Market state and trends in renewable and low-carbon gases in Europe

A Gas for Climate report

December 2020

GAS FOR CLIMATE
A path to 2050

Guidehouse

Imprint

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Executive summary

Renewable and low-carbon gases are indispensable to fully decarbonise the European Union (EU) energy system.

The EU aims to fully decarbonise its economy, requiring a complete overhaul of the energy system and its infrastructure by 2050. The Green Deal, as announced by the European Commission (EC) in December 2019, aims to achieve at least 55% reduction in greenhouse gas (GHG) emissions by 2030 compared to 1990 levels. Raising the ambitions of EU climate policy will require significant investment in energy efficiency, renewable energy, new low-carbon technologies, and grid infrastructure. It will also necessitate the close integration of the electricity and gas sectors and their respective infrastructures. Over the past few years, a series of studies by the Gas for Climate consortium showed that renewable and low-carbon gases have an important role to play in the future EU energy system. Combined with the existing gas infrastructure, renewable and low-carbon gases can help to achieve the transition to a net-zero energy system at the lowest societal costs.[1]

Gas for Climate defined a critical pathway of required developments across the supply chains for biomethane and green and blue hydrogen between today and 2050 to achieve a decarbonised energy system. A comprehensive overview of the current market state and trends towards further scale-up and cost reductions was not yet available.

To facilitate achieving at least 55% GHG reduction by 2030 and to set Europe on a pathway towards full decarbonisation at the lowest overall societal costs, Gas for Climate defined a critical pathway of required developments in the 2020s across supply, certain demand sectors, and infrastructure. Two renewable and low-carbon gases will play a key role in decarbonising the European energy system: biomethane and (green and blue) hydrogen. In the short term, biomethane is expected to further scale up; green and blue hydrogen are expected to further develop to accelerate scale-up starting in the mid-2020s. These required developments will enable an 11% share of renewable gas (biomethane and green hydrogen) in total EU gas demand by 2030.

1 All reports can be downloaded from the Gas for Climate consortium webpage at https://gasforclimate2050.eu/
2 (Guidehouse, 2020)

The pathways study demonstrated that current policies and trends are insufficient to drive the abovementioned required developments.[2] Additional policy and market action is required to speed up the transition. Renewable and low-carbon hydrogen and biomethane developments are already attracting a lot of positive attention in the media, in policy discussions, and in company strategies. Yet, a comprehensive overview of the current market state and of trends towards further scale-up and cost reductions was not yet available.

This market state and trends report is the first-of-a-kind comprehensive overview of the market state and trends of biomethane and green and blue hydrogen. The report identifies key trends across the supply chain of biomethane and green and blue hydrogen in Europe and tracks the status of each key trend towards achieving the required pathway developments in the early 2020s-2030.

This report identifies key trends in biomethane and green and blue hydrogen supply, demand, and infrastructure across Europe; it focuses on indicators and project examples by collecting and combining factual and statistical information and showcasing projects. These key trends are also analysed to track their progress in line with the required pathway developments in the short term (early 2020s-2030):

- **Green:** Trend is in line with required pathway developments.
- **Blue:** Emerging trend is developing.
- **Yellow:** Early developments, no trend yet.

While the transformation towards net-zero CO_2 emissions is multifaceted and consists of many interlinked market and technological developments, the main focus of this analysis is on key trends in those sectors and subsectors that are most promising to decarbonise in the early 2020s-2030. This report is the first in a series aiming to provide regular insight into the current state and trends across the supply chain of renewable and low-carbon gases in Europe.

The majority of the identified key trends show emerging developments across Europe that are in line with the required developments on the path to 2030 (blue). Additional action is required to further bring down hydrogen production costs, boost cross-border trade of hydrogen and increase building renovation levels. In addition, early developments are shown in hydrogen use in the refining and chemical industry as well as in shipping, but more efforts are required to establish a trend (yellow). Significant developments are seen in the deployment of biomethane and green and blue hydrogen projects, biomethane feedstock changes, hydrogen developments in the iron and steel sector and biomethane grid injection levels (green); these trends are breaking through in line with the required pathway developments and are highly likely to continue.

Supply – Biomethane

A significant biogas sector exists in Europe, producing around 170 TWh/year (16 bcm natural gas equivalent, 2018). Biomethane production volumes are rapidly growing, with around 23 TWh (~2 bcm natural gas equivalent) produced in 2018. The scale-up of biomethane production shows a positive trend in the EU—strong growth of around 15% in biomethane production volumes and a 17% increase of anaerobic digestion plants in 2018. With flatting growth in biogas developments, this indicates a shift from biogas to biomethane production. Feedstock used for biomethane production is progressively shifting from dedicated energy crops to waste and residue feedstocks in new plants. In 2019, waste and residue feedstocks were used in almost 65% of EU biomethane plants compared to 40% in 2012.

Almost all biomethane in Europe is produced using anaerobic digestion technology, with average digester sizes showing a growth of around 4% between 2017 and 2018. Membrane separation is increasingly being adopted—it is now the most common upgrading technique, with a market share of approximately 34% of cumulative installations in 2019. Other biomethane production techniques, such as thermal and hydrothermal gasification show high potential, but are only in an early commercial stage and industrial demonstration stage, respectively.

Emerging trends are seen in biomethane cost reduction and cross-border trade. Current biomethane production costs for anaerobic digestion in Europe range between €50/MWh and €90/MWh (~€0.50/m^3 to €0.90/m^3), mainly depending on feedstock used and the size of the digester. Costs are gradually coming down for larger anaerobic digestion plants with certain waste stream feedstocks. Production costs for thermal gasification are estimated to be around €90-€100/MWh (~€1.0/m^3). Cross-border trade of biomethane certificates is still limited in the EU at less than 10% of biomethane production levels, but a gradual increase is occurring with key players being Denmark, Sweden, and Germany and the development of the European Renewable Gas Registry (ERGaR) certificate of origin (CoO) scheme.

Supply – Hydrogen

In the EU, around 339 TWh_{LHV} (10.2 Mt H_2, 33 bcm natural gas equivalent) of hydrogen was produced in 2019. Compared to grey hydrogen, the share of green and blue hydrogen produced is still small (less than 1% of production). Yet, electrolyser capacity and the number of projects in the feasibility phase show a rapid growth in the EU. Technological developments are on track, and decisions on pilot projects for 10 MW and larger are coming up. Electrolyser capacities have been growing, with an average annual growth rate of around 20% between 2016 and 2019. Large-scale blue hydrogen projects are under development across industrial clusters around the North Sea. Based on current announcements, a significant acceleration of green and blue hydrogen projects is expected between 2020 and 2030. The EU Hydrogen Strategy and national hydrogen strategies are expected to drive this increase even further.

Emerging trends are seen amongst hydrogen production technologies. Most green and blue hydrogen production routes are in an early commercial stage, but plant and stack sizes are increasing, and hydrogen production and CO_2-capturing processes are becoming more efficient. Electrolyser capacities are growing, and Proton Exchange Membrane (PEM) technology is closing the gap with Alkaline Electrolysis (ALK) and Solid Oxide Electrolysis Cells (SOEC) efficiencies, by adding 4% system efficiency, on average, since 2017. Newly announced blue hydrogen projects mostly rely on ATR technology, which has various economic and operational benefits in combination with CCS at large scales.

An increasing number of upcoming electrolyser projects intend to source renewable electricity as feedstock. Over 54% of announced electrolyser projects in the EU have disclosed their sourcing plans, with wind energy being the preferred renewable electricity source (39% of announced projects, representing 77% of announced capacity).

Early developments are taking place around production costs and cross-border trading, but additional attention is required. Production costs for green hydrogen range from €70/MWh to €130/MWh, and mainly depend on electricity price and electrolyser parameters. Costs are expected to drop to the level of grey and blue in the coming decades. Blue hydrogen is currently more cost-competitive compared to green hydrogen, with costs estimated between €37/MWh and €41/MWh depending on the technology and infrastructure requirements. Cross-border trade of hydrogen certificates is still limited in the EU, with the first CertifHy certificates launched in 2018. Hydrogen certificate trading is expected to increase following national and EU developments.

Demand – Industry

Green or blue hydrogen can play an important role to decarbonise the iron and steel sector, which has limited alternatives for decarbonisation. New hydrogen processes in steelmaking are in the demonstration and early commercial stages in Europe. These processes include directly injecting hydrogen into blast furnaces which can reduce GHG emissions between 20% and 40%, or using hydrogen for the direct reduction of iron which can achieve emission reductions of more than 95%.

Biomethane is gaining interest as an alternative to natural gas for medium and high temperature heat generation and as a feedstock and energy carrier. Multiple industry sectors are starting to integrate biomethane, either as an energy carrier when biomethane is injected in the natural gas grid, through the integration of biomethane production in industry processes, or as a feedstock to produce high value chemicals.

All large EU refineries use natural gas and other fossil fuels to produce grey hydrogen through different reforming processes. About 45% of industrial hydrogen consumption is used for oil refining, followed by ammonia production (34%). Early project developments and investigations are ongoing in the refining sector and chemicals sector to adapt grey hydrogen production to blue hydrogen or to substitute grey hydrogen for green hydrogen. Shifting from grey to blue or green hydrogen can be done without major process adaptations, but additional attention is needed to further boost these developments.

Demand – Transport

The uptake of renewable and low-carbon gases in road transport and fuelling infrastructure is emerging in the EU. Increasing deployment of bio-CNG/LNG and early hydrogen is taking place in the heavy road transport sector, and adoption of compressed natural gas (CNG) and liquified natural gas (LNG) vehicles grew respectively by 5% and 35% annually since 2016, for buses and heavy freight trucks. Biomethane use in Europe already represents 17% of all the gas used in road transport today. The number of LNG and hydrogen fuelling stations is still limited but experienced significant growth over the last year, and the number of CNG fuelling stations is gradually increasing as well. In addition, the use of hydrogen in transport is gaining traction.

Early stage hydrogen developments are taking place in the EU shipping sector. Several pilots are ongoing to test maritime applications of hydrogen fuel cells, mostly in Northern Europe. LNG use in shipping is growing, as LNG bunkering facilities for ships are increasingly being established across the EU (supported by the TEN-T regulation).

Demand – Built environment

Decarbonisation and renovation of the built environment is challenging because of the high abatement cost for deep renovations, the high number of buildings requiring renovation (>97%), the dispersed ownership of the building stock, and the potential construction of new infrastructure. In Europe, an emerging trend is seen with the uptake of hybrid heating technologies. Early deployment is taking place with around 18,000 hybrid heat pumps installed in Europe in 2017, and uptake is gaining momentum, particularly in Italy and France. Also, recently several gas DSOs have started to intensively explore the potential of using gas grids to distribute hydrogen (e.g. to decarbonise heat), referencing TSO plans for a European Hydrogen Backbone.

The Renovation Wave for Europe was announced by the European Commission in October 2020. Currently, the weighted annual energy renovation rate in the EU is only around 1%, with deep renovations only being carried out in 0.2% of the building stock annually. Early developments are taking place to increase these renovation levels in the EU, but more action is needed.

Infrastructure – Biomethane

Over the last decade, biomethane grid injection volumes have increased from around 5.5 TWh to approximately 20 TWh per year in Europe, resulting in a 0.4% share in the gas network, with higher ratios in some countries. This share is expected to further increase to 5%-8% (on average) by 2030 based on European and national targets, with differing shares among EU member states. About 90% of biomethane plants in the EU are connected to the gas grid, though differences in the connection profile exist between countries.

The early commercial deployment of biomethane centralised upgrading and reverse flow are emerging trends seen in the EU. Several reverse flow plants are installed in France (two in 2019), Germany (more than six in 2020), and the Netherlands (one in 2019). Biogas pooling for centralised upgrading is in an early development stage, with two main projects in Europe: one in Bitburg, Germany and the other in Twente, the Netherlands.

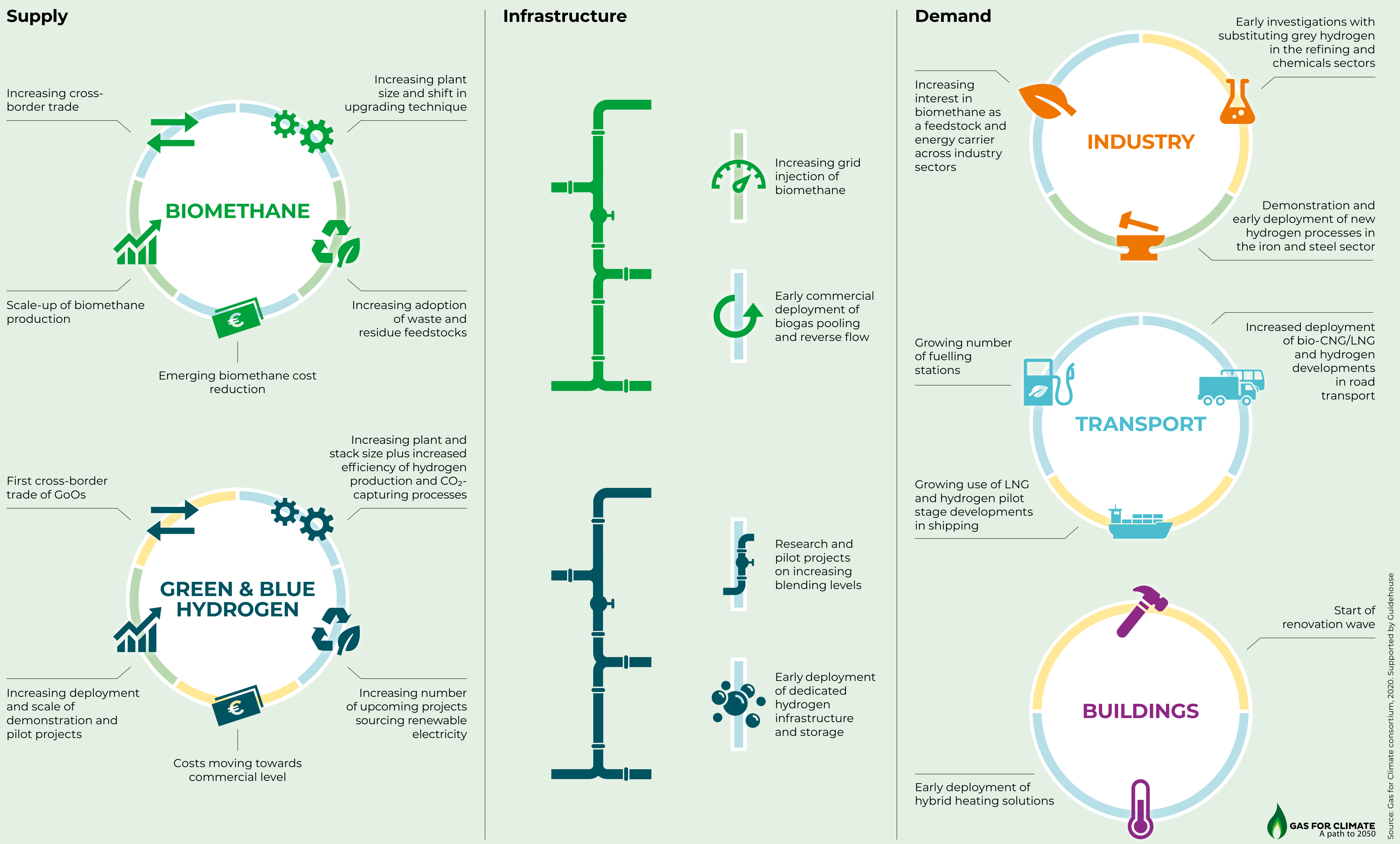
Infrastructure – Hydrogen

Emerging trends are seen in the EU with research and pilot projects regarding increasing levels of hydrogen blending in natural gas grids and the development of dedicated hydrogen infrastructure. Hydrogen blending tolerances in the natural gas distribution grids could range between 5% and 20% and are achievable without major upgrades or adaptations to appliances and infrastructure. Research and pilot projects on blending levels are ongoing.

Regional dedicated pipeline infrastructures already exist, connecting merchant producers to users of (grey) hydrogen. Further dedicated hydrogen infrastructure development is gaining momentum through the conversion of gas infrastructure and the early development of new hydrogen networks, such as the European Hydrogen Backbone.

Key trends in renewable and low-carbon gases in Europe

Green: Trend is in line with required pathway developments
Blue: Emerging trend is developing
Yellow: Early developments, no trend yet



Contents

1. Introduction

The European Union (EU) aims to fully decarbonise its economy, which requires a complete overhaul of the energy system and its infrastructure by 2050. The European Commission announced the European Green Deal in December 2019; this deal includes a wide variety of plans to step up climate mitigation policies. At the EU level, debate is ongoing to bring developments to reduce greenhouse gas (GHG) emissions by at least 55% by 2030 forward. Raising the ambitions of EU climate policy will require significant investment in energy efficiency, renewable energy, new low-carbon technologies, and grid infrastructure. It will also necessitate the close integration of the electricity and gas sectors and their respective infrastructures. A decarbonised Europe will be based on an interplay between the production of renewable electricity and renewable and low-carbon gases to transport, store, and supply all sectors with renewable energy at the lowest possible costs.

In a series of reports over the past few years, the Gas for Climate consortium has showed that renewable and low-carbon gases have an important role to play in the EU energy system and that existing gas infrastructure and knowledge can support the transition to an energy system with net-zero CO_2 emissions at the lowest societal cost.[3] The Gas for Climate vision and pathways[2] towards 2050 cover all energy-intensive economic sectors and demonstrate that renewable electricity and renewable and low-carbon gases play a crucial role in achieving Europe's climate ambitions for 2030 and 2050 (see Box 1). The pathway analysis also demonstrated that current policies and trends are not yet sufficient to realise that ambition. Policy and market action are required to speed up the transition, and progress of necessary developments must be closely monitored to ensure the transition is done at the lowest societal costs.

Renewable and low-carbon hydrogen and biomethane developments attract a lot of positive attention in the media, both in discussions of new policies and in company strategies. However, a single comprehensive overview of the current market state of deployment and of trends towards further scale-up and cost reductions is missing. This report aims to fill this gap by providing an overview to policymakers, energy users and producers, equipment manufacturers, and infrastructure companies. It is the first in a series that aims to provide insight into the current state and trends of renewable gases.

The authors would like to thank the European Biogas Association (EBA) for its extensive insight into the latest biogas and biomethane statistics in Europe. This report also builds on important data retrieved from the Fuel Cells and Hydrogen Joint Undertaking (FCH JU), the Fuel Cell and Hydrogen Observatory (FCHO), and the European Alternative Fuels Observatory (EAFO).

Key trends in renewable and low-carbon gas development

The Gas for *Climate Decarbonisation Pathways 2020-2050* study developed a timeline of required developments for biomethane and green and blue hydrogen along the supply chain to achieve a 2050 decarbonised energy system in Europe.[2] This report looks at the current market state and trends of

3 All reports can be downloaded from the Gas for Climate consortium webpage at https://gasforclimate2050.eu/.

biomethane and green and blue hydrogen supply, demand, and infrastructure in Europe, and identifies key trends along the supply chain. The following chapters detail each key trend and analyse the status of each key trend towards achieving the critical decarbonisation timeline in the early 2020s-2030:

- **Green:** Trend is in line with required pathway developments.
- **Blue:** Emerging trend is developing.
- **Yellow:** Early developments, no trend yet.

While the transformation towards net-zero CO_2 emissions is multifaceted and consists of many interlinked market and technological developments, the main focus of the analysis is on key trends in those sectors and subsectors that are most promising in the early 2020s-2030, as identified in the pathways study.

This report is structured in three chapters that analyse the market state and trends of biomethane and green and blue hydrogen supply (chapter 2), end uses in selected demand sectors and subsectors (chapter 3), and infrastructure developments (chapter 4). Each chapter includes several identified key trends, supported by collected and combined factual and statistical information, subtrends, and showcase projects around Europe. The focus of the key trends are the 27 EU member states (EU27) in 2018-2019. However, the employed data sources often differ in geographical scope and time of publication, which results in some trends being provided on a wider European level or other years, as indicated.

Showcase projects illustrate trends

The key trends in this report are supported by project examples. These projects were selected based on ongoing developments in the EU27 and, where applicable, more broadly across Europe. These projects reflect the latest developments in the field and are in concrete development or operation. More exhaustive lists of projects can be found in the European Biomethane Map (GIE and EBA, 2020), the International Energy Agency's (IEA's) Hydrogen Projects Database (IEA, 2020), the Hydrogen Europe project database (Hydrogen Europe, 2020b) and Clean Hydrogen Monitor 2020 (Hydrogen Europe, 2020a), the Fuel Cells and Hydrogen Joint Undertaking project database (Fuel Cells and Hydrogen Joint Undertaking, 2020a), and the European Network of Transmission System Operators for Gas' (ENTSOG's) Innovative Projects Platform (ENTSOG, 2020).

Box 1. Gas for Climate

In June 2017, a group of European gas transmission system operators (TSOs) and biogas associations convened to explore the future role and value of gas and gas infrastructure in a fully integrated and decarbonised EU energy system. This group became the Gas for Climate initiative. Gas for Climate is committed to achieving net-zero GHG emissions in the EU by 2050, mainly through renewable energy. The group sees an important role for existing gas infrastructure to the transport, storage, and distribution of biomethane and hydrogen in a smart combination with a large increase of renewable electricity. The group consists of 10 TSOs (Enagás, Energinet, Fluxys Belgium, Gasunie, GRTgaz, ONTRAS, OGE, Snam, Swedegas, and Teréga) and two biomethane associations (European Biogas Association and Consorzio Italiano Biogas). Members are based in eight EU member states.

In April 2020, Gas for Climate launched the *Gas Decarbonisation Pathways 2020-2050* study, analysing the transition towards the lowest cost climate-neutral system by 2050. This study developed gas decarbonisation pathways from 2020 to 2050, and identified what investments and actions are needed across the energy system along the way. The central pathway in this study achieves the 2050 Optimised Gas end state, as first analysed in the Gas for Climate 2019 study *"the optimal role for gas in a net-zero emissions energy system"*.

Figure 1.1.
The two latest Gas for Climate studies; "The optimal role for gas in a net-zero emissions energy system" (2019) and "The Gas Decarbonisation Pathways 2020-2050 study" (2020)

The *Gas Decarbonisation Pathways 2020-2050* study highlights that additional EU climate and energy policies are needed to position Europe on the road to net-zero by 2050. Its central and aspirational Accelerated Decarbonisation Pathway examines which investments and innovations need to take place to achieve a 2030 GHG reduction target of 55% and climate neutrality by 2050. The European Green Deal can facilitate these developments, accelerating emissions reductions, creating sustainable EU jobs, and creating first-mover advantages for EU industry by:

- Adapting the EU policy framework to make gas infrastructure future-proof in an integrated energy system and a key asset for the sustainable and cost-efficient decarbonisation of the EU economy.
- Stimulating the supply of biomethane and hydrogen through a binding mandate for 10% gas from renewable sources by 2030.
- Fostering cross-border trade and transport of hydrogen and biomethane and clarifying market rules for green and blue hydrogen including for hydrogen transport.
- Incentivising demand for hydrogen and biomethane in EU industry and producing dispatchable electricity by strengthening and broadening the EU emissions trading system (ETS) with targeted and time-bound contracts for difference.

2. Supply of renewable and low-carbon gases

The supply of renewable and low-carbon gases comprises renewable gas production and conversion technologies as well as renewable and low-carbon feedstock. Two main renewable and low-carbon gases will play a key role in decarbonising the European energy system: biomethane and green or blue hydrogen. In the short term, biomethane is expected to further scale-up; green and blue hydrogen are expected to further develop to accelerate scale-up starting in the mid-2020s. This chapter identifies key trends regarding biomethane and green and blue hydrogen supply following the approach laid out in chapter 1. The following sections detail each key trend and indicate the status of each key trend towards achieving the required pathway developments in the early 2020s-2030.[2]

2.1 Biogas and biomethane

Key trends

Almost all biomethane in Europe is produced using anaerobic digestion *technology*, with average digester sizes showing a growth trend of around 4% between 2017 and 2018. Membrane separation is increasingly being adopted—it is now the most common upgrading technique, with a market share of approximately 34% of cumulative installations in 2019. Other biomethane production techniques, such as thermal and hydrothermal gasification show high potential, but are only in an early commercial stage and industrial demonstration stage, respectively.

***Biomethane feedstock* in the EU is progressively shifting from dedicated energy crops to waste and residue feedstocks in new plants. Waste and residue feedstocks[4] were used in almost 65% of biomethane plants in the EU in 2019, up from approximately 40% of plants in 2012.**

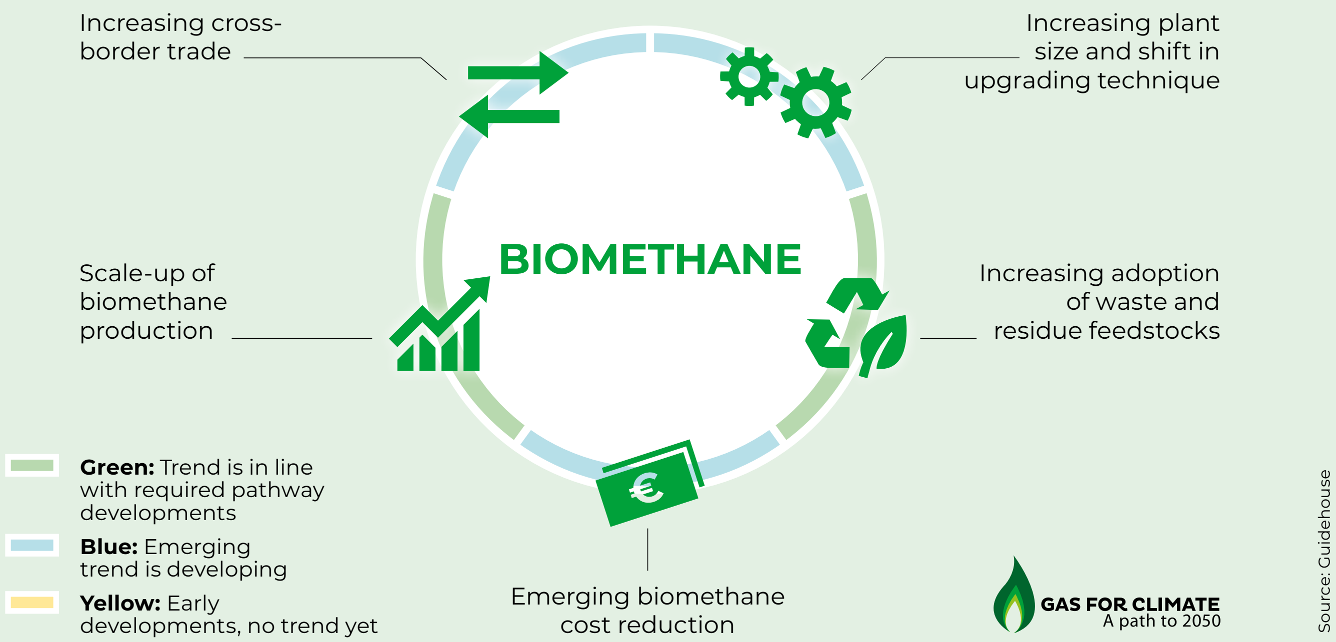
An emerging trend is seen with biomethane cost reduction potential, with *biomethane production costs* for anaerobic digestion in Europe ranging between €50/MWh-€90/MWh (~€0.50/m³-€0.90/m³)—and mainly depending on feedstock and digester size. Costs are gradually coming down for larger anaerobic digestion plants with certain waste stream feedstocks. Production costs for thermal gasification are estimated to be around €90-€100/MWh (~€1.0/m³).

4 This report defines waste and residue feedstocks as a combination of the (GIE and EBA, 2020) agricultural residues, manure and plant residues, industrial organic waste from food and beverage industries, sewage sludge and waste, bio-and municipal waste, and landfill.

***Biomethane production* volumes are rapidly growing in Europe, with around 23 TWh (~2 bcm natural gas equivalent) produced in 2018. The scale-up of biomethane production shows a positive trend-strong growth of around 15% in biomethane production volumes and a 17% increase of anaerobic digestion plants in 2018. This growth indicates a shift from biogas to biomethane production.**

***An emerging trend is seen with cross-border trade* of biomethane certificates. Cross-border trade is limited in the EU at less than 10% of biomethane production levels, but it is gradually increasing. Denmark, Sweden, and Germany are key players and the European Renewable Gas Registry (ERGaR) Certificate of Origin (CoO) scheme is being developed.**

Figure 2.1.
Key trends for biomethane and biogas supply



A significant biogas sector exists in Europe, with production around 170 TWh/year in 2018 (16 bcm natural gas equivalent).[2, 5] Biomethane production is rapidly growing. In 2018, around 23 TWh (~2 bcm natural gas equivalent) of biomethane was produced in Europe.[5]

This section details the key trends regarding biomethane supply. In the early 2020s, developments will focus on scaling up biomethane production to increase supply in Europe from approximately 23 TWh in 2018 to 300-370 TWh in 2030. This increase is achieved through the further development and scale-up of gasification and digestor technologies, developments in feedstock, increased production and deployment of installations, and emerging cost reductions. The required developments to supply biomethane are translated into key trends around technology, feedstock, production cost, deployment and production, and market and are supported by showcase projects (Figure 2.1). The following paragraphs detail each key trend and indicate the status of each key trend towards achieving the critical decarbonisation timeline in the early 2020s-2030.[2]

5 (EBA, 2019a)

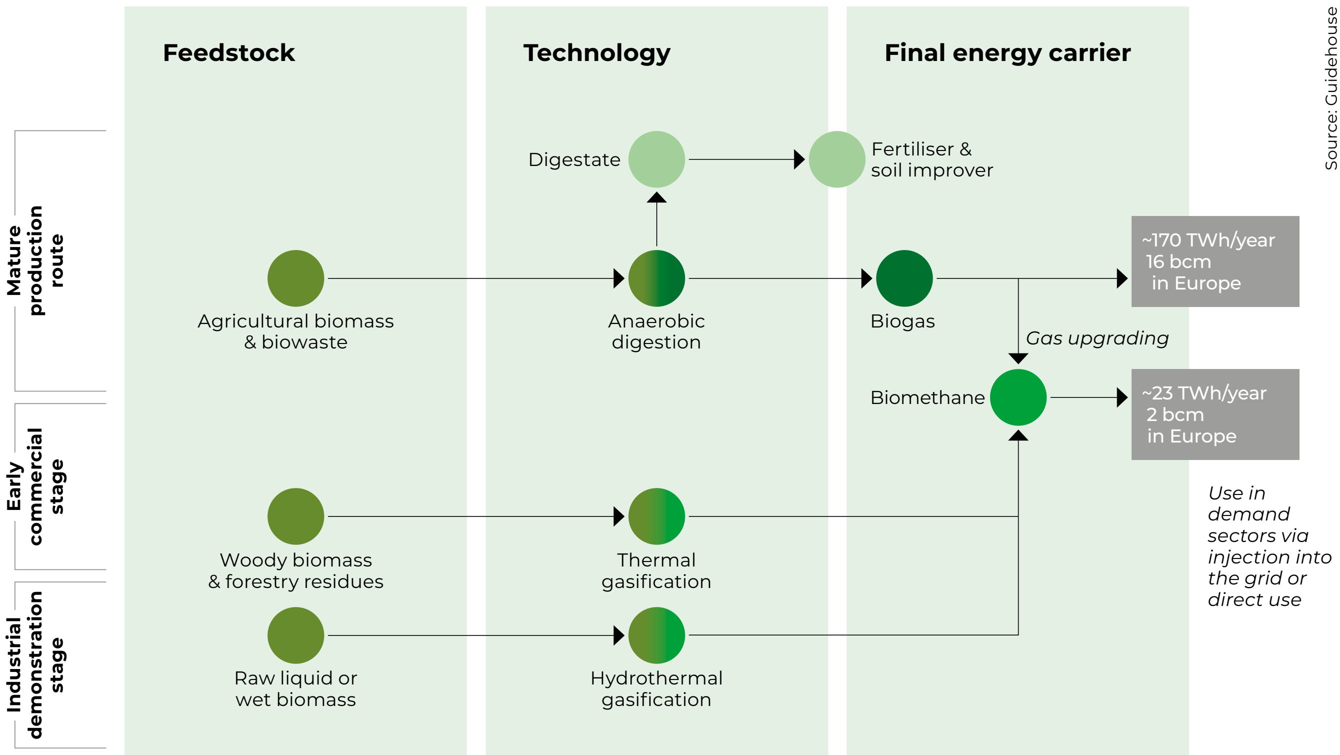
2.1.1 Increasing plant size and shift in upgrading technique

Almost all biomethane in Europe is produced by anaerobic digestion today. Thermal gasification is only in an early commercial stage, and hydrothermal gasification is at an industrial demonstration stage.

Biogas and biomethane are produced from organic feedstock. Two main biomethane production technologies exist: anaerobic digestion by upgrading biogas and gasification (Figure 2.2). Gasification includes thermal gasification (i.e. pyrogasification), which converts dry woody biomass, and hydrothermal gasification, also known as supercritical water gasification (SCW), which converts raw liquid and wet biomass by upgrading syngas.

Biomethane combustion emissions have a short carbon cycle and count as zero-emission following the IPPC guidelines.[6] Over the life cycle of biomethane production, including feedstock cultivation, processing, and transport, a minimum of 80%-85% GHG emissions reduction can be achieved compared to natural gas.[7] Even negative emissions can be achieved by capturing emissions from the biogas upgrading and combustion processes. Biomethane has the unique property of being similar to natural

Figure 2.2.
Overview of the two main production routes of biomethane



Source: Guidehouse

6 (Navigant, 2019)
7 (Ecofys, 2018)

gas and can, with the right purity levels (~97% methane content depending on applicable gas grid requirements[8]), be injected into the natural gas grid without major system adaptations.

The **anaerobic digestion** process produces biogas and digestate from a series of biological processes in which microorganisms break down organic feedstock (biomass) in a digester in the absence of oxygen. The resulting digestate by-product can be used as a fertiliser. The produced biogas contains around 55% methane, mostly combined with CO_2. Biogas cannot directly be injected into the gas grid. To enable injection into the gas grid, biogas needs to be *upgraded to biomethane* with a defined methane content by removing CO_2 and other contaminants.[9] Purification (removing pollutants) is also required prior to injection into the gas grid to adhere to European specifications for grid injection.[10]

Thermal gasification, or pyrogasification, uses woody and lignocellulose biomass (forestry residues) to produce biomethane (or solid organic waste in more general). A benefit of this technology is that it allows the use of additional biomass types (forestry residues) for biomethane production as compared with anaerobic digestion. Thermal gasification produces a mixture of CO, hydrogen, and CO_2 (syngas) through a complete thermal breakdown of the feedstock in a gasifier in the presence of a controlled amount of oxygen and steam at high temperatures.[11] Biomethane is produced at high pressures of ~40 bar.[2] After the gasification process, a gas cleaning unit removes pollutants like sulphur and chlorides from the syngas.[7] The cleaned syngas is then converted to biomethane (methanation) in a catalytic reactor using nickel catalysts or a biological reactor. The methanation process converts the cleaned gas into a mix of biomethane, CO_2, and water; a gas upgrading unit removes in a next step this CO_2 and water. The resulting biomethane meets the standards for injection into the gas grid.

Hydrothermal gasification, or SWC, enables treatment and gas conversion of raw liquid or wet biomass. The hydrothermal gasification process uses the specific properties of water in the supercritical phase (>374°C and >221 bar), where water becomes a reactive solvent. The wet biomass is increased in pressure and temperature until reaching the supercritical phase. In this phase, carbon from the organic dry biomass reacts with hydrogen from water molecules and produces a high pressure, methane-rich syngas also containing hydrogen and CO_2. After gas cleaning, which mainly removes CO_2, the resulting biomethane can be injected into the gas grid. Two hydrothermal gasification technology families exist with or without the use of a catalyst.

Anaerobic digestion is widely adopted to produce biogas and biomethane for almost all biomethane production in Europe today. Biomass to biomethane yield has a wide range around 0.36 m^3 of biomethane per kg of feedstock—for example, 0.21 m^3/kg for manure, 0.36 m^3/kg for maize, and 0.40 m^3/kg for biowaste.[9, 12]

Gasification is a less mature technology than anaerobic digestion but is able to produce biomethane at a larger scale.[9] Thermal gasification is only in an early commercial stage, with several large demonstration plants across Europe.[2, 13] In addition, thermal gasification has a higher yield in energy output than anaerobic digestion with about 0.55 m^3 of biomethane per kg feedstock.[7] Large-scale early commercial projects exist, among others, in Germany (<1 GWh biomethane production through gasification in 2018).[14] In the Netherlands,

8 European CEN standards exists on the blending of biomethane in natural gas (EN 16723-1:2016 for the injection of biomethane in the natural gas grid). In addition, country-specific methane content and gas quality standards for grid injection exist. For example, in some countries, most notably the Netherlands, Germany, and Belgium, the methane content of gas is about 80% in part of the gas grid due to the production of low calorific gas in Groningen. The biomethane used in these countries should have a methane content of 85% instead of 97% for injection in the low calorific gas grid. Groningen gas extraction will be phased out by 2030. (Navigant, 2019)

9 (IEA, 2020a)

10 CEN developed a standard for biomethane specification to enable its injection in gas grids, published in 2016. (European Committee for Standardisation (CEN))

11 (Florence School of Regulation, 2018)

12 (Ecofys, 2018); Biogas yields are retrieved from http://publications.jrc.ec.europa.eu/repository/bitstream/JRC104759/ld1a27215enn.pdf and are adjusted for biomethane content of 55% in biogas. With a large share of maize and triticale in the mix, it is not completely implausible to assume that the yield would increase towards the high end of the range.

13 (IEA Bioenergy, 2019)

14 (REGATRACE, 2020a)

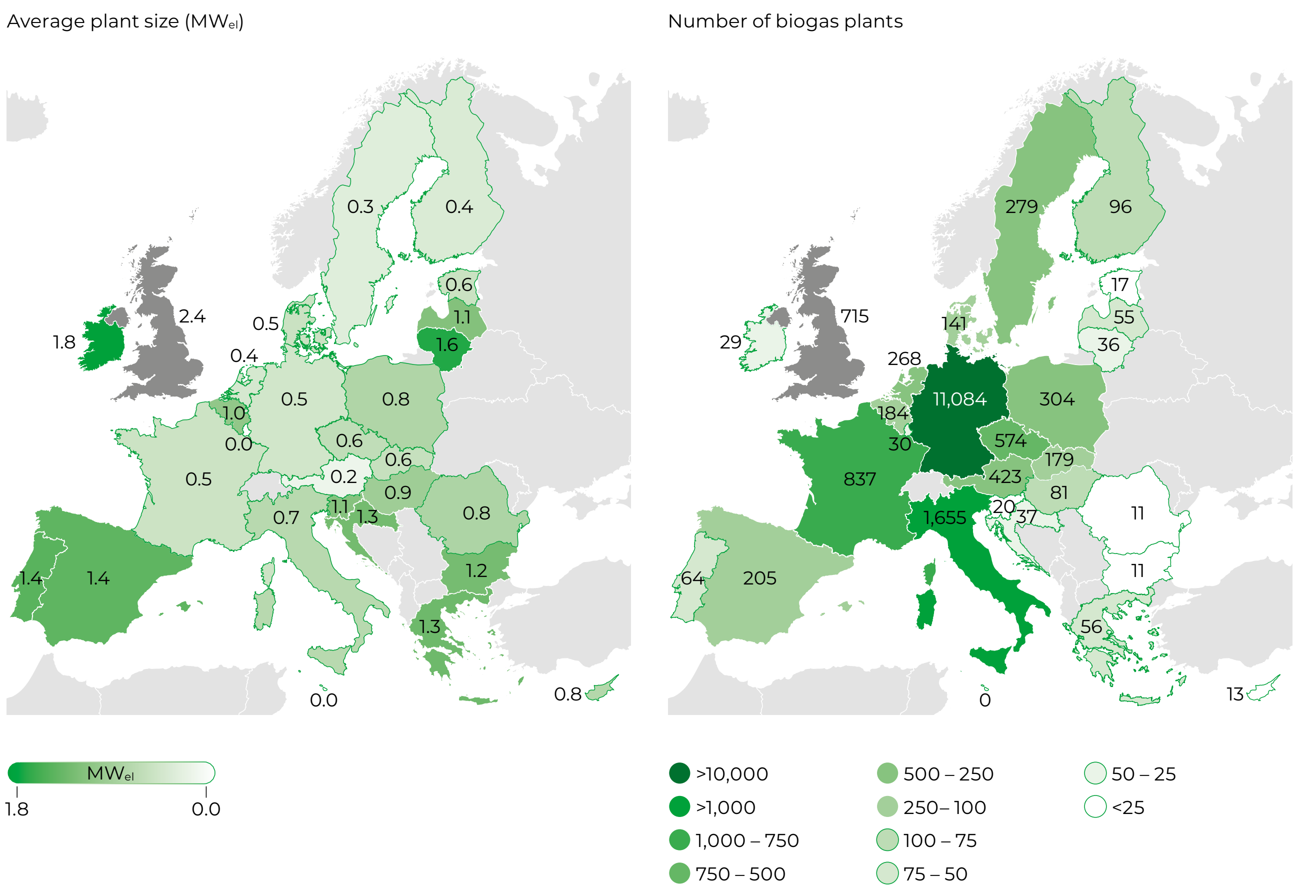
Torrgas is working with Gasunie to construct a 25 MW gasification-to-methane plant in Delfzijl.[15] Hydrothermal gasification is in the demonstration or pilot stage.[16] In the Netherlands, Gasunie and SCW Systems are working together to upscale the first industrial demonstration plant in Alkmaar, increasing production from an initial 1.8 MWth to 18.6 MWth in 2021.[16] Gasification technologies are less mature than commercial anaerobic digestion but are expected to further scale-up starting in the mid-2020s. Therefore, the remainder of this report focuses on biomethane production from anaerobic digestion unless otherwise indicated.

In Europe, digesters for biomethane production range in size from about 100 Nm³/hr (~0.2 MW_{el} biogas output) to over 3,000 Nm³/hr (~6.2 MW_{el} biogas output) for large industrial plants. The average digester size in the EU went up by approximately 4% between 2017 and 2018.

For biomethane production through anaerobic digestion, organic feedstock is fed into a digestion tank for fermentation. Digesters are designed based on the type of feedstock (wet/dry/solid),[17] the required process mode (continuous/batch),[18] and production characteristics. Biomethane production installations can come in various sizes, ranging from local to industrial scale following the output flow rates of the biogas units:[9]

- **Small:** 100 Normal cubic metres per hour [Nm³/hr] -250 Nm³/hr (~0.2-~0.50 MW_{el}[19])
- **Medium:** 250 Nm³/hr-750 Nm³/hr (~0.50 MW_{el}-1.54 MW_{el})
- **Large:** >750 Nm³/hr (or >1.54 MW_{el})
- **Very large:** >3,000 Nm³/hr (or >~6.17 MW_{el}). From 2015 onwards, the size of biomethane production installation has been increasing with very large units of several thousands of m³/h.

Figure 2.3.
Average size (MW_{el}) and number of biogas production installations in EU27 countries in 2018



Source: based on data from (EBA, 2019)

The average size of biogas plants in the EU27 ranged from 0.2 MW_{el} to approximately 1.8 MW_{el} in biogas output in 2018 (Figure 2.3).[5] Differences occur due to the variation in applications of biogas, scale of production (local vs. large scale), and differences in feedstock. The electricity generated by these plants amounted to 65 TWh in 2018. With average electrical efficiency of 38%, this means an input of 171 TWh of biogas (16 bcm in natural gas equivalent).[2] On average, the countries with the largest number of biogas installations have smaller size installations and vice versa.

