RESEARCH REPORT
Thinking ahead for Europe

No. 2019/03, August 2019

The future of gas in Europe:

Review of recent studies on the future of gas

Mihnea Cătuţi, Christian Egenhofer & Milan Elkerbout

Abstract

In the context of the EU transition to a low-carbon economy, the gas industry will face significant transformations over the next decades up to 2050 and beyond. A substantial number of studies on the future of gas have been published recently, which each come to different outcomes and projections, in some cases even to radically different conclusions. This report reviews the findings of the most recent reports on the evolution of the EU gas market foreseen up to 2030 and 2050 with the aim of identifying the different outcomes and examining the reason for divergent results. Up until 2030, the demand for natural gas is projected to remain stable or to decrease slightly. Switching to natural gas-fired power plants can represent a short and medium-term solution for countries going through a coal phase-out. Gas can also contribute to the flexibility in the power sector necessitated by the increasing share of variable renewables such as wind and solar. The demand projections for 2050 show more significant differences between results. The higher the assumed 2050 GHG emissions reduction target in the scenario, the lower the projected demand for natural gas will be. As the EU moves towards its 2050 targets, a mix of low and zero-carbon gaseous fuels, such as biogas, biomethane, (blue and green) hydrogen, and synthetic methane, are expected to replace natural gas. Biogas and biomethane are currently the most commercially ready alternatives to natural gas and require no major infrastructural upgrades. However, their production will be limited by the availability of feedstock and regional contexts. Hydrogen can also be produced to replace the use of natural gas. Delivering high volumes and developing a fully-fledged hydrogen infrastructure is improbable without blue hydrogen, produced from natural gas and using carbon capture and storage (CCS). Blue hydrogen would help in ramping up the production of hydrogen in initial phases, yet its production is not a carbon-neutral process – even with the use of CCS technology. Green hydrogen is produced from renewable sources and therefore requires high volumes of affordable renewable electricity and the further development and cost reduction of electrolyser technology. The demand for low and zero-carbon gaseous fuels will depend on their end-uses in the power, buildings, industrial and transport sectors. This will be determined by costs, convenience, availability, acceptability and the infrastructure choices of the EU and its member states. This will also have implications for the existing gas networks and their operators, some of which will need to be adapted. Policymakers will face the challenge of an increasingly decentralised management of distribution.

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978-94-6138-744-8

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Introduction

Under the Paris Agreement the EU has committed to reducing its greenhouse gas emissions (GHG) by at least 40% by 2030 for its first nationally determined contribution (NDC). The recent legislative acts of the Clean Energy for All Europeans Package also set binding EU collective targets of 32% for renewable energy and 32.5% for energy efficiency improvements (both up from 27% as agreed by the European Council in 2014). The implementation of these current policies should lead to a 45% decrease in GHG emissions by 2030 compared to 1990 levels. While these policies will continue to have an impact after 2030, they will be insufficient for meeting the temperature targets of the Paris Agreement (European Commission 2018, p. 5). The IPCC (2018) Special Report published in October 2018 assessed the risks associated with global temperature increases of 1.5°C, compared to the 2°C target that informed EU policy before the Paris Agreement. This has also led to a discussion on updating the EU's mid-century climate policy, which currently aims for a reduction in GHG emissions of 80-95% by 2050.

In November 2018, the European Commission released its Long-Term Strategy (European Commission, 2018), which presents a set of scenarios for the decarbonisation of the EU's economy and puts forward the Commission's vision for achieving net-zero GHG emissions in the EU by 2050. The eight scenarios designed for this strategy vary in the intensity of application of electrification, hydrogen, e-fuels as well as energy efficiency measures. The Eurostat (2018) analysis shows that unabated emissions from natural gas will become increasingly incompatible with climate targets. Currently, natural gas represents over 23% of total EU primary energy consumption. Under the Commission scenarios, the share of natural gas in the energy mix is expected to decline, raising questions about what new gas infrastructure investments may be required.

While increasing levels of electrification represents a necessary decarbonisation strategy for several sectors, electricity will not be able to cover all EU energy needs in the future, especially in some sectors that are difficult to decarbonise.[1] Renewable methane[2] and hydrogen will likely play an important role, especially for industrial energy demand where it is used as feedstock, for the power sector by providing flexibility and storage, for heating in the building sector, and as fuels in the transport sector. We can assume that the future role of the EU gas market and infrastructure will be determined by the ability of the sector to decarbonise and to switch to low and zero-carbon forms of gas. Demand for gas until 2030 is stable, and the choices made in the next few years will determine the future of gas up to 2050 and beyond. As low and zero-

[1] See European Parliament (2018), p. 17, European Commission (2018), p. 12, Eurelectric (2018), p.42.

[2] By 'renewable methane' this report understands biogas, biomethane, syngas, synthetic methane. Together with hydrogen, these gases represent the main solution for decarbonising natural gas.

carbon forms of gas have a key role to play after 2030, they have a limited time frame to become market-ready. Table 1 provides a set of definitions for a multitude of gaseous fuels.

Table 1. Types of Gas

Natural Gas	- CH_4 from fossil fuel sources	
Biogas	- a mixture of gases resulting from the biological breakdown of organic material in the absence of oxygen	- *biogas* contains 50-65% methane and CO_2
Biomethane	- purified biogas that can be used interchangeably with natural gas, usually obtained from anaerobic digestion or thermal gasification	- *anaerobic digestion* is a process that produces *biogas* from biomass. Biogas containing around 50-65% methane is then purified into biomethane - *thermal gasification* is used to break down woody biomass or cellulose into synthetic gas, called *syngas*. The process is completed through methanation or separation to obtain biomethane
Hydrogen	- H_2 that is usually obtained either through natural gas steam reforming, as a by-product of chlor-alkali electrolysis and in smaller amounts from the electrolysis of water	- *grey hydrogen* is produced in industrial processes from natural gas with no carbon capture - *blue hydrogen* is produced from natural gas steam reforming using CCS[3] - *green hydrogen* is produced through the electrolysis of water using renewable electricity. Green hydrogen has no lifecycle GHG emissions, apart from those stemming from the materials used[4]
Power-to-methane	- *synthetic methane* produced through the hydrogenation of carbon dioxide	- it can be obtained as an additional step to electrolysis[5]

[3] CCS refers to Carbon Capture and Storage. CCU refers to Carbon Capture and Utilisation. The term CCUS is also used to refer to Carbon Capture, Utilisation, and Storage.

[4] Low-carbon hydrogen may also be produced from other sources such as nuclear and biomass. There are currently no established colours for hydrogen from these sources. IEA (2019), p.37-66 gives an overview of hydrogen producing methods and technologies.

[5] The conversion of electrical power to either hydrogen or synthetic gas is usually referred to as Power-to-Gas.

In recent years, a large number of studies on the future of gas in the EU have been published. This report represents a review of this literature with the aim of highlighting its main results, understanding the causes for differences and, as a result, identifying key policy questions.[6] The focus is on the EU. The evolution of the global gas sector may be different; developing economies account for 80% of the projected growth in gas demand, led by China, India and other Asian countries (IEA, 2017).

Summary of Results

This report is structured in three parts. Each section identifies a number of conclusions including open questions relevant for policy-making purposes.

Part 1: Demand for Gas in 2030

- The demand for natural gas until 2030 is likely to be stable (or slightly decrease).
- Natural gas can provide flexibility for variable renewable electricity, given its ability to store energy at large scale and across seasons. However, the extent to which gas will be required as a source of flexibility remains uncertain.
- Switching to gas-fired power plants can provide short and medium-term solutions for countries facing a coal or nuclear phase-out. Investments in natural gas infrastructure will need to take into account the lifetime of gas infrastructure projects to avoid the risk of becoming stranded assets.
- Gas switching from coal in the power sector can decrease CO_2 emissions and local air pollution. However, in order to ensure a genuine contribution of natural gas to decarbonisation, methane leakage must be accounted for and reduced.

Questions:

- What are the long-term implications of a short and medium-term switch to natural gas and the subsequent investments in infrastructure and gas-fired power generation?
- In the context of a potential coal to natural gas switching in power generation, can methane leakage be realistically accounted for and controlled in order to safeguard the greenhouse gas emissions benefits expected from such a switch?
- What role will natural gas play as a source of flexibility for renewable energy? How does natural gas compare to other flexibility options such as those related to demand response, battery storage, grid reinforcement and operation, or adjustment to market rules?

