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DECARBONISING THE GAS VALUE CHAIN

CHALLENGES, SOLUTIONS AND RECOMMENDATIONS

2021

PRIME MOVERS' GROUP ON GAS QUALITY AND H_2 HANDLING
SUBGROUP 2 WORK

CEDEC GD4S Gas Distributors For Sustainability GEODE eurogas 30 years

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EXECUTIVE SUMMARY

Achieving carbon neutrality by 2050 will require the transformation of the current energy system, which is heavily dependent on fossil fuels. As the gas industry is gearing up its efforts to rollout increasing levels of renewable and low-carbon gases, the European gas system will see already in the near future a diverse mix of gases which need to be handled technically. Knowing and understanding the possibilities and limitations of consumers connected to the gas network has become more important than ever to maintain the competitiveness of the European industry while progressively working towards the decarbonisation goals.

The gas sector plays an important role to achieve the ambitious energy and climate goals and to unlock the potential of a more integrated energy system. In this regard, the prime movers group on gas quality and hydrogen handling was created. This group provides a common place for a fair discussion among main gas-related stakeholders, with the goal of:

- Addressing the main technical challenges that decarbonisation poses.
- Learning about which solutions are available, and which developments are expected to be in the market to facilitate a cost efficient handling of gas quality and hydrogen.

Initiated by the European associations representing gas TSOs and DSOs (ENTSOG, CEDEC, Eurogas, GD4S and Geode), all relevant stakeholders from the whole gas value chain were invited to participate. They have contributed to this important work by providing their sector views on future potential challenges and developments. Although the work is not meant to be comprehensive, it is expected to provide a solid starting point for upcoming discussions deriving from the update of the Gas Directive[1] and the Gas regulation[2] as well as for the realization of European Commission Hydrogen[3] and Energy System[4] Strategies.

Nowadays, point-to-point hydrogen connections at industrial level and pilot projects dealing with hydrogen blending into the natural gas are already in place. In the short/mid-term it is likely that different pathways will coexist: methane backbone (using natural gas, biomethane and/or syngas), hydrogen blending and the incipient development of the European Hydrogen Backbone at TSO and DSO level. Taking as starting point current possibilities and limitations, the group provides an overview of the upcoming developments for the short, mid and long-term until the realization of the European Hydrogen Backbone at TSO level, and grids in transition to renewable and low-carbon gases at DSO level. The group concludes that, in general, blending percentages up to 2% vol. H_2 into the natural gas system are already possible without any additional mitigation efforts. This value reflects the common minimum denominator due to the fact that some industrial processes and CNG stations cannot handle more than 2% vol. H_2 nowadays. However, some sectors like domestic and commercial gas appliances and the distribution level are ready to handle up to 10% vol. H_2 and in some cases even up to 20% vol. H_2 without further adaptations costs.

1 COM(2021) 803 final

2 COM(2021) 804 final

3 COM(2020) 301 final

4 COM(2020) 299 final

Picture courtesy of Gasunie Deutschland GmbH & Co. KG

In the mid-term, hydrogen demand is expected to increase at all levels. Therefore, the full deployment of dedicated H_2 grids at TSO and DSO level will become more important. Depending on national and regional conditions, as well as customers' needs, requirements and grid topology, hydrogen blending up to 20% vol. is also expected to be present in certain regions. In the long run most sectors will retrofit to dedicated hydrogen systems. Yet, this may not be possible for specific industrial processes e.g., the production of chemicals which are largely dependent on the methane molecule. As a consequence, methane networks using natural gas, biomethane and/or syngas depending on the region, will also play a role in the future.

The group acknowledges that as the choices and decisions are influenced by the overall EU climate and energy policies, as well as the overall market conditions, and will most probably differ amongst EU Member States, what might be seen as a short-term development for one country may be a medium-term one for another country. Hence, it is not possible to define concrete timelines for each development (although indicative ones are included for informative purposes) especially when it comes to grid development. TSOs and DSOs will need to manage and accommodate diversity of technological choices for the benefit and safety of the climate and all consumers while ensuring that achievements of the internal energy market for gas and interoperability between the different energy carriers are maintained and further developed, including hydrogen.

Although great efforts have been dedicated to provide a comprehensive and updated picture, forecasting the long-term future is not possible. The rapid evolvement of technologies and the market needs and the upcoming changes in the legislative framework will definitely have an impact on how each sector sees its way through decarbonisation. Therefore, the analysis presented here is of an illustrative nature, examining the impacts, challenges and opportunities of possible ways of decarbonising the gas value chain. Most likely the future will be a combination of all options, in one form or another, and the information provided should be understood as a best estimate in time of how each stakeholder sees, at this point in time, the future developments within its sector.

Lastly, it is important to note that all stakeholders participating in this group are driven by the same goal of finding solutions for the fast and cost-efficient decarbonisation of the sector with the aim to keep the security of supply at the high level that European customers and the energy system need. Although there is a strong commitment and willingness, there are still controversial views and interests with respect to the preferred solutions. Besides, in some cases, technological developments are not yet mature in the market and many projects are currently ongoing, whose results will be key to reach a better understanding of the decarbonisation possibilities.

ACRONYMS AND ABBREVIATIONS

Term	Meaning
BAU	Business as Usual
CBA	Cost Benefit Analysis
CBP	Common Business Practice
CCS	Carbon Capture and Storage
CEN	European Committee for Standardization
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
COM	Communication
DLE	Dry Low Emission
DSO	Distribution System Operator (of gas)
EC	European Commission
ECHA	European Clean Hydrogen Alliance
EED	Energy Efficiency Directive
EHB	European Hydrogen Backbone
EnC CP	Energy Community Contracting Parties
EPBD	Energy Performance of Buildings Directive
ETS	Emissions Trading System
EU	European Union
FC	Fuel Cell
GAD	Gas Appliances Directive
GC	Gas Chromatograph
GCV	Gross Calorific Value
GQ	Gas Quality
GQS	Gas Quality Study
GT	Gas Turbine
H_2	Hydrogen
H_2NG	Hydrogen/Natural Gas blend
HHV	Higher Heating Value
HRSG	Heat recovery steam generator

Term	Meaning
IA	Interconnection Agreements
ICE	Internal Combustion Engine
ISP	Independent Service Providers
LCOS	Levelized Cost Of Storage
LBG	Liquified Biogas
LNG	Liquified Natural Gas
MJ	Megajoule
MN	Methane Number
NCV	Net Calorific Value
NG	Natural Gas
NRA	National Regulator Authority
NSB	National Standardisation Body
OBA	Operational Balancing Account
OEM	Original Equipment Manufacturer
PEF	Primary Energy Factor
PMG	Prime Movers Group
PNR	Pre-Normative Research
PV	Photovoltaic
QT	Quality Tracking
R&D	Research & Development
RED	Renewables Energy Directive
RFNBO	Renewable Fuels from Non-Biological Origin
SFGas	Sector Forum Gas (CEN)
SG	Subgroup
SoS	Security of Supply
TC	Technical Committee
TPA	Third Party Access
TSO	Transmission System Operator (of gas)
UGS	Underground Gas Storage
WG	Working Group
WI	Wobbe Index

1 PRIME MOVERS' GROUP IN GAS QUALITY AND HYDROGEN HANDLING

1.1 CONTEXT

As the gas industry is gearing up its efforts to rollout increasing levels of renewable and low-carbon gases, the European gas system needs to adapt to deal with the upcoming diverse gas mixes. A wide range of research studies, regulatory and legislative works have been carried out to deal with different aspects related to these issues:

- the EASEE-gas Common Business Practice on H-gas Quality at cross-border points of 2005 (Common Business Practices 2005-001/02)
- the mandate M/400 of 2007 asking CEN to elaborate a standard on H-gas quality specifications based on a pre-normative study on the impact of gas quality on safety, performance, and fitness for purpose of residential gas appliances
- the EU network code on Interoperability and Data Exchange (EU regulation 2015/703)
- the EU standard EN16726:2015 (ref. M/400)
- The EU standards EN16723-1/2 on Natural gas and biomethane for use in transport and biomethane for injection in the natural gas grid
- ENTSOG Impact analysis of a reference to the EN16726:2015 in the network code on Interoperability and Data Exchange (2016)
- CEN SFGas GQS: Recommendations and considerations on Wobbe index aspects related to H-gas[5]
- the EU Strategy for Energy System Integration (COM (2020) 299 final)
- the Hydrogen strategy for a climate-neutral Europe (COM (2020) 301 final)

In this regard, and taking into account the proposals under the "Hydrogen and Gas markets Decarbonisation Package" (COM(2021) 803 final and COM(2021) 804 final), a coordinated EU approach to manage fluctuating gas compositions across Europe is needed to support the ongoing revision of the EU gas quality standard[6], ensure end-user appliances safety and guide decision makers in the process of the sector decarbonization.

5 Final report to be published.

6 As far as Wobbe index is concerned, the original concept foresaw that CEN SFGas GQS report only provides a Wobbe index proposal to be implemented into the EU gas quality standard (EN16726) during its revision. However, as a result of the work carried out in CEN SFGas GQS, the definition or upgrade of gas quality handling processes and procedures (e.g. information exchange) will also be needed. Currently, the EN16726 is under revision in CEN TC 234 WG11.

1.2 SCOPE

In the broader context of the Green Deal and on the pathway to achieve the 2050 decarbonisation targets, a whole system analysis of the energy system is necessary to assess the most efficient way forward, especially in the gas sector. In particular, decarbonisation of the gas grid in a cost-effective manner will require a whole system approach where the gas value chain works cooperatively together and builds on existing tools whilst assessing potential shortcomings. In this context, coordination and information exchange between all gas systems operators, and other stakeholders is key to manage the system efficiently but is also pivotal to understand the reality behind gas uses today. In this regard, ENTSOG and four DSOs associations (CEDEC,EUROGAS, GEODE, GD4S) set up the prime movers group in September 2020 to collaborate with other stakeholders to investigate how to achieve EU decarbonization goals, building on an integrated Energy System bridging different energy vectors and sectors.

1.3 PROCESS

Given the current dynamics at European level, especially in the framework of the Energy System Integration and the Hydrogen Strategies together with questions related to hydrogen injection, it was essential to discuss together with stakeholders from the whole gas value chain, the upcoming potential challenges that decarbonisation poses.

The primary objective of the group is to provide a common place that allows for a fair discussion among main gas-related stakeholders, in order to address the main technical challenges that decarbonisation poses. But also, to learn about which solutions are already out there, which developments will be in the market to facilitate a cost-efficient handling of gas quality and H_2. It is expected to reach a better understanding on the main principles to handle gas quality related to renewable, and low-carbon gases, that can optimise the diversification of supplies, decarbonisation of the grid and guarantee end-user safety and access to the product they require.

The goal of the group is to develop recommendations on the main principles to handle Gas Quality and Hydrogen to optimize:

- Gas supply diversification (via renewable and low-carbon hydrogen and biomethane)
- Decarbonization of the gas system
- Guarantee safe, efficient and gas usage with low or no GHG emissions
- Continued support for security of energy supplies

At the same time, the group facilitated knowledge sharing on gas quality and H_2 handling topics, as well as provided the necessary technical inputs to Commission proposals under the 'Hydrogen and Gas markets Decarbonisation Package'.

At the early stage of the prime movers group the stakeholders of the gas value chain worked on identifying the main problems foreseen related to variable gas quality in the short and long-term and on listing the main technical issues that need to be tackled at first. After categorising the various issues that were identified, the group assessed possible solutions for each area of concern, considering the main barriers preventing the implementation of those proposed solutions. Discussions held aim at providing policy makers and technical stakeholders with a regular update about evolving best practices, projects, and regulatory developments, as well as possible ways forward in addressing the upcoming issues related to blending and gas quality in general.

Based on stakeholders' feedback and requests, two subgroups were formed at the beginning of 2021:

- **Subgroup 1 (SG1):** Chaired by Alice Vatin (AFNOR) and facilitated by Hiltrud Schülken (CEN) and Rosa Puentes (ENTSOG). The group was in charge of developing proposals for the normative framework needed to implement the Wobbe Index classification system at exit points proposed by CEN SFGas GQS. The group gathered EU associations representatives as well as National Standardisation Bodies (NSB) representatives that were previously involved in developing the WI proposal of entry range and classification system at exit points[7].
- **Subgroup 2 (SG2):** Chaired by Peter van Wesenbeeck (EASEE-gas) and Ruggero Bimbatti (GD4S) and facilitated by Thilo von der Grün (ENTSOG) and Rosa Puentes (ENTSOG). The group worked on a whole gas value chain 'roadmap' based on recommendations, best practices and lessons learnt about existing and potential gas quality and H_2 handling issues, options and tools. The results from the first deliverable[8] were published in July 2021 and provide an overview of each sector possibilities and vision on the use of hydrogen. Those inputs are integrated in this document with the relevant updates. This document constituted the final deliverable of this subgroup.

The prime movers' group will continue meeting during the first half of 2022 with bi-monthly meetings. Depending on the outcome of the new legislative proposals (i.e., Gas Directive and Gas Regulation), another set up could be foreseen for the second half of 2022.

All public material developed within the Prime movers' group Gas Quality and Hydrogen handling is available at the group **website**.

7 Document not publicly available.

8 First deliverable: *"PMG-Subgroup 2) Value chain 'roadmap' & solutions. Conclusions from discussions held between January and June 2021"* [23].

1.4 STAKEHOLDERS INVOLVED

Relevant stakeholders of the gas value chain were invited to participate*.

Main contributors to the prime movers group:

Other stakeholders following the prime movers group process (i.e., observers*):**

1.5 HIGHLIGHTS FROM THE WORK CARRIED OUT DURING 2021

Discussions held within the prime movers' group and subgroups have led to a better understanding of different points, including but not limited to:

- Potential mitigation measures for gas quality and hydrogen handling
- Sector concerns towards gas quality variations and hydrogen blends
- Expected hydrogen developments in each sector
- Real possibilities for hydrogen and gas quality management
- Potential ways to decarbonise the gas value chain
- Open questions that need to be further discussed
- Tools that need to be deployed
- Associations' work and efforts towards decarbonization
- How regulation could solve (or mitigate) upcoming challenges posed by decarbonisation
- Key principles needed to implement CEN SFGas GQS proposal of a Wobbe Index classification system at exit points

A public stakeholder workshop took place on 25th November 2021. Presentations and key points are available at the **event website**.

* Other sector associations, which are not represented here, were also invited to join although no answer was received.

** GWI representative was invited to participate due to the experience and involvement in gas quality topics during the past years, particularly in CEN SFGas GQS work

*** These stakeholders accepted the invitation to join the group although did not actively provided inputs.

1.6 SUBGROUP 2 WORK

1.6.1 SCOPE AND GOAL

In order to adequately identify and assess the main points of concern of different stakeholders along the gas value chain, an intensive dialogue at EU level with different customers, DSOs and TSOs, electricity sector, regulators, etc. was needed.

Subgroup 2 was created with the goal of providing an overview of potential future developments in each sector, including possible solutions for each area of concern and the main barriers preventing the implementation of the those solutions.

This final deliverable gathers the knowledge about the technical challenges and solutions needed for the decarbonization of the different gas related sectors, while striving for a more interconnected energy system.

1.6.2 STAKEHOLDERS INVOLVED

Main contributors to SG2 work:

Other stakeholders following SG2 process: (i.e., observers*):

* These stakeholders accepted the invitation to join the group although did not actively provided inputs.

2 INTRODUCTION TO THE **VALUE CHAIN DECARBONISATION ROADMAP**

To achieve energy System Integration the system must be planned and operated as a whole, linking different energy carriers, infrastructures, and consumption sectors. One way to deliver sector integration is by deploying renewable and low-carbon hydrogen. It can be used as a feedstock, a fuel or an energy carrier that can be stored, and has many possible applications across industry, transport, power and buildings sectors.

Picture courtesy of ONTRAS Gastransport GmbH

Although a more interconnected energy system is expected to be more efficient, and to reduce costs for society, it comes with challenges that must be addressed early in the process. For the gas sector, some of these challenges come from the expected changes in gas quality when hydrogen is injected in the grid or the need to adapt the systems to handle hydrogen (either in blends or as dedicated systems).

This report aims at providing an analysis of existing and potential barriers in order to understand which tools and technological developments will be needed to support a deep, sustainable and cost-effective decarbonization of the sector in the long run.

Although great efforts have been dedicated to provide a comprehensive and updated picture, forecasting the long-term future is not possible. Especially due to the rapid evolvement of the sector and the upcoming changes in the legislative framework which will definitely have an impact on how each sector sees its way through decarbonisation. Therefore, the analysis presented here is of an illustrative nature, examining the impacts, challenges and opportunities of possible ways of decarbonising the gas value chain. Most likely the future will be a combination of all options, in one form or another, and the information provided should be understood as a best estimate in time of how each stakeholder sees, at this point in time, the future developments within its sector.

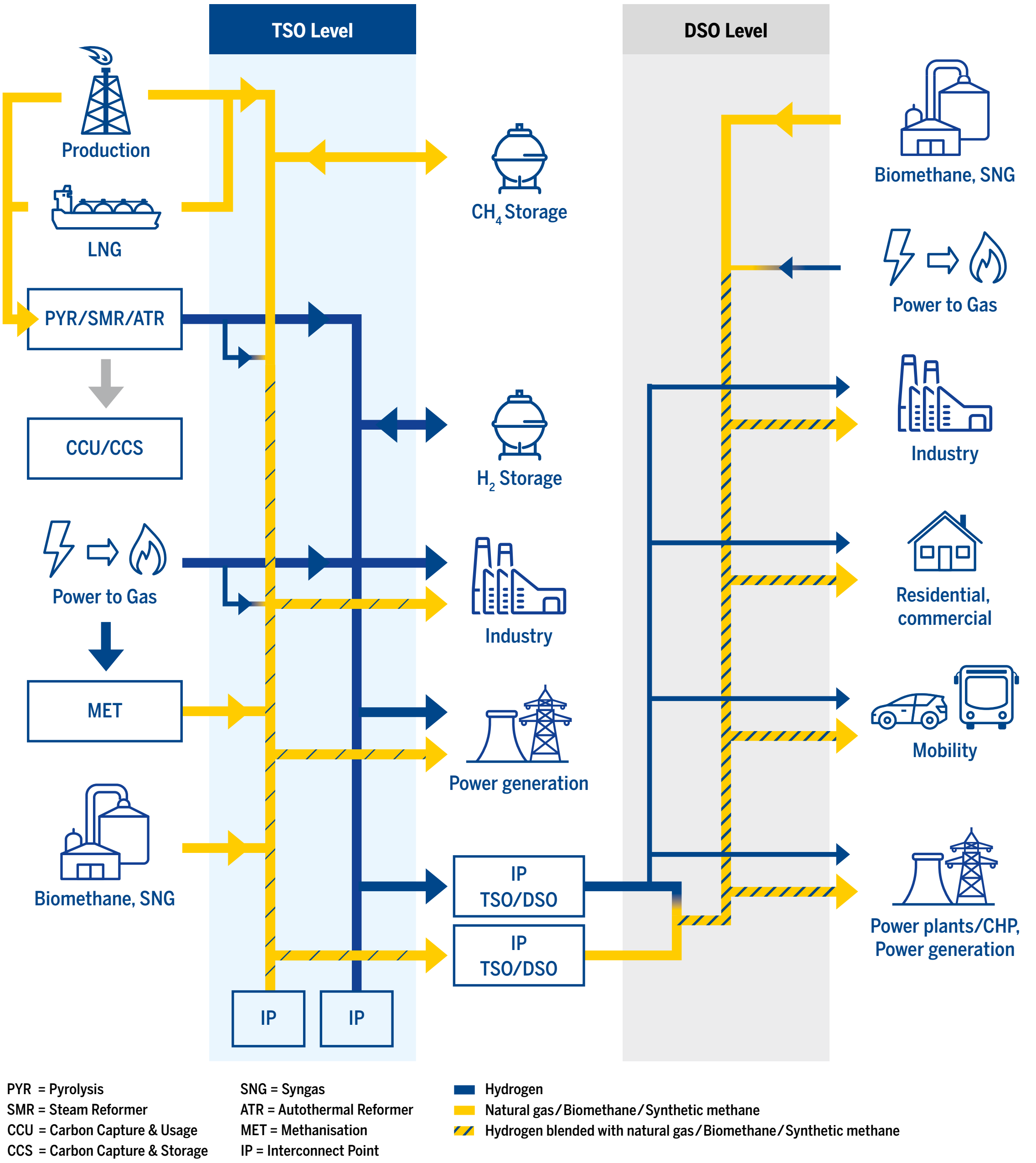

Figure 1: Illustrative example of potential future scenario within a more interconnected energy system

It is also worth mentioning that as the choices and decisions are influenced by the overall EU climate and energy policies, as well as the overall market conditions, and may differ amongst EU Member States, what might be seen as a short-term development for one country may be a medium-term one for another. Hence, it is not possible to define concrete timelines for each development especially when it comes to grid development. TSOs and DSOs will need to manage and accommodate diversity of technological choices for the benefit and safety of all consumers while ensuring that achievements of the internal energy market for gas and interoperability between the different energy carriers are maintained and further developed.

Lastly, it is important to note that all stakeholders participating in this group are driven by the same goal of finding solutions for the decarbonisation of the sector. Although there is a strong commitment and willingness, there are still controversial views and interests with respect to the preferred solutions. Besides, in some cases, technological developments are not yet mature in the market and many projects are currently ongoing, whose results will be key to reach a better understanding of the decarbonisation possibilities.

It is important to note that the blending levels (in %) are expressed in volumetric terms and represent the H_2 blending rates. 10% of blending rate means in this analysis that 10% of the volume is constituted by H_2, which represent approximately 3% of the energy content of the gas mixture (HHV). Besides, reference conditions (15:15) are used, unless otherwise is indicated.

3 STRUCTURE OF THE REPORT

This report is structured in four sections:

- Status quo (i.e., today's situation)
- Short/midterm developments
- Midterm developments, and
- Completion of the European Hydrogen Back-bone

Each section includes an overview of:

- **Current or upcoming challenges:** related to gas quality and hydrogen handling. Expected to arise due to the diversification of supply sources and decarbonisation of the sector.
- **Potential solutions:** available or future tools and technologies that could be implemented to solve or mitigate the impact of the previously identifies challenges. This section also includes projects, studies or tests that are currently assessing the possibilities of implementing such solutions.
- **Recommendations:** brought forward by each sector pointing out what would be needed to implement the proposed solutions, including but not limited to: regulatory changes, market tools, technological developments, etc.

Picture courtesy of Enagás

4 BASELINE: STATUS QUO

This sub-section provides an overview of current situation: what each sector can (or cannot) do and the available tools in the market to face experienced challenges. The following assumptions were taken into account:

- The existence of natural gas systems where hydrogen injection in the grid is present in pilot projects but not widely used
- The fact that hydrogen is mainly produced for dedicated onsite consumption and consequently dedicated H_2 systems are usually point-to-point connections
- The increase in biomethane injection

As starting point, 2% vol. H_2 is found as a reasonable value. Even though some sectors can already handle up to 10% vol. H_2 or even 25% vol. H_2, 2% vol. H_2 reflects the common minimum denominator due to the fact that some industrial processes cannot handle more than 2% vol. H_2 nowadays. It is also worth mentioning that throughout Europe the connected customers to the DSO or TSO vary widely. For this reason the potential final hydrogen blend transported or distributed will be most likely decided for each grid section depending on the local structure, connected customers and national technical rules, and standards in place.