Within Europe, there is a trend towards larger digester sizes for biogas and biomethane production.[2] In 2018, the European average stands at 0.61 MW_{el}, or 296 Nm^3/hr, up approximately 4% from 0.59 MW_{el}, or 279 Nm^3/hr in 2017.[2, 5] Some countries have larger average digester sizes. For example, the average biogas digester size in the UK is 2.4 MW_{el} (1,300 Nm^3/hr) and is 1.8 MW_{el} (870 Nm^3/hr) in Ireland. Germany, Austria, Switzerland, Denmark, and Estonia have average digester sizes below the European average.[2, 5] The European average is expected to increase, especially in industrial areas where waste streams can be combined, enabling cost reductions through economies of scale. Biodigesters can also be adopted at industrial scale by adapting existing wastewater treatment plants to process municipal sludge (order of ~1,000 m^3/h), for example in Amsterdam, or by using landfill gas recovery systems to recover biogas produced from closed landfill sites (order of ~2,000 m^3/h), for example in Sinsheim.[9] Selected projects are highlighted in the showcase projects. The average digester size is expected to increase from 296 Nm^3/hr to at least 500 Nm^3/hr in 2050.[2]

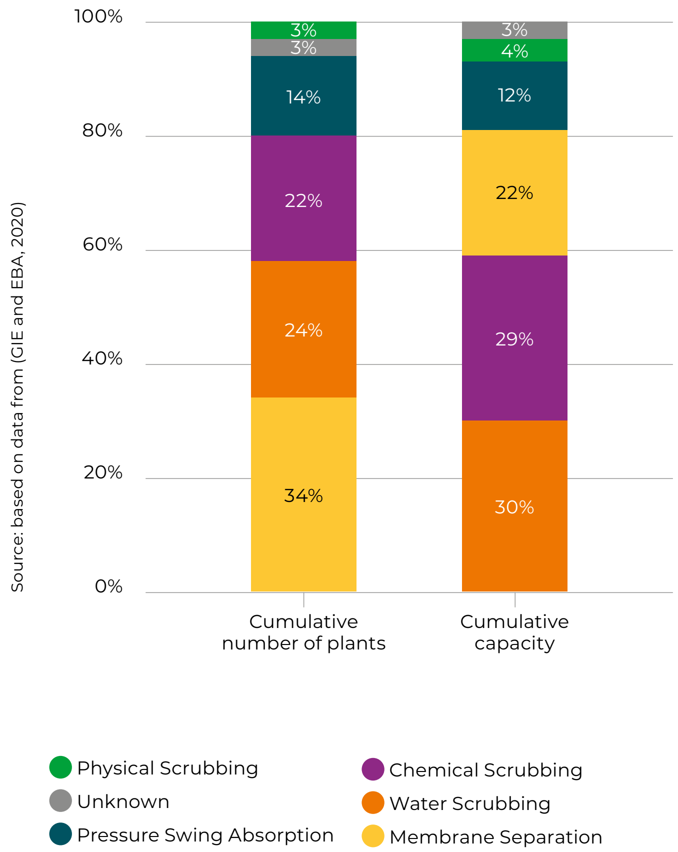
The most common anaerobic digestion biogas to biomethane upgrading techniques in the EU are membrane separation, and water and chemical scrubbing. Over the last decade, membrane separation is increasingly being adopted—it is now the most common upgrading technique with a market share of approximately 34% of cumulative installations in 2019.

In Europe, almost 12% of biogas was upgraded to biomethane in the anaerobic digestion production process in 2018.[20] Various upgrading technologies exist based on the different chemical and physical behaviours of methane and CO_2.[21] Upgrading technologies can be categorised based on their separation mechanism—for example, adsorption or absorption (physical and chemical):[21]

- **Pressurised swing adsorption (PSA)** separates CO_2 by using its connection behaviour to a surface under elevated pressures. PSA is a complex process that requires pretreatment and requires low energy use.[22] In addition, PSA results in the most (low) methane losses of all upgrading techniques. PSW, however, only has a low energy demand.

15 (Torrgas, 2020)
16 (Gasunie, 2019)
17 Wet anaerobic digestion uses feedstock with at most a 10%-20% share of dry matter in contrast to dry anaerobic digestion, which uses feedstock with at least 20%-40% share of dry matter. Dry digestion allows feedstock with a high content of dry matter such as crop residues, household waste, and livestock manure compared to wet digestion, which limits the share of dry feedstock it can process. Advantages of dry digestion include lower energy and water use, but it requires feedstock loading and unloading technologies and results in batch production. Advantages of wet digestion include lower costs of investment and operations and maintenance as well as a greater flexibility in the use of feedstock. However, it requires the use of liquid and mixing equipment to prepare the feedstock and consequentially, higher energy use. (Biogas World, 2018).
18 Dry anaerobic digestion can produce in a continuous or batch system. In batch systems, the digestion process is determined by the feedstock loading and unloading actions. Dry digestion can be continuous when several digestors operate in parallel to allow a constant level of production. (Biogas World, 2018).
19 Biogas output. Guidehouse assumed a biogas LHV of 19.5 MJ/m^3 and a biomethane LHV of 34.7 MJ/m^3, which is calculated using LHV (50 MJ/kg) of raw biogas as included in the EU RED Annex III, corrected for biogas impurities and CO_2 content. The biomethane LHV is slightly higher than the 33 MJ used in the previous 2018 Gas for Climate study, in which we calculated at room conditions being 24°C and 1 bar rather than the more widely used standard conditions, being 0°C and 1 bar.
20 (IEA, 2020a); *EBA in-house analysis, 2020*
21 (EnergiForsk, 2016)
22 (Adnan, Ong, Chew, & Show, 2019)

Figure 2.4.
Cumulative distribution of EU27 biomethane plants per biogas-biomethane upgrading technique in 2019 based on total number of plants (576) and total capacity (261k m³/hr)



- **Chemical scrubbing, physical scrubbing or water scrubbing** (absorption) use different types of liquid to dissolve gas to remove CO_2 (e.g. chemical solvents, water, or an organic physical material). Chemical scrubbing requires high amounts of energy for steam production, pretreatment, and chemical inputs. However, it results in a faster upgrading process than physical scrubbing and almost no methane loss.[22] In addition, chemical scrubbing leads to almost no methane losses under specific circumstances and when surplus high heat abundant, the process can be well integrated. Physical scrubbing is a simpler process with low operational cost and maintenance, but it requires large amounts of water, energy, and an external heat source.[22]

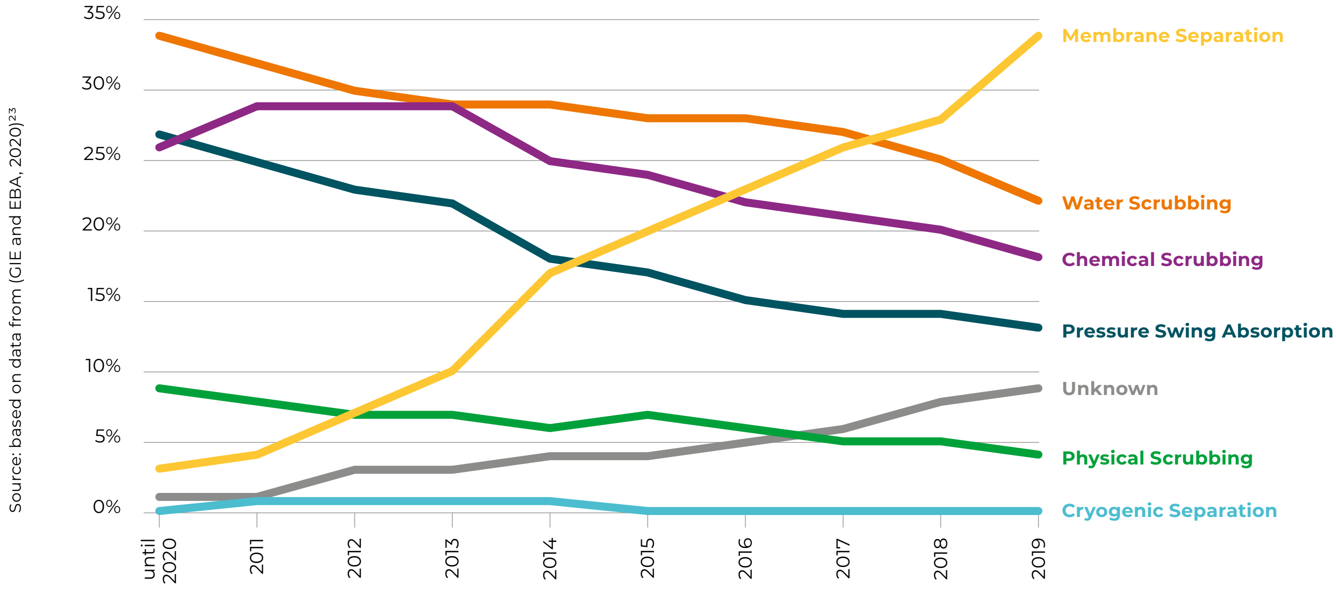
- **Membrane separation** uses a permeable membrane to separate CO_2 and methane molecules based on their different physical characteristics. Membrane separation is a simple process with low costs and energy use, but requires pre-treatment. Due to the use of a physical barrier rather than a liquid or elevated pressure, it is more environmentally friendly. However, compared to chemical scrubbing, membrane separation has relative higher methane loss.[22]

The most common upgrading techniques in the EU are membrane separation (34% of total biomethane plants in 2019), and water and chemical scrubbing, with a combined share of approximately 46% of total biomethane plants in 2019 (Figure 2.4).[23] Membrane separation has been increasingly adopted in the EU over the last decade due to its specific advantages (Figure 2.5). It is now the most common upgrading technique, leading to a rapid increase in market share.

The relative use of biogas-biomethane upgrading techniques varies by country. Figure 2.6 indicates the distribution of upgrading techniques by country for selected EU countries. The countries with the largest number of biomethane plants use a mix of upgrading technologies. In 2018, Germany had 200 biomethane upgrading plants; with main upgrading techniques a mix of water and chemical scrubbing and pressure swing adsorption. In contrast, in 2018, Italy had five upgrading plants and Belgium had one upgrading plant; both countries use membrane separation as the upgrading technique.[24]

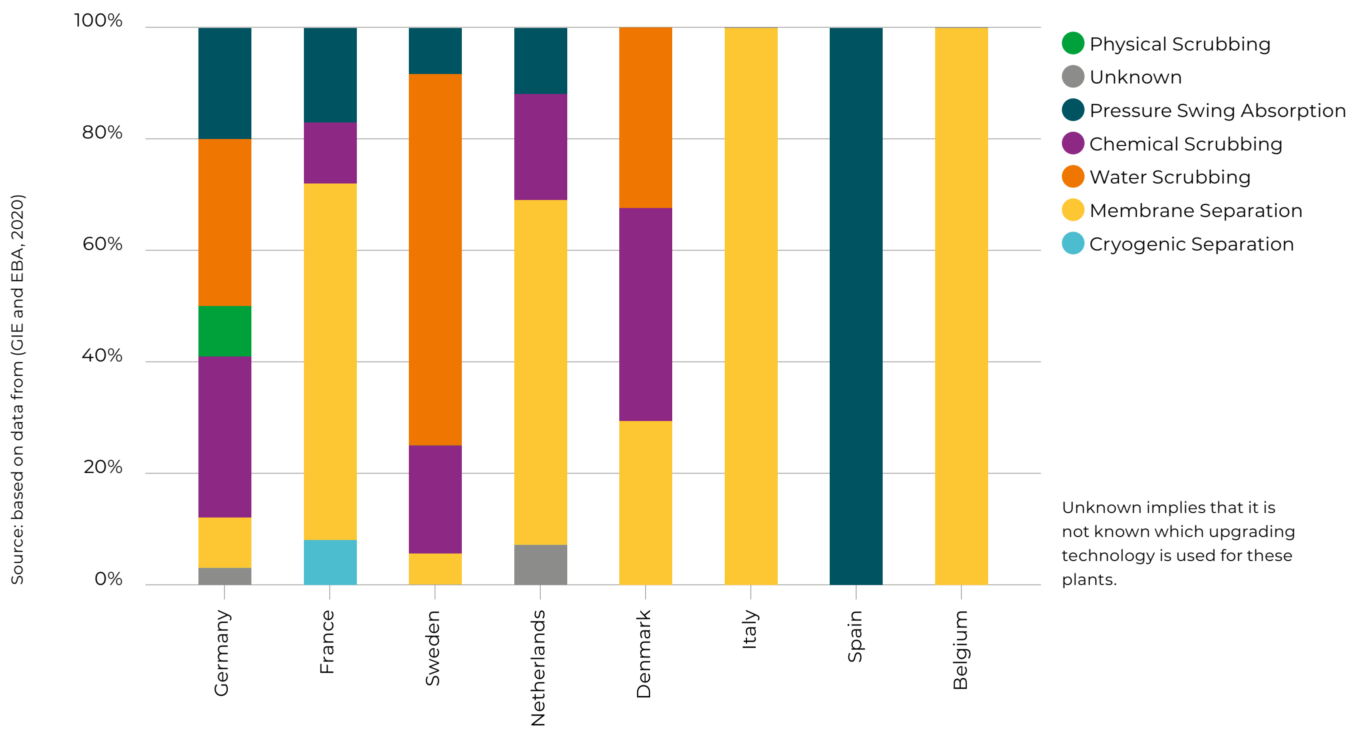
23 *EBA in-house analysis, 2020*
24 (GIE and EBA, 2020)

Figure 2.5.
Cumulative change in biogas-biomethane upgrading techniques based on number of plants in Europe



Unknown implies that it is not known which upgrading technology is used for these plants.

Figure 2.6.
Indication of cumulative relative use of upgrading techniques based on number of plants in selected EU countries in 2019



Unknown implies that it is not known which upgrading technology is used for these plants.

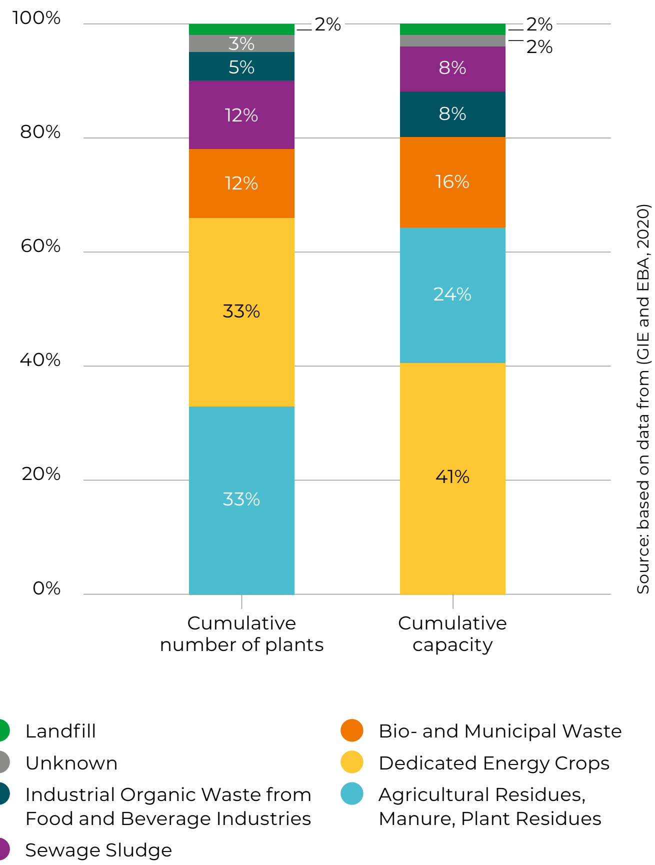
2.1.2 Increasing adoption of waste and residue feedstocks

Agricultural feedstock (dedicated energy crops and agricultural and waste streams) was used for biomethane production in about 66% of installations in the EU in 2019.

Sustainable biomass[25] is a feedstock for biogas and biomethane production and includes biomass from sequential agricultural cropping, forestry harvesting residues, animal manure, food waste, wastewater, and agricultural residues. In the EU, biomethane feedstock for anaerobic digestion comes from about 66% from agricultural feedstock (dedicated energy crops, and agricultural residues and waste streams), followed by (water) sewage sludge and other feedstocks (Figure 2.7). The production and conversion efficiency of biomethane depends on the quantity and quality of the feedstock. Feedstock can be dry or wet, which determines the digestion process (see Box 2).

Very large biomethane plants predominantly use bio- and municipal waste, industrial organic waste from food and beverage industries, and agricultural residues, manure, and plant residues (Figure 2.8).

Figure 2.7.
Cumulative distribution of biomethane feedstock in the EU27 in 2019 based on the total number of plants (576) and total capacity (261k m³/hr)



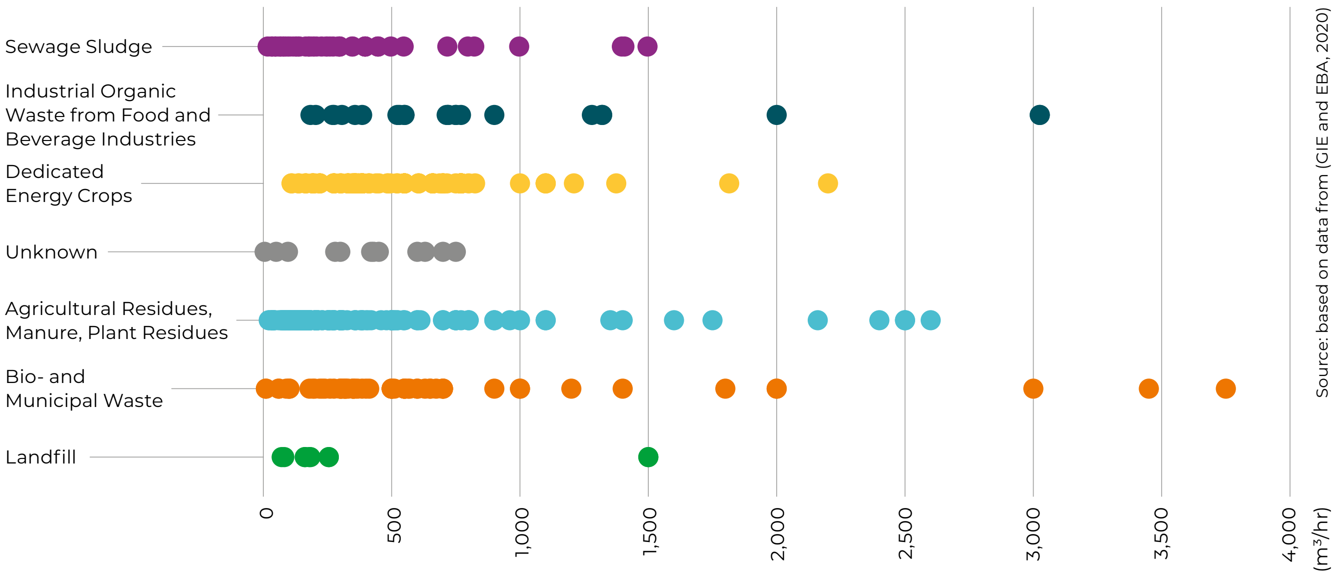
25 The EU introduced mandatory sustainability criteria for biofuels and biogas in the 2009 EU Renewable Energy Directive (RED) in response to growing concerns and the public debate on bioenergy sustainability. These sustainability criteria are updated and expanded to woody bioenergy in the revised RED II Directive. The positions of various stakeholders in the debate can be viewed in three European Commission consultations on the topic.
https://ec.europa.eu/energy/en/consultations/preparation-sustainable-bioenergy-policy-period-after-2020
https://ec.europa.eu/energy/en/consultations/preparation-report-additional-sustainability-measures-solid-and-gaseous-biomass-used
https://ec.europa.eu/energy/en/consultations/indirect-land-use-change-and-biofuels, see further: http://task38.org/Sustainability_updated_2009.pdf

Box 2. Definition of feedstock types from (GIE and EBA, 2020)

- **Agricultural residues, manure, plant residues:** All substrates related to agricultural production except for energy crops. This includes manure, straw, cover/catch crops, and crop residues.
- **Dedicated energy crops:** Primary crops with high starch content.
- **Industrial organic waste:** Industrial organic waste for example from food and beverages industries.
- **Sewage sludge and waste:** Sludge produced at a wastewater treatment plant.
- **Bio-and municipal waste:** Municipal and organic household waste.
- **Landfill:** Organic waste producing biogas collected on a landfill, sometimes referred to as landfill gas in literature.

In this report **waste and residue feedstocks** include the following categories from (GIE and EBA, 2020): agricultural residues, manure and plant residues; industrial organic waste from food and beverages industries; sewage sludge and waste; bio-and municipal waste; and landfill.

Figure 2.8.
Biomethane production plant capacity (m³/hr) vs. feedstock in the EU (cumulative numbers in 2019)

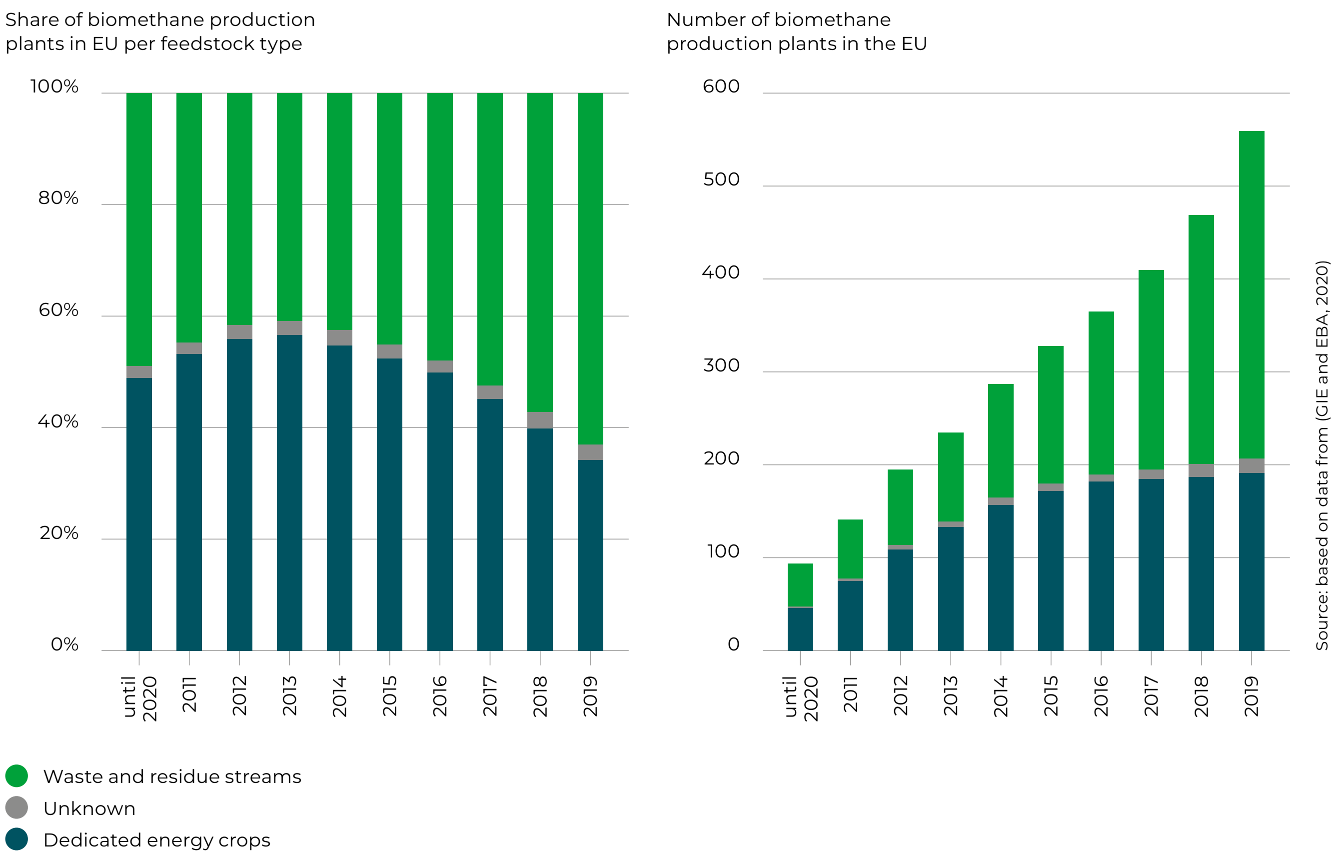


Source: based on data from (GIE and EBA, 2020)

Dedicated energy crops are progressively making way for waste and residue[26] feedstocks in new anaerobic digestion plants. Waste and residue feedstocks were used in about 63% of biomethane plants in the EU in 2019, up from approximately 40% of plants in 2012.

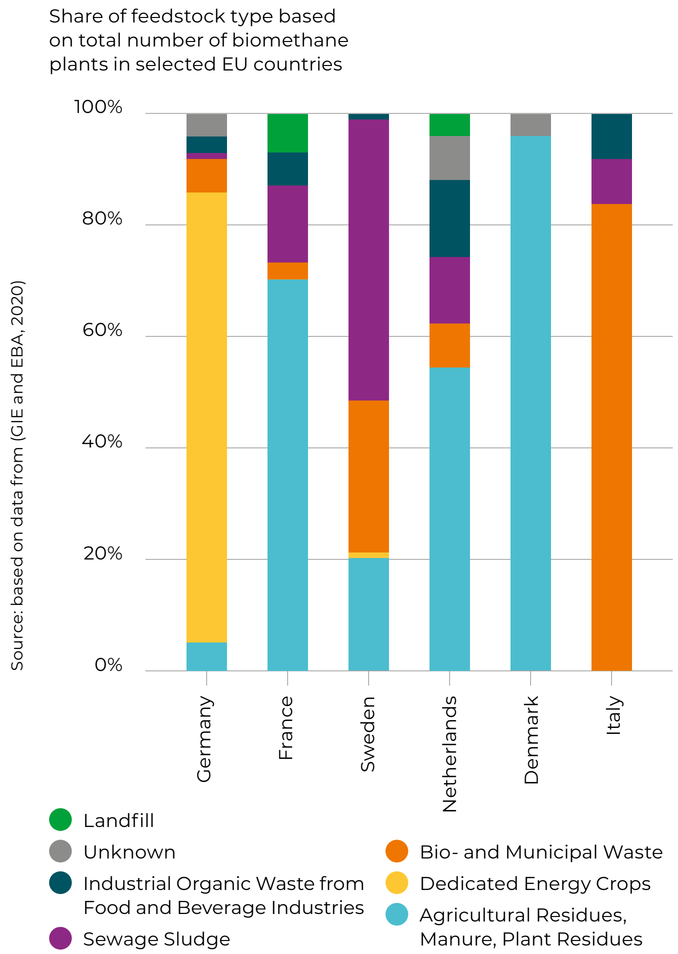
Although the biomethane market is growing, the type of feedstock used is changing from dedicated energy crops to waste and residue streams. The absolute share of biomethane production plants employing dedicated energy crops has flattened over the last few years, whereas their relative share has decreased (Figure 2.9).[24, 27] Dedicated (energy) crops are progressively making way for waste and residue feedstocks in new plants (see Box 2). The share of waste and residue feedstock in the EU increased from around 40% of total biomethane plants in 2012 to around 63% of total biomethane plants in 2019 (Figure 2.9).[24, 27, 28] This trend can be explained through the flattening number of biomethane plants in Germany that mainly use dedicated energy crops compared to upcoming biomethane growing countries, such as France and Italy, which generally adopt waste and residue feedstocks (see also section 2.1.4). This trend is expected to continue in the coming years.

Figure 2.9.
Share and number of total biomethane production plants per feedstock type: energy crops (i.e. dedicated crops) vs. waste and residue streams in the EU27



26 Waste and residue feedstocks in this report include (see Box 2): agricultural residues, manure and plant residues; industrial organic waste from food and beverages industries, sewage sludge and waste; bio-and municipal waste; and landfill following the definitions of (GIE and EBA, 2020)
27 (The Oxford Institute for Energy Studies, 2019)
28 The same trend can be seen when looking at total production capacity (m^3/hr) rather than total number of plants in the EU. Reach a total of approximately 57% of cumulative production capacity in the EU based on agricultural and municipal waste stream feedstocks.

Figure 2.10.
Indication of cumulative relative use of feedstock based on number of plants in selected EU countries in 2019



The relative use of feedstock varies by country. Figure 2.10 indicates the distribution of feedstock for EU countries with the largest number of biomethane plants based on the total number of plants in 2019.

2.1.3 Emerging biomethane cost reduction

Biomethane production costs for anaerobic digestion in Europe have a large spread —€50/MWh-€90/MWh (~€0.50/m³-€0.90/m³)— and mainly depend on feedstock and digester size. The production cost for thermal gasification is estimated around €90-€100/MWh (~€1.0/m³). Costs are gradually coming down for larger anaerobic digestion plants that use certain waste stream feedstocks.

The cost drivers for biogas production include capital and operational costs, the size of the digester, the production technique, and the feedstock cost (Table 2.1). Biomethane production costs also include the cost of the upgrading unit.

Table 2.1.
Overview of the cost values (2018) for the most important parameters in biomethane anaerobic digestion production process

<table>
<tr><th></th><th>Size digester (Nm³/hr)</th><th>CAPEX (€/MWh) biogas digester*</th><th>OPEX (€/MWh) biogas digester*</th><th>Biogas to biomethane upgrading* (€/MWh)</th><th>Feedstock cost (€/tDM)*</th><th>Maturity level</th></tr>
<tr><td>Small</td><td>100</td><td>25</td><td>22</td><td rowspan="4">5 - 12</td><td rowspan="4">0-120

Average in Europe:[6]
19-36</td><td rowspan="4">Mature</td></tr>
<tr><td>Medium</td><td>500</td><td>20</td><td>17</td></tr>
<tr><td>Large</td><td>1,000</td><td>15</td><td>12</td></tr>
<tr><td>Very large</td><td>>2,000-3,000</td><td>Not available[29]</td><td>Not available[29]</td></tr>
</table>

* Costs converted from USD/MBtu and rounded, with $1 = €0.85.

Source: (IEA, 2020c)

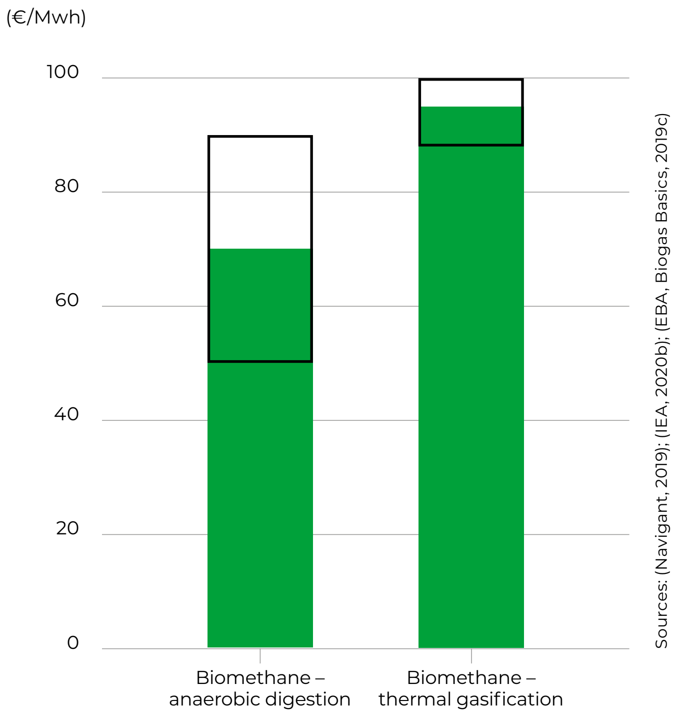
29 Estimates for landfill gas recovery systems ~2,000 m³/hr include €2.32/MWh CAPEX and €4.64/MWh OPEX. (IEA, 2020a). *Costs converted from USD/MBtu and rounded with $1 = €0.85.*

The cost for **feedstock** varies greatly—the average feedstock cost in the EU was between €19 and €36/tonne dry matter (tDM) in 2015.[2, 6] Feedstock cost can generally range from a negative or zero cost for certain waste products (e.g. industrial waste streams with integrated biomethane production) to up to approximately €85/tDM and higher for certain agricultural feedstock.[9] Current estimates in Europe are, on average, around €25/tDM for manure, €47/tDM for agricultural residues, €78/tDM for silage, and €120/tDM for dedicated energy crops.[2, 6]

The **total production cost of biomethane** based on anaerobic digestion ranges between €50/MWh and €90/MWh in Europe, with an average cost of around €70/MWh (Figure 2.11).[6] Biomethane production based on anaerobic digestion mostly use medium silage digesters resulting results in production costs of about €90/MWh. Using manure or agricultural residues as feedstock in combination with larger digesters (around 1,000 Nm³/hr) reduces the production costs to about €70/MWh. Cost can be further reduced for very large-scale production and the use of waste residues feedstock to approximately €50/MWh.[30]

The **production costs of biomethane based on thermal gasification** are estimated around €90/MWh-€100/MWh.[31, 32] The production cost of thermal gasification has been proven to be able to reduce to around €88/MWh.[33]

Figure 2.11.
Ranges of current biomethane production costs, including feedstock, CAPEX and OPEX



Production costs for biomethane production through both anaerobic digestion and thermal gasification are expected to drop to about €47MWh-€57/MWh in 2050.[2] Biomethane production costs are still high, in particular compared to the price of alternative fuels, such as natural gas (including natural gas price and carbon price). However, certain consumers may want to pay a premium for biomethane to achieve their corporate emissions reduction targets or obtain round-the-clock green energy. The value of biomethane can also be strengthened through the marketing of biomethane digestate as organic fertiliser or through other positive (cross-sectoral) externalities (see section 2.1.4).

Current biomethane production installations are mostly located close to existing natural gas grids, resulting in limited grid connection and injection costs (around 5% of total production costs).[6] Grid injection and connection costs depend on the type of production process. For anaerobic digestion plants, the upgrading facilities are often located close to gas grids, resulting in an estimated average grid injection and connection cost of around €4.7 /MWh per year.[6] The total biomethane network costs also include costs for biogas pipelines to the biomethane upgrading facility and a pipeline from the biomethane facility to the gas grid. Total biomethane network costs are estimated to be around €9.7/MWh.[6]

30 (EBA, Biogas Basics, 2019c)
31 (Chalmers University of Technology, 2018)
32 The cost figures are slightly lower than what is reported in the cited reference because these costs are recalibrated using a social discount rate of 5%.
33 (GoBiGas, 2018)

For thermal gasification plants, grid injection and connection costs are expected to be limited because the biomethane is already produced at high pressure, enabling more ready injection into the gas grid. These units are therefore logically located close to infrastructure hubs with ready access to feedstock and existing gas grid connections. The grid connection and injection costs are estimated to be around €2/MWh per year.[6]

2.1.4 Scale-up of biomethane production[34]

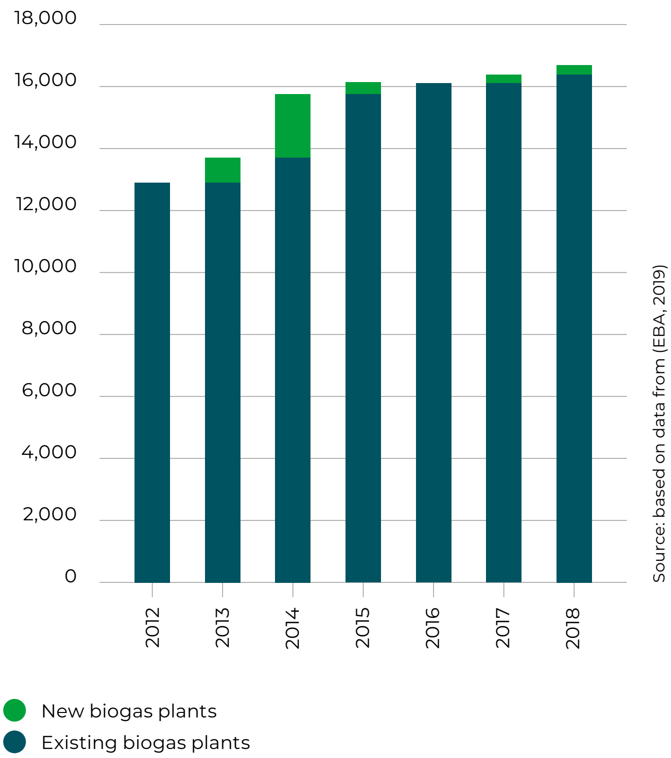
The growth in the number of biogas production plants is flattening in the EU27 with a yearly increase below 3% between 2014 and 2018, reaching about 16,689 biogas plants at the end of 2018. Germany is the largest player in the EU, with 66% of all biogas plants, followed by Italy (10%) and France (5%).

Over the past decade, the number of biogas production facilities has grown in the EU (Figure 2.12), reaching about 16,689 plants at the end of 2018. The growth has flattened over the last 5 years—there was just a 2% increase in the number of plants in 2018 relative to 2017, reflecting 303 additional biogas installations. The most significant growth between 2017 and 2018 was seen in Germany (+113 installations), France (+95 installations), and Sweden (+81 installations). At the end of 2018, all central-western EU countries had biogas production facilities. The largest number of biogas plants in the EU are in Germany (66%), Italy (10%), and France (5%).

Biomethane production and number of plants (anaerobic digestion) show strong growth in the EU27, with an approximate 15% and 17% increase in 2018, respectively. This growth indicates a shift from biogas to biomethane production.

The number of biomethane production installations is growing in the EU27 (Figure 2.13). In 2018, about 473 biomethane plants were in operation across the EU (610 plants across Europe).[2] Germany, France, Sweden, Denmark, and the Netherlands combined represent about 90% of these installations. The number of biomethane production facilities in the EU continues to grow with a 17% increase in new installations in 2018 (12% across Europe). This growth indicates a shift from biogas to biomethane plants and comes from anaerobic digestion plants; thermal gasification plants are in an early commercial stage and are expected to scale-up starting in the mid-2020s.

Figure 2.12.
Development of number of biogas production installations in EU27 countries



A significant step up in biomethane production in the EU occurred around 2016; production has been steadily increasing, driven by EU and national policies to increase shares and stimulate the use of biomethane. Next to EU policies such as the Renewable Energy Directive (RED) II, many EU member states have implemented policies

34 This section is largely based on the statistical data provided by the EBA. The trends focus on the current status in European or EU27 countries at the end of 2018, unless otherwise indicated.

supporting the production and use of biomethane, such as specific targets on biomethane production and use in France and Italy (see section 2.1.5).[14] These policies are expected to enable continued growth. European biomethane production reached a total of approximately 23 TWh (~2 bcm natural gas equivalent) in 2018, of which about 17.3 TWh (~1.6 cm) was in the EU27. This is an increase of approximately 15% compared to 2017.

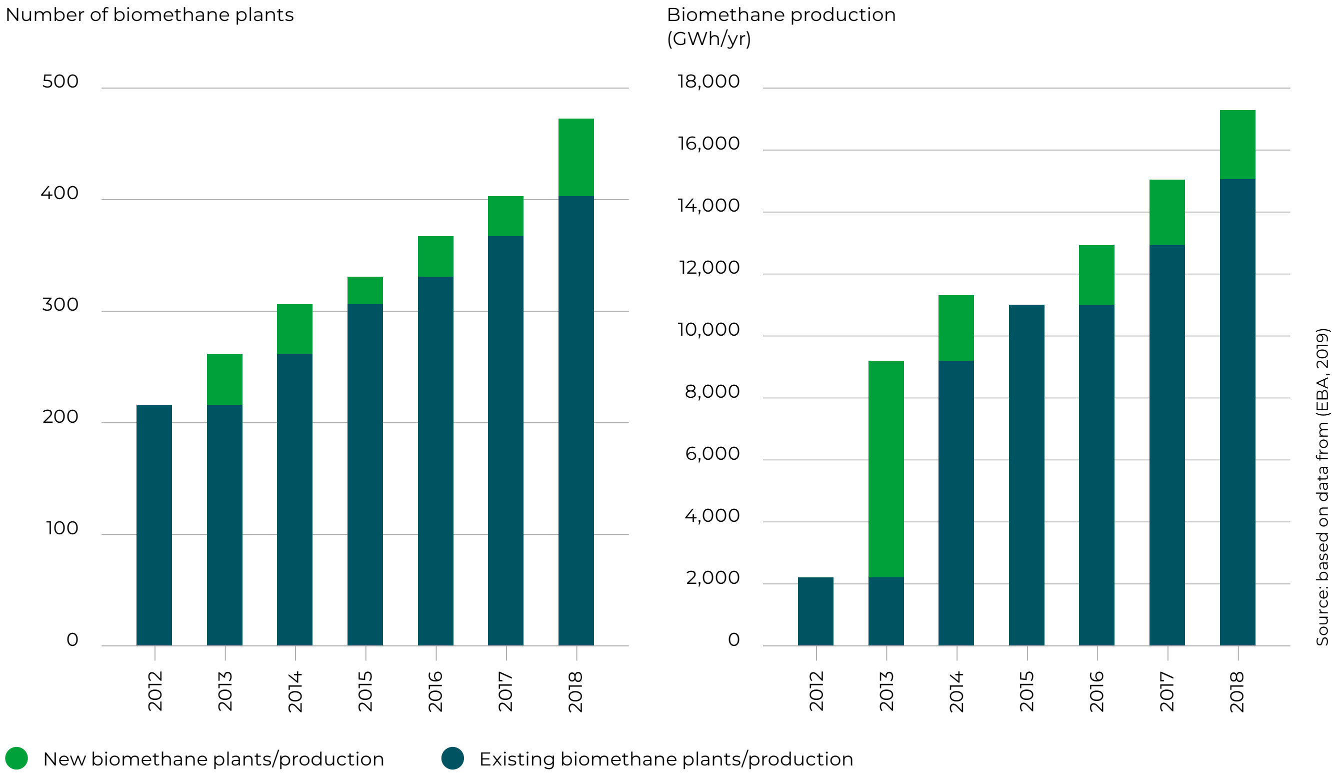
Biomethane is expected to provide a growing contribution to the EU energy system as outlined in the European Methane Strategy.[35] At the moment, biomethane production is scaling up but possible other cross-sectoral effects that come from biomethane production can contribute to the system, such as waste use, rural development, soil improvement, and recovery. Further research on these contributions and their advantages is still required, but initial research shows positive signals. This report therefore does not focus on these possible other cross-sectoral effects.

Germany is the largest player in the European biomethane sector (close to 200 biomethane plants), but growth levels are flattening. The largest growth in biomethane developments is taking place in France, followed by the Netherlands and Denmark.

Since 2018, most central-western EU27 countries have biomethane production facilities, with the highest number of facilities in Germany, France, and Sweden. The UK also has a large number of biomethane plants, reaching 93 plants in 2018.

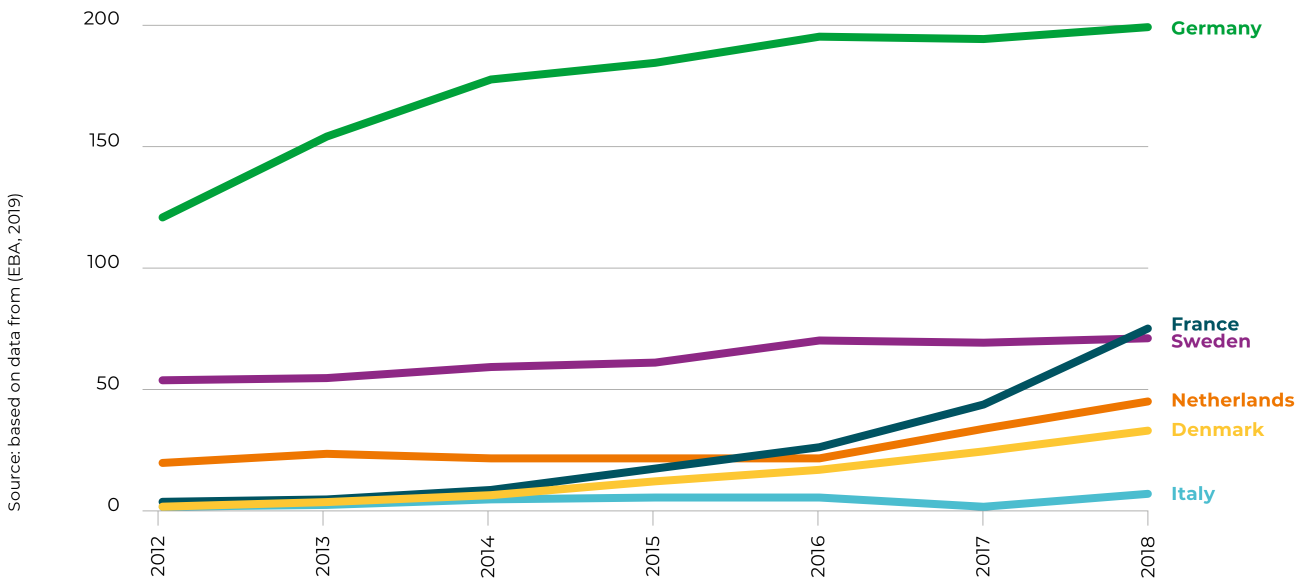
The EU27 countries showing the largest growth in the number of biomethane installations between 2017 and 2018 are France (+32 plants in 2018, totalling 76), the Netherlands (+12 plants in 2018, totalling 46), and Denmark (+9 plants in 2018, totalling 34) (Figure 2.14).[5] Germany is the largest player in the EU with around 200 biomethane plants and approximately 10 TWh production in 2018, but growth levels are flattening due to changes in

Figure 2.13.
Development of number of biomethane installations and level of biomethane production in the EU27



35 (European Commission, 2020a)

Figure 2.14.
Development of number of biomethane production installations for selected EU27 countries



national support schemes. France is an example of ongoing growth in biomethane production installations; in 2019, a new biomethane facility was opened every week. In addition, Denmark has financed the building of several large biomethane plants with a production volume well over 1,000 m³/hr each, going up to 2,000 m³/hr and more. Such installations are about seven times larger than the current EU average, and both the sourcing of the feedstock and the redistribution of digestate back to the fields occurs within a range of 25 km.[2]

2.1.5 Increasing cross-border trade

Each country in Europe has several different players in the biomethane sector. However, the market for the large industrial production of biomethane (1,000 m³/hr and above) is more consolidated with a few main players. For agricultural biomethane production plants there is a large spread over a range of different types of players per country.

