor station has three compressors with a rating of 29 MW (2 x 11 MW, 1 x 7 MW), and a maximum working pressure of 100 bar. The propulsion type is an electric motor and a gas turbine.
- The Rückersdorf compressor station has three compressors with a rating of 76.2 MW (3 x 25.4 MW), and a maximum working pressure of 100 bar. The propulsion type is a gas turbine.
- The Weisweiler compressor station has three compressors with a rating of 37.5 MW (3 x 12.5 MW), and a maximum working pressure of 100 bar. The propulsion type is an electromotor.

➢ Fluxys TENP GmbH [17]

In Germany, Fluxys TENP GmbH holds a 49% stake in the TENP pipeline (51% Open Grid Europe), which connects the German gas market with Switzerland, Belgium and the Netherlands. It consists of two strings, each 500 km long, from Bocholtz on the Dutch border and Eynatten on the Belgian border to Wallbach on the Swiss border, where the TENP pipeline is connected to the Transitgas pipeline. Accordingly, it has three border crossing points.

The TENP system consists in 2 lines of 500 km each with a technical capacity of 18,5 bcm (North-South direction) and 5,4 bcm in the opposite direction. It comprises also 4 compressor stations (maintained by OGE): Hügelheim (34.7 MW), Mittelbrunn (54.5 MW), Schwarzach (42.4 MW) and Stolberg (46.8 MW).

➢ Fluxys Deutschland [18]

Fluxys Deutschland GmbH is a transmission system operator marketing 23.87% of the transport capacity of the NEL pipeline and 16.5% of the transport capacity of the EUGAL pipeline. The NEL and EUGAL pipelines enable the onward transport of gas landed on the German Baltic Sea coast within Germany and to neighbouring European countries.

The 441-km long NEL pipeline runs from the entry station near Greifswald in a westerly direction through Mecklenburg-Western Pomerania to Lower Saxony. It is also connected to the EUGAL pipeline, which allows gas to flow both to the west and to the south. After reaching Lubmin, the NEL turns south-westwards towards the Mecklenburg Lake District. The high-pressure grid has only one exit point/exit range, and the annual exit consumption for DSO's and end consumers is 57 Mio. m³ or 643 GWh (2021).

➢ ONTRAS [19]

Ontras is a transport network operator with a 7,739 km long supra-regional transport network concentrated in the eastern German states. About one seventh of the network is in fractional ownership. The network has an impressive annual energy output of 155 billion kWh and comprises 442 exit points, 130 downstream network operators (within grid areas), 34 final consumers, 23 connected biogas plants, 2 power-to-gas plants connected to the network, and 6 stores linked to the grid.

➢ Gastransport Nord GmbH [20]

GTG is a transport network operator with a 324.6 km long transport network in north-western Lower Saxony, which is completely designed as a high-pressure network and has 73 exit points. In 2021 the simultaneous annual maximum load was 8,485 MW and the annual work withdrawn by distribution companies and end customers was of 31,221,898,060 kWh,

➢ Gasunie Deutschland Transport Services GmbH [21]

Gasunie's high-pressure transport network in Germany, which is about 4,600 km long, is connected to Gasunie's transport network in the Netherlands. The Gasunie network in Germany also includes participations in the European gas interconnector EUGAL and the North European gas pipeline NEL. This means that the Gasunie network is also connected to Nord Stream and thus to Russian natural gas reserves. In total, Gasunie's network in Germany has five border crossing points.

Gasunie operates more than 4,600 km of transport grid in Germany, with diameters varying from 4 to 40 in OD and 175 exit stations. This TSO also operates the following 31 compressor stations:

- Bierwang (Uniper OGE) / 15.260 kW
- Bunde (OGE) 11.400 kW
- Ellund (DEUDAN) 11.480 kW
- Elten (NETG) 31.690 kW
- Emsbüren (OGE) 21.055 kW
- Gernsheim (OGE) 11.750 kW
- Gernsheim (MEGAL) 60.410 kW
- Gescher (OGE) 47.700 kW
- Herbstein (OGE) 45.460 kW
- Holtum (NETRA) 23.720 kW
- Hügelheim (TENP) 34.700 kW
- Krummhörn Transport (OGE) 44.970 kW
- Legden (ZEELINK) 30.400 kW
- Mittelbrunn (TENP) 54.500 kW
- Mittelbrunn (MEGAL) 50.199 kW
- Porz (METG) 96.850 kW
- Rimpar (OGE) 9.450 kW
- Rimpar (MEGAL) 26.915 kW

- Rothenstadt (MEGAL) 67.680 kW
- Scheidt (METG) 21.000 kW
- Schwarzach (TENP) 42.414 kW
- St. Hubert (NETG) 21.320 kW
- Stolberg (TENP) 46.841 kW
- Waidhaus (OGE) 20.530 kW
- Waidhaus (MEGAL) 132.380 kW
- Wardenburg (NETRA) 35.550 kW
- Werne (OGE) 153.370 kW
- Wertingen (bayernets) 33.000 kW
- Würselen (ZEELINK) 40.800 kW
- Wildenranna (MEGAL) 15.360 kW

➢ Open Grid Europe GmbH [22]

Open Grid Europe's transmission network has a length of almost 12,000 km and consists, among other things, of pipelines owned by pipeline companies in which OGE holds shares together with partner companies. These include MEGAL together with GRTgaz, TENP together with Fluxys TENP, DEUDAN together with Gasunie, NETRA together with Gasunie, METG (OGE only), NETG, together with Thyssengas and ZEELINK together with Thyssengas. OGE also operates 11 compressor stations with a total of 396.2 MW installed capacity.

The DEUDAN pipeline (constructed in 1982 and expanded in 1996), has the distinction of being the first gas pipeline in Germany that transports green hydrogen, which is blended with natural gas at a concentration of up to 2%, and has been doing so since 2020. This pipe is 111 km long and includes one compressor station (11.48 MW).

The natural gas pipeline system of NETG was put into operation in 1967 and includes two compressor stations at the Elten and St. Hubert locations (near Krefeld). The pipeline system consists of two parallel pipelines with up to one meter in pipe diameter (DN1000) over a length of approximately 280 km. It serves to transport natural gas from the Netherlands to the adjacent infrastructure within Germany. Several pipelines branch off from the NETG natural gas transport pipeline system, supplying natural gas to major cities and industrial customers in the Lower Rhine and Rhineland regions, among others.

➢ Thyssengas [23, 24]

Thyssengas' 4,411 km long transport network is mainly located in North Rhine-Westphalia. Thyssengas is connected to national and international transmission system operators (connection points to Belgium, the Netherlands and the North Sea pipeline coming from Norway).

This TSO operates a grid with well-defined diameters. The grid includes 6 compressor stations and 1.016 exit stations (85 stations operate at pressures >70 bar, another 85 stations at pressures between 40-70 bar, 115 stations operate at pressures between 25-40 bar and the 731 remaining operate between 16 and 40 bar.

➢ Terranets bw GmbH [25]

Terranets transport grid is greater than 2,700 km and it is located in South Germany. Terranets receives gas from more than 45 entry points of other long-distance gas transmission network operators. Around 300 network coupling points connect approximately 60 network operators and 25 industrial customers directly to the high-pressure gas grid. Two gas compressor stations, located in the Karlsruhe and Ulm regions, are currently operational, and two more are planned for Scharenstetten and another in the Nordschwarzwaldleitung area. There are also two future pipelines in project: the Spessart-Odenwald pipeline, which will be 115 km long, with a diameter of 40 inches and a maximum operating pressure of 90 bar, and will start operating in 2027, and the Nordschwarzwald pipeline, which already exists and is being expanded to increase transport capacity.

➢ GRTGaz Deutchland [26]

GRTgaz Deutschland is a certified independent TSO, wholly owned subsidiary of GRTgaz SA, which is the largest TSO in France. GRTgaz Deutschland operates a transport system of around 1,200 kilometres that transports gas through the south of Germany. This network connects Germany's gas infrastructure with the net-works in France, the Czech Republic and Austria. The MEGAL pipeline, in which GRTgaz Deutsch-land has a 49% share (51% OGE), is of decisive importance..

The MEGAL Nord pipeline consists of two parallel pipelines that are each 460 km long and connect the two cross-border points at Waidhaus and Medelsheim. The pipeline is operated at a pressure of maximum 84 bar between Waidhaus and Renzenhof, and maximum 80 bar between Renzenhof and Medelsheim. Four compressor stations are currently required for its operation.

The MEGAL Süd pipeline also has two pipelines. The first pipeline connects Oberkappel at the Austrian border and Schwandorf in Bavaria, with a length of 169 km and a maximum operating pressure of 67.5 bar. The parallel pipeline between Windberg and Schwandorf, which is 72 km long and operates at a pressure of up to 100 bar, was taken into operation in 2012. The two compressor stations enable a bi-directional gas flow.

GRTgaz Deutschland offers capacities through PRISMA European Capacity Platform GmbH, on whose platform they are auctioned. They also hold shares in Trading Hub Europe GmbH, which manages the balancing group for the market area of the same name. The MEGAL pipeline system is a part of the market area THE and offers a bi-directional cross-border point at the German-Czech border in Waidhaus, at the German-French border in Medelsheim, as well as at the bi-directional cross-border point at the German-Austrian border in Oberkappel.

➢ Nowega [27]

Nowega operates in Lower Saxony. Nowega's transport network covers a length of about 1,600 km with 104 exit points. from the Dutch border across Lower Saxony and parts of NRW to the Wendland region.

➢ OPAL and Lubmin-Brandov Gastransport GmbH [28]

OPAL Gastransport operates an Europe's single natural gas pipeline in north-west Europe. The pipeline has a nominal diameter of DN1400 and a length of 473 km, with a capacity of transporting 36 billion cubic meters of natural gas per year. This accounts for one-third of Germany's annual demand for natural gas. The OPAL runs 473 km from Greifswald on the Baltic Sea coast through the federal states of Mecklenburg-Western Pomerania, Brandenburg and Saxony to the Czech Republic near Brandov. At the Radeland compressor station, which is halfway along the route, the gas is compressed for further transport.

In Radeland, south of Berlin, the natural gas is compressed in the compressor station for further transport to Brandov. The compressor station, situated halfway between the landfall of the Nord Stream pipeline in Lubmin and the endpoint at the German-Czech border near Olbernhau/Brandov, has three gas turbines with a total output of approximately 96 MW, which enables the natural gas to be compressed to up to 100 bars.

The OPAL is a joint project of W & G Transport Holding GmbH (WGTH) and Lubmin-Brandov Gastransport GmbH (LBTG). It was realised within the framework of a community based on fractional shares, according to which 80 percent of the co-ownership shares are held by WGTH and 20% by LBTG. WGTH's shares are leased by OPAL Gastransport GmbH & Co. KG.

➢ Ferngas [29]

The long-distance pipeline network of Ferngas Netzgesellschaft mbH is about 214 km long and is located in Thuringia.

3.1.11 Greece

➢ DESFA SA [30]

The National Natural Gas Transmission System in Greece consists of a main transmission pipeline extending 512 km from the Greek-Bulgarian border at Promachonas to Attica, with a design pressure of 70 bar. From this main pipeline, transmission branches extend 953.2 km to supply natural gas to various regions in Greece, including Eastern Macedonia, Thrace, Thessaloniki, Platy, Volos, Trikala, Oinofyta, Antikyra, Aliveri, Korinthos, Megalopoli, Thisvi, and Attica. The metallic pipeline uses external coatings to provide protection against mechanical wear and corrosion.

The system has two border metering stations, located at Sidirokastro in Serres and Kipi in Evros. The Sidirokastro station measures the quantity and quality of imported natural gas from Bulgaria and performs simple natural processes such as the removal of solid and liquid particles with filters and the heating of gas with heat exchangers. Gas supply to the Greek network is regulated according to the program of the Gas Control and Dispatching Center. The Kipi station measures the quantity and quality of imported natural gas from Turkey and regulates gas supply to the Greek network with three regulating lines.

Both border metering stations use parallel metering lines and gas chromatographs and analysers to measure the quantity and quality of natural gas. The Sidirokastro station has five parallel metering lines with orifice and the Kipi station has three parallel metering lines equipped with turbine and ultrasonic meters.

DESFA has only one compression station, located next to the Operation & Maintenance Center of Northern Greece at the main pipeline (kilometric position 414). The Compression Station consists of two compression units consisting of a centrifugal compressor (SOLAR 453) and gas turbine (SOLAR TAURUS 70) with 7.7 MW power each in operation and one in backup.

3.1.12 Hungary

➢ FGSZ Földgázszállító Zrt [31]

The Hungarian transport grid spans a total length of 5,889 km, consisting of nearly 400 independent underground pipelines with diameters ranging from DN80 to DN1400, and lengths ranging from 1 km to 100 km. 8 compressor stations can be found in Beregdaróc, Nemesbikk, Hajdúszoboszló, Városföld, Csanádpalota, Szada, Báta, and Mosonmagyaróvár. They are equipped with centrifugal compressors driven by high-performance gas turbines.

There are nearly 400 gas transmission metering and/or regulation stations. These stations share common technological functions, which include filtering, pre-heating, heat exchange, pressure regulation, and secure provision of pressure. Most stations are equipped with active monitoring regulators, which automatically start up backup equipment in the event of any failure, providing further security for consumers. Overpressure protection of connected systems is ensured by slam-shut valves and safety blow-off devices. Measurement of gas flow is carried out using different meters such as ultrasonic, turbine, orifice, rotary, and Coriolis flow meters. Gas-analysing chromatographs are also used to check the gas composition. High-pressure pumps are used for odorization.

3.1.13 Ireland

➢ Gas Networks Ireland [32]

Gas Networks Ireland is the main TSO in Ireland. It operates a grid of almost 2,500 km with 53 entry points, all of them metered.

3.1.14 Italy

➢ Snam Rete Gas S.p.A. [33, 34]

Snam Rete Gas's network covers approximately 41,000 km. The national gas pipeline network covers 9,571 km of them. The pipelines are divided into land pipelines, with a maximum diameter of DN1400, transporting gas at pressures between 24 and 75 bar, and submarine pipelines that cross the Strait of Messina with a diameter of between DN500 and DN600 and transport gas at a pressure of up to 115 bar. Besides, part of the system is the pipeline connecting the Toscana LNG offshore terminal (OLT) in Livorno with a diameter of DN800, operating at 84 bar. The main lines of the national network interconnected with the import pipelines are the following:

1- *Mazara del Vallo - Minerbio*: two lines (in some sections three lines), DN1050 - DN1200, connecting Mazara del Vallo to Minerbio, each about 1,500 km long. The pipelines connect in Mazara del Vallo to the trans-Mediterranean sealines, which cross the canal of Sicily, interconnecting Tunisia with Italy, and which are part of the import lines for natural gas from Algeria. natural gas from Algeria.

2- *Gela - Enna*: a 67 km long line (DN900), connecting Gela, the arrival point of the gas pipeline Greenstream submarine import pipeline from Libya, to the national transport network near Enna, along the Algerian gas import backbone.

3- *Tarvisio - Sergnano*: three lines of approximately 900 km in length (DN850 - DN1400), which connect the system with the Austrian network via the TAG pipeline (see section 3.1.1), crossing the Po Valley, and extend as far as Sergnano. The expansion (170 km) was carried out on the section from Zimella to Cervignano and in September 2018 the one on the section from Cervignano to Mortara (56 km). The new line, with a diameter of DN1400, replaces the old existing line with a diameter of 850/750 mm.

4- *Gorizia - Flaibano*: a line with a length of about 65 km (DN650 - DN1050) connecting the Slovenian transport network at the interconnection point of Gorizia with the national network near Flaibano along the import ridge from Tarvisio.

5- *Passo Gries - Mortara*: a line with a total length of 177 km (DN1200), connecting the Swiss transmission system at Passo Gries, the entry point of the Transitgas pipeline, extending to the Mortara junction in the Po Valley.

6- *TAP interconnection*: a line with a total length of about 56 km (DN1400), which connects the entry point into Italy of the Trans Adriatic Pipeline (transporting gas from the Azeri fields of the Caspian Sea), within the municipality of Melendugno (BR), to the Palagiano-Brindisi gas pipeline at the interconnection point of Brindisi.

The regional transport network (23,112 km), consists of pipelines with diameters and operating pressures that are usually smaller than those of the national network. Its function is to deliver natural gas on an inter-regional, regional and local scale for the supply of gas to industrial users and distribution companies. There are more than 8,000 km of pipes missing that could not be properly identified.

The Snam Rete Gas national network is also interconnected to the following LNG plants: GNL Italia in Panigaglia, Adriatic LNG in Porto Viro, Livorno OLT. Besides, part of the Snam Rete Gas infrastructure are 13 compression stations, generally comprising several compression units consisting of gas turbines and centrifugal compressors. The total installed capacity reaches 961 MW.

In addition to Snam Rete Gas, there are eight other TSOs carrying out gas transportation activities in Italy. In particular, *SGI - Società Gasdotti Italia S.p.a* and *Infrastrutture Trasporto Gas S.p.a* operate part of the national transport network and will be detailed in the next subsections. The other operators that operate transport networks only own regional networks and are interconnected to the Snam Rete Gas transport network from which they supply the gas they transport to their redelivery points.

➢ Società Gasdotti Italia S.p.A. [35]

The SGI transit system comprises a set of high-pressure gas pipelines, which extend to approximately 1,500 km with varying diameter pipes ranging from 2 to 20 in, including approximately 400 km of national network and about 1,100 km of regional network This system includes various networks such as the former Cellino network in Marche-Abruzzo, the ex SGM network in Lazio until Puglia through Molise and a small stretch in Campania, the Collalto pipeline in Veneto, the Garaguso network in Basilicata, the Cirò network in Calabria, and the Comiso network in Sicily, province of Ragusa. It also has 307 exit points (industrial plants and urban distribution networks.)

The SGI network has 9 points of interconnection with the national transport network Snam Rete Gas, 11 points of entry from national production fields with the main operators in the sector such as Eni, Edison, Società Adriatica hydrocarbons, and Gas Plus Italy, 2 points of interconnection with storage sites such as Edison storage. It transports an average of about 1 billion Nm^3 per year of natural gas over the last three years.

➢ Infrastrutture Trasporto Gas S.p.a.'s [33]

Its transport network consists of just over 80 km that are part of the national gas pipeline network and is composed of a methane pipeline connecting the regasification terminal in Cavarzere with the network owned by Snam Rete Gas.

3.1.15 Latvia

➢ Conexus Baltic Grid [36]

The total length of this TSO’s transmission pipelines, including their branches, is 1,190 km. These pipelines are divided into regional gas pipelines that serve Latvian supply and international gas pipelines that ensure gas transit to neighbouring countries. The international transmission pipelines are 577 km in length and consist of the Riga – Pahneva, Pleskava - Riga, Izborska - Inčukalns UGS, Riga - Inčukalns UGS I-line, Riga - Inčukalns UGS II-line, and Vireši - Tallinn pipelines.

The regional transmission pipelines are longer, with a total length of 6,130 km. They include the Riga – Daugavpils, Iecava – Liepāja, Upmala – Preili – Rezekne gas pipelines, and gas pipelines to gas control stations. International gas pipelines have a diameter of DN700 and a working pressure ranging from 28 to 40 bars, while regional gas pipelines have a diameter between DN100 and DN500 with a working pressure of up to 35 bar and a design working pressure of up to 55 bar. Latvia odorises the gas at transport level.

Conexus report 42 transmission metering and/or regulation stations in their grid.

3.1.16 Lithuania

- **AB Amber Grid [37]**

In 2022, the gas pipelines in Lithuania had a total length of 2288 km, and they transported 63 TWh of natural gas. The Amber Grid network is interconnected with four countries, namely Latvia, Belarus, Poland, and Russia's Kaliningrad Oblast. Additionally, it is connected to the Klaipėda LNG terminal. Lithuania's well-developed gas transmission system serves as a regional corridor for the transmission of gas northwards to Latvia and southwards to Poland. The network of main gas pipelines in Lithuania has been developed since 1961. The most commonly used pipelines have a diameter of DN700, while the maximum diameter of the gas pipelines in the Lithuanian network is DN1220. Most of the transmission system has a design pressure of 54 bar. With the installation of the Klaipėda LNG terminal in Lithuania, most of the gas for the needs of Lithuania and the Baltic States comes through it. Currently, 1,833 km of pipelines in Lithuania's gas transmission system are suitable for internal diagnostics. However, by 2024, it is expected that 80% of the main gas pipelines will be adjusted.

Amber Grid operates 2 compressor stations. The Jauniūnai station was installed in 2010. It has a total capacity of 34.5 MW and includes three gas turbines with centrifugal gas compressors. It compresses the gas up to 54 bar. The Panevėžys station (1974) transports the gas towards Riga, Klaipėda, and Vilnius. The station can operate with reverse flow gas. Its seven reciprocating compressors have a total capacity of 7.7 MW.

There are also several gas metering and/or regulation stations in Lithuania's grid. The Kiemėnai Gas Metering Station was built in 2005 and is a reversible metering station that allows the use of Latvia's Inčukalns underground natural gas storage facility. It is designed to operate in automatic mode and has a capacity of 270,000 Nm^3/h from Lithuania to Latvia and 260,000 Nm^3/h in the opposite direction. The ELLI project is underway, and by the end of 2023, the capacity from Lithuania to Latvia is planned to be increased to 448,000 Nm^3/h, and to 443,000 Nm^3/h in the opposite direction. The Šakiai Gas Metering Station was built in 1994 on the border with Russia's Kaliningrad Oblast and was reconstructed in 2009. It has a capacity of 480,000 Nm^3/h. The Santaka Gas Metering Station and Regulation is the gas interconnection project between Lithuania and Poland, which was built in 2021. The Santaka station is the gateway to Europe for Lithuania's gas transmission system, where gas transferred to the station by European suppliers is metered, checked, and adjusted to meet the system's needs. Similarly, gas from Lithuania is transferred to Poland and other European countries via this station.

Future projects in the Lithuania's grid can be highlighted. The project "Enhancing the Capacity of the Gas Pipeline Interconnector between Latvia and Lithuania" (ELLI) is aimed at increasing the capacity of the gas interconnector between Latvia and Lithuania (from MOP 40 to 50 bar). The investments will increase the capacity of the gas interconnector to 130.47 GWh/day in the Latvian direction (currently 67.6 GWh/day) and 119.5 GWh/day in the Lithuanian direction (currently 65.1 GWh/day).

3.1.17 Luxembourg

- **Creos Luxembourg S.A. [38]**

Luxembourg has a small 280 km grid operated by Creos. Most of the grid operates at 80 bar, but there are 39 km operating at 40 bar. Creos reports a total of 62 transmission metering and/or regulation stations.

3.1.18 Norway

- **Gassco [39]**

Gassco is the operator for the integrated system for transporting gas from the Norwegian continental shelf to other European countries. There are lines operated by Gasco:

1. Haltenpipe - From Heidrun to Tjeldbergodden, length of 250 km and diameter of 16". Available technical capacity (ATC) of 7 MSm^3/d. Technical Service Provider (TSP) is Statoil and Operator is Gassco.

2. Europipe - From Draupner E to Dornum, Tyskland, length of 620 km and diameter of 40". Available technical capacity (ATC) of 46 MSm^3/d. Technical Service Provider (TSP) is Statoil and Operator is Gassco.

3. Europipe II - From Kårstø to Dornum, Tyskland, length of 658 km and diameter of 42". Available technical capacity (ATC) of 71 MSm^3/d. Technical Service Provider (TSP) is Statoil and Operator is Gassco.

4. Norne Gas Transport - From Norne-feltet to Åsgard Transport (Gassled område B), length of 126 km and diameter of 16". Available technical capacity (ATC) of 7 MSm^3/d. Technical Service Provider (TSP) is Statoil and Operator is Gassco.

5. Franpipe - From Draupner E to Dunkerque, Frankrike, length of 840 km and diameter of 42". Available technical capacity (ATC) of 55 MSm^3/d. Technical Service Provider (TSP) is Statoil and Operator is Gassco.

6. Åsgard transport - From Åsgard to Kårstø, length of 707 km and diameter of 42". Available technical capacity (ATC) of 70 MSm^3/d. Technical Service Provider (TSP) is Statoil and Operator is Gassco.

7. Norpipe - From Ekofisk to Emden, Tyskland, length of 443 km and diameter of 36". Available technical capacity (ATC) of 32 MSm^3/d. The Operator is Gassco.

8. Statpipe Rich Gas - From Statfjord to Kårstø, length of 308 km and diameter of 30". Available technical capacity (ATC) of 25 MSm^3/d. Technical Service Provider (TSP) is Statoil and Operator is Gassco.

9. Statpipe Dry Gas - Part I - From Kårstø to Draupner S, length of 228 km and diameter of 28". Available technical capacity (ATC) of 21 MSm^3/d. Technical Service Provider (TSP) is Statoil and Operator is Gassco.

10. Statpipe Dry Gas - Part II - From Heimdal to Draupner S, length of 155 km and diameter of 36". Available technical capacity (ATC) of 31 MSm^3/d. Technical Service Provider (TSP) is Statoil and Operator is Gassco.

11. Vesterled - From Heimdal Riser to St Fergus, UK, length of 361 km and diameter of 32". Available technical capacity (ATC) of 39 MSm^3/d. The Operator is Gassco.

12. Oseberg Gas Transport - From Oseberg to Heimdal Riser, length of 109 km and diameter of 36". Available technical capacity (ATC) of 35 MSm^3/d. Technical Service Provider (TSP) is Statoil and Operator is Gassco.

13. Zeepipe: There are two different Zeepipe pipelines (Zeepipe I and Zeepipe II) that transport natural gas from Sleipner and Kollsnes respectively to different locations. The available technical capacity for Zeepipe I is 42 MSm^3/d and for Zeepipe II A and II B, it is 74 MSm^3/d and 73 MSm^3/d respectively.

14. Langeled: This pipeline transports natural gas from Nyhamna to Easington in the UK. The pipeline has a length of 1166 km and a diameter of 42"/44". The technical available capacity for the pipeline is 75/72 MSm^3/d.

15. Tampen Link: This pipeline transports natural gas from Statfjord to Flags. The pipeline has a length of 23 km and a diameter of 32". The available technical capacity for the pipeline is 10-27 MSm^3/d.

16. Kvitebjørn gas export: This pipeline transports natural gas from the Kvitebjørn platform to Kollsnes. The pipeline has a length of 147 km and a diameter of 30". The available technical capacity for the pipeline is 27 MSm^3/d.

17. Gjøa Gas Pipe: This pipeline transports natural gas from the Gjøa field to the transport system FLAGS. The pipeline has a length of 131 km and a diameter of 28". The available technical capacity for the pipeline is 17 MSm^3/d.

18. Valemon rich gas pipe: This pipeline transports natural gas from Valemon to Heimdal. The pipeline has a length of 177 km and a diameter of 22". The technical available capacity for the pipeline is 13 MSm^3/d.

19. Knarr: This pipeline transports natural gas from Knarr to the transport system FLAGS. The pipeline has a length of 106 km and a diameter of 12". The technical available capacity for the pipeline is 1.7 MSm^3/d.

20. Utsira High gas pipeline: This pipeline transports natural gas from the Edvard Grieg field to the transport system SAGE. The pipeline has a length of 94 km and a diameter of 16". The technical available capacity for the pipeline is 5.0 MSm^3/d.

All of these pipelines are operated by Gassco, with technical service providers including Equinor and Statoil.

3.1.19 Poland

➢ GAZ-SYSTEM S.A. [40]

The transmission system in Poland is comprised of two systems that are linked together: the Transit Gas Pipeline System, which spans approximately 4,000 kilometers and transports 51.39 TWh of natural gas from Russia through Belarus and Poland to Western Europe, and the National Transmission System, which is an 11,792-kilometer grid that carries 192.8 TWh of natural gas. The National Transmission System consists of two sub-systems for natural gas, one for high-methane natural gas (grade E) and the other for low-methane natural gas (grade Lw). 683.9 km of this grid operates at 84 bar.

Gaz System reports a total of 36 valve placements in their grid, 15 compressor stations (five of them providing a total installed power of 400 MW), 878 exit points and 71 entry points.

3.1.20 Portugal

➢ REN - Gasodutos, S.A. [41]

Its natural gas transport grid consists in 1,375 km of pipelines, geographically distributed along two main axes. 1) A South-North Axis, from the LNG terminal in Sines to Valença do Minho, which guarantees the supply of natural gas in the coastal part of Portugal, where the regions with the highest population density are located. This main axis has a branch to Mangualde. 2) An East-West Axis, from Campo Maior to the vicinity of Figueira da Foz. This main axis has a branch to Guarda.

In 2013, the connection between the branch of the two main axes was completed, linking Mangualde to Guarda, which strengthened the fulfillment of demand in the center and north of the country.

There are two interconnections between the Natural Gas Transmission Network and the Spanish natural gas transportation network: Campo Maior - Badajoz and Valença do Minho - Tuy. Both connection points have entry and exit capacity.

REN Gasoductos also reports 53 transmission valve nodes in their grid, 1 compressor station (of unknown power), 71 transmission regulation and/or metering stations and 3 delivery points to industrial customers.

3.1.21 Romania

➢ Transgaz S.A. [42]

This TSO's grid is 13,430 km long, of which 369 km are transit pipelines; The pipe diameter varies between OD 1" to 48". The operating pressure of the transport grid is comprehended between 6 and 35 bar, while the transit grid operates at 54 bar. The main lines in the grid are the following:

1. Podișor – Recaș gas transmission pipeline: 479 km, OD 32", and design pressure 63 bar
2. Recaș - Horia GCS gas transmission pipeline: 50 km, OD 32", and design pressure 63 bar
3. "Extension of the Romanian transmission system for taking over gas from the Black Sea shore": A 24.37 km long pipeline of OD 20", designed to operate at 55 bar.
4. BRUA NATURAL GAS TRANSMISSION CORRIDOR:

Trasngaz reports 5 compression stations in its line: STC Sinca, STC Onesti, STC Silistea, STC Podisor and STC Jupa. Another transport facilities are 58 valve nodes, 894 pressure regulation and/or metering stations (894 physical exit points and 32 DSOs), 225 exit points (15 gas power plants, 19 industrial complexes, 167 commercial consumers and 24 residential consumers) and 85 entry points.

Romania odorizes the gas at transport level and Transgaz possess 902 odorization devices.

3.1.22 Serbia

➢ Srbijagas [43]

Srbijagas is the main TSO in Serbia. It owns a grid comprising 2,230 km pipes of 25 years of average age with a 540,000 m^3/h capacity. Srbijagas reports 1 compressor station of 4.4 MW and 165 Gas Metering and Regulation Stations.

3.1.23 Slovakia

➢ Eustream, a.s. [44]

The transmission system in Slovakia consists of four to five parallel pipes (DN1200 or DN1400), operating at a pressure of 73.5 bar. To ensure continuous gas flow, the system relies on five compressor stations with a combined output of nearly 550 MW. There are 6 cross-border interconnexions to and from the transmission system of neighbor countries: Veľké Kapušany (Ukraine), Baumgarten (Austria), Lanžhot (Czech Republic), Budince (Ukraine), Veľké Zlievce (Hungary), Výrava(Poland). Besided Eustream operated 5 compressor stations with a total installed capacity of 550 MW.

3.1.24 Slovenia

➢ PLINOVODI d.o.o. [45]

The Slovenian gas transmission system consists of 1,195km of pipelines, along with 2 compressor stations located in Kidričevo and Ajdovščina. Additionally, there are 251 Metering and Regulation Stations, or similar facilities, within the system. This network serves as a connection for most industrial and urban centers in Slovenia, excluding the Obalno-kraška region, Bela Krajina, and a portion of Inner and Lower Carniola.

As of January 1, 2021, this TSO has entered into transmission contracts with 159 network users. Among these users, there are 12 DSOs operating in 84 municipalities, 131 industrial or commercial customers, including 5 system users classified as closed distribution systems, two power plants, and 14 domestic or foreign natural gas suppliers without booking capacity at the final exit point within the Republic of Slovenia. It has also 3 cross-border interconnection points.

Almost 800 km of grid were installed before 1990, 238 km were installed from 2000 to 2010 and almost 180 km have been installed in the last decade.

PLINOVODI operates 2 compressor stations (19.5 MW installed capacity) and 251 transmission pressure regulation and/or metering stations.

3.1.25 Spain

➢ ENAGAS TRANSPORTE S.A.U [46]

The gas network operated by Enagás spans over 11,000 kms. Within this network, there are 16 gas pipelines comprising a total of 103 sections, strategically distributed across the country. The maximum pressure capacity of the trunk network's gas pipelines varies between 72 and 80 bar, depending on the design specifications of each section. The minimum pressure threshold is set at 30 bar, except for specific underwater sections like the Almería international connection and the pipeline linking Denia to the Balearic Islands, which are designed to withstand a pressure of 220 bar.

Enagás has established six international cross-border points: two with Africa, two with Portugal, and two with France. Currently, Enagás operates 19 compressor stations, collectively providing a total installed capacity of almost 520 MW. The maximum gas pressure within these compressor stations ranges from 72 to 80 bar, depending on the design pressure of the associated pipeline. The minimum pressure levels are maintained between 40 and 45 bar. All of them contain turbo compressors and one of the stations uses electric motor compressors.

➢ Medgaz [47]

With an initial capacity of 8 bcm/year, MEDGAZ transports natural gas from Beni-Saf on the Algerian coast to Almería. The project has been operational since 2009. The submarine pipeline covers a distance of 210 km across the Mediterranean seabed, reaching a maximum depth of 2,160 m. In Algeria, it connects with the Hassi R'Mel-Beni Saf pipeline, managed by Sonatrach. In Spain, it is linked to the Almería-Albacete pipeline operated by ENAGAS, enabling its integration into the Spanish and European gas systems. The pipe has a diameter of 24 in.

Shareholders in the project are: SONATRACH (36%), CEPSA (20%), IBERDROLA (20%), ENDESA (12%), and GDF SUEZ (12%).

➢ Redexis [48]

Redexis provides natural gas transportation services in Spain through a transmission network that exceeds 1,600 km in length, thanks to 51 pipelines and an investment of more than 250 million euros. The company operates in the Autonomous Communities of Andalusia (294 km), Aragón (559 km), Balearic Islands (181 km), Castilla y León (358), Castilla-La Mancha (83 km), Valencia (103 km), and the Region of Murcia (65 km).

This network is made up of high-pressure gas pipelines, which transport natural gas from the trunk network to industrial centres, power plants or distribution networks in accordance with the provisions of legislation and regulations. The operating pressure of these pipelines depends on whether they belong to the primary network, which operates at a pressure higher than 60 bar, or to the secondary network with a pressure level between 16 and 60 bar.

3.1.26 Sweden

➢ Swedegas AB [49]

The Swedish trunk network spans from Dragör in Denmark to Stenungsund, located just north of Gothenburg, covering a distance of over 600 km, which includes branch lines. This network facilitates the transport of natural gas from the Danish North Sea and Germany through Denmark into Sweden. Swedega is responsible for the gas network that extends from Dragör to Stenungsund and incorporates approximately 40 measuring and control stations along its route. The pipes within the network are designed and inspected to withstand a gas pressure of 80 bar. Initially, the line has a diameter of DN600 from Denmark to Helsingborg, after which it reduces to DN500 mm until reaching Gothenburg. Finally, from Gothenburg to Stenungsund, the line narrows down to DN400.

Swedegas also reports a total of 40 transmission pressure regulation and/or metering stations in their grid.

3.1.27 Switzerland

➢ Swissgas [50]

The transit gas transport system in Switzerland comprises a main pipeline that stretches from Wallbach at the German-Swiss border to Griespass at the Swiss-Italian border. Additionally, there is a branch pipeline originating from the French-Swiss border at Oltingue, which connects with the main pipeline at Lostorf. Through this system, the Swiss natural gas network is interconnected with the natural gas networks of Germany, France, and Italy. Moreover, the transit gas transport system serves as the foundation for significant regional transport pipelines that extend into eastern Switzerland, the Swiss Plateau, as well as central and western Switzerland. Currently, imported natural gas flows only in the north-to-south direction via Germany or France. However, a reverse flow mechanism is scheduled to be implemented in 2018. This will allow natural gas to be transported through the transit gas transport pipelines in the opposite direction, from south to north.

Swissgas, owing to its shareholding in Transitgas AG, possesses transport capacities within the transit gas pipeline. These capacities facilitate the transfer of natural gas to the transport pipelines of regional companies, as well as the transit of gas from the French border (Oltingue) or the German border (Wallbach) to the Italian border (Griespass). Swissgas operates 260 km of this grid.

➢ Transitgas AG [51]

The Transitgas transport system comprises a network of natural gas pipelines spanning 292 km, featuring numerous tunnels, a compressor station equipped with waste heat recovery plants, a metering station, and various slide-gate valve stations. During the expansion of the Transitgas transport system between 1997 and 2003, a connection to the French gas grid was established. The 36 in pipeline enters Switzerland near Rodersdorf and traverses primarily from west to east across the Swiss Jura, covering approximately a distance of 55 km, before reaching the existing pipeline system at the Lostorf station. In Seewen, another metering station is linked to the Swiss gas industry exit, allowing the withdrawal of natural gas for the Swiss market.

The current pipeline system consists of a 131.7 km of 48 in pipeline and a 160.7 km 36 in pipeline, with pipe wall thickness ranging from 11.9 to 35.3 mm. It spans from north to south, crossing the Swiss Plateau and the Alps, and connects to the French natural gas grid in the western region. With the implementation of reverse flow, the gas supply becomes more flexible, enabling operation from south to north and in other potential directions.

Two parallel pipelines originating from Germany pass under the Rhine and terminate at the pig reception station of the Wallbach metering station. Each of these pipelines has a diameter of 36 in. From the station, two 36 in pipelines run in parallel to the Däniken station, where one of them transitions from 36 to 48 in diameter. Continuing in a southerly direction, both pipelines reach the Ruswil compressor station. Along the route, eight Swissgas exit metering stations are connected, allowing the withdrawal of natural gas for the Swiss market.

The Ruswil compressor station serves as the exit point for one 48 in pipeline, which subsequently reaches the pig and slide-gate valve station in Entlebuch. In close proximity, the earlier 34 in pipeline runs parallel and terminates at the pig gate in this station. This pipeline acts as an intermediate storage facility, capable of containing the quantity of natural gas released during decompression in the Ruswil compressor station.

The 48 in pipeline continues its course towards the south, crossing a significant portion of the Alps until it reaches the Grieshorn Massive, where it enters Italian territory through a tunnel situated at an altitude of 2,400 meters. In Upper Valais, another Swissgas exit metering station is connected, allowing the withdrawal of natural gas for the Swiss market.

The southern route from Ruswil encounters various mountain ridges, including the Brienzer Rothorn, Grimsel, and Grieshorn, which had to be overcome. In total, the pipeline system comprises 14 passable tunnels spanning a combined length of 37.4 km, with cross-sections ranging between 9 and 12 m^2. One side of the tunnels accommodates the pipeline, while the other side serves as a control passage. Some tunnels include sloping sections with lengths between 95 and 760 m, featuring gradients ranging from 41% to 85%.

Along the entire natural gas pipeline, remote-controlled slide-gate valves are installed at maximum intervals of 15 km, enabling the cutoff of gas flow when necessary.

➢ Gasverbund Mittelland [52]

Gasverbund Mittelland operates a 568 km transport grid with 101 transport facilities among valve nodes and pressure regulation stations.

➢ Erdgas Ostschweiz AG [53]

Erdgas Ostschweiz's grid spans a total length of 607.5 km, with pipe diameters between 4 and 28 in. There are plans for further expansion in the coming years. Depending on the pipeline section, the maximum permitted operating pressure ranges up to 70 bar. The high-pressure network is interconnected with the terranets BW GmbH network in the north, the Energienetze GmbH network in the east, and the transit gas pipeline in the west. To draw and measure the contractually agreed quantities of natural gas from upstream systems, Erdgas Ostschweiz AG operates two customs metering stations. Additionally, they have approximately 65 pressure reduction stations that supply natural gas to customers' transmission and distribution networks.

➢ GAZNAT SA [54]

The Ruswil compressor station plays a crucial role in the transportation of natural gas from northwestern Switzerland through the Transitgas gas pipeline. Its purpose is to compress the gas for injection into the network in western Switzerland, operating at a pressure of 80 bar.

The high-pressure gas pipeline network used to transport natural gas to the Gaznat-served area spans nearly 600 km, operating at 70 bar. The diameter of the tubes in this network varies between 10 in and 24 in. These tubes are welded together and buried with a minimum covering of one meter of ground. To prevent corrosion, the entire network is insulated using polyethylene or bitumen, and a cathodic protection system is implemented. Valve nodes, serving as sectioning or safety posts, are strategically placed approximately every 20 km to allow for flow interruption if required.

An undefined number of pressure reduction stations is reported, including the following devices: pressure regulators, flow meters, volume correctors, safety valves and other kind of valves, filters, data processing and transmission devices.

3.1.28 The Netherlands

➢ Gasunie Transport Services B.V. [55]

Gasunie Transport Services operates transmission networks consisting of pipelines and facilities, divided into a high-pressure grid (HTL) and an intermediate-pressure grid (RTL). The HTL is further divided into networks for transporting Groningen gas (G-gas) and High Calorific gas (H-gas), which are connected via blending stations where different combinations of H-gas and nitrogen are blended and injected into the G-gas network. The HTL network includes several compressor stations to increase gas pressure for further transport. The RTL is primarily supplied from the G-gas HTL through metering and pressure control facilities (M&R stations). No specific details of the grid could be collected from this TSO.

➢ BBL Company V.O.F. [56]

BBL Company operates the BBL pipeline, which runs for 235 km between Balgzand in the Netherlands and Bacton in Great Britain. The pipeline has an hourly capacity of 20,600,000 kWh/h for forward flow (NL -> GB) and 7,000,000 kWh/h for reverse flow (GB -> NL). As of 18 July 2019, the BBL pipeline has been operational and is prepared to transport gas physically from Great Britain to the Netherlands. BBLC offers 7 GWh/h physical reverse flow capacity throughout the year, allowing shippers to take advantage of differences between GB and Dutch gas prices in both directions. The BBL pipeline has a daily capacity of 494 GWh for Forward Flow and 168 GWh for Reverse Flow.

The BBL pipeline operates at 137 bar and it has installed 4 compressor station with a total capacity of 92 MW.

3.1.29 Ukraine

The main TSOs in Ukraine are NaftoGaz and UKrTRansGaz. No reliable and detailed information could be found about their grid. We guess that the information too sensitive because Ukraine is involved in the middle of a military conflict and natural gas assets are being a target.

A recent report [57] on the national energy sector explains that the gas transmission system in Ukraine has a total length exceeding 38,000 km and interconnections with EU member states such as Poland, Slovakia, Hungary, and Romania. The GTS has a total capacity of 281 bcm/year at entry points and 146 bcm at exit points. In 2021, Ukraine's GTS facilitated the transit of 41.6 bcm of Russian natural gas to Europe. However, starting from May 2022, the volume of Russian gas transit through Ukraine to the EU decreased by approximately 30% due to the interruption of gas flow through the "Sokhranivka" gas metering station, which is located in a territory temporarily occupied by Russia. Consequently, from May to August 2022, gas transit through Ukraine decreased to 40-42 mio m^3/day or 37-38.5% of the capacity contracted by Gazprom (109 mio m^3/day). Russian hostilities resulted in damage to approximately 200 km of gas pipelines and equipment. Despite these damages, the Ukrainian TSOs have expressed their readiness to increase transit volumes to the EU via the "Sudzha" gas metering station (with a capacity of 77-244 mio m^3/day), while Gazprom reduced its transit volumes.

Regarding natural gas production, Ukraine possesses the third-largest proven reserves in Europe, estimated at around 719 bcm. The largest reserves are located in regions such as Poltava, Kharkiv, Lviv, and the Black and Azov Seas. In 2021, there were approximately 560 licenses issued and 25 large companies operating in the oil and gas exploration and production sector, including three state-owned enterprises and 22 companies with Ukrainian and foreign investments. Over the past 20 years, Ukraine's natural gas production has averaged around 20 bcm/year. The main production regions are Poltava and Kharkiv (excluding territories temporarily occupied by Russia before February 24, 2022), accounting for approximately 90% of the total production. However, after February 24, 2022, around 20% of the country's natural gas reserves came under Russian occupation, leading to the suspension of more than 150 gas production facilities, primarily in the Kharkiv region. As a result, average daily production decreased by almost 11% (49 mio m^3/day).

In terms of underground gas storage (UGS), Ukraine boasts the largest UGS facilities in Europe and ranks third globally, after the United States and Russia. There are 13 UGS facilities in Ukraine with a total working gas storage capacity of 31.95 bcm/year. The maximum gas injection and withdrawal capacities exceed 250 and 260 mio m^3/day, respectively. Most UGS capacities are situated in Western Ukraine, accounting for 25.32 bcm/year (79%). However, following the hostilities, one UGS facility in the East (with a capacity of 0.42 bcm/year) was suspended, and another UGS facility in the central part of Ukraine (with a capacity of 0.31 bcm/year) was damaged. Consequently, approximately 8% of UGS capacities are currently unavailable.

3.1.30 UK

➢ National Grid [58, 59][1][2]

National Grid owns the gas transmission system in Great Britain, consisting of approximately 7,660 km of high-pressure pipelines, currently operated at pressures of up to 94 bar. This TSO reports also 618 above-ground facilities. Among them, 24 compressor stations with a total installed capacity of 1.128 MW can be highlighted.

➢ TSOs in North Ireland [32]

Operating on behalf of the four TSOs in the area, the Gas Market Operator for Northern Ireland (GMO NI) manages the natural gas transmission market in Northern Ireland. The TSOs involved are GNI (UK) Ltd (a wholly owned subsidiary of Gas Networks Ireland) and Mutual Energy (MEL), representing its relevant subsidiaries: Premier Transmission Limited (PTL), Belfast Gas Transmission Limited (BGTL), and West Transmission Limited (WTL).

Northern Ireland has four transmission pipelines:

1. The Scotland to Northern Ireland Pipeline (SNIP) spans 135 km (nominal diameter of 24 in), connecting Twynholm in Scotland to Ballylumford. Premier Transmission Limited, a part of the Mutual Energy Ltd. group of companies, owns the SNIP. It was completed in 1996.

2. The Belfast Gas Transmission pipeline (BGTP) is a 26 km long DN600 pipe with a MOP of 75 bar that links the SNIP to the North West Pipeline. It also supplies gas to the Belfast distribution network. Belfast Gas Transmission Limited (BGTL), another Mutual Energy Ltd. subsidiary, owns the BGTP.

3. The North-West Pipeline (NWP), with a nominal diameter of 18 inches, connects to the BGTP at Car-rickfergus and extends an additional 112 km to Coolkeeragh Power Station. GNI (UK) owns and operates the NWP, and the Firmus Energy distribution network connects several towns to it.

4. The SNP pipeline, with a nominal diameter of 18 inches, was built in 2006. It connects to the NWP at Ballyalbanagh, Co. Antrim, and extends 156 km to Gormanston, Co. Meath in ROI. Through the Fir-mus Energy (Distribution) Limited (FeDL) distribution network, the SNP supplies towns from Newry to Belfast and includes an offtake supplying the PNGL distribution network. The pipeline facilitates supplies into the NI Network via GNI's Interconnector 2 (IC2) by booking capacity and placing nominations at the South North IP Entry Point and through the ROI transmission system.

The gas transmission system in Northern Ireland, referred to as the NI Network, begins at Moffat in Scotland, where the GNI (UK) network connects with the National Grid's National Transmission System (NG NTS) in Great Britain (GB). This connection enables the seamless importation of gas from GB to NI. The GNI (UK) owned Scottish Onshore System (SWSOS) includes a compressor station at Beattock, connected to Brighouse Bay by two pipelines capable of operating at 85 bar.

At Brighouse Bay, a second compressor station compresses gas for transport through two sub-sea interconnectors, which Gas Networks Ireland (GNI) utilizes to transport gas to the Republic of Ireland

[1] https://www.nationalgas.com/document/139131/download
[2] https://www.nationalgas.com/open-data-requests

(ROI) at pressures exceeding 140 bar if necessary. The pressurized gas also feeds Gormanston Phase 2 Above Ground Installation (AGI), which is part of the NI Network and connected via the South North Pipeline (SNP).

Before reaching the Brighouse Bay compressor station, an offtake station at Twynholm supplies gas to Northern Ireland through the Scotland to Northern Ireland Pipeline (SNIP). The SNIP pipeline operates at a Maximum Operating Pressure of 75 bar. While there is no dedicated compressor station for the SNIP alone, PTL has the contractual ability to request and pay for elevated Twynholm inlet pressures above the contractual guaranteed supply pressure of 56 bar.

3.2 Overview of public information

3.2.1 National overview

The data collected in section 3.1 have been summarised in this subsection to provide an overview of the current status of the national grids in Europe. The different tables in Annex I show the data collected for each TSO gathered into their corresponding country.

The total length of the transport pipelines in Europe adds 258,968.98 km. As shown in Figure 1, around 60 % of this length is of an unknown diameter. Nominal diameters above 20 in are the most common with percentages over 6-10%, while those below 20 in are slightly less used, but still present. Figure 2 depicts the pipelines length in each European country classified by their nominal diameter in inches. The data from Table 11, Table 12, Table 13, Table 14 and Table 15 (Annex I), gathering information about each TSO grid, have been used. France, Germany, Italy and Ukraine have the longest grids (over 35,000 km each), followed by Hungary, Norway, Poland, Romania, Spain and UK with grids longer than 5,000 km. On the whole, the individual countries follow the general trend regarding the distribution of pipeline diameters.

