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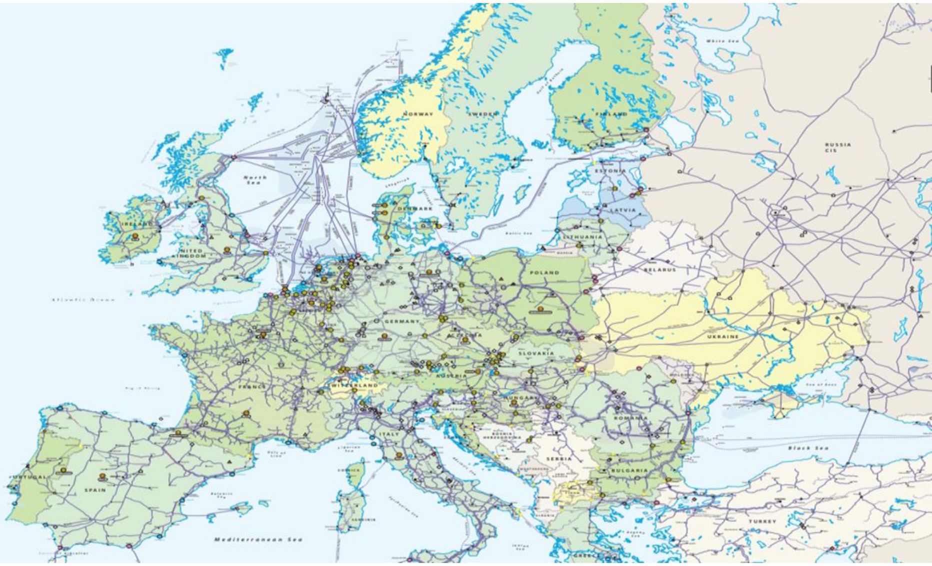

PMG-Sub-group 2) Value chain ‘roadmap’ & solutions

Conclusions from discussions held between January and June 2021

Co-chairs of PMG-SG2:

Peter van Wesenbeeck, EASEE-gas
Ruggero Bimbatti, GD4S

June 2021

Disclaimer

The information included in this presentation is subject to changes. The proposals are presented for informative purposes only since the work is still in progress. Stakeholders from the whole gas value chain provided their inputs in a best effort basis and based on current knowledge.

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Presentation of Prime movers' Group in GQ&H2 handling

Prime movers' group on Gas Quality and H2 handling

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 low GHG usage

While facilitating knowledge sharing on gas quality and H2 handling topics, as well as providing the necessary technical inputs to future Commission proposals in 'Hydrogen and Gas markets Decarbonisation Package'

Promote a fact-based, technology-neutral, and **fair discussion** among stakeholder of the whole gas value chain	Assess the need for **new or upgraded tools** to ensure system interoperability, security of supply and **meet end-users' needs and safety requirements**	Facilitate the development of **innovative and cost-efficient ways** to handle gas quality

Deliverables proposed for 2021

1. During Q1 and Q2 2021: Recommendations to implement the proposed WI classification system at exit points by CEN TF1 (Sub-group 1, SG1 in short)

2. For Q3: Co-developed roadmap from the whole gas value chain based on recommendations, best practices and lessons learnt about existing and potential gas quality and H2 handling options and tools. The final deliverable seeks to sketch out a cost-efficient 'step-by-step' approach to connect each individual sector or area within a future decarbonized gas system (Sub-group 2, SG2 in short). **First findings can be found in this presentation.**

The group deals with both blending issues as well pure hydrogen quality aspects, since each comes with distinct challenges
Public material is available in the process website: prime-movers-group-gas-quality-and-hydrogen-handling

Around 40 EU organisations have joined

* GWI representative is invited to participate due to his experience and involvement in gas quality topics, particularly in CEN GQS

Findings from PMG-SG2 work

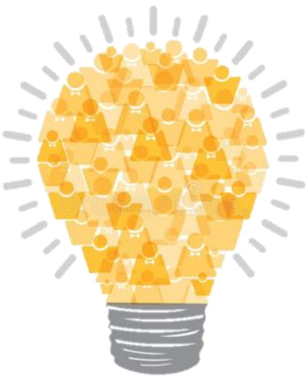
Sub-group 2 scope & goal

Provide conclusions that could be inputs to future Commission proposals on gas market design

Facilitate **knowledge sharing and exchange** about the commonly faced **challenges related to gas quality and H2 handling**, as well as best practices and lessons learned on how to overcome them

Identification and **assessment of the possibilities** for implementing gas quality & H2 management tools at different interfaces and check the **feasibility of interlinking** them for decarbonised systems

Seek to sketch out a cost-efficient **'step-by-step' approach** to connect each individual sector or area within a future 'decarbonized' gas system. Assess what can be done and by when (short/medium and long-term)



Key points of SG2 deliverable (Q3 2021)

Deliverable type

- Include all aspects (**technical, economic, policy**) **under different timelines** (today, short/mid, long term)
- Indicate **current barriers, future developments** (regulatory & technical), and **recommendations/action plan**
- Provide sufficient information to point out trends

Technical

- Identify **technical feasibility of proposed solutions**
- Link **solutions to date** (what is possible by when)
- State of the art knowledge

Economic

- **Cost of H2-ready components**
- Hydrogen **deblending costs** & feasibility
- **Gas quality management costs**

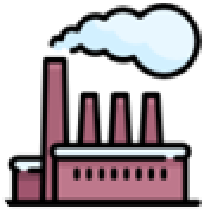
July deliverable
(PMG-SG2-014 &
PMG-SG2-015
documents)

Policy

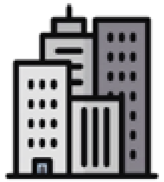
- Overall goal is to **give inputs to EC work on "Hydrogen and decarbonised gas market package"**
- Assess regulatory **barriers & include recommendations**
- **Mutual understanding** of ideas, concerns and challenges along the gas value chain