4.1 CHALLENGES IN GAS QUALITY AND H_2 MANAGEMENT

4.1.1 EUROPEAN HEATING INDUSTRY (EHI) VIEWS FOR RESIDENTIAL & COMMERCIAL SECTOR

The building sector is seen as hard-to-decarbonise. It is the single largest source of energy consumption in the EU, representing 40% of final energy consumption and 36% of CO_2 emissions[9]. Moreover, heating and hot water production takes up the largest share (about 80%) of a building's total energy consumption. But most of the heating systems installed in Europe today – that is almost 60% of the total – are old and inefficient. Since 71% of currently installed heating appliances are gas-based, increasing the share of green gases in heating and cooling is a crucial step to meet the EU's long-term climate goals 2030 and 2050 in a cost-optimal and resource-adequate way.

RESIDENTIAL APPLIANCES

The installed stock can already run on biomethane as well as varying degrees of methane-hydrogen blends depending on the age of the boilers. Boilers installed after the implementation of the Gas Appliance Directive[10] the majority of which being atmospheric boilers have shown in tests that they could handle up to 10% vol. of hydrogen. Nevertheless, because of certification rules, these appliances cannot be re-certified or re-classified as such.

Since 2005, there are increasing sales of condensing boilers, which are generally able to work with up to 20% vol. hydrogen, but this is currently not a mandatory requirement.

The technologies for appliances operating with up to 100% vol. hydrogen are already available. For the coming transition period, the following definitions are in use by EHI:

- A **'20% vol. hydrogen appliance'** is a gas appliance that is designed and approved to operate safely and efficiently without conversion using a gas that has a fluctuating hydrogen content of between 0 and 20% vol. by volume.
- A **'100% vol. hydrogen-ready appliance'** is a gas appliance that is designed and approved to be installed and to operate on methane, biomethane or 20% vol. hydrogen blends and, following a conversion and re-commissioning process in situ, that can then operate safely and efficiently using 100% vol. hydrogen'.
- A **'100% vol. hydrogen appliance'** is a gas appliance that is designed and approved to operate safely and efficiently without conversion using 100% vol. hydrogen.

These definitions are key in ensuring that appliances are future proof and can adequately enable consumers and end-users to decarbonise their energy uses. Through the various solutions outlined above, this will apply for all possible future developments of green gases at national and regional level.

In addition to the differing abilities of the currently installed stock to handle blends, the low replacement rate of heating systems presents a challenge to large-scale utilisation of green gases in heating: Today, old and inefficient systems represent the bulk of heat emissions from buildings; replacing them with modern, efficient, renewable-based and future-proof appliances would pave the way for their full decarbonisation. Appliances are on average 25 years old; if they were labelled today, most of them would end up in class C, D or lower. Today, only 4% of heating systems are replaced per year[11].

9 A Renovation Wave for Europe, European Commission, 2020, p. 23.

10 European Council Directive 90/396/EEC and Directive 93/68/EEC

11 EU pathways to a decarbonised building sector, ECOFYS, 2016.

INDUSTRIAL APPLIANCES

Industrial appliances today account for more than 30% of the gas consumption from public networks in the EU[12]. They are to be divided into three main groups.

1. Medium and high power appliances for big buildings and district heating.
2. Medium and high power appliances for energy supply to industrial processes via hot water, steam, thermal oil or other heat transmission fluid.
3. Small to high power appliances for direct use of flue gas in industrial processes or methane as a raw material for chemical processes.

This distinction is crucial in order to understand how to decarbonize the industrial gas appliances.

- **Group 1** is sensitive to gas quality, but can tolerate a limited variation, in particular towards lower energy content in the gas.
- **Group 2** is more sensitive to gas quality in order to guarantee the requested power output and temperature for the connected industrial processes.
- **Group 3** is the most sensitive to gas quality and does not tolerate almost any variation.

While the total number of industrial appliances is much lower than the number of household appliances, their overall consumption in terms of volume is high. Therefore, economic efficiency can be an important driver for modernisation and decarbonisation of this segment.

4.1.2 C.E.F.A.C.D. VIEWS FOR RESIDENTIAL & COMMERCIAL SECTOR

HEATING AND COOKING APPLIANCES

For heating and cooking appliances, challenges related to gas quality variation and hydrogen handling can be already identified. Yet, ongoing projects like THyGA (Testing Hydrogen admixture for Gas Applications)[13] are expected to provide the necessary inputs on challenges and solutions along 2022. Besides, the ongoing project on "Removing the technical barriers to use of hydrogen in natural gas networks and for (natural) gas end users" funded by the European Commission is reviewing the current scientific and technical framework concerning the use of hydrogen, and drawing from this review a gap analysis which can then be translated into a set of pre-normative research (PNR) requirements. This work will then contribute to the process of standardisation for the introduction of hydrogen into the gas networks and for end users[14].

12 Gas consumption according to Eurostat in 2019 [tons of oil equivalent] in EU27 [47] [48].

13 THyGA aims at closing knowledge gaps regarding H_2NG blends, to identify and recommend appropriate codes, standards that should be modified or adapted to answer the needs for new and existing appliance. The project has received funding from the Fuel Cells and Hydrogen 2 Joint Undertaking under grant agreement No (No. 874983). This Joint Undertaking receives support from the European Union's Horizon 2020 research and innovation program, Hydrogen Europe and Hydrogen Europe research.

14 GERG is delivering this project on behalf of CEN. Stakeholders involved: AFECOR, CONCAWE, EASEE-gas, EHI, ENTSOG, EUROMOT, FARECOGAZ, IFIEC, MARCOGAZ, NGVA. Along with several CEN and CEN-CENELEC Committees and national standardisation bodies.

4.1.3 EUGINE VIEWS FOR POWER GENERATION SECTOR
ENGINES

The installed fleet was optimised for natural gas. Without any modifications most plants will be capable to operate only with a small share of H_2.

The retrofitting is not only a question of the engine, but concerns the full power plant (explosiveness protection, exhaust treatment…). EUGINE has developed a checklist[15] to help industry, investors, and policymakers to evaluate the hydrogen readiness of existing plants. A pre-filled version of the checklist should help interested parties gain an overview of the potential impact of switching an existing engine power plant, built for the use with natural gas, to hydrogen. The switch could be either towards pure (100% vol.) hydrogen or to a blend of natural gas and a certain share of hydrogen (25% vol. H_2 blend).

The EUGINE H_2-Ready Checklist identifies six main plant components that need to be looked at when evaluating the plant's H_2-readiness level: the gas/fuel system, the engine, the cooling system, the oil system, the exhaust gas system and the safety system. A look at the pre-filled checklist shows that, for up to 25% vol. blends, the largest probability for adaptation lies in the safety system, followed by the engine (esp. turbo charger) and the gas/fuel system (gas metering, sealings, valves, piping).

4.1.4 EUROMOT VIEWS FOR POWER GENERATION SECTOR
ENGINES

INSTALLED STOCK

Engines can accept Wobbe Index (WI) range variations within a bandwidth of 3.7 MJ/m³ although their performance is best guaranteed in a 2.5 MJ/m³ WI window that most of them are usually experiencing. Furthermore, the performance can decrease for a WI >52.7 MJ/m³ because of the associated lower methane number. For safety reasons, the minimum required ignition energy is also of importance. For example, adding H_2 to LNG with a WI close to 53–54 MJ/m³ could decrease methane number (MN) to values below 65 which has negative consequences on the output and efficiency of engines.


Picture courtesy of INNIO Jenbacher

A fixed fraction of 10% vol. or even 20% vol. H_2 in a fixed base gas quality can be handled more easily than a variable fraction in natural gas varying in the wide EASEE-gas range[16]. For all, 'gas quality boundary conditions' (as expressed in EUROMOT position paper [1]) should be respected, mainly the stability of the H_2 fraction as it strongly depends on the 'base gas'. (e.g., a fixed 20% vol. H_2 roughly leads to a decrease of 2 MJ/m³ in the WI bandwidth while a variable H_2 fraction between 0 and 20% vol. in natural gas having a fixed WI bandwidth of 3.7 MJ/m³ leads to a widening of the WI bandwidth to 5.7 MJ/m³).

For carburettor engines, the addition of H_2 increases the back firing risk because of the factor 10 lower minimum ignition energy of hydrogen compared with that of natural gas and the much higher flame speed of hydrogen-air mixtures.

Also, H_2 does penetrate in the space (the top-land crevice) between the piston and the cylinder and react with the lubricant oil. This could lead to an increase in the wear rate because of carbon formation in the piston-ring area of the engine and decrease the lifetime of the lubricant. Additional measures also have to be taken to avoid crankcase explosions. The higher combustion temperature of hydrogen compared with that of natural gas can lead to higher specific NOx emissions.

An additional issue arises due to the fact that billing of energy supplied by natural gas is based on the upper calorific value. For natural gas, the lower heating value is approximately 90% of the upper heating value, but for hydrogen it is only 85%. This is a disadvantage for applications that can only use the lower calorific value, like gas turbines, gas engines and non-condensing heating ones.

15 Available at **EUGINE website**

16 EASEE-gas CBP Harmonisation of Natural Gas Quality 2005-001/02 [49]

4.1.5 EUTurbines VIEWS FOR POWER GENERATION SECTOR TURBINES

The switch from natural gas to the use of hydrogen in power generation may impact the power plant. There are different areas that should be checked – not necessarily modified – to ensure the well-functioning of a power plant with hydrogen blends or pure hydrogen. These areas include the core engine, the exhaust gas system, the fuel supply system, safety systems, the heat recovery steam generator (HRSG), electrical equipment and plant operation aspects.

4.1.6 CEFIC AND IFIEC VIEWS FOR THE FEEDSTOCK INDUSTRY

Currently, hydrogen is not normally present in natural gas grids (or only in traces). The injection of hydrogen in the natural gas stream (i.e., blending) will cause gas quality variations. Some of the established chemical processes will be highly affected by hydrogen, which can lead to destabilization of the process, efficiency losses, pre-ignition and safety shutdowns. Therefore, at least, additional analysis and control equipment will be required to detect hydrogen and keep the process stable or safely shut it down (which is a worst case scenario as this affects all other downstream processes and can have a high economic impact). Highly fluctuating hydrogen content would be a severe challenge as chemical processes always need some time to get into a stable operation.

From a pure technical point of view, these gas quality variations can be handled by additional analysis, control and separation equipment, but there is no "one size fits all" solution and case-by-case assessments are needed since applications and processes are optimized for the typical (historical) natural gas quality at exit point. For sensitive appliances and processes the Wobbe Index may not exceed a range of 3,7 MJ/m³ (15:15).

Steady fluctuations (e.g. of hydrogen content) are the most critical aspect, leading to higher cost, lower efficiency and higher emissions and can eventually cause unexpected outages.

There are processes which are very sensitive to hydrogen[17]:

- Acetylene process could handle up to 1.5–2% vol. H_2.
- Desulphurisation for CH_4 could handle up to 3% vol. H_2. Above that value catalyst get deactivated.
- For other processes, a 3% vol. H_2 does not need to be necessarily a problem.

For the installed stock the industry needs guarantees of the equipment manufacturers that existing appliances can handle H_2, including the new applicable guarantee conditions connected to the appliance.

4.1.7 NGVA VIEWS FOR THE MOBILITY SECTOR

INSTALLED STOCK

New steel cylinders (i.e. type 1) for CNG cars are certified under regulation UN ECE R 110 so they can admit up to 2% vol. H_2 (R 110 adopts the requirements of ISO 11439). Type 4 CNG tanks which are made of composite materials with thermoplastic liner, and type 3 tanks (if their liner is not in carbon steel) can withstand higher percentages. Yet, the price could be higher (e.g. x2 or more) than the one for steel tanks. Besides the cost aspect, some OEM seem to still prefer type 1 cylinders for other reasons. For fuel cells, only very high purity H_2 is accepted with the present technology.

Note: The present technology at CNG refuelling stations has steel components whose resistance to H_2 embrittlement must be investigated.

17 Although they are considered to be a minority in the market these commodity value chains are worth billions of Euros.

4.1.8 ENTSOG VIEWS FOR TSOs

This document compiles a number of currently available technical and economic studies from different sources. For the avoidance of any doubts, this information has not been verified nor challenged by ENTSOG and does not necessarily represent ENTSOG's position.

For TSOs, the challenges can be divided into two categories:

1. Challenges for TSOs' own assets (e.g., pipelines, valves, compressor units, turbines, simulation software, etc.)
2. Challenges for the gas quality parameters that must be kept at exit points (e.g., end users, storages, other TSOs, etc.)

1. TSOs' ASSETS

The challenges for the TSOs' own assets increase with the share of H_2 in the natural gas and with the fluctuation of the actual H_2 share. This is in relation to the materials but also the functioning of the different components, whereas the combination of both determines the smallest common denominator. These effects has to be considered when assessing the effect H_2 will have on the TSO's current assets, but also when planning to invest in new assets.

In the following, the main components of the TSO network are described and assessed[18].

A. Steel pipelines

For most steels, literature shows a good resilience against hydrogen. For certain steels however, the effect of hydrogen embrittlement[19] has to be assessed by fracture-mechanical tests on a case-by-case basis [2]. The result of hydrogen embrittlement is that components crack and fracture at stresses less than the yield strength of the metal[20]. Parameters of interest are, among others: the chemical composition of the steel, the heat treatment of the material, the welding procedure specification, and the way a pipeline has been operated over the years [3].

Solutions include lowering the piping design factor, identification of piping hydrogen toughness, the application of 'inner coating' to chemically protect the steel wall, monitoring of pipes, development of integrity plans, and safety coefficients or changes in the transmission conditions, e.g. by reducing the frequency and intensity of pressure cycles or by addition of gases like O2 or CO_2 that inhibit hydrogen embrittlement. The optimal solution varies per pipeline, as it depends on several criteria including pipeline transport capacity requirements, status of existing pipelines and trade-offs between capital and operating expenditure [4], [5].

For 2% vol. of H_2, a general suitability of pipeline steel is expected.

The general function of a pipeline is not impaired. However, when hydrogen is blended into natural gas and the volume flow in the respective pipeline remains constant, the pressure drop decreases due to the compressibility of H_2, but less energy is transported due to the volumetric energy density of H_2. Increasing the volumetric flowrate to transport the same amount of energy however leads to higher pressure losses along the pipeline, since the friction from increased volume flow has a greater effect in comparison to the decreasing effect of on compressibility.

For 2% vol. of H_2, the effect on the entry and exit capacity of a market area is in most cases negligible.

18 The main source of the description is the document *"Kompendium Wasserstoff in Gasfernleitungsnetzen"* that the DBI prepared for the DVGW and FNB Gas (the German TSO Association).Not all components and information from the compendium are presented here. TSOs are currently checking their own components in more detail.

19 Hydrogen embrittlement is a metal's loss of ductility and reduction of load bearing capability due to the absorption of hydrogen atoms or molecules by the metal.

20 Source: Hydrogen Embrittlement of Steel – Industrial Metallurgists

B. Valves

The internal and external tightness of the valve, are not considered critical for up to 10% vol. of H_2 based on publications of DBI [2] and GERG for shut-off and ball valves. A study by Energinet did not identify increased leakages for H_2 levels of up to 14% vol. and pressures up to 80 bar. A next phase of the study is expected to assess H_2 concentrations of up to 25% vol. However, case-by-case assessments are required [2].

A general suitability of valves can be expected for 2% vol. H_2.

C. Measurement

C.1. Gas Chromatographs

The material of gas chromatographs in contact with the process gas can be assumed to be ready for 100% vol. H_2. Concerning the function, gas chromatographs can measure determine the gas composition of blends of hydrogen and natural gas. Depending on the technology, above 20% vol. of H_2 shares are possible. Still, some existing GCs cannot measure hydrogen [2].

For 2% vol. H_2, some Gas Chromatographs require upgrading or replacement.

C.2. Volume converters

Only the measuring part of the volume converters is in direct contact with the gas. The converter calculates the volumetric flow rate under normal conditions. The typical equations used for this exercise can guarantee sufficient precision for between 10 mol.% H_2 (SGERG-88 and AGA8)[21] and 40 mol.% (GERG2004/08). For AGA8 and GERG2004/08, the molar composition of the gas is required [5].

For 2% vol. H_2, volume converters are typically suitable.

C.3. Flow measurement

Different flow measurement techniques exist (e.g., turbine meter, rotary displacement meters, ultrasonic meters, Coriolis meter). The DBI quotes a general readiness for 5% vol. H_2 and case-by-case decisions for higher H_2 shares [2]. The measurement uncertainties must be checked on the turbine meters due to the low density of the H_2NG mixture. CEN CENELEC has validated the use of turbine meters for a mixture of up to 10% vol. hydrogen. However, other technologies, and in particular ultrasound, accept a hydrogen content of up to 15% vol. with little or no dispersion [6].

Existing flow measurement devices are expected to be fit for 2% vol. H_2.

21 SGERG-88 is an equation of state that calculates the compressibility factor of natural gases. The equation, which does not require detailed gas analysis, can predict the compressibility factor when three of the four following gas properties are known: the gross calorific value, the relative density, and the mole fractions of N_2 and CO_2. The AGA8 method enables the calculation of the thermodynamic properties of natural gases consisting of up to 21 components [38].

D. Compressor station

Along a pipeline, friction causes transported gas to lose pressure. Compressor stations compensate these losses to boost the system's energy throughput [5].

D.1. Compressors

Turbo-compressors with one or two impellers are operated with gas turbines or motors with a drive power of up to 30 MW [7]. Hydrogen has a significantly lower molar weight than natural gas, which is an important parameter for the commonly used centrifugal compressors. Therefore, existing compressors are usually not fully optimised for blends, although different compressor models react in different ways to hydrogen blends [5].

Besides the necessity to check the relevant materials for H_2 readiness, the shape of the compressor maps will change with H_2 addition. This will possibly limit the achievable pressure ratio and outlet gas pressure.

SIEMENS [7] has published the following statements about the adaptability of existing and new compressor stations to H_2 blends. It should however be noted that these conclusions do not have to match the findings of other manufacturers. Depending on the hydrogen content in the pipeline, this infrastructure can be maintained or adapted accordingly [7]:

- *"Up to approx. 10% vol. H_2, the compressor can generally continue to be used without major changes.*
- *The compressor housing can be maintained up to approx. 40% vol. H_2, impellers and feedback stages as well as gears must be adjusted.*
- *From approx. 40% vol. H_2 the compressor must be replaced".*

For 2% vol. H_2, no major changes are expected for compressor stations.

D.2. Compressor drivers

Compressors that are driven by gas turbines draw their drive energy directly from the line and must be adapted accordingly to the hydrogen admixture. Most common gas turbines for pipelines can already burn a significant amount of H_2 in the fuel [7]. However, based on the materials used, control systems, stoichiometry, and blading, suitable H_2 thresholds for existing turbines can vary between 1–20% vol. H_2. A DBI analysis also limits the maximum H_2 share for gas turbines to 8% vol. for fluctuating H_2 contents, based on a maximum Wobbe Index variation of 2% [2]. Some gas turbines are declared as not suitable over 2 Vol.-% vol. hydrogen in the fuel gas by the OEM[22]. The ongoing work at EUTurbines will help in assessing turbines' readiness and update current knowledge on the topic.

If the compressors are electricity driven, no major changes are required for the motors. At most, the speed must be adjusted and safety for hydrogen operation checked [7].

For 2% vol. H_2, gas turbine and electrical drives are typically suitable

Besides the possibility to burn a blend of H_2 and natural gas, the changing blend compressibility and volume flow affecting the compressor unit also have an impact on the drive power requirement of the compressor drive units. This effect is mitigated by the fact that TSOs often purchase standard gas turbine products with a drive power that therefore usually is slightly oversized for the compressor units' specifications.

For 2% vol. H_2, the additional drive power requirements are expected to be negligible in most cases.

22 Some TSOs own experience with OEMs

Due to the intensive development work in this area, it can be assumed that by 2030 the standard compressor drive turbines can be operated with up to 100% vol. hydrogen or can be converted accordingly[23].

Compliance with the applicable NOx can be "limited" with Dry Low Emission (DLE) technology.

The following figure shows an example of the H_2 compatibility for relevant gas turbines from Siemens Energy [7].

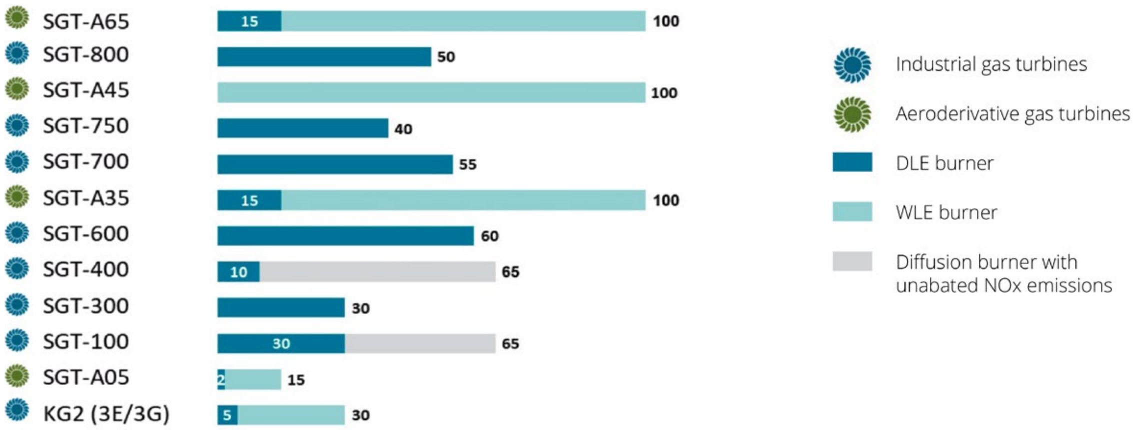

Figure 2: Siemens Energy gas turbines are suitable for hydrogen in the new system portfolio (numbers representing % of H_2) [8]

23 Siemens Energy inputs

2. GAS QUALITY

A. Introduction

Today, there are requests to revise gas quality standards both at entry and exit points. TSOs often receive requests from gas suppliers to extend the operational limits at injection points, and at the same time are faced with the wish from the end-users to keep the gas quality as narrow and stable as possible at exit points. For the TSOs, accommodating these requests and, at the same time, securing a free flow of gas across the borders is a technical challenge. The operation of the transmission network influences the gas quality in the system only to a certain extent, at entry points as well as at exit points. Furthermore, the competence for the regulatory limits in the gas quality standards lays at the national authority in each EU Member State [9].

Variations in gas quality can arise due to production related and technical causes or changes in the natural gas purchased amounts. Production related variations are due to fluctuations in the gas field where the gas is produced, i.e. the composition of gas extracted from a certain field will change slightly. These variations occur over years and decades and do not cause any sudden, large variations in the gas quality transported through the grid. Technical induced variations and changes in the purchased amounts however can be large and sudden effects and are what may affect end users both technically

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and economically. These variations may for example occur when gases produced at different gas fields are mixed in the grid, or when gas from a new source is being fed into the grid [10].

Nowadays, TSOs cooperate to find solutions to cope with gas quality variations and avoid potential cross-border restrictions. The operational measure adopted at the Danish-German border in 2016 to avoid the immediate market restrictions in relation to biomethane (due to its oxygen content) is a good example of how TSO-TSO cooperation is key to address these issues [11]. This case, however, demonstrates that flexibility for gas quality is necessary as a long-term solution to ensure the integrity of the gas networks and the internal gas market.