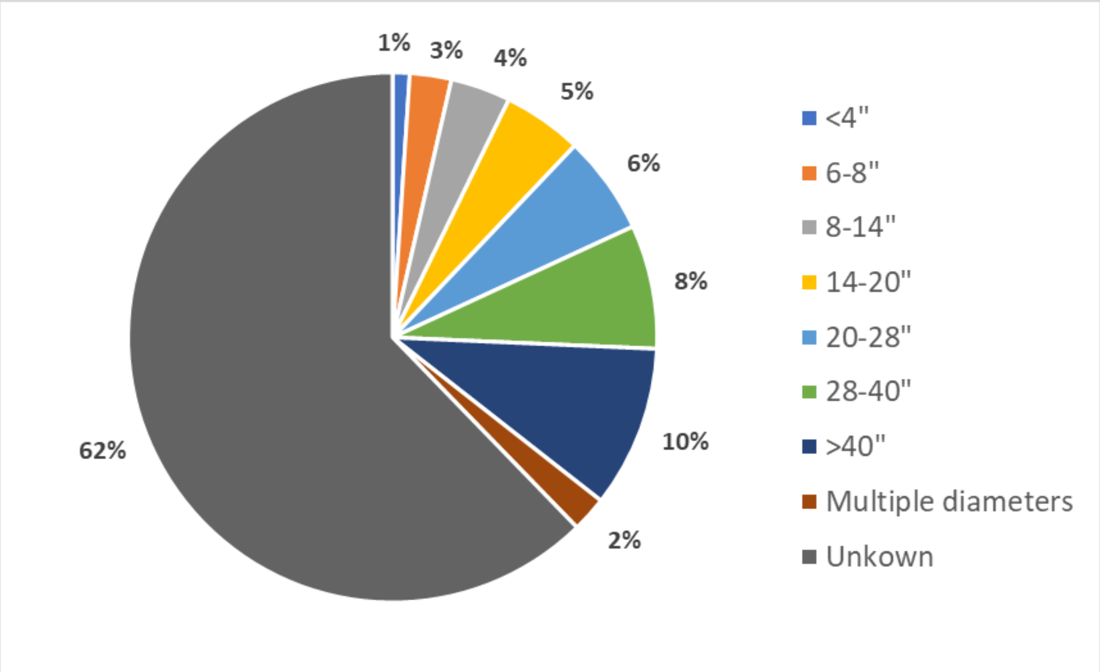


Figure 1. Distribution of nominal diameters in inches of the pipes in the European grid as percentage of the total length

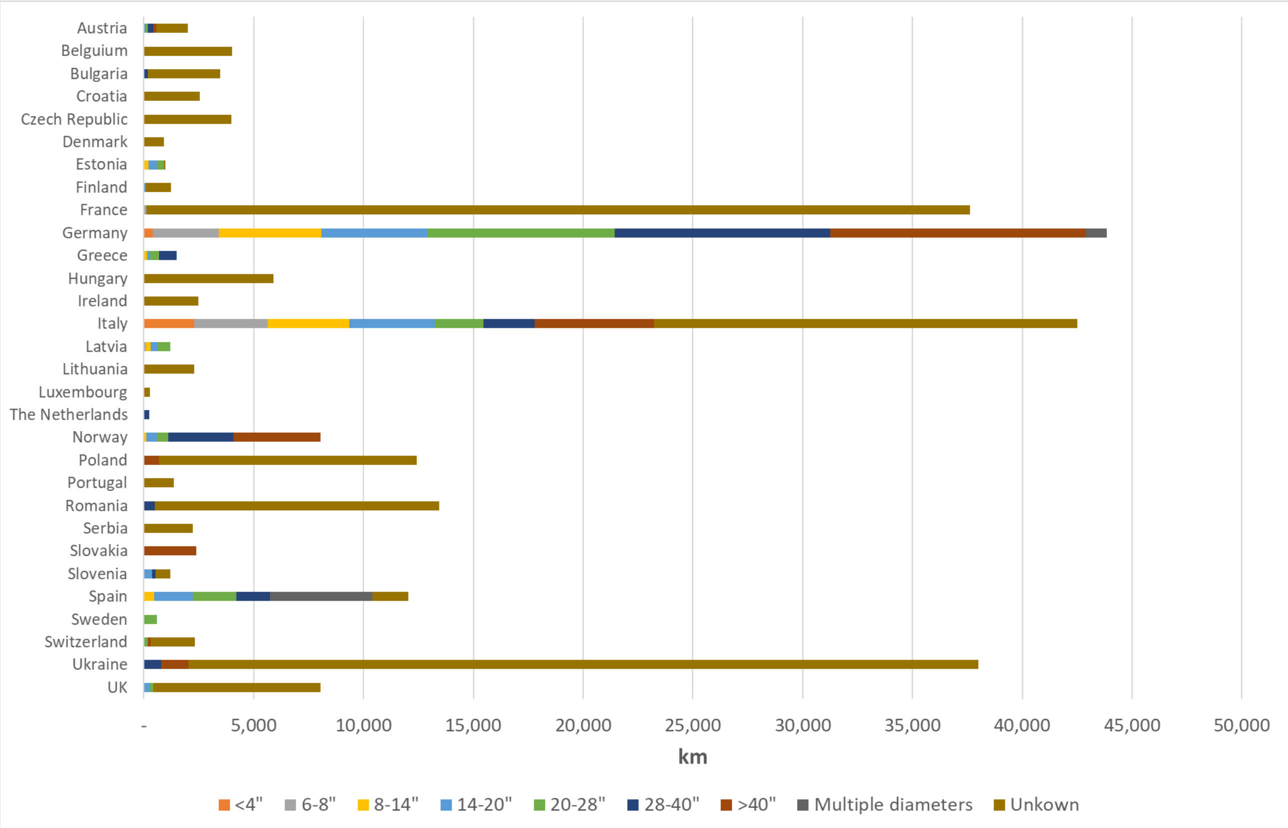


Figure 2. Length of the grid of individual European countries classified by nominal diameter

As happens with the pipe diameter, the installation period of 73 % of the European pipes is unknown (see Figure 3). From the known grid, the most common installation periods are before 1975, between 2001-2005 and between 2016-2020. The detailed information for each national grid is depicted in Figure 4. countries with the longest grids (i.e. France, Germany and Ukraine) don't provide information about the installation period of their pipes, except for Italy. The same happens with other countries with short grids, such as Belgium, Bulgaria, Estonia, Finland, Hungary, Ireland, Portugal, Serbia, Slovakia, Slovenia or Sweden. It seems that the installation period is something that is not usually registered by TSOs, or at least it is not considered relevant to be made public or it is necessary to keep it confidential. On the whole it can be seen how old and new pipes cohabitate in the grid and certain lengths of pipelines are periodically reinstalled. The numerical data can be seen in Table 16, Table 17, Table 18, Table 19 and Table 20 in Annex I.

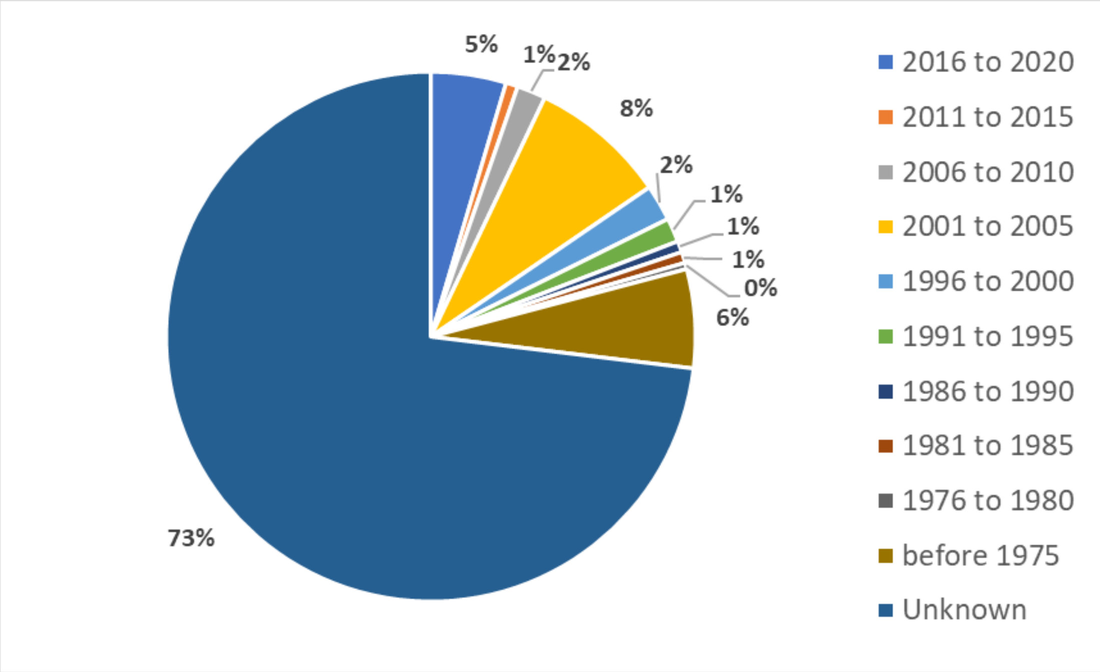


Figure 3. Installation timeline of European pipelines as percentage of the total length installed

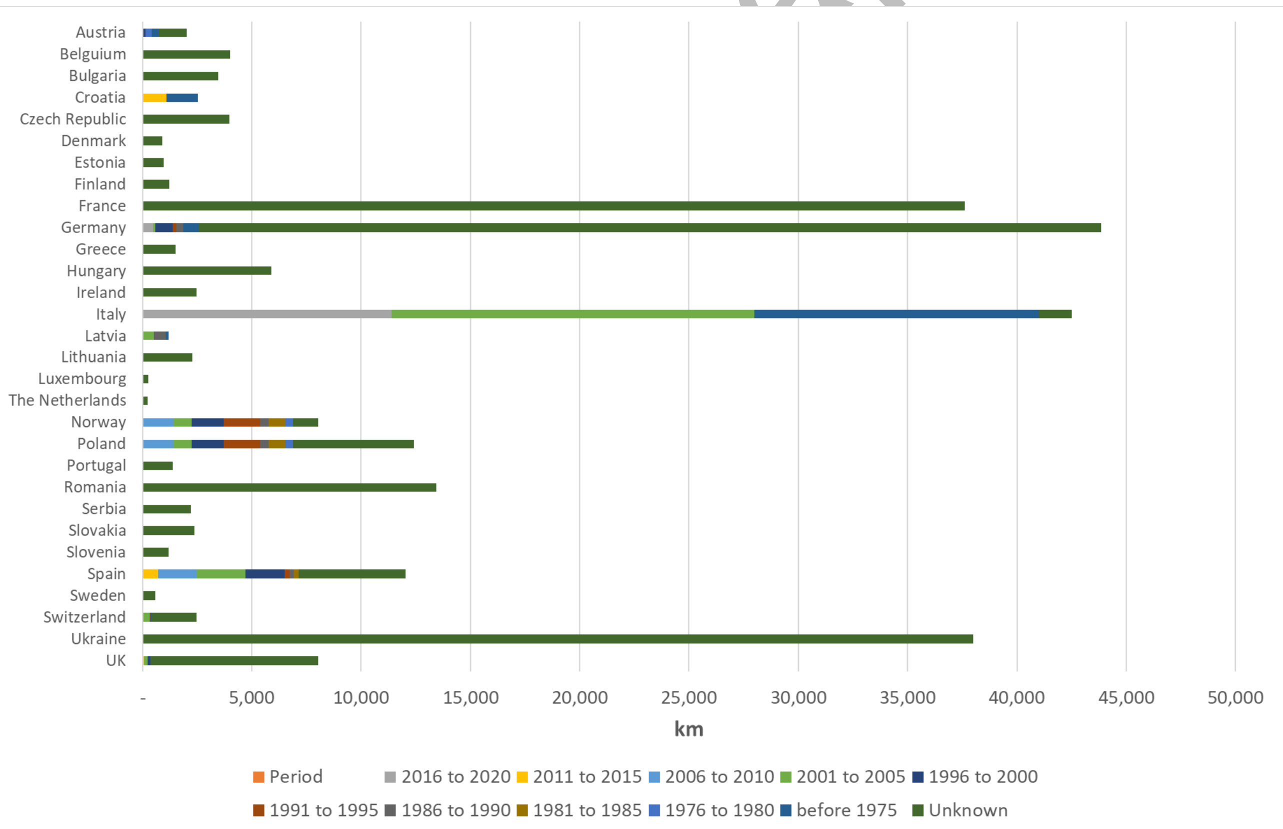


Figure 4. Installation timeline of national pipelines: length installed in different year intervals

Finally, the Maximum Operating Pressure of the grid is even less known that the installation period. As shown in Figure 5, the MOP of 83% of the total European pipes is unknown, making it difficult to achieve accurate percentages for the known grid. Having a close view into the national grids (Figure 6), basically most of the grids are operated at 70-85 bar (such as those in Spain, Slovakia, Switzerland, Czech Republic or Luxembourg), but there is an important part of the grid operating at 40 bar (Romania). The latter is a country with an important transit grid operating at lower pressures. More information about MOP in European grids can be found in Annex I (Table 21, Table 22, Table 23, Table 24 and Table 25).

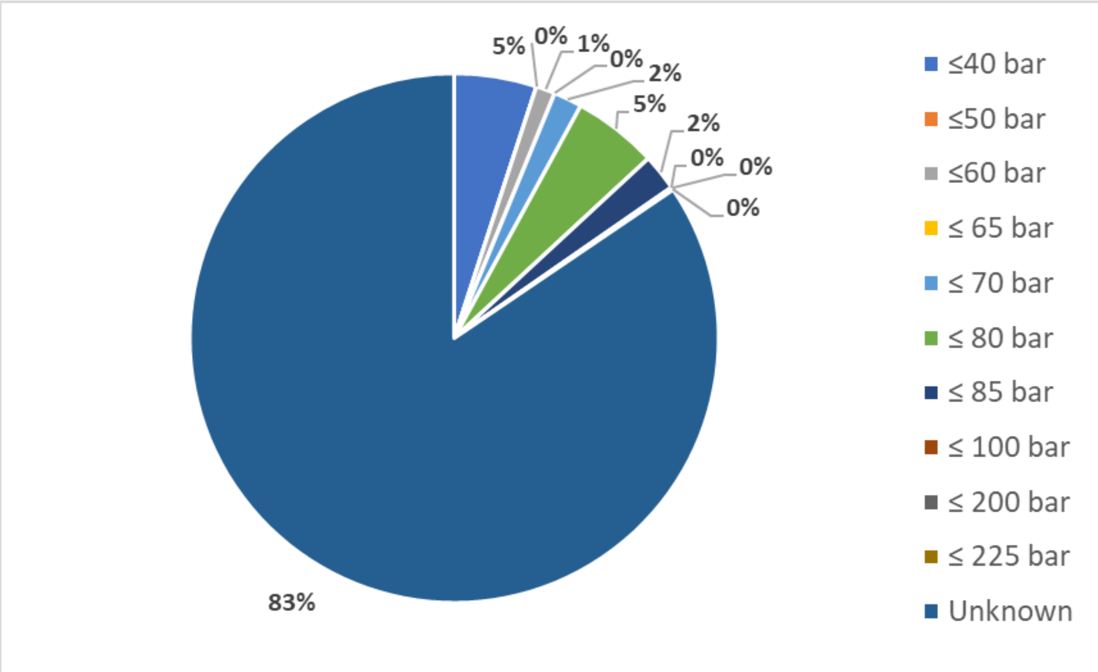


Figure 5 Distribution of MOP in bar of the pipes in the European grid as percentage of the total length

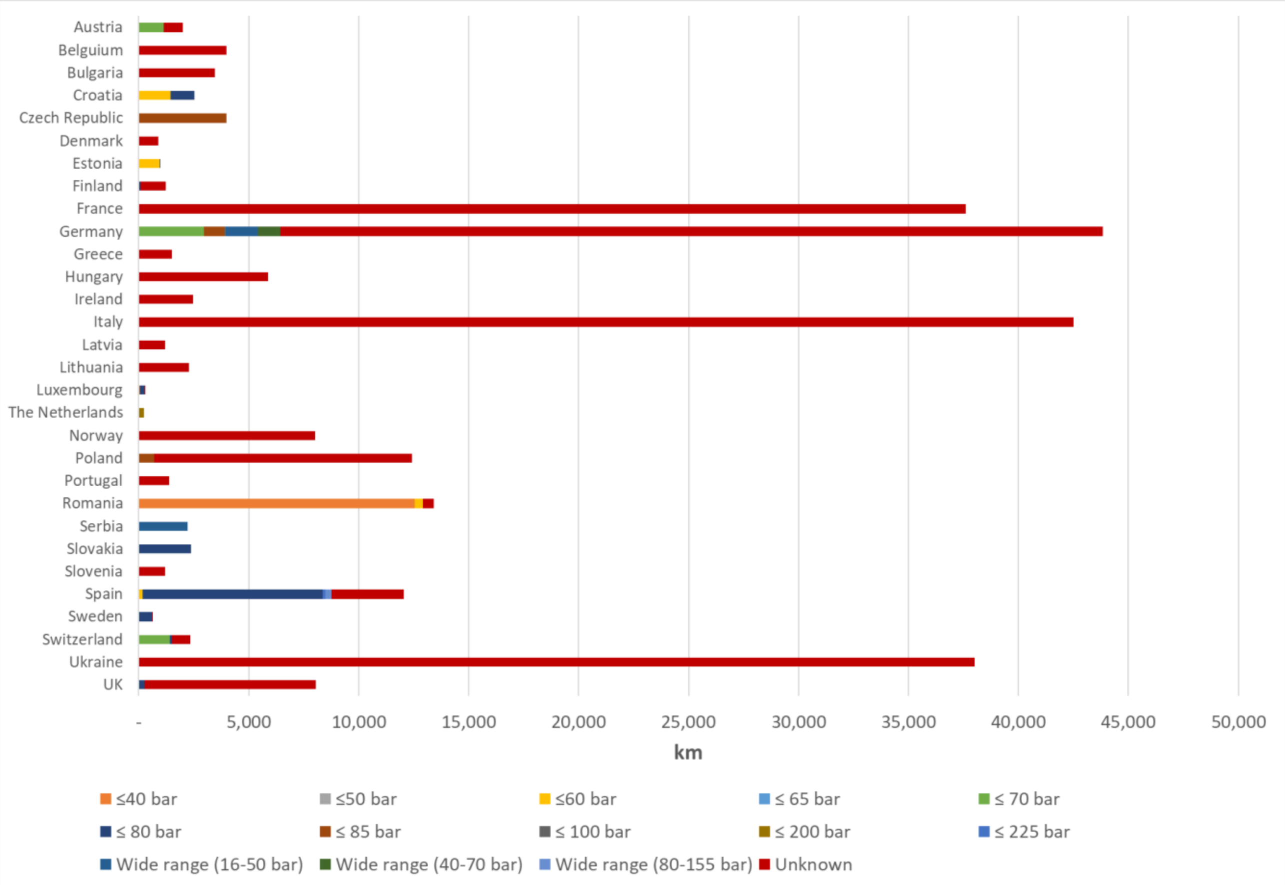


Figure 6 Length of the grid of individual European countries classified by MOP

The status of European transport facilities is collected in Table 26, Table 27, Table 28, Table 29 and Table 30 of Annex I. The results are also depicted in Figure 7 and Figure 8. The number of compressor stations (and their installed power) is coherent with the length of each national grid shown in Figure 1 for some countries. This way Germany and Ukraine report over 70 stations, meaning a frequency of 1.9 stations every 1,000 km of grid. A similar frequency can be found for Spain. Other countries with long grids (Italy or France) report, however, fewer stations in comparison (0.3-0.8 stations every 1,000 km of grid), which may indicate that some information is missing in open databases. It is curious the data from UK, where 3.2 stations can be found every 100 km of grid. More detailed information can be found in the literature in the case of Germany in a report from FNB Gas. [60]

Other kind of facilities can be found in Figure 8, where valve nodes, pressure regulation and/or metering stations, exit points (including connection to industrial customers) and entry points are depicted. The information is, however, not enough to reach proper conclusions.

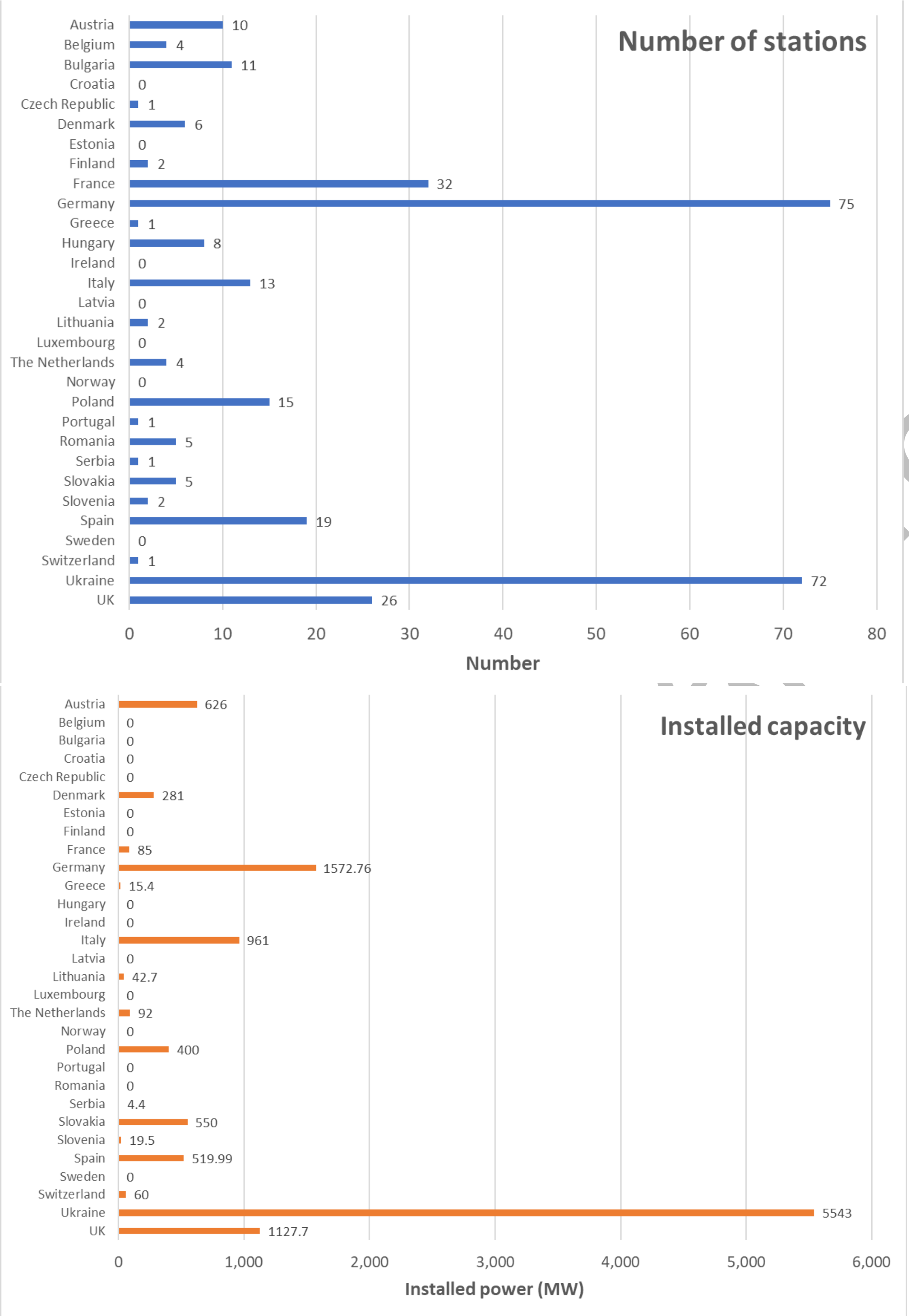


Figure 7. Number of compressor stations (top) and their installed capacity (bottom) in the different national grids in Europe

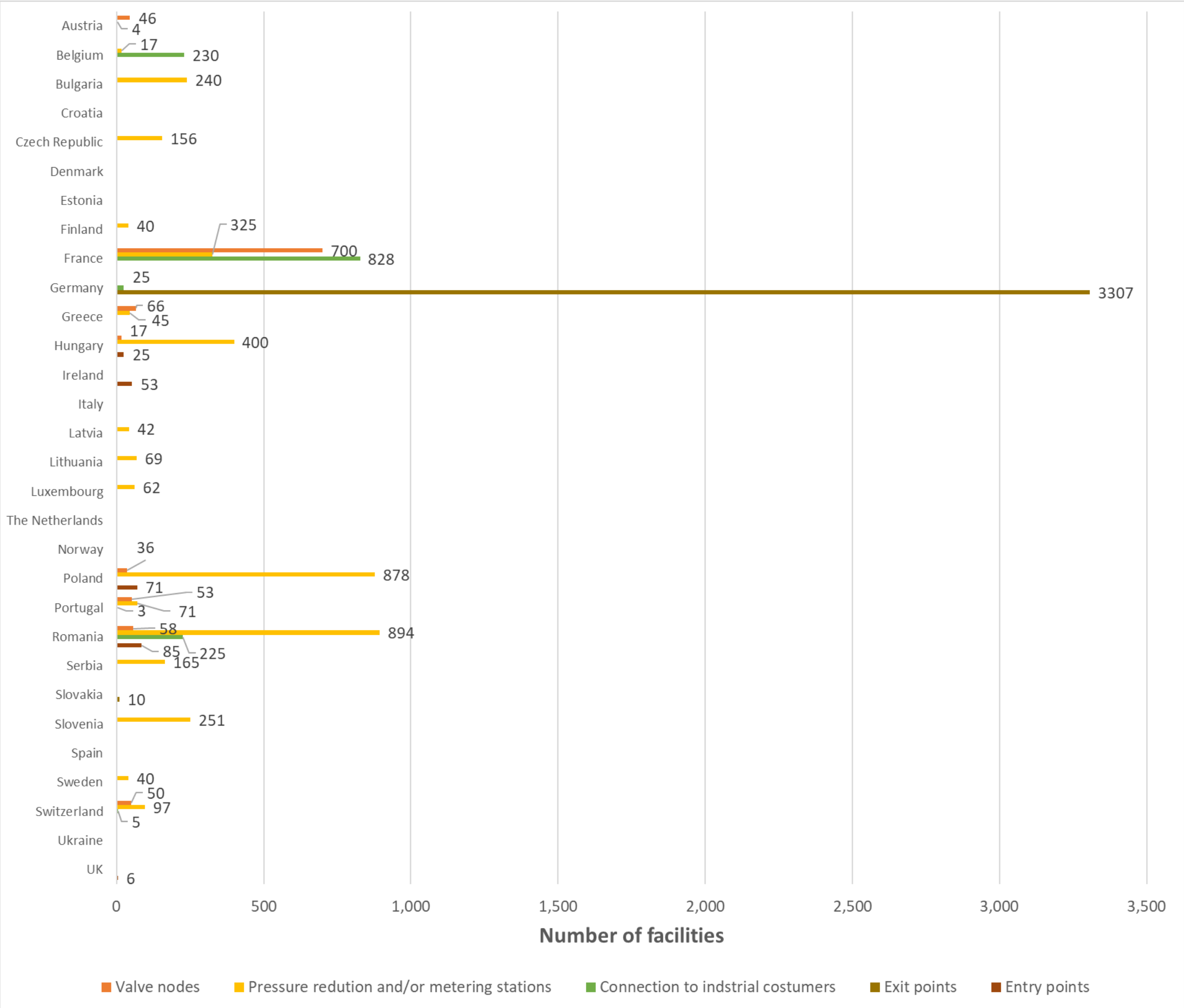


Figure 8. Number of transmission facilities in the different European countries (valve nodes, pressure regulation and/or metering stations, exit points (including connection to industrial customers) and entry points

3.2.2 Overview in clusters

The information shown in section 3.2.1 has been gathered into geographic clusters. The countries considered in each of them are defined in Table 2. This methodology (already defined in D2.3) has been followed to protect the confidentiality of the information provided by those TSOs that have contributed to section 3.3, because this way the information of companies that are single operators in one specific country dilutes itself within one region. The same proceeding is applied in this section to allow the comparison between the public and confidential collected data afterwards.

Table 2. Countries included in each geographic clusters defined for this report

South Europe	Western Europe	Middle Europe	Northern Europe	Eastern Europe
Spain	France	Germany	Norway	Ukraine
Portugal	UK	Poland	Denmark	Romania
Italy	Ireland	Czech Republic	Finland	Ukraine
Croatia	Luxembourg	Austria	Sweden	Romania
Serbia	Belgium	Switzerland		
Greece	The Netherlands	Lithuania		
Bulgaria		Latvia		
		Slovakia		
		Estonia		
		Slovenia		
		Hungary		

Figure 9 depicts the length of pipes in each cluster as a function of its nominal diameter. Pipes with unknown diameters have been excluded for a better visualisation of the results. Diameters over 40 in are the most spread regardless the cluster, except for Western Europe. In a second term, diameters between 14-40 in dominate the share The result is coherent with the great capacity of the grid. The installation period of each cluster pipes can be seen in Figure 10. On the whole, older and newer grids can be found together in the same cluster. Finally, the MOP of each cluster grid is shown in Figure 11. With the few data available, it seems that most of the grid operates between 70 and 85 bar in all clusters, except for Eastern Europe where there is an important length operating at 40 bar. The numerical data for these figures can be found in Annex I (Table 31)

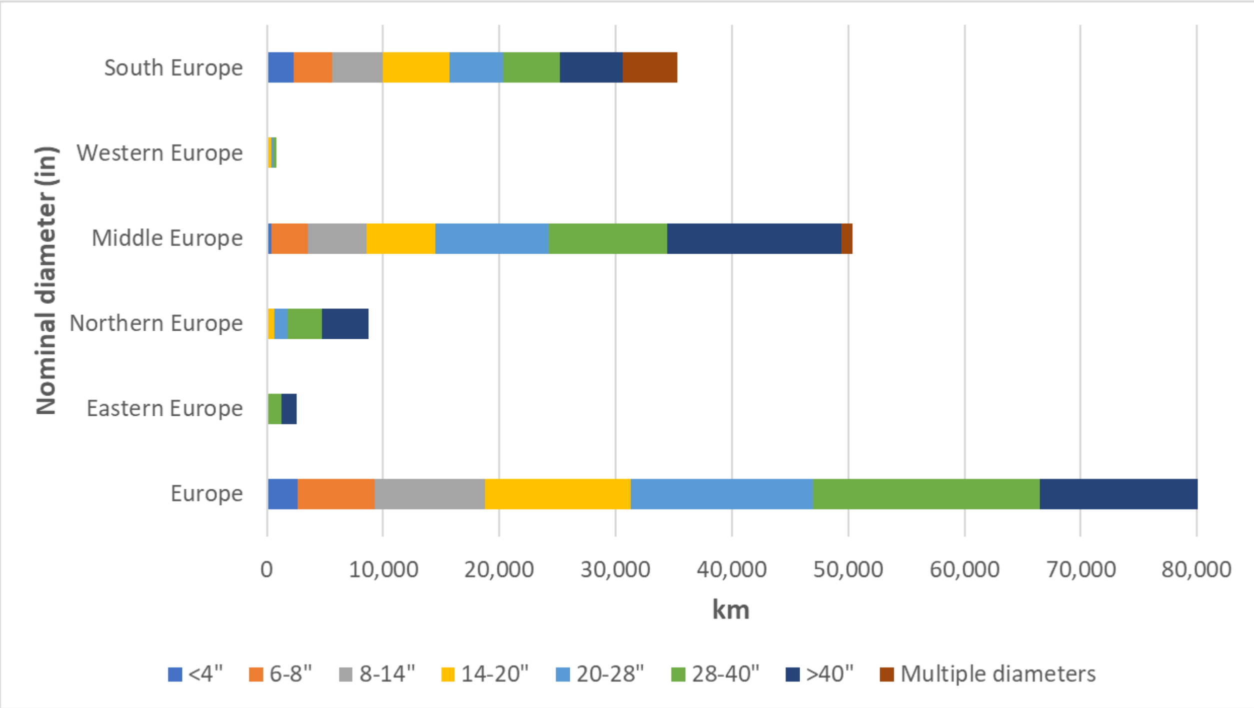


Figure 9. Length of the grid of individual European clusters classified by nominal diameter

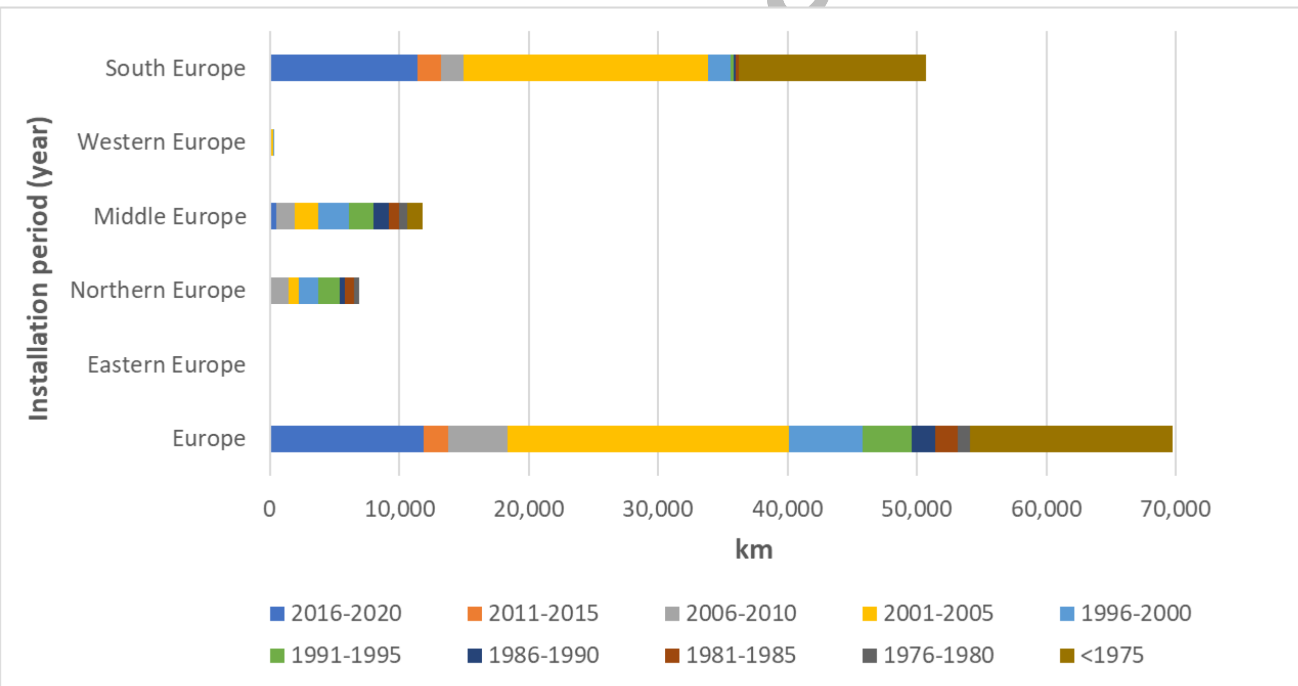


Figure 10. Installation timeline of pipelines in each cluster: length installed in different year intervals

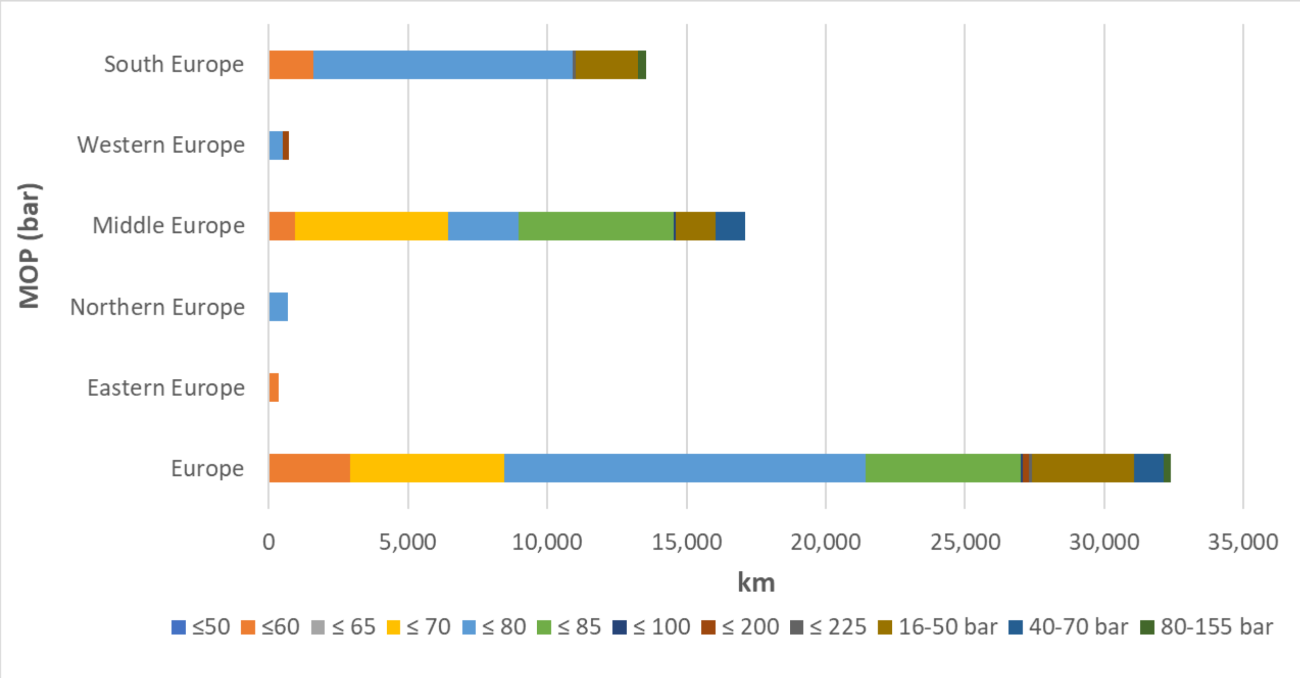
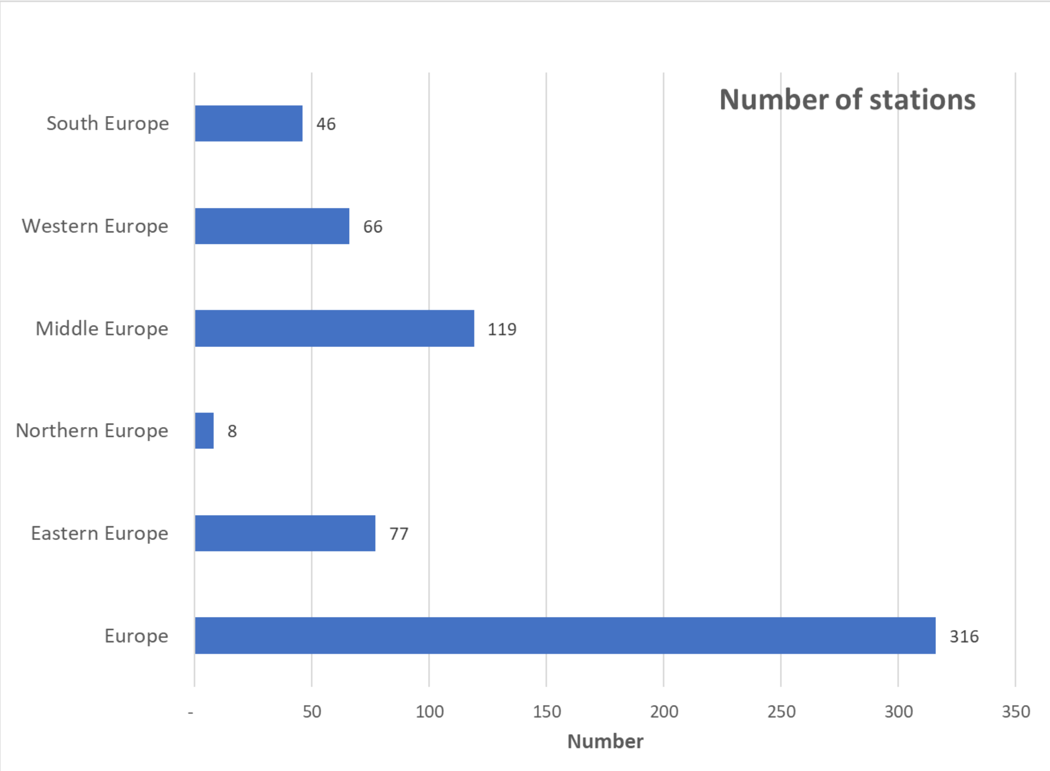


Figure 11. Length of the grid of European clusters classified by MOP

Compressor stations and other transport facilities are also collected into geographic clusters in Figure 12 and Figure 13, respectively. The middle Europe cluster gathers almost half of the compressor stations in Europe and basically double the stations in South and Middle Europe. The tendency is similar for pressure regulation and/or metering stations, but the picture is quite different for the remaining transport facilities (see Figure 13). Most valve nodes and connections to industrial customers have been found for the Western cluster. All exit points correspond to the Middle Europe cluster and the entry points are distributed between relatively equally among the Western, Eastern and Middle Europe clusters. As happened in section 3.2.1, the information gathered is not enough to reach proper conclusions. The numerical information for these figures can be found in Table 32 of Annex I.



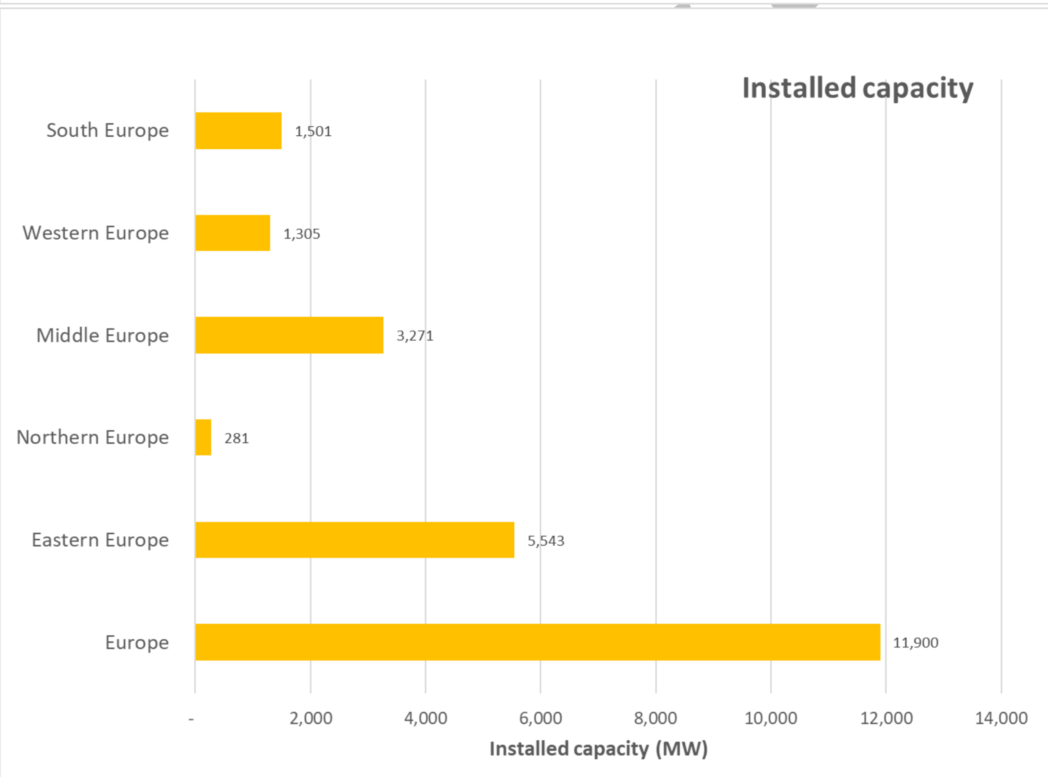


Figure 12 Number of compressor stations (top) and their installed capacity (bottom) in the different geographic clusters in Europe

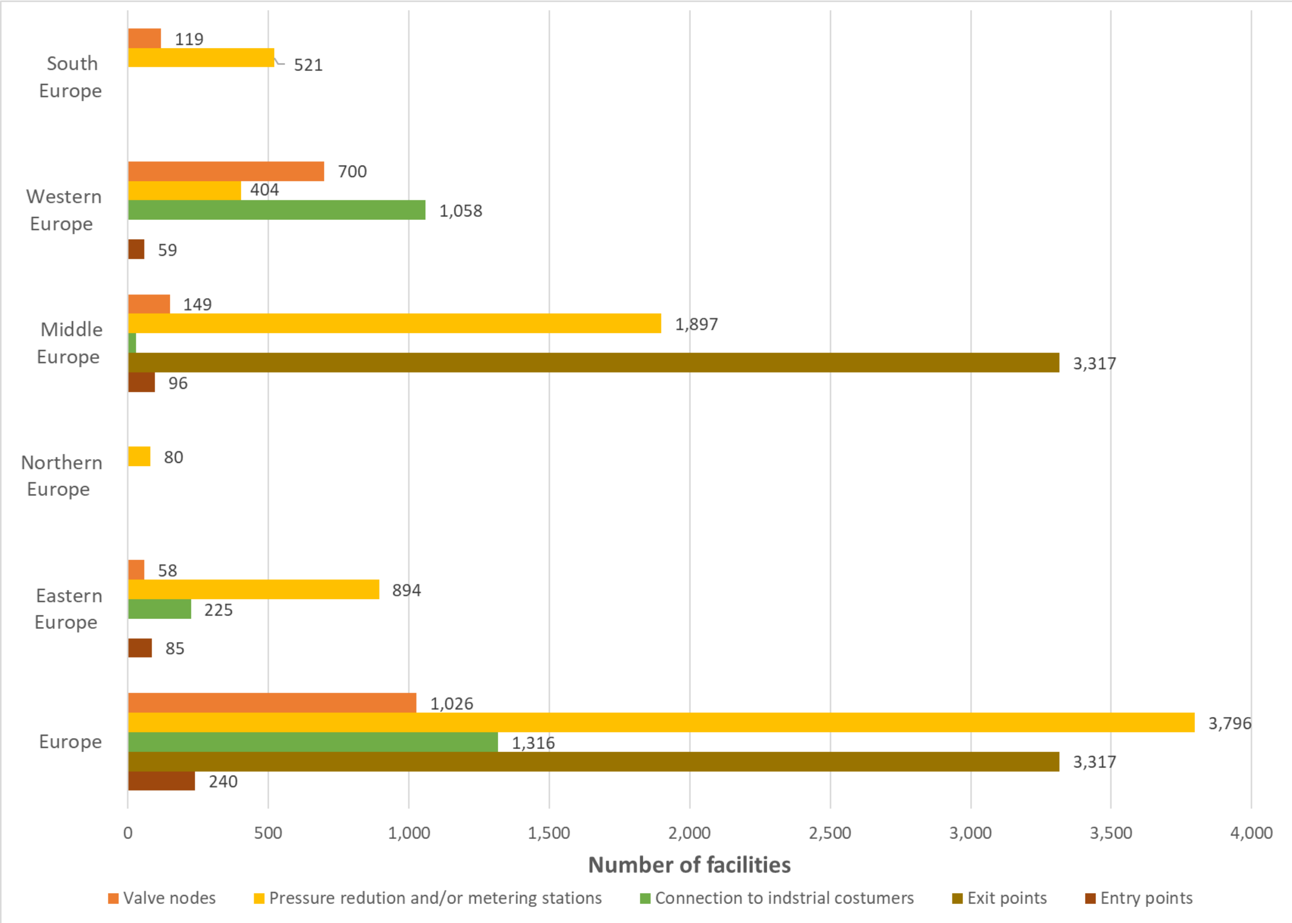


Figure 13 Number of transmission facilities in the different geographic clusters (valve nodes, pressure regulation and/or metering stations, exit points (including connection to industrial customers) and entry points

3.3 Picture of the grid based on confidential information gathered by direct survey

The results provided in this section have already been shown in D2.3. A descriptive picture of the European natural gas transmission grid and its facilities has been compiled by via the conduction of the infrastructure survey mentioned above. The information has been provided by the European TSOs and gas operators associations. The results are gathered into geographical clusters to protect sensitive information, as defined in Table 2. Just one extra contribution from one TSO of the Western Europe cluster could be collected. The results are therefore rather similar to those detailed in D2.3 and the differences affect only to this specific cluster.

The survey has two different parts. Part one is focused on information about pipelines and part two on facilities, installation and equipment. Both are described in depth in the following sections. Noteworthy, the discussion of results has been done using the data received. The representativity of the conclusions stated may not be completely accurate for those clusters in which size of the grid is bigger than the data achieved with the survey.

➢ Pipelines

Detailed information of almost 73,000 km of the European transmission gas grid has been collected (see Figure 14). The main part corresponds to Middle Europe with more than 45,000 km, followed by South Europe (near 14,000 km). Western Europe and Northern Europe contribute to these numbers with over 12,000 and 600 km, respectively. Unfortunately, no information about Eastern Europe could be gathered. The information collected about the pipelines considers their size, material, coating used, installation period and maximum operating pressure (MOP). All these properties will be discussed afterwards.

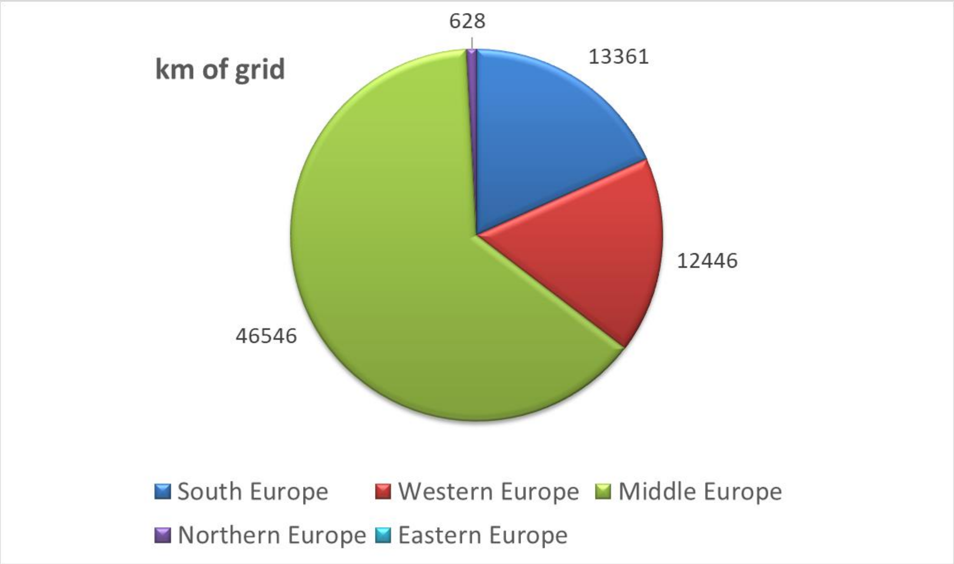


Figure 14. Total length of transmission pipelines collected in through the surveys

Steel material

The information collected from the different institutions that contributed to the survey was converted into the American nomenclature (API 5L), when necessary, to achieve comparable results. Figure 15 depicts the steel quality used in the different European clusters. The numerical data can be found in (Table 33). According to this information, a wide range of steel qualities from API 5L Gr A to Gr X80 are being used in Europe.

