Potentials of sector coupling for decarbonisation - Assessing regulatory barriers in linking the gas and electricity sectors in the EU

- Intermediate report

This study was carried out for the European Commission by Frontier Economics, together with CE Delft and THEMA Consulting Group, as part of the COWI Consortium.

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Directorate-General for Energy
Internal Energy Market

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REPORT OBJECTIVE

This intermediate report presents the results of the first phase of a project on regulatory barriers and gaps preventing closer linking ('sector coupling') of the EU gas and electricity sectors (both in terms of their markets and infrastructure) and hindering the deployment of renewable and low-carbon gases.

The main objectives of this phase are:

- to provide a vision of the future energy mix/system for the EU (in 2030 and in 2050) in which full decarbonisation of the energy system is achieved;
- to discuss the future role of gases in this system;
- to identify the potential technologies necessary for these developments; and
- to explore how these technologies could lead to linkages between the electricity and gas sectors.

The findings of this phase form a basis for the subsequent phases of this project: the identification of regulatory barriers and gaps to sector coupling, and developing recommendations to resolve these. They serve to identify those technologies for which we will explore whether regulatory barriers could hamper their development and deployment. They also consider the nature of the energy transition (which allows for analysis of the potential policies required to support this transition).

THE CONCEPT OF SECTOR COUPLING

Recent studies that explore how the decarbonisation levels agreed in the Paris Climate Agreement can be realised have increased our understanding of what the future EU energy system may look like. One key insight from these studies is that decarbonisation of the energy system will result in an increasing level of integration of different energy carriers, in particular gas, electricity and heat. For the purpose of this study, we understand sector coupling as linking the EU electricity and gas sectors, both in terms of their markets and infrastructure.

A key driver behind this is the reduction in the cost of producing electricity from renewable sources in recent years. Continued cost reductions could provide a business case for using this electricity to produce gases such as hydrogen or methane in a carbon-neutral way. The gases produced could be transported and stored at lower cost than electricity by making use of existing infrastructure. Their use may also avoid potentially costly and distruptive changes to end-use appliances.

There are other ways in which the electricity and gas sectors could be increasingly integrated in the future. These include, for example, the use of biomethane in power generation and the flexible ('smart') use of electricity and gas heating depending on price, whether in individual buildings (in 'hybrid' heat pumps) or in district heating networks.

THE FUTURE EU ENERGY SYSTEM

In the coming decades, the EU energy system needs to change dramatically to make the transition to a decarbonised energy system. This transition is necessary to achieve the EU's 2030 climate targets as well as the EU's commitments under the Paris Agreement, which aims to limit the average global temperature rise to well below 2°C.

An assessment of recent literature leads to the conclusion that despite significant uncertainties, a number of likely key elements of the EU's future decarbonised energy system can be identified:

- The future energy system is expected to be based on a large share of renewable energy as primary source of energy, with a large share of renewable electricity notably from solar and wind (produced in the EU) and biomass use in all sectors.
- Fossil fuel use should be largely phased out, with uncertainty over the remaining role for natural gas. Natural gas might play a minor enduring role in industry and power generation. The extent of this role may be partly dependent on whether CCS can be deployed commercially, which is itself uncertain.
- Total final energy demand is expected to reduce significantly through energy efficiency measures in all end-use sectors, notably with a large reduction in heat demand.
- Electrification will be a key development in transport and heating, though many scenarios also feature significant use of renewable and low-carbon gases. Precisely which gases are used is a further uncertainty, with hydrogen, synthetic methane and biomethane all featuring in varying quantities by 2050.
- Increased electrification of final demand and Power to X production will likely result in an increased demand for electricity. Additionally, Power to X production involves efficiency losses that amplify the increase in electricity demand.
- In power production, carbon intensive fossil fuels (coal, lignite, oil) are expected to be replaced by renewable power production, with use of natural gas potentially increasing in the transition (i.e. to 2030) but eventually largely being phased out by 2050. The long-term role of nuclear power is a key uncertainty: without it, and without widespread deployment of fossil generation with CCS, there will be a greater need for seasonal flexibility elsewhere in the power system.
- System flexibility for the electricity grid is expected to be achieved by a combination of demand side management/response (DSM/DSR), energy storage (for example in batteries, heat storage, or in hydrogen or synthetic methane) and peak gas power plants. The latter can be run on natural gas, with increasing shares of renewable or low-carbon gases (biomethane, hydrogen and/or methane from renewable electricity or from natural gas with CCS).

THE ROLE OF GASES AND SECTOR COUPLING AND IMPLICATIONS FOR INFRASTRUCTURE

It is, in principle, possible to use all the different renewable and low-carbon gases in all applications for which natural gas is used today (such as heat and power production), as well as others for which natural gas is not significantly used at the moment (such as transport). This would, however, require the gases to meet the current quality standards, or alternatively, an adaptation of the quality standards themselves and/or end-use equipment and infrastructure. Overall, their continued use could help to reduce the costs of decarbonisation through a combination of limiting the costs of end-user appliances and avoiding the need for reinforcements and upgrades to the electricity grid (by making use of the existing gas grid to transmit energy).

However, their respective roles in the future energy mix are still uncertain. Clearly, developments in cost will be an important driver of which gases are predominantly used. But policy will also play a role. In particular, given the co-ordination that would be required (e.g. appliance switchovers, infrastructure upgrades), any future in which hydrogen is transported or used in significant quantities within the EU requires strategic decisionmaking by policymakers (whether at national or at EU-level).

These developments have a range of impacts on gas infrastructure and storage needs. These impacts differ significantly between scenarios applied in recent literature, but include the following:

- Since natural gas demand is expected to decrease in the coming decades, the (average) utilization level of the transmission grid, LNG import terminals and import pipelines is also likely to decline, mitigated by the extent to which these convert to using increasing shares of renewable or low-carbon gases.
- The impacts on the transmission grid, the distribution grid and storage facilities are likely to differ from location to location. Some existing grids might be used for renewable methane or biomethane or transformed to (local) hydrogen grids, and others may become obsolete.
- Any large-scale use of hydrogen might also require conversion of existing gas storage or new hydrogen storage locations. New fuelling infrastructure may need to be developed for the transport sector.
- Existing gas storage facilities might need to be adjusted to allow for a more dynamic operation to store renewable gases.
- Synthetic methane production is likely to require a CO_2 transport infrastructure, to transport captured CO_2 from industrial processes to the methanation plant, or further development of CO_2-capture from air technologies.
- Given much of renewable and low-carbon gas production could be located at distribution level, flows on the distribution grid (and flows between transmission and distribution) will require increased active management.
- Greater substitutability of gas and power for final energy consumption (e.g. in heating) could require closer co-ordination between gas and power system operation, both at transmission and distribution level.

The large-scale market uptake of renewable and low-carbon gas technologies requires innovations and R&D efforts in all aspects of the value chains, to further develop the necessary technologies, reduce cost and improve efficiencies. This is expected to require also large-scale investments over the coming decades, for example in renewable energy production, production plants for the gases, upgrading of existing infrastructure and storage, new infrastructure and storage, and new end-use applications. Planning these investments efficiently will likely require an integrated development of the gas and electricity systems.

ABBREVIATIONS

AE[R]	Advanced Energy [R]evolution scenario developed by Greenpeace
BEV	Battery electric vehicle
CCGT	Combined cycle gas turbine
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Use
CNG	Compressed natural gas
CSP	Concentrated Solar Power
E[R]	Energy [R]evolution scenario developed by Greenpeace
EU	European Union
FCEV	Fuel cell electric vehicle
FCH JU	Fuel Cells and Hydrogen Joint Undertaking
GHG	Greenhouse gases
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
LNG	Liquified natural gas
MENA region	the Middle East and North Africa region
OECD	Organisation for Economic Co-operation and Development
OECD Europe	all European members of the OECD : Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey and United Kingdom.
PV	Photovoltaic
RED	Renewable Energy Directive (2009/28/EC)
RED II	Renewable Energy Directive (recast) (2018/…/EC)
SNG	Synthetic natural gas

1. Introduction

Frontier Economics ('Frontier'), together with CE Delft and THEMA Consulting Group ('THEMA'), as part of the COWI Consortium (hereafter "the consortium") have been appointed by the European Commission to carry out a study on the integration of the EU gas and electricity sectors - Assessing regulatory barriers (ENER/B2/2018-260).

This report constitutes the interim report of the study. In this section we recall the objectives of the study, including definitions and scope for the technologies analysed, and we present the structure of the report.

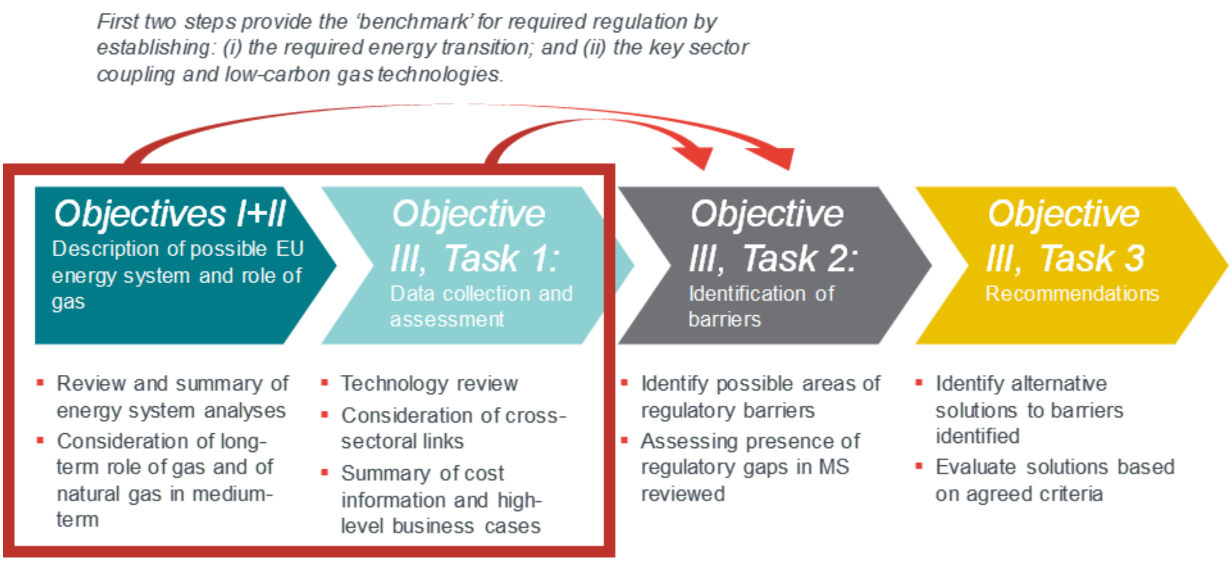
1.1. Objective

This interim report presents the results of the first phase of the project. The main objective is to provide a broad overview of the possible future energy system in the EU in which full decarbonisation of the energy system is achieved, and to discuss the future role of gases in each of these possible futures, from a technological point of view:

- Objective I – providing the context by describing possible future EU energy systems
- Objective II – within these possible energy systems describing the role of gases to contribute to decarbonisation
- Objective III – collection of data and assessment of low-carbon gas technologies and renewable gases

The findings will form a basis for the following steps of this project, which further zoom in on the regulatory changes that can drive and facilitate these futures, as is depicted in Figure 1. The last section of this report discusses the next step to meet Objective III task 2 and 3.

Figure 1 Summary of analytical steps required



Source: Frontier Economics, CE Delft

1.2. BACKGROUND OF THIS STUDY

Following the signing of the Paris Climate Agreement, the EU and many national governments, institutions and stakeholders have increased their efforts to explore how the agreed decarbonisation levels can be realised. Since energy production and consumption account for more than 75% of the EU's greenhouse gas (GHG) emissions, decarbonisation of the EU's energy system plays a central role in decarbonising the EU economy, as confirmed in the recent European Commission communication and accompanying in-depth analysis 'A Clean Planet for all' (hereafter 'EU Long-Term Strategy', (EC, 2018a)).

The 2020 and 2030 climate and energy frameworks[1] aim to reduce CO_2 emissions from energy supply and demand through regulations such as the EU Emission Trading System, the Renewable Energy Directive and the Energy Efficiency Directive. These policy frameworks are expected to contribute significantly to the GHG reduction needed to achieve the commintments under the Paris Agreement. Assuming that already agreed EU legislation is fully implemented, they potentially result in a reduction of total GHG emissions of around 45% by 2030, increasing to around 60% in 2050 (EC, 2018a).

The EU Long-term Strategy (EC, 2018a) concludes that these reductions, however, would not be enough to meet the goals of the Paris Agreement - which require net-zero CO_2 emissions to be achieved by 2050, globally - and that the EU energy system must reach net-zero GHG emissions by 2050.

To better understand the challenges and opportunities this energy transition creates, an increasing number of recent and also still ongoing studies explore various aspects of this transition. These studies create valuable insights on the implications of the set targets in reality, i.e. what the energy system might look like in 2030 and 2050. At the same time, however, they also reveal that many developments are still highly uncertain in light of different possible technology pathways for achieving the GHG reduction targets. These pathways may in turn depend on (amongst other factors) cost developments, the policy framework and public support.

A key insight from recent studies is that the decarbonisation of the energy system will result in an increasing level of integration of different energy carriers. Electricity, gas and heat will be much more integrated into one system than is the case today.

One of the key drivers for this development is the cost reduction of on- and offshore wind and solar power production of recent years. Future outlooks therefore expect strong growth of these types of variable, non-dispatchable renewable energy. Their variable production rates lead to an increasing need for large scale demand flexibility and energy storage, for both short- and long-term variations in production.

Converting an increasing share of the renewable electricity produced to hydrogen or methane, and perhaps other types of gases or liquids (often referred to as Power to Gas or more generally Power to X), could help address this issue and offer additional advantages. The gases or liquids produced can be transported and stored at lower cost than electricity (in the case of gases by making use of existing infrastructure). Their use

[1] The 2020 package includes the three key targets for the year 2020 of: a 20% cut in GHG emissions (from 1990 levels); 20% of EU final energy consumption to be sourced from renewables; and a 20% improvement in energy efficiency (see https://ec.europa.eu/clima/policies/strategies/2020_en). The respective targets in the 2030 framework are: a 40% cut in GHG emissions (OJ L 282, 19.10.2016, p4); 32% of energy from renewables (OJ L 328, 21.12.2018, p. 82–209); and a 32.5% improvement in energy efficiency (OJ L 328, 21.12.2018, p. 210–230).

may also avoid potentially costly and distruptive replacement of end-use appliances. Both advantages have financial and system operation benefits which will be discussed further in this report, outweighing the production costs of Power to X (including additional energy losses in transformation). As concluded in the Commission's in-depth analysis in support to the Communication 'A Clean Planet for all' (EC, 2018b), this type of energy storage and sectoral integration has the potential to make the energy transition more cost-effective.

It is therefore likely that in the coming decades, gases produced from renewable electricity, together with biomethane and possibly also low-carbon gases (notably hydrogen produced from natural gas with carbon capture and storage), will replace part of the current natural gas use as well as other fossil energy carriers. The remaining natural gas will likely be replaced by alternative decarbonisation options, such as electrification and geothermal heat.

1.3. SECTOR COUPLING: THE FOCUS OF THIS STUDY

This study focusses on one essential part of these changes to the energy system: the coupling of the electricity and gas sectors. Other types of sector integration, such as integration of the electricity sector with the transport or heating sectors, are also addressed as these may also be important aspects of the energy transition, but they are not the focus of this study.

Chapters 2, 3 and 4 of this intermediate report describe the current insights on the main aspects of the energy transition relevant for the regulatory assessment that will be carried out in the second part of the project. Key questions to be addressed include the following:

- How will the EU energy mix change over time?
- What is the likely role of natural gas in these developments, and what role can hydrogen, synthetic methane and biomethane play in the future energy system?
- What new technologies may become a key part of the future energy system?
- What are the resulting impacts on the European gas infrastructure?

These questions will be addressed mostly qualitatively in this report, with only some illustrative quantifications. The main reason for this approach is that uncertainties regarding the future energy system remain substantial. Key technologies are still in the development phase, new innovations will appear over time, and costs of technologies will reduce once they prove succesful. Research into many of the key technologies has only started in recent years, and details about their large scale roll-out have not been studied yet. Also the optimisation of the energy system as such is still subject to further research (EC, 2018a). It is important that the regulatory assessment and policy recommendations that will be developed in Tasks 2 and 3 (see Figure 1, above) take these uncertainties into account. This requires that regulation and policy are robust and flexible, to avoid foreclosing potentially cost-effective technologies early on in the transition process.

1.4. DEFINITIONS AND SCOPE

This study discusses a wide range of gases that are likely to play a role in the decarbonisation of the EU energy supply of the coming decades. To prevent misunderstandings and ensure a uniform terminology throughout this project, a comprehensive list of relevant definitions will be developed. We propose to adhere to the definitions included in Article 2 of the Renewable Energy Directive recast (RED II) (EU, 2018) where possible, with additional terminology specific to this report defined only where necessary.

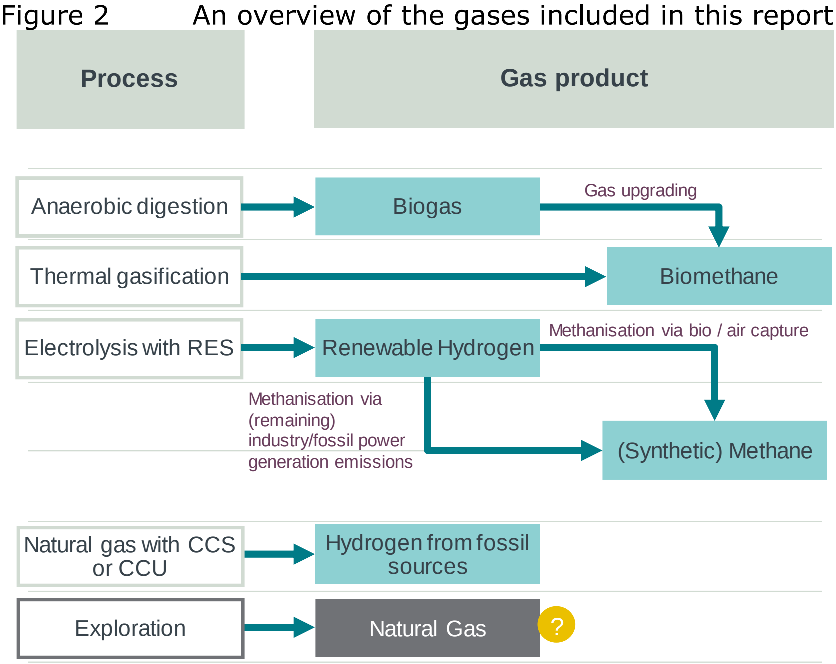
A selection of key definitions from the RED II and a number of additional definitions that will be relevant for this study are provided in the following table. This list may be modified and expanded throughout the project.

Term	**Meaning**
Selected definitions from the RED II	
Energy from renewable sources Or Renewable energy	Energy from renewable non-fossil sources, namely wind, solar (solar thermal and solar photovoltaic) and geothermal energy, ambient energy, tide, wave and other ocean energy, hydropower, biomass, landfill gas, sewage treatment plant gas and biogases
Renewable liquid and gaseous transport fuels of non-biological origin	Liquid or gaseous fuels which are used in transport other than biofuels whose energy content comes from renewable energy sources other than biomass
Biofuels	Liquid fuel for transport produced from biomass
Biogas	Gaseous fuels produced from biomass
Additional terminology relevant for this study	
Gases	All types of gaseous fuels, including natural gas, hydrogen, renewable gas, biomethane, decarbonised gas, etc.
Renewable gases Gases from renewable sources	Gaseous fuels produced from renewable non-fossil sources, namely wind, solar (solar thermal and solar photovoltaic) and geothermal energy, ambient energy, tide, wave and other ocean energy, hydropower, biomass, landfill gas, sewage treatment plant gas and biogas
Natural gas	Naturally occurring gas of fossil origin, consisting primarily of methane
Biomethane	Gaseous fuels with a quality that allows injection into the natural gas grid produced either from biogas through upgrading, or by thermal gasification of biomass.
Power-to-Gas, PtG	Technology to transform electricity into a gaseous energy carrier (notably hydrogen or methane)
Renewable hydrogen	Hydrogen produced from renewable energy sources
Hydrogen from fossil sources	Hydrogen derived from either gasification of solid fuels (e.g. coal) or from reforming of natural gas.

Hydrogen from fossil sources using Carbon Capture and Storage	Hydrogen derived from either gasification of solid fuels (e.g. coal) or from reforming of natural gas. In this report, we use the term to primarily refer to hydrogen produced from natural gas where the CO2 has been to a high extent captured (sometimes referred to as blue hydrogen)
Synthetic methane	Methane produced from hydrogen.

A schematic overview of the main categories of gases included in this report is depicted in the figure below.