B. Hydrogen addition

While gas quality variability is generally not an issue in the current gas system, the injection of hydrogen can have a major influence according to some industry experts, not only because of the influence on relative density and gross calorific value and hence Wobbe Index but also for the change in flame speed and combustion temperature.

This change in properties may limit the operational window (or Wobbe Index range) that end-use applications can handle. This means in practice that, while applications could be readjusted or retrofitted for relatively high shares of hydrogen, gas quality stability would need to be even greater than today.

However, hydrogen blending with natural gas grids will very often be linked to power-to-gas installations, which will operate on an intermittent basis. With the current limitations in hydrogen fractions (typically 2% vol.), gas quality variability is not expected to increase significantly. However, for higher concentrations, local ranges (e.g. in terms of Wobbe Index) could be wider than today. It is worth mentioning that not only the end-use-application, but also the gas infrastructure itself may be affected by higher H_2 concentrations.

Yet, the injection of hydrogen is seen as a potential key enabler towards a close to carbon-neutral future. On the other hand, TSOs also recognize that the best decarbonising choice may vary across different areas depending on local existing infrastructure, geography, housing stock, access to CO_2 storage infrastructure, etc. The permissible levels of hydrogen are typically set by national legislation based on natural gas composition reflecting the natural gases typically distributed in the given Member State. Consequently, there is a gap between what can be injected from a technical, safety and operational point of view and what is allowed according to national legislation. Several organisations such as Marcogaz, GERG, and CEN, as well as different projects, are currently investigating the potential of gas infrastructure elements and end-use applications from a technical, safety and operational point of view regarding the allowable H_2 content. For instance, the ongoing project "Removing the technical barriers to use of hydrogen in natural gas networks and for (natural) gas end users" funded by the European Commission is reviewing the current scientific and technical framework concerning the use of hydrogen, and drawing from this review a gap analysis which can then be translated into a set of pre-normative research (PNR) requirements. This work will then contribute to the process of standardisation for the introduction of hydrogen into the gas networks and for end users.

Besides, the introduction of hydrogen into the natural gas grids will likely extend the role that TSOs play in gas quality management and add new tasks and responsibilities, as well as potentially determine the need to offer or contract additional gas quality services. On the market side, the challenge remains on how to agree on the permissible hydrogen blending capacity within the system and across borders so that a reasonable compromise can be reached and the freedom to trade gas across the balancing zones is preserved.

At cross-border level, under the obligations of the Interoperability Network Code (INT NC), TSOs have implemented bilateral Interconnection Agreements (IAs) that define the applicable operational rules on interconnection points (IPs). Although the INT NC does not request gas quality specifications in Interconnection Agreements, most of the TSOs have agreed on such specifications in their agreements.

However, for the moment, hydrogen is usually not found in the list of parameters that are subject to specifications in the Interconnection Agreements[24]. A revision of current Interconnection Agreements would be needed to ensure that hydrogen can be safely and efficiently transport across borders in the future.

4.1.9 CEDEC, EUROGAS, GD4S, GEODE VIEWS FOR DSOs

1. DSOs ASSETS

Gas distribution is a fragmented system composed by over 1.400 very large, large, medium, small, and very small operators, running approximately 2.000.000 km of network across Europe. Furthermore, the number of gas DSOs nationwide is strikingly different: ranging from hundreds in Germany and Italy to as many as four or five in other countries, with no correlation with the size of their respective gas markets. Some of these are only gas DSOs; others are gas and electricity DSOs. Some countries have a very strong gas penetration in the energy market, reaching percentages of 90–95% of the total households. In others, this number is less than 30% . Finally, there are significant variations on the markets actually served: in some countries most of the final consumption transits through the distribution networks including all industrial end-users; in others DSOs are central in residential and commercial demand, but do not supply the majority of industrial users. For these reasons it is difficult to identify a common threshold for the development of hydrogen injection into the gas distribution network and local fit-for-purpose solutions might be developed according to the needs of the connected customers and the characteristics of the grid.

All DSO grids will transition in the future to renewable and low-carbon gases. The speed of this transition will depend on many factors and cannot be foreseen at the moment, but it will happen. Depending on the availability of the locally produced gases and the development of the EU Hydrogen Backbone, the final composition of the gas can vary: one grid might operate with 100% vol. biomethane and another grid on 100% vol. hydrogen. This means that all grid assets and all end-user appliances and applications have to be prepared for this transition to renewable and low-carbon gases. As this is a complex process involving many actors, each DSO will soon start with the conversion planning. It is important that results from ongoing projects in Europe are shared as much as possible since lessons learnt can help others. The results from on-field tests with new or existing appliances and grids for blends up to 20% vol. of H_2 (e.g. Dunkerque[25], HyDeploy [12]) are a very good examples.

In this regard, to facilitate the knowledge sharing of DSOs along Europe "Ready4H2"[26] was founded in late 2021. DSOs, companies and associations from 17 countries have joined to support the process. The first report was published on December 2021 collecting the experiences from 14 countries. The conclusion drawn is that 96% of the 1.193.000 km of pipes are 100% vol. hydrogen ready.

24 Based on TSOs answers

25 GRDF

26 Ready4H2 website

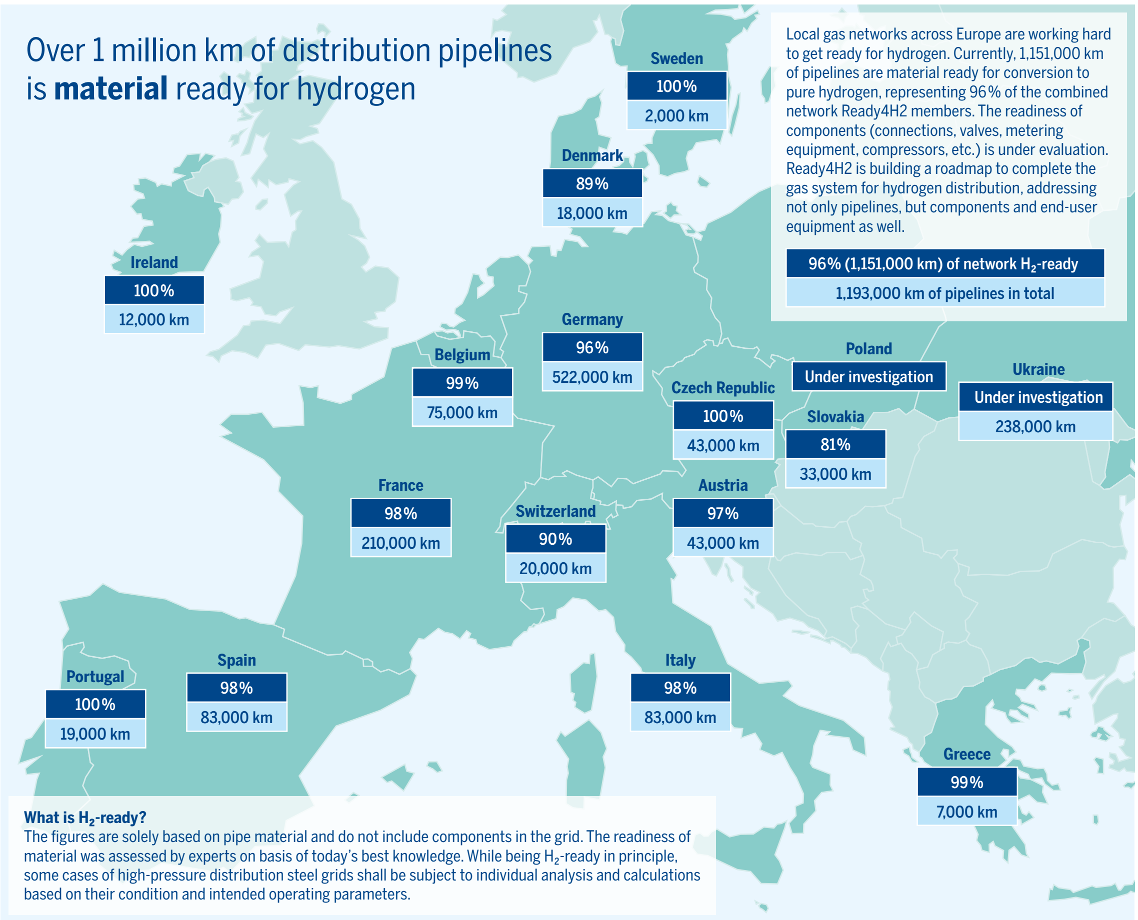


Figure 3: Ready4H2 project

More information is provided in section 7.2.8.

2. GAS QUALITY

In most countries the responsibility for the gas quality lies with the TSO (except for biomethane or other injections). The DSO depends mainly on the gas quality of the TSO at the interconnection points between both. The gas quality in the country is defined in the national technical rules building on the CEN standard. On the EU level the Interoperability Network Code (INT NC) contains rules about how TSOs need to inform DSOs, SSOs and connected customers whose processes are adversely affected by gas quality changes[27]. According to the proposals of the gas package[28], this responsibility will be extended to DSOs.

For biomethane injections, DSOs need to ensure that the injection points meet the national gas quality standards. Depending on the feedstock used and the upgrading process to biomethane additional LPG can sometimes be added to meet to the gas quality requirements. Yet, this needs to be carefully controlled since an excess of LPG is problem for certain applications, for environmental and for cost reasons.

In order to carry out this task in several countries gas DSOs are already operating the grid using 'smart grid' tracking tools. This has become important with the increase levels of biomethane been injected with different gas qualities. These tracking systems combine IT tools with gas measurements and sensors and also ensure the proper billing for each customer. These tools will become essential to fulfil the potential new requirements on gas quality management derived from the updated Gas Directive and Regulation. For more information see section 4.2.9.

27 INT NC article 17

28 COM(2021) 803 final and COM(2021) 804 final

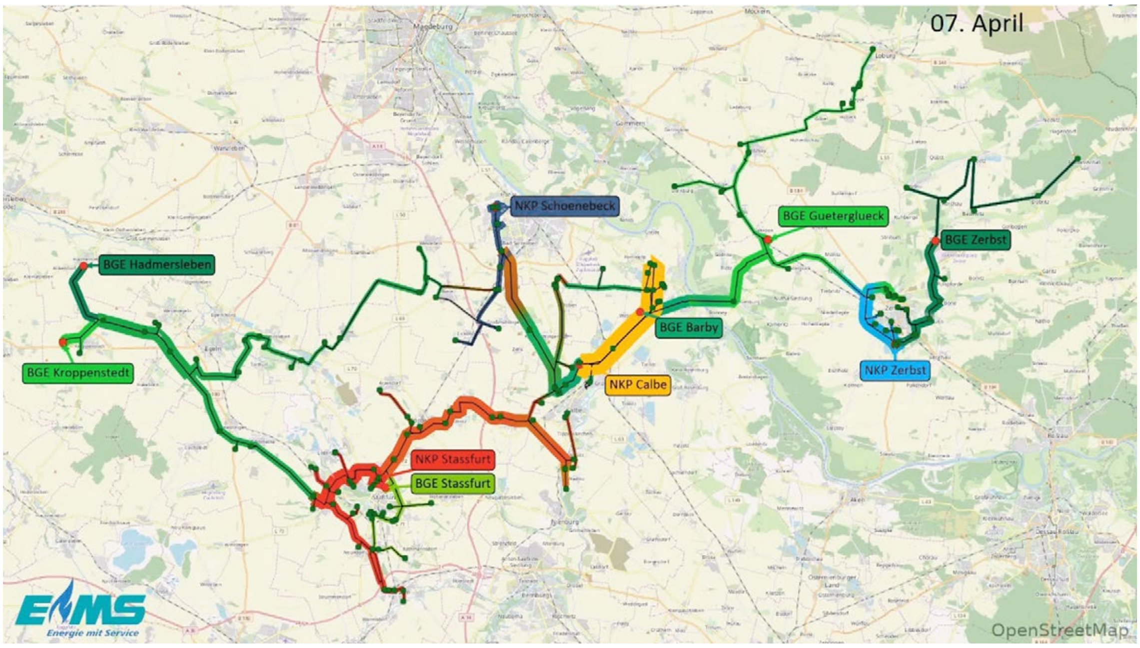


Figure 4: Simulation from Thüga

On the other hand, hydrogen injections to the DSO level are subject to special approvals depending on the allowed H_2 blends in the vicinity of the injection, the simulation of the gas flows during the different seasons, and the material of the components. The allowed level of H_2 in the grid varies between the countries. For instance, Germany has currently a max. level <10% vol. The national technical associations are working on the upgrading the technical rules books and defining the relevant tests that have to be carried out before H_2 can be injected in the grid. Even if a 20% vol. blend of hydrogen reduces the CO_2 only by 8.3% it starts the decarbonization of the hard-to-abate heating sector and offers smaller producers of H_2 a connection to the market that otherwise would not exist.

4.1.10 ENERGY COMMUNITY SECRETARIAT VIEWS

The challenges related to gas quality and H_2 management will not only be technical but also legal and regulatory. For the Contracting Parties to the Energy Community (EnC CP) those challenges can be divided in two levels: national and cross-border. Namely, the gas quality which might be accepted by distribution and transmission network operators and injected in gas storages is usually prescribed by national rules (i.e.,. supply rules, Network Codes or some specific gas quality acts). Those do not generally include hydrogen at all or, if allowed, it is at very low shares (less than 2% vol. H_2 in general). This absence has a negative impact on local, national and cross-border level flows in the near future and possibly even already today.

An additional problem also of legal nature is the absence of a definition for hydrogen, biomethane, and synthetic gases as commodities in the gas market by the national legislation. This hinders their acceptance by gas infrastructure and trading at the market.

4.1.11 GIE VIEWS FOR STORAGES

The analysis of storage assets shows that the injection and storage of H_2NG of more than 2% vol. H_2 have significant technical and commercial impacts on surface and subsurface storage facilities for all types of storage assets. Therefore, there is a need to assess and handle adequately the technical and commercial impacts to enable blending in gas storage facilities [13].

Storage type	Depleted field	Aquifer	Salt cavern	Lined rock cavern
General suitability for hydrogen	Site-specific	Site-specific	High	High
General technical readiness level for hydrogen storage	3–6* * Some operators have tested hydrogen and natural gas blends, and rocks from reservoirs have been tested with pure hydrogen in laboratory settings	3	8	5 – 6
Suitability for hydrogen	Hydrogen-methane blending (up to 10% vol. hydrogen) proven; pure hydrogen storage under study	Under study, but learnings from depleted fields can be utilised	Proven	First hydrogen storage in development (2022)

Table 1: Summary of the suitability of underground storage types for hydrogen [13]

4.1.12 GERG VIEWS FOR R&D

As of today, from a research perspective, the main challenge is the acquisition of sufficient information, derived both from literature and experimental tests, in order to assess critical aspects like gas quality requirements, according to end-use applications and asset materials compatibility/readiness for both H_2NG and pure H_2.

GERG Hydrogen Research Roadmap 2021 [14] has identified the key R&D elements emerging on the sector. In regards to gas quality, those elements are:

- Impact of H_2 and H_2NG on main industrial processes in order to evaluate the need of modifications/retrofitting.
- Impact of the speed of change of H_2 concentration on industrial applications.
- Impact of H_2NG on the metrological behaviour of fiscal flow meters.

4.2 POTENTIAL SOLUTIONS & ASSOCIATED COSTS

4.2.1 EUROPEAN HEATING INDUSTRY (EHI) VIEWS FOR RESIDENTIAL & COMMERCIAL SECTOR

Gas-fuelled heating appliances (i.e. condensing boilers, micro-cogeneration including fuel cells, gas fired heat pumps and hybrid heat pumps) will continue to play an important role and complement the electrification of heating. To fully decarbonise gas-based heating, a substantial increase of green gases, whether methane or hydrogen, in blended and pure form, is needed.

As stated in the previous section, appliances installed in the field are already capable of working with up to 100% vol. biomethane or synthetic methane. In addition, modern gas condensing boilers (i.e. appliances installed after 2005) are generally able to work with up to 20% vol. H_2 blend. Hydrogen fluctuations in the gas blend do not adversely affect the appliance. HyDeploy project also confirms this: *"The evidence generated showed that UK appliances are capable of operating with a 20% vol. hydrogen blend safely and with good performance and without the need for adjustment".*[29] In addition, there are fuel cells on the market today that are already capable of functioning with 100% vol. hydrogen.

The standardisation update to make all heating appliances "100% vol. H_2-ready" enabling them to handle different fluctuations of methane-hydrogen blends is well-underway and will be fully finalised by 2025 at the latest. In this field, there are several technical committees currently revising the necessary standard requirements that shall apply to hydrogen appliances. These committees are (non-exhaustive list):

- CEN/TC 48 Domestic gas-fired water heaters
- CEN/TC 49 Gas cooking appliances
- CEN/TC 58 Safety and control devices for equipment burning gaseous or liquid fuels
- CEN/TC 106 Large kitchen appliances using gaseous fuels
- CEN/TC 109 Central heating boilers using gaseous fuels
- CEN/TC 131 Gas Burners using Fans
- CEN/TC 180 Decentralized gas heating
- CEN/TC 186 Industrial Thermoprocessing
- CEN/TC 234 Gas infrastructure
- CEN/TC 238 Test gases, test pressures, appliance categories and gas appliance types
- CEN/TC 299 Gas-fired sorption appliances
- CEN/TC 408 Biomethane for use in transport and injection in natural gas pipelines
- IEC/TC 105 Fuel cell technologies

In the meantime, because of certification rules, currently installed appliances cannot be re-certified or re-classified for the use of hydrogen in general. Therefore, a case by case approach shall be followed whereby technicians should ensure old appliances are compatible when increasing hydrogen blends in grids.

The German Association for Gas and Water Supply (DVGW) supports the possibility to blend in 10% vol. of hydrogen in a September 2021 revision (see G 260 Appendix D informative), if the technical condition of the appliance as well as the appliance settings are taken into account.[30]

Finally, the provisions in the Energy Performance of Buildings Directive (EPBD) and in the rest of the whole 'Fit for 55' package should lead to a replacement rate of appliances of 6%, which we (i.e., EHI) consider to be the one to be achieved, to reach out our common 2030 and 2050 targets.

29 HyDeploy **"Demonstrating non-disruptive carbon savings through hydrogen blending"**

30 DVGW G260 9/2021: "Gas appliances are, according to the present knowledge, suited for concentrations of up to 10 vol %. Concerning suitability for concentrations of up to 20 vol %, extended studies are being carried out in the context of research project".

4.2.2 C.E.F.A.C.D. VIEWS FOR RESIDENTIAL & COMMERCIAL SECTOR
HEATING AND COOKING APPLIANCES

Current knowledge confirms that up to 10% vol. H_2 can be handled by heating and cooking appliances, even if the hydrogen percentage is fluctuating. Above that level on field tests and research is needed. Ongoing projects like THyGA (Testing Hydrogen admixture for Gas Applications) are expected to provide the necessary inputs on challenges and solutions along 2022.

4.2.3 EUGINE VIEWS FOR POWER GENERATION SECTOR
ENGINES

The situation for existing engines needs a case-by-case analysis as the plants were built according to specific requirements agreed between operators and technology providers. For most engine power plants, only small modifications will be necessary to enable a use with up to 25% vol. H_2 – depending on the base gas. Often, an upgrade for the use with 100% vol. H_2 will be possible.

New engine power plants build today will typically start operating with natural gas for a number of years. However, a new power plant can already be designed and built to be H_2-ready. This allows operators to easily upgrade the plant for the specific hydrogen content available in the gas grid.

In September 2021, EUGINE published a paper providing a definition for new H_2-Ready engines [15]. Three different "H_2-Ready categories" are listed, depending on the hydrogen percentage that can be handled by the engine:

- H_2-Readiness Level A: 100% vol. hydrogen
- H_2-Readiness Level B: up to 25% vol. hydrogen blended into natural gas
- H_2-Readiness Level C: up to 10% vol. hydrogen blended into natural gas

For each level, three sub-levels have also been defined depending on the degree of modifications needed to switch to hydrogen at a later stage:

- "No substantial modifications": Limited modifications may be needed, with costs up to 5% of overall plant building costs.
- "Minor upgrading required": Upgrade costs estimated to be up to 10% of overall plant building costs.
- "Upgrading technically and economically possible": Plant is technically suitable to be upgraded, with upgrade costs estimated to be up to 30% of overall plant building costs.

4.2.4 EUROMOT VIEWS FOR POWER GENERATION SECTOR
ENGINES

INSTALLED STOCK

For current stock a 2–3% vol. H_2 injection is not a problem. Methane Number (MN) will not be noticeably affected, and it is even "good" for ignition purposes.

MODERN STOCK

New applications are usually equipped with control equipment systems which allow them to handle wider Wobbe Index (WI) than current installed stock. Yet, EUROMOT believes that there are technical possibilities to limit the WI range to 49–52.7 MJ/m³ and produce biomethane with a WI >49 MJ/m³. Maintaining that WI range helps already substantially to lower the negative issues caused by gas quality variations. This even helps to limit the issues of the blending of natural gas with hydrogen. Additionally, ballasting natural gas and H_2NG with nitrogen does not help to improve the (otherwise) low Methane Number.

4.2.5 EUTurbines VIEWS FOR POWER GENERATION SECTOR
TURBINES

EUTurbines published on September 2021 a paper that provides a common understanding of H_2-readiness for new gas power plants [16]. H_2-readiness is defined by: Share (% vol.) of hydrogen and the technical adaptions needed to reach the desired H_2-readiness level in the future.

It is assumed that the gas grid in the case of blending will not deliver shares above 25% vol. H_2 – above that level there will most likely be a switch to dedicated hydrogen systems in one step. By 2050, that switch should be fully concluded. Based on these assumptions, the gas turbine industry defines H_2-readiness for new gas power plants in three levels, according to the hydrogen content of the gas used:

- H_2-Readiness Level A: 100% vol. hydrogen
- H_2-Readiness Level B: up to 25% vol. hydrogen blended into natural gas
- H_2-Readiness Level C: up to 10% vol. hydrogen blended into natural gas

New gas turbine power plants built today will typically start operating with natural gas for a number of years – until larger amounts of hydrogen become available. However, H_2-readiness considerations are needed when planning and commissioning a new gas power plant – this will determine the level of modifications and related investments needed to operate a new gas power plant at the desired hydrogen level in the future.

The gas turbine industry defines three categories for each H_2-readiness level:

- "No substantial modifications": No substantial modification of the power plant's hardware is necessary to reach the relevant H_2-readiness level. However, the plant may require adaptations in operation, service and maintenance, operating procedures, software etc. Modifications are estimated by the technology supplier to remain up to 5% of the overall costs of building a new power plant. Also, there may be modifications necessary in the gas supply outside the plant.
- "Minor upgrading necessary": The plant is technically suitable and retrofittable to operate with the hydrogen share of the category. Certain modifications of the hardware, software, etc. will be required before being able to operate. Many of the upgrading efforts can be done as part of planned regular inspection and maintenance activities. The technology suppliers estimate the costs for this upgrade up to 10% of the overall cost of building a new power plant.
- "Upgrading technically and economically possible": The plant is technically suitable and retrofittable to operate with the hydrogen share of the category. Certain modifications of the hardware, software, etc. will be required before being able to practically operate with the mentioned hydrogen level. The technology suppliers estimate the costs for this upgrade up to 20% of the overall cost of building this power plant.

The installed fleet has been optimised for natural gas. However, plants may be capable of operating with a small share of H_2 without modifications. Solutions to adapt with limited efforts existing technology to higher shares of hydrogen are available and need to be considered on a case-by-case basis.