Note: Description of icons used

Industry
(Combustion)

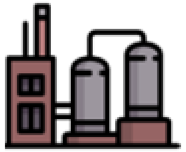


Industry
(Power Station)



Residential
(Domestic heating, cooking)

Mobility sector



Industry
(Feedstock)

Level of hydrogen

Level of Natural gas/biomethane/ synthetic methane

Note: All H2 percentages are reflected in Vol.-%

Current scenario (2021). Findings

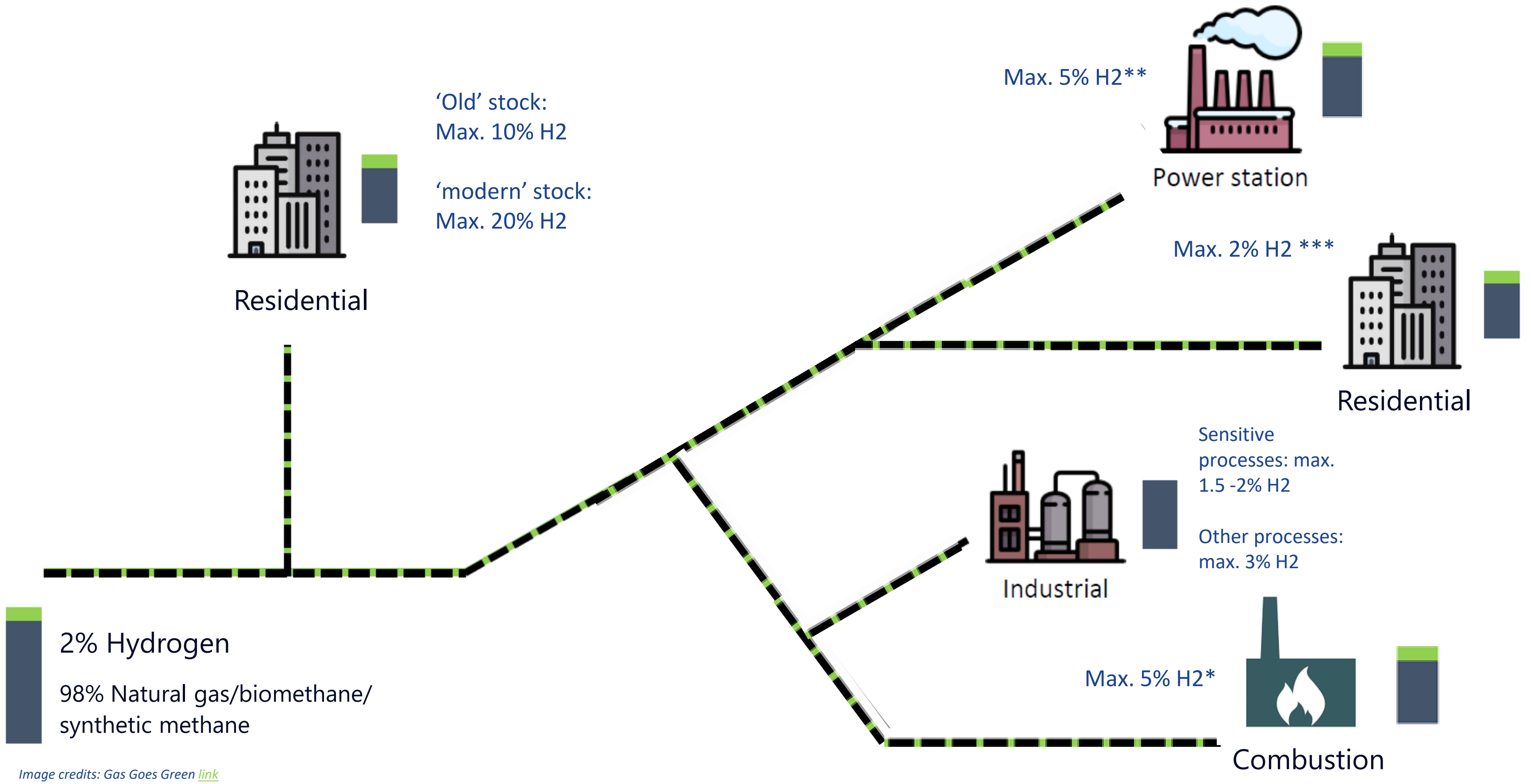


Image credits: Gas Goes Green link

- Except for sensitive processes (e.g., acetylene process), current industrial stock can handle 3% H2
- Depending on the sector, (and NG base composition) this percentage can go higher (e.g., up to 5% H2 for power plants). Yet, large H2 fluctuation in NG cannot be properly handled. Therefore, no intermittent hydrogen injection possible.
- The domestic sector can already handle 10% - 20% H2 without further investments

*based on stakeholder inputs
**with minor modifications, on a case-by-case basis
*** if CNG station present