Each country in Europe has several different players in the biomethane sector.[36] However, the market for the **large industrial production** of biomethane (1,000 m³/hr and above) is more consolidated with a few main players, including:[36] Nature Energy (seven plants in Denmark), Gasum (six plants in Sweden), VERBIO Vereinigte BioEnergie AG (three plants in Germany only), and E.ON (three plants in Germany/Sweden). Only a small number of farmer associations are involved in these large projects. Recycling and other waste management companies are increasingly involved due to the use of waste streams as feedstock for biomethane.

For **agricultural plants** using agricultural residues, manure, or plant residues, there is a large spread of players ranging from a single farmer or farmer cooperative to non-farm or non-biogas-specific organisations.[36] In many instances, specific entities are owned by more than one company or farmer. In the majority of agricultural biomethane projects, at least one farmer or farmer cooperative is involved and that farmer/farmer cooperative is often only involved in one project. Non-farmer or non-biogas organisations are limited and are

36 Based on data from (GIE and EBA, 2020)

predominantly focusing on consumer dairy (e.g. Arla, FrieslandCampina), automotive (Audi), or energy (E.ON). In some countries, one player has a large share in the market of agricultural biomethane production:

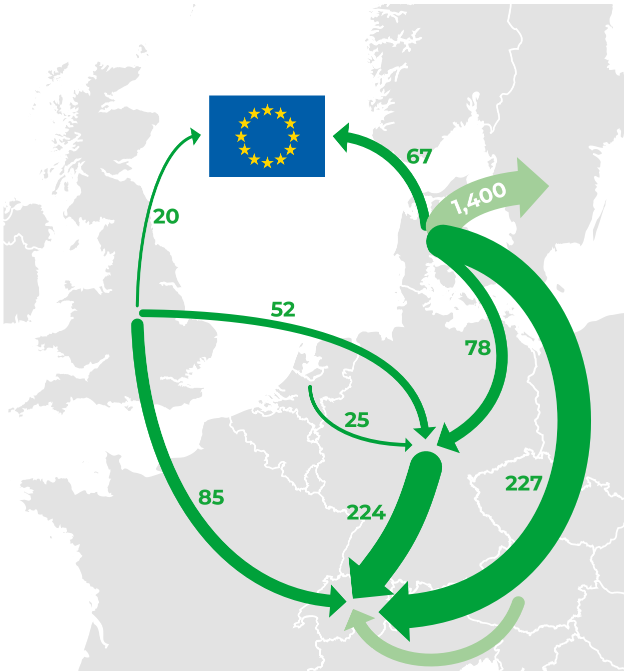
- **Sweden:** Finnish company Gasum was either involved from the start or got the plants via acquisition or subsidiary for a large share of plants.
- **Netherlands:** Bioenergy specialist HoSt is either directly or via subsidiary Bright Biomethane involved as owner or developer in a large share of plants. In some cases, large companies such as FrieslandCampina and Rabobank are involved in the projects as well. Agradu BV is another player in the Dutch market.

Most countries balance biomethane supply and demand nationally, resulting in limited cross-border trade of biomethane certificates (<10% of biomethane production). Cross-border trade of biomethane certificates is increasing in the EU; Denmark, Sweden, and Germany are the key players.

Most countries balance biomethane supply and demand locally or nationally. Cross-border trade of biomethane certificates is still limited in Europe (less than 10% of biomethane production) due to the lack of sufficient European harmonisation and cooperation between member states.[14] However, cross-border trade is growing; the growth is driven by the possible use of biomethane for the emission trading scheme (ETS) to clear CO_2 certificates and the development of harmonisation and cooperation on biomethane certification between member states (Figure 2.15).[37] Apart from the cross-border trade of GoO, the total biomethane trade in Europe also includes bilateral commercial contracts between countries, especially where no GoO scheme is in place.

Figure 2.16 gives an overview of selected biomethane-producing countries that had data availability on consumption.[37] Differences in consumption and production of countries and cross-border trade relate to available support schemes and whether this support targets biomethane production and grid injection (e.g.

Figure 2.15.
European trade volumes of biomethane certificates in 2019 (GWh)



Adapted from source: (DENA, 2020)

Germany and Denmark) or end use (e.g. Sweden). In Great Britain, the Netherlands, and Denmark, biomethane certificates can, for example, be offered much cheaper because biomethane in these countries is already subsidised for feeding into the natural gas network. Around three-quarters of the Danish certificates were therefore traded outside of Denmark in 2019.[37, 38] The opposite is true for Sweden; Sweden imported 200 GWh from Denmark in 2016, which increased to about 1,132 GWh in 2018 and is continuing to grow.[14] In 2019, Sweden imported almost 1.8 TWh biomethane, of which almost 66% resulted from Danish imports.[39] In 2018, Germany produced around 1,498 GWh of biomethane more than its consumption. This biomethane was partly used for export to the Netherlands and Switzerland.[14] Another large consumer of biomethane certificates is the Swiss market, which is being supplied from Denmark, Great Britain, and Germany.[37]

37 (DENA, 2020)
38 (Energinet, 2020)
39 (EnergiGas Sverige, 2020)

Ongoing initiatives with national registries and European coordination through the European Renewable Gas Registry (ERGaR) are gaining momentum. Six EU countries have a national biomethane registry.

Several initiatives are ongoing to increase biomethane trade volumes across Europe:

- The European standard-setting body CEN published two standards in 2016, including one on biomethane for injection in the natural gas network (EN 16723-1:2016).[40] CEN is working to improve parts of these standards. The FaSTGO (Facilitating Standards for Guarantees of Origin) project is ongoing, providing advice to the EC regarding the revision of the CEN 16325 standard.[41]
- The European Renewable Gas Registry (ERGaR) was founded in 2017 to enable cooperation and cross-border trade between European registries of biomethane certificates.[42] ERGaR is currently working on a CoO scheme to facilitate the cross-border *title transfer of CoOs between participating national biomethane registries*. The scheme is in the final stages of development and is expected to go-live soon.[43] This independent registry will help preventing the double sale and double counting of certificates through a technical hub for cross-border transfers of CoO.
- Bilateral and multilateral agreements to exchange certificates are in place between national registries (Table 2.2)—e.g. between Austria and Germany, Germany and Denmark, and the UK and Germany.[44]

Figure 2.16.
Estimated biomethane production and consumption for selected EU countries in 2018

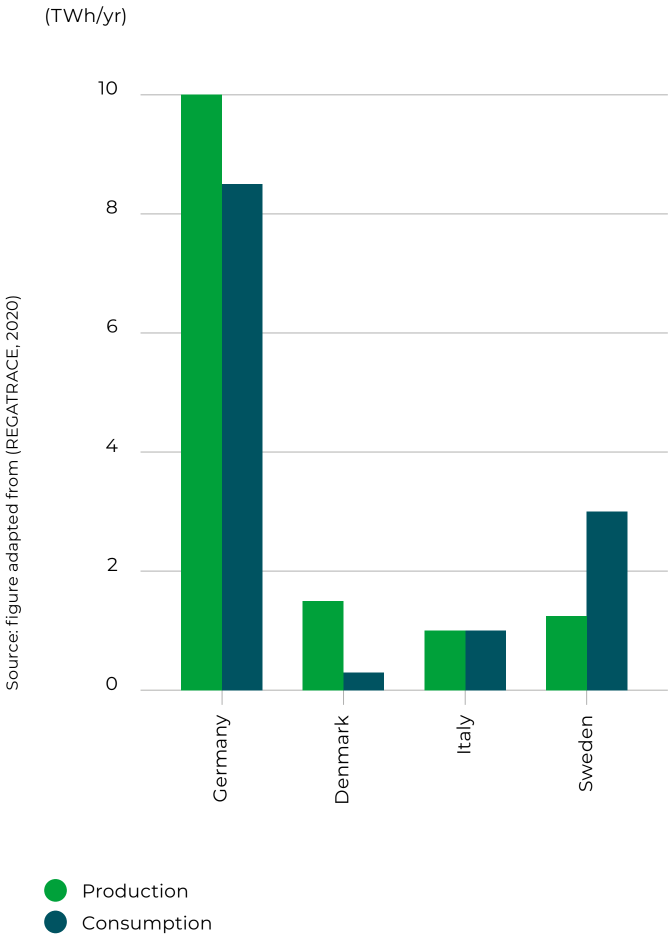


Table 2.2.
National biomethane registries in Europe[44, 45]

Country	National registry
Austria	AGCS Biomethane Register Austria
Belgium (Flanders)	Gas.be
Denmark	Danish Biomethane Registry (Energinet)
Estonia	Renewable Gas Registry (Elering AS)
France	French registry for biomethane guarantees of origin (GRDF)
Germany	Biogasregister (DENA)
Switzer-land	Swiss Biomethane Registry (SAGI)
UK	Green Gas Certification Scheme – Biomethane certification scheme (REA)

Source: REGATRACE

40 (CEN - European Committee of Standaridsation, 2016)
41 (AIB - Association of Issuing Bodies, 2020)
42 (ERGaR, 2020a)
43 (ERGaR, 2020b)
44 (REGATRACE, 2020b)
45 (REGATRACE, 2020c)

2.1.6 Showcase projects

Sewage water treatment plant

- Waternet/AGV, DMT, OrangeGas, Linde Gas
- 9.7 million m^3 of biomethane annual production capacity
- Sewage sludge - anaerobic digestion
- Under development, operational in 2021
- Amsterdam, the Netherlands
- https://www.waternet.nl/werkzaamheden/bouw-groengasinstallatie/

In the western port area of Amsterdam, the current sewage water treatment plant is being transformed and optimised to produce biomethane for households and (cargo) cars. After purifying the wastewater in the treatment plant, a sewage sludge remains. This sludge will be transferred into an anaerobic digester to produce biogas. The biogas upgrading system separates the biogas into pure CO_2 and biomethane. By adding nitrogen to the purified biomethane stream, the same caloric value as natural gas will be achieved and is ready to inject into the gas pipeline. The CO_2 stream can be captured and utilised in nearby greenhouses. The biogas upgrading system will upgrade 14.7 million m^3 raw biogas into 9.7 million m^3 of biomethane per year. The project will supply about 10% of the total amount of green gas injected in the national grid in the Netherlands. The biogas upgrading technology is delivered by DMT Environmental Technology and will be installed by Waternet on behalf of WaterBoard Amstel, Gooi, and Vecht. DMT Environmental Technology is a member of the EBA.

Aben Green Energy

- Aben Green Energy
- 18 million m^3 of biomethane annual production capacity
- Organic residues – anaerobic digestion
- In operation, since 2019
- Westdorpe, the Netherlands
- https://www.abenbv.nl/energie/biogasinstallaties/

Aben Green Energy is a large biomethane production facility in the Netherlands that uses organic residues from the food and feed industry. The facility has an annual production capacity of 18 million m^3 of biomethane (2,200 Nm^3/h) supplying over 12,000 Dutch households. The plant started operating in 2019 and immediately hit its feed-in targets. The facility is working to double the capacity to produce both biomethane and bio-LNG. The CO_2 stream is cleaned and liquified for supply to industry and horticulture.

Source: Aben Green Energy

Integrated agro-ecology fertiliser project

On 18 December 2019, the La Castellana biomethane plant started to produce biomethane and inject it into the Italian gas grid owned by Snam. The facility is located at a farm in Lombardy, which adopted the Biogasdoneright model for sustainable agriculture. Biomethane is produced from agricultural residues and sustainable sequential crops. Biogas digestive is being fed back to the field, avoiding the use of chemical fertilisers. La Castellana is one of the first biomethane plants in Italy and produces 635 m^3 of biomethane per hour.

- La Castellana
- 1.2 million m^3 of biomethane annual production capacity
- Agricultural residues and sequential crops – anaerobic digestion
- In operation since 2019
- Lombardy, Italy

Source: CIB

Torrgas project

- Gasunie, DBI-Virtuhcon GmbH, GasTerra, Groeifonds, AkzoNobel, SNN, Waddenfonds
- 175 GWh annual production capacity
- Woody residues - torrefaction and gasification
- Under development, expected in 2021
- Delfzijl, the Netherlands
- http://torrgas.nl/

Torrefaction is a method to produce biofuel from woody residues. The Torrgas process converts these residues via a two-stage gasification technology into a biofuel. Activated carbon is produced in the first step, which can be used to purify water, improve soil, or as a bio-composite. The second step creates syngas that can be converted into green gas and hydrogen. The Torrgas project aims to realise a 20 MW commercial gasification installation based on woody residual flows in Delfzijl in the northern Netherlands. The project consists of constructing a gasification installation, a gas cleaning unit, and a methanation system. The aim of the project is to supply green gas to the natural gas network and steam to the local steam network. Gasunie New Energy is developing this installation in close collaboration with Torrgas and other project partners. The final preparations will be made in the second half of 2020, with the goal of starting construction in Delfzijl in 2021. The plant is expected to become operational in the first half of 2021.

Korskro biogas plant

Nature Energy

22 million m³ of biomethane annual production capacity

Manure - anaerobic digestion

In operation since 2019

Korskro, Denmark

https://natureenergy.dk/

The Korskro biogas plant processes approximately 710,000 tonnes of biomass annually. Around 85% of this biomass comes from livestock manure and deep bedding from cattle, pigs, and mink supplied by approximately 100 farmers from the livestock-intensive area around the plant in Denmark. The remaining 15% consist of a feedstock mix of food waste, organic waste from industry and retail, and energy crops. After completing the first phase, the plant is producing around 22 million Nm^3 of biomethane that is injected into the natural gas network. Fully expanded, the plant will be able to process 1 million tonnes (Mt) of food waste and residual agricultural products annually.

Soure: Nature Energy

Bio-LNG as a biofuel

Cooperativa Agricola Speranza; Maganetti Spedizioni SpA

2,000 ton of liquefied biomethane per year

Biomethane liquefaction and CO_2 capture

In operation since 2020

Candiolo, Italy

Cooperative Speranza owns two biogas agricultural plants with a capacity of 1 MW_{el} each that produce around 4.2 million m^3 biogas per year and provide heat (1,000 KWth/h) to the Candiolo Cancer Institute in Italy. In 2020, the cooperative built a new biomethane plant with a liquefaction unit and a CO_2 capture system. Using 100% agricultural residues and catch crops, the new biomethane plant produces 2,000 ton of liquefied biomethane per year. The liquefied biomethane is used as an advanced biofuel by Maganetti Spa, a transport company that owns 42 liquified natural gas (LNG) trucks. The CO_2 is certified food-grade and sold to food industries. Cooperativa Speranza and Maganetti SpA are planning to build a new LNG fuelling station where part of the liquefied biomethane will be sold.

Biowaste to biomethane plant

Since September 2019, the biomethane plant in Sinsheim operated by MVV, a German energy provider, and AVR, a waste recycling company, has been in regular operation feeding biomethane produced from biowaste into the German gas grid. Around 60,000 tons of biogenic waste are fermented annually and dried into certified compost. This compost contributes to the formation of humus and is used in the regional agriculture as a long-term organic fertiliser. The raw biogas produced in the fermentation process is processed into biomethane before it is fed into the natural gas grid via a new 4.3 km gas pipeline built by MVV. Each year, biomethane with an energy content of around 51 million kWh is to be produced.

- MVV, AVR
- 3.9 million m³ of biomethane annual production capacity
- Biogenic waste - anaerobic digestion
- In operation since 2019
- Sinsheim, Germany
- https://www.avr-umweltservice.de/de/Unternehmen/Die_AVR-Gruppe/AVR_Bio_Terra_GmbH.php

Dry and wet manure to biomethane

- revis bioenergy
- 6.1 million m³ of biomethane annual production capacity
- Wet and dry manure - anaerobic digestion
- In operation since 2020
- Dülmen, Germany

Source: revis bioenergy

In 2020, revis bioenergy put the Dülmen biogas plant into operation to absorb and ferment the wet and dry farm manure from 40 farmers in the region. The plant receives 70,000 tons of manure on a yearly basis; the manure is fed via an automated crane into the plant. The plant produces 1,400 Nm³/h of biogas, which is upgraded into biomethane (700 Nm³/h biomethane production capacity), corresponding to approximately 70 GWh per year. The biomethane is injected into the region's natural gas network. revis bioenergy aims to use all material flows from the biogas plants, including green fuels such as biomethane, bio-LNG, green ammonia, and green industrial products such as CO_2, fertiliser, and peat substitute products. revis is planning to install a power2biogas plant as a next step.

UNUE – upgrading facility and injection

In September 2020, BioEnGas and Suma Capital began the construction of the Unue project, which aims to transform biogas into biomethane. The project will be developed at a biogas plant located in the Spanish province of Burgos and aims to produce and inject approximately 20 GWh of biomethane per year into the national natural gas network. The biogas will be obtained through the anaerobic digestion of organic industrial, agricultural, and livestock waste. The project is expected to launch in the first half of 2021.

Source: BioEnGas

- BioEnGas (Enagás Group), Suma Capital, Biogasnalia, AGF Ingeniería de Procesos
- 2.1 million m^3 of biomethane annual production capacity
- Industrial, agricultural, and livestock waste – anaerobic digestion
- Under construction, operational in 2021
- Polígono de Villalonquéjar, Spain
- https://www.enagas.es/enagas/en/Comunicacion/NotasPrensa/29_09_20_NP_Proyecto_biometano_Burgos_Bioengas_y_Suma_Capital

2.2 Green and blue hydrogen

Key trends

Emerging trends are seen with hydrogen *production technologies*. Most green and blue hydrogen production routes are in an early commercial stage (<1% of EU hydrogen production), but plant and stack sizes are increasing, and hydrogen production and CO_2-capturing processes are becoming more efficient. Electrolyser capacities are growing, and PEM technology is closing the gap with ALK and SOEC efficiencies, by adding 4% system efficiency, on average, since 2017. Newly announced blue hydrogen projects mostly rely on ATR technology as deploying this in combination with CCS at large scales has various economic and operational benefits.

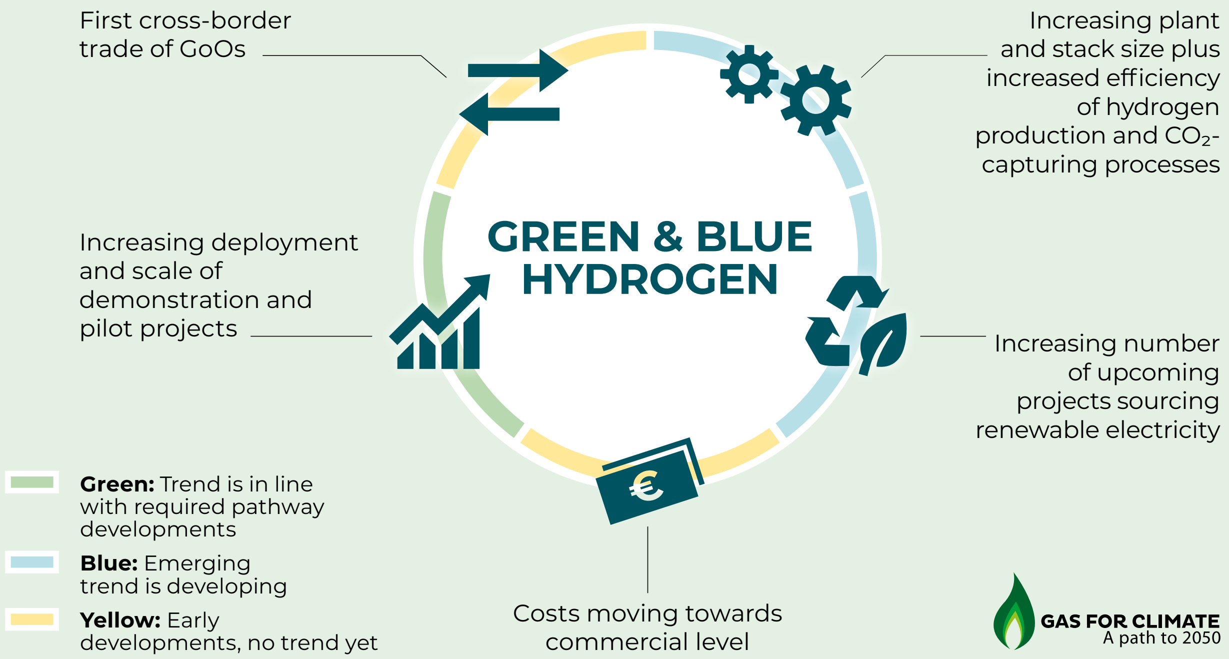
An increasing number of upcoming electrolyser projects intend to source renewable electricity as *feedstock* for green hydrogen production. Over 54% of announced electrolyser projects in the EU have disclosed their sourcing plans, with wind energy being the preferred renewable electricity source (39% of announced projects and equal to 77% of announced capacity).

Early developments are taking place around green and blue hydrogen *production costs*, but additional attention is required. Production costs for green hydrogen range from €70/MWh to €130/MWh— and mainly depend on electricity price and electrolyser parameters. Costs are expected to drop to the level of grey and blue in the coming decades. Blue hydrogen is currently more cost-competitive compared to green hydrogen. With costs estimated between €37/MWh and €41/MWh, depending on the technology and infrastructure requirements.

Electrolyser *capacity* and the number of feasibility projects show a rapid growth in the EU. Technological developments are on track, and decisions on pilot projects for 10 MW and larger are coming up. Electrolyser capacities grew—the average annual growth rate was approximately 20% between 2016 and 2019. Large-scale blue hydrogen projects are under development across industrial clusters around the North Sea. Based on current project announcements, a significant acceleration of hydrogen project developments is expected between 2020 and 2030. A further increase is expected, driven by the EU Hydrogen Strategy and national hydrogen strategies.

Early developments are taking place around cross-border trading, but additional attention is required. *Cross-border trade* of hydrogen certificates is limited in the EU, with the first CertifHy certificates launched in 2018. Trading of hydrogen certificates is expected to increase following national and EU developments.

Figure 2.17.
Key trends for green and blue hydrogen supply



GAS FOR CLIMATE
A path to 2050

Source: Guidehouse

This section details the key trends regarding green and blue hydrogen supply. In the early 2020s, developments will focus on kicking off developments in green and blue hydrogen supply to develop 85 TWh blue hydrogen and at least 100 TWh green hydrogen supply by 2030. This will be possible by further developing and scaling up production technologies and renewable electricity, and increasing production and deployment, thus enabling cost reductions. The required developments to supply green and blue hydrogen are translated into key trends around technology, feedstock, production cost, deployment and production, and market, each supported by showcase projects (Figure 2.19). The following paragraphs detail each key trend and indicate the status of each trend towards achieving the critical decarbonisation timeline in the early 2020s-2030.

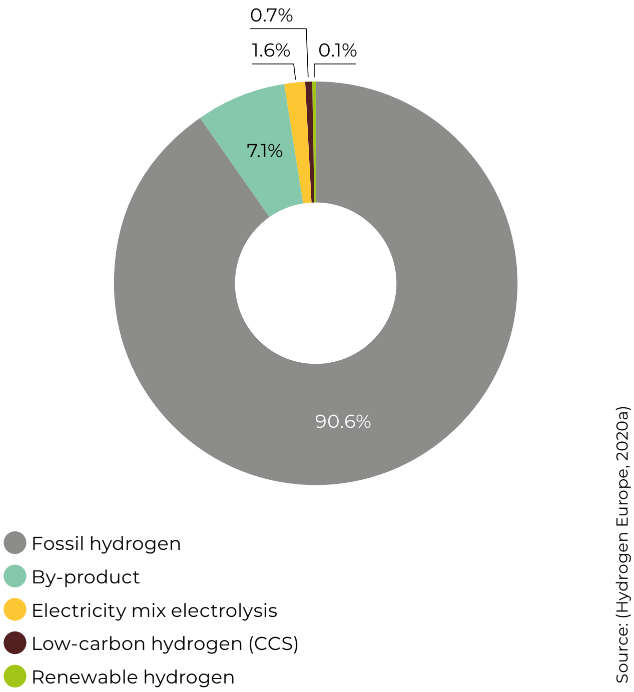
2.2.1 Increasing plant and stack size plus increased efficiency of hydrogen production and CO_2-capturing processes

Almost all hydrogen in Europe is currently produced by grey hydrogen production routes. Green and blue hydrogen production routes are only in an early commercial stage (<1% of EU hydrogen production).

In the EU, around 339 TWh_{LHV} (10.2 Mt H_2, 33 bcm natural gas equivalent) of hydrogen was produced in 2019,[46] constituting around 13% of the global production. Compared to grey hydrogen, the share of green and blue hydrogen produced is still small at less than 1% of production in the EU (Figure 2.18).[47]

Renewable and low-carbon hydrogen can be produced through multiple technology and feedstock routes (Figure 2.19).

Figure 2.18. Distribution of hydrogen production in Europe in 2020



The **fossil-based production** route without applying carbon capture (grey hydrogen) is an emissions-intensive process, leading to life cycle emissions ranging from 104 to 237 gCO_2-eq./MJ (12.5-28.4 tCO_2-eq./t H_2) depending on the production technology and feedstock.[48] Renewable and low-carbon production can be achieved through water electrolysis using renewable electricity or thermochemical conversion of biomass (green hydrogen) or through capturing CO_2 emissions from hydrogen produced from fossil feedstocks (blue hydrogen) or biomass feedstocks (climate-positive green hydrogen).

46 (Fuel Cells and Hydrogen Joint Undertaking, 2019)
47 (Hydrogen Europe, 2020a)
48 (DENA, 2019)

When using **renewable electricity**, electrolysis can achieve significant emission reductions compared to unabated fossil routes. Electrolysis-based routes can even achieve an emissions intensity that is one-third that of fossil routes that use carbon capture and storage (CCS) and a slightly lower greenhouse gas (GHG) intensity compared to hydrogen derived from biomass.[48] However, capturing and storing CO_2 emissions from the bio-conversion route could result in negative CO_2 emissions, meaning more emissions are permanently sequestered than emitted (i.e. climate-positive hydrogen).

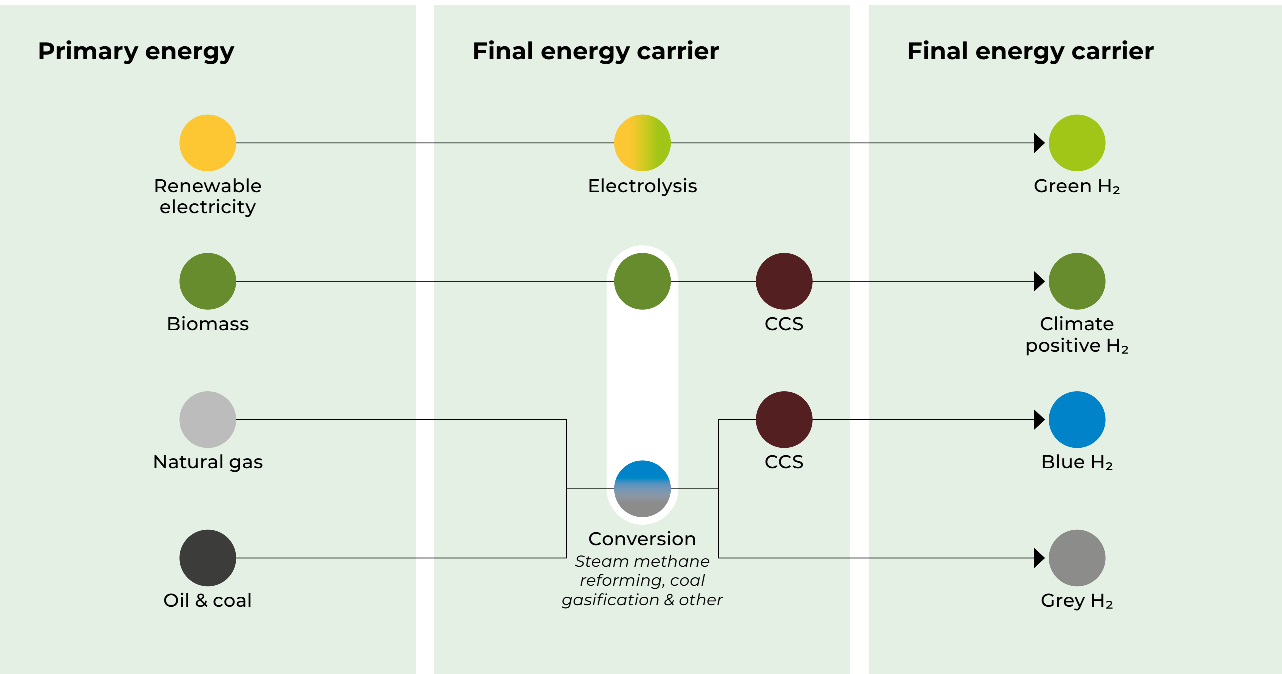
The basic process for grey or blue hydrogen production involves stripping fossil hydrocarbon molecules of their hydrogen atoms. Mature processes that deconstruct these molecules into smaller parts include reforming, partial oxidation, and gasification processes. These processes can, in principle, be performed on any fossil source such as natural gas, coal, and oil. The benefit of blue hydrogen is that the existing fleet of EU hydrogen plants can be retrofitted with CCS, rapidly scaling up the availability of low-carbon hydrogen to existing uses.

Alkaline Electrolysis (ALK), Proton Exchange Membrane (PEM) and Solid Oxide Electrolysis Cells (SOEC) technologies are considered the most mature technologies to produce electrolysis-based hydrogen. PEM energy efficiency has increased by 4% since 2017, whereas ALK and SOEC increased by 2%. The efficiency gap is slowly closing, although ALK will likely remain ahead for the foreseeable future.

Multiple types of electrolysers are being developed. Four water electrolysis technologies are considered in the advanced stages of maturity: ALK, PEM, SOEC, and AEM. Table 2.3 summarises their key technical parameters.

ALK are the most mature and least costly (€/kW) technology today, predominantly used for brine electrolysis.[49] Some ALK system setups have limited ability to respond to load changes, which is essential for off-grid integration and the flexibility requirements of a power system with high penetration of renewables.[51] R&D efforts in the industry have improved the response time

Figure 2.19.
Overview of the production routes for the various types of hydrogen



Source: Guidehouse

49 (Hydrogen Europe, 2020b)
50 Excluding steam input
51 (Thyssen Krupp, 2020a)

Table 2.3.
Overview of the key parameters of water electrolysis technologies (based on current values)[49]

Technology	System efficiency (LHV) (%)	Efficiency degradation at stack (%/1,000 hrs)	Ramp-up from standby mode	Footprint (m^2/MW)	Current density (A/cm^2)	Use of critical raw materials in catalyst (mg/W)	Maturity level
ALK	67%	0.12	60 seconds	100	0.6	0.6	Multiple commercial applications (multi-MW)
PEM	61%	0.19	2 seconds	60	2.2	2.7	Commercial scale-up (multi-MW)
SOEC	83%[50]	1.9	10 minutes	150	0.6	N/A	Commercial scale-up, small scale (MW)
AEM	61%	>1.0	30 seconds	90	0.8	1.7	Commercial scale-up, small scale (kW)

Source: Guidehouse analysis and Hydrogen Europe

significantly. thyssenKrupp, Nel, and McPhy are among the main ALK technology suppliers. thyssenKrupp recently announced it will significantly increase its production capacity for ALK electrolysers to 1 GW annually.[52] Nel is planning to commence production in 2020 with an annual capacity of 360 MW in its new manufacturing plant, with for the possibility to further expand to 1 GW per annum.[53] McPhy has raised capital to expand its manufacturing capacity and will target large-scale projects exceeding 100 MW scale.[54]

PEM electrolysers have a simple and compact design. They are more expensive than ALK electrolysers and have a lower system energy efficiency. However, they are flexible, with ramp-up or ramp-down times of seconds. PEM electrolysers operate at higher output pressures (30 bar) compared to the majority of ALK systems. The focus for PEM remains in the search for new materials in the stack and the recycling of the precious metals used. Technology companies like ITM Power, Nel, Siemens, Giner ELX, and Hydrogenics are among the main PEM technology providers. The largest PEM electrolyser currently in operation is the 6 MW PEM system at EnergiePark Mainz.[49] The largest announcement to date in Europe is in Rhineland, Germany, where Shell and ITM Power are constructing a 10 MW electrolyser.[55] In terms of manufacturing, ITM Power announced the construction of a new manufacturing facility that will enable an upgrade in production capacity to around 1 GW/year.[56]

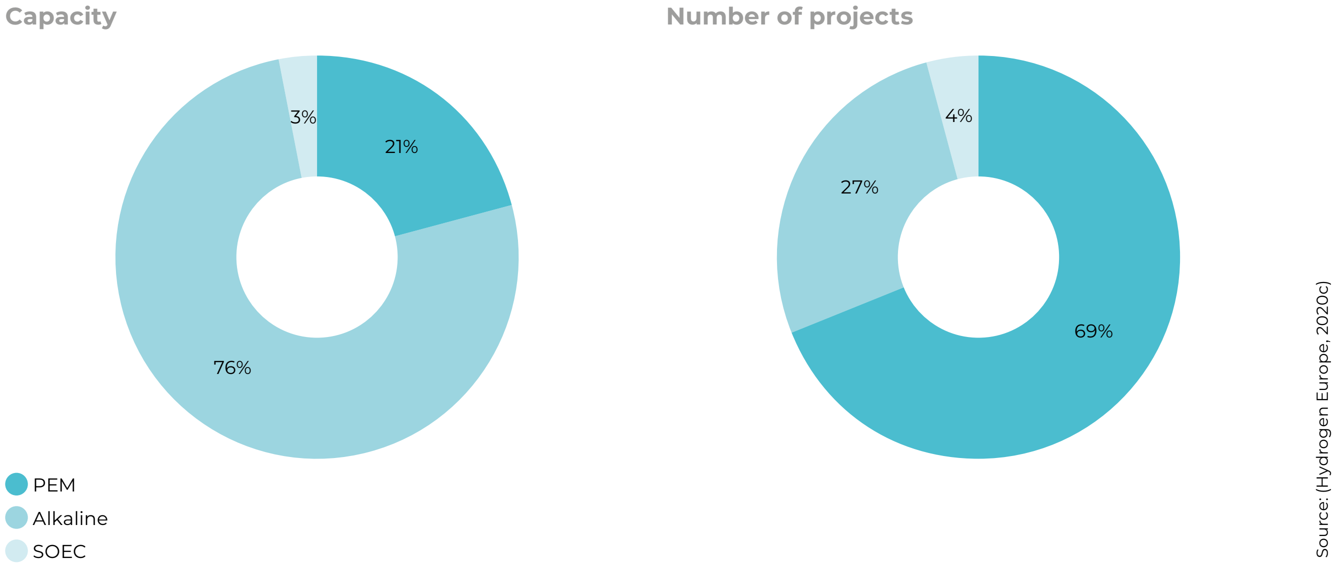
52 (Thyssen Krupp, 2020b)
53 (Nel, 2018)
54 (McPhy, 2020)
55 (Refhyne, 2020)
56 (ITM Power, 2019)

SOECs are used for high temperature electrolysis and can also be used in co-electrolysis with CO_2 to produce syngas for e-fuels or other chemical processes. SOEC technology is in an earlier stage of development[49], yet it is promising as substantially higher efficiencies can be reached where waste steam is available. The main challenge is to resolve the degradation of materials.[57] Sunfire and Haldor Topsoe are the main market players in the development of SOEC technology. Sunfire delivered the largest SOEC electrolyser of 720 kW of capacity to Salzgitter Flachstahl in Germany.[58] A consortium of Sunfire, Climeworks, and EDF, under the name of Nordic Blue Crude, are developing a 20 MW power-to-liquids facility based on an SOEC system. The consortium's aim is to scale this capacity 10-fold between 2022 and 2025.[59]

Another promising electrolyser technology is **AEM electrolysis**. AEM is a new technology in an early stage of development and is an upgrade of PEM electrolysers.[60] Enapter announced the start of a 260 MW/year electrolyser production facility in Germany this year.[61]

From the announced green hydrogen projects in the EU and UK that have detailed their technology, 27% of the projects use ALK electrolysers, constituting 76% of the planned capacity.[47] PEM technology is the technology of choice in 69% of announced projects, but that only reflects 21% of the announced capacity. This confirms that PEM projects are currently smaller in size compared to ALK projects. PEM technology has improved its system efficiency by 4% since 2017, reaching an average of 61% (LHV) in 2020. Expectations of PEM efficiency improvement were higher compared to what was achieved over the past years. System efficiencies for ALK and SOEC technologies were already higher and increased by 2% since 2017, reaching 67% and 83% in 2020, respectively.[49] The efficiency gap between PEM, and ALK and SOEC technologies is slowly closing, although ALK efficiency will likely remain ahead for the foreseeable future.[62] Efficiency is just one of the metrics to assess performance next to e.g. system flexibility, plant size, and stack degradation.

Figure 2.20.
Distribution of water electrolysis technologies for announced green hydrogen projects in the EU and UK between 2020 and 2040 based on total capacity and number of projects

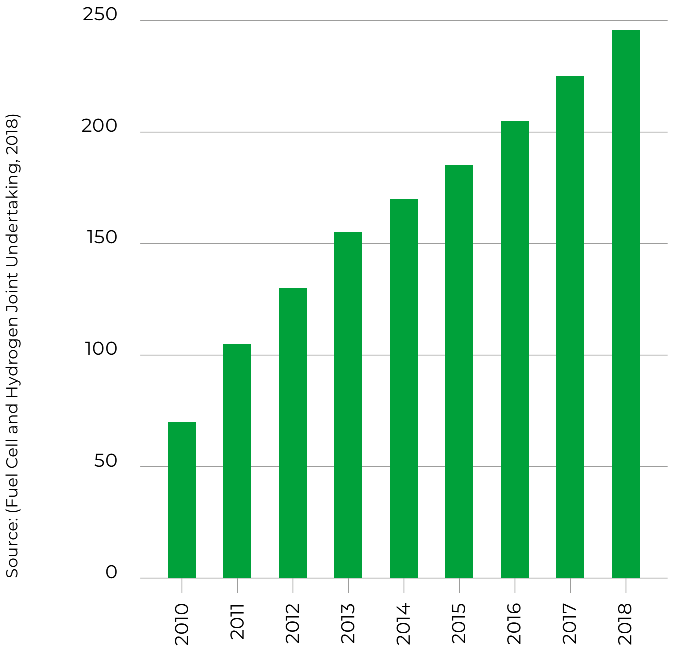


57 (ASSET study, 2018)
58 (Sunfire, 2020)
59 (Nordic GTL, 2019)
60 (Enapter, 2020a)
61 (Enapter, 2020b)
62 (IRENA, 2018)

Maturing the electrolyser sector requires projects on the 100 MW to GW scale, which is a scale jump of 1-2 orders of magnitude from current levels. Currently announced EU projects suggest that this scale will be reached well before 2030.

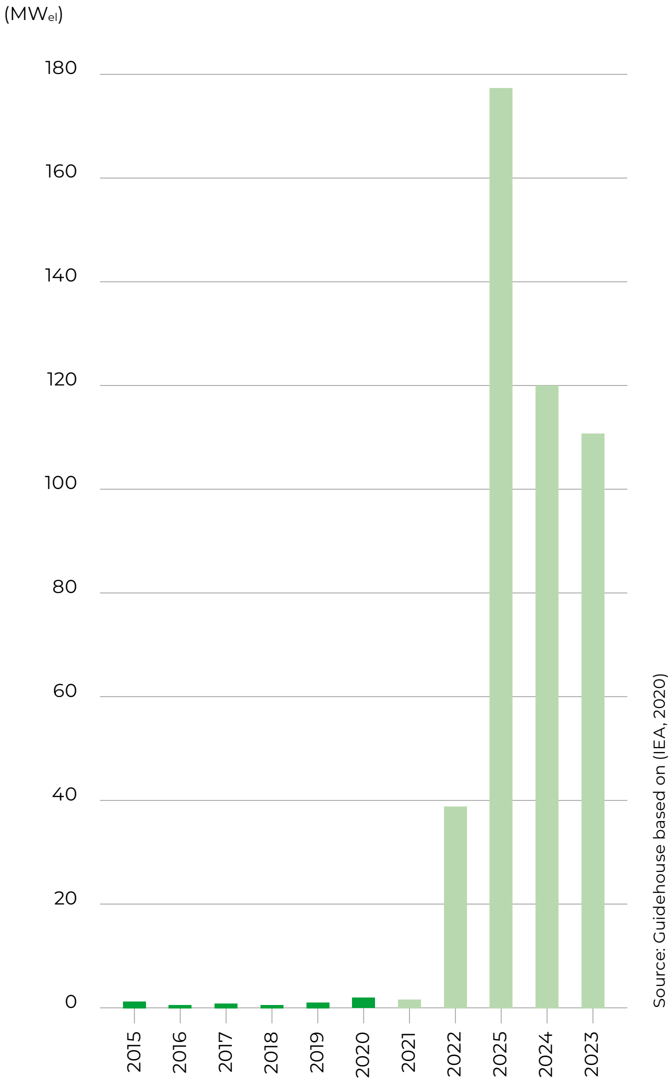
Many hydrogen R&D projects have been developed over the past decade (Figure 2.21). This growth helped to increase the scale of electrolysers and increase the knowledge surrounding the integration of renewable power generation with electrolyser operation and hydrogen use in specific demand sectors, such as road transport. The number of R&D projects in the EU increased linearly to 227 in 2018. These R&D developments attracted about €844 million in EU R&D subsidies from the FP7 and H2020 programmes between 2008 and 2018, complemented by €886 million from other sources, including private company funding.[63]

Figure 2.21.
Total number of hydrogen related projects (both production and use) supported by EU R&D funds



The average sizes of operational and announced electrolyser projects suggest that project sizes are rapidly growing, from an average size of around 2 MW_{el} in 2019 to 110 MW_{el} in 2025 (Figure 2.22). Announced projects after 2025 have even larger capacities, with some projects exceeding 2.5 GW_{el} in 2030.[64]

Figure 2.22.
EU average capacity of existing and announced PEM and ALK electrolyser projects



63 (Fuel Cells and Hydrogen Joint Undertaking, 2018)
64 Guidehouse, based on IEA hydrogen database, 2020; (IEA, 2020)

Steam methane reforming (SMR) and autothermal reforming (ATR) technologies are mature technologies for grey hydrogen production today; SMR is responsible for a majority of hydrogen production. However, newly announced blue hydrogen projects mostly rely on ATR technology as deploying this in combination with CCS at large scales has various economic and operational benefits.