Level A **100% H_2**	Level B **25% H_2**	Level C **10% H_2**
A1 no substantial modifications	**B1** no substantial modifications	**C1** no substantial modifications
A2 minor upgrading	**B2** minor upgrading	**C2** minor upgrading
A3 upgrading possible	**B3** upgrading possible	**C3** upgrading possible

Categories

No substantial modifications: Limited modifications may be needed, with costs **up to 5%** of overall plant building costs.

Minor upgrading required: Upgrade costs estimated to be **up to 10%** of overall plant building costs,

Upgrading technically and economically possible: Technology suppliers estimate the cost for this upgrade **up to 20%** (turbine based) – **up to 30%** (engine based) of the overall cost of building this power plant.

Source: EUGINE

4.2.6 EUROPEAN NETWORK OF TURBINES (ETN) VIEWS FOR POWER GENERATION TURBINES[31,32]

Considerable efforts have been launched by all gas turbine manufacturers in order to determine more clearly how much hydrogen can be tolerated by existing gas turbine products, which detrimental effects would be triggered (e.g. higher NOx emissions, reduced lifetime of hot gas path components) and which – immediate and long term – measures could be taken to alleviate the problems, major work still remains to be done in order to qualify gas turbines for high hydrogen content gaseous fuels (mainly hydrogen mixed into natural gas) as well as working on hydrogen only.

The majority of gas turbine OEMs can offer specialised gas turbine products (originally developed for syngas applications) which **can also run on natural gas and hydrogen mixtures with significantly high H_2 content (about 60% vol. H_2, in some cases even up 100% vol.H_2)**. These gas turbine engines, require special combustion technology (diffusion burner, dilution with N_2 and/or steam, water injection) in order to cope with the challenging properties of the highly reactive fuel mixtures, and do most often still not allow the same low NOx emission values (25 ppm) guaranteed by natural gas fired gas turbines.

With adapted Dry Low Emission (DLE) combustion systems OEMs report of successful testing of frontrunner gas turbine products operated with fuel gas mixtures with up to 20% vol. H_2 (or even 30% vol. H_2). In some of these cases a de-rating of the gas turbine engine is still required (de-rating accomplished by reduced flame temperature). Combustor developments with novel combustion concepts (e.g. micro mixing concepts and constant pressure sequential combustion) are also being pursued and have shown promising results on gas turbine test bench installations.

For retrofits, every machine has to be evaluated on a case by case basis for hydrogen consumption, considering fuel skid, controls, and combustion system. As a general guideline, there are break points to consider, namely:

- Low levels of hydrogen mixed with natural gas, to a level that does not require any changes to materials, designs and control and protection. These levels may be considered to be in the range of [0–10% vol.], depending on the existing system.
- Medium levels of hydrogen mixed with natural gas, to a level that does not require significant changes to materials, designs, controls and protection. These levels may be considered to be in the range of [10–30% vol.].
- Higher levels of hydrogen, which require a wider retrofit scope, and which probably then economically suggest that hydrogen fuel capability should be maximized given the assumption of fuel delivery, combustion module, control and protection retrofit [30–100% vol.]

Several OEMs and Independent Service Providers (ISPs) offer gas turbine specific retrofit solutions that are capable to fire up to 30% vol. H_2 in natural gas without exceeding the NOx emission limits of 25 ppm.

31 ETN, Hydrogen Gas Turbines, January 2020

32 ETN, ETN R&D Recommendation Report 2021

4.2.7 CEFIC AND IFIEC VIEWS FOR THE FEEDSTOCK INDUSTRY

From a technical point of view, gas quality variations caused by hydrogen can be handled but there is no "one size fits all" solution and case-by-case assessments are needed since applications and processes are optimized for the typical (historical) natural gas quality at exit point. For sensitive appliances and feedstock processes the Wobbe Index may not exceed a range of 3.7 MJ/m³ (15:15).

Complexity of solution depends on the application and process itself, the installed equipment and the expected hydrogen or by-product content. Installations and industrial processes switching from natural gas to H_2 can be accompanied by very high CAPEX on a cases by cases basis.

In heating/burning processes at least a Wobbe Index detection and a hydrogen detection will be required to control and possibly adapt the process in case of changing gas quality.

For chemical processes, analysis, control equipment and possibly separation equipment (e.g. membrane technology and/or pressure swing adsorption) are required to keep the chemical processes in a stable operation and possibly utilize the hydrogen. The associated costs for installing and operating this equipment are an additional burden in the global competition. As separation processes always require energy, installing such equipment to keep the chemical value chains running is controversial with regards to other EU directives e.g. Energy Efficiency Directive (EED) and Emissions Trading System (ETS) or state aid.

4.2.8 ENTSOG VIEWS FOR TSOs

An internal assessment of TSOs infrastructure readiness for H_2 blends was carried out among ENTSOG members in 2020. ENTSOG's hypothesis, based on the answers received and experience in some countries, is that 2% vol. hydrogen is possible at least in 75% of the gas transmission network without significant investments, and this is the first level ENTSOG members are striving to achieve. Lots of data confirm the hypothesis but the analysis in some countries is not fully completed. For the TSOs where the analysis was not fully completed by the time the questionnaire was launched, further results are expected to be available in foreseeable time as many TSOs are currently screening their assets in order to increase their knowledge and experience concerning the impact of H_2 blends on their infrastructure. In this regard, ENTSOG is currently assessing the technical possibilities and associated costs of retrofitting the gas networks to 2% vol., 5% vol., and 10% vol. H_2. First results will be made public in the first half of 2022. Besides, the H_2GAR results will bring some more inputs to the discussion[33].

ENTSOG members are also aware that further technology developments and information provision have the potential to overcome some of the technical challenges that may result from diversification and decarbonisation of supplies. TSOs are working on getting ready to be able to measure H_2 content. A major deployment of new (or upgraded) devices and 'smart' tools is expected to be required across the network (including at IPs), especially gas analysers to measure H_2 content. Additional gas analysers and tracking systems may be necessary to follow H_2 along the network. In general, the presence of 2% vol. H_2 in the TSO grid does not require relevant investments in gas quality and H_2 measurement and data sharing tools[34]. In some cases, measuring up to 5% vol. H_2 would already be possible[35].

Other mitigation measures for gas quality and hydrogen handling could be the ones included in the list below. Depending on grid topology, mix of gas supply sources, etc TSOs currently have different access to those measures and some could only be performed by other parties.

33 H_2GAR is a collaboration between TSOs in order to share knowledge/information (available or in progress) about H_2NG transportation in order to speed up the injection process and to save effort and resources.

34 However, it has to be highlighted that for some TSOs GCs would need to be replaced to be able to measure even 2% vol. H_2.

35 The scope of the exercise was limited to gas quality and hydrogen measurement and data sharing tools and associated costs.

A. Gas treatment

- Ballasting of gas with nitrogen: Quality conversion with nitrogen ballasting can be used to lower the Wobbe Index of gas flows. To determine the associated annual costs DNV used the annual volume of nitrogen with a cost level of producing nitrogen. For the calculations they used the cost levels for a nitrogen[36] production location of Gasunie Transport Services. The OPEX of a nitrogen plant the size of the existing large scale nitrogen production plant at the Ommen station was 3.3€ct/m³ N_2. Also, the investment costs of a nitrogen plant were reflected in the price of nitrogen. The CAPEX of such a station was €1200 per m³/h N_2 installed. Combining the OPEX and CAPEX elements resulted in a price for nitrogen of 4.9€ct/m³ N_2 [17]
- Addition of LPG to biomethane: Addition of LPG to the biomethane will enrich the gas, thus raising the WI of the blend.
- Removal of higher hydrocarbons at the liquefaction train (LNG): Removing higher hydrocarbons makes the natural gas leaner, thus lowering the WI.
- Further upgrading of biomethane, mainly removing CO_2, but also N_2 or O2 means having a higher concentration of CH_4 in the biomethane, which means a higher WI for the blend, closer to 50.7 MJ/m³ (15/15).
- Blending station: Blending is a gas quality management option where gas with a Wobbe Index below (or above) the defined Wobbe Index bandwidth is blended in a controlled way in a gas flow with a higher (or lower) gas quality to such an extent that the resulting gas flow is above the lower range of the Wobbe Index bandwidth.
- Reformers could produce H_2 from natural gas to keep the blend stable for sensitive end-users. Yet, this is not considered necessary for the 2% vol. H_2 scenario.

De-blending and methanation are not considered necessary in a 2% vol. H_2 scenario. These measures are described in the 10% vol. H_2 scenario section.

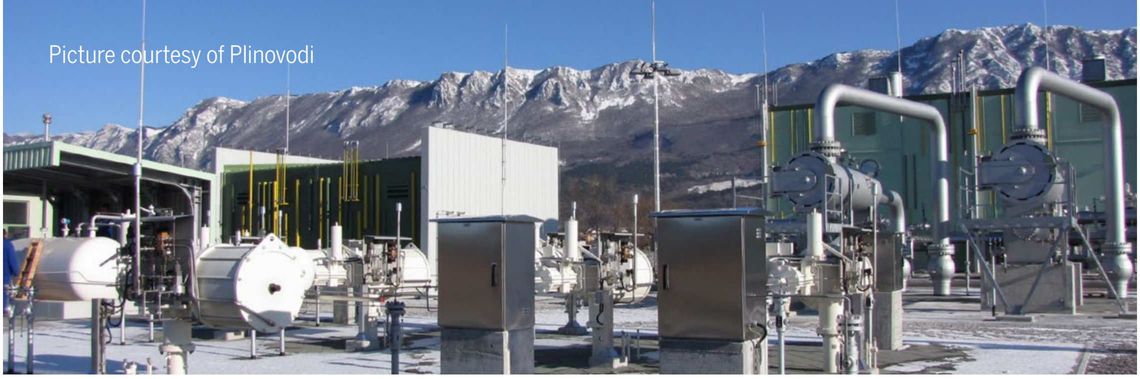
B. Grid management (flows)

- Co-mingling (continuous blending of two gas flows with different gas qualities without actively control the gas flows): blending two gas flows using the topology of the grid.
- Static gradient splitter: Divide flow in 2–3 streams that mix again after transiting at different speed and different distances. It could be used to mitigate large fluctuations on gas quality.
- Parallel pipelines: Similar effect as with static gradient splitter but at larger scale with 2 streams only.
- Swapping of flows: The gas is not flowing as requested by individual nominations, but it is flowing where it is the most suitable from a gas quality point of view while ensuring the nominations are followed on aggregated basis.
- Spreading of flow variations at IPs or at production sites: It means that there is a temporary deviation between the actual flow and the nominations resulting in an Operational Balancing Account (OBA) position and therefore create some OBA position for the duration of the spreading. Flexibility of the system is therefore needed (line pack) to compensate for the increased OBA usage. Agreement with the adjacent TSO is needed as it will face the opposite impact on OBA.
- Reverse flow systems: Depending on regional developments, more reverse flow facilities (injecting gas from DSO grids into the TSO systems) are expected to be commissioned:
  - An installation with a maximum capacity of 8.500 m³/h has a CAPEX of 8–9 M€ (including de-odorization)[37]
  - An installation with a maximum capacity of 1.500 m³/h has a CAPEX of 3 M€ (if de-odorization is not needed)[38]

36 Note: Costs levels for nitrogen depend on the load factor of the installation and are strongly depending on the electricity costs.

37 Based on information provided by a TSO

38 ETN, Hydrogen Gas Turbines, January 2020



D. Limit hydrogen variability at the point of injection

- Injecting hydrogen in pipelines with steady and higher throughput so the share of H_2 is relatively small.
- Coordinated planning and steering of H_2 (and biomethane) injection points: expenditures for gas quality handling like de-blending and methanation could be significantly reduced by collecting, indicating, and assessing H_2 injection requests (e.g., location, capacity, buffer storage size) in the TSOs' national development plans in line with downstream requirements and possibilities (e.g., right for interruption and/or unacceptance of H_2 injections).

Lastly, to safeguard the desired exit pressure:

1. If market circumstances lead to a lower demand and thus the TSO has not to take additional measures, the transported energy could be reduced and/or
2. the pressure could be increased somewhere in between by new compressor stations and/or
3. the pressure loss could be reduced by building pipeline loops.

For option 1, over 6% vol. H_2 the pressure drops in the pipeline with the presence of H_2 and reduces the pipeline peak capacity compared to H-gas. It should however be noted that the capacity of a whole system is determined by its critical bottlenecks. For example, the capacity of a pipeline link consisting of 3 subsequent pipelines is equal to the one with the smallest capacity. On the other hand, many pipelines are not fully utilised because the market conditions changed during the years after dimensioning and construction of those pipelines.. The entry and exit capacities used for market areas could therefore be upheld by upgrading the critical bottlenecks only. Pipeline loops may however be favourable over new compressor stations if sufficient utilisation is expected, since the OPEX of compressor stations would outweigh its lower CAPEX compared to pipelines.

4.2.9 CEDEC, EUROGAS, GD4S, GEODE VIEWS FOR DSOs

It is expected that gas quality tracking systems including forecasts for the Wobbe index, gross calorific value and hydrogen concentration will be needed at DSO level especially for regional grids. The need for this kind of systems will depend on several key points:

- Number of locally connected production sites
- Number of IPs to different upstream systems
- Sensitivity of end-users to gas quality changes
- Potential mitigation measures available
- Size of grid and pressure levels involved

For small grids, tracking systems are not generally needed as the hydrogen level will be the same in the whole grid. As soon as hydrogen is distributed to larger grid areas and e.g. high pressure pipes with line pack ability coming into play, a tracking system can be a good solution.

Although tracking systems will help, the right solution has to be chosen for each DSO and sometimes for each grid area depending on the local situation. The results from ongoing and finished projects provides already an overview of potential solutions and possibilities. For instance, in Freiburg the hydrogen injection of preblended 2% vol. H_2 has been running since 2018 in the middle of a commercial area without any negative effect on the end-users. The results of HyDeploy in UK also show, that even with blends of 20% vol. H_2 the appliances were not negatively affected. For these first projects pre-blending and injecting stable H_2 percentages is a practical way to mitigate risks. Connecting H_2 producers to small H_2 storages is a solution to ensure a stable blend.

Other projects are investigating the installation of a methanisation plant to stabilize the H_2 injection by producing syngas. While larger projects and higher H_2 percentages are assessing the economically and technical feasibility of installing separation systems e.g., membranes to protect sensitive customers.

Regarding the costs for an addition of 20% vol. of H_2 the assumption can be made – also in reference to the various projects – that the adjustment costs of the grid are relatively low.

Lastly, it is worth mentioning that for a deep and sustainable decarbonization of the gas sector biomethane plays an important role as it can be easily integrated into the grid and used by appliances. To increase the number of biomethane plants connected to the grids it is essential to keep the costs of the upgrading process as low as possible. If appliances and applications are able to operate with a wider range of gas quality this will allow a more flexible operation of the grids and keep the costs down to encourage new biogas plant operators to consider the change to a grid injection instead of locally producing electricity and heat.

4.2.10 ENERGY COMMUNITY SECRETARIAT VIEWS

Two main changes would be needed:

- Amending national legislative acts related to gas quality, in order to allow acceptance of hydrogen (by at least 2% vol.) in natural gas mix.
- Introducing relevant and harmonised definitions of hydrogen, biomethane, synthetic gases in national legislation related to gas market and renewable energy sources.

There are no specific costs for proposed legislative adjustment, except for working hours of responsible bodies along the required procedural steps.

4.2.11 GIE VIEWS FOR STORAGES

The major cost components for developing underground storage are cushion gas, site exploration and development, compressors, and other surface and subsurface infrastructure. It is difficult to generalise storage costs because of the wide variety in sizes, operating conditions of storage, and the number of injection and withdrawal cycles. The table below summarises the findings. These estimates are based on literature with a set of assumptions about the storage specifics and the way the storage would be operated (e.g. the number of cycles), which all influence the calculated levelised cost of storage (LCOS). As such, the summary should not be seen as a comparison between different types of storage (that is too premature), but rather an indication of the order of magnitude of the investment and levelised cost [13].

Type of storage	LCOS (€/kg H_2)	CAPEX (€/kg H_2)	Notes
Salt cavern	0.18	29	80,000 m³ [R. K. Ahluwalia et al., “System level analysis of hydrogen storage options,” 2019]
	0.23	NA	Bloomberg, Hydrogen Economy Outlook, 2020
	0.35	25.5	WGC 35,261 tH_2 [DNV GL, Hydrogen in the electricity value chain, 2019.]
	1.34	27.46	A.S. Lord et al., Geologic storage of hydrogen: Scaling up to meet city transport demands,” International Journal of Hydrogen, Volume 39, September 2014.
	NA	82€million	500,000 m³ [M. Reuß et al., “Seasonal storage and alternative carriers: A flexible hydrogen supply chain model,” Applied Energy, Volume 200, 15 August 2017]
Depleted gas field	1.02	17.41	WGC 1,912 tH_2 [A.S. Lord et al., Geologic storage of hydrogen: Scaling up to meet city transport demands,” International Journal of Hydrogen, Volume 39, September 2014.]
Aquifer	1.07	17.8	WGC 1,912 tH_2 [A.S. Lord et al., Geologic storage of hydrogen: Scaling up to meet city transport demands,” International Journal of Hydrogen, Volume 39, September 2014.]
Hard rock cavern	2.3	38.91	WGC 1,912 tH_2 [A.S. Lord et al., Geologic storage of hydrogen: Scaling up to meet city transport demands,” International Journal of Hydrogen, Volume 39, September 2014.]

Table 2: LCOS and investment cost (CAPEX) estimations for hydrogen underground storage [13]

5 SHORT/MID-TERM **DEVELOPMENTS**

In this regard, in the short/mid-term it is likely that different pathways will coexist: methane backbone (using natural gas, biomethane and/or syngas), hydrogen blending and the incipient development of the European Hydrogen Backbone (EHB) at TSO[39] and DSO level.


Picture courtesy of Gasunie Deutschland GmbH & Co. KG

These developments could be expected by 2025–2030 but, as previously stated, since the choices and decisions are influenced by the overall EU climate and energy policies and will differ amongst EU Member States, what might be seen as a short-term development for one country may be a medium/long-term one for another. Hence, it is not possible to define concrete timelines for each specific development.

Since the biomethane injection is expected to increase in upcoming years, biomethane (and synthetic methane in some cases) will continue to replace unabated natural gas. On the other hand, hydrogen blends in the system could reach up to 10% vol. H_2 and 20% vol. in projects/hydrogen valleys[40]. Although some end-users could consume such blended gas, the use of de-blending and methanation facilities will start becoming more widely available in order to supply sensitive customers with the requested gas quality.

It is to be expected that in this timeframe more dedicated hydrogen projects will be commissioned[41]. Within the European Clean Hydrogen Alliance (ECHA), hundreds of hydrogen projects have been collected which already gives a positive signal about the expected developments in the short/mid-term.

39 The EHB vision shows that by 2030, separated hydrogen networks can develop, consisting mainly of repurposed existing natural gas pipelines. These initial stretches include the proposed Dutch and German national backbones, with additional sections in Belgium and France. Hydrogen networks were also expected to emerge in Denmark, Italy, Spain, Sweden, France, and Germany, Hungary, UK and Finland [4].

40 For instance: Avacon netz **website**, WestKüste 100 project **website**

41 For instance: **"Zukunft der Gasverteilnetze: reiner Wasserstoff"**, Stad Aardgasvrij project **website**, H100 Fife project **website**, GreenHysland project **website**

5.1 CHALLENGES IN GAS QUALITY AND H_2 MANAGEMENT

5.1.1 EUROPEAN HEATING INDUSTRY (EHI) VIEWS FOR RESIDENTIAL & COMMERCIAL SECTOR

Foreseeably there will be increasing regional differences in gas blends used for heating during this period – whether methane, biomethane, methane-hydrogen blends (i.e., H_2NG) or possible hydrogen islands. The installed stock will have to handle a growing range of gas mixes. No technological challenges on the equipment side are foreseen. It is expected that the necessary technologies are market-ready and the roll-out of hydrogen-ready appliances is well underway. As stated above, stalling replacement rates for modernizing heating systems, however, risk slowing down the process.

5.1.2 EUGINE VIEWS FOR POWER GENERATION SECTOR
ENGINES

In the short/mid-term the situation should not be fundamentally different from today. Existing engines, not build following a H_2-Readiness standard, can generally be retrofitted. See section 4.2.3 for furter information.

5.1.3 EUROMOT VIEWS FOR POWER GENERATION SECTOR
ENGINES

Depending on the base natural gas composition, new applications will be able to handle higher hydrogen percentage than up to 5% vol. to up to 20% vol. H_2 although the resulting end gas quality range should be limited and stable.

In 10 years' time (approx. 2030), it could be expected that there are engines on the market for 100% vol. H_2 that provide only a 10% decrease of specific output power in comparison with the current natural gas ones.

Retrofitting existing carburettor-based engines (a gas-air mixture in the intake manifold) can be more complex than engines with port injection systems. Retrofitting naturally-aspirated engines will always result in a considerable power and fuel efficiency loss. Further, as soon as a new control strategy is required based on signals from the gas supplier, existing control systems might be inadequate and might have to be replaced. This will substantially add costs to the retrofit. In addition, retrofitted installations will have to comply with the ENTSOE rules for grid connection which might even require the replacement of the generator[42].

5.1.4 EUTurbines VIEWS FOR POWER GENERATION SECTOR
TURBINES

In the short/mid-term the situation should not be fundamentally different from today. Existing gas turbine-based power plants can generally be retrofitted but the assessment needs to be done on a case-by-case basis.

42 Note: This is only the case if the engines are used for the production of electricity at TSO level or for regional CHP installations.

5.1.5 CEFIC AND IFIEC VIEWS FOR THE FEEDSTOCK INDUSTRY

From a technical point of view, gas quality variations caused by hydrogen can be handled but there is no "one size fits all" solution and case-by-case assessments are needed. For high H_2 percentages (e.g., 10% vol. H_2), there exists a great uncertainty about the possibilities to handle H_2 due to the great differences between current processes and technology installed.

The complexity of solution depends on the application/process itself, the installed equipment and the expected Hydrogen or by-product content.

In heating/burning processes at least a Wobbe Index detection and a hydrogen detection will be required to control & possibly adapt the process in case of changing gas quality.

For chemical processes, analysis, control equipment and possibly separation equipment (e.g. membrane technology and/or pressure swing adsorption) are required to keep the chemical processes in a stable operation and possibly utilize the hydrogen. The associated costs for installing and operating this equipment are an additional burden in the global competition. As separation processes always require energy, installing such equipment to keep the chemical value chains running is controversial with regards to other EU directives e.g. EED, ETS or state aid.

5.1.6 ENTSOG VIEWS FOR TSOs

The general explanations provided in the 2% vol. H_2 scenario section are still valid for 10% vol. H_2.

1. TSOs' ASSETS

Compared to a 2% vol. H_2 scenario, more assets require detailed analyses. For pipelines, valves, volume converters, and flow measurement equipment a general suitability for 10% vol. H_2 is still expected. For pipelines, the effect on the maximum throughput capacity could yet become visible: Mainly depending on the base gas and the pressure level, the transport capacity of a pipeline could decrease by a few percent. Most existing[43] GCs cannot measure H_2 shares of up to 10% vol. There are already in the market GCs that can measure up to 20% vol. H_2[44]. On the other hand, there is a lack of information on analysers currently used in the field for H_2.