Figure 2 An overview of the gases included in this report: illustrative definitions -



1.5. STRUCTURE OF THIS REPORT

This report is structured as follows:

- In Chapter 2 we describe the possible future decarbonised EU energy system;
- Chapter 3 discusses in more detail the role of gases and gas infrastructure in this decarbonisation of the energy system;
- Chapter 4 then provides more detailed information on the renewable and low-carbon gas technologies that are likely to play a role in the decarbonised energy system;
- In Chapter 5 we outline what our next steps will be, following the initial analysis;
- Appendices A and B provide two technology briefs on the key technologies, to add to section 4; Appendix C lists examples of recent or currently ongoing pilot and demonstration projects of some of these technologies.

2. POSSIBLE FUTURE DECARBONISED EU ENERGY SYSTEM

2.1. INTRODUCTION

In the coming decades, the EU energy system needs to shift towards low-carbon and renewable energy sources. This transition is necessary to achieve the EU's 2030 climate targets as well as the EU's commitments under the Paris Agreement, which aims to limit the average global temperature rise to well below 2°C.

Following the signing of the Paris Climate Agreement, the EU and many national governments, institutions and stakeholders have increased their efforts to explore what a decarbonised future energy system may look like. Scenarios have been developed to assess the impact of potential developments, storylines have been drafted to explore the changes that can be expected and the R&D efforts of new technologies and potential innovations of current technologies have been increased. Many of these efforts are still exploratory, as important parameters remain uncertain. The future energy system is likely to be complex, for instance due to the need to integrate increasing shares of wind and solar power production. Many different and often new technologies could play a role in the future energy system, with sector coupling creating new interlinkages between energy carriers.

Nevertheless, a number of recent studies provide significant insight into some of the key parameters of the future EU energy system. In this chapter, we describe the main findings of our literature review. The main aim of this chapter is to condense the key features and results of a range of recent and diverse scenarios and storylines developed by various parties into a possible future EU energy system in line with the Paris climate goals.

The chapter is structured as follows:

- We first set out our approach, including setting out the studies reviewed as part of the exercise.
- We set out the main areas of consensus on the evolution of the EU energy system from the studies reviewed.
- We highlight some of the key uncertainties regarding the future EU energy system.
- We conclude with an over-arching vision of the EU energy system, bringing together the areas of consensus and uncertainties.

2.2. APPROACH

This overview is based on studies published in recent years that describe potential future decarbonised energy systems for the EU. Only current studies were included to ensure that up-to date developments are taken into account as much as possible, most notably the cost reductions of wind and solar power production and the lack of progress in the implementation of carbon capture and storage (CCS). The main studies assesed are:

- Global Energy Transformation - A Roadmap to 2050, (IRENA, 2018a);
- Perspectives for the Energy Transition, (IEA ; IRENA, 2017);
- Energy [R]evolution – A sustainable world energy outlook 2015 (Greenpeace, 2015).

- A Clean Planet for all, A European long-term strategic vision for a prosperous, modern, competitive and climate neutral economy, (EC, 2018b), and the in-depth analysis in support of this Communication (the 'EU Long-term Strategy') (EC, 2018b);

- The Role of Trans-European Gas Infrastructure in the Light of the 2050 Decarbonisation Targets (Trinomics, Ludwig Bölkow Systemechnik, Artelys and E3-Modelling, 2018);

- Sectoral integration – long-term perspective in the EU Energy System, (ASSET, 2018);

The first four reports are scenario studies exploring the implications of decarbonisation of energy supply at a global level, based on high-level modelling. They also provide results for Europe (EU or OECD Europe) as a whole. The Commission's in-depth analysis in support to the EU Long-term Strategy (EC, 2018b) develops a range of scenarios that explore how the EU can decarbonise, based on modelling (with the PRIMES-GAINS-GLOBIOM model suite, supplemented with the FORECAST model). The Trinomics study explores 200 other studies and distills their main storylines. The Asset study explores the implications and impacts of different strategies for sectoral integration based on hydrogen.

Since biomethane is relevant for this study, but often not studied in detail in high-level reports, three additional studies were used for this topic: a CE Delft et.al. study on optimal use of biogas from waste streams (CE Delft, Eclareon en Wageningen Research, 2016), an assessment of the role for renewable methane in European decarbonisation by ICCT (ICCT, 2018) and an Ecofys sytudy for Gas for Climate (Ecofys, 2018)

The key features of these reports were analysed, focussing on their main assumptions, objectives and scopes. The following important aspects were taken into consideration to arrive at a condensed outlook of the future EU energy system:

a. <u>Final energy demand</u> in the key sectors (electricity, buildings/heat, industry, transport) by customer types;

b. The mix of the <u>energy carriers to meet those energy needs</u> and the corresponding primary energy carriers;

c. The required <u>system flexibility, seasonal storage, transport and enabling technologies</u> (power to gas, gas-to-power etc).

As explained above, the scenarios and storylines that were assessed are exploratory, assessing the effects of different assumptions and technologies. They are not intended to predict what exactly *will* happen, but rather provide insight on what *could* happen, given certain technological and cost developments, policies, and consumer preferences.

The studied scenarios and storylines - and therefore also the main findings in this chapter - do not differentiate by region within the EU. That said, certain factors mean the nature of the energy transition is likely to differ between EU regions:

- **Geographical factors:** Regional differences within the EU exist in, for example, energy resources, power demand, heating and cooling demand, as well as in the potential and availability of renewable energy sources. For example, in North-West Europe there is a high (seasonal) heat demand and high potential for wind energy, especially offshore wind energy in Western Europe, while in the South there is a lower heat demand, higher cooling demand and higher potential for solar energy. Hydro power is available in

North and Central Europe, while biomass is especially available in the North and East.
- **Past investment decisions:** Historical differences in investments have resulted in regional differences in energy systems and infrastructure, which are likely to heavily influence cost-effective choices in the future. For example, the business case for a significant future role for renewable gases will be stronger in regions with extensive gas grids than in regions with less-developed gas infrastructure.

These differences mean that the relative importance of different energy technologies (including sector coupling technologies) will differ between regions. Future policy at EU level needs to facilitate the full range of potential technological solutions.

2.3. KEY ELEMENTS OF THE FUTURE ENERGY SYSTEM

In this section, we discuss the following elements in turn:

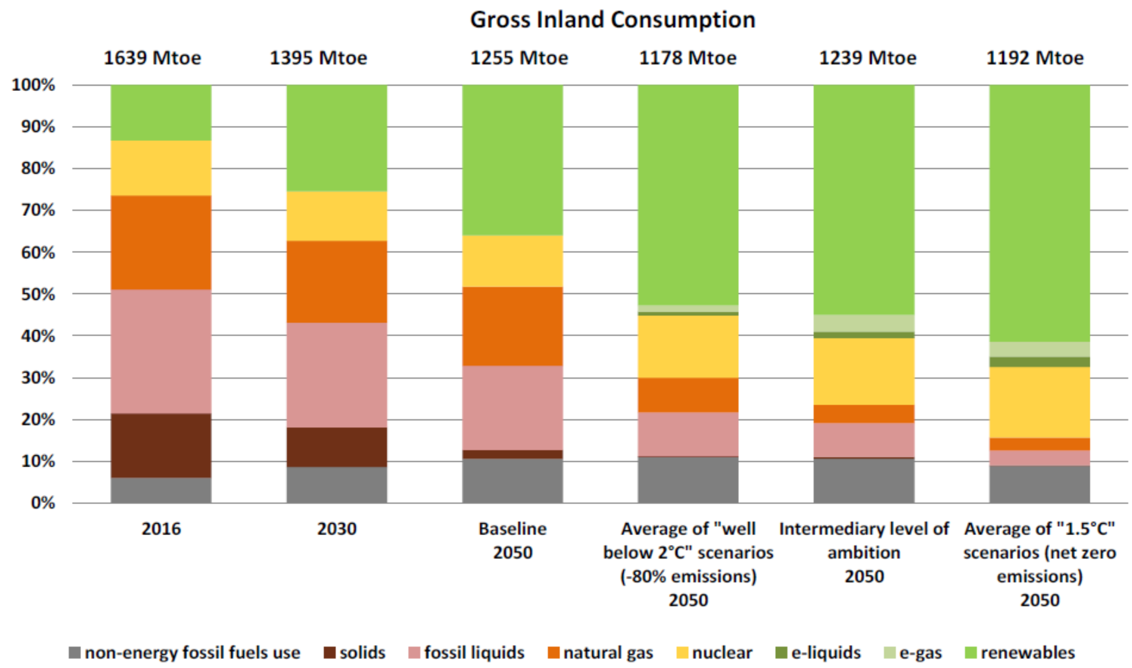
- The make up of primary energy supply – in particular, the role of renewables;
- Final energy demand;
- Electricity supply, demand and flexibility requirements;
- Gas supply and demand; and
- The role of CC(U)S.

2.3.1. PRIMARY ENERGY SUPPLY

All studies assessed find that **a substantial amount of renewable energy production** has to be developed. The expected share of renewable energy in the EU's primary energy consumption by 2050 is generally considered to be high: IRENA (2018) reports 74% renewable energy, Asset (2018) up to 51% and Greenpeace (2015) find 79% and 92%, depending on the scenario (E[R] and AE[R][2], respectively), while exact values are not provided in the other studies. The recent EU scenarios presented in the EU's long term strategy (EC, 2018a) result in a total share of renewable energy of about 55% to 70% in gross inland consumption, as illustrated in Figure 2 below. In general, the share of renewable energy in the EU's 2050 primary energy supply is found to depend on the level of decarbonisation achieved, the contribution of nuclear energy, and the level of CCS which may enable continued use of natural gas and oil in a decarbonised future.

[2] E[R] = Energy [R]evolution scenario; AE[R] = Advanced Energy [R]evolution scenario

Figure 2 Fuel mix in Gross Inland Consumption in the EU: in 2016, forecast for 2030, baseline for 2050 (current policies) and averages of scenarios for different GHG reduction scenarios (from (EC, 2018a)).



NB. E-gas = gases produced with renewable electricity (Power to Gas); e-liquids are liquid fuels produced from these gases.

Where this is clearly quantified, the vast majority of this renewable energy is assumed to be produced within the EU. This may be the result of cost assumptions in the scenarios (this is, for example, the case in the recent EU decarbonisation scenarios in (EC, 2018b) and in the Greenpeace scenarios (Greenpeace, 2015)). In some cases, it is the result of an explicit choice made in the scenario or storyline, for example to explore the benefits of the EU's potential for growth of domestic renewable energy production, or to reduce Europe's energy independence (as mentioned in the Asset study (ASSET, 2018), for example). That said, it may be cheaper to import renewable energy from outside of the EU (partiuclarly gases and fuels which may be cheaper to transport over long distances than electricity), where the economics may be more favourable (e.g. solar in northern Africa or the Middle East[3]). Clearly, though, the future costs of producing renewable gases remain subject to uncertainty and the security of supply implications of large-scale imports would require further consideration.

Some scenarios do explicitly consider the import of gaseous or liquid renewable gases (and biomass) from outside the EU. For example, CSP-produced[4] renewable gases imported from the MENA area (mentioned in the (A)E[R] scenarios), or import of CO_2-free gas from Eastern countires outside EU (mentioned in the Trinomics study).

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[3] https://www.agora-energiewende.de/fileadmin2/Projekte/2017/SynKost_2050/Agora_SynKost_Study_EN_WEB.pdf

[4] CSP is an abbreviation for Concentrated Solar Power

However, the scenarios are descriptive in this respect and do not present detailed quantifications.

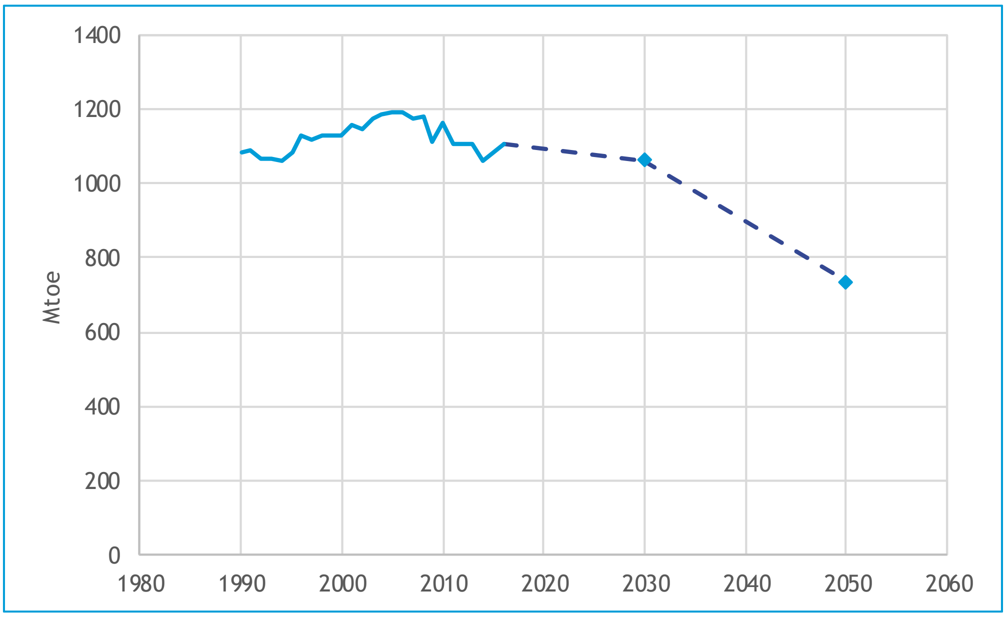
In the scenarios where these electricity based fuels play an important role (and are produced within the EU), primary energy demand is larger than in many other scenarios, due to their relatively low conversion efficiency[5] - even though the final energy demand might not be that different.

2.3.2. *FINAL ENERGY CONSUMPTION*

A **significant *final energy* demand reduction due to energy savings and energy efficiency** of end-use applications is an important aspect of all scenarios. The highest energy efficiency gains are expected in heat demand. For example, Trinomics et al (2018) assume a decrease of 50% by 2050 in all storylines. These energy savings are achieved through measures such as new energy efficient buildings, building insulation, and more efficient heating, e.g. highly energy efficient electrical heat pumps. The scenarios developed for the Commission's long-term strategy (EC, 2018a) also all result in 24% - 38% reductions of final energy consumption in 2050, compared to 2015 energy consumption levels. These figures are put into the context of historical final energy demand in the EU in Figure 3 below.

[5] This is observed, in the Assets study (ASSET, 2018) and for example, in comparing the Energy [R]evolution (E[r]) and Advanced Energy [R]evolution (AE[r]) scenarios of Greenpeace (Greenpeace, 2015) for the OECD Europe. The latter results in a 100% decarbonised energy system by using more renewable gases, while the E[r] does not result in 100% decarbonisation. The additional conversion losses result in a 3.4% higher primary energy demand, while the final energy demand is 0.6% lower.

Figure 3 EU final energy demand, historic data (from Eurostat), forecast for 2030 and average for the decarbonisation scenarios for 2050 developed for the EU 2050 strategy (EC, 2018a)



The evolution of final energy demand within the key end-use sectors can be characterised as follows:

- In **transport,** a shift towards transport modes with lower climate impact, so-called **modal shift, is an important measure** to achieve energy savings, together with energy efficiency measures.
- All scenarios assume **a strong reduction in heat demand of buildings**.
- In **industry,** energy efficiency measures are applied (best available technologies and innovations), resulting in lower energy demand.

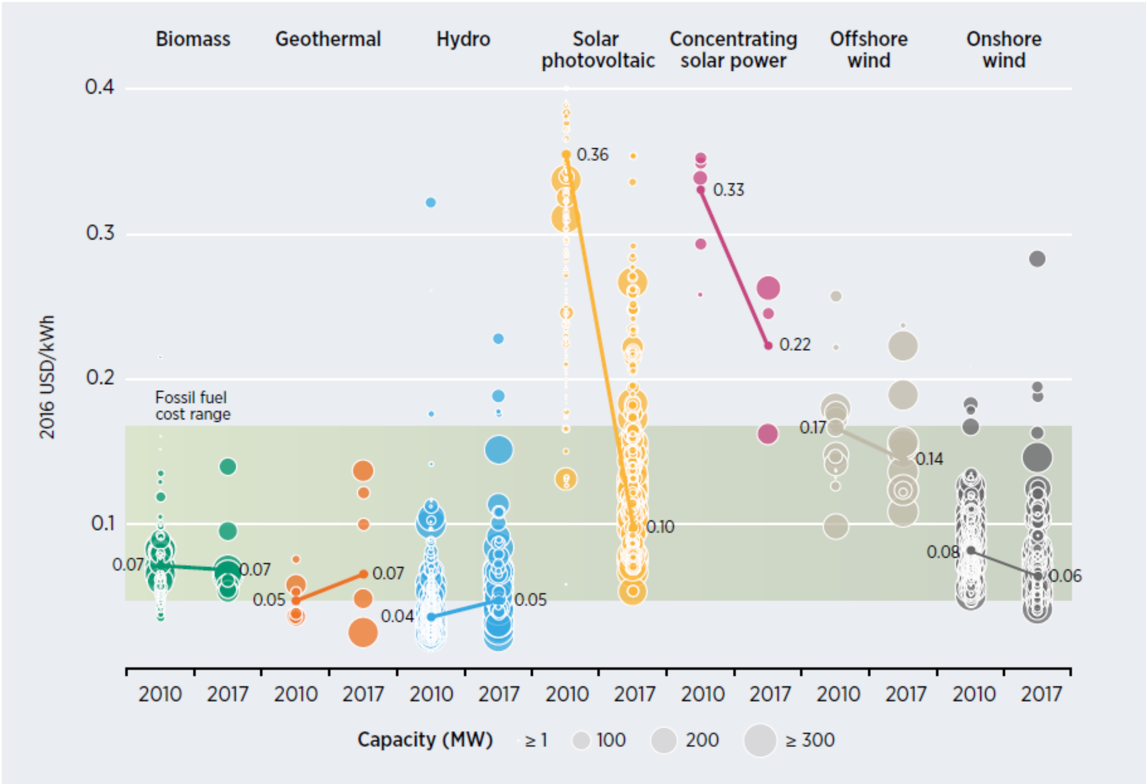
2.3.3. ELECTRICITY SUPPLY, DEMAND AND FLEXIBILITY

In all scenarios, **electricity is increasingly produced from renewable sources, mainly from wind and solar power**[6]. The main reason for this development is that, within the constraints of the scenarios and storylines (e.g. policy drivers such as an increasing CO_2 price, or CO_2-emission constraints/targets), these two technologies become increasingly competitive, with both having significant growth potential. Their production costs are relatively low (in terms of €/kWh), compared to alternative low-carbon and renewable energy options. This is illustrated in the figure below, which is from a study on Renewable Power Generation Costs in 2017 by IRENA (IRENA, 2018b). The figure shows the significant reductions achieved globally in recent years in the levelised cost of electricity for various utility-scale renewable power generation technologies. Their share therefore increases further as fossil-fueled power generation

[6] Asset (2018) reports a RES share in power generation in the EU slightly above 70% by 2050 (around 50% in 2030). IRENA (2018) reports a 94% share of renewable energy in power in the EU for the 2050 REmap scenario. Greenpeace (2015) reports a 95% in the E[R] scenario (66% in 2030), and 100% in the AE[R] scenario (70% in 2030) for OECD Europe (including Israel and Switzerland) in 2050. In the E[R] scenario about 34% (27%) of the electricity generation consists of wind energy and 37% (11%) of PV, in AE[R] this is 36% (30%) and 41% (13%) in 2050 (2030), respectively. Even without RES for renewable hydrogen.

is gradually replaced by power generation from renewable sources (or other forms of carbon-free electricity).

Figure 4 Global levelised cost of electricity from utility-scale renewable power generation technologies, 2010-2017 (from (IRENA, 2018b)).



Source: IRENA Renewable Cost Database.

Note: The diameter of the circle represents the size of the project, with its centre the value for the cost of each project on the Y axis. The thick lines are the global weighted average LCOE value for plants commissioned in each year. Real weighted average cost of capital is 7.5% for OECD countries and China and 10% for the rest of the world. The band represents the fossil fuel-fired power generation cost range.