Two mature hydrogen production technologies coupled with carbon, capture and storage (CCS) are the most discussed: SMR and ATR. Methane pyrolysis is another technology that can be used for the large-scale production of hydrogen, which is in an early stage of development.[65] Methane pyrolysis is also a well-known process to produce e.g. carbon black.[2, 65]

SMR[66] is a well-established and mature technology responsible for most grey hydrogen production.[67] In the SMR process, natural gas and steam are fed to a reformer, through which synthesis gas is produced; this is mainly a mixture of hydrogen, water, carbon monoxide (CO), and CO_2. SMR is among the cheapest methods to produce hydrogen, but it produces significant CO_2 emissions. Emissions can come down with increased efficiency, high CO_2 capture rates, and a change to bio-based feedstock (e.g. biomethane). Capturing and storing the CO_2 enables the abatement of direct emissions in hydrogen plants (both SMR and ATR) by 60%-95%, depending on the CO_2 capture technology and the use of natural gas or hydrogen as fuel for the furnace. Using hydrogen in the furnace eliminates one point-source of CO_2, leaving only the CO_2 from the shifted syngas. However, this increases CAPEX and OPEX.[68] System efficiencies for SMR range between 69% and 85% without CCS, largely depending on scale and operating temperature.[69, 70] Large-scale units generally have a better energy efficiency.[71] Adding a CO_2 capture unit usually leads to a drop in efficiency of about 2%, depending on the process and share captured.[72] NTNU, for example, reports an efficiency of 82% including CCS.[47] SMR plants, ranging from small- to large-scale, can be retrofitted with CO_2 capture technology.[6] Upstream emissions from natural gas production and distribution are still present, leading to a higher GHG intensity compared to green hydrogen production even when all direct plant emissions are abated. When aiming to maximise the abatement of site emissions, ATR is often preferred over SMR for greenfield blue hydrogen plants.

ATR is used to obtain syngas; it combines the SMR process with partial oxidation (POX) reaction which provides the process heat. Depending on the grid emission factor, unabated ATR can be more emissions-intensive compared to SMR due to the need for oxygen, which is produced in an air separation unit. However, ATRs have only one point-source of CO_2 onsite, which facilitates CO_2 capture and thereby the abatement of the site emissions. Various process designs quote an abatement of 95% of site emissions when CO_2 capture is applied.[73] Capture technologies that separate CO_2 and hydrogen from the process gas in one process step with a vacuum pressure swing adsorption (VPSA) technology are under investigation. These technologies enable capture rates of up to 99% and increased system cost savings.[74] Using low-cost by-product oxygen originated from the electrolysis process could further reduce indirect emissions from power generation at ATR plants.

The final choice for SMR or ATR depends on the project goals. An important difference is that ATR yields a lower H_2 to CO ratio. Without CCS, ATR is generally preferred when the CO product is desired, e.g. for methanol production.[75] Recently announced blue hydrogen projects note high reliability of ATR plants, with recorded utilisation as high as 99,7% in the methanol industry. ATR plants have a broad operating range with almost unlimited scalability compared to SMR and high flexibility.[76] Capturing close to 100% of site emissions is also less costly for ATR. ATR is a therefore logical choice when the aim is to maximise CO_2 capture at the lowest cost.

65 (Schneider, Bjohr, Graf, & Kolb, 2020)
66 (U.S. Department of Energy, n.d.)
67 (H2tools, 2015)
68 Upstream emissions from natural gas production and distribution are still present, leading to a higher GHG intensity compared to green hydrogen even when all direct plant emissions are abated.
69 (Edwards R.; Larive J.-F.; Beziat J.-C., 2011)
70 (J.M. Ogden, 2001)
71 (ASSET study, 2020)
72 (IEA, 2017a)
73 (D., Jakobsen; V., Åtland, 2016)
74 (Antonini, et al., 2020)
75 (Air Liquide, 2019)
76 (Deltalings - H-vision, 2019)

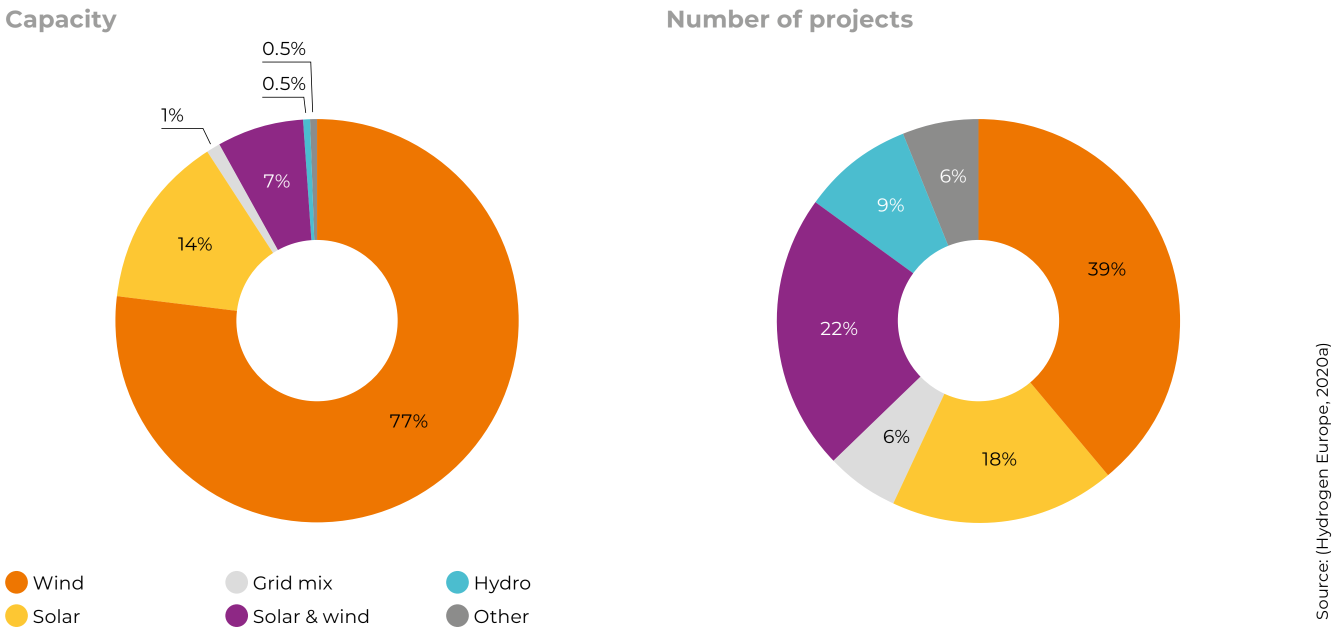
2.2.2 Increasing number of upcoming projects source renewable electricity

About 54% of announced electrolyser projects in the EU disclose their electricity sourcing strategy. Wind energy is the preferred source announced for 39% of green hydrogen projects (77% of capacity).

The increasing deployment of renewable electricity generation is creating a favourable environment to kick off engagements between renewable electricity providers and green hydrogen projects.[77,78] About 54% of announced electrolyser projects in the EU also announce their electricity sourcing plans (Figure 2.23).[47] Wind technology leads—it has been announced as source for 39% of green hydrogen projects (77% of capacity).[79] Solar represents the second most preferred source, announced for 18% of green hydrogen projects (14% of announced capacity).[47] In addition, combinations of wind and solar, often allowing for a higher capacity factor, cover 22% of announced projects (7% of capacity).

The development of renewable electricity procurement for hydrogen production will also depend on the outcome of the RED II Article 27 Delegated Act, which will establish requirements for eligible renewable electricity sources.[80] Provisions may be extended from eligible fuels in the transport sector to all green hydrogen and renewable fuels of non-biological production regardless of their end use.

Figure 2.23.
Distribution of electricity sources for announced green hydrogen capacity and projects in the EU between 2020 and 2040 based on total capacity and number of projects



77 (Eneco, 2020)
78 (Orsted, 2020)
79 (Hydrogen Europe, 2020a)
80 (European Commission, 2018)

2.2.3 Costs moving towards commercial level

Production costs for green hydrogen range from €70/MWh to €130/MWh, which is still about 2-4 times higher than the production cost of grey and blue hydrogen. Short-term green hydrogen production cost estimates have become more optimistic since 2017 and are expected to reach similar levels as grey and blue in the coming decades.

The main cost drivers for green hydrogen production include electrolyser CAPEX and efficiency, electrolyser full load hours, cost of renewable electricity, and cost of system integration.

Electrolyser **system investment costs** and **efficiency** largely depend on the technology used and are independent of the location within the EU (see Table 2.4).

Table 2.4.
Overview of the 2020 technology cost parameters of green hydrogen production technologies (LHV)

Technology	Capital costs 2020 (€/kWin)[81]
ALK	600
PEM	900
SOEC	2,130
AEM	-

Source: (Hydrogen Europe, 2020b)

Although comparing electrolyser costs can be challenging due to often different cost estimation scopes, compared to 2017 estimates show to be increasingly optimistic about the short- and long-term costs of electrolysers[49, 82]; Bloomberg New Energy Finance[83], for example, quotes a potential decrease from €500/kW today to €115/kW and €80/kW in 2030 and 2050, respectively, and Hydrogen Europe[49] recently specified system cost targets of €480/kW by 2024. With the announced plans for electrolyser manufacturing capacity expansion by thyssenKrupp, Nel, and ITM Power, cost projections are expected to decrease in the coming years.[84] These cost reductions can be realised by economies of scale in the manufacturing part of the supply chain, which can be enabled with electrolyser capacities of over 10 MW, R&D, and standardisation and automation of production.[85] All technologies are, furthermore, expected to experience further improvements in efficiency, although PEM technology is expected to make the largest progression in efficiency over the coming years.

Although future reductions in electrolyser CAPEX will make a low **capacity factor or full load hours** less detrimental to the economic performance of hydrogen production, the capacity factor is key as long as capital costs make up a significant part of the levelised cost, in particular, optimising renewable electricity sourcing to maximise full load hours.

With the expected decrease in investment costs, **renewable energy** will constitute an increasingly large share of production costs. This cost can be the levelised cost of energy (LCOE) in the case of dedicated renewable power production coupled to hydrogen production, or the electricity price in the situation where renewable energy plants serve both electricity and hydrogen markets. The evolution of electricity prices varies by location and remains uncertain because it depends on various external factors, including the evolution of policies, the power generation mix, and the power demand in end-use sectors.

81 Capital costs are based on 100 MW production volume for a single company and on a 10-year system lifetime running in steady state operation. Stack replacements are not included in the capital cost. Costs are for installation on a pre-prepared site (fundament/building and necessary connections are available). Transformers and rectifiers are to be included in the capital cost.
82 (Hydrogen Council, 2017)
83 (Bloomberg, 2019)
84 Guidehouse analysis based on discussions with electrolyser manufacturers, 2020
85 Guidehouse analysis based on surveys with electrolyser producers, 2020

System integration cost factors to deliver green hydrogen include grid injection costs, transport and distribution costs, and storage costs. Typical hydrogen delivery systems consist of a conversion unit (e.g. compression, liquefaction), transmission and distribution components (e.g. long distance, high pressure transport pipeline infrastructure, [see section 4.5], local low pressure distribution network), and inter-seasonal and intraday storage capacities.[71]

Green hydrogen production cost in the EU ranges from about €70/MWh to €130/MWh (Figure 2.24).[86] Small-scale pilot projects can show a much higher cost.[87] The production cost depends on the project scale, electrolyser cost, and varying electricity cost. Production costs are expected to reach similar levels as grey and blue in the coming decades. Estimations for green hydrogen production costs for 2050 range between €17/MWh and €84/MWh (Figure 2.24).[2, 88]

Current production costs for blue hydrogen are estimated to be between €37/MWh and €41/MWh, depending on the technology. While improvements in industrial symbiosis, natural gas pyrolysis, project size, CO_2 capture technology, and transport and storage infrastructure may bring down costs, the price of natural gas futures are likely to continue to dominate the trend.

With natural gas futures reaching historical lows of below €10/MWh in 2019, **production costs for blue hydrogen** have significantly decreased over past years.[89] Assuming a slightly more conservative €15/MWh, current costs for SMR with CCS are estimated at €41/MWh, whereas ATR is estimated at €37/MWh (Figure 2.24).[90] Besides fuel costs, other key cost drivers for blue hydrogen production include CAPEX for the hydrogen production and the carbon capture units, the production scale of the plant, and electricity prices in the case of ATR.

Capital costs of SMR and ATR plants with CCS (Table 2.5) are dominated by hydrogen-related units like the reformer and water-gas shift reactor but highly depend on the plant capacity. The carbon capture equipment, transport/storage infrastructure, and the air separation unit (ASU; in case of ATR) also take a large share. Auxiliary components like water systems, heat integration, and power and engineering costs can account for about 30% of total costs.[73] Future projects should demonstrate the possibilities for industrial symbiosis between ATR plants and electrolysis; this is currently investigated in the Hydrogen Accelerator project.[91]

Carbon capture technology is rapidly developing. Some capture technologies are specifically relevant for hydrogen plants as they are integrated with existing technical units in the plants.[92] One example is the sorption-enhanced water-gas shift, where the existing water-gas shift reaction is combined with in-situ removal of CO_2. The integration increases the conversion of CO to almost 100%, while reducing the energy intensity of CO_2 capture by nearly 20% compared to default amine capture technology.[92] Another innovation relates to the hydrogen purification step.[74] Replacing the existing CO_2 capture equipment with a single VPSA is expected to lead to reduced process complexity and potentially reduced capital cost. VPSA technology can also be retrofitted to existing hydrogen production facilities by reusing existing equipment based on experience from operating PSA units for hydrogen purification.[74]

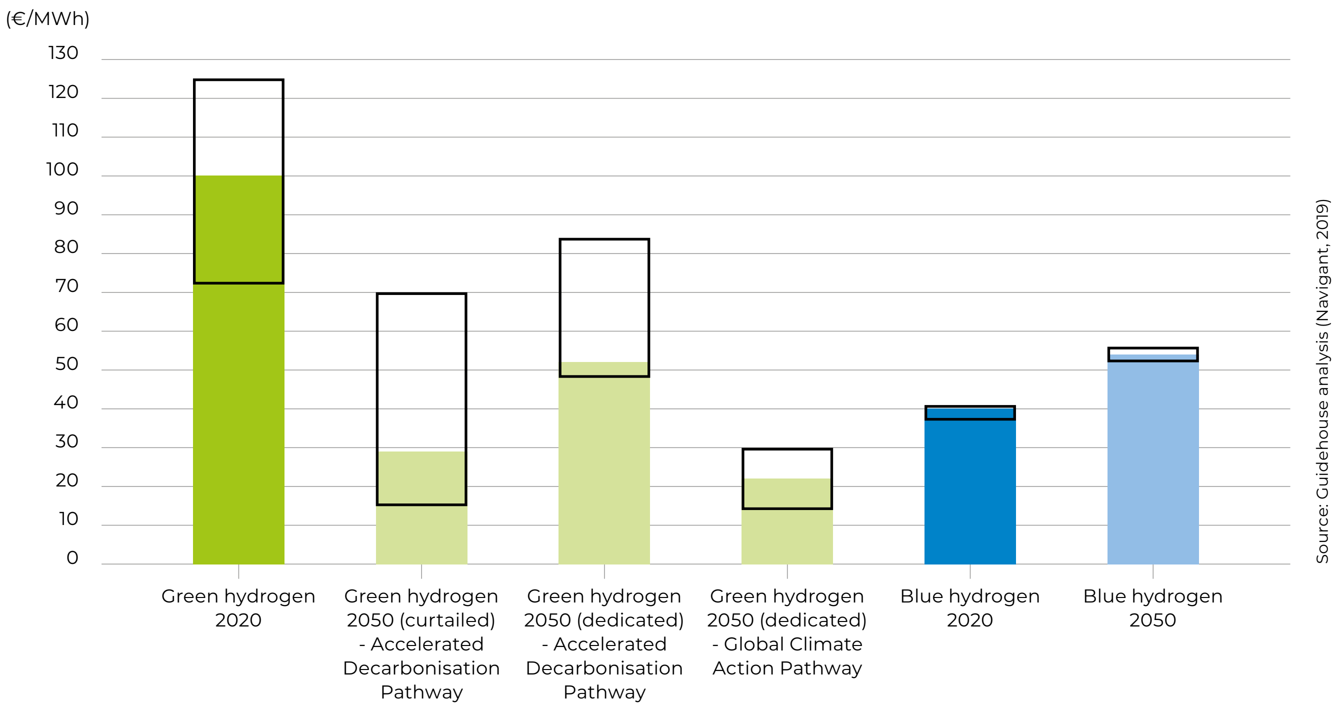
Table 2.5.
Overview of the 2020 technology cost parameters of blue hydrogen production technologies

Technology	System investment cost (LHV) (€/kWH$_{2\text{-out}}$)
SMR, retrofit with CCS	700
SMR, new with CCS	790-1,650
ATR, retrofit with CCS	690
ATR, new with CCS	950-1,500

Source: (ASSET study, 2020)

86 This range is based on a lower range value from (Guidehouse, 2020)
87 (Hydrogen Europe, 2020a), which includes small-scale pilot projects.
88 These estimates take into account significant cost reductions for CAPEX, RES costs, and increased load hours and efficiencies. (Guidehouse, 2020)
89 (CME Group, 2020)
90 Prices based on natural gas price around of €15/MWh and a scale of 300 MW$_{in}$ or 500 t H_2 per day. (Guidehouse, 2020)
91 (Topsector Energy, 2020)
92 (H-vision, 2019)

Figure 2.24.
Hydrogen production cost estimates for 2020 and 2050



The 2050 data assumes a carbon price of 100 €/tCO_2.
* Scenarios reported in Gas for Climate 2020 Report: Gas Decarbonisation Pathways 2020-2050

The **production scale** for blue hydrogen significantly impacts the production cost. Production costs are estimated to decrease by 20%-30% when production capacity is increased from 100 tonnes H_2/day to 500 tonnes H_2/day (i.e. 60 MW_{in} to 300 MW_{in}).[73] ATR plants benefit more from economies of scale compared to SMR, given that SMR encounters manufacturing limitations at lower scales. Air Liquide quotes that its SMR technology can scale to a capacity of 350,000 Nm^3/h syngas, whereas their ATR technology scales up to 1 million Nm^3/h.[93]

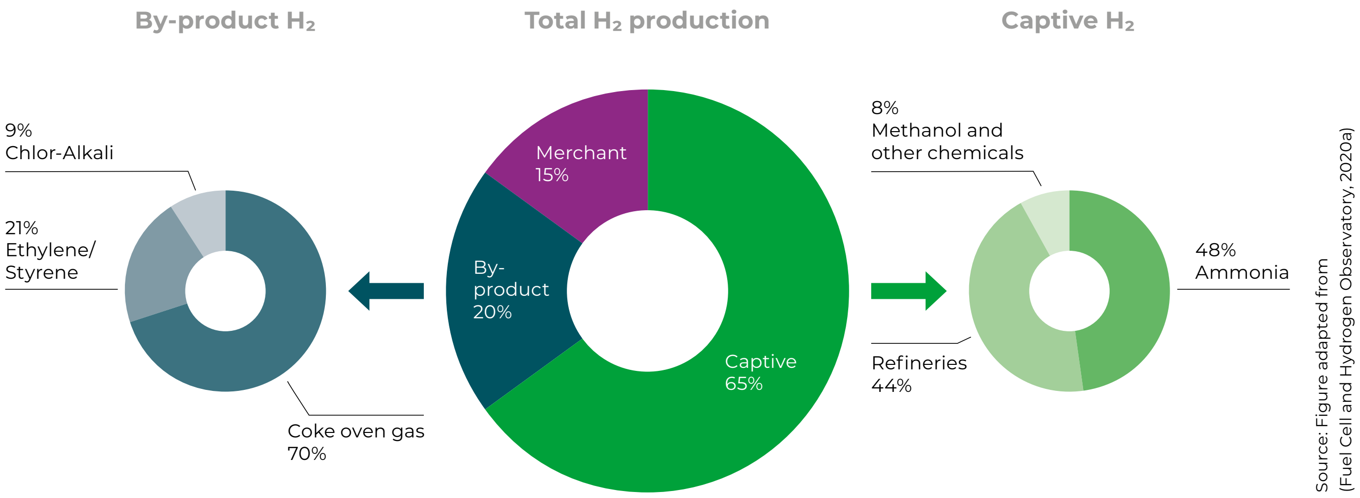
Green and blue hydrogen production costs are still relatively high compared to the price of incumbent fuels or feedstocks like natural gas and oil. However, certain consumers may want to pay a premium for green or blue hydrogen—firstly, by complying with increasingly stringent regulation following RED II[80] and secondly to achieve their corporate emissions reduction targets or to obtain round-the-clock green energy. Several governments also promote the development of green and blue hydrogen production through subsidy schemes and the Innovation Fund.[94] The expected increase in EU ETS CO_2 prices will contribute to closing the gap. However, at current allowance prices the cost of grey hydrogen will only add about €300 of carbon costs per tonne H_2, or around €10/MWh.[95]

2.2.4 Increased deployment and scale of demonstration and pilot projects

While global (grey) hydrogen production has grown by 3% per year over the past decades, (grey) hydrogen production in the EU has been stable at around 339 TWhLVH (33 bcm natural gas equivalent) in past years. Most of this production is linked to industrial activities.

93 (Air Liquide, 2020a); (Air Liquide, 2020b)
94 (European Commission, 2020b)
95 This is assuming direct plant emissions of 10 tCO_2/t H_2 (EU ETS benchmark is 8.85 tCO_2/t H_2) and an EU ETS price of €30/tCO_2.

Figure 2.25.
Share of captive, merchant and by-product hydrogen (Mtonnes per year) in the EU in 2018



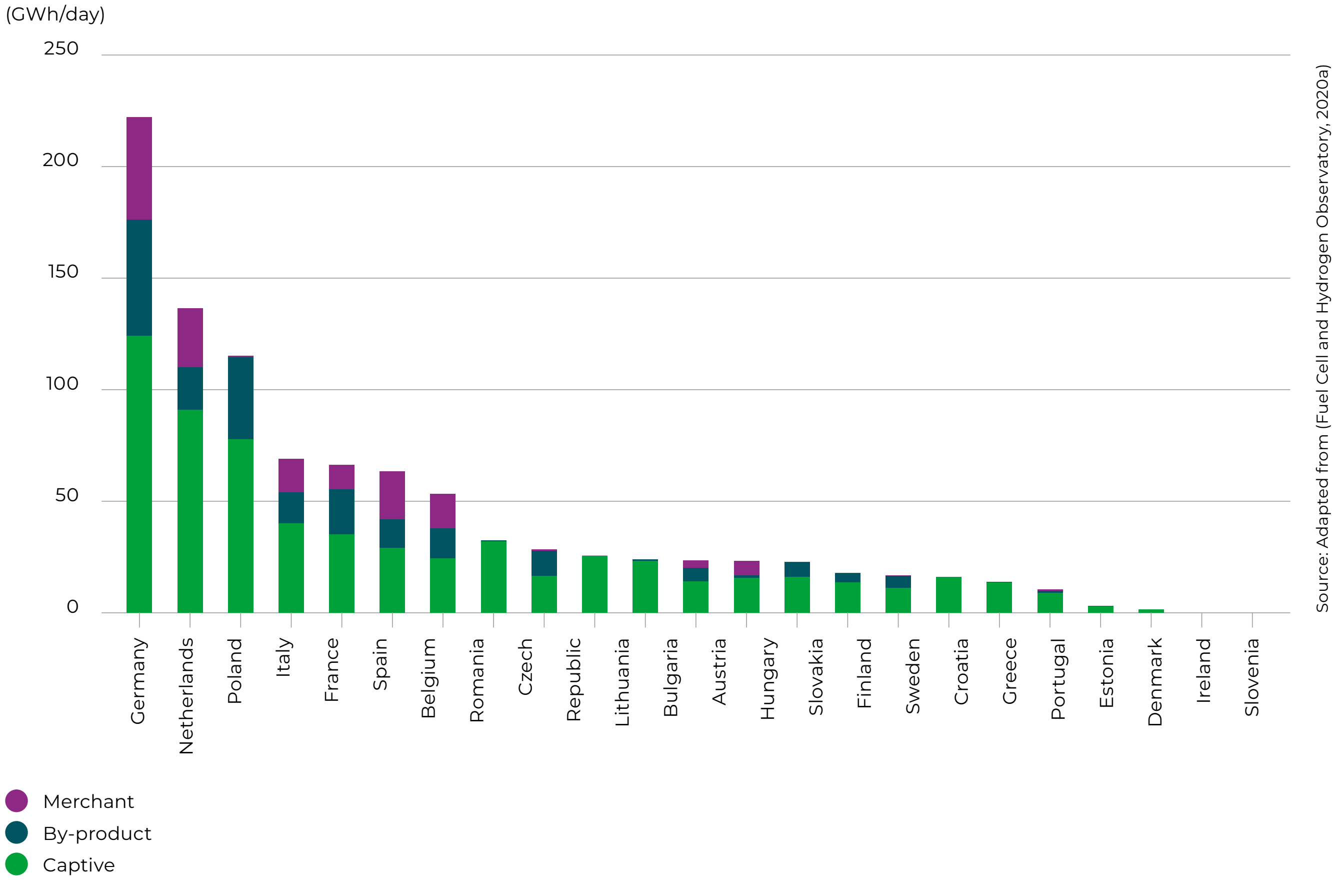
Globally, grey hydrogen production has steadily increased by about 3% per year over the past decade, largely due to increased demand for refinery processes (see section 3.1). Historical data from the H2tools platform, Eurostat,[96] and data from S&P Global and Platts[97], suggest that grey hydrogen production in the EU has been relatively constant over the past few years at around 339 TWhLVH (33 bcm natural gas equivalent).[67, 97] Close to all of this production is linked to industrial activities. Generally, the hydrogen market can be divided into captive, merchant, and by-product production of hydrogen (Figure 2.25).[98]

- **Captive hydrogen** is produced onsite in industrial facilities like refineries, ammonia and methanol plants, to be used directly at the same location and constitutes about 64% of current EU hydrogen production (see section 3.1).
- **By-product** hydrogen production makes up 20% of the total and is the result of industrial processes, such as refinery cracking and steel manufacturing. By-product hydrogen is typically used (onsite) for heat generation but is sometimes traded.[46]
- **Merchant** hydrogen production makes up only 15%. Industrial gas producers are often located in industrial clusters to supply refineries (see section 2.2.5).[71, 98]

Although hydrogen is already being produced in most EU27 countries, the distribution is not equal across countries (Figure 2.26). The three countries with the largest daily hydrogen production are Germany, the Netherlands, and Poland.[98] Together, they produced almost half of the daily EU hydrogen production in 2018. Germany and the Netherlands are the largest producers of merchant hydrogen. Together with Italy, France, Spain, and Belgium, these countries cover 91% of the total merchant hydrogen market, which is largely the result of the big industrial clusters present in these countries.

96 (Eurostat, 2020)
97 (S&P Global, Platts, 2020)
98 (Fuel Cell and Hydrogen Observatory, 2020a)

Figure 2.26.
Total grey hydrogen production capacity in EU27 countries in 2019, including captive, by-product and merchant hydrogen

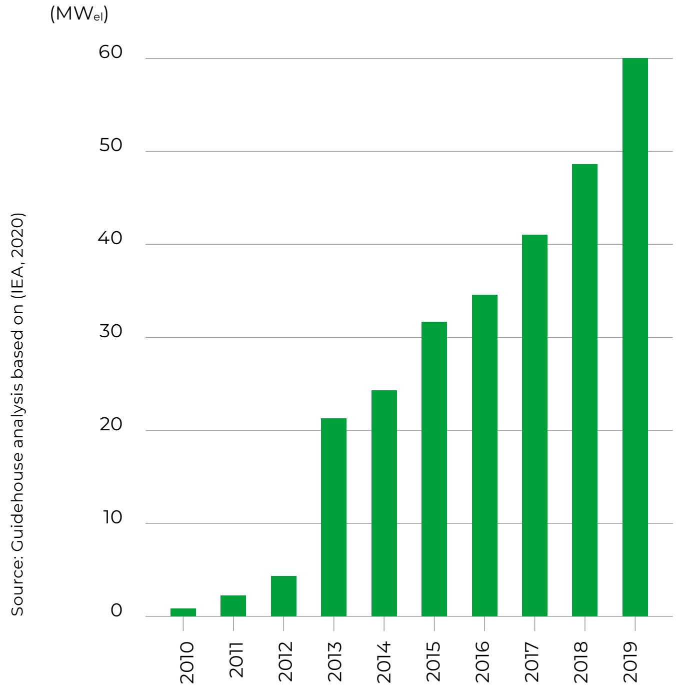


Deployment of electrolyser capacity is growing rapidly in the EU, with an average annual growth rate of approximately 20% between 2016 and 2019.

The European Commission Joint Research Centre (JRC) estimated the total installed capacity of electrolysers in the EU to be around 1 GW.[99] Of this capacity, the FCHO identified 70 power-to-gas projects in 2018/2019 using renewable electricity, totalling 58 MW of green hydrogen production capacity.[98] Many of these projects are still pre-commercial and were built as part of a demonstration project with operating times of only 2-3 years.[98] Despite its small size, the cumulative capacity of electrolysis in the EU has been developing rapidly, with a yearly average growth rate of around 20% between 2016 and 2019, as estimated from the projects tracked in IEA's hydrogen project database (Figure 2.27).[63]

99 (JRC, 2019)

Figure 2.27.
Overview of installed capacities of electrolysis in the EU27



No large-scale blue hydrogen takes place in the EU; in France and the Netherlands, two facilities capture CO_2 from hydrogen plants for downstream utilisation. Blue hydrogen developments can be expected close to large industrial clusters around the North Sea due to the prospect of a widespread CO_2 transport and storage network based on shipping routes and pipelines.

In the EU, no large-scale blue hydrogen production sites exist to date. Only two projects capture CO_2 from large-scale hydrogen production: the Air Liquide Port Jérôme facility in France (50,000 Nm^3 H_2/h) and the Shell Pernis refinery in the Netherlands (200,000 Nm^3 H_2/h).[98] In the Air Liquide plant, the captured CO_2 is upgraded to carbonate sparkling beverages, whereas the Shell plant supplies the CO_2 to greenhouses via a pipeline, replacing the need to produce CO_2 from fossil sources.

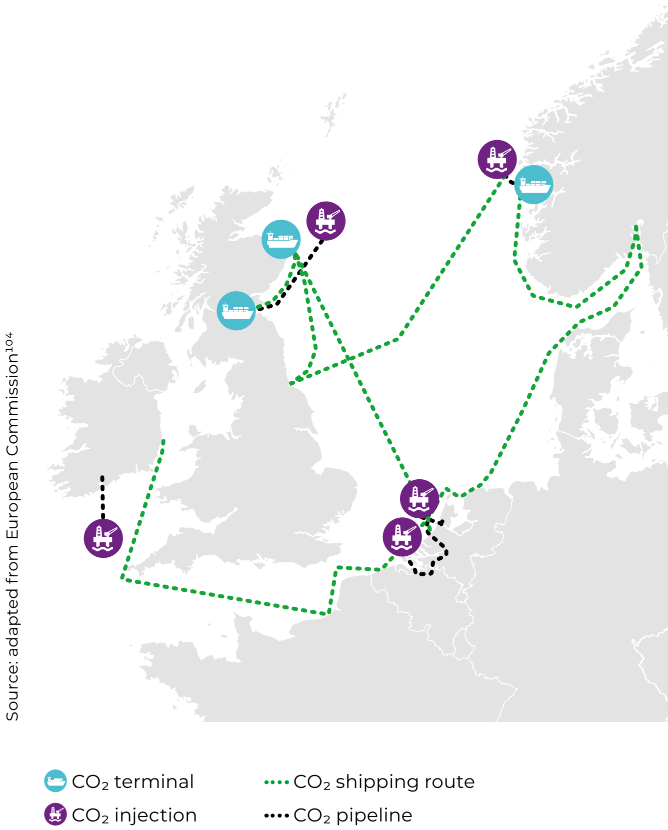
Blue hydrogen projects are planned to become operational in the coming years, with the largest capacity additions in countries around the North Sea, namely the Netherlands, Germany, and Sweden.[100] Key projects announced in previous years are detailed in the showcase projects. These are mostly projects that convert existing grey hydrogen into blue hydrogen by adding CCS. However, some projects also aim to add significant greenfield capacity for new end -uses, such as the H-vision project in the Port of Rotterdam.

Late in 2019, the European Commission awarded five CCS projects with the label of Projects of Common Interest (PCI) (Figure 2.28), a status required to receive infrastructure funding from the CEF. Blue hydrogen projects have been awarded this status before, most prominently the Porthos project. The following three PCI projects intend to transport CO_2 captured from hydrogen production facilities:[101] the CO_2 SAPLING Project, CO_2 TransPorts and the Northern Lights project.

Development of CO_2 infrastructure, both pipelines and shipping routes, is expected to rapidly enable blue hydrogen production in the countries bordering the North Sea area by retrofitting existing production. To date, no hydrogen-related CCS projects have received PCI status outside the North Sea area. In Germany and Sweden, blue hydrogen is also being explored, although Germany is not in favour of domestic CO_2 storage. This implies that Germany has to look to cross-border CO_2 transport if it is to engage in CO_2 capture, for example, under the H2morrow[102] and Preem CCS projects.[103]

100 (IEA, 2020)
101 2020/389, Amending Regulation (EU) No 347/2013 of the European Parliament and of the Council as regards the Union list of projects of common interest (2019), https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32020R0389&from=en
102 (OGE, 2020)
103 (Offshore Energy, 2020)

Figure 2.28.
Large scale CCS projects that are in development and received EU support through their PCI status[104]



Projects include industrial clusters in Belgium and the Netherlands where large volumes of grey hydrogen are produced today that could be converted to blue hydrogen.

CO_2 transport and storage infrastructure will develop in areas where there is a sufficient supply of CO_2 from point-sources, both now and in the future. Industrial clusters with a large share of emissions from (petro)chemicals, hydrogen, cement, and steel production will likely be able to provide sufficient guarantees to pipeline operators. Two basins in the North Sea, off the coast of the Netherlands and Norway, are the only basins that have received official permits for CO_2 storage, so legally developments can only materialise here in the short term.

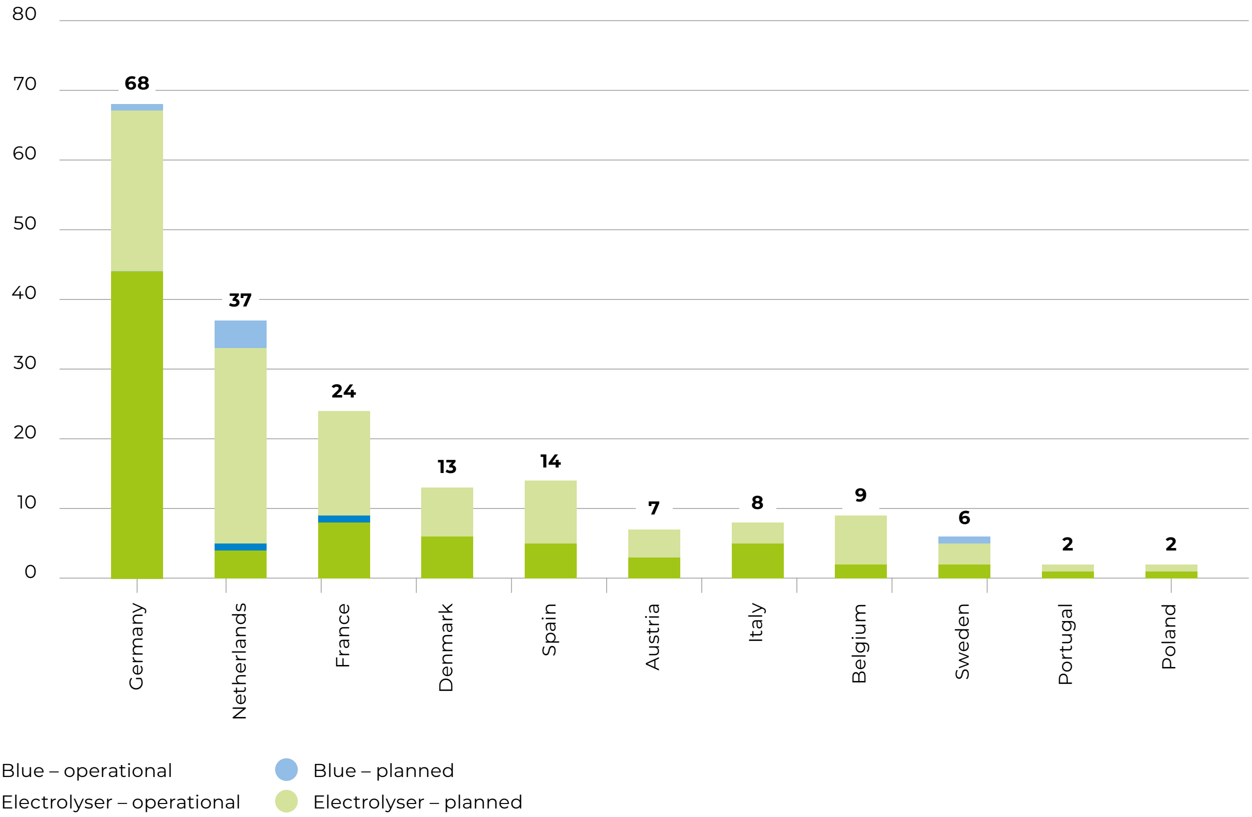
The recent steep increases in the EU ETS carbon price[105] and other policy and support measures, such as the ETS Innovation Fund launched in the summer of 2020, the Dutch SDE++ support scheme, and the Connecting Europe Facility (CEF) are expected to increase blue hydrogen production capacity in the coming years. In the future, industries with a high demand in hydrogen could also trigger the construction of a new SMR/ATR plant (see section 3.1).

Based on current project announcements, an acceleration of blue and especially green hydrogen project developments is expected between 2020 and 2030. A further increase is expected, driven by the EU and national hydrogen strategies, reaching at least 40 GW of electrolyser capacity in the EU by 2030 (European Hydrogen Strategy).

Most of the electrolyser projects (around 55%) the EU are located in Germany. In addition, the UK has six operational electrolyser projects, nine planned electrolyser projects, and six planned blue hydrogen projects. The IEA hydrogen project database of planned and announced projects shows that hydrogen production capacity is expected to continue to grow during the 2020s (Figure 2.29).[100] A further 110 electrolyser projects are planned to become operational by 2030, mainly in Germany, the Netherlands, France, Spain, Denmark and Belgium. Almost all electrolyser projects have plans for capacities at megawatt-scale.[100] The uptake of new projects could be lower in reality as some planned projects may not materialise on the announced potential start date.

104 European Commission, Projects of Common Interest, https://ec.europa.eu/energy/infrastructure/transparency_platform/map-viewer/main.html
105 EU carbon prices could average €35-€40/tCO_2 over the period 2019-2023. Source: Carbon Tracker, 2018. *Carbon Countdown – Prices and Politics in the EU-ETS*.

Figure 2.29.
Number of electrolyser and blue hydrogen projects in the EU27 operational in 2020 and planned until 2030



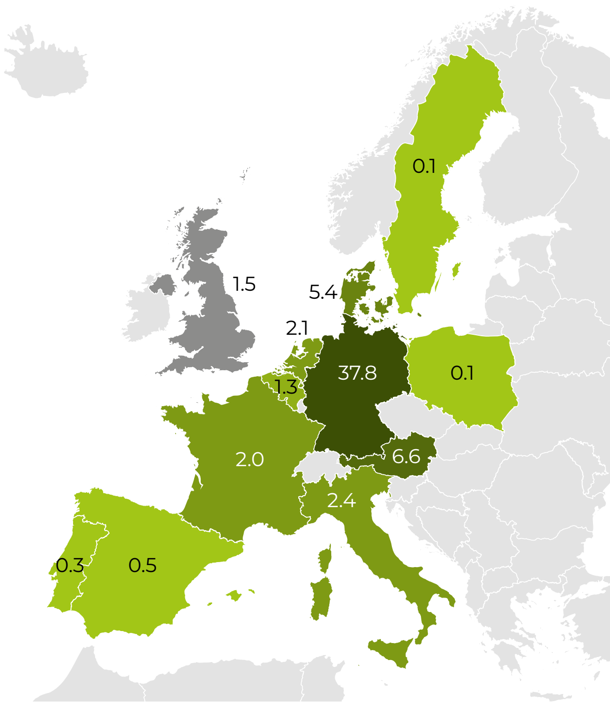
Source: Guidehouse analysis based on (IEA, 2020)

In terms of capacity, countries like Portugal, the Netherlands, France, and Germany are expected to contribute, with 1.7 GW of hydrogen production capacity installed by 2023 (Figure 2.30). By 2027, an additional 3.3 GW of installed capacity is expected in the Netherlands and France. By 2030, Belgium and Italy are estimated to be major contributors, with an expected additional capacity of almost 11 GW. Over the course of 2020, the European Commission and several countries have announced hydrogen strategies, which are expected to further accelerate the development of electrolyser capacity towards 2030 and 2040.[106] The EU Hydrogen Strategy has set a clear target of installing at least 6 GW of electrolysers in the EU by 2024 and 40 GW of electrolyser capacity by 2030.[107]

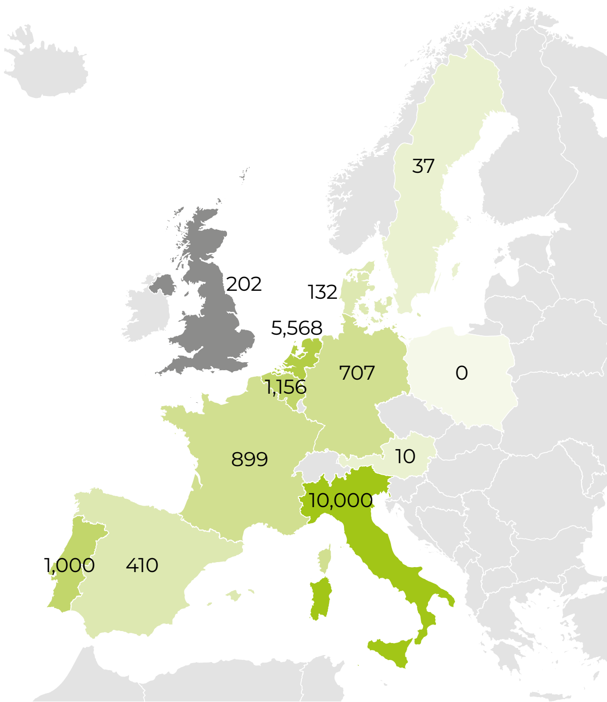
106 (Ludwig Bolkow Systemtechnik, 2020)
107 (European Commission, 2020c)

Figure 2.30.
Capacities (MW_{el}) of electrolyser and blue hydrogen projects operational in 2020 and planned until 2030 in the EU

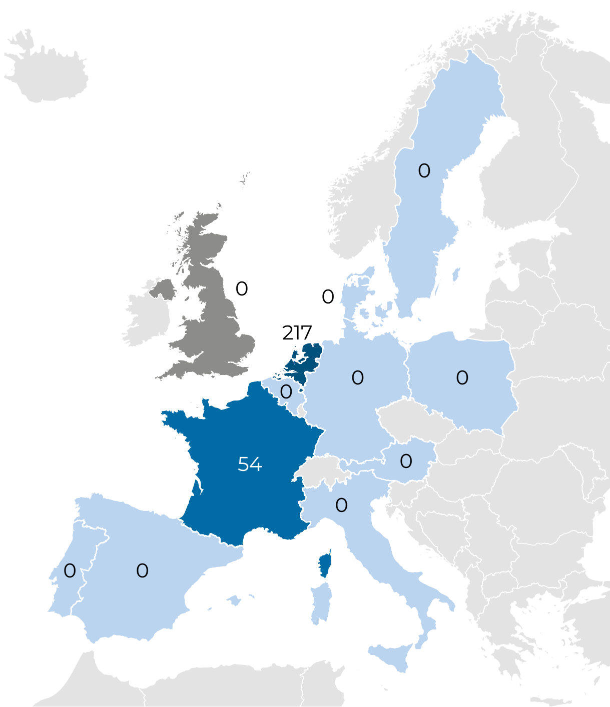
Electrolyser – operational



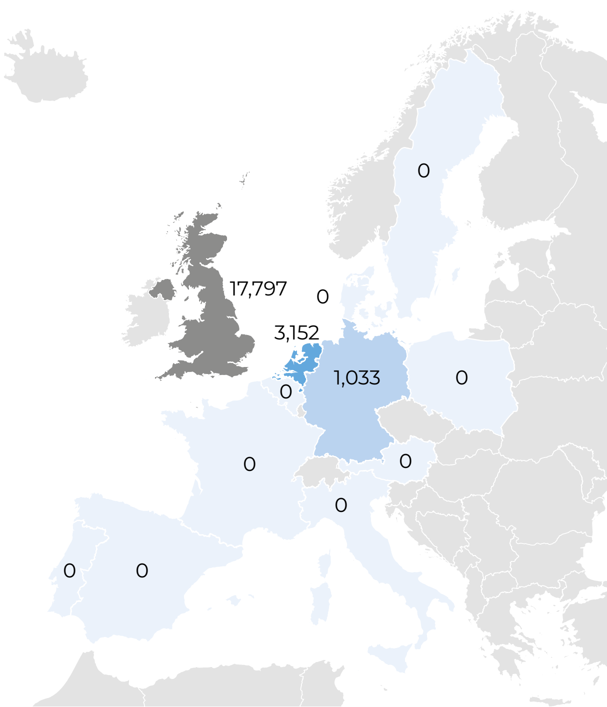
Electrolyser – planned



Blue – operational



Blue – planned



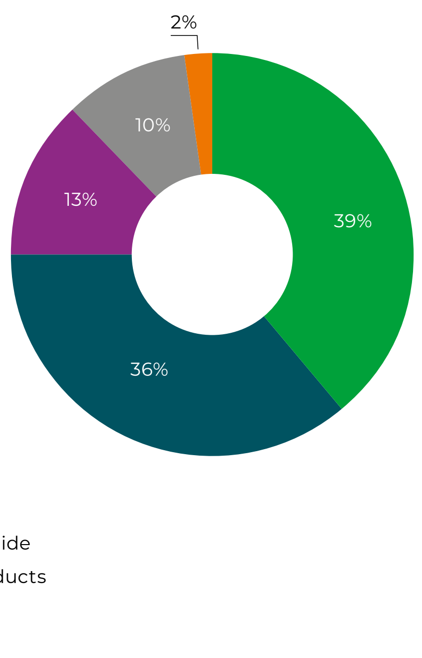
Source: Guidehouse analysis based on (IEA, 2020)

2.2.5 First cross-border trade of GoOs

Of the grey hydrogen production in Europe, only a small share (15%) is (bilaterally) traded (merchant). Most hydrogen production is integrated with industrial processes, either as captive production (64%) or as a by-product of a process (21%). The largest players in the EU merchant hydrogen market are Linde, Air Liquide, and Air Products, producing predominantly grey hydrogen and covering 88% of the market.