Note: All H2 percentages are reflected in Vol.-%

Short/mid-term scenario (2025-2030). Findings

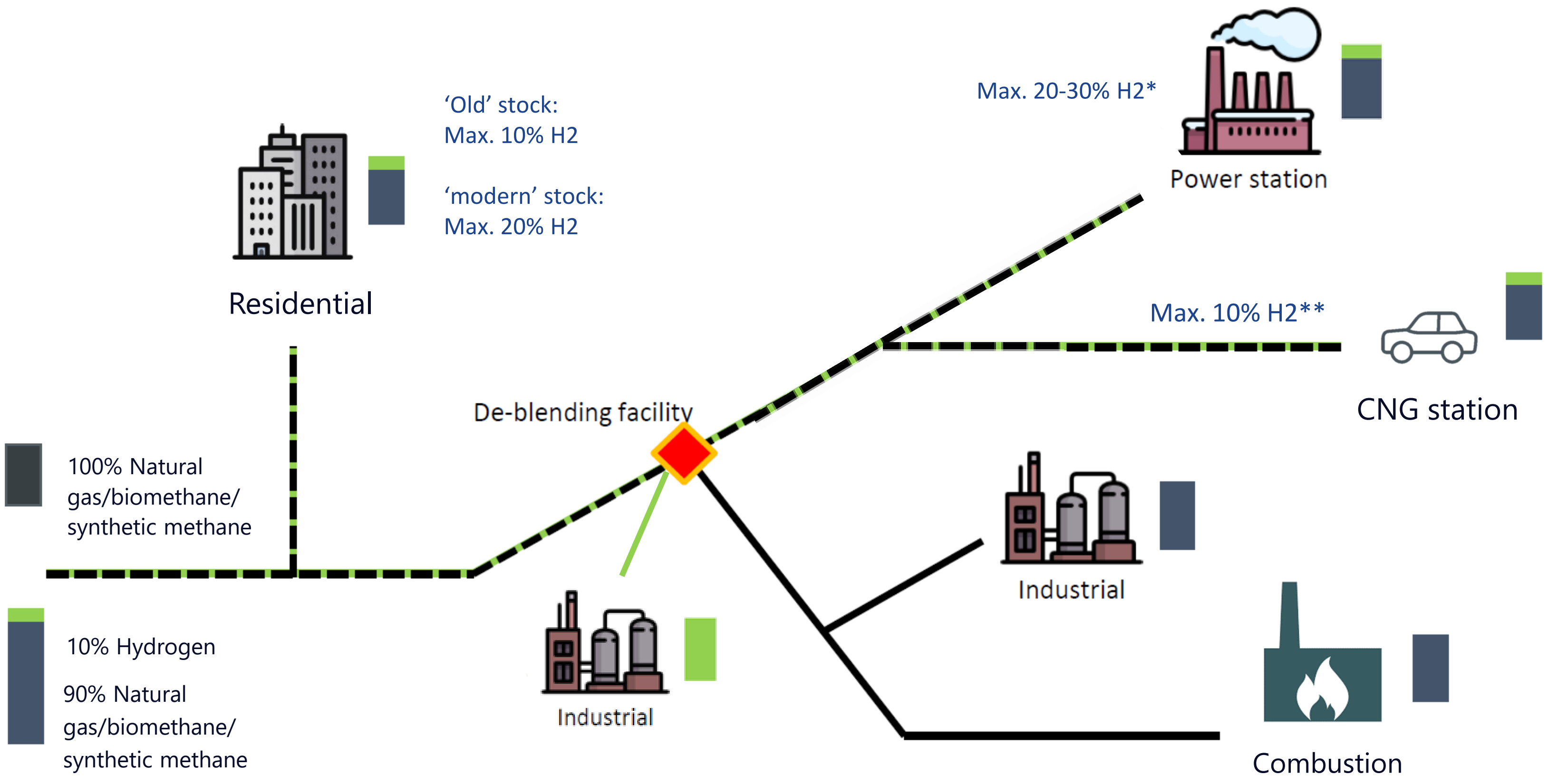


Image credits: Gas Goes Green link

**with upgrade, on a case-by-case basis*
*** for CNG vehicles. Not ready in the market yet*

- In the short-term, minor retrofitting will allow current industrial stock, except feedstock usage, to handle higher H2 percentages (e.g., 20% - 30% H2 by turbines and engines). Yet, H2 fluctuation in NG will still be a concern for the industry. No intermittent hydrogen injection possible.
- The domestic heating sector is ready for 10% - 20% H2 (i.e., no further investments) and has no issue with fluctuating percentages. Intermittent injection of hydrogen is allowed.
- H2 blending with de-blending downstream could be used for dedicated hydrogen transport to industrial users
- *Since only domestic sector can manage H2 fluctuations, and keeping the H2 vol.-% constant is complex (without storages or H2 backbone systems nearby) H2 NG blends > 2% - 3% H2 seems only feasible regionally*