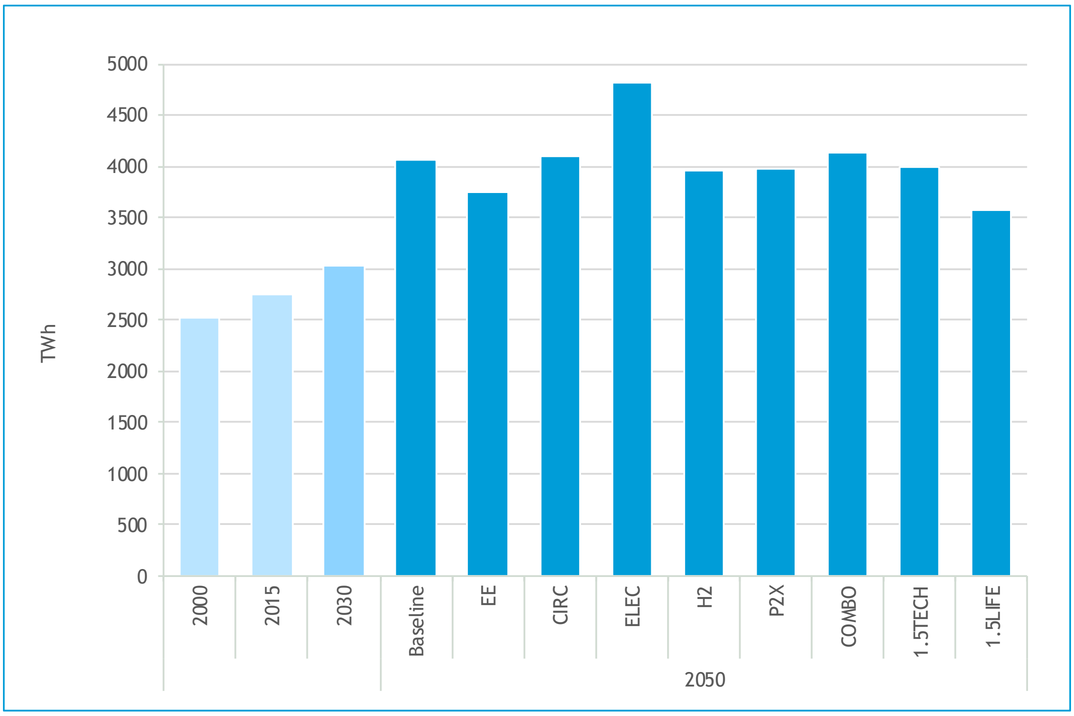
Simultaneously, **overall electricity demand is forecast to increase** over time for two reasons:

- Decarbonisation relies in part on **electrification of end-use applications**, notably in heating (heat pumps) and transport (battery electric vehicles). These technologies can be a very efficient means to move from fossil to renewable energy in these sectors and applications, at a cost that could be competitive with alternative decarbonisation options in parts of these sectors. For example, all scenarios consider electrifcation of passenger cars to be the most cost-effective means to decarbonise that part of the transport sector. While these technologies increase electricity demand, they reduce final demand for fossil fuels (mainly natural gas and oil-based fuels).

- The production of some **renewable or low-carbon alternative fuels**, such as electrolysis based hydrogen (power-to-hydrogen), methane (power-to-methane) and liquid hydrocarbons (through power-to-liquids) requires vast amounts of renewable electricity.[7]

These trends are illustrated in the following graph, which shows total electricity consumption in 2050 in the EU for the decarbonisation scenarios developed for the EU long term strategy (EC, 2018a), compared to historic levels in 2000 and 2015, and the forecast for 2030. Compared to 2015, electricity consumption is expected to increase by 30% to 75% until 2050, which amounts to yearly increases by between 0.7% and 1.6%, on average[8].

Figure 5 Total EU electricity consumption (in TWh) in the decarbonisation scenarios of the EU long term strategy for 2050, compared to 2000 and 2015 actual consumption and 2030 forecast consumption. Data source: European Commission



This growth of renewable electricity production from energy sources with an intermittent and variable character, creates a growing **need for power system flexibility**, for times where wind and solar power production are insufficient to meet power demand. Solutions to this challenge depend on the scenarios considered.

Many scenarios feature (natural) gas fired power plants (gas turbines and CCGT), whether or not combined with CCS, in the short to medium term. These can in principle be fuelled with any of the gases included in this report, including natural gas, biomethane, renewable hydrogen and methane, and synthetic methane, although modifications will be necessary[9]. As gas fired power plants are more flexible and less carbon intensive than other fossil fuel power plants, **gases (including natural gas)**

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[7] This is due to their relatively low conversion efficiency from electricity to gas: about 67-87% efficiency is expected in the long-term for electrolysis and 59-73% for power-to-methane (Trinomics, Ludwig Bölkow Systemechnik, Artelys and E3-Modelling, 2018).
[8] For comparison, recent decarbonisation pathways developed by Eurelectric resulted in average yearly growth rates of final electricity demand by between 1.4% and 2.6%, over the same time period (Eurelectric, 2018).
[9] The use of hydrogen or hydrogen blends in power plants is further elaborated in the section on deployment of Appendix A

can serve as a transition fuel enabling a fast growth of renewable electricity production as these plants can be ramped up or down quickly in times of fluctuating supply from wind and solar production, while reducing carbon emissions at the same time.

Other flexibility options (in power demand) become increasingly important, such as: batteries and demand response. Electrolysers that convert renewable electricity to renewable hydrogen also fall into this category, if their operation varies with power production. The importance of each of these technologies differs in each scenario. While electrolysers play an important role in scenarios with a focus on application of hydrogen, batteries and demand side management are more important in scenarios with a stronger focus on electrification.

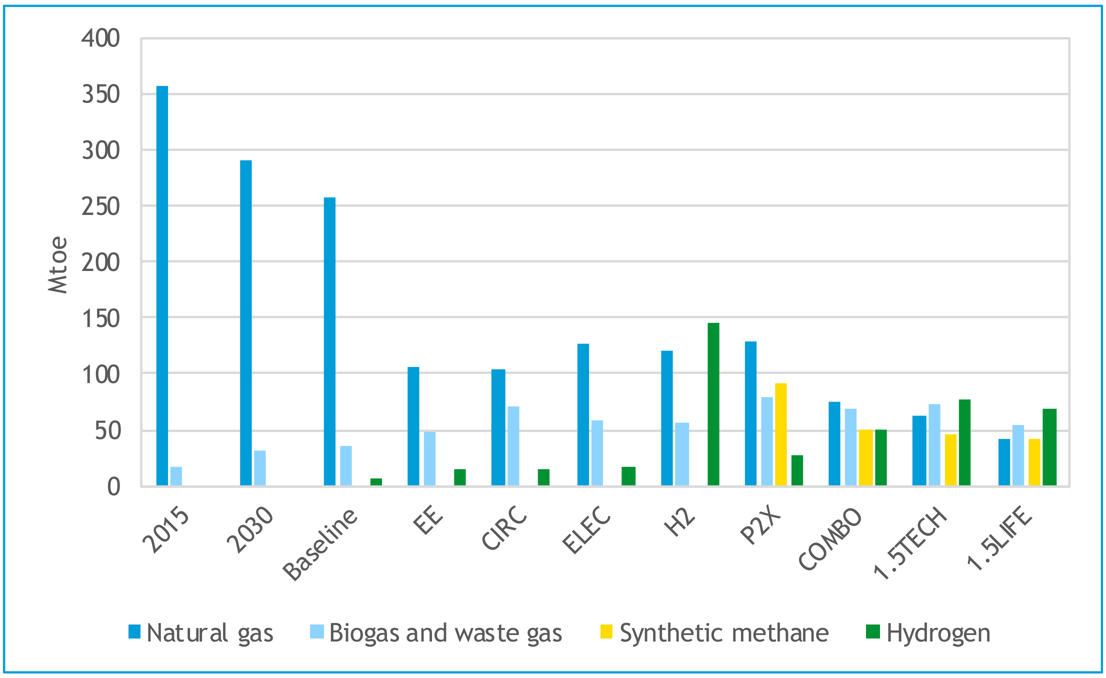
2.3.4. GAS DEMAND AND SUPPLY

In some scenarios, **natural gas demand** peaks somewhere around 2030 due to the shift from solid fossil fuels to natural gas (mainly in power production). In the scenarios developed for the EU Long-term Strategy (EC, 2018a), EU-wide natural gas demand is already expected to be 18% lower in 2030 than in 2015 (a reduction from 358 Mtoe to 292 Mtoe).

From 2030 onwards, scenarios tend to show a reduction or phase-out in natural gas demand as it is gradually replaced by renewables or synthetic fuels (e.g. hydrogen, synthetic methane). Some gas power plants continue to deliver flexibility when their fuel is switched to biomethane, renewable or synthetic hydrogen. In the scenarios that achieve high levels of decarbonisation of the energy sector, any residual use of natural gas in power production is in conjunction with CCS, rather than unabated. In the (EC, 2018a) scenarios, by 2050, natural gas demand is expected to be between 64% and 88% lower than in 2015, depending on the GHG emission reduction ambition. In absolute terms, this means a reduction in natural gas demand to between 42 and 130 Mtoe in 2050.

The demand for natural gas and other gases in 2015, 2030 and in the various 2050 scenarios is shown in the following figure.

Figure 6 EU demand for gaseous fuels, in 2015, forecast for 2030, baseline for 2050 and different decarbonisation scenarios for 2050 developed for the EU 2050 strategy (EC, 2018a).



Within each end-use sector, the main drivers of demand for gases can be summarised as follows:

- In **transport,** while the majority of cars and light duty vehicles are expected to be battery electric vehicles (BEV) by 2050, **renewable hydrogen** is expected to make up a large share in the overall transport fuel mix, particularly for heavy duty vehicles. Renewable methane and renewable liquid fuels (both Power to Liquids and advanced biofuels) are also used in (mainly) heavy duty and long-distance vehicles. Renewable fuels can also be applied in maritime transport and aviation[10]. While some scenarios focus more on electrification, hydrogen or renewable methane, they all expect a mix of fuels and technologies.
- All scenarios assume an increasing market penetration of heat pumps in **buildings**, resulting in **electrification of heat demand**. Solid biomass, biomethane, solar collectors, geothermal heat, environmental heat and hydrogen will **reduce demand for natural gas and other fossil fuels**. Several scenarios see an important role for **renewable hydrogen** in domestic heating, while other scenarios assume a large share of **renewable methane combined with biomethane**, blended with natural gas until 2050.
- In **industry,** heat demand will be made more sustainable by applying, where possible, heat pumps, solar and geothermal heat, bioenergy, power-to-heat and renewable hydrogen or methane. This will substitute at least some of the natural gas used in industrial processes today. Emissions from remaining natural gas use will be captured and stored (CCS). However, **some process emissions are considered inevitable** (or very costly to reduce) and will remain in industry.

[10] Trinomics et al (2018) and Greenpeace (2015) describe this option.

The **potential role of biomethane depends** in all scenarios on assumptions regarding the availability of sustainable biomass for biogas production:

- A study by CE Delft, Eclareon and Wageningen Research (CE Delft, Eclareon en Wageningen Research, 2016) for the European Commission focusses on biomethane production from anaerobic digestion from waste streams and waste gas from sewage sludge. These gases are in line with the RED II sustainability criteria and do not count towards the 7% cap on biofuels produced from food and feed crops. The study estimated that this biomethane could represent 2.7-3.7% of the total EU energy consumption in 2030, depending on the amount of feedstock deployed and the learning effects attainable. This amounts to an increase of biogas production from the current level of 14.9 Mtoe towards 28.8 to 40.2 Mtoe in 2030 (CE Delft, Eclareon en Wageningen Research, 2016).
- Consistent with this, as shown in Figure 6 above, the recent European Commission scenarios project EU biogas and waste gas consumption of 36 Mtoe in 2030, further increasing to 47 – 80 Mtoe in 2050.
- ICCT (2018) finds that biomethane produced from manure and sewage sludge could displace at most about 34 Mtoe, or 7% of current gas demand. If this entire renewable methane potential were used in transport, it could displace 7% of total transport energy demand in 2050. If it were instead used in heating, it could displace 10% of energy use in residential heating, or 3% of energy demand in power generation (ICCT, 2018).
- A study commissioned by Gas for Climate (Ecofys, 2018) takes a broader view, by also looking at the potential of sustainable biomethane production with thermal gasification, from woody biomass types, and also taking into account agricultural produce additional to existing crop production (in a 'sequential cropping' scheme). Their assessment finds an EU biomethane potential of at least 94 Mtoe, of which about 60 Mtoe is produced with anaerobic digestion and the remainder from thermal gasification.

The **role of electricity-based hydrogen and synthetic gases (Power to Gas) differs** per scenario. For example, in the scenarios for the EU long-term Stategy (EC, 2018a), consumption of these gases varies between about 14 and 146 Mtoe in 2050, which amount to a share in the total energy consumption of 2% to 18%, respectively (see also Figure 6 above). The high end of this range in particular requires a very ambitious growth path for these technologies between 2030 and 2050, considering that their production and consumption is virtually zero at the moment, and the Commission does not expect a signficiant contribution by 2030. For comparison, the Gas for Climate study (Ecofys, 2018) estimates a potential to produce renewable gas from power by 2050 to be about 23 Mteo.

Unless the additional electricity demand required for Power to X production is met by additional RES or zero-carbon generation (or by RES or zero-carbon generation that would otherwise have been curtailed), Power to X production will lead to additional emissions within the power sector. This may be particularly relevant in the 2030 timeframe during which fossil fuels might play a large role in the electricity mix, though is likely to be less relevant towards 2050.

Methane leakage

At various steps of the natural gas, biomethane and synthetic methane value chains, methane emissions may occur: during gas extraction or production, during transport and distribution or during final use. Methane has a GHG impact of about 25 times that of CO_2 over a 100 year period, with an even higher short and medium term impact: 72 times that of CO_2 over a 20 year period (EC, 2018b). Even a small percentage of methane leakage can have a high impact on GHG emission reductions of a fuel switch (from coal, for example) to methane. These emissions must therefore be taken into account in the GHG impact assessment of various routes and projects, and mitigation measures will be needed to reduce the climate impact of these gases (Trinomics, Ludwig Bölkow Systemechnik, Artelys and E3-Modelling, 2018) (EC, 2018b).

2.3.5. *THE ROLE OF CC(U)S*

The **role of CCS and CCU is limited in most decarbonisation scenarios** and sometimes not even applied (e.g. in the Energy [R]evolution scenarios). Where these technologies are included, they are applied in industry and power generation.

CCS is in use in a range of projects globally, but not yet in the EU. Cost are not competitive in the current policy framework and in some cases (e.g. in the Netherlands) lack of public support for subsurface CO_2 storage has been a barrier to its deployment. Various CCU projects are at commercial pilot stage around the world[11]. Both CCS and CCU are deemed technically feasible for large point sources of carbon emission (power plants and CO_2-intensive industry). Many scenarios find that this technology may become a competitive decarbonisation solution for certain sectors in the future, allowing the continued use of fossil fuels in a decarbonised energy system.

The potential contribution of CCS and CCU to future decarbonisation is therefore uncertain, depending on cost developments (of CC(U)S but also of alternative decarbonisation options), policy incentives, markets and standards (EC, 2018b). To illustrate their potential role: the recent European Commission scenarios find that CCU and CCS may be a cost-effective option for CO_2-reduction in industry, most notably in the cement and chemicals industry, but their role is likely to be limited to 0.1-0.5% of electricity production in 2050 (although in one scenario, 1.5TECH, this share increases to 5%) (EC, 2018b).

2.4. KEY UNCERTAINTIES

Whereas the scenarios have various common key elements, developments that are 'likely to happen', uncertainties and how these are addressed in the scenarios and storylines can be equally relevant. In scenario modelling and storyline development, uncertainties are typically reflected as different assumptions, for example regarding cost development over time, or policy support and drivers.

Common assumptions on key uncertainties result in similarities between scenarios, while on the other hand the different views on uncertainties can result in major differences between the scenarios. The following key uncertainties have been identified:

- **Electrification versus renewable and low-carbon gases**: scenarios differ in the relative importance of these two carriers in transport and heating (in part due to the other uncertainties listed below).

- The **role of nuclear** power is uncertain. In some scenarios, it is phased out quickly (e.g. Energy [R]evolution), in others it is sustained at today's level (e.g. REmap scenario) or increases to a varying degree (EC, 2018a), and in others it is simply not mentioned. The more nuclear capacity there is in the future electricity mix, the less need there will be for alternative sources of (seasonal) electricity system flexibility. This could in turn facilitate increased electrification of heating demand.

[11] CO_2 utilisation projects

- **The role of renewable hydrogen and Power to Liquids**: scenarios differ in the amount produced and sectors they are applied in.

- **Advanced biofuels, biogas and biomass**: there are uncertainties about availability of feedstock and most scenarios do not discuss the applications of these energy carriers in detail.

- Energy carriers in **maritime and aviation**: these sectors are out of scope in many scenarios, though advanced biofuels, Power to Liquid and renewable and low carbon gases are all mentioned as options.

- Uncertainty about the **role of natural gas**: in some scenarios, natural gas is fully replaced by renewable alternatives. In others, natural gas is projected to still play a minor role in industry and in power production in 2050 (in both sectors combined with CCS if high levels of decarbonisation are to be achieved).

- Many scenarios envisage a **role for CCS** as a cost-effective decarbonisation option for certain industrial processes and, to a lesser extent, for power generation. However, the importance of CCS to the overall decarbonisation effort is typically expected to be limited, and varies between scenarios. If CCS were to be established, it could also enable further production of low-carbon hydrogen from natural gas (through steam methane reforming).

2.5. CONCLUSIONS

Scenarios and storylines that have been developed in recent years to assess how to achieve full decarbonisation of the EU's energy system by 2050 are still very exploratory, describing possible futures rather than forecasting what will happen. Nevertheless, many features can be identified that are common to all studies assessed, despite their variation in focus, regional scope and assumptions:

- The future energy system is based on a large share of renewable energy as primary source of energy, with a large share of renewable electricity notably from solar and wind (produced in the EU) and biomass use in all sectors.

- Fossil fuel use will be largely phased out, with uncertainty over the remaining role for natural gas. Natural gas might play a minor enduring role in industry and power generation. The extent of this role is partly dependent on whether CCS can be deployed commercially, which is itself uncertain.

- Total final energy demand is expected to reduce significantly through energy efficiency measures in all end-use sectors, notably with a large reduction in heat demand.

- Electrification will be a key development in transport and heating, though many scenarios also feature significant use of renewable and low-carbon gases. Precisely which gases are used is a further uncertainty, with hydrogen, synthetic methane and biomethane all featuring in varying quantities by 2050.

- Increased electrification of final demand and Power to X production will likely result in an increased demand for electricity. Additionally, Power to X production involves efficiency losses that amplify the increase in electricity demand.

- In power production, carbon intensive fossil fuels (coal, lignite, oil) are expected to be replaced by renewable power production, with use of natural gas potentially increasing in the transition (i.e. to 2030) but eventually largely being phased out by 2050. The long-term role of nuclear power is a key uncertainty: without it, and without widespread deployment of fossil generation with CCS, there will be a greater need for seasonal flexibility elsewhere in the power system.

- System flexibility for the electricity grid is expected to be achieved by a combination of demand side management/response (DSM/DSR), energy storage (for example in batteries, heat storage, or in hydrogen or synthetic methane) and peak gas power plants. The latter can be run on natural gas, with increasing shares of renewable or low-carbon gases (biomethane, hydrogen and/or methane from renewable electricity or from natural gas with CCS).

The topics most relevant to the gas sector and sector coupling are elaborated further in the next chapters.

3. THE ROLE OF GASES AND GAS INFRASTRUCTURE IN A DECARBONIZED ENERGY SYSTEM

3.1. INTRODUCTION

Whereas the previous chapter outlined what a decarbonized energy system in 2050 could look like and what the key elements and key uncertainties of this future system may be, this chapter provides insights into the effects of decarbonisation of the EU energy system on supply, storage, transport, and demand of gases and on gas infrastructure. To do so, the chapter zooms in on the aspects of the future energy system most relevant for the role of gases and the associated gas infrastructure requirements.

We distinguish between two dimensions that develop in the period up to 2050, and impact on the changing role of gases over time:

- **The green dimension** which describes the increasing uptake of renewable and low-carbon gases, replacing natural gas and other fossil fuels. These renewable and low-carbon gases can provide system benefits and contribute to the decarbonisation of the EU economy in line with the 2030 EU targets and consistent with the EU's longer term (i.e. 2050) commitments under the Paris Agreement.

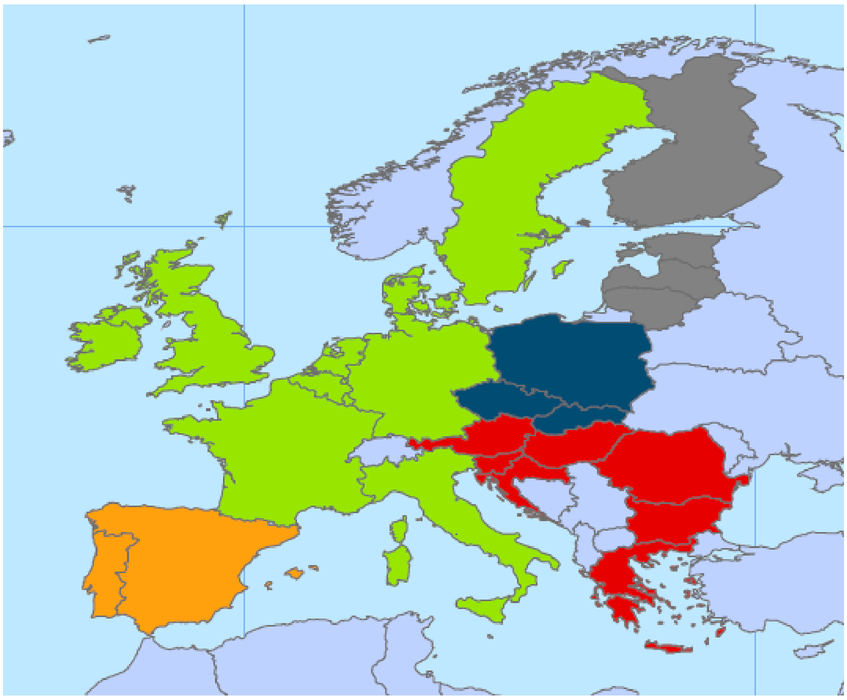
- **The substitute dimension** in which natural gas can still play a role as transition fuel in replacing fossil fuels with higher carbon content, i.e. coal and oil.

