GAS FOR CLIMATE

The optimal role for gas in a net-zero emissions energy system

March 2019

NAVIGANT

Gas for Climate. The optimal role for gas in a net-zero emissions energy system

Prepared for:

By: Wouter Terlouw, Daan Peters, Juriaan van Tilburg, Matthias Schimmel, Tom Berg, Jan Cihlar, Goher Ur Rehman Mir, Matthias Spöttle, Maarten Staats, Ainhoa Villar Lejaretta, Maud Buseman, Mark Schenkel, Irina van Hoorn, Chris Wassmer, Eva Kamensek, Tobias Fichter

Reviewed by Kees van der Leun and Prof. Dr. Kornelis Blok

Navigant Netherlands B.V.
Stadsplateau 15
3521 AZ Utrecht
+31 30 662 3300
navigant.com

Reference No.: 203997
Date: 18 March 2019

Executive summary

The purpose of this study is to assess the cost-optimal way to fully decarbonise the EU energy system by 2050 and to explore the role and value of renewable and low-carbon gas used in existing gas infrastructure. This is being done by comparing a "minimal gas" scenario with an "optimised gas" scenario. This study is an updated version of the February 2018 Gas for Climate study, with an extended scope of analysis.

The current study adds an analysis of EU energy demand in the industry and transport sectors. It also includes an updated supply and cost analysis for biomethane and green hydrogen, including dedicated renewable electricity production to produce hydrogen, and an analysis on power to methane. Finally, we assessed the potential role of blue hydrogen, natural gas combined with carbon capture and storage (CCS) or carbon capture and utilisation (CCU).

Both the "minimal gas" and "optimised gas" scenarios arrive at a net-zero emissions EU energy system by 2050. The scenarios both assume a significant increase in renewable electricity (wind, solar PV, and some hydropower). The main difference between the scenarios is the role of renewable and low carbon (or 'decarbonised') gas, and the role of biomass power. The "minimal gas" scenario decarbonises the EU energy system assuming a large role for direct electricity use in the buildings, industry and transport sectors, with some biomethane being used to produce high temperature industrial heat. Renewable electricity is produced from wind, solar and hydropower, combined with solid biomass power. The "optimised gas" scenario also has a strongly increased role of direct electricity in the buildings, industry and transport sectors. Yet it concludes that renewable and low-carbon gas will be used to provide flexible electricity production, to provide heat to buildings in times of peak demand, to produce high temperature industrial heat and feedstock, and to fuel heavy road transport and international shipping.

The study's main conclusions are:

1. **Full decarbonisation** of the energy system **requires substantial quantities of renewable electricity** in both study scenarios. Electricity production will more than double and renewable electricity production from wind and solar-PV will increase ten-fold compared to today.
2. Strong growth in wind and solar PV requires dispatchable electricity production by either solid biomass or gas**. Battery seasonal storage is unrealistic even at strongly reduced costs**.
3. **Full decarbonisation of high temperature industrial heat requires gas** in both scenarios.
4. Existing **gas grids ensure the reliability and flexibility of the energy system**. They can be used to transport and distribute renewable methane and hydrogen.
5. It is possible to **sustainably scale-up renewable gas**–biomethane, power to methane and green hydrogen–at strongly reduced production costs.
6. **Blue hydrogen** produced from natural gas combined with CCS can be a scalable and cost-effective option. Because green hydrogen is still expensive today and because its ramp-up is linked to the speed of growing wind and solar capacity to necessary levels, an early scale-up of blue hydrogen can accelerate decarbonisation.
7. The "optimised gas" scenario allocates 1,170 TWh renewable methane and 1,710 TWh hydrogen to the buildings, industry, transport, and power sectors. This equals about 270 billion cubic metres of natural gas (energy content). Compared to the "minimal gas" scenario, the **use of gas through gas infrastructure saves society €217 billion annually across the energy system** by 2050
8. The "minimal gas" scenario requires 809 TWh of (probably partly imported) solid biomass power, nine times more than the 89 TWh in "optimised gas".
9. The **future energy system can become fully renewable**, with blue hydrogen being replaced by renewable green hydrogen towards 2050–2060 following a large scale-up of wind and solar.

These conclusions are in line with the results of the 2018 Gas for Climate study. Especially conclusions 1-3, the biomethane scale-up potential mentioned under conclusion 5, the large energy system cost savings under point 7 and the large role for solid biomass power under point 9 are similar to what we concluded in the previous study. The current study shows larger gas volumes (2900 TWh versus 1000 TWh) and energy system cost savings (€217bn versus €138bn annually) following a more extensive analysis into hydrogen supply and into energy demand in industry and transport.

As shown in the graph below, cost savings per unit of energy are highest in the heating of buildings, where renewable gas is used combined with electricity in hybrid heat pumps in buildings that are connected to gas grids today. Also, the use of renewable gas in electricity production generates significant energy system savings because it avoids costly investments in solid biomass power or even costlier battery seasonal storage. Using less solid biopower in “minimal gas” would increase the costs of this scenario and therefore increase the cost savings by implementing “optimised gas”

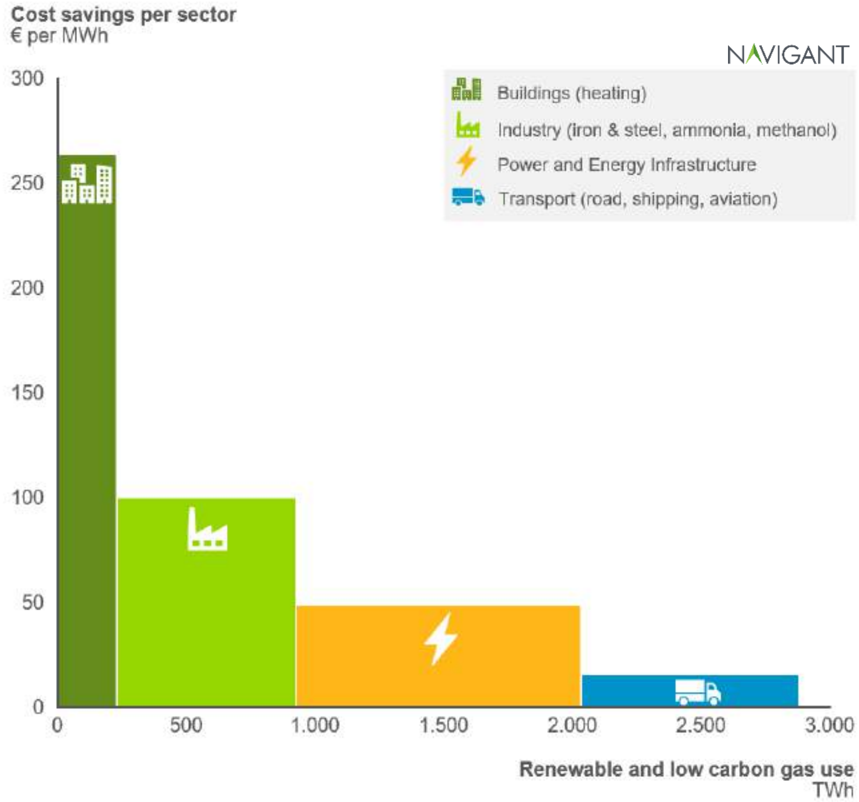

Figure 1 Quantities of gas used per sector and resulting energy system cost savings in the “optimised gas” scenario versus the “minimal gas” scenario

The total annual costs amount to more than two trillion euro in both scenarios. Most of these costs are not additional costs related to decarbonisation but are regular energy system costs and transport vehicle costs that exist today as well. For all relevant uses of energy, Navigant chose the scope of our cost estimates that enabled us to perform a fair cost comparison between the two scenarios. This means for example that we included all energy production costs for both scenarios, yet for road transport we include road vehicle and fuel costs, while for aviation we only include fuel costs because the costs for aeroplanes will be similar in both scenarios. Also, cost for upgrades in the electricity transmission grid are fully included, while low voltage distribution is not because strong electrification in both scenarios would result in similar grid replacement costs It can safely be concluded that the €217 billion euro cost savings in the “optimised gas” scenario are a substantial share of additional costs beyond ‘business as usual’ energy system costs.

In addition to substantial reductions in additional energy system costs, the "optimised gas" scenario has non-cost related benefits including promoting rural employment from increased biomethane production and avoiding unnecessary new overhead powerlines that could meet societal opposition.

Although reduced compared to today, the EU will still require large quantities of energy in 2050. In our 2050 scenarios domestic sources of coal and nuclear are (almost) phased out, raising the question where required energy will be produced. Today, the EU imports more than 50% of its energy. In theory it is feasible to produce all required energy in both study scenarios domestically within the EU by 2050. However, producing renewable energy in other parts of the world can be an attractive alternative, and it is more likely that international trade in energy will continue to exist. This could include imports of solid biomass in the "minimal gas" scenario or imports of green hydrogen in the "optimised gas" scenario.

The "optimised gas" scenario includes only renewable gas to show that it is possible to achieve net-zero emissions by 2050, with no remaining role for low-carbon gas. Yet because the costs of green and blue hydrogen can be similar by 2050, there could still be a role for blue hydrogen. Blue hydrogen can grow the use of low-carbon hydrogen in coming years, allowing faster decarbonisation. Towards 2050, natural gas will be phased out and blue hydrogen would increasingly be replaced by green hydrogen and renewable methane. The speed by which green hydrogen can replace blue hydrogen depends on how fast all direct electricity demand can be produced from renewables and how fast additional renewable electricity generation capacity is constructed beyond that. It furthermore depends on whether policy makers will limit the use of blue hydrogen by 2050. Any large scale-up of green hydrogen production prior to the moment when all demand for direct electricity is covered by renewable power results in indirect increases in fossil electricity generation.

This study analyses the optimal 2050 decarbonised energy system; it does not include detailed analysis on the way to get there. In developing the system towards the desired 2050 state, it can be effective to transport blended methane and hydrogen through gas grids in coming years with hydrogen shares of up to 10% in transported gas, while gradually creating dedicated hydrogen transport grids by retrofitting part of the existing gas grids. Likewise, while by 2050 biomethane adds more value in buildings and electricity production and light transport can be expected to be electrified, it can make sense to continue to use bio-CNG in transport today to create an initial market for sustainable biomethane, and to accelerate transport decarbonisation.

Comparison with the 1.5TECH scenario from the European Commission and the Decarbonisation Pathways by Eurelectric

Throughout this study, Navigant compares its scenarios with recently published scenarios by the European Commission in the *A Clean Planet for all - A European long-term strategic vision for a prosperous, modern, competitive and climate neutral economy* communication by the European Commission[1] as well as the *Decarbonisation Pathways* study by Eurelectric.[2] From the EC communication, Navigant focuses on the 1.5TECH scenario which is in line with the 1.5 degrees Celsius ambition.

The 1.5TECH scenario from the EC is similar to the Navigant "optimised gas" scenario. Both are in line with the Paris Agreement and show strong decarbonisation in all sectors. Both scenarios also see a strongly increasing role of (direct) electricity, which is also in line with the *Decarbonisation Pathways* from Eurelectric. Also, the role of renewable and low carbon gas in the 1.5TECH scenario from the EC (about 3,000 TWh) is similar to the renewable and low carbon gas in the "optimised gas" scenario (almost 2900 TWh).

[1] https://ec.europa.eu/clima/policies/strategies/2050_en

[2] https://www.eurelectric.org/decarbonisation-pathways/

Further details on key study conclusions

Large increase in renewable electricity
Full decarbonisation of the EU energy system in a cost-optimal way requires substantial quantities of renewable electricity in both study scenarios as shown in the figure below.

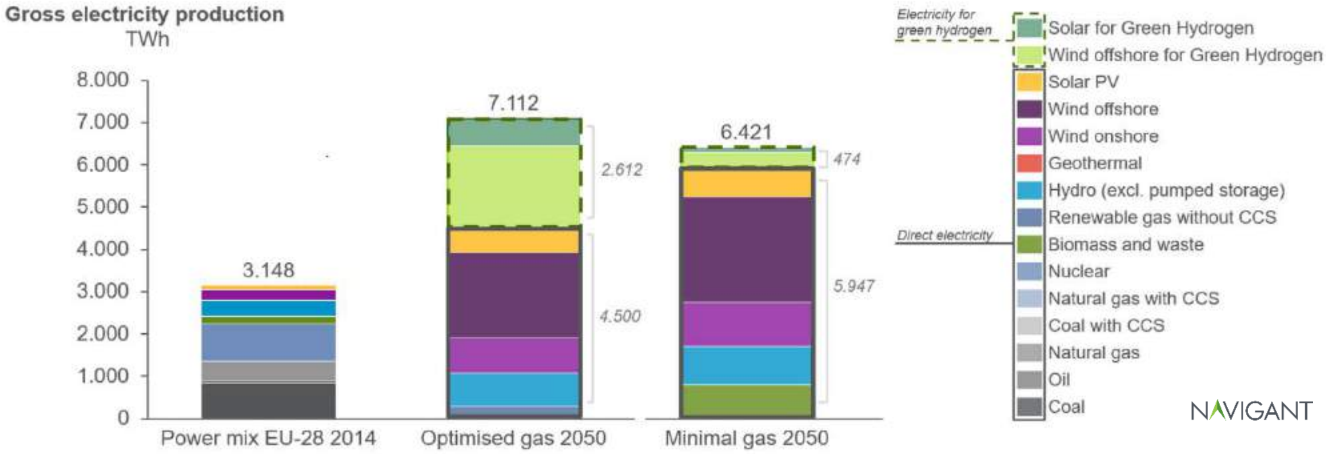

Figure 2 Gross electricity generation in both scenarios compared to EU-28 power mix in 2014

Renewable methane and hydrogen provide cost-effective dispatchable power
Either solid biomass, large-scale battery seasonal storage or renewable or low-carbon gas is required to provide dispatchable electricity production once wind power and solar PV are scaled more than tenfold by 2050. Renewable methane and hydrogen supplied through gas infrastructure provide dispatchable electricity and offer seasonable storage in a cost-effective way.

Biomethane and power to methane
Biomethane and power to methane can supply up to 1,170 TWh at strongly reduced costs, consisting of 1,010 TWh of biomethane and 160 TWh of power to methane.

Navigant's analysis shows that by 2050 all biomethane can be zero emissions renewable gas, in the sense that any remaining lifecycle emissions can be compensated by negative emissions created in agriculture on farms producing biomethane. Based on our assessment of potential biomethane cost reductions we conclude that production costs can decrease from the current €70–90/MWh to €47–57/MWh in 2050. These costs reflect large-scale biomass to biomethane gasification close to existing gas grids, as well as more local biomethane production in digesters.

An assessment of the feasibility of increasing renewable methane production by methanation of CO_2 captured in biogas upgrading showed that this technology could increase the renewable methane potential although costs will remain somewhat higher than biomethane or hydrogen costs.

Navigant's assessment on the biomethane potential has not significantly changed from its 2018 analysis, now 95 bcm instead of our previous 98 bcm of natural gas equivalent. In response to questions and comments on the uncertainties of the supply of sustainable silage when implementing Biogasdoneright (winter silage cropping) throughout Europe the potential in southern Europe versus countries with a more moderate climate is now differentiated. Navigant performed a deeper analysis of the availability of woody biomass for biomethane, including short-rotation plantation wood cultivated on abandoned farmland.

Green hydrogen

Dedicated wind and solar PV generation could produce green hydrogen as the main product. Navigant found that there is large theoretical potential of offshore wind and solar PV, going beyond the estimated 2050 EU renewable power projection. This means that the technical potential for green hydrogen production is virtually limitless. However, there are considerations such as the land use change risks associated with an increase in non-rooftop solar PV and competing sea uses to offshore wind that will limit the green hydrogen potential. The costs of hydrogen based on dedicated renewable electricity can come down to about €52/MWh.

Navigant found that pipeline transport of green hydrogen is the most economical and that shipping hydrogen will likely remain expensive due to high costs of liquefaction. While imports of hydrogen to the EU are possible, the most likely option would be hydrogen produced in neighbouring regions (e.g. North Africa) being transported to Europe through pipelines. Mixing hydrogen with methane is possible but is unlikely to be the optimal solution by 2050.

Blue hydrogen as a valuable temporary energy carrier

Navigant concludes that the technical potential for blue hydrogen based on using permanent carbon capture and utilisation (CCU) in the EU is small. However, blue hydrogen based on applying CCS can be scaled up to very large quantities within a relatively short timeframe to 1,500 TWh, or 142 bcm natural gas equivalent. However, limited political acceptance today is a barrier to scaling up CCS. To increase political acceptance, policymakers can ensure that blue hydrogen plays a role as a bridge fuel to achieve net-zero emissions faster compared to a fully renewable system. To ensure that blue hydrogen will be a net-zero emissions gas in 2050, the remaining 5–10% of uncaptured CO_2 needs to be compensated elsewhere in the energy system by then. This can be done by using biomethane in combination with CCS. In 2050, the estimated cost of blue hydrogen is comparable to green hydrogen. This means that pro-active policy to ensure the greening of hydrogen supply is required.

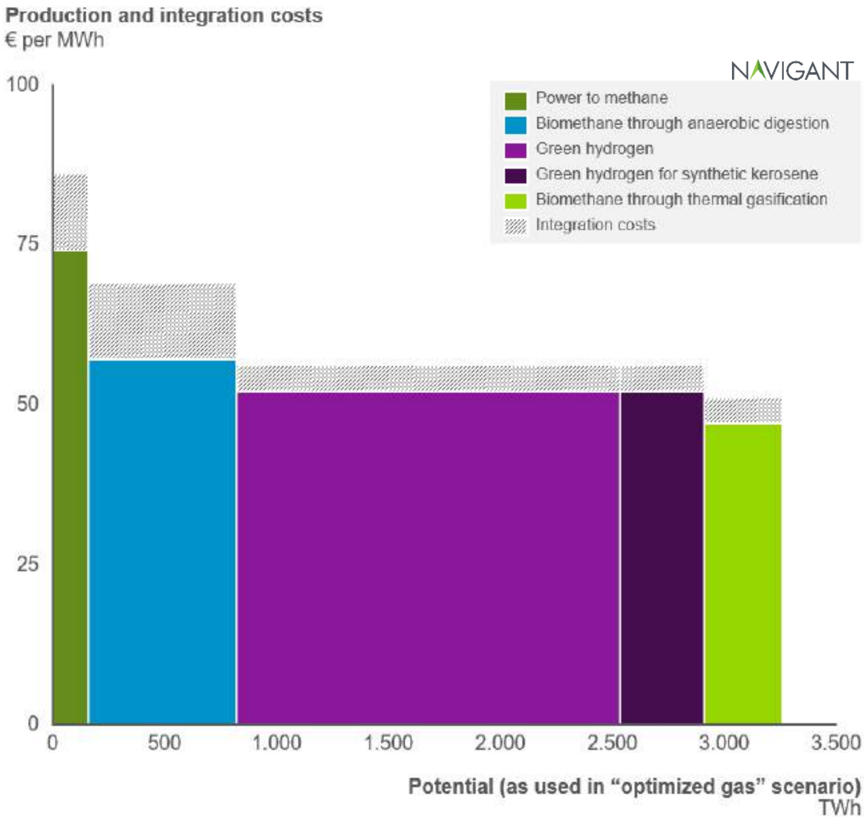

Figure 3 An overview of renewable gas volumes and the production and integration costs

2050 demand for electricity and gas in both study scenarios

The “minimal gas” and “optimised gas” scenarios both require a large increase in renewable electricity. Also, full decarbonisation of high temperature industrial heat requires a share of renewable gas in both study scenarios. Yet significant differences between both scenarios exist. In the “optimised gas” scenario, existing gas infrastructure is used to transport and distribute 1,170 TWh renewable methane and 1,710 TWh hydrogen to the EU buildings, industry, transport, and power sectors. This corresponds to a 2050 gas consumption of 272 billion cubic metres of natural gas equivalent (in terms of energy). The “minimal gas” scenario assumes that gas infrastructure would be mostly decommissioned and flexibility in the electricity system will be either provided by expensive solid biomass power or even more expensive battery seasonal storage. Battery storage remains expensive compared to gas grid storage, even if battery costs reduce to €60,000 per MWh of storage capacity by 2050. It should be noted that renewable methane use is supply-driven whereas hydrogen use is demand driven. Furthermore, hydropower and liquid biofuel are supply-driven and direct electricity consumption throughout the energy system is demand driven.