Besides, nowadays, there are no recommendation or standards associated to the measurement of H_2 in the grid. The ongoing project on "Removing the technical barriers to use of hydrogen in natural gas networks and for (natural) gas end users" funded by the European Commission is reviewing the current scientific and technical framework concerning the use of hydrogen, and drawing from this review a gap analysis which can then be translated into a set of pre-normative research (PNR) requirements.

This work will then contribute to the process of standardisation for the introduction of hydrogen into the gas networks and for end users[45].

Furthermore, the reduced maximum pressure ratio of the turbo compressors requires attention. Depending on the gas temperature and pressure level, also the required compressor drive power increases notably. Some gas turbines are declared as not suitable over 2% vol. hydrogen in the fuel gas by the OEM[46]. Here, retrofitting or replacement becomes necessary.

In a meshed network, only the individual transport capacities of the systems' bottlenecks are however determining the entry and exit capacities of the market area. Thus, for other parts of the system, a certain transport capacity decrease would not be crucial.

Many TSOs are currently investigating the readiness of their assets for blends including the question how to maintain the desired peak transport capacities of bottleneck sections, which is the most important parameter for the system development.

Picture courtesy of Gasum

43 Note: if GCs are replaced for 2% vol.H_2, they will (in general) be able to measure up to 10% vol. as well

44 CEN & GERG Pre-Normative Research (PNR) study provides an overview of available GCs certified to measure H_2 up to 20% vol.

45 GERG is delivering this project on behalf of CEN

46 Based on one TSO own experience with turbines OEMs

2. GAS QUALITY

A. Gas quality parameters in standards

One of the most sensitive common gas quality parameter seems to be the relative density. Depending on the initial composition of natural gas, between 4% vol. (Russian gas) and 15% vol. of added hydrogen would bring the relative density below 0.555, which is the lower limit defined in EN16726:2016.

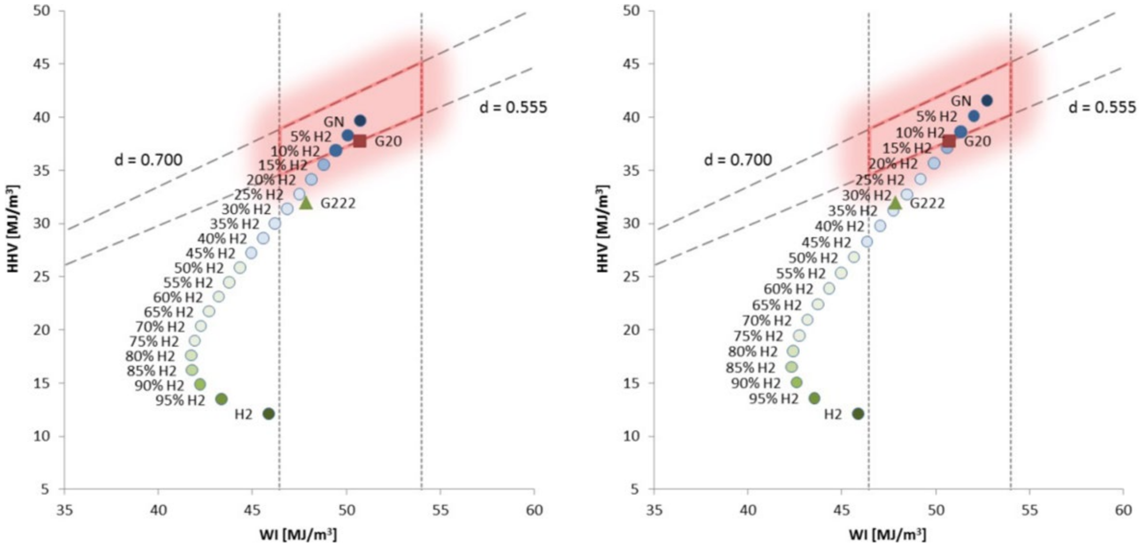


Figure 5: Influence of H_2 addition on GCV (HHV) and Wobbe Index of typical pipeline gas (left) and LNG (right) – shadow red area defined EASEE-gas CBP limit for reference purposes.

Other affected parameters besides the H_2 share itself are the methane number, the Gross Calorific Value (GCV), and the WI. With fluctuating H_2 shares, also the bandwidth of these parameters will increase.

For some natural gas compositions, e.g. from Russia, the lower limit of the relative density parameter could effectively restrict the H_2 share to approximately 4% vol. For biomethane with high CH_4 shares, similar thresholds are valid based on the complete composition.

When H_2 is injected into low-processed biomethane, also WI and GCV lower limits[47] could be breached below H_2 levels of 10% vol.

B. Gas quality forecasting

Some sensitive end users are asking to receive gas qualities with narrower specifications than stipulated in the national gas quality standards or a guarantee that a certain H_2 share will not be breached. This would require the use of forecasting and other gas quality management tools (e.g., de-blending). In this context, cooperation, and information exchange among relevant market players (upstream operators, shippers, producers, TSOs, DSOs, consumers, etc) on gas quality and quantities to improve forecasts on gas quality variability should be promoted. Yet, since forecasting gas quality at individual exit points is not a capability that TSOs have at present, it may be difficult to achieve a robust assessment, particularly for networks with a high level of supply diversity and variable demand pattern. This will be even more challenging when H_2 is injected in the system. Using conservative forecasting assumptions (e.g., dynamic changes of entry and exit patterns as well as entry gas qualities in the full range set out in the Interconnection Agreements) would lead to oversized or redundant mitigation measures. A reasonable balance must be found between the investment in these measures and risk aversion. Besides, up to now there is no reliable or accurate data related to future upstream gas qualities, so there is a limit until which TSOs can provide forecasts. This might not be enough for users to adequately manage their gas quality risks. In any case, TSOs support carrying out a transparent cost-benefit analysis (CBA) including the whole gas value chain from producer to end user to find cost-efficient solutions.

47 These limit values are not part of EN16726 but from national gas quality standards.

5.1.7 CEDEC, EUROGAS, GD4S, GEODE VIEWS FOR DSOs

At the DSO level the challenge is to plan a stable system that can cope with different injections of methane (including biomethane and syngas) and hydrogen based gases, variable consumptions of active consumers, and blends coming from the TSO side. As described in the previous section, the ongoing development of the forecasting systems combined with tracking systems by several DSOs in Europe can offer experiences and lessons learnt for others. Experiences from past developments of forecasting, systems the more precise a consumption and flow forecast has to be, the higher the associated costs.

Between 2025 and 2030 the first pipelines at TSO level will be repurposed to 100% vol. hydrogen. Depending on end-users ability or capacity to retrofit or replace their systems to run on hydrogen, the planning of the conversion at DSO level will go ahead. The picture below shows a generic potential pathway that for example a regional grid operator could carry out to retrofit/repurpose the grid in one region. Any conversion process to dedicated H_2 systems will be jointly coordinated with TSOs, adjacent connected DSOs, large industrial end-users as well as CHP plants, specialised conversion technicians and local installers. In countries like Germany, Netherlands, Belgium and France such conversion processes have already been carried out due to the ongoing H-/L-Gas switch (and the gas switch from town gas to natural gas in the 90s in eastern Germany). Experienced gathered during those processes will facilitate the conversion to hydrogen.

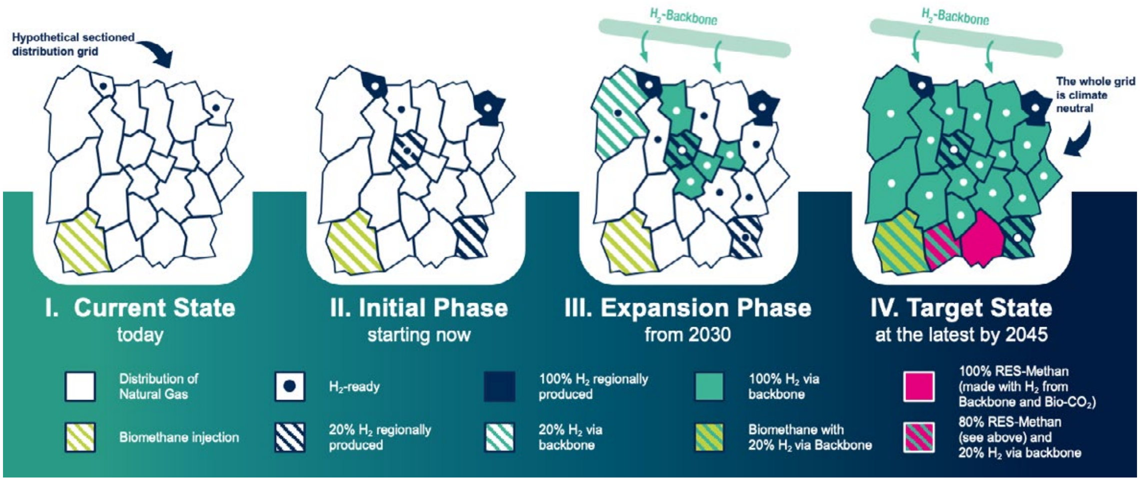


Figure 6: Example of grid conversion planning. Source: H2vort

In order to achieve a cost-effective decarbonisation of the grid, flexibility is key on all sides of the market. Having new appliances and applications in the market being able to handle different types of gases will help the integration of renewable and low-carbon gases e.g. the most recent CHP project in Hamburg [18] or the CHP plant in Hassfurt [19] or Vienna[48] . The substitution of large CHP plants with heat pumps, geothermal energy or waste heat is not sufficient in many regions to deliver enough heat during winter with a sufficient security of supply and at the needed temperature. The coal to gas switch is ongoing in several countries while in others, like Germany, many new gas fired power plants are needed to substitute the phase out of nuclear power plants and complement the renewable electricity production. The new German coalition contract demands that they are built hydrogen ready

The proposal of 49% renewable energy in heating (RED II) and the stricter rules of the taxonomy have already led to an increased interest in the use of renewable and low-carbon gases. the proposed targets for energy efficiency and the definition of efficient district heating (EED) triggers the discussion between operators of district heating systems and their connected gas grid operators about the timelines (i.e., when the different sectors will be ready to handle hydrogen). This will be of critical importance for a cost-efficient and timely decaborbisation of the whole sector.

48 APA-OTS: "Grünes Kraftwerk: Weltweit erster Wasserstoff-Betriebsversuch in Wiener Gasturbine geplant"

5.1.8 ENERGY COMMUNITY SECRETARIAT VIEWS

As previously described, the existing legal gap at the interfaces between European Member State (EU MS) and Energy Community's Contracting Party (EnC CP) (voluntary implementation of existing Network Codes by EU MSs at the borders with the third countries) could hinder cross border flows of biomethane and hydrogen in the near future.

Besides, since the production and injection of hydrogen and biomethane will most probably happen at local level first, i.e. at distribution networks, it is expected that reverse flows from distribution to transmission network are enabled and therefore quality control in the opposite direction will be needed. This means a change in current responsibilities for gas quality management and new potential issues may arise, for instance, due to odourisation.

5.1.9 GERG VIEWS FOR R&D

GERG Hydrogen Research Roadmap 2021 [14] has identified the key R&D elements emerging. In regards to gas quality, those elements are:

- Blending methods and potential improvements to fulfil metrology and quality requirements of the final H_2NG.
- Energy content calculation of H_2NG with high accuracy by updating the state equations of H_2NG, along with sufficiently accurate measurement and tracking.
- Impact of H_2 and H_2NG on energy efficiency compared to natural gas.
- Reference test gases suitable for H_2NG.

5.2 POTENTIAL SOLUTIONS & ASSOCIATED COSTS

5.2.1 EUROPEAN HEATING INDUSTRY (EHI) VIEWS FOR RESIDENTIAL & COMMERCIAL SECTOR

SOLUTIONS

Heating appliances rolled out from 2025 onwards can adapt to different hydrogen-methane blends depending on the regional gas mix. For those regions that decide to switch to 100% vol. hydrogen, new appliances will be convertible at marginal costs via a dedicated conversion kit. Thus, any lock-in effects will be avoided for consumers.

Varying gas quality due to changing methane-hydrogen blends could also be balanced by self-adjusting appliances in the residential sector. Current hydrogen test programmes from manufacturers as well such as the THyGA project tend to confirm that biomethane-hydrogen mixtures do not have severe impacts on the efficiency of the boiler.

With improved real time gas quality data on site, adjustments of high-capacity burners (>70 kW) and decentralised radiant heaters to methane-hydrogen mixtures can be properly made. These appliances could be converted directly to 100% vol. hydrogen.

COSTS

With a focus on the appliance, the large-scale decarbonisation of gas-based heating systems via green fuels – biomethane and renewable fuels from non-biological origin (RFNBO) such as hydrogen – is cost-efficient for end-users and can provide a unique opportunity for low-cost decarbonisation of buildings. The switch to biomethane does not lead to any additional costs for end-users. Current estimates for additional costs for hydrogen-ready appliances are based on aggregated figures from EHI members. These prices can drop in the future, also depending on quantities built.

The increased purchase price of hydrogen ready appliances compared to natural gas appliances using the same technology is very limited[49]. For the condensing boilers, it is around 17% . compared to a natural gas boiler. The added cost for the hydrogen conversion kits to enable the switch from natural gas to 100% vol. hydrogen represents around 13% of the natural gas boiler purchase price.

For the heat pumps, whether thermally-driven or hybrid, the total price increase for the consumer (i.e. with the conversion kit included) is marginal. For the thermally-driven heat pumps, it is no more than 6% while for hybrids, it is about 8%. As the price of hydrogen and biomethane is expected to be competitive with natural gas in between 2030 and 2050, no increase in fuel price has been taken into account. More details on the exact average cost estimates can be found in the EHI position paper on the use of green gases for heating[50].

49 Please note the figures are EHI aggregated current estimations.

50 EHI position paper on the use of green gases for heating

Moreover, EHI is currently assessing the increased price for a 100% vol. hydrogen appliance. The EHI position paper on green gases for heating will be updated to include the estimate compared to a natural gas appliance.

Economies of scale can have a substantial positive influence on the costs for hydrogen ready boilers and hydrogen conversion kits. To ensure stability for market actors and end-users, clear frameworks to support the transition to hydrogen-ready heating are necessary. A stable and well-designed regulatory framework can help support the accelerate rollout of future-proof appliances based on a competitive market. By definition this does not allow for future inflation.

5.2.2 EUGINE VIEWS FOR POWER GENERATION SECTOR ENGINES

In the short to mid-term, most new engines will be H_2-Ready, that is, capable to run on a given share of hydrogen and/or to be retrofitted with limited efforts once hydrogen or higher shares of hydrogen become available. For further information on the EUGINE H_2-Ready concept, see section 4.2.3.

5.2.3 EUROMOT VIEWS FOR POWER GENERATION SECTOR ENGINES

Most gas engines produced by EUROMOT member companies will be, after some form of upgrade, or are already able to operate on blends composed of up to 20% vol. hydrogen[51]. Since the combustion behaviour of hydrogen differs considerably from natural gas, EUROMOT suggests that hydrogen blends of in between 20% vol. and 100% vol. should be precluded. Fine tuning' engines to run on different gases is possible, but it is not possible for an engine to run on a wide range of different gases at the same time. Also the rate of change in gas quality should be limited, where the maximum rate of change depends on the gas quality.

EUROMOT brings to the attention that when planning local H_2 injection in distribution networks (especially ring systems) gas quality fluctuations and plug flow needs to be taken into account.

5.2.4 EUTurbines VIEWS FOR POWER GENERATION SECTOR TURBINES

In the short to mid-term, most new gas power plants will be H_2-Ready, that is, capable to run on a given share of hydrogen and/or to be retrofitted with limited efforts once hydrogen or higher shares of hydrogen become available. For further information on the EUTurbines H_2-Ready concept, see previous section.

Already in 2019, the gas turbine manufacturers committed themselves to providing customers with gas turbines that can handle a share of 20% vol. hydrogen by 2020 and to meeting demand for gas turbines operating with 100% vol. hydrogen by 2030 [20]. The gas turbine manufacturers are developing new dry low emission burners that aim at handling up to 100% vol. hydrogen – the most sustainable and efficient option, while ensuring safety and compliance with emission requirements.

51 Assuming gas quality boundary conditions as WI range from 49.0 to 52.7 MJ/m³ (15/15 °C) and MN >70 (calculated via the method included in standard EN 16726:2015).

5.2.5 EUROPEAN NETWORK OF TURBINES (ETN) VIEWS FOR POWER GENERATION TURBINES[52,53]

For current installed stock, hydrogen blends between 0–10% vol hydrogen in natural gas, no changes to combustion hardware or fuel delivery system are expected. Minor modifications are necessary to control system/instrumentation (e.g., fuel gas chromatograph compatible with hydrogen). Depending on the governing legislation, modifications to the natural gas pipeline network might be required leading to significant costs.

Several OEMs and ISPs offer gas turbine specific retrofit solutions that are capable to fire up to 30% vol. H_2 in natural gas without exceeding the NOx emission limits of 25 ppm. In such cases, upgrades are required of combustion systems, fuel system, controls, instrumentation and electrical equipment. Above 25% vol. hydrogen, ATEX compliance has to be taken into account.

For high hydrogen concentrations (>50% vol. H_2) European projects are ongoing to develop and demonstrate the applicability at full scale/full pressure of potential low emission, reliable (safe ignition, stable flames) combustion technologies also allowing for high operational flexibility. Valuable results will become available to apply in new build and retrofit solutions within the coming years.

5.2.6 CEFIC AND IFIEC VIEWS FOR THE FEEDSTOCK INDUSTRY

Switching installations and industrial processes from gas to H_2 can be accompanied by very high CAPEX, e.g. in chemical processes using natural gas as feedstock, separation technologies might be required depending on absolute level of Hydrogen. The possible rate of change of Hydrogen content must be considered when designing the separation process.

A possible design for separation of Hydrogen blended natural gas is presented below:

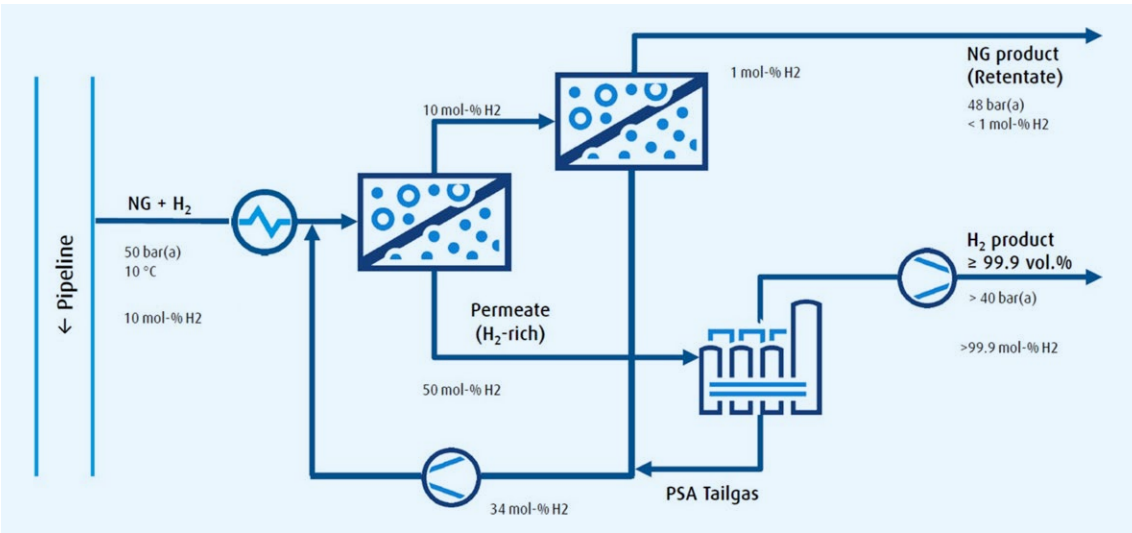


Figure 7: Possible set up for separation of hydrogen blended in natural gas [21].

Also, knowing the type of gas coming to the installation and when it is expected to come will be necessary. The associated costs for installing and operating this equipment are an additional burden in the global competition.

52 ETN, Hydrogen Gas Turbines, January 2020

53 ETN, ETN R&D Recommendation Report 2021

5.2.7 NGVA VIEWS FOR THE MOBILITY SECTOR

It is currently under discussion whether 10% vol. H_2 might be achievable by some manufacturers for ICE vehicles. Transition towards 100% vol. H_2 for mobility sector might be one solution in the long run.

The present CNG infrastructure can be a platform for delivering also pure H_2 in future, as another fuel sold separately form the natural gas. Dedicated H_2 small scale infrastructure could also be an option in the future.

5.2.8 ENTSOG VIEWS FOR TSOs

1. TSOs' ASSETS

A study carried out by French operators [6] showed that to date only limited adaptations are required to be able to inject 6% vol. hydrogen into the networks. The real first investment threshold has been identified at around 10% vol. (retrofitting of compressors). The challenges listed in the previous section require further analysis by TSOs. A general mitigation measure could be to limit the H_2 share at transmission parts of the TSOs' systems to a value below 10% vol., but to allow higher shares in unidirectional parts of the system where a backflow to a compressor station can be excluded. End-user requirements could then also be included in the exercise of identifying reasonable grid parts for such higher H_2 shares.

2. GAS QUALITY

The increased variability of gas quality parameters will require more sophisticated tools that are described below. Solutions to manage gas quality presented for 2% vol. H_2 are also valid for this scenario.

A. Gas quality tracking and metering

- Quality tracking (QT) tools are advanced calculation tools that allows for the system in its entirety to be simulated and the quality to be determined by the simulations. Acceptable errors and variations must be determined also in the case of implementing a QT system, but this type of tool allows for higher precision and thus reduced risk of unacceptable errors. Although QT systems have been implemented and used for some time, they are still seemingly not well regulated. As the operation of a QT system will require resources it remains to be determined at which levels and grids this type of system should be implemented in, and how to share the costs. However, it should be noticed that if successfully implemented with an acceptable high precision, QT system can reduce costs as it can replace the need to install multiple GCs at exit points with small flows.
- Many Gas Chromatographs would have to be replaced to enable a 10% vol. H_2 share. However, once GCs are replaced, they could handle up to 25–30% vol. H_2. Such a GC is approx. 30.000€ more expensive than a standard one. GCs are usually replaced approx. every 10 years, so replacing them cost-efficiently is possible.
- New GCV, WI or H_2 analysers (depending on the case) will need to be installed at some points in the grid to support the GQ tracking and for industrial customers that may need near-real-time GQ data. H_2 analysers are not yet commercially available but costs are expected similar to GCV or WI ones[54].

54 See example of ENGIE lab Crigen here introducing WobHylis®, a complete product to determine precise Wobbe index and calorific value of blends from Natural Gas and H_2 by algorithmic correlation-based and introducing a continuous online H_2 measurement.

B. De-blending[55]

Another possible solution is to utilise the gas transmission and distribution networks to transport hydrogen/methane blends within the existing pipelines and "de-blend" the mixed gas streams at scale on a regional basis. If proven to be technically and economically feasible, the concept could provide a credible pathway to achieving the transition from <20% vol. hydrogen/methane blends to a fully decarbonised gas network, whilst providing the added optionality for sensitive customers requiring natural gas with only a low H_2 share during the transitional phase to a fully decarbonised gas network. This method of distributing low carbon hydrogen would allow certain sensitive consumers, such as feedstock industries, to continue to receive a steady supply of natural gas (or biomethane or syngas) without disruption to the transition of the gas network. Other consumers, such as early adopters of hydrogen, will conversely be able to receive a hydrogen gas stream. Therefore, this technology maintains optionality for consumers during the transition to a low carbon gas network.