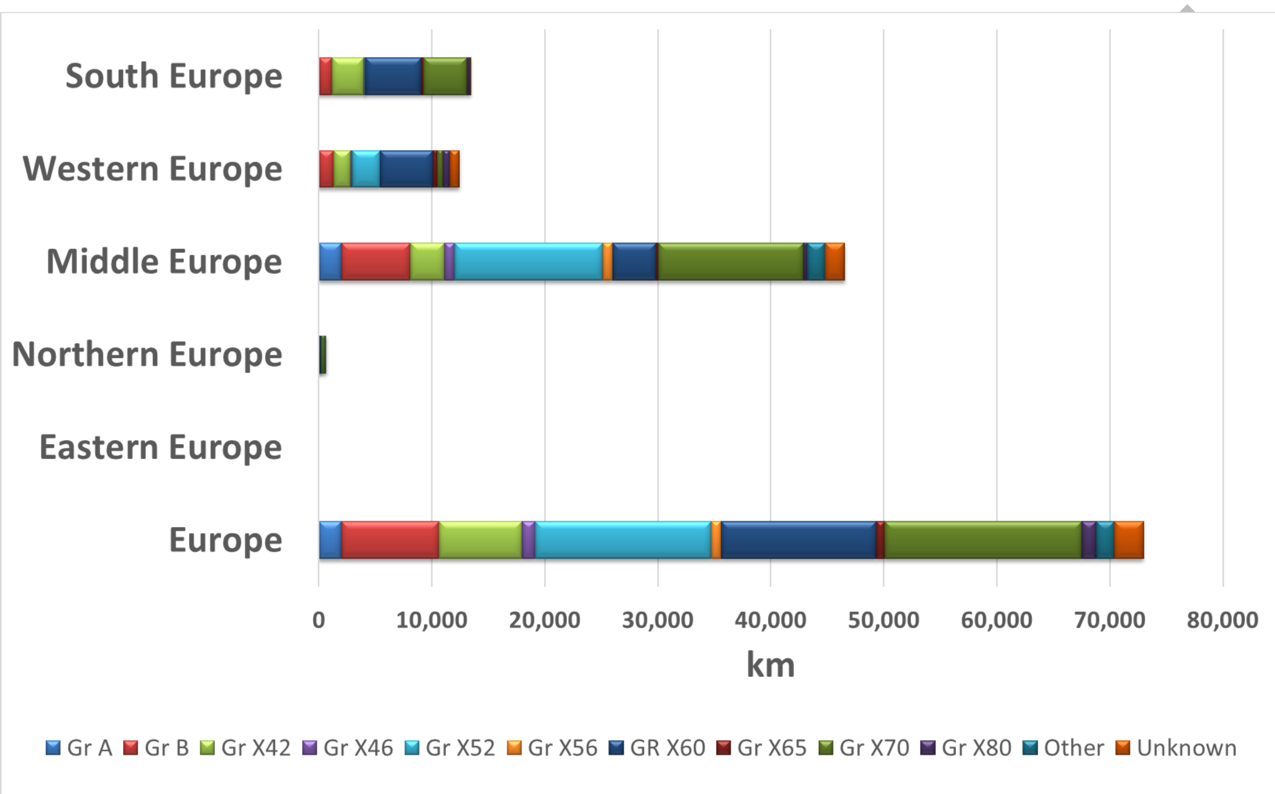


Figure 15. Distribution of the steel quality for the different clusters studied.

As depicted in Figure 15, some steel materials are more common in the European grid, i.e. API 5L Gr B (11.8 % of the grid collected), X42 (10.0 %), X52 (21.4%), X60 (18.8 %) and X70 (23.9 %), of which high-steel qualities (over X52) are used twice as frequently. Focusing on the different clusters, different tendencies in each region can be observed. The X70 quality is the most common in Middle Europe cluster (28.0 % share for both), and especially in the Northern Europe cluster, being used in 52.0% of the grid. It is also quite relevant in South Europe with 28.4 % of share. In Western Europe, the previous quality X60 is, however, more common (37.5 % of the pipes). Lower qualities (i.e. X42 and X52) are also common in South, Western and Middle Europe (20-28 % of the grid), while they are rather unusual in the Northern cluster.

Diameter

The length of the pipelines collected where also classified according to their outer diameter (OD) in inches. The results are displayed in Figure 16 as total length for each cluster and the whole Europe. The numerical data can be found in Annex II (Table 33). Considering the whole continent, more than half of the pipes are between 11 and 30 in nominal diameter. 33.3 % of the pipes in the European transmission grid have diameters between 11 and 20 in OD, while 22.5% of them are between 21 and 30 in.

Looking into each specific cluster, it can be seen how South Europe, Western Europe and Middle Europe follow a similar tendency than the whole of Europe. However, in Northern Europe, the great majority of pipes (63 %) have an outer diameter of 11-20 in.

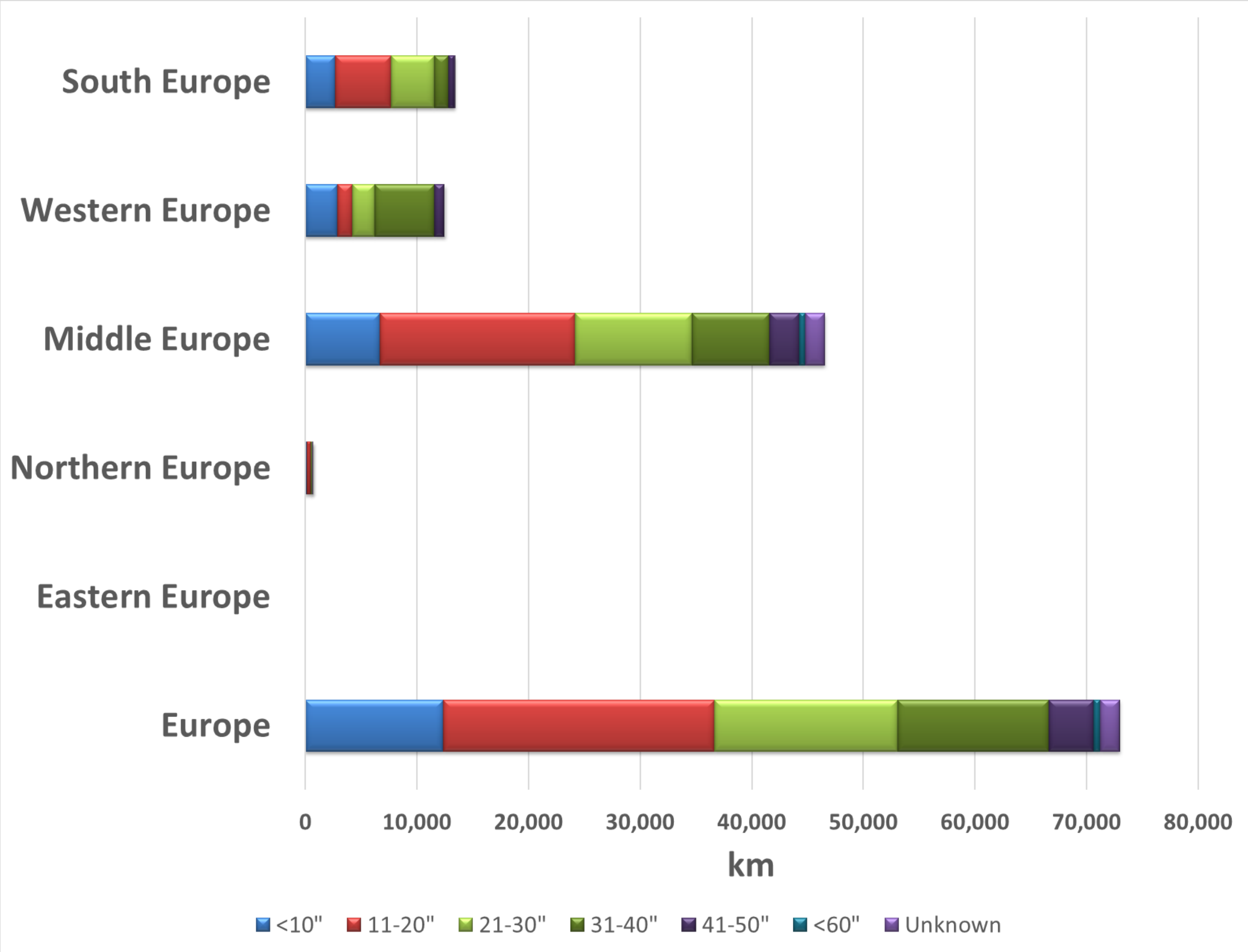


Figure 16. Diameter of the European transmission grid pipelines

Maximum Operating Pressure - MOP

The pipelines collected in the different countries have also been classified in accordance to their maximum operating pressure (MOP) in service. The results for each geographic cluster and the whole of Europe can be seen in Figure 17. The numerical data can be found in Table 33. When considering Europe as a whole, it can be seen how there are two different pressures dominating, since MOP <59 bar and <80 bar share almost one third of the length of the grid collected. The next most common MOP would be < 70 bar, with 19.1 % of the grid length. The "equilibrium" between <59 bar and <80 bar is imposed by Middle Europe, which leads the tendency due to the major contribution to the total grid length in Europe. However, other clusters do not show this symmetry. In the case of South Europe, MOP <80 bar is predominant with 80 % of the grid length, followed by <59 bar with 16 %. In Northern Europe, MOP<80 bar is also dominant. In Western Europe, most of the grid operate between 70 and 85 bar. The results make sense because peripheral countries are typical entry points of natural gas in Europe and their grid are operating at higher pressures and are composed of steels of high quality. Central countries are usually the final step of the natural gas transport chain, and the operating pressures of the grid can be lower.

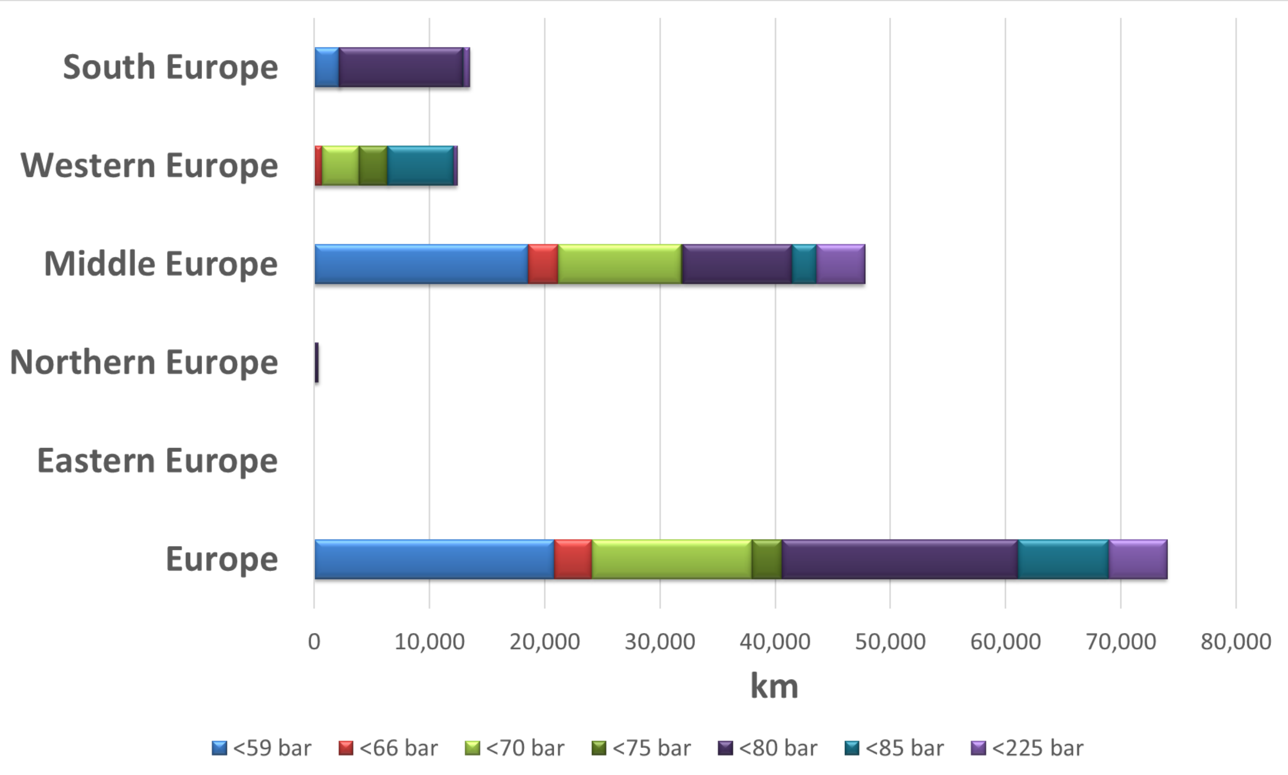


Figure 17. MOP of the transmission European grid pipelines

Welding material

For the case of welding materials, it has not been possible to prepare a quantitative review because of the lack of accurate numerical values of the length of pipes welded with a certain PQR (i.e. Procedure Qualification Record). Nevertheless, the information gathered allows to show in a qualitative way the most common materials used in each cluster when available (see Table 3). The results are exactly the same that those in D2.3.

Table 3. Welding materials used in each cluster. When indicated with an "X" this material is used

Welding material	South Europe	Western Europe	Middle Europe	Northern Europe	Eastern Europe
AWS A 5.1-E 6010	X	X	X		
AWS A 5.1-E 7010			X		
AWS A 5.1-E 7016		X	X		
AWS A 5.1-E7018	X	X	X		
AWS A 5.5-E XX10-X	X				
AWS A 5.5-E XX15-X	X				
AWS A 5.5-E XX16-X		X			
AWS A 5.5-E XX18-X	X	X	X		
AWS A 5.5-E XX18M-X	X	X	X		
AWS A 5.17-EH12-X		X			
AWS A 5.18-ER 70S-X		X	X		
AWS A 5.18-ER 70S-1B		X			
AWS A 5.28-ER XXS-X	X		X		

AWS A 5.28-E XXC-X		X	
AWS A 5.28-ER XXS-X			X
AWS A 5.20-E X1T-XG-J		X	
AWS A 5.20-E X1T-XM-J	X		
AWS A 5.29-EXT1-XM-X		X	
AWS A 5.36-EXT1-MX-Ni1J		X	

Outer coating

The coating procedures were also collected with the survey on the inventory of the transmission grid. The most relevant coating materials found are shown in Figure 18 and the numerical data can be found in Table 33.

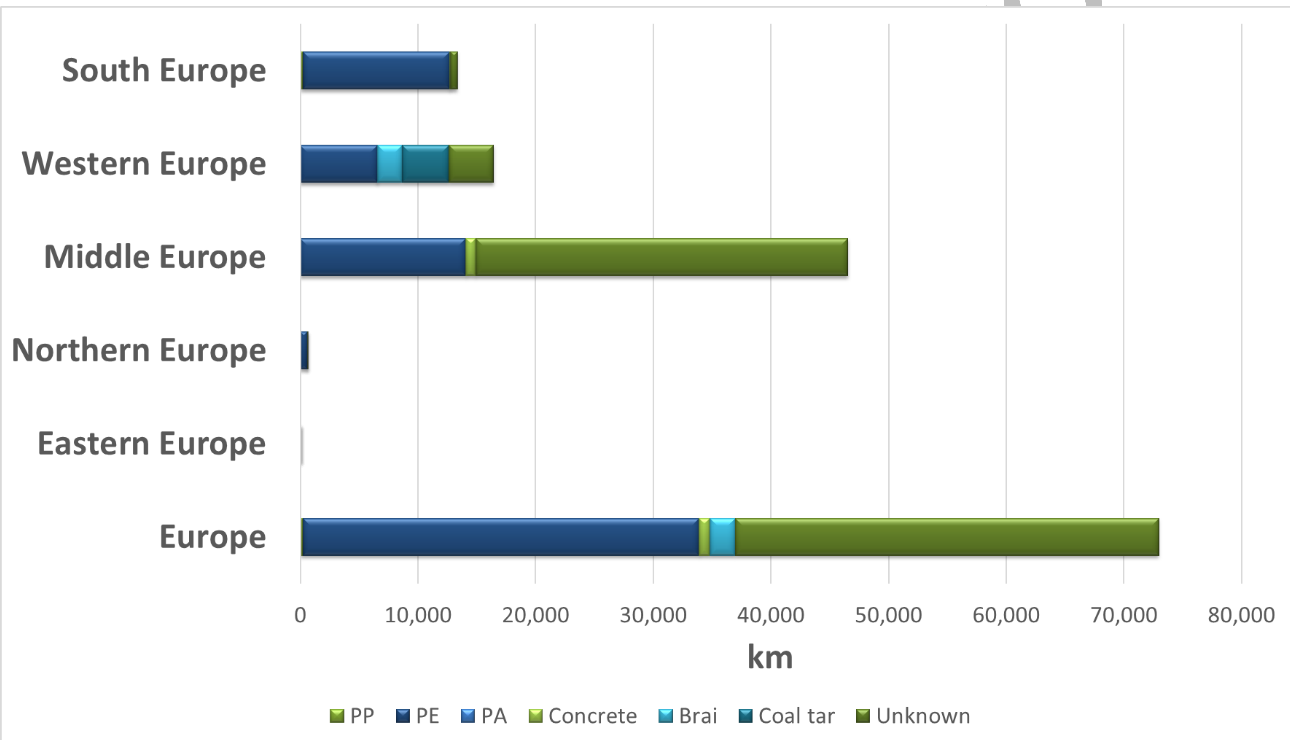


Figure 18. Outer coating materials used in the European transmission grid pipelines.

Basically, there are six materials used for external coating of the pipelines: polymers (such as polyethylene, polyamide and polypropylene), concrete or brai. The use of polyethylene is clearly dominant in each of the clusters (especially in South and Western Europe with more than 90% of the pipes coated in this material), and therefore, in Europe as a whole (46.2 % of the pipes are coated with PE). Besides, in Western Europe there is an important part of the pipes that are coated using Coal Tar (32 % of the pipe length in this cluster) or Brai (17.1 % of the pipes). Unfortunately, the coating material of 68 % of the pipes in Middle Europe was not able to be acquired, meaning that there is no information about the material of the external coating of almost half the pipes in Europe.

Inner coating

Similarly to the outer coating, the materials used for the inner coating of pipelines in Europe was also collected. The results are depicted in Figure 19. The numerical data can be found Table 33.

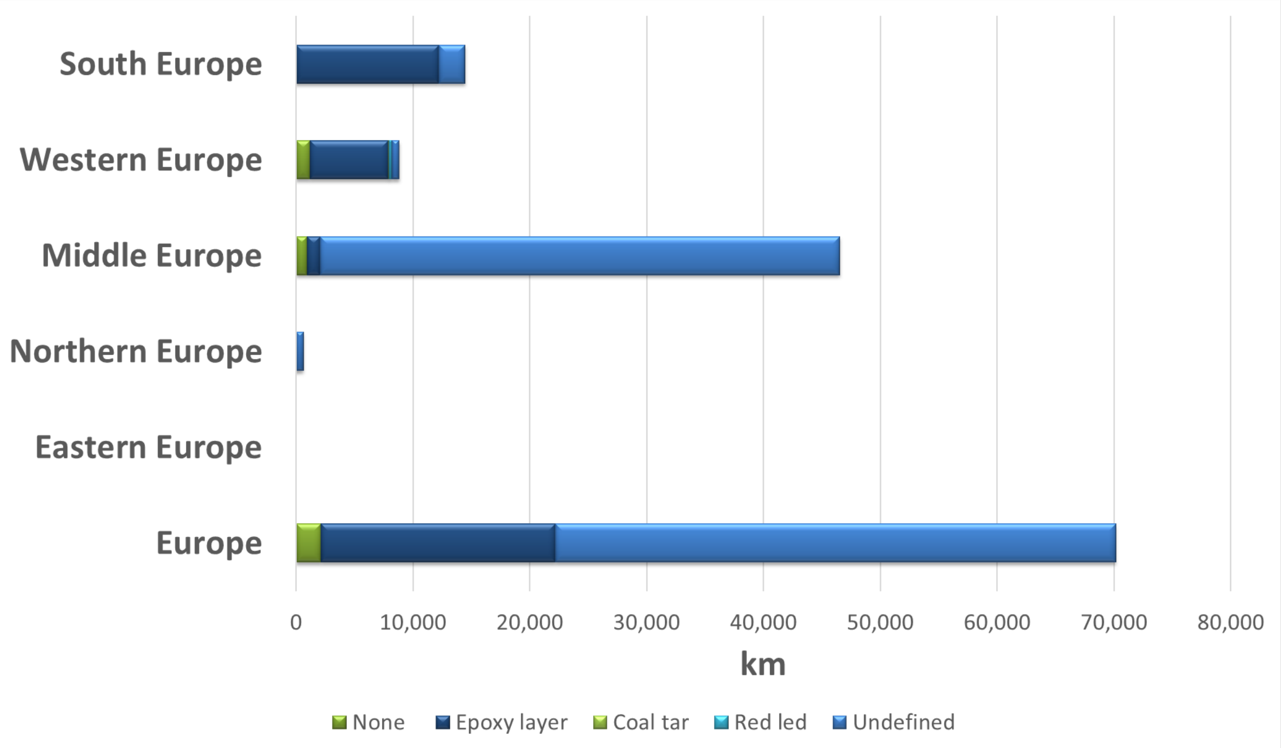


Figure 19. Inner coating materials used in the European transmission grid pipelines.

There are two option available: 1) using epoxy resin as coating material and 2) using no coating at all. Almost 28% of the pipes in Europe are coated internally with Epoxy, while 3 % remain uncoated, according to the data collected. There is, however, 65.7 % of the length in Europe of which no data could be collected. The predominance of the use of epoxy is also clear in South Europe and in Western Europe (91.6% and 54.0 % of the whole pipe length, respectively). Besides, in Western Europe other materials are reported, such as red led.

Installation period

The last goal of the inventory of the gas grid regarding pipelines was tracking the installation period of the different grids in each cluster.

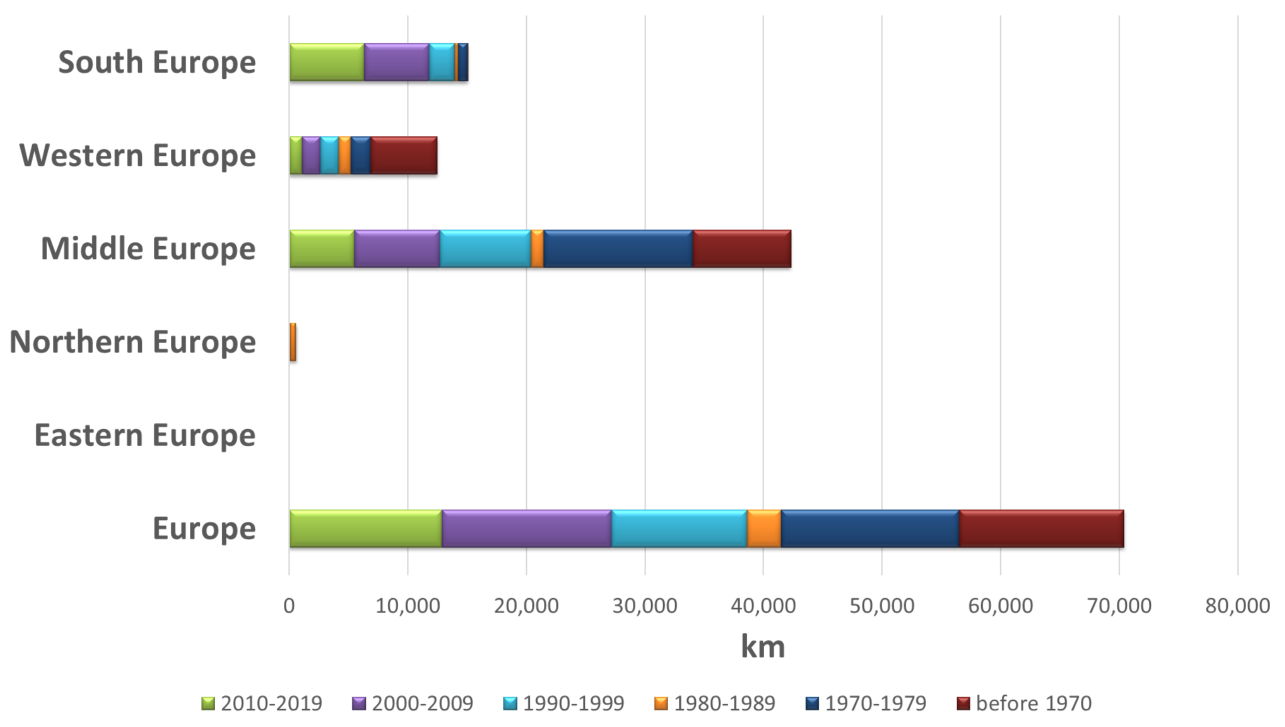


Figure 20. Installation period of pipelines in the European transmission gas grid

The results gathered are shown in Figure 20 as well as in Annex II (Table 34). Looking onto Europe as a whole, the installation periods are quite distributed over the last decades. It can be considered that around 20 % of the grid length has been installed every decade, except for the 1980-1989 period, where only 4 % of the pipes were installed. While Middle Europe follows basically this tendency, the behaviour is different in the other clusters. In South Europe, the grid is relatively new, with 78 % of the pipes installed after 2009. In Western Europe, however, 45% of the pipes were installed before 1970, consequently the grid is much older. The age of Northern Europe with 80 % of its grid installed 1980-1989 falls in between.

The expected year of renewal of the pipelines was also asked in the survey. However, the amount of information gathered was insufficient to draw proper conclusions. It can only be stated that i) 25% of grid installed in Western Europe before 1975 will be replaced by 2030, ii) 76 % of the pipes in Northern Europe will be replaced between 2060 and 2070 and 8 % by 2080 and iii) 5 % of the pipes in Middle Europe will be replaced by 2080.

➢ Facilities

The information gathered about the facilities available in the European transmission grid is divided into three categories: transmission facilities, odorization systems and gas control systems. The results for each of them will be developed in the following.

Transmission facilities

As shown in Figure 21, over 6,700 transport facilities have been collected for the grid, of which 3,748 correspond to valve nodes, 181 to compressor stations, 169 to Pressure Reduction Stations (PRS), 182 to Metering Stations (MS) and 2,427 City Gates (transmission/distribution pressure reduction stations). While PRS and MS can be found with a frequency of around 2,5 items per 1,000 km of grid, that of City Gates is 13 times higher, being the most common facility in the grid. Regarding compressor stations, one stations can be found every 400 km of grid. Valve nodes are the second most common facilities, with over 50 items per 1,000 km of grid. This frequency is calculated dividing the number of items collected by the kilometers of grid according to the data depicted in Figure 14.

Having a close look into each cluster, the proportion of compressor stations is higher in Northern Europe with almost 5 stations per 1,000 km of grid. Middle Europe and Western Europe have the same proportion as the whole continent and South Europe shows 1 unit less (i.e. 1.4 units per 1,000 km of grid). Only South Europe, Western Europe and Middle Europe contribute to valve nodes data. The frequency found in Western Europe and South Europe is similar (60-70 positions per 1,000 km of grid, respectively) and slightly higher than the European case. This frequency is slightly inferior in Middle Europe (43.7 positions/1,000 km grid). The numerical data can be found in Table 35.

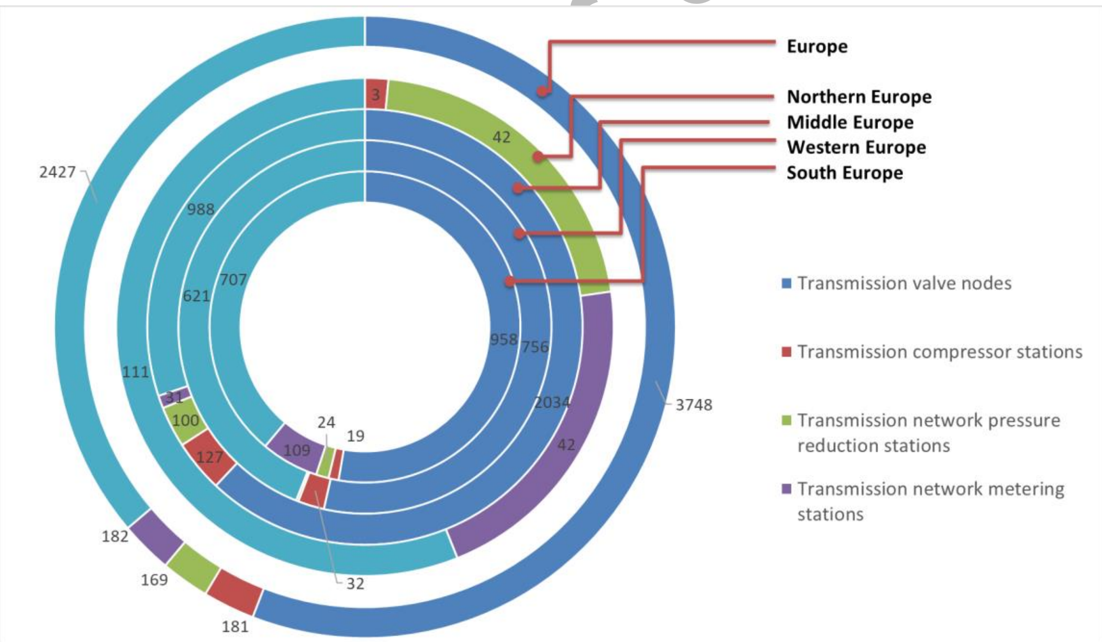


Figure 21. Transmission facilities in the European gas grid

The proportion of metering stations and regulation stations is also very dependent on the cluster. City gates are the more common facilities with frequencies between 20 and 180 positions/1,000 km grid. The heterogeneity in the data for the different clusters may be due to a poor response to some aspects of the survey.

No relevant general conclusions about the hydrogen content these devices can handle could be achieved from the answers to the survey.

Odorization systems

The information about odorization systems that was collected with the survey is displayed in Figure 22. The numerical data can be found in Table 35. No additional information could be collected in comparison to that explained in D2.3.

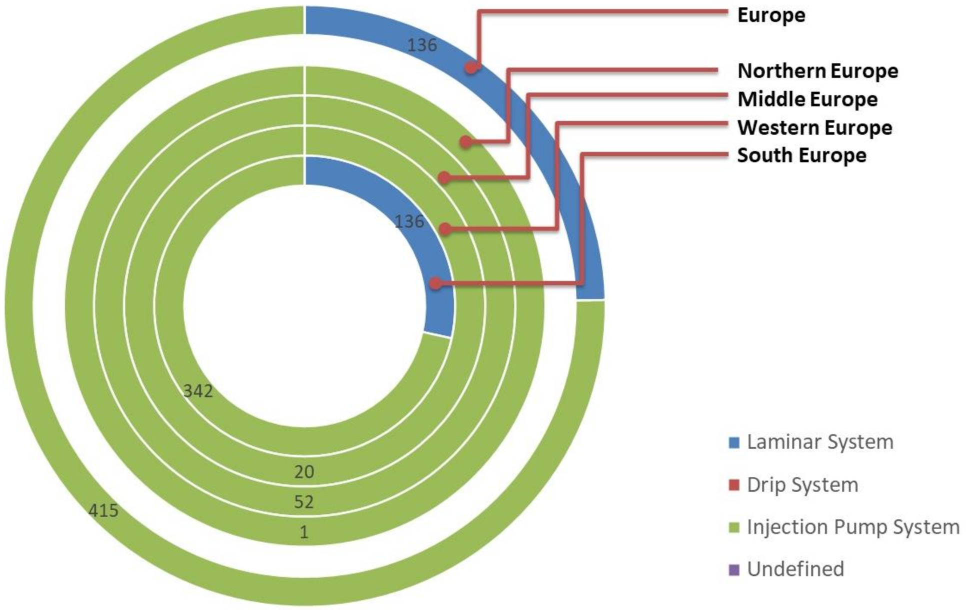


Figure 22. Odorization systems used in the European transmission grid.

A total of 415 injection pump devices and 136 laminar systems were gathered for the whole continent. Most of them belong to South Europe (91 % of the injection pumps and 100 % of the laminar systems). And no drip system was quantified.

Noteworthy THT (tetrahydro-thiophene) was identified as the most common odorant used by European TSOs according to the answers to the survey collected, since South Europe, Western Europe and Northern Europe only report this odorant for their devices. DMS (dimethyl sulphide) and IPM (isopropyl mercaptan) are also occasionally used. A quantitative assessment can, however, not be given.

The hydrogen content these devices can handle could not be achieved from the answers to the survey. The information provided about odorization devices is not much because some of the countries that contribute with the highest length to the total transmission grid do not odorize at transmission level but at distribution level, such as Germany.

Gas quality control systems

Gas quality control systems were divided into quality control systems itself and flow control systems. The units collected for the former are depicted in Figure 23. The numerical data can be found in Table 35.

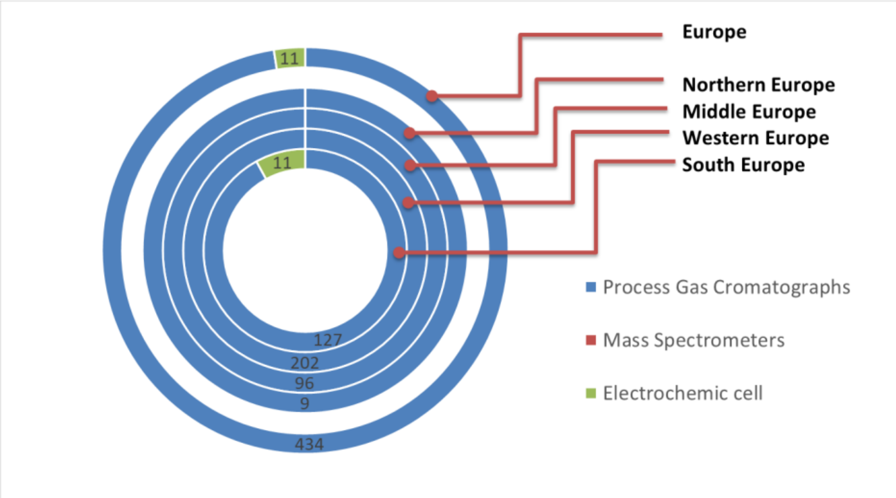


Figure 23. Type of quality control systems used in the European transmission grid.

A total of 445 devices were gathered for whole Europe. This means a concentration over 6 devices per each 1,000 km of grid. Most of them correspond to process gas chromatographs, while only 11 are electrochemical cells. No mass spectrometers were recorded with the survey. Process gas chromatographs are dominant in all clusters and electrochemical cells could only be found in South Europe.

The concentration of quality control systems is higher in South Europe, Western Europe and Northern Europe (10-16 units per 1,000 km of grid), while in Middle Europe is around 2. This means that the information gather for the last cluster is poor and makes the European average decrease to 6 devices per each 1,000 km of grid and may not be representative.

Flow control systems were divided into gas metering systems and gas pressure control systems. The information gathered about both of them is shown in Figure 24 and Figure 25, respectively.

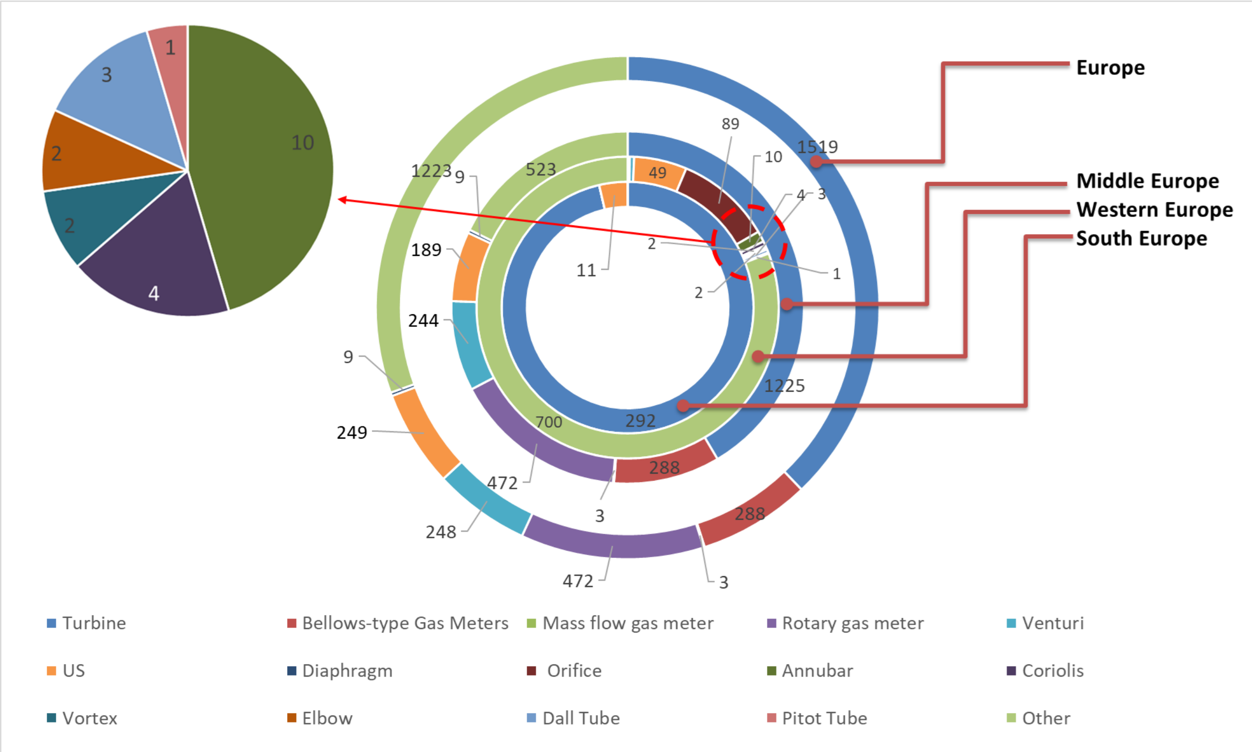


Figure 24. Type of gas meters used in the European transmission grid.

As seen in Figure 24, there are different gas metering systems available in Europe, among which turbine, bellows-type, mass flow, rotary, Venturi and ultrasonic gas meters can be highlighted. Over 4,000 devices were gathered in the whole continent. This is a concentration of 55 gas meters per 1,000 km of grid. Turbine gas meters are the most commonly used devices, with 1,519 units available in the European grid. The second most commonly gas meters are rotary gas meters with 472 devices. Bellows-type, Venturi and US gas meters are equally used (between 7-12 % of the units collected). The technology of almost half of them is, however, not defined. This uncertainty is particularly high in Western Europe and Middle Europe, since the technology used for over 700 and 371 devices reported, respectively, is unknown.

Looking into each cluster in detail, turbine gas meters are the most common devices in South Europe and Middle Europe. Besides, Middle Europe shows the greater variety of devices. Regarding the frequency of gas meters in the grid, Middle Europe shows a similar value to that European (60 gas meters per 1,000 km of grid). However, this amount is the half in South Europe and three times greater in Western Europe. Western Europe also reports different technologies such as Orifice, Annubar, Coriolis, Vortex, Elbow, Dall Tube and Pitot Tube flowmeters, with 89, 10, 4, 2, 2, 3, and 1 unit, respectively.

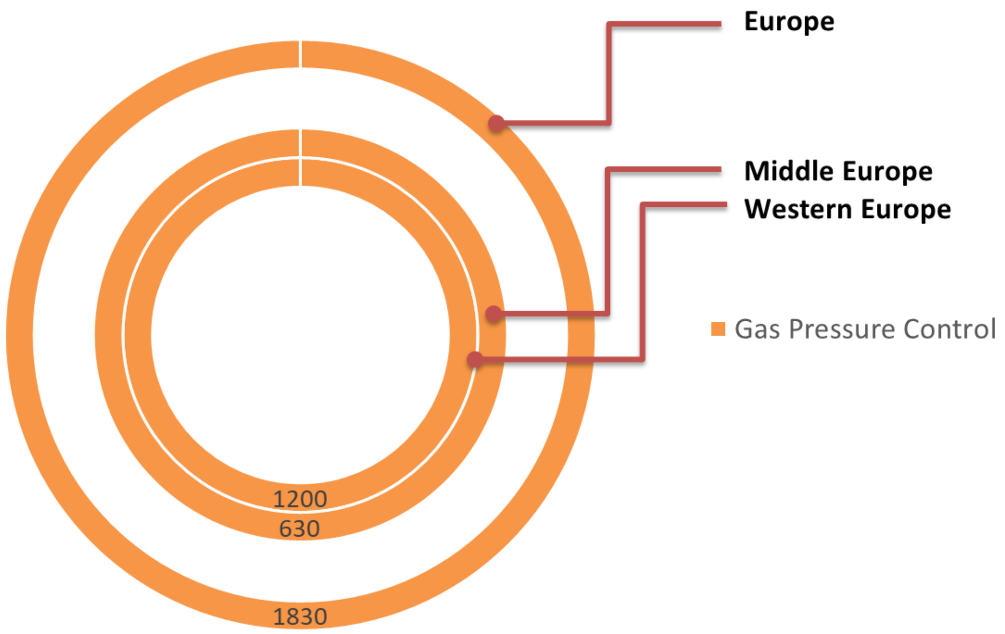


Figure 25. Gas pressure control systems used in the European transmission grid.

Finally, the number of gas pressure control systems gathered for Europe can be seen in Figure 25. Only data for Western Europe and Middle Europe could be collected, resulting in a poor overview of the whole European grid, and no additional information to that already detailed in D2.3 could be added in this report. In Western Europe, 1,200 devices were reported, i.e. a frequency of 250 units per 1,000km of the cluster's grid, of which the most part are membrane regulators. In Middle Europe, the numbers drop to 630 devices (13.5 units per 1,000km of the cluster's grid). The use of flow control systems in the Western Europe cluster seems more popular than in other regions in Europe according to the information gathered. The numerical data can be in Table 35.

No relevant general conclusions about the hydrogen content these devices can handle could be achieved from the answers to the survey.

3.4 Summary of achievements

Table 4 shows a comparison between the length of the existing grid in each geographic cluster (according to the public information collected in sections 3.1 and 3.2 and that collected through the surveys shared with European TSOs and gas associations (section 3.3). On the whole, almost one third of the total European grid has been collected. The South and Western Europe clusters follow basically the same coverage level, while the Middle Europe cluster is the best covered area, with 63% of the grid characterised thanks to the input of TSOs and gas associations. This fact is extremely important because this clusters grid contributes with the longest section of grid to the continent. On the other hand, no information could be gathered for East Europe through this survey.

Table 4. Comparison between length of grid collected though public and confidential information

Cluster	South Europe	Western Europe	Middle Europe	Northern Europe	Eastern Europe	TOTAL
km public	65,640.57	52,648.60	74,270.66	10,758.00	51,430.00	254,747.83
km surveys	13,361.00	12,446.10	46,545.88	628.46	-	72,981.44
% covered	20%	24%	63%	6%	0%	29%

It can be therefore concluded that thanks to this extensive coverage the detailed confidential information can be considered sufficient so that the statements in section 3.3 are relevant for the European transport grid. Additionally, this reinforces the findings of the ongoing experimental campaign in WP4, as the selection of testing items is based on this grid inventory.

The public information gathered in sections 3.1 and 3.2considers 254,747.83 km of transport pipes in Europe. Although a great part of this length has unknown characteristics (over 70%), some useful conclusions can be obtained in any event. Regarding its diameter, nominal diameters above 20 in are the most common (5-8% of the total grid length). Old and new pipes cohabitate in the grid and certain lengths of pipelines are periodically reinstalled, because the year intervals for installation period are manly equally distributed, with slight predominance of the intervals 2016-2020, 2001-2005 and before 1975. Finally, most of the grids operate at 70-85 bar (such as those in Spain, Slovakia, Switzerland, Czech Republic or Luxembourg), but there is an important part of the grid operating at 40 bar (Romania) due to the long transit grid present in this country.

If this public information is compared to that confidential gathered via surveys shared with TSOs and gas associations and collected in section 3.3, a deeper understanding of the European grid can be achieved. A direct comparison of grid length, nominal diameters and MOP can be performed. Comparing Figure 9 and Figure 16 a similar distribution of nominal diameters can be observed. Similar distribution of results can be also found comparing Figure 10 and Figure 20, regarding the installation period of the pipes, and Figure 11 and Figure 17, regarding the MOP in the grid. This fact concludes that the information gathered through the surveys in relevant and it is in line with that provided openly by European TSOs.

The confidential information gathered in section 3.3allows to characterise in depth additional aspects of the pipes, such as their base material and coating. API 5L Gr B (11.8 % of the grid collected), X42 (10.0 %), X52 (21.4%), X60 (18.8 %) and X70 (23.9 %) are the most frequent steel qualities in Europe. The quality of the steel used in the pipes is associated with the operating pressure of the network, higher pressures force the use of higher quality steels (grade) to avoid the use of pipelines with higher thickness. Clusters including a high number of gas inlets to the system (e.g. South

Europe), have a higher quantity of grids operating at high pressures (75-85 bar), and therefore, these clusters are using higher quality steels (API 5L X60, X70) in their grid. Regarding the external coating polymers (such as polyethylene, polyamide and polypropylene), concrete or brai are typical materials that can be found in the grid, with special relevance for polyethylene. In the case of the internal coating, Epoxy resin is the most common material, although there is an important part of the grid that uses no coating at all. This issue is interesting because coating materials can become a mitigation measure when exposing carbon steels to hydrogen.

The transport facilities collected in this report correspond to valve nodes, pressure regulation and/or metering stations, exit points (including connection to industrial customers) and entry points. The public information gathered in section 3.2 report a total of 317 compressor stations, 1,026 valve nodes and 3,796 pressure regulation and or metering stations. This number is insufficient in comparison to the data gathered with the surveys sent to TSOs and gas associations. The confidential information of section 3.3 details 181 compressor stations and 2,778 pressure regulation and or metering stations of all kinds, which means 57 and 73% of the quantities collected by searching in the official TSOs' websites. In the case of valve nodes, the 3,748 facilities reported by TSOs are even superior to the 1,026 found in public databases. It can be stated that information about transport facilities is not easily achievable and needs for the willingness of TSOs to contribute with their own data to tackle studies such as that developed in HIGGS.

4 Hydrogen concentration legally admissible in national grids

Figure 30 in deliverable 2.3 of WP2 shows the permitted hydrogen concentrations in the respective Member States of the European Union at that time (2021). In addition to other individual sources referenced in D2.3, this graph was based on a survey sent mainly to TSOs in the Member States, a publication from ACER, a deliverable from the THyGA project and a MARCOGAZ study. As national hydrogen strategies and regulatory frameworks are changing very dynamically in each country, an update of the allowable hydrogen concentrations in relation to the hydrogen injection potential is provided here in Figure 26.

The basis of this report is the following:

- ACER Opinion No 08/2022 on the review of national gas and hydrogen network development plans to assess their consistency with the EU 10-year network development plan, published on 16 December 2022 and representing the situation in August 2022. Question 4 explicitly asked for the maximum hydrogen concentrations accepted by TSOs in natural gas transmission networks.

- In the framework of WP6, a survey is being carried out among European TSOs, mainly focusing on the admixtures and the future handling of hydrogen at transmission network level in the respective Member States. The background of this survey is the current developments around the "Hydrogen and Decarbonised Gas Market Package". The survey also asked about the current limits for hydrogen admixture in the gas network. The results are not yet final at the time of writing of D6.1.

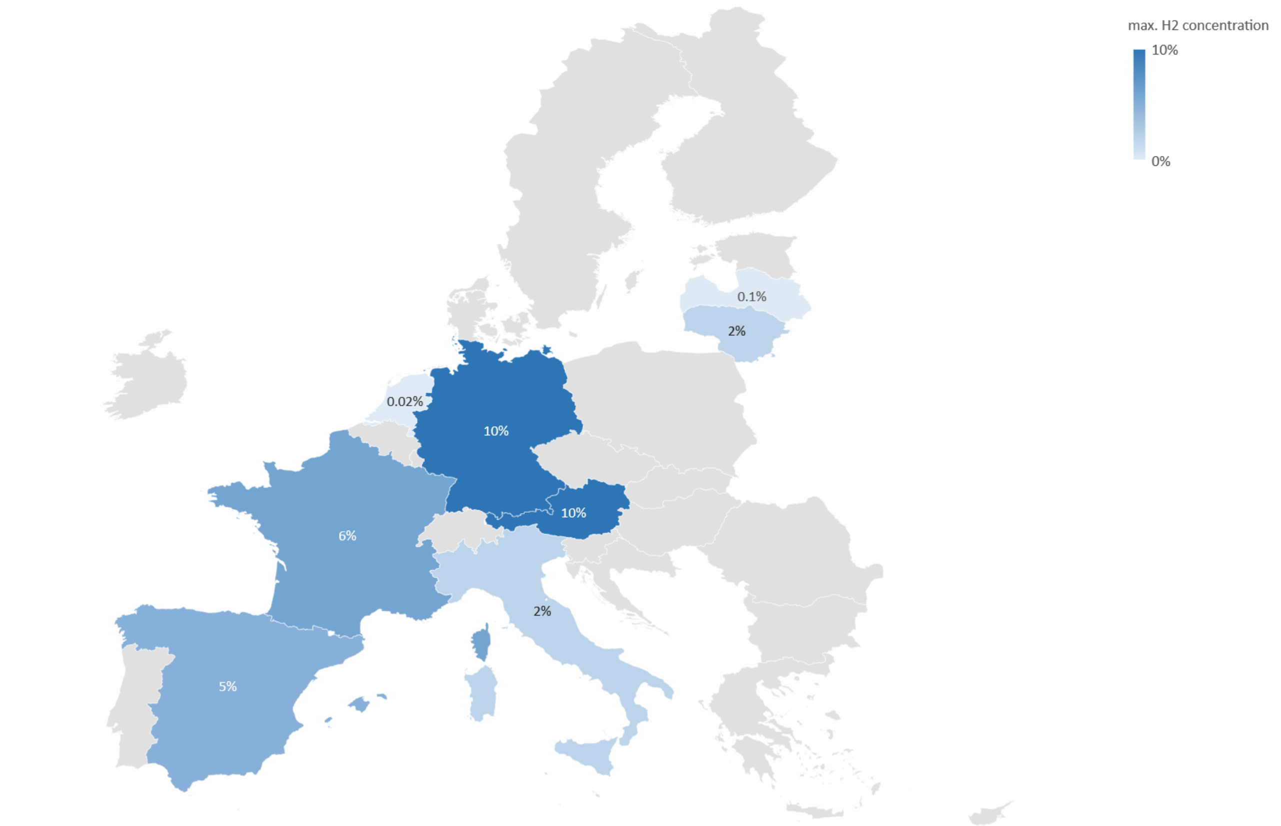


Figure 26. Maximum allowed hydrogen concentration of gas grids across Europe

The results from the different sources are essentially congruent. For Austria, after consultation with the ÖVGW, we assume 10% instead of 5%, deviating from the ACER publication.

Compared to the values published in D2.3, the maximum permitted hydrogen concentrations have changed in the following countries:

- Lithuania: 2% instead of 0.1%

- Italy: new value 2%

It should be noted that these blends are maximum values and that country-specific restrictions may apply. The above figure's depiction is just another way to display the hydrogen concentration limits in Figure 30 of the deliverable report D 2.3. The difference between both graphs is, that in Figure 26 (this report) the maximum hydrogen limit in the distinguished countries is chosen.

A more comprehensive update of the results from D2.3 will be published in D6.3.

5 Potential for hydrogen injection: alignment with EU policies (2030-2045/2050)

In this section, a review is conducted to assess the potential of hydrogen injection in various European countries and its alignment with EU policies. The period from 2020 to 2023 serves as the baseline scenario, with projections made for 2030 and 2045/50. The total gas demand in the baseline scenario is considered as the minimum capacity for the different grids, while the total gas demand up to 2050 is anticipated. If complete decarbonization of the grids is to be achieved, this demand will be met with renewable gases in the upcoming years. Hydrogen will therefore compete with the development of biogas for on-site consumption or biomethane for grid injection. Consequently, only the demand not covered by biogas/biomethane, or climate-friendly synthetic gas can be fulfilled by hydrogen. By balancing the supply and consumption of hydrogen, the potential for hydrogen imports and exports among different European countries can be forecasted. These can be facilitated through existing infrastructure that is no longer utilized due to reduced gas demand resulting from increased electrification and the improved efficiency of gas devices.