The graph below illustrates the supply and demand of renewable and low-carbon gas in the “optimised gas” scenario. Subsequently, the allocation of energy to demand sectors is described for both scenarios.

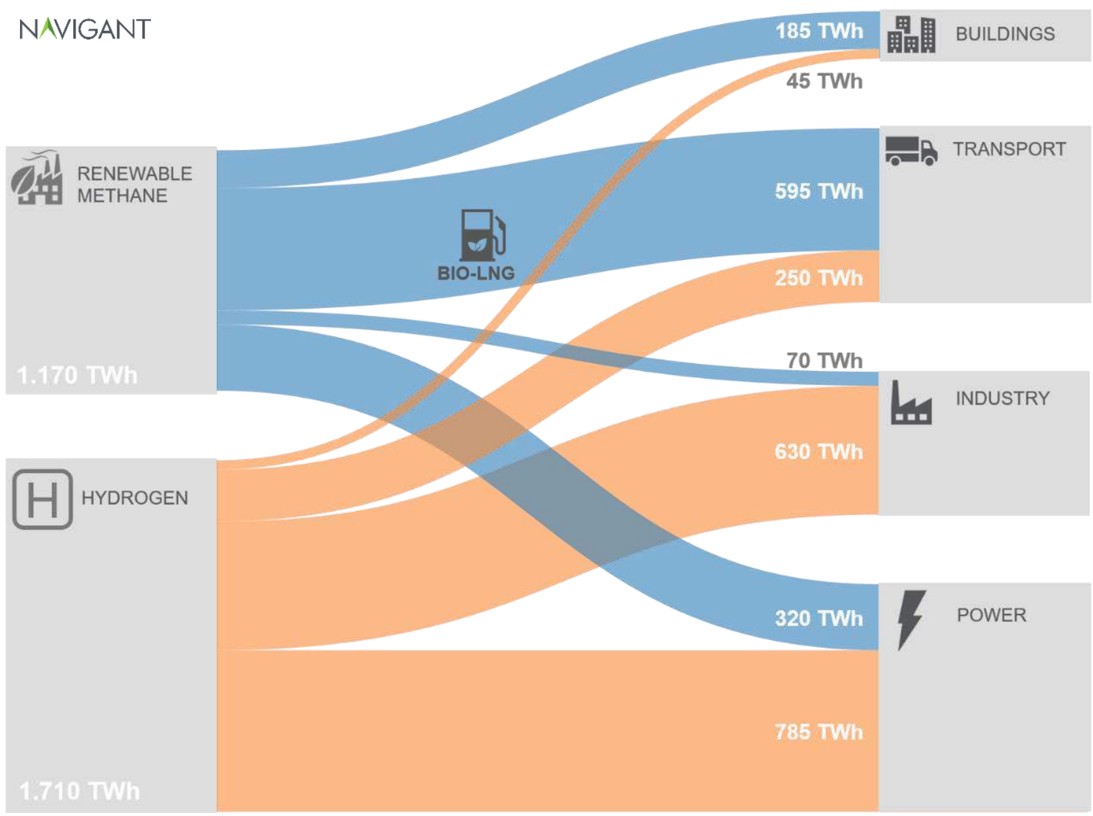

Figure 4 Renewable and low-carbon gas supply and demand in the "optimised gas" scenario

<u>Electricity production and heating of buildings</u>

Navigant analysed the possible role of hydrogen and biomethane in electricity production and heating of buildings based on the updated supply potentials. The outcomes differ little from the previous study. In both our ‘optimised gas’ and “minimal gas” scenario most buildings will by 2050 be heated by all-electric heat pumps, and both scenarios assume increased levels of district heating. In the power sector, now also hydrogen is used for dispatchable electricity generation.

For heating of buildings, in the “optimised gas” scenario all buildings with gas connections today will continue to use gas by 2050, mainly biomethane and some hydrogen used during periods of peak demand in hybrid heat pumps, in combination with electricity.
Gas consumption per building will be much lower by 2050 compared to today. The “minimal gas” scenario assumes that only all-electric heat pumps and district heating will be available.

Industry

Navigant assessed the expected 2050 energy demand in the iron and steel, ammonia and methanol, and cement and lime industries, as well as the optimal net-zero emissions energy mix. The assessment concluded that industrial low temperature heat will be mostly based on direct electricity in both study scenarios. High temperature industrial heat is mainly provided by hydrogen in both scenarios, plus some biomethane and hydrogen as industrial feedstock. CCS will be needed to reduce process emissions, for example, from steelmaking and cement production. The difference between both scenarios is that in “minimal gas” green hydrogen is produced at industrial sites, not requiring gas infrastructure, whereas in “optimal gas” green hydrogen is produced close to large-scale (offshore) electricity generation and transported to demand hubs using existing gas infrastructure.

Transport

Navigant also assessed scenarios to fully decarbonise EU transport by 2050 and the potential role for renewable and low-carbon gas, focusing on road transport (passenger cars, trucks, and buses), shipping, and aviation. Shipping and aviation include domestic and intra-EU shipping and aviation, as well as intercontinental fuelling and bunkering. We conclude that EU transport energy demand can be reduced by half in both our study scenarios from today’s 4500 TWh to about 2100 TWh by 2050. Light road transport (passenger cars, light commercial vehicles) and domestic shipping will be primarily electric in 2050 in both study scenarios. Long-distance heavy transport requires fuels with a high energy density, meaning that direct use of electricity (from batteries) is less suitable for international shipping and aviation. In heavy road transport and international shipping, hydrogen and bio-LNG dominate in the “optimised gas” scenario while large quantities of biodiesel are used in the “minimal gas” scenario. Aviation will continue to use kerosene, being a mix of bio jet fuel and synthetic kerosene in both scenarios.

While multiple parallel fuelling options are implemented locally, the energy mix for long-haul truck transport, shipping, and aviation must be internationally uniform. It is not feasible for one country to fuel ships with liquified biomethane (bio-LNG) while a neighbouring country offers biodiesel. In aviation, the two most promising renewable fuels, bio jet fuel and synthetic kerosene, can use the same fuelling infrastructure as today.

Maintaining gas infrastructure generates €217 billion in annual energy system cost savings

The European gas transmission and distribution (T&D) network consists of approximately 260,000 km of high-pressure network of which 200,000 km are operated (mainly) by transmission system operators (TSOs), plus approximately 1.4 million km of medium and low-pressure pipelines operated by distribution system operators (DSOs). Gas infrastructure ensures the reliability and flexibility of the energy system. Navigant expects gas transmission and distribution networks to still have a valuable role by 2050, transporting biomethane and hydrogen. In both scenarios described in this study, volumes of gas used in networks are lower in 2050 than in 2019. Still, the use of gas in existing infrastructure will generate significant net energy system cost benefits.

Compared to the “minimal gas” scenario, the use of this gas through existing gas infrastructure saves society €217 billion annually across the energy system. Cost savings per unit of energy are highest in the heating of buildings, where renewable gas is used combined with electricity by means of hybrid heat pumps, in buildings that are connected to gas grids today. Also, the use of renewable gas in electricity production generates significant energy system savings because it avoids costly investments in solid biomass power or even costlier battery seasonal storage.

Table of Contents

Abbreviations

Abbreviation	Explanation
AD	Anaerobic digestion
AE	Alkaline electrolyser
ATR	Autothermal reforming
bcm	Billion cubic meters
BoP	Balance of plan
CAPEX	Capital expenditure
CCS	Carbon capture and storage
CCU	Carbon capture and utilization
CH_4	Methane
CO_2	Carbon dioxide
COP	Coefficient of performance
DSO	Distribution system operator
EV	Electric vehicle
FLH	Full-load hour
H_2	Hydrogen
LCOE	Levelised cost of energy
MWh	Megawatt-hour
O&M	Operations and maintenance
OPEX	Operational expenditure
PEM	Proton exchange membrane
PV	Photovoltaic
RED	Renewable Energy Directive
SOEC	Solid oxide electrolysis cells
SMR	Steam methane reforming
TSO	Transmission grid operators
TWh	Terawatt hour

1. Introduction

In February 2018, the Gas for Climate consortium published a study performed by Ecofys, now part of Navigant, called '*Gas for Climate. How gas can help to achieve the Paris Agreement target in an affordable way*'. That study explored the potential of EU-produced biomethane and green hydrogen from surplus renewable power generation and analysed the energy system cost benefits of using this renewable gas through existing gas infrastructure to achieve a net-zero emissions EU energy system by 2050. The energy system costs of a 'with gas' scenario were compared to a 'no gas' scenario. The study found a large potential to scale up renewable gas production in the EU and concluded that full decarbonisation with a role for renewable gas offers significant societal cost benefits, in the order of €138 billion per year. The study did not cover the full EU energy system yet focused on the heating of buildings and electricity production, setting aside part of the renewable gas to decarbonise EU industry.

This study is an update of the previous GfC study with an expanded scope of analysis.

This study is an update of the previous GfC study with an expanded scope of analysis. Starting point remains that global warming must be kept to well below 2°C. Achieving this target means that the EU energy system must be fully decarbonised by 2050. This requires significant investment in energy efficiency, renewable energy, new low-carbon technologies, and grid infrastructure. Because such investments are made for a period of 20–60 years, policies that promote a stable environment for businesses which encourages low-carbon investments must be made today.

Achieving a net zero-carbon energy system will only be possible with forceful efforts to increase energy efficiency in all sectors combined with a rapid scale-up of renewable energy and low-carbon technologies. In addition, Europe's energy supply should also remain reliable, secure, and competitive—crucial elements to ensure public acceptance of the energy transition.

Europe has made important steps towards a more sustainable, secure, yet still competitive energy supply. The share of renewable energy has greatly increased in recent years, driven partly by EU regulations centred around the Renewable Energy Directive (RED). This large-scale implementation caused renewable electricity technologies to further mature, resulting in cost reductions. The costs of electricity from wind and solar dropped impressively. In Europe the levelized costs of energy (LCOE) for onshore wind decreased by 24% from 2010–2016 and globally the LCOE of utility-scale PV plants have fallen by 73% from 2010–2017.[3] At the same time, the role of coal as a carbon-intense energy source has slowly begun to dwindle as it gradually is replaced by renewables and natural gas.

Renewable electricity provided 30% of the total EU electricity supply in 2016.[4] This share is expected to grow to more than 50% by 2030. With increasing levels of wind and solar PV power and increasing demand for electricity for heat pumps and electric vehicles (EV), there will be a growing need for flexibility in the electricity system. The electricity system is designed in such a way that supply and demand are in constant balance, without much possibility to store energy in the electricity system. Constantly changing electricity demand and supply following changing weather conditions and differences in demand between day and night and between summer and winter need to be balanced with dispatchable supply. Today, this function is performed by coal-, oil-, and gas-fired power plants, because coal, oil, and gas can be stored in large quantities at low prices.

[3] IRENA (2018), Power Generation Costs. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Jan/IRENA_2017_Power_Costs_2018.pdf .

[4] Eurostat (2019), Renewable Energy Statistics. http://ec.europa.eu/eurostat/statistics-explained/index.php/Renewable_energy_statistics

All provide flexibility in the energy system, but the large additional benefit of natural gas is that it has a lower greenhouse gas intensity compared to oil (-23%) and coal (-41%).[5] The combustion of natural gas also reduces air pollution (e.g., NO_x, SO_x, particulate matter) compared to coal and oil.

As the energy system progresses towards full decarbonisation, a mix of technologies will be necessary to keep the energy system secure, reliable, affordable, socially acceptable, and environmentally friendly. To find the optimal mix, all possibilities must be investigated.

1.1 Gas for Climate

The future energy system will be fully renewable, and biomethane and green hydrogen will play a major role in combination with renewable electricity. However, to meet climate goals, short-term decarbonisation is needed too. Using renewable and low-carbon gas can accelerate decarbonisation efforts in the coming decades.

In June 2017, a group of European gas transmission system operators (TSOs) and biogas producing organisations joined forces to explore the future of gas and gas infrastructure in a decarbonised EU energy system. This became the Gas for Climate group. The group is committed to achieving net-zero greenhouse gas emissions in the EU by 2050 and is united in its conviction that renewable and low-carbon gas used through existing gas infrastructure will help to deliver this at the lowest possible costs and maximum benefits for the European economy. Gas for Climate aims to assess and create awareness about the role of renewable and low-carbon gas in the future energy system. The group consists of seven leading European gas TSOs (Enagás, Fluxys, Gasunie, GRTgaz, Open Grid Europe, Snam, and Teréga) and two renewable gas producers' associations (European Biogas Association and Consorzio Italiano Biogas). Gas for Climate members are based in six EU member states that are collectively responsible for the transport of 75% of total current natural gas consumption in Europe.

1.2 Aim and scope of this study

The February 2018 Gas for Climate study triggered a dialogue on the subject with many stakeholders. The consortium presented and discussed the study with many policymakers, industry stakeholders, and NGOs. This led to the growing awareness that renewable gas can be scaled up to significant quantities and can be a valuable addition alongside renewable electricity in a net-zero emissions energy system.

This study is an update of the 2018 study. It aims to address all valuable input which the Gas for Climate consortium and Navigant received into a refined analysis, and it explains the study methodologies and assumptions where necessary.

> The "optimised gas" scenario assumes that renewable and low carbon gas are used in a smart combination with renewable electricity

The purpose of the study remains the same: to assess the possible role and value for gas used in existing gas infrastructure in a net-zero emissions EU energy system compared to a situation in which a minimal quantity of gas would be used. To estimate the societal value of gas, two energy scenarios were developed in this study. Both scenarios assume a net-zero emissions EU energy system by 2050. The scenarios differ in the extent to which renewable and low-carbon gas play a role in the scenarios. In the "optimised gas" scenario, renewable and low-carbon gas can be used to its full potential, whereas in the "minimal gas" scenario, renewable and low-carbon gas use is limited to those sectors where no alternatives are available.

[5] IPCC (2006), IPCC Guidelines for National Greenhouse gas Inventories.

The “optimised gas” scenario assumes that renewable and low-carbon gas are used in a smart combination with renewable electricity (see Figure 4). The scenarios illustrate different future energy systems for the EU. How the transition to a net-zero emission energy system will develop is also dependent on regional aspects, like local availability of resources, ongoing innovation efforts or political and public attitude towards different decarbonisation options. The likely energy system of the future will therefore be a combination of decarbonisation solutions.

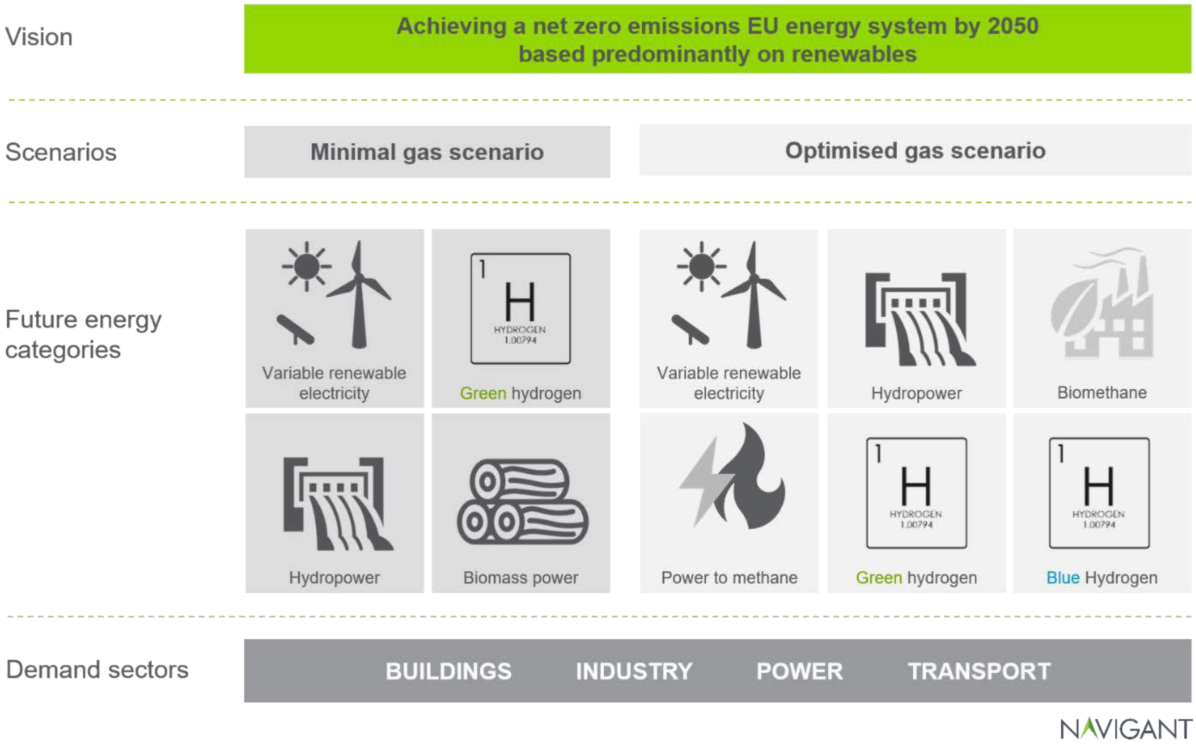

Figure 5 Scope of the study

Compared to the 2018 study, this study has a significantly expanded scope of analysis. The main changes are:

- Analysing in more detail the supply and cost for biomethane and including an analysis on power to methane.
- Exploring the supply and cost of green hydrogen in more detail, specifically covering dedicated renewable electricity generation to produce hydrogen.
- Assessing the potential role of low-carbon gas – blue hydrogen or natural gas combined with carbon capture and storage (CCS) or carbon capture and utilisation (CCU).
- Analysing the future energy mix and the possible role of gas in decarbonising industrial energy and feedstock demand, focusing on the highest-emitting sectors iron and steel, chemicals, and cement and lime production.
- Analysing the cost-optimal way to decarbonise EU road transport, shipping and aviation.
- Comparing a “minimal gas” scenario with an “optimised gas” scenario, both aiming to decarbonise the full EU energy system by 2050. An energy system model is deployed to determine energy supply and demand in both scenarios.
- Analysing the role of gas and electricity infrastructure in the 2050 “minimal gas” and “optimised gas” scenarios.

The energy consumption in scope of the analysis is over 80% of the current EU final energy demand (Figure 6). The remaining 20% includes primarily the energy demand in other industry sectors and in the agriculture sector.