[6] The analysis and findings of this paper are based on the projections and results of different reports from a wide range of organisations and institutions. Such scenarios, often used to investigate various possible energy futures and reduce uncertainty, have, however, been criticised for only being able to provide limited insights into future energy developments (see for example Laugs and Moll, 2017). Therefore, such projections come with a significant degree of uncertainty.

Part 2: The role of 'gas' in 2040-2050

- Projections of demand for gas in 2040 and 2050 vary significantly between scenarios, but the majority indicate a continuous decline in consumption.
- The share of *natural* gas will strongly decrease, while the overall demand for gas, including multiple other 'gaseous fuels' (biogas, biomethane, hydrogen, synthetic methane) will depend on a number of factors including costs, availability, acceptability, end-uses, infrastructure developments and policy decisions.
- The results of scenario projections vary based on the assumptions made about the levels of GHG emissions reduction. Scenarios targeting at least -80% GHG emissions foresee a strong decrease in *natural* gas consumption, but only scenarios consistent with a 95-100% reduction in GHG emissions project a near-complete phase-out of unabated *natural* gas. Achieving net-zero GHG emissions in the EU by 2050[7] will almost certainly require the development of renewable and low-carbon forms of gases such as biogas, biomethane, hydrogen or synthetic methane to replace much of the natural gas consumption.
- The future position of natural gas in the fuel mix beyond the 2040-2050 period (for example for the production of blue hydrogen) will be linked with the large-scale deployment of carbon capture and storage technology. However, some studies show caution about the perspectives of CCS and CCUS, given the currently limited progress in CCS deployment, especially in sectors such as power and heating.
- Biogas and biomethane are the most commercially ready forms of renewable gas, but production potential might be limited by the availability of feedstock. Estimations of hydrogen production depend on assumptions about the level of technological development and scale-up and the price of natural gas (for blue hydrogen) or the price and availability of renewable electricity and the evolution of the cost of electrolysis (for green hydrogen), as well as the price of carbon. The prospects for hydrogen production differ according to the role and scale assumed for blue hydrogen. The relatively lower costs of blue hydrogen – compared to green hydrogen – would allow the development of a fully-fledged hydrogen infrastructure. Blue hydrogen, however, is not carbon neutral. The potential for synthetic methane produced through Power-to-Methane depends on the level of green hydrogen production and to the price and availability of stored CO_2. Given the associated conversion losses, the production potential for synthetic methane is lower than that of biomethane and hydrogen.

Questions:

- Which of the assumptions made in scenario designs are the most realistic for GHG emissions reduction for 2050?
- What level of CCS deployment can be assumed?
- What is the potential for renewable gas and hydrogen production by 2050 and at what cost?

[7] The EU has not yet decided on a 2050 target. The space for gas will depend on how such a target eventually will be formulated, e.g. gross versus net, domestic versus international reduction etc.

- What is the role of blue hydrogen for a fully decarbonised EU economy in 2050?
- How much renewable electricity will be available for green hydrogen production and at what cost?

Part 3: End-uses in the long term and implications for network development

- The future demand for gas in 2050 will largely be determined by the level of market penetration of different 'gaseous fuels', i.e. biogas, biomethane, hydrogen and synthetic methane, in the power, buildings, industrial and transport sectors. The end-uses and market penetration of these fuels will depend on cost-competitiveness and local availability.
- In the context of increasing electrification and integration of variable renewable energy sources, hydrogen, biogas and biomethane can play an important role in the future power system. Power-to-Gas is an option for absorbing surplus renewable electricity, thereby avoiding curtailment. Hydrogen can address the challenge of seasonal storage, i.e. peak demand periods particularly during winter, but it can also represent a dispatchable source in power generation. Biogas and biomethane-fired combined cycle gas turbines may be used to provide peak capacity.
- In the buildings sector, heat pumps will likely be the preferred solution for the heating and cooling of new buildings. Meanwhile, in the existing building stock hydrogen and biomethane represent options for decarbonising the current heating systems. Hybrid heat pumps using both electricity and gas can also provide competitive solutions. In district heating systems, renewable methane and hydrogen are likely to compete with large-scale heat pumps and with sector-coupling solutions such as residual industrial heat. Simultaneously, energy efficiency and insulation measures will reduce the overall energy demand in buildings.
- In the industrial sector, the overall energy demand is expected to decrease as a result of energy efficiency measures and structural changes in the European energy-intensive industry. Based on local availability, hydrogen and biomethane will be needed for reducing the GHG emissions in producing high temperature heat and for feedstock for some industrial processes where few other alternatives exist.
- In the transport sector, light-duty transport and cars appear to be mostly decarbonised through the introduction of battery electric vehicles. Fuel cell electric vehicles may also provide competitive solutions for this segment and for trucks and buses. Heavy-duty long-distance transport will likely remain dependent on liquid fuels such as biofuels, e-liquids, biomethane-based LNG and compressed natural gas (CNG), and hydrogen. The aviation sector will require a mix of bio jet fuels and synthetic kerosene. Therefore, hydrogen and renewable methane will have applications for different segments of the transport sector, but they will also compete with other alternative fuels in each of these categories. The development of refuelling infrastructure will be a key component for their expansion.
- Different decarbonisation options such as natural gas switching to biomethane or hydrogen will be crucial in some countries and regions, but marginal or irrelevant in others. This will be based on where gas is produced and consumed, how far it will need to be transported

and the region-specific costs for each technology. At the same time, pipelines will need to be adapted to accommodate different types of fuels based on local context, posing new, yet different challenges to distribution (DSOs) and transmission companies (TSOs). EU policymakers will also increasingly face the challenge of more decentralised management of distribution.

Questions:

- Will methane and hydrogen compete for the same markets in 2050? In what sectors will each of them be most relevant?
- What are the implications of future end-uses of gaseous fuels for transmission and distribution strategies?

Part 1: Demand for Gas in 2030

The dynamics of the demand for gas in the EU have been changing in recent years. The decline in demand for natural gas that has been observed over the past decade can be attributed to a number of factors: i) decreased industrial activity as a result of the economic crisis; ii) the price of natural gas compared to coal and renewables in the power sector; iii) the increased share of renewable energy and electricity storage as a result of government policy, cost reduction and technological development. This has created uncertainty about the future demand for natural gas in the EU, which is reflected in the successive scaling down of gas demand projections for 2030 made by the European Commission and the International Energy Agency (IEA) in its calculations for the yearly World Energy Outlook.[8] The decline that followed the peak demand for natural gas of 544bcm reached in 2010 has been partially reversed since 2014 with yearly increases in EU gas consumption of 4-7% (IEA, 2018, p. 200). This may, however, have been partly the result of a succession of isolated events, making it unclear whether this is related to an underlying change to market fundamentals.[9]

Most projections for the next decade (see Figure 1) foresee a robust demand for gas and potential increases in pipeline and LNG imports in Europe, due to decreasing domestic gas production. In the 2030 demand projections, the term ‘gas’ is unambiguous, referring almost entirely to natural gas, i.e. CH_4. During this time frame, natural gas switching can represent an option for the decarbonisation of the power sector of member states that are heavily dependent on coal. In Germany, for example, as a result of the planned nuclear and coal phase-outs, it is expected that natural gas will increase its share in the electricity sector by 2030 (Agora Energiewende, 2018, p. 29). Numerous other European countries[10] have also announced their plans to phase coal out over the next decade. As a result, significant coal generation capacity in Europe needs to be replaced by other sources of energy. A potential increase in the price of ETS allowances may further accelerate a switch from coal to gas in the electricity sector. Compared to coal, the combustion of natural gas generates 40% fewer CO_2 emissions per each unit of energy output and fewer emissions of the main air pollutants, such as fine particulate matter (PM2.5), sulphur dioxide (SO_2) and nitrogen dioxide (NO_2) (IEA, 2017, p. 401).