Only 15% of the 339 TWh_{LHV} of EU hydrogen production is traded (i.e. merchant hydrogen) (Figure 2.25).[98] Three producers are responsible for 88 % of the EU market for merchant hydrogen (Figure 2.31).[98] The remaining part of the market consists of smaller companies.

Figure 2.31.
Market shares of merchant hydrogen production capacity in Mtonnes per year in the EU in 2018



Source: adapted from (Fuel Cell and Hydrogen Observatory, 2020a)

Several large players are developing electrolyser projects in the EU that are more than $10MW_{el}$, for example, Shell, ENGIE, Gasunie, and Air Liquide.

The market for green hydrogen is still developing, and multiple companies are involved in new pilots and projects. The IEA hydrogen database shows 33 projects with a concrete announced start date and with electrolyser capacity exceeding 10 MW_{el}.[100] With a few exceptions, these announced projects all involve multiple partner companies, ranging from 2 to 30, with the majority having 2-3 partners. Many of these are companies are already active in the gas, energy, and chemical sectors. Some companies are involved in multiple projects— for example, ENGIE, Gasunie, Air Liquide, Nouryon, and Shell.[100] However, almost none of these projects indicate that the final investment decision has already been taken.

CertifHy launched the first pilot GoO for green and low-carbon hydrogen in 2018. To date, more than 77,000 CertifHy GoOs have been issued, of which 75,000 were for blue hydrogen and 2,900 for green hydrogen. Hydrogen certificate trading is expected to increase following national and EU developments.

CertifHy was launched in 2018 based on a request from the European Commission. The project is financed by FCH JU and was developed in cooperation with stakeholders in the sector. The CertifHy project aims to develop and implement a common European-wide voluntary green and low-carbon hydrogen GoO scheme.[108] The CertifHy pilot project also consists of setting up a registry and issuing body to manage the issuance, transfer, and cancellation of GoOs.

CertifHy issued the first GoO in late 2018.[109] By early 2019, the scheme attracted several companies that registered as account holders. More than 77,000 CertifHy GoOs, equivalent to 2.3 ktonnes of hydrogen, have been issued. Of these, 2,900 GoOs (86 tonnes) were issued for hydrogen from renewable energy and 75,000 (2,2 ktonnes) for fossil-based hydrogen.[110] GoOs issued under this scheme are expected to continue to grow as the CertifHy scheme consolidates more stakeholders and the market is further established.

108 (CertifHy, 2019a)
109 (CertifHy, 2019b)
110 (FCH, 2019)

2.2.6 Showcase projects

Green hydrogen projects

STORE&GO WindGas Falkenhagen

- Uniper Energy Storage and partners
- 1.08 MWhLHV of hydrogen production per hour
- Alkaline electrolysis
- In operation, since 2017
- Falkenhagen, Germany
- https://www.uniper.energy/storage/what-we-do/power-to-gas

In Falkenhagen in the state of Brandenburg, Uniper Energy Storage has constructed a demonstration plant for storing wind energy in the natural gas grid. Around 1.08 MWh of hydrogen production per hour (LHV) is generated using alkaline electrolysis and fed via a 1.6 km hydrogen pipeline into the gas grid operated by ONTRAS Gastransport GmbH. In the first year of operation, more than 2 GWh of green hydrogen was fed into the grid. In May 2018, the project entered the next 2-year phase by expanding the power-to-gas plant to a methanation plant for green methane production. In this stage, hydrogen from renewable energy sources is converted into methane using CO_2 from a bioethanol plant. The STORE&GO project brings together 27 partners from six countries to explore the opportunities to integrate power-to-gas applications into the European energy network.

Hyoffwind

The Hyoffwind green energy project aims to build a power-to-gas installation to convert renewable electricity into green hydrogen through electrolysis. Hyoffwind has been set up as an industrial-scale installation (electrolysis of 25 $MW_{el\ in}$), where Zeebrugge (Belgium) would act as an energy hub. First steps are being taken to start constructing the installation by mid-2021; the first production is planned for early 2023. Hyoffwind aims to create economic added value for companies active throughout the hydrogen value chain (production-transport-offtake) and to kick-start local knowledge on hydrogen and the hydrogen economy.

- Colruyt Group (Eoly), Parkwind, and Fluxys
- 25 $MW_{el\ in}$ (input of electrical capacity)
- Electrolysis
- In development, planned for early 2023
- Zeebrugge, Belgium
- https://www.fluxys.com/en/press-releases/fluxys-group/2020/200227_press_hyoffwind_installation

Iberdrola, Fertiberia – green hydrogen for ammonia production

Iberdrola and Fertiberia joined forces in 2020 to construct a large green hydrogen plant for industrial use. The plant will consist of a 100 MW PV solar plant, a lithium ion battery system (storage capacity of 20 MWh), and a hydrogen electrolyser with the capacity to produce around 360 kgH_2/hour (20 $MW_{el\ in}$). The green hydrogen produced will be used in Fertiberia's ammonia factory in Puertollano to manufacture green fertilisers. The plant is expected to be operational in 2021.

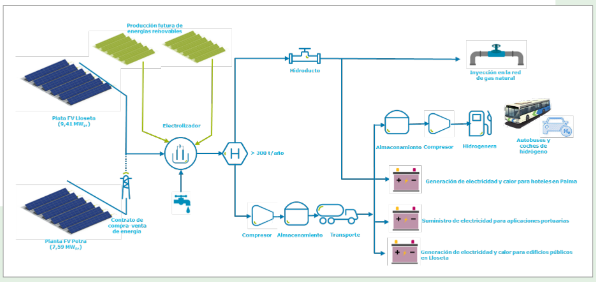
- Iberdrola, Fertiberia
- 20 $MW_{el\ in}$
- PEM electrolysis
- Under construction, operational in 2021
- Puertollano, Spain
- https://www.iberdrola.com/sala-comunicacion/noticias/detalle/iberdrola-pone-marcha-fertiberia-mayor-planta-hidrogeno-verde-para-industrial-europa

Green Hysland

- Enagás, ACCIONIA, CEMEX, Redexis, Govern Illes Balears, Institute for Energy Diversification and Saving (IDEA)
- 10 GWh of locally produced hydrogen per year
- Generation, distribution, and use of renewable hydrogen
- In planning, 2021-2025
- Mallorca, Spain
- https://www.enagas.es/enagas/en/Comunicacion/NotasPrensa/19_10_2020_NP_Financiaci%C3%B3n_Green_Hysland

The Green Hysland project is an integrated island economy based on green hydrogen that will be developed in the Balearic Islands. Green Hysland will generate, distribute, and use at least 10 GWh of renewable hydrogen locally per year, produced from solar energy on the island of Mallorca. Green hydrogen will have multiple applications on the island, including the fuel supply to a fleet of fuel cell buses and fuel cell rental vehicles, the generation of heat and power for commercial and public buildings, the supply of auxiliary power for ferries and port operations, and the creation of a hydrogen refuelling station. The project also includes green hydrogen injection into the island's gas pipeline network through a GoO system to decarbonise the gas supply. The initiative requires a total investment of around €50 million, including renewable electricity generation and equipment for green hydrogen end uses.

The project is part of the Spanish Hydrogen Road Map: a commitment to renewable hydrogen and will include the development of business models for replicating the project to other EU islands and beyond. The Fuel Cells and Hydrogen Joint Undertaking (FCH JU) of the European Commission has selected the project Green Hysland in the Balearic Islands for an EU grant agreement valued at 10 million euros which is under negotiation. The project is coordinated by Enagás and promoted together with ACCIONA, CEMEX, and Redexis. The consortium consists of 30 partners from 11 different countries (nine of them from the EU plus Chile and Morocco) from industry, academia, and the public sector. The Green Hysland project is part of the IPCEI Green Crane.



Source: Green Hysland

Source: Jupiter 1000

Jupiter 1000

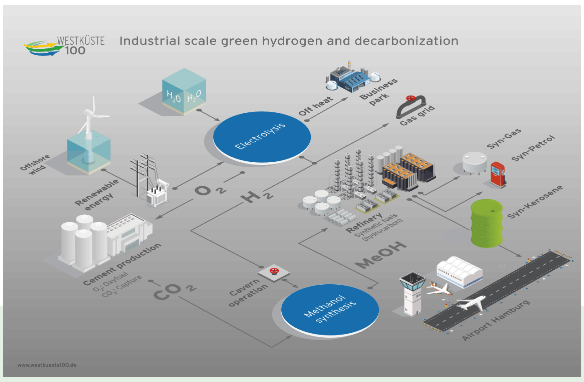
The Jupiter 1000 project is an industrial demonstration project of power-to-gas technologies, producing green hydrogen from renewable energy through an alkaline electrolyser and a PEM electrolyser. Part of the produced hydrogen is combined with CO_2 captured from a nearby industrial site and turned into synthetic methane. Synthetic methane or green hydrogen is then injected into the gas grid. First injection of hydrogen took place in the beginning of 2020. GRTgaz and its project partners are working on future technical and economic standards for a full-sized installation of this type.

- GRTgaz
- 0.5 $MW_{el\ in}$ Alkaline electrolysis, 0.5 $MW_{el\ in}$ PEM electrolysis
- Alkaline and PEM electrolysis
- In operation, since 2020
- Fos-sur-Mer, France
- https://www.jupiter1000.eu

Westküste 100

- EDF Germany, Holcim Germany, OGE, Ørsted, Raffinerie Heide, Stadtwerke Heide, thyssenkrupp Industrial Solutions, Thüga and the Region Heide development agency and the Westküste University of Applied Science
- Demonstration project with 30 $MW_{el\ in}$ electrolyser
- Water electrolysis
- Under construction, 2020-2025
- Heide (Schleswig-Holstein), Germany
- https://www.westkueste100.de/en

The goal of the Westküste 100 real-world laboratory is to fly, build, and heat more sustainably in the future. The plan is to map a regional hydrogen economy on an industrial scale on the west coast of the Northern German province Schleswig-Holstein. This province is a strong wind energy region and has excellent geological hydrogen storage conditions. The hydrogen will be used to produce climate-friendly fuels for aircraft and will be fed into gas grids. In fuel production without fossil fuels, unavoidable CO_2 from regional cement production is used for the production process. Real-world laboratories offer the opportunity to accelerate the transfer of technology and innovation from research to practice, enabling technical and non-technical ideas and innovations to be developed and tested under real conditions and on an industrial scale. Within the 5-year project period, an electrolysis plant with 30 $MW_{el\ in}$ capacity will be installed. This plant will provide insights into the operation, maintenance, control, and grid serviceability of the plant that can be transferred to the next scaling step. This next step could be a 700 $MW_{el\ in}$ electrolysis plant, for which the electricity is generated by an offshore wind farm. The Westküste 100 project is a cross-industry partnership between multiple companies and institutes.



Source: Westküste 100

Blue hydrogen/carbon capture, utilisation and storage (CCUS) projects

Cross-border CCUS – Antwerp@C

The Antwerp@C consortium, consisting of chemical and energy companies, aims to reduce CO_2 emissions in the Port of Antwerp. The project has been awarded a €9 million CEF grant. The Antwerp@C project is estimated to have the potential to reduce CO_2 emissions within the port by half between 2020 and 2030. The consortium is exploring options for building infrastructure to support future CCUS applications. A feasibility study is being carried out to investigate the possibility of building a central CO_2 backbone (pipeline along the industrial zones on both the right and left banks for the Scheldt river), along with various shared processing units, a shared CO_2 liquefaction unit, interim storage facilities, and cross-border transport of CO_2, both by ship and by pipeline. Because Belgium does not have suitable geological strata, international collaboration will be necessary to transport the CO_2 across borders and to store it permanently in depleted offshore gas fields. Antwerp@C is investigating the possibilities of transport to Rotterdam by pipeline or by ship to Norway.

- Air Liquide, BASF, Borealis, ExxonMobil, INEOS, Fluxys, Port of Antwerp, Total
- Halve CO_2 emissions in Port of Antwerp by 2030
- CCUS
- Planning phase, timeline between 2020 and 2030
- Antwerp, Belgium

H-vision

H-vision is a large-scale blue hydrogen project in the Port of Rotterdam area in the Netherlands. A consortium of multiple parties is developing four SMR plants, with a total capacity of 500 MWh-665 MWh of hydrogen production per hour (LHV). CO_2 will be captured and stored in empty gas fields under the North Sea. The goal is to realise the complete project by 2030. In 2018, a feasibility study was started to explore the business case, technological challenges, hydrogen markets, and CCS. The first plant is planned to open in 2025. The H-vision project will realise additional hydrogen supply to be used in power generation and as chemical feedstock. The final goal is to capture and store 8 Mt of CO_2 per year.

Source: Port of Rotterdam

- Deltalinqs, Air Liquide, BP, Gasunie, Port of Rotterdam, Power Plant Rotterdam, Shell, Uniper, Vopak, ExxonMobil
- 500 MWh-665 MWh of hydrogen production per hour (LHV) plus the capture and storage of 8 Mt of CO_2 per year
- SMR
- Under development, first plant expected in 2025
- Port of Rotterdam, the Netherlands
- https://www.deltalinqs.nl/h-vision-en

Porthos

Energie Beheer Nederland (EBN), Gasunie, and the Port of Rotterdam Authority

Expected capacity of 2.5 $MtCO_2$ storage per year

CCUS

Under development, expected in 2023

Port of Rotterdam, the Netherlands

https://www.porthosco2.nl/en/

The Port of Rotterdam CO_2 transport hub and offshore storage (Porthos) project is a CCUS project near the Port of Rotterdam in the Netherlands. The project aims to transport and store CO_2 produced by refineries and chemical- and hydrogen plants into empty gas fields in the North Sea. The CO_2 will be captured by various companies, supplying their CO_2 to the Porthos pipeline that will run through the Rotterdam port area. The CO_2 will then be pressurised in a compressor station and transported through an offshore pipeline, before getting pumped into an empty gas field situated 20 km off the coast and more than 3 km beneath the North Sea. As soon as the final investment decision has been taken (expected 2021), the construction of the infrastructure will start. It is expected that the system will be operational by 2024. The Porthos CCUS project has been recognised by the EU as a Project of Common Interest and will be capable of storing approximately 2.5 Mt of CO_2 per year.

Northern Endurance Partnership

In October 2020, the Northern Endurance Partnership (NEP) was confirmed by the project partners. The NEP aims to develop offshore CO_2 transport and infrastructure in the UK. The infrastructure will connect two onshore projects, that aim to decarbonise industrial clusters in Teesside and Humberside, to the Endurance reservoir. This reservoir is the most mature large scale saline aquifer for CO_2 storage in the offshore UK Continental Shelf, that can enable industrial decarbonisation from both clusters. The projects aim to be commissioned by 2026 with the goal to achieve net zero as early as 2030 through a combination of carbon capture, hydrogen and fuel-switching. If successful, NEP linked to these two projects will allow decarbonisation of nearly 50% of the UK's industrial emissions. BP will lead the Northern Endurance Partnership as operator and the team progressing the project will draw on expertise from across all the partners.

BP, Eni, Equinor, National Grid, Shell, Total

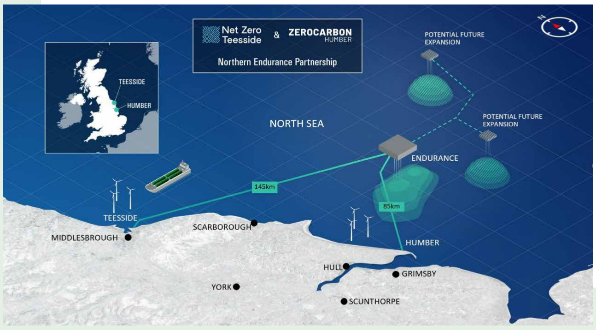
Decarbonisation of ~50% of UK's industrial emissions

CCUS

Planning, expected in 2026

East coast, UK

https://www.equinor.com/en/where-we-are/united-kingdom/Northern-Endurance-Partnership-NEP.html



Source: Source: Northern Endurance Partnership

3. Demand and end uses of renewable and low-carbon gases

Demand and end uses of renewable and low-carbon gases cover multiple sectors and subsectors, including industry, transport, built environment, and power. A distinction should be made between the physical consumption of renewable gases and the virtual allocation and transfer of certificates or GoO related to the renewable attribute of renewables.

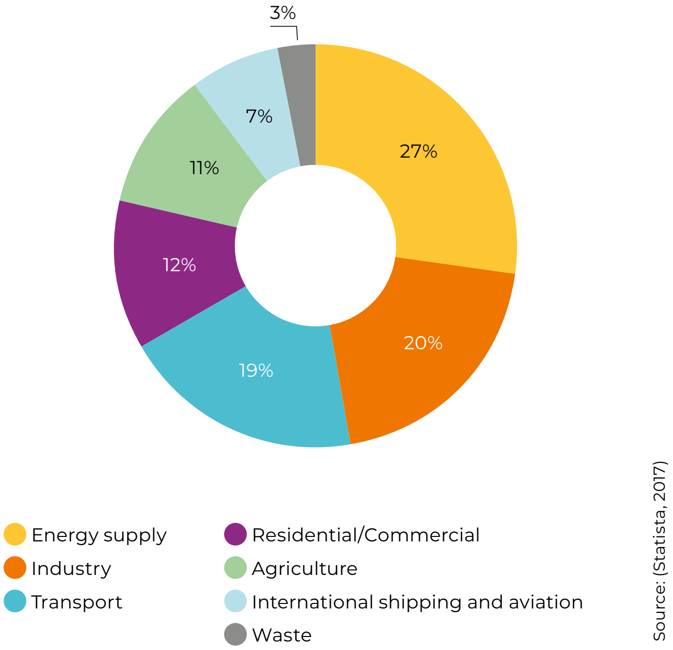
The total CO_2-eq. emissions in the EU amounted to 4.6 billion tonnes in 2017 (Figure 3.1). The gross final energy consumption in the EU was around 12,328 TWh (1,162 bcm) in 2017. Apart from the energy supply sector, the industry, transport, and built environment sectors are the largest share of both emissions and final energy consumption in the EU.

- The industry sector is responsible for approximately 25% of the EU's final energy consumption and accounted for about 19% of total CO_2-eq. emissions in the EU in 2017.
- The transport sector is responsible for approximately 31% of the EU's final energy consumption and accounted for about 20% of total CO_2-eq. emissions in the EU in in 2017.
- The built environment sector is responsible for approximately 27% of the EU's final energy consumption and accounted for about 12% of total CO_2-eq. emissions in the EU in 2017.

Over 23 TWh of European biomethane was used across demand sectors in 2018. Of this about 20 TWh was used through injection in the gas distribution and transmission grids, making up about 0.4% of European gas transported through infrastructure.

Biomethane can substitute natural gas across demand sectors through physical demand or it can be virtually allocated in specific sectors through an appropriate GoO system. The EU natural gas demand in 2018 was 4,577 TWh (NCV), mainly used in buildings, industry, and power generation (Figure 3.2).[111] In 2018, some 0.4% or approximately

Figure 3.1.
Share of CO_2 equivalent emissions per sector in the EU in 2017, with a total of 4.6 billion tonnes CO_2 equivalent emissions



111 Inland consumption in 2018 in net calorific values based on Eurostat, Supply, transformation and consumption of gas [nrg_cb_gas].

20 TWh of all gas transported through Europe's gas infrastructure consists of biomethane (grid-injected biomethane) (see also chapter 4).[2]

Figure 3.3 illustrates an estimated overview of biomethane use per sector for selected EU countries based on analysis by REGATRACE.[14] In Germany, biomethane is predominantly used for electricity production in combined heat and power (CHP) units, whereas in Italy, the government encourages biomethane consumption in the transport sector. Most countries do not have reliable data on biomethane end-use applications and do not necessarily apply similar counting methods.[14]

Green and blue hydrogen can substitute grey hydrogen in existing (industrial) processes or can be used as feedstock in new hydrogen-based processes and applications. In 2018, around 276 TWh_{LHV}[113] of (grey) hydrogen was consumed in Europe, with Germany, the Netherlands, Poland, and Belgium the top four consumers.

(Grey) hydrogen has been used for many years in various industrial processes on the demand side. In 2018, around 276 TWh_{LHV} of (grey) hydrogen was consumed in Europe, with Germany, the Netherlands, Poland, and Belgium the top four consumers. The remainder of the produced

Figure 3.2.
EU natural gas demand per sector (TWh) with a total EU natural gas demand of 4577 TWh (NCV) in 2018[112]

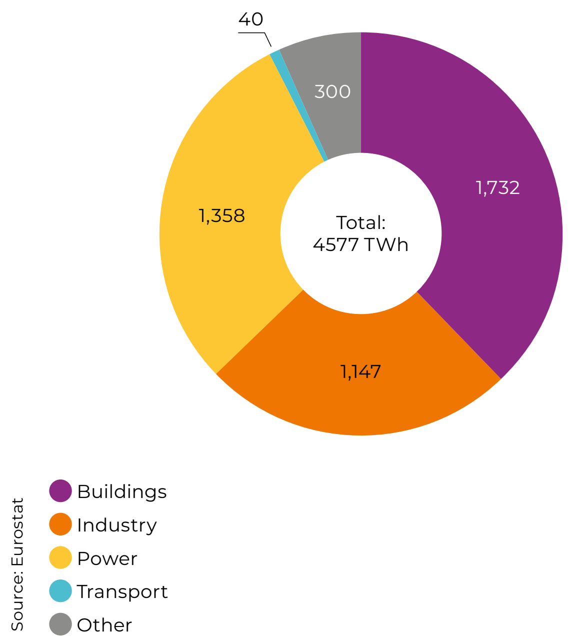
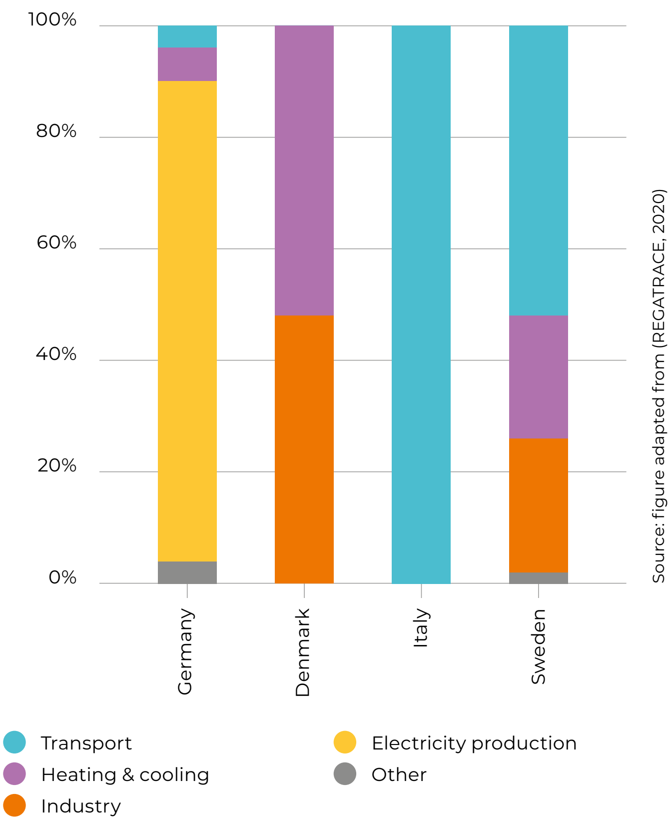


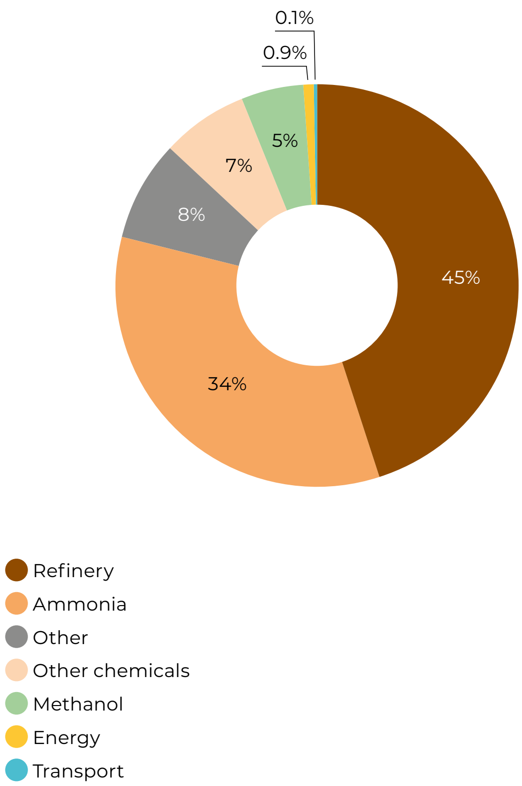
Figure 3.3.
Estimation of current uses of biomethane across sectors in selected European countries in 2018



The total biomethane consumption was estimated by REGATRACE per country (see Figure 2.17). Most countries do not have reliable data on end-use applications and do not necessarily apply similar counting methods.

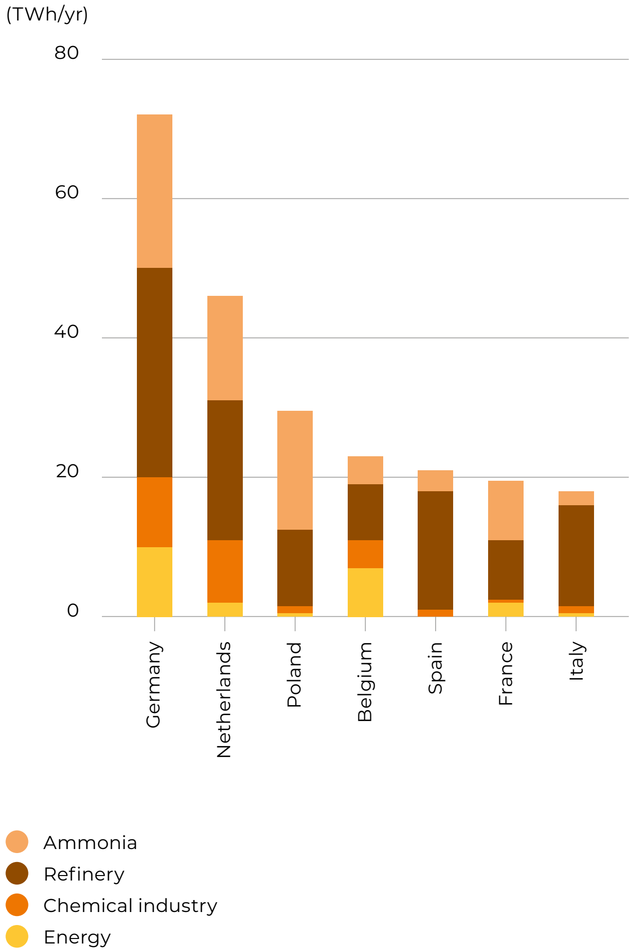
112 Inland consumption in 2018 in net calorific values based on Eurostat, Supply, transformation and consumption of gas [nrg_cb_gas].
113 The remaining hydrogen production is predominantly used to generate heat.

Figure 3.4.
Share of total (grey) hydrogen demand per sector in Europe in 2018, with total hydrogen demand around 276 TWh_{LHV}



Source: adapted from (Fuel Cell and Hydrogen Observatory, 2020a)

Figure 3.5.
Hydrogen consumption per sector in selected EU countries in 2018



Source: adapted from (Fuel Cell and Hydrogen Observatory, 2020a)

hydrogen is predominantly used to generate heat. Almost all grey hydrogen in Europe is consumed by industry in the refining (45%) and ammonia production (34%) sectors (Figure 3.4).[113] The latter has resulted in experience with handling and using hydrogen, including the development of local and regional pipeline infrastructures around the world, including parts of Europe. This experience and existing infrastructure will help develop new hydrogen production and end-use routes, allowing green and blue hydrogen to benefit from these existing assets.

Hydrogen demand sectors in Germany (22%), the Netherlands (14%), Poland (9%), and Belgium (7%) combined use about half of total EU hydrogen demand (Figure 3.5).[98]

This chapter identifies key trends regarding demand and end uses of biomethane and green and blue hydrogen in industry, transport, and the built environment, following the approach as laid out in chapter 1. The following sections detail the key trends per sector and indicate the status of each key trend towards achieving the required pathway developments in the early 2020s-2030.[2]

3.1 Industry sector

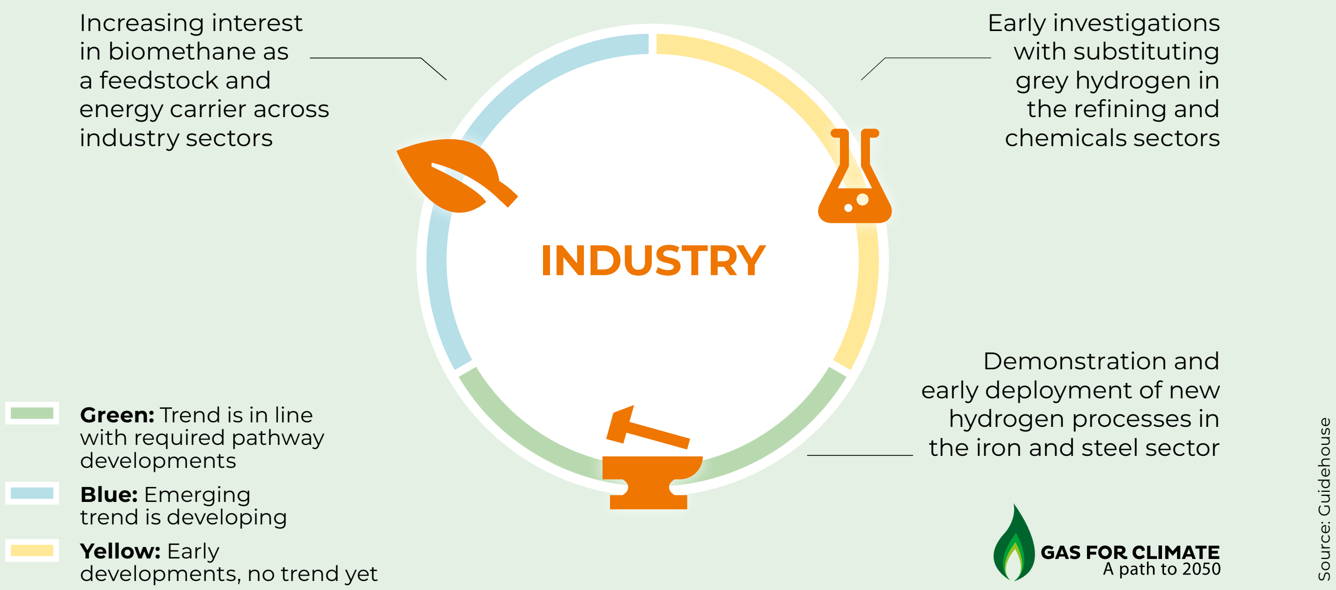
Key trends

Early developments are taking place in the EU refining and chemicals sectors, with ongoing investigations regarding the adaptation of grey hydrogen production to blue hydrogen and the substitution of grey hydrogen for green hydrogen in existing processes. Additional attention is required to further boost these developments.

New hydrogen processes are in the demonstration and early commercial stages in the European iron & steel sector, which is in line with the required developments towards 2030. These processes include direct injection of hydrogen into blast furnaces and using hydrogen for the direct reduction of iron.

Biomethane is gaining interest as a feedstock or energy carrier across industry sectors, either as an energy carrier when biomethane is injected in the natural gas grid, through integration of biomethane production in industry processes, or as a feedstock to produce high value chemicals.

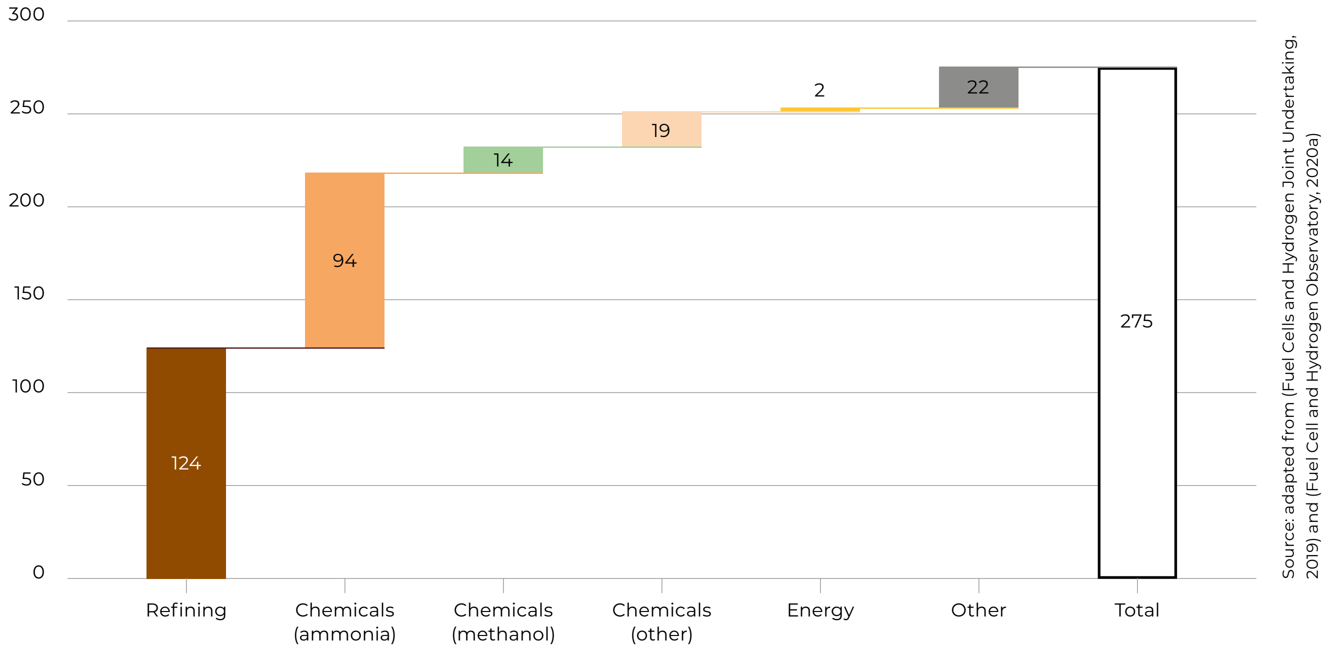
Figure 3.6.
Key trends for renewable and low carbon gas developments in the industry



Almost all (predominantly grey) hydrogen in the EU is used in industry.[46, 98] Hydrogen is mostly used as industrial feedstock in the oil refining and chemicals (fertiliser) production sectors and as fuel in the (metal) process industry (Figure 3.7).[46] About 45% of industrial hydrogen consumption is used for oil refining for hydrocracking and hydrotreating processes to provide energy and desulphurisation.[98] This is followed by ammonia production (34%) (ammonia is an important material in the fertiliser industry).[46, 114] The remaining share of industrial hydrogen demand comes from other chemicals and energy production, including methanol production. Only a small share of existing hydrogen feedstock is used in other industrial processes, including steelmaking and metal welding (less than 8%).[49]

114 (CertifHy, 2015)

Figure 3.7.
Uses of hydrogen in industry in 2018 (TWh_{LHV}/yr)



Developments in the industry sector in the early 2020s are focused on those sectors that are most emissions-intensive and hard to decarbonise—specifically the **oil refining, chemicals, and iron and steel sectors**. The **oil refining sector** uses hydrotreating and hydrocracking processes.[2] The **chemical industry** provides essential products and materials to many different downstream sectors.[2] The oil refining and chemicals sectors (including the pharmaceutical sector) were responsible for about 126 Mt of CO_2-eq. emissions in 2015.[115] A large share of these emissions can be attributed to the required fossil-based feedstocks, such as natural gas (e.g. for ammonia production) or crude oil (e.g. for diesel and gasoline production through refining). The European **steel sector** is one of the most carbon-emitting and energy-consuming sectors in Europe, through the use of coal and other fossil fuels for steelmaking. The European steel sector accounts for 216 Mt of CO_2 emissions in 2015 which is about 5% of European CO_2-eq. emissions.[116]

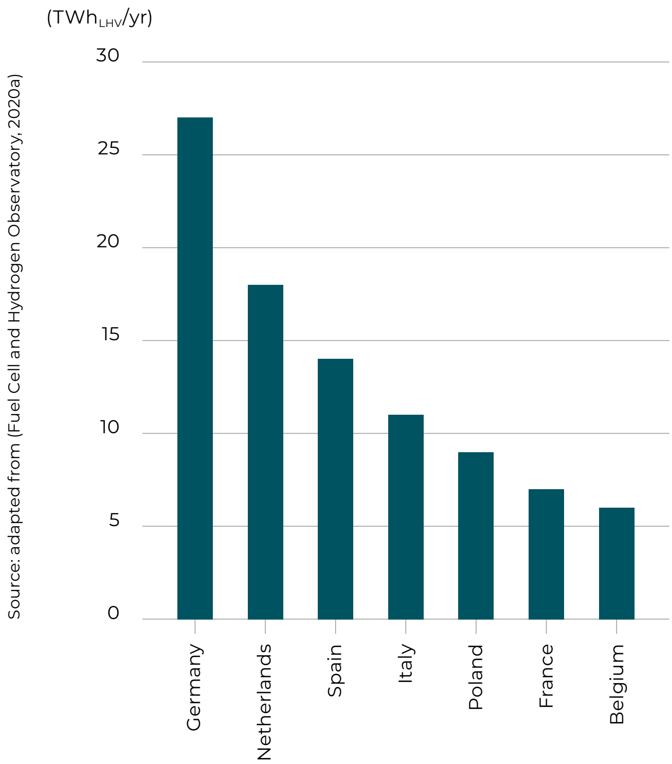
This section details the key trends regarding the use of biomethane and green and blue hydrogen in the industry sector (Figure 3.6). In the early 2020s, developments will focus on starting off substituting grey hydrogen feedstock with blue or green hydrogen in existing processes, starting to implement new processes that use hydrogen as feedstock, and increasing adoption of biomethane across industry applications. The following paragraphs detail each key trend and indicate the status of each key trend towards achieving the critical decarbonisation timeline of the early 2020s-2030.

115 Ibid
116 (European Environment Agency, 2020a)

3.1.1 Early investigations with substituting grey hydrogen in the refining and chemicals sectors

In 2018, the European refining industry consumed approximately 124 TWh_{LHV} of grey hydrogen, with Germany (21%) and the Netherlands (14%) the top consumers. Early project developments are ongoing to substitute grey hydrogen with blue or green hydrogen in the refining sector. Shifting from grey to blue or green hydrogen can be done without major refining process adaptations.

Figure 3.8.
Hydrogen use in refining in Europe in 2018 in top seven countries (combined almost 75% of about 124 TWh_{LHV})



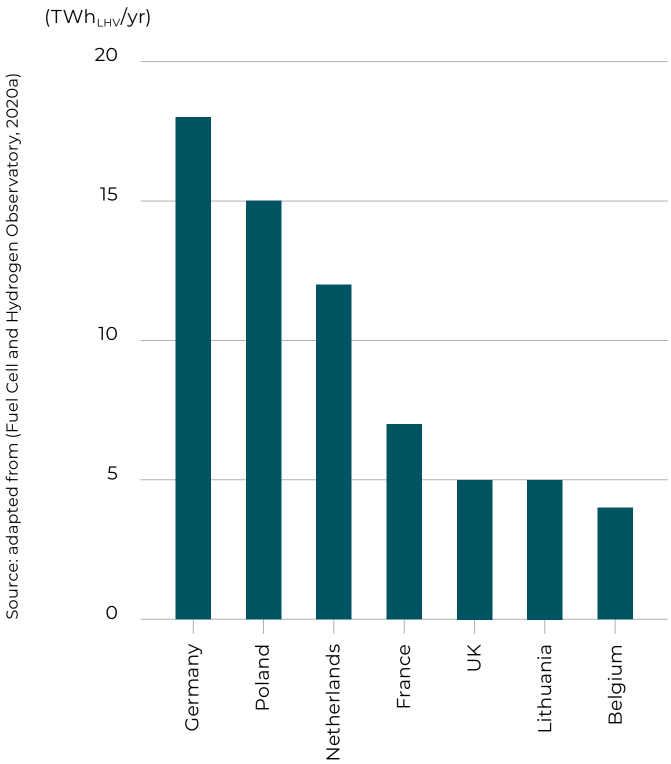
All large EU refineries mostly use natural gas and other fossil fuels to produce grey hydrogen through different reforming processes (see section 2.2.1).[98] In the refining industry, increasing targets for desulphurisation increase demand for hydrogen (about 124 TWh_{LHV} in 2018). In Europe, seven countries consumed about three-quarters of the total hydrogen for refining in 2018 (Figure 3.8): Germany (21%), the Netherlands (14%), Spain (11%), Italy (9%), Poland (8%), and France and Belgium (about 5% each).

This existing grey hydrogen feedstock can be replaced by green or blue hydrogen to decarbonise refining processes without major adaptations.[46] Early investigations and developments are ongoing regarding feedstock substitution. Out of the 228 identified hydrogen production plants by the FCHO[98] that were using fossil fuels as feedstock, only two were identified as using carbon capture technologies (see section 2.2.4). Both projects are in the refining sector: the Air Liquide Cryocap installation in Port-Jérôme, France, and the Shell refinery in Rotterdam.[98]

In 2018, approximately 94 TWh_{LHV} of grey hydrogen was consumed for European ammonia production in Europe; Germany (20%), Poland (14%), and the Netherlands (13%) were the top consumers. Substituting grey hydrogen is in the early stages.