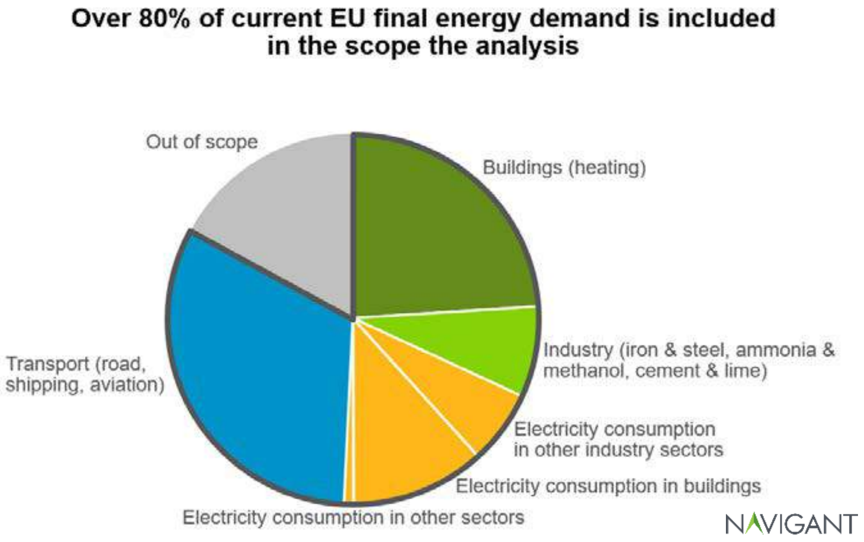

Figure 6 Energy consumption in scope of the analysis[6]

1.3 Domestic energy production versus imports

In 2016, a share of 54% of the EU gross inland energy consumption was imported from countries outside the EU. This share increased represents any increase of 7%-points from 47% in 2000. Europe's energy dependency has thus increased in recent years, which has led to geopolitical concerns. It can be expected that the energy transition will reduce this dependency. The EU has a large potential to produce renewable electricity from wind, solar PV and hydropower domestically and to produce green hydrogen and biomethane from EU-produced renewable electricity and biomass. This could significantly reduce import dependency. At the same time, a certain degree of international trade in energy can be positive, as international energy cooperation between the EU and non-EU countries has led to mutual benefits.

Self-sufficiency in terms of energy supplies is not only challenging to achieve, could also not be desirable. Europe is currently experiencing waves of migration, especially from Africa, and debates are ongoing on how to improve the conditions in countries from which people flee in the hope for a better and economically more prosperous life. At the same time current geostrategic policies of some key countries seem to be dominated by unilateralism rather than multilateralism. Organising the future renewable and low-carbon gas supply to Europe through imports via existing gas import pipelines could have positive contributions in terms of reducing regional and global tensions.

> This study assumes that all renewable energy is produced in Europe, yet energy imports can still be expected

This study assumes that renewable energy would be produced within Europe. Still it remains likely that international trade in energy will continue, meaning that the EU will import part of its energy from non-EU countries.

[6] The figure describes the scope of the study on a final energy demand level. Part of the current energy consumption in for example the iron & steel industry, such as cokes ovens, are considered as "transformation" in statistics and not as "final energy demand". Therefore, part of the energy consumption in the iron & steel sector is not covered by the figure above.

Imports of renewable and low-carbon gas from regions with abundant and cheap energy resources, for example in terms of wind, solar, the capacity to store CO_2, or costs, can provide competitive alternative sources for the European market. Such imports can further decrease supply costs and increase the potential and socio-economic benefit of decarbonising the gas market beyond what is outlined in this study. Also, exports of renewable and low-carbon gas, for example to Europe, will also facilitate economic and infrastructure development in supply countries. However, it would have exceeded the scope of this study to have considered the vast number of potential international sources of renewable and low-carbon gas and corresponding possible future imports to Europe.

1.4 Reading guide

The study consists of seven chapters. After giving in this Chapter 1 an overview and introduction of this study, Chapter 2begins with a more detailed assessment of the different renewable and low-carbon gas supply options in the EU. Chapter 3 sets out the methodology to determine the value of renewable and low-carbon gas.

Next, Chapter 4 describes the approach to decarbonise EU energy demand in the demand sectors: buildings, industry, and transport. Chapter 5 elaborates on the approach to decarbonise the EU power sector, followed by Chapter 6 in which the role of transport and distribution infrastructure is explained.

Chapter 7 presents the final picture, showing how the different gas options come together in the different demand sectors and highlighting the annual energy system costs savings that can be realised in the “optimised gas” scenario as compared to the “minimal gas” scenario.

Additional details on the study’s methodology and results are included in the Appendices.

2. Renewable and low-carbon gas for the "optimised gas" scenario

2.1 Introduction

This chapter analyses the potential supply and production costs of renewable and low-carbon gases in the EU by 2050 as part of the construction of the "optimised gas" scenario. As this study focuses on achieving a net-zero emissions EU energy system by 2050, all sources of gas consumed in the EU energy system by 2050 must be net-zero emissions gas. The sources of gas can be either renewable gas or low-carbon gas–natural gas combined with CCS or CCU, also including blue hydrogen.

This study defines renewable gas as all gas produced from renewable sources. This includes biomethane, green hydrogen, produced from renewable electricity (power-to-gas), and power to methane, in which biogenic CO_2 and green hydrogen are methanised. Low-carbon gas is gas that, during production, has small volumes of CO_2 that remain uncaptured. Low-carbon gas includes blue hydrogen and natural gas combined with CCS.

This chapter explores the potential supply of both renewable gas and low-carbon gas. The analysis of both gasses relates to the urgency of addressing climate change and the importance of the time dimension of greenhouse gas emissions: it is not only relevant how much greenhouse gas emissions are mitigated, it is also important when mitigation takes place. The earlier mitigation starts the smaller the absolute quantity over time of emitted greenhouse gasses up to 2050. Reducing annual emissions today has a greater impact on avoiding dangerous climate change compared to mitigating the same tonne of CO_2 in 2050. Hence mitigation efforts should start today. The recent report by the Intergovernmental Panel on Climate Change (IPCC) on how to achieve 1.5°C highlights that without CCS it will be difficult to keep global warming below 1.5°C. This is due to the need for storable forms of energy, also on longer term (seasonable storage for winter heating). Green hydrogen can minimise the role of CCS, yet as long as renewable electricity generation falls short to cover all direct electricity demand, blue hydrogen can play a valuable role in accelerating climate change mitigation.

As long as renewable electricity generation falls short to cover all direct electricity demand, blue hydrogen can play a valuable role

The subsequent sections provide an overview of the overall potentials and costs of biomethane (Section 2.2), power to methane (Section 2.3), green hydrogen (Section 2.4), and blue hydrogen (Section 2.5) .

While biomethane and hydrogen are different gases, it can be used similarly in almost all energy sectors, ranging from producing electricity, to heating buildings, producing high temperature heat in industry, and fuelling transport. Biomethane has a higher energy density compared to hydrogen, meaning that volumes of hydrogen are much higher compared to natural gas on a per energy unit basis. Both biomethane and hydrogen can be transported through existing gas infrastructure and the two can even be mixed. Chapter 6 explores the optimal way to transport both biomethane and hydrogen and associated costs.

2.2 Biomethane

KEY TAKEAWAYS

- EU biomethane production can be up scaled from 2 billion cubic metres (bcm) today to 95 bcm natural gas equivalent, or around 1,010 TWh.
- This scaling up is possible at significantly lowered production cost compared to today.
- Biomethane can be produced as a zero emissions renewable gas in a sustainable way without competition with other biomass users.

2.2.1 Introduction

This section quantifies the sustainable potential of biomethane produced in the EU from biomass collected in the EU by 2050, as well as its production costs. Firstly, the sustainability considerations are discussed. Subsequently, the two main technology pathways to produce biomethane are described and then, the available potential and production costs are quantified.

Ensuring sustainable biomethane production

Renewable gas can only be scaled up if it is produced using strict sustainability criteria. It has the potential to offer substantial environmental and social co-benefits which are important enablers of achieving production at scale. In calculating the potential for renewable gas, this study starts from the perspective that all biomass should be produced and harvested sustainably and that net-zero lifecycle emissions should be ensured. This section explains how sustainable production of biomethane can be ensured.

> Renewable gas can only be scaled up if it is produced using strict sustainability criteria

Biomethane can be produced from agricultural residues and crops (via biogas) or from woody biomass. Direct and indirect sustainability risks are mainly associated with crop cultivation and roundwood production. These risks have been widely documented and discussed and are covered here.[7] Sustainable biomethane must not displace existing food and feed production nor lead to unwanted direct or indirect land use change and should have a short carbon cycle. Within these constraints, it is possible to use crops and woody residues sustainably. This study restricts the production potential for biomethane to biomass that can be made available without negative sustainability impacts and that can even lead to positive impacts.

On the agricultural side, residues such as straw and manure are assumed to be used to produce biomethane, as opposed to agricultural crops produced as the main crop. For biomethane production, Navigant only considered the crops that are produced in addition to the existing (main) crops in a sequential cropping scheme. This means that two crops instead of one are produced on the existing agricultural land within one year. On the forestry side, Navigant assumes that it is possible to use forestry harvesting residues, landscaping wood, and a small share of wood thinnings, younger trees that are harvested from plantation forests to create more space and light for other trees to grow.

---

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

Roundwood is excluded from the core potential estimate due to the long period it takes for replanted trees to grow back and recapture CO_2 from the atmosphere after trees have been being cut and burned–the carbon debt. Algae are excluded from the potential estimate due to lack of evidence that this feedstock could be commercially viable source of biomass by 2050. A future breakthrough in energy-efficient algae cultivation could dramatically change the biomethane supply potential.

Navigant assumes that a sufficient quantity of the total agricultural crop and forestry harvesting residues should be left on the land to maintain soil quality. The team also considers that a portion of collectable residue material is used for other purposes.

Biomethane can be a net-zero emissions renewable gas

The combustion of biomethane for power and heat production results in greenhouse gas emissions like those of natural gas. Yet in the process of growing the biomass feedstock, an identical quantity of CO_2 is captured from the atmosphere. This means that biomethane combustion emissions have a short carbon cycle and, according to the IPCC guidelines, count as zero emissions. At the same time, emissions occur in the cultivation, processing, and transportation of biomass feedstocks. Taking these into account, the overall lifecycle greenhouse gas emission reductions of biomethane (produced in a closed anaerobic digester with off-gas combustion) compared to natural gas typically ranges from 68% with maize as feedstock, 86% with biowaste as feedstock and above 100% with manure as feedstock.[8] It should be noted that other forms of renewable energy including wind power and solar PV also have associated lifecycle greenhouse gas emissions related to steel production, logistics and In both study scenarios, all forms of energy need to have net-zero associated greenhouse gas emissions by 2050. This means that biomethane and hydrogen should both be net-zero carbon gases. For biomethane this means that all logistics and processing emissions need to be mitigated by 2050, and that cultivation emissions need to be minimised and remaining emissions be compensated for through avoided emissions or negative emissions. Finally, methane leakage from biomethane transport and distribution should be eradicated. The previous Gas for Climate study included a list of measures that can be taken to minimise methane leakage.[9] An analysis of greenhouse gas emissions associated with biomethane production and how these can be reduced to net zero by 2050 is included in Appendix C.4.

> In both study scenarios, all forms of energy need to have net zero associated greenhouse gas emissions by 2050

2.2.2 Two technologies to produce biomethane

Two main technologies exist to produce biomethane: anaerobic digestion and thermal gasification.[10] The first is widely used to produce biogas from agricultural biomass that can be upgraded to biomethane. The latter is a not yet commercial technology to produce biomethane from woody and lignocellulose biomass.

Anaerobic digestion involves a series of biological processes in which microorganisms break down biodegradable material in the absence of oxygen. The process results in biogas and digestate. Biogas contains around 55% methane, the rest being mainly short carbon cycle CO_2.

[8] Directive (EU) 2018/2001 of 11 December 2018 (RED II Directive), Annex IV, part A.

[9] Ecofys, a Navigant company, Gas for Climate. How gas can help to achieve the Paris Agreement target in an affordable way (February 2018), section 3.2.2, page 11-13.

[10] Additional processes to produce biomethane through gasification are under development, e.g., supercritical water gasification which transforms liquid biomass into biomethane.

To enable injection into the gas grid, biogas needs to be upgraded to biomethane with 97% methane content by removing CO_2.[11] Digestate can be used as a fertiliser. Figure 7 provides a schematic overview of the anaerobic digestion process.

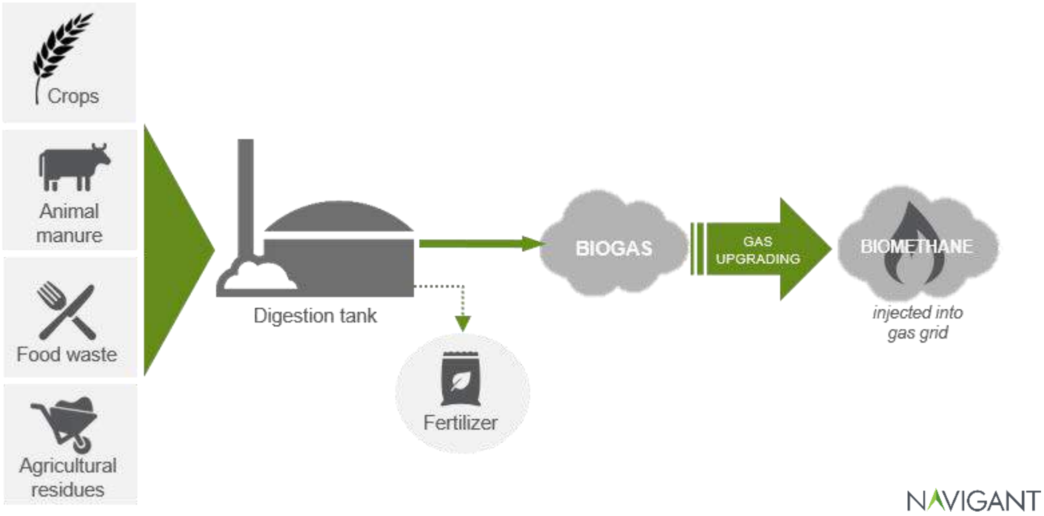

Figure 7 Schematic overview of the anaerobic digestion process

Virtually all biogas and biomethane produced today is based on anaerobic digestion. At the end of 2017, Europe had nearly 18,000 biogas plants producing about 6.5 TWh of electricity, while a share of raw biogas production was being upgraded in 540 biomethane installations to produce 2 bcm of biomethane.[12] Biogas and biomethane production is growing, although not as fast as in the years up to 2014.

Thermal gasification involves a complete thermal breakdown of woody biomass and consumer wastes, which takes place in a gasifier in the presence of a controlled amount of oxygen and steam. A mixture of carbon monoxide, hydrogen, and CO_2 is produced—called syngas or synthesis gas. The gas is cooled, and ash content is removed. In a gas cleaning unit, pollutants like sulphur and chlorides are separated. Methanation of the syngas is then performed in a catalytic reactor using nickel catalysts. With methanation, the cleaned gas is converted into biomethane, CO_2, and water. CO_2 and water are then removed in a gas upgrading unit. Figure 8 below presents the schematic overview of the thermal gasification process.

Figure 8 Schematic overview of the thermal gasification process

[11] We note that in some countries, most notably the Netherlands, Germany and Belgium, the methane content of gas is about 80% today, in part of the gas grid, due to the production of low calorific gas in Groningen. This means that biomethane used in these countries today should have a methane content of 85% instead of 97% for injection in the low calorific gas grid. Groningen gas extraction will be phased out by 2030, we assume that by 2050, all biomethane will have a 97% methane content.

[12] European Biogas Association, Annual Report 2018, page 10. See: http://european-biogas.eu/wp-content/uploads/2019/02/EBA-Annual-Report-2018.pdf. Current biomethane installations have an average production of around 450m3 of biomethane/hr assuming 8000 running hours per year.

At present, the production of biomethane from thermal gasification is small compared to the production of biomethane from anaerobic digestion. Thermal gasification technology is not yet commercially available whereas anaerobic digestion is already used commercially in thousands of biogas plants across the EU. This study assumes that thermal gasification will reach full commercial maturity well before 2050. Box 1 provides further information on the trends in thermal gasification technology.

Box 1 Trends in thermal gasification technology

Thermal gasification technology allows the conversion of woody biomass into biomethane at large scale. The technology is being tested in various demonstration projects with the aim to achieve full commercialization. An example is the Ambigo project in the Netherlands. The GoBiGas project in Sweden showed the scale-up potential of the technology and the fact that further cost reductions are required. New projects including the Ambigo gasification project by Gasunie are currently being developed. By 2050, assuming that cost reductions will materialize, large biomass gasification plants can be constructed at (port) location to ensure that a steady supply of sufficient quantities of biomass can be made available from across Europe. The technology, therefore, requires a proper assessment of biomass supply chains for ensuring operational as well as financial feasibility. In this context, the technology calls for securing long-term and reliable supply contracts for various waste and biomass feedstocks. A lot of research is being undertaken that focuses on various components of the technology. The research areas include but are not limited to high-pressure gasification, sorption enhanced gasification, alternative hot gas cleanup, air separation techniques, as well as the downstream methanation process. Advancement in these areas are likely to have considerable impacts on technology's operational reliability, cost as well as efficiency. In principle, gasification technology could be applied to a diverse mix of feedstocks, so feedstock handling and flexibility is an area that also deserves further investigation. In this study, gasification technology is used for the conversion of woody biomass to biomethane. At present, biomass to biomethane conversion efficiency is around 65%. We expect the efficiency to increase up to 75% by 2050 due to incremental improvements alongside various technological and process developments mentioned above.

2.2.3 Biomethane potential from sustainable biomass for both conversion pathways

The total biomethane potential mainly depends on the quantity of feedstocks and feedstock mix, and the biomass to biomethane yield. Navigant considered both the production of biomethane from agricultural residues and sustainably cultivated crops through anaerobic digestion, and biomethane from woody biomass and post-consumer waste through thermal gasification. The feedstock availability for biomethane is limited by the need to ensure sustainable production. Table 25 in Appendix C.1 provides an overview of the feedstocks used to produce biomethane as included in this study, and the main assumptions on the feedstocks' available potentials, taking into account other feedstock uses and the need to ensure sustainable agriculture and forestry.

Based on the available sustainable feedstock mix and their respective energy densities, Navigant calculated a total EU biomethane potential. The biomass to biomethane yield is feedstock-specific for both anaerobic digestion and gasification, leading to a total biomethane production potential of 95 bcm in natural gas equivalent terms (1,010 TWh) per year by 2050.[13],[14]

---

[13] To estimate the biomethane potential, Navigant used differentiated biomass to biomethane yields for feedstocks considered for anaerobic digestion as well as thermal gasification. For anaerobic digestion, we assume that the yields from mono-digestion of feedstocks would be the same in a co-digestion process which means that the combined yield of multiple feedstocks in a co-digestion process would not be higher than the sum of the individual feedstock yields. Therefore, any possibility of yield enhancement due to co-digestion of feedstocks is not factored in our estimation. We also assumed that the theoretical biomass to biomethane yields for anaerobic digestion would stay the same towards 2050. However, there is a possibility to achieve efficiency improvements due to pre-preparation of biomass feedstocks.

Thermal gasification is not yet commercial and is being tested in demonstration projects. The overall energy conversion efficiency for biomass to biomethane from gasification is 65% today and can increase to 75% by 2050. The previous Gas for Climate study assumed a 90% gasification process efficiency. Since its publication Navigant checked this assumption with various experts.

Navigant used a biomethane LHV of 34.7 MJ/m^3 to derive the energy content against the m^3 of biomethane produced. Finally, the biomethane potential is presented in natural gas equivalents using natural gas LHV of 38.2 MJ/m^3 (EU high calorific natural gas)

[14] Navigant assumed a biomethane LHV of 34.7 MJ/m^3 which is calculated using LHV (50 MJ/kg) of raw biogas as included in the EU-RED Annex III, corrected for biogas impurities and CO_2 content. The biomethane LHV is slightly higher than the 33 MJ we used in the previous 2018 Gas for Climate study, in which we calculated at 'Room conditions' being 24°C and 1 bar rather than the more widely used 'Standard conditions', being 0°C and 1 bar.