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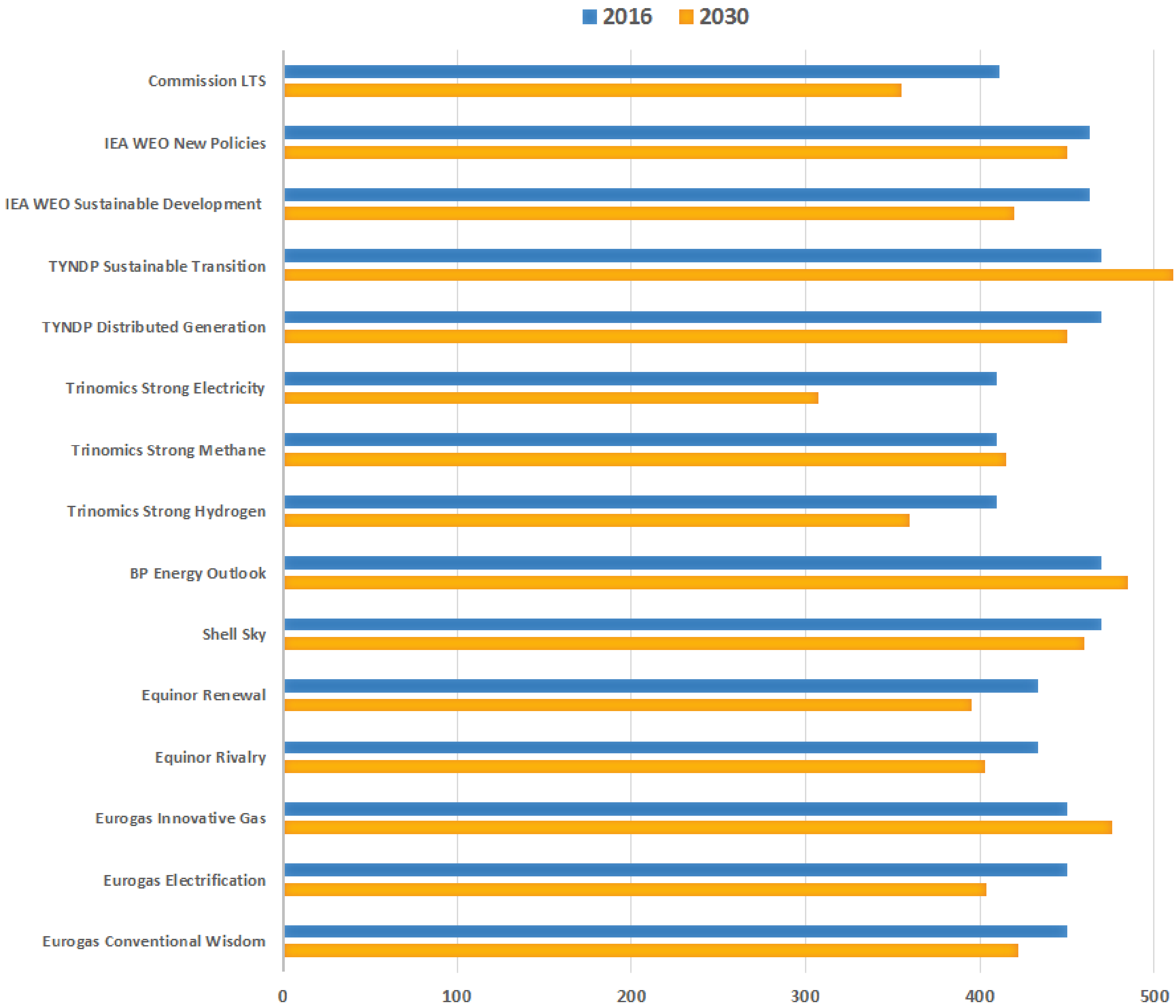
[8] See Stern (2017a), p. 7-8. IEA decreased its 2030 yearly gas demand projection for the EU in its World Energy Outlook from 684bcm in 2008 to 521bcm in 2016.

[9] As explained in the IEA (2018b) gas forecast for 2023. The observed growth in demand for natural gas in Europe has been caused by temporary nuclear shut down for maintenance in France in 2016-2017 and the decrease in hydropower production in southern Europe. Both nuclear facilities in France and hydro power production in southern Europe are expected to return to normal levels, leaving little room for growth for gas demand.

[10] See IEA (2018b), p. 53. France announced a coal phase-out by 2022-2023, Austria, Ireland and Italy by 2025, and Denmark, Finland, the Netherlands and Portugal by 2030. Belgium already closed its last coal-fired power plant in 2016.

Figure 1. Projected gas demand for 2030 (bcm)



Source: Commission (2018); IEA (2018); TYNDP (2018); Trinomics (2018); BP (2019); Shell (2018); Equinor (2018); Eurogas (2018).

However, analyses of the future of gas also need to incorporate better the challenges related to methane leakage – upstream and downstream – which represent a major concern for climate change. Leakages can occur across the entire gas chain and the sources can be both unintentional (for example in low pressure distribution systems that still use cast iron pipes) and purposeful emissions (when gas is vented rather than flared). The extraction, processing and transmission over long distances of natural gas are estimated to account for approximately 60-80% of current methane leakages (Ecofys, 2018, p.12). The IEA's 2017 World Energy Outlook concluded that this phenomenon amounts to up to 1.7% of total natural gas consumed. Methane is a powerful greenhouse gas, as the IPCC estimates that it is 34 times more potent than CO_2 over a 100-year period,[11] while Eurostat uses a global warming potential (GWP) factor for methane of 25.[12] Based on the assumed GWP, as little as 3% methane leakage could cancel out the emissions benefits of switching from coal to natural gas in power generation (IEA, 2018, p. 417). Further research into the effect that methane has on global warming is still necessary to fully understand the phenomenon. The current rate of methane that is leaked might be underestimated and improperly accounted for (e.g. Grubert and Brandt, 2019, p. 760). The European Commission has proposed to address this concern in the Governance Regulation,[13] and the solutions for this issue are being discussed collectively in Europe, for example through the Madrid Forum.[14]

Natural gas can also provide flexibility solutions for the electricity sector, in the context of an increasing variable renewables share, given its ability to store energy at large scale and across seasons. In fact, a share of the recent inter-year gas consumption fluctuations has been attributed to the seasonal variability of renewable sources in the electricity sector, which emphasises the role of gas as a source of flexibility.[15] However, various other sources of flexibility exist, such as in generation, storage, improved interconnectivity, demand response and integration of different sectors.

While acknowledging a potential role for gas, the IRENA (2018, p.23) report emphasises the necessity for improvements in congestion management and strengthening of the grid. If more EU interconnectors were built and operated at high capacity by 2030, cross-border market integration could further decrease the flexibility need for renewable power generation. Integration of short-term and balancing markets and aggregation could also significantly diminish the need for flexibility.[16] Therefore, the extent to which natural gas will be needed for this purpose remains uncertain.

Any new investments in natural gas also need to consider the developments in the sector after 2030. Despite its advantages compared to coal, natural gas is also a fossil fuel and its combustion still produces CO_2 emissions, which may not be fully eliminated even with the use of CCS.[17] This may become more problematic in the context of stricter future GHG emissions reduction targets. Consequently, in a 2050 net-zero emissions energy system, the future of the gas industry is linked with its ability to be fully decarbonised. Without this, the future of gas

[11] See https://unfccc.int/news/new-methane-signs-underline-urgency-to-reverse-emissions.

[12] See https://ec.europa.eu/eurostat/statistics-explained/index.php/Glossary:Carbon_dioxide_equivalent.

[13] Article 16 of the new Governance Regulation of the Energy Union stipulates that the Commission shall develop a strategy for measuring and understanding the implications of methane emissions.

[14] See https://www.gie.eu/index.php/gie-publications/methane-emission-report-2019/27786-gie-marcogaz-report-for-the-madrid-forum-potential-way-gas-industry-can-contribute-to-the-reduction-of-methane-emissions/file.

[15] See SNAM (2018), p. 17. Examples given in this report include a yearly gas consumption growth of 3bcm Spain and 1bcm in Portugal in the context of lower hydropower production and a yearly gas consumption decline of 2bcm in the UK and 1bcm in Norway resulting from increased in wind power generation.

[16] See CEPS (2017) on Improving the Market Flexibility in the Electricity Sector.

[17] Even with the use of CCS technology, an estimated of up to 10% of emissions may still escape (as explained in Trinomics, 2018, p. 17).

demand will likely decline sharply after 2030 (e.g. Stern, 2017b). In the long term, renewable methane and hydrogen can provide carbon emissions-free alternatives to natural gas.

As shown in a recent IEA study (2019b), given the existing infrastructure, the EU has one of the highest potentials in the world for switching from coal to gas-fired power generation, which can provide rapid emissions reductions. However, the window of opportunity for such a choice is limited. After 2030, natural gas investments are increasingly facing the risk of stranded assets, given the long lifetime of gas infrastructure projects. New gas-powered generators have a lifespan of 20 years, large pipelines and Liquified Natural Gas projects are normally designed to run more than two decades, while storage can potentially be functional for up to 40-50 years (e.g. Stern, 2019, p. 17). In a list of Projects of Common Interest (PCIs) published by the Commission in 2017, 53 PCIs were gas projects (European Commission 2017, p.2). This raised questions about the long-term implications of these gas infrastructure investments, both in terms of potentially stranded assets and value added, for decarbonisation efforts in a long-term perspective.