In the chemical industry, hydrogen is mainly used for ammonia production as feedstock for, among others, fertilisers and nitric oxide. In 2018, about 94 TWh_{LHV} of hydrogen was consumed for ammonia production.[98] Ammonia production is based on grey hydrogen produced through a steam methane reforming process (see section 2.2.1). This existing feedstock can be substituted with green or blue hydrogen without major adaptations.[46] Seven countries in Europe consumed about 70% of the total hydrogen consumption for ammonia production in 2018 (Figure 3.9): Germany (20%), Poland (14%), the Netherlands (13%), France (7%), the UK (5%), Lithuania (5%), and Belgium (4%). Substitution of grey hydrogen is in early stages in this sector.

**Figure 3.9.
Hydrogen use in ammonia production in Europe in 2018 in top seven countries (combined approximately 70%)**



In 2018, about 33 TWh_{LHV} of grey hydrogen was consumed for European methanol production; early commercial adoption of substituting grey hydrogen is ongoing.

Hydrogen demand in the remainder of the European chemical industry, including methanol production, was about 33 TWh_{LHV} in 2018; Germany and the Netherlands combined consumed about half of this. In Europe, most methanol is produced through the compression of syngas and reaction over a catalyst. This syngas for methanol production is predominantly obtained from steam methane reforming, whereas autothermal reforming or coal gasification are also used in other regions.

Early developments to substitute grey hydrogen with blue and green hydrogen are ongoing in this sector. One established commercial CO_2 methanol plant is the George Olah plant in Iceland, which uses green hydrogen for methanol production.[117] Liquid Wind, based in Sweden, aims to capture CO_2 from a waste-to-energy plant and combine it with green hydrogen to produce e-methanol; this product will be used to substitute feedstock in existing industries and tap into novel end-use applications like fuel.[118]

3.1.2 Demonstration and early deployment of new hydrogen processes in the iron and steel sector

Hydrogen can be used as a new feedstock to decarbonise the steelmaking industry through direct injection of hydrogen into blast furnaces or using hydrogen for the direct reduction of iron. Both applications are in the demonstration and early commercial stages.

The steelmaking and metal processing industry uses a limited injection of hydrogen (5%-7%) and nitrogen in annealing furnaces as an inert protective atmosphere.[98] Green or blue hydrogen can play a role as a new feedstock in the decarbonisation of the steelmaking industry, which has limited alternatives for decarbonisation. Two main processes exist to decarbonise steelmaking with low-carbon hydrogen:[2]

- Direct injection of hydrogen into the blast furnace instead of coal, which reduces GHG intensity of emissions between 20% and 40%.
- Direct reduction of iron ore (DRI) through an entirely new H_2-based steelmaking process where hydrogen is used as a reducing agent for the direct reduction of iron ore. This process can achieve emission reductions of more than 95%.

117 (Carbon Recycling International, 2011)
118 (Liquid Wind, 2020)

These new hydrogen applications are in demonstration or early commercial stages in the H2FUTURE, HYBRIT, and GrInHy 2.0 projects, among others.[119] These applications require significant installation costs that exceed €100 million per technology installation.[2] These investment costs are similar to the investment costs of conventional installations. The main difference with conventional installations is the operational costs; operational costs depend on the electricity price for green hydrogen production. With industrial investment cycles around 30 years or more, investments in these new applications should be planned carefully to prevent lock-in of conventional technologies.[2] It is important to invest in technologies that are compatible with long-term decarbonisation goals. The Gas for Climate pathways study showed that few conventional installations will be replaced by 2030 in Europe. Most installations will be replaced after 2030. Guidehouse analysis shows that about one-quarter of European steelmaking plants could have a natural reinvestment moment by the mid-2030s (based on an average investment cycle of 30 years).

3.1.3 Increasing interest in biomethane as a feedstock and energy carrier across industry sectors

Biomethane is gaining interest as an alternative to natural gas for medium and high temperature heat generation and as a feedstock and energy carrier in multiple industry sectors, either through using natural gas injected with biomethane, through integration of biomethane production in industry processes, or as a feedstock to produce high value chemicals.

Biomethane is gaining interest as a way to decarbonise the industry and power thermal generation sectors, either as an energy carrier when biomethane is injected in the natural gas grid, through integration of biomethane production in industry processes, or as a feedstock to produce high value chemicals.

- Biomethane can be used as a substitute for natural gas in industrial applications and processes to produce high value chemicals (e.g. methanol production). This concept is gaining interest with early commercial applications.[120]
- The food and feed producing industry that uses biomethane can integrate food and feed production with biogas and biomethane production onsite from food and feed waste and residues, through co-investment in biomethane production. This integrated process provides an organic waste management service and benefits from the availability of zero-cost feedstocks. This integration also increases the efficiency of processes by supplying onsite energy needs and reducing the CO_2 footprint of industry. This application is in early commercial development—for example by Tesco Ireland.[121]
- Biogas can be generated from waste sludge in the pulp and paper industry and can be used for low- to medium- grade heating within the process.[122] This application is in a pre-commercial stage—e.g. the Effisludge project in Norway.[123]
- Biogas and biomethane can be produced from wastewater sludge in municipal installations as indicated in section 2.1 with the sewage treatment plant in Amsterdam.

119 (H2Future, 2020); (HYBRIT, 2020); (GrInHy2.0, 2020)
120 (Baena-Moreno, Pastor-Perez, Wang, & Reina, 2020); (ETIP Bioenergy, 2020)
121 (TESCO Ireland, 2020)
122 (Linkoping University, 2019)
123 (EffiSludge, 2020)

3.1.4 Showcase projects

Hydrogen in industry

George Olah Renewable Methanol Plant

- Carbon Recycling International
- 4,000 Mt pa of methanol per year
- CCU
- In operation, since 2012
- Svartsengi, Iceland
- https://www.carbonrecycling.is/projects#project-goplant

The George Olah Plant is a large commercial CO_2 methanol plant located in Iceland. The plant uses renewable electricity from geothermal and hydropower sources to produce green hydrogen and combines it with captured carbon in a catalytic reaction to produce methanol. With a capacity of 4,000 Mt pa of methanol, the plant recycles 5,500 tonnes of CO_2 per annum. The production and use of this low-carbon methanol as an automotive fuel releases 90% less CO_2 than a comparable amount of energy from fossil fuel. This plant demonstrates in an actual industrial setting the technical, economic, and environmental benefits associated with adapting Carbon Recycling International's emissions-to-liquids technology.

Climate-neutral steel production through hydrogenMethanol Plant

- thyssenkrupp Steel Germany, Air Liquide, IN4climate, BFI
- Three blast furnaces
- Hydrogen for use in steel blast furnaces
- In development, testing started in 2019
- Duisburg, Germany
- https://www.thyssenkrupp.com/en/newsroom/press-releases/world-first-in-duisburg-as-nrw-economics-minister-pinkwart-launches-tests-at-thyssenkrupp-into-blast-furnace-use-of-hydrogen-17280.html

thyssenkrupp Steel started testing hydrogen for use in steel blast furnaces at its Duisburg site in Germany to reduce CO_2 emissions from traditional steel production using cokes. Injecting coal produces CO_2 emissions; using hydrogen generates water vapor instead. The company aims to reduce 20% of its CO_2 emissions using hydrogen in all three of its blast furnaces by 2022. The current tests are funded by State Government of North Rhine-Westphalia's IN4Climate.NRW program. The project is part of the climate strategy of thyssenkrupp towards climate neutrality by 2050, and is a next step into further commercialising the application. The hydrogen injection is provided by project partner Air Liquide.

H2FUTURE project

H2FUTURE is a European project to generate green hydrogen from renewable electricity for steel making. Under the coordination of the utility VERBUND, the steel manufacturer Voestalpine, and Siemens, a large-scale 6 $MW_{el\ in}$ PEM electrolysis system has been installed and is operated at the Linz steel plant in Austria. Testing PEM electrolysis technology on an industrial scale and simulating rapid load changes in electricity generated from renewable energy sources and from electric arc furnace steelmaking (grid balancing) are the key elements of this project. The Netherlands' research centre TNO and K1-MET (Austria) will study the replicability of the experimental results on larger scales for the steel industry in the EU27. The project received funding from the FCH JU.

- **VERBUND, Voestalpine, Siemens, Austrian Power Grid, TNO, K1-MET**
- **6 $MW_{el\ in}$**
- **PEM Electrolysis for steelmaking**
- **In operation, since 2019**
- **Linz, Austria**
- **https://www.h2future-project.eu/**

HYBRIT

- **SSAB, LKAB, and Vattenfall**
- **Several pilot projects**
- **Hydrogen for use in steel blast furnaces**
- **In operation, since 2020**
- **Sweden, Finland**
- **https://www.hybritdevelopment.com/**

SSAB, LKAB, and Vattenfall's joint initiative HYBRIT aims to replace coking coal, traditionally needed for ore-based steelmaking, with fossil-free energy and hydrogen. In August 2020, a pilot plant for fossil-free steel production at the SSAB site in Luleå, Sweden was opened. The goal is to develop a solution for fossil-free steel production by 2035. The HYBRIT concept enables the decoupling of energy carriers and reduction agents generating CO_2. If successful, Sweden's CO_2 emissions can be reduced by 10% and Finland's by 7%.

Source: HYBRIT, Fotograf Åsa Bäcklin

GrInHy 2.0

Sunfire GmbH, Paul Wurth S.A., Tenova SpA, French research centre CEA and Salzgitter Mannesmann Forschung GmbH

720 kWel in, producing 600 kWh hydrogen per hour

Steam electrolysis based on SOEC

In development, plant expected in 2021

Salzgitter, Germany

https://www.green-industrial-hydrogen.com/

GrInHy2.0 (Green Industrial Hydrogen via steam electrolysis) is a follow-up project to the first stage of GrInHy, which has already operated successfully in Salzgitter.

Together with project partners Sunfire GmbH, Paul Wurth S.A., Tenova SpA, French research centre CEA, and Salzgitter Mannesmann Forschung GmbH, a steam electrolyser is being constructed for the energy efficient production of hydrogen. Because of a significant energy input in the form of steam—preferably from industrial waste heat—steam electrolysis based on SOEC achieves good electrical efficiencies. GrInHy2.0 is implementing a high temperature electrolyser with an electrical power input of 720 kW (producing 200 Nm^3/h (18 kg/h)) in an industrial environment. By the end of 2022, it is expected to have been in operation for at least 13,000 hours, producing around 100 tonnes of high purity (99.98 %) hydrogen. This hydrogen will be used for annealing processes in integrated steel works to replace the hydrogen produced from natural gas. The GrInHy2.0 project has an overall budget of € 5.5 million.

Biogas and biomethane in industry

EffiSludge

Scandinavian Biogas, Biokraft, Norske Skog

25 million Nm^3 biogas annual production capacity

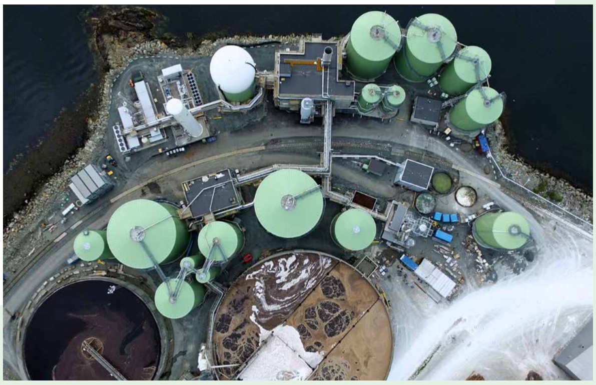
Anaerobic digestion of wastewater from the paper and pulp industry

In operation, since 2018

Skogn, Norway

http://scandinavianbiogas.com/effisludge/

The Effisludge for LIFE Liquid Biogas plant is located in Skogn, Norway. The project is fully integrated with the local pulp and paper mill. Biogas is generated by processing wastewater sludge generated at the mill site in co-digestion with other substrates. At Skogn, the waste-activated sludge generated at the mill is digested together with fish waste to generate 25 million Nm^3 biogas per year (first year was 12.5 million Nm^3). With a total budget of €3.1 million, the project was granted €1.8 million EU funding in 2015. The wastewater treatment performances and related parameters are being monitored for life cycle analysis evaluation and will run until December 2020.



Source: Effisludge

Tesco Ireland’s waste food to biomethane

- Tesco Ireland, Green Generation, Gas Networks Ireland
- Digestion of 6,400 tonnes of waste food
- Anaerobic digestion of food waste
- In development, partnership since 2020
- Ireland
- https://www.tescoireland.ie/news/news/article/tesco-becomes-the-first-irish-retailer-to-purchase-renewable-gas-made-from-its-own-surplus-food-to-power-stores

Tesco plans to cut carbon emissions by converting waste food from their stores into biomethane. As part of the new initiative; Green Generation will process Tesco’s food surplus that has not been donated to FoodCloud (a surplus food charity partner) at its anaerobic digestion plant in Nurney. The produced biomethane will be fed into the natural gas network from which Tesco will purchase the renewable gas outputs. This project will result in a circular economy approach to minimise Tesco Ireland’s carbon footprint. Tesco Ireland intends to supply more than 6,400 tonnes of waste food each year from its stores. This amount will enable production of enough biomethane to supply six Irish Tesco stores, effectively allowing the chain to cut carbon emissions by 1,200 tonnes per year.

Liquefied biomethane for steelmaking

Uddeholm, a manufacturer of tool steel for industrial tools, is using liquefied biogas (LBG) in Sweden as part of its efforts produce steel in a sustainable way. The company replaced heavy fuel oil with liquefied natural gas (LNG) in 2014. By replacing natural gas with biogas, the company reduces CO_2 emissions from their production even further. LBG can substitute LNG without addiotnal changes and can be used directly into the plant’s heat production. Skangas delivers Swedish LBG from the Lidköping biogas facility. Here the biomethane is produced through processing of various types of organic waste made from 100% local feedstocks. The gas is liquefied by cooling it to a temperature of minus 150–170 °C for delivery as LBG.

- Uddeholm, Skangas, Gasum Group’s Lidköping biogas facility
- Liquefied biomethane (LBG)
- In operation, since 2018
- Uddeholm, Sweden
- https://bioenergyinternational.com/biogas/skangas-supply-liquefied-biomethane-lbg-uddeholm-production-use

Source: Skangas

3.2 Transport sector

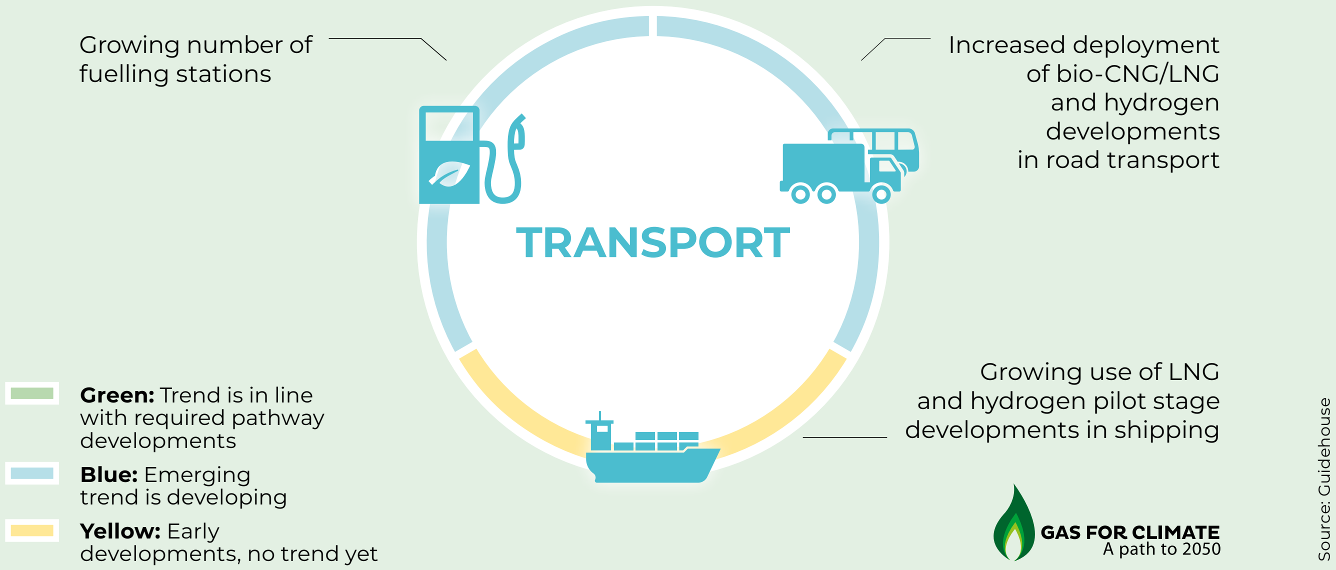
Key trends

The uptake of renewable and low-carbon gases in road transport and fuelling infrastructure is emerging in the EU. Increasing deployment of bio-CNG/LNG and early stage hydrogen developments are taking place in the heavy road transport sector. The adoption of CNG and LNG vehicles grew by 5% and 35% annually since 2016 for buses and heavy freight trucks, respectively. Currently, biomethane use in Europe already represents 17% of all the gas used in road transport.

Early stage hydrogen developments are taking place in the EU shipping sector. Several pilots are ongoing to test maritime applications of hydrogen fuel cells, mostly in Northern Europe. LNG use in shipping is growing, as LNG bunkering facilities for ships are increasingly being established across the EU (supported by the TEN-T regulation).

The number of *gas fuelling stations* in the EU is growing. LNG and hydrogen fuelling stations are still limited but experienced a significant step up over the last year and CNG fuelling stations are gradually increasing.

Figure 3.10.
Key trends for renewable and low carbon gas developments in the transport sectors



Decarbonising the transport sector requires a switch to alternative fuels, either through fuels that do not emit CO_2 or through fuels for which the CO_2 is of biogenic origin. Electrification through battery and hydrogen fuel cell technologies and sustainable (liquid) biofuels, such as biomethane (bio-CNG/LNG) and biokerosene, are seen as solutions to achieve this switch. Electrification has been identified as the dominant pathway solution for light road vehicles and for part of the shipping sector.[2] In contrast, for long haul and heavy transport such as freight, coaches, and (inter)national shipping, hydrogen and (bio)CNG/LNG are expected to be among the most societally cost-effective solutions, alongside sustainable liquid biofuels. In aviation adoption of non-fossil fuels is expected to only scale-up starting from 2030.[2]

Although the role of renewable and low-carbon gases in transport is still limited in Europe, its contribution could grow fast. This section details the key trends regarding the use of biomethane and green and blue hydrogen in the transport sector (Figure 3.10). Developments in the early 2020s will focus on those fuels and modes of transport that are most promising to decarbonise in this period, including bio-LNG/CNG and hydrogen in trucks, buses, and shipping, which is in line with the pathways report:

- Switching oil-based fuels to gaseous fuels (CNG, LNG and hydrogen). These fuels are at different stages of development for road transport and shipping.
- Increased adoption of renewable and low-carbon gases, both as a pure gas and as a blend with natural gas (CNG and LNG).

The following paragraphs detail each key trend and indicate the status of each key trend towards achieving the critical decarbonisation timeline in the early 2020s-2030.

3.2.1 Increased deployment of bio-CNG/LNG and hydrogen developments in road transport (trucks and buses)

In the EU, CNG and LNG vehicle adoption has been growing over the past decade—by 5% and 35% annually, respectively, since 2016—for buses and heavy freight trucks in the EU. The use of hydrogen in transport is also gaining traction, especially in the bus segment, which has close to 2,000 buses planned for deployment in the EU in the coming years.

The use of **natural gas** for road transport has been around for decades and received increased interest to reduce harmful SO_x, NO_x and particulate matter emissions coming from other fuels, especially in urban environments. The use of CNG and electricity has been growing in the EU bus and heavy transport segment (Figure 3.11 and Figure 3.12). The adoption of CNG and LNG buses and heavy freight trucks in the EU has grown by 5% and 35%, on average, per year since 2016, respectively. In the bus segment, the use of CNG reached a market penetration of about 2.5% in 2018 (Figure 3.11).[124] In heavy duty transport,[125] the number of gas-based vehicles grew to over 31,000 vehicles in 2019 (Figure 3.12). These are mainly CNG- and LNG-fuelled vehicles, constituting about 0.6% of the total market of heavy duty vehicles.[126]

Figure 3.11 and Figure 3.12 show that the use of **hydrogen** in the EU transport sector is still limited, with only tens of hydrogen fuel cell vehicles registered annually, mainly in the passenger car and bus segments.[127] Globally, most fuel cell systems for transport and other applications are shipped to Asia, mainly Japan and South Korea. North America and Europe have smaller shares of total shipped fuel cells, with 14% and 12%, respectively.[128] Fuel cell vehicles use onboard stored hydrogen, which is converted with air to water and electricity. The produced electricity is used to drive the vehicle. Hydrogen is stored on vehicles in dedicated tanks at pressures of 35 MPa-70 MPa. The larger the pressure, the higher the driving range per unit volume.

The use of hydrogen in **buses** remains very limited, representing less than 0.5% of the market in 2018.[124] Local developments towards the rollout of hydrogen-based buses are ongoing, however. In mid-2019, 88 buses were reported to be operational by Horizon Europe, with a further 141 contracted and 1,889 planned for deployment.[129] A set of projects targeting multiple EU countries are driving the scale-up of fuel cell buses; these projects include JIVE (300 fuel cell buses in 22 cities in 2020) and H2Bus Europe (1,000 fuel cell buses, of which 200 in 2023). Projects are supported by the FCH JU and the CEF. Project partners claim that the hydrogen from electrolysis will be priced at parity with diesel on a kilometre basis, around €5-€7 /kg depending on local conditions.[130]

124 Guidehouse analysis based on Eurostat, Motor coaches, buses and trolley buses, by type of vehicle, 2020. https://ec.europa.eu/eurostat/databrowser/view/road_eqs_busveh/default/table?lang=en
125 Exceeding 3.5 tons gross weight.
126 Guidehouse analysis based on Eurostat, Lorries and road tractors, by age, 2020. https://ec.europa.eu/eurostat/en/web/products-datasets/-/ROAD_EQS_LORROA
127 (European Alternative Fuels Observatory, 2020a)
128 (Fuel Cell and Hydrogen Observatory, 2020b)
129 Horizon Europe, Strategic Research and Innovation Agenda, 2019.
130 (Fuel Cell Electric Buses - knowledge database, 2020)

Figure 3.11.
Cumulative number of buses (thousands) in the EU on either electricity or gas (CNG/LNG/H_2)

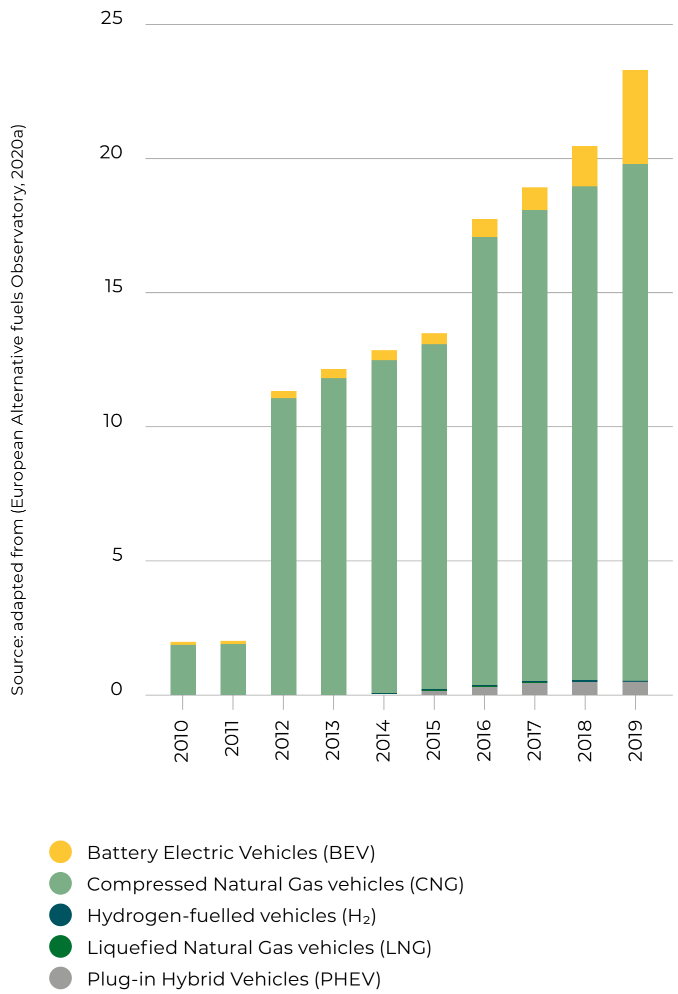
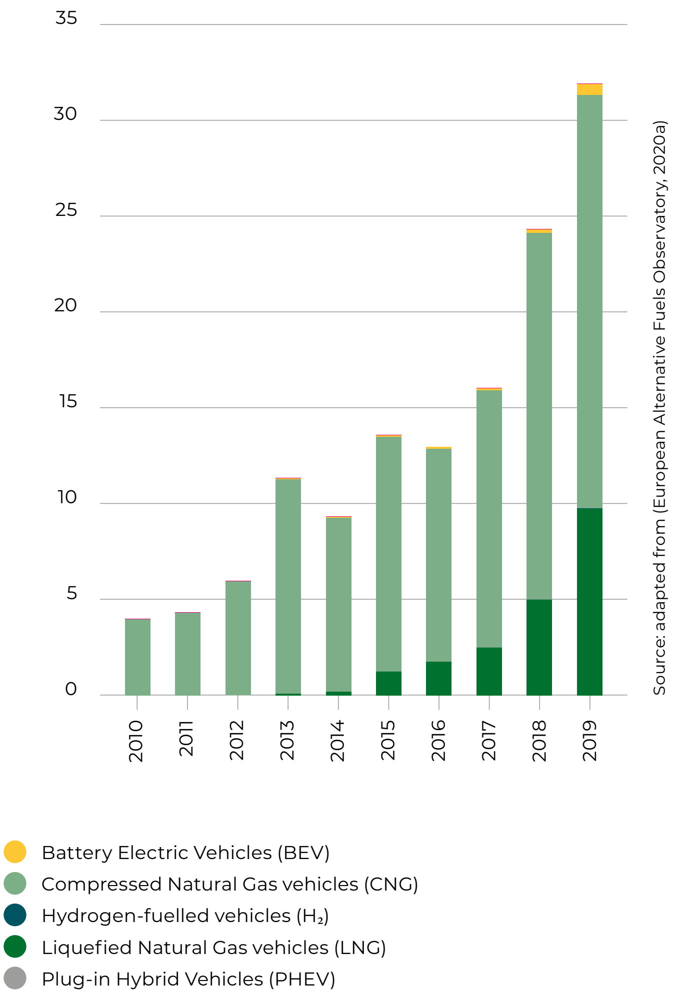


Figure 3.12.
Cumulative number of heavy-duty trucks in the EU (thousands) on either electricity or gas (CNG/LNG/H_2)

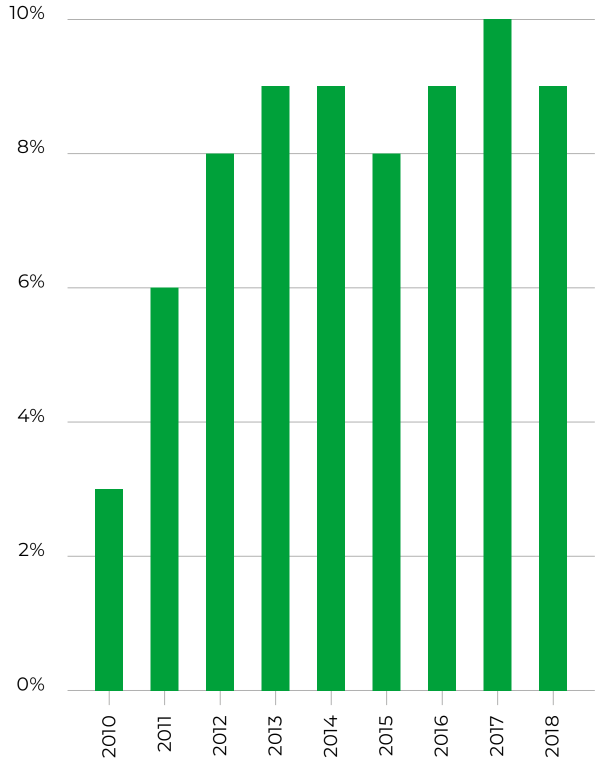


* Data for LNG heavy duty trucks is from 2015 onwards and is based on (EBA, GIE, NGVA Europe & SEA LNG, 2020)

The **heavy truck segment** is trailing a few years behind the use of hydrogen in buses. Several projects are ongoing, focusing on the development of trucks, real-world testing, and early deployment. These projects typically consist of consortia covering the entire hydrogen truck supply chain, involving hydrogen production, fuel cell manufacturing, and integration. Together, projects like H2Haul and REVIVE aim to deploy around 30 fuel cell trucks in the EU over the next years by testing trucks and improving their technology readiness level.[129]

In 2018, approximately 9.4% of biomethane was used in CNG and LNG in EU road transport, used either in pure form or blended with natural gas. This share is expected to increase, as biomethane represents 17% of all gas used in road transport across Europe today.

Figure 3.13.
Percentage of biomethane in the CNG and LNG used in road transport in the EU



Source: adapted from (European Alternative fuels Observatory, 2020a)

The percentage of biomethane in road transport in the EU tripled between 2010 and 2012 for the share of CNG and LNG vehicles. Since then, the use of biomethane in the EU has remained relatively stable at percentages between 8% and 10%, according to the European Alternative Fuels Observatory, with differences between countries (Figure 3.13). In 2018, about 1,8 TWh (154 ktoe, 0,18 bcm) of biomethane was used in the EU in the transport sector.[127] A positive trend on the use of biomethane is reflected in the 100% biomethane CNG fuelling stations available in, for example, the Netherlands and Sweden.[131] In addition, recent data from NGVA Europe shows that 25% of CNG and LNG fuelling stations in Europe are already supplying biomethane today. This represents, on average, 17% of all the gas used in road transport, around 23,4 TWh (2,4 bcm).[132]

3.2.2 Growing use of LNG and hydrogen in pilot stage developments in shipping

A transition towards renewable and low-carbon gases in the shipping sector—and international shipping in particular—is complex considering the long lifetimes of ships, large fuel storage demand, low operating margins, and the need to have matching fuel options on each port the ship bunkers. In January 2020, the International Maritime Organisation (IMO) issued a regulation to limit the sulphur mass content of fuel oil to 0.50%.[133] The IMO put forward adoption of low-carbon fuels as a way to achieve 2030 and 2050 decarbonisation targets. The attention to fuel types and resulting SO_x emissions will add to ongoing discussions on the fuels used in the shipping sector in the future; the sector is also aiming to cut CO_2, NO_x, and particulate matter emissions.[134]

LNG use in shipping is growing, and several pilots are ongoing to test the maritime applications of hydrogen fuel cells, mostly in Northern Europe. Multiple low-carbon and renewable fuel options, such as hydrogen, biodiesel, ammonia, and methanol, are in an early development stage in the shipping sector.

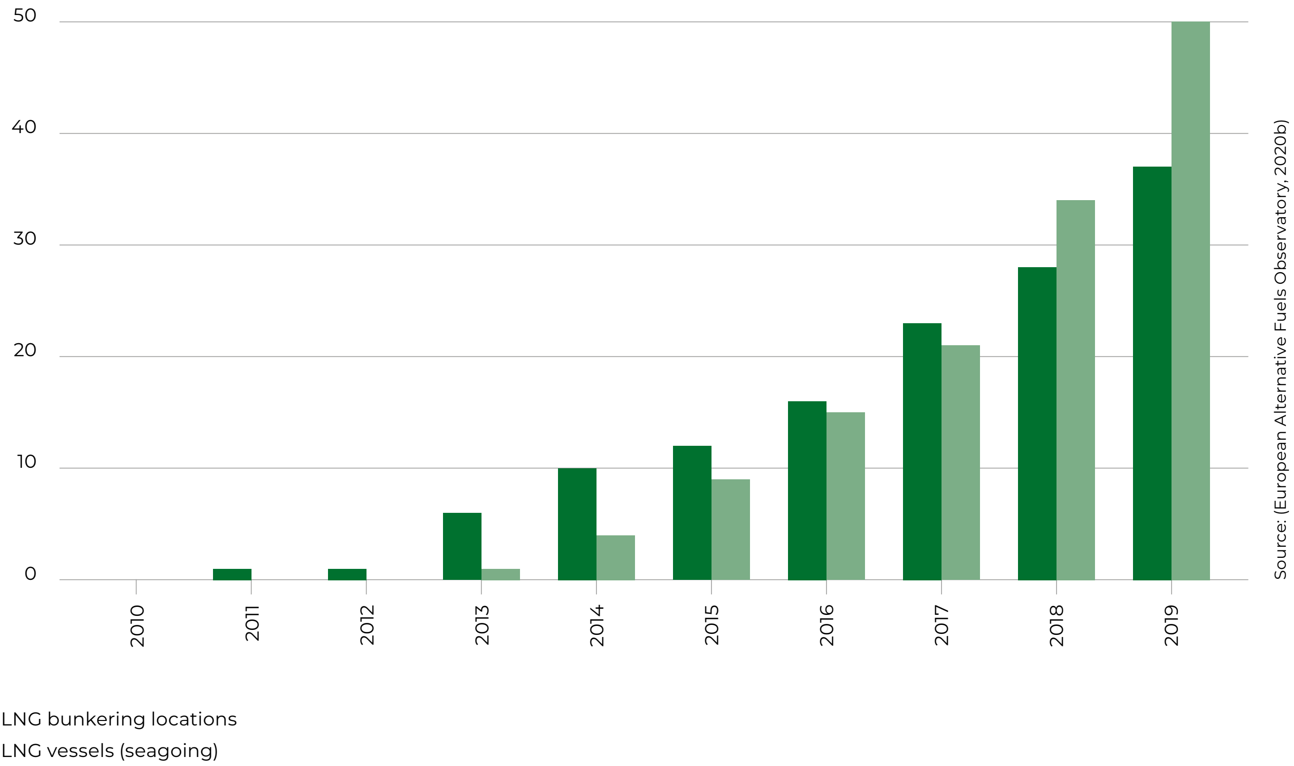
The number of ships using LNG has been growing in Europe, reaching 160 vessels in operation and 115 LNG-ready vessels in 2019 (Figure 3.14).[135] This growth is driven in part by the development of LNG carriers, which use LNG for their own

131 (NGVA, 2020a)
132 (NGVA Europe, 2020b)
133 (International Maritime Organisation, 2020)
134 (DNV GL, 2018)
135 On inland shipping no statistics are available

propulsion, and is facilitated by the large EU LNG import capacity and the EU TEN-T regulation.[135] LNG offers a decarbonisation route when bio-LNG is progressively blended into it. Although data on bio-LNG in shipping is not available, recent projects indicate that market interest is growing. The EU LNG import capacity is sufficient to meet 43% of total 2015 natural gas demand; in recent years, only 10% has been utilised for imports.[136] LNG import locations are mainly located in the North and South Western parts of the EU, mostly located close to or in existing port areas with key shipping routes.

No statistics are available on the amount of **biomethane** used by LNG ships. LNG is imported from port locations around the EU (i.e. close to where demand from ships will be). Some developments are ongoing, with the Port of Gothenburg offering bio-LNG services[137] and other port areas in Germany, Belgium, and the Netherlands introducing bunker barges for bio-LNG.[138] Despite these early developments, the availability and costs of biomethane are still considered to be a bottleneck for wider adoption.[139]

Figure 3.14.
Overview of the number of LNG seagoing ships in Europe (excluding Norway) and the number of LNG fuelling locations in the EU27



* Number of LNG vessels in operation and LNG-ready vessels is based on (EBA, GIE, NGVA Europe & SEA LNG, 2020).

136 (European Commission, 2016)
137 (NGV Journal, 2019)
138 (GreenPort, 2020)
139 (Argus Media, 2020)

Figure 3.15.
Overview of LNG bunkering facilities in port locations across the EU in 2020

Source: (European Alternative Fuels Observatory, 2020b)

Supported by the TEN-T regulation, LNG bunkering facilities for ships are being established across the EU.

A network of LNG bunkering facilities is being established as part of the alternative fuel recharging and refuelling station development, which is supported by TEN-T regulation; this development builds on existing infrastructure and expands it to cover additional areas in the EU. Figure 3.15 shows LNG bunkering facilities in the EU in 2020. These facilities include LNG bunkered from an LNG import terminal, from storage tanks onshore, or on barges or trucks carrying LNG supply. Ships entering these locations will likely be the first to make the switch to LNG and will have the opportunity to increasingly adopt liquified biomethane when it comes available. The amount of seagoing ships using this LNG infrastructure is growing.[135]

Hydrogen-based shipping is still in an early commercial phase, with projects being deployed mostly in Northern Europe and limited to small vessels or using fuel cells for auxiliary equipment power.

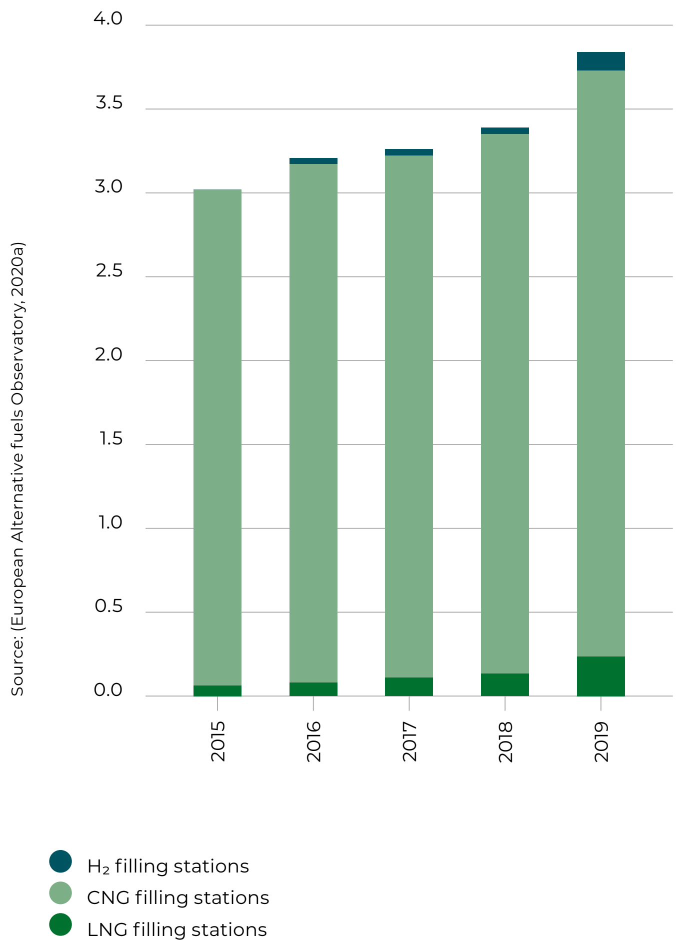
Hydrogen use in shipping is gaining attention,[140] although current developments are mainly limited to smaller scale and pilot projects. Other fuel options exist as well, such as using synthetic methanol and ammonia in shipping. These fuels benefit from having a higher energy density than hydrogen and offering more energy efficient fuel storage.

The interest in hydrogen for shipping is not new. Over the past 20 years, hydrogen use has been limited to relatively small, in-land, near-coastal vessels and ferries, often at a demonstration level without the intention to develop towards commercial maturity. The exemption is using fuel cells in some types of submarines. These have been operated for over a decade by the German and Italian navies for silent, underwater operations.[141] The total use of hydrogen in the shipping sector is still limited and no statistics are available on hydrogen consumption or bunkering facilities. Despite the current early commercial phase, larger vessel sizes are being considered and developed, including the use of hydrogen as auxiliary power on large cargo and cruise ships.[49] Hydrogen can be blended with conventional fuels in internal combustion engines, but most developments focus on using hydrogen in fuel cells because of better fuel efficiency.

Key areas of research, development, and pilot testing include safety aspects related to handling hydrogen as a maritime fuel, using liquified hydrogen, and improving the weight and strength of pressurised hydrogen storage containers. Liquefied hydrogen comes at relatively high additional energy cost

140 (Fuel Cells and Hydrogen Joint Undertaking, 2020b)
141 (NavalTechnology, 2020)

Figure 3.16.
Number of gas fuelling stations in the EU (thousands)



Note that 2020 data set is not yet complete.

(+30%) and hydrogen will boil off during operation.[142] One solution could be using the boiled-off hydrogen to propel the ship. Due to these barriers, hydrogen use in shipping can be expected to develop first in short distance, specialised vessels, such as ferries and maritime maintenance vessels.

Several projects are being launched to reduce the beforementioned barriers and to improve the experience in organising the full supply chain from hydrogen production to bunkering and use as a maritime fuel (see showcase projects in section 3.2.4).

3.2.3 Growing number of fuelling stations

Gas fuelling stations are rapidly being deployed across the EU to support CNG, LNG, and fuel cell vehicle uptake. The number of LNG and hydrogen fuelling stations is still limited but experienced a significant step up over the last year. The number of CNG fuelling stations is gradually increasing.

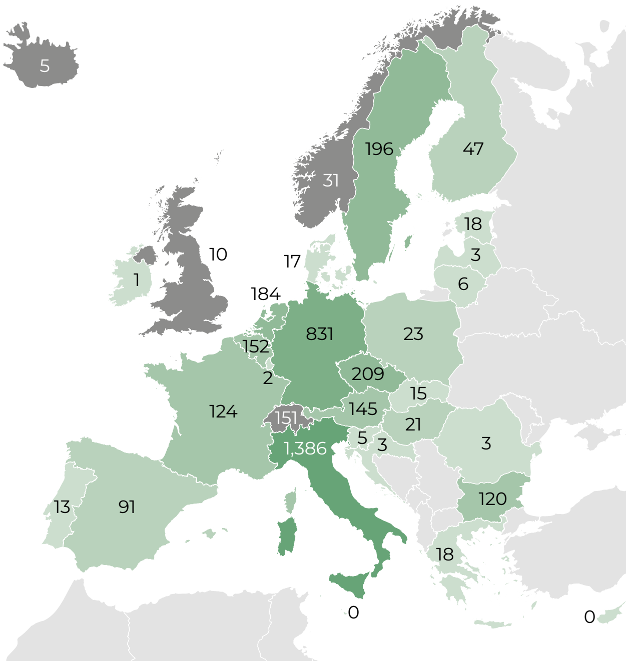
One of the prerequisites in the adoption of gas-based transport fuels is sufficient coverage of the EU fuelling infrastructure; infrastructure rollout is defined by the EU Alternative Fuels Infrastructure Directive.[143] The number of LNG and hydrogen fuelling stations is still limited. Over the past few years, the number of fuelling stations has increased, with a particularly strong increase in the number of LNG and hydrogen fuelling stations over the last year (Figure 3.16). The number of CNG fuelling stations gradually increased over the last few years.

Regional differences exist in the number of fuelling stations across EU member states. Italy has a historically strong and increasing position in natural gas-based CNG use and associated fuelling stations, while hydrogen fuelling stations are mainly located in Germany (Figure 3.17). Many CNG stations provide a blend of natural gas and biomethane. The share of biomethane for transport is largest in Northern European countries, where 100% biomethane is offered in over half of fuelling stations.