This consists of 62 bcm (660 TWh) produced through anaerobic digestion and 33 bcm (350 TWh) produced through thermal gasification. A breakdown of the biomethane potential is provided in Figure 9.[15]

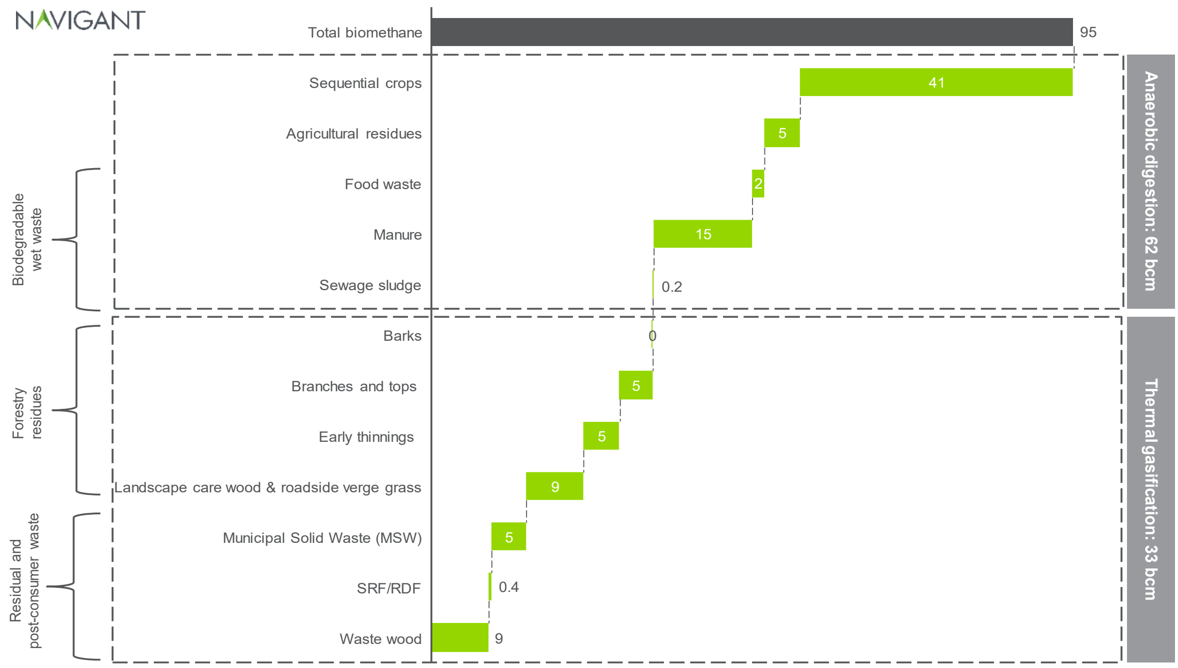

Figure 9 EU biomethane potential per conversion technology and feedstock (in bcm natural gas equivalent) type by 2050[16]

Box 2 Biogasdoneright to produce sustainable, low ILUC-risk biomethane

The report's analysis assumes that the largest contribution of biomass for biomethane comes from maize, triticale, wheat, or ryegrass silage produced as sequential crops. These are crops produced as an additional (second) crop before or after the harvest of the main crop on the same agricultural land. This study estimates that 41 bcm (431 TWh) of biomethane can be produced from second crops produced in this way. Navigant's view on the potential for sequential cropping is based on an optimised concept developed in Italy by CIB members called Biogasdoneright[17]. Biogasdoneright is a departure from a traditional way of farming towards more innovative and sustainable farming practices. It increases the agricultural productivity of existing farmland without negative environmental impacts and without direct or indirect land use change. Biogasdoneright leads to co-benefits such as decreasing soil erosion risks, an increase in on-farm biodiversity and a potential increase of the soil carbon content by leaving more agricultural residues on the land. It could also result in negative carbon emissions. Navigant assessed the environmental sustainability of Biogasdoneright in Italy together with experts from Wageningen University and could verify the concepts sustainability claims[18]. Navigant did not yet evaluate the soil carbon accumulation as this would require multi-year carbon budget assessments.

This study assumes a significant scale-up of sequential cropping, also outside Italy. In the analysis, it is assumed that maize, triticale, wheat, or ryegrass silage can be cultivated on 10% of the current total Utilised Agricultural Area (UAA) in the EU.[19] The study further assumes that no additional land will be used for silage monocropping for biomethane production. This means that no existing food and feed production is displaced towards biogas production. Navigant assumed that the second crop, in a sequential cropping scenario, can achieve 30% of additional biomass compared to the monocrop. In southern European countries such as Italy the additional biomass production amounts to 60%, as has been demonstrated in Italy. This additional biomass is assumed to be available for sustainable biomethane.

[15] The biomethane potential from individual feedstocks is rounded so they do not necessarily add up to the total.

[16] Numbers are rounded so they do not necessarily add up to the total.

[17] Consorzio Italiano Biogas (CIB), Biogasdoneright. Anaerobic digestion and soil carbon sequestration. A sustainable, low carbon and win-win BECCS solution (2017), See: https://www.consorziobiogas.it/wp-content/uploads/2017/05/Biogasdoneright-No-VEC-Web.pdf

[18] Ecofys (now part of Navigant), Assessing the case for sequential cropping to produce low ILUC risk biomethane (2016).

[19] Total Utilised Agricultural Area (UAA) in the EU is around 175 million hectares. https://ec.europa.eu/eurostat/statistics-explained/index.php/Farm_structure_statistics

Potential to import biomethane from Ukraine and Belarus

This study focuses on biomethane produced in the EU from EU-produced biomass feedstock. However, it is possible that additional biomethane would be imported from outside the EU, for example from Ukraine and Belarus—countries whose gas pipeline networks are already connected to the EU network. Navigant assessed the biomethane production potential for both countries using the same feedstock assumptions as applied for the EU. If both countries would dedicate 60% of their available biomethane production potential from sequential crops and agricultural residues to the EU market, an additional volume of 13 bcm (138 TWh) of biomethane could become available for the EU market annually.

Production pathways to convert the full sustainable biomass potentials to biomethane

The EU biomethane potential is based on sustainable feedstock availability across Europe. Thermal gasification plants will be large installations with a capacity of 200 MW each. These will typically be located at port locations with connections to existing gas grids. Woody biomass will be transported to these installations per ship. By 2050, over 200 of such installations could be in operation. Anaerobic digesters need to be closer located to the places where biomass is sourced due to the relatively high moisture content of agricultural biomass. This means that biogas production installations will be smaller in size. Currently, average biogas digester size in Italy is around 200 m^3/hr[20] whereas in Germany it is around 150 m^3/hr.[21,22]

> Biomethane produced in large gasification plants plus most biomethane produced in small biogas upgrading plants can be fed to gas grids

Navigant expects that by 2050 the average biogas plant can have a size of 500 m^3/hr, meaning that feedstocks will be sourced from neighbouring farms as starts to become common in large digesters in Italy today. By 2050, over 30,000 of such installations could be in operation.

From a production cost perspective, it will be cost-efficient to transport raw biogas from two neighbouring digestors via small PVC pipes to a central biomethane installation, where CO_2 is removed from raw biogas to create biomethane at natural gas quality, with a methane content of 97%. Such biomethane installations has a capacity of 1,000 m^3/hr. The way in which we think biomethane will be delivered to existing gas grids will be further discussed in Chapter 6. Navigant concludes that all biomethane produced in large-scale gasification plants plus most biomethane produced in small biogas upgrading plants can be fed into gas grids. However, a certain share of digesters will be located far away from existing gas grids and it will be very costly to connect the entire biomethane production potential to gas grids. Therefore, we assume that 30% raw biogas produced in digesters will be upgraded to bio-LNG onsite and transported to end consumers or to the nearest gas grids per truck. This assumption is not based on a bottom-up comparison of biomass availabilities against topologies of gas networks and could benefit from further analysis. This option is costlier, as will be discussed below, yet still leads to net energy system cost benefits as will be described in Chapter 7.

---

[20] http://www.isaac-project.it/en/biogas-in-italia/

[21] http://www.fnr.de/fileadmin/allgemein/pdf/broschueren/broschuere_basisdaten_bioenergie_2017_engl_web.pdf

[22] http://nigeria.ahk.de/fileadmin/ahk_nigeria/Renewable_Energy/Biogas/German_Experiences_in_Biogas_Production_and_its_value_for_Nigeria.pdf

The various renewable methane production pathways as included in our "optimised gas" scenario are pictured in Figure 10 below.

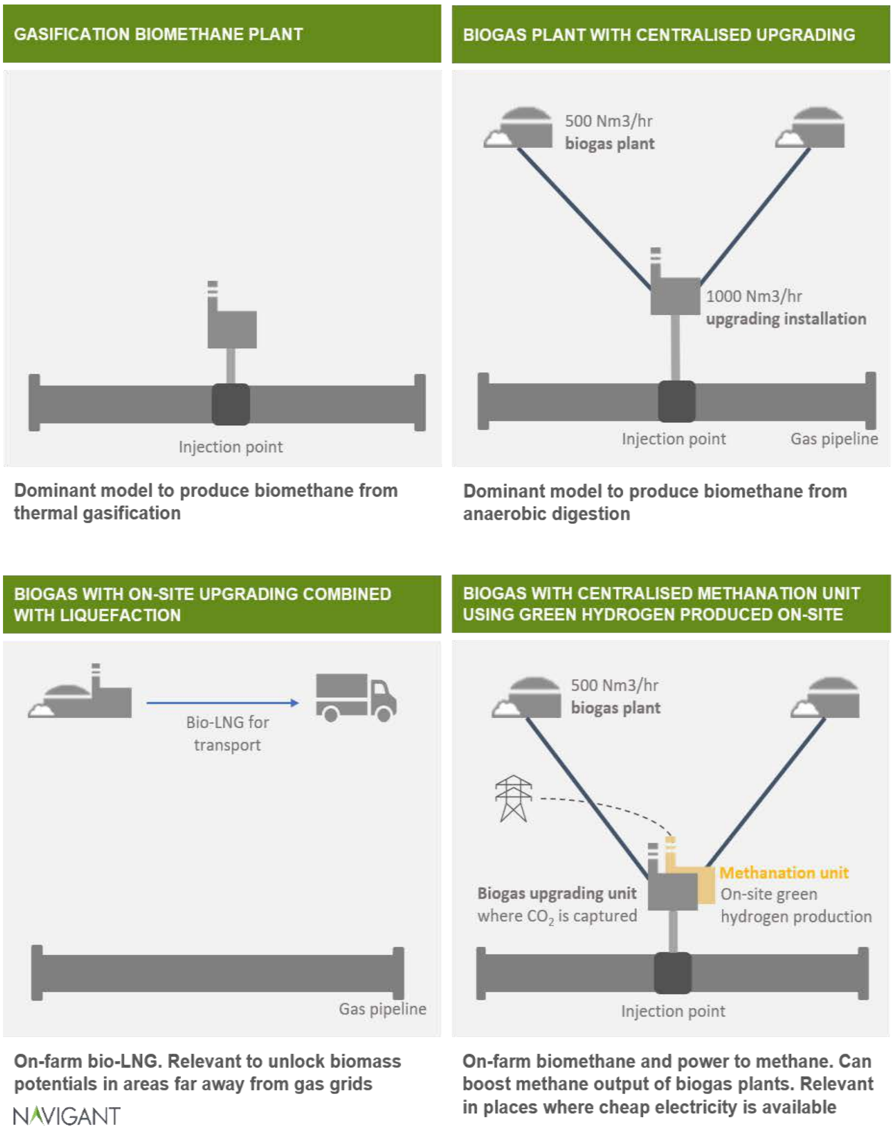

Figure 10 Renewable methane production pathways

Navigant did not perform a bottom-up comparative analysis of how existing gas grids are distributed across the EU and how this grid lay-out compares to local biomethane supply potentials. Without such analysis, the estimation of the total EU biomethane potential that can be fed into existing gas grids on a cost-effective basis is a rough estimate. This study assumes that all woody biomass that could be processed into biomethane will be converted in large thermal gasification plants located at existing industrial site with access to existing gas grids within less than one kilometre, allowing all biomethane to be injected into existing gas grids. For anaerobic digestion-based feedstocks, Navigant estimates that 70% of the potential will be converted to biomethane and fed into gas grids while 30% will be supplied by trucks in the form of bio-LNG.

Thus, out of the total biomethane potential of 95 bcm, 33 bcm produced through thermal gasification will be injected to gas grids, plus 43 out of 62 bcm of biomethane from the anaerobic digestion route. In total, 76 bcm of biomethane will be supplied through gas grids while 19 bcm natural gas equivalent would be supplied as bio-LNG.

2.2.4 Significant cost reductions possible to produce biomethane

This section assesses the future cost to produce biomethane and bio-LNG. The focus lies on production costs, whereas the cost to integrate biomethane into existing gas grids are described and quantified in Section 6.6.2.

Biomethane can be produced today for €70–90/MWh based on anaerobic digestion. The costs depend heavily on the feedstocks used. Manure and agricultural residues are cheaper than silage. Biomethane can be produce for €70/MWh today when produced in large digesters with manure as feedstock. Most production today takes place in small digesters with a share of silage maize, at a cost of close to €90/MWh. These costs include limited costs (around 5%) to connect biomethane to existing gas grid. These costs are low today since today's biomethane installations are located close to existing gas grids. Biomethane from thermal gasification hardly takes place today, Navigant estimates the cost today to be close to €90/MWh based on demonstration scale production.

The estimated 2050 costs for biomethane represent production costs from a societal perspective. This study used an average technical lifetime of production facilities of 25 years for anaerobic digestion and 20 years for thermal gasification. Navigant did not consider any subsidies and included only the societal discount rate, which is assumed at 5%.

Future costs reductions for biomethane from anaerobic digestion

Based on literature and market observations, a considerable cost-reduction potential exists for biomethane production from anaerobic digestion. The cost of biomethane from anaerobic digestion can be reduced to €57/MWh by 2050, mainly based on the following factors:

> The cost of biomethane from anaerobic digestion can be reduced by €20/MWh to reach €57/MWh by 2050

1. Increase in biomethane production installation size. Currently, average biogas digester size in Italy is around 200 m^3/hr[23] whereas in Germany it is around 150 m^3/hr.[24,25] Navigant assumes that by 2050 biomethane installations with a capacity of 1,000 m^3/hr will fed by two separate smaller raw biogas plants of 500 m^3/hr each.
2. Innovative agricultural practices leading to the development of biogas digestate used as a valuable natural fertiliser.
3. Modest efficiency increases in the conversion of biomass to biomethane.
4. Reductions in feedstock costs based on the introduction of Biogasdoneright, which leads to an increase of silage production per hectare and a lower average feedstock cost.

[23] http://www.isaac-project.it/en/biogas-in-italia/

[24] http://www.fnr.de/fileadmin/allgemein/pdf/broschueren/broschuere_basisdaten_bioenergie_2017_engl_web.pdf

[25] http://nigeria.ahk.de/fileadmin/ahk_nigeria/Renewable_Energy/Biogas/German_Experiences_in_Biogas_Production_and_its_value_for_Nigeria.pdf

The Figure below shows the 2050 levelised costs of energy (LCOE) from anaerobic digestion and how this compares to today's cost. LCOE is the total cost (including capital cost) of producing a unit of energy.

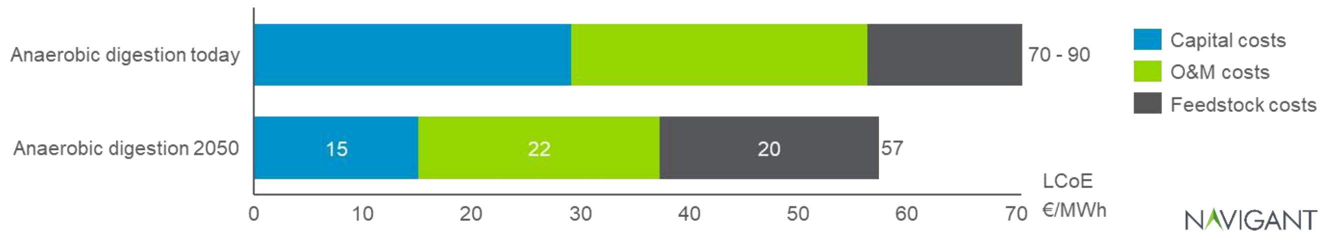

Figure 11 Production costs for biomethane based on anaerobic digestion

The primary factors contributing to cost reduction towards 2050 are feedstock valorisation, higher operating hours, and economies of scale due to the larger upgrading units of 1,000 m^3/hr.

Future costs reductions for biomethane from thermal gasification

Thermal gasification needs to develop further and overcome quite a few technological challenges. However, based on literature review and inputs received from technology experts Navigant identified a number of factors that can generate significant cost reductions. Biomethane costs from thermal gasification could by 2050 be 50% lower than today due to:

1. Construction of multiple commercial plants resulting in improved operations, optimised processes, and higher plant utilisation. These factors guarantee higher plant reliability
2. Scaling up gasification plants will substantially lower costs due to economies of scale. A gradual scaling up would be needed to address technology challenges at smaller scale first. Reduced technology risks and improved performance would incentivise deployment of bigger facilities.
3. Multiple factors impact plant energy conversion efficiency. Improvement in syngas cleaning methods, more robust methanation catalysts, higher pressure gasification and improved over all plant integration can improve efficiency

Biomethane costs from thermal gasification could by 2050 be 50% lower than today

Figure 12 shows the levelised costs of energy (LCOE) of biomethane based on thermal gasification.

Figure 12 Production costs for thermal gasification

Thermal gasification costs of €88/MWh represent the costs for the Gothenburg Biomass Gasification (GoBiGas) project, where a first-of-its-kind demonstration plant to produce 20 MW biomethane was commissioned in 2013.[26] These are social costs calculated using a discount rate of 5%. The feedstock costs for today are estimated using the 2050 feedstock mix. The major difference in today's production costs and the costs from 2050 are increased energy conversion efficiency (from 65% to 75%), economies of scale benefits and deployment of multiple plants which result in increased plant reliability, better understanding of technology risks, and high operability. The production costs of €47/MWh for 2050 are estimated against a plant size of 200 MW_{th}.

> The total 2050 biomethane potential is 95 bcm biomethane, of which 76 bcm will be gas grid transported and 19 bcm be supplied per truck as bio-LNG

The production costs of biomethane from anaerobic digestion and thermal gasification do not include the costs of gas transport and grid injection.

Biomethane feedstock costs

For anaerobic digestion, Navigant used the weighted average feedstock costs of three main feedstocks which together produce 97% of the total biomethane via anaerobic digestion route. Of this 97% biomethane potential, silage from sequential crops contributes 67%, agricultural residues 9%, and 24% manure. The feedstock costs per ton of dry matter are used to estimate overall weighted average feedstock costs (see Table 27 in Appendix C). Navigant also factored in cost reduction due to the valorisation of biogas digestate as a fertiliser, leading to a weighted average cost of €20/MWh.

For thermal gasification, the feedstock costs from woody residues and post-consumer waste were used to estimate the weighted average feedstock costs. Woody residues contribute 53% to the total biomethane production volumes from thermal gasification whereas post-consumer wastes produce 47%. Using these percentage shares, the estimated weighted average feedstock cost from thermal gasification turns out to be €15/MWh.

Navigant assumes similar costs for agricultural residue-based feedstocks in 2050 as today, as the markets for most of these feedstocks are established (such as for straw and husks) and it is uncertain how these markets will develop. For the biomass fraction of municipal solid waste and waste wood, processing costs might be needed to separate organic matter from the undesired materials like plastics, metals, etc. Sequential crops have much lower production costs than conventional maize silage.[27] Table 27 in Appendix C.2 provides the assumed feedstock costs for 2050.

Bio-LNG costs[28]

Based on literature review,[29] Navigant concludes that on-farm liquefaction is possible at a cost of €12/MWh in addition to biomethane production costs of €57/MWh. This leads to a total bio-LNG cost of €69/MWh by 2050.