Most projections indicate a decline in demand for gas by 2040 and 2050 (see Figure 2 in the next section). There may be increases in demand in individual sectors, but overall, the future consumption of gas is generally predicted to fall.[18] Europe's choice of promoting energy efficiency measures and the electrification of end-users will create further pressures on gas demand (IEA, 2018a, p. 71). As a result of forecasting a decreased demand for gas, some studies[19] do not recommend any large-scale natural gas infrastructure investments (with the exception of a few LNG terminals), as all future consumption needs can be served using the existing infrastructure. New projects may be able to improve security of supply and improve the functioning of the internal market, but investments would need to be made based on careful evaluation (IEA, 2019b, p. 71). Future investments will also need to take into account not only the future demand for gas, but also the type of gaseous fuels that need to be developed in the context of a decarbonised European economy.

[18] As explained in Trinomics (2018) p. 22. Gas consumption may increase in the power sector for providing flexibility or in the transport sector. At the same time, the demand in the heating sector will significantly decrease given improved building insulation and increases in use of heat pump technologies.
[19] See for example Set-Nav (2019).

Part 2: The role of 'gas' in 2040-2050

In the longer-term perspective, as can be seen in Figure 2, reports differ significantly in their estimations of total demand for gas by 2040 or 2050.[20] Most projections indicate a sustained decline of gas consumption in the EU. The only studies that project a slightly increased or constant demand for gas usually start from the assumption of a large-scale replacement of coal with gas plants and significant innovations in the gas sector. What is clear is that the share of *natural* gas will drastically decrease, as the make-up of the gas sector will become more complex with the usage of multiple 'gaseous fuels' (i.e. natural gas, biomethane, biogas, synthetic gas, hydrogen).

Gas demand projections and GHG reduction targets

Studies generally show a long-term correlation between the assumed GHG emission reduction target and the expected demand for gas (especially natural gas).[21] The level of the GHG reduction target also has a strong effect on the types of gas that will be consumed in 2050. In scenarios with GHG emission reductions of less than 80%, demand for gas is projected to be constant or to slightly increase; in these scenarios, natural gas remains an important energy carrier. These projections generally represent business-usual scenarios that reflect current policies and market trends. However, now, the EU 2050 GHG emissions reduction target is already 80-95%. Therefore, for the purposes of this report, scenarios that do not create the conditions for at least an 80% reduction in GHG emissions are disregarded as insufficiently ambitious and are only used for comparative purposes.

Scenarios targeting at least -80% GHG emissions generally project a decline in gas consumption. An important distinction can be drawn between scenarios that assume GHG emissions reductions of 80% and scenarios that start from the premise of a 95-100% reduction in GHG emissions. Stronger decarbonisation scenarios imply not only a combination of energy efficiency measures, electrification, and technological developments, but also require behavioural changes at a societal level. Both categories foresee a big decrease in natural gas consumption, but only scenarios consistent with a 95-100% reduction in GHG emissions project the nearly complete phase-out of natural gas.

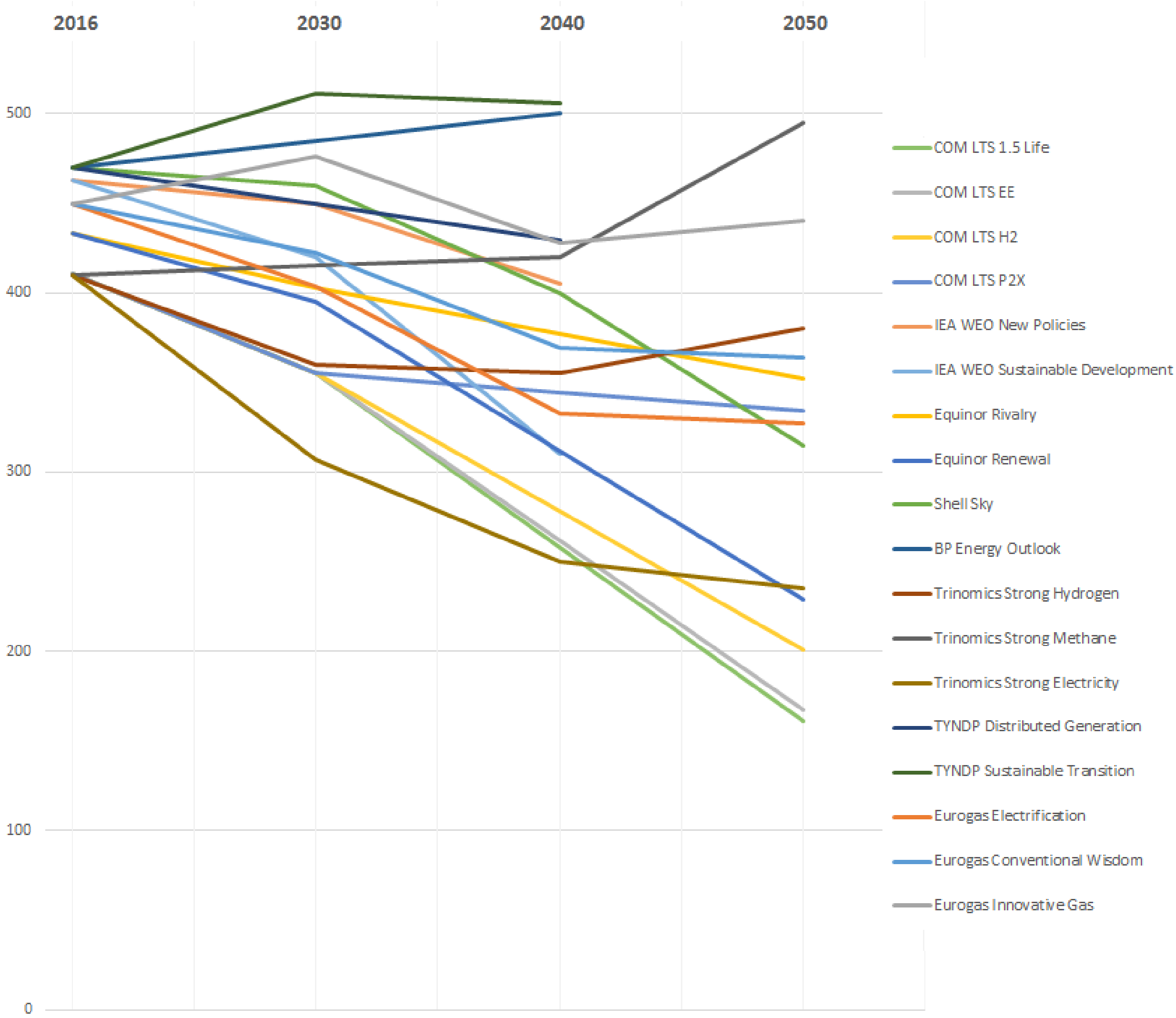
When it comes to total demand for gaseous fuels in general, the picture is far more complex. A good example of this can be seen in the scenario analysis conducted in the European Commission's long-term strategy (see Figure 3). The 1.5TECH and 1.5LIFE scenarios, which are designed to obtain a 100% GHG emissions reduction, estimate higher demand than some of the -80% GHG scenarios that do not focus on a significant evolution of a particular form of gas.

[20] Some studies only communicate projections for 2040 or for 2050. For studies that only calculate projections until 2040 it can be difficult to understand which scenarios would meet 2050 targets and what assumptions are made about the 10-year period they do not cover until 2050.

[21] Trinomics (2018) shows that among the reports it analysed, 94% of the scenarios assuming GHG reductions greater than 95% project a decrease in gas demand up to 2050, compared to 67% of scenarios assuming an 80% decrease and 29% of scenarios that achieve GHG reductions of less than 80%.

Among these, the EE scenario assumes deep energy efficiency gains in all sectors of the economy, CIRC assumes an increased resource and material efficiency,[22] and ELEC assumes the electrification of all sectors.[23] Therefore, achieving net-zero GHG emissions by 2050 requires the development of low and zero-carbon solutions such as biogas, biomethane, synthetic methane and hydrogen.