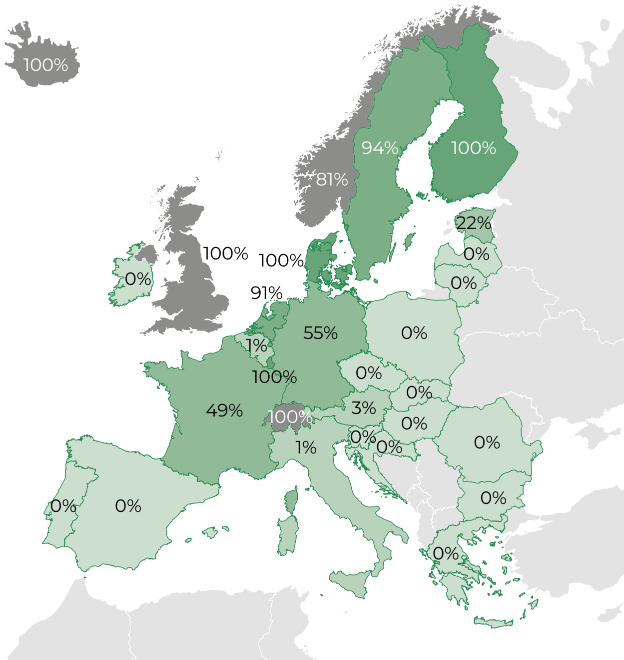
142 (McKinlay, Turnock, & Hudson, 2020)
143 (EUR-lex, 2014)

Figure 3.17.
Number of CNG, LNG, and hydrogen fuelling stations in the EU member states in 2019

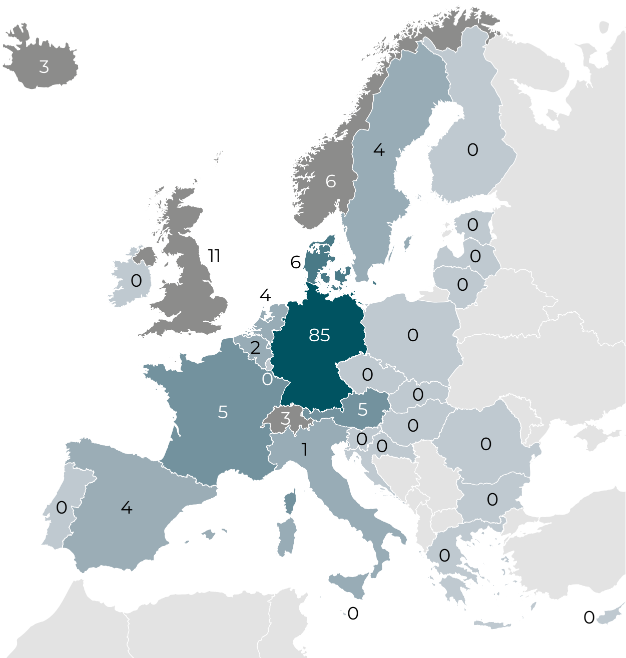
CNG filling stations



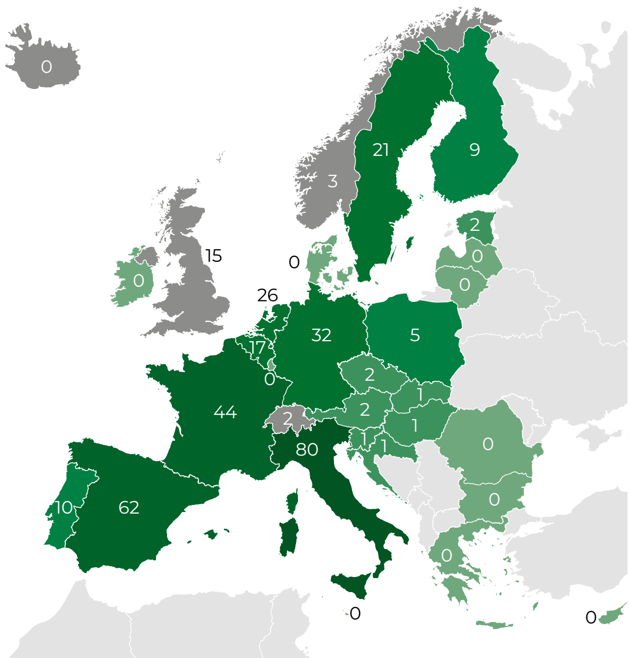
% bio-CNG filling stations



Hydrogen filling stations



LNG filling stations



Source: Guidehouse analysis based on (NGVA, 2020) and (H2.live, 2020), Spain H_2: https://industria.gob.es/es-ES/Servicios/Documents/aplicacion-marco-energias-alternativas.pdf

3.2.4 Showcase projects

Hydrogen in heavy transport

H2Bus Europe

- Multiple players in the hydrogen fuel cell electric value chain
- 1,000 buses
- Fuel cell electric buses
- In development, 600 buses expected by 2023
- Europe
- https://www.fuelcellbuses.eu/projects/h2bus-europe

Everfuel, Wrightbus, Ballard Power Systems, Hexagon Composites, Nel Hydrogen, and Ryse Hydrogen—all players in the hydrogen fuel cell electric value chain—joined forces to form the H2Bus Consortium in 2019. The members committed to deploying 1,000 hydrogen fuel cell electric buses and supporting infrastructure in European cities at commercially competitive rates. Previous hydrogen bus programmes (such as JIVE) had an important catalytic effect in Europe, allowing fuel cell bus manufacturers to scale-up their production and start developing volume-related offers. The first phase of the project, totalling 600 buses, is supported by €40 million from the EU's CEF. The grant will enable 200 hydrogen fuel cell electric buses and supporting infrastructure to be deployed in Denmark, Latvia, and the UK by 2023. Other targeted rollout locations include Norway, Sweden, the Netherlands, Belgium, and Germany. The consortium will also offer an affordable and reliable supply of green hydrogen straight to the operators' depot. Nel Hydrogen will supply electrolysers and hydrogen stations, Hexagon will supply hydrogen trailers.

H2Haul

- Multiple equipment manufacturers and other partners
- Size: 16 trucks
- Heavy duty hydrogen fuel cell trucks
- In operation, 2019-2024
- Europe
- https://www.h2haul.eu/

The H2Haul (hydrogen fuel cell trucks for heavy duty, zero-emission logistics) consortium consists of 15 partners from seven European countries, including multiple equipment manufacturers and analysis, dissemination, and coordination partners. H2Haul, co-financed by the FCH JU, aims to develop and deploy 16 zero-emission fuel cell trucks at four sites in Belgium, France, Germany, and Switzerland. In addition, new high capacity hydrogen refuelling stations will be installed to provide hydrogen supplies to the trucks. The project started in 2019 and will run for 5 years. This project will gather insights and information that will be disseminated to truck operators, retail sector representatives, policymakers, and the hydrogen industry. H2Haul aims to validate the ability of hydrogen fuel cell trucks to provide zero-emission mobility in heavy duty applications, laying the foundation for the commercialisation of this sector in Europe.

REVIVE

REVIVE, which stands for Refuse Vehicle Innovation and Validation in Europe, will run for 4 years: from 2018 through 2021. The REVIVE project aims to significantly advance the state of development of fuel cell refuse trucks by integrating fuel cell powertrains into 15 vehicles and deploying them across eight sites in Europe. The project will deliver technical progress by integrating fuel cell systems from three suppliers into a mainstream chassis and developing effective hardware and control strategies. Any lessons learnt will apply to the full range of equipment manufacturers supplying vehicles into the European market. The project will also explore the potential for waste-to-wheel business models, where the fuel cell trucks are combined with green hydrogen sourced from waste plants. REVIVE aims to support the wider rollout of hydrogen mobility by introducing a further source of hydrogen demand that can improve the economics of existing and future refuelling station deployments, in turn facilitating the rollout of other vehicle types

Multiple European municipalities, vehicle operators, manufacturers and experts

15 trucks

Fuel cell refuse trucks

In operation, 2018-2021

Europe

https://h2revive.eu/

Source: H2REVIVE

Biomethane and biogas in transport

Waste to biogas and bio-LNG

Renewi, Nordsol, and Shell signed an agreement in 2020 to build a Nordsol plant at a Renewi site in the Netherlands and jointly produce bio-LNG. This collaboration aims to contribute to the circular economy and completes the cycle of turning organic waste into a sustainable fuel for long haul transport. The plant is expected to produce the first bio-LNG by mid-2021. Throughout the Netherlands, Renewi collects organic waste from multiple industries (including retail and catering) and converts it into biogas. Part of this biogas will be delivered to the Nordsol plant to produce bio-LNG. Nordsol has integrated and optimised proven processes into a compact installation that can convert biogas into bio-LNG. The technology makes it possible to produce bio-LNG locally at an affordable price point. Shell will distribute the bio-LNG to nearby Shell LNG stations to supply customers with bio-LNG and help them reduce their carbon footprint.

Renewi, Nordsol, and Shell

Organic waste to bio-LNG

In development, expected in 2021

The Netherlands

https://www.shell.nl/media/nieuwsberichten/2020/renewi-nordsol-en-shell-zetten-samen-in-op-bio-lng.html

Biomethane in shipping

Bio2Bunker

- Titan LNG
- Three bunker barges
- Bio-LNG bunkering
- In development since 2020
- Zeebrugge, Belgium; Rotterdam, the Netherlands; Lubeck, Germany
- https://titan-lng.com/titan-lngs-ambitious-bio-lng-breakthrough-project-receives-eu-funding/

Titan LNG, a supplier of LNG to the marine and industrial markets in Europe, was granted €11,000,000 in funding from the EU's CEF in 2020. The EU's grant scheme supports transport infrastructure, connectivity, and the switch to greener fuels for transport. Bio2Bunker develops and expands a bio-LNG bunkering supply chain by introducing three bunker barges in Zeebrugge, Rotterdam, and Lübeck. For the Amsterdam-Rotterdam-Antwerp region, the Titan Hyperion will be constructed; it resupply its FlexFuelers with LNG combined with bio-LNG and later synthetic liquefied gas, made by combining green hydrogen and CO_2.

Hydrogen in shipping

MARANDA

In the MARANDA project, a hydrogen-fuelled PEM fuel cell hybrid powertrain system is being developed for marine applications; the project is being validated in test benches and onboard the research vessel Aranda. The 165 kW (2 x 82.5 kW AC) fuel cell powertrain will provide power to the vessel's electrical equipment and the dynamic positioning during measurements. A mobile hydrogen storage container, refillable in any 350-bar hydrogen refuelling station, will also be developed under this project. The project consortium includes companies from the whole fuel cell value chain, from balance-of-plant components to a systems integrator and an end user.

- ABB OY, Persee, PowerCell AB Sweden, Swiss Hydrogen SA
- 165 kW (2 x 82.5 kW AC) fuel cell powertrain
- PEM fuel cell
- Under construction, 2017-2021
- Europe
- https://www.fch.europa.eu/sites/default/files/4.%20Laurence%20Grand-Cl%C3%A9ment%20-%20MARANDA.pdf

Source: FCH JU

HySeas III

HySeas III is the final part of a three-part research program; the programme began in 2013 looking into the theory of hydrogen-powered vessels (HySeas I) and was followed by a detailed technical and commercial study to design a hydrogen fuel cell-powered vessel (Hyseas II, 2014-2015). HySeas III builds on the first two parts by aiming to demonstrate that fuel cells may be successfully integrated into a proven marine hybrid electric drive system and hydrogen storage and bunkering arrangements. The project does this by developing, constructing, testing, and validating a full-sized drivetrain on land. Should this test be successful, Scottish Transport has agreed to fund the building of a roll-on, roll-off passenger ferry, which will integrate the entire hydrogen/electric drivetrain subject to extensive monitoring and testing.

- Team of commercial and public sector organisations, coordinated by the university of St. Andrews
- Full size drivetrain
- PEM fuel cell
- In operation, since 2013
- Orkney, UK
- https://www.hyseas3.eu/

Liquid Hydrogen at Mongstad Industrial Park

Source: Wilhelmsen.com

- BKK, Air Liquide, Equinor, Wilhelmsen, NorSea, Norled, Viking Ocean Cruises, NCE Maritime CleanTech, Arena Ocean Hyway cCuster, NORCE
- One production plant for liquid hydrogen, two hydrogen vessels
- In development, expected in early 2024
- Norway
- https://maritimecleantech.no/2020/05/11/mongstad-selected-for-planned-hydrogen-production-plant-in-norway/

In 2019, a consortium led by BKK was awarded a grant by public funding scheme PILOT-E to develop a complete liquid hydrogen supply chain in Norway for maritime applications. Mongstad Industrial Park is the candidate production and liquefaction site, close to customers in the maritime sector and Equinor's Mongstad refinery. The first hydrogen users are envisaged to be two common goods carrier vessels under development by Wilhelmsen. In parallel, the consortium partners are developing solutions for storage and transportation to end users in the maritime sector. The project aims to make liquid hydrogen available for commercial shipping by early 2024. Wilhelmsen and Equinor conducted a feasibility study on two ships transporting equipment and materials between onshore bases in Stavanger and Mongstad. The ships could replace a substantial number of the trucks driving between these bases. The project also aims to set up hydrogen terminals at NorSea supply bases along the coast to secure hydrogen availability also for other vessels.

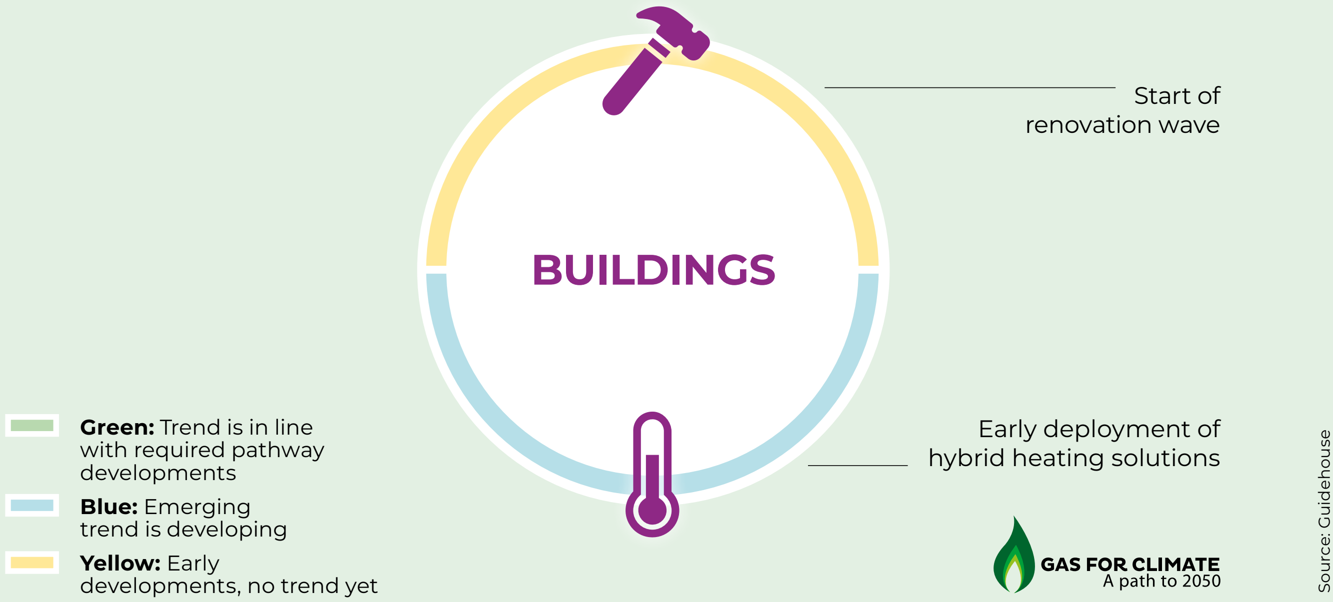
3.3 Built environment sector

Key trends

Early developments are taking place to increase *building renovation* levels in the EU. The Renovation Wave for Europe was announced by the European Commission in October 2020. The weighted annual energy renovation rate in the EU is only around 1%, with deep renovations only being carried out in 0.2% of the building stock annually.

In Europe, emerging trends are seen with the uptake of hybrid heating technologies. Early deployment of hybrid heating solutions in the built environment is taking place. In 2017, around 18,000 hybrid heat pumps were installed in Europe and uptake is gaining momentum, particularly in Italy and France. Also, recently several gas DSOs have started to intensively explore the potential of using gas grids to distribute hydrogen (e.g. to decarbonise heat), referencing TSO plans for a European Hydrogen Backbone.

Figure 3.18.
Key trends for renewable and low-carbon gas developments in the built environment



The building stock in Europe is heterogeneous and relatively old; about 85% of buildings date from before 2001.[144] Most of those existing buildings are not energy efficient.[145] In 2017, up to 97% of existing buildings required renovation to meet energy efficiency level A.[146] The average cost of renovation depends on the governing climate, the type of building, and increases steadily with renovation depth.[147]

Space heating and domestic hot water use about 3,600 TWh[148] annually and can be provided by a range of energy sources and energy carriers. This demand is mostly met by fossil fuels. In Europe, about 44% of energy in the built environment used for space heating is natural gas (Figure 3.19 Share). This percentage varies between countries and regions depending on available resources,

144 (European Commission, 2020d)
145 (European Commission, 2020d): *"Building codes with specific regulation on thermal insulation of the building envelope started appearing after the 1970s in Europe. This means that a large share of today's EU building stock was built without any energy performance requirement: one third (35%) of the EU building stock is over 50 years old, more than 40% of the building stock was built before 1960. Almost 75% of it is energy inefficient according to current building standards."* Source: JRC report, *Achieving the cost effective energy transformation of Europe's buildings.*

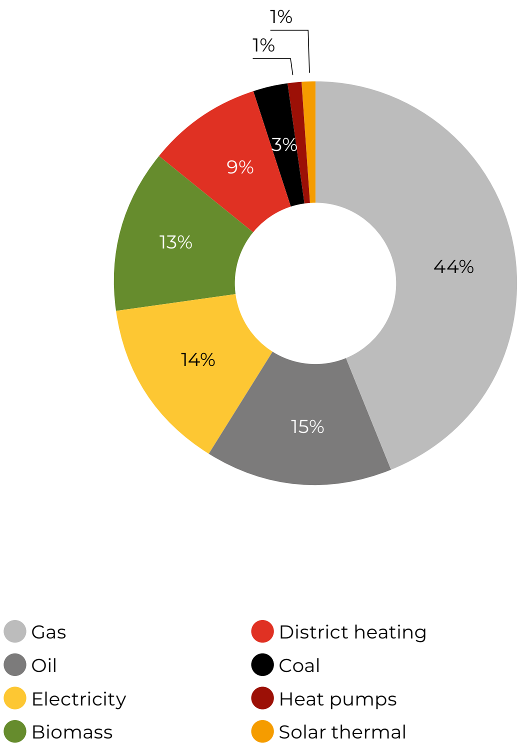
access to infrastructure, building heating and cooling needs, and the prevailing climate.[149] For example, natural gas is used to meet about 84% of residential heat demand in the Netherlands, while this is only about 57% and 42% in Italy and Germany, respectively.[150] The use of renewable gases is—next to electrification, insulation, and reduction of energy demand—key to decarbonising the European heating demand in the built environment.

The building insulation level and energy carrier for space heating and hot water provision will determine the applicable efficient heating technologies:

- **New or deeply renovated buildings** can efficiently apply all-electric, low temperature heating technologies such as all-electric heat pumps. If such installations become widespread, these technologies require implementation of new appliances and adaptations of existing electricity infrastructure and grid connections to accommodate new demand peaks and integrate high levels of renewable electricity.[6]

- For **buildings with an existing natural gas connection**, hybrid heating solutions using electricity and renewable gas can be used to decarbonise, requiring less extensive renovation and system adaptation efforts compared to full electrification.[2] Biomethane can be injected into the gas grid without major system upgrades and can be easily used from a technical and equipment perspective in building heating applications, such as condensing boilers or hybrid heat pumps, without changes for consumers.[151] In addition, several gas DSOs have recently started to intensively explore the potential of using gas grids to distribute hydrogen, referencing TSO plans for a European Hydrogen Backbone. Hydrogen can be blended with natural gas or dedicated hydrogen networks can be set up (see chapter 4).

Figure 3.19.
Share of energy carriers in Europe for space heating and hot water in the built environment, with a total consumption of about 3,600 TWh in 2018



Source: Guidehouse analysis based on data from heatroadmaps.eu (Guidehouse, 2020)

146 (BPIE, 2017).
147 Energy renovations are applied in various depths like light, medium, and deep renovation. The weighted energy renovation rate describes the annual reduction of primary energy consumption within the total stock of buildings (residential or nonresidential, respectively) for heating, ventilation, domestic hot water, lighting (only nonresidential buildings), and auxiliary energy achieved through the sum of energy renovations of all depths.
148 Based on data from heatroadmaps.eu for 2018, available at: https://heatroadmap.eu/wp-content/uploads/2018/09/HRE4-Exchange-Template-WP3_v22b_website.xlsx and internal analysis. Cooling demand assumed to be negligible.
149 For example, the Netherlands has a huge natural gas resource in the northern part of the country.
150 Based on data from heatroadmaps.eu for 2018, available at: https://heatroadmap.eu/wp-content/uploads/2018/09/HRE4-Exchange-Template-WP3_v22b_website.xlsx and internal analysis. Cooling demand assumed to be negligible.
151 (Hydrogen Europe, 2019b)

Decarbonisation and renovation of the built environment is challenging because of the high abatement cost for deep renovations, the high number of buildings requiring renovation (>97%), the dispersed ownership of the building stock, and the potential construction of new infrastructure. This section details the key trends regarding the use of biomethane and green and blue hydrogen to decarbonise the built environment (Figure 3.18). Developments in the early 2020s focus on accelerating building renovation levels in Europe and developing and increasing the adoption of hybrid heating technologies. The following paragraphs detail each key trend and indicate the status of each key trend towards achieving the critical decarbonisation timeline of the early 2020s-2030.

3.3.1 Start of renovation wave

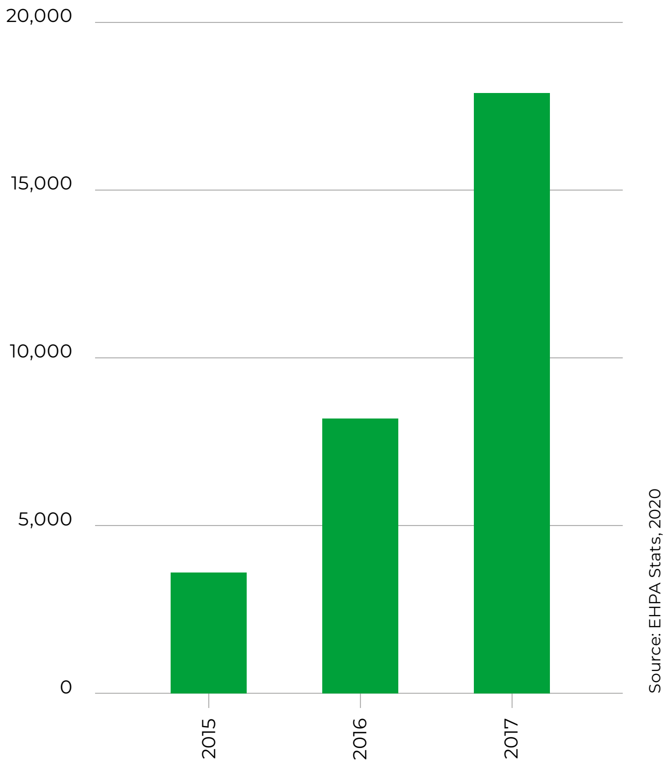
The weighted annual energy renovation rate in the EU is only around 1%, with deep renovations only being carried out in 0.2% of the building stock annually. The renovation wave in Europe will start with the announcement of the Renovation Wave for Europe by the European Commission in October 2020.

The average annual weighted energy renovation rate for buildings (residential and non-residential) in the EU is only between 1% and 1.5%, with mostly step-by-step[152] renovations focusing on cost-effective measures and only a limited share of deep renovation (0.2%).[144, 153] The depth of renovation defines how extensive the renovation is and what the achieved primary energy savings are; this ranges from blow threshold to deep renovations (above 60% primary energy savings) as defined by a study by Ipsos and Navigant.[154]

To accelerate carbon emissions reduction in the building sector, the European Commission announced its Renovation Wave for Europe.[144] The goal of the Renovation Wave is to achieve a doubling of the annual renovation rates in Europe by 2030, for both residential and non-residential building stock. Deep energy renovations will also be stimulated. The Renovation Wave aims to lead to the renovation of 35 million buildings in the EU by 2030. The European Commission also specifies that an increased rate and depth of renovation needs to be maintained post-2030 to achieve EU climate neutrality by 2050.

3.3.2 Early deployment of hybrid heating solutions

Figure 3.20.
Stock of hybrid heat pump units in Europe



152 Step-by-step measures or renovations means renovations are done over a couple of years with individual building components—e.g. one year the roof, another year the windows, and another year the heating system. This type of renovation is in contrast to one where multiple (or all) building components are renovated at the same time.
153 (European Commission, 2019a)
154 (Ipsos and Navigant, 2019), pgs. 15-17.

In 2017, around 18,000 hybrid heat pumps were installed in Europe and uptake is gaining momentum, particularly in Italy and France.

Hybrid heat pumps are a hybrid heating solution that combine a small electric heat pump with a gas boiler. This combination reduces insulation costs (no need for deep renovation of the building envelope) and heating technology costs (application of smaller heat pumps), while requiring only a small amount of renewable gas.[2] Hybrid heat pumps also reduce stress on the electricity system, especially during times with low temperatures (e.g. winter heating peaks) where the efficiency of electric heat pumps reduces by up to 75%.[2] This can be counterbalanced by use of renewable gas in a hybrid heat pump system.

Overall, heat pumps only make up a small share of residential heating solutions in Europe. Around 1.3 million households purchased different types of heat pumps in 2018, a number that has grown significantly—12% yearly average growth—since 2015.[155] Less than 10% of all EU buildings use heat pumps for heat generation.[156] Hybrid heat pump adoption is even more limited, with around 18,000 installed units in Europe in 2017.[157] Hybrid heat pump adoption has been increasing in the EU over the last few years (Figure 3.20), with most adoption in Italy followed by France.[157]

155 (IEA, 2020c)
156 (European Heat Pump Association, 2020)
157 (EHPA Stats, 2020)

3.3.3 Showcase projects

PACE

- COGEN Europe, together with manufacturers and research partners
- >2,800 households
- PEM and SOFC fuel cells
- In operation, 2016-2021
- Europe
- www.pace-energy.eu

PACE (stands for Pathway to a Competitive European Fuel Cell micro-Cogeneration market) is an EU-funded project focusing on the large-scale deployment of the fuel cell micro-cogeneration in over 2,800 customer homes and small enterprises in 10 European countries. Fuel cell micro-cogeneration is a technology that uses a single fuel (hydrogen, natural gas, or LPG) to produce heat and electricity for a building. This technology has a low heat-to-power ratio; therefore, it is well suited to the evolving trend in buildings towards higher electricity use and low space heating demand. The 5-year PACE project brings together European manufacturers, utilities, and research institutes. The project will enable manufacturers to move towards product industrialisation and will foster market development at the national level by engaging building professionals and the wider energy community. The PACE project is a €90 million public-private project co-funded by the FCH JU.

Dutch hydrogen boiler pilot project

Source: BDR Thermea Group

- Remeha, Stedin, municipality of Rotterdam, and housing association Ressort Wonen
- 400 households
- Hydrogen-powered domestic boiler
- In development, 2019-2021
- Rozenburg, the Netherlands
- https://www.bdrthermeagroup.com/en/stories/first-real-life-application-of-a-hydrogen-boiler-in-the-world

This pilot project on hydrogen-powered domestic boilers took off in mid-2019. The boilers can be operated under real conditions and are being developed by BDR Thermea Group in Italy. The project is overseen by Remeha in the Netherlands and is a joint initiative between the network operator Stedin, the municipality of Rotterdam, and the housing association Ressort Wonen. Green hydrogen is generated via wind or solar energy and supplied via an existing natural gas pipeline to the hydrogen boiler installed next to a conventional natural gas boiler. This combination ensures the supply of heat and water at all times. The aim is to install 400 hydrogen-powered domestic boilers in 2 years. After this first pilot in the Netherlands another field trial will be carried out in the UK; other network operators and building owners are invited to participate in further field trials and advance the development of hydrogen-powered domestic heating.

City of Leeds H21 hydrogen project

- Northern Gas Networks, Wales & West Utilities, Kiwa Gastec, Amec Foster Wheeler
- Feasibility study
- In development, live trial expected in 2021/2022
- Leeds, UK
- https://www.h21.green/projects/

In 2016, Northern Gas Networks, the gas distributer for the North of England, developed the H21 Leeds City Gate feasibility study. Based on a blueprint of the city of Leeds, the study concluded it was technically possible and economically viable to decarbonise the UK's gas distribution networks by converting them from natural gas to 100% hydrogen. Leeds City Gate also demonstrated this could be achieved at an acceptable cost to the customer. Before this vision can be fully realised, the critical safety-based evidence for such a conversion, upstream and downstream of the metre, must be provided. The identified design parameters for a city the size of Leeds included, among others, that hydrogen would be provided through a production capacity of 1,025 $MW_{el\ in}$ via four SMRs of 256 $MW_{el\ in}$ each located at Teesside due to its access to CCS. Total annual demand in a peak year would be 6.4 TWh, with 1.5 Mt of CO_2 sequestered each year. Total cost is estimated to be around £2 billion.

4.
Infrastructure and transport of renewable and low-carbon gases

Key trends

Biomethane grid injection **volumes in Europe have increased from around 5.5 TWh to approximately 20 TWh per year over the last decade, resulting in a 0.4% share in the gas network, with higher ratios in some countries. This share is expected to increase to 5%-8%, on average, by 2030 based on European and national targets, with differing shares among EU member states.**

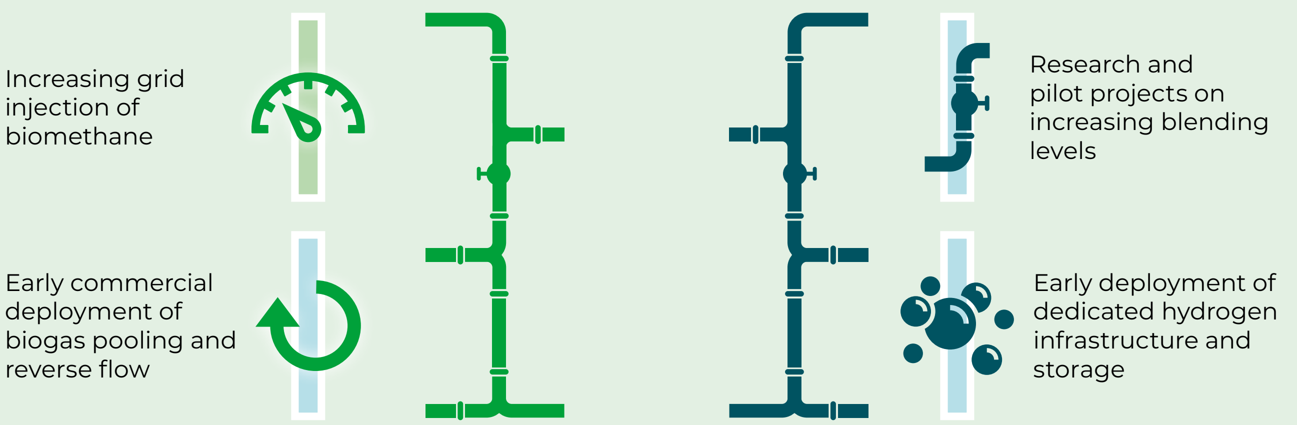
Early commercial deployment of *biomethane centralised upgrading and reverse flow* are emerging trends in the EU. Several reverse flow plants are installed in France (two in 2019), Germany (more than six in 2020), and the Netherlands (one in 2019). Biogas pooling is in an early development stage, with two main projects in Europe: one in Bitburg, Germany and the other in Twente, the Netherlands.

Emerging trends are seen in Europe with hydrogen blending in the natural gas grid. Certain levels of blending hydrogen with natural gas are achievable without major upgrades or adaptations to appliances and gas infrastructure. Research and pilot projects on increasing the *blending levels of hydrogen* are ongoing; hydrogen blending tolerances in the grid range between 5% and 20%.

Dedicated hydrogen infrastructure **development is gaining momentum through the conversion of gas infrastructure and the early development of new hydrogen networks, such as the European Hydrogen Backbone.**

Figure 4.1.
Key trends for hydrogen and biomethane infrastructure with an overview of selected showcase projects to illustrate ongoing developments

GAS FOR CLIMATE
A path to 2050



Green: Trend is in line with required pathway developments
Blue: Emerging trend is developing
Yellow: Early developments, no trend yet

Source: Guidehouse

Gas infrastructure includes any assets and processes from the point of injection to end use including blending stations, pipelines for transmission and distribution, compressor stations, metering, city gate stations, and storage sites. Gas infrastructure transports and distributes about 25% of the EU's primary energy consumption in 2018, or about 4,500 TWh (NCV), which equalled around 425 bcm of natural gas in 2018.[158] In large parts of the EU, gas infrastructure is well developed. When considering cost per energy unit transported, hydrogen transported by pipelines can be 10-20 times cheaper than transporting that same amount of energy via electricity cables.[159]

This chapter identifies key trends regarding biomethane and green and blue hydrogen infrastructure following the approach laid out in chapter 1. Developments in the early 2020s will focus on a scale-up of biomethane injection in the gas grid from approximately 23 TWh to 300-370 TWh by 2030, aided by the scale-up of innovative grid technologies, and a scale-up and substitution of the current grey hydrogen supply (339 TWh_{LHV}) with green and blue hydrogen to achieve 345 TWh of supply through pipelines in 2030, either through blending or dedicated infrastructure. The following sections detail each key trend and indicate the status of each key trend towards achieving the required pathway developments in the early 2020s-2030.[2]

4.1 Increasing grid injection of biomethane

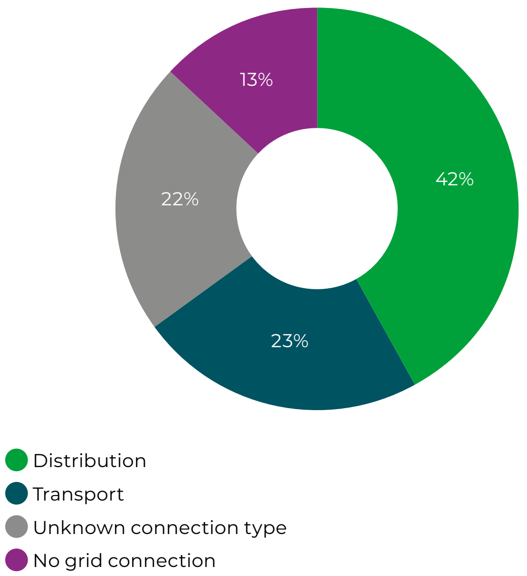
About 90% of biomethane plants in the EU are connected to the gas grid. About 20 TWh/yr of biomethane was injected in and transported through gas grids in Europe in 2018 (approximately 0.4% of transported gas). Large differences exist between countries regarding the connection profile.

Biomethane is similar to natural gas (LHV 36 MJ/m^3),[9] allowing it to be injected into the natural gas transmission or distribution grids with the appropriate purity and quality standards. Biomethane can be blended with natural gas without requiring any gas grid modifications.[2] Biomethane is often produced in small-to-medium installations located close to gas grids.[2] About 20 TWh of biomethane was injected in and transported through gas grids in Europe in 2018 (about approximately 0.4% of transported gas), with higher ratios in some countries.[2] In the EU, about 90% of biomethane plants were connected to the gas grid in 2019, either at the distribution or transmission level (Figure 4.2).

Biomethane grid connection types vary by country (Figure 4.3). Germany had almost only grid-connected installations in 2019; Sweden had predominantly non-grid connected installations (~79%); Denmark (96%) and France (89%) had mostly distribution grid-connected installations; and Italy mainly had transmission grid-connected installations (75%).

158 Quantity reported in net calorific value, equalling about 5,000 TWh in gross calorific value. Eurostat, Natural gas supply statistics, gross inland consumption of natural gas in 2018. Total EU energy consumption in 2017 was 1,675 Mtoe or around 19,000 TWh. Eurostat: https://ec.europa.eu/eurostat/statistics-explained/index.php/Natural_gas_supply_statistics
159 (Vermeulen, 2017)

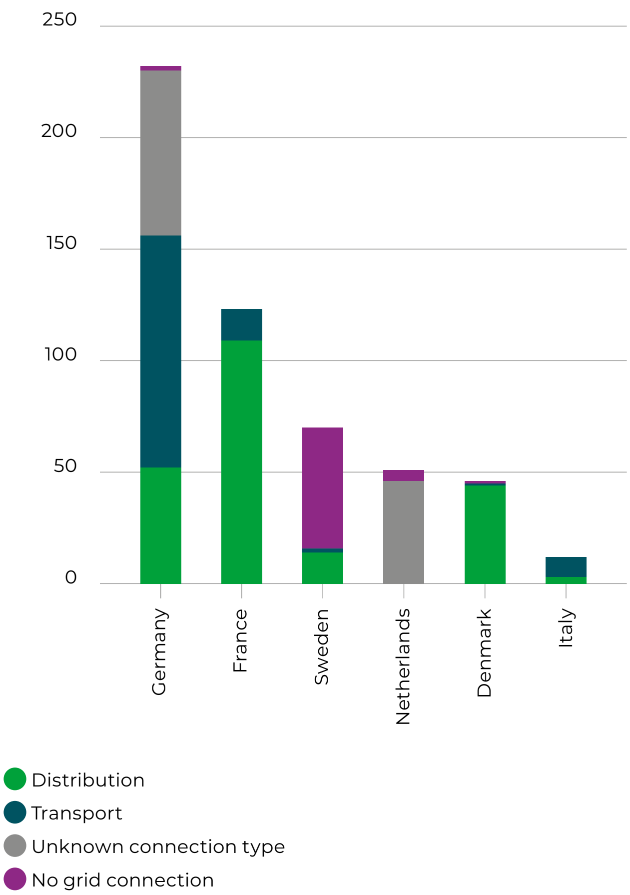
Figure 4.2.
Distribution of grid connection types across EU biomethane plants in 2019, with a total of 576 biomethane plants in the EU27 in 2019



Unknown connections have no data available on whether the connection is at the distribution or transport level. Transport grid from 16 bar.

Source: figure adapted from (GIE and EBA, 2020)

Figure 4.3.
Cumulative number of biomethane plants per grid injection type for selected countries in Europe in 2019

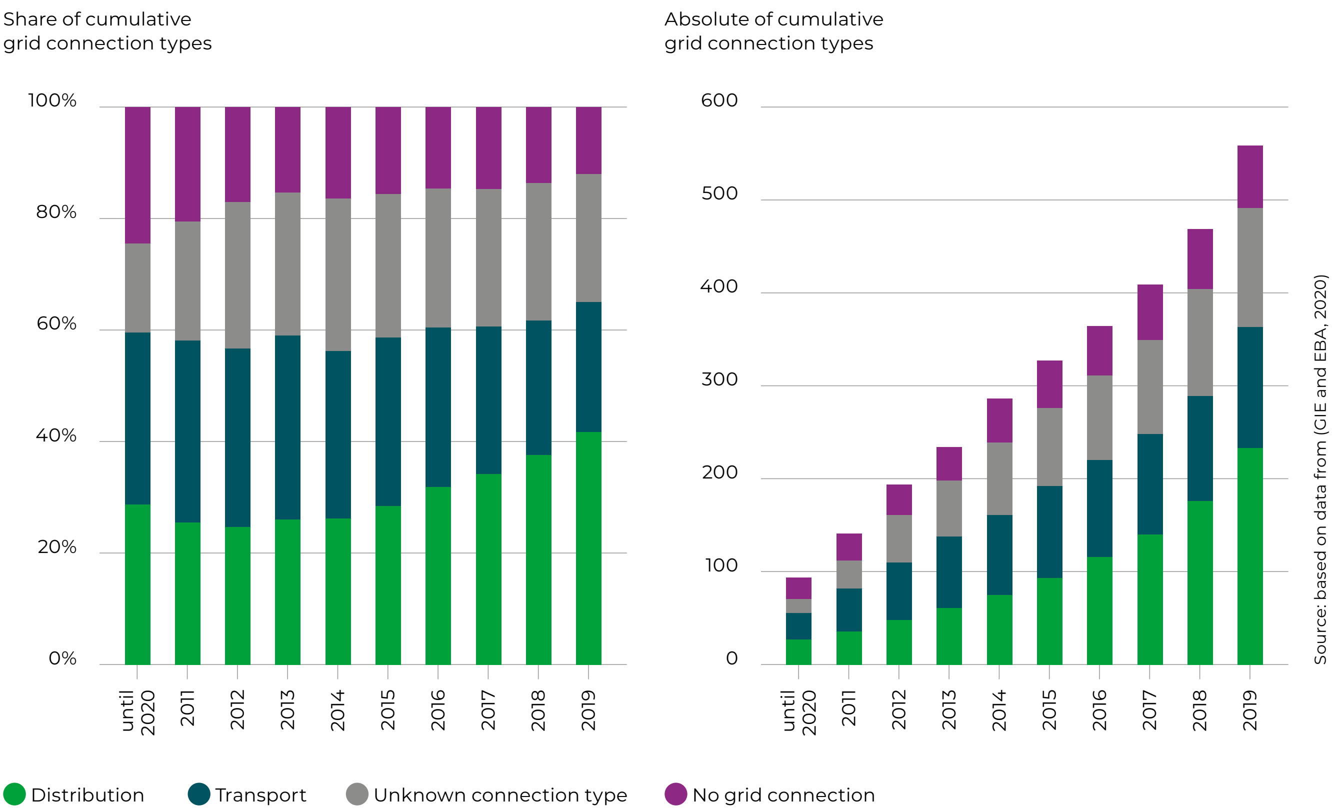


Source based on data from (GIE and EBA, 2020)

Biomethane grid injection volume in Europe has increased from around 5.5 TWh to approximately 20 TWh per year over the last decade. This share is expected to increase to 5%-8%, on average, by 2030 based on European and national targets, with differing shares among EU member states.[2]

EU biomethane production and injection in gas distribution and transmission grids is increasing because of European and national policies, such as the RED II, the Gas Directive, the Innovation Fund, and CEN standards. The biomethane injection volume in the EU has increased from around 5.5 TWh/yr in 2010 to around 20 TWh/yr in 2018. The share of biomethane plants without a grid connection in the EU has gradually decreased to about 12% of biomethane plants in 2019 (Figure 4.4). The share of biomethane injected into the EU gas grid is expected to increase from 0.4% to 5%-8%, on average, by 2030 based on targets on European and national levels, with differing shares among member states.[2]

Figure 4.4.
Development of cumulative grid connection types of biomethane plants in the EU



France is paving the way for a regional biomethane planning framework to map high potential zones that aim to increase and coordinate biomethane production and grid injection.

EU member states are starting to establish issuing bodies for end-consumer disclosure (so-called GoO) according to RED II, Article 19.[80] For example, France used the transposition of the RED II to introduce a binding mandate for 10% biomethane in the French gas grid by 2030.[2] To facilitate this, France is developing a national biomethane planning framework to map the high potential zones for biomethane production and grid injection (see showcase projects in section 4.3). Several other European countries are also developing innovative concepts to further scale-up biomethane gas grid injection; these are highlighted through the showcase projects.

4.2 Early commercial deployment of biogas pooling and reverse flow

Biogas pooling is in an early development stage, with two main projects in Europe: one in Bitburg, Germany and the other in Twente, the Netherlands.

Biogas production installations are often small or medium in size. In Europe, about 16 bcm of produced biogas is currently not upgraded to biomethane, which can be injected into the gas grid. This biogas is largely used for local baseload heat and electricity production.[2] To increase injection volumes of biomethane into the gas grid, biogas needs to be upgraded to the desired quality and purity standards through a costly upgrading process.

Biomethane grid connection costs can be significant when multiple smaller biomethane plants individually connect to gas grids. Biogas pooling is a way to upgrade existing dispersed biogas production in a large, centralised biomethane upgrading facility located close to the gas grid. Produced biogas at multiple dispersed installations can be transported through biogas pipelines to the centralised upgrading facility. In this way, pooling enables existing dispersed biogas production plants to increase efficiency and share the costs to upgrade biogas to biomethane.[2] This concept does not require each biogas installation to individually invest in an upgrading facility; instead, it allows for dynamic adaptation to fluctuating raw gas compositions and provides flexibility for baseload electricity production through the centralised production of biomethane.

Pooling concepts are in the early stages of development, with two main projects: one in Bitburg, Germany (biogaspartner) and the other in Twente, the Netherlands (biogasnetwork). Another example project includes the Stadtwerke Schwäbisch Hall, where a regional biogas grid was developed to transport biogas from rural and regional areas to CHP plants in the nearby urban region. The local energy supplier has the flexibility to use the biogas for heat generation purposes or to upgrade it to biomethane.

Reverse flow plants are in early commercial deployment, with several plants installed in France (two in 2019), Germany (more than six in 2020), and the Netherlands (one in 2019).