Note: All H2 percentages are reflected in Vol.-%

Mid-term scenario (2030-2040). Findings

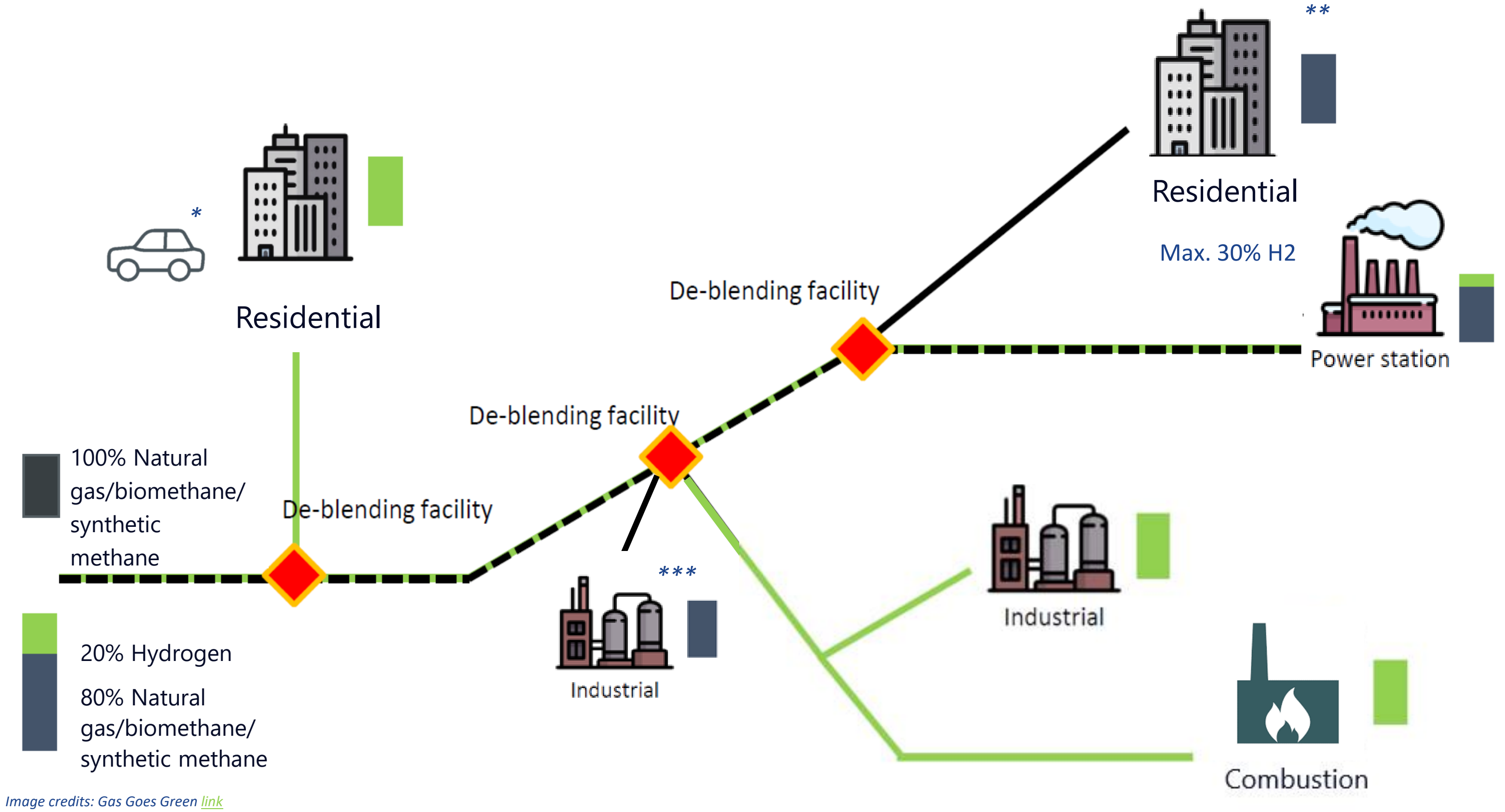


Image credits: Gas Goes Green link

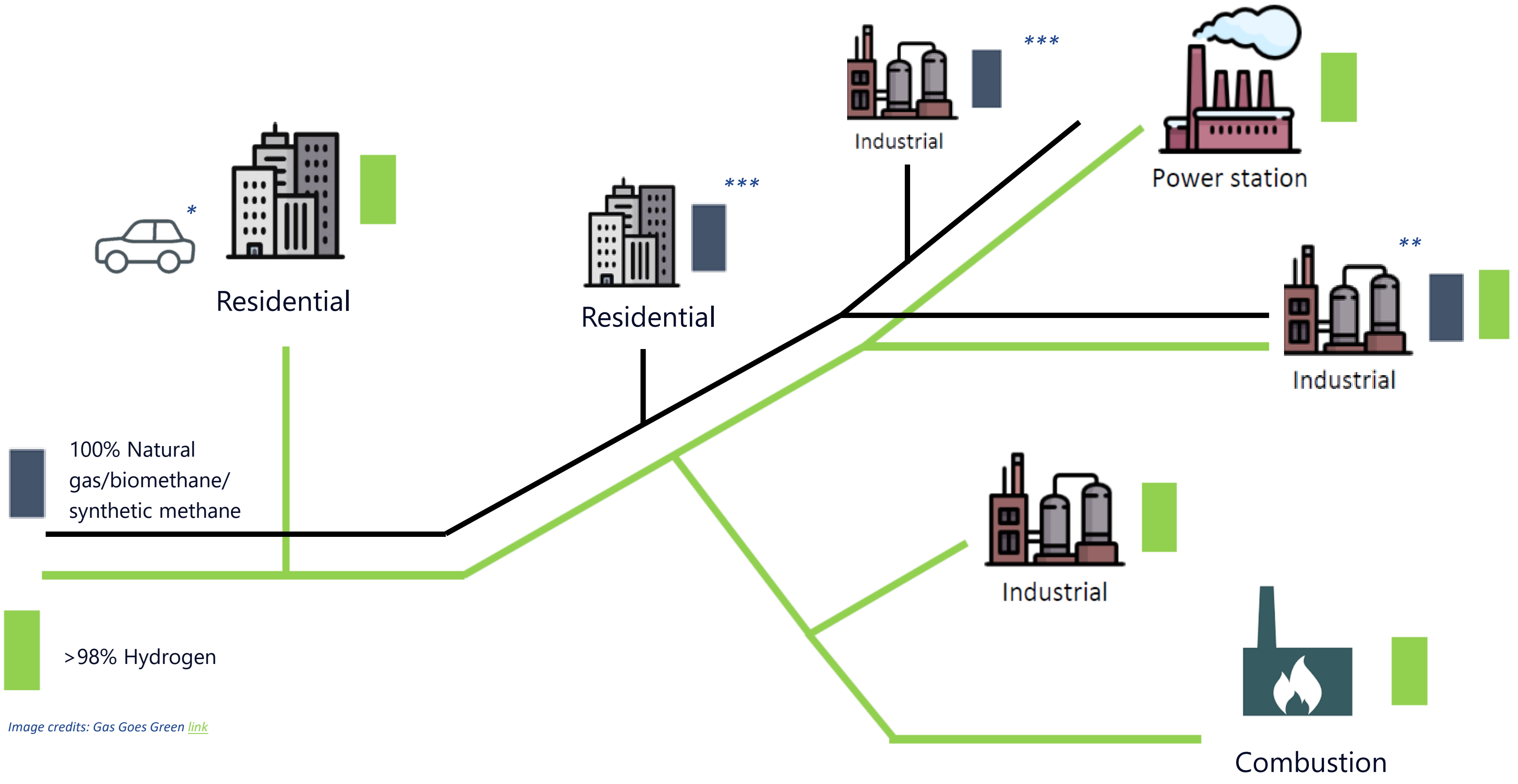
**Fuel cell vehicles*
*** Some regions may still consume NG, biomethane or synthetic methane*
**** Nowadays some industries require CH4 for their processes. R&D is ongoing to analyse the potential solutions*