The section's first approach is providing a general overview of the expected trends in Europe as a whole, completing it afterwards with a detailed review county by country. The information gathered feeds the scenarios developed for 2020, 2030 and 2045/50, where the potential for hydrogen imports and exports, as well as the grid capacity of each country is studied. The information collected sometimes vary significantly depending on the source consulted, being difficult to make a final statement. This is way to scenarios have been developed for 2030 and 2045/50, considering the lowest and highest production/demand from all the information gathered.

5.1 General overview

According to the International Energy Agency (IEA), [61] Europe is expected to experience a decline in gas demand in the coming decades. This decrease will be driven by factors such as improvements in energy efficiency, the increased utilization of renewable energy sources, and the implementation of policies aimed at reducing greenhouse gas emissions.

<u>The IEA's Sustainable Development Scenario (SDS) forecasts a reduction in gas demand from around 5,017 TWh in 2019 to approximately 4,071 TWh by 2040, and further down to about 3,256 TWh by 2050</u>.

However, it is important to note that the level of gas demand in Europe will depend on various factors, including the pace of energy efficiency improvements, the level of government support for renewable energy, and the development of low-carbon gas technologies like biogas and hydrogen.

The European countries have shown their commitment to achieve net-zero greenhouse gas emissions by 2050, which may further contribute to the reduction of gas demand. For instance, the European Union's Green Deal [62] sets the target of achieving net-zero emissions by 2050, and several EU member states have announced plans to phase out the use of fossil fuels, including gas, in the coming decades. As part of the transition, the EU has adopted binding climate targets, including a 55% reduction in CO_2 emissions by 2030 and the goal of becoming climate neutral by 2050. These targets have significant implications for the role of gas in Europe's energy mix. While the current gas consumption can be partly replaced by biogas and hydrogen, a substantial portion of the existing gas consumption will need to be replaced by electricity before 2050. In line with this, EU member states have decided to gradually phase out coal-fired power stations and some have also chosen to retire nuclear power plants, leading to the decommissioning of a significant portion of electricity production capacity by 2030. Renewable energy is expected to play a primary role in replacing this capacity, although it may be challenging to fully replace all decommissioned coal and nuclear power plants with renewable sources. As a result, the short-term solution may involve the construction of new gas-fired power stations, while simultaneously expanding renewable energy production.

To support the transition to the net-zero emissions scenario, the EU's REPowerEU Plan [63] has set ambitious targets for biomethane and green hydrogen production.

The target for biomethane has been doubled from 198 TWh to 407 TWh by 2030, while the target for green hydrogen has quadrupled from 188 TWh to 660 TWh by 2030, with 330 TWh to be produced domestically within the EU and another 330 TWh to be imported.

In terms of direct electrification, while electricity currently represents about one-fifth of the energy system demand, most 2050 energy models predict that it will account for over 50% of the final demand. However, the remaining portion of the demand is likely to be met by on-demand fuels such as renwable and low-carbon hydrogen, biomethane, and biofuels. [64]

Although predictions vary depending on the source consulted, **the gas demand in some countries is expected to remain constant until 2030, but will drop to a half in 2050, being replaced by electrification**. Looking ahead to 2050, it is anticipated that biomethane could cover 30-40% of the gas demand, while the remaining portion could be fulfilled by renewable and low-carbon hydrogen. [65]. However, the situation may differ locally among the different countries and a review country by country is tackled in the coming subsections. Biomethane and hydrogen grids are therefore going to cohabitate in the coming years in the European network. It is necessary to review in parallel the expectations for both renewable gases to determine how much hydrogen can allocate the natural gas grids in the future.

The European strategy for hydrogen infrastructure will focus on three key supply corridors. These priority corridors include the Mediterranean region, the North Sea area, and, when feasible, Ukraine. These designated corridors align closely with the supply routes outlined by the EHB initiative. [66] Establishing these corridors would mark an important initial milestone towards the development of a comprehensive pan-European hydrogen infrastructure that is interconnected with neighbouring regions. Besides, the EU aims at developing at least 100 hydrogen valleys worldwide by 2030 and the joint purchasing of hydrogen. [63]

Regarding imports of hydrogen from outside Europe, Gas for Climate explains this three key supply corridors in their report: “Facilitating hydrogen imports from non-EU countries”. [67] Within the North Sea region, there exist six pipelines originating from Norway (Europipe I & II, Norpipe, Zeepipe and Franpipe), as well as two from the UK (Interconnector and Balgzand Bacton Line) -see sections 3.1.6, 3.1.19 and 3.1.30-, which hold the potential for repurposing. Given its substantial renewable energy capacity, the North Sea pipelines offer a promising opportunity for the production of competitive renewable and low-carbon hydrogen. With their close proximity and the ability to harness wind resources, these pipelines could serve as a reliable source.

The estimated import capacity for renewable and low-carbon hydrogen through the North Sea pipelines stands at 1,023 TWh.

Additionally, North Africa also possesses favourable conditions for the transportation of hydrogen through pipelines to Europe. North Africa boasts significant renewable energy potential, particularly in solar and wind resources. By repurposing existing natural gas pipeline infrastructure, it becomes possible to tap into this renewable energy potential and generate large-scale renewable hydrogen. There are currently two pipelines connecting North Africa to Southwestern Europe (Spain) via Algeria and Morocco (Medgaz and Maghreb-Europe), and another two linking North Africa to Southern Europe (Italy) through Algeria, Tunisia, and Libya (TransMediterranean and Green Stream).

The combined import capacity through the pipelines in the Mediterranean corridor is estimated at 495 TWh of hydrogen.

The Ukrainian corridor presents further opportunities, leveraging the abundant renewable potential in Eastern Europe. In the medium term, this pipeline corridor offers access to cost-effective hydrogen supply from Eastern and South-Eastern Europe, including the possibility of hydrogen imports from Ukraine and partially from Poland (Yamal II). The primary supply pipeline from Ukraine is the Transgas pipeline, which serves Slovakia, the Czech Republic, Austria, Germany, and Italy (see section 3.1.29).

The import capacity through the Transgas pipeline is projected to reach 924 TWh of hydrogen. **The total import capacity via pipelines in this three corridors adds 2,442 TWh of hydrogen**.

However, it is important to note the uncertainties surrounding this scenario. One uncertainty lies in the need to compensate for the reduction in Russian natural gas, which previously accounted for 39% of EU natural gas pipeline imports before the Russian-Ukrainian conflict. Another uncertainty relates to the development of hydrogen projects in potential export regions. While numerous announcements have been made regarding large-scale hydrogen projects, particularly in the North Sea region and North Africa, none of them are operational at present.

The European Hydrogen Backbone (EAB) has identified five supply corridors to deliver abundant and low-cost hydrogen supply by 2030. [66] Two supply corridors originate from the south of Europe, traversing Italy and the Iberian Peninsula (Corridor A and B). In these corridors, domestic hydrogen primarily produced from solar power is supplemented by imports of renewable hydrogen from North Africa. The pipeline supplies countries along its path and extends to the southern regions of Central Europe. A North Sea supply corridor (corridor C) capitalizes on the abundant offshore wind resources, enabling renewable hydrogen production. This corridor is further supported by the production of low-carbon hydrogen in Norway and the UK. The supply from this corridor caters to Central European countries. The Nordic supply corridor (corridor D) serves as a transportation route for renewable hydrogen generated from onshore and offshore wind installations in countries surrounding the Baltic Sea. Finally, another supply corridor originates from East and South-East Europe, tapping into the renewable hydrogen potentials found in South-East Europe and Ukraine. This corridor supplies the Eastern part of Europe (corridor E).

The report shows an intricate network of hydrogen flows across Europe, showcasing the diverse sources and routes of renewable hydrogen supply within the modelled European energy system.

The analysis of national hydrogen production and demand is conducted in the subsequent subsections, using 2020-23 as the baseline scenario and making projections from 2030 to 2050, relying on the available information regarding anticipated hydrogen-related projects. Simultaneously, assessments are made for biomethane, particularly in countries with robust strategies that could establish a significant foothold in the hydrogen market.

5.2 Review of individual countries

This section presents a country-by-country review of the current gas demand and the projected demand until 2050, with a particular emphasis on the production and demand of renewable gases, namely synthetic methane, biogas/biomethane, and hydrogen. The numbers collected may vary significantly depending on the information source, as these studies might have considered different factors in their models and estimations. Additionally, some studies were conducted at different times, which, although relatively close, were enough to yield varying estimations due to the dynamic nature of the hydrogen world.

5.2.1 Austria

Austria consumed **90.38 TWh of natural gas in 2021**. [68] The gas consumption is expected to **drop to 60-76.5 TWh by 2030**. [69, 70]

The objective of Austria's government's is to **inject 5 TWh of renewable gas into the grid by 2030**, a significant increase compared to the current supply of biogas to residential and service buildings, which stands at approximately 140 GWh. [71] Austria has recently unveiled its hydrogen strategy, [72] setting a target of achieving **1 GW of electrolysis capacity by 2030**. Furthermore, the country aims to achieve a **fully renewable energy mix for electricity generation by 2030**, utilizing sources such as wind, solar, hydro, biomass, and biogas. As of the end of 2021, Austria had a total renewable energy capacity of 22 GW, with solar PV contributing 2.69 GW and the majority, 14.5 GW, derived from hydropower, according to the International Renewable Energy Agency (IRENA). [73]

Given Austria's substantial gas import dependency, the country possesses a well-developed gas infrastructure that offers the flexibility and storage capacity required to accommodate the increasing share of variable renewable electricity and hydrogen in the energy mix by 2030. It will be crucial to maintain this infrastructure during the transition period until new energy sources are ready to penetrate the market. [71]

In 2020 Austria produced 1,487 GWh of biogas and 138 GWh of biomethane in 423 operational biogas plants and 15 biomethane plants. 93% of the biomethane plants are connected to the distribution grid and 7% to the transport grid. [65] **Austria may have potential for producing 7 TWh of biomethane by 2030 and 45.47 TWh by 2050.** [74] Other sources state a total production capacity of 14 TWh of renewable gases, composed by **10 TWh of biomethane and 4 TWh of green hydrogen by 2030.** [69]

The Austrian Ministry for Climate Protection (Federal Ministry for Climate Protection, Environment, Energy, Mobility, Innovation, and Technology) forecasts a **green gas potential of 20.3 TWh by 2040**, while It is estimated that the **total gas demand in Austria by 2040 will reach 89 TWh**, being a contrary trend to the decrease expected by 2030 explained in the beginning of the section. This green gas potential comprises 53% biomethane derived from anaerobic digestion (10.8 TWh) and 47% synthetic gas from biomass gasification (9.5 TWh). [75] Based on this numbers, Austria would therefore still need 68.7 TWh of hydrogen to achieve the target for climate neutrality by 2040.

The Clean Hydrogen Monitor [76] report details an **electrolysis capacity for Austria of 989 MW by 2030**, coherent with the supply capacity explained in the EHB report [66] (**3.7 TWh/a**). The hydrogen production potential according to this last report may reach **5 TWh/a and 7 TWh/a in 2040 and 2050** respectively. The **hydrogen demand by 2030 may reach 8 TWh/a.** **By 2040 and 2050 it should rise to 31-36 TWh/a and 44-52 TWh/a, respectively**. [66, 77]

5.2.2 Belgium

In the case of Belgium, the possibilities for hydrogen injection, while adhering to the current 2 %mol limitation in the grid, have been identified as follows: [78]

- The main pipeline from the Netherlands to France holds the highest potential for hydrogen injection. The capacity for hydrogen injection into this pipeline corresponds to the installation of a total capacity of 10 MWe of electrolysers, equivalent to 2000 Nm^3/h of H_2.
- The pipeline connecting Zeebrugge to Ville-sur-Haine (Mons - French border) and the pipeline between Berneau (Liège - German border) and Ville-sur-Haine (Mons - French border) can accommodate a combined total of 10 MWe of electrolyser capacity, also equivalent to 2000 Nm^3/h of H_2.
- Given the significant gas volumes received directly from Norway, the area near the Zeebrugge LNG terminal presents the most promising opportunities for hydrogen injection. The theoretical total electrolyser capacity for this area can reach up to 100 MWe. Other sections of the transportation grid, based on typical volume observations, could potentially accept production units of up to 1 MWe (equivalent to 200 Nm^3/h of H_2).

Detail information about this pipes and transport facilities can be seen in section 3.1.2.

The **total gas demand in 2021 in Belgium was of 190 TWh**. [68] Looking ahead to 2030, the daily gas demand on the Belgian gas market is expected to increase from 61 GWh/h in 2020 to a range between 65 and 67 GWh/h (an increase of 9.8%). [79] However, the **total gas demand may remain constant until 2050**. [80] The natural gas demand in Belgium is expected to decrease to **10 -75 TWh by 2050**, being almost all gas demand replaced by hydrogen or synthetic methane. [81] **By 2050**, the Federal Planning Bureau has suggested that the **annual demand for hydrogen in Belgium could range from 80 TWh to 99 TWh**, depending on the specific scenario being considered. [82] An study from Deloitte [81] increases this range to **50-125 TWh**.

Biogas will have limited potential in Belgium. **In 2020 Belgium produced 2,700 GWh of biogas and 5 GWh of biomethane** in its 134 biogas plants in Flanders and 55 in Wallonia and 5 active biomethane plants. [65] B**y 2030, it is projected that the biomethane capacity could witness a significant increase of up to 8 TWh/a**, primarily utilizing agricultural waste streams. [83] In the region of Flanders, the existing biogas production of 1.4 TWh/a, which currently receives support that is gradually diminishing, can be readily transitioned to biomethane production by 2025. Furthermore, in 2022, the Zeebrugge Terminal liquefaction plant anticipates shipping over 200 GWh of BioLNG. It is worth noting that this bioLNG process is certified under ISCC EU and complies with the RED II regulations. While a portion of the bioLNG is supplied to Belgian filling stations for heavy-duty transport, a significant share is directed towards Sweden, Norway, and Germany. **By 2050, Belgium may be able to produce up to 13.84 TWh of biomethane**.

The hydrogen strategy of Belgium [84] was updated in 2022. The expected **hydrogen demand according to this report may be 125-200 TWh/a by 2050**. The electrolysis capacity will remain limited in Belgium because of the limited local renewable energy potential. There is, however, a target to install at least **150 MW of electrolysis capacity by 2026.** Belgium is expected to **import significant quantities of renewable hydrogen in 2030 (20 TWh) and 2050 (200- 350 TWh) to cover its domestic demand as well as the transit activities to neighbouring countries.**

The national strategy also explains that hydrogen transit may occur via two lines: the North Sea route and the Southern route. As stated in the Esbjerg declaration in May 2022, Belgium, Denmark, Germany, and The Netherlands have made a joint commitment to develop 65 GW of offshore wind capacity and 20 GW of renewable hydrogen production in the North Sea by 2030. Looking further ahead, their target for 2050 is to achieve 150 GW of offshore wind capacity. Additionally, in September 2022, the nine NSEC (North Seas Energy Cooperation) countries announced a collective goal of 260 GW of offshore wind capacity by 2050. These ambitious plans highlight the North Sea's potential to become a vast Green Power Plant for Europe. Besides, the European Hydrogen Backbone initiative envisions the establishment of a pipeline connection between the North of Spain and Belgium, passing through France and Germany, with a projected completion date as early as 2030, possibly reaching Belgium via Liège. However, it is expected that most of the hydrogen volumes produced in the Iberian region will be consumed along the pipeline route, reducing the likelihood of significant imports reaching Belgium by 2030. The European Hydrogen Backbone further predicts the development of additional pipelines and interconnections through Portugal, Spain, and France by 2040, making it a more realistic timeline for piped imports from the South.

The Clean Hydrogen Monitor [76] report details a higher **electrolysis capacity for Belgium (1,555 MW by 2030)**. The supply capacity predicted in the EHB report [66] may be higher with **21 TWh/a**. The hydrogen production potential according to this last report may reach **28 TWh/a in 2040, but drop to 11 TWh/a in 2050**. The **hydrogen demand by 2030 may reach 25 TWh/a.** **By 2040 and 2050 it should rise to 65-78 TWh/a and 94-109 TWh/a, respectively**. [66, 77]

5.2.3 Bulgaria

The **total gas demand in Bulgaria in 2021 was 31.34 TWh**. [68] Bulgartransgaz EAD forecasts an increase in this demand to **44.39 TWh by 2030**. [85] **By 2040 and 2050, the expectations are 11.65 and 9.78 TWh, respectively**. [86]

By 2030, Bulgaria is aiming to develop a hydrogen roadmap with a focus on achieving a **green hydrogen production capacity of 1.1GW**. [87] The country's strategy involves the utilization of renewable sources through electrolysis to produce hydrogen. Moreover, Bulgaria has set a target of installing an extra 800MW of wind capacity and 280MW of solar capacity by 2030 as part of its plan. **By 2050** the plan is rising the production capacity to **5 GW of electrolysers** for domestic consumption and export. [88]

Hydrogen demand in 2050 is expected to be 0.25-1.66 TWh, i.e. maximum 2% of the total final energy demand. [86] It is **biomethane or synthetic gas** the renewable gas with greatest share in the total gas demand, with up to **5.32 TWh expected demand**. The **potential for biomethane production has been reported as 7.91 TWh in 2030 and 35 TWh in 2050**. Bulgaria would therefore become a biomethane exporting country in the future.

The Clean Hydrogen Monitor [76] report considers a much higher **electrolysis capacity for Bulgaria by 2030, with 3.8 GW installed capacity**. The supply capacity predicted in the EHB report [66] is however much lower(**1.6 TWh/a)**. The hydrogen production potential according to this last report may reach **9 TWh/a in 2040 and rise to 39 TWh/a in 2050**. The **hydrogen demand by 2030 may reach 0.17-5 TWh/a.** **By 2040 and 2050 it should rise to 13-17 TWh/a and 23 TWh/a, respectively**. [66, 77]

In the Republic of Bulgaria, the National Recovery and Resilience Plan encompasses a provision for the development of an infrastructure capable of transporting natural gas, hydrogen, and other low-carbon gaseous fuels, as well as their mixtures. [85] This infrastructure will be established in the eastern Maritsa coal basin and Bobov Dol region. The primary objective of this project is to facilitate the gradual phase-out of coal and replace it with alternative environmentally friendly energy sources, such as hydrogen, in the country's coal regions. To facilitate this transition, the plan initially involves the use of the existing gas pipeline infrastructure until sufficient hydrogen production capacity is established. This infrastructure will enable the transportation of low-carbon gaseous fuels and their mixtures, including hydrogen, biogas, and natural gas, in varying ratios. The proposed infrastructure will be integrated into the existing gas transmission infrastructure of Bulgartransgaz EAD, with a total length of approximately 175 km.

The project comprises two main subprojects. The first subproject entails the design, construction, and commissioning of infrastructure suitable for the transport of hydrogen and low-carbon gaseous fuels to supply consumers in the Eastern Maritsa coal basin. This includes gas pipelines with a total length of around 125 km, serving consumers such as TPP Maritsa East - 2, ContourGlobal Maritsa East 3, AES - 3C Maritsa East 1, and others.

The second subproject focuses on the design, construction, and commissioning of infrastructure suitable for the transport of hydrogen and low-carbon gaseous fuels to supply consumers in the Bobov Dol region. This includes gas pipelines with a total length of approximately 50 km, serving consumers such as TTP Bobov Dol and others.

5.2.4 Croatia

The **total gas demand in Croatia in 2020 was 29.37 TWh**. [89] The gas demand will basically remain constant by **2030**. [90]

Croatia launched its hydrogen national strategy in 2022. [91] Two scenarios are defined with lower and higher hydrogen production. The former calculates the electrolyser capacity if the electricity needed to produce hydrogen is obtained from the grid. The latter makes this calculation if this electricity is obtained exclusively from RES.

The strategy plans installing an **electrolysis capacity of 70-1,273 MW in 2030, 900-4,755 MW in 2040 and 2,750-7,329 MW in 2050**, to produce **0.17-1.52, 2.27-5.70 and 7.06-8.78 TWh/a, respectively**. The **expected hydrogen demand by 2030, 2040 and 2050** is expected to reach up to 0.2, 3 and 11% of the total energy demand, respectively (i.e. **0.21 TWh in 2030, 2.71 TWh in 2040 and 8.41 TWh in 2050).** Production and demand of hydrogen are quite balanced and no exports are expected unless the electricity capacity from RES increases from 2040 on.

The Clean Hydrogen Monitor [76] report considers a much smaller **electrolysis capacity for Croatia by 2030 (just 2 MW)**. The supply capacity predicted in the EHB report [66] is, however coherent with the lower scenario of the national strategy, being **0.1 TWh/a**. The hydrogen production potential according to this last report may reach **11 TWh/a in 2040 and increase slightly to 18 TWh/a in 2050**. The installed electrolysis capacity of the national strategy seems not to match the calculated production, basing on the reported values and those of this alternative report. The **hydrogen demand by 2030 may reach 2 TWh/a.** **By 2040 and 2050 it should rise to 6-8 TWh/a and 11-12 TWh/a, respectively**. [66, 77]

No biomethane production is expected by 2030, and the **potential for 2050 is producing 5.23 TWh** of biomethane. [65]

5.2.5 Czech Republic

The total gas demand in Czech Republic in 2020 was 92.24 TWh. [68] Natural gas is expected to remain an important fuel in Czech Republic towards **2040**, when the government expects its share in total primary energy consumption to be 18-25% (i.e. **up to 120.49 TWh**). From 2020 to 2040, the use of natural gas in heat supply will remain stable while the use in transport and electricity production will increase by 91% and 81%, respectively. [92] **By 2050, the gas demand may drop to 54.63 TWh**. [93]

NET4GAS is participated in the European Hydrogen Backbone project, envisaging that use of the Gazelle pipeline for hydrogen transport around 2035. This TSO has prepared a Ten-Year Plan for the Development of the Transmission System of the Czech Republic, aiming at the maintenance of the capacity of the transport grid and its modernization. [94]

Czech Republic launched its national hydrogen strategy in 2021. [95] It states how in 2020, the predominant methods for hydrogen production included steam methane reforming (SMR), partial oxidation (POX) of heavy oil fractions, and electrolysis. The carbon footprint of hydrogen produced through electrolysis using grid electricity in the Czech Republic was 176 g CO_2/MJ, significantly higher than hydrogen produced through steam methane reforming. Thus, this hydrogen cannot be considered low-carbon. Currently, the average emission intensity of hydrogen production in the Czech Republic stands at 116 g CO_2/MJ.

Initially, the hydrogen strategy envisions the utilization of existing technologies (grey hydrogen) for hydrogen production, gradually increasing the use of renewable sources. However, hydrogen production possibilities using existing technologies such as RES, biomethane, current nuclear power plants, chemical production, and organic waste decomposition in the Czech Republic have inherent limitations that cannot be overcome. Consequently, the importation of low-carbon hydrogen through pipelines from abroad becomes necessary. Although the use of imported hydrogen will not alter our import dependence level, as we currently import most of the oil and gas, the countries from which we import hydrogen are likely to differ from those supplying oil and gas. Potential countries for hydrogen imports include those with high RES potential, such as Mediterranean countries and North and Baltic Sea countries within the EU, as well as Ukraine, North African countries, Russia, or the Middle East outside the EU. Nuclear power plants or pyrolytic decomposition of natural gas with carbon processing/storage are potential technologies that could produce sufficient quantities of low-carbon hydrogen within the Czech Republic.

The national strategy also develops the plant for the gas infrastructure. Due to its central geographic location in Europe, the Czech Republic is expected to maintain its significance as an important transit state in the transmission system, facilitating hydrogen transport from the east (e.g., Ukraine via Slovakia), the south (e.g., North Africa via Italy and Austria), and the northwest (e.g., Germany). For lower production volumes, the primary decision will involve choosing between transporting compressed gaseous hydrogen and transporting liquefied hydrogen. At higher volumes, considerations will also include the conversion or construction of gas pipelines. Existing contracts make it unlikely to use the existing pipeline infrastructure for hydrogen imports until 2035. Therefore, local production will remain the primary source of low-carbon hydrogen until then. Hydrogen integration in industries is expected to involve the development of pilot applications and testing until 2040. From 2035 onwards, a dedicated transport infrastructure should be established, gradually replacing natural gas with hydrogen from 2040 to 2050. In households, the blending of H_2 with NG in the distribution grid is not anticipated until 2040, with compatibility testing conducted in pilot installations. The blending scenario is expected to continue until 2047 when a full conversion to 100% H2 is anticipated.

There are three-time stages explained in the national strategy to fulfil the transition to hydrogen:

- 2021–2025: Hydrogen use limited to the transport sector. Due to the low number of hydrogen vehicles, full production utilization is unlikely. Any surplus hydrogen should be utilized in chemical production, which has high absorption capacity and minimal technology change investment requirements. Pure hydrogen pipelines are not yet in place, and alternative methods of transportation such as cylinders, liquid hydrogen, or hydrogen bound in organic compounds (LOHC) or hydrides will be used.

- 2026–2030: Operational verification of hydrogen use in industries may commence. Existing gas networks can be extensively used for the transportation and distribution of hydrogen mixed with natural gas. Contracts for the construction of new hydrogen pipelines or the conversion of existing pipelines into hydrogen pipelines for domestic and transit transport in the Czech Republic may begin during this period. The Czech Republic will become a net importer of hydrogen, similar to its current status as an importer of natural gas and oil.

- 2031–2050: The construction and repurposing of hydrogen pipelines will commence, driven by the establishment of large hydrogen producers and consumers.

Although the plan seems fully developed, no specific numbers about hydrogen production and demand could be found.

The Clean Hydrogen Monitor [76] report considers an **electrolysis capacity for Czech Republic of 47 MW by 2030**. The supply capacity predicted in the EHB report [66] would be of **0.1 TWh/a**. The hydrogen production potential according to this last report may remain constant until 2050, which would be owing to the lack of data provided by the country on the whole. The **hydrogen demand** is however calculated and my reach **5 TWh/a by 2030.** **By 2040 and 2050 it should rise to 15-17 TWh/a and 25-27 TWh/a, respectively**. [66, 77]

Regarding the development of biogas, **in 2020 the Czech Republic produced 6,833 GWh of biogas and 8 GWh of biomethane**. [65] The estimations for **2030 and 2050 are that the Czech Republic may reach a biomethane production potential of 7 and 40 TWh**, respectively. [74]

5.2.6 Denmark

Denmark consumed **28.95 TWh of natural gas in 2020**. [68] The total Danish energy mix is projected to have natural gas covering from approximately 11% in 2023 to 10% in 2030. [96] The predicted national **gas consumption** is expected to be **21 TWh in 2030**, (**6.17 TWh of biogas and 15.05 TWh of natural gas**), dropping to **16.2 TWh in 2040**. In terms of biogas production, it is estimated to reach 5.8 TWh in 2030 and 5.9 TWh in 2040. [96, 97]. Predictions from Energinet are more ambitious and the volume of biogas added to the gas system doubles to 11.6 TWh in 2030, representing a share 75% of Danish gas consumption. [98]. The **gas consumption** is estimated to decrease to **16.7-22.2 TWh by 2050**, due to the fact that both district and local heating will be replacing gas technologies unless green gas can be supplied. If this were the case, the availability of more advanced technologies such as electricity storage through PtG (with methanation) could increase the resource to 27.8 TWh. [99]

Denmark has seen more growth in biomethane production than any other European country ater UK. The constant growth in the number of biogas plants supplying gas to the gas system has led to an average **biomethane share of 21% in volume throughout 2021**. [98] Since 2013, a total of 51 biogas facilities have been connected to the gas system. Currently, 96% of the biomethane plants are connected to the distribution grid and 4% to the transport grid. [65] The combined maximum connection capacity of these plants exceeds 6.3 TWh/a. To accommodate the added biogas, a "reverse flow" mechanism is used to transfer surplus biogas from the distribution system to the transmission system at five locations in Denmark. An additional reverse-flow plant is currently under construction. Over the past 12 months, more than 0.31 TWh of biogas, including production from the Bevtoft biogas plant, have been added to the transmission system.

As biogas production grows and consumption declines, adjustments in the transmission system are necessary to accommodate these changes. Evida and Energinet are working closely together to establish reverse-flow plants that will enable the transportation, storage, and utilization of biogas throughout the gas grid, including the large gas storage facilities. However, the consumption of all biogas in Denmark is uncertain due to the nature of purchasing guarantees of origin for renewable energy-injected gas into the system. [98]

The Clean Hydrogen Monitor [76] report an **electrolysis capacity for Denmark of 6,288 MW by 2030**. The supply capacity predicted in the EHB report [66] is of **40 TWh/a**. The hydrogen production potential according to this last report may reach **101 TWh/a in 2040 and increase to 142 TWh/a in 2050**. The **hydrogen demand by 2030 may reach 8-27 TWh/a.** **By 2040 and 2050 it should rise to 12-52 TWh/a and 21-67 TWh/a, respectively**. [66, 77]

The TSOs Energinet and Gasunie have embarked on a pre-feasibility study [100] to assess the viability of establishing a dedicated hydrogen pipeline network for the efficient transportation of renewable hydrogen to meet the demand in the German market from the Danish production centres. The proposed network would transport hydrogen generated from renewable electricity in Denmark to customers in Germany. The study focuses on evaluating the potential for exporting renewable hydrogen from Denmark, analysing the hydrogen market in Germany, assessing the technical feasibility of establishing a hydrogen connection, which involves repurposing existing methane infrastructure along two potential routes: Esbjerg (DK) to Hamburg (DE) and Holstebro (DK) to Hamburg (DE) and developing design features for a scalable network, including the incorporation of various compressor stations.

This study forecasts **Denmark's hydrogen export potential to range from 2-15 TWh, 3-22 TWh, and 5-28 TWh in 2030, 2035, and 2040**, respectively. The lower estimates are considered conservative, especially considering the increasing demand for large-scale PtX (Power-to-X) production in the market. According to the Danish National Hydrogen Strategy, [101] there is a target to achieve **5 GWe of electrolyser capacity by 2030**, with the potential to reach **10 GWe by 2035**. This capacity would correspond to the production of **14 TWh and potentially 28 TWh of hydrogen**, assuming that the electrolyser units operate for an average of 4,000 full load hours per year. This fact means that **Denmark may have the capacity to export all the hydrogen produced**, something that may be likely to happen because Energinet states in their Security of gas supply 2021 report [98] that **by 2034, biogas production is expected to be able to meet the whole Danish gas consumption** on an annual basis. From Figure 5 in pre-feasibility study [100] report it can be concluded that **2040 may lead to up to 38.64 TWh/a of hydrogen production capacity**, and **2050 to up to 108.14 TWh/a of hydrogen production capacity**, of which 63.22 TWh of them may be exported. This means that there is a need to develop new infrastructure, or else the surplus of hydrogen will have to be exported using alternative means of transportation.

Energinet and Gasunie pre-feasibility study [100] presents an example of how an initial hydrogen network between Denmark and Germany could be constructed in expansion stages and subsequently scaled up to accommodate higher transport capacity demands. In the initial phase, a 340 km pipeline connecting Esbjerg and Heidenau near Hamburg could transport up to 2.5 GWh/h of hydrogen without the need for pipeline compressors. The capacity can be increased to 8.6 GWh/h by implementing compression power. The location of compressor stations influences the system's costs and potential transport capacities. The study assumes that 50-60% of existing gas pipelines can be repurposed for hydrogen in the future, taking into account the anticipated demand for methane and biomethane transportation. **The coexistence of parallel systems for methane and hydrogen is expected for an extended period, even in 2050 when the methane network will transition to 100% green gas**. Esbjerg and Holstebro in Denmark are identified as potential starting points for large-scale hydrogen transport due to their proximity to the west coast of Jutland, where most offshore wind resources will be developed. Additionally, the land area between Esbjerg and Holstebro offers significant potential for large-scale solar PV development. Starting in Holstebro has the advantage of proximity to geological salt caverns for hydrogen storage north of Viborg in Denmark. The choice of entry point for hydrogen into the potential transmission network, whether Esbjerg or Holstebro, depends on factors such as the cost of integrating renewables into the broader energy system in Denmark.

Even with higher PtX demand, the amount of hydrogen produced is expected to exceed the national demand and a cross-border hydrogen infrastructure will be essential to enable exporting hydrogen to neighbour countries with large import needs, such as Germany and Sweden.

5.2.7 Estonia

The TSO Elering lunched in 2022 its Transmission Network Development Plan [102] for the years 2022-2031. And all the information displayed in this section comes from this report. Based on the study's findings, there are various possibilities for substituting natural gas with alternative energy sources in the national electricity network until 2050. The choice of the most suitable alternative energy carrier depends on the specific economic sector or purpose. Biomethane or biogas shows significant potential as a replacement for natural gas, especially in the industrial and transportation sectors. Industries that generate suitable waste products during their production processes can utilize biogas locally. Biomass usage could see an increase, particularly in heat production, where the incorporation of heat storage enables biomass cogeneration plants or boilers to meet the heat demand instead of traditional boilers. Large industries with consistent heat requirements could also consider local biomass CHP plants. Moreover, transitioning from natural gas to electricity will benefit from improved energy efficiency through building renovations and the adoption of heat pumps, which are already competitive with other heat generation solutions. Looking ahead, hydrogen will play a crucial role as a long-term energy storage solution for renewable electricity and in the decarbonization of heavy transportation.

Biomethane production commenced in Estonia back in April 2018, with Kunda being the pioneering producer. Rohegaas OÜ, located in Lääne-Viru county, joined the biomethane production sector, followed by another producer, Biomethane OÜ, in Kundu in July 2018. Subsequently, Vinni Biogas OÜ and Tartu Biogas OÜ began their biomethane production in July 2020. The year 2021 marked the entry of a second biomethane producer, Vinni Biogas OÜ and Tartu Biogas OÜ, into the biomethane market. In terms of production volumes, **152.4 GWh were produced in 2021**. Among the sources, 55.6 GWh originated from sewage sludge, 61.1 GWh from animal manure, 25.0 GWh from food industry residues, 5.9 GWh from bio-waste, and 4.8 GWh from other biomass. It's important to note that all produced biomethane is exclusively utilized in the transportation sector, it is therefore not injected in the grid.

In 2030 the total gas demand may slightly rise to 5.2 TWh. The expectations for **2030 are that 678.08 GWh of biogas may be produced**.104.32 GWh of them locally would be locally consumed, while the remaining 573.76 GWh would be transported through pipes. **No production of hydrogen is expected by 2030**. In **2035 the total gas demand should basically remain constant**. The energy mix becomes, however, different and **production of hydrogen of 203.88 GWh** may occur. Of the expected **917.46 GWh biogas production, 713.58 GWh may be injected into the gas** grid as biomethane. In **2040**, the **total gas demand will slightly drop to 4.9 TWh**, but the amount of fossil fuels have clearly decreased from predominance in 2020 to just 35% of the share. By this year, **1230.25 GWh of biogas may be produced** (442.89 TWh locally consumed and 787.36 GWh injected into the grid) and the **production of hydrogen may rise to 393.68 GWh**. Finally, the **gas demand by 2050 is expected to drop to 3.8 TWh** due to partial electrification of the energy sector. **1,035.18 GWh of biogas are expected to be produced** (805.14 GWh locally consumed, the remaining 230.04 GWh transported in pipes), decreasing in comparison to the previous period due to the lower total gas demand. **The amount of hydrogen produced may, however, still increase reaching 498.42 GWh**. Therefore, in Estonia biomethane may be partially replaced by hydrogen or electrification by 2050.

The Clean Hydrogen Monitor report [76] predicts an **electrolysis capacity for Estonia of 63 MW by 2030**. The supply capacity detailed in the EHB report [66] is of **1.1 TWh/a**. The hydrogen production potential according to this last report may reach **19 TWh/a in 2040 and increase to 35.1 TWh/a**

in 2050. **No hydrogen demand is however expected by 2030**. **By 2040 the first hydrogen demand of 1.5-2.0 TWh/a may appear and remain constant until 2050**. [66, 77]

Based on these findings, Estonia may relay strongly in biomethane to meet the gas demand. Most of the hydrogen produced may be dedicated to feed corridor D (Nordic and Baltic regions) and export hydrogen to the most demanding countries, since the total gas demand will not be too high in the future.

5.2.8 Finland

In **2020** the **natural gas consumption in Finland was 25.43 TWh**. [68] Also **in 2020 878 GWh of biogas and 109 GWh of biomethane were produced** in Finland. [65] Finnish biomethane sector is mostly off grid due to its limited gas network. The potential for biomethane production has been reported as **8.26 TWh by 2030 and 72.69 TWh by 2050**. [74]

The Clean Hydrogen Monitor report [76] considers an **electrolysis capacity for Finland of 2,526 MW by 2030**. The supply capacity predicted in the EHB report [66] is, however much higher, being **61 TWh/a**. The hydrogen production potential according to this last report may reach **93 TWh/a in 2040 and increase to 139 TWh/a in 2050**. The **hydrogen demand by 2030 may reach 6-25 TWh/a.** **By 2040 and 2050 it should rise to 17-53 TWh/a and 27-66 TWh/a, respectively**. [66, 77]

According to the Finish Hydrogen Strategy, [103] the existing hydrogen infrastructure in Finland is limited to smaller pipelines within industrial sites connecting two companies, such as the one between Nouryon and Stora Enso in Oulu and the pipeline from Borealis to Neste in Porvoo. However, due to a significant decline in natural gas usage over the past 15 years, there is potential to repurpose some of the existing natural gas transmission pipelines for hydrogen transport. Further in-depth studies will be required to explore this possibility. Besides, to enhance hydrogen distribution, it is crucial to improve the prerequisites for efficient hydrogen transport using tube trailers and to initiate the construction of the first hydrogen pipelines. It should be considered whether **the construction of initial hydrogen pipelines can be initiated as early as 2030**.

Regarding planned hydrogen infrastructures, the Nordic Hydrogen Route [104] can be highlighted. This project is a collaborative effort between Gasgrid Finland Oy (Finish TSO) and Nordion Energi (Swedish TSO) that aims to accelerate the development of a hydrogen economy by establishing a cross-border hydrogen infrastructure in the Bothnian Bay region and fostering an open hydrogen market by 2030. The plan involves constructing approximately 1,000 km of dedicated hydrogen pipelines, strategically positioned to cater to a projected 65 TWh of hydrogen demand in the Bothnian Bay region by 2050. The primary route will follow the coastline, with an additional branch extending to Kiruna.

The estimated investment for the Nordic Hydrogen Route amounts to 3.5 billion EUR, offering a competitive hydrogen transportation cost ranging from 0.1 to 0.2 EUR per kilogram. This infrastructure would also catalyse substantial investments of approximately 37 billion EUR in wind power and electrolysis, amplifying the growth potential of the renewable energy sector. By 2050, the pipeline network has the potential to contribute to annual emissions reductions of up to 20 million metric tons of CO_2e. This represents around 20% of the current combined yearly emissions in Finland and Sweden, helping both countries achieve their respective climate neutrality targets of 2035 and 2045.

The Nordic-Baltic Hydrogen Corridor [105] represents a collaborative effort among the European TSOs Gasgrid Finland (Finland), Elering (Estonia), Conexus Baltic Grid (Latvia), Amber Grid (Lithuania), GAZ-SYSTEM (Poland), and ONTRAS (Germany). These TSOs have entered into a cooperation agreement with the goal of developing hydrogen infrastructure that spans from Finland, through

Estonia, Latvia, Lithuania, and Poland, all the way to Germany. The primary objective is to meet the European Union's target of 10 million tonnes of domestically produced renewable hydrogen by 2030. [63] To accomplish this, the project envisions the establishment of a comprehensive **network of hydrogen pipelines spanning approximately 13,500 km**. This infrastructure will have the capacity to supply **184 TWh of green hydrogen by 2030**, with a long-term goal of surpassing **500 TWh by 2040**.

5.2.9 France

Regarding current status of biogas and biomethane, 91 biomethane plants started operation in 2020 while another 81 plants were installed between January and July 2021.89% of the biomethane plants is connected to the distribution grid and 11% to the transport grid. In 2021 the French biogas production was 6.1 TWh and the biomethane production, 2.2 TWh. [65]

The French national hydrogen strategy [106] defines two scenarios that outline different ambitions for the demand of low carbon hydrogen. **By 2030**, the demand is expected to be around **22.4-36.0 TWh**, and by **2040**, it could reach **85.5-123.1 TWh**. To meet this demand, decarbonized hydrogen consumption will be concentrated primarily in seven major clusters: Greater West, Seine Valley, North, Moselle-Rhin, Rhône-Alps, Mediterranean, and South-West. These clusters are projected to represent 85% of the total demand in the long run. Furthermore, the major production sites for hydrogen will be strategically located around the main demand centers, such as urban centers, ports, and airports. To support the hydrogen supply chain **by 2030, it is estimated that 6.5-10 GW of electrolysis capacity** will be required. Additionally, approximately 685 km of pipelines and underground storage capacity for 495-660 GWh of hydrogen will need to be developed. In line with these requirements, the EAB report [66] suggests that nearly 700 km of pipeline will be necessary in France by 2030.

GRTGaz, the major TSO in France (see section 3.1.9), launched a report in 2021 called "GRTGaz in Motion" [107] in which they provide an estimation of the gas share in the grid in the coming years. This report explains how the **total gas demand in France in 2019 was 494 TWh**, mostly covered by natural gas. **In 2030, the total gas demand is expected to drop to 376 TWh.** Natural gas appears again as the most important fuel, but low-carbon **hydrogen and biogas start gaining relevance, with an expected production of 20 and 57 TWh**. By **2050, the total gas demand** is expected to decrease again to **321 TWh.** At this moment, natural gas is expected to disappear completely from the grid, aiming the desired carbon neutrality. The gas demand would be covered by **renewable/low-carbon hydrogen (95 TWh) and biomethane (217 TWh). 9 TWh of synthetic natural gas** obtained via methanation is also expected. It can be concluded that **France has a strong strategy towards bio- or synthetic methane and preference over hydrogen as renewable gas in the grid**. Hydrogen will only cover 5.3% and 29.6 % of the total demand by 2030 and 2050, respectively, while biogas will supply 15 % and 70% of the total gas share, demand by 2030 and 2050, respectively. To make this scenario compatible with the national hydrogen strategy it is necessary to adjust to the lower numbers in the latter.

The Clean Hydrogen Monitor report [76] considers an **electrolysis capacity for France of 6,276 MW by 2030**. The supply capacity predicted in the EHB report [66] is, however, higher (**18.2 TWh/a)**. The hydrogen production potential according to this last report may reach **112 TWh/a in 2040, rising to 174 TWh/a in 2050**. The **hydrogen demand by 2030 may reach 34 TWh/a. By 2040 and 2050 it should rise to 97-117 TWh/a and 161-181 TWh/a, respectively**. [66, 77]

By 2030, GRTgaz has set a target of incorporating **40 TWh of renewable gas into its networks**. This amount would account for approximately 10% of the final gas consumption in the country. [108] To accommodate the increasing production of renewable gases in various regions, GRTgaz is taking measures to adapt its network. One of these measures involves the construction of "reverse flow stations," which are small compression facilities able to transfer of local biomethane surpluses from the distribution networks to the transmission network, where they can be stored or consumed in neighbouring areas. At present, there are already 4 operational reverse flow stations in France, with an additional 28 stations in the process of being commissioned. Among these upcoming facilities is one located in Céton, a municipality neighboring Cherré-Au in the Orne department. The implementation of these stations will facilitate the injection of 124 GWh of biomethane into the territory, which shares borders with three French regions: Pays de la Loire, Normandy, and Centre-Val de Loire. GRTgaz envisions a hydrogen network spanning approximately **1,000 km by 2030**. This network will be a combination of newly built infrastructure as well as the conversion of a portion of the existing gas network. [109] **Teréga** (second biggest TSO in France-see section 3.1.9-), also states that **40 TWh of hydrogen could be injected in their grid, but by 2050 instead**. [110]

Finally, there are some projects related to hydrogen transport in grid in France that can be highlighted:

- RHYn (Rhine HYdrogen Network) project: [109] The objective of the project is to support and enhance the hydrogen ecosystem in the Upper Rhine region by establishing a connection between the Dessenheim area and the Chalampé-Ottmarsheim industrial area by 2028. Subsequently, the network may be expanded southward towards Basel. Out of the total 100 km of the planned hydrogen network, a minimum of 60 km will be converted from the existing pipeline infrastructure. The pipeline will be designed with the capacity to transport 125,000 tonnes of hydrogen annually. By utilizing hydrogen, this infrastructure has the potential to reduce carbon emissions by up to 1 million tonnes of CO2 per year.

- The MOSAHYC (Moselle Sarre Hydrogen Conversion) project [111] aims to create a hydrogen network spanning 100 kilometers, connecting Völklingen, Perl (Sarre), Bouzonville, and Carling (Moselle). The network will utilize 80 kilometers of repurposed gas pipelines. With a maximum capacity of 75,000 m3/h, the project is scheduled to be commissioned as early as 2026

- In the international scope, GRTGaz and Fluxys are launching a call to develop a cross-border network for low-carbon hydrogen transmission between Valenciennes in France and Mons in Belgium. [112] This 70 km network will be the first hydrogen infrastructure connecting the two countries, contributing to decarbonization efforts in the shared industrial heritage of the Hainaut region. The call invites proposals for the design, construction, and operation of this open-access network, promoting international collaboration for a sustainable hydrogen future.

5.2.10 Germany

The **natural gas demand in Germany was 966.9 TWh in 2020**. It is expected to decrease to **530-775 TWh in 2030** and decrease even further in **2050 until reaching 344-557 TWh.** [113] The German Federal Environment Agency provides a wider range for the total gas demand by 2050 of **238-693 TWh.** [114]

The expected production and demand of hydrogen depends considerably on the source consulted. According to the national hydrogen strategy [115] the demand for hydrogen in Germany is projected to be significant in various sectors to achieve greenhouse gas neutrality and reduce emissions. The **steel production industry alone would require over 80 TWh of hydrogen by 2050** to become GHG-neutral. Additionally, approximately **22 TWh of green hydrogen would be necessary for German refinery and ammonia production** to transition to hydrogen-based processes. To address the infrastructure requirements, the Federal Government is considering the potential conversion of natural gas pipelinesinto hydrogen infrastructure. They also plan to assess the compatibility of existing or upgraded gas infrastructure with hydrogen to ensure its effective integration.

The plan for **electrolyser production involves reaching a capacity of 5 GW by 2030**, with 3 GW coming from IPCEI projects (Important Project of Common European Interest) and an additional 2 GW allocated for the petrochemical field, following the RED II program. This means that about **14 TWh/a of the required hydrogen production is expected to be realized in Germany by 2030.** In terms of infrastructure, an **initial hydrogen network with a length of around 1,700 km could be established.** To further enhance hydrogen production and reduce emissions, a target of a **25% reduction in greenhouse gas emissions by 2030** has been set. Considering the growing demand for hydrogen, estimates suggest that the **demand could already reach 90-110 TWh by 2030**, highlighting the urgency and significance of hydrogen development and deployment in various sectors of the German economy. No estimations about the global demand are given over 2030.

In a recent study published by the Foundation for Work and the Environment, a hydrogen demand forecast was made for Germany from **110 TWh in 2030**, projecting a development **up to 450 TWh by 2050**. [116] This study highlights the diverse range of sectors and applications that contribute to Germany's hydrogen demand. It underscores the need to consider industrial, transportation, and building sectors when planning for hydrogen deployment and infrastructure development in the country. Industrial applications account for just over 4% of the total hydrogen demand in 2050, amounting to 184 TWh. Of this, nearly one-third, 64 TWh, is attributed to energy-related needs. The majority of the industrial hydrogen demand, totalling 120 TWh, is for non-energy applications such as the utilization of hydrogen as a raw material or "feedstock." In the transportation sector, despite a 75% electrification rate for passenger cars and light commercial vehicles, a hydrogen demand of 92 TWh is still predicted. The building sector, on the other hand, is expected to have a total hydrogen demand of approximately 172 TWh.

A DENA report [117] from 2021 forecasts that the total amount of power fuels in all consumption sectors of the energy industry will grow to 657 TWh **by 2045, of which 458 TWh would be covered by renewable hydrogen** and 198 TWh are accounted for by various synthetic gaseous and liquid energy carriers.

As part of the current market survey conducted by "Wasserstoff Erzeugung und Bedarf" (WEB), a total of 488 hydrogen projects have been reported by market partners, with 39 of them located in the Free State of Bavaria. Accordingly, the reported **hydrogen demand in Germany is projected to increase from 231 TWh for the period until 2032** to **427 TWh in 2040** and further to **598 TWh in 2050**. [118]

The simulation of fluid mechanics forms the basis of the H2 Network 2050 study, [119] wherein TSOs have established specific capacities at all entry and exit points of the future German network. In these simulations, the future hydrogen demand is primarily fulfilled through imports. The capacities at the cross-border Interconnection Points are determined by the assumed hydrogen production potential in various regions. For **2030** the study predicts a **total length of 5,100 km**, of which 3,700 km would consist of repurposed gas pipelines. This grid is expected to support a **hydrogen demand of 71 TWh** and a peak consumption of 10 GWh/h. The necessary investment would reach 6 billion Euros. The TSOs participating have included approximately **63 GW of electrolyzer capacity for 2050**, with a significant portion located in northern Germany. When designing the network, the TSOs took into account different load scenarios depending on the availability of renewable energy sources and the storage capacity of caverns connected to the pipeline network. **The H2 Network 2050 spans a length of around 13,300 km**, with approximately 11,000 pipeline kilometers being converted from existing gas pipelines. The planned hydrogen transport network is capable of delivering an energy volume of **504 TWh** (calorific value), with a peak demand of approximately 110 GWh/h of hydrogen. The investment needed would be of 18 billion Euros

A summary of the different scenarios for Germany is given in Table 5

Table 5.Summary of hydrogen production and demand scenarios for Germany

Study	Scenario	2030 hydrogen demand (TWh)					2050 hydrogen demand (TWh)					
		Steel	Chemical/Refineries	Transport	Energy/Heat	Total	Building sector	Steel	Chemical/Refineries	Transport	Energy/Heat	Total
National strategy	-	-	-	-	-	90-110	-	80	22	-	-	???
Foundation for Work and the Environment	-	-	-	-	-	110	172		120	92	64	450
DENA	-	-		-	-	-	-	-		-	-	458
AGORA	-	15	15	4	20	54		36	33	40	156	265
Fraunhofer ISE	R100	-	-	-	-	100	-	100	-	170	70	340
H2 Network 2050	-	-	-	-	-	71	-	-	-	-	-	504
WEB	-	-	-	-	-	231	-	-	-	-	-	598

Going into more global studies, the Clean Hydrogen Monitor report [76] considers an **electrolysis capacity for Germany of 7,295 MW by 2030**. The supply capacity predicted in the EHB report [66] is coherent to this amount with **20.0 TWh/a**. The hydrogen production potential according to this last report may reach **102 TWh/a in 2040, rising to 192 TWh/a in 2050**. The **hydrogen demand by**

<u>2030 may reach 70-90 TWh/a.</u> <u>By 2040 and 2050 it should rise to 280-364 TWh/a and up to 505 TWh/a, respectively</u>. [66, 77]

There are many projects currently ongoing in Germany. Some of them are detailed below:

- *H2EU+Store project*: [120] This project is an international cooperation between several companies to transport hydrogen produced in Ukraine to central Europe. The project is structured as a phased plan in its implementation, aligned with the establishment of new Ukrainian renewable (PV/Wind/Hydro) and electrolysis capacities, as well as the conversion of the transportation infrastructure and storage facilities: Phase 1 (2021 - 2030): Realization of 2.5 TWh/a H_2, Phase 2 (2031 - 2040): Increase to 40 TWh/a H_2 by 2040 and Phase 3 (2041 - 2050): Increase to 80 TWh/a H_2 by 2050. The partners involved are RAG Austria AG, Eco-Optima LLC, Bayerngas GmbH, bayernets GmbH, Open Grid Europe GmbH, Gas Connect Austria GmbH, Nafta, a.s. and eustream, a.s., and the plans seem to remain unaltered despite the war in Ukraine.