Figure 2. Projected gas demand in 2040-2050 (bcm) [24]



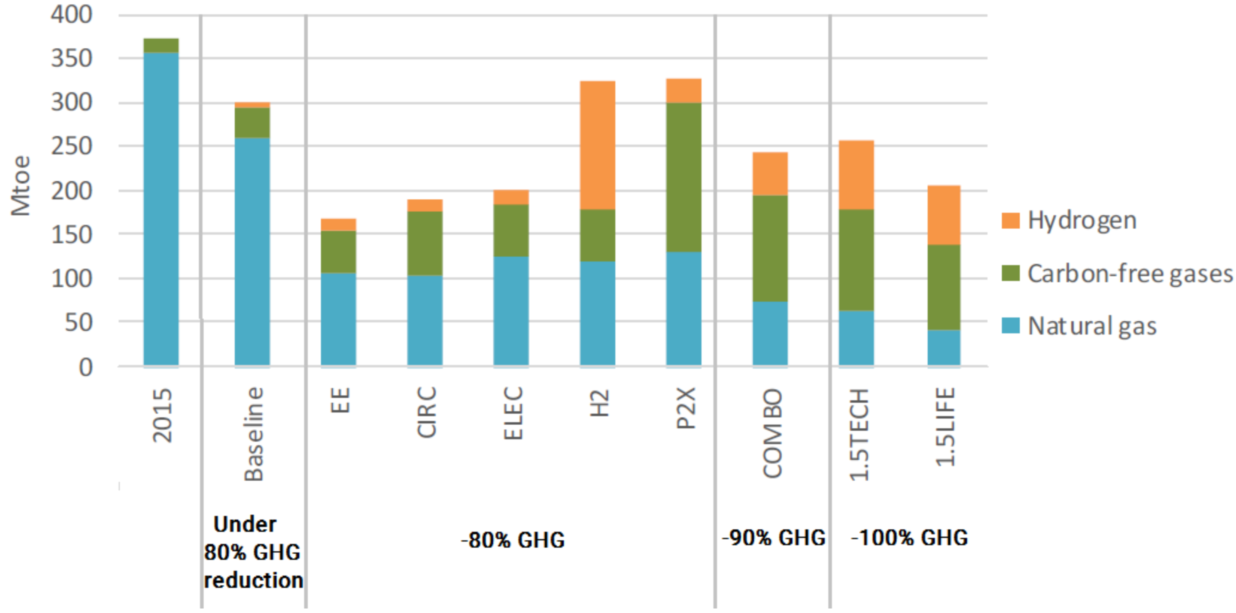
Source: Commission (2018); IEA (2018); TYNDP (2018); Trinomics (2018); BP (2019); Shell (2018); Equinor (2018); Eurogas (2018).

[22] EE and CIRC scenarios assume the greatest decreases in primary energy consumptions of 50% and 45%, respectively.

[23] ELEC assumes a 53% share of electricity in the final energy consumption, compared to 41% for P2X and 43% for H2.

[24] Such a compilation of different studies is only indicative of the general picture of gas demand estimations. Statistical and methodological differences between the studies prevent a perfect comparison. Gap-filler data has been added by the author for studies that give demand projections for 2040, but not for 2050.

Figure 3. Projected consumption of gaseous fuels in 2050 in the European Commission Long-term Strategy[25]



Source: European Commission (2018), p. 85.

Most scenarios deemed in line with the Paris Agreement commitments (usually at least 80% reduction in GHG emissions by 2050) that are less ambitious than scenarios approaching net-zero emissions also project a decrease in demand for gas and a change in the make-up of the gaseous fuels. Nonetheless, while they foresee a prominent role for renewable methane and hydrogen, natural gas would still be consumed given its cost advantage when compared to other gaseous fuels. As the architecture of the Paris Agreement supports an increase in the level of ambition over time, EU member states are debating a potential commitment to a full decarbonisation of the economy by 2050. More ambitious climate change goals that may be agreed at the EU-level could generate additional pressures on the gas industry to decarbonise its products if it seeks to remain relevant.

Development and scale up of CCS

The development and large-scale deployment of CCS technology is essential for the future use of *natural* gas and for the production of blue hydrogen.[26] A sensitivity analysis conducted by Equinor (2018, p. 19) to investigate the viability of a 2°C scenario showed that without any new CCS technology developments, an additional 9% increase in wind and solar capacity combined with high energy efficiency improvements in the industrial sector would be required to

[25] Carbon-free gases refers to biogas, e-gas and waste-gas.

[26] It should be noted that Steam Methane Reforming is not the only technology that can be used to obtain hydrogen from CH_4. Pyrolysis is a developing technology that decomposes methane into hydrogen and solid carbon. One of the potential advantages of pyrolysis compared to steam methane reforming is that the resulting carbon is solid rather than gaseous, therefore it does not require complex storage or the development of CCS. For a more detailed analysis see Pöyry (2019).

compensate. The IPCC (2018) estimates that the Paris Agreement target of 2°C would be twice as expensive to reach without the use of CCS.

However, scenarios with an over-reliance on significant CCS development in their assumptions for scenario design can have drawbacks.[27] Concerns have been expressed about the progress in the development of CCS projects in some sectors, which, with the exception of some notable projects, has been limited.[28] Based on such considerations, some studies show caution when making estimations about the availability of CCS in the future. Ecofys (2018) does not make any estimations for potential natural gas with CCS, while ECF (2019) questions the viability of CCS in its scenario design, both because of cost and technological uncertainties, and residual CO_2 emissions. Higher carbon pricing or other support policies can provide incentives for CCS for large-scale emitters of carbon dioxide in the future,[29] but public perception and acceptability remain a challenge and uncertainties still exist about the overall prospects.

Production potentials and costs

Reports come to different estimations for the potential volumes of renewable methane and hydrogen and their associated costs. Projections vary mainly due to different assumptions about technology costs, deployment rates as well as the prices and availability of renewable electricity, and prices of natural gas. Figure 4 shows a comparison of various estimations of production capacity for these gaseous fuels.

Biogas and biomethane are the most commercially ready forms of renewable gas, with over 450 installations across Europe.[30] The production of biomethane has increased from 750 GWh in 2011 to 17,000 GWh (approx. 1.7bcm) in 2016. Given its maturity level, few scenarios put a high priority on significant future developments in the production methods of biomethane (Trinomics, 2018, p. 20). As a result, biomethane-centred scenarios are not as numerous and diverse as scenarios focusing on Power-to-X or Hydrogen. This does not mean that further developments are not expected, especially when it comes to biomethane produced through thermal gasification, which is not yet commercially ready. Cost reductions in biomethane production are still possible, as Navigant (2019) estimates that by 2050, prices will decrease from 70-90 EUR/MWh to 57 EUR/MWh for anaerobic digestion technologies and from 88 EUR/MWh to 47 EUR/MWh for thermal gasification technologies.

[27] It should be noted that some studies starting from the premise of a fully decarbonised EU economy by 2050 completely exclude natural gas and grey hydrogen from their scenarios. This is because regardless of the performance level of CCS technologies, such energy sources would still produce some CO_2 emissions during their life cycle.

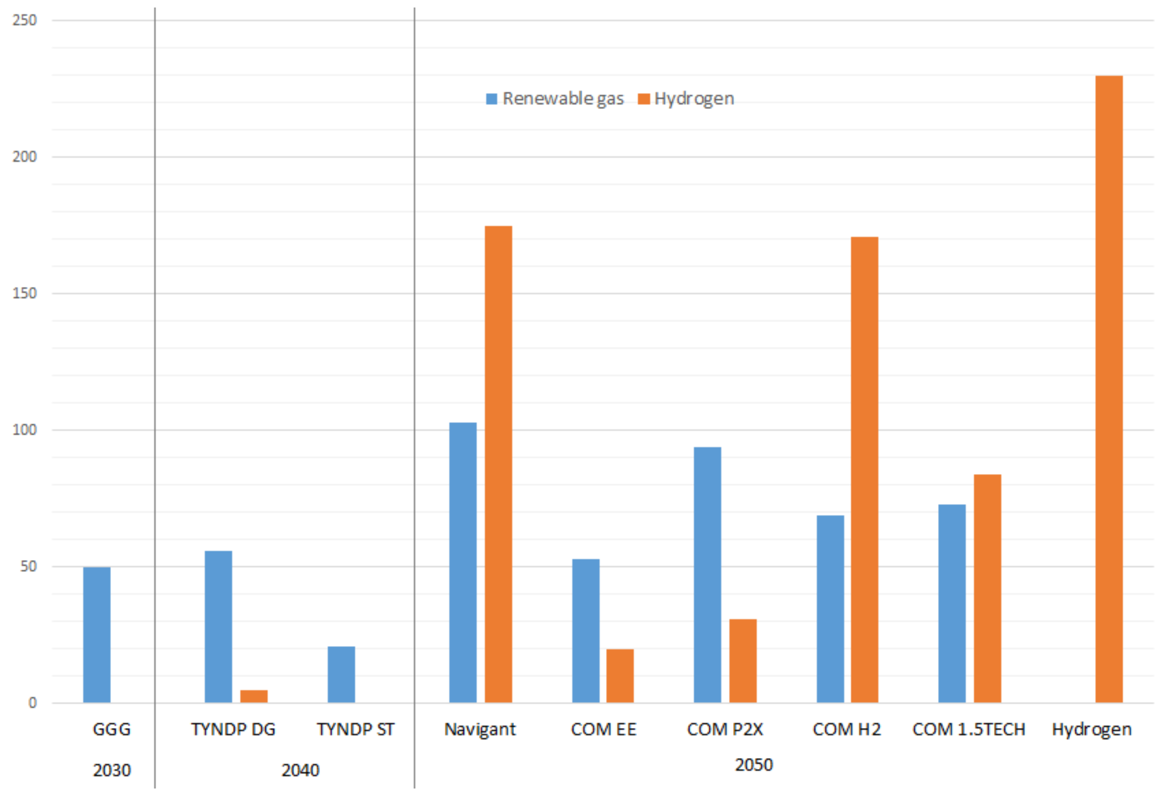
[28] While acknowledging the necessity for CCS in the decarbonisation of energy-intensive industries, the European Commission (2018) expressed concerns about the potential development for CCS for electricity and heating.