An example[56] is provided below:

H_2 transport from Baumgarten to Linz (steel industry): CAPEX of €347 M

- H_2 injection facility including compressor station: €43 M
- Upgrade of relevant section of WAG pipeline (compressor, pipeline, and metering stations) for 4% vol. H_2: €146 M
- De-blending facility at break-out point on WAG pipeline: €60 M
- New pipeline section between breakout point and steel works: €98 M

Another example of de-blending costs is provided in the study carried out by Cadent, National Grid Gas Transmission, Northern Gas Networks, SGN, Wales & West Utilities "Hydrogen Deblending in the GB Gas Network." [22]

CEFIC/IFIEC inputs to part I of this roadmap [23] included a rough estimation of costs for deblended H_2 of 1–2€/kg H_2 (for a mixture of 10% vol. H_2 in NG and considering only deblending costs)[57].

C. Methanation[58]

Producing synthetic methane from hydrogen and CO_2 using a methanation process is a possible alternative to the gradual adaptation of the network to the transport of CH_4/H_2 gas mixtures. Several experiments are underway to accelerate the technological maturity of different methanation technologies [6]. Methanation CAPEX are expected to decrease to approx. 500€/kW of CH_4 (GCV) in the next 10 years[59]. This solution can be advantageous for areas where there are options to have point sources of CO_2 for example after upgrading raw biogas.

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55 Marcogaz views on de-blending: it can potentially be technically complicated to implement de-blending in a commercial scale above pilot tests. The reason is that de-blending creates an output of two separate gas streams with different physical properties, which shall be used by two different segments of customers connected to two different grids. The consumption in the two different segments will not fluctuate simultaneously with the exact same consumption profile. This means that de-blending must be implemented with one of the following options: • Gas storage facilities for one or both output gas streams are available and connected to the system • The two separate grids have alternative supply sources available • Separated and non-used hydrogen is compressed and distributed to consumers by truck • Separated and non-used hydrogen or natural gas is compressed and re-injected into the grid. This option will have to observe potential effects on the gas quality in the grid. As an alternative to de-blending with the purpose of removing hydrogen from the gas to sensitive industrial customers, such customers can potentially be supplied with LNG/LBG instead.

56 Developments in blending and deblending of hydrogen in the gas networks are ongoing in multiple European countries, including Germany, France, and Spain [39].

57 CEFIC and IFIEC note: As it is expected that the blended gas mixture is more expensive than the natural gas without hydrogen (meaning the hydrogen is not free of charge), the cost for hydrogen (or natural gas; whatever your target product is) taken out of a blend will be even higher (which means for hydrogen a price at least doubling compared to the current H_2 production costs based on SMRs and ATRs).

58 Marcogaz views on methanation: Methanation is a process which produces methane with H_2 and CO_2 as feedstock. Methanation processes can be biological or catalytic, and both technologies have been demonstrated (in e.g. the Store & Go project and other projects). CO_2 can be sourced from biogas plants, power plants, waste incineration plants or industry using carbon capture technologies. CO_2 from biogas plants delivering biomethane to the gas grid is in particular interesting, since the CO_2 is already separated from the biogas and released to the atmosphere as part of the biogas upgrading process. Since the produced methane meets the quality specifications for the gas system, the distribution and utilisation of the delivered gas will be completely without constraints and complications, and the offtake capacity will be practically unlimited.

59 Based on a TSO input.

D. Optimum geographical location

It is expected that expenditures for gas quality handling like de-blending and methanation could be significantly reduced by collecting, indicating, and assessing H_2 injection requests (e.g., location, capacity, buffer storage size) in the TSOs' national development plans in line with downstream requirements and possibilities (e.g., right for interruption and/or unacceptance of H_2 injections).

More information will be available when ENTSOG finalises the assessment of the technical possibilities and associated costs of retrofitting the gas networks to 2% vol., 5% vol. and 10% vol. (expected by mid-2022).

5.2.9 CEDEC, EUROGAS, GD4S, GEODE VIEWS FOR DSOs

For grids operated with H_2 blends the potential mitigations solutions are similar to the ones used at the TSO level, but usually much smaller and decentralized:

- Methanisation, if green CO_2 is available[60]
- Tracking systems, that allow a very precise billing even in blends
- Membranes for sensitive customers
- Converting special areas of the grid to 100% vol. H_2 if sufficient H_2 is available. This development will be driven by the need of industrial consumers and CHP plants to decarbonize due to the various applicable legislative requirements e.g. ETS or Taxonomy.
- If many end-users are connected with a gas applications sensitive to changes in H_2 content a secondary controllable H_2 production site could be a solution. With the development of the pyrolysis or plasmalysis technology with methane, waste, waste-water or others as a feedstock, hydrogen from electroylsis can be combined locally to ensure a high level of security of supply and stable H_2 blend levels. This is also important in areas where the amount of renewable electricity is not sufficient.
- Local storages e.g. high pressure pipeline storage, which has been in place already in the past to optimize grid capacities, as well as new hydrogen storage technologies, such as the metal hybrid ones.
- Active customers with the possibility to shift their demands. District heating systems with their heating storages or industrial end-users operating their own CHP plants are especially interesting.
- Reverse-flow stations delivering gas to higher pressure levels of the DSO or TSO if the amount of gas produced exceeds the grid capacity. The cost benefit of this solution depends on how often they are needed, whether the gas has to be de-odourized and to which level the gas has to be compressed.
- Connecting DSO grids between each other
- Optimizing line packs
- And many more that are not yet know today

The choice of the solution will depend very much on the local situation. Many solutions need several actors to be involved e.g. end-users, producers, suppliers. The experiences from the many ongoing projects around Europe and the information sharing among players will help to find the most cost-efficient solution.

5.2.10 ENERGY COMMUNITY SECRETARIAT VIEWS

EnC believes that when defining the rules for the EU and their implementation at the borders to the third countries it is important to ensure that cross-border flows are maintained, and current natural gas transit countries are not overseen in the process.

Besides, new gases will bring changes in flow patterns, and thus share of responsibilities, obligations and communication between TSOs and DSOs is one of crucial topics to be defined by the new gas package, and then elaborated further by amendments of existing Network Codes and most probably by introduction of new secondary acts.

60 For instance, CCUS combined with CO_2 pipeline transport could be used in large industrial installations that need the methane molecule for their processes, as envisaged by the latest communication of the EU Commission (COM (2021) 800 Final)

5.3 RECOMMENDATIONS

5.3.1 EUROPEAN HEATING INDUSTRY (EHI) VIEWS FOR RESIDENTIAL & COMMERCIAL SECTOR

Increased energy system efficiency and deep decarbonisation of buildings are key to fulfil the EU Green Deal. Achieving the targets for heating in a cost-optimal manner will require the use of both electrons and molecules. Action at EU level, such as via the Fit for 55 package, must secure the use of green gases including hydrogen for heating. If heating appliances are 'green' gas ready, Member States and regions will have maximum flexibility in selecting the most suitable decarbonisation pathway for their local conditions.

Space and water heaters that are sold today, are on the market for an average of 15 to 24 years[61]. This means the right framework conditions must be set now to avoid fossil fuel lock-ins and ensure that consumers have access to heating appliances compatible with a decarbonised gas grid. It is a necessary and welcome step that ecodesign and energy labelling requirements take this into account.

To facilitate this, the roadmaps for the market uptake of heating appliances capable of processing green gases and the roadmaps for green gas uptake in the gas infrastructure need to be synchronised. EHI welcomes that the European Commission services have taken some actions to include measures on the greening of energy carriers in ecodesign and energy labelling proposals, such as the ecodesign requirement for 20% vol. hydrogen, bio-methane and bio-fuels. However, the proposed measures will not lead to a cost-optimal and affordable energy transition and some measures will even be counter-productive.

WHAT DO WE SUGGEST?

- Deletion of the suggested Primary Energy Factor (PEF) correction of 1.65 on the energy label for hydrogen ready appliances, because this will leave consumers with stranded investments in case of a full conversion to hydrogen (Energy labelling space heaters, Annex III, Labels 6 and 7; energy labelling water heaters, Annex III, Point 5). Why?
  - The PEF for grid electricity stems from the Energy Efficiency Directive.
  - The suggested concept for the PEF assumes hydrogen production from fossil gas – but that it is not an option.
  - Envisaged concepts for large new hydrogen production installations rely to a large extent on electrolysis based on dedicated renewable electricity capacities, outside of electricity markets.
  - The PEF for renewable based electricity in the calculation of the PEF in the energy efficiency directive is set at 1, regardless the conversion efficiency, the same should apply to the PEF for hydrogen.
- At least 2 years after the review ecodesign and energy labelling regulation for space heating and water heaters enters into force, i.e. 2026–2027:
  - to introduce an optional pictogram on the energy label for the purpose of raising awareness, indicating the capability of appliances to use (Energy labelling space heaters, Annex III; Energy labelling water heaters, Annex III):
    - biomethane, e-methane, bio LPG;
    - a variable share of hydrogen of up to 20% vol. (in combination with biomethane or natural gas);
    - 100% vol. hydrogen.
    - to introduce an ecodesign requirement for the following gas fired appliances to work with a variable share of hydrogen of up to 20% vol. (in combination with biomethane or natural gas) (Ecodesign space heaters, Annex II, Point 4; Ecodesign water heaters, Annex II, Point 1.3):
    - all models of heaters (space and combination, including B1 boilers) ≤70 kW
    - new models[62] of heaters (space and combination, including B1 boilers) >70 kW;
    - new models[63] of water heaters;

61 Review study of ecodesign and energy labelling for water heaters and tanks Task 5, VHK, for the European Commission, July 2019.

62 New models means models of which no units were placed on the market prior to the application date

63 CEN & GERG Pre-Normative Research (PNR) study provides an overview of available GCs certified to measure H_2 up to 20% vol.

- When a technical update is needed after 2026 in view of ecodesign requirements: to introduce an ecodesign requirement for the following gas fired appliances to work with a variable share of hydrogen of up to 20% vol. (in combination with biomethane or natural gas) (Ecodesign space heaters, Annex II, Point 4; Ecodesign water heaters, Annex II, Point 1.3) (see detailed reasoning):
  - existing models[64] of heaters (space and combination, including B1 boilers) >70 kW;
  - existing models[65] of water heaters.
- In 2029: to introduce an ecodesign requirement for hydrogen readiness, i.e. make sure that the following gas fired appliances are capable of operating safely and efficiently with 100% vol. hydrogen, either after a conversion or without (Ecodesign space heaters, Annex II, Point 4; Ecodesign water heaters, Annex II, Point 1.3) (see detailed reasoning):
  - all models of heaters (space and combination, excluding B1 boilers) ≤70 kW;
  - new models[66] of heaters (space and combination, excluding B1 boilers) >70 kW;
  - new models[66] of water heaters;
  - new models[66] of B1 boilers.
- Change the definition of 'hydrogen ready' to avoid that the hydrogen kit needs to be placed on the market by the manufacturer together with the boiler, this would lead to material loss in case there will be no conversion or in case of loss by the end-consumer. Instead add the conversion kit to the list of parts that should be made available in the material efficiency requirements (Ecodesign space heaters, Annex I, Point 33; Ecodesign water heaters, Annex I, Point 43; Energy labelling space heaters, Annex, Point 34; Energy labelling water heaters, Annex I, Point 44).

5.3.2 EUGINE VIEWS FOR POWER GENERATION SECTOR ENGINES

Reliable information on the gas quality (H_2-fraction, composition of the base gas, calorific value) is of high importance and should, if possible, be provided real-time.

In addition, EUGINE -in cooperation with EUTurbines- has sketched out some basic requirements to help make hydrogen power a reality. It is important to note that, for hydrogen power to develop by 2030, those requirements will need to be met as soon as possible. Those basic requirements include:

- An integrated infrastructure planning that includes technology providers
- Power plants' access to hydrogen networks
- Predictable hydrogen market developments
- Business models valuing flexible, dispatchable and decarbonised power

5.3.3 EUROMOT VIEWS FOR POWER GENERATION SECTOR ENGINES

The views expressed in previous sections are also applicable to this scenario. EUROMOT emphasizes that providing stable and predictable gas quality and H_2 content in the blend over a given time frame is necessary.

64 Existing models means models of which units were placed on the market prior to the application date

65 GERG is delivering this project on behalf of CEN

66 CEN & GERG Pre-Normative Research (PNR) study provides an overview of available GCs certified to measure H_2 up to 20% vol.

5.3.4 EUTurbines VIEWS FOR POWER GENERATION SECTOR

TURBINES

Reliable information on the gas quality (H_2-fraction, composition of the base gas, calorific value) is of high importance and should, if possible, be provided real-time. Certainty around the hydrogen available should help facilitate investments in hydrogen-ready gas power plants.

EUTurbines, jointly with EUGINE, has identified the main requirements to help make hydrogen power become a reality.[67] It is however important to note that, for hydrogen power to develop by 2030, those requirements will need to be met as soon as possible. For investments in future-proof technology to be made in a timely manner, the following requirements need to be met:

- An integrated infrastructure planning that includes technology providers
- Power plants' access to hydrogen networks
- Predictable hydrogen market developments
- Business models valuing flexible, dispatchable and decarbonised power

5.3.5 CEFIC AND IFIEC VIEWS FOR THE FEEDSTOCK INDUSTRY

CEFIC and IFIEC emphasize that it is highly uncertain that prices for hydrogen and biomethane will be competitive to natural gas before 2040 and strongly recommend to include scenario's with price increases of blended gases compared to natural gas.

5.3.6 NGVA VIEWS FOR THE MOBILITY SECTOR

Reciprocating engines need stable gas composition since H_2 content fluctuation causes variations of WI, anti-knocking power, combustion velocity, etc. The engine must be very flexible to accept variations above a certain threshold (to be defined). Probably this is one of the biggest challenges.

For ICEs, the OEM can design proper solutions suitable to H_2NG. But the variability of composition can become an issue. Potential solutions could involve de-blending facilities but it has its complexity, scalability issues and the associated costs must be duly assessed.

67 Available **here**

5.3.7 ENTSOG VIEWS FOR TSOs

ENTSOG members put forward the following recommendations to enable a smooth transition to a decarbonised gas system:

1. TECHNICAL ASSESSMENTS

- TSOs, DSOs, manufacturers and technical associations/institutes should further work together in exploring the possibilities of 100% vol. H_2 and H_2 blends in the system. In this regard, ENTSOG is currently assessing the technical possibilities and associated cots of retrofitting the gas networks to 2% vol., 5% vol. and 10% vol. First results will be made public in the first half of 2022.
- Assess the suitability of quality tracking tools with varying H_2 content and diffusion effect.
- Experimental research is required to test and prove the possibilities of separation techniques (e.g., membrane technology for the separation of hydrogen from H_2NG-streams.) Further membrane separation technology development and system modelling would support the development of experimental test set-up and conditions[68].

2. STANDARDS AND REGULATION

- The current relative density requirement in the CEN standard EN16726 (from 0.555 to 0.7) should be revised in the context of current CEN harmonisation work as the lower value hinders the development of higher blending percentages of hydrogen into the natural gas.. However, this issue should be solved together with other aspects influencing gas quality like WI and GCV. It is worth mentioning that test gases in the standard EN437:2021 already foresees the testing of H-gas appliances G222 with up to 23% vol. H_2 [24].
- In any case, EN16726 should recognise the different H_2 tolerance of end-use applications and infrastructure elements. Rather than settling for the common least denominator (e.g. 2% vol. for CNG), hydrogen injection requests should be assessed by the relevant operators on a flexible case by case approach with the oversight of the competent authorities. Otherwise, the development of business cases for renewable and decarbonised gases in the short term could be hindered. In addition, standardisation should be implemented to enable the envisaged flexibility to operate.
- Within the framework of the future applicable EU legislation, a common EU-wide minimum H_2 acceptability threshold should be considered to facilitate cross-border flows of H_2. Provisions in the gas decarbonisation package should design the process to fix such minimum amongst the TSOs and NRAs concerned and the adjacent TSOs potentially impacted. The process should also consider requirements of end users and connected non-EU TSOs. The process could be activated as of the entry into force of the new legislative package.
- While the minimum H_2 acceptability threshold should be valid EU-wide, the maximum H_2 share should be left to the freedom of contract and not be restricted by a cap of any percentage. European legislation should not hamper the adoption of flexible regional solutions that are technically and economically feasible.
- National legislation and accordingly bilateral interconnection agreements need to be revised to allow the flow of blend gases at IPs.
- A way to guarantee a fair distribution of hydrogen injection possibilities will need to be established.

68 *"Membrane separation of natural gas and hydrogen in Prenzlau"* project is assessing this. Together, DBI Gas- und Umwelttechnik GmbH (DBI), Ontras Gastransport GmbH, the French transmission system operator Grtgaz S.A., Mitteldeutsche Netzgesellschaft Gas mbH (Mitnetz Gas), and DVGW Deutscher Verein des Gas- und Wasserfaches e.V. and, as an associated partner, the renewable energy company Enertrag jointly analyse how hydrogen can be separated from natural gas-hydrogen mixtures using different membranes.

5.3.8 CEDEC, EUROGAS, GD4S, GEODE VIEWS FOR DSOs

To reach the decarbonization targets of the Fit-for-55 proposals in buildings and industry the gas DSO play a very important role. In many countries almost 100% of all industrial consumers and a high percentage of the district heating production is connected to the gas DSOs, as well as all the residential and commercial heating market. None of these markets is easy to abate in the given time frame. The legislation should support the efforts of the DSOs to drive the transition to renewable and low-carbon gases. The existing infrastructure is highly adaptable and has the ability to accept a variety of gases at low transition costs. Blending biomethane, hydrogen or SNG to the grids offers a first step. The development of flexible and hydrogen-ready appliances and applications and their mass production is key to go further.

The ability of DSOs to blend hydrogen delivered from the TSO backbone offers stability to the overall system as the conversion of the TSO pipeline systems and the hydrogen production plants need a stable and planned demand.

The mass production and installation of fuel cells should be supported as it is not only offering high efficient heat and electricity close to the end-user, but it also supports the delivery of electricity in winter where renewable electricity can be very fluctuating or even very low. Decentralized production close to the end-users reduces stress on the overall energy system. The development of gas/hydrogen heat pumps can further increase the use of ambient energy and offers the end-users alternatives to decarbonise.

On the other hand, connection of biomethane plants to the gas grid is seen as a good opportunity for farmers as it offers them additional income and a solution for example to manure management. Waste-Water treatment plants can inject their sewage gas to the grid as well as waste plants with a gasification process. Small scale electrolysers can connect onshore wind and PV to be able to produce as much electricity as possible. There are restrictions on how much a distribution grid can absorb, but as has been explained previously, many different mitigation possibilities also exist. The connection of gas producers to the grid should be incentivised to be able to produce and inject as much European renewable and low carbon gas as possible. The DSO must have the ability to reduce injection tariffs as proposed in the gas package for the TSO side to create a level playing field between both levels.


Photo by Appolinary Kalashnikova on Unsplash

The technical rules in some countries only allow very low hydrogen levels even if the grids are already able to take up to 100% vol. This rules should be adapted together with the grid operators in the countries.

The cooperation between TSO and DSO is key. This is already working in many countries but must be further explored and detailed. The amendment of the Network Code Interoperability is the key regulation in this regard, the work on the amendments should start right away and not wait until the gas package is finalized. The DSO responsibility for the gas quality in the grid has to be prepared, the needed communication between TSO-DSO-larger end-users further analyzed and organised. These processes are very important and need lead times before they come into operation. The definition of acceptable gas quality parameters is key to identify risks and mitigation strategies. As gas systems react slower than electricity systems early knowledge is key to allow for measures to kick in. This goes hand in hand with a higher level of digitalization. Also, a closer cooperation between the DSO and their large connected end-users is key. Knowledge on timelines of maintained measures – where machinery and plants are revised and taken apart – can help to plan ahead for both sides.

Experiences in more complex and integrated systems e.g. hydrogen valleys with a large number of different sectors involved, are needed to test the different available mitigation strategies and, when those mitigation measures have proven to be the most cost-efficient solution, clear rules have to be defined on the role of each of the involved actors and the processes ruling their relationship

Lastly, more research is needed in the field of membranes and small scale storages.

5.3.9 ENERGY COMMUNITY SECRETARIAT VIEWS

Realistically, short term period is too short away to expect significant, if any, increase of hydrogen flows in the natural gas networks within the Contracting Parties to the Energy Community (except maybe Ukraine). But, all legal and regulatory adjustments should be made to enable changes of gas mix in networks, and allow hydrogen and biomethane production at least at limited and local level.

5.3.10 GIE VIEWS FOR STORAGES

For storages, R&D needed can be summarised as follows [13]:

- Depleted field: Effects of residual natural gas, insitu bacteria reactions
- Aquifer: In-situ bacteria reactions, tightness of rocks
- Salt cavern: Accuracy of the timing of injections and withdrawals
- Lined rock cavern: Compatibility of lining materials with hydrogen

5.3.11 GERG VIEWS FOR R&D

Three main aspects need to be considered when striving to find solutions:

- Identify at the earliest possible stage, the potential end-uses or applications limiting the use of H_2NG and perform a similar market assessment for hydrogen-ready applications expected compared to baseline scenario.
- Collaboration with international players in other regions such as the U.S. and Australia for information/experience sharing. Similarly, collaboration among TSOs, DSOs and other players across the gas value chain.
- Further investment in R&D.

5.3.12 EURELECTRIC VIEWS[69]

Grid planning:

- The increasing interlink energy systems requires an upgrade on grids, in order to support the integration of renewable and low-carbon energy carriers in all sectors of the economy;
- National network planning must be aligned with the European Network Development, considering joint scenarios built on gases and electricity projections consistent with the efficiency-first principle;
- Any future policy formulation should take into consideration the connectiveness and diversity of individual member states energy systems, and the specific role of H_2;
- Investment planning in networks should be based both on CBA considering all available options and the evolution of demand.

Gas Quality:

- Gas Quality coordination between member states will be crucial, considering reinforced cross-border coordination tools and increased transparency on the application of current standards;
- Robust gas quality standards (both CEN and national) should be set allowing for the injection of renewable and low-carbon gases into the existing methane gas network in order to limit potential negative impacts for operators and end users (at various levels such as safety, production efficiency, product quality, emissions);

69 References [46], [40], [41], [42], [43], [45], [44].

Picture courtesy of Gas Connect Austria

- National H_2 blending levels set by Member States in a standardized and transparent way, based on EU rules;
- Concerning gas quality monitoring, measurement and management, gas producers should cooperate and agree on quality parameters & ranges allowed by local TSO or DSO;
- TSO and DSO should set rules for gas quality harmonization and carry technical improvements on relevant interconnection points;
- For turbines sector: Detailed & system-wide impact assessment and study, in conjunction with gas-fuelled power plants and their respective OEM's, are needed to assess the impacts of gas quality changes. Changes in gas quality characteristics can result in impacted performances of gas-fuelled power plants which in turn could create a security of electricity supply risk for a Member State. Given the potential impact of gas quality changes, detailed assessment should be overseen by national regulators in conjunction with gas-fuelled power plants and their respective OEM's to understand the impacts in full before any changes are finalised to ensure risks are minimized [25].

Regulatory Framework:

- The recent development in the H_2 market requires the setting of a regulatory framework on which the same criteria and principles apply to both H_2 and gas markets, including technology neutrality, third party access to regulated infrastructures and access to the retail market to all end users, ensuring a level playing field;
- Future hydrogen storage development should be open to market mechanisms, reflecting the same regulatory framework applied to methane storage for large-scale storage units.