- *GetH2Nukleus project*: [121] *The GET H2 Nukleus project aims to connect green hydrogen production with industrial consumers in Lower Saxony and NRW. The planned network, stretching approximately 130 km from Lingen to Gelsenkirchen. Evonik, Nowega, OGE, and RWE Generation are collaborating in the project. Green hydrogen will be produced from wind power in Lingen, Lower Saxony, with an electrolysis plant of over 100 MW capacity to be constructed at the RWE power plant site. Existing gas pipelines operated by transmission system operators Nowega and OGE will be repurposed to transport 100%* H_2*. Additionally, Evonik is constructing a new partial pipeline section connecting the Marl Chemical Park and the Ruhr Oel refinery in bp Gelsenkirchen. This European project initiative will link Germany, the Netherlands, Belgium, and France via a hydrogen network.*

- *Projekt Flow – making hydrogen happen*: [122] 1,100 km long pipe connecting Lubmin – Schwedt – Berlin – Leipzig – Leuna – Erfurt – Ludwigshafen – Karlsruhe – Stuttgart with up to 20 GW injection capacity that is expected to be available from 2025 on.

- *ONTRAS private initiative*: [123] ONTRAS is establishing the groundwork for a hydrogen infrastructure in central and eastern Germany through the ONTRAS start network, spanning approximately 950 km. Around 60% of the hydrogen pipelines consist of repurposed ONTRAS natural gas pipelines, while the remaining 40% will be newly constructed. By being part of the European Hydrogen Backbone, the ONTRAS start network for hydrogen facilitates the connection between producers and consumers in central and eastern Germany, as well as access to import points and storage facilities, ensuring flexible transportation options and a high level of supply security. At the heart of the hydrogen start network lie the two pipeline projects known as "doing hydrogen" and "Green Octopus Mitteldeutschland".

- *Bornholm-Lubmin hydrogen pipeline*. [124] The German-Danish cooperation project, led by GASCADE and Energinet, aims to establish a 140-kilometer pipeline connection from Bornholm to Lubmin with an import capacity of up to 10 GW. The H_2 Interconnector Bornholm-Lubmin is scheduled to enable the transportation of hydrogen from the Danish island of Bornholm to Lubmin starting from 2027. This cross-border hydrogen infrastructure aims to support and accelerate the development of offshore wind energy in the region and the wider Baltic Sea area, while ensuring a reliable and cost-efficient decarbonization pathway for the energy system in northeastern Europe.

- *AquaDuctus pipeline*. [125] As part of the AquaVentus initiative, the offshore AquaDuctus pipeline will be responsible for transporting green hydrogen from the North Sea directly to the mainland. The AquaVentus initiative aims to install 10 GW of electrolysis capacity for hydrogen production from offshore wind power, spanning between Helgoland and Doggerbank. Once the construction of the production plants is fully finalized, AquaDuctus is projected to transport up to 1Mt of green hydrogen (33 TWh) annually starting from 2035 onwards.

Regarding biogas, most of the nearly 10,000 biogas plants operating in Germany produce biogas under the German Renewable Energy Sources Act (EEG). **Currently, about 71 TWh of biogas and 10 TWh of biomethane are already made available every year**. With a consistent expansion of biomethane processing, up to **100 TWh of biomethane could be produced and fed into the gas grids by 2030**. This amount could rise to **250 TWh by 2050**. [126] Germany holds the majority share of biogas plants in Europe, accounting for 60% of the total, and 27% of European biomethane plants are also located in Germany. However, despite its current status as the leading producer, the biogas market in Germany is experiencing a decline, and the growth rate of German biomethane production is slower compared to countries such as the United Kingdom, Denmark, France, the Netherlands, and Italy. [65] Nevertheless, the rise from 10 to 250 TWh would still be very ambitious. Contrary to the case of France, hydrogen seems to play a more important role than biomethane in the German future energy system.

5.2.11 Greece

The **natural gas demand in Greece was 32.87 TWh in 2021**. This amount is expected to drop to **21.04 TWh in 2030.** [127] Other sources, however, estimate that the natural gas demand could **increase 35% in 2030**. [128] No estimations could be gathered for 2040 or 2050.

In 2022 Greece started drafting its own National Hydrogen Strategy. [129] **By 2030, Greece aims to produce 3.5 TWh of hydrogen**, with a total capacity of 750 MW sourced from renewable energy projects (3 GW capacity, 80% photovoltaic, 20% wind). The primary use of the produced hydrogen will be to replace natural gas and partially petroleum in refineries, industry, and transportation. Looking ahead to **2040, Greece's potential for green hydrogen production is estimated at around 3 Mtoe (34.89 TWh), with 1 Mtoe (11.63 TWh) intended for export**. **By 2050, the country plans to increase its production to 7.4 Mtoe (86.06 TWh) and export 2.3 Mtoe (26.75 TWh)**. To meet these goals, around 60 GW of renewable energy sources (RES) will be allocated for electrolysis units, with 30 GW targeted by 2040. The draft National Strategy, expected to undergo public consultation during 2023.

The Greek plan comprises four stages. The initial phase spans from 2022 to 2027, during which uncertainties in investments are expected due to high costs. State aid will be necessary to support infrastructure development during these five years. The second phase, from 2025 to 2030, involves the commencement of pilot projects, upgrades, and adjustments to gas pipelines, as well as planning for hydrogen storage, with the state providing aid and tax incentives. The third phase, from 2027 to 2035, focuses on establishing the market and implementing hydrogen-only networks to facilitate cross-border transactions. It also includes the development of large-scale hydrogen storage and other related initiatives. The fourth phase, from 2030 to 2045, centres on the industrial maturation of the hydrogen sector. This phase is expected to involve the completion of pan-European hydrogen and synthetic fuel infrastructure, the conversion of significant portions of existing gas networks to hydrogen, the implementation of storage systems, and medium to large-scale compression and liquefaction. Additionally, national interoperability with the European system will be established. The Hydrogen Strategy also identifies growth potential in various sectors.

The **hydrogen demand in Greece is expected to be 7 TWh in 2030, 27 TWh in 2040 and 42 TWh in 2050**. [130] Comparing this numbers with the hydrogen production discussed at the beginning of the section, Greece may start as an importing country in 2030 to turn from 2040 on in a hydrogen exporting country.

The Clean Hydrogen Monitor report [76] considers an **electrolysis capacity for Greece of 5,428 MW by 2030**. The supply capacity predicted in the EHB report [66] is coherent to this amount with **11.0 TWh/a**. The hydrogen production potential according to this last report may reach **54 TWh/a in 2040, rising to 87 TWh/a in 2050**. The **hydrogen demand by 2030 may reach 0.33-7.0 TWh/a. By 2040 and 2050 it should rise to around 28 TWh/a and up to 44 TWh/a, respectively**. [66, 77]

The Greek TSO DESFA (see section 3.1.11) has recently presented a proposal for the *EL24 project*, [131] also known as the *H_2 Hellenic Network*. This project aims to establish a regional, open-access, high-pressure network for the transmission of clean hydrogen across Greece. The H2 Hellenic Network, selected as part of Greece's participation in the IPCEI Hydrogen initiative, seeks to connect hydrogen supply and demand throughout the country, with a particular focus on production points in the southern region, extending up to the Greek-Bulgarian border and the Thessaloniki-Kavala area. These regions house storage facilities and hydrogen-intensive industries. The project serves as a starting point for a growing hydrogen network, both in terms of scope and volume. It will be connected to potential partners, including hydrogen producers and consumers, within Greece and neighbouring countries. Furthermore, it will contribute to the development of the southeaster section of the EAB initiative. Spanning a total distance of 147 km, the pipeline will stretch from Trikala in the Imathia region to Ptolemaida. It will feature four distribution branches serving the urban centers of Edessa, Skydra, Naoussa, Veria, Florina Amynteo, Ptolemaida, and Kozani. Additionally, the pipeline is designed to be compatible with the transportation of hydrogen, making it Greece's first pipeline fully capable of supporting the transmission of renewable gases. The gas pipeline, which is part of DESFA's ten-year development plan spanning from 2022 to 2031, has a budget of 147 million euros and is projected to be completed in autumn 2026. [132]

The injection of biogas / biomethane into the national transmission system is not done to date and is not provided for under the legal framework. [129] Some reports expect a **biomethane production potential in Greece of 6.5 and 30 TWh/a by 2030 and 2050, respectively**.

5.2.12 Hungary

Hungary's hydrogen national strategy [133] was launched in 2021. The report shows how in 2020 6.3 TWh of grey hydrogen were produced. The estimations for **2030 are to basically keep the production rate (6.4 TWh)**, but including 0.8 TWh of low-carbon hydrogen in it. **For 2040, 6.6 TWh of hydrogen are estimated to be produced** (of which 5.0 TWh would be low-carbon hydrogen and 0.7 TWh, green hydrogen). Finally, **in 2050 it is expected to be produced 9.8 TWh of hydrogen** (43 % low-carbon hydrogen and 57 % green hydrogen). The use of low-carbon hydrogen and electrolysis-based carbon-free hydrogen is expected to rise from 2040 on until industrial hydrogen becomes significantly decarbonised by 2050. The strategy shows that all the hydrogen consumed will be demanded at national level.

The Clean Hydrogen Monitor report [76] considers an **electrolysis capacity in Hungry of 141 MW by 2030**. The supply capacity of **0.4 TWh/a** predicted in the EHB report [66] is coherent to this amount. The hydrogen production potential according to this last report may reach **11 TWh/a in 2040, doubling to 32 TWh/a in 2050**. The **hydrogen demand by 2030 may reach 7.0-9.3 TWh/a. By 2040 and 2050 it should rise up to 15 TWh/a and 25 TWh/a, respectively**. [66, 77] Based on these last reports, Hungary would become a hydrogen exporting country from 2040 on that would deliver the surpluss in hydrogen to Central Europe through Corridor E, contrary to the self-sufficient country developed in the national strategy.

The TSO FGSZ (see section 3.1.12) states that the role of natural gas in the emission reduction of the Hungarian economy is strengthened and supported by strong security of supply. In line with the National Clean Development Strategy and the National Energy Strategy objectives, a 40% reduction in emissions is targeted, compared to the 1990 baseline. This target is to be further increased to 65% by 2040, in order for the Hungarian economy to achieve net carbon neutrality by 2050. By taking these measures, Hungary can contribute to the European Green Deal action plan, which was announced by the European Committee on 11th December 2019. [134]

The strategy of Hungary towards the transport of hydrogen via the natural gas grid consists in adapting to the Hydrogen European Backbone scenario. This way, the European TSOs Transgaz of Romania, GAZ-SYSTEM of Poland, Eustream of Slovakia, and FGSZ of Hungary have agreed on a strategic partnership to explore the possibilities of decarbonising the operation of the grid, transporting green gases. The collaboration will results in the development of a feasibility study. [135]

According to the IEA, [136] **Natural gas consumption reached 117.41 TWh in 2020**, being the most significant energy source in the country. **Until 2030,** natural gas may hold the largest share of final energy consumption in Hungary (**total demand of 79.65-209.26 TWh**). However, its contribution is projected to decrease significantly after 2040, with a complete phase-out in certain sectors. In the transport and industrial sectors, hydrogen will partially replace natural gas, accounting for 11-15% of the final energy consumption by 2050. Despite Hungary's commitment to phasing out coal from electricity generation by 2030, coal is still expected to be a part of the energy mix in 2050, primarily in the industrial sector, albeit with the smallest share among all energy sources. The final energy consumption in **2050** is projected to reach 134.44-149.17 TWh, due to expected economic growth driven by investments for the energy transition, of which up to **129.29 TWh would be provided by natural gas and renewable gases**. The decrease in the total demand is lower than in other countries in Europe, mainly due to lower electrification of the energy sector. Besides, to achieve net zero emission by 2050, Hungary plans to use natural sink capacities to balance out the remaining emissions in 2050, e.g. reforestation. Specifically for biogas and biomethane, the **biomethane production potential of Hungry has been estimated in 11.5 TWh/a by 2030 and 45.0 TWh/a by 2050**. [74]

5.2.13 Ireland

Ireland's Programme for Government [137] sets out a commitment to reduce overall greenhouse gas emissions by 7% until 2030, with the aim of achieving net-zero emissions by 2050. Ireland's carbon budget program sets emission reduction targets for various sectors, including electricity, transport, buildings, industry, and agriculture. The goals range from 25% to 75% reductions per sector **by 2030**, relative to 2018 emission levels. The agreement also allocates additional resources for solar (increasing the target to 5,500 MW), offshore wind (raising the target from 5,000 MW to 7,000 MW), **green hydrogen (2 GWs from dedicated offshore wind), agri-forestry, and anaerobic digestion (up to 5.7 TWh of biomethane)**. [138] By displacing natural gas with green hydrogen produced from offshore wind, Ireland could eliminate approximately one million tonnes of CO_2 equivalent from its national emissions annually.

Gas Networks Irland, the main Irish TSO (see section 3.1.13), has reported three possible scenarios have been reported for 2030: [139]

- Low Demand –2 GW for green hydrogen from dedicated offshore, which equates to around.5.2 TWh/a. These sectoral emissions targets do not meet the 51% reduction required.
- Medium Demand –Ireland delivers its fair share of the EU's REPowerEU target by 2030 (17% of gas demand or around 9.75 TWh).

- High Demand – A 20% target (blending limit) would equate to c.11.5 TWh.

This means that the **hydrogen production capacity of Ireland by 2030 may reach 5.2-11.5 TWh.**

According to the SEAI's National Heat Study, [140] Ireland has the potential to **produce around 90 TWh of green hydrogen per year by 2050** because of the abundance of wind energy resources, especially offshore wind. To provide context, **the total gas demand in Ireland was 56.26 TWh in 2021**. Therefore, green hydrogen has the potential to significantly reduce Ireland's gas imports.

The widespread use of hydrogen is expected to emerge in the 2030s and beyond as dedicated offshore wind farms are developed, leading to the establishment of hydrogen valleys or clusters. The initial entry of hydrogen into the Irish gas network is likely to occur through the Interconnector at Moffat in Scotland and is anticipated to happen later in this decade. Gas Networks Ireland is collaborating with National Grid UK to ensure that the Interconnection Point is ready to accept a hydrogen/natural gas blend of up to 5% by 2025. [138] The EHB study suggests that one of Ireland's interconnectors to the UK could become a hydrogen interconnector by 2040, although repurposing it sooner would be possible if there is sufficient demand for export and if Ireland has fully utilized hydrogen volumes for its own decarbonization needs.

Currently, mainland Europe typically stores approximately 90 days of annual gas consumption in underground geological formations during the heating season. However, Ireland lacks large-scale gas storage facilities, and its only underground storage facility at Kinsale Head ceased operations in 2017 and is being decommissioned. With Ireland's only gas interconnection to a non-EU state (UK) and the UK itself having only 5 days of storage, **Ireland may require up to 20 TWh of decarbonized energy storage to replace fossil fuels in the electricity system over the next three decades**. Suitable geological formations will determine the locations for hydrogen storage, with the depleted Kinsale gas field, for example, having the potential to store up to 3 TWh of green hydrogen, equivalent to approximately 10% of current Irish annual electricity consumption. Other potential sites for large-scale hydrogen storage in Ireland include Islandmagee in Co. Antrim, the future depleted Corrib gas field, salt caverns offshore Dublin, and Shannon. [138] Gas Networks Ireland states that the pipeline steel grades utilized in the Irish transmission network comply with international hydrogen pipeline design codes and are compatible with hydrogen. Approximately half of the transmission system pipes can accommodate 100% hydrogen or hydrogen/natural gas blends at their current design pressure. However, the other 50% of the pipes require qualification testing to allow for the current design pressure with hydrogen concentrations exceeding 10%. However, a modification to the Code of Operations Part G Technical (Appendix 1) will be required to permit transport of hydrogen through the Irish gas network. [141]

According to the Net Zero by 2050 report, [140] the **total gas demand in 2030 is expected to be 34-53 TWh**. No demand for hydrogen is predicted for this year. In **2040, the total gas demand may be 20-45 TWh**, of which **4.94-9.36 TWh would be consumed as hydrogen**. In **2050 the total gas demand would fit between 13-41 TWh**. The demand for **hydrogen may lay between 7.54-23.40 TWh.** It is curious how according to this report the injection of biomethane disappears in 2050 and all the biogas is consumed off grid (up to 7.8 TWh), so hydrogen would be replacing biogas as renewable gas in Ireland in the coming years.

The Clean Hydrogen Monitor report [76] considers an **electrolysis capacity in Ireland of 3,250 MW by 2030**. The supply capacity of **9 TWh/a** predicted in the EHB report [66] is coherent to this amount. The hydrogen production potential according to this last report may reach **46 TWh/a in 2040, almost doubling to 70 TWh/a in 2050**. The **hydrogen demand by 2030 may be none or at the most reach 3 TWh/a. By 2040 and 2050 it should rise up to 13-17 TWh/a and up to 30 TWh/a, respectively**. [66, 77]

Biomethane will also play a role in Ireland as renewable gas, although not as significant as hydrogen. Gas Network Ireland predicts that **11.5 TWh/a of biomethane** could be supplied to energy customers, being around 20% of predicted natural gas demand **in 2030**. [99] **Up to 5.1 TWh may be available for injection in the grid by 2050**. [142] The total biomethane production potential is however estimated in **18.14 TWh**. [74]

5.2.14 Italy

The natural **gas demand in Italy in 2020** was 746 TWh. [68] With its 1,710 active biogas plants and 23 biomethane plants, Italy has set a **biomethane production target of 11.74 TWh/a by 2023.**

Italy launched its national hydrogen strategy in 2020. [143] The investments dedicated to the entire hydrogen chain until 2030 are quantified at 10 billion €. The goal set by the government is to achieve a hydrogen penetration in end uses of 2% of the final energy consumption by **2030 (24 TWh**) and up to 20 % by **2050**. These would be delivered by **5GW of electrolyser capacity** which would however cover up slightly more than half the said amount, suggesting a role for blue hydrogen as well. The National Recovery and Resilience Plan recognises hydrogen's leading role, allocating foreground, allocating 3.6 billion € of funds to foster the penetration of hydrogen in the energy, industry and transport sectors.

Snam, main TSO in Italy (see section 3.1.14) has reviewed future scenarios in their grid to allow the analysis of its possible evolution. [144] Two specific scenarios are studied, the National Trend Italy (NT) and the Global Ambition scenario (GA). The role of gas is confirmed as fundamental in all analysed scenarios to enable the energy transition thanks to the gradual replacement of natural gas with green gas. **By 2030, gas demand in Italy** varies greatly depending on the scenario considered. The NT Italy scenario forecasts a demand of **659 TWh**. The GA scenario stands at scenario stands at **773.2 TWh**. The contribution of **green gas** is also different in the scenarios, about **11 TWh in NT Italy (10.6 TWh of biomethane and 0.34 TWh of hydrogen) and about 45 TWh in the GA scenario (35.9 TWh of biomethane and 8.7 TWh of hydrogen)**. The hydrogen demand is lower that that reported in the national hydrogen strategy. In **2040**, gas demand remains higher than in 2030 for the NT Italy scenario, **reaching 654 TWh**, thanks to the growth of **green gas reaching about 87 TWh (74 TWh of biomethane and 13.1 TWh of hydrogen)**. In the GA scenario the gas demand drops slightly compared to 2030 and stands at around **690 TWh** in 2040, with a contribution from **green gas reaching 123 TWh (98.3 TWh of biomethane and 24.6 TWh of hydrogen)**.

Other sources highlight a greater biogas potential in Italy already by **2030**, with an estimated total of 10 billion Nm3 per year. This potential includes agricultural crops and residues, organic municipal waste, and other feedstocks. In terms of energy, this resource is equivalent to **100 TWh/a**, with 40.40 TWh allocated for direct use and the remaining amount intended for grid injection. Looking ahead to **2050**, the estimated **biogas resource is proposed to increase significantly to 350 TWh/ar**. Out of this total, 97.21 TWh is anticipated for direct use, while 252.79 TWh is intended for grid injection. [99] In any event, it is clear that biomethane will play an important role as renewable gas in the Italian grid.

A more recent study named, *the Italian Long-Term Strategy on the Reduction of Greenhouse Gas Emissions* (Long-Term Strategy, LTS) [145] contains first indications to achieve climate neutrality **by 2050. Gas will maintain a primary role in the overall energy mix, covering a share of no less than 33%.** In this scenario, natural gas is expected to be around 33 TWh (4% of total demand) while maintaining a significant share significant share in supporting the electricity system (around 20% for generation), also thanks to its characteristics of flexibility and security. In relation to final consumption, natural gas remains particularly present in the industrial sector with an expected share of about 10% of total energy demand in the sector. Furthermore, looking at mobility, there are approximately 3 million vehicles expected to be gas-powered by 2050. With strongly growing volumes, alongside natural gas, there is **room for biomethane (at least 99 TWh**) supported by the development of biogas and its upgrade to biomethane for use in both end uses and in the power generation sector. According to the LTS, moreover, **hydrogen will predominantly enter the energy mix with 111-163 TWh**, i.e. up to 21% of energy consumption. However, it is reasonable to assume that hydrogen is also capable of covering higher shares higher shares (in the order of magnitude of 25% of final consumption), driven by the decarbonisation of industrial sectors, where hydrogen is often the best solution for decarbonisation, and to some extent of other sectors as well. the potential re-use of the existing gas network will accelerate.

The Clean Hydrogen Monitor report [76] considers an **electrolysis capacity in Italy of 2,564 MW by 2030**. The supply capacity of **7 TWh/a** predicted in the EHB report [66] is coherent to this amount. The hydrogen production potential according to this last report may reach **49 TWh/a in 2040, almost doubling to 93 TWh/a in 2050**. The **hydrogen demand by 2030 may be between 9.6-23.0TWh/a. By 2040 and 2050 it should rise up to 89-154 TWh/a and up to 187-237 TWh/a, respectively**. [66, 77]

Regarding the readiness of the grid, Snam reports that about 99% of the existing pipelines are suitable for the transport of hydrogen blends up to 100%. Some localised interventions are however necessary, such as the replacement of some components and/or the reduction of the maximum operating pressure on some pipeline sections. Snam Rete Gas is working with the National Fire Brigade and the universities of Rome Padua, Pisa and Turin, to define a new technical rule for the transport of hydrogen through underground pipelines, which will constitute the necessary national regulatory reference in analogy with what has been developed over the past decades for the transport of natural gas. [144]

Two projects were identified for the realisation of electrolysers with 'network-related function', located in Apulia and Sicily to be developed in two phases. [144] The first phase involves the installation of two electrolysers in Puglia and Sicily with a size slightly smaller than 100 MW in the vicinity of the methane pipelines dedicated to the import from Melendugno and Mazara/Gela so that the hydrogen produced can be mixed in the network gas (blending) with the incoming volumes up to a maximum percentage of 2% by volume. The second phase will be developed to facilitate the recovery of the increasing volumes of overgeneration expected by the scenarios and will require the installation of approximately a further 1.4 GW of electrolysers in proximity of the most congested electricity grid nodes. For further details, please refer to the project fiches presented in the document "Intervention chapter 'Energy Transition Interventions'.

Basing on the information given above, the hydrogen production capacity in Italy seems insufficient to cover the expected demand, and large amounts of hydrogen are expected to be imported, unless more electrolysers are commissioned, or other sources of hydrogen are used. Besides, biomethane seems to have the same level of importance as hydrogen as renewable gas in Italy in the future.

5.2.15 Latvia

The total energy consumption in Lativia was 46.61 TWh **in 2020 (15.79 TWh covered by natural gas**). The projected final energy consumption for **2030** decreases to 43.22 TWh, where **15.59 TWh** would be covered by natural gas, remaining therefore the gas demand constant. [146]

No hydrogen strategy has been developed in Latvia so far and the information available is scarce. The Clean Hydrogen Monitor report [76] considers an **electrolysis capacity in Latvia of 30 MW by 2030**, leading to negligible supply capacity (<0.1 TWh/a). The hydrogen production potential may reach **9 TWh/a in 2040 and 20 TWh/a in 2050**. [66] No **hydrogen demand is expected by 2030 either. By 2040 and 2050 it should be up to 1 TWh/a and 1.6-3.0 TWh/a, respectively**. [66, 77]

Latvia will be contributing to the Nordic-Baltic Hydrogen Corridor (see section 5.2.8) as an intermediate country adding some hydrogen to the grid.

The **biogas and biomethane production in Latvia was small in 2020, with 860 and 4 GWh**, respectively. [65] The long term strategy of Latvia towards this renewable gas for internal consumption seems, however, powerful, since the **potential for biomethane production has been estimated in 1.40 TWh/a by 2030 and 15.6 TWh/a by 2050**. [74] The whole gas demand in Latvia could be covered by biomethane in 2050.

5.2.16 Lithuania

The total gas demand in Lithuania in 2020 was 23.60 TWh. [68]The **biogas production this year was 860 GWh**, none of it upgraded to biomethane. [75]

By 2030, it is projected that approximately 8% of Lithuania's total natural gas demand, equivalent to **1.6 TWh, will be supplied by renewable energy sources** entering the gas system with guarantees of origin. This includes **0.7 TWh of energy from green hydrogen and 0.9 TWh from biogas**. To identify potential risks in the gas infrastructure, a hydrogen research program was initiated in December 2021, supported by a scientific organization. The pilot project and study phase will provide valuable insights for the gradual adaptation of the gas transmission system infrastructure to accommodate the transportation of a hydrogen/methane blend. This measure aims to **replace natural gas with green hydrogen gas, allowing for the injection of up to 10% of the existing gas transport system by 2026, which corresponds to over 0.7 TWh**. [147]

The Hydrogen Development Roadmap [148] estimates similar numbers for the hydrogen demand and production expected in the coming years. The base case scenario estimates a **hydrogen demand of 0.86 TWh by 2030, 6.73 TWh by 2040 and over 12.54 TWh per year by 2050**. Hydrogen production in 2030-2040 may be biased towards the north-east region of Lithuania, with high potential demand in the Central Lithuania region connected by pipelines. The goal for **2030 is to reach 300-350 MW of electrolysis production capacity to serve 0.86 TWh of demand**. The supply of renewable electricity is expected sufficient for 2030 demand, but limited onshore and offshore wind resources could make it difficult to meet hydrogen production requirements for 2050. There is going to be a need for cooperation with neighbouring countries on either renewable power sourcing for electrolysers, LNG sourcing for blue hydrogen production, or importing hydrogen itself.

The Clean Hydrogen Monitor report [76] considers an **electrolysis capacity in Lithuania of 200 MW by 2030**. The supply capacity of **1 TWh/a** reported in the EHB report [66] may be slightly higher. The hydrogen production potential according to this last report may reach **9 TWh/a in 2040, increasing to 15 TWh/a in 2050**. The **hydrogen demand by 2030 may be either none or reach 5 TWh/a. By 2040 and 2050 it should rise up to 11-15 TWh/a and up to 21 TWh/a, respectively**. [66, 77]

In the case of alternative renewable gases, the **potential for biomethane production** has been estimated **in 4.5 TWh/a by 2030 and 9.5 TWh/a by 2050**. [74]

During the 2030s, there will be a rise in dedicated hydrogen pipelines, facilitating the establishment of production facilities near renewable electricity sources. Initially, these pipelines may coexist with natural gas pipelines but have the potential to replace them as the importance of natural gas diminishes in the 2040s, aligning with Lithuania's journey towards achieving Net Zero. In addition to the domestic network, the Baltic states will be connected by the EU hydrogen backbone by 2040. This transnational infrastructure will play a crucial role in stabilizing hydrogen pricing and fostering cross-border trade of hydrogen within the Baltics. [148]

Amber grid, the main TSO in Lithaunia (see section 3.1.16), plans to adapt their gas transmission system to the new energy over the next ten years, so that Lithuania's pipelines will carry not only natural gas but also hydrogen. [149] As part of the network development plan for the period 2022-2031, an infrastructure project has been outlined to address the transportation of green hydrogen within the existing gas system. [150] The project will be implemented in two phases. From 2023 to 2025, a pilot project will be carried out to explore the necessary adaptations required for integrating green hydrogen into the gas system. This phase aims to gather essential insights and knowledge on the feasibility and practicality of transporting green hydrogen effectively. Starting from 2026 and onwards, the focus will shift towards gradually adapting the gas transmission system infrastructure to accommodate the transportation of a hydrogen/methane blend. This gradual adaptation will involve the necessary modifications and upgrades to ensure the safe and efficient transmission of the blended gas. The successful implementation of these infrastructure projects will **pave the way for the substitution of up to 10% of the natural gas system with green hydrogen gas by 2030**.

The adoption of the Alternative Fuels Law in 2021 strengthens the potential for development in the Lithuanian biomethane sector. By 2030, there is a target of 15% renewable energy utilization in the transport sector, which entails increasing the electrification of transportation, promoting gaseous fuels and hydrogen gas derived from biomass, and raising blending requirements for biofuels. These measures will incentivize investors to construct biomethane plants, integrate them into the gas grid, and generate environmentally friendly energy. Amber Grid is actively engaged in advancing biogas in Lithuania, which can be introduced into the natural gas system or transported through it. [151]

5.2.17 Luxembourg

Luxembourg launched its hydrogen national strategy [152] in 2021. In Luxembourg, an **annual consumption of fossil hydrogen of around 15 GWh** has been identified in industry. Substituting this fossil hydrogen with renewable hydrogen should be an intermediate objective before gradually decarbonizing other processes that are difficult to decarbonize through electrification. Luxembourg aims for climate neutrality by 2050. This decarbonization potential is translated into **hydrogen demand potential that could exceed 4.12-9.90 TWh/a** for the three priority sectors: industry, transport and an integrated energy system. 6-15 TWh of renewable electricity are necessary to reach this demand.

The **total gas demand in Luxembourg was 9.9 TWh in 2050**. [68] The expected hydrogen demand by 2050 would cover all this energy amount.

5.2.18 Norway

Despite the fact that 93% of Norway's domestic energy production in 2020 consisted of natural gas and oil, Norway's energy demand is highly electrified. The total energy demand in Norway was 232.6 TWh in 2020 and electricity covers almost half of the country's total energy demand. **The total gas demand is just 25.82 TWh, comprised by natural gas (10.00 TWh) and biogas (15.82 TWh)** [153]

The Norwegian government launched in 2020 its hydrogen national strategy [154] in 2020. There is however no estimation for hydrogen demand nor production in it. It is explained how in Norway, electricity used to produce hydrogen through electrolysis is exempt from taxes. This helps to reduce the cost level at which hydrogen becomes competitive compared with other energy carriers. In 2020, the consumer tax on electricity is NOK 0.1613/kWh.

DNV has recently launched its energy transition Norway 2022 report. In it DNV predicts that most of the hydrogen production in Norway will be derived from natural gas, with a growing emphasis on

CCS (blue hydrogen) by **2030. The demand and production of hydrogen will then both stand at 15.84 TWh/a. By 2040, the anticipated hydrogen demand will experience a slight increase to 17.16 TWh/a**. This requirement can be satisfied by the **22.44 TWh/a of blue hydrogen**. Furthermore, it is projected that **green hydrogen production will reach 9.9 TWh/a this year**. Looking ahead to **2050, the domestic demand for hydrogen in Norway will soar to 39.60 TWh/a**. The primary consumers will be industrial heat, followed by e-fuel, ammonia, and methanol for shipping and aviation. **However, hydrogen production will far surpass demand, reaching 140.91 TWh/a (42.90 TWh/a blue hydrogen and 98.01 TWh/a green hydrogen)**. Starting from 2040, there will be periods when wind energy generation across Northern Europe becomes highly lucrative, making it more profitable to produce green hydrogen from electricity instead of exporting the electricity directly. Consequently, the production of green hydrogen will increasingly exceed domestic demand, and **by 2040, Norway will export 33 TWh/a of hydrogen annually, rising to 112.2 TWh/a by 2050**.

Nonetheless, **Norway is confident in the fact that the majority of energy exports will still comprise gas and oil by 2050.** Norway possesses abundant untapped energy resources in the form of wind and natural gas, and it is unlikely that the EU and the UK will be able to meet their extensive requirements for renewable electricity and hydrogen without significant imports. **Norwegian natural gas can be converted to blue hydrogen and exported to Northern Europe**, albeit at a slightly higher cost compared to subsidized green hydrogen from Southern Europe. With equal subsidies, the costs of blue hydrogen from Norway will be comparable, and the competition will depend on the extent to which existing gas infrastructure can be repurposed. It is entirely plausible that Northern Europe will necessitate both sources of hydrogen. Hence, if Norway desires to maintain its position as a significant energy-exporting nation, the country has ample opportunities to export a greater amount of power, as well as green and blue hydrogen.

The Clean Hydrogen Monitor report [76] considers an **electrolysis capacity in Norway of 1,975 MW by 2030**. The supply capacity detailed in the EHB report [66] is considerably higher, reaching **46 TWh/a**. The hydrogen production potential according to this last report may reach **151 TWh/a in 2040**. Surprisingly, this amount is expected to **drop to 112 TWh/a in 2050**. The **hydrogen demand by 2030 may be of 8.0-12.3 TWh/a. By 2040 and 2050 it should rise up to 17 TWh/a and just to 24 TWh/a, respectively**. [66, 77] Contrary to other countries, the hydrogen production in Norway seems to boost by 2030 and stabilize and even decrease later on.

Regarding biogas, the realistic potential for **production of biogas in Norway in 2030 is estimated at 2.5 TWh and** costs vary from 0.3 to 3 NOK/kWh for different feedstocks and value chains. [155] Other reports increase this potential to **4.3 TWh/a by 2030 and increase it to 14.9 TWh/a by 2050**.

5.2.19 Poland

In 2021 Poland consumed 269.82 TWh of natural gas. [156] Contrary to other European countries, Poland expected in a first term to increase the gas demand in the coming years. In April 2021, the Energy Policy until 2040 (PEP2040) [157] was developed, outlining the plans for Poland's energy consumption. The policy aimed **to increase the annual gas consumption in until reaching 325.64 TWh in 2030**. However, these projections underestimated the rapid growth of renewable energy sources and did not prioritize achieving energy indolence. The increase in gas demand was expected to continue until 2035, when the second nuclear power reactor would be launched. However, surveys conducted by Gaz-System (see section 3.1.19) from December 2022 to early February 2023 among industrial, energy and natural gas customers showed a surprisingly significant decrease in the projected demand for natural gas. Moderate scenarios suggest that the **peak demand for natural gas would occur in 2028, reaching 282.61 TWh or in 2030 reaching 325.64 TWh**, and then decline to **255.86 TWh in 2036** after the launch of the second nuclear unit. The maximum projected demand has been reduced by nearly 10 bcm. Poland has veered away from being heavily reliant on gas and now has a chance to achieve genuine diversification of energy sources by 2036. [158]

The Polish hydrogen national strategy was launched in 2021. [159] In Poland, as of 2020, nearly 95% of hydrogen was generated from fossil fuels, involving natural gas steam reforming, partial oxidation of methane, and coal gasification (which is in line with the global average of 76%). Poland's Hydrogen Strategy proposes a hybrid solution, involving a medium-term approach (until 2030) focused on developing low-emission hydrogen production technologies (with a carbon footprint below 5.8 kg CO2 eq/kg H_2), followed by a gradual increase in the utilization of zero-emission hydrogen in the long term, extending beyond 2040. By 2030, the aim is to reach **an installed production capacity of 2 GW**, sourced from low- and zero-emission methods. At this time, the goal is to have approximately 800-1000 hydrogen-powered buses in operation, gradually replacing conventional vehicles. A network of refuelling stations will continue to expand, supporting the production of hydrogen-based fuels like ammonia or methanol.

By 2030, the plan is to establish a minimum of 5 hydrogen valleys, which serve as hubs for advancing the hydrogen economy, integrating sectors, transforming industries for climate purposes, and constructing infrastructure (see Table 6): [160]

Table 6. Hydrogen valleys in Poland by 2030

Hydrogen Valley	Date of Establishment	Statutory Objectives
Pomeranian	1 October 2019	The objective is to establish a comprehensive hydrogen ecosystem in the Pomeranian region, encompassing various initiatives such as the implementation of hydrogen-powered land and sea transport systems (including buses, trains, and ships) and the connection of the Tri-City and Hel ports. Additionally, 'power-to-gas' projects will be developed in the region, focusing on converting surplus power into hydrogen. Furthermore, efforts will be made to raise awareness about hydrogen among the residents of the voivodeship.
Sub-Carpathian	18 May 2021	By 2030, the program aims to achieve a minimum estimated potential of 20,000 tons of hydrogen per year (0.66 TWh). Furthermore, it seeks to attain a 15% share of hydrogen as a fuel in the transportation energy mix specifically for the Pomeranian region.
Greater Poland	5 July 2021	Producing fuel cells, hydrogen buses, and work on hydrogen as a fuel to power aircraft.
Silesian-Lesser	31 January 2022	Cross-sectoral cooperation for the dissemination of hydrogen solutions and the production of green hydrogen.
Poland	25 February 2022	The focus is on supporting the advancement of the hydrogen economy and establishing the Silesian-Lesser Poland hydrogen industry. This industry will be based on the production of hydrogen through the electrolysis process, utilizing energy generated from renewable energy source (RES) installations. The generated hydrogen will be employed in various sectors, including energy, heat, transport, infrastructure, and industry
Lower Silesian	8 April 2022	The objective is to foster the creation of economic networks, facilitating collaboration and partnerships between suppliers, subcontractors, and various stakeholders. Emphasis will be placed on fostering connections between universities, research institutes, start-ups, clusters, implementation companies, local government units, and large state-treasury companies. This collaborative approach aims to promote knowledge sharing, innovation, and economic growth within the hydrogen sector.

Poland has the potential to become a leader in hydrogen energy due to its experience in hydrogen applications and existing transmission and storage infrastructure. The key hydrogen investments in Poland include: [161]

- *ZE PAK*: As the first hydrogen production company in Poland, ZE PAK acquired a **2.5 MW electrolyser in April 2020** to generate emission-free hydrogen as part of a 50 MW biomass unit in Konin. The company is also investing in green hydrogen refuelling stations.

- *LOTOS Petrobaltic*: This company plans to construct wind-powered electrolyzers to produce hydrogen during periods of lower electricity demand. Their business strategy involves building **100 MW electrolyzers by 2025**, with expansions to **1 GW by 2030 and 4 GW by 2040**. The hydrogen produced will be utilized by the company's refinery in Gdansk.

- *AZOTY PULAWY GROUP*: As Poland's largest producer, AZOTY PULAWY GROUP is responsible for 32% of the country's domestic hydrogen production. Currently, the company produces "grey" hydrogen for fertilizer production. To maintain its market position, Grupa Azoty aims to gradually decarbonize hydrogen production by investing in renewable energy sources and electrolyzers.
- *PKN ORLEN*: Poland's largest state-owned energy company, PKN ORLEN, has plans to construct **54 hydrogen charging stations across Poland by 2030, along with 250 MW electrolysers**. The "Hydrogen Eagle" initiative will support the transportation sector.

By 2040, Poland's annual hydrogen demand is expected to exceed 100 TWh. To meet this demand, hydrogen production in Poland will be pursued through three pathways: utilizing surplus renewable energy sources, operating a dedicated portion of renewable generation integrated with dedicated electrolyzers in the off-grid system, and dispersed production for local requirements.There is a realistic possibility that **by 2040, electrolysers with a capacity exceeding 20 GW will be able to satisfy the hydrogen demand in Poland**. [161] The **hydrogen production may reach 87 TWh in 2030 and rise to 375 TWh in 2050**, being consumed in the transport and industry sector. [162]

The Clean Hydrogen Monitor report [76] considers an **electrolysis capacity in Poland of 1,065 MW by 2030**. The supply capacity detailed in the EHB report [66] is coherent with this capacity with **2.9 TWh/a of hydrogen produced**. The hydrogen production potential according to this last report may reach **43 TWh/a in 2040 and 113 TWh/a by 2050**. The **hydrogen demand by 2030 may be of 0.33-22.0 TWh/a. By 2040 and 2050 it should rise considerably up to 88-120 TWh/a and around 155 TWh/a, respectively**. [66, 77].

Poland produced **in 2020 3.29 TWh of biogas** in its 328 plant, although none of it was upgraded to biomethane. The estimations for **2030 and 2050 reach 38.03 and 146.77 TWh**, respectively. [74]

Gaz System is actively collaborating with potential domestic and foreign stakeholders on initiatives associated with the possible implementation of a hydrogen economy in Poland. As part of these efforts, Gaz System is involved in developing assumptions for a hydrogen grid. This grid encompasses main transmission corridors in the country, interconnections with other countries, entry points from hydrogen production facilities or energy conversion services like electrolysers, entry-exit points to hydrogen storage facilities, and exit points to end-consumers and local distribution networks. Furthermore, Gaz System has launched a dialogue with market players through a questionnaire that focuses on new projects related to hydrogen, biomethane, and ammonia. This initiative aims to foster engagement and gather valuable input from industry participants, facilitating the exchange of ideas and information within the sector. [163]

5.2.20 Portugal

The natural gas demand in Portugal was 70.94 TWh in 2020. [164] The government is also clearly aiming to reduce natural gas demand, especially towards 2050. The Roadmap to Climate Neutrality 2050 (RNC2050) [165] indicates that primary energy consumption of natural gas should fall from **40.83 TWh in 2020 to 33.89-36.94 TWh in 2030 and to 8.33-9.44 TWh in 2050**.

The national Hydrogen strategy of Portugal (EN-H2) [166] considers several targets by **2030**. These goals include achieving installed hydrogen production capacity, increasing the number of hydrogen vehicles (both for passengers and goods), establishing 50 to 100 hydrogen filling stations, and achieving an installed capacity of **1- 1.5 GW in electrolyzes**. The idea is that hydrogen reaches **1.5-**

2% of the final energy consumption. The EN-H2 sets 2030 goals for 10-15% of the volume of gas delivered by natural gas networks to be hydrogen produced from renewable energy, and for bio-methane to cover 4.5% of total energy demand. The **projections to 2040 and 2050 consider 2-3 GW and 4-6 GW in electrolyzes, respectively**

The strategy will be developed in three phases:

- Phase 1 (2020-2023) focuses on laying the groundwork for hydrogen adoption. During this phase, the government will concentrate on adopting the necessary regulatory framework, implementing investment support measures, approving small to medium-sized projects, designing incentives for research and development, and initiating the Sines industrial project.

- Phase 2 (2024-2030) aims to build upon the progress made in Phase 1. It involves strengthening the regulatory framework and further enhancing support mechanisms with the assistance of European Union funds. Varied scale hydrogen projects will be implemented nationwide during this phase. The centerpiece of Phase 2 is the large-scale Sines project, which is expected to have an installed electrolyser capacity of at least 1 GW by 2030.

- Phase 3 (2030-2050) represents the consolidation of hydrogen as a key instrument for decarbonization. During this phase, the focus will be on solidifying the role of hydrogen in achieving decarbonization objectives, further expanding its applications, and maximizing its potential across various sectors of the economy.

The EN-H2 [166] highlights a major project centered around a hydrogen production complex in the port of Sines. The private consortium managing the Sines project released an initial plan in July 2020, aiming for rapid deployment of a 10 MW electrolyser pilot project. By 2030, their goal is to achieve an electrolyser capacity of 1.0-1.5 GW, with an estimated cost ranging from EUR 400-450 million. This ambitious project exemplifies Portugal's commitment to developing a robust hydrogen industry, fostering significant advancements in electrolyser capacity and supporting the country's energy transition and decarbonization effort [167]

The Portuguese government has introduced a comprehensive plan, known as *Ley de las Grandes Opciones*, which outlines a series of measures to promote the development of renewable energy sources. [168] This plan includes the implementation of new auction schemes specifically targeting offshore wind and renewable gas, with a strong emphasis on hydrogen and its various derivatives, such as ammonia, green methanol, and synthetic fuels. As per the official document, the first tender for green hydrogen will be launched within this year. According to the plan, the government aims to award **10-year contracts for the production of 3,000 tons of green hydrogen and 10,000 tons of renewable methane**. The reference price for green hydrogen has been set at 127 €/MWh, while the reference price for renewable methane is 62 €/MWh. These prices will serve as guidelines for the auction process, ensuring transparency and stability in the market.

By 2050, the government intends for almost all of the gas delivered via the natural gas network to be renewable gas, with the largest share coming from synthetic methane. [164] The share of the gas demand in the coming years as percentage of volume of gas delivered via pipeline would be the following:

- **2030**: 4.48 % synthetic natural gas, 4.25 % biomethane, 3.3 % renewable hydrogen and 87.97 % natural gas

- **2040**: 26.89 % synthetic natural gas, 8.25 % biomethane, 7.55 % renewable hydrogen and 57.31 % natural gas

- **2050**: 76.65% synthetic natural gas, 11.56 % biomethane, 7.78 % renewable hydrogen and 4.01 % natural gas

The Clean Hydrogen Monitor report [76] considers an **electrolysis capacity in Portugal of 3,825 MW by 2030**. The supply capacity of **16 TWh/a** detailed in the EHB report [66] is coherent with this electrolysis capacity. The hydrogen production potential according to this last report may reach **55 TWh/a in 2040 and 74 TWh/a by 2050**. The **hydrogen demand by 2030 may be of 5.0-5.7 TWh/a. By 2040 and 2050 it should rise considerably up to 20-22 TWh/a and around 28-33 TWh/a, respectively**. [66, 77].

Regarding the production of biomethane, it has been reported that Portugal may have a potential for producing up to **7.4 TWh/a of biomethane by 2030 and 42.8 TWh/a by 2050**. [74]

Portugal has created a different strategy to that of the other European countries in which **hydrogen will be highly used for the production of synthetic methane** instead of directly used. The surplus can however be exported.

5.2.21 Romania

Romania consumed **132.58 TWh of natural gas in 2021**. [169] **In 2030 the demand is expected to reach 157.00 TWh**. [170] Regarding **biogas**, the production in 2021 is negligible and the production capacity towards **2030 and 2050 may be 23.49 and 93.04 TWh**, respectively.

According to the TSO Trasngaz [171] (see section 3.1.21), the natural gas infrastructure has the capacity to accommodate up to 10% of hydrogen and other decarbonized gases, such as biomethane. The estimated investment of the National Recovery and Resilience Plan (PNRR) for this project amounts to 400 mio€. The allocated budget is expected to cover the construction of approximately 4,000 km of smart pipelines, along with the installation of 160,000 smart metering system connections. **To enable the injection of up to 10% hydrogen into the smart gas network, approximately 0.31 TWh of green hydrogen will be required**. This green hydrogen will be produced through electrolyzes, which will be powered by approximately 580 GWh of renewable energy generated from sources such as photovoltaic, hydro, and wind power. For instance, the renewable energy equivalent of 580 GWh can be generated within a year by photovoltaic farms with an installed power capacity of around 450 MW or microhydro plants with an installed power capacity of approximately 150 MW. By making this investment, Romania aims to actively contribute to the implementation of the European Union's hydrogen strategy.

There is currently no hydrogen strategy for Romania. It is expected to be launched this year 2023. However, the National Recovery and Resilience Plan (PNRR) includes provisions for the development of a regional natural gas infrastructure, encompassing transport, distribution, and compressor stations. According to PNRR provisions, the intervention aims at promoting investments in building new capacities of **at least 100 MW in electrolysis plants, with an estimated generated quantity of at least 10,000 tons of renewable hydrogen per year (0.33 TWh/a) and must be carried out by Q4/2025**.

Studies based on Fit for 55 package proposals on hydrogen use show that **an electrolysis capacity between 1,470 MW and 2,350 MW should be installed in Romania by 2030** and this will require between 3 GW and 4.5 GW new renewable energy sources to be installed in addition to the capacities included in the National Energy and Climate Plan. [172] The main applications of renewable hydrogen by **2030** will be in industry and transport, aiming a **total demand between 5.11 and 8.16 TWh**. [173]

Transgaz has identified 10 corridors that may be included in the 'backbone' of the future European hydrogen transmission system: [171]

- Black Sea – Podisor corridor
- Giurgiu – Podisor – Jupa – Nădlac (BRUA) Corridor
- Onești – Gherăești – Letscani – Ungheni (Republic of Moldova) Corridor
- Petrovaselo – Comloșu Mare (Serbia) Corridor
- Jupa – Prunișor Corridor
- Isaccea – Onești Corridor
- Silistea – Bucharest Corridor
- Onești – Coroi – Hațeg Corridor
- Coroi – Mediesu Aurit Corridor
- Podișor – Coroi Corridor

If mixtures of 10 vol% of hydrogen were transported through such transmission corridors, the total quantity of hydrogen that can be transported would be: 1.31 TWh to/from Hungary, 0.45 TWh/a to/from Bulgaria (Ruse), 1.78 TWh/a to/from Bulgaria (Negru Voda), 0.48 TWh/a to/from Serbia, 0.65 TWh/a to/from the Republic of Moldova and 3.59 TWh/a to/from Ukraine. A total of 8.23 TWh/a of hydrogen.

The Clean Hydrogen Monitor report [76] considers an **electrolysis capacity in Romania of 1,235 MW by 2030**. The supply capacity of **5.2 TWh/a** detailed in the EHB report [66] may be slightly higher. The hydrogen production potential according to this last report may reach **50 TWh/a in 2040 and 83 TWh/a by 2050**. The **hydrogen demand by 2030 may be of 8.3-14.0 TWh/a. By 2040 and 2050 it should rise considerably up to 24-34 TWh/a and up to 46 TWh/a, respectively**. [66, 77].

5.2.22 Serbia

Serbia consumed **26.40 TWh of natural gas in 2021**. [174]There are currently 24 operational biogas plants, producing 417 GWh of biogas. No biomethane plants have so far been installed in Serbia, as there is no sufficient legal and regulatory framework for its production and use. [65] No production potential for biogas in Serbia could be found for 2030 nor 2050.