Both dimensions are discussed in separate sections (3.2 and 3.3), although they will coexist in the coming decades. To meet the longer-term EU and national energy and climate goals, the substitute dimension will need to diminish in the period 2030-2050 in favour of the green dimension. We discuss the deployment potential of renewable and low-carbon gases in section 3.4, before discussing potential future gas infrastructure needs in section 3.5.

As explained in the introduction to this report, the descriptions in this chapter are mainly qualitative. The precise outcomes in terms of the supply of and demand for gases are still very uncertain and not of key relevance for the regulatory assessment that is the main objective of this study. The main aim of this chapter is to give a comprehensive overview of the potential role of gases in the energy transition of the coming decades and in a decarbonised energy system in 2050. The policy and regulatory assessment will then need to provide the necessary boundary conditions and policy framework to enable and facilitiate these developments, fully taking into account existing uncertainties.

The results of the analysis in this chapter are provided at the EU level. However, the role of gases differs by region within Europe, and will continue to do so in the future. Trinomics et al (2018) provides a regional classification, shown in the figure below. From this figure and its description in the table that follows, it can be seen that the indicated regions differ in the development of renewable gases (particularly the case in the North- and Southwest regions), connection to EU pipelines (limited in the Southwest region) and import dependence (especially an issue in the Northeast/ Southeast/ East). Furthermore, gas consumption in the Northwest region is three times higher than the combined gas consumption of the other regions.

Figure 7 Regional classification of EU countries in relation to the role of gas (Trinomics et al., 2018)



Short summary of area descriptions (Trinomics et al., 2018):

Colour	Region	Short description
Green	Northwest	Developing technical or structural approaches for replacing natural gas by renewable gases and admixing biomethane. Region with high innovation. Gas transport via pipelines, gas from the Netherlands, Russia, Norway and LNG-import. Potential access to renewable gas imports from MENA countries through the Trans-Mediterranean Pipeline from Algeria via Tunisia to Italy.
Orange	Southwest	Decarbonisation of gas is one of the objectives in this region. Limited connection to the EU gas system. Maghreb-Europe Gas Pipeline from Algeria via Morocco to Spain plays an important role, together with LNG imports. Potential access to renewable gas imports from MENA countries.
Red	Southeast	Focus on gas source diversification by developing LNG-import and gas infrastructure, to reduce gas import dependence from Russia. Development of Southern Gas corridor. Might be able to be supplied with green gases from the MENA countries in the future (through Algeria-Italy pipeline).
Blue	East	Important gas transit region. Concerns about security of supply and gas import dependence from Russia. Therefore, development of reverse flow infrastructure and LNG regasification terminals. Possibilities for import of CO2-free gas from Eastern countries outside EU and use of Baltic off-shore wind.
Grey	Northeast	Strong import dependence on Russia, security of supply issues. Some LNG imports. Potential to produce biomethane and renewable gases from Baltic off-shore wind.

3.2. The green dimension

In this section, we first summarise the evidence on overall EU demand for gases in 2050, before discussing the potential roles of different types of gas.

Reduced gas demand in 2050

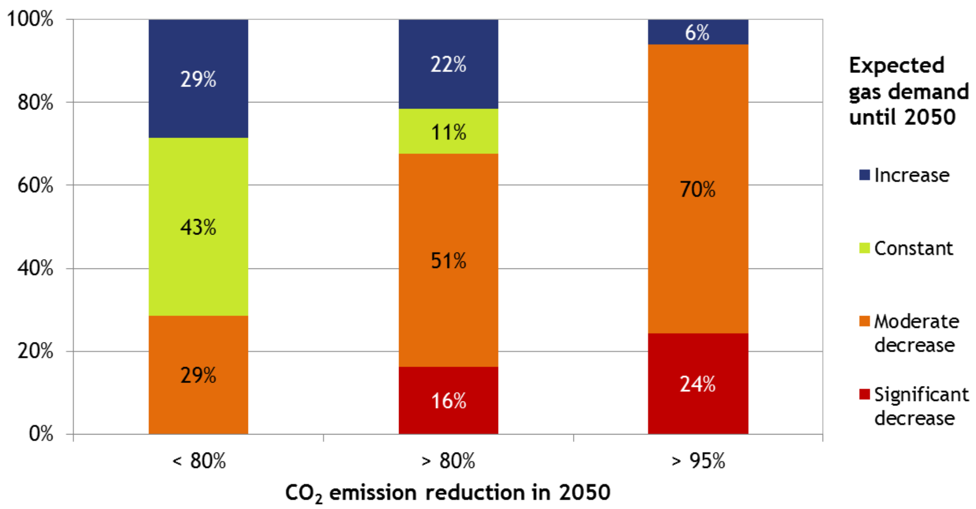
A consistent conclusion from the studied scenarios is that overall gas demand will fall by 2050, although the share of demand met by renewable forms of gas will increase. This is the case in the recent scenarios for 2050 developed by the Commission (EC, 2018b), as was illustrated in Figure 2. It was also the finding of a recent report from Trinomics et al (Trinomics, Ludwig Bölkow Systemechnik, Artelys and E3-Modelling, 2018) where published storylines on the future role of gas and the gas infrastructure across Europe are analysed.

- The vast majority of the storylines with over 80% GHG-emission reduction are found to expect a decrease of the gas demand in 2050 (see figure below).

- In case of over 95% GHG-emission reduction, a decreasing role of gas is expected in nearly all scenarios.

Although the overall gas demand decreases in most storylines, an **increasing gas demand is expected for some sectors, such as the power sector** due to the benefits of flexible gas units in an energy system with a large share of variable electricity production (wind and solar). Also, gas demand **could increase in the transport sector**, replacing oil-based fuels in transport modes with few low-carbon alternatives (although the available studies were found to vary widely in their assumptions of the share of methane combustion engine vehicles versus battery electric or hydrogen fuel cell vehicles), In other sectors such as the heating sector, demand is likely to decrease more strongly as the majority of studies were found to predict a strong impact of improved building insulation and the uptake of efficient electric heat pumps.

Figure 8 Correlation between GHG-emission reduction and expected gas demand until 2050 in storylines (expressed in share of storylines) (Trinomics, Ludwig Bölkow Systemechnik, Artelys and E3-Modelling, 2018)

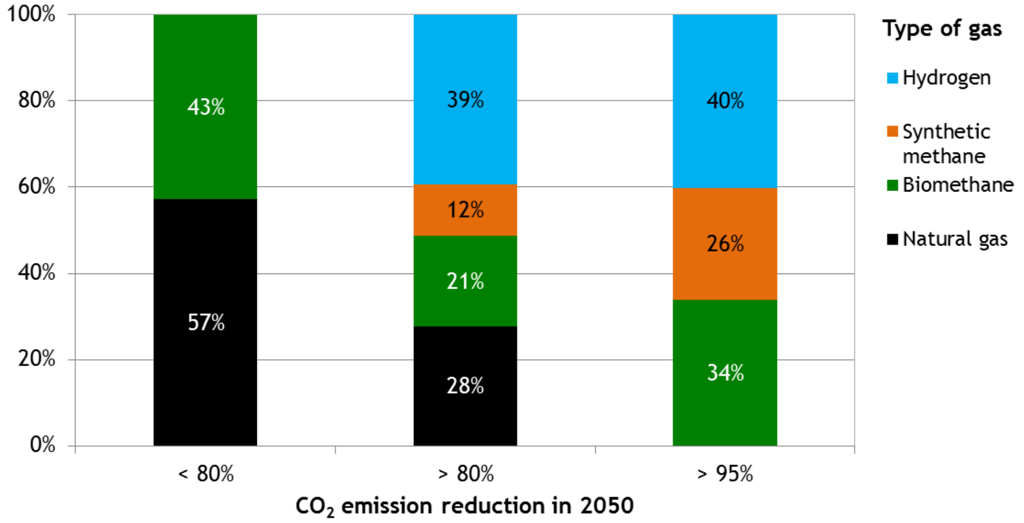


Renewable and low-carbon gases are the preferred gases

Trinomics et al (2018) also analyse the correlation between GHG-reduction and the preferred type of gas in the analysed storylines (see Figure 9 below).

Clearly **hydrogen, biomethane and synthetic methane are the preferred gases** in most storylines with over 80% or over 95% GHG-emission reduction. This is consistent with the requirement to achieve a major shift to carbon emission free energy sources to reach the Paris Agreement climate goals. In storylines with over 95% CO_2 emission reduction, natural gas is completely replaced by renewable and low-carbon gases, predominantly by renewable hydrogen and synthetic methane from renewable electricity (in 66% of the storylines analysed by Trinomics et al (2018)).

Figure 9 Correlation between GHG-emission reduction and type of gas in 2050 in storylines (expressed in share of storylines).



Source: Trinomics et al (2018)

These conclusions are roughly in line with the Commission's recent 2050 scenarios (EC, 2018b; EC, 2018b), although these do not result in a full phase-out of natural gas as was shown in Figure 2 and Figure 6 of the previous chapter.

As will be further discussed in Chapter 4, the prominent role of the production of gases from renewable electricity in the green dimension will enhance sector coupling of the gas and electricity sectors. The price of gas will be increasingly driven by the price of electricity (whereas currently in many markets the opposite is the case) and electricity network flows may become increasingly dependent on those on the gas network.

The role of gases in general

We first discuss the role of gases in general before discussing issues specific to biomethane, hydrogen, synthetic methane an imported gas.

Use of gases can help to minimise the costs of running the energy system, where the counterfactual is increased electrification, as discussed for example in the Gas for Climate study (Ecofys, 2018) and as study on the importance of gas infrastructure for Germany's energy transition (Frontier et.al., 2018):

- In regions with significant use of gas heating, continued use of gas can help to avoid conversion to heat pumps, which, on current cost projections for 2050, would be costlier than gas heating.
- By making use of existing gas transmission and distribution infrastructure, use of gases can help minimise the need for costly reinforcement and upgrades of electricity networks.
- Chemical storage of energy (such as gas storage) may be one of the few feasible solutions for seasonal storage of energy in many regions. By making use of existing gas storage infrastructure, use of gases can help reduce the costs of balancing overall energy supply and demand.

The role of biomethane

Biomethane is the only type of renewable gas already produced and in use in various Member States, most notably in Germany, followed by Italy and the UK (data from the Biogas Barometer (EurObserv'ER, 2017)). Total biogas production in the EU was 16.1 Mtoe in 2016. A large share of this biogas is currently used directly for electricity and heat production, the remaining share (11% in 2015, according to (CE Delft, Eclareon en Wageningen Research, 2016)) is upgraded into biomethane. Biomethane can already be used locally or injected into the natural gas grid (subject to meeting technical standards) and used as a renewable fuel in all sectors: for heat production, dispatchable power production, and as a transport fuel (in CNG or LNG vehicles).

Biomethane can also act as an enabler for integration of variable renewable energy sources, notably wind and solar, when used for dispatchable power production. Such use can reduce the need for fossil power backup plants, contribute to the mitigation of electricity price fluctuations, and assist with balancing the electricity system (CE Delft, Eclareon en Wageningen Research, 2016).

The role of hydrogen

Although recent studies identify hydrogen from renewable energy as one of the most promising energy carriers of the decarbonised future, they also find that it is still currently relatively expensive to produce. As reported, for example, in (EC, 2018b) and (ASSET, 2018), large-scale development of this route requires significant investments, mostly in production facilities (renewable energy production and electrolysers), infrastructure and end-use technology (e.g. process equipment in industry, vehicle engines, household appliances, etc). Whether or not hydrogen will play a signficiant role in (parts of) the future energy system is therefore likely to depend on future cost reductions of the hydrogen value chain and on the cost of alternative decarbonisation options. Compared to electrification, for example, some hydrogen routes may have some key advantages that can outweigh higher cost for certain applications, such as lower transport and storage cost, and the possibility for storage with higher energy density (important for heavy goods transport, for example). For industry, hydrogen from renewable energy would allow for the elimination of emissions in non-energy uses, and it can be used for both high and low temperature heat production (with combustion processes or fuel cells) (ASSET, 2018). These hydrogen applications need the development of a transmission and distribution infrastructure. Existing gas infrastructure can be used or upgraded, but costs are still uncertain. While (ASSET, 2018) concludes that this is a time consuming and expensive endeavour, research for the organisation of Dutch grid operators (KIWA, 2018) concludes that this may be done at moderate cost. A study commissioned by DG Energy is currently ongoing to further assess the impact of the use of the biomethane and hydrogen potential on trans-European infrastructure.

Conventional hydrogen production from natural gas may have a better business case in the near term, and can be a useful – but not an essential - interim route to develop the necessary infrastructure and market for a future 'hydrogen economy'. A study by CE Delft on hydrogen routes for the Netherlands (CE Delft, 2018) argues that in combination with CCS (where politically acceptable), hydrogen production from natural gas can also lead to CO_2 reductions over time while the large scale renewable energy production needed for renewable hydrogen production (at attractive cost) is still being developed. This requires succesful development of CCS, however, which has not yet been realised in the EU as yet[12].

The large-scale development of hydrogen systems could increase the integration between the electricity and heat sectors, if hydrogen is produced from renewable electricity and burned for heat provision or used in fuel cells for power and heat provision. Likely, it could further increase the integration between the electricity and mobility sectors, also with the transport modes that can not be electrifed with battery electric vehicles: hydrogen from electricity may be used in fuel cell electric vehicles (FCEVs) for mobility.

More information on the hydrogen supply chain and technologies can be found in Annex A.

The role of synthetic methane

Synthetic methane can be produced by combining hydrogen produced by water electrolysis using renewable electricity with CO_2 in a methanation process. If no additional fossil fuels are burned to obtain the required CO_2 and the electricity used for the hydrogen production is renewable, the synthetic methane production process is CO_2-neutral. The CO_2 could be retrieved from the air by means of direct air capture, which has been tested in a pilot plant since 2015[13], or it can be captured from bio-based industrial processes or combustion of biomass. The latter option is technologically more mature, as CO_2-capture processes are already in use globally, albeit to capture CO_2 from fossil-based processes (see the examples referred to in footnote 10 and Annex A). Fossil fuel CO_2 emissions could be used for methanation as an intermediate technology but these could only be part of a decarbonised energy system if then captured and reused, to prevent emission of this fossil CO_2 into the air when the synthetic methane is used. These routes are likely to require development of a CO_2-grid to transport the CO_2 from the industrial sources to the methanation plant (the Dutch OCAP grid is an example of such a grid already in operation[14]). See Appendix B for an elaboration on the available technologies for the methane value chain.

Th methanation process adds cost, but methane has some advantages when compared to hydrogen: the resulting gas can make use of existing gas infrastructure without requiring upgrades or changes to quality standards and does not require different end-use applications than natural gas.

Similarly to hydrogen, the development of synthetic methane production and supply could enhance the integration between the electricity and heat sectors. The methane is then burned for heat provision (in conventional boilers or used in internal reforming fuel cells for power and heat provision). Further integration of the electricity and mobility sectors could occur when synthetic methane is used in compressed methane vehicles.

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[12] CCS projects are in operation outside the EU, though, for example the Sleipner project in the North Sea (Norway) and in various projects in the USA. See Carbon capture, utilisation and storage for a global overview

[13] Direct Air Capture

[14] The Dutch OCAP grid is an example of such a grid already in operation, see OCAP Nederland

Import of gases

Even though most scenarios and storylines focus on domestic production of renewable energy, it is possible that the import of renewable and low-carbon gases could become a competitive alternative and should not be overlooked when assessing policy and regulatory barriers. Potential future import of renewable and low-carbon gases may be possible from the MENA region (to Northwest/ Southwest/ Southeast Europe) or from eastern non-EU countries (to Northeast/ East Europe). These trade routes could make use of existing natural gas pipelines, provided the gases are compatible with EU gas network technical standards.

Furthermore, biomethane and synthetic methane could be imported globally, through LNG terminals and dedicated ships. The same may become possible for hydrogen imports as well, if existing LNG terminals are adapted to hydrogen (or new hydrogen terminals are built) and if hydrogen transport ships are developed and built. These do not yet exist.

3.3. THE SUBSTITUTE DIMENSION

Concurrent to the increasing replacement of natural gas by renewable and low-carbon energy sources (the green dimension) a parallel development may increase the demand for natural gas temporarily in the coming decades.

Natural gas as a transition fuel

In this substitution dimension, **the role of natural gas will become more important especially in power production and the transport sector**, while natural gas for (domestic) heating becomes less important. Compared to many other fossil fuels natural gas has lower CO_2-emissions per unit of energy. CO_2-emission reductions can therefore be achieved by replacing carbon intensive fossil fuels with natural gas, for example coal in power production and diesel in transport. EU climate and energy policies, such as the EU ETS carbon price and emissions limits for participants in capacity remuneration mechanisms, should also incentivise a shift in power production from coal to gas.

A fuel switch from coal to natural gas is expected to be more easily achieved than an immediate switch to, for example, hydrogen, since conventional technologies for natural gas are mature and in place and existing infrastructure can be used.

Furthermore, natural gas can be blended with renewable energy carriers, allowing for gradual decarbonisation over time whilst using the existing gas infrastructure. For example, biomethane, hydrogen (from either electrolysis or natural gas with CCS) and synthetic methane can be added to natural gas.

- Synthetic methane has a very similar chemical composition to natural gas and so can in principle be blended with natural gas without restriction.
- Biomethane can also be injected in the gas network. However, it typically has a higher oxygen content compared to natural gas. Given some assets connected to the gas grid (such as storage facilities) can sometimes be sensitive to higher concentrations of oxygen, this means that solutions need to be found to protect such assets (including stricter oxygen limits or removing oxygen from gas at the connection point for the vulnerable assets) (Trinomics, Ludwig Bölkow Systemechnik, Artelys and E3-Modelling, 2018).
- Hydrogen can be blended with natural gas up to possibly about 15% or 20% by volume, but research is ongoing to further assess this technology. (Trinomics, Ludwig Bölkow Systemechnik, Artelys and E3-Modelling, 2018) conclude that where some studies suggest that hydrogen could be blended with natural gas

up to 10 or 15% of the gas by volume, without requiring major adaptations to the gas transmission infrastructure and end-user appliances, other sources refer to 2% maximum, in order to avoid risks for corrosion in the transmission grid, and negative impacts for end-user appliances, in particular gas fuelled vehicles. In the UK, the HyDeploy project is ongoing to assess the implications of a $20\%_{vol}$ hydrogen blending level on gas appliances through laboratory and field testing (Cadent, 2018).

And finally, **(modern) natural gas fired power plants can substantially contribute to delivering the system flexibility** needed to allow for a fast growth of intermittent renewable power production. At the same time new flexible loads, e.g. electrolysers, can be developed.

For these reasons, natural gas is considered as a transition fuel in many scenarios.

However, there are also **concerns that increased use of natural gas for these applications could lead to a lock-in effect**, making the eventual transition towards low-carbon solutions more difficult and costly. In power production, a subsequent fuel switch from natural gas to renewable hydrogen may be relatively easy: hydrogen turbines are somewhat different to natural gas turbines but the balance of plant (boilers, compressors, pumps, cooling systems) will be similar to that of a natural gas plant. This is not the case for all applications. Natural gas vehicles, for example, are not likely to be converted to hydrogen, as hydrogen vehicles will rather make use of fuel cell technology, which can have a two times higher energy efficiency than hydrogen combustion engine vehicles. See also Appendix A for more information on these technologies. In general, with sector coupling technologies in mind, such lock-in should not arise if the emphasis is on preservation of existing infrastructure (rather than on significant new investment) and as long as the 'option' to re-purpose infrastructure for renewable and low-carbon gases is maintained.

As is currently the case, in the period between now and 2050 the role of natural gas differs per sector and Member State. The substitute dimension may lead to an increasing natural gas demand in the power sector in countries that switch from coal to gas to achieve GHG emission reduction (e.g. due to planned closure of coal power plants in Germany, the Netherlands, or due to increasing CO_2 prices), whereas other countries might opt for a shift from coal towards renewable energy (including renewable gases) without increasing natural gas demand. In any case, all studies assessed show that **in 2030 natural gas will still be the dominant type of gas. By 2050 it will be strongly reduced or completely replaced by renewable or low carbon gases**.