Medium- and larger-scale biomethane plants feeding into low pressure (<4 bar or between 4 and 6 bar depending on the country[160]) gas distribution pipes in areas with little local gas demand might lead to local oversupply—for example, during summer months with low gas demand.[161] Local oversupply could be mitigated by allowing biomethane to flow upwards towards medium or even high pressure grids using a solution called reverse flow technology.[2] A reverse flow unit is a facility that allows gas transfer from the distribution system to the upstream transmission system using a decentralised gas compression mechanism that increases pressure.[162] The reverse flow concept allows the biomethane injected at the distribution level to be transported to different regions and across borders through transmission grids (bidirectional transport).[2, 163]

This solution fundamentally changes grid flows compared to the current downward flows from high to medium to low pressure. Reverse flow technology is being implemented and generally requires limited investments. The cost of a reverse flow installation, however, depends on the hours of operation and the pressure on the transport network (compression costs). The operating cost of a reverse flow installation could, in some cases, be higher than a direct connection to the transport network.

Reverse flow plants are in early commercial deployment. The first two reverse flow plants in France were commissioned in 2019.[164] One reverse flow plant was installed in the Netherlands in 2019.[165] In 2020, more than six reverse flow plants were installed in Germany.[166]

160 (Green Gas Grids, 2013)
161 (European Commission, 2019b)
162 (West Grid Synergy, 2020)
163 (Renewable Gas French Panorama 2017, 2017)
164 (Green Gas Initiative, 2017)
165 (Enexis group, 2019)
166 (Ontras Gastransport GmbH, 2020)

4.3 Biomethane showcase projects

Source: West Grid Synergy

West Grid Synergy

In western France (Brittany and Pays de la Loire), West Grid Synergy aims to design and experiment smart grid solutions to maximise biomethane injection into its transmission and distribution systems. One of the smart solutions that already has been implemented is the first two reverse flow facilities, designed and developed by GRTgaz in Pontivy and Pouzauges. The reverse flow unit is a facility that allows gas transfer from the distribution system to the transmission system thanks to a gas compression mechanism. It enables an increase in local storage capacity for biomethane injection into the distribution system. The objective now is to assess how these installations operate under real conditions to optimise infrastructure settings. Another implemented solution is the different meshing infrastructures have been applied in this West Grid Synergy project. A 43 km gas pipeline has connected a manufacturer to the grid, and some connections have allowed formerly independent distribution systems to be merged. These meshing operations allow biomethane production projects to be locally absorbed.

GRTgaz,
GRDF, Sorégies, Morbihan energies, SyDEV, SléML

Multiple solutions

Smart grid solutions, reverse flow technology

Ongoing

Brittany and Pays de la Loire, France

https://www.westgridsynergy.fr/projet-west-grid-synergy

Ongoing smart grid studies in the West Grid Synergy projects are; biomethane storage features to minimise congestion, “smart delivery” units to prioritise biomethane injection over conventional gas delivery and communicating sensors and smart meters.

Micro biogas grid – Schwäbisch Hall

Stadtwerke Schwäbisch Hall constructed a micro biogas network, separate from the natural gas network, to transport biogas from the agglomeration/rural areas to municipal utilities' heating and power stations in the urban region. The municipality operates several CHP plants, which provide 100% of the district heating network to the city. The micro biogas grid enables the construction of small biogas plants at the location where liquid manure is produced. At the same time, an effective, largely complete use of heat is achieved. Within the biogas grid, the local energy supplier has the flexibility to use the biogas for heating purposes or to upgrade it to biomethane.

Department of Public Works for the city of Schwäbisch Hall and regional biogas producers

Micro biogas network

In operation, since 2010

Schwäbisch Hall, Germany

biogasnetwerk project

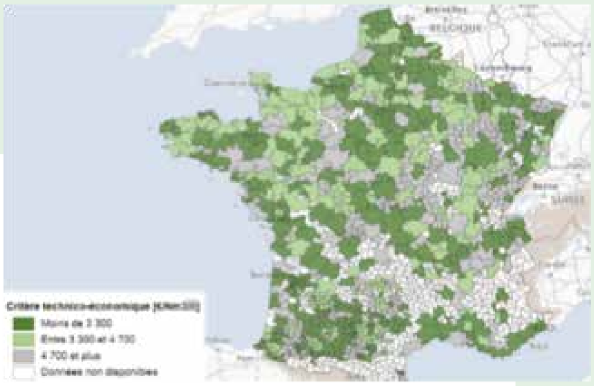
- GasUnie New Energy and Cogas
- 2 million m³ biogas annual production capacity and a 7.5 km pipeline
- Biogas plant network (pooling)
- In operation, since 2017
- Twente, the Netherlands
- https://www.gasunienewenergy.nl/projecten/biogasnetwerk-twente

The old Lenferink firm in Fleringen owns a pig farm and transports and processes manure. A digester was built at the farm that produces 2 million m³ of biogas on a yearly basis. A 7.5 km long pipeline has been developed from the farm to a central biogas to biomethane upgrading installation in Almelo. There the biogas is upgraded to biomethane and injected into the natural gas grid. The pipeline between Fleringen and Almelo is the start of a biogasnetwork in the region. In 2020, an inventory was kicked off to extend the network, so that more biogas producers can use the central upgrading facility, lowering the threshold for farmers to start producing biogas.

biogaspartner project

- Collaboration of industry partners in the biomethane industry and the Deutsche Energie-Agentur (Dena)
- 10,000 cubic metres of raw biogas per hour over 45 km pipeline
- Biogas plant network (pooling)
- In operation
- Bitburg, Germany
- https://www.biogaspartner.de/

In collaboration with industry partners along the biomethane value chain, Dena developed the biogaspartner project. The aim of this project was to develop a platform to inject biogas into the natural gas network and use the injected biomethane. The platform built a new biogas pipeline that has the capacity to bundle the raw biogas supplies of up to 48 biogas plants in the Bitburg region in Germany. The 45 km pipeline transports the bundled biogas to a central upgrading plant in Bitburg. From there, the biogas is upgraded to biomethane and is fed into the natural gas grid of the Trier public utility company. The biogas plant network in the region has potential to produce around 10,000 cubic metres of raw biogas per hour. Since May 2020, an initial seven plants have been sending 1,800 cubic metres per hour of biogas to the upgrading plant.



French innovative biomethane planning framework

A regulatory framework is being established to allow for optimised planning of biomethane injection and gas network adaptations in France. The main objective of the framework is to have an integrated overview of the high potential zones for biomethane injection through caps on socialised cost levels. In an ongoing process, the framework identifies cost-efficient zones for gas networks' adaptation in a common process between gas TSOs and DSOs, the French regulator, and consultations with territorial stakeholders. The French energy regulator (CRE) tasked the network operators to develop a technoeconomic potential map for France; a first version was published in March 2020. Mapping is targeted for approximately 500 zones for their biomethane production potential, their required costs for gas networks adaptation, and their identified best biomethane grid connection scheme. For each zone, CRE's approval is needed to validate the connection scheme and network adaptations. The map will be updated regularly to include the results of detailed studies led by operators and local players on the zones where biomethane projects materialise.

- French TSOs and distribution system operators (DSOs), CRE
- National planning framework
- Under development, first map published in 2020
- France
- https://www.cre.fr/Documents/Deliberations/Decision/mecanismes-encadrant-l-insertion-du-biomethane-dans-les-reseaux-de-gaz, https://opendata.reseaux-energies.fr/, https://gazrenouvelables.fr/

(Source Figure: Teréga, 2020. Cartographie d'accès aux réseaux de gaz. https://www2.terega.fr/nos-offres/biomethane/acces-aux- reseaux-de-gaz.html)

Reverse-flow facilities in German Gas network

ONTRAS currently operates six reverse flow facilities throughout its network (more than any other German TSO) with a combined energy capacity of 58,332 kW enabling the feed-in of biomethane from the distribution networks to the transmission networks. In rural areas, the supply of biomethane can excede local demand, especially during summer months. By utilising these facilities, surplus biomethane can be transported beyond the local distribution network and utilised at demand sites in other regions. The ONTRAS gas management systems monitor the quantity and the quality of the gas being injected to ensure optimal network operation. Local compressor units achieve the required pressure for injection of the gas into the transmission network (between 25 bar and 55 bar depending on the location).

- ONTRAS, various distribution system operators
- 6 locations, combined energy capacity of 58,332 kW
- Reverse flow unit
- In operation
- Eastern Germany

4.4 Research and pilot projects on increasing hydrogen blending levels

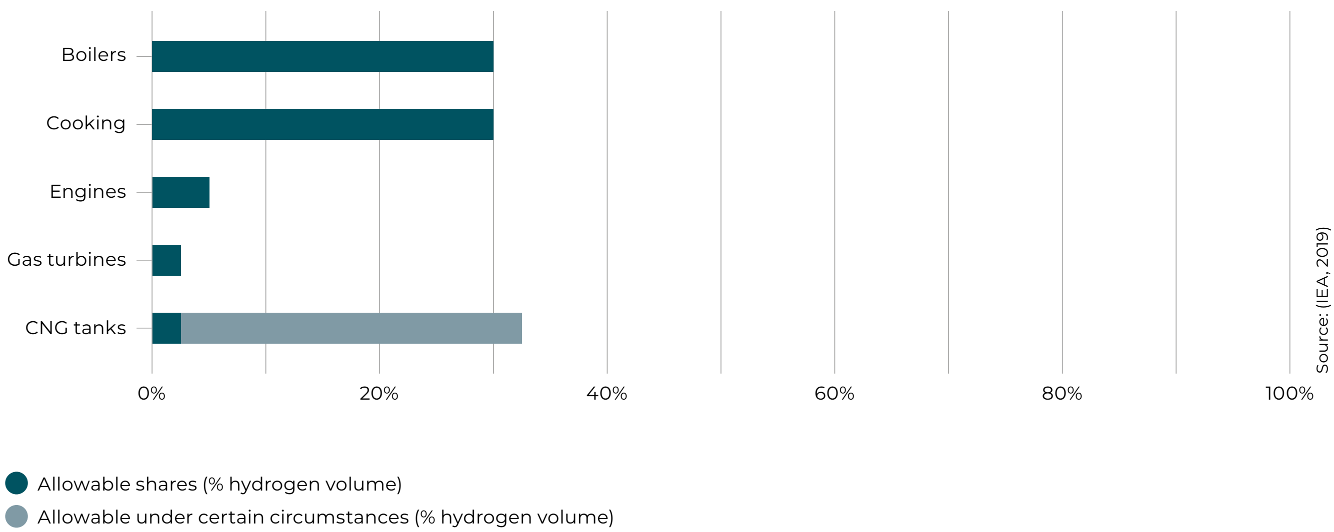
Blending is in an early commercial stage, with several pilot projects ongoing across Europe. Hydrogen blending tolerances in the gas distribution grid could range between 5% and 20%.

Hydrogen blending in the existing gas grid is identified under the pathway as a way to quickly scale-up hydrogen supply, while limiting the need for hydrogen pipeline and end-user investments.[2] Certain levels of blending hydrogen with natural gas are achievable without major upgrades or adaptations to appliances and gas infrastructure.[46] Studies report blending percentages of between 5% and 20% of volume to be technically feasible in current gas distribution grids with minimal investments.[167]

However, the actual feasibility of blending levels depends on the hydrogen tolerance of end users and in appliances, including the ability to deal with varying blends. When moving to higher blending percentages, changes might need to be made to the infrastructure and to the end-user equipment and appliances (e.g. different burners). In general, building appliances have a higher tolerance for hydrogen admixing than industrial applications. The maximum concentration depends strongly on the type of end user and their specific gas demand (Figure 4.5). Blending is in the early commercial stage with several pilot projects ongoing, including the Thyga project.[168] Avacon Netz and the German Gas and Water Association (DVGW) are also examining up to 20% hydrogen in natural gas blends in the Avacon distribution network in Saxony-Anhalt.[169]

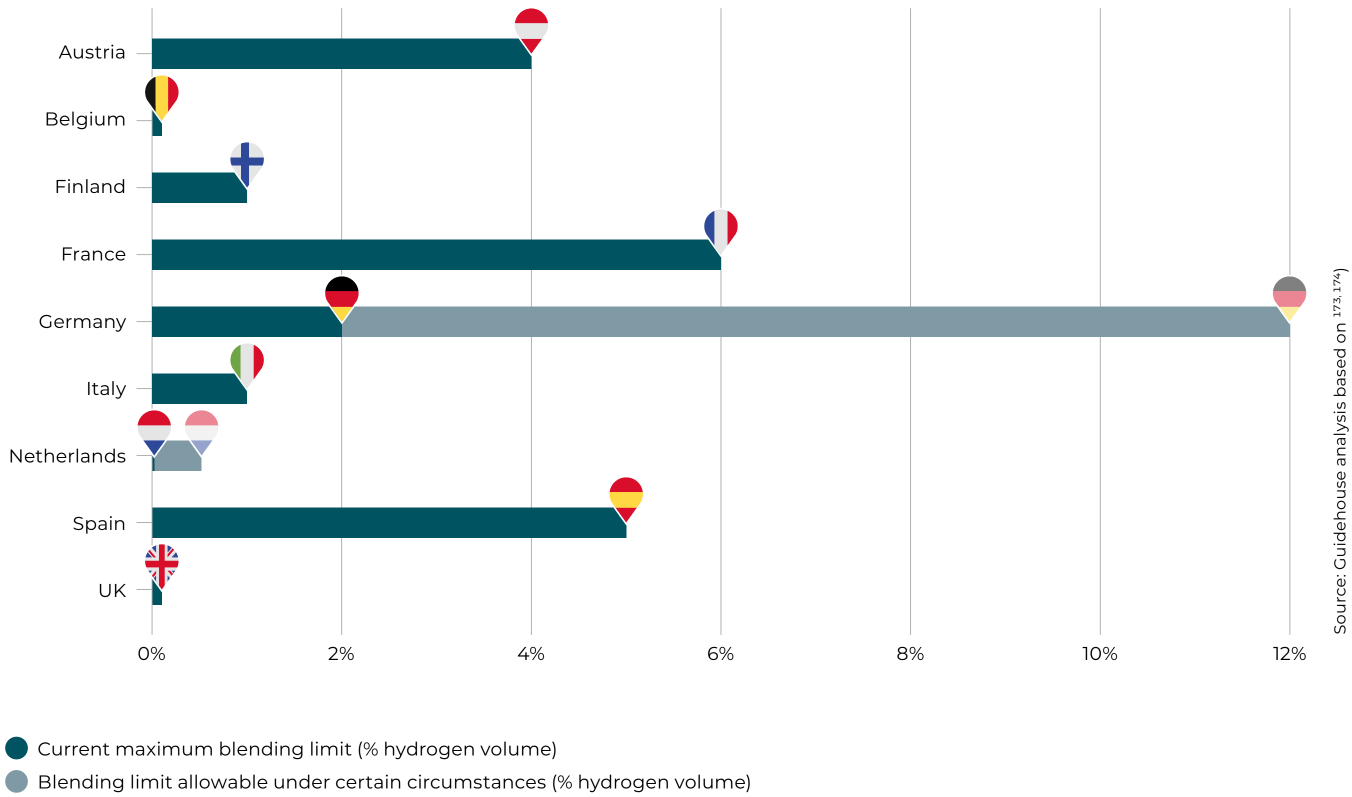
Using pure hydrogen, in contrast, requires significant upgrades to appliances and infrastructure but at a lower cost than full electrification.[46] End-use appliances also require conversions and adaptation to use hydrogen as an energy carrier. The City of Leeds H21 project, for example, estimates the cost and effort required for boiler and cook top replacements.[170]

Figure 4.5.
Tolerance of end-use applications for hydrogen blends



167 (GRT Gaz et al., 2019); (National Renewable Energy Laboratory; M.W. Melaina, O. Antonia, M. Penev, 2013)
168 (THyGA, 2020)
169 (Avacon, 2020)
170 (H21 Projects, 2020)

Figure 4.6.
Current maximum limits on hydrogen blending in natural gas grids



At a distribution grid level, situations can arise where a relatively homogenous group of end users is connected to a branch of the grid, such as building owners. Homogenous end users will allow more easy blending of hydrogen than in situations where also some industrial users are connected. On a transmission grid level, many different users are connected to the grid. A possible technical solution to safeguard low tolerance end users, such as gas turbines, would be a downstream separation of the hydrogen from the blended gas stream through separation membranes (de-blending).[2] Pilot projects are underway to test technoeconomic aspects of hydrogen separation, including the HIGGS project[171] and the membrane separation pilot project in Prenzlau.[172]

Taking into account constraints in hydrogen tolerance in the grid and at the end users, EU member states have set specific limits on the amount of hydrogen that can be blended into natural gas grids (Figure 4.6). Various projects are ongoing to develop a better understanding of the maximum concentration with which hydrogen can be blended (see showcase projects in section 4.6).

171 (Hidrogeno Aragon, 2020)
172 (GRTgaz, 2020)
173 The 10% limit in Germany applies to networks to which no CNG fuelling stations are connected. The 1% for Italy is specified in SNAM's network code: https://www.snam.it/export/sites/snam-rp/repository-srg/file/it/business-servizi/codice-rete-tariffe/Codice_di_rete/Codice_di_Rete/Capitoli_e_allegati/ALLEGATI/allegato_11_A_RevLXXII.pdf
174 Based on Guidehouse information and IEA, The future of hydrogen, 2019 & Journal of Hydrogen, Incentives and legal barriers for Power-to-Hydrogen pathways: An international snapshot, 2019 & Energy and Environmental Science, the role of hydrogen and fuel cells in the global energy System, 2019 & Hylaw online database, 2020, https://www.hylaw.eu/database

4.5 Early deployment of dedicated hydrogen infrastructure and storage

A gas pipeline typically transports hydrogen between the production facility and usage; truck transport is used for smaller volumes. Hydrogen can be blended with natural gas or dedicated hydrogen infrastructure can be developed. The FCH JU states in its Hydrogen Roadmap for Europe that around 66 hydrogen blending and pure hydrogen projects are under development in Europe.

The FCH JU states in its Hydrogen Roadmap for Europe that around 66 hydrogen blending and pure hydrogen projects are under development in Europe.[46] For hydrogen users, a dedicated hydrogen pipeline or gas grid connection will be more cost-effective than an electricity grid connection to produce green hydrogen via electrolysis onsite.[2]

(Grey) hydrogen-dedicated pipeline infrastructures are already in place, connecting merchant producers to users. These pipelines are generally distribution pipes that operate at low pressures (10-20 bar) and are operated by hydrogen producers.[175] In the EU, 613 km of pipelines were installed in Belgium in 2016, 376 km in Germany, 303 km in France, and 237 km in the Netherlands, among others.[176] These infrastructures are generally point-to-point, although some regional grids exist that transport hydrogen between industrial hubs, such as the Air Liquide grid-connecting industrial hubs in the North of France and the ports of Antwerp and Rotterdam in Belgium.[177]

Dedicated hydrogen infrastructure development is gaining momentum through conversion and repurposing of gas infrastructure as well as the early development of hydrogen networks, such as the European Hydrogen Backbone.

While new hydrogen infrastructure can be developed, it will be more cost-effective to convert existing pipelines for dedicated hydrogen transport. Existing natural gas infrastructure can undergo repurposing to noncorrosive and nonpermeable material to transport 100% hydrogen depending on the type of steel used for the infrastructure and the pipe pressure.[2, 46] Repurposing mainly incurs costs to replace the compressor stations, valves, and metering stations; costs vary based on the local gas grid characteristics.[2] The exact requirements for network upgrading to use 100% hydrogen are being investigated in multiple pilot projects, such as in the City of Leeds H21 project and the SGN Hydrogen 100 project.[178]

Retrofitting existing gas infrastructure to transport 100% hydrogen has only been tested on a pilot scale. Based on an estimation in the European Hydrogen Backbone study,[179] investment costs to refurbish natural gas transmission pipelines are estimated at 10%-35% of new build pipelines; investment costs for new dedicated hydrogen pipelines range between 110% and 150% of the investment cost of a new natural gas pipeline with a similar diameter.[180] The levelised costs for hydrogen transmission for refurbished natural gas infrastructure are estimated to be between €0.07 and €0.15/kg/1,000km.[179] The levelised costs for hydrogen transmission for new hydrogen infrastructure, in contrast, are estimated to range between €0.16 and €0.23/kg/1,000km.[179]

The Dutch TSO Gasunie has already converted a 12 km natural gas pipeline into a hydrogen pipeline to transport by-product hydrogen from DOW to be used as feedstock by Yara in Zeeland, the Netherlands.[181] Multiple other projects are

175 (Hydrogen Tools, 2016)
176 (Hydrogen Europe, 2016) referring to (Hydrogen Tools, 2016)
177 (Air Liquide, 2009)
178 (Leeds City Gate, 2017) The H21 report assumes upfront conversion of the distribution network to a hydrogen-ready grid through a modernisation programme that is due to be undertaken. See (Leeds CIty Gate h21)
179 (Enagás, Energinet, Fluxys Belgium, Gasunie, GRTgaz, NET4GAS, OGE, ONTRAS, Snam, Swedegas, Teréga, 2020)
180 Note that the range varies significantly depending on pipeline diameter. See the European Hydrogen Backbone study for further details.
181 (Gasunie, 2018)

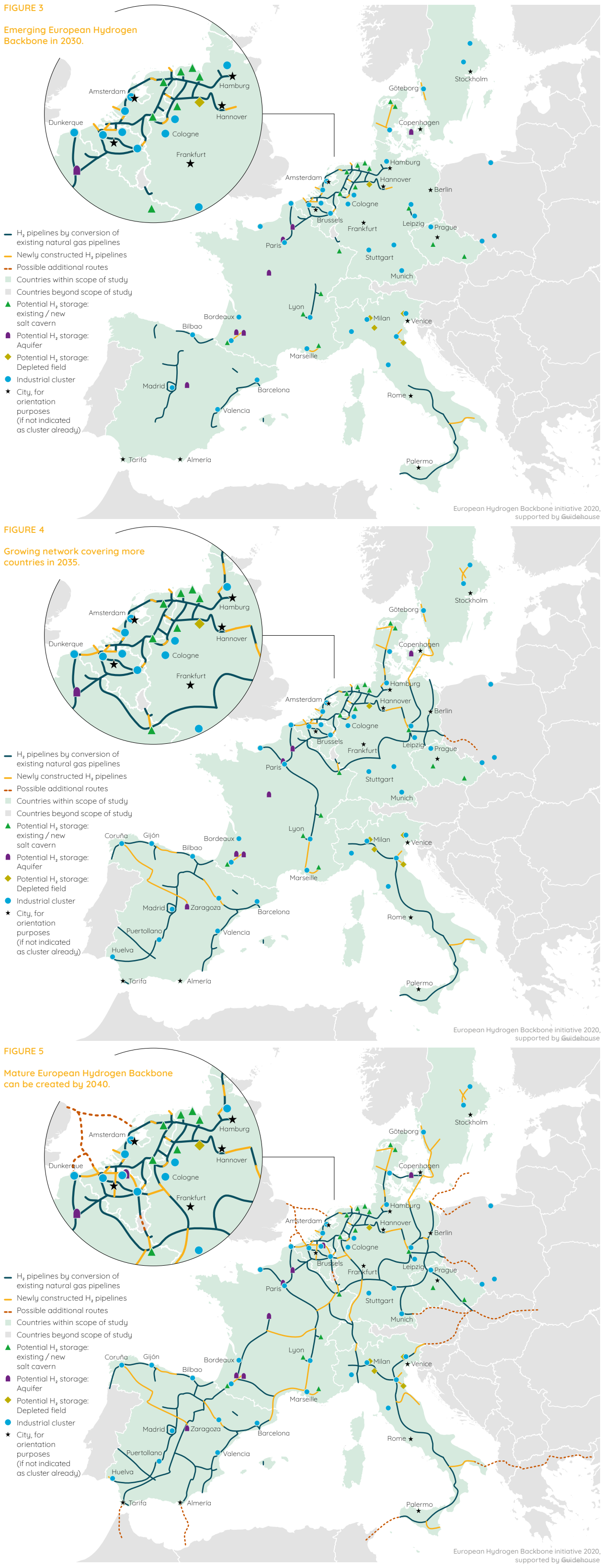
exploring how existing natural gas pipelines can optimally be converted to transport hydrogen. In July 2020, the European Hydrogen Backbone initiative was launched, illustrating how a pan-European hydrogen transmission infrastructure can be developed by 2040 by building on existing gas infrastructure (Figure 4.7). About 75% of the future hydrogen backbone can consist of converted, existing natural gas pipelines, and only 25% will need to be new-built dedicated hydrogen pipelines.[179]

In Europe, early projects are exploring the use and potential of hydrogen storage in salt caverns to match future supply and demand.

The natural gas grid has a large intrinsic storage capacity (line packing), which is further enhanced by underground gas storage—for instance in salt caverns and depleted natural gas fields. Such large-scale storage can match seasonal demand and supply fluctuations. About 15%-20% of the total gas consumption is stored to balance gas production and consumption.[182] Storage of future green hydrogen production allows intermittent renewable electricity production to be decoupled from demand. Across the EU, several projects are being developed that explore this power-to-gas-to-power cycle and the required storage capabilities.

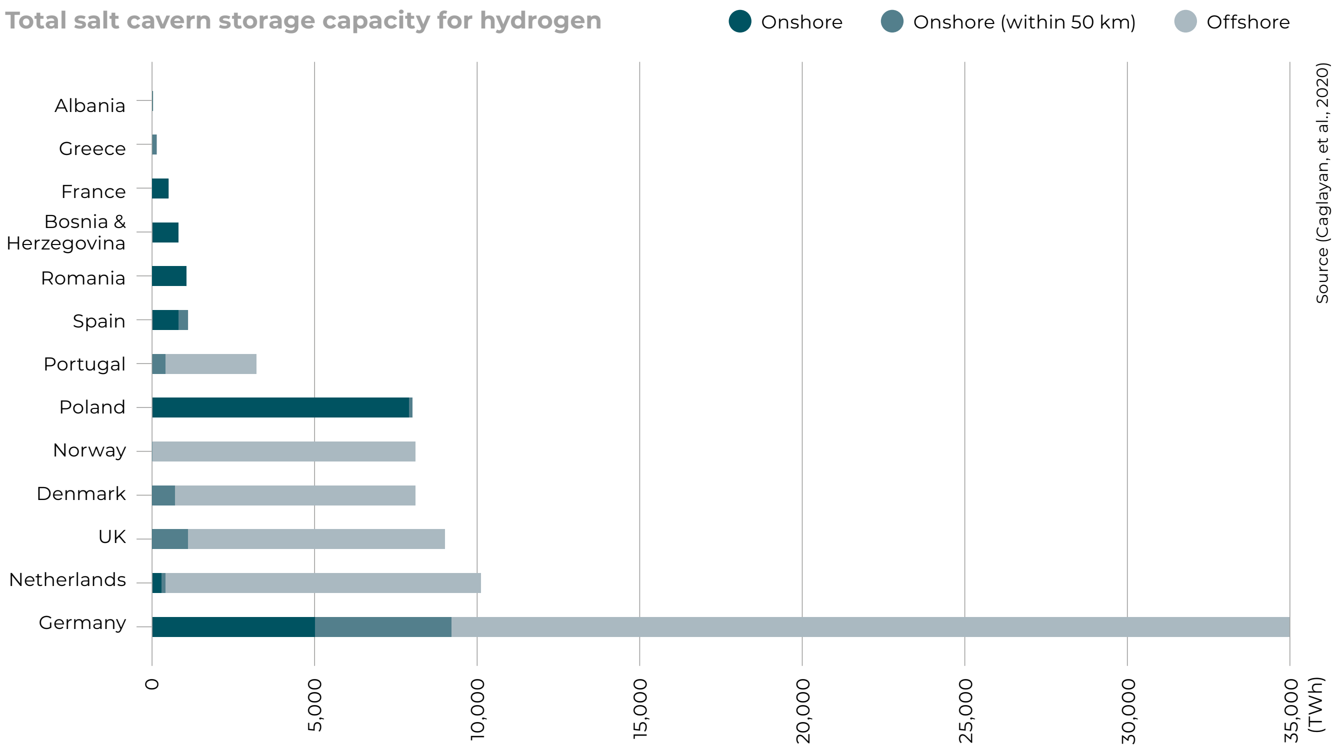
Hydrogen storage in salt caverns is one of the most promising ways to store large volumes of hydrogen. In a typical salt cavern, storage capacity at 200 bar is around 6,000 tons of hydrogen or about 240 GWh. Storing energy in the form of hydrogen in salt caverns is estimated to cost around €100 million for a single salt cavern, which is at least a factor of 100 cheaper than storing that amount of energy in an electric battery.[182] Estimations are that there is sufficient potential capacity in European salt caverns to store large amounts of hydrogen in many EU countries (Figure 4.8).[183] The current gas demand in the EU is around 4,577 TWh (as of 2018),[184] suggesting the technical H_2 storage potential in the EU is sufficient to support a resilient future hydrogen energy system.

Figure 4.7.
Progressive development of dedicated hydrogen infrastructure in the EU as proposed by the Hydrogen Backbone initiative[179]



182 (Hydrogen Europe, 2020c)
183 (Caglayan, et al., 2020)
184 Inland consumption in 2018 in net calorific values based on Eurostat, "Supply, transformation and consumption of gas [nrg_cb_gas]." https://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=nrg_cb_gas&lang=en

Figure 4.8.
Total salt cavern storage capacity for hydrogen



4.6 Hydrogen showcase projects

Blending

H2NG supply in Contursi Terme

In 2019, Snam launched its experiment of blending 5% of hydrogen with natural gas in the Italian gas transmission network. The experiment involves the supply of H2NG (a blend of hydrogen and gas) to two industrial companies in the area: a mineral water bottling company and a pasta factory. The test marked the first step in Snam's hydrogen developments. In a few months the volume of the hydrogen blend was doubled to 10% and experimentally introduced into the natural gas transmission network in Contursi Terme.

- Snam and two industrial companies
- 5%-10% hydrogen and natural gas blend
- Blending
- In operation
- Contursi Terme (Salerno), Italy
- https://www.snam.it/en/Media/news_events/2020/Snam_hydrogen_blend_doubled_in_Contursi_trial.html

HIGGS

The HIGGS project's main objective is to further develop the potential of hydrogen injection into the high-pressure transmission level of the natural gas grid as a way to decarbonise the gas system and gas demand sectors. The HIGGS project aims to cover the gaps of knowledge of the impact that high levels of hydrogen may have on the gas infrastructure, its components and its management. In order to reach this goal, several activities are being developed in this project. They include the mapping of technical, legal and regulatory barriers and enablers, the testing and validation of systems and innovation, the techno-economic modelling and the preparation of a set of conclusions as a pathway towards enabling the injection of hydrogen in high-pressure gas grids. The HIGGS project has a duration of 36 months and a budget of €2 million from European funding. A testing platform will be developed at the facilities of the Aragon Hydrogen Foundation where will tested how different degrees of natural gas and hydrogen mixtures will behave in relation to the transport infrastructure, simulating different operating conditions by varying the flow, composition, and quality of the gas. A novel gas separation system based on membrane technology will be developed within the framework of this project.

- Tecnalia, HSR Hochschule, ERIG, DVGW
- Testing platform and gas separation development
- Study and analysis on blending and deblending
- Project will run from 2020-2022
- Europe
- https://hidrogenoaragon.org/en/proyectos/higgs_en/

Pilot plant Membrane separation technology

In May 2020, six partners from the gas and research industries signed the "Membrane separation natural gas-hydrogen Prenzlau" cooperation agreement. The project analyses how hydrogen can be separated from natural gas-hydrogen mixtures (deblending) using different membranes in a pilot plant near Prenzlau. The local power-to-gas plant at ENERTRAG supplies green hydrogen generated from wind power. This green hydrogen is mixed with natural gas in the ONTRAS network, up to 20% by volume, via the existing feed-in system. The pilot plant tests what type of membranes are best suited to recover hydrogen, what quantities can be separated from the gas stream, and the degree of purity that can be achieved.

- DBI, ONTRAS, GRTgaz, MITNETZ Gas, DVGW, ENERTRAG
- Pilot plant
- Deblending –membrane separation of natural gas and hydrogen mixtures
- In operation
- Prenzlau, Germany
- http://www.grtgaz.com/en/press/press-releases/news-details/article/projet-pilote-de-prenzlau.html

Source: Peter Eichler

HyDeploy

Northern Gas Networks, Progressive Energy Ltd., Keele University, HSE – Science Division, and ITM Power

20% hydrogen blending

Blending of hydrogen and natural gas

I2019-early 2020s

Staffordsire, UK

https://hydeploy.co.uk/

HyDeploy is a hydrogen project designed to help reduce UK CO_2 emissions and reach the net-zero target for 2050. HyDeploy aims to demonstrate that blending natural gas with 20% hydrogen volume is safe and a greener alternative to natural gas. Furthermore, the project is providing evidence that cooking and heating appliances can take the blend without any changes needed. HyDeploy @ Keele is the first stage of this three-stage programme. In November 2019, the UK Health & Safety Executive gave permission to run a live test of blended hydrogen and natural gas on part of the private gas network at the Keele University campus in Staffordshire.

HyDeploy is the first project in the UK to inject hydrogen into a natural gas network. Once the Keele stage has been completed, HyDeploy will move to a larger demonstration on a public network in the North East. After that, HyDeploy will have another large demonstration in the northwest. These demonstrations are designed to test the blend across a range of networks and customers so that the evidence is representative of the UK as a whole. With HSE approval, and success at Keele, these phases will go ahead in the early 2020s.

THyGA project

ENGIE, DGC, GWI, Gas.be, CEA, DVGW, BDR Thermea Group, Electrolux, GERG

Studies and analysis, development of certification protocol on blending

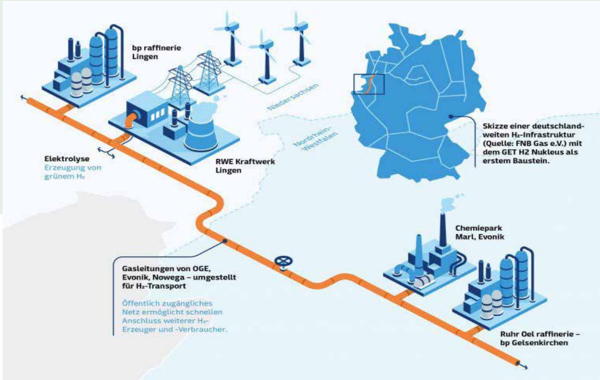
Demonstration project, 2020-2023

Europe

https://thyga-project.eu/

The THyGA project (Testing Hydrogen admixture for Gas Applications) sets out to develop and communicate a detailed understanding of the impact of blends of natural gas and hydrogen on end-use applications, specifically in the domestic and commercial sectors. The THyGA project has been selected for funding as part of the 2019 FCH JU work programme. The main goal of the project is to enable the wide adoption of H2NG (hydrogen in natural gas) blends by closing knowledge gaps regarding technical impacts on residential and commercial gas appliances. The project consortium will identify and recommend appropriate codes and standards that should be adopted and develop a strategy for addressing the challenges for new and existing appliances. The project is being coordinated by ENGIE. Eight other partners from six European countries (DGC, Electrolux, BDR, Gas.be, CEA, GWI, DVGW-EBI, and GERG) will work together on this project over 36 months. The consortium includes laboratories, gas value chain companies, manufacturers representing different applications (cooking, heating), and an international association. It will be supplemented by an advisory panel of manufacturers and gas companies.

Hydrogen infrastructure



Source: GetH2Nukleus

GetH2Nukleus

The GET H2 partners BP, Evonik, Nowega, OGE, and RWE Generation want to jointly build the first publicly accessible hydrogen infrastructure. The GET H2 Nucleus project will combine green hydrogen production with industrial customers in Lower Saxony and North Rhein Westphalia. The approximately 130 km network from Lingen to Gelsenkirchen will be a hydrogen network with non-discriminatory access and transparent prices. By coupling the continuous production of green hydrogen on an industrial scale, the transport and storage in existing infrastructure, and the continuous acceptance by industry, the GET H2 Nucleus aims to contribute to a reliable and sustainable hydrogen economy in Germany. Production of green hydrogen and supply to customers is scheduled to start in 2023. The green hydrogen is to be produced from wind power in Lingen, Lower Saxony. An electrolysis plant with a capacity of more than 100 $MW_{el\ in}$ is to be built at the RWE power plant site in Lingen. Existing gas pipelines of the transmission system operators Nowega and OGE will be converted to dedicated hydrogen infrastructure able to transport 100% hydrogen. This infrastructure will be used to transport the produced hydrogen to chemical parks and refineries in Lingen, Marl, and Gelsenkirchen. These companies will use the green hydrogen in their production processes, thereby reducing their CO_2 emissions.

- OGE, BP, Evonik, Nowega, RWE Generation
- 130 km hydrogen pipeline, 100 $MW_{el\ in}$ electrolyser
- Electrolysis and retrofitting of existing pipelines
- In development, hydrogen production scheduled to start in 2023
- Lower Saxony and North Rhein Westphalia, Germany
- https://www.get-h2.de/projekt-nukleus/

MosaHYc

- GRTgaz, Creos Deutschland
- 70 km hydrogen infrastructure
- Retrofitting of existing pipelines
- In development, investment decision expected in 2022
- Germany and France
- http://www.grtgaz.com/en/press/press-releases/news-details/article/hydrogene-lancement-du-projet-mosahyc.html

GRTgaz and Creos Deutschland are collaborating to create a new regional and cross-border dedicated hydrogen transmission network, connecting Saar (Germany), Lorraine (France), and the Luxembourg border. The MosaHYc (Mosel Saar HYdrogen Conversion) project will focus on retrofitting two existing natural gas pipelines into a 70 km pure hydrogen infrastructure, capable of transporting up to 20,000 m^3/h (60 MW) of pure hydrogen. The infrastructure is aiming to form the backbone of a regional and cross-border hydrogen hub, creating a hydrogen valley between the three countries and supporting further hydrogen developments foreseen in nearby industrial clusters. GRTgaz and Creos Deutschland will cooperate with the national authorities on the technical aspects and political and regulatory framework to allow for an investment decision by 2022.

European Hydrogen Backbone

- Various EU gas transmission companies
- Plan for 23,000 km hydrogen network
- Retrofitting of existing pipelines (75%), new infrastructure (25%)
- Plan for development between 2020 and 2040
- Europe
- https://gasforclimate2050.eu/news-item/gas-infrastructure-companies-present-a-european-hydrogen-backbone-plan/

A group of 11 European gas infrastructure companies from nine EU member states developed a plan for a dedicated hydrogen transport infrastructure. The plan shows that existing gas infrastructure can be retrofitted to transport hydrogen at an affordable cost. The plan, developed by Enagás, Energinet, Fluxys Belgium, Gasunie, GRTgaz, NET4GAS, OGE, ONTRAS, Teréga, Snam, and Swedegas, foresees a hydrogen network gradually emerging from the mid-2020s onwards to an initial 6,800 km pipeline network by 2030, connecting hydrogen valleys in Europe. By 2040, a hydrogen network of 23,000 km is foreseen, 75% of which will consist of converted/retrofitted natural gas pipelines connected by new pipeline infrastructure (25%). The network can be used for large-scale hydrogen transport over longer distances in an energy efficient way, also considering hydrogen imports. The cost of the network is estimated between €27 billion and €64 billion, with a levelised cost between €0.09 and €0.17 per kg of hydrogen per 1,000 km. The wide range of the estimate is due to uncertainties in location-dependent compressor costs.

Green Octopus Project

- Gasunie, Fluxys, ENGIE, Port of Antwerp, SalzgitterAG
- 2,000 km hydrogen backbone
- Retrofitting of existing pipelines
- Planning phase
- Germany, Belgium, France, the Netherlands, Denmark
- https://www.hydrogen4climateaction.eu/projects

The Green Octopus (IPCEI) project focuses on creating a 2,000 km hydrogen backbone between France, Belgium, Germany, and the Netherlands by repurposing existing pipelines. This backbone would serve hydrogen supply and demand facilitated by the ports and industrial clusters in the region, integrating energy systems and coupling sectors. By maximising the implementation of offshore wind energy, 6 GW of wind-based hydrogen could be produced and transported through the pipelines. The Green Octopus Project aims to drive cross-border solutions and encourage collaboration between companies and member states.

HyBalance

AirLiquide, Centrica energy trading, Copenhagen Hydrogen Network, Cummins, Hydrogen Valley, Ludwig-Bölkow-Sytemtechnik, Energinet, Akzo Nobel, Sintex

1.2 $MW_{el\ in}$ PEM electrolyser, 230 Nm^3/h in hydrogen production

Electricity storage in the form of hydrogen

In operation, since 2018

Hobro, Denmark

www.hybalance.eu

The HyBalance facility, located in the north of Denmark, was inaugurated in 2018. The plant produces hydrogen with a 1.2 $MW_{el\ in}$ PEM electrolyser with electricity from the grid. The facility is the main component of the HyBalance project, which aims to demonstrate renewable hydrogen use in energy systems. The technology showcase project received both European and Danish funding – through the FCH JU and the Danish funding programme. The project has demonstrated that it is possible to store electricity on a larger scale in the form of hydrogen produced through PEM electrolysis. The PEM electrolysis technology showed it was able to achieve a high level of availability and efficiency, making it a good candidate to help balance the electricity grid. By September 2020, the HyBalance facility produced 120 tons of hydrogen; 50% of the hydrogen was delivered through a pipeline to an industrial complex close to the facility. The remaining 50% of the hydrogen was delivered by tube trailers to other industries and for use in the transport sector. The HyBalance project was developed by a consortium with multiple parties, led by Air Liquide.

Demo4Grid

Fen Sustain Systems GMBH, Aragon Hydrogen Foundation, IHT, Instrumentacion y components SA, MPREIS Warenvertriebs GMBH

4 $MW_{el\ in}$ pressurised alkaline electrolyser (PAE) electrolyser

PAE

Demonstration project, 2017-2022

Völs, Austria

www.demo4grid.eu

In the EU project Demonstration for Grid Services (Demo4Grid), a large single-stack alkaline-pressure electrolysis plant is set up and tested in Tyrol (Austria) to regulate the regional electricity network, and generate green hydrogen. The Demo4Grid project is aiming to demonstrate the PAE technology to provide balancing services to the electricity system in a commercial setup with real operational and market conditions. The electrolyser should regulate the electricity network of the regional electricity supplier TIWAG and heat the Therese Mölk Bakery of the regional food producer and trader MPreis with green hydrogen. In order to validate existing significant differences in local market and grid requirements Demo4Grid choose to setup a demonstration site in Austria to demonstrate a viable business case for the operation of a large-scale electrolyser adapted to specific local conditions that will be found throughout Europe. The Green Energy Center Europe in Innsbruck is the catalyst and regional dissemination point for this project, working together with European project partners over a 5 years project time.

REMOTE

- Ballard, Hydrogenics, PowiDian, Enel Green Power, Politecnico di Torino, IRIS, Tronderenergi, Enie Eps, SINTEF, CERTH, Orizwn Anonymh Techniki
- Four demo sites
- Fuel cells-based hydrogen energy storage solutions
- Demonstration project, 2018-2021
- Italy, Greece, Norway
- www.remote-euproject.eu

REMOTE (Remote area Energy supply with Multiple Options for integrated hydrogen-based Technologies) is an EU-funded project aimed to demonstrate the technical and economic feasibility of two fuel cell-based hydrogen energy storage solutions (integrated power-to-power system, and non-integrated power-to-gas + gas-to-power system). Four demonstration units supplied by renewable electricity are currently developed in isolated microgrids or off-grid remote areas in two locations in Italy, one in Greece, and one in Norway.

H100 Fife – Hydrogen grid for heating of residential area

- SGN
- 300 households
- Green hydrogen domestic heating network
- In development, fully operational in 2022/2023
- Levenmouth, Scotland
- https://www.sgn.co.uk/h100fife

H100 Fife is a development plan by SGN for a green hydrogen heating network. The British gas distribution company aims to employ a direct supply of renewable power to produce hydrogen for domestic heating. In the project's first phase, the green hydrogen network will heat around 300 local homes. The hydrogen will be produced by an electrolysis plant, powered by the Offshore Renewable Energy Catapult's nearby offshore wind turbine. The system will be designed and built based on the same safety and reliability standards as expected from the current gas system. An onsite storage unit will hold enough hydrogen to ensure supply during peaks of high demand and low production. H100 Fife will also play an important role in gathering insights regarding customer interest towards hydrogen and low-carbon heating solutions.

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