There is currently no hydrogen strategy in Serbia but is already being drafted. According to the last reports, [175] the hydrogen production may start in Serbia in 2025. **By 2035**, hydrogen should be produced in renewable power plants with a total installed capacity of 100 MW (80 MW in wind farms and 20 MW in solar power plants), **using 270 GWh to generate about 5,100 tons of hydrogen per year (0.17 TWh/a). By 2050 Serbia should be producing about 20,600 tons of hydrogen (0.68 TWh)** from 1,080 GWh of electricity generated in renewable power plants with an overall capacity of 400 MW (320 MW in wind farms and 80 MW in solar power plants).

This hydrogen production seems insufficient to reach the expected gas demand based on the numbers given for 2021 at the beginning of this section.

5.2.23 Slovakia

The **total natural gas demand in Slovakia in 2020 was 58.01 TWh**. [176] The gas demand is expected to increase up to **38.38 TWh in 2030**. [177]

Slovakia launched its hydrogen national strategy [178] in 2021. **By 2030, Slovakia may consume 6.6 TWh/a** based on the current hydrogen use. The expectation is that the consumption will reach **13.2-19.8 TWh by 2050**, with the majority of 90% being covered by low-carbon sources. **The production of green and blue hydrogen (made from nuclear and renewable energy sources) may, however, only reach 1.49 TWh in 2030**, being necessary to import hydrogen to reach the demand [179].

The Clean Hydrogen Monitor report [76] considers an **electrolysis capacity in Slovakia of 263 MW by 2030**. The supply capacity of **0.6 TWh/a** detailed in the EHB report [66] is coherent with this insalled capacity. The hydrogen production potential according to this last report may increase to **6 TWh/a in 2040 and double to 13 TWh/a by 2050**. The **hydrogen demand by 2030 may be of 0.3-7.0 TWh/a. By 2040 and 2050 it should rise considerably up to 13-20 TWh/a and up to 23-26 TWh/a, respectively**. [66, 77].

Eustream, main TSO in Slovakia (see section 3.1.23), has announced that it will soon be technologically prepared to transport over 7.1 TWh of hydrogen annually, allowing for the expected gradual increase in hydrogen supply and demand. To accommodate this, the company has planned adjustments to its network to ensure it is technologically capable of blending up to 5% hydrogen into the transported natural gas. These adjustments are targeted to be completed by the end of 2023. As a member of the European Hydrogen Backbone initiative, Eustream is also planning to dedicate a portion of its transmission network exclusively for the transport of 100% hydrogen. This commitment highlights their contribution to the development of a hydrogen-based energy system. Additionally, Eustream has set its sights on developing its own photovoltaic plant to generate green hydrogen within its premises. This fact will allow them to produce green hydrogen and utilize it for fueling compressors. [180]

Eustream's first pilot project to decarbonize its own operations is scheduled for the Veľké Kapušany compressor station, with hydrogen production expected to commence in 2023. This project demonstrates their proactive approach towards reducing carbon emissions and embracing sustainable energy solutions. [180]

The Central European Hydrogen Corridor (CEHC) [181] is a significant initiative aimed at transporting hydrogen throughout Central Europe by utilizing existing infrastructure. According to a pre-feasibility study, it has been determined that the technical feasibility exists to transport approximately 120 GWh of hydrogen per day or 42.9 TWh/a by 2030. The CEHC will primarily facilitate the transportation of hydrogen from promising future major hydrogen supply areas in Ukraine, which offer favorable conditions for large-scale green hydrogen production, through Slovakia and the Czech Republic, to meet the substantial hydrogen demand in Germany and the wider EU. Moreover, the corridor will also enable the transport of hydrogen between production facilities and consumers within the Czech Republic and Slovakia. Several key companies are actively involved in this initiative, including EUSTREAM (the Slovak gas TSO), GTSOU (Gas TSO of Ukraine), NET4GAS (the Czech gas TSO), and OGE (a leading German gas TSO). The 1,225 km stretch of the CEHC from the Ukrainian/Slovak border to the high-demand areas in Southern Germany is estimated to require a total investment ranging from 1,000 to 1,500 mio€.

The investment costs for the Ukrainian section of the corridor will depend on the precise location of hydrogen production sites in Ukraine. The anticipated levelized cost of hydrogen transmission is estimated to range from 0.10 to 0.15 EUR/kg per 1000 km. These figures fall within the lower end of the cost estimates provided by the European Hydrogen Backbone initiative, which ranges from 0.11 to 0.21 EUR/kg per 1,000 km. The current plan is to complete the CEHC project by 2030, with construction commencing as early as 2024.It is noteworthy that despite the ongoing war in Ukraine, the project's promoters remain committed to its realization, highlighting the importance and resilience of the initiative.

Biomethane will also play its role in the energy mix of Slovakia. Biomethane will be preferentially used in transport and high-efficiency cogeneration. A realistic target is more than **3.50 TWh/a of biomethane will be produced by 2030**. [182] The production capacity of **biomethane may reach 11.28 TWh in 2050**. [74]

5.2.24 Slovenia

Slovenia consumed **9.65 TWh of natural gas in 2020**. [68] this amount should increase slightly by **2030 to 13.96 TWh**. [177]

Slovenia adopted the National Energy and Climate Plan (NEPN) [183] on 27 February 2020, in accordance with the Regulation (EU) 2018/1999. By the year 2030, Slovenia is required to achieve a minimum of 27% share of RES in its final energy consumption. The goal is also to reduce GHG emissions by at least 20%, with specific targets of 76% in general use, 43% in industry, and 34% in the energy sector. The plan aims for at least 41% of RES in the heating and cooling sector and at least 11% in the transport sector. These objectives will also impact the future role of natural gas. To meet the RES targets in the electricity, heating, and cooling sectors, as well as the GHG emission reduction targets, it is projected that **at least 10% of natural gas by 2030 will be replaced by hydrogen or methane derived from renewable sources**. This proportion is expected to **increase to 25% by 2040**. Based on the projected energy balance **for 2030, the energy supply will need to include 1,047GWh of synthetic gas and 116GWh of hydrogen**. [184]

According to the NEPN, [183] Slovenia has estimated a potential **total biogas production of approximately 480 GWh by 2030**, which could increase to up to **700 GWh by 2040**. To achieve the set targets, Slovenia has already initiated a wide range of measures aimed at achieving 9.0 TWh of final energy savings by 2030 through existing measures. By implementing the additional measures outlined in the ambitious NEPN scenario, the amount of final energy savings is projected to increase by nearly 7 TWh by 2030. These additional savings will primarily come from the transport sector (3.9 TWh), followed by industry (1.4 TWh), and general consumption (1.3 TWh). Slovenia's commitment to these measures reflects its dedication to sustainable energy practices and achieving its energy and climate goals. The numbers given by Gas for Climate [74] regarding the biogas production capacity matches those from the NEPN and increase the **biogas production potential to 5.23 TWh in 2050**.

The Clean Hydrogen Monitor report [76] considers **no electrolysis capacity in Slovenia 2030**. No production capacity is detailed in the EHB report [66] either. The hydrogen production potential according to this last report may increase to **4 TWh/a in 2040 keep constant until 2050**. The **hydrogen demand by 2030 may be of 0.4-1.0 TWh/a. By 2040 and 2050 it should rise considerably up to 3.9-5.0 TWh/a and around 7 TWh/a, respectively**. [66, 77].

5.2.25 Spain

In **2022, the demand for natural gas in Spain reached 364.3 TWh**. [185] The natural gas demand may **decrease slightly to 339.60 TWh in 2030**. [186] In 2021 the primary energy consumption was 1396 TWh. This amount would fall to 1,163 TWh in 2030 and to approximately 1,047 TWh in 2040 and less than 930 TWh in 2050. [187]

Enagás has studied the theoretical capacity for hydrogen injection in Spain by examining 30 sections of the basic transportation network. **Considering a blending of 3% H_2 with natural gas** in the system (in line with the RePowerEU initiative), **approximately 3.5 TWh/year of hydrogen could be injected into the Spanish grid**. The theoretical injection capacities considered are not constant throughout the year, as they are modified based on system operation scenarios (summer and winter) as well as input configurations. [188]

The **estimated potential for renewable hydrogen production in Spain for 2030 is between 66-99 TWh, and for 2040, it is between 99-132 TWh** [189]. It is expected to **import 24.75 TWh from Portugal through the H2Med/CelZa project.** Besides, through the maritime connection between Barcelona and Marseille (H2Med/BarMar), up to 99 TWh could be exported, which is equivalent to 10% of the total anticipated demand in Europe by 2030. [190] There is also an estimated maritime export of around 14.85 TWh. The estimated **hydrogen demand in Spain in 2030** according to this same report would be **42.9 TWh**. This numbers are coherent with the national hydrogen strategy [191] launched in 2020.

The Clean Hydrogen Monitor report [76] has forecasted an **electrolysis capacity in Spain of 74.2 GW by 2030**. The supply capacity detailed in the EHB report [66] may be lower with **74 TWh/a**. The hydrogen production potential according to this last report may increase considerably up to **224 TWh/a in 2040 and even more by 2050 with 374 TWh/a**. The **hydrogen demand by 2030 may be of 30-46 TWh/a. By 2040 and 2050 it should rise considerably up to 107-156 TWh/a and up to 165-261 TWh/a, respectively**. [66, 77].

The unequal distribution between production and demand in Spanish territory justifies the need for a national hydrogen transportation network. Enagás has already identified 30% of gas pipeline sections to be converted into hydrogen pipelines, a percentage that could potentially increase up to 70%. [190] The *Vía de la Plata*, *Eje Cornisa Cantábrica* and *Eje Valle del Ebro* corridors are expected to become hydrogen transportation routes by 2030. These corridors will span from southern to northern Spain, from the northwest to the beginning of the Pyrenees, and along the Ebro River valley, respectively. By 2040, the gas infrastructure will be reinforced, and the cross-border connection with France in Irún and Larrau will be upgraded to increase export capacity. Additionally, the interconnection with Africa will be enhanced to further increase export capacity to the rest of Europe. Finally, the geological storage facilities in Cantabria, the Basque Country, and Yela will be made compatible with hydrogen to ensure a secure gas supply. The storages in Cantabria and the Basque country are expected to add together a total storage capacity of 575 GWh. [192]

The main hydrogen international connections for the transport of hydrogen via pipeline are expected to be the BarMar (Spain-France) and the CelZa (Spain-Portugal). [192] The BarMar will be a 455 km undersea pipe of OD 28 in that will operate at 210 bar. It will contain a compressor station in Barcelona (140 MW capacity) to pump up to 66 TWh of hydrogen towards France. The CelZa will be a 248 km pipe, also of OD 28 in. It will operate at 100 bar thanks to a compressor station of 24.6 MW that wil transfer up to 24.75 TWh of hydrogen to Portugal. Besides, the TSOs of Spain (Enagás), France (GRTgaz and Teréga), and Portugal (REN) have signed the Green2TSO initiative, aimed at transforming the gas network into a hydrogen network through open innovation. The Green2TSO consortium will carry out pilot projects, technology trials, and other activities to accelerate the transformation of the natural gas network. [193]

Regarding **biogas production, in 2020 Spain produced more than 8 TWh of biogas and 95 GWh were upgraded to biomethane**. [65] The perspective for **2030 and 2050 is that the potential for the production of biomethane may reach 47 and 237 TWh**, respectively. [74]

Some important projects for the prodcution of renewable gases in Spain can be highlighted:

- The Biogas Roadmap approved by the Council of Ministers in 2022 complies with the provisions of the National Integrated Energy and Climate Plan 2021-2030 (PNIEC), which establishes, as one of its measures, the promotion of renewable gas penetration through the approval of specific plans. This includes biogas, biomethane, renewable hydrogen, and other forms of renewable gas.

- The Galivi Solar project being developed by Redexis in Lorca is a pioneering initiative in Spain that will allow the injection of up to 40 GWh of biomethane per year into the distribution network. [194]

- Green Hysland: Spain's first hydrogen pipeline, specifically located in Mallorca, within the framework of the European project Green Hysland. The hydrogen pipeline complies with the consumption targets set by the Green Hysland European project (Deployment of an H2 Ecosystem on the Island of Mallorca) and has been designed to distribute renewable hydrogen generated at the Lloseta photovoltaic plant. The project includes at least 9.9 GWh of electrolysis-based hydrogen production capacity connected to local photovoltaic plants, the development of the hydrogen pipeline, as well as various end-use applications such as buses and cars, cogeneration applications with fuel cells, and thermal applications in buildings. [194]

- Redexis and Air Liquide have partnered to deploy up to 100 hydrogen refueling stations in Spain before 2030, strategically located in major logistics centers such as Madrid and Barcelona, as well as the main transportation corridors connecting the country with Europe, the Mediterranean and Atlantic corridors, as part of the DESIRE H2 project. [195]

- Enagás Renovable and Naturgy will develop in La Robla a renewable hydrogen plant, whose production capacity will be multiplied up to 280 MW. The planned start-up is in 2026 with an estimated investment of 485 mio€. The plant will be located on the grounds of Naturgy's former thermal power plant, which received final closure authorization in 2020 and is currently undergoing dismantling. [196]

5.2.26 Sweden

Natural gas consumption in Sweden reached 15.12 TWh in 2021. [197] The total gas demand is expected to remain constant until 2050. The reason for this scenario, contrary to the general trend of decreasing the demand, is that the consumption of natural gas is already low in comparison to other energy sources. [198]

The Gas Barometer monitors the use of biogas in the Swedish network. [199] **In 2022, 2.2 TWh of biogas were injected in the national transmission grid**, meaning 33.7 % of the total gas transported. Most of the biogas produced in Sweden is not connected to the grid and **10 TWh** was the total production. [65] The national biogas strategy [200] proposes **15 TWh of biogas production as national target by 2030**. 12 TWh would be demanded in the transport sector while the remaining 3 TWh would be consumed by industry. **By 2050, the biomethane potential in Sweden may reach 123 TWh**. [74] The idea is reaching 100% of renewable gases in the grid by 2045 at the latest.

A study titled "The role of gas and gas infrastructure in Swedish decarbonisation pathways 2020-2045" emphasizes that the future need for a combination of green gases in Sweden's energy system. In particular, the **demand for biogas** across the country is projected to increase significantly, reaching **14-29 TWh/a by 2045**. The Pathway Study also highlights the necessity for a new hydrogen infrastructure in Sweden, which could potentially be one of the largest infrastructure investments the country has ever faced. To meet the country's estimated hydrogen demand, a substantial amount of electricity, approximately 50-65 TWh, would be required for production. Furthermore, the study forecasts that Sweden's electricity demand will nearly double by 2045, rising from the current 130 TWh to 241-253 TWh per year. To address this growing demand and facilitate the transportation of hydrogen to regions where it is most needed, the establishment of a hydrogen transmission network would be crucial. Significantly, the study concludes that Sweden has the potential to become self-sufficient in hydrogen production. Particularly favourable prospects for hydrogen production are identified in electricity area 2. By harnessing this potential and investing in the necessary infrastructure, Sweden can work towards a sustainable and decarbonized energy future.

The Swedish hydrogen national strategy has proposed a two-phase strategy with a total of **15 GW of hydrogen electrolyser capacity in the country by 2045**. Of this **5 GW should be implemented in the first phase by 2030**. These capacities would supply the expected demand of **22-42TWh of green hydrogen by 2030**, increasing to **44-84TWh by 2045**. [201]

The Clean Hydrogen Monitor report [76] has forecasted an **electrolysis capacity in Sweden of 3,651 MW by 2030**. The supply capacity detailed in the EHB report [66] may be much higher with **64 TWh/a**. The hydrogen production potential according to this last report may double to **125 TWh/a in 2040 and increase more by 2050 to 166 TWh/a**. Predictions for hydrogen demand are rather heterogeneous. The **hydrogen demand by 2030 may be of 9-50 TWh/a. By 2040 and 2050 it should rise considerably up to 25-100 TWh/a and up to 34-123 TWh/a, respectively**. [66, 77].

TSOs in Finland and Sweden, namely Gasgrid Finland and Nordion Energi (see sections 3.1.8 and 3.1.26), have joined forces to explore the development of a new hydrogen infrastructure and market in the Bothnian Bay region. [202] The main objective is to meet the potential demand for hydrogen, which is expected to play a crucial role in facilitating the transition and expansion of industries in the region. This demand is estimated to reach approximately 100 TWh. The collaboration between Gasgrid Finland and Nordion Energi aims to assess the feasibility and explore the possibilities of establishing the necessary infrastructure to support the hydrogen market. By investing in the development of a robust hydrogen network, the TSOs aim to enable the utilization and distribution of hydrogen as an energy source in various industries. The Bothnian Bay region holds significant potential for hydrogen development, and the establishment of a hydrogen infrastructure could have far-reaching impacts on the local economy and energy sector. This initiative aligns with the broader goals of decarbonization and sustainable energy transition, fostering innovation and driving the growth of the hydrogen market in Finland and Sweden.

5.2.27 Switzerland

The **natural gas consumption in Switzerland** amounted to **41.87 TWh in 2021**. [203] The gas demand in Switzerland **in 2030 is expected to be composed by 23.89 TWh of natural** gas and 21.39 TWh of renewable gases. In **2040**, **natural gas would drop to 11.11 TWh** while **renewable gases may rise to 33.05 TWh**. By **2050**, just renewable gases may be present in the grid, with a total expected demand of **41.94 TWh**. [204]

The **hydrogen production capacity in Switzerland may be of 20 MW of electrolysis in 2030**, which may be equivalent to 0.1 TWh/a. [76] The production in the following years is unknown.

In the case of biogas, **in 2020 Switzerland produced 1.4 TWh of biogas and 369 GWh of biomethane**, being the latter mainly used as vehicle fuel. [65] The prospections for **2030 and 2050 is that Switzerland may have the potential to reach a production of biomethane of 6.16 and 9.77 TWh**.

No data about expected hydrogen demand could be found. However, given the data about biogas production and the that of renewable gases expected in the grid in the coming years, **the hydrogen demand can be calculated and may reach 26.89 and 32.17 TWh in 2030 and 2050,** respectively.

5.2.28 The Netherlands

408.21 TWh of natural gas were consumed in The Netherlands in 2021. [205] The **total gas consumption in 2030 has been estimated in 286.21 TWh**. This consumption may drop drastically **by 2050 to 95.83 TWh**. [206]

Gasunie (main TSO in The Netherlands-see section 3.1.28) has developed a plan considering three scenarios up to 2031 in their transport services Investment plan [207] with the following key aspects:

- National Driver: CO_2 reduction >50%. Aims for energy autonomy in the long run. More sector coupling through P2G. Focus on all-electric. Limited P2H in industry. The ND scenario foresees comparatively limited growth of hydrogen. Industrial demand for application as a feedstock decreases. On balance, industrial hydrogen demand remains more or less the same. In addition, the ND scenario foresees growth of hydrogen in the electricity sector. The additional hydrogen supply required for this comes mainly from electrolysis of renewable electricity

- International ambition: CO_2 reduction >50%, Import dependency. More biomethane. High uptake of H_2 (mainly blue SMR and import), More CCS (10 MT). The IA scenario foresees the most growth of hydrogen. This growth is visible in almost all sectors: industry, mobility, and electricity generation. In the built environment, hydrogen demand remains limited to a few pilot projects for now, but from 2035, the share of hydrogen starts to grow in this sector too. The additional hydrogen supply in the IA scenario comes mainly from blue hydrogen production. An international hydrogen market emerges around 2030, creating the possibility of importing hydrogen. The Netherlands becomes a transit country for hydrogen to Germany.

- Climate agreement: CO_2 target probably not completely reached. Mix of technologies for domestic heating. 19.18 TWh of biomethane, 3.5 GW electrolysis and 7 MT of CCS. The climate agreement scenario lies between the ND and IA scenarios in terms of hydrogen. In terms of domestic hydrogen demand, the KA scenario is somewhat similar to ND. In terms of supply, this scenario foresees a mix of grey, blue, and green hydrogen. This scenario also assumes a transit flow of hydrogen towards Germany, in line with the cabinet's hydrogen vision, the German national hydrogen strategy, and the German Netzentwicklungsplan.

According to this report, **by 2030**, the natural gas production in The Netherlands from the Groningen field may reach 43.04 TWh, and the production of **biogas is expected to be between 4.20-28.87 TWh.** The **hydrogen demand by 2030 may be of 59.94-85.55 TWh**, with an export potential of up to 21.26 TWh, while the **hydrogen supply is expected to be of 63.16-88.58 TWh** (39.80 TWh of this amount provided by grey hydrogen and the remaining amount by blue and green hydrogen). **By 2050**, the different scenarios predict a **biogas production of 16.56-109.91 TWh** and a **hydrogen production capacity of 97.11-328.58 TWh**.

The scenarios for IP2022 also quantified the demand for hydrogen. Around 60 TWh of hydrogen is currently produced in the Netherlands, mainly for use in fertiliser and oil refining. Some 40% comes from residual streams from industrial processes. The remaining 60 %is produced from natural gas via steam methane reforming (SMR).

The Clean Hydrogen Monitor report [76] has forecasted an **electrolysis capacity in The Netherlands of 10.1 GW by 2030**. The supply capacity detailed in the EHB report [66] may be a bit higher with **42 TWh/a**. The hydrogen production potential according to this last report may increase to **107 TWh/a in 2040 and even more by 2050 to 190 TWh/a**. The **hydrogen demand by 2030 may be of 27-46 TWh/a. By 2040 and 2050 it should rise considerably up to 88-109 TWh/a and up to 133-153 TWh/a, respectively**. [66, 77].

The transport of hydrogen via pipelines in The Netherlands is not new. In 2018, the first gas pipeline owned by Gasunie in the Netherlands was repurposed for the transport of hydrogen. This pipeline is 12 km long and it is used commercially for delivering over 4 kT of hydrogen per year. [208]

The HyWay27 study [209] highlights the advantage in converting part of Gasunie's natural gas transmission network to transport hydrogen, connecting the five main industrial clusters by 2030. Higher capacities can be achieved later in time by installing compressors or by deploying additional natural gas pipelines. This will be followed by regional and cross-border connections. The final hydrogen transport network is expected to consist largely(about 85%) of existing natural gas pipelines. This mapped the deployment of existing natural gas pipelines for hydrogen. These pipelines are now part of GTS's natural gas network. The main transmission grid for natural gas consists of several parallel pipelines. As natural gas transport declines, transport pipelines may gradually become available for hydrogen transport. GTS has identified routes that fit the required connections in the hydrogen transport network. Research has shown that the pipelines can be technically adapted to safely transport hydrogen, involving actions such as replacing valves and cleaning the pipelines. Gasunie has already gained experience in Zeeland with converting an existing natural gas pipeline for hydrogen. Since 2018, hydrogen has been transported between Dow's sites in Terneuzen and Yara in Sluiskil.

5.2.29 Ukraine

Ukraine consumed **303.54 TWh of natural gas in 2021**. [210] Prospections for Ukraine are difficult to make due to the ongoing war they are immersed into and the scarce information available. However, the transition to hydrogen seems to keep ongoing.

Ukraine's draft Hydrogen Strategy, [211] formulated in December 2021, is focused on leveraging its well-established natural gas infrastructure for renewable hydrogen exports. The strategy sets ambitious targets, **aiming for up to 10 GW of renewable hydrogen production capacity by 2030, with 7.5 GW dedicated specifically to EU exports**. By aligning with the Hydrogen Europe's 2×40 GW initiative, [212] which has received endorsement from both the German and Ukrainian Energy Ministries, Ukraine envisions **installing 8 GW of capacity by 2030**. Achieving this goal would enable the production of approximately 21 TWh/a of green hydrogen.

The “Ukraine Hydrogen Valley” project is much more ambitious and envisions a **potential for hydrogen export of 286.94 TWh/a by 2030, 644.74 TWh/a by 2040 and 1,109 TWh/a by 2050**, which would basically cover the whole European demand. [213] Ukraine possesses significant technical potential for renewable energy, capable of creating 500-700 GW of capacity. Leveraging this potential, Ukraine has the **ability to produce approximately 1,485 TWh of hydrogen**. To put this into perspective, it represents approximately half of the current global hydrogen consumption. This highlights the substantial role Ukraine could play in the future hydrogen market. [214]

Prospections from the EHB [66] are more moderate and predict a **supply capacity of 12 TWh/a by 2030 and 50 and 100 TWh/a by 2040 and 2050, respectively**. The national demand is not considered.

Ukraine is already developing two projects with the capacity to produce green hydrogen, generating 100 MW of energy. Potential evaluation studies have been carried out, revealing that the Odesa region alone has the potential to generate up to 3 GW of green hydrogen. The 'Danub' project, which was planned before the war, aims to construct multiple hydrogen production facilities for export to the EU, located in Lviv and Odesa. Ukraine is steadfast in its pursuit of hydrogen transformation and achieving complete energy independence from Russia. With ambitious goals, we believe that Ukraine can build a remarkable 10 GW of green hydrogen production capacity in just a few years. This substantial capacity will cater to our domestic market and also serve as an export to EU countries. [215]

Ukraine is also the source of the hydrogen transported in the Central European Hydrogen Corridor, [181] already explained in section 5.2.23, and which is expected to **export 42.9 TWh/a of hydrogen to Germany by 2030.**

There are big uncertainties because of the current war in Ukraine. The hydrogen potential will highly depend on the operational state of the national gas infrastructure and the speed of economic recovery and infrastructure investment. [66]

5.2.30 UK

The **total gas demand in 2021 in UK was 860.7 TWh**. [216] UK could cut its consumption of gas by a quarter **by 2030 (645.53 TWh)**. The UK Government should put this target at the heart of their energy security strategy. [217] By 2050, it is estimated that hydrogen could supply 28% of the UK's heat, while the overall gas demand in the country is expected to rise to 130% of the 2016 levels. Of this increased gas demand, approximately 55% is projected to be met by hydrogen. [218] Being the total gas demand in 2016 494,775 GWh, it can be therefore calculated that the **total gas demand in 2050 is expected to be 559.10 TWh, of which 307.51 TWh would be consumed as hydrogen**. The remaining **251.60 TWh must be therefore supplied as biomethane or synthetic gas**.

The OGUK has provided projections for future gas demand, indicating a range of potential values. According to their estimates, the **total gas demand is expected to range between 532.42-634.76 TWh in 2030, 260.51-533.46 TWh in 2040, and 85.29-558.47 TWh in 2050**. [219] The maximum consumption scenarios align with the estimations made above.

Currently 27 TWh of hydrogen are produced in UK. Just 1 TWh is green hydrogen, while the rest of it is gray hydrogen. [220] UK's hydrogen national strategy [221] was launched in 2021. The demand for hydrogen is projected to experience a significant surge in the early 2030s, indicating a potential need for **7-20GW of production capacity by 2035**. According to the pathways modelled by BEIS for CB6, the demand for hydrogen is expected to double between 2030 and 2035, and it will continue to grow rapidly throughout the 2030s and **2040s to reach 120-235 TWh**. **By 2050, the economy might require anywhere between 250-460TWh of hydrogen**, which could account for up to a third of the final energy consumption. As progressing towards the mid-2030s, the hydrogen network could extend its reach to cover various applications spanning tens to hundreds of kilometres. This expansion might even include the conversion of hydrogen into ammonia, which can be used as a shipping fuel. With the development of larger cluster networks and the increase in end users and storage capabilities, we anticipate that all sectors of the hydrogen economy will attain technological and market maturity by 2050, possibly leading to national-level distribution. Scotland aims to become a leading hydrogen nation. In December 2020 a Hydrogen Policy Statement released by Scottish Government included a target to deliver 5GW of hydrogen by 2030. [220]

The Clean Hydrogen Monitor report [76] has forecasted an **electrolysis capacity in UK of 1,674 MW by 2030**. The supply capacity detailed in the EHB report [66] may be higher with **40 TWh/a**. The hydrogen production potential according to this last report may increase to **204 TWh/a in 2040 and even more by 2050 to 297 TWh/a.** The **hydrogen demand by 2030 may be of 27-29 TWh/a. By 2040 and 2050 it should rise considerably up to 145-171 TWh/a and up to 244-248 TWh/a, respectively**. [66, 77].

According to National Grid's Future Energy Scenarios 2021, [222] different net-zero compliant scenarios indicate a **requirement of 12TWh to 51TWh of hydrogen storage by 2050**. Currently, the UK has seven active natural gas storage facilities, utilizing salt caverns and depleted gas fields, which offer a storage capacity of approximately 145TWh.

Additionally, Project Union [223] aims to develop a hydrogen transmission backbone for the UK, connecting industrial clusters across the country, potentially spanning 2,000km. This project repurposes 25% of current gas transmission pipelines and could carry at least a quarter of the UK's gas demand. The initial backbone is set to be completed by 2030.

Regarding biogas, in **2020 UK produced 20 TWh of biogas and 7 TWh of biomethane**. 76% of the biomethane plants are connected to the distribution grid and 22% to the transport grid. [65] Prospects for **2030 and 2050 estimate a potential for biomethane production of 52.45 and 136.30 TWh**. [74]

5.3 Summary and partial conclusions

Table 7 contains a summary of the most important information that has been explained across section 5.2 of this report.

Table 7. Summary table of all information gathered in section 5.2

Country	2020-2023	Until 2030	Until 2040	Until 2050	Conclusions
Austria	90.87 TWh of natural gas demand in 2021 138 GWh/a of biomethane production	Total gas consumption of 60-76.5 TWh The government aims to inject 5 TWh of renewable gas into the grid and provide a biogas supply to residential and service buildings of around 140 GWh. Up to 1 GW electrolysis capacity. Potential to produce up to 4 TWh of hydrogen. Potential for producing up to 7-10 TWh of biomethane	Total gas demand of 89 TWh Achieve climate neutrality as target. Potential for 10.8 TWh of synthetic gas and 9.5 TWh of biogas. Need for 68.7 TWh to reach neutrality. Potential to produce 5 TWh of hydrogen. Hydrogen demand of 31-36 TWh	Total gas demand may remain constant Potential for producing 45.47 TWh of biomethane Potential to produce 7 TWh of hydrogen. Hydrogen demand of 44-52 TWh	H_2 importing country
Belgium	Total gas demand of 190 TWh. In 2020 Belgium produced 2,700 GWh of biogas and 5 GWh of biomethane	Constant total gas demand. 1,555 MW of electrolysis capacity by 2026. Hydrogen production up to 21 TWh/a Hydrogen demand of 25 TWh/a Import of up to 20 TWh of hydrogen , considering also hydrogen transit	Constant total gas demand. Up to 8 TWh of biomethane production. Hydrogen production up to 28 TWh/a Hydrogen demand of 65-78 TWh/a	Constant total gas demand Hydrogen demand of 50-200 TWh Up to 13.84 TWh of biomethane production. Hydrogen production of 11 TWh/a Hydrogen demand of 94-109 TWh/a	H_2 Importing country

Country	2020-2023	Until 2030	Until 2040	Until 2050	Conclusions
				Import of 200-350 TWh of hydrogen, considering also hydrogen transit	
Bulgaria	Total gas demand of 31.34 TWh in 2021	Total gas demand of 44.39 TWh 1.1-3.8 GW electrolysis capacity. Hydrogen supply of 1.6 TWh/a Biomethane production potential of 7.91 TWh Hydrogen demand of 0.17-5 TWh/a	Total gas demand of 11.65 TWh Hydrogen production of 9 TWh/a Hydrogen demand of 13-17 TWh/a	Total gas demand of 9.78 TWh 5 GW electrolysis capacity. Hydrogen production of 39 TWh/a Hydrogen demand of 0.25-23 TWh Biomethane production potential of 35 TWh, while the demand may remain at 5.32 TWh	Small hydrogen export. More weight for biomethane
Croatia	Total gas demand of 29.37 TWh in 2020	Constant total gas demand. Electrolysis capacity of 2-1,223 MW Hydrogen production of 0.10-1.52 TWh/a Hydrogen demand of 0.21-2.0 TWh No biogas production	Hydrogen production of 2.27-11.00 TWh/a Hydrogen demand of 2.71-8.00 TWh	Hydrogen production of 7.06-18.00 TWh/a Hydrogen demand of 8.41-12.00 TWh Biomethane production potential of 5.23 TWh	Neutral country
Czech Republic	The total gas demand in 2020 was 92.24 TWh Production of 6,833 GWh of biogas and 8 GWh of biomethane	Hydrogen production capacity of 0.1 TWh/a Hydrogen demand of 5 TWh/a Hydrogen transport expected as a blend Potential for producing 7 TWh/a of biomethane	Expecting a total gas demand of 120.49 TWh Hydrogen production capacity of 0.1 TWh/a Hydrogen demand of 15-17 TWh/a Using the existing pipeline infrastructure to import hydrogen is not expected until 2035. Pilot and test applications of hydrogen in	Expected gas demand of 54.63 TWh Hydrogen production capacity of 0.1 TWh/a Hydrogen demand of 25-27 TWh/a From 2040 to 2050 natural gas should be	H_2 Importing country

Country	2020-2023	Until 2030	Until 2040	Until 2050	Conclusions
			industries until 2040. From 2035 on a dedicated transport infrastructure should be developed.	gradually replaced by hydrogen. Potential for producing 40 TWh/a of biomethane	
Denmark	Natural gas covers about 12 % of the total Danish energy mix (28.95 TWh). Biogas/biomethane in the gas system of 6.3 TWh/a	Total gas demand of 21 TWh (6.17 TWh of biogas) Electrolysis capacity of 6,288 MW 14-40 TWh/a of hydrogen produced. Hydrogen demand of 8-27 TWh/a Capacicity to export between 2-15 TWh of hyrdrogen	Total gas demand of 16.4 TWh Aprox. 14.54 TWh of biomethane injected in the grid. Up to 38.64-101 TWh of hydrogen production capacity. Hydrogen demand of 12-52 TWh/a The export potential lays between 5-28 TWh. The whole gas demand is covered by biogas and all hydrogen is expected to be exported	Gas consumption is estimated to decrease to 16.7-22.2TWh Up to 108.14-142 TWh of hydrogen production capacity Hydrogen demand of 21-67 TWh/a 63.22 TWh of hydrogen may be exported. New gas infrastructure or alternative means of transport necessary to export the hydrogen.	Big role of biomethane to cover the gas demand H_2 exporting country
Estonia	Total gas demand of 4.8 TWh. 1.5 TWh of biomethane produced in 2021. None of it injected in the grid (Bio CNG and used in the transport sector)	Total gas demand of 5.2 TWh 678.08 GWh of biogas produced (104.32 GWh locally consumed, the rest transported in pipes as biomethane) Hydrogen production of 1.1 TWh/a No demand of hydrogen expected	Total gas demand of 4.9 TWh 1.2 TWh of biogas produced (442.89 GWh locally consumed, the rest transported in pipes) 0.4-19 TWh of hydrogen produced Hydrogen demand of 1.5-2.0 TWh	Total gas demand of 3.8 TWh 1,2 TWh of biogas produced (805.14 GWh locally consumed, the rest transported in pipes) 0.5-35.1 TWh of hydrogen produced. Hydrogen demand of 1.5-2.0 TWh Biomethane may be partially replaced by hydrogen or electrification	H_2 exporting country

Country	2020-2023	Until 2030	Until 2040	Until 2050	Conclusions
Finland	Natural gas consumption of 25.43 TWh in 2020. 878 GWh of biogas and 109 GWh of biomethane produced	Electrolysis capacity of 2,526 MW and hydrogen supply of 61 TWh/a Hydrogen demand of 6-25 TWh/a First hydrogen pipelines could be built already by 2030. Potential for producing 8.26 TWh of biomethane	Hydrogen production of 93 TWh/a Hydrogen demand of 17-53 TWh/a	Hydrogen production of 139 TWh/a Hydrogen demand of 27-66 TWh/a 1,000 km of new, dedicated hydrogen pipelines will serve 65 TWh of hydrogen in the Bothnian Bay region. Potential for producing 72.69 TWh of biomethane	H_2 exporting country
France	Total gas demand of 494 TWh. Biogas production: 6.1 TWh. Biomethane production: 2.2 TWh	Total gas demand of 376 TWh Electrolysis capacity of 6,276 MW Hydrogen supply of 18.2 TWh/a Hydrogen demand of 20-34 TWh/a Biogas demand of 57 TWh 1,170 km of grid dedicated to hydrogen among different projects	Hydrogen supply of 112 TWh/a Hydrogen demand of 85-117 TWh/a	Total gas demand of 321 TWh Hydrogen production of 95-174 TWh/a Hydrogen demand of 161-181 TWh/a Potential to produce up to 226 TWh of bio- or synthetic methane. Teréga expects that 40 TWh of this hydrogen can be injected in their grid	Neutral country. Strong commitment to biogas
Germany	Total natural gas demand of 966.9 TWh About 10 TWh of biomethane are already made available every year	Expected gas demand of 530-775 TWh 5-7.3 GW electrolyser production expected (14-20 TWh/a). Hydrogen demand between 37 and 231 TWh depending on the source of the study.	10 GW electrolyser production expected. Hydrogen supply of 102 TWh/a Expected hydrogen demand of 280-427 TWh	Expected gas demand of 238-693 TWh Hydrogen production of up to 192 TWh/a Hydrogen demand between 156 and 598 TWh depending on the source of the study	H_2 importing country

Country	2020-2023	Until 2030	Until 2040	Until 2050	Conclusions
		Up to 100 TWh of biomethane could be produced and fed into the gas grids. The hydrogen dedicated grid is expected to reach 5,100 km (of which 3,700 km would be repurposed pipelines), with a demand of 71 TWh		It is envisaged a need to import at least 150 TWh of renewable hydrogen in 2050 Up to 250 TWh of biomethane injected into the gas grids. The hydrogen dedicated grid is expected to reach 13,300 km (of which 11,000 km would be repurposed pipelines), with a demand of 504 TWh	
Greece	Natural gas demand of 32.87 TWh. No biomethane injected in the grid. Lack of legal framework	Natural gas demand of 21.04-44.37 TWh. Electrolysis capacity of 5,428 MW 3.5-11.0 TWh hydrogen production. 0.33-7 TWh of expected hydrogen demand A pipeline will cover 147 km from Trikala to Ptolemaida, being part of the EHB Biomethane production potential of 6.5 TWh/a	Hydrogen production of 34.89-54.00 TWh (11.63 TWh for export) Hydrogen demand of 27-28 TWh	Hydrogen production of 87 TWh (26.75 TWh for export). Hydrogen demand of up to 44 TWh Biomethane production potential of 30 TWh/a	H_2 exporting country
Hungary	Total gas demand of 117.41 TWh.	Total gas demand of 79.65-209.26 TWh Electrolysis capacity of 141 MW. Hydrogen production of 0.4-6.4 TWh	Hydrogen production of 6.6-11.0 TWh Hydrogen demand of 15 TWh	Total gas demand of 129.29 TWh. Hydrogen production of 9.8-32.0 TWh. Hydrogen demand of 25 TWh	H_2 exporting country

Coun-try	2020-2023	Until 2030	Until 2040	Until 2050	Conclusions
		Hydrogen demand of 4-9.3 TWh Biomethane production potential of 11.5 TWh/a		Biomethane production potential of 45 TWh/a	
Ireland	Total gas demand of 56.26 TWh	Total gas demand of 34-53 TWh Electrolysis capacity of 3,250 MW Production of green hydrogen of 5.2-11.5 TWh and up to 11.5 TWh of biomethane. Hydrogen demand negligible or reaching 3 TWh/a.	Total gas demand of 20-45 TWh. Hydrogen production of 46 TWh/a Hydrogen demand of 4.9-17.0 TWh Repurposing cross-border points to enable green hydrogen export/import with UK.	Total gas demand of 13-41 TWh. Hydrogen production capacity of 70-90 TWh and hydrogen demand of 7.5-30.0 TWh. 5.1-18.1 TWh of biomethane for injection Ireland could need up to 20 TWh of decarbonised energy storage to ultimately replace fossil fuels in the electricity system	H_2 exporting country in the long term
Italy	Total gas demand of 746 TWh Biomethane production of 11.74 TWh/a	Total gas demand of 659-773 TWh expected. Demand of 11-45 TWh of green gases (10.6-35.9 TWh of biomethane and 0.34-24.0 TWh of hydrogen). 2-2.6 GW of electrolysis capacity and hydrogen supply of 7 TWh/a Biogas potential in Italy is estimated to reach 100 TWh/a.	Total gas demand of 654-690 TWh. Hydrogen production of 49 TWh/a. Demand of green gas reaching about 87-252 TWh (74-98.3 TWh of biomethane and 13.1-154.0 TWh of hydrogen)	Total gas demand of 528-776 TWh Biogas potential in Italy is estimated to reach 350 TWh/a Demand of at least 99 TWh of biomethane and 111-237 TWh of hydrogen 5GW of electrolysis capacity. Hydrogen production of 93 TWh/a	H_2 importing country
Latvia	Total gas demand of 15.79 TWh	Total gas demand of 15.59 TWh	Hydrogen demand of 1 TWh Hydrogen production of 9 TWh	Hydrogen demand of 1.6-3.0 TWh	H_2 Exporting country. Almost no hydrogen consumption and strong

Country	2020-2023	Until 2030	Until 2040	Until 2050	Conclusions
	Biogas production of 860 GWh. Biomethane production of 4 GWh	No hydrogen demand nor production Biomethane production of 1.40 TWh/a		Hydrogen production of 20 TWh Biomethane production of 15.6 TWh/a	strategy towards biomethane by 2050
Lithuania	Total gas demand of 23.60 TWh Biogas production of 860 GWh. No upgrade to biomethane	Total gas demand of 20 TWh Substitution of up to 10% of the natural gas system with green hydrogen. Electrolysis capacity of 200 MW Hydrogen supply of 0.86-1.0 TWh/a. Hydrogen demand of 0-5 TWh. Biomethane production of up to 4.5 TWh/a 0.7 TWh of green hydrogen and 0.9 TWh from biogas are expected to enter the gas system (8% of Lithuania's total natural gas demand)	Hydrogen production of 9 TWh/a Hydrogen demand of 6.73 -15.0 TWh	Hydrogen production of 15 TWh/a Hydrogen demand of 12.5 -21.0 TWh Biomethane production of up to 9.5 TWh/a	H_2 importing or neutral country
Luxembourg	Total gas demand in Luxembourg was 9.9 TWh Consumption of fossil hydrogen of around 15 GWh/a			The expected hydrogen demand is 4.12-9.90 TWh/a	Neutral country
Norway	Total gas demand of 25.82 TWh, comprised by natural gas (10.00	Electrolysis capacity of almost 2 GW Hydrogen production of 16-46 TWh/a	Hydrogen demand around 17 TWh/a. Hydrogen production of 32.34 TWh/a (22.44 TWh/a of blue	Hydrogen demand of 24.0-39.6 TWh/a Hydrogen production of 112 and up to 140.91 TWh/a (42.90 TWh/a	H_2 exporting country

Country	2020-2023	Until 2030	Until 2040	Until 2050	Conclusions
	TWh) and biogas (15.82 TWh)	Hydrogen demand of 8-16 TWh/a Biomethane production of 2.5-4.3 TWh/a	hydrogen and 9.9 TWh/a of green hydrogen) up to 151 TWh/a Capacity to export export 33 TWh/a of hydrogen	blue hydrogen and 98.01 TWh/a green hydrogen) Capacity to export export 112.2 TWh/a of hydrogen Biomethane production of 14.9 TWh/a	
Poland	Total gas demand of 269.82 TWh 3.29 TWh of biogas production. None of it was upgraded to biomethane	Natural gas demand of 325.64 TWh Installed hydrogen production capacity of 1.1-2.0 GW from low- and zero-emission sources Hydrogen supply of 2.9 TWh/a Hydrogen demand of 0.33-22.0 TWh/a 38.03 TWh/a biogas production	Hydrogen demand of 88-120 TWh completely covered by 20 GW electrolysis or just partially (hydrogen production of 43 TWh/a)	Hydrogen production of 113-375 TWh in 2050. Hydrogen demand of 155 TWh/a 146.77 TWh biogas production	Neutral or importing country by 2030 by exporting country by 2050 depending on the source of information
Portugal	Natural gas demand of 70.94 TWh Primary energy consumption of natural gas of 40.83 TWh	Primary energy consumption of natural gas of 33.89-36.94 TWh 1.0 – 3.8 GW hydrogen production capacity (supply of 16 TWh/a) Biomethane covers 4.5% of total energy demand Hydrogen demand of 5.0-5.7 TWh/a 7.4 TWh/a of biomethane production Composition of the gas in the grid (vol %): 4.48 %	2 - 3 GW hydrogen production capacity (supply of up to 55 TWh/a) Hydrogen demand of 20-22 TWh/a Composition of the gas in the grid (vol %): 26.89 % synthetic natural gas, 8.25 % biomethane, 7.55 % renewable hydrogen and 57.31 % natural gas	Primary energy consumption of natural gas of 8.33-9.44 TWh 4-6 GW hydrogen production capacity (supply of up to 74 TWh/a) Hydrogen demand of 28-33 TWh/a 42.8 TWh/a of biomethane production Composition of the gas in the grid (vol %): 76.65% synthetic natural gas, 11.56 %	Strong strategy towards synthetic natural gas to cover the gas demand. High hydrogen supply, but to use is as reagent in the synthesis of synthetic methane, besides its export

Coun-try	2020-2023	Until 2030	Until 2040	Until 2050	Conclusions
		synthetic natural gas, 4.25 % biomethane, 3.3 % renewable hydrogen and 87.97 % natural gas		biomethane, 7.78 % renewable hydrogen and 4.01 % natural gas	
Romania	Demand of 132.58 TWh of natural gas	Expected natural gas demand of 157.00 TWh Electrolysis capacity in Romania of 1,2-2.4 GW Hydrogen supply of 5.2 TWh/a Hydrogen demand of 5.1 – 14.0 TWh Biogas production capacity of 23.49 TWh	Hydrogen production of 50 TWh/a Total hydrogen demand of 24-34TWh	Hydrogen production of 83 TWh/a Total hydrogen demand up to 46 TWh Biogas production potential 93.04 TWh	H_2 exporting country
Serbia	26.40 TWh of natural gas consumption. Production of 417 GWh of biogas	No data found	Production of 0.17 TWh of hydrogen (by 2035)	Production of 0.68 TWh of hydrogen	Uncertain. Possible hydrogen importing country
Slovakia	Natural gas demand of 58.01 TWh	Electrolysis capacity of 263 MW Hydrogen production up to 0.60-1.49 TWh/ Hydrogen demand of 0.3-7.0 TWh/a Biogas production of 3.50 TWh/a Feasibility to transport 120 GWh of hydrogen per day	Hydrogen production up to 6 TWh/ Hydrogen demand of 13-20 TWh/a	Hydrogen production of 13 TWh/a Hydrogen demand of 13.2-26.0 TWh Biogas production of 11.28 TWh/a	H_2 importing country
Slovenia	Total gas demand of 9.65 TWh No production of gas from renewable sources	Expected gas demand of 13.96 TWh No hydrogen production At least 10% natural gas replaced by hydrogen or	Hydrogen production of 0.8-4 TWh/a Hydrogen demand of 0.2-5.0 TWh/a	Hydrogen production of 4 TWh/a Hydrogen demand of 7 TWh/a	Hydrogen neutral or importing county depending on the source of information

Country	2020-2023	Until 2030	Until 2040	Until 2050	Conclusions
		renewable methane (1,047GWh of synthetic gas, up to 480 GWh of biogas and up to 116GWh of hydrogen necessary).	At least 25% natural gas replaced by hydrogen or renewable methane. A production of biogas of 700 GWh expected	Biogas production potential of 5.23 TWh	
Spain	Gas demand of 364.3 TWh Biogas production of 8 TWh and 95 GWh of biomethane	Electrolysis capacity of 74.2 GW by 2030 Hydrogen production of 66-99 TWh/a Demand for renewable hydrogen forecast at 30-46 TWh/a Potential to produce 47 TWh of biomethane Export to France (H2Med/ BarMar) of up to 66TWh (10% of the total expected demand in Europe in 2030) and a maritime export of around 14.85 TWh.	Natural gas demand of 339.60 TWh Hydrogen production capacity forecasted at 99-224 TWh. Hydrogen demand of 107-156 TWh Import from Portugal of 24.75 TWh of hydrogen (H2Med/CelZa)	Hydrogen production capacity forecasted at 374 TWh. Hydrogen demand of 165-261TWh Potential to produce 237 TWh of biomethane	H_2 exporting country
Sweden	Natural gas consumption in Sweden reached 15.12 TWh in 2021 Around 30% of the gas transmitted consists of biogas (2.6 TWh). Total biogas production of 10 TWh.	Constant total gas demand National target of 15 TWh for biogas production 9-50 TWh of green hydrogen demand (fully covered by 3.7-5.0 GW electrolysis)	Constant total gas demand Hydrogen production of 125 TWh/a Hydrogen demand of 25-100 TWh/a	Constant total gas demand 44-84 TWh of green hydrogen demand (fully covered by 15 GW electrolysis) or 34-123 TWh/a Biogas demand across Sweden is estimated to increase to 14–29 TWh per year in 2045. Potential for producing up to 123 TWh of biomethane by 2050	Neutral or exporting county depending on the source of information. Biomethane exporting country

Country	2020-2023	Until 2030	Until 2040	Until 2050	Conclusions
				100% renewable gases in the grid by 2045 (3,000,000 Nm^3).	
Switzerland	Natural gas consumption of 41.87 TWh	Demand of 23.89 TWh of natural gas and 21.39 TWh of renewable gases (6.16 TWh of biomethane and 26.89 TWh of hydrogen) Almost no production capacity of hydrogen	Natural gas demand of 11.11 TWh and 33.05 TWh of renewable gases	Demand of 41.94 TWh of renewable gases (9.77 TWh of biomethane and 32.17 TWh of hydrogen)	H_2 importing country
The Netherlands	408.21 TWh of natural gas were consumed in The Netherlands in 2021. Around 60 TWh of hydrogen is currently produced	Total gas consumption estimated in 286.21 TWh. Natural gas production of 43.04 TWh. Biogas production of 4.20-28.87 TWh. Electrolysis capacity of 10.1 GW Hydrogen production of 42.0-88.6 TWh/a Hydrogen demand of 27.0-85.6 TWh The Netherlands becomes a transit country for hydrogen to Germany	Hydrogen production of 107 TWh/a Hydrogen demand of 190 TWh	Total gas consumption estimated in 95.83 TWh. Hydrogen production of 97.1-328.6 TWh/a Hydrogen demand of 133-153TWh Biogas production of 16.56-109.91 TWh	Hydrogen neutral country until 2040 and exporting country by 2050
Ukraine	303.54 TWh of natural gas consumption in 2021	8-10 GW of electrolysis Hydrogen export potential of 12-286.94 TWh/a	Hydrogen export potential of 50-644.74 TWh/a	Hydrogen export potential of 100-1,109 TWh/a. Maximum potential hydrogen production of 1,485 TWh	H_2 exporting country, but rather unpredictible. Numbers highly heterogeneous based on the source consulted
UK	The total gas demand in 2021 in	Gas consumption reduced by a quarter (532.42-645.53 TWh)	Total gas demand 260.51-533.46 TWh	Total gas demand estimated in 85.29-559.10	H_2 exporting country

Coun-try	2020-2023	Until 2030	Until 2040	Until 2050	Conclusions
	UK was 860.7 TWh. 27 TWh of hydro-gen produced in UK (1 TWh of green hydrogen and 26 TWh of gray hydrogen. Production of 20 TWh of biogas and 7 TWh of bio-methane	1.6-10GW H_2 production capacity, leading to up to. 40 TWh/a of H_2 supply 27-38TWh of hydrogen demand expected. Project Union backbone completed (2,000 km of grid) Potential for producing 52.45 TWh of biomethane	7-20GW of production capacity may be needed by 2035, reaching 204 TWh/a production by 2040 Expected hydrogen demand of 120-235 TWh	TWh, with 55% supplied by hydrogen. Hydrogen production of 297 TWh/a 250-460TWh of hydro-gen could be needed across the economy. 20-35% of the UK's final energy consumption could be made up of hy-drogen Potential for producing 136.30 TWh of bio-methane	

5.4 Availability of hydrogen for injection and cross-border hydrogen flows

The information collected in section 5.2 allows to build case scenarios to study the potential for hydrogen injection in the European gas grid. A baseline scenario for 2020 has been developed and mid-term and long-term scenarios for 2030 and 2045/50 are also developed. The are detailed in the following subsections.