3.4. RENEWABLE AND LOW-CARBON GAS DEPLOYMENT POTENTIAL

The green dimension clearly relies on the increasing availability of renewable and low-carbon gases. Renewable and low-carbon hydrogen and methane can then be potentially deployed in all main energy applications (sectors): electricity, heat, mobility, and also as feedstock for the chemical industry. However, a number of constraints can be identified:

- Biomethane, methane and hydrogen from renewable electricity and possibly hydrogen from natural gas with CCS could replace natural gas in these sectors, but they compete with other decarbonisation options in all of them. Their market shares will therefore develop depending on cost developments of these gases and the alternative options, their availability, the policy and regulatory framework, consumer preferences, etc.
- At the same time, the deployment potential of these gases will be constrained by their competiveness in comparison to fossil fuels, determined by similar factors.

- Also, the available production capacity for renewable and low-carbon gases sets a physical limitation to this potential.

Electricity sector
In the electricity sector, renewable electricity generation will play a dominant role, but during periods of energy shortage, biomethane and possibly also hydrogen and methane produced from electricity during surplus periods[15], could be (re)converted to electricity. This can become especially important in power systems to manage seasonal swings in energy demand (for which batteries would be inappropriate) and to bridge windless periods, which could last weeks.

Heating sector
Regarding residential and industrial heating, natural gas currently has a dominant share in most European countries. Renewable methane (biomethane or synthetic methane) may be the 'natural' substitute, as they allow for continued use of the existing infrastructure and applications. Compared to synthetic methane, the use of renewable hydrogen would prevent the need of an additional methanation step, which would reduce cost and increase overall energy efficiency but it creates the need for modification of the natural gas network and investment in hydrogen boilers. Replacing the natural gas by biomethane could be an option in locations where there is sufficient potential available. In addition, a range of alternative options may be more cost-effective in many cases, such as switchting to electric heat punps, solar or geothermal energy or residual heat from industry. These routes are likely to have high up-front costs and may require heat distribution grids or electricity grid expansation. In combination with (small-scale, local) heat storage heat pumps would allow for direct use of renewable electricity, reducing the need for hydrogen conversion and/or methanisation. Which option is the most attractive will depend on the overal system costs of the various routes in the specific situation.

Mobility sector
In the mobility sector, battery electric vehicles (BEV) will form a main competitor of hydrogen and methane vehicles. When charged using currently available electricity from wind and solar power, battery-electric vehicles have a much better round-trip efficiency than hydrogen and methane vehicles when hydrogen and methane are produced from electricity (in the order of 80-90% for BEVs vs. 30-40% for FCEVs). However, it may not always be possible to charge BEVs during electricity surplus periods (e.g. when fast charging is used). Furthermore, BEV charging infrastructure could well become more expensive than hydrogen refuelling infrastructure when considering millions of road vehicles, as is concluded in (Robinius, et al., 2018), and a high BEV share may also require additional power grid reinforcement costs. Finally, customers may opt for hydrogen or methane vehicles because of higher fuelling rates and ranges. For trucks, buses and ships, methane, hydrogen and liquid fuels appear more suitable energy carriers than electricity, because energy storage in batteries is relatively heavy, which becomes more critical for heavy-duty, long-distance transport. More information about the use of hydrogen in mobility and a comparison with other energy carriers can be found in (ASSET, 2018).

Feedstock for industry

[15] As noted in Section 4.4, given high costs, the business case for hydrogen produced via electrolysis is likely to rely (based on current cost projections) on continuous (rather than flexible) operation. Our view is therefore that this sort of flexibility is less likely to come from hydrogen or synthetic methane, although it cannot be ruled out if costs fall significantly or if electricity price spreads are wide enough to provide a sufficient return.

Outside the scope of this report, but nevertheless important to consider is that hydrogen and other renewable and low-carbon fuels derived from wind and solar energy are also likely to play a key role in the decarbonisation of feedstock for industry. This feedstock is currently largely fossil based.

Competition between sectors
The supply of the various renewable and low-carbon gases is likely to be limited, at least in the short to medium term, as renewable energy capacity is still growing. As a result, the various end-use sectors will compete for these gases. This may result in highest market demand from sectors willing to pay the highest price for them, possibly driven by a policy framework that results in a preference from one sector over another (e.g. a renewable energy quota in transport may create a higher willingness to pay for biomethane and Power to Gas in that sector than a CO_2 price in industry). However, other factors will also play a role, such as infrastructure availability and cost.

The potential supply of biomethane principally depends on the availability of sustainable biomass feedstocks. Taking into consideration the RED II sustainabilty criteria (EU, 2018) that are based on the premise that biomass used should not compete with food production and should not lead to indirect land use change, this availability is expected to be much smaller than the possible demand for biofuels produced from it.

The potential supply of renewable hydrogen and methane will depend mainly on renewable energy cost, production capacities and available infrastructure (ASSET, 2018).

In the broader transition to a low-carbon economy, renewable and low-carbon gases may have most value in the chemical industry (incl. bioplastics production), and perhaps in maritime and heavy duty transport. There are fewer cost-competitive decarbonisation options in those sectors, and possibly higher added value (i.e. willingness to pay) for the final products in those markets. That said, as highlighted by the discussion above and also in Chapter 2, there remains uncertainty over the role of gases compared to alternatives, and one cannot rule out the possibility that tehnological innovation could change the picture (for example making electric trucks more clearly competitive than those fueled by gases or renewable liquid fuels).

3.5. GAS INFRASTRUCTURE NEEDS

The developments in both the green and the subsitute dimensions have implications for the gas infrastructure needs. This study does not aim to assess these impacts in detail and quantify the cost of these changes (other studies are currently carried out to assess cost). For this study it is, however, important to have an understanding of what the potential infrastructure needs could be in the future energy system and in the intermediate period, taking into account the various outlooks for the future descibed in the previous chapter. As explained before, a general understanding of the key developments and uncertainties can be key to identify the main regulatory barriers in the next part of the study. The potential key developments and related considerations are described below.

This changing role of gas has a range of **different impacts on gas infrastructure needs**. First, the overall demand for gases is expected to decrease over time (due to factors such as electrification, energy efficiency and the growth of geothermal energy, as was explained in the section 3.2). As a result there will be a reduced need for gas transport infrastructure at all levels of the system: the transmission and distribution grid level, import pipelines, LNG terminals and storage facilities. The decline in use of gas infrastructure impacts may be reduced by:

- In the medium-term, increased role of natural gas as a transition fuel; and
- In the long-term, decarbonisation of gas supply, through increasing the share of biomethane and/or synthetic methane from renewable electricity.

Import facilities and transmission grid

A reduced demand for natural gas will lead to a decreased utilization level of transmission pipelines, LNG import terminals and import pipelines, unless these will be used to transport or import renewable or low-carbon gases in the form of (liquefied) methane, bio or synthetic, or, to some extent, blended hydrogen (up to ~20%, see Appendix A). In some scenarios LNG import terminals and re-gasification plants are eventually decommissioned, for example because existing LNG import infrastructure cannot be used or transformed to liquid hydrogen infrastructure. This would require new assets (Trinomics, Ludwig Bölkow Systemechnik, Artelys and E3-Modelling, 2018).

Some international and inter-European pipelines could in some scenarios be upgraded to hydrogen pipelines. This might be the case especially in countries with significant gas pipeline infrastructure currently used for transit purposes (for example, the Netherlands and the Czech Republic). Other pipelines may continue to transport methane, opening up the possibility of 'parellel' infrastructure for hydrogen and methane. The costs of doing so would require further study.

Another issue is that nowadays the gas grid is downstream organised, from (high pressure) transmission grid to (low pressure) distribution grid, reflecting the process of central infeed and decentral consumption. However, a growing decentral injection of biomethane and renewable gases can result in reversing flows from the distribution grid to the transmission grid. Therefore it might be necessary, in some cases, to upgrade and change sections of the gas grid to allow for upstream gas flows (bi-directional or reverse-flow). This is also necessary in a renewable energy system with large central (geological) gas storages, which would allow the large-scale and seasonal storage of renewable energy that is likely to be necessary in an energy system with a large share of wind and solar energy.

The distribution grid

The impact of the energy transition on the local gas distribution grid and storage facilities will differ by region.

- In the intermediate period (before full decarbonisation of the energy system), a large part of the distribution grid will still be needed for transport of natural gas. Increasing shares of biomethane and, depending on the scenario, synthetic methane and renewable and low-carbon hydrogen can contribute to decarbonisation without impacting the infrastructure needs. As mentioned above (and discussed further in Appendix A), the share of hydrogen that could be mixed with natural gas without requiring changes to the natural gas infrastructure and end-use applications is limited, and still uncertain. Blending too much hydrogen in the gas grid results in a different composition of the gas, which will affect e.g. end users since burners in gas devices are adjusted to certain gas specifications. From a technology standpoint, hydrogen may be allowed to be blended with natural gas between 2-20% of the gas by volume, depending on the gas specification sensitivity of the connected assets (Trinomics, Ludwig Bölkow Systemechnik, Artelys and E3-Modelling, 2018) (Cadent, 2018). Note that existing regulations are currently much more limiting. In the Netherlands, for example, the maximum hydrogen blending limit for the high pressure grid is 0.02%mol, as concluded by DNV GL in (DNV GL, 2017). These regulatory barriers will be further explored in the next part of the project.

- Some parts of the grid might (subject to technical limits, which will vary by region) be transformed to (local) hydrogen grids, or grids that allow higher levels of hydrogen in natural gas. These would either have to be designed as stand-alone grids, or be designed in such a way as to prevent flows to the wider gas grid.

- Some parts of the local distribution grids may become obsolete, as districts, municipalities and perhaps regions switch to other renewable or low-carbon heating technologies.

- At the same time, growth in gas demand in the road transport sector might result in new demand for the existing gas distribution grid, and the need for new infrastructure investments to connect fuelling stations. This demand increase may, however, be temporary unless renewable and low-carbon gases will achieve a signficiant market share in road transport in the longer term.

The role of the distribution level gas grid and how extensive it will be in 2050, therefore highly depends on:

- The uptake of alternative heating options (including increased electrification[16] of heat demand, the use of solar thermal or geothermal energy, and the penetration of district heating networks);
- Demand for gases in road transport; and
- The potential growth of renewable and low-carbon gases.

Converting existing grids to increased shares of hydrogen

In scenarios where hydrogen plays a dominant role, it is likely that parts of the existing gas grid – on both transmission and distribution level – will be transformed to a hydrogen grid. The transformation offers the opportunity to continue using these parts of the existing infrastructure, but is an enormous operation on national or EU scale. It is possible, however, to convert the grid gradually, section by section, in the period until 2050. This also requires simultaneous conversion of end-use equipment from natural gas to hydrogen burning. This transition is explored further in the H21 Leeds City Gate Project, for the case of converting the gas distribution network of Leeds (UK) to hydrogen (Leeds City Gate, 2017).

The natural gas grid can be transformed to a hydrogen grid by using the existing pipelines, but it requires adaption of operational control regarding pipeline integrity management (corrosion and crack growth control, constant pressure and adaption of the flow velocity), according to (NaturalHy, 2009; DNV GL, 2017). Differences in material properties of hydrogen compared to natural gas, require the replacement or adaption of compressors in the gas grid.

The suitability of pipelines depends on the material, operating pressure, age and overall condition of the pipelines (Dodds & Demoullin, 2013). High-pressure pipelines made of high-strength steel are subject to hydrogen embrittlement. Hydrogen, which has a much smaller molecule than components in natural gas have, will diffuse into surface flaws. This results in material degradation due to new or increased crack growth. Dodds and

[16] In a strong electrification scenario Trinomics et al (2018) envision large parts of the distribution grid being decommissioned, and remaining gas custumers being concentrated in island grids. These island grids may, or may not, be connected to the transmission grid. They are likely to be structured around decentral CO_2-neutral gas sources (renewable or low-carbon gas production plants and/or storage facilities).

Demoullin (Dodds & Demoullin, 2013) conclude from this that the existing UK high pressure pipelines are not suitable for hydrogen transport. On the other hand, the NaturalHy consostium (NaturalHy, 2009) and DNV GL (DNV GL, 2017) conclude that 100% hydrogen may be allowed in parts of the the natural gas grid in the Netherlands with some adaptations, when properly controlled, noting the service lifetime of the pipeline is reduced (NaturalHy, 2009).

High pressure pipelines made of softer steels reduce the rate of embrittlement, and are more suitable for high pressure hydrogen transport (Dodds & Demoullin, 2013). Embrittlement of low-pressure steel and iron pipes might happen at high enough pressure (depending on material, stress history and type of welding) (Dodds & Demoullin, 2013). Polymer pipes do not suffer from (conventional) corrosion, but do undergo degradation over their lifetime and show leakage of very small amount of hydrogen (NaturalHy, 2009; Dodds & Demoullin, 2013).

Stakeholders have previously mentioned that conversion to hydrogen could require a significant reduction in the gas demand, since pipeline transport capacities are significantly reduced when transporting hydrogen instead of methane (at the same gas flow speed) (Trinomics, Ludwig Bölkow Systemechnik, Artelys and E3-Modelling, 2018). However, increasing the gas flow speed by a factor three will compensate for this effect (DNV GL, 2017).

Gas storage

By taking advantage of the significant existing gas storage capacity across the EU, gases can be used to manage seasonal swings in heating demand. While these swings in demand might be reduced in the future[17], alternative options to manage them are limited.

That said, some challenges arise with the use of storage by renewable and low-carbon gases, and in particular with hydrogen:

- Existing gas storages might need to be updated to allow for a more dynamic operation to store renewable gases produced from intermittent renewable electricity sources, and extract them in times of electricity production deficits (Trinomics, Ludwig Bölkow Systemechnik, Artelys and E3-Modelling, 2018).
- While storage of hydrogen is possible in salt caverns, and possibly also in depleted gas reservoirs (DNV GL, 2017; Amid, et al., 2016), storage capacities are reduced by a third when used to store (pure) hydrogen, due to the lower energy density of hydrogen compared to natural gas (DNV GL, 2017).
- In addition, to the extent storage capacity is connected to the transmission grid, then hydrogen will not be able to make use of existing storage if the transmission grid itself is not suitable for hydrogen (see discussion above).

3.6. Conclusions

Two dimensions can be distinguished when considering the changing role of gas in the EU energy system in the coming decades.

[17] The decarbonisation scenarios and storylines assessed in Chapter 2 all indicate that seasonal peaks in gas demand during winter are significantly reduced compared to today's levels, due to a strong reduction of the heat demand, electrification in the heating sector and increased use of geothermal and solar thermal energy.

- In the green dimension, the increased use of renewable and low-carbon gases can provide system benefits and contribute to the decarbonisation of the EU economy. Unabated natural gas use will reduce and will be replaced by renewable and low-carbon, alternative energy sources: renewable heat, renewable electricity, renewable gases or hydrogen from natural gas combined with CCS.

- In the substitute dimension, natural gas plays a role as transition fuel in replacing fossil fuels with higher carbon content, mainly coal. In this dimension, the role of natural gas will become more important in the mid-term especially in power production and the transport sector.

Both dimensions will coexist in the coming decades, but the substitute dimension will need to diminish in the period 2030-2050 in favour of the green dimension in line with the fulfillment of GHG reduction targets of the EU.

Gas demand may increase in some sectors, such as the power sector. There, the benefits of flexible gas units will increase over time, as the share of wind and solar power production increases.

It is possible to use all the different renewable and low-carbon gases in all applications for which natural gas is used today (such as heat and power production), as well as others for which natural gas is not significantly used at the moment (such as transport). However, where there are fewer barriers to blending biomethane and synthetic methane to high levels, there are limits on hydrogen blending due to its different chemical composition. Technical blending limits are still uncertain and likely to depend on the specific end-use equipment and infrastructure characteristics: current estimates vary between 2% and 20% by volume.

The continued use of natural gas infrastructure and applications could help to reduce the costs of decarbonisation through a combination of reducing the costs of replacing infrastructure and end-user appliances and avoiding the need for reinforcements and upgrades to the electricity grid. All gases could be imported, either via pipeline or LNG (subject to any necessary infrastructure upgrades being carried out, particularly in the case of hydrogen), so EU production costs or limits on EU production potential need not pose a particular barrier to their use with the EU.

However, their respective roles in the future energy mix are still uncertain. Given the co-ordination that would be required (e.g. appliance switchovers, infrastructure upgrades), any future in which hydrogen is transported or used in significant quantities within the EU requires strategic decisionmaking by policymakers. However, a hydrogen switchover need not necessarily be EU-wide: hydrogen and renewable methane (both biomethane and synthetic) could co-exist in the EU system, with different gases being used in different regions. National and EU policymakers are still in the early stages of thinking about this issue.

As well as policy, other factors result in uncertainty over the roles of the different renewable and low-carbon gases in the future energy mix:

- The costs of the various renewable and low-carbon gases relative to each other;
- The costs of gases relative to other decarbonisation measures; and
- In which sectors the 'value' of gases will be greatest

Each gas has certain advantages and disadvantages. As noted above, all gases can be used in all end-use sectors, though hydrogen can also be used as a feedstock in industry. Compared to hydrogen from electrolysis, producing synthetic methane involves an additional step (combining carbon with hydrogen) and therefore additional cost.

However, use of renewable methane (synthetic or bio) avoids the need for appliance switchovers and upgrades to infrastructure.

These developments have a range of impacts on gas infrastructure and storage needs. These impacts differ significantly between scenarios, but include the following:

- Since natural gas demand is expected to reduce in the coming decades, the (average) utilization level of the transmission grid, LNG import terminals and import pipelines is also likely to reduce, mitigated by the extent these convert to increasing shares of renewable or low-carbon gases.
- The impacts on the transmission grid, the distribution grid and storage facilities are likely to differ from location to location. Some existing grids might be used for renewable methane or biomethane or transformed to (local) hydrogen grids, and others may become obsolete.
- Given much of renewable and low-carbon gas production could be located at distribution level, flows on the distribution grid (and flows between transmission and distribution) will require increased active management.
- Large-scale use of hydrogen furthermore requires conversion of existing gas storage or new hydrogen storage locations, and new fuelling infrastructure may need to be developed for the transport sector.
- Existing gas storages might need to be updated to allow for a more dynamic operation to store renewable gases.
- Synthetic methane production is likely to require a CO_2 transport infrastructure (to transport captured CO_2 from industrial processes to the methanation plant), or further development of CO_2-capture from air technologies.

4. OVERVIEW OF KEY TECHNOLOGIES FOR SECTOR COUPLING

4.1. INTRODUCTION

In this section we discuss the technological perspective on sector coupling in more detail. This includes:

- The potential benefits of sector coupling;
- How linkages between energy carriers will develop and what this means for infrastructure needs;
- Possible business cases for some hydrogen and biomethane projects; and
- A brief discussion on developments at Member State level.

We describe the individual technologies that belong to these supply chains in two separate technology briefs, which can be found in Appendices A and B to this report. The descriptions in the technology briefs include cost figures, indications of the technology readiness level, pilot projects, and an indication of current market size in European countries.

4.2. POTENTIAL BENEFITS OF SECTOR COUPLING

The previous chapters contained a range of potential developments that may result in sector coupling between gas and electricity.

In the green dimension, electricity and gas sector coupling has been found to potentially provide several advantages in the future energy system:[18]

- Electrolysers that convert electricity to hydrogen can deliver flexibility to the electricity system (both up- and downward regulation). As the share of variable renewable energy production in the system increases, this can contribute to system stability and increase demand for electricity (and therefore the price) in times of high production and low demand.[19] This flexibility can increase the capacity factor of renewable electricity production by avoiding the down regulation of renewable electricity in periods that would otherwise result in excess generation.

- High levels of electrification are likely to require large investments in the electricity grid to accommodate the (much) higher supply and demand of electricity. These investments may be avoided through continued use of gases.

    - An alternative to using existing gas transport capacity would be to build new electricity grid infrastructure. However, given the high energy density of gases, significant electricity grid infrastructure would be needed to replace the energy transported by gas pipelines. For example, one current extra-high voltage electricity system (between 345 and 765 kV) can offer a transmission capacity of ca 3GW. A typical high-pressure natural gas pipeline in a comparable corridor can offer more than ten times that capacity[20]. Significant new-build of electricity grid

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[18] Note that the first of these advantages is specific to power-to-gas technologies, but the others are also relevant for biomethane.

[19] In a similar way, alternative flexibility solutions such as battery storage, power-to-heat technologies and demand flexibility can contribute to system flexibility.

[20] Comparison based on data from ABB on an HVDC cable system (ABB, 2015) and a study by OIES on the OPAL gas pipeline (OIES, 2017).

- infrastructure also poses challenges in terms of public acceptance of energy infrastructure.
- Large-scale storage of renewable gases is expected to be more cost-effective than that of electricity. This is especially relevant for long term, seasonal storage, necessary to ensure security of supply also in longer periods of high energy demand and low supply.[21]

In both the green and the substitute dimension, gas power plants can play a key role in the future energy system by providing dispatchable electricity production (in the green dimension with CCS). Due to their short ramp-up times they can respond to short term flexibility needs resulting from variable production from wind and solar, and are also capable of providing stable levels of production during longer periods of low production from these energy sources. This type of sector coupling can be relevant for all types of gases discussed here.