---

[26] GoBiGas, 2018. Demonstration of the Production of Biomethane from Biomass via Gasification. https://www.goteborgenergi.se/Files/Webb20/Kategoriserad%20information/Forskningsprojekt/The%20GoBiGas%20Project%20-%20Demonstration%20of%20the%20Production%20of%20Biomethane%20from%20Biomass%20v%20230507_6_0.pdf?TS=636807191662780982

[27] Cost for conventional maize silage is 120 €/t-dry matter whereas for triticale silage from sequential crops it is around 80 €/t-dry matter, slightly lower costs are assumed for 2050. From: Ecofys and WUR, 2016. Assessing the case for sequential cropping to produce low ILUC risk biomethane. https://www.ecofys.com/files/files/ecofys-2016-assessing-benefits-sequential-cropping.pdf

[28] It is also possible to produce liquid biomethane directly from raw biogas using cryogenic upgrading. The concept aims at integrating biogas to biomethane upgrading and subsequent liquefaction into a single process. The costs for cryogenic upgrading against a plant size of 500 m^3/hr are estimated to be €16/MWh. These costs are comparable with our biomethane production model where biogas upgrading costs €3/MWh and on-farm liquefaction costs €12/MWh.

[29] Liquefaction costs vary between 3 and 5 $/MMBtu, we take an average of 4 to derive costs in €/MWh. https://www.dnvgl.com/maritime/lng/current-price-development-oil-and-gas.html

2.2.5 Conclusion

As in the previous Gas for Climate study, Navigant concludes that biomethane production in the EU can be scaled up significantly. Today, biomethane production totals 2 bcm, even though biogas production has already reached a significant scale of 14 bcm. It is possible to increase biomethane production sustainably while ensuring that biomethane will be a net-zero emissions renewable gas. By 2050, a quantity of 22 bcm of biomethane could be produced based on the anaerobic digestion of agricultural wastes, food waste, and sewage sludge plus 41 bcm from the anaerobic digestion of sustainable silage cultivated as autumn, winter, and spring crop and 33 bcm from the thermal gasification of woody residues. This leads to a total 2050 biomethane potential of 95 bcm of biomethane by 2050, of which 76 bcm will be gas grid transported and 19 bcm be supplied per truck as bio-LNG.

2.3 Power to methane

2.3.1 Introduction

Power to methane, or methanation, is a technology by which synthetic methane can be produced based on hydrogenation of carbon dioxide. This can take place in a methanation reactor unit as an additional step to electrolysis with hydrogen produced from renewable electricity or as a coupled process in biogas plants where residual CO_2 can be revalorised. Hydrogen and CO_2 can be combined in a digestor where microorganisms would act as bio-catalysts. Synthetic natural gas can be then produced with a methane content of 96–99%.

This section explores the potential for power to methane production using captured CO_2 from anaerobic digestion plants and H_2 from excess electricity. Navigant assumes that power to methane is not produced at large-scale biomethane thermal gasification plants since the large volumes of CO_2 that become available at those plants could more easily be stored below ground to create negative emissions.

2.3.2 Power to methane potential

It is possible to increase the renewable methane potential by producing power to methane. In our “optimised gas” scenario we assume that the methane output of a share of digestion-based biomethane plants will be boosted by power to methane production. It is assumed that the required CO_2 would be available free of charge and that electricity would be transported to biomethane plants and processed into hydrogen onsite. Excess renewable electricity from the grid at zero cost would be used as input to the electrolyser unit that is assumed to run for 2,000 full-load hours annually. Typically, the electrolyser can be operated in a more intermittent way, quickly ramping up when excess electricity from the grid is available and ramping down when it is not available. Navigant assumes that small-scale onsite hydrogen storage will allow for a downstream steadier operation of the methanation reactor unit, which is assumed to run for 4,000 full-load hours annually. By using onsite hydrogen storage, a smaller methanation unit will be required, driving the methanation reactor’s specific CAPEX down. This production model is illustrated in Figure 13.

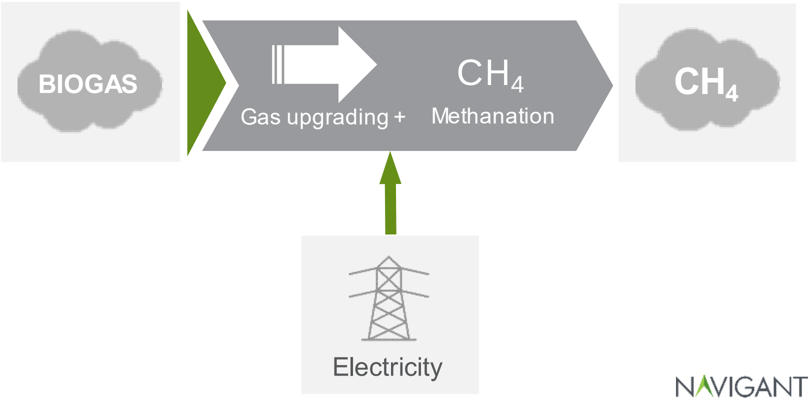

Figure 13 Power to methane production using CO_2 captured in biogas upgrading to biomethane

From Navigant's overall energy system analysis, 205 TWh of excess electricity would be available by 2050 to produce 200 TWh of green hydrogen. To produce power to methane with the same amount of hydrogen, 33 million tonnes of CO_2 is required, which requires, in turn, a raw biogas production volume of 43 bcm natural gas equivalent with a CO_2 content of 45% and methane content of 55%. Assuming a methanation reaction efficiency of 80%. This results in total EU-wide production of 160 TWh (HHV) of renewable methane from power to methane, or 15 bcm of natural gas equivalent (energy density). Table 28 in Appendix C.5 gives an overview of the technical assumptions used to derive the methane potential.

2.3.3 Power to methane costs

Navigant assumes that power to methane is produced from CO_2 captured at biogas upgrading installations and green hydrogen. This requires an onsite electrolyser unit with small-scale compressed hydrogen storage capacity, where excess power from the grid can be used to produce hydrogen and be stored onsite; and a methanation unit, where hydrogen and CO_2 are combined to produce synthetic methane. There is also another possibility in which biomethane plants would receive hydrogen feedstock produced elsewhere. However, this would require a dedicated hydrogen infrastructure in remote areas which is likely to be expensive.

> Power to methane is produced from CO_2 captured at biogas upgrading installations and green hydrogen

The levelised cost of power to methane in 2050 following the above production process has been assessed. Further details on the cost calculation approach are given in Appendix C.5. The levelised cost of power to methane consists of annualized investment costs, annual operation and maintenance costs, and methane feedstock costs. Considering all cost assumptions in Table 29 in Appendix B.5, including free CO2 available from biogas upgrading to biomethane, €12/MWh methanation unit investment costs, €8/MWh for methanation unit O&M costs and €54/MWh of hydrogen feedstock including onsite hydrogen storage cost, Navigant calculated a LCOE for power to methane of €74/MWh by 2050.

2.3.4 Conclusion

> The "optimised gas" scenario includes a total renewable methane potential of 1,170 TWh or 110 bcm

It is possible to use green hydrogen and CO_2 captured when upgrading biogas to biomethane to create additional methane. In the "optimised gas" scenario, CO_2 from large-scale thermal gasification plants can be stored belowground to create negative emissions. At aerobic digestion installations, much smaller quantities of CO_2 become available and it would be difficult and expensive to store this CO_2 belowground at farms.

Therefore, it makes sense to capture this CO_2 and use it, with hydrogen, to produce power to methane. If applied to half of the EU anaerobic digestion biogas upgrading plants by 2050, this could generate an additional methane supply of 160 TWh, additional to the biomethane potential, or 15 bcm of natural gas equivalent (energy density). Adding this quantity to the biomethane potential as quantified in Section 2.2.3. This means that the “optimised gas” scenario includes a total renewable methane potential of 1,170 TWh or 110 bcm of natural gas equivalent (energy density).

2.4 Green hydrogen

KEY TAKEAWAYS

- By 2050, about 200 TWh of green hydrogen from curtailed electricity can be supplied for an average cost of 29 €/MWh. In addition, more than 2,000 TWh of green hydrogen from dedicated renewable electricity generation can be supplied for 52 €/MWh. Total green hydrogen demand in various sectors amounts to 1,710TWh or about 160 billion cubic metres of natural gas equivalent.
- Hydrogen is a storable energy source that can balance fluctuating demand and enable high shares of intermittent renewable electricity sources. Hydrogen can also provide inter-seasonal storage, both of which are needed in a net-zero energy system.
- For green hydrogen production to satisfy the total hydrogen demand by 2050, the relevant policy framework must be in place as early as possible in order to foster implementation.

2.4.1 Introduction

Hydrogen is the lightest molecule and the hydrogen atom is the most abundant element in the universe. It can become a key enabler of the low-carbon transformation as a chemical feedstock and fuel, and as an energy carrier in numerous sectors including transport, built environment, and power. On Earth, hydrogen only exists in a chemically bound form, so it must be produced by specific processes. A very important difference between hydrogen and methane is the fact that hydrogen does not emit greenhouse gases when being burned.

Hydrogen has been used for many years in various industrial processes. In 2003, 96% of the hydrogen produced worldwide came from the thermochemical conversion of fossil fuels, mainly natural gas, and there is no indication that this has changed significantly. [30] The remainder is produced via electrolysis. Hydrogen produced from fossil fuels leads to significant greenhouse gas emissions (referred to as “grey hydrogen”)[31] unless CO_2 is captured. However, demonstration projects are underway for hydrogen production from fossil feedstocks coupled with carbon capture and storage (referred to as “blue hydrogen”). Potentially, blue hydrogen production from natural gas can be coupled with a share of biomass feedstocks that could bring the overall hydrogen greenhouse gas footprint to net zero or even negative. With an increasing share of low-cost renewable electricity, green hydrogen production via electrolysis is also a promising decarbonisation option for the near future.

---

[30] International Energy Agency (2005): Prospects for Hydrogen and Fuel Cells, http://ieahydrogen.org/Activities/Subtask-A,-Hydrogen-Resouce-Study-2008,-Resource-S/2005-IEA-Prospects-for-H2-and-FC.aspx.

[31] Depending on the specifics of the supply chain, the total GHG emissions for grey hydrogen have been estimated in a range from 230 gCO_{2eq}/kWh (minimum found for stream methane reforming) to 642 gCO_{2eq}/kWh (maximum for coal gasification). Compare with 210 gCO_{2eq}/kWh for natural gas (all figures are shown before efficiency losses from carriers to electricity or heat). See Balcombe et al. (2018). The carbon credentials of hydrogen gas networks and supply chains, Renewable and Sustainable Energy Reviews, https://www.sciencedirect.com/science/article/pii/S1364032118302983.

To recap the above, this study distinguishes three types of hydrogen based on greenhouse gas emission impacts:

- **Grey hydrogen** is gas produced by thermochemical conversion of fossil fuels without the capture of CO_2. Grey hydrogen is not considered in our analysis as it cannot play a role in a net-zero greenhouse gas emission energy system.
- **Blue hydrogen** is a low-carbon gas produced by thermochemical conversion of fossil fuels with carbon capture and storage.[32]
- **Green hydrogen** is a renewable gas produced from renewable resources such as solar PV, wind or hydropower**.**

In this study, electrolysis is considered to produce green hydrogen (i.e., electrolytical hydrogen), although many other production methods are available.[33, 34] This section describes the future role of green hydrogen. Section 2.5 provides an analysis of blue hydrogen.

Green hydrogen can be produced through the following three technologies:

- **Alkaline Electrolysers** (AE) are the most mature and currently cheapest (€/kW) technology option. However, they have limited ability to respond to load changes, which is essential for the flexibility requirements of a power system with high penetration of renewables. Furthermore, the design is complex, implying limited cost-reduction options.
- **Proton Exchange Membrane** (PEM) electrolysers have a simple design, are currently more expensive than alkaline electrolysers, and are assumed to have a high cost-reduction potential. Crucially, they are flexible, with ramp up or ramp down times in seconds, which makes them ideal for a variety of applications in the power sector.
- **The Solid Oxide Electrolysis Cells** (SOECs) use high temperature electrolysis; they are at an early stage of development. Theoretically, solid oxide electrolysis is a promising technology due to its high efficiency, its ability to recover the heat needed for electrolysis, and its possibility to operate in reverse mode (regenerative electrolysis). The inability to have a flexible load and the high degradation of the membranes are the two major challenges of SOECs.[35]

Besides the potential climate benefits, the main advantages of using hydrogen in the energy system are its storability, its prospective large-scale availability, and its wide range of applications. Hydrogen is one of the prime candidates to facilitate sector coupling,[36] and fits well into the efforts for increased electrification by providing long-term storage and possibly also dispatchable power generation.[37]

The study differentiates between four different production routes for green hydrogen. The different routes are used to showcase the impact of different capacity factors (full-load hours, FLH) and feedstock electricity costs on green hydrogen production cost:

1) Production from curtailed electricity
2) Dedicated production from North Sea (or Baltic Sea) offshore wind power

---

[32] Other options, most notably carbon capture and utilization (e.g. via methane cracking) need to be further technically developed and also evaluated for their real greenhouse gas emission reduction potential (i.e. long-term carbon sequestration potential).

[33] For instance, direct photochemical conversion, supercritical wet biomass conversion, biomass gasification, fermentation, etc.

[34] Further specifications (e.g. specific GHG intensity limits in green / blue hydrogen production) on these definitions will be available at the conclusion of the design phase for the green hydrogen guarantees of origin at CertifHy (http://www.certifhy.eu/).

[35] ASSET (2018). Sectoral integration – long-term perspective in the EU energy system, https://ec.europa.eu/energy/sites/ener/files/documents/final_draft_asset_study_12.05.pdf.

[36] The idea to closely interlink the three-main energy consuming segments, the built environment, industrials and transport and to optimally use energy infrastructure.

[37] This is mainly valid for PEM electrolysis with fast ramp up times that can theoretically be switched from generator to load and vice versa almost immediately. Other options, such as using biomethane in existing gas peaking plants, might however be more prominent.

3) Dedicated production from Southern European PV
4) Dedicated production from Southern European hybrid sources (PV plus onshore wind power)

2.4.2 Green hydrogen potential in the EU

The EU green hydrogen potential is demand driven. Considerable demand for hydrogen may exist in the EU by 2050. This study identifies a potential to produce 200 TWh (19 bcm natural gas equivalent) of green hydrogen from excess electricity. This allows excess renewable electricity generation to be stored in a useful form. Navigant estimates the cost of green hydrogen using excess electricity, where a zero-cost of power is assumed, at €17–71/MWh.

In the "optimised gas" scenario, the power-to-hydrogen demand has been quantified at 1,710 TWh of hydrogen (about 162 bcm natural gas equivalent)[38], much beyond the around 200 TWh which uses excess electricity. Navigant's analysis of the renewable energy potentials in the EU shows that the whole demand could be met only with fully developed offshore wind and rooftop solar PV resources. In this case (with onshore wind and hydropower generation kept at their 2015 levels), the generating capacity available for power-to-gas and the hydrogen demand are matching (Figure 14).[39] To increase the security of supply, green hydrogen production might then need to be supplemented with domestic non-electric hydrogen production or by imports.

> The EU green hydrogen potential is demand driven

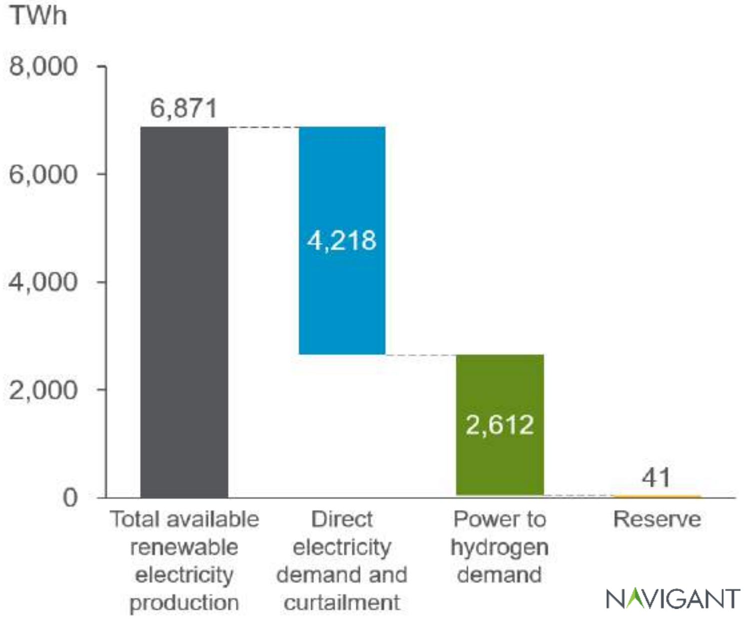

Figure 14 Renewable electricity production vs demand in the "optimised gas" scenario in 2050

[38] This is including hydrogen required for synthetic kerosene production (380 TWh).

[39] Note that the reserve has been quantified before power to hydrogen conversion, it is thus shown in TWh of electricity. The analysis assumes development of the economic potential (LCOE below 55-60 EUR/MWh) in the Atlantic, North and Baltic seas for offshore wind (2030 potential) and solar PV potential on buildings across EU (2070 potential). Generation capacity for onshore wind and hydropower are kept at their respective 2015 levels as their further development might be constrained. Sources: Wind Europe (2017): Unleashing Europe's offshore wind potential: A new resource assessment, https://windeurope.org/wp-content/uploads/files/about-wind/reports/Unleashing-Europes-offshore-wind-potential.pdf ; Shell (n.d.): GLOBAL ENERGY RESOURCES DATABASE, https://www.shell.com/energy-and-innovation/the-energy-future/scenarios/shell-scenarios-energy-models/energy-resource-database.html#iframe=L3dlYmFwcHMvRW5lcmd5UmVzb3VyY2VEYXRhYmFzZS8jb3Blbk1vZGFs ; EEA (2009): Europe's onshore and offshore wind energy potential: An assessment of environmental and economic constraints, https://www.energy.eu/publications/a07.pdf ; Ram M., Bogdanov D., Aghahosseni,A., Oyewo A.S., Gulagi A., Child M., Fell H.-J., Breyer C. 2017): Global Energy System based on 100% Renewable Energy – Power Sector, http://energywatchgroup.org/wp-content/uploads/2017/11/Full-Study-100-Renewable-Energy-Worldwide-Power-Sector.pdf.

The competitiveness of the domestically produced green hydrogen using non-zero electricity costs against alternatives (e.g., direct electrification, biomethane, etc.) is crucial to understanding the future role of hydrogen in the EU. Navigant has focused on the regions with the best combination of full-load hours (FLH) and levelized cost of energy (LCOE) for renewable energy sources: North Sea (offshore wind power) and Southern Europe (standalone solar PV, or solar PV combined with onshore wind) (see Figure 15). A detailed description and calculation of green hydrogen production costs for these two regions can be found in Appendix F.

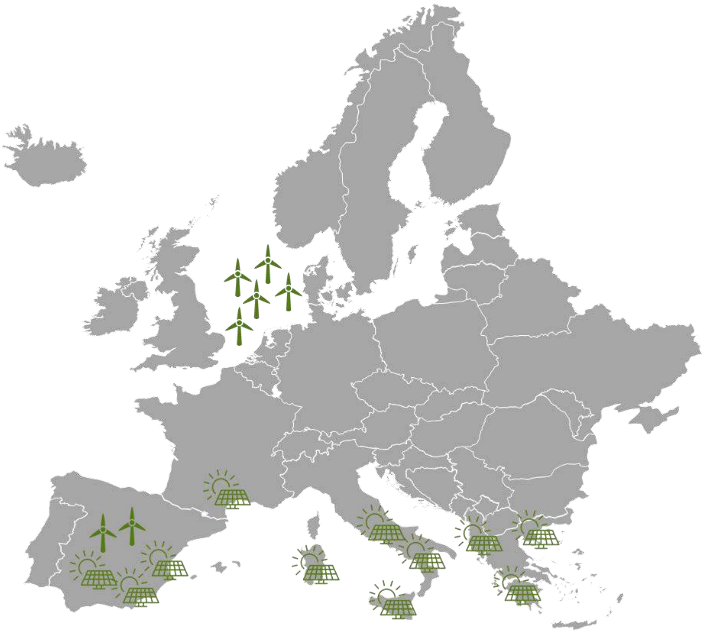

Figure 15 Overview of assessed hydrogen production hubs[40]

Alternatively, part of the domestic hydrogen demand could be covered by blue hydrogen (Section 2.5) or by imports of green hydrogen from other regions. North Africa is of interest given its proximity with the EU and its high technical potential for green hydrogen from solar energy (80,000 TWh/year of hydrogen).[41] Existing natural gas pipelines from North Africa to Europe also can be retrofitted to transport pure hydrogen. The scenarios in this study focus on energy produced within the EU despite the high potential for importing green hydrogen. The North African import option is further explained in Appendix F.