- Some industries consider that limited investments would be needed to reach higher H2 levels (e.g., up to 25% H2). Yet H2 fluctuation and composition of base NG are of concern. Intermittent injection of hydrogen is not allowed.
- In the domestic heating sector, 20% H2 appliances are available. In the future, they will also be able to be converted to 100% H2 easily (H2ready)
- Industry prefers 100% H2 above H2NG blends and converts part of their processes to 100% H2
- Methanation & deblending facilities are also expected to be deployed in some areas: Deblending costs can be roughly assumed with 1 to 2 €/kg H2 for a membrane/PSA scheme[1].
- *By planning H2 injection points (e.g., location, capacity, buffer storage size) in line with downstream needs and possibilities, expenditures for de-blending and methanation can be significantly reduced*

[1] More details can be found here

Note: All H2 percentages are reflected in Vol.-%

H2 backbone scenario. Findings



- In the long-term, most sectors have plans that allow for a retrofit to 100% H2
- Industry will convert their processes to use 100% H2 (if possible)
- *There will also be customers supplied by grids transporting & distributing biomethane*

**Fuel cell vehicles need a higher purity. For ICE ones, 98%H2 could be sufficient.*
*** Some industrial processes may require both molecules for their processes*
**** There could be customers supplied by grids transporting & distributing natural gas, biomethane or synthetic methane*

Note: All H2 percentages are reflected in Vol.-%

Summary of high-level findings

- Nowadays, up to **2% H2 is not seen as a problem**
- For the mid-term, it is expected that **20% H2 is feasible** (except for regions with feedstock industries or CNG refilling stations). Strongly dependent on composition of base NG.
  - Some industries consider that limited investments would be needed to reach higher H2 levels (e.g., up to 25% H2). Yet H2 fluctuation and composition of base NG are of concern. Intermittent injection of hydrogen is not allowed.
  - The domestic heating sector is ready for 10% H2 (i.e. no further investments) and has no issue with fluctuating percentages. Intermittent injection of hydrogen is allowed
  - Deblending/methanation is a solution to fulfil stricter requirements (feedstock, CNG refilling stations)
  - (Chemical) industry is converting their processes to 100% H2 (H2 backbone, deblending)
- In the long-term, most sectors have plans that allow for a **retrofit to 100% H2**, and some industries are converting their processes to 100% H2, as well.

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Annexes. Details on individual sectors' inputs

Feedback received: Domestic heating

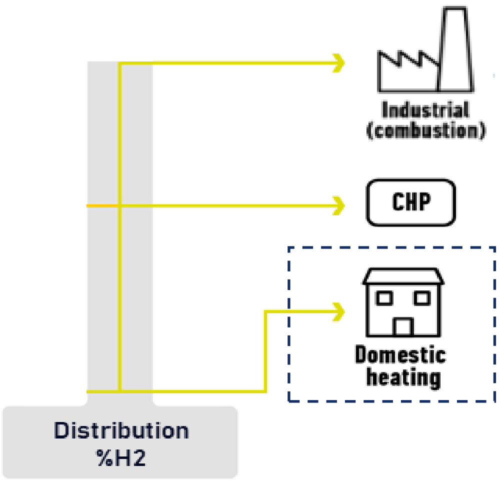

Image credits: ENTSOG roadmap, 2019 link

Installed stock	Gas end use products installed in field (>1995) can work with bio methane and bio-LPG and **up to 10% H2 blend** without any extra cost. Note: Domestic cooking installed stock can generally **handle 10% H2** (even if fluctuating) based on C.E.F.A.C.D inputs
Modern stock	Many modern domestic (≤70 kW) gas condensing boilers can work with **up to 20 vol-% H2** blend[1] with new certification without any extra cost. **H2 fluctuations are not a problem.** [1] 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"
100% hydrogen-ready appliances (new & retofitted)	Increased purchase price of the hydrogen ready boiler compared to a natural gas boiler is on **average about 17%;** about **3.3% for thermally-driven heat pumps**. The price of hydrogen conversion kit **from natural gas to 100% hydrogen** as a percentage of the hydrogen ready boiler purchase **price is about 13%**; about **2.5% for thermally driven heat pumps.** Note: This is based on aggregated figures from EHI members in the position paper attached. These prices can drop in the future, also depending on quantities built.
EHI recommendations	In **2025**: to introduce a mandatory ecodesign requirement for domestic (≤70 kW) gas condensing boilers and thermally driven heat pumps to be '**20% hydrogen appliances**'.
	In **2029**: mandatory ecodesign requirement for domestic (≤70 kW) gas condensing boilers and thermally driven heat pumps are '**100% hydrogen-ready appliances**'. It means that all domestic boilers and thermally driven HPs put on the market to work with natural gas should be designed and approved to be installed and to operate on with it and, following a conversion and re-commissioning process, to then operate safely and efficiently using 100% hydrogen.
	The average replacement rate across Europe is about 4%/ year, which means that the time before replacement is around 25 years.