Apart from the renewable and low-carbon gas technologies this study focusses on, other decarbonisation technologies may also lead to sector coupling between gas and electricity, in particular requiring closer co-ordination of system operation of the gas and electricity systems, both at transmission and distribution level.

- In residential and low-temperature industrial heating, hybrid heat pumps that can run on both electricity and gas could provide energy system benefits. A hybrid heat pump consists of an electric heat pump that is the main provider of heat, with a gas boiler that is activated when the heat pump does not produce enough heat. This allows for heat pumps with a smaller capacity, and can prevent costly expansions of the electricity distribution network. If used 'smartly', hybrid heat pumps could also introduce flexible use of electricity and gases for heating depending on availability and price, which would help to balance the electricity system and reduce energy costs for consumers.
- Similarly, other power-to-heat technologies such as electric resistance heaters can be operated smartly alongside gas-powered heating systems.
- District heating networks offer another arena in which power-to-heat and gas heating technologies could operate alongside each other, dispatching flexibly depending on availability and price.[22]

The EU-wide potential for these hybrid technologies has not yet been assessed.

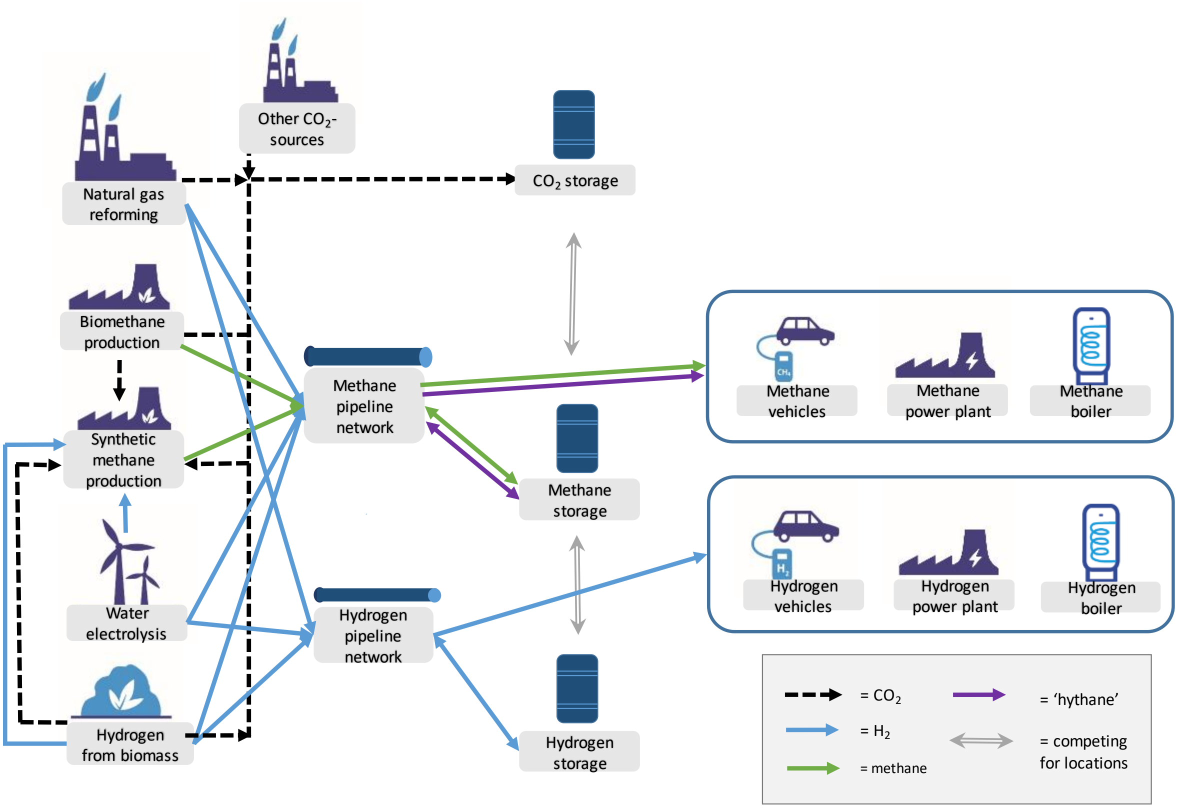
For more information on the technologies to produce, transport and use renewable and low-carbon hydrogen and methane, see the relevant sections in Appendix A and B.

4.3. LINKAGES BETWEEN ENERGY CARRIERS AND IMPLICATIONS FOR INFRASTRUCTURE

These developments will not only lead to increased gas and electricity sector coupling, but large-scale deployment of the technologies that are part of the hydrogen and methane supply chains will also result in linkages between natural gas, hydrogen and methane. This is illustrated in Figure 10.

[21] For short term storage, other technologies may also be applied such as battery storage and power to heat.
[22] The value of this flexibility might be higher especially where heat storage is not available, as this makes it more difficult to simply store heat produced directly from cheap power for later use when power might be more expensive).

Figure 10 High-level overview of linkages between gases for energy use in 2050: Natural gas, hydrogen and methane



- Natural gas reforming and CCS provides the possibility to convert natural gas upstream in the supply chain to low-carbon hydrogen.

- Hydrogen production from biomass competes with biomethane production from biomass. The CO_2 produced in both processes can be captured and stored; it could also be used to produce synthetic methane.

- Similarly, hydrogen could either be used directly or in synthetic methane production. This could lead to competition between synthetic methane and hydrogen, with the cost of the CO_2 used in the synthetic methane process (see point above) becoming an important factor in determining the effectiveness of this competition.

- As discussed earlier, hydrogen could be injected into the methane (natural gas) pipeline network up to a blending level of 2-20% by volume (with the maximum blending level still uncertain) without needing substantial additional investments in the gas network.

- Parts of the natural gas network could be adapted to transport 100% hydrogen. This also likely requires the replacement of end-use appliances and turbines. Although such adaptation could lead to a situation in which natural gas networks and hydrogen networks exist in parallel, it could provide the best match with local/regional production capacities in certain areas. Hydrogen and methane could be produced, transported and consumed more locally than is the case for natural gas today. In such a scenario, links between the hydrogen and methane supply chains would be broken at the level of injection to the grid (as they would no longer be blended together). However, links would remain elsewhere in the value chain (e.g. in production), as set out in the second and third bullets above.

- Hydrogen, methane and CO_2 could all be stored in underground locations or in available gas storage vessels. These are further discussed in the relevant sections of the Appendices. Some of the underground locations may be suitable for storing either gas, but this is still a topic of research. Also, natural gas (LNG) transport vessels could perhaps be modified to transport hydrogen or CO_2. In such cases these gases would be competing for the same storage capacity.

In short, the simultaneous development of low-carbon and renewable hydrogen and methane supply chains would create several supply chain linkages, some of which are complementary and synergetic, and some of which are substitutional. An adequate assessment of the options and planning at all levels of the energy system (national, regional, European) is therefore key to prevent sunk costs, reap the benefits of synergies, and prevent sub-optimal investments.

4.4. Business cases

Several uncertainties affect estimates of the costs and business cases for these technologies: the pace of innovation, the likely complexity of the future energy system and the lack of visibility surrounding the future regulatory and policy framework. In addition, regional and even local differences may be significant, as the business case of certain value chains will depend on factors such as the availability of existing infrastructure, the location of energy production and of end consumers, and the availability of alternative decarbonisation options.

Within this context, this section aims to provide some insight into the costs and business cases for relevant technologies. First we summarise available evidence on their costs, benefits and scalability by technology. Then we compare the maturity of the various technologies, which may act as an indication of level of cost reductions that may be expected in the future, if R&D efforts and production volumes increase.

Hydrogen
To decarbonise the electricity system, the share of wind and solar generation is foreseen to increase immensely in the coming decades, as explained in Chapter 2. As is concluded in (ASSET, 2018), the electricity price is among the key factors that will affect the production cost of hydrogen. Very significant additional investments in renewable energy production capacity (beyond that already planned), in hydrogen production plants, in infrastructure and in end-use appliances are likely to be necessary for a large scale roll out of this energy carrier (ASSET, 2018) (EC, 2018b).

For (PEM) electrolysers the number of operating hours needs to be high (at current cost levels), so that the capital costs of the installations can be earned back. The current expectation is therefore that the electrolysers will work in baseload operation (ASSET, 2018) (IRENA, 2018c). By ensuring a constant demand, these technologies could help avoid situations of surpus electricity and RES-E curtailment.

Provided a sufficient spread between gas and electricity prices, an alternative business case could be to operate electrolysers principally when electricity prices are low. This flexible operation would bring additional benefits in terms of electricity system balancing, (IRENA, 2018c). Indeed, many of the scenarios analysed in Chapter 2 expect the growth of variable electricity production to be a key driver for water electrolysis to become a cost-effective option to balance electricity supply and demand (see, for example (ASSET, 2018)).

Although the price of renewable hydrogen from wind and solar power is currently above 5 €/kg (compared to 1.5 €/kg for low-carbon hydrogen), the above developments could bring this (system-levelised) price down to the same level as low-carbon hydrogen by 2050. The production of hydrogen at high-yield wind and solar energy locations in other parts of the world and hydrogen shipping can also contribute to price decreases, and may enable the development of a global hydrogen market, as is concluded by CE Delft in an assessment of different hydrogen production routes (CE Delft, 2018).

In transport, hydrogen vehicles and fuelling infrastructure challenges need to be tackled at the same time, to solve the 'chicken-and-egg-problem'. Of course, also in this application the various conversion steps create significant energy losses over the hydrogen value chain. There could also be a situation that alternative renewable or low-carbon energy carriers may become more competitive in the future (e.g. renewable methane rather than hydrogen, or electric transport). For heating and electricity production, it is estimated that low-carbon and renewable hydrogen can compete with natural gas in 2030 if a CO_2-price of about 40 €/ton is factored into the natural gas price (CE Delft, 2018).

Biomethane
Scarlat et al (2018) show that, in the EU in the year 2015, biogas production reached 18 billion m3 (15.6 Mtoe). That biogas was used to produce 61 TJ electricity (1.5 ktoe) and 127 TJ (3.0 ktoe) heat. The remainder was used as a transport fuel or injected into the natural gas grid. These numbers make Europe a world leader in biogas and biomethane production and use. Thus, the EU already has a renewable methane supply infrastructure in operation. Together with the existing extensive natural gas network, this forms a good basis for further development of the renewable methane supply chain towards 2050. As a result, Scarlat et al (2018) conclude that 'bioenergy production has the potential to contribute significantly to the development of a green, low carbon economy', although they note that the developments sofar were supported in several countries by renewable energy policies, as biogas and biomethane could not yet compete with natural gas.

This is also confirmed in (CE Delft, Eclareon en Wageningen Research, 2016), where it is concluded that the presence, stability and reliability of the policy framework and support schemes is the number one driver for biogas production in all EU countries. Costs of production are found to vary significantly for biogas, but are typically higher than the price of the fossil fuels they replace (natural gas, diesel, etc.) (CE Delft, Eclareon en Wageningen Research, 2016).

A potential future business case of biogas is to use it for electricity grid balancing, which will become more valuable in a power system with high shares of wind and solar power (CE Delft, Eclareon en Wageningen Research, 2016; Scarlat, et al., 2018).

Maturity
More detail on the cost and maturity of the technologies for the methane and hydrogen routes is provided in the technology briefs in Appendix A (on hydrogen) and Appendix B (on methane).

We find that, because methane technologies have been used for a longer period of time and on a larger scale than hydrogen technologies, they are generally cheaper and more mature than hydrogen technologies. This difference will become smaller, however, when hydrogen technologies start to be mass-produced

4.5. NATIONAL MARKET PERSPECTIVE

Since the development of these sector coupling technologies and value chains has only recently started and the cost of these renewable and low-carbon gases are still high, market developments are currently very much policy-driven and, with the exception of biomethane, still relatively small-scale. Detailed national or regional assessments of the future decarbonised energy system are still either lacking (in many cases) or exploratory. It is therefore too early and outside the scope of this study to provide a detailed national market outlook.

Looking at the current ongoing R&D and demonstration projects, we can conclude that many of the European hydrogen projects currently in operation take place in the UK, Germany, Austria, Italy and the Netherlands[23]. These countries could be considered the current frontrunners in the hydrogen economy. These projects are mainly research and demonstration projects for specific technologies such as hydrogen trucks or hydrogen compressors, and many are funded by the Fuel Cells and Hydrogen Joint Undertaking programme (FCH JU)[24].

This situation may change quite rapidly, however, in the coming decades. European countries introducing ambitious targets on decarbonisation may encourage companies to invest in hydrogen technologies. For example, the Dutch government is discussing banning new petrol and diesel cars by 2030, which may lead to further development of hydrogen supply systems and refuelling stations[25]. Furthermore, countries with high wind and solar power shares and ambitions and/or high shares of gas in the energy mix, such as Germany, Denmark, UK and Spain, may invest in hydrogen technology for use in heating, transport and (seasonal) energy storage. At the same time, the more general climate and energy policies and regulations may further drive the investments needed (e.g. the renewable energy targets of the RED II, a CO_2 tax or a high CO_2 price in the EU ETS, etc.).

Countries that currently have a developed LNG distribution infrastructure, which are countries in Western, Northern and Southern Europe with sea access, could use and extend this existing infrastructure as part of a transition to biomethane and/or synthetic methane (Gabl, 2016). European countries that already have a significant amount of gaseous methane vehicles on the road, i.e. Italy, Germany, Sweden, the Netherlands and the UK, have a good starting position for growing biomethane and/or synthetic methane use in the mobility sector.

The table in Appendix C provides some examples of hydrogen, methane, CO_2 capture and CCS pilot projects that are currently ongoing in Europe, to illustrate the diversity of current projects.

4.6. CONCLUSIONS

In the future energy system, electricity and gas sector coupling could have several effects:

- Greater substitutability of gas and power for final energy consumption (e.g. in heating) could require closer co-ordination between gas and power system operation, both at transmission and distribution level;

- Electrolysers converting electricity to hydrogen can deliver flexibility to the electricity system, increasing the capacity factor of renewable electricity production;

- Investments in the electricity grid may be avoided, and gas infrastructure stranded assets may be reduced, by taking advantage of existing gas infrastructure's ability to transport large volumes of energy;

- Large-scale storage of renewable gases is expected to be more cost-effective than large-scale storage of electricity, especially over longer periods of time; and

[23] See Hydrogen Europe for an overview
[24] Fuel cells and Hydrogen (fch) joint undertaking
[25] The Dutch government confirms plan to ban new petrol and diesel cars by 2030

- Gas power plants can play a key role in the future energy system since they can provide dispatchable electricity production; they also reduced GHG emissions when used to replace coal electricity production.

These developments would need the large-scale roll out of a wide range of new technologies. This requires innovation and R&D efforts in all parts of the value chains, to further develop the necessary technologies, reduce cost and improve efficiencies. Over the coming decades, large-scale investments are necessary, for example in renewable energy production, production plants for renewable and low-carbon gases, upgrading of existing infrastructure and storage, construction of new infrastructure and storage, and roll-out of new end-use applications. Planning these investments efficiently will likely require an integrated development of the gas and electricity systems.

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Appendix A Hydrogen technology brief

Introduction to hydrogen supply chain

Scope: Only those technologies are considered that do not lead to CO_2 emissions, or reduce these significantly. Hydrogen produced from coal is out of scope. Compression, liquefaction and chemical conversion of hydrogen are considered under hydrogen storage.

Definitions: *Low-carbon hydrogen* is hydrogen produced from natural gas, where the produced CO_2 is captured and stored. *Renewable hydrogen* is hydrogen produced from renewable energy sources, including biomass, and wind and solar energy through water electrolysis.

See figure 9 (in Section 4.3) for a schematic of the key value chains and infrastructures for this technology.

Technologies in hydrogen supply chain

Hydrogen production

Natural gas reforming

Natural gas reforming currently is the main method of producing hydrogen. If the co-produced CO_2 is stored the hydrogen can be called 'low-carbon'. There are different technological processes that fall under natural gas reforming: steam methane reforming, partial oxidation and autothermal reforming (ATR). Five steps can be discerned in the production process of low-carbon hydrogen: pretreatment of natural gas, pre-reforming, reforming, water-gas-shift and hydrogen purification. The produced hydrogen is stored temporarily before it can be transported (CE Delft, 2018).

ATR is a cost-effective production method, which can be combined with capture of all CO_2 produced. It is not used much yet, but it has a high technology readiness level (TRL) of 8-9[26] (CE Delft, 2018). Estimates of the production cost for low-carbon hydrogen in the Netherlands, produced with ATR technology and CCS are provided in (CE Delft, 2018), and were found to be about 1.6 €/kg hydrogen for 2017, with future cost developments depending significantly on the cost of the natural gas.

Carbon capture and storage

When carbon capture and storage (CCS) is used in combination with natural gas reforming, hydrogen production from natural gas is expected to result in up to 90% GHG emission abatement (ASSET, 2018). CCS systems include many components and processes: CO_2 capture (separation from hydrogen), chilling, compression, storage, transport by road vehicles, ships and/or piplines, and injection into a saline aquifer (Gassnova SF; Gassco, 2016). Alternatively, CO_2 could be liquefied for the purpose of temporary storage and transport.

Offshore CCS (storage below the seabed) has been practiced in Norway since 1996 in the Sleipner, Gudrun and the Snøhvit projects (petroleum fields), but these are the only CCS projects currently in operation in Europe, and the only offshore projects in the world[27]. Thus, experience with this technology is still relatively low, and some risks may still be unknown.

Planning and investment costs of a full-scale CCS infrastructure with one to three onshore CO_2 capture facilities and CO_2 shipping to an offshore storage location with

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[26] The TRL is set on a scale of 1 to 9, where 9 is the most mature technology.

[27] Norwegian Petroleum: Carbon capture and storage

capacity of 0.6-1.3 Mton CO_2 per year: 776-1340 million euro (~600-2,200 €/ton CO_2/year). Abatement costs: 140-210 €/ton. Later projects will be able to benefit from the infrastructure invested in, reducing these costs (Gassnova SF; Gassco, 2016). Currently, the cost of CCS in the supply chain of low-carbon hydrogen could amount to 30% of total supply chain costs (CE Delft, 2018).

The competitiveness of hydrogen production with this route versus the power-to-hydrogen production from renewable energy is still uncertain, and likely to depend on the cost development of the various technologies and the scale of the plants. (ASSET, 2018), for example, finds that the value chain of steam reforming with CCS is likely to be significantly less competitive than an electrolysis-based value chain benefitting from large economies of scale. CE Delft (2018) concludes, however, that the levelized cost of hydrogen production from natural gas with CCS is currently much lower than cost of renewble hydrogen, but expects cost to converge in the coming two decades.

Water electrolysis

Water electrolysis (also called power-to-hydrogen) requires an electrolyser, which splits water into hydrogen and oxygen using electricity. It requires pure water. Different electrolyser types exist: alkaline, proton exchange membrane (PEM), solid oxide electrolyser (SOE). If the electricity used originates from renewable generation such as wind turbines and solar panels, the hydrogen can be considered renewable hydrogen. The alkaline electrolyser is the cheapest type, but is less flexible than the PEM electrolyser. The capital cost of the PEM electrolyser is currently estimated at around 1,000-1,300 €/kW, but could drop to 320-650 €/kW in 2040 (CE Delft, 2018). The current capital cost of a centralised SOE is estimated at 5,000 €/kW by (ASSET, 2018). A possible future technology option is to install an electrolyser within a wind turbine, which would prevent the need for electricity grid connection. This is currently explored for onshore turbines. For offshore turbines, the need for pure water is an issue (CE Delft, 2018).

Hydrogen from biomass

Biomass is another potential energy source for the production of renewable hydrogen. Alternative production methods are thermochemical gasification, fast pyrolysis, solar gasification, supercritical conversion and biological hydrogen production. Florin and Harris (2007) describe the thermochemical conversion of biomass to a synthesis gas consisting of a mixture of hydrogen, carbon monoxide, CO_2 and methane as a promising method of hydrogen production, where a calcium-based CO_2-sorbent can be used to increase the hydrogen output.

Hydrogen from solar energy

There are various processes, other than water electrolysis, with which solar energy can be converted to renewable hydrogen. These processes include thermochemical conversion, photo-electrolysis, photocatalysis and biophotolysis, and are still in the R&D phase (FCH JU, 2015).

Hydrogen transport

Gas pipeline network

Could be a natural gas pipeline, or a dedicated hydrogen pipeline. In case of a natural gas pipeline: it could be blended with natural gas, or (part of) the natural gas network could be adapted so as to transport hydrogen. A DNV GL study concluded that the Dutch natural gas grid could transport 100% hydrogen after replacement of certain infrastructure components, without loss in energy transport capacity (DNV GL, 2017). To achieve the same energy throughput, however, hydrogen transport speed will have to be 3 times as high as in natural gas transport (DNV GL, 2017). In a feasibility study for the city of Leeds, Northern Gas Networks et al (2016) argue that it is possible to gradually convert natural gas grids to hydrogen grids. This has not been demonstrated yet on a large scale, however.