2.4.3 Quantifying green hydrogen cost from dedicated production in the EU

Navigant focuses on the most mature green hydrogen production route via electrolysis of water, which uses electricity to split water (H_2O) into hydrogen and oxygen. Table 1 provides an overview of the current values for the most important parameters in water electrolysis technologies.

---

[40] Map designed with PresentationGO.com

[41] Green hydrogen potential calculated by Navigant based on solar PV technical potential for North Africa in IRENA (2014): Estimating the Renewable Energy Potential in Africa - A GIS-based approach, http://www.irena.org/publications/2014/Aug/Estimating-the-Renewable-Energy-Potential-in-Africa-A-GIS-based-approach.

Table 1 Current (2018) values for water electrolysis technology parameters[42]

Technology	Temp. [°C]	Electrolyte	Efficiency [%][43]	System costs 2018 [€/kW]	Service life [h][44]	Maturity level
AE	60–80	Potassium hydroxide	65–82	450-600	60,000 – 90,000	Mature
PEM	60–80	Solid membrane	65–78	800-1,000	20,000 – 60,000	Demonstration level for large systems
SOEC	700–900	Oxide ceramics	85 (lab)	N/A	Ca. 1,000	Laboratory development

For this study, Navigant used PEM electrolysis as it possesses the biggest cost-reduction potential and seems to be only at the beginning of its learning curve. The production cost for electrolytical hydrogen is determined by four main factors that can vary significantly based on the business case and proposed project:

- System costs for the production facility, including CAPEX for electrolyser and auxiliary systems (or Balance of Plant, BoP), each constituting roughly 50% of the system costs in current PEM systems;[45]
- Feedstock electricity cost;
- Capacity factor expressed in full-load hours (FLH);
- Electrolyser system energy efficiency.

OPEX (excluding energy costs) is a fifth major cost component, but it is relatively constant in different PEM set ups (in its relation to system costs) and hence not investigated further. Major OPEX categories include labour costs to operate the plant, costs of component replacements, property tax, and insurance.

Whereas system costs and efficiency are largely independent of the location of the electrolyser within the EU, feedstock electricity costs and capacity factors are not. Table 2 illustrates the effect of feedstock electricity costs and FLH on the production cost of green hydrogen.

With the expected technology maturity leading to reduced electrolyser system costs of €420/kW by 2050,[46] green hydrogen from dedicated production in Southern Europe (PV or hybrid) are estimated at €44–59/MWh and from North Sea wind power at €48–61/MWh. Given the uncertainties of 2050 costs, Navigant concludes that the cost of producing green hydrogen in either of these set ups will be similar.

---

[42] Based on E4tech (2014). Development of Water Electrolysis in the European Union, http://www.e4tech.com/reports/development-of-water-electrolysis-in-the-european-union/ and Navigant industrial intelligence. We have reviewed several other studies that report similar figures regarding system energy efficiencies and typically somewhat higher values for electrolyser system cost. The studies reviewed include: Energy Brainpool (2018; in German): Auf dem Weg in die Wettbewerbsfähigkeit: Elektrolysegase Erneuerbaren Ursprungs, https://www.greenpeace-energy.de/fileadmin/docs/pressematerial/180419_GPE_Kurzanalyse_Kostenentwicklung-erneuerbare-Elektrolysegase_fin....pdf ; Agora Energiewende (2018): The Future Cost of Electricity-Based Synthetic Fuels, https://www.agora-energiewende.de/fileadmin2/Projekte/2017/SynKost_2050/Agora_SynKost_Study_EN_WEB.pdf ; or Hinico (2017); Study on early business cases for H2 in energy storage and more broadly power to H2 applications, https://www.fch.europa.eu/sites/default/files/P2H_Full_Study_FCHJU.pdf.

[43] System energy efficiency on lower heating value.

[44] Before stack replacement.

[45] We include additional 10% installation costs on top of the system cost. Based on NREL (2018): H2A: Hydrogen Analysis Production Case Studies: Current Central Hydrogen Production from Polymer Electrolyte Membrane (PEM) Electrolysis version 3.2018, https://www.nrel.gov/hydrogen/h2a-production-case-studies.html.

[46] Depreciation period: 30 years; Societal discount rate: 5%; OPEX (Including replacement, maintenance and labour costs): 3% of CAPEX per annum; system energy efficiency: 80% (LHV).

Production cost from excess electricity (at zero electricity cost) is cheapest at €17/MWh at high capacity factor (2,881 FLH) but it is limited to the previously mentioned 19 bcm natural gas equivalent. In case of low capacity factor (709 FLH), the production cost increases to €71/MWh.
Table 2 summarises the main input parameters and the resulting production cost for the different production routes.

Table 2 Main input parameters used for estimating production costs of green hydrogen in 2050

Production route	Full system installation costs ([€/MW_{input}]	Full-load hours (FLH) [hours/yr][47]	Feedstock electricity cost[48] [€/MWh]	Production cost[49] [€/MWh]
Curtailed	420	709-2,881	0	**17-71**
Dedicated - North Sea offshore wind power	420	4,500-5,000	30–40	**48-61**
Dedicated - Southern European PV	420	1,500-2,000	15–20	**44-59**
Dedicated - Southern European hybrid	420	3,500-4,000	25–30	**44-52**

Green hydrogen production costs of €44–61/MWh by 2050 are much lower than the current costs of green hydrogen €90–210/MWh (Figure 16).[50] These cost reductions come mainly from economies of scale, from cheaper electricity, and from improvements in system energy efficiency.

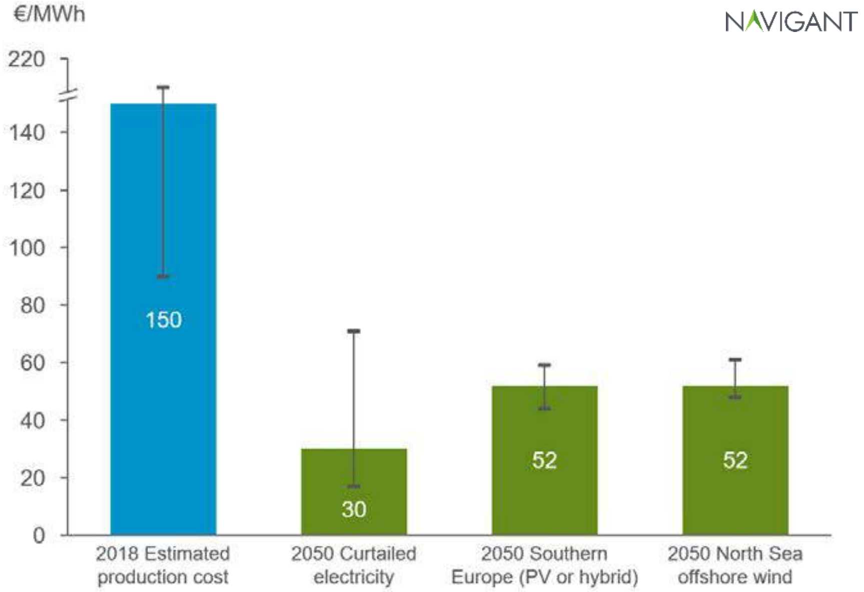

Figure 16 Green hydrogen production cost estimation for 2018 and 2050

[47] Based on: Ecofys (2018): Gas for Climate: How gas can help to achieve the Paris Agreement target in an affordable way, https://www.gasforclimate2050.eu/files/files/Ecofys_Gas_for_Climate_Feb2018.pdf, Fasihi & Breyer (2018): Synthetic Fuels and Chemicals: Options and Systemic Impact, https://www.strommarkttreffen.org/2018-06-29_Fasihi_Synthetic_fuels&chemicals_options_and_systemic_impact.pdf, and Navigant offshore wind expertise.

[48] Navigant scenario.

[49] Excluding gross retail margin.

[50] 2018 cost range based on: Energy Brainpool (2018; in German): Auf dem Weg in die Wettbewerbsfähigkeit: Elektrolysegase Erneuerbaren Ursprungs, https://www.greenpeace-energy.de/fileadmin/docs/pressematerial/180419_GPE_Kurzanalyse_Kostenentwicklung-erneuerbare-Elektrolysegase_fin....pdf ; Agora Energiewende (2018): The Future Cost of Electricity-Based Synthetic Fuels, https://www.agora-energiewende.de/fileadmin2/Projekte/2017/SynKost_2050/Agora_SynKost_Study_EN_WEB.pdf ; CE Delft (2018; in Dutch): Waterstofroutes Nederland – Blauw, groen en import, https://www.ce.nl/publicaties/2127/waterstofroutes-nederland-blauw-groen-en-import ; and Navigant Research (2017): Power-to-Gas for Renewables Integration, https://www.navigantresearch.com/reports/power-to-gas-for-renewables-integration.

2.4.4 Conclusion

The introduction of green hydrogen into the energy system in 2050 is feasible, both from an availability and a cost perspective. In the "optimised gas" scenario, a significant demand for hydrogen is envisioned. Importantly, the total electricity demand (i.e., combined direct electricity and power-to-gas) can be fully met by economically sensible development of offshore wind and rooftop solar PV, while keeping onshore wind and hydropower generation at their 2015 levels. It must be noted, however, that if the envisioned scale for green hydrogen generation is to be reached by 2050, the relevant policy framework has to be in place as early as possible.

> The success of green hydrogen will depend on the legislative framework

In 2018, green hydrogen is too expensive for any of its envisioned uses. However, major production cost reductions are expected by 2050, primarily driven by cost decreases of the electrolysis system due to economies of scale and availability of cheap renewable electricity. The latter will be at least partly determined by the electricity market structure, e.g., by the access of power-to-gas producers to wholesale/low-cost electricity. The success of green hydrogen will depend on the legislative framework. This will be further emphasised when discussing the gas transmission, distribution, and storage infrastructure, which could enable a relatively cost-efficient hydrogen delivery to end-users.

2.5 Blue hydrogen

KEY TAKEAWAYS

- A sizeable blue hydrogen market can be established at a relatively fast pace in many locations across Europe. CO_2 storage potential is not a constraining factor to produce blue hydrogen in the EU. However, due to the concentration of hydrogen production in North-Western Europe, cross-border cooperation on CO_2 storage will be needed with countries that have more availability.
- By retrofitting existing hydrogen production with CCS, up to 190 TWh (5.8 million tonnes of hydrogen, 18 bcm natural gas equivalent) can be produced annually within a period of around ten years. Costs of blue hydrogen production beyond retrofitting range from €36–63/MWh, which is comparable to the cost of biomethane and green hydrogen from dedicated electricity production in 2050.
- While the technical potential for blue hydrogen is not a constraint, remaining emissions from CCS could be a constraint if engineering efforts have not led to a 100% capture rate by 2050. This would imply a need by 2050 to compensate for any remaining emissions. However, even when scaling up blue hydrogen to ambitious levels of 1,500 TWh per year (45 million tonnes, 142 bcm natural gas equivalent), sufficient negative emissions can be realised to compensate any remaining emissions.

2.5.1 Introduction

In the previous sections we described the potential supply of renewable gas–biomethane, power to methane, and green hydrogen. Next to that, we also investigate the potential role of low-carbon gas–blue hydrogen production and natural gas use combined with CCS. In this introduction, we sketch both low-carbon gas routes shortly. After that, the blue hydrogen potential will then be further discussed in the following sections, while the role of natural gas with CCS will be discussed in the industry section in Chapter 4.

To illustrate decarbonisation with blue hydrogen production and natural gas use combined with CCS we make distinction between *distributed decarbonisation* and *centralised decarbonisation:*

- *Distributed decarbonisation* (post-combustion CCS on downstream level)*:* Using natural gas in industrial processes equipped with CCS.[51] In this route, CCS is applied to various individual point-sources of industry CO_2 emissions. Natural gas is therefore decarbonised downstream as an end-of-pipe solution; hence the use of gas is decarbonised in a distributed way. The technical and economic feasibility of this route is dependent on the specific industrial process. High flue gas pressure, a high concentration of CO_2 in the flue gas, and large amounts of CO_2 typically decrease the cost of applying CCS to an industrial process. This pathway is further discussed in Chapter 4.3 on industry, however not applied in one of the two study scenarios.
- *Centralised decarbonisation* (pre-combustion CCS on upstream level)*:* Producing decarbonised, blue hydrogen from natural gas feedstock with CCS integrated into the production process. Blue hydrogen is used further downstream in industrial processes to substitute carbon-based fuels or feedstock.[52] Hence, the gas is already decarbonised centrally, upstream. This route could also be useful for industrial installations that are too small or too far off from a CO_2 pipeline network or a CO_2 storage site. In this case, it could be more beneficial to decarbonise gas higher in the value chain in a hydrogen production unit and transport it to the consumption site using existing H_2 networks (mainly in Northwest Europe).

  Additionally, a multipurpose H_2 transport infrastructure can be developed to allow for many end-users to decarbonise their energy needs with blue hydrogen. This pathway is used in further analysis to deploy low-carbon hydrogen as a mitigation option.

Instead of permanently sequestering the captured CO_2, it can also be used to increase the efficiency of manufacturing processes,[53] to produce fuels, feedstocks, or construction materials through carbon capture and utilisation.

The following sections focus on the potential of CO_2 storage (Section 2.5.2) and the resulting potential (Section 2.5.3) and cost (Section 2.5.4) of blue hydrogen (*centralised decarbonisation*), while the application of CCS in industrial processes (*distributed decarbonisation*) is discussed in more detail in the section on industry (Section 4.3).

2.5.2 Potential of CO_2 storage

To produce blue hydrogen or decarbonise other processes with CCS in Europe, it is helpful to have an understanding of the distribution and size of the European CO_2 storage potential. Appendix E.6.2 provides a comprehensive analysis of the potential for CCS and CCU in Europe, and gives insights into the geological storage potential, costs, regulation, and required cross-border cooperation. From this analysis Navigant concludes that the EU possesses a large geological storage potential for CO_2 of around 104 GtCO_2. In their transposition of the EU CCS Directive into national law,[54] some Member States have chosen to introduce bans or restrictions on the storage of CO_2 within their country.

> CO_2 storage potential is significant, equalling 57 years of the EU's 2016 emissions from industry and gas-fired power production

[51] This could be based on post-combustion capture or oxy-fuel capture.

[52] Sometimes also referred to as pre-combustion CCS.

[53] Examples: enhanced oil recovery, horticulture, urea production.

[54] The directive on the geological storage of CO_2 establishes a legal framework for the safe geological storage of CO_2. It contains provisions on l CO_2 storage in geological formations in the EU and the treatment of storage sites over their lifetime. Source: European Commission, 2009. *Directive on the geological storage of carbon dioxide.* https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009L0031&from=EN

Current legislative and regulatory limitations would have an impact on the CO_2 storage potential in the EU, reducing it from 104 GtCO_2 to around 77 GtCO_2. The remaining CO_2 storage potential is significant, equalling 57 years of the EU's 2016 emissions from industry and gas-fired power production. This means that there is a large potential for centralised and distributed decarbonisation using CCS. Unfavourable political and public attitudes towards geological CO_2 storage might limit the application in some areas, but this can be mitigated by either storing CO_2 in countries where the situation is more favourable, and by clearly defining CCS and CCU as intermediate solutions required to optimise speed and costs of achieving net-zero emissions. A flexible CO_2 transport infrastructure that relies on shipping where possible instead of pipeline transport would avoid further lock-in into capital-intensive infrastructure. Where CO_2 pipelines are needed to decarbonise industry, depreciation times could be limited. In the meantime, industrial sectors can develop more cost-effective solutions to mitigate emissions and make a full system transition towards renewable energy by 2050.

Besides storage in geological reservoirs (CCS), CO_2 can also be used to increase the efficiency of manufacturing processes,[55] to produce fuels, feedstocks or construction materials (CCU). Generally, only the latter category, embedding CO_2 into construction materials, leads to permanent storage of CO_2 and can continue to play a role in a decarbonised energy system, unless the other categories either use biogenic CO_2 or recycle the CO_2 in their end-of-life phase.
In total, about 300 MtCO_2 per year could be used in construction material (70 MtCO_2) and chemical feedstock (230 MtCO_2), and a circular economy can contribute to the permanency of CO_2 storage in products when these are not landfilled or incinerated but recycled. CCU has an important role to play in the decarbonisation of some sectors, especially the chemicals and petrochemicals sector.
To realise the full CO_2 storage potential in chemical feedstock, a low-carbon EU power demand arises of 1,900 TWh for the entire chemical sector.[56] This is around 60% of the 2016 power demand of the entire EU.[57] The production of CO_2-based feedstocks is often more energy intensive, mainly due to additional hydrogen demand. In general, natural gas is displaced when CO_2 is used as a feedstock but might continue to be supplied in the industries where the CO_2 is sourced from or where the low-carbon hydrogen is used to produce the feedstocks.

2.5.3 Potential of blue hydrogen

Blue hydrogen is a low-carbon gas produced by the thermochemical conversion of fossil fuels (typically natural gas) in combination with CCS.[58] Two production technologies are considered, the currently dominant steam methane reforming (SMR), and autothermal reforming (ATR). In the ATR set-up, a larger share of CO_2 can typically be captured and no additional burning of gas for heat is required since the process is exothermic. However, the ATR process does require an oxygen supply, which leads to additional electricity-related emissions if the oxygen is not supplied as a by-product or as renewable power, thus partly offsetting the climate-related advantage of ATR.[59] Methane catalytic cracking for large-scale hydrogen production may also turn out to become more cost-effective in the future and could become more interesting due to the eliminated need to remove carbon monoxide, but is currently not considered due to its technology infancy.[60]

---

[55] Examples: enhanced oil recovery, horticulture, urea production.

[56] DECHEMA, 2016. Low carbon energy and feedstock for the European chemical industry. https://dechema.de/dechema_media/Downloads/Positionspapiere/Technology_study_Low_carbon_energy_and_feedstock_for_the_European_chemical_industry.pdf

[57] Eurostat, 2018. Electricity production, consumption and market overview. https://ec.europa.eu/eurostat/statistics-explained/index.php/Electricity_production,_consumption_and_market_overview

[58] Hydrogen via electrolysis using nuclear electricity is also referred to as blue hydrogen.

[59] It is estimated there is 27 MW of power demand required to operate an ATR to produce 500 tonnes of H2 per day. This is compared to 2.3 MW for an SMR plant of the same output. If the grid emission factor is in the order of 400 grams CO_2 per kWh, the emissions from an ATR could be higher than SMR, even though the capture rate in an ATR is higher. Source: Jakobsen & Åtland, 2016. *Concepts for Large Scale Hydrogen Production*.

[60] Epling et al., 2011. Review of methane catalytic cracking for hydrogen production. International Journal of Hydrogen Energy 36(4):2904-293.