Information presented in the table is based on European Heating Industry (EHI) inputs

Additional note: Based on 2G manufacturer information replacing current small-scale CHP units to 100% H2 ones, has approx. +20% costs

Note: All H2 percentages are reflected in Vol.-%

Feedback received: Feedstock industry

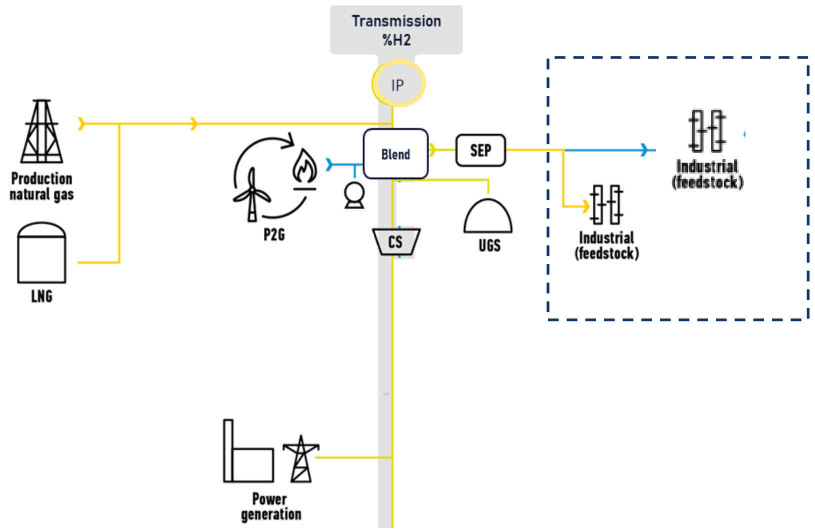

Image credits: ENTSOG roadmap, 2019 link

Installed application	Uncertainty about the possibilities to handle H2 due to the great differences between current processes and technology installed. There are very sensitive processes that can only handle **1.5-2% H2***. For other processes, a **3% H2 does not need to be a problem**. H2 to be provided in "steady" way (i.e., not fluctuating) *Although they are considered to be a minority in the market these commodity value chains are worth billions of euros.
Retroffiting application	Work in progress
Replacement	
Information provision	Information about the type of gas coming to the installation and when it is expected to come.
Industry Recommendations	**Deblending facilities** as a real potential mitigation solution for sensitive chemical processes. Rough estimation: for 10% H2 in NG, to obtain 'pure' NG and 'pure' H2, approx. costs 1 – 2 €/kg H2 (only for the deblending; additional costs on top of commodity price, grid costs, taxes, levies, …) H2 to be provided in a "steady" way (i.e., not fluctuating concentrations)

Information presented in the table is based on CEFIC and IFIEC inputs

Note: All H2 percentages are reflected in Vol.-%

Feedback received: Engines (1/2)

EUROMOT
The European Association of Internal Combustion Engine Manufacturers

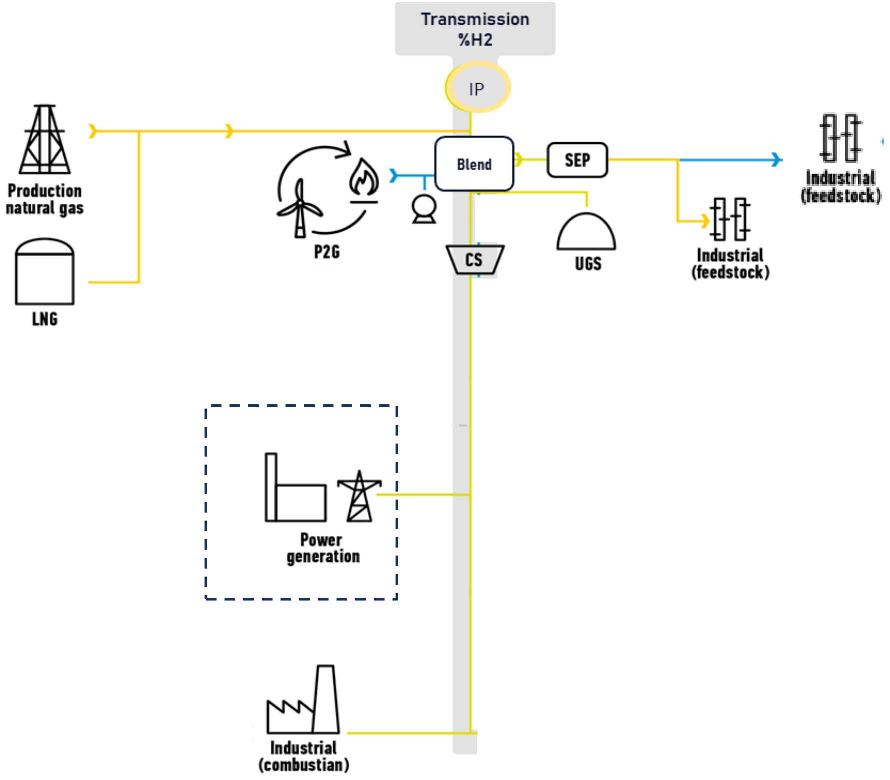

Image credits: ENTSOG roadmap, 2019 link

Installed stock	For current stock, a **2 – 3% H2 injection should not be a problem**. MN will not noticeably be affected, and it is even "good" for ignition purposes.
Retrofitting installed stock	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***. Since the combustion behavior of Hydrogen differs considerably from natural gas, EUROMOT suggests that hydrogen blends of in between 20 vol-% and 100 vol-% should be precluded. *assuming GQ 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).
Replacement of application	New applications are usually equipped with control equipment which allows them to handle wider WI than current installed stock. Engine manufacturers are now working on developing **engines suitable for 100% hydrogen**. By 2030 it could be expected that there are in the market engines for 100% H2 that provide only a 10% decrease of output power in comparison with current NG ones.
Information provision	%H2 fraction and composition of base NG & real-time signal about the Hydrogen content and the calorific value of the final blend
Industry Recommendations	Stable and predictable GQ and H2 content in the blend over given time frame will be essential.