Dedicated hydrogen pipelines have been used in industrial clusters for decades. Capital costs of a dedicated hydrogen pipeline of 250 kilometer (120 bar) with a transport capacity of 675 MWth cost 107 M€ (428,000 €/km) in 2009 (Roads2HyCom, 2009).
Investment in a dedicated ammonia pipeline costs about 114,000 euro per kilometer[28], where the ammonia can be used as a 'hydrogen carrier' when produced by coverting hydrogen and nitrogen from air into NH_3. Thus, this may be almost four times cheaper than a dedicated hydrogen pipeline. However, additional conversion steps will be necessary, both to produce the ammonia and to then convert it back to hydrogen to be used for energy.
Estimations of the costs of adaptation of natural gas pipelines are still largely unknown.

Hydrogen blending and separation

Hydrogen could possibly be mixed with natural gas up to ~20% by volume without requiring changes to the natural gas infrastructure or end-use applications[29], which can facilitate a gradual shift from natural gas to hydrogen. There are large-scale demonstration projects that combine water electrolysis with hydrogen injection into the gas grid in Germany, France and the UK, which show that this technology is ready for market entry (Roland Berger, 2017). There are still significant uncertainties, however, as concluded by (Trinomics, Ludwig Bölkow Systemechnik, Artelys and E3-Modelling, 2018). They find that some studies suggest that hydrogen could be blended with natural gas up to 10 or 15% of the gas by volume, without requiring major adaptations to the gas transmission infrastructure and end-user appliances, but that other sources refer to 2% maximum, in order to avoid risks for corrosion in the transmission grid, and negative impacts for end-user appliances, in particular gas fuelled vehicles. Laboratory and field testing is ongoing in the UK to assess the implications of a $20\%_{vol}$ hydrogen blending level on gas appliances (Cadent, 2018).
It is also possible to separate the hydrogen again from the mixture, with which the pure hydrogen can be obtained that is required for hydrogen fuel cells (Ibeh, et al., 2007). This will require aditional energy input for the separation, but this may be compensated (to some extent) by the higher fuel efficiency of fuels cells, compared to combustion processes. This is still in the R&D phase and not mentioned in the recent literature on this topic surveyed for this study.

Hydrogen transport vehicle

Road, water or rail vehicle to transport hydrogen from production site to consumption sites or to pipeline network. Could transport hydrogen in gaseous, liquid or chemical form. Currently, liquid hydrogen transport vehicles are not commercially available yet, but Kawasaki is developing a ship for demonstration of transport of liquid hydrogen from Australia to Japan[30].
Investment in hydrogen road transport vehicles costs 344 €/kW for gaseous hydrogen and 74 €/kW for liquid hydrogen, according to estimations by ASSET (2018).

Hydrogen storage

Underground hydrogen storage

Gaseous hydrogen could be stored in salt caverns or empty gas fields for large-scale and seasonal energy storage. The storage of hydrogen in salt caverns is already applied in the UK, and research on the effect of frequent fluctuations in hydrogen injection in and withdrawal from UK salt caverns is investigated. With potential storage of millions of m^3 and storage at up to 250 bar, hundreds of kilotonnes of hydrogen could be stored in these salt caverns (ETI, 2018). The potential for underground hydrogen storage throughout the EU has not yet been determined.

[28] Transportation & Delivery of Anhydrous Ammonia
[29] Positive progress to reduce UK C02 emissions
[30] Liquefied Hydrogen Supply Chain and Carrier Ship to Realize Hydrogen Economy

ASSET (2018) estimates the capital cost of underground hydrogen storage at 7,200 euro per MWh of hydrogen stored per year. ETI (2018) estimates the total costs of a 300,000 m^3 salt cavern project (including CAPEX and OPEX for 30 years) at 30-40 M€.

Compressed hydrogen storage

The compression of hydrogen reduces the required storage volume. The most common way of storing hydrogen is in high pressure gas steel cylinders, commonly at 200 bar at maximum (Makridis, 2017). Pressurized hydrogen tanks can store at a pressure up to 1,000 bar. At hydrogen refuelling stations, gaseous hydrogen is compressed to above 350 bar (for buses) or 700 bar (for passenger cars). The capital and fixed costs of a hydrogen compression station is estimated at 2.3 euro per MWh of hydrogen compressed (HHV), and the capital cost of pressurized tanks at 6,000 euro per MWh of hydrogen stored per year (ASSET, 2018). A hydrogen compressor with a maximum flow of ~34 kg/hour costs between 45,000 and 136,000 euro[31]. The higher the pressure the higher the cost. Storage vessels (tanks and cylinders) are a mature technology (ASSET, 2018).

Liquid hydrogen storage

Includes hydrogen liquefaction facility, storage tank and regasification facility. These can be in different locations, when liquid hydrogen is transported from production to consumption sites. Hydrogen is cooled to -253 °C to increase the volumetic density at a low pressure of about 10 bar, compared to compressed storage. Liquefying hydrogen requires 20-30% of the energy of the hydrogen, and the storage period can be limited because of boil-off (hydrogen lost by evaporation) (ASSET, 2018).
The capital cost of a hydrogen liquefaction plant is estimated at 761 €/kW of hydrogen (HHV), and a regasification 'refuelling station' at 855 €/kW. The capital cost of liquid hydrogen storage is estimated at 8,455 euro per MWh of hydrogen stored per year (ASSET, 2018).

Chemical hydrogen storage

Includes conversion of hydrogen to ammonia and methanol as a form of storage. Other chemical storage options, such as formic acid, metal hydrides and liquid organic hydrogen carriers, are still in the R&D phase. Conversion and reconversion to hydrogen goes with energy conversion losses, but increases the energy density (MJ/m^3) of the energy carrier and often turns it into a liquid or solid, which makes it easier to store and transport.
The conversion of hydrogen to ammonia (NH_3) – by means of the Haber-Bosch process, in which nitrogen is combined with hydrogen - is widely used for the production of fertilizer. Ammonia is a gas at room temperature, but becomes a liquid already at -33.34 °C (against -252.9 °C in case of hydrogen). The reconversion to hydrogen requires an ammonia cracker unit. Assuming a production capacity of 5.4 kton NH_3 per day, capital costs of ammonia production, storage and cracking are about 435 M€, 2.7 M€, and 275 M€, respectively, or ~132 M€/kton NH_3/day in total (CE Delft, 2018).
The investment cost of metal hydride-based hydrogen storage is estimated to be 12,700 euro per MWh of hydrogen stored per year (ASSET, 2018).

Hydrogen deployment

Hydrogen refuelling

Can be a hydrogen refuelling station for road vehicles, a bunkering system for ships, or a refuelling system for trains or airplanes. A hydrogen refuelling station includes

[31] Hydrogen compressor

dispenser and chiller, to reduce the temperature of the gaseous hydrogen, which rises because of the gas expansion during refuelling. In 2014, there were 200 hydrogen refuelling stations in operation worldwide, 74 of which used hydrogen from water electrolysis. The European flagship project Hydrogen Mobility Europe aims to develop the first pan-European network of hydrogen refuelling stations, investing 170 M€ in public and private capital to build 49 stations, which comes down to about 3.5 M€ per station[32]. In Germany, 24 public hydrogen refuelling stations have become operational in 2017, which led to a total of 45 public stations in the country (a number only surpassed by Japan)[33].
Investment costs depend on the size of the refuelling station: A large station may cost 325 €/kW of hydrogen (HHV), against 1,009 €/kW for a small station (ASSET, 2018).

Hydrogen vehicles

Three hydrogen-powered vehicle technologies exist: fuell cell electric vehicles (FCEVs), hydrogen internal combustion energy vehicles (H2ICE), and hydrogen-enriched compressed natural gas vehicles (HCNG).
HCNG is a mixture of compressed natural gas and hydrogen. From a technological perspective, the hydrogen blending level is limited by incompatibility of materials in the tank and fuel system of the vehicles (JRC, 2015), by engine operation issues and by a potential increase in NO_x emissions (concluded in an extensive literature study on the potential effects of HCNG use in vehicles (Mehra, et al., 2017)).
During a workshop organised by JRC in 2014, a number of key research topics were identified for this technology, most notably resolving tank issues, adaptation of combustion systems for gas engines to a higher hydrogen content and the development of cost efficient measurement systems for CNG filling stations (JRC, 2015). The current regulatory limit for hydrogen in CNG vehicles is 2% by volume. Further research was recommended to explore the potential for increasing this limit to 10%. Following up on this work, a CEN-CENELEC Working Group on hydrogen identified defining technical requirements for steel tanks for CNG vehicles and an assessment of the long term durability of the steel tanks as prerequisites for raising the hydrogen concentration limit above 2% (vol) in the gas distribution grid (JRC et.al, 2016). The Working Group also recommended developing the necessary CEN standards for the technology.
FCEVs can have a two times higher energy efficiency than H2ICEs, and there are currently at least three passenger cars on the market (from Toyota, Hyundai and Honda). At the end of 2017, a total of 6,364 FCEVs have been sold globally since they entered the market in 2013[34].
FCEVs makes use of proton exchange membrane (PEM) fuel cells (PEM fuel cells), in which hydrogen from an on-board fuel tank and oxygen from air are converted to electricity, heat and pure water. When parked, FCEVs could potentially connect to the power grid and provide power to buildings and power grids, which is currently being experimented with (Oldenbroek, et al., 2018). The Toyota Mirai passenger car currently costs 78,600 euro in Germany[35]. These high costs are caused by the low production numbers of FCEVs and fuel cells.
FCEVs make use of gaseous hydrogen. It is a technical possibility to refuel with liquid hydrogen (with vehicles internally converting liquid hydrogen to gaseous hydrogen), but the low operating temperatures result in a complex and expensive on-board energy system, and this technology is therefore not considered competitive (von Helmolt and Eberle, 2014).

[32] About Fuel Cells
[33] Germany had the highest increase of hydrogen refuelling stations worldwide in 2017
[34] Hydrogen Fuel Cell Vehicles - A Global Analysis
[35] Hyundai sees Germany as key market for Nexo fuel cell car

In Europe, many public demonstration projects have been implemented in the last fifteen years that introduced small numbers of hydrogen buses in European cities, e.g. 6 buses in Aberdeen in 2014, 5 buses in Antwerp in 2014, and 8 buses in 2010 in London[36]. In principle, other types of vehicles can be powered by hydrogen fuel cells as well. In 2018, the two first hydrogen trains in the world, developed by Alstom, have been launched in northern Germany[37]. That hydrogen ships are technically feasible is demonstrated by the world's first hydrogen boat that will tour the world, a catamaran that produces hydrogen from seawater, and runs on hydrogen and solar and wind energy[38]. Hydrogen fuel cell airplanes are in the R&D phase. The first flight with a small hydrogen airplane has been made, but developing hydrogen planes for mass travel will probably take decades[39].
The PEM fuel cell cost 252 €/kW when manufactured at 20,000 units per year for application in vehicles in 2015, but with mass production at 500,000 units per year and state-of-the-art technology the U.S. Department of Energy expects that a price of 48 €/kW is possible[40].

Hydrogen power plant
Can be based on hydrogen combustion in a turbine, or electrochemical conversion in fuel cells. Can be combined heat and power (CHP). The design of a hydrogen turbine will be a bit different from that of a natural gas turbine, because hydrogen behaves differently when it is combusted. The balance of plant (boilers, compressors, pumps, cooling systems) will be similar. A multi-fuel turbine is also possible; this has already been implemented in coal gasification power plants, with usage of up to 50% of mass of hydrogen. Hydrogen could also be admixed in natural gas or syngas turbines, but this may deteriorate the combustion conditions and performance (SBG Energy Institute, 2014). This technology is still under development; it has a TRL of 4-7, with possible market introduction in 3-10 years (TKI TKI Nieuw Gas, 2018).
Fuel cells could be used in buildings to produce power and heat by electrochemically converting hydrogen and oxygen to water, but they could also be stacked to form a fuel cell power plant. Fuel cell power plants are in the early market phase. In 2017, three Dutch companies delivered world's first 2 MW_{el} proton exchange membrane (PEM) fuel cell power plant in China at a chlor-alkali production plant (which produces hydrogen with a high purity). The plant will also deliver 1.5 MW of heat[41].
The total system cost of a PEM combined heat and power fuel cell power plant has been estimated by (Battelle Memorial Institute, 2016) at 1,490 €/kW for a 100 kW plant and 1,038 €/kW for a 250 kW plant at a production volume of 50,000 units per year. For a solid oxide fuel cell (SOFC) power plant the cost estimates are 883 €/kW for a 100 kW plant and 722 €/kW for a 250 kW plant (Battelle Memorial Institute, 2016).

Hydrogen boiler
Can be residential or industrial. Could be a multi-fuel boiler (see 'Hydrogen power plant'). Current natural gas-fired residential boilers may be suitable for natural gas-hydrogen mixtures, and with technical modifications the hydrogen share may be increased. It is probable that residential boilers need to be replaced in case of 100% hydrogen supply. Possible technologies are the fuel cell (which produces both electricity and heat), the high-efficiency hydrogen boiler, the catalytic boiler or the gas-fired heat

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[36] Fuel Cell Electric Buses : Demos in Europe
[37] World's First Hydrogen Trains Launch in Germany
[38] World's First Hydrogen Ship Promises Potential for Sustainable Shipping
[39] The plane that runs on hydrogen and emits only water
[40] DOE Hydrogen and Fuel Cells Program Record
[41] Dutch partners deliver first 2 MW PEM fuel cell plant in China

pump (Dodds & Demoullin, 2013). The need for replacement of gas pipelines in buildings depends on the materials they are made of. For cooking on hydrogen, the replacement of gas burners is probably sufficient, but an additive is needed for odorization and to make the flame visible. The total costs of switching to 100% hydrogen use (including the purchase and installation of a hydrogen boiler) have been estimated at about 4,000 euro per household (Northern Gas Networks, et al., 2016), which is currently twice as expensive as a high-efficiency boiler on natural gas (CE Delft, 2017). On a city/neighbourhood level, hydrogen could be burned in a large boiler to produce heat, which is then fed into a heat network.

Another option is a hybrid heat pump that combines an electric heat pump with a hydrogen boiler. However, this particular combination of technologies has not been deployed yet, and the current cost estimate is more than 6,000 euro[42].

These technologies are still under research. Obviously, their market introduction is dependent on the availability of hydrogen infrastructure and supply.

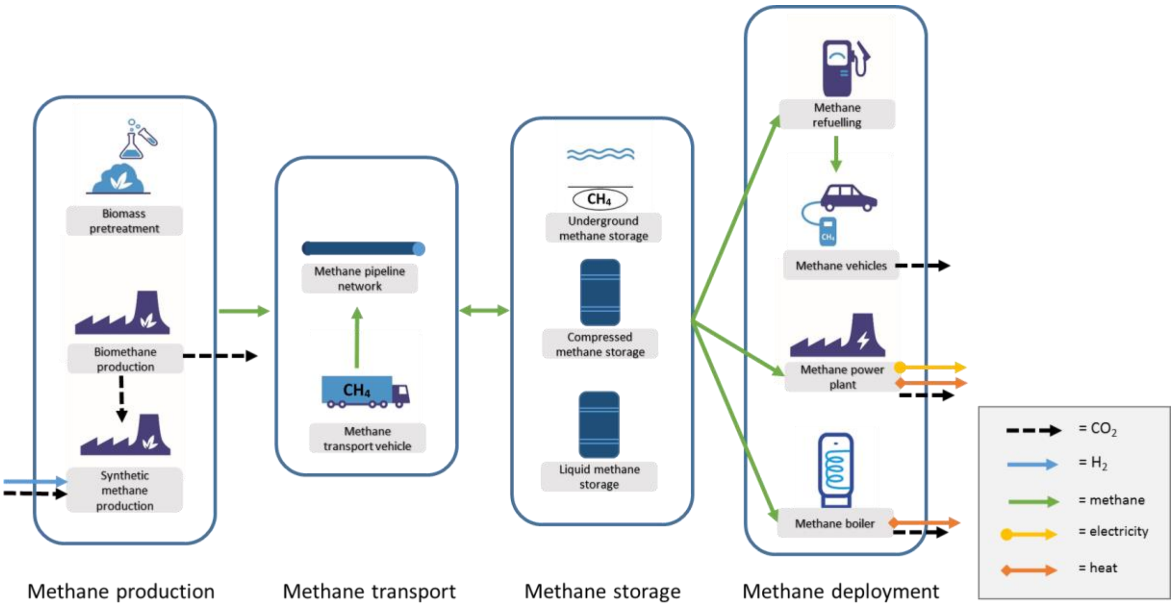
[42] Based on the 4,000 euro estimate for a hydrogen boiler by Northern Gas Networks et al (2016) and the 4,000 euro estimate for a hybrid heat pump (CE Delft, 2017).

Appendix B Methane technology brief

Introduction to methane supply chain

Scope: Only those technologies are considered that do not lead to additional, non-biogenic CO_2 emissions. The use of chemically converted methane, such as vehicles driving on methanol, is out of scope.
Definitions: *Methane* is an overarching term that includes natural gas, biomethane, and synthetic methane. *Biomethane* is methane produced from biomass. *Synthetic methane* is defined here as methane produced from hydrogen. The term 'methane' encompasses both gaseous methane and liquid methane. *Biogas* is a mixture of biomethane and CO_2, which is an intermediate product in the biomethane production process.

Figure 11: The methane supply chain and its constituent technologies



Technologies in methane supply chain

Methane production

Biomass pre-treatment
Biomethane can be produced from various biomass feedstocks (agricultural residues, sewage sludge, biological waste from households and industry, wood, manure, energy crops, landfill gas, algae, etc.). Some feedstocks are easier to process than others. Therefore, some feedstocks must undergo pre-treatment, to improve the biogas yield of anaerobic digestion (see 'biomethane production') (EBA, 2013; IRENA, 2018c). With biological hydrolysis, water molecules are added to biomolecules to induce the splitting of large biomolecules into smaller ones[43].

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[43] Hydrolysis

Biomethane production

Biomethane can be produced by anaerobic digestion in combination with biogas upgrading, or by biomass gasification in combination with syngas cleaning (EBA, 2013). Anaerobic digestion is the conversion of biomass to biogas by bacteria in the absence of oxygen. Raw biogas contains ~60% methane and ~40% CO_2 (IRENA, 2018c). Biogas itself is widely used for production of power and heat in Europe, but for the application in vehicles and for injection into the natural gas grid, it needs to be upgraded to biomethane (Scarlat, et al., 2018). The upgrading of biogas consists of the removal of the CO_2 and pollutants. CO_2 is removed through separation by adsorption, absorption, or membranes[44]. The resulting biomethane has a chemical composition that is close to natural gas, and can therefore be used in the same end-use applications (EBA, 2013; IRENA, 2018c). The technologies involved in biomethane production through anaerobic digestion are mature.

The capital costs of biomethane production through anaerobic digestion are influenced by the feedstocks used, as the technologies must be adapted to those. The largest part of the total costs is formed by the operating costs, of which the feedstock cost is a large component. The auxiliary energy supply takes up the largest part of the costs. The production cost is typically 0.18-0.32 €/m^3 for biomethane based on manure, and 0.09-0.41 €/m^3 for biomethane based on industrial waste. The total biomethane cost from feedstock supply to gas grid injection under Central European conditions ranges from 0.23 to 1.59 €/m^3 (IRENA, 2018c).

Biomass gasification can utilize a wider range of biomass feedstocks that are also more widely available, compared to anaerobic digestion. The feedstocks types used are different than those used in anaerobic digestion. The biomass gasification process consists of gasification (using a gasifier), cooling, polluting compounds removal, methanation (using a catalytic reactor), and water and CO_2 removal (ECN, 2011). Thus, this production process is fundamentally different from that of anaerobic digestion: After gasification, the produced synthesis gas needs to be converted to methane in a methanation process, which is also used in the water electrolysis-based synthetic methane production (see below).

Biomethane is produced in all EU Member States (EurObserv'ER, 2017), although production varies significantly per country. Germany has about 200 biomethane production plants, which produce 860 Mtoe (10 TWh) in total. The total European production capacity is twice as high (Elek, 2018) In contrast, the total European biogas production, reached 16,094 ktoe of primary energy in 2016 (EurObserv'ER, 2017), which was mostly used for power production (Scarlat, et al., 2018). Thus, in terms of available biogas and biogas production capacity, there is a lot of room for growth of biomethane production.

Synthetic methane production

Synthetic methane can be produced by combining hydrogen produced by water electrolysis using renewable electricity with CO_2 in a methanation process. If no additional fossil fuels are burned to obtain the required CO_2 (and the electricity used for the hydrogen production is renewable), the synthetic methane production process is CO_2-neutral. The CO_2 could be retrieved from the air by means of direct air capture, which has been tested in a pilot plant since 2015[45]. Alternatively, the CO_2 could be captured from bio-based industrial processes or combustion of biomass (e.g. from a biomass boiler, from a biogas upgrading or bioethanol plant. The water electrolysis technology is discussed in the hydrogen technology brief.