[29] See for example Shell (2018), p. 17.

[30] See the Ten-Year Network Development Plan (TYNDP) scenarios developed jointly by the ENTSOs for gas and electricity (2018), p. 38.

One of the main factors in determining the future production levels of biomethane is the availability of feedstock and agricultural land.[31] The sources of feedstock for biogas production include organic waste, industrial waste, agricultural waste and energy crops (CEER, 2018, p. 10). Syngas produced through thermal gasification uses mainly woody matter or cellulose. Therefore, the availability of feedstock[32] depends on future developments in the EU agricultural and forestry sectors. The reliance on feedstock also means that biomethane production is influenced by fuel costs. As a result, in the past, biomethane production has depended on support schemes at member state level to increase its price competitiveness levels (Stern, 2017a, p. 11). However, given the maturity levels it is reaching in some markets, feed-in tariffs have been reduced or are being phased out (CEER, 2018, p. 31). As a result of the limitations associated with the availability of feedstock and the consequent total production potential, biomethane has not been viewed as a solution for decarbonising the entire gas sector and its use has so far been mostly in rural areas.[33]

Figure 4. Production projections for renewable gas and hydrogen (bcm)



Source: GGG (2014); TYNDP (2018); Navigant (2019); European Commission (2018); Hydrogen (2019).

[31] The development of biomethane is also linked with sustainability questions related to the bioenergy industry more broadly. Initiatives exist, however, aiming to show how biomethane can be produced in a more sustainable manner. See, for example, ARTFuels (2018). The recently revised Renewable Energy Directive (REDII) defines the sustainability criteria for production.

[32] Estimated production potentials are naturally based on the assumptions made about the type of feedstock that is used for biomethane production. An ICCT (2018) report shows how different assumptions about feedstock sources and availability can lead to different estimations regarding biomethane potential.

[33] As explained in Piebalgs et al. (2018), p.3.

Hydrogen can be a complementary solution for the gas sector in its transition to carbon neutrality. Based on its type, the total production potential is influenced by assumptions on technology costs, i.e. learning curves, prices and availability of renewable electricity (in the case of green hydrogen) and natural gas as well as availability of CCUS (in the case of blue hydrogen).[34] The cost of production for blue hydrogen is forecast to be about 36-63 EUR/MWh in 2050 (Navigant, 2019, p. 30). Depending on the source of renewable energy (wind or solar) and on geographical location, the cost of green hydrogen is projected to be around 44-61 EUR/MWh in 2050 (Navigant, 2019, p. 23). It should be noted that these cost estimations rely on the availability and access to cheap renewable electricity, which would be required from both dedicated capacity and surplus.[35] The cost estimations for green hydrogen are also based on significant advancements of an electrolyser technology that is currently only used in niche applications and therefore has a high cost-reduction potential, especially in terms of capital costs. Currently, alkaline electrolysis is the most common technology for green hydrogen, with capital costs between 1,000 and 2,000 EUR/kWel. However, scenario assumptions rely on significant evolution of the Proton Exchange Membrane (PEM) technology, which has the potential to reduce its capital costs from about 1,000 EUR/KWel to 400 EUR/kWel by 2050.[36]

One of the key questions for the future of hydrogen is whether the development of blue hydrogen production is desirable in the long term, given the fact that it is not carbon neutral.[37] For example, ECF (2019) and Navigant (2019) both make calculations for achieving net-zero emissions in their reports. However, the ECF report only uses green hydrogen in its projections. Conversely, the Navigant report starts from the assumption of an initial large-scale deployment of blue hydrogen, which can be used to ramp-up hydrogen demand and to overcome some of the initial challenges associated with the early-stage production of green hydrogen. In this scenario, green hydrogen would replace blue hydrogen at a later stage, when it becomes more price-competitive and when the GHG emissions reduction targets become stricter. The speed of the transition would depend on the pace of expansion of renewable electricity capacity and the pace of technological cost reduction for electrolysis. This is based on the assumption that, especially when produced with Proton Exchange Membrane technology, there is a considerable potential for cost reduction in the production of green hydrogen by 2050,[38] when it will reach similar price levels to those of blue hydrogen.

[34] The costs of hydrogen are also linked to where it is produced – inside or outside the EU – which may imply further consideration about transport means and costs.

[35] An Agora Energiewende (2018b) study done by Frontier Economics shows that inexpensive renewable electricity will be needed for power-to-x and power-to-liquid solutions to be economically efficient. However, the excess renewable power will be insufficient to cover all production needs, so dedicated renewable power plants will likely need to be built.

[36] Figures from European Parliament (2018).

[37] As previously discussed, the use of CCS does not capture all CO_2 emissions from the combustion of fossil fuels such as natural gas.

[38] Estimates used by Navigant (2019) for current cost are 90-210 EUR/MWh for green hydrogen and 47-51 EUR/MWh for blue hydrogen. Therefore, by 2050 the cost of green hydrogen would be less than half than currently, while the price of blue hydrogen would remain relatively similar to its current level.

It should also be noted that the steam reformers used to produce blue hydrogen have a higher production capacity compared to that of the current electrolyser technology used for green hydrogen. In addition, given the constraints associated with the availability of cheap renewable electricity, the potential for green hydrogen production is lower than that for blue hydrogen. Whether blue hydrogen is seen as an option has very significant implications for both the future competitiveness of hydrogen and especially for the development of the current gas and the future hydrogen infrastructure, which will be needed in 'high-volume' hydrogen scenarios.[39]

Finally, the projected potential production and costs of **synthetic methane** obtained through power-to-methane rely on the assumptions made about the development levels of green hydrogen, as well as the price and availability of the carbon needed for its production. This can be done as a coupled process in biogas plants in order to revalorise residual CO_2.[40] Nonetheless, the potential for power-to-methane is relatively low when compared to hydrogen and biomethane. The reasons for this are the currently limited availability and high costs of stored CO_2, the associated conversion losses of the production process and the expected technology learning curves. Synthetic methane obtained through power-to-methane, which has equivalent properties to methane, has projected production costs for 2050 of around 74 EUR/MWh, if it is produced using CO_2 captured when upgrading biogas to biomethane. Using CO_2 from other sources would likely imply significantly higher production costs.

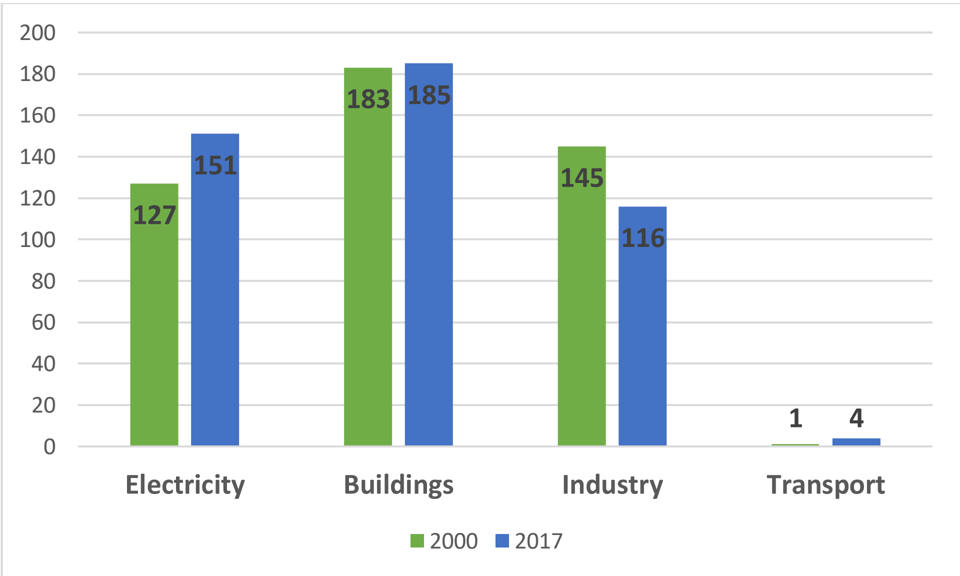
[39] Other types of low carbon hydrogen may also become more cost-competitive in the future, such as hydrogen from nuclear or biomass. See IEA (2019a), p.37.