Information presented in the table is based on Euromot inputs

Note: All H2 percentages are reflected in Vol.-%

Feedback received: Engines (2/2)

European Engine Power Plants Association

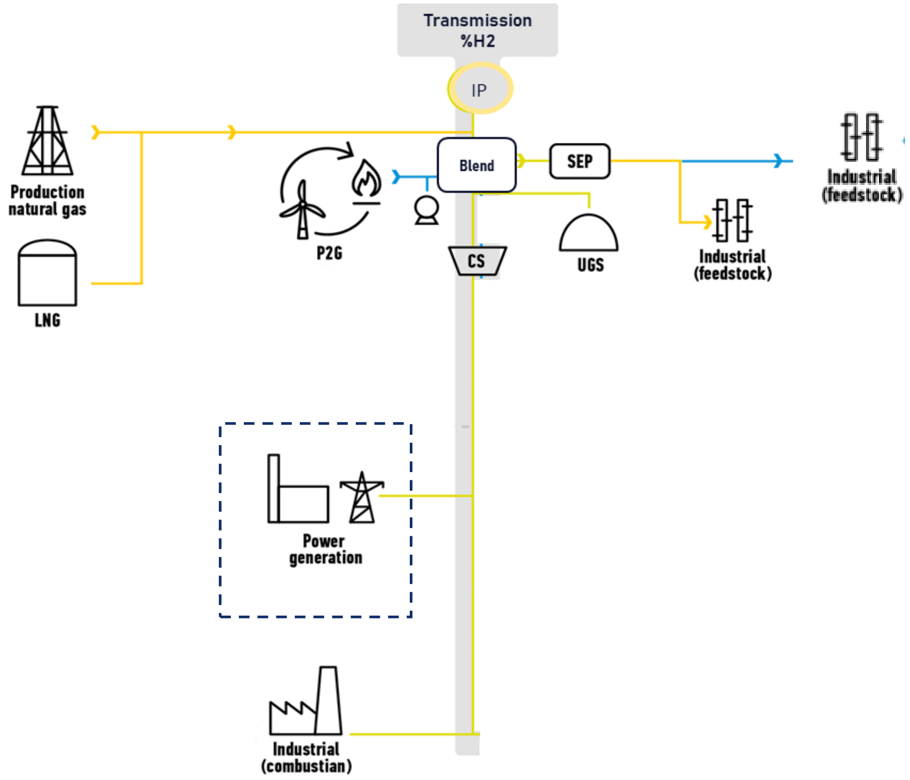

Image credits: ENTSOG roadmap, 2019 link

Installed stock	The installed fleet was optimised for natural gas. Without any modifications most plants will be capable to operate only with **a small share of H2.**
Retrofitting installed stock	The situation 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% H2 – depending on the base gas**. Often an **upgrade for the use with 100% H2 will be possible**. The retrofitting is not only a question of the engine, but concerns the full power plant (explosiveness protection, exhaust treatment ….). EUGINE will provide a checklist for the analysis.
New Plants	In the future, industry will mark all plants with regards to their hydrogen-readiness level. Customers will thus be able to decide for what hydrogen shares (up to 10%, up to 25% or 100%) the plant shall be technically suitable and 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.**
Information provision/ Requirements	The hydrogen-readiness assumes a provision with a predictable and over time relatively constant composition of the gas mix / hydrogen from the grid. Costs for adding onsite gas mixing solutions to control the gas quality would considerably increase costs.
Industry Recommendations	Reliable information on the gas quality (H2-fraction, composition of the base gas, calorific value) is of high importance and should be provided real-time.

Information presented in the table is based on EUGINE inputs

Note: All H2 percentages are reflected in Vol.-%

Feedback received: Gas Turbines (1/2)

Installed stock	Typically, current hardware limited **to 5-10% H2** (according to OEM). No CAPEX needed. <u>**0-5%vol** hydrogen in natural gas</u> • Minor cost impact • No changes to combustion hardware or fuel delivery system, minor modifications to control system/instrumentation (e.g., fuel gas chromatograph compatible with hydrogen)
Retrofitting installed stock	Upgrading existing plants needs individual analysis, beyond the scope of gas turbine units alone. Up to **20-30% H2** blending requires in most cases small modifications to the gas turbine unit. <u>Retrofit for blends : **5-30%vol** hydrogen in natural gas</u> • Cost estimate : 20€/kWe GT output (*) • Upgrade to combustion system and controls. Instrumentation and electrical equipment upgrade for ATEX compliance above 25%vol hydrogen. Require start-up on standard fuel and fuel blending skid. <u>Retrofit for blends : **30-50%vol** hydrogen in natural gas</u> • Cost estimate : 415€/kWe GT output (*) • New machine, currently available from the OEMs, larger fuel delivery pipework, ATEX-rated instrumentation, new combustion system, controls system changes. Start-up on standard fuel required along with fuel blending skid. <u>Replacement for **100% hydrogen**</u> • Cost estimate : 400€/kWe GT output (equivalent to assumed heavy duty gas turbine CAPEX) (*) • New machine, not currently available from the OEMs, use with 100% H_2 only • Replacement 100% hydrogen GT assumed to be established technology by 2030 and NOx emissions compliant without water/steam dilution or flue gas treatment (e.g., SCR).

Information presented in the table is based on European Turbines Network (ETN)

Notes

(*) There may be significant differences between costs for different manufacturers and different gas turbines

(**) H_2 capability given as a range varies by OEM, GT model, and combustion system, rather than an absolute capability range for all heavy duty GTs.

(***) H_2 capability is generally restricted by the OEM to a given fuel composition with limited allowable variation.