6 MID-TERM **DEVELOPMENTS**

For this scenario, hydrogen demand is expected to increase at all levels. Therefore, the full deployment of dedicated H_2 grids at TSO and DSO level is expected to be happening. Depending on national and regional conditions, as well as customers' needs, requirements and grid topology, hydrogen blending up to 20% vol. is expected to be present in some regions either for consumption or as a buffer to inject hydrogen surplus.


Picture courtesy of Gas Connect Austria

These developments could be expected by 2030–2040 but, as previously stated, since the choices and decisions are influenced by the overall EU climate and energy policies and may even differ amongst EU Member States, what might be seen as a short-term development for one country may be a medium/long-term one for another. Hence, it is not possible to define concrete timelines for each specific development.

6.1 CHALLENGES IN GAS QUALITY AND H_2 MANAGEMENT

6.1.1 EUROPEAN HEATING INDUSTRY (EHI) VIEWS FOR RESIDENTIAL & COMMERCIAL SECTOR

It is expected that by this time 100% vol. hydrogen ready appliances are sold on the market. Therefore, no new challenges in addition to those already described should arise. Given that long-term scenarios plans such as the ENTSOG Ten Year-Network-Development-Plan as well as national scenarios such as the one from the German Energy Agency expect a continued substantial share of gas-based heating appliances up until 2050 and beyond, the swift replacement of heating appliances in favour of 100% green solutions is key. A prerequisite is sufficient supply of green gases. In case of growing numbers of hydrogen valleys, already installed stock would be made hydrogen-ready via conversion kits at marginal additional costs.

6.1.2 EUGINE VIEWS FOR POWER GENERATION SECTOR

ENGINES

No new challenges as those already described in the previous scenarios should arise.

6.1.3 EUTurbines VIEWS FOR POWER GENERATION SECTOR

TURBINES

No new technological challenges as those already described in the previous scenarios should arise.

Ultimately, one of the main challenges is to ensure that the hydrogen reaches gas power plants.

6.1.4 CEFIC AND IFIEC VIEWS FOR THE FEEDSTOCK INDUSTRY

It is not clear yet which solutions will be the most appropriate for the feedstock industry in the long run. There are many ongoing projects aiming at identifying those solutions but not definitive results are available yet.

Besides, there is not enough knowledge to know how a fast change in H_2 content could impact the installation. Thus, it seems difficult to discuss future scenarios due to the uncertainty about the potential pathways for decarbonisation and electricity prices.

CEFIC and IFIEC do not exclude high extra CAPEX, losses of efficiency and reliability of industrial appliances and operations, higher emissions and more uncertainty about safety issues.

According to IFIEC and CEFIC responsibility and liability should be addressed up- and midstream in the first place, as end users cannot be accountable for gas quality changes.

6.1.5 ENTSOG VIEWS FOR TSOs

1. TSOs' ASSETS

As discussed above, most network parts besides pipelines would require a more detailed assessment for 20% vol. H_2. Especially compressor stations would require investments.

2. GAS QUALITY

Extending the hydrogen addition to 20% vol. leads to a significant reduction of Wobbe Index and GCV. Also, even heavy H-gases could face difficulties to meet the minimum relative density requirements.

Adding such levels of H_2 to a zone that is already receiving biomethane may lead to both Wobbe Index and GCV concerns [26].

6.1.6 CEDEC, EUROGAS, GD4S, GEODE VIEWS FOR DSOs

After 2030 it is expected that high quota of renewable and low carbon gases will be the standard in the grids. The RED II proposals foresees a 49% Renewable energy quote in buildings, while the taxonomy and potential rising of CO_2 prices will drive the discussions at the industrial level or with CHP/Power plants.

A cost efficient decarbonization with H_2 blends has its technical limits if existing appliances and applications shall be used and mitigation costs kept to minimum. In the years after 2030 the DSOs will already have developed a plan which will be very dependent on their local situation, local resources of renewable and low-carbon gases production but also on the developments of the European hydrogen backbone. In regions with a high potential of biomethane, DSOs grids could be 100% biomethane, or by a long-term blend. If enough renewable CO_2 is available, or if CO_2 from CCS is counted towards the production of low-carbon gases, also a future methane (including biomethane and/or syngas) based grid is possible with e.g. 70% vol. biomethane + 30% vol. H_2. Alternatively a more hydrogen based blend could be foreseen with 70% vol. H_2 + 30%vol. biomethane. In other areas with a high local H_2 production and an easy connection to H_2 backbone, a switch to 100% H_2 is likely to be the preferred option. Still, biogas from all possible sources should be used (incl. biogas from waste and waste-water treatment plants or other sources), which could also be used to produce hydrogen with the pyrolysis, plasmalysis or small SMR/ATR.

Looking further into the future, the rapid development of rooftop PV or agri-PV could also serve small scale electrolysers. Customers will have a more active role and since small scale electrolysers with

2,4 kW are already on the market and will go into the mass production[70], the ability to offer them a connection to hydrogen grids lies only with the DSO.

A prerequisite for all these potential futures is to have flexible and efficient gas appliances and applications, as they would allow the customers, the grid operators and the gas producers the widest space to find solutions for a deep, sustainable and cost-efficient decarbonisation.

6.1.7 GERG VIEWS FOR R&D

GERG Hydrogen Research Roadmap 2021 [14] has identified the key R&D elements emerging. In regards to gas quality, those elements are:

- Working methods to prevent contamination of H_2 when transported with former natural gas transmission systems.
- Cost-effective adaptation of sensitive existing appliances to H_2 and H_2NG.
- Metering

6.2 POTENTIAL SOLUTIONS & ASSOCIATED COSTS

6.2.1 EUROPEAN HEATING INDUSTRY (EHI) VIEWS FOR RESIDENTIAL & COMMERCIAL SECTOR

All newly sold equipment will be green-gas ready, the variations within the installed stock to handle different levels of hydrogen-methane blends will decrease. Thus, boilers will be capable of handling different gas blends depending on the regional settings and energy mix. Hybrid solutions, thermally-driven heat pumps, micro-cogeneration including fuel cells, will also be able to run with green gases, including hydrogen.

Compared to the Short/mid-term scenario (2025–2030), the price of a hydrogen heating appliance is expected to go down over the next decade. As they are expected to become the new reference on the market for gas appliances, their price in the 2030s is not expected to be higher than that of methane condensing boilers today without taking into account the evolution of inflation.


Picture courtesy of BASF

6.2.2 EUGINE VIEWS FOR POWER GENERATION SECTOR

ENGINES

In the future, industry will mark all plants with regards to their hydrogen-readiness level. Customers will thus be able to decide the hydrogen share (up to 10% vol., up to 25% vol. or 100% vol.) for which the plant shall be technically suitable and/or adapted. Modifications for the use with a higher hydrogen level will be possible and normally not exceed 30% of the costs for a new similar plant. See section 4.2.3 for more information.

70 Enapter Ramps Up Development of Electrolyser Mass-Production System

6.2.3 EUROMOT VIEWS FOR POWER GENERATION SECTOR
ENGINES

For naturally aspirated engines (i.e., no turbocharger) adding 20% vol. H_2 to natural gas can decrease the output power by 20% depending on the base gas quality and decreases at the same time the fuel efficiency, while increasing the NOx emissions due to the lack of extra air available. Many existing engines might need a lower compression ration meaning the replacement of the pistons. Also the requirement to accept signals on gas quality (Wobbe Index, Methane Number, hydrogen fraction) might require a replacement of the control equipment and output and emission control strategy

6.2.4 EUTurbines VIEWS FOR POWER GENERATION SECTOR
TURBINES

In the future, customers will thus be able to decide the hydrogen share (up to 10% vol., up to 25% vol. or 100% vol.) for which the plant shall be technically suitable and/or adapted. Modifications for the use with a higher hydrogen level will be possible and normally not exceed 20% of the overall cost of building this power plant. See section 4.2.5 for more information.

6.2.5 EUROPEAN NETWORK OF TURBINES (ETN) VIEWS FOR POWER GENERATION
TURBINES[71,72]

For new turbines, the industry is committed to enable gas turbines to run entirely on hydrogen gas fuels by 2030. To enable this transition, additional research and full-scale demonstrations are ongoing to achieve these goals. Engine specific retrofits for existing machines will become more available, with an increased hydrogen to natural gas ratio. Obviously, capital expenditures associated with retrofit solutions for gas turbines powerplants have to be met by market conditions favourable for the wide-spread introduction of the technology. Regulatory measures should ensure a level playing field for all technology providers.

6.2.6 ENTSOG VIEWS FOR TSOs

1. TSOs' ASSETS

Several trials and tests are ongoing to assess the impact of 20% vol. H_2 blends and higher H_2 volumes on the grid, as well as to find solutions to potential challenges that may arise:

- HyNTS programme (UK): Aims at identifying the requirements to enable a physical trial of Hydrogen injection into the NTS, identifying the gaps in the safety case and indicating the most suitable NTS location for a live small-scale trial. A feasibility study with the aim of determining the capability of the NTS to transport hydrogen. Includes a review of relevant assets, pipeline case study and draft scope for offline trials.
- Snam (IT): a trial of 30% vol. blend of natural gas and hydrogen has been carried out to power furnaces at a steelmaker in northern Italy.
- H_2GAR: The goal is to define the state of the art regarding the conservation of materials used for the transport of hydrogen, in order to identify any technological and regulatory gaps, both for existing and for new pipelines.
- Compendium – Hydrogen in gas transmission and distribution grids by DBI and DVGW: Setup of holistic and complete inventory of the German gas transport and distribution network from materials, gas network, building connections and installation to gas applications up to 100% vol. hydrogen.
- HIGGS – Hydrogen in Gas Grids: Funded under Grant Agreement 875091. Gas infrastructure, its component and management in high-pressure transmission gas grid.

71 ETN, Hydrogen Gas Turbines, January 2020

72 ETN, ETN R&D Recommendation Report 2021

- H_2-20 (Avacon project): Approval of 20 vol.-% vol. H_2 admixing in a real environment (region Flämig in Saxony-Anhalt) with 400 private customers.
- Roadmap Gas 2050 by DVGW: Holistic concept for the complete value chain of the gas energy system (well-to-wheel) from production of renewable gasses, transport in the German gas grid and the usage in gas applications (existing and new).
- Ontras (German TSO) is studying the impacts of blended hydrogen on pipe integrity through the H_2-PIMS project. Their goal is to determine the conditions for converting the equipment. This initiative is part of the HYPOS project, which aims to investigate the compatibility of existing gas transmission infrastructures with CH_4/H_2 mixtures with the involvement of around one hundred German partners (universities, research centers, large industrial companies, SMEs, etc.)
- DNV undertook the HyStart feasibility study which highlighted issues and solutions to enable hydrogen injection into the gas grid at concentrations of up to 20% vol.. The study covered gas quality, materials, leak detection, components/ infrastructure suitability, hydrogen injection systems, flow measurement, hazards/ risks, control philosophy and end-use equipment operability.

2. GAS QUALITY

Introducing 20% vol. H_2 blends pose difficulties to remain other relevant gas quality parameters. It should therefore only be introduced to TSO grids on a case-by-case basis.

6.2.7 CEDEC, EUROGAS, GD4S, GEODE VIEWS FOR DSOs

Inputs provided for previous sections are also applicable to this one.

Picture courtesy of Swedegas AB

6.3 RECOMMENDATIONS

6.3.1 EUROPEAN HEATING INDUSTRY (EHI) VIEWS FOR RESIDENTIAL & COMMERCIAL SECTOR

Recommendations from previous scenarios are also applicable here. The technical equipment is foreseen to be 100% vol. hydrogen ready by then.

To leverage this potential, the right framework conditions – such as securing green molecules for building decarbonisation – must be set in the 2020s by European and national policies.

6.3.2 EUGINE VIEWS FOR POWER GENERATION SECTOR ENGINES

Inputs provided for previous sections are also applicable to this one.

6.3.3 EUTurbines VIEWS FOR POWER GENERATION SECTOR TURBINES

Inputs provided for previous sections are also applicable to this one.

6.3.4 EUROPEAN NETWORK OF TURBINES (ETN) VIEWS FOR POWER GENERATION TURBINES

Further developments are crucial for the use of hydrogen in gas turbines. For example:

- Dry low NOx combustors : many existing plants would depend on successful development of this technology to enable retrofit, with no viable alternative
- GT enclosures are done on a case by case basis, standardisation would enable further deployment

6.3.5 ENTSOG VIEWS FOR TSOs

Recommendations from previous scenarios are also applicable for this one.

6.3.6 CEDEC, EUROGAS, GD4S, GEODE VIEWS FOR DSOs

To organize the cost-efficient transition at the DSO level it is import that the DSO is allowed to operate the gas grids distribution the different kind of gases together. Experiences from the ongoing H-Gas/L-Gas conversion and from the town gas conversion clearly shows, that the process will go in continuous steps and that a separation of the grid ownership and operation would make it nearly impossible to organize in a cost efficient, customer friendly and safe way.

Besides, many production technologies for renewable and low-carbon gases are still incipient e.g. the photocatalytic hydrogen production or the different kind of pyrolsysis, but the learning curves are steep. The combination of decentralized production of renewable and low-carbon gases in combination with large scale production and transport offers flexibility and includes the local actors as cities, citizens and industry.

7 COMPLETION OF THE **EUROPEAN HYDROGEN BACKBONE**

To unlock the full potential of a hydrogen economy the adaptation of the existing natural gas pipelines for hydrogen transmission[73], as well as the construction of an dedicated infrastructure exclusively to hydrogen transport along with the retrofit of end-users to dedicated hydrogen systems will be needed. Most sectors have already acknowledged to have plans for such retrofit to use exclusively hydrogen.

Picture courtesy of GASCADE

Yet, that may not be possible for some specific industrial processes. Therefore, in order to continue supplying consumers who are largely dependent on methane to be used for the production of chemicals, there will also be methane networks in the future at the transmission and distribution network level. This methane network could include biogas/biomethane and synthetic natural gas (SNG) depending on the national and regional developments.

73 By 2040, a pan-European dedicated hydrogen transport infrastructure can be envisaged with a total length of around 39,700 kilometres, consisting of 69% repurposed existing infrastructure and 31% of new hydrogen pipelines [4].

7.1 CHALLENGES IN GAS QUALITY AND H_2 MANAGEMENT

7.1.1 EUROPEAN HEATING INDUSTRY (EHI) VIEWS FOR RESIDENTIAL & COMMERCIAL SECTOR

Similarly to previous scenarios, if the recommendations have been applied, the heating sector should be fully hydrogen ready. We do not expect any new challenges at this stage.

7.1.2 EUGINE VIEWS FOR POWER GENERATION SECTOR

ENGINES

As stated in the previous sections, in the future, industry will mark all plants with regards to their hydrogen-readiness level. Customers will thus be able to decide the hydrogen share (up to 10% vol., up to 25% vol. or 100% vol.) for which the plant shall be technically suitable and/or adapted. It will therefore be possible for customers to buy a plant ready to run on 100% vol. hydrogen.

7.1.3 EUROMOT VIEWS FOR POWER GENERATION SECTOR

ENGINES

The current generation of new engines that can run on 100% vol. H_2 can only deliver 50% power output (in comparison with natural gas ones) and consequently have a double investment cost increase per unit of power capacity and a decrease in fuel efficiency. The reason is that the engine has to run on a very fuel-lean mixture to avoid pre-ignition and knocking. However, the industry is working on the development of dedicated hydrogen-fuelled engines with high performance and low NOx emissions. The optimisation of such engines is only possible during a process with long-term testing of materials and wear rates. Running a hydrogen engine under laboratory conditions is only a first step.

7.1.4 EUTurbines VIEWS FOR POWER GENERATION SECTOR

TURBINES

No new technological challenges as those already described in the previous scenarios should arise. Ultimately, one of the main challenges is to ensure that the hydrogen reaches gas power plants.

7.1.5 EUROPEAN NETWORK OF TURBINES (ETN) VIEWS FOR POWER GENERATION

TURBINES[74,75]

Gas turbines users will have to deal with a wide range of variable hydrogen/natural gas mixtures (especially so during a transition period with still limited H_2 production capacity) while maintaining operational flexibility in order to compensate grid frequency excursions in future. OEMs have committed to fire up to 100% vol. hydrogen in new build gas turbines by 2030. For gas turbine specific upgrade packages a specific roadmap is unclear and obviously is determined by a favourable business case and regulatory measures.

7.1.6 CEFIC AND IFIEC VIEWS FOR THE FEEDSTOCK INDUSTRY

Depending on the grid infrastructure (new or repurposed) hydrogen quality may vary across the grid (especially at the beginning of such a dedicated grid). On the other hand, storages can significantly impact the Hydrogen quality as the operating mode of storages does not fit to the optimal operating mode of upgrading/separation technologies

74 ETN, Hydrogen Gas Turbines, January 2020

75 ETN, ETN R&D Recommendation Report 2021

7.1.7 ENTSOG VIEWS FOR TSOs

1. TSOs ASSETS

The repurposing of an existing natural gas infrastructure to hydrogen implies dealing with several technical challenges linked to the different chemical properties of hydrogen in comparison to natural gas. According to Gas for Climate, existing natural gas infrastructure does not require massive changes to be fit for 100% vol. hydrogen transport as the infrastructure materials are often fit for hydrogen transport as well. However, the decision whether existing pipeline can transport 100% vol. hydrogen and the respective changes need to be considered case by case taking into account the technical state and chemical composition of the material [5].

At standard conditions, methane has three times the calorific heating value per cubic meter of hydrogen. Assuming the same operating pressure and the same pressure drop along the pipeline, hydrogen will also flow at three times the velocity due to its low density. Further the same gas pipeline today transporting mainly natural gas, can transport about three times as many cubic meters of hydrogen during a given period and thus deliver roughly the same amount of energy. This results in the energy transportation capacity being only 10 to 20% smaller compared to high-calorific natural gas [8].

The main elements of the conversion process include:

1. Technical conditions of gas pipeline
2. Cleaning
3. Integrity management of the steel pipes and fittings: As for natural gas pipelines, it is necessary to regularly inspect the pipeline and identify possible cracks. Embrittlement can in principle accelerate propagation of cracks. This is only likely, though, if the pipeline already has fractures and is subjected to dynamic stresses due to fluctuating internal pressure during hydrogen operation.. The replacement of valves could be required. For 100% vol. H_2, a general suitability of pipeline steel is expected and first experiments (e.g., DVGW Project SyWestH_2) support this assumption[76].
4. Compression of hydrogen[77]: a complete switch to a 100% vol. hydrogen pipeline requires installing new turbines or motors and new compressors. Analyses by some gas TSOs show that operating hydrogen pipelines at less than their maximum capacity gives much more attractive transport costs per MWh transported as additional expensive high-capacity compressor stations and corresponding energy consumption can be avoided. The fixed pipeline-related costs per MWh obviously increase, yet compressor costs and the corresponding cost of the energy fall sharply.
5. Tightness of the system including valves: as hydrogen is a much smaller molecule than methane internal and external tightness of the system needs to be adequately certified, additionally material used for sealing needs to be chosen as applicable to work with hydrogen.
6. Replacement of measuring equipment: gas chromatographs has to be equipped with an additional column able to measure hydrogen, i.e., in case of pressure transducers dedicated membranes able to cope with hydrogen need to be used, gas meters need to be in the proper flow rate. On the other hand, there are no recommendation or standards associated to the measurement of H_2 in the grid. CEN & GERG Pre-Normative Research (PNR) Study provides a comprehensive overview on the current status of this topic.
7. Upgrade of the software: software of the flow computers needs to be upgraded, i.e. calculation algorithms have to include 'pure' hydrogen (i.e., not in blends with natural gas).

76 First publications of Mr Marewski and MPA Stuttgart are available.

77 However, it is still not clear which type, reciprocal or centrifugal, will be best suited.

2. HYDROGEN QUALITY

Another important issue to tackle is the differences between repurposed pipelines for H_2 and new built ones. Current research shows that repurposed NG pipelines could transport at least 98% vol. H_2. Yet, field tests are ongoing and this value is expected to be higher depending on the results from the research.

This quality is suitable for the majority of hydrogen applications as a reducing agent, e.g. in steel production, or as a fuel, e.g. in the generation of process heat, and takes into account possible hydrocarbons that are initially still present in converted natural gas pipelines. Initial studies have shown that the hydrogen quality is only slightly impaired by these residues [27].

Yet, the recommended purity is not high enough to meet the requirements for PEM fuel cells (which is according to EN 17124 >99,97% vol.), and additional clean-up will be required due to the existence of 'impurities' derived from the use of the pipeline with NG before and some production processes of hydrogen, like for example reforming. On the other hand, producing the highest level of purity (i.e., close to 100% vol. H_2) is only possible if H_2 is produced by water electrolysis and not by other sources (e.g., biomass gasification). Interestingly, in many cases, the important factor in determining the impact on appliances is the level of specific impurities, such as H_2S or CO, rather than the overall hydrogen purity percentage.

7.1.8 CEDEC, EUROGAS, GD4S, GEODE VIEWS FOR DSOs

Inputs provided for previous sections are also applicable to this one.

7.1.9 ENERGY COMMUNITY SECRETARIAT VIEWS

The main challenge will be, as mentioned in previous sections the existing legal gap at the interfaces between EU MS – EnC CP (voluntary implementation of existing Network Codes by EU MSs at the borders with the third countries) which could hinder cross border flows of hydrogen in near future, as well in development of hydrogen backbone. If not solved, it is expected to have impact at mid and long term scenario as well, widening gap between the EU MSs and EnC CPs on legal and technical levels.

7.1.10 GERG VIEWS FOR R&D

GERG Hydrogen Research Roadmap 2021 [14] has identified the key R&D elements emerging. Two main elements are identified:

- Clear understanding of H_2 leakage, detection and associated emissions.
- Understanding if variations in hydrogen supply (e.g., green vs blue) do not represent an issue at this stage.


Picture courtesy of ENGIE

7.2 POTENTIAL SOLUTIONS & ASSOCIATED COSTS

7.2.1 EUROPEAN HEATING INDUSTRY (EHI) VIEWS FOR RESIDENTIAL & COMMERCIAL SECTOR

Similarly to the previous scenarios, the heating sector should be fully hydrogen ready at this point. As from 2040, hydrogen appliances should be on the market for at least more than ten years.

7.2.2 EUGINE VIEWS FOR POWER GENERATION SECTOR
ENGINES

As already stated, existing plants, even if they start running on natural gas, can be built with future hydrogen operation in mind. For such hydrogen-ready plants, upgrade costs should not exceed 30% of overall plant building costs. Other (not H_2-Ready) plants might be upgraded following a case-by-case assessment. For mor information on upgrading power plants that are not H_2-Ready, see the EUGINE checklist. See section 4.2.3. for more information.

7.2.3 EUROMOT VIEWS FOR POWER GENERATION SECTOR
ENGINES

Until now, the engine manufacturers had no reason to develop engines dedicated to hydrogen because that fuel was generally not available, and the price is still too high to make it an economic preposition for the end customers. However, the engine manufacturers are now working on developing engines suitable for 100% vol. hydrogen considering the fact that probably after a time span of at least one decade hydrogen might become an economic fuel.