5.4.1 Baseline scenario (2020)

This section introduces the baseline scenario to study the potential for hydrogen injection in the European grids based on hypothetical cases regardless the legal framework. This case study calculates the needs for hydrogen in each European country if part of the total gas demand were to be replaced by hydrogen for partial decarbonisation of the grid. The current gas demand in each European country is considered, and the needs of hydrogen to replace from 2 to 5% of the total gas volume are calculated and compared with the available merchant hydrogen in 2020. Noteworthy, this is not a real case because merchant hydrogen is not ready for injection, but it can show the gap that exists to add 2/3/5% to get a feeling for the challenge.

Table 8. Gas demand and hydrogen needs for decarbonising the grid in the baseline scenario

Country	Natural gas demand	Biogas production	Merchant hydrogen	Hydrogen demand			Hydrogen surplus		
				2 mol%	3 mol%	5 mol%	2 mol%	3 mol%	5 mol%
	TWh								
Austria	90.87	0.14	0.16	0.60	0.91	1.51	-0.45	-0.75	-1.35
Belgium	190.00	2.75	5.68	1.28	1.92	3.20	4.40	3.77	2.49
Bulgaria	31.34		0.00	0.21	0.31	0.52	-0.21	-0.31	-0.52
Croatia	29.37		0.00	0.19	0.29	0.49	-0.19	-0.29	-0.49
Czech Republic	92.24	6.81	0.00	0.66	0.99	1.64	-0.66	-0.99	-1.64
Denmark	28.95	6.30	0.04	0.23	0.35	0.58	-0.20	-0.31	-0.55
Estonia	4.80	1.50	0.00	0.04	0.06	0.10	-0.04	-0.06	-0.10
Finland	25.43	1.00	0.78	0.18	0.26	0.44	0.61	0.52	0.35
France	494.00	8.30	3.75	3.33	5.00	8.33	0.42	-1.25	-4.58
Germany	966.90	10.00	14.05	6.48	9.72	16.20	7.57	4.33	-2.15
Greece	32.87		0.00	0.22	0.33	0.55	-0.22	-0.32	-0.54
Hungary	117.41		2.31	0.78	1.17	1.95	1.53	1.14	0.36
Ireland	56.26		0.00	0.37	0.56	0.93	-0.37	-0.56	-0.93
Italy	746.00	11.74	4.82	5.03	7.54	12.57	-0.21	-2.72	-7.75
Latvia	15.79	0.80	0.00	0.11	0.17	0.28	-0.11	-0.17	-0.28
Lithuania	23.60	0.86	0.00	0.16	0.24	0.41	-0.16	-0.24	-0.41
Luxembourg	9.90		0.00	0.07	0.10	0.16	-0.07	-0.10	-0.16
Norway	10.00	15.82	0.02	0.17	0.26	0.43	-0.15	-0.24	-0.41

Country	Natural gas demand	Biogas production	Merchant hydrogen	Hydrogen demand			Hydrogen surplus		
				2 mol%	3 mol%	5 mol%	2 mol%	3 mol%	5 mol%
	TWh								
Poland	269.82	3.29	0.25	1.81	2.72	4.53	-1.56	-2.47	-4.28
Portugal	70.94		0.37	0.47	0.71	1.18	-0.10	-0.33	-0.80
Romania	132.58		0.00	0.88	1.32	2.20	-0.88	-1.32	-2.20
Serbia	20.40	0.42	0.00	0.14	0.21	0.35	-0.14	-0.21	-0.35
Slovakia	58.01		0.02	0.38	0.58	0.96	-0.36	-0.56	-0.94
Slovenia	9.65		0.00	0.06	0.10	0.16	-0.06	-0.09	-0.16
Spain	364.30	8.10	5.54	2.47	3.71	6.18	3.07	1.84	-0.63
Sweden	15.12	10.00	0.05	0.17	0.25	0.42	-0.12	-0.20	-0.37
Switzerland	41.87		0.02	0.28	0.42	0.69	-0.25	-0.39	-0.67
The Netherlands	408.21		7.36	2.71	4.06	6.77	4.65	3.30	0.59
Ukraine	303.54		0.00	2.01	3.02	5.03	-2.01	-3.02	-5.03
UK	860.7	27	1.75	5.89	8.83	14.72	-4.13	-7.08	-12.97

Table 8 contains all the information necessary to define the baseline scenario. The total gas demand (i.e. the addition of natural gas and renewable methane) has been obtained from the information gathered in Table 7. The natural gas demand can provide the minimum capacity of the grid, which will be useful in the coming sections. The "merchant hydrogen" column considers all the available hydrogen for selling according to the database of the Fuel Cells and Hydrogen Observatory. [224] The table shows the needs for hydrogen in TWh to replace 2-5% of the total gas volume in the grid, keeping the total energy content in the grid constant. Finally, the hydrogen surplus is calculated as the difference between hydrogen supply (merchant hydrogen) and the amount needed for the replacement.

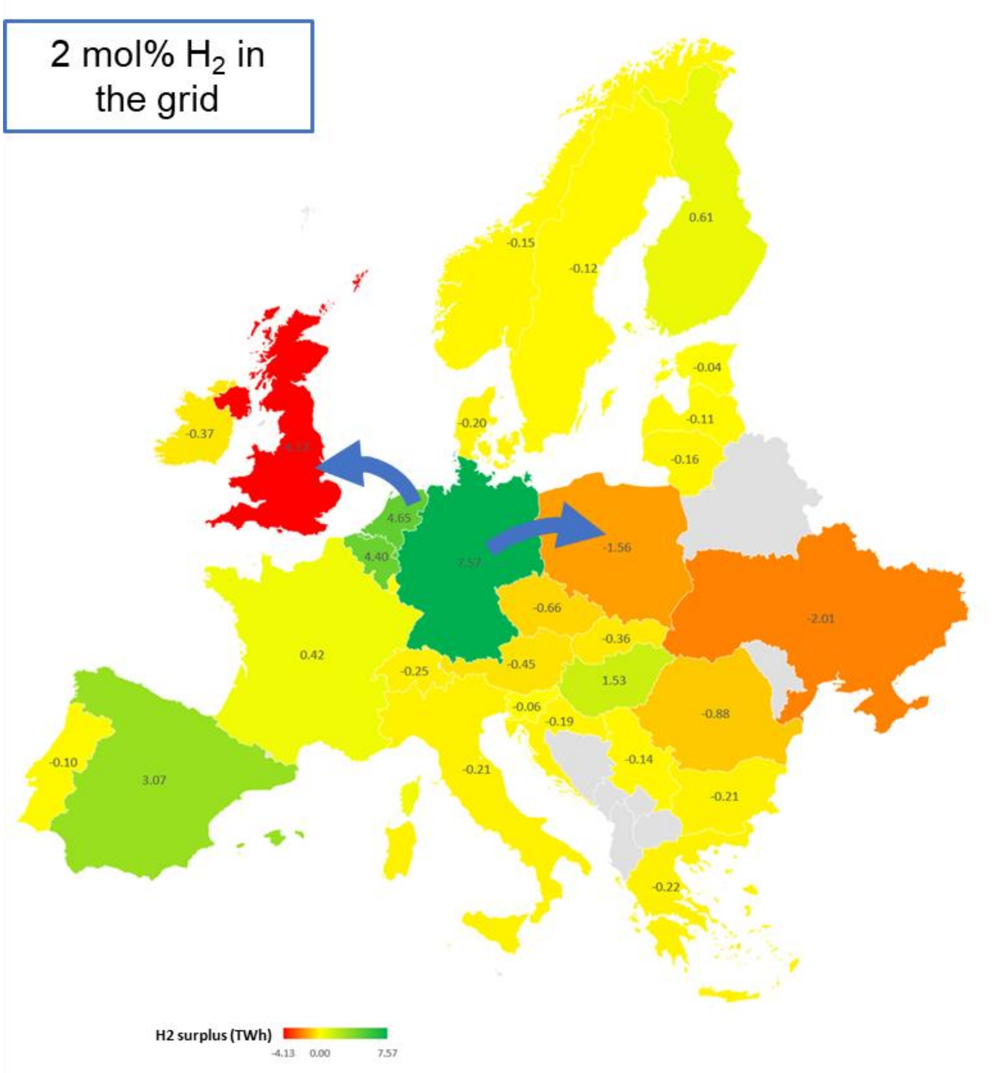


Figure 27. Surplus of hydrogen available for injection in the gas grid if a 2 mol% H_2 blend was considered. Blue arrows show potential cross-border flows.

Figure 27 illustrates the first hypothetical case, in which it is supposed that 2 mol% H_2 blend level is achieved in all countries and all the merchant hydrogen is available for injection in the grid instead of sold to other users. The map shows the surplus of hydrogen in each country (difference between merchant hydrogen and the amount of hydrogen needed to reach this 2 mol%). It can be seen how Germany, Spain, The Netherlands and Belgium would reach this level easily and would have 3.1-7.5 TWh of hydrogen surplus. Finland, France or Hungry can also reach this level of blend, but with little hydrogen surplus (0.4-1.4 TWh of hydrogen). The country with the greatest hydrogen need would be UK, which would be supplied through the Interconnector and BBL lines via the Zeebrugge IZT cross-border point. Poland and Ukraine would need up to 2 TWh of hydrogen that may come from Germany via the Mallnow and GCP GAZ-SYSTEM/ONTRAS cross-border points. [225] Besides, Finland could meet the demand of their neighbouring countries Sweden and Norway. Spain would have no way of exportin his hydrogen via pipeline at this point.

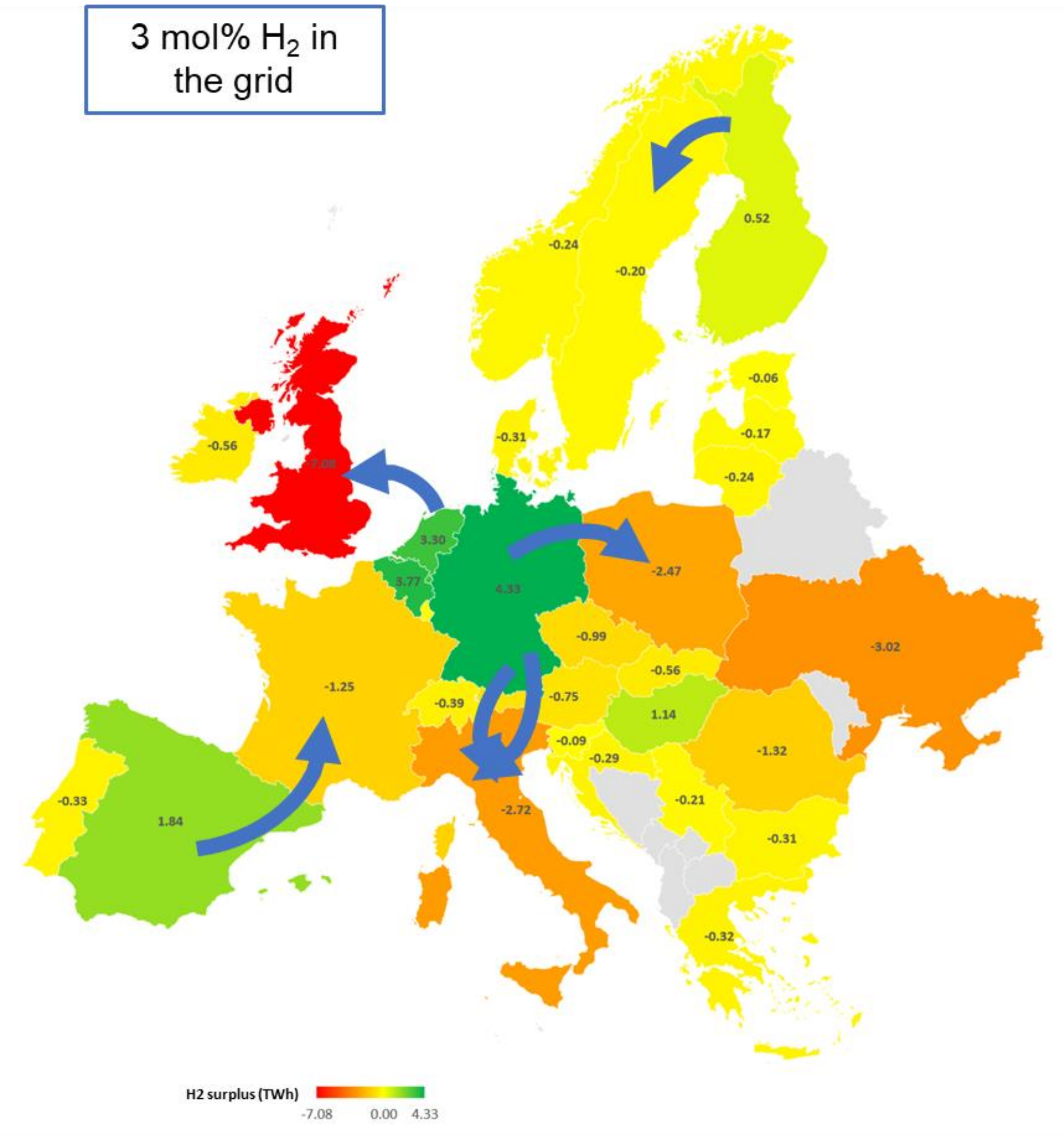


Figure 28. Surplus of hydrogen available for injection in the gas grid if a 3 mol% H_2 blend was considered. Blue arrows show potential cross-border flows.

Figure 28 depicts the second case of study, where 3 mol% H_2 blend level is achieved in all countries and all the merchant hydrogen is available for injection. The map shows the surplus of hydrogen across Europe. Once again, Germany, Spain, The Netherlands and Belgium are the countries with the higher surplus, although this time logically lower (1.8-4.3 TWh), and UK is the country with the higher hydrogen needs (i.e. 7.1 TWh). Besides the hydrogen transport to UK and Poland discussed above, a new flow of hydrogen may appear from Spain to France through the VIP Pyrenees point [225], since the surplus of Spain can cover the demand in France. Italy would appear with a hydrogen demand of 2.7 TWh that can only be achieved with the German hydrogen transported via Switzerland and Austria, being split between Poland and Italy.

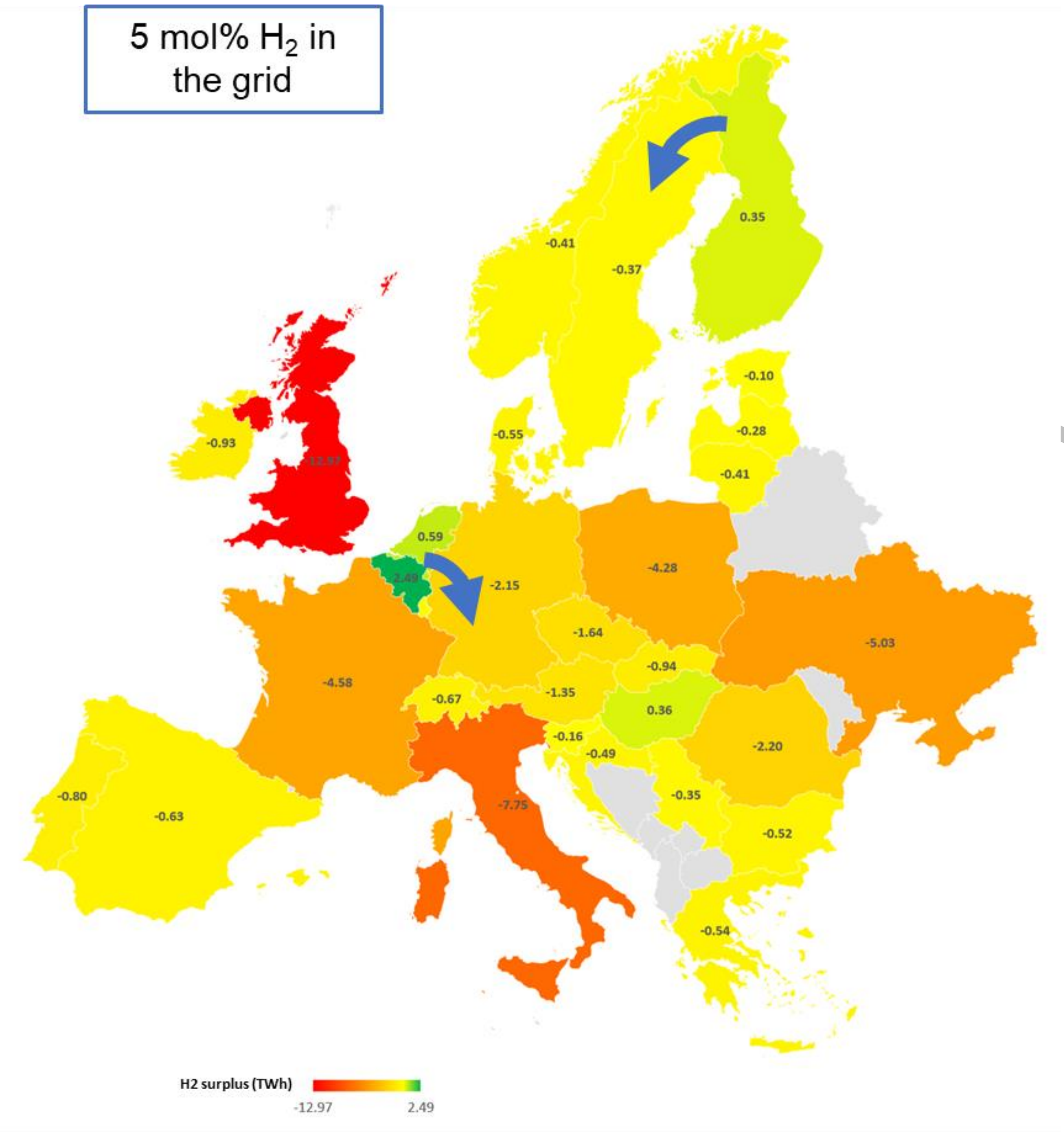


Figure 29. Surplus of hydrogen available for injection in the gas grid if a 5 mol% H_2 blend was considered. Blue arrows show potential cross-border flows.

Figure 29 depicts the final scenario, where all European grids reach 5 mol% H_2 blend level. The map shows once more the surplus of hydrogen across Europe. In this case the demand is too high for the countries with high gas demands. It is the case of Germany or Spain, for instance, that become new hydrogen demanding countries. Just Belgium, The Netherlands, Hungary and Finland remain with some surplus of hydrogen to export. Finland would be able to cover partially the demand of Sweden and Norway. And Belgium and The Netherlands would cover that of Germany. Most of the European countries would need additional sources of hydrogen to meet the demands. Decarbonising the European gas grid needs for extra hydrogen production capacity, which should be accomplished in the coming years as it will be detailed in the following subsections.

5.4.2 Mid-term future scenario (2030)

The mid-term scenario tries to forecast the transit of hydrogen across Europe by 2030 attending to the total gas demand, the hydrogen production, and the hydrogen demand in the different countries at that moment. Table 9 contains all the information gathered in Table 7 from section 5.2 regarding the expected gas consumption. The production of renewable methane (biogas, biomethane or synthetic methane) is also considered because part of the total gas demand will be met by this renewable gas, especially in those counties with powerful strategies. This way it can be calculated how much of the total gas demand can be covered by renewable methane by 2030, and form the remaining amount of energy demand, how much "room" there is in the grid for injecting hydrogen, and how this amount aligns with the expected hydrogen demand in each county. Two scenarios are considered based on 1) the maximum and 2) the minimum production/demand capacities.

Table 9. Summary of total gas demand and production and demand of renewable gases in each European country by 2030

Country	Total gas demand (TWh)		Renwable methane production (TWh)		Hydrogen production (TWh)		Hydrogen demand (TWh)	
	Min.	Max.	Min.	Max.	Min.	Max.	Min.	Max.
Austria	60.0	76.5	7.0	10.0	4.0		-	-
Belgium	190.0		0.0		21.0		25.0	
Bulgaria	44.4		7.9		1.6		0.2	5.0
Croatia	29.4		0.0		0.1	1.5	0.2	2.0
Czech Republic	92.2*		7.0		0.1		5.0	0.0
Denmark	21.0		6.2		14.0	40.0	8.0	27.0
Estonia	5.2		0.7		1.1		-	-
Finland	25.4*		8.3		61.0		6.0	25.0
France	376.0		57.0		18.2		20.0	34.0
Germany	530.0	775.0	100.0		14.0	20.0	37.0	231.0
Greece	21.0	44.4	6.5		3.5	11.0	0.3	7.0
Hungary	79.7	209.3	11.5		0.4	6.4	11.5	0.0
Ireland	34.0	53.0	11.5		5.2	11.5	0.0	3.0
Italy	659.0	773.0	100.0		7.0	-	0.3	24.0
Latvia	20.0		1.4		0.0	-	-	-
Lithuania	20.0		4.5		0.9	1.0	0.0	5.0
Luxembourg	9.9*		0.0	-	0.0	-	-	-

Country	Total gas demand (TWh)		Renwable methane production (TWh)		Hydrogen production (TWh)		Hydrogen demand (TWh)	
	Min.	Max.	Min.	Max.	Min.	Max.	Min.	Max.
Norway	10.0*		2.5	4.3	16.0	46.0	8.0	16.0
Poland	325.6		38.0		2.9		0.3	22.0
Portugal	70.9*		7.0		16.0	-	5.0	5.7
Romania	157.0		23.5		5.2	-	5.1	14.0
Serbia	20.4*		-	-	-	-	-	-
Slovakia	58.0*		3.5		0.6	1.5	0.3	7.0
Slovenia	14.0		1.5		-	-	-	-
Spain	364.3*		47.0		66.0	99.0	30.0	46.0
Sweden	15.1		15.0		9.0	50.0	9.0	50.0
Switzerland	23.9		6.2		-	-	26.9	-
The Netherlands	286.2		4.2	28.9	42.0	88.6	27.0	85.6
UK	532.0	645.5	52.5		40.0	-	27.0	38.0

*Demand estimated as constant since 2020 due to lack of data

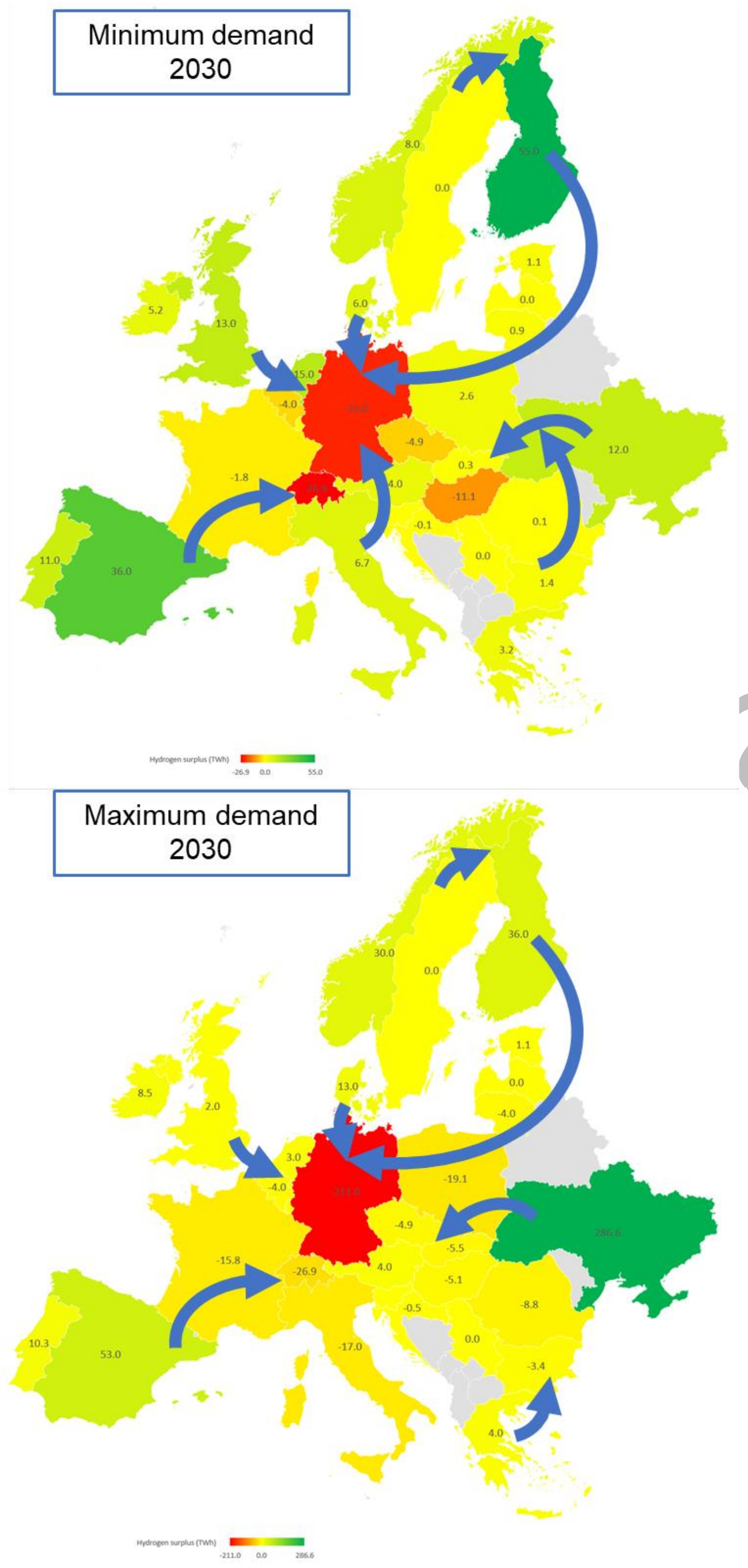
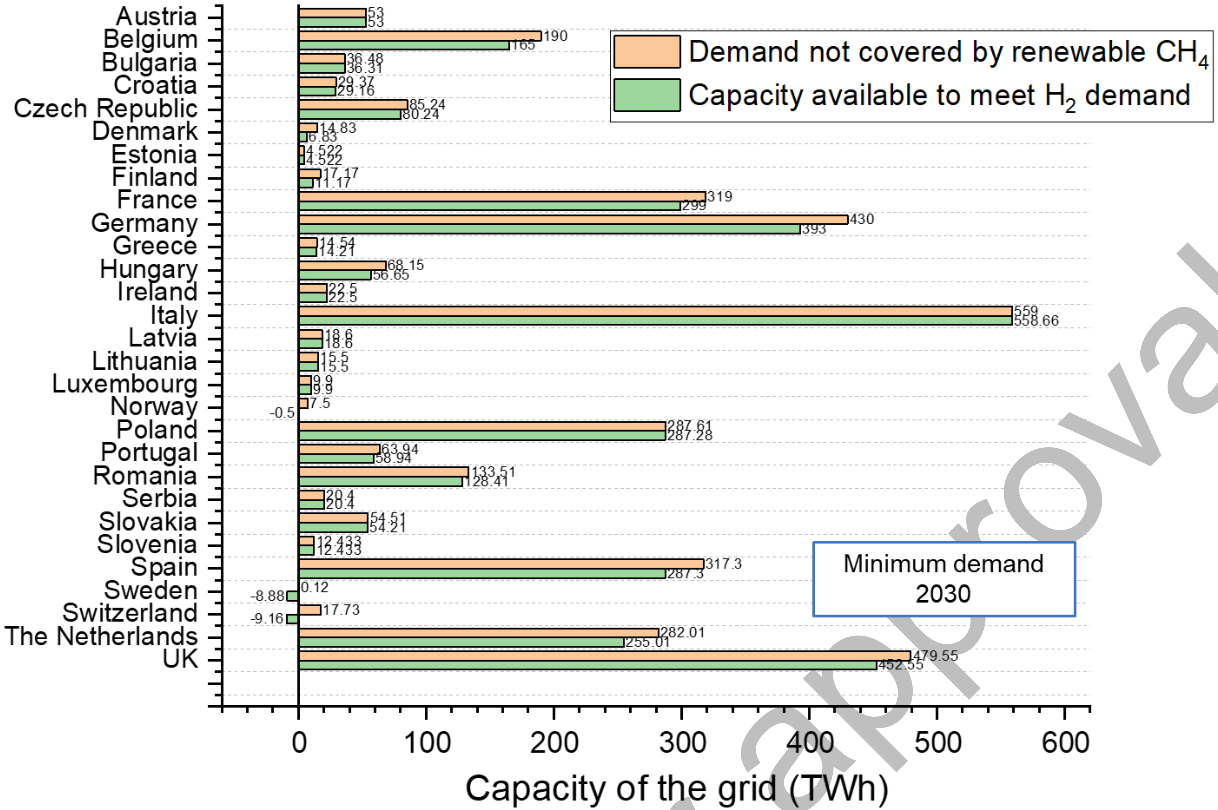


Figure 30. Hydrogen surplus in the European countries by 2030 and potential supply corridors (blue arrows)

Figure 30 depicts the hydrogen surplus across Europe by 2030 for the low and high demand scenarios. This surplus has been calculated as the difference between hydrogen production and demand with the data from Table 9. In the case of Ukraine, the forecaseted export capacity has been selected. In the minimum demand scenario, Switzerland and Germany would be the highest hydrogen demanding countries, needing to import 23 and 26 TWh of hydrogen, respectively. Other importing countries would be Belgium, Czech Republic, Hungary and France, with import needs ranging from 1.8 to 11.1 TWh of hydrogen. On the other side, the counties with the highest export capacities would be Finland (55 TWh) and Spain (36 TWh), followed by The Netherlands, UK, Portugal, Norway and Ukraine with export capacities ranging from 8-15 TWh. The remaining countries would be self-sufficient or have little hydrogen surplus. Hydrogen delivery may follow the path indicated by the blue arrows, which match the Corridors A, B, C and D detailed in the EHB report. [66] The demand in Eastern Europe could be only partially covered by Greece and Ukraine.

In the case of the maximum demand scenario, Germany remains being the county with the highest hydrogen needs (211 TWh), followed by Switzerland (26 TWh). Countries such as Italy or Poland that were self-sufficient now need to import below 20 TWh of hydrogen. The import needs of Belgium, Bulgaria, Croatia, Czech Republic, Romania and Slovakia also increase considerably from 0.5 to 5.5 TWh. Ukraine may become the highest exporting country with286 TWh export capacity. Noteworthy, as stated in previous sections, the forecasts for Ukraine are highly dependent on the evolution of the war and the recovery of the county once ended. After Ukraien, Spain would become the main exporting country with 53 TWh capacity followed by Finland (36 TWh) and Norway (30 TWh). Demark, Portugal and Ireland show an interesting contribution to hydrogen exports with 13.0, 10.0 and 8.5 TWh, respectively. Hydrogen delivery may follow the same path explained in the former paragraph, but this time there would be no supply from Italy, whose demand would be unattended. Besides, there would be no capacity to cover the huge demand in Central Europe and at least 140 TWh of extra hydrogen supply would be necessary in the high-producing countries.



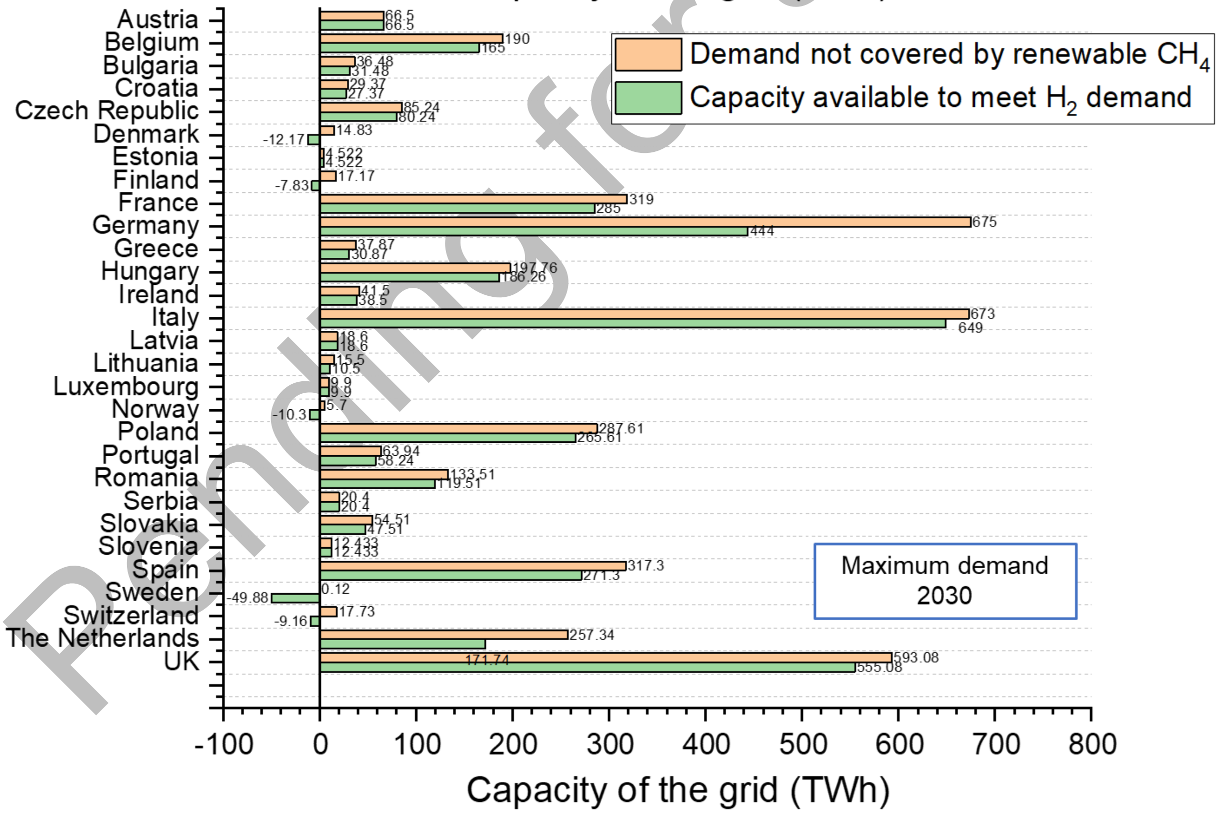


Figure 31. Gas demand not covered by renewable methane and capacity of the grid available to meet hydrogen demand based on the expected minimum (top) and maximum (bottom) demand/production scenarios by 2030.

Figure 31 shows the gas demand that cannot be covered by renewable methane by 2030. It has been calculated as the difference between the total gas demand and the production capacity of renewable methane in each country. The graph also shows the capacity that the grid still has to transport hydrogen in terms of energy delivered. This capacity has been calculated as the difference between the hydrogen demand expected in each county and the “room” that the infrastructure still has for hydrogen transport. The latter is considered as the total gas demand in the baseline scenario, being the minimum capacity of the grid, and the demand already covered by renewable methane. This way, positive values mean that the grid can absorb all the demand of hydrogen expected and the numbers depicted correspond to the energy that has to be delivered as natural gas. Negative values would mean that the demand is already covered by methane and new infrastructure, or other means of transportation are necessary to reach the amount of hydrogen demanded. Figure 31 considers two graphs, the upper one for the scenario with the lowest energy demand and the bottom one for that of the highest gas demand (see Table 9).

It can be seen how for the case of minimum demand; all counties could inject as much hydrogen as to meet the total hydrogen demand in the country via pipeline. Just Norway, Switzerland and Sweden would need 0.5-9 TWh of extra capacity in the grid for this. In most cases injecting such an amount of hydrogen mean replacing 5-25% of the gas energy by this gas. In Ireland and Greece it would mean higher values around 33%, and even much higher in Finland (67 %) due to the “small” national grid in comparison to the amount of hydrogen demanded, as well as the great production of renewable methane. It also have to be considered that the assumptions made come from different sources which may not match, leading to this unbalance.

In the case of the high-demand scenario, the grids of Denmark and Finland would add to the list of counties where an expansion of the grid would be needed. Norway would need to double the capacity of its grid, and Sweden triplicate it. This fact is critical if hydrogen is going to be transported to Central Europe as depicted in Figure 30. Switzerland would need 9 TWh extra capacity, which seems achievable without modifying the national grid. The amount of natural gas replaced by hydrogen remains as 5-25% of the gas energy, as in the minimum demand case.

5.4.3 Long-term future scenario (2045-50)

The long-term scenario tries to forecast the transit of hydrogen across Europe by 2045-2050 attending to the total gas demand, the hydrogen production, and the hydrogen demand in the different countries at that moment. The mythology is the same developed in 5.4.2. Table 10 contains all the information gathered in Table 7 from section 5.2 regarding the expected gas consumption. The production of renewable methane is considered to see how much of the total gas demand can be met by this renewable gas. The portion of the total gas demand covered by renewable methane by 2045-20 is calculated, and the remaining amount of energy demand must be covered by hydrogen to reach the individual decarbonisation goals. This amount of hydrogen is compared with the expected hydrogen demand in each county to study the possible alignment, need to expand the infrastructure, etc. Two scenarios are considered again based on 1) the maximum and 2) the minimum production/demand capacities.

Table 10. Summary of total gas demand and production and demand of renewable gases in each European country by 2045-50

Country	Total gas demand (TWh)		Biogas production (TWh)		Hydrogen production (TWh)		Hydrogen demand (TWh)	
	Min.	Max.	Min.	Max.	Min.	Max.	Min.	Max.
Austria	89.0		45.5		7.0		44.0	52.0
Belgium	190.0		13.8		11.0		94.0	109.0
Bulgaria	11.7		35.0		39.0		0.3	23.0
Croatia	14.7*		5.2		7.1	18.0	8.4	12.0
Czech Republic	120.5		0.0		0.1		25.0	27.0
Denmark	16.4		0.0		108.1	142.0	21.0	67.0
Estonia	4.9		1.2		0.5	35.1	1.5	2.0
Finland	12.7*		72.7		139.0		27.0	66.0
France	247.0*		226.0		95.0	174.0	161.0	181.0
Germany	238	693	250.0		192.0		156.0	598.0
Greece	16.4*		30.0		87.0		44.0	
Hungary	58.7*		45.0		9.8	32.0	25.0	
Ireland	20.0	45.0	5.1	18.1	70.0	90.0	7.5	30.0
Italy	654.0	690.0	99.0	350.0	93.0		111.0	237.0
Latvia	7.9*		15.6		20.0		1.6	3.0
Lithuania	11.8*		9.5		15.0		12.5	21.0

Country	Total gas demand (TWh)		Biogas production (TWh)		Hydrogen produc-tion (TWh)		Hydrogen demand (TWh)	
	Min.	**Max.**	**Min.**	**Max.**	**Min.**	**Max.**	**Min.**	**Max.**
Luxem-bourg	5.0*		0.0		0.0		4.1	9.9
Norway	5.0*		14.9		112.0	140.9	24.0	39.6
Poland	88.0	120.0	146.8		113.0	375.0	155.0	
Portugal	35.5*		42.8		74.0		28.0	33.0
Romania	66.3*		93.0		83.0		46.0	
Serbia	10.2*		0.0		0.7		0.0	
Slovakia	29.0*		11.3		13.0		13.2	26.0
Slovenia	4.8*		5.2		4.0		7.0	
Spain	339.6		237.0		374.0		165.0	261.0
Sweden	7.6*		123.0		34.0	123.0	44.0	88.0
Switzerland	11.1		9.8		0.0		32.2	
The Nether-lands	204.1*		16.6		97.1	328.6	133.0	109.9
UK	260.5	533.5	130.4		297.0		250.0	460.0

*Demand estimated as half of the demand in 2020 due to lack of data

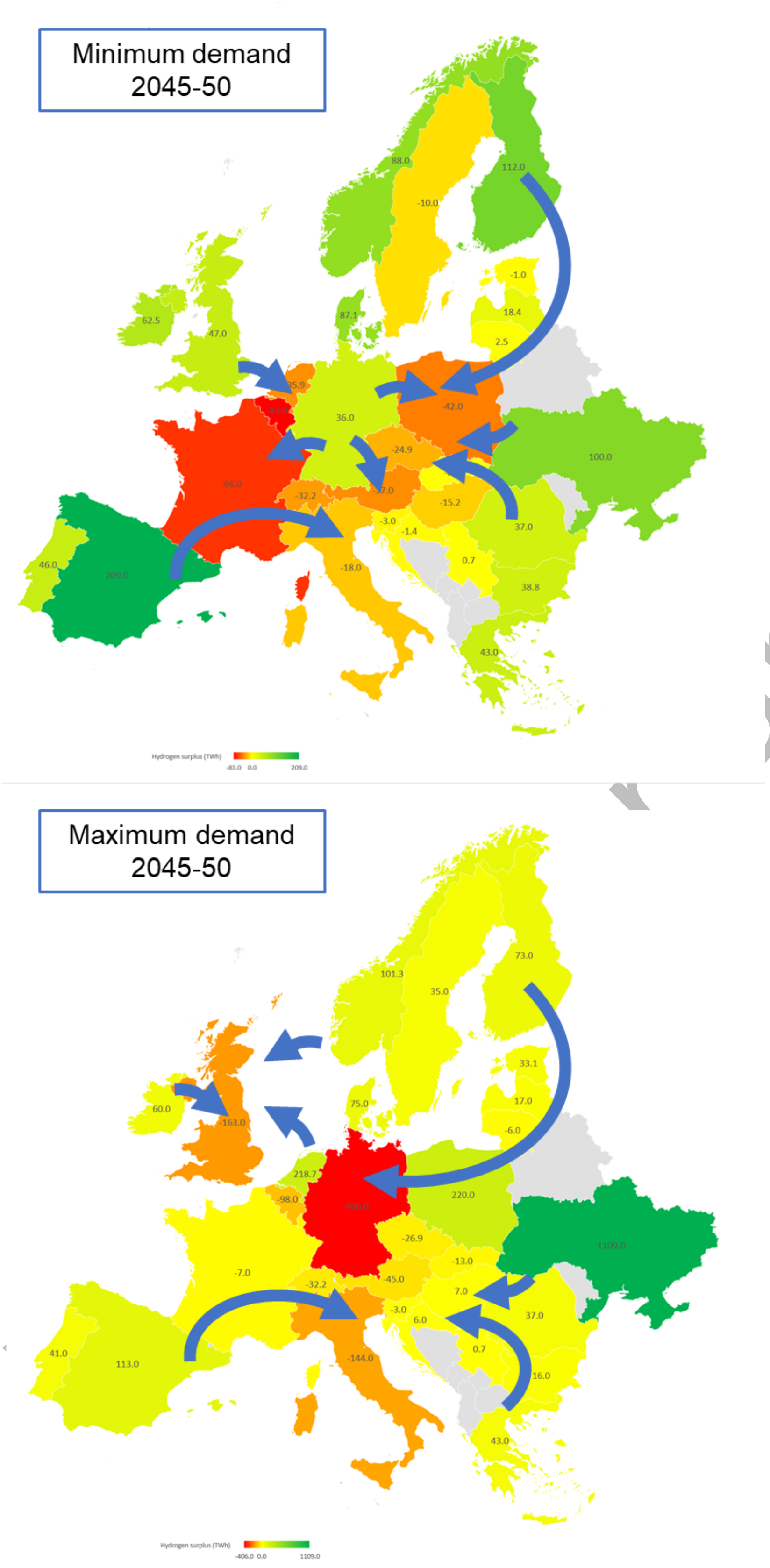


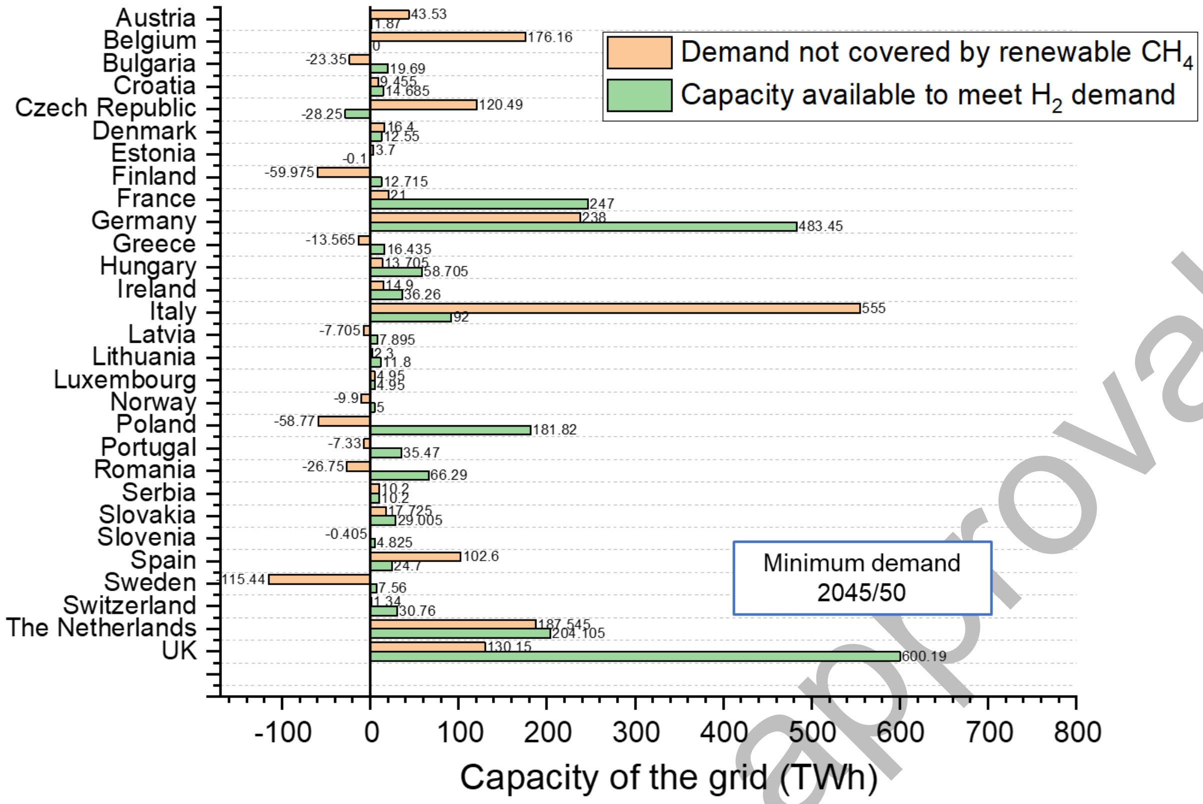
Figure 32. Hydrogen surplus in the European countries by 2045-50 and potential supply corridors (blue arrows)

Figure 32 shows the hydrogen surplus across Europe by 2045-50 for the low and high demand scenarios. This surplus has been calculated as the difference between hydrogen production and demand with the data from Table 10. In the case of Ukraine, the expected hydrogen export capacity has been considered. In the minimum demand scenario, the highest hydrogen demanding countries would be Belgium, France and Poland, with a total need of 83, 66 and 42 TWh of hydrogen to import. Austria, Switzerland and The Netherland would also be importing countries, needing to acquire around 30 TWh of hydrogen. Also relevant are the import needs of Czech Republic, Hungary, Italy and Sweden, which would import 10-25 TWh of hydrogen. On the other side of the balance, Spain would be the greatest producer country, being able to export up to 209 TWh of hydrogen, followed by Finland, Ukraine and Demark (112, 100 and 87 TWh of export capacity, respectively). Bulgaria, Germany, Greece, Portugal, Romania and UK can also add interesting amounts of hydrogen to the European market, with export capacities of around 40 TWh each. Ireland with 62 TWh hydrogen surplus and Norway with 88 TWh would also be potential hydrogen exporting countries.

The hydrogen supply among countries may follow the blue arrows indicated in Figure 32. The Scandinavian countries may deliver hydrogen to Poland and Central Europe along the Baltic Sea, as defined in the Corridor D of the EAB. [66] Spain would deliver hydrogen to France, and via France could supply gas to Italy, being a contrary route to the corridor defined by the EHB. [66] Ukraine, Greece, Bulgaria and Romania would also deliver hydrogen to the Central European countries, again coherent with the Corridor E of the EAB report. [66] It is curious how in this scenario Germany becomes and exporting country that can supply hydrogen to either France, Austria, Czech Republic or Poland.

When studying the maximum demand scenario, the behaviour of some countries changes drastically. In this scenario Germany and UK would be the countries with the greatest hydrogen import needs (406 and 163 TWh, respectively) while they were import countries in the previous scenario. Other big importing countries would be Italy (144 TWh), Norway (101 TWh) or Belgium (98 TWh). Austria, Croatia or Swertzand complete the list of importing countries with import needs around 30-40 TWh, followed by France, Lithuania, Luxembug, Slovakia or Slovenia (<13 TWh). Ukraine would become the highest exporting country, with an export capacity of up to 1,100 TWh. Once again, the real capacity of Ukraine is very difficult to forecast due to the ongoing war in this country.Poland and The Netherlands would be the second high exporting counties in Europe (around 220 TWh). The exporting potential of Spain can also be highlighted (113 Twh), followed closely by Denmark and Finland with 75 and 73 TWh of export capacity, respectively, and Ireland with 60 TWh. Greece, Portugal, Romania, Estonia and Sweden would also become hydrogen exporting nations with capacity to export up to 43 TWh of gas.

Once again, some blue arrows in Figure 32 show potential ways to deliver hydrogen among countries. According to our results, Spain and Portugal would deliver hydrogen to Italy via France. Once again the Corridor A of the EAB would have a reverse flow and would merge with Corridor B, which would deliver hydrogen to Italy instead to Central Europe. [66] What is coherent with our study is the Corridor D and E of the EAB report. [66] The Scandinavian countries may deliver hydrogen to Poland and Central Europe along the Baltic Sea and Greece, Bulgaria and Romania would also deliver hydrogen to the Central European countries. UK would have an important hydrogen demand to meet. Part of it would be supplied by Ireland, and the rest of it may come from The Netherlands or the Scandinavian peninsula.