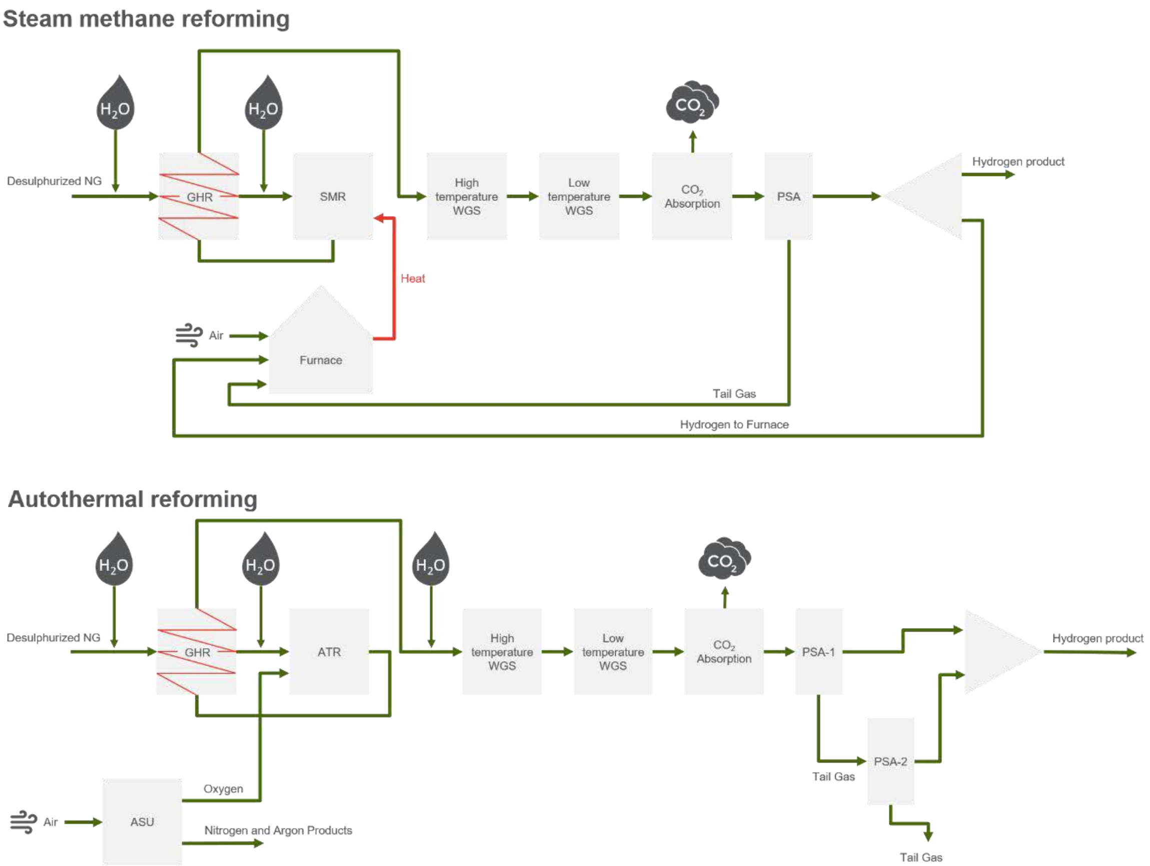

Figure 17 Comparison of steam methane reforming and autothermal reforming as pathways to produce blue hydrogen.

Currently around 270 TWh (8 million tonnes, 25 bcm natural gas equivalent) of hydrogen is produced in the EU.[61] Most of this production is concentrated in North-western Europe. The production in the EU is largely produced by steam methane reformers (190 TWh, 5.8 million tonnes, 18 bcm natural gas equivalent),[62] but also partly through cracking hydrocarbons in refineries and as a by-product from chemicals production.[63] Nearly all steam methane reformers could be retrofitted with CO_2 capture technology since even small-scale installations produce sufficient CO_2 to allow for CCS.[64] Since most steam methane reformers are situated in or around industrial clusters, and the purity of the flue gas CO_2 is relatively high, capture costs are among the lowest compared to other industrial processes and to thermal power generation.

[61] CertifHy, 2015. *Overview of the market segmentation for hydrogen across potential customer groups, based on key application areas.* http://www.certifhy.eu/images/D1_2_Overview_of_the_market_segmentation_Final_22_June_low-res.pdf

[62] Maisonnier et al., 2007. *"European Hydrogen Infrastructure Atlas" and "Industrial Excess Hydrogen Analysis" PART II: Industrial surplus hydrogen and markets and production.* http://citeseerx.ist.psu.edu/viewdoc/download;jsessionid=535A04C6EB3703701C83F6675DDA8CBD?doi=10.1.1.477.3069&rep=rep1&type=pdf

[63] Hydrogen Europe, 2015. *Merchant Hydrogen Plant Capacities in Europe*. https://h2tools.org/hyarc/hydrogen-data/merchant-hydrogen-plant-capacities-europe

[64] Small-scale installations are considered to produce around 10,000 Nm^3/hour. This equals emissions in the order of 0.7 $MtCO_2$/year. Source: Air Liquide, 2018. Steam Methane Reforming - Hydrogen Production. https://www.engineering-airliquide.com/steam-methane-reforming-hydrogen-production; Jakobsen & Åtland, 2016. *Concepts for Large Scale Hydrogen Production*.

In carbon capture processes, not all CO_2 can be captured economically. In an autothermal reformer, around 5% of the CO_2 emitted by the process cannot be captured cost-effectively.[65] Steam methane reformers can be optimised to capture 90% of their emissions. It should be noted that this is not a technical maximum, but rather an economic optimisation that can be increased with additional engineering and investment, which would be rather costly.[66] If carbon capture is not applied in such way that all CO_2 is captured by 2050, the remaining CO_2 emissions could be compensated in other parts of the energy system to achieve a net-zero emissions energy system. This can be done by using bio-based feedstocks in processes equipped with CCS or by realising negative emissions elsewhere. When scaling up blue hydrogen to ambitious levels of 1,500 TWh (45 million tonnes, 142 bcm natural gas equivalent),[67] around 30 $MtCO_2$ negative emissions would be required to offset remaining emissions.

> Steam methane reformers can be optimised to capture >90% of their emissions

Navigant's calculations show that this can be realised in the EU industry sectors (Appendix D.3), though literature suggests that even more cost-effective solutions for negative emissions are available without difficulty in the EU.[68]

Thanks to the existing natural gas infrastructure in Europe and the existence of SMR facilities, a sizeable production of blue hydrogen can be reached within a relatively short timeframe in existing plants. Since CO_2 storage potential is not a limiting factor to produce blue hydrogen, up to 190 TWh (5.8 million tonnes, 18 bcm natural gas equivalent) of low-carbon hydrogen[69] could be produced annually within the next 10 years by retrofitting existing hydrogen manufacturing units with CCS. Blue hydrogen via SMR could then be a solution for development of a hydrogen market from the early 2020s onwards, with blue hydrogen via ATR or SMR and dedicated green hydrogen production coming later, when the hydrogen demand across segments increases and green hydrogen becomes more cost competitive. How fast blue hydrogen capacities will develop after the retrofitting phase, depends on the price of natural gas, the availability of by-product hydrogen and the affordability and availability of alternative thermochemical routes such as autothermal reforming, partial oxidation, electrolysis, downhole conversion, or microwave technologies.[70] More cost-effective hydrogen imports could potentially also play a role, but this was not within the scope of this study.

---

[65] Jakobsen & Åtland, 2016. *Concepts for Large Scale Hydrogen Production*.

[66] Cappellen et al., 2018. Feasibility study into blue hydrogen.

[67] This 1,500 TWh relates to an upper bound of hydrogen demand in the Gas for Climate model.

[68] Griscom et al., 2017. Natural climate solutions.

[69] CertifHy, 2015. *Overview of the market segmentation for hydrogen across potential customer groups, based on key application areas*. https://www.fch.europa.eu/sites/default/files/project_results_and_deliverables/D%201.2.%20Overview%20of%20the%20market%20segmenatation%20for%20hydrogen%20across%20potential%20customer%20groups%20based%20on%20key%20application%20areas.pdf

[70] Royal Society, 2018. Options for producing low-carbon hydrogen at scale. https://royalsociety.org/~/media/policy/projects/hydrogen-production/energy-briefing-green-hydrogen.pdf

2.5.4 Costs

This section discusses the costs of blue hydrogen for the two most developed and cost-effective thermochemical routes, SMR and ATR.

The costs of producing blue hydrogen in a SMR, optimised to capture and sequester 90% of the CO_2 emissions, is estimated at €39–63/MWh in 2050,[71,72] depending on the natural gas price. The natural gas price is an important sensitivity to test when green hydrogen becomes more cost competitive. Hydrogen from SMR seems somewhat costlier to produce than through ATR, which has a production cost of €36–56/MWh in 2050 (Table 34). Current (2019) production costs for blue hydrogen are estimated at €47 and €51/MWh, for ATR and SMR, respectively.[73]

The CAPEX of both production processes consists of the H_2 production plant (reactor), carbon capture installation, carbon transport infrastructure, and CO_2 storage facilities (drilling and injection). CAPEX build-up of SMR and ATR differs by the higher costs for the reactor in SMR and additional costs for an air separation unit in ATR. Costs for air separation could decrease significantly if low-cost by-product O_2 can be supplied from the water electrolysis process.[74,75] OPEX in both systems mainly consists (60–70%) of the natural gas price. Other cost components are related to operation and maintenance and electricity costs. In both production processes, OPEX makes up around 60% of the total hydrogen production cost.

Besides natural gas and electricity prices, the production cost of hydrogen in these processes is influenced by the production scale. Whereas the levelised cost of hydrogen production in electrolysers is fairly independent from the plant capacity, production cost for low-carbon thermochemical conversion routes decreases by 20–30% when moving from a capacity of 100 tonnes H_2/day to 500 tonnes H_2/day.[76] Production cost is also sensitive to financial parameters such as discount rate and installation lifetime.

Depending on the SMR configuration, it can be more attractive to extend the lifetime of existing SMR capacity and retrofit it with CCS than to decommission the installation and build a new installation. Costs for retrofitting may therefore be lower than reported here. However, when capacity expansion is foreseen, ATR will likely be more economically attractive than SMR. Assuming a typical lifetime of 30 years, many SMRs will have to be replaced by 2050. This also provides a perspective on the respective roles of green and blue hydrogen towards 2050. If blue hydrogen capacity is expanded beyond what is produced in retrofitted SMRs, this would only be replaced by green hydrogen close to 2050 when the economic lifetime of these installations is over, unless they are retired earlier.

---

[71] Based on 500 tonnes of H_2 production per day, delivered at 20 bar. Assuming 5% discount rate and 30-year lifetime, consistent with Navigant financial assumptions throughout the report. Jakobsen & Åtland assume a discount rate of 10% with a lifetime of 25 years. A sensitivity on natural gas prices between 0.17–0.35 €/m^3 was included. Based on: Jakobsen & Åtland, 2016. *Concepts for Large Scale Hydrogen Production*.

[72] For reference, the cost of biomethane was estimated to be €60/MWh.

[73] Assuming a natural gas price of 0.31 €/m^3 that is used throughout this report.

[74] Moore, 2017. Renewable Power-to-Gas: A technological and economic review

[75] Götz et al., 2015. Renewable Power-to-Gas: A technological and economic review.

[76] Jakobsen & Åtland, 2016. *Concepts for Large Scale Hydrogen Production*.

2.5.5 Conclusion

> The blue hydrogen potential is almost unconstrained. By 2050 blue hydrogen needs to be net-zero emissions

The technical potential of blue hydrogen is large. While the potential for permanent CCU in the EU is relatively small,[77] ample possibilities for permanent sequestration of CO_2 exist. Societal acceptance constitutes a clear barrier to the scale up of CCS as well as economic limitations to the share of CO_2 that can be captured in fossil-based production routes. The potential for blue hydrogen is almost unconstrained. By 2050 blue hydrogen needs to be net-zero emissions by engineering efforts or by compensation by negative emissions; for example, by using biomethane or other bio-based feedstock in combination with CCS. Literature suggests that sufficient negative emissions can be realised to support a very ambitious scale up of blue hydrogen. The estimated cost of blue hydrogen in 2050 is comparable to that of green hydrogen, but it will likely be more cost-effective in the short term, especially with low-cost CCS retrofitting.

2.6 Additional benefits of low-carbon and renewable gas

This section highlights additional benefits of low-carbon gas and renewable gas production that have not been quantified. These are related to strengthening the rural economy, synergy with food production, and energy security and reliability.

Choosing an energy system with renewable gas can provide the EU with a reliable and secure energy system
Security of supply is an important pillar of the Energy Union and an important driver for the energy transition. Choosing an energy system with renewable gas can provide the EU with a reliable and secure energy system. Renewable gas produced within Europe increases security and stability of the energy system. It can also be imported through existing gas infrastructure. This study shows that large quantities of biomethane can be produced within Europe, abiding by strict sustainability criteria and reducing the import dependency of the European energy system. This study's "optimised gas" scenario shows that all energy production can take place within the EU, while, as discussed in Section 1.3., energy imports are still likely by 2050, albeit possibly at less than current levels.

Renewable gas production can strengthen the rural economy
An increase of farmers' revenues from biomethane production would improve their quality of life and their ability to invest. Also, if biomethane production is based on sequential cropping (Biogasdoneright), the earnings from production on existing cropland increase.

Negative emissions in industry
Some sectors have emissions that will be difficult to eliminate by 2050, such as aviation and shipping. To the extent possible, these sectors could use bio-based fuels. However, climate scientists are convinced that some degree of negative emissions is needed to compensate for the most hard-to-abate emissions in the energy system. If low-carbon gas is produced based on a fossil energy route with CCS, investments to enable negative emissions such as carbon capture installations and CO_2 transport infrastructure have already been made. A fuel to biogenic feedstocks such as biomethane or solid biomass combined with CCS leads to negative emissions. Facilities that are nearby and already emit biogenic CO_2 can additionally benefit from nearby CO_2 transport and storage infrastructure.

[77] Taking the assumption that CO2 has to be sequestrated permanently.

Soil organic carbon sequestration
The production of sustainable biomethane can enable a business case for sustainable agriculture. To produce feedstock for their anaerobic digesters, a group of 600 Italian farmers, organised in the Italian Biogas Consortium (CIB), have developed the concept of growing a sequential crop after their annual (food or feed) crop. This ensures that the soil is covered almost throughout the year, which reduces the need for synthetic fertiliser. This sequential crop is fed into an anaerobic digester, together with animal manure and food waste, and the remaining digestate is brought back into the soil. Among other plant-fertilising nutrients, this brings back organic carbon to the soil. This Biogasdoneright concept has demonstrated an increase in soil fertility, water retention properties, and a reduction of erosion. Due to the sequestration of additional carbon into soils, the agriculture sector can also make a noteworthy contribution in decarbonising and compensating part of their hard-to-abate nitrous oxide and methane emissions.

Soil organic carbon enhancement can make a significant contribution to a net-zero agriculture sector by 2050.
Remaining hard-to-abate emissions in the agriculture sector by 2050 are projected to be around 300 $MtCO_2$ based on an ambitious scenario by the European Commission.[78] With a potential of 47–73 $MtCO_2$ per year, soil organic carbon enhancement measures that are stimulated by the production of biogas can make a noteworthy contribution towards a net-zero agriculture system by compensating 16–21% of these remaining emissions, which are primarily non-CO_2 emissions. This potential can be even larger when considering other measures such as agroforestry and including grass in the crop rotations.

Blue hydrogen and renewable gas can decarbonise remote and small-scale industry
Post-combustion CCS can be effective in decarbonising industry emissions as an end-of-pipe solution; it is also able to capture emissions that do not originate from fuel combustion, i.e., process emissions from the cement and steel industry. However, post-combustion CCS also requires capital-intensive CO_2 transport by pipeline or ship. The required economies of scale for such investments are often impossible to reach for remote and smaller-scale industrial facilities. In these situations, it may be more cost-effective to capture the CO_2 in large hydrogen manufacturing plants and supply this to those facilities that are too far off to use post-combustion carbon capture and storage. Existing hydrogen and gas networks can be used, or new pipelines can be developed to supply blue hydrogen or renewable gas to such locations to also enable the decarbonisation of these installations.

2.7 Conclusion

The analysis in this chapter focuses on the supply side and shows that biomethane production in the EU can be scaled up significantly. Today, biomethane production totals 2 bcm, even though biogas production has reached a significant scale of 14 bcm already. It is possible to increase the quantity in a sustainable way while ensuring that biomethane will be a net-zero emissions renewable gas. By 2050, a quantity of 22 bcm of biomethane could be produced based on the anaerobic digestion of agricultural wastes, food waste, and sewage sludge. An additional 33 bcm can come from the thermal gasification of woody residues. Navigant anticipates a potential of 41 bcm from the anaerobic digestion of sustainable silage cultivated as autumn, winter, and spring crop. This leads to a total availability of 95 bcm of biomethane.

Besides biomethane, it is possible to use CO_2 that becomes available in the biogas production process to create additional methane, using hydrogen as input. Navigant assumes that CO_2 from large-scale thermal gasification plants can be stored belowground to create negative emissions. From aerobic digestion installations, much smaller quantities of CO_2 become available and it would be difficult and expensive to store this CO_2 below ground at farms.

[78] European Commission, 2018. *In-depth analysis in support of the Commission communication COM(2018)773.* p.167
https://ec.europa.eu/clima/sites/clima/files/docs/pages/com_2018_733_analysis_in_support_en_0.pdf

Therefore, it makes sense to capture this CO_2 and use it, with hydrogen, to produce synthetic methane in the power to methane process. If applied to half of the EU anaerobic digestion biogas upgrading plants by 2050 this could generate an additional green methane supply of 160 TWh leading to a total renewable methane potential of 1,170 TWh (110 bcm of natural gas equivalent). This quantity of renewable methane can be supplied at substantially lower costs compared to todays production cost levels. Especially biomethane production cost levels can be expected to decrease substantially.

The role blue hydrogen and green hydrogen will play towards 2050 will depend on various factors, such as the price of natural gas and electricity, technology development and the availability of carbon capture, transport, and storage infrastructure. Since the costs of green and blue hydrogen are expected to become comparable and the sensitivities regarding key parameters are large, a cost of €52/MWh for both production routes is assumed. However, from an energy system perspective it is useful to start producing green hydrogen only when there is enough curtailed electricity from renewable energy sources. If green hydrogen starts earlier, it means that dedicated renewable power capacity is built to produce green hydrogen when electricity production is not yet made fully renewable. This bears the risk that an increase in green hydrogen production would lead to increased fossil electricity generation elsewhere in the EU energy system, which defeats the premise of zero-carbon hydrogen. This means that, beside demonstration projects, green hydrogen should only be scaled up in large volumes when either (1) enough curtailed electricity is available, or (2) when the electricity grid is sufficiently decarbonized to label green hydrogen as low carbon.

> Costs of green and blue hydrogen are expected to become comparable

Therefore, in addition to large-scale green hydrogen demonstration projects aiming to improve the technology and reduce costs, blue hydrogen can be a promising option to scale up the low-carbon hydrogen supply in the short term. Existing hydrogen production capacity can often be retrofitted with carbon capture equipment, transforming the production of grey hydrogen into blue hydrogen. This allows a scale-up of blue hydrogen of up to around 5.8 million tonnes (190 TWh) in the EU. Beyond this quantity, blue hydrogen can play a role to create and satisfy additional demand for hydrogen in the energy system.

Towards 2050, Navigant expects a significant volume of around 200 TWh of curtailed electricity which allows a sizable production of green hydrogen. By 2050, the EU electricity system will have been fully decarbonized: green hydrogen can be implemented at full scale and replace blue hydrogen.
In practice, the deployment of blue and green hydrogen could occur simultaneously in the EU due to varying local conditions in terms of availability of renewable electricity and availability of political willingness to implement CCS.

Figure 18 shows the production costs of the various renewable and low-carbon gas options. In addition, there are costs for the integration into existing gas grids, these are described in Chapter 6.