Feedback received: Gas Turbines (2/2)

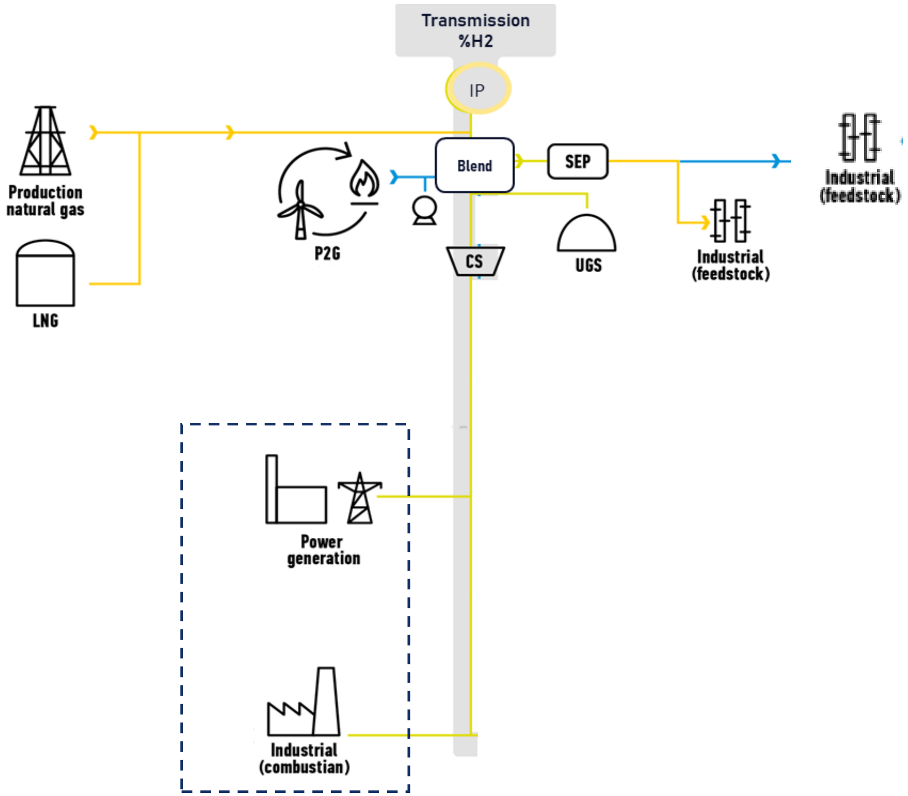

Image credits: ENTSOG roadmap, 2019 link

H2-ready new plants	A new power plant built today needs to account for: (a) additional initial investment to allow the future retrofit (b) the retrofit cost itself 2030 horizon: planning for 20-30%vol H2 co-firing with natural gas (a) An **additional <5% investment** to allow the future retrofit (b) An approx. cost of **<10% of the initial investment for the retrofit** in ~2030 2040 horizon: planning for 100%vol hydrogen firing (a) An **additional <5% investment** to allow the future retrofit (b) An approx. cost of **<15% of the initial investment for the retrofit** in ~2040
Industry Recommendations	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

Information presented in the table is based on European Turbines Network (ETN)

Note: All H2 percentages are reflected in Vol.-%

Feedback received: Mobility

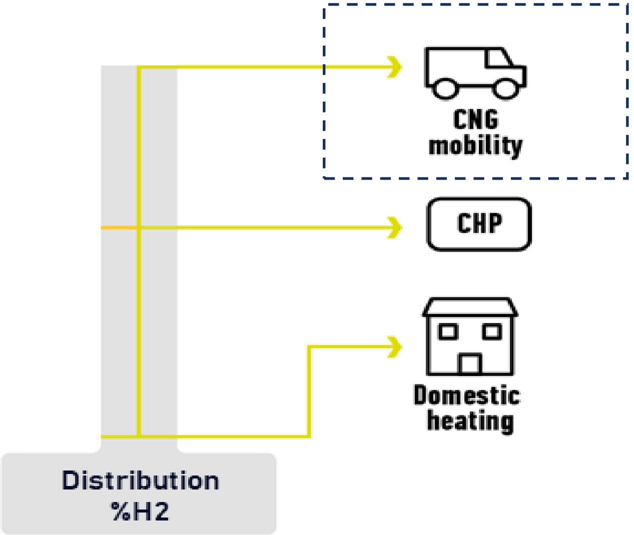

Image credits: ENTSOG roadmap, 2019 link

Installed stock	Note: The present technology CNG refueling stations have steel components which resistance to H2 embrittlement must be investigated. 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% H2** (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 cost, some OEM seem to still prefer type 1 cylinders for other reasons. For fuel cells, only very high purity H2 is accepted with the present FC technology.
New stock (in the mid-term)	Under discussion. **10% H2 might be achievable** by some manufacturers for ICE vehicles. Transition towards **100% H2 for mobility sector might be one solution**. The present CNG infrastructure can be a platform for delivering also pure H2 in future, as another fuel sold, so with some synergy. Maybe also dedicated H2 small scale infrastructure is worth considering,
Industry Recommendations	Reciprocating engines need stable gas composition; variations in H2 content causes variations of WI, anti-knocking power, combustion velocity, etc. The engine must be very flexible to accept variations above a certain threshold (TBD); probably this is really challenging now. For ICE the OEM can design proper solutions suitable to blends. But the variability of composition can become an issue. Potential solution would be de-blending; but it has complexity, scalability and costs that must be duly assessed

Information presented in the table is based on NGVA inputs

Thank you for your attention

Co-chairs of PMG-SG2:

Ruggero Bimbatti

Peter van Wesenbeeck

For further questions, please contact:

Rosa Puentes (rosa.puentes@entsog.eu)
Thilo von der Grün (Thilo.Gruen@entsog.eu)
Nicolas Jensen (njen@eurogas.org)
Leonardo D'Acquisto (leonardo.dacquisto@italgas.it)
Monica Di Pinti (monica.dipinti@cedec.com)
Henning Eklund (heklund@geode-eu.org)