[40] As assumed in the Navigant (2019) study. This is not applied to thermal gasification, as the large volumes of CO_2 produced through that process are seen as easier to store underground.

Part 3: End-uses of methane and hydrogen in the long term and implications for gas networks

An important element for understanding the future of gas relates to the end-uses of gaseous fuels that will be the main drivers for demand in the long term. The potential demand for hydrogen and renewable methane varies significantly between the power, buildings, industrial and transport sectors, where they will compete with other fuels and technologies to provide solutions for decarbonisation. Figure 5 shows what are the past and current demand levels for gas in these sectors. At the same time, different gaseous solutions may also compete with one other for the same markets in the future. Different gaseous fuels such as biomethane or hydrogen will play a major role in some countries and regions, but it will be marginal or irrelevant in others. This will depend on where the gas is produced and consumed, on transport costs or region-specific production costs. At the same time, pipelines will need to be adapted to accommodate different types of gaseous fuels based on local context. This will pose new, yet different challenges to distribution (DSOs) and transmission companies (TSOs).

Figure 5. Natural gas consumption in the EU by sector (bcm)



Source: IEA (2018), p. 202.

(1) Electricity

Increasing electrification and integration of renewable energy sources offer new opportunities for hydrogen and renewable methane in the future power system. For example, Power-to-Gas can use the surpluses stemming from renewable electricity installations.[41] The gas network can provide solutions for regions lacking renewable generation capacities, thereby reducing the need for expanding the long-distance electricity transmission grid or for additional generation

[41] Power-to-Gas will be in competition for absorbing the surplus renewable electricity with other alternatives such as pumped hydro, power-to-heat, batteries (stationary and in electric vehicles), etc.

capacity where it is costly or faces public opposition. Sector-coupling solutions are expected to play a prominent role especially after 2030 (see Agora Energiewende, 2018, p. 35).

When it comes to long-term storage, gas can be easily stored in large quantities, for example underground. The main alternatives would be pumped hydro storage and batteries. There is limited potential in Europe for additional pumped storage. The competitiveness of battery storage has increased significantly over the past few years and it is already competitive in some markets (see Stern, 2017b, p. 35). However, some estimates indicate that even in the case of further significant cost reductions, batteries may still struggle to achieve a high market share (see Navigant, 2019, p. 3). Frontier Economics (2019) estimates that even at a lower cost of 80 EUR/kWh, long-term and seasonal storage volume in batteries would be more than 100 times more expensive than in large gas facilities.[42] This is different for short-term balancing where batteries will be more competitive. In the future, hydrogen and biomethane may be able to provide dispatchable power to cater for the flexibility market. Hydrogen emerges as a potential energy storage carrier, which can be deposited and used in hydrogen gas turbines to generate electricity at peak times.[43] Likewise, biogas and biomethane-fired combined cycle gas turbines can also be used to provide peak capacity (Navigant, 2019, p. 82).

(2) Buildings

In the heating, i.e. of buildings, sector, which amounts to 38% of total gas consumption in Europe, gas demand is expected to decline by an average of 1.2% per year (IEA, 2018, p. 202), mainly as a result of energy efficiency and building insulation measures. Such measures, alongside the electrification of the sector are at the forefront of policy of many governments. Heat pumps are generally more efficient than boilers (they can deliver up to three times more useful heat than electricity they consume.[44] Such installations could provide electricity-based solutions for the heating of new buildings, but they would require more difficult retrofitting interventions with higher initial costs in the case of existing buildings (IRENA, 2018, p. 92). This may represent a challenge for decarbonising the building stock, as an estimated half of current buildings are more than 40 years old, while the current pace of renovation in the EU-28 is between 0.4 and 1.2% (BPIE, 2017). Renewable methane and hydrogen could provide cost-efficient solutions. Hydrogen injections in the gas grid can be used in the short and medium-term strategy to reduce natural gas consumption, while biogas and biomethane could provide an alternative to some of the methane used for heating. Hybrid heat pumps, combining an air-source heat pump with a gas condensing boiler, can also provide solutions for buildings connected to the gas grid and ensure heating during periods of peak demand on colder winter days. Such installations can use renewable electricity and renewable methane for their operation.

[42] Significant gas storage capacity already exists in European countries, which can be used to store energy in bulk for extended periods of time. See Frontier (2019), p.15.

[43] As used by ECF (2019) in their modelling exercise.

[44] Heat pumps may require higher levels of insulation to minimise the heat loss that can be compensated, especially during cold spells. See Navigant (2019), p. 41.

District heating currently supplies only 10% of the EU's heating needs, but this share is likely to increase in the future.[45] To date, most district heating systems in Europe use natural gas and coal as fuel, and therefore face a decarbonisation challenge. Among potential technological solutions, renewable gas-fired combined heat and power plants, geothermal energy, biomass, industrial waste heat and large-scale heat pumps could reduce the share of fossil fuels. Renewable methane and hydrogen will thus compete with other heat sources in both future district heating networks and individual heating installations.

(3) Industry

Having peaked at 145bcm in the year 2000, the demand for gas in EU industry has since registered a 20% decline, largely due to the transition from industry to energy services and to structural changes in energy-intensive industry (IEA, 2018a). The new policies scenario of the 2018 IEA World Energy Outlook foresees a further decrease in gas consumption of European industry of 12% by 2040, depending on the future energy-intensity and size of European industrial production. The implementation of a circular economy solution and the redesign of industrial processes will also reduce waste, the quantity of virgin material used, and energy use (see European Commission, 2018, p. 144). In addition, the development of CCS and CCU technologies will be paramount for developments in the sector, as they will be important for providing CO_2 for industrial processes.

When it comes to industrial processes using natural gas, few low-carbon alternatives other than gaseous fuels are available for decarbonisation. Electrification could be a solution for providing low temperature heat to industry, but not for high temperature heat (Navigant, 2019). Hydrogen, on the other hand, can be used for this purpose, alongside a number of other applications for the industrial sector. Hydrogen already has a history of being used as feedstock by the chemical industry, and it may also be used as a reductant in the steelmaking process, as feedstock for ammonia production and, together with captured carbon dioxide, it can replace natural gas in the chemical production of olefins and hydrocarbon solvents. Among the high heat segments, the use of hydrogen will be the most cost-efficient in industries where it is already used as an input or produced as a by-product (Hydrogen Europe Roadmap, 2019, p. 38). Simultaneously, biomethane will also be suitable for replacing natural gas molecules as industrial feedstock and it may be used in areas where locally available.

(4) Transport

Currently, transport represents only a minor consumer of gas in the EU, amounting to less than 1% of total demand. At the same time, transport accounts for around one third of overall energy consumption, overwhelmingly relying on liquid fossil fuels. The European Commission (2018, p. 108) acknowledges that there will be no single solution for the decarbonisation of this sector, with multiple alternative fuels being needed for different transport modes. Therefore,

[45] According to the Commission (2018), district heating and cooling networks could supply up to 50% of the demand in the future.

there is a potential for growth in demand for hydrogen and renewable methane, but there will be direct competition with other fuels in each segment of this complex sector.