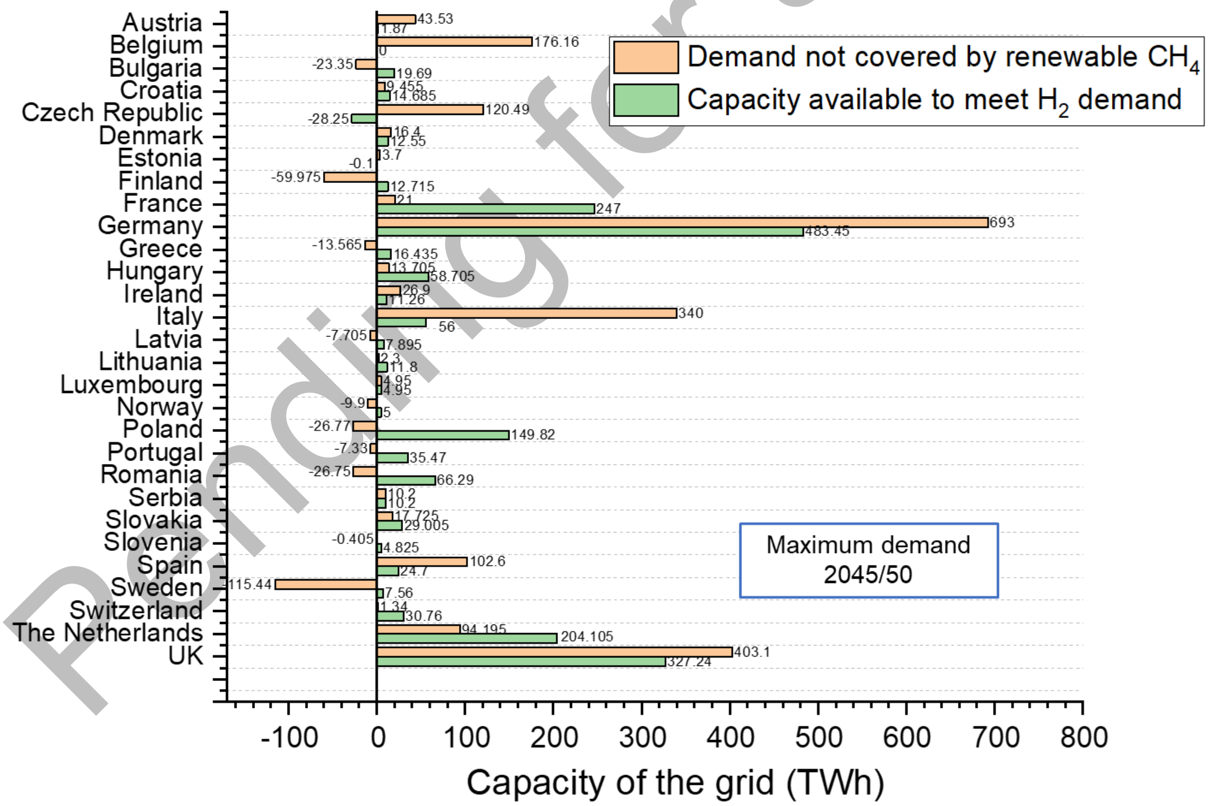


Figure 33. Gas demand not covered by renewable methane and capacity of grid available to meet hydrogen demand based on the expected minimum (top) and maximum (bottom) demand/production scenarios by 2045-50

Figure 33 shows the gas demand that cannot be covered by renewable methane by 2045-50. It has been calculated as the difference between the total gas demand by 2050 and the production capacity of renewable methane in each country, using the values detailed in Table 10. The graph also shows the capacity that the grid still has to transport hydrogen in terms of energy delivered. This capacity has been calculated as the difference between the hydrogen demand expected in each county and the "room" that the infrastructure still has for hydrogen transport. The latter is considered as the total gas demand in the baseline scenario, being the minimum capacity of the grid, and the demand already covered by renewable methane. In this manner, positive values indicate the grid's capacity to fully accommodate the projected hydrogen demand, while the depicted numbers correspond to the energy required to be supplied as natural gas. Conversely, negative values would signify that the demand is already met by methane and additional infrastructure, or alternative transportation methods are needed to meet the required amount of hydrogen. Figure 33 encompasses two graphs, the upper graph representing the scenario with the least energy demand, and the lower graph representing the scenario with the highest gas demand (refer to Table 10).

In both gas demand scenarios, the same countries show a great potential for renewable methane. It is the case of Bulgaria, Finland, Greece, Latvia, Norway, Poland, Portugal, Romania, Slovenia and Sweden, which could meet all their national gas demand just with renewable methane and not needing hydrogen at all. The surplus of renewable methane may be exported to neighbouring countries, being the flows of methane out of the scope of this report. Fortunately, all these countries have enough grid capacity to accommodate both the renewable methane and hydrogen demand, as long as the current grid capacity remains unaltered. The only exception is the Czech Republic, which would need to increase in 28 TWh its grid capacity. The grids of countries such as France, Germany, Poland, The Netherlands, Ukraine or UK are oversized enough to meet the transport need of all renewable gases. Others such as those of Austria, Belgium, Estonia, Norway or Slovenia seem more limited but still with enough capacity. The Norwegian grid is in particular rather critical, since Norway is expected to become an important hydrogen exporting country towards Central Europe. Unless renewable methane is not injected but consumed off-grids, Norway will need to increase its grid capacity in the future for hydrogen transport.

Finally, the deliverable D5.4 of WP5 outlines the key elements and principles that will guide the evolution of the European natural gas grid towards 2050. This vision by 2050 explains that the European natural gas grid will facilitate the transportation and distribution of renewable and low-carbon gases, such as biomethane, hydrogen, and synthetic methane. It will be adapted to incorporate hydrogen injection and blending, while new pipelines will transport 100% sustainable hydrogen. The future grid will embrace decentralization, utilizing diverse supply sources like biomethane plants, local hydrogen production, and Power-to-Gas systems. Smart and digital infrastructure with advanced technologies will optimize grid management, while large-scale gas storage facilities will store excess renewable energy. Cross-border cooperation, harmonized regulations, and stakeholder collaboration will be vital, requiring significant investment from various sources. The vision in WP5 is therefore aligned with the results explained in this report.

5.4.4 Alignment with EU policies

The major basis for the injection of hydrogen into gas transmission grids builds:

- the Hydrogen and decarbonised gas market package (DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on common rules for the internal markets in renewable and natural gases and in hydrogen, so-called EU Gas Directive [226]), published by the EU Commission in December 2022, and currently in interinstitutional negotiations between EU Parliament, EU Council European Commission (trialogue)

- together with the TEN-E regulation (Regulation on Guidelines for Trans-European Energy Infrastructure [227]), published in May 2022 and in force since June 2022, laying down guidelines for the development and interoperability of trans-European energy infrastructure including hydrogen and contributing to the EC climate goals and 'ensuring interconnections, energy security, market and system integration and competition that benefits all Member States, as well as affordability of energy prices'.

Both are not subject to D 2.3 as the deliverable was completed before the documents were available. Deliverable D 2.3 refers to the general EC hydrogen strategy and the concept of Fit-for-55, both not detailed enough to carry out the alignment requested in the project description for this deliverable (D6.1).

The gas/hydrogen market package revises the legal requirements for the internal gas market and stipulates the requirements for the future hydrogen market, both contributing to the decarbonisation goals for the energy systems. Due to the trialogue process and the deviating positions of the EU Parliament, EU Council and EU Commission significant changes can be expected in the final documents. Thus, a final analysis cannot be made at present time of this deliverable report's editing neither.

However, it is to highlight already that while the EU gas/hydrogen market package [226] includes limits of hydrogen blending in cross-border natural gas transport at a maximum of 5% hydrogen concentration, the EU Council arguments for 2 % and the EU Parliament for 3%. A legal limitation of hydrogen blending at cross-border gas transport will lead to the fact that blending hydrogen with natural gas above the finally stipulated limit of 2%, 3% or 5% may hardly take place in the gas transmission grids. It is therefore expected that dedicated and repurposed lines will be develop for delivering 100 % H_2 at transport pressure level in the future, according to the flows considered in the previous subsections.

The update of the EC policies and also the identification of potential gaps and barriers in RCS are subject to D.6.3.

5.5 The status of future gas grids in Europe

This section contains a description of the possible characteristics of the transport grids in Europe. This information corresponds to the feedback received from WP5 though the report D5.4.

The gas grid is expected to increase the volume of hydrogen transported. The hydrogen content may vary, ranging from low percentages to higher concentrations until reaching 100 %H_2, depending on the specific applications and regions. The gas grid has been designed basing on the properties of natural gas. Modifications will be therefore required to accommodate higher hydrogen concentrations. The compatibility of materials used in pipelines and other infrastructure with hydrogen is a crucial aspect to ensure safety and prevent leaks. Additionally, end-use appliances such as boilers, furnaces and cookers may require modifications, even their replacement by new ones, to handle higher hydrogen concentrations.

To enable the integration of hydrogen into the gas grid, advanced technologies for separating hydrogen from gas can be employed. For very small admixture levels (0 - 2 vol.-% hydrogen), no separation is envisaged, while it can get relevant for hydrogen blends in the 2 - 30 vol.-% H_2 range.

D 5.4 develops four case scenarios for the arrangement of future gas grids, based on the hydrogen concentration and the use of separation technologies:

- 2 Vol.-% H_2 without H_2/NG separation: Allowing for a gradual transition, the current status quo represented by this type of gas grid sets the baseline of what is possible today in most EU member states. It minimizes the need for immediate and extensive infrastructure modifications by accommodating low volumes of maximum 2 vol.-% of hydrogen.

- 30 Vol.-% H_2 without H_2/NG separation: Achieving relatively constant transport costs without separation is possible, but it necessitates uniform permissible proportions of hydrogen in the gas grid, particularly for facilitating transport across national borders. The absence of separation in the grid prevents, however, seasonal storage of hydrogen at transport level. Hydrogen must be consumed or transferred to lower levels in the grid for further processing. Thus, finding reliable partners capable of supplying large quantities of hydrogen becomes crucial. Retrofitting the gas grid requires hydrogen-capable components that have demonstrated compatibility with high concentrations of hydrogen through experiments.

- 30 Vol.-% H_2 with H_2/NG separation: In order to ensure proper operation of processes downstream at the distribution and/or end-users level, separation technology is necessary for certain gas consumers. Additionally, the utilization of separation technology offers the possibility of seasonal hydrogen storage by isolating it from the gas and storing it separately in designated facilities along the gas grid. Strategic implementation of separation technology at specific points in the transmission grid enables the extraction of hydrogen, facilitating the distribution and/or storage of pure hydrogen based on downstream applications within the grid. The separation of hydrogen at the transmission level promotes the integration of larger volumes of hydrogen into the energy system by balancing the supply and demand of renewable energy sources. The use of separation technology at certain city gates is much more efficient from an economic point of view than equipping every city gate, as detailed in D 5.3.

- 100 Vol.-% H_2: Addressing infrastructure and materials compatibility, hydrogen production and supply, storage capacity, and public acceptance are among the key considerations required for repurposing a gas grid to accommodate 100% hydrogen.

Full information about this study can be found in D5.4.

6 Conclusions

This deliverable provides a comprehensive analysis of the European natural gas grid, focusing on two main aspects. The first part of the report completes the inventory of pipelines and assets in the European transport natural gas grid started in D2.3 of WP2, while the second part examines the potential for hydrogen injection in the European grids and compares it with current EU policies, according to activity of task 6.1 of WP6.

The initial part of the report focuses on completing the inventory of the European natural gas grid of D2.3. A meticulous analysis was conducted in a first approach, considering information obtained from websites of up to 59 TSOs operating in Europe. The inventory covered crucial aspects such as pipeline design parameters (diameter, MOP and installation period) and transport facilities (compressor stations, valve nodes, pressure regulation and/or metering stations, entry and exit points).

The key conclusions from this review are the following:

- The total length of transport pipelines in Europe is approximately 258,968.98 km, with the majority having an unknown diameter.
- France, Germany, Italy, and Ukraine possess the longest grids, followed by Hungary, Norway, Poland, Romania, Spain, and the UK.
- The installation period of most European pipes is unknown, with the most common periods being before 1975, between 2001-2005, and between 2016-2020.
- The MOP of most European pipes is unknown, but most grids operate at 70-85 bar, except for Romania, which has a significant portion operating at 40 bar.
- Germany and Ukraine have the highest frequency of compressor stations per kilometer of grid length.

This first review has been complemented with a survey that was shared with the main TSOs and gas associations in Europe asking for specific information about their grids.. The survey collected data on approximately 73,000 km of the transmission gas grid, with the Middle Europe cluster being the most well-defined area, characterized by 63% of the grid.

The key conclusions from the information collected are the following:

- Steel materials used in the European grid range from API 5L Gr A to Gr X80, with higher steel qualities (over X52) being more prevalent.
- Pipeline diameters are primarily between 11-30 in., with some variations in Northern Europe.
- MOP varies among clusters, with MOP <59 bar and <80 bar dominating the overall European grid.
- External coating materials include polymers like polyethylene (PE) and polyamide, with PE being the dominant material.
- Epoxy resin is the most common material for inner pipeline coating, but data for a significant portion of the Middle Europe cluster is missing.
- The installation period of pipelines is distributed over the decades, with South Europe having a relatively new grid and Western Europe having an older grid.

- Valve nodes, city gates, and compressor stations are the most common facilities in the transmission grid.
- THT (tetrahydro-thiophene) is the most common odorant used in odorization systems.
- Quality control systems primarily use process gas chromatographs, while turbine gas meters are commonly used for flow control.

The second part of D 6.1 explores the potential for hydrogen injection in the European grids, considering future energy trends and EU policies. The analysis consists of three scenarios: baseline (2020-23), mid-term (2030), and long-term (2045/50). A review country by country regarding the expected future gas demand and how it can be met by renewable gases reached the following conclusions:

- Several countries, such as Austria, Belgium, Czech Republic, Denmark, Germany, Italy, Slovakia, and Switzerland, are expected to become hydrogen importing countries to meet their national gas demand by 2050.
- Countries like Estonia, Finland, Greece, Hungary, Latvia, Norway, Portugal, Romania, Spain, Ukraine, and the UK are projected to become hydrogen exporters.
- Countries such as Croatia, France, and Luxembourg are likely to consume all the hydrogen produced at a local level with no need for imports or surplus for export.
- Poland, Slovenia, and Sweden exhibit varying tendencies as importers, exporters, or neutral countries based on the source of information consulted.
- Some countries, including Bulgaria, Denmark, France, Latvia, and Sweden, are focusing on renewable methane production to meet their local demand, indicating limited hydrogen production for exporting purposes.

In the baseline scenario (2020), a hypothetical case was considered to decarbonise the grid by blending natural gas with hydrogen. The analysis compared the calculated needs of hydrogen to replace 2-5% of total gas volume with the available merchant hydrogen in 2020. The findings reveal that if a 2 mol% hydrogen concentration is allowed in the grid, Germany, Spain, the Netherlands, and Belgium would easily reach this level and have surplus hydrogen for export. However, Spain would face challenges in exporting its hydrogen via pipelines. Other countries like Finland, France, and Hungary would also achieve this blend level but with minimal surplus. The UK would need to import hydrogen from the Netherlands.

For a 3 mol% hydrogen concentration, Germany, Spain, the Netherlands, and Belgium would have higher surpluses, while the UK would have greater hydrogen needs. A new hydrogen corridor from Spain to France could emerge to meet the demand. To achieve Italy's hydrogen demand, transportation from Germany via Switzerland and Austria would be necessary. In the 5 mol% hydrogen scenario, Germany and Spain would become new hydrogen-demanding nations, while Belgium, the Netherlands, Hungary, and Finland would have surplus hydrogen for export.

The mid-term scenario for 2030 predicted hydrogen transit across Europe according to two demand case of studies. In the minimum demand scenario, Switzerland and Germany would import the most hydrogen, while countries like Finland and Spain would be major exporters. In the maximum demand scenario, Germany and the UK would have the highest import needs, with Ukraine emerging as the top exporter.

Finally, the long-term scenario for 2045/50 showed Belgium, France, and Poland with the highest hydrogen import needs, while Spain becomes the largest producer and exporter. Germany transitions into an exporting country, and countries like Greece, Portugal, and Sweden also become hydrogen exporters.

Delivery routes and grid capacities for hydrogen transportation have also been considered. In the mid-term case, most countries can inject enough hydrogen into their grids to meet demand, while expansions would be needed in some countries. In the long-term case, several countries have potential for renewable methane to meet national demand, and most countries have sufficient grid capacity for renewable gases.

This report highlights the EU Gas Directive and TEN-E regulation as key frameworks for integrating hydrogen into gas grids. The current limit of 2% blending suggests limited blending opportunities beyond this threshold. Consequently, dedicated infrastructure for 100% hydrogen transport is expected to be developed. Ongoing negotiations may impact the final version of the EU Gas Directive. Overall, the analysis acknowledges the importance of these regulations while recognizing the need for further updates and a comprehensive assessment of their implications.

Overall, the findings highlight the potential for hydrogen injection in the European gas grid and the challenges of supply, demand, transportation, and grid capacity across different scenarios and timeframes. The achievements of D6.1 align with the Vision 2050 developed in WP5, as well as with the case scenarios for future transport gas grids.

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Acknowledgements

This project has received funding from the Fuel Cells and Hydrogen 2 Joint Undertaking (now Clean Hydrogen Partnership) under Grant Agreement No. 875091 'HIGGS'. This Joint Undertaking receives support from the European Union's Horizon 2020 Research and Innovation program, Hydrogen Europe and Hydrogen Europe Research.

Glosary

bcm: billion cubic meters

EHB: European Hydrogen Backbone

GHG: Greenhouse Gas

GTS: Gas Transmission Operator

kT: kilotonnes (of hydrogen)

mioNm: million normal cubic meters

Mt: million tonnes

P2G: power to gas

P2H: power to hydrogen

RES: renewable energy sources

TSO: Transport System Operator

Annex I: Information about TSO’s networks based on public information

Table 11. Length of TSO’s grid classified as a function of its nominal diameter in inches (part 1/5)

Diameter	Austria		Belguium	Bulgaria		Croatia	Czech Republic	Denmark	Estonia	Finland	France	France
	Gas Connect Austria	TAG	Fluxys Belgium	Bulgartransgaz	ICGB AD	Plinacro	Net4Gas	Energinet	Elering	Gasgrid Finland Oy	GRTGaz	Teréga
	km											
<4"	-	-	-	-	-	-	-	-	-	-	-	-
6-8"	-	-	-	-	-	-	-	-	-	-	-	112.00
8-14"	-	-	-	-	-	-	-	-	192.80	-	-	-
14-20"	32.50	-	-	-	-	-	-	-	407.50	77.00	-	-
20-28"	140.00	-	-	-	-	-	-	-	298.70	-	-	-
28-40"	245.00	-	-	-	182.60	-	-	-	-	-	-	-
>40"	140.00	-	-	-	-	-	-	-	-	-	-	-
Multiple diameters	-	-	-	-	-	-	-	-	-	-	-	-
Unkown	315.00	1,140.00	4,000.00	3,276.00	-	2,544.43	3,973.00	900.00	78.00	1,150.00	32,500.00	5,003.00
TOTAL	**872.50**	**1,140.00**	**4,000.00**	**3,276.00**	**182.60**	**2,544.43**	**3,973.00**	**900.00**	**977.00**	**1,227.00**	**32,500.00**	**5,115.00**

Table 12 Length of TSO’s grid classified as a function of its nominal diameter in inches (part 2/5)

Diameter	Germany															
	Bayernets	Fluxys TENP	Fluxys Deutschland	GASCADE	ONTRAS	Gastransport Nord	Gasunie Deutschland	OGE	Ferngas	NETG	Thyssengas	Terranets	GRTGaz Deutchland	NEL	Nowega	OPAL
	km															
<4"	9.60	0.03	-	2.00	110.00	1.70	16.00	2.00	2.00		115.00	0.59	-		149.13	
6-8"	26.70	0.34	-	200.00	220.00	46.40	312.00	346.00	13.00		1,415.00	97.02	-		323.59	
8-14"	327.90	2.57	-	54.00	686.00	0.10	528.00	1,414.00	6.00		731.00	773.31	-		142.01	
14-20"	366.40	0.02	-	147.00	836.00	255.50	418.00	1,026.00	-		599.00	635.02	-		559.65	
20-28"	486.20	0.32	-	38.00	3,135.00	20.90	781.00	1,947.00	-		693.00	1,143.19	-		263.91	
28-40"	360.20	556.95	-	1,175.00	1,713.00	-	654.00	3,571.00	146.00	560.00	494.00	82.06	357.00		156.21	
>40"	87.40	449.73	1,250.46	1,620.00	1,039.00	-	1,931.00	3,571.00	47.00		364.00	-	844.00	441.00	-	
Multiple diameters																943.00
Unkown																
TOTAL	**1,664.40**	**1,009.96**	**1,250.46**	**3,236.00**	**7,739.00**	**324.60**	**4,640.00**	**11,877.00**	**214.00**	**560.00**	**4,411.00**	**2,731.19**	**1,201.00**	**441.00**	**1,594.50**	**943.00**

Table 13 Length of TSO's grid classified as a function of its nominal diameter in inches (part 3/5)

Diameter	Greece	Hungary	Ireland	Italy		Latvia	Lithuania	Luxembourg	The Netherlands		Norway	Poland
	DESFA SA	FGSZ	Gas Networks Ireland	Snam	Società Gasdotti Italia	Conexus	Amber Grid	Creos	Gasunie	BBL	Gassco	GAZ-SYSTEM
	km											
<4"	-	-	-	2,270.70	-	-	-	-	-	-	-	-
6-8"	-	-	-	3,380.40	-	88.00	-	-	-	-	-	-
8-14"	142.50	-	-	3,713.20	-	225.00	-	-	-	-	106.00	-
14-20"	127.00	-	-	3,884.10	-	300.00	-	-	-	-	470.00	-
20-28"	411.90	-	-	2,210.00	-	577.00	-	-	-	-	536.00	-
28-40"	820.10	-	-	2,345.60	-	-	-	-	-	235.00	2,980.00	-
>40"	-	-	-	5,414.50	-	-	-	-	-	-	3,938.00	683.90
Multiple diameters	-	-	-	-	-	-	-	-	-	-	-	-
Unkown	-	5,889.00	2,477.00	17,781.50	1,500.00	-	2,288.00	283.60	-	-	-	11,742.00
TOTAL	**1,501.50**	**5,889.00**	**2,477.00**	**41,000.00**	**1,500.00**	**1,190.00**	**2,288.00**	**283.60**	**-**	**235.00**	**8,030.00**	**12,425.90**

Table 14 Length of TSO's grid classified as a function of its nominal diameter in inches (part 4/5)

Diameter	Portugal	Romania	Serbia	Slovakia	Slovenia	Spain			Sweden	Switzerland				
	REN - Gasodutos	Transgaz	Srbijagas	Eustream	PLINOVODI	Enagás	Medgaz	Redexis	Swedegas	Swissgas	Transitgas	Gasverbund Mittelland	Erdgas Ostschweiz	GAZNAT
<4"	-	-	-	-	-	-	-	-						
6-8"	-	-	-	-	-	-	-	-						
8-14"	-	-	-	-	-	459.92	-	-						
14-20"	-	24.37	-	-	374.00	1,754.53	-	-						
20-28"	-	-	-	-	-	1,794.05	210.00	-	601.00		160.80			
28-40"	-	479.00	-	-	167.00	1,511.19	-	-						
>40"	-	-	-	2,376.00	-	-	-	-			132.00			
Multiple diameters	-	-	-	-	-	4,663.35	-	-						
Unkown	1,375.00	12,926.63	2,223.00	-	654.00	-	-	1,645.00		260.00		568.00	607.50	600.00
TOTAL	**1,375.00**	**13,430.00**	**2,223.00**	**2,376.00**	**1,195.00**	**10,183.04**	**210.00**	**1,645.00**	**601.00**	**260.00**	**292.80**	**568.00**	**607.50**	**600.00**

Table 15 Length of TSO's grid classified as a function of its nominal diameter in inches (part 5/5)

Diameter	Ukraine	UK		TOTAL
	NaftoGaz, UkrTransGaz	National grid	Nord Ireland TSOs	-
	km			
<4"	-	-	-	2,527.03
6-8"	-	-	-	4,881.84
8-14"	-	-	-	7,129.89
14-20"	-	-	268.00	10,301.62
20-28"	-	-	170.00	12,409.47
28-40"	789.86	-	-	16,428.30
>40"	1,248.66	-	-	20,379.19
Multiple diameters	-	-	-	4,663.35
Unkown	35,961.48	7,600.00	-	176,027.14
TOTAL	38,000.00	7,600.00	438.00	254,747.83

Table 16 Length of TSO's grid classified as a function of its installation period (part 1/5)

Period	Austria		Belguium	Bulgaria		Croatia	Czech Republic	Denmark	Estonia	Finland	France	France
	Gas Connect Austria	TAG	Fluxys Belgium	Bulgartransgaz	ICGB AD	Plinacro	Net4Gas	Energinet	Elering	Gasgrid Finland Oy	GRTGaz	Teréga
	km											
2016 to 2020												
2011 to 2015						1,100.00						
2006 to 2010	4.00											
2001 to 2005												
1996 to 2000	142.50											
1991 to 1995												
1986 to 1990												
1981 to 1985												
1976 to 1980	271.00											
before 1975	315.00					1,444.43						
Unknown	140.00	1,140.00	4,000.00	3,276.00	182.60	-	3,973.00	900.00	977.00	1,227.00	32,500.00	5,115.00

Table 17 Length of TSO's grid classified as a function of its installation period (part 2/5)

Period	Germany																
	Bayernets	Fluxys TENP	Fluxys Deutschland	GASCADE	ONTRAS	Gastransport Nord	Gasunie Deutschland	OGE	Ferngas	NETG	Thyssengas	Terranets	GRTGaz Deutchland	NEL	Nowega	OPAL
	km																
2016 to 2020				507.00													
2011 to 2015																	
2006 to 2010																	
2001 to 2005				97.00													
1996 to 2000				659.00					111.00								
1991 to 1995				189.00													
1986 to 1990				314.00													
1981 to 1985																	
1976 to 1980																	
before 1975				679.00													
Unknown	1,664.40	1,009.96	1,250.46	791.00	7,739.00	324.60	4,640.00	11,877.00	103.00	560.00	4,411.00	2,731.19	1,201.00	441.00	1,594.50	943.00

Table 18 Length of TSO's grid classified as a function of its installation period (part 3/5)

Period	Greece	Hungary	Ireland	Italy		Latvia	Lithuania	Luxembourg	The Netherlands		Norway	Poland
	DESFA SA	FGSZ	Gas Networks Ireland	Snam	Società Gasdotti Italia	Conexus	Amber Grid	Creos	Gasunie	BBL	Gassco	GAZ-SYSTEM
	km											
2016 to 2020				11,393.00								
2011 to 2015												
2006 to 2010											1,406.00	1,406.00
2001 to 2005				16,607.00		538.00					854.00	854.00
1996 to 2000											1,447.00	1,447.00
1991 to 1995											1,684.00	1,684.00
1986 to 1990						519.80					383.00	383.00
1981 to 1985											751.00	751.00
1976 to 1980											361.00	361.00
before 1975				13,000.00		132.20						
Unknown	1,501.50	5,889.00	2,477.00	-	1,500.00	-	2,288.00	283.60	-	235.00	1,144.00	5,539.90

Table 19 Length of TSO's grid classified as a function of its installation period (part 4/5)

Period	Portugal	Romania	Serbia	Slovakia	Slovenia	Spain			Sweden	Switzerland				
	REN - Gasodutos	Transgaz	Srbijagas	Eustream	PLINOVODI	Enagás	Medgaz	Redexis	Swedegas	Swissgas	Transitgas	Gasverbund Mittelland	Erdgas Ostschweiz	GAZNAT
	km													
2016 to 2020														
2011 to 2015						728.05								
2006 to 2010						1,532.52	210.00							
2001 to 2005						2,256.07					335.00			
1996 to 2000						1,782.34								
1991 to 1995						216.78					33.00			
1986 to 1990						181.75								
1981 to 1985						246.97								
1976 to 1980														
before 1975											70.00			
Unknown	1,375.00	13,430.00	2,223.00	2,376.00	1,195.00	3,238.56	-	1,645.00	601.00	260.00		568.00	607.50	600.00

Table 20 Length of TSO's grid classified as a function of its installation period (part 5/5)

Period	Ukraine	UK		TOTAL
	NaftoGaz, UkrTransGaz	National grid	Nord Ireland TSOs	-
	km			
2016 to 2020				11,900.00
2011 to 2015			78.00	1,906.05
2006 to 2010				4,558.52
2001 to 2005			156.00	21,697.07
1996 to 2000			135.00	5,723.84
1991 to 1995				3,806.78
1986 to 1990				1,781.55
1981 to 1985				1,748.97
1976 to 1980				993.00
before 1975				15,640.63
Unknown	38,000.00	7,600.00	69.00	185,136.62

Table 21 Length of TSO's grid classified as a function of its Maximum Operating Pressure (part 1/5)

MOP	Austria		Belguium	Bulgaria		Croatia	Czech Republic	Denmark	Estonia	Finland	France	France
	Gas Connect Austria	TAG	Fluxys Belgium	Bulgartransgaz	ICGB AD	Plinacro	Net4Gas	Energinet	Elering	Gasgrid Finland Oy	GRTGaz	Teréga
	km											
≤40 bar												
≤50 bar												
≤60 bar						1,444.43			937.30			
≤ 65 bar												
≤ 70 bar		1,140.00										
≤ 80 bar						1,100.00			39.70	77.00		
≤ 85 bar							3,973.00					
≤ 100 bar												
≤ 200 bar												
≤ 225 bar												
Wide range (16-50 bar)												
Wide range (40-70 bar)												
Wide range (80-155 bar)												
Unknown	872.50	-	4,000.00	3,276.00	182.60	-	-	900.00	-	1,150.00	32,500.00	5,115.00

Table 22 Length of TSO's grid classified as a function of its Maximum Operating Pressure (part 2/5)

MOP	Germany															
	Bayernets	Fluxys TENP	Fluxys Deutschland	GASCADE	ONTRAS	Gastransport Nord	Gasunie Deutschland	OGE	Ferngas	NETG	Thyssengas	Terranets	GRTGaz Deutchland	NEL	Nowega	OPAL
	km															
≤40 bar																
≤50 bar																
≤60 bar																
≤ 65 bar																
≤ 70 bar									214.00		1,646.00		169.00			943.00
≤ 80 bar																
≤ 85 bar													920.00			
≤ 100 bar													72.00			
≤ 200 bar																
≤ 225 bar																
ide range (16-50 bar)											1,440.00					
ide range (40-70 bar)											1,037.00					
de range (80-155 bar)																
Unknown	1,664.40	1,009.96	1,250.46	3,236.00	7,739.00	324.60	4,640.00	11,877.00	-	560.00	288.00	2,731.19	40.00	441.00	1,594.50	-

Table 23 Length of TSO's grid classified as a function of its Maximum Operating Pressure (part 3/5)

MOP	Greece	Hungary	Ireland	Italy		Latvia	Lithuania	Luxembourg	The Netherlands		Norway	Poland
	DESFA SA	FGSZ	Gas Networks Ireland	Snam	Società Gasdotti Italia	Conexus	Amber Grid	Creos	Gasunie	BBL	Gassco	GAZ-SYSTEM
	km											
≤40 bar								39.40				
≤50 bar												
≤60 bar												
≤ 65 bar												
≤ 70 bar												
≤ 80 bar								216.50				
≤ 85 bar												683.90
≤ 100 bar												
≤ 200 bar										235.00		
≤ 225 bar												
Wide range (16-50 bar)												
Wide range (40-70 bar)												
Wide range (80-155 bar)												
Unknown	1,501.50	5,889.00	2,477.00	41,000.00	1,500.00	1,190.00	2,288.00	27.70	-	-	8,030.00	11,742.00

Table 24 Length of TSO's grid classified as a function of its Maximum Operating Pressure (part 4/5)

MOP	Portugal	Romania	Serbia	Slovakia	Slovenia	Spain			Sweden	Switzerland				
	REN - Gasodutos	Transgaz	Srbijagas	Eustream	PLINOVODI	Enagás	Medgaz	Redexis	Swedegas	Swissgas	Transitgas	Gasverbund Mittelland	Erdgas Ostschweiz	GAZNAT
	km													
≤40 bar		12,557.63												
≤50 bar														
≤60 bar		369.00				172.65								
≤ 65 bar														
≤ 70 bar											198.80		607.50	600.00
≤ 80 bar				2,376.00		8,197.68			600.00		94.00			
≤ 85 bar														
≤ 100 bar														
≤ 200 bar														
≤ 225 bar						123.50								
Wide range (16-50 bar)			2,223.00											
Wide range (40-70 bar)														
Wide range (80-155 bar)						274.49								
Unknown	1,375.00	503.37	-	-	1,195.00	1,414.72	210.00	1,645.00	1.00	260.00	-	568.00	-	-

Table 25 Length of TSO’s grid classified as a function of its Maximum Operating Pressure (part 5/5)

MOP	Ukraine	UK		TOTAL
	NaftoGaz, UkrTransGaz	National grid	Nord Ireland TSOs	-
	km			
≤40 bar				12,597.03
≤50 bar				-
≤60 bar				2,923.38
≤ 65 bar				-
≤ 70 bar				4,361.30
≤ 80 bar			270.00	12,970.88
≤ 85 bar				5,576.90
≤ 100 bar				72.00
≤ 200 bar				235.00
≤ 225 bar				123.50
Wide range (16-50 bar)				3,663.00
Wide range (40-70 bar)				1,037.00
Wide range (80-155 bar)				274.49
Unknown	38,000.00	7,600.00	168.00	210,913.35

Table 26. Transport facilities of European TSOs (part 1/5)

Transport facilities	Austria		Belgium	Bulgaria		Croatia	Czech Republic	Denmark	Estonia	Finland	France	France
	Gas Connect Austria	TAG	Fluxys Belgium	Bulgartransgaz	ICGB AD	Plinacro	Net4Gas	Energinet	Elering	Gasgrid Finland Oy	GRTGaz	Teréga
Transmission valves positions (number)	36	10								166		700
Transmission compressor stations (number)	5	5	4	11		1	6		2	9	26	6
Transmission compressor stations (MW)	146	480					281			60.4		85
Transmission pressure reduction and/or metering stations* (number)		4	17	240		156			40			325
Conection to industrial costumers (number)			230								716	112
Exit stations (number)												
Entry points (number)												
Scrapper stations (number)												
Remote Telecommunication Stations (number)												

Table 27. Transport facilities of European TSOs (part 2/5)

Transport facilities	Germany															
	Bayernets	Fluxys TENP	Fluxys Deutschland	GASCADE	ONTRAS	Gastransport Nord	Gasunie Deutschland	OGE	Ferngas	NETG	Thyssengas	Terranets	GRTGaz Deutchland	NEL	Nowega	OPAL
Transmission valves positions (number)																
Transmission compressor stations (number)	2	4		10			31	11		2	6	2	6			1
Transmission compressor stations (MW)		178.455		552				396.205					347			99.1
Transmission pressure reduction and/or metering stations* (number)																
Conection to industrial costumers (number)												25				
Exit stations (number)	189	22	2	74	438	73	206	994	18		1016	275				
Entry points (number)																
Scrapper stations (number)																
Remote Telecommunication Stations (number)																

*Include Transmission/transmission pressure reduction stations, Transmission/transmission metering stations, Transmission/transmission regulation and metering stations, Transmission/distribution pressure reduction stations and Transmission/distribution metering and regulation stations (city gates, etc.)

Table 28. Transport facilities of European TSOs (part 3/5)

Transport facilities	Greece	Hungary	Ireland	Italy		Latvia	Lithuania	Luxembourg	The Netherlands		Norway	Poland
	DESFA SA	FGSZ	Gas Networks Ireland	Snam	Società Gasdotti Italia	Conexus	Amber Grid	Creos	Gasunie	BBL	Gassco	GAZ-SYSTEM
Transmission valves positions (number)	66	17										36
Transmission compressor stations (number)	1	8		13			2			4		15
Transmission compressor stations (MW)	15.4			961			42.7			92		400**
Transmission pressure reduction and/or metering stations* (number)	45	400				42	69	62				878
Conection to industrial costumers (number)												
Exit stations (number)												
Entry points (number)		25	53									71
Scrapper stations (number)	50											
Remote Telecommunication Stations (number)	15											

*Include Transmission/transmission pressure reduction stations, Transmission/transmission metering stations, Transmission/transmission regulation and metering stations, Transmission/distribution pressure reduction stations and Transmission/distribution metering and regulation stations (city gates, etc.)

** Just 5 of them

Table 29. Transport facilities of European TSOs (part 4/5)

Transport facilities	Portugal	Romania	Serbia	Slovakia	Slovenia	Spain			Sweden	Switzerland				
	REN - Gasodutos	Transgaz	Srbijagas	Eustream	PLINOVODI	Enagás	Medgaz	Redexis	Swedegas	Swissgas	Transitgas	Gasverbund Mittelland	Erdgas Ostschweiz	GAZNAT
Transmission valves positions (number)	53	58									20			30
Transmission compressor stations (number)	1	5	1	5	2	19					1			
Transmission compressor stations (MW)			4.4	550	19.5	519.99					60			
Transmission pressure reduction and/or metering stations* (number)	71	894	165		251				40	26	6		65	
Conection to industrial costumers (number)	3	225											5	
Exit stations (number)				10										
Entry points (number)		85												
Scrapper stations (number)														
Remote Telecommunication Stations (number)														

*Include Transmission/transmission pressure reduction stations, Transmission/transmission metering stations, Transmission/transmission regulation and metering stations, Transmission/distribution pressure reduction stations and Transmission/distribution metering and regulation stations (city gates, etc.)

Table 30. Transport facilities of European TSOs (part 5/5)

Transport facilities	Ukraine	UK		TOTAL
	NaftoGaz, UkrTransGaz	National grid	Nord Ireland TSOs	-
Transmission valves positions (number)				1,192
Transmission compressor stations (number)	72	24	2	326
Transmission compressor stations (MW)	5,543.0	1,127.7		11,972
Transmission pressure reduction and/or metering stations* (number)				3,796
Conection to industrial costumers (number)				1,316
Exit stations (number)				1,751
Entry points (number)		6		240
Scrapper stations (number)				50
Remote Telecommunication Stations (number)				15

*Include Transmission/transmission pressure reduction stations, Transmission/transmission metering stations, Transmission/transmission regulation and metering stations, Transmission/distribution pressure reduction stations and Transmission/distribution metering and regulation stations (city gates, etc.)

Table 31. Length of grid in the different geographic clusters as a function of nominal diameter, installation period and MOP

Diameter	South Europe	Western Europe	Middle Europe	Northern Europe	Eastern Europe	Europe
	km					
<4"	2,270.70	-	408.05	-	-	**2,678.75**
6-8"	3,380.40	112.00	3,088.05	-	-	**6,580.45**
8-14"	4,315.62	-	5,082.70	106.00	-	**9,504.32**
14-20"	5,765.63	268.00	5,956.59	547.00	24.37	**12,561.59**
20-28"	4,625.95	170.00	9,685.02	1,137.00	-	**15,617.97**
28-40"	4,859.49	235.00	10,237.42	2,980.00	1,268.86	**19,580.77**
>40"	5,414.50	-	14,976.49	3,938.00	1,248.66	**25,577.65**
Multiple diameters	4,663.35	-	943.00	-	-	**5,606.35**
Unkown	30,344.93	51,863.60	28,114.50	2,050.00	48,888.11	**161,261.14**
TOTAL	**65,640.57**	**52,648.60**	**78,491.81**	**10,758.00**	**51,430.00**	**258,968.98**

Period	South Europe	Western Europe	Middle Europe	Northern Europe	Eastern Europe	Europe
	km					
2016-2020	11,393.00	-	507.00	-	-	11,900.00
2011-2015	1,828.05	78.00	-	-	-	1,906.05
2006-2010	1,742.52	-	1,410.00	1,406.00	-	4,558.52
2001-2005	18,863.07	156.00	1,824.00	854.00	-	21,697.07
1996-2000	1,782.34	135.00	2,359.50	1,447.00	-	5,723.84
1991-1995	216.78	-	1,906.00	1,684.00	-	3,806.78
1986-1990	181.75	-	1,216.80	383.00	-	1,781.55
1981-1985	246.97	-	751.00	751.00	-	1,748.97
1976-1980	-	-	632.00	361.00	-	993.00
<1975	14,444.43	-	1,196.20	-	-	15,640.63
Unknown	14,941.66	52,279.60	66,834.51	3,872.00	51,430.00	189,357.77

MOP	South Europe	Western Europe	Middle Europe	Northern Europe	Eastern Europe	Europe
	km					
≤40	-	39.40	-	-	12,557.63	12,597.03
≤50	-	-	-	-	-	-
≤60	1,617.08	-	937.30	-	369.00	2,923.38
≤ 65	-	-	-	-	-	-
≤ 70	-	-	4,361.30	-	-	4,361.30
≤ 80	9,297.68	486.50	2,509.70	677.00	-	12,970.88
≤ 85	-	-	5,576.90	-	-	5,576.90
≤ 100	-	-	72.00	-	-	72.00
≤ 200	-	235.00	-	-	-	235.00
≤ 225	123.50	-	-	-	-	123.50
16-50 bar	2,223.00	-	1,440.00	-	-	3,663.00
40-70 bar	-	-	1,037.00	-	-	1,037.00
80-155 bar	274.49	-	-	-	-	274.49
Unknown	52,104.82	51,887.70	62,557.61	10,081.00	38,503.37	215,134.50

Table 32. Transport facilities gathered into geographic clusters

Transport facilities	South Europe	Western Europe	Middle Europe	Northern Europe	Eastern Europe	Europe
Transmission valves positions (number)	119	700	149	-	58	1,026
Transmission compressor stations (number)	46	66	119	8	77	316
Transmission compressor stations (MW)	1,501	1,305	3,271	281	5,543	11,900
Transmission pressure reduction and/or metering stations* (number)	521	404	1,897	80	894	3,796
Conection to industrial costumers (number)	3	1,058	30	-	225	1,316
Exit stations (number)	-	-	3,317	-	-	3,317
Entry points (number)	-	59	96	-	85	240
Scrapper stations (number)	50	-	-	-	-	50
Remote Telecommunication Stations (number)	15	-	-	-	-	15

Annex II Information about TSO's networks based on confidential information collected via surveys

Table 33. Numerical information gathered about European pipelines for each cluster

Property		Cluster					
		South Europe (km)	Western Europe (km)	Middle Europe (km)	Northern Europe (km)	Eastern Europe (km)	Europe (km)
Total cluster length		13,361.00	12,446.10	46,545.88	628.46		72,981.44
Steel	API 5L Gr A	-	-	2,010.09	-		2,010.09
	API 5L Gr B	1,196.82	1,339.91	6,102.50	24.15		8,663.38
	API 5L Gr X42	2,822.47	1,472.30	2,987.86	24.70		7,307.33
	API 5L Gr X46	18.39	179.78	947.40	-		1,145.57
	API 5L Gr X52	74.13	2,424.69	13,088.18	6.82		15,593.83
	API 5L Gr X56	-	48.93	848.68	-		897.61
	API 5L Gr X60	4,977.78	4,664.66	3,890.92	170.15		13,703.51
	API 5L Gr X65	202.05	376.90	207.33	-		786.28
	API 5L Gr X70	3,798.57	476.00	12,828.46	328.20		17,431.23
	API 5L Gr X80	268.55	654.44	342.77	-		1,265.75
	Other	2.24	-	1,536.38	74.44		1,613.06
	Unknown	2.24	808.51	1,755.30	-		2,566.05
Diameter	<10"	2,697.25	2,864.60	6,705.05	120.75		12,387.65
	11-20"	5,027.44	1,381.41	17,469.74	394.95		24,273.54
	21-30"	3,826.89	2,000.55	10,469.84	103.40		16,400.68
	31-40"	1,256.56	5,342.45	6,941.26	-		13,540.27
	41-50"	550.63	857.08	2,651.11	-		4,058.82
	<60"	-	-	575.52	-		575.52
	Unknown	4.48	-	1,734.74	9.36		1,748.58
Maximun operating pressure	<59 bar	2,165.80	-	18,570.20	81.25		20,817.25
	<66 bar	-	703.00	2,574.30	-		3,277.30
	<70 bar	-	3,194.25	10,730.54	-		13,924.79
	<75 bar	-	2,463.06	131.70	-		2,594.76
	<80 bar	10,750.00	-	9,464.29	238.10		20,452.39
	<85 bar	62.31	5,721.47	2,101.81	-		7,885.58
	<225 bar	526.20	317.29	4,202.28	-		5,045.77
	Other	-	-	-	-		-
	Unknown	6.85	-	-	-		6.85
Welding material	AWS A 5.1-E 6010	x	x	332.43	-		332.43
	AWS A 5.1-E 7010	-	-	381.89	-		381.89
	AWS A 5.1-E 7016	-	x	-	-		-
	AWS A 5.1-E7018	x	x	75.58	-		75.58
	AWS A 5.5-E XX10-X	x	-	-	-		-
	AWS A 5.5-E XX15-X	x	-	-	-		-
	AWS A 5.5-E XX16-X	-	x	-	-		-
	AWS A 5.5-E XX18-X	x	x	-	-		-
	AWS A 5.5-E XX18M-X	-	-	-	-		-
	AWS A 5.17-EH12-X	-	x	-	-		-
	AWS A 5.18-ER 70S-X	-	x	-	-		-
	AWS A 5.18-ER 70S-1B	-	x	-	-		-
	AWS A 5.28-ER XXS-X	x	-	-	-		-
	AWS A 5.28-E XXC-X	-	x	-	-		-
	AWS A 5.28-ER XXS-X	-	-	-	-		-
	AWS A 5.20-E X1T-XG-J	-	x	-	-		-
	AWS A 5.20-E X1T-XM-J	x	-	-	-		-
	AWS A 5.29-EXT1-XM-X	-	x	-	-		-
	AWS A 5.36-EXT1-MX-Ni1J	-	x	-	-		-
	Other	-	-	-	-		-
Outer Coating	PP	210.00	-	-	-	-	210.00
	PE	12,468.21	6,538.19	14,081.75	606.00	-	33,694.15
	PA	-	-	-	-	-	-
	Concrete	89.50	-	835.39	-	-	924.89
	Brai	-	2,129.00	-	-	-	2,129.00
	Coal tar		3,982.14				
	Unknown	593.29	3,778.91	31,628.75	22.46	-	36,023.41
Inner coating/painting	None	-	1,190.00	947.50	-		2,137.50
	Epoxy layer	12,243.75	6,717.70	1,118.26	-		20,079.71
	Coal tar		42.91				
	Red led		277.32				
	Other	-	-	-	-		-
	Undefined	2,234.51	601.17	44,481.00	628.46		47,945.14

Table 34. Numerical information gathered about the renewal time of European pipel

Intallation period (year)	Cluster					
	South Europe (km)	Western Europe (km)	Middle Europe (km)	Northern Europe (km)	Eastern Europe (km)	Europe (km)
2010-2019	6,320.75	1,112.69	5,484.71	1.00		12,919.15
2000-2009	5,492.08	1,524.07	7,208.62	57.00		14,281.77
1990-1999	2,168.80	1,554.24	7,679.82	42.00		11,444.86
1980-1989	271.88	1,029.91	1,082.11	439.00		2,822.90
1970-1979	762.53	1,656.56	12,605.09	-		15,024.19
before 1970	46.66	5,602.10	8,265.67	-		13,914.43
Unknown			4,219.86	89.46		
Total length installed	15,062.71	12,479.58	42,326.02	539.00	-	70,407.31

Table 35. Numerical information gathered about transmission facilities in the European gas grid

Category				Cluster											
				South Europe		Western Europe		Middle Europe		Northern Europe		Eastern Europe		Europe	
				Number	Frequency*	Number	Frequency*	Number	Frequency*	Number	Frequency*	Number	Frequency*	Number	Frequency*
Transmission facilities	LNG terminals			6	0.449068184	7	0.6	1	0.0	1	1.6			15	0.2
	Transmission valve nodes			958	71.70121997	756	60.7	2034	43.7					3748	51.4
	Transmission compressor stations			19	1.422049248	32	2.6	127	2.7	3	4.8			181	2.5
	Transmission network pressure reduction stations			24	1.8	3	0.2	100	2.1	42	66.8			169	2.3
	Transmission network metering stations			109	8.2			31	0.7	42	66.8			182	2.5
	City Gate (transmission/distribution) pressure reduction stations			707	52.9	621	49.9	988	21.2	111	176.6			2427	33.3
	Underground storages	Cavern				9	0.7	7	0.2	0	0.0			16	0.2
		Porous													
		Depleted fields		3	0.2									3	0.0
		Aquifer		1	0.1	2	0.2	1						4	0.1
		Undefined				12	1.0	15	0.3					27	0.4
		TOTAL		4	0.3	23	1.8	19	0.4	1	1.6			47	0.6
	Cross border interconnection points			6	0.4	3	0.2	15	0.3					24	0.3
	TOTAL			1833	137.2	1454	116.8	2973	63.9	200	318.2			6460	88.5
Odorization systems	System	Laminar System		136	10.2									136	1.9
		Drip System													
		Injection Pump System		342	25.6	20	1.6	52	1.1	1	1.6			415	5.7
		Undefined													
		TOTAL		478	35.8	20	1.6	52	1.1	1	1.6			551	7.5
	Odorant type	THT (tetrahydro-thiophene)				#¡VALOR!	#¡VALOR!	12	0.3	1	1.6				
		S-free													
		Scentinel E													
		Scentinel TB													
		Spotleak Z													
		Spotleak 1009													
		Spotleak 1005													
		TBM (tert-butyl mercaptan)													
		DMS (dimethyl sulfide)													
		MES (methyl ethyl sulfide)													
		IPM (isopropyl mercaptan)													
		TOTAL						14	0.3	1	1.6			15	0.2
Gas quality control systems	Quality control Systems	Process Gas Cromatographs		127	9.5	202	16.2	96	2.1	9	14.3			434	5.9
		Mass Spectrometers													
		Electrochemic cell		11	0.8									11	0.2
	Flow Control Systems	Gas Pressure Control	Undefined			1200	96.4	630	13.5					1830	25.1
		Gas Meter	Turbine	292	21.9	2	0.2	1225	26.3					1519	20.8
			Bellows-type Gas Meters					288	6.2					288	3.9
			Mass flow gas meter					3	0.1					3	0.0
			Rotary gas meter					472	10.1					472	6.5
			Venturi			4	0.3	244	5.2					248	3.4
			US	11	0.8	49	3.9	189	4.1					249	3.4
			Diaphragm					9	0.2					9	0.1
			Orifice			89									
			Annubar			10									
			Coriolis			4									
			Vortex			2									
			Elbow			2									
			Dall Tube			3									
			Pitot Tube			1									
			Other			700	56.2	523	11.2					1223	16.8
	TOTAL			441	33.0	2268	182.2	3527	75.8	9	14.3			6245	85.6

* Number of facilities/1000 km pipeline length