The methanation process can make use of different production methods and reactor types. In the catalytic methanation production method, possible reactor types are the fixed-bed reactor, fluidized-bed reactor, the structured reactor and the three-phase

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[44] If the captured CO_2 is stored, the overall process results in negative emissions. The overall process is called 'bio-energy with carbon capture and storage (BECCS)'.

[45] Direct Air Capture

reactor, of which the first two are mature technologies and the last two are in the R&D phase. Another production method is biochemical conversion, which makes use of aqueous solutions (Götz, et al., 2016).
The electrolysis unit takes up the largest part of the capital cost of the synthetic methane production system. The capital cost figures for the methanation system given in literature vary widely, but realistic estimations from the year 2014 appear 400 €/kW synthetic methane for a 5 MW plant and 130 €/kW methane for a 110 MW plant (Götz, et al., 2016).

Methane transport

Methane pipeline network
Depending on the location of the feedstock for biogas and biomethane production, the feedstock may need to be transported to a biogas production plant, and the biogas may need to be transported to a methanation plant. This can be done via truck, ship or pipeline.
Biomethane and synthetic methane can be injected in the natural gas network (and thus be blended with natural gas), as the chemical composition is very similar. Thus, these energy carriers can be used by the same consumers and end-use systems as for natural gas. This requires connecting the methanation plant to the natural gas network, which may require extension of the existing grid, especially since biogas production plants are often in remote locations (CE Delft, Eclareon en Wageningen Research, 2016). Biogas, however, cannot be blended with natural gas as it is, as it has a high CO_2-content, and various other impurities.
As the use of natural gas pipelines for biomethane or synthetic methane transport does not require physical modifications, using existing pipelines will not incur investment costs, while new methane pipelines can be expected to have the same capital costs as current natural gas pipelines. For example, Nord Stream 2, the planned new 1,230-kilometer undersea natural gas pipeline with a capacity of 55 bcm/year from Russia to Germany will cost 9.5 billion euro (7.7 million euro per kilometre)[46]. The construction costs of on-land natural gas pipelines with the same capacity will be substantially cheaper.

Methane transport vehicle
Road, water or rail vehicle to transport methane from production site to consumption sites or to pipeline network. Could transport methane in gaseous, liquid or chemical form. Long-distance transport of methane takes place in liquid form, which is currently mainly LNG. Ships are used for intercontinental LNG transport, trucks for transport from coastal areas to inland demand sites. Inland transport of LNG by rail or waterway is in an early development phase (Gabl, 2016). The transport of gaseous biomethane or synthetic methane occurs by means of high-pressure cylinders under 200-250 bar (IRENA, 2018c).

Methane storage

Underground methane storage
Underground natural gas storage, which can occur in depleted fields, salt caverns and aquifers, is an established technology: In 2016, there were 143 underground gas storage facilities in Europe, of which 49 in Germany, 13 in France, and 12 in Italy (CEDIGAZ, 2017). The investment cost in a new facility can be twice as high for salt caverns as for other facilities (287-345 million euro per bcm), but the higher number of

[46] Why World Worries About Russia's Natural Gas Pipeline

cycles can make average storage costs lower than other storage facility types (FERC, 2004).

Compressed methane storage

The same 200-250 bar cylinders that are used for the transportation of compressed natural gas (CNG) can be used for stationary compressed natural gas storage. Another storage vessel is a spherical tank, in which CNG could be stored up to 380 bar[47]. This is particularly useful for refuelling stations that supply methane-fired vehicles, as the on-board storage occurs at max. 250 bar. Existing CNG vessels can also be used for biomethane and synthetic methane.
A CNG storage tank at a refuelling station is estimated to cost between € 50,000 and € 100,000 (Smith & Gonzales, 2014) .

Liquid methane storage

Includes methane liquefaction facility, storage tank and regasification facility. These can be in different locations, when liquid methane is transported from production to consumption sites.
Methane can be liquefied when cooled down to -162 °C, which reduces the volume 600 times, and involves the removal of other gas compounds (Gabl, 2016). Liquid natural gas (LNG) liquefaction, storage tanks and regasification facilities are used for oversea transport of natural gas. European LNG vessels at existing import terminals measure up to 266,000 m^3 in size (King & Spalding , 2018). LNG storage tanks are also located at LNG refuelling stations (see 'methane refuelling'). LNG infrastructure can also be used for biomethane and synthetic natural gas due to the similar gas composition.
In Europe, there are currently 28 large LNG import terminals with a total regasification capacity of 227 bcm per year, with capacity expansions under way or planned (King & Spalding , 2018). European countries with a high accessibility to LNG are Norway, Sweden, the UK, the Netherlands, Belgium, France, Spain, Portugal, and Lithuania. (Gabl, 2016).
A LNG storage tank with a capacity of 28,500 m^3 costs about M€ 47.3 in case of a full containment tank, and M€ 23.7 in case of a single containment tank[48]. A tank with a capacity of 113,500 m^3 costs M€ 84.6 for a full containment tank and M€ 42.3 for a single containment tank. These costs include in-tank pumps and a boil-off compression system (Baker Jr., 2013).

Methane deployment

Methane power plant

Natural gas has a substantial share in the European electricity production mix: In 2015, ~19% of electricity in the EU was produced by natural gas-fired power plants. Countries with a high natural gas share (in 2015) are the Netherlands (58%), Luxembourg (49%), Ireland (48.5%), Lithuania (47%), Latvia (43%) and Italy (39%)[49].
The existing natural gas power plants could also burn biomethane or synthetic methane in the future. In Germany, there already is a total biomethane CHP plant capacity of

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[47] CNG Storage: CNG Vessels, CNG Spheres
[48] A full containment LNG tank has an inner main tank of steel and an enclosed concrete outer tank for primary vapour containment and secure secondary liquid containment. A single containment LNG tank does not have a concrete outer tank, but an outer tank wall of carbon steel, and diked containment (Baker Jr., 2013).
[49] Europe's Electricity Production by Country and Fuel Type

550 MW_{el} (Elek, 2018). Another option is to add a CO_2 capture facility to existing power plants, which would make it possible to continue the use of natural gas without causing CO_2 emissions. The CO_2 would then need to be stored permanently (see 'carbon capture and storage' in the hydrogen technology brief).
Methane-fired power plants make use of furnaces and turbines. Fuel cell power plants are a technology option that are still under development. Solid oxide fuel cells (SOFCs) can internally reform methane into hydrogen and carbon monoxide, which are then used in an electrochemical oxidation process to produce electricity.
Methane power plants may include heat capture and utilisation, which would make them combined heat and power (CHP) plants. As SOFCs work at very high temperatures (500-1000 °C), this would be a valuable and energy efficient option for SOFC power plants[50]. The share of CHP in total electricity generation in the EU was about 10% in 2014 [51], of which ~45% uses natural gas as a fuel (COGEN Europe, 2016).
Currently, most of the biogas produced in the EU is used directly for electricity generation, often in CHP mode. There were more than 16,000 biogas power plants in the EU in 2015, with a total electricity capacity of more than 10 GW. A large share of this is in Germany (Scarlat, et al., 2018). These are decentralised plants. It is important to note that, to use biogas directly for power production, dedicated biogas engines are needed, as well as a dedicated biogas distribution system.

Methane boiler
Biomethane and synthetic methane can be used in existing domestic and industrial boilers for heat production without adaptations to the boilers, as the chemical composition is the same as natural gas. For large (collective or industrial) boilers, CO_2 capture is an option, which would allow for continued natural gas use (in combination with CCS), or for the realisation of negative CO_2 emissions (if CO_2 from biomethane or synthetic methane is captured).
Biogas could also be burned directly in dedicated boilers for heat generation, but only a small part of the biogas produced in Europe is used in this way (Scarlat, et al., 2018). It is important to realise that biogas cannot be injected into the natural gas grid as it is, so it should be used locally or transported separately.
Another option is a hybrid heat pump that combines an electric heat pump with a boiler. This is a relatively new technology, but is already deployed in households. The costs of purchase and installation in the Netherlands have been estimated at 3,600-4,600 euro, incl. VAT (CE Delft, 2017).

Methane vehicles
Vehicles running on gaseous or liquid biomethane or synthetic methane. CO_2 capture within vehicles is in an early research phase[52], and does not appear practical, as captured CO_2 would need to be stored on-board, and at some point removed from the vehicles.
Compressed gaseous biomethane or synthetic methane can be used in conventional natural gas-fuelled vehicles, such as passenger cars, buses and trucks. It is stored in the vehicles at a pressure up to 250 bar. Currently, there are only a few European countries with a relevant but low share of methane vehicles: Italy, Germany, Sweden, the Netherlands, Belgium[53] and the UK (Elek, 2018). This often concerns natural gas.

[50] Solid oxide fuel cell
[51] Eurostat Combined Heat and Power (CHP) data
[52] Watch Out Tesla, Aramco's Carbon Capture Truck Is Coming
[53] Are natural gas cars a real alternative?

In Sweden, however, the usage of biomethane in the transport sector is higher than 90% of gas use in this sector[54].
Liquid biomethane or synthetic methane can be used in LNG-fuelled vehicles. LNG is already used for mobility in the U.S., Asia and part of Europe. In Europe, there are ca. 150 LNG fuelled ships and 1,500 LNG fuelled trucks (which pales in comparison to the 25,000 trucks in the U.S. and the 240,000 trucks in China). Also, in Scandinavia there are passenger ships that run on LNG (Gabl, 2016). LNG is also a feasible option for trains and aircraft, but both are still in the R&D phase[55,56].
Another technology option for methane use in mobility is a hybrid fuel cell system in a vehicle, where methane is internally reformed into hydrogen and carbon monoxide, after which the hydrogen and possibly the CO (depending on the fuel cell type) react electrochemically with oxygen in a fuel cell to produce electricity for propulsion. This is still in the development phase[57].
A LNG mono fuel truck in Europe currently costs 20,000-30,000 euro more than a comparable diesel truck, but this was 40,000 euro several years before (Gabl, 2016).

Methane refuelling
Can be a gaseous or liquid methane refuelling station for road vehicles, a liquid methane bunkering system for ships, or a liquid methane refuelling system for trains or airplanes. There are about 3,600 compressed natural gas (CNG) refuelling stations in Europe[58]. A large part of these are in Italy (1,232 stations), Germany (858 stations), the Czech Republic (181 stations), Sweden (178 stations), the Netherlands (173 stations), Austria (159 stations), and Switzerland (149 stations)[59]. A small CNG refuelling station (357-714 m^3/day) costs € 193,000-463,000, a medium station (1,784-2,854 m^3/day) costs € 424,000-694,000, and a large station (5,350-7,136 m^3/day) costs € 925,000-1,390,000. These investment costs include a compressor, a storage tank, a fuel dispenser, and installation costs (Smith & Gonzales, 2014).
Europe currently has around 100 LNG refuelling stations for trucks, and more than 30 bunkering systems for ships (Gabl, 2016). A lot of the LNG stations are in Italy (29), Spain (28), France (24), the Netherlands (24), and the UK (13)[60]. A full-scale LNG refuelling station from Shell with a storage capacity of 40 tonnes of LNG, which can fuel at least 75 trucks, costs about 1 million euro (Gabl, 2016).
To fill and deplete the on-board storage tanks of ships (methane transport ships or methane-powered ships), a methane bunkering system is needed. This consists of methane storage and methane bunkering equipment, such as pumps and hoses. Since ships can carry much more methane in liquid form, LNG is currently the main form of on-board storage.

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[54] Biomethane reaches 90% share in Swedish vehicle gas
[55] Powering the trains of tomorrow
[56] Could natural gas fuel commercial flights of the future?
[57] Toyota Experimenting With Natural Gas Fuel Cells
[58] Europe CNG filling stations
[59] NGVA Stations map
[60] NGVA Stations maphttps://www.ngva.eu/stations-map/

Appendix C Examples of pilot and demonstation projects

The following tables provide some illustrative examples of hydrogen, methane, CO_2 capture and CCS pilot and demonstration projects that are currently ongoing in Europe, together with some key data on the projects. This overview is intended as an illustration of the diversity of current projects, this is not a comprehensive overview of ongoing projects. *The project names are hyperlinks to websites with more information.*

Hydrogen

Project	Country (pilot or demonstration location)	Brief summary	Period	Funding	Topic
Project REFHYNE : Clean Refinery Hydrogen for Europe	Germany	This demonstration project will install and operate a 10MW electrolyser at a large refinery in Rhineland, Germany. The electrolyser will provide bulk quantities of hydrogen to the refinery's hydrogen pipeline system. The electrolyser will be operated in a highly responsive mode, helping to balance the refinery's internal electricity grid and also selling Primary Control Reserve service to the German Transmission System Operators.	2018 - 2022	EU through FCH JU	Power to gas for industry
Project H2Future : Hydrogen Meeting Future Needs of Low Carbon Manufacturing Value Chains	Austria	Demonstration project for grid balancing services with hydrogen electrolysis, to show that the PEM electrolyser is able both to use timely power price opportunities (in order to provide affordable hydrogen for current uses of the steel making processes), and to attract extra revenues from grid services which improves the hydrogen price attractiveness.	2017 -2021	EU through FCH JU	Power to gas for industry

Project Demo4Grid: Demonstration of 4MW Pressurized Alkaline Electrolyser for Grid Balancing Services	Austria	The main aim of project Demo4Grid is the commercial setup and demonstration of a technical solution utilizing "above state of the art" Pressurized Alkaline Electrolyser (PAE) technology for providing grid balancing services in real operational and market conditions.	2017 - 2022	EU through FCH JU	Power to gas for grid injection
Project REMOTE : Remote area Energy supply with Multiple Options for integrated hydrogen-based TEchnologies	Italy	REMOTE will demonstrate technical and economic feasibility of two fuel cells-based H_2 energy storage solutions (integrated P2P system; non-integrated P2G+G2P system), deployed in 4 DEMOs, based on renewables, in isolated micro-grid or off grid remote areas	2018 - 2021	EU through FCH JU	Power to Gas for heat, power and transport, in isolated areas
Project BIG HIT : Building Innovative Green Hydrogen systems in an Isolated Territory: a pilot for Europe	UK	BIG HIT will create a replicable hydrogen territory in Orkney (Scotland) by implementing a fully integrated model of hydrogen production (from wind and tidal turbines), storage, transportation and utilisation for heat, power and mobility.	2016 - 2021	EU through FCH JU	Power to Gas for heat, power and transport, in isolated areas
Tennet : North Sea Wind Power Hub	Netherlands, Germany	Further development of the North Sea Wind Power Hub (NSWPH), an artificial island that could be developed as a central hub to support the necessary energy evacuation infrastructure e.g. electrical or power to gas conversion.	ongoing	TenneT Netherlands, TenneT Germany, Energinet, Gasunie and Port of Rotterdam	Offshore wind to gas (power to gas)
DEMCOPEM-2MW project: World's first 2MW PEM fuel cell power plant	Netherlands, China	The DEMCOPEM-2MW project is to design, construct and demonstrate an economical combined heat and power PEM fuel cell power plant (2 MW electrical power and 1.5 MW heat) and integration into a chlor-alkali (CA) production plant.	2015 - 2019	EU through FCH JU	Fuel cell heat and power plants for industry

Project Everywh2ere: portable fuel cells to be used as power supply for temporary events throughout Europe	EU-wide	EVERYWH2ERE project will integrate already demonstrated robust PEMFC stacks and low weight intrinsecally safe pressurized hydrogen technologies into easy to install, easy to transport FC based transportable gensets. 8 FC containered "plug and play"gensets to be tested in construction sites, music festivals and urban public events all around Europe.	2018 - 2023	EU through FCH JU	Fuel cells for small scale power generation
Project ComSos : Commercial-scale SOFC systems	Finland, Germany, Italy, Netherlands, Switserland	ComSos - Commercial-scale SOFC systems - is an EU funded project aimed to validate and demonstrate fuel cell based combined heat and power solutions in the mid-sized power ranges of 10-12 kW, 20-25 kW, and 50-60 kW, referred to as Mini FC-CHP.	2018 - 2021	EU through FCH JU	Fuel cells for power and heat generation
PACE : Pathway to a Competitive European Fuel Cell micro-Cogeneration Market	11 European countries	The objective of the project is to unlock the market for Fuel Cell micro-Cogeneration large scale uptake by preparing the supply chain and working with policy-makers in selected countries to promote a successful transition to mass commercialisation.	2016 - 2021	EU through FCH JU	Fuel cells in the built environment
ClearGen Demo ; The Integration and demonstration of Large Stationary Fuel Cell Systems for Distributed Generation	Denmark	The Integration and demonstration of Large Stationary Fuel Cell Systems for Distributed Generation, at a chemical production plant	2012 - 2020	EU through FCH JU	Large stationary fuel cell systems
Project DESTA : Demonstration of 1st European SOFC Truck APU	Austria	Within the DESTA project the first European SOFC ("Solid Oxide Fuel Cell") Truck APU ("Auxiliary Power Unit") will be demonstrated. SOFC technology offers big advantages compared to other fuel cell technologies due to compatibility to conventional road fuels like diesel.	2012-2015	EU through FCH JU	Fuel cells for trucks
Highvlocity : Cities speeding up the integration of hydrogen buses	Belgium, Italy, Netherlands, UK	The High V.LO-City project implements a fleet of 14 hydrogen fuel cell public buses in 4 regions acrosse Europe, to demonstrate the economic and technical viability of these buses	2012 - 2019	EU through FCH JU	Hyrogen fuel cell buses

		and of intelligent infrastructure solutions, necessary for broad market introduction.			
The Aberdeen Hydrogen Bus Project	UK	The project will deliver a hydrogen infrastructure in Aberdeen, including an electrolyser, a bus refuelling station, 10 hydrogen buses and a maintenance facility.	2013 - 2019	EU through FCH JU	Hyrogen fuel cell buses

Methane

Project	Country (pilot or demonstration location)	Brief summary	Period	Funding	Topic
Project STORE&GO: Power-to-Gas storage concepts	Germany, Switzerland and Italy	Three demonstration plants for testing various Power to Gas concepts, with different renewable energy sources, consumers, electricity and gas grid types, CO_2 sources, etc.	2016 - 2020	European Union through Horizon 2020	Power to gas and synthetic methane production for grid injection
Tauron: A pilot plant will convert CO_2 into natural gas	Poland	This project is aimed at converting the carbon dioxide captured from power units into synthetic natural gas to be used as a vehicle fuel (SNG).	ongoing	KIC InnoEnergy, European Union Horizon 2020	CO_2 capture and synthetic methane production for vehicles
GRTgaz: Power to Gas, Jupiter 1000	France	To build a power to gas demonstration plant (Jupiter 1000) that produces synthetic methane through transforming electricity into hydrogen (water electrolysis) and then combining this with CO_2, to inect into the natural gas grid.	2016 - ongoing	European Regional Development Fund	Power to gas, CO_2 capture, synthetic methane production for grid injection

ETIA and GRTgaz: partners in a pilot plant producing synthetic methane by gasification	France	The objective is to build a pilot plant producing synthetic methane by gasification, to produce continuously-available renewable energy from local biogenic resources and to convert waste into synthetic gas.	2017 - ongoing	EIA and GRTgaz	Biomethane production through gasification of biomass
VERBIO Biofuel and Technology : Biomethane from straw	Germany	To further develop VERBIO's innovative technology to produce biomethane from 100% straw at it's production site in Schwedt/Oder	2014 - 2019	NER300 funding programme	Biomethane production from straw through fermentation

CO_2 Capture and Storage

Project	**Country (pilot or demonstration location)**	**Brief summary**	**Period**	**Funding**	**Topic**
CEMCAP: CO2 capture technologies for the cement industry	Europe, Norway	CEMCAP will demonstrate CO_2 capture technologies for the cement industry in an industrially relevant environment.	2015 - 2019	European Union through Horizon 2020	CO_2 capture in the cement industry
STEPWISE a H2020 Project: Pilot-Description	Sweden	STEPWISE proposes a novel technology for capturing CO_2 from Blast Furnace Gas (BFG) emitted by the iron and steel industry, based on the so-called SEWGS process (Sorption Enhanced Water Gas Shift).	2015 - 2019	European Union through Horizon 2020	CO_2 capture in the steel industry
Leilac: Low Emissions Intensity Lime & Cement	Belgium	LEILAC will develop, build and operate a pilot plant to assess a CO_2 capture technology for the lime and cement industries.	2016 - 2021	European Union through Horizon 2020	CO_2 capture in the cement industry

ACT Acorn: A scalable full-chain industrial CCS project	UK	To deliver a low-cost carbon capture and storage (CCS) system in north east Scotland by 2023	2017 - ongoing	European Union through Horizon 2020, ERA-NET ACT	Carbon capture and storage
The CLIMIT programme	Norway	Financial support for development of CCS technology	2017 - 2022	Norwegian government	Carbon capture and storage

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