For the retrofitting of installed stock to 100% vol. H_2, the decrease in knock resistance, and the increase in flame speed, among other parameters can lead to a decrease of power output by a factor two. For naturally aspirated engines, only the addition of a turbocharger might help to compensate for this to some extent, but this requires addition research because of the change in process conditions especially for the valve lubrication. For turbocharged engines, some mitigation in the power output decrease can be possible by changing the turbocharger system. However, this requires testing to reveal the long-term effect on the wear rate of the engine. It will be evident that the relative costs of modifications depend to a large extent on the power capacity of an engine. The costs per kW power for smaller engines can be much higher than for larger engines.

Engine manufacturers are now working on developing engines suitable for 100% vol. hydrogen. By 2030 it could be expected that there are in the market engines for 100% vol. H_2 that provide only a 10% decrease of output power in comparison with current NG ones. On the long run, operating an engine on 'pure' hydrogen might offer an even better performance and life compared with running on fluctuating gas quality variations.

7.2.4 EUTurbines VIEWS FOR POWER GENERATION SECTOR
TURBINES

In the future, customers will thus be able to decide the hydrogen share (up to 10% vol., up to 25% vol. or 100% vol.) for which the plant shall be technically suitable and/or adapted. Modifications for the use with a higher hydrogen level will be possible and normally not exceed 20% of the overall cost of building this power plan. See section 4.2.5. for more information.

7.2.5 EUROPEAN NETWORK OF TURBINES (ETN) VIEWS FOR POWER GENERATION
TURBINES

Gas turbines users will have to deal with a wide range of variable hydrogen/natural gas mixtures (especially so during a transition period with still limited H_2 production capacity) while maintaining operational flexibility in order to compensate grid frequency excursions in future. OEMs have committed to fire up to 100% vol. hydrogen in new build gas turbines by 2030. For gas turbine specific upgrade packages a specific roadmap is unclear and obviously is determined by a favourable business case and regulatory measures.

7.2.6 CEFIC AND IFIEC VIEWS FOR THE FEEDSTOCK INDUSTRY

Different upgrading/separation technologies are required to achieve the required Hydrogen quality. Yet, these technologies lead to a higher energy demand which interferes with other dossiers promoting energy efficiency (e.g. state aid, EED or ETS). Also, these technologies have higher OPEX.

7.2.7 ENTSOG VIEWS FOR TSOs

1. ASSETS

The existing pipeline routes represent an extremely valuable element of the transmission system and offer the opportunity to build a climate-neutral hydrogen industry in a manageable time and with little investment. As measuring devices, compressors and fittings can be exchanged relatively easily, replacing or building new pipelines would be very expensive. In addition to the technical costs, the necessary spatial planning and planning approval procedures are extremely time- and cost-intensive. In the best-case scenario, the process takes five to seven years from initial planning to commissioning. The gas network's pipeline routes, including their rights of way and use, are however available and accepted by the population [7].

Regarding costs, the average repurposing costs of transmission pipelines are expected to be between 10 and 35% of the construction costs for new dedicated hydrogen pipelines. Those values are provided by the European Hydrogen Backbone report [4], while cost assumptions from other sources like the German national network development plan remain within those boundaries [4] [29] [30] [31]. The substantial cost-saving potential of repurposing is also seconded by the findings of the ReStream study by Carbon Limits and DNV [3]. The study also provides initial screening results of the suitability of existing oil and gas pipelines for repurposing as well as a list of technical challenges and possible mitigation measures.

		Low	Medium	High
Pipeline cost	€ billion	33	41	51
Compression cost	€ billion	10	15	30
Total investment cost	**€ billion**	**43**	**56**	**81**
OPEX (excluding electricity)	€ billion/year	0.8	1.1	1.8
Electricity cost	€ billion/year	0.9	1.1	2.0
Total OPEX	**€ billion/year**	**1.7**	**2.2**	**3.8**

Table 3: Estimated investment and operating cost of the European Hydrogen Backbone (2040)

SIEMENS, GASCADE and NOWEGA estimated that the costs for retrofitting the lines – including decommissioning, water pressure tests, replacement of fittings and blowers and dismantling of connections, etc. – to be around 10–15% of a new construction according to current estimates by transmission system operators. Converting the compressor infrastructure to maximize the flow of energy in hydrogen operation requires approximately three times the compression performance compared to natural gas operation. Accordingly, the compression equipment of a hydrogen pipeline, including the drives, would be about three times the cost of a natural gas pipeline [7].

Hydrogen pipelines are also the most cost-efficient option for long-distance, high-volume transport at €0.11–0.21/kg (€3.3–6.3/MWh) per 1,000 km, outcompeting transport by ship for all reasonable distances within Europe and neighbouring regions [32].

Several studies have been carried out indicating the costs or elements needed to repurpose natural gas grids to H_2 ones, including but not limited to:

- Conversion of high-pressure gas lines made of steel pipes for a design pressure of more than 16 bar for the transport of hydrogen (DVGW, 2020.)
- European Hydrogen Backbone – A EUROPEAN HYDROGEN INFRASTRUCTURE VISION COVERING 21 COUNTRIES [4]
- Hydrogen infrastructure – the pillar of energy transition The practical conversion of long-distance gas networks to hydrogen operation [7]
- Re-Stream – Study on the reuse of oil and gas infrastructure for hydrogen and CCS in Europe [3]
- German TSOs: German National Network Development Plan 2020–2030 [31]
- Polish Hydrogen Strategy [33]

Several projects including field tests and trials are also ongoing:

- 'GET H_2 Nucleus' model project: Between Lingen and Gelsenkirchen, the companies BP, Evonik, Nowega, OGE, and RWE Generation are currently developing the first publicly-accessible hydrogen infrastructure over a length of 130 kilometres in the GET H_2 Nucleus project.
- Northern Gas Network, a UK natural gas distributor, has led the H21 Leeds Citygate project to determine the technical and economic feasibility of converting existing gas infrastructures in the Leeds metropolitan area to 100% vol. hydrogen, in order to decarbonise industrial and domestic uses.
- In 2017, DNV conducted a study on behalf of the Netherlands Ministry of the Economy to determine the conditions for converting the equipment of Dutch TSO (GTS) to transport pure hydrogen.
- FenHYx (Future Energy Network for Hydrogen and Blend) initiated by GRTgaz, aims at testing the transmission system equipment and materials under real conditions for different CH_4/H_2 mixtures. The platform will pool European R&D efforts, using FenHYx equipment to design and develop common approaches for carriers across Europe, with a view to increasing the injection of hydrogen into the gas system. FenHYx will improve the understanding both of the impact of hydrogen on the gas networks, and of the adaptation required to ensure their safe and efficient operation.
- "Lacq-Hydrogen" and "Green Crane" also aiming at repurposing an existing transborder pipe between France and Spain, within an integrated "at-scale" value chain and business model.
- "Hydrogen Highway" (PL): feasibility study for dedicated hydrogen pipeline "north-south" Poland.

Many more are also ongoing. A status overview can be found on the **ENTSOG H_2 project visualisation platform** where more than 80 retrofitting/repurposing projects in Europe are being showcased since October 2021:

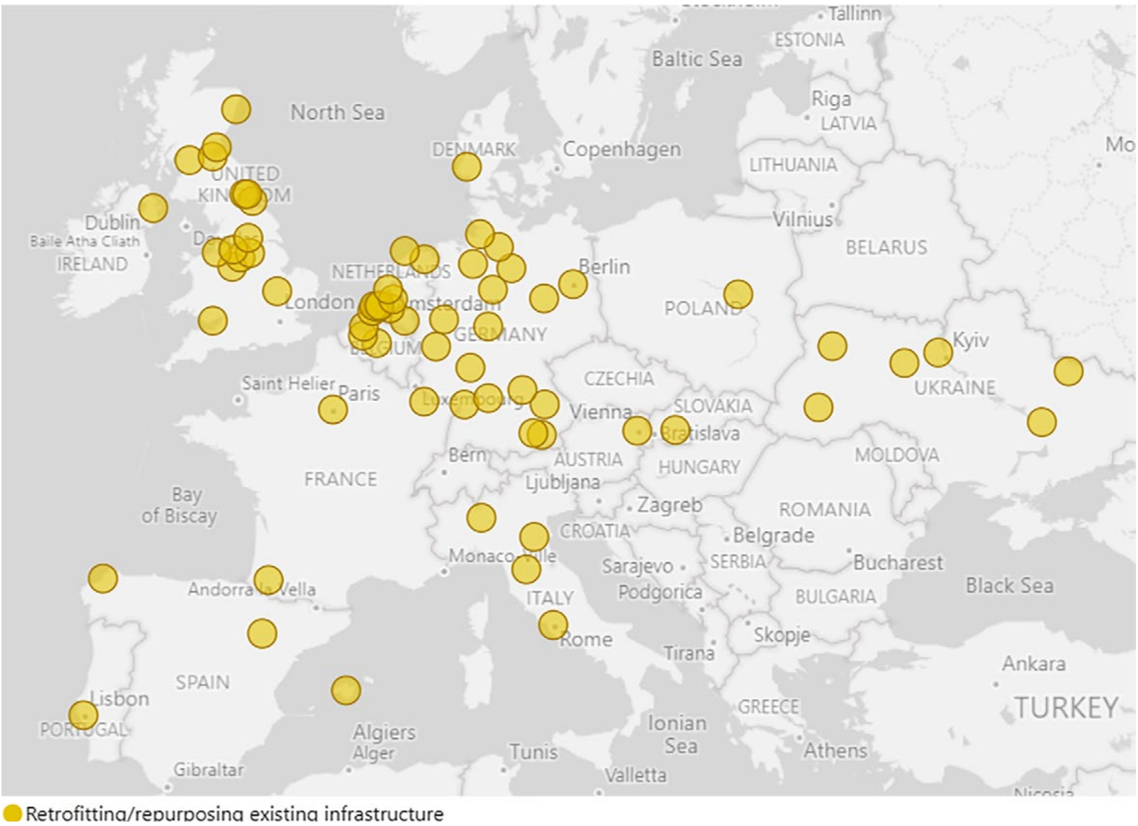

Figure 8: Snapshot of "Retrofitting/repurposing existing infrastructure projects" in ENTSOG H_2 project visualisation platform (December 2021).

On the other hand HyWay27 "Repurposing the Dutch grid for hydrogen transport" [34] has already finished and it explored whether, and if so under which conditions, parts of the existing Dutch natural gas network can be repurposed for the transmission of hydrogen. One of the key conclusions is that, in The Netherlands, existing natural gas network can be used to accommodate the interregional transmission flows that are expected in the long term: key pipelines can be freed up entirely and repurposed for hydrogen transmission. Besides, reusing existing natural gas grids is more cost-effective than laying new pipelines for hydrogen transmission. A transmission network connecting all industrial clusters to producers and storage locations requires an investment of around €1.5 billion.

Regarding standardisation, there is a general agreement amongst material experts of the participating operators that the criteria defined in ASME B31.12 are very conservative regarding the behaviour of high-grade steel in the presence of hydrogen. For this reason, it is important to note that there is ongoing research on the use of higher-grade steels (X65, X70 and above) for the transport of hydrogen. The additional material testing and potential updates of the standards may facilitate the reuse of pipelines with higher grade steels.

2. HYDROGEN QUALITY

The main advantage of this scenario relies on the fact that if an EU standard on H_2 specification is adopted, it would be expected that no relevant gas quality issues appear, so the free flow of gas across IPs should not be hindered[78] (yet odorization issues may still appear).

7.2.8 CEDEC, EUROGAS, GD4S, GEODE VIEWS FOR DSOs

The conversion of existing TSO pipelines needs to be coordinated with all DSO connected to these pipeline systems. This process has to be well planned between all actors – similar to the H-Gas/L-Gas conversion process with a long enough lead time. The offtake of hydrogen at the DSO level offers the TSO a planned offtake which helps the overall energy system. The earlier DSOs and their end-users are hydrogen ready the more flexible the TSO can plan the H_2 backbone. As soon as large feeder pipelines e.g. from the North Sea, are repurposed to hydrogen an immediate stable offtake is key in the downstream systems. If parallel systems of hydrogen and methane exist, also DSOs running on hydrogen blends offer a buffer function for the TSO system.

It should not be forgotten that in many countries a high percentage of the industrial consumers are connected to the distribution grids. Their need for renewable and low-carbon gases is high. To offer these customers solutions – with the needed security of supply level – a connection of the DSO to the back bone is essential.

In order to coordinate such a conversion process and facilitate the knowledge sharing of DSOs along Europe, "Ready4H2"[79] was founded in late 2021. DSOs, companies and associations from 17 countries have joined to support the process. The first report was published on December 2021 collecting the experiences from 14 countries. The conclusion drawn is that 96% of the 1.193.000 km of pipes are 100% vol. hydrogen ready. This result is also supported by a study carried out in the Netherlands [35] . This overview will be updated continuously with further knowledge and tests, since more countries are interested to join the project.

The pipelines are the most relevant part of the grid as they are underground, they make up >90% of the asset base . Metering and pressure regulation stations usually are the next biggest asset, but they are above ground and the majority of the components don´t have to be exchanged. Even if e.g. the meter or the some flange or the seals have to substituted the costs are much less than building new stations or cabins. Most recent grid-flow simulations show that the grid capacity can be kept at nearly the same level even if the energy content of hydrogen is only a third of natural gas but can be compensated through a higher speed in the pipes. As the mass flow remains the same this is possible.

Through the project the continuously growing database shall be better used with more information sharing. One alternative discussed is the expansion of the Kompendium[80] which already cooperates very closely with the Swiss and Austrian gas association and build a European database that can be used by grid operators and laboratories and manufacturers alike. This speeds up the analytical works that each DSO has to do and saves costs along the way for everyone.

The final result of "Ready4H2" is a roadmap with concrete initiatives for how the gas distribution companies at the European and national level can be a link between hydrogen producers and consumers.

78 This would be the case once a European hydrogen specification is available. A process is being started in CEN TC 234/WG11 with the purpose of defining the properties and quality of hydrogen as a gaseous fuel, transported, and distributed to the points of use by a converted/repurposed natural gas system.

79 Ready4H2 **website**

80 *"Kompendium Wasserstoff in Gasverteilnetzen"* **website**

7.3 RECOMMENDATIONS

7.3.1 EUROPEAN HEATING INDUSTRY (EHI) VIEWS FOR RESIDENTIAL & COMMERCIAL SECTOR

At this point, the European heating stock will be able to handle methane-hydrogen blends as well as 100% hydrogen grids. To leverage the decarbonization potential of hydrogen in heating, access and sufficient supply of hydrogen will be key for success.

7.3.2 EUGINE AND EUTurbines VIEWS FOR POWER GENERATION SECTOR ENGINES AND TURBINES

For hydrogen power to develop, it is especially important that power plants get access to the future hydrogen backbone. Specifically:

- Hydrogen power plants and hydrogen-ready power plants must be allowed to connect to repurposed and new hydrogen transport infrastructure as soon as possible.
- Regulated Third Party Access rights (TPA) and regulated tariffs should be introduced as soon as possible for hydrogen networks, based on the currently existing model for methane gas networks.
- Independent energy market regulators should be entrusted with overseeing the development of competitive markets and the avoidance of monopolistic market outcomes.

7.3.3 EUROMOT VIEWS FOR POWER GENERATION SECTOR ENGINES

The performance of reciprocating is quite insensitive to the quality of hydrogen. The presence of limited fractions of oxygen, nitrogen or CO_2 does not affect the engine performance. However, EUROMOT recommends using sulphur free odorants considering the negative influence of sulphur on the acidifying emissions.

7.3.4 CEFIC AND IFIEC VIEWS FOR THE FEEDSTOCK INDUSTRY

Defining a minimum quality standard for Hydrogen to be injected into the grid is needed to avoid significant gas quality variations. It is expected that different upgrading/separation technologies are required to achieve the required Hydrogen quality for the chemical industry. In the worst case, existing upgrading/separation units at the chemical sites cannot be used, which will cause additional investment.

7.3.5 ENTSOG VIEWS FOR TSOs

1. TSOs ASSETS

- Currently, it is not possible to provide recommendations for this item but, as previously presented, there are many projects ongoing which are working on the topic and whose results are expected to be soon available. Some recommendations from Hyway27 [34]:
  - There needs to be a roll-out plan that sets out how the transmission network will be rolled out and the principles behind this
  - A vision of the market regulation is desirable so that choices can be made concerning repurposing the transmission network in tandem with its operation
  - Clarity is needed on the available financial support for the entire supply chain

2. HYDROGEN QUALITY

- Harmonised EU specification for H_2 being transported in former natural gas infrastructure. Common understanding of the type of impurities which cannot be allowed in H_2 pipelines, their impact, and the required treatment to eliminate them.
- Standardized designs for systems and components are also needed to unify specifications among system and component providers, which simplifies technology development and lowers supplier costs.
- A harmonised hydrogen quality standard needs to be developed to facilitate cross-border flows of H_2 in a timely and efficient manner. In case of different purity requirements at the border, the party on the side requesting H_2 with higher purity than the common EU-threshold will be responsible for the necessary investments to adapt the H_2 purity.
- An EU-wide H_2 purity requirement of 98 Vol.-% vol. at exit points is a reasonable starting point considering the purity achieved by different production methods, and requirements of end-users. Most probably, repurposed pipelines (and storages) will be able to deliver higher purities. Once this has been demonstrated in practice, the standards should be revised accordingly. Both a draft EASEE-gas CBP and a German standard look into required purities for hydrogen transport via repurposed natural gas pipelines [5]. Also, CEN TC 234 WG 11 has launched a new work item proposal to develop a European standard for H_2 quality[81]. It should be noted that certain industries require different on-site purity levels. In addition, the Hy4Heat project concluded [36]: *"The hydrogen content in the purity standard has been discussed with stakeholders (hydrogen producers, domestic appliance manufacturers, fuel cell manufacturers, GDNO's) and the 98% vol. minimum hydrogen content is viewed as a reasonable and pragmatic value. The range and quantity of trace components reflects those from existing hydrogen standards and ones from existing natural gas quality requirements. The overall view is that large scale hydrogen production systems can produce hydrogen purity to meet these limits and that the concentration of the trace components will not impact on the overall hydrogen fuel utilisation in traditional domestic appliance designs (albeit ones that are suitable for hydrogen use)."*

81 The starting point of CEN work on H_2 quality standard is the German standard G2060 which includes a 98% vol. H_2 purity level [37].


Picture courtesy of EBA

7.3.6 CEDEC, EUROGAS, GD4S, GEODE VIEWS FOR DSOs

The existing gas infrastructure is a valuable asset to reach the climate targets. The joint operation of methane and hydrogen grids allows DSOs to react flexible to the upstream and downstream developments. This also enables the DSOs to react to the needs of the connected end-users and producers. More research is needed on small scale production of hydrogen, SNG or biomethane and decentralized storage to allow as much as possible the decentralized production. The mass-production and roll-out of modern and high efficient hydrogen ready appliances and applications is key for a smooth transition. Digitalization and smart grids with tracking systems will enable the whole process.

7.3.7 ENERGY COMMUNITY SECRETARIAT VIEWS

Out-EU dimension of the EU decarbonisation should be considered when defining future rules and actions. Importance of smooth cross-border flows, potential external sources and transit countries should be taken into account when defining the rules for the EU and their implementation at the borders to the third countries, as well as when extending the acquis in the Energy Community.

8 CONCLUSIONS

In order to timely deliver on the ambitious European policy objectives, a smart energy system integration is needed. This means that renewable and low carbon gases can be transported, stored, and distributed through gas infrastructure and are used in a dynamic combination with the electric grid along the different end-use sectors. Providing such an interconnected energy system does not come without challenges, especially due to the fact that injection of hydrogen in the system changes the gas quality which is of paramount important for several industrial processes.

The challenge for the coming years will be to define and develop the necessary policies and technologies that will retain the interoperability of different parts of the EU gas network and therefore allow for a sustainable and economically viable decarbonization of all sectors. The repurposing of natural gas pipelines into dedicated hydrogen networks is already materialising and in some member states, repurposed H_2 backbones can be a reality in just few years.

New technological developments and strengthening the information provision among parties have the potential to overcome some of the technical challenges that may arise, yet the expected diversification and decarbonisation of gas supplies poses an extra challenge to achieve a cost-effective and interconnected energy system. Stakeholders discussions have led to a better understanding of which challenges may arise and which tools and solutions need to be implemented to ensure a smooth transition. As a result, the group concludes that nowadays, up to 2% vol. H_2 can be in general technically handled. This percentage can be higher in many sectors, except in those which use very sensitive processes (like the acetylene production).

Short/mid-term developments are expected to allow current industrial stock, except feedstock usage, to handle higher H_2 percentages. Yet, the fluctuation of the hydrogen percentage in natural gas will still be a concern for the industry. In those cases, de-blending could be used for dedicated hydrogen transport to industrial users. The situation for the domestic sector is different since it is ready to handle up to 10% vol. H_2 (even when fluctuating) and without further investments. Since only domestic sector can manage H_2 fluctuations, keeping the H_2 percentage constant is complex (without storages or a hydrogen backbone systems nearby) higher hydrogen blends seem only feasible regionally.

In certain cases, a turning point from which the increased H_2 concentrations in the system might not be feasible technically or economically will be defined. In these regions, once that turning point is reached, a complete transition to hydrogen may be more cost-efficient than increasing the concentration of hydrogen in mixtures with natural gas. In other regions, a timely construction of a H_2 backbone will be of highest priority and heavily relying on the repurposing of existing natural gas pipelines. Nevertheless, there is no single solution for the entire European gas sector due to the specificities of different regions and different (sometimes competing) policies. In this regard, in the short/mid-term it is likely that different pathways will coexist: methane backbone (using natural gas, biomethane and/or syngas), hydrogen blending and the incipient development of the European Hydrogen Backbone at TSO and DSO level.

Further into the future, hydrogen demand is expected to increase at all levels. Therefore, the full deployment of dedicated H_2 grids at TSO and DSO level is expected to be taking place. Depending on national and regional conditions, as well as customers' needs, requirements and grid topology, hydrogen blending up to 20% vol. is expected to be present in some regions either for consumption or as a buffer to inject hydrogen surplus. Major deployment of new (or upgraded) devices and 'smart' tools is expected to be required across the network (including at IPs), especially gas analysers to measure H_2 content.

In the long run, most sectors will likely retrofit to dedicated H_2 systems. Yet, that may not be possible for some specific industrial processes. Therefore, in order to continue supplying consumers who are largely dependent on methane to be used for the production of chemicals, there will also be methane networks in the future at the transmission and distribution network level. This methane network could include biogas/biomethane and synthetic natural gas (SNG) depending on the national and regional developments. The group acknowledges that additional efforts will be needed to timely provide the set of updated standards and codes for a widespread adoption of H_2 in all parts of the gas value chain in a timely manner.

Although great efforts have been dedicated to provide a comprehensive and updated picture, forecasting the long-term future is not possible. Especially due to the rapid evolvement of the sector and the upcoming changes in the legislative framework which will definitely have an impact on how each sector sees its way through decarbonisation. Therefore, the analysis presented here is of an illustrative nature, examining the impacts, challenges and opportunities of possible ways of decarbonising the gas value chain. Most likely the future will be a combination of all options in one form or another. In any case, the information provided should be understood as a best estimate in time of how each stakeholder sees the future developments within its sector.

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LEGAL DISCLAIMER

This report was prepared by all participating associations (see section 1.6.2) on the basis of information collected and compiled by within subgroup 2 of the prime movers group in gas quality and hydrogen handling.

The information contained herein does not necessarily represent the views of all members of the stakeholders involved. The mention of specific companies or certain projects or products does not imply that they are endorsed or recommended by the stakeholders involved in preference to others of a similar nature that are not mentioned.

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