In cars and light-duty transport, developments of battery-based electric vehicles are on the rise. To cater for rising demand, charging infrastructure – at least in some member states or cities – is being put in place. For this segment, a continuous trend of increased electrification is expected, mainly through the sustained market penetration of battery electric vehicles (BEV), and also, to a lesser extent, of fuel cell electric vehicles (FCEV). Hydrogen-based FCEVs represent a low-carbon mobility option offering a similar driving performance as conventional vehicles and such vehicles could potentially become competitive in the medium to long term (IRENA, 2017b, p.7). However, large-scale deployment would be dependent on significant infrastructure investments. The IEA estimated in its 2015 technology roadmap for hydrogen and fuel cells that for every additional fuel cell electric vehicle sold up to 2050 an additional $900-1900 infrastructure investment is needed.[46] Meanwhile, gas-based solutions such as compressed natural gas (CNG), are overlooked in some scenarios due to insufficient proof of technological development and price competitiveness.[47]

Given the low energy density and high weight of batteries, combined with long-range requirements, electricity is not as likely to represent a viable solution for heavy-duty long-distance transport (European Commission, 2018, p. 10). This segment will likely remain dependent on liquid fuels in the future. Fuel cell electric vehicles can become more competitive as heavier vehicles travelling over long distances, especially trucks and buses. Meanwhile, gas-fired vehicles have a similar operating efficiency as their diesel equivalents and produce fewer GHG emissions (CEER, 2018, p. 27). The competitiveness of these two options is dependent on a significant development of the refuelling infrastructure. Carbon-free biofuels and e-fuels represent important alternatives, as they can more easily replace the fossil fuels that are currently used in heavy-duty transport. Such alternatives also do not come without limitations. While e-fuels would not require significant adaptation, the cost and energy considerations and carbon origin may provide limitations to their viability for this segment (European Commission, 2018, p. 111). Biofuels also raise questions of sustainability and rely on the availability of agricultural land for their production.

Maritime long-distance shipping, which is currently dependent on oil derivatives, requires fuels with high energy density. It is assumed that the sector will require a combination of biofuels, hydrogen, bio-LNG, bio-CNG and e-liquids.

Aviation poses one of the most difficult decarbonisation challenges and will likely remain the largest emitter form the transport sector in 2050.[48] Low-carbon solutions will most likely be

[46] Some other estimations have shown that in the case of a high level of penetration of either BEV or FCEV, of about 20 million vehicles, the cumulative charging infrastructure costs may be lower for hydrogen fuelling (Robinus et al., 2018). These estimations are, however, based on the availability of significant amounts of surplus electricity to be used for electrolysis.

[47] An example is the Eurogas (2018) report.

[48] Aviation remains the largest emitter in 2050 in all scenarios that the Long-Term Strategy of the European Commission (2018) identifies, including the Baseline scenario.

based on bio jet fuel and synthetic kerosene. Hydrogen together with captured CO_2 can be converted into synthetic fuel, which has similar properties to the current fuels used in the aviation sector. However, this process faces the challenge of lower conversion efficiency (see Hydrogen, 2019, p. 31). Given improvements in economics and technological advances, hydrogen-based fuels could provide an option for the aviation sector in the future.

Overall, hydrogen and renewable methane enjoy prospects for growth in a future transport sector that will be based on a highly complex fuel mix.[49] The extent to which they will develop will depend on the evolution of each segment of the transport sector and on how alternative fuels will be competitive in each category. Hydrogen and renewable methane will be most needed in those sectors that require fuels with high energy density, and where electrification does not represent a viable alternative.

Gas transmission and distribution

The demand for renewable methane and hydrogen and its potential end-uses will have important implications for gas networks. The current European gas network consists of approximately 260,000 km of high-pressure pipelines mostly operated by transmission system operators and 1.4 million km of medium and low pressure pipelines operated by distribution system operators.[50] In the context of a decreasing demand for gas in the long term, combined with the high costs associated with the production of biomethane and hydrogen, the gas network will likely decrease in size.

The future gas grid will need to be capable of accepting either biomethane or hydrogen, or a mixture of both, which may require anything from marginal adjustments to complete replacements. The most straightforward transition based on existing infrastructure would be to biomethane, which does not require any major technical upgrades to the network. However, projections show that insufficient quantities of renewable methane will be produced (see Figure 4) to maintain current grid capacity. As a medium-term strategy, networks can inject hydrogen into the current gas grid to boost cash flows at low marginal costs towards breakeven for hydrogen producing facilities in the early technological phases, when the risks of insufficient demand are very high (IRENA, 2018b, p. 38). It should be noted, however, that there are limits to the extent hydrogen can be safely blended with methane in the pipeline. Current research shows that blending hydrogen in relatively small concentrations of up to 10-20% can be done safely without major infrastructural upgrades. Regulatory standards would need to be reviewed in this regard, for example in the Gas Quality Directive, as, for the time being, EU member states allow concentrations of hydrogen varying from 0.1% in the UK to 12% to be injected into the grid (Stern, 2019, p. 18).

[49] Relevant examples are the net-zero 1.5TECH and 1.5LIFE scenarios in the Commission LTS. In both scenarios a large variety of alternative fuels, including hydrogen and renewable methane, supply the energy needs of different segments of the transport sector.

[50] As estimated in Navigant (2019).

A focus on hydrogen would require dedicated pipelines. Any such transition would generate significant additional costs and may prove more cost-efficient for hydrogen applications on a local or regional basis. The viability of such a conversion of the pipeline from natural gas to hydrogen has been tested through projects such as the Gasunie hydrogen pipeline from Dow to Yara[51] and the H21 Leeds City Gate pilot project in the UK.[52] As the choices for which product will be transported through pipelines will likely be local rather than national, the choices made by distribution companies in this regard might be the most consequential for the EU. EU policymakers will increasingly face the challenge of more decentralised management of distribution.

Different decarbonisation options such as gas switching to biomethane or hydrogen will vary across regions. If the solution is switching to hydrogen, it will be less costly for distribution companies to make the necessary adjustments to the distribution network than it will be for the larger long-distance transmission systems. At the same time, an upgrade or refurbishment of transmission grids would almost certainly require the simultaneous upgrade or refurbishment of all the networks they supply. Based on the future potential of hydrogen production (especially if only green hydrogen is considered), it remains to be seen to what extent substantial transmission infrastructure would be used for transporting hydrogen over long distances.

[51] See https://www.gasunie.nl/en/news/gasunie-hydrogen-pipeline-from-dow-to-yara-brought-into-operation.

[52] For more details see H21 (2016). The project shows that the heat demand for the city of Leeds can be met with hydrogen produced through steam methane reforming, stored in caverns, and distributed through the upgraded existing pipeline.

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Annex 1. Glossary of Selected Terms and Abbreviations

Bcm	Billion Cubic Meters of Natural Gas
Biofuel	Liquid or gaseous transport fuels such as biodiesel or bioethanol made from biomass, which are subject to sustainability criteria at the EU-level
Biogas	A mixture of gases containing 50-65% methane resulted from the biological breakdown of organic material in the absence of oxygen
Biomass	The biodegradable fraction of products, waste and residuals from biological origin from agriculture (including vegetal and animal substances), forestry and related industries including fisheries and aquaculture, as well as biodegradable fraction of industrial and municipal waste
Biomethane	Purified methane obtained through anaerobic digestion or thermal gasification
Blue hydrogen	Hydrogen gas produced from natural gas, usually through steam reforming, combined with the use of carbon capture
CHP	Combined Heat and Power, or Cogeneration
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Utilisation
CCUS	Carbon Capture, Utilisation and Storage
CNG	Compressed Natural Gas
DSO	Distribution System Operator
E-fuel	Gaseous or liquid fuels generated using renewable electricity
Flexibility	The extent to which power systems can modify electricity production or consumption in response to variability
GHG	Greenhouse gases
Green hydrogen	Hydrogen gas produced from the electrolysis of water using renewable electricity
Grey hydrogen	Hydrogen gas produced from fossil fuels, mainly natural gas, with no carbon capture
Gas switching	Replacing the use of coal in power generation with natural gas
GWP	Global Warming Potential
LNG	Liquified Natural Gas
Methane leakage	Unintentional or purposeful releases of methane gas into the atmosphere

Natural Gas	Naturally occurring hydrocarbon mainly consisting methane (CH_4)
Net-zero emissions	Remaining, i.e. residual emissions should be balanced by 'carbon removal', e.g. carbon sinks such as forests which absorb carbon dioxide from the atmosphere
PCI	Project of Common Interest
PEM	Proton Exchange Membrane
Power-to-Gas	A process that converts electrical power into a gaseous fuel
Power-to-Hydrogen	A process that converts electrical power into hydrogen, usually through electrolysis
Power-to-Methane	A process that produces synthetic methane through the hydrogenation of carbon dioxide using hydrogen resulted from electrolysis
Power-to-X	An umbrella term that refers to processes that covert electrical power into an energy carrier, heat, product, or raw material
Pumped hydro	A type of hydroelectric energy storage using two water reservoirs at different elevations, that recharges though the pumping of water to the upper reservoir and generates power as water moves down to the lower reservoir through a turbine
Sector coupling	The integration of energy end-use and supply sectors with one another, having the potential of improving efficiency and flexibility of energy systems
SMR	Steam Methane Reforming
TSO	Transmission System Operator

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