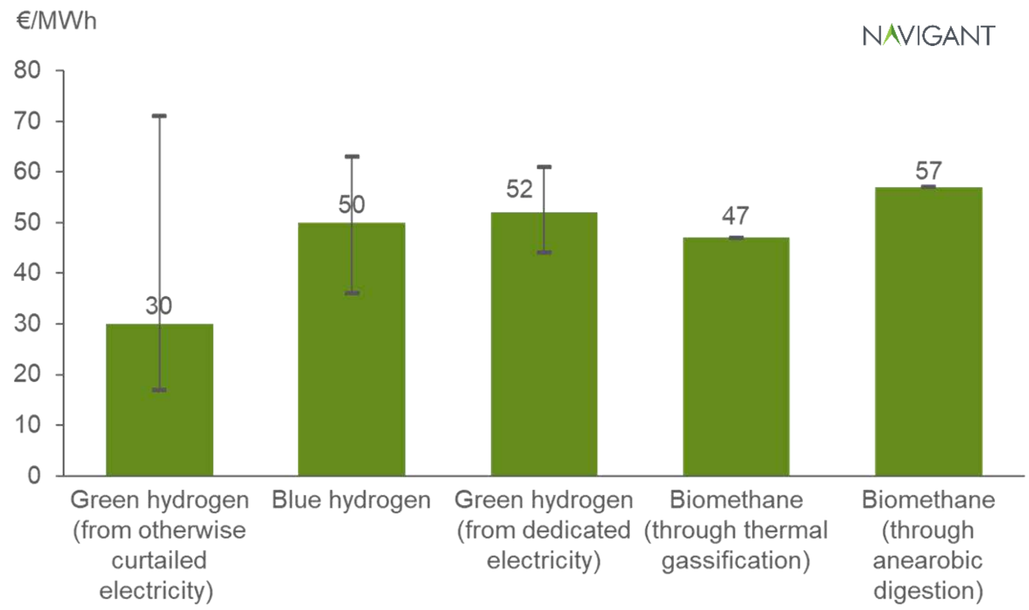

Figure 18 Comparison of hydrogen and biomethane production costs in 2050.

Box 3 Comparison with other scenarios: Renewable and low-carbon gas

Throughout this study, Navigant compares its scenarios with recently published scenarios by the European Commission in the *A Clean Planet for all - A European long-term strategic vision for a prosperous, modern, competitive and climate neutral economy* communication by the European Commission[79] as well as the *Decarbonisation Pathways* study by Eurelectric.[80] From the EC communication, Navigant focuses on the 1.5TECH scenario which is in line with the 1.5 degrees Celsius ambition.

The consumption of gaseous fuels (defined as natural gas, carbon-free gases and hydrogen) in the 1.5TECH scenario presented by the EC amounts to about 3000 TWh, of which about 800 TWh of biogas and gas from waste, about 900 TWh of hydrogen, close to 500 TWh of synthetic methane (so-called e-gas) and over 600 TWh of natural gas. The consumption of gaseous fuels in the 1.5TECH scenario (3,000 TWh) is similar to our scenario (2,880 TWh). The main difference is the fairly substantial role for natural gas in the 1.5TECH scenario. The amount of biomethane is slightly higher in Navigant's "optimised gas" scenario, while the amount of hydrogen is higher, and synthetic methane is lower.

In the 1.5TECH scenario, the biogas and gas from waste is predominantly used in the power sector (>80%) while in our scenarios, its use is more distributed over buildings, transport and power. In the 1.5TECH scenario there is still a substantial demand for natural gas (over 500 MWh) in a variety of sectors. Consumption of synthetic methane is mainly used in buildings, industry and transport. In Navigant's scenario, a potential of 160 TWh of power to methane is used throughout the energy system, in addition Navigant has 267 MWh of synthetic kerosene as e-fuel for aviation.

Next to direct electrification, the Eurelectric scenario also focuses on the electricity consumption for *indirect electrification* (e.g., power-to-gas) which ranges from 600-1,200 TWh in its various decarbonisation scenarios. In Navigant's "optimised gas" scenario, electricity consumption for hydrogen (about 2600 TWh is higher because of the large role of hydrogen in that scenario as well as the use of hydrogen for synthetic kerosene production.

[79] https://ec.europa.eu/clima/policies/strategies/2050_en

[80] https://www.eurelectric.org/decarbonisation-pathways/

3. Methodology to compare "minimal gas" with "optimised gas"

3.1 Introduction

This study assesses the potential role and value for renewable and low-carbon gas used in existing gas infrastructure in a net-zero emissions EU energy system compared to a situation in which a minimal quantity of gas would be used. Having established the insights in the potential availability of renewable and low-carbon gas in Chapter 2, the following sections discuss how renewable and low-carbon gas can add maximum value in the energy system. Before doing so, the concept of energy system costs illustrates how the allocation of renewable and low-carbon gas over the buildings, industry, transport, and power sectors will result in energy system cost savings.

3.2 Defining energy system costs and societal value

Moving to a net-zero carbon energy system necessitates changing the current energy system. The precise direction of this change depends on the decarbonisation options or pathways. For policymakers, it is essential to understand how these changes could influence the future energy system and what the associated costs could be. Navigant's quantification of the societal value of renewable and low-carbon gas can be used to support political decisions on future energy policies.

The concept of the energy system is represented by the total financial costs of achieving a net-zero emissions energy system for society. Cost savings represent the societal value of renewable and low-carbon gas used in existing gas infrastructure. These cost savings can be realised by including energy carriers in the overall energy system in an optimal way, compared to a situation in which only a minimum quantity of renewable and low-carbon gas would be used. In calculating these costs, Navigant takes a societal perspective, meaning that subsidies and taxes are not considered and that a social discount rate of 5% is applied.[81]

The energy system costs are calculated on an annual basis and reflect the total annual costs in 2050 for the EU-28, combining capital and operational costs. Investment costs are annualised using an annuity factor based on the technical lifetime of the technology and the assumed social discount rate. The annual costs are expressed in 2018 euros. The optimal mix of decarbonisation options consist of two key elements: increasing energy efficiency in all sectors and scaling up renewable energy. This can be complemented with other low-carbon energy sources. Finding the optimal mix of decarbonisation options is relevant in all sectors. However, the focus of this quantification is on the role of renewable and low-carbon gas in the heating of buildings, in industry, transport, and the power sectors.

[81] Required investments will be partly done by governments, partly by households and partly by private investors. The level of the discount rate reflects this. It considers the rate at which governments can borrow (0-3%), a household mortgage interest rate of 4-5%, as well as a higher return on capital for the private sector. This social discount rate is in line with the discount rate recommended by the European Commission for cost-benefit analysis according to Annex III to the Implementing Regulation on application form and CBA methodology, which recommends a 5% discount rate for Cohesion countries and a 3% discount rate for other Member States.

3.3 Defining two energy system decarbonisation scenarios

To estimate the societal value in the buildings, industry, transport and power sectors, two energy scenarios are developed in this study. Both scenarios assume a net-zero emissions EU energy system by 2050. The scenarios differ in the extent to which renewable and low-carbon gas play a role in the scenarios. In the “optimised gas” scenario, renewable methane can be used to its full potential and green and blue hydrogen are used based on their optimal demand in a smart combination with renewable electricity. In the “minimal gas” scenario, renewable and low-carbon gas use is limited to those sectors where no reasonable alternatives are available.

In the **buildings** sector, gas heating technologies like hybrid heat pumps, are only deployed in the “optimised gas” scenario. In the “minimal gas” scenario, all-electric heat pumps are used instead. As consequence, more thorough renovation of buildings is required to accommodate the increase in all-electric heat pumps. Both scenarios also consider a certain share of district heating.

The **industry** sector analysis in this study focuses on the three energy-intensive industries with high emissions: iron and steel, ammonia and methanol, cement and lime production. In both the “optimised gas” and the “minimal gas” there must be a role for gases—partly because there are no alternatives, like in steel mills, or because gas is inherent to the production process, like in ammonia and methanol production. Nevertheless, we focus on those technologies that limit the use of gas or gas infrastructure in the “minimal gas” scenario, while assuming the existence of methane and hydrogen infrastructure in the “optimised gas” scenario. To produce ammonia and methanol specifically, the hydrogen required in the “minimal gas” scenario will be fully produced onsite, resulting in an ammonia and methanol industry that effectively uses electricity only.

In the **transport** sector, hydrogen, bio-CNG, and bio-LNG are only considered in the “optimised gas” scenario. In the “minimal gas” scenario electricity and advanced biofuel is used for transport to the largest extend possible.

Finally, in the **power** sector, dispatchable power generation in the “optimised gas” scenario is realised through gas-fired power plants—like combined-cycle gas turbines (CCGT) and open cycle gas turbines (OCGT)[82]—using biomethane and hydrogen as well as biomass fired power plants. In contrast, dispatchable power in the “minimal gas” scenario is fully relying on biomass fired plants. Figure 19 gives an overview of the main differences between the scenarios. In the subsequent sections, these will be discussed in more detail.

[82] CCGT and OCGT plants are both gas-fired power plant, however the CCGT is more efficient because of combining a gas-cycle with a steam cycle, while the OCGT only uses a gas-cycle.

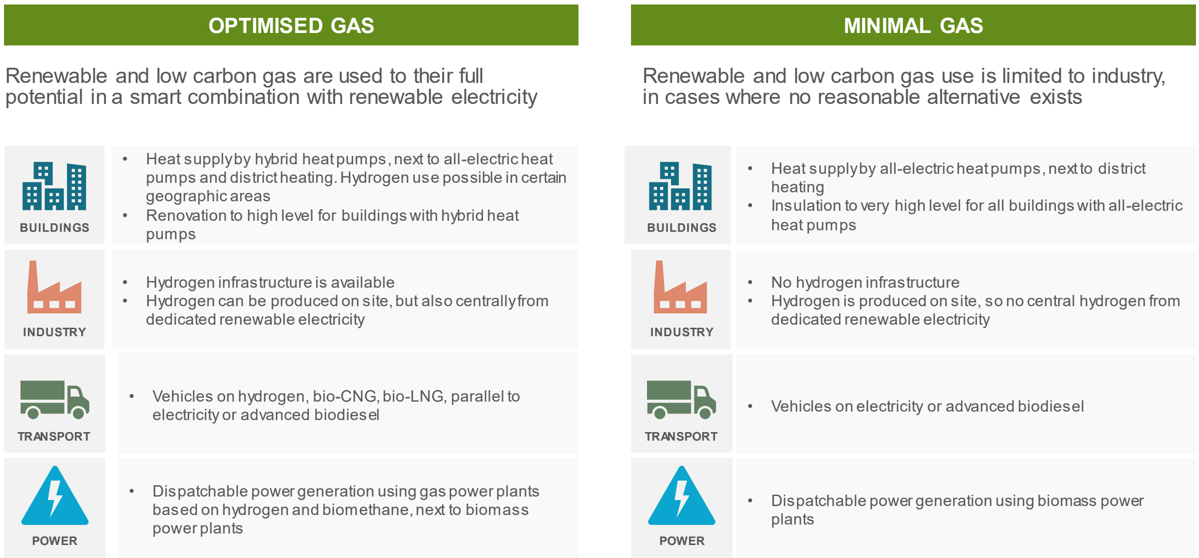

Figure 19 Overview of differences between the “optimised gas” and “minimal gas” scenarios.

The societal value of renewable and low-carbon gas is defined as the potential cost savings in the “optimised gas” scenario, compared to the “minimal gas” scenario in achieving a net-zero emissions EU energy system by 2050. Further detail on the energy system cost calculation is provided in Appendix B.

3.4 Allocating renewable and low-carbon gas across sectors

Renewable and low-carbon gas have many potential roles in the future energy system. The available volume of renewable and low-carbon gas must be allocated across the various sectors, preferably by using it first in those sectors where it adds most value. This value can originate from differences in energy costs, technology costs, or from cost savings in the distribution and transmission infrastructure. To allocate renewable and low-carbon gas to the various sectors, we investigate in which sectors renewable and low-carbon gas realises most savings as compared to the alternative non-gas decarbonisation options. It should be noted that renewable methane use is supply-driven whereas hydrogen use is demand driven. Furthermore, hydropower and liquid biofuel are supply-driven and direct electricity consumption throughout the energy system is demand driven.

We investigate the decarbonisation options in the building, industry, transport and power sector. The various decarbonisation pathways are discussed in detail in Chapter 4 for buildings, industry, and transport and in Chapter 5 for the power sector. Technical details of the analyses are also provided in Appendix G to Appendix J.

We subsequently analyse the entire EU energy system to define the most cost-efficient net-zero emissions EU energy system. We allocate the available renewable and low-carbon gas in the “optimised gas” scenario to the various demand sectors.

This overall energy system analysis is carried out by incorporating the insights from the sector analyses in the Navigant Energy System Model. The energy system model is built using Analytica software and enables the development of various decarbonisation scenarios by changing shares of decarbonisation options in the various sectors assessed. The model is used to analyse the minimal societal cost under specified availability of biomethane, hydrogen, and biofuels. The model distinguishes between several sectors, subsectors and technologies and allocates biomethane, hydrogen, and biofuels availability over these subsectors and technologies based on the lowest cost principle. A simplified overview of the model is shown in Figure 20.

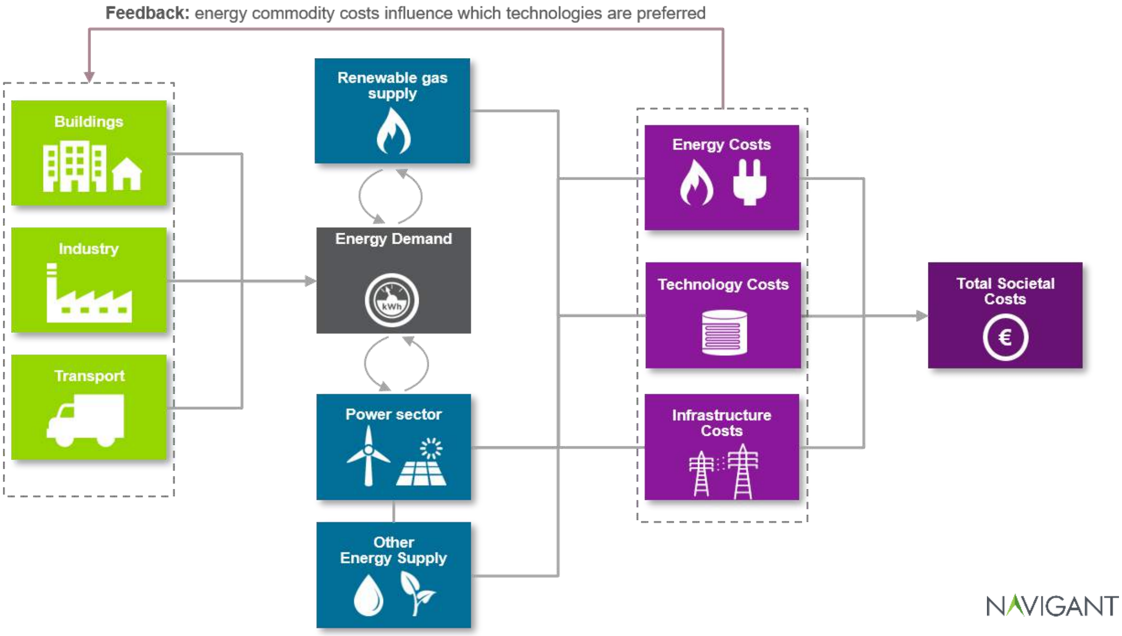

Figure 20 Simplified overview of the Navigant Energy System model

The analysis is performed in the model by the following steps:

1. Calculate **energy demand** in the buildings, industry, and transport sector based on technology shares (different in the various scenarios) as well as activity increase (e.g., increase in building area) and energy consumption per unit of energy service (e.g., energy consumption per kilometre driven).
2. Model **electricity generation** based on the available variable renewable electricity generation as well as the potential technologies for dispatchable power generation.
3. Check energy demand with potential **energy supply** (e.g., the biomethane potential as assessed in Chapter 2).
4. Calculate **energy system costs** based on the analysis of energy demand, electricity generation, and potential energy supply.

The model consists of various dedicated modules:

- **Renewable and low-carbon gas supply:** Modelling of renewable and low-carbon gas supply and comparison with the demand in the buildings, industry, transport, and power sectors.
- **Buildings:** Modelling of residential and commercial energy demand for heating based on the renovation level and heating technologies.
- **Industry:** Modelling of industrial energy demand for steel, ammonia, and methanol production based on the sectoral decarbonisation options.
- **Transport:** Modelling of transport energy demand for passenger cars, freight trucks, buses, ships, and aircrafts based on the various vehicle technologies.
- **Power:** Modelling of electricity costs and energy demand for dispatchable power based on the total electricity demand in the buildings, industry, and transport sector, on the variable renewable electricity supply and on the dispatchable electricity generation options.
- **Infrastructure:** Modelling of electricity, gas, and heat infrastructure costs.

Next to the possibility to develop scenarios by defining technology shares, the model also features an optimization module to find the most attractive technology mix to achieve the lowest energy system costs. To establish the two decarbonisation scenarios in this study, the model is optimised twice: once including the various renewable and low-carbon technologies and once excluding those technologies.

The definition of the optimization is described in Figure 21. The allocation of renewable and low-carbon gas is performed by optimizing the technology shares (decision variables) to achieve a least cost decarbonisation scenario (objective function). The potential supply of biomethane, hydrogen, and biofuel are limiting the total demand for these carriers. In addition, minimum and maximum technology shares are defined to ensure minimum or maximum deployment of technologies (constraints). For example, the maximum share of gas-based technologies in buildings needs to be set to the current share of gas connections. The minimum and maximum shares are also used to exclude the gas-based technologies in the “minimal gas” scenario.

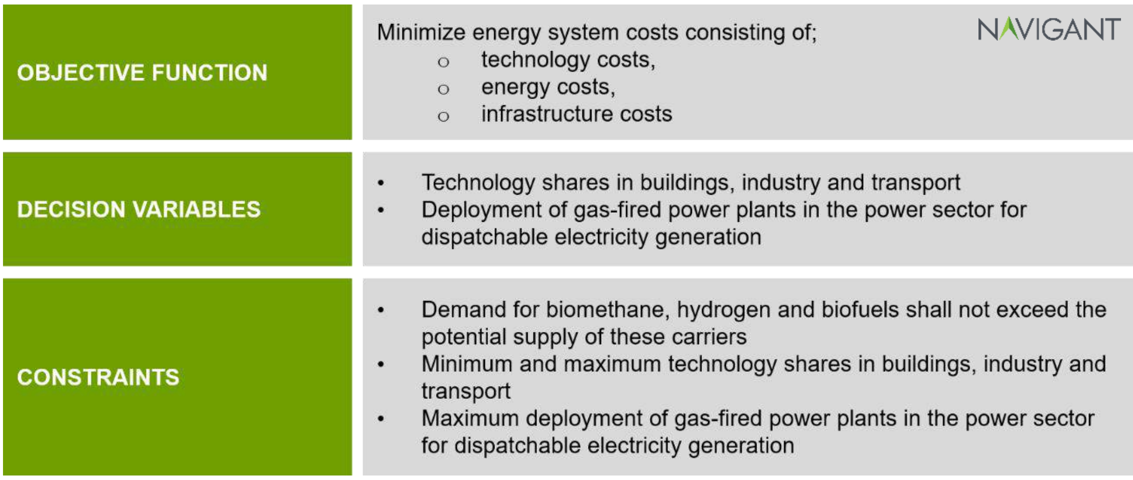

Figure 21 Optimization objective function, decision variables, and constraints

The high-level results from the allocation of renewable and low-carbon gas in the “optimised gas” scenario as well as the electricity and other energy demand is provided in Table 3. The full energy allocation to demand sectors for both scenarios is given in Appendix A. In the following sections, this allocation will be discussed per sector and details on energy system costs provided. In Chapter 7 the overall comparison will be made, including all sectors and the distribution and transmission infrastructure.

Table 3 Allocation of gas, electricity and other energy in the “optimised gas” scenario in 2050 (in TWh)

Sector	Biomethane	Hydrogen	Electricity	Other
Buildings (heating)	185	46	399	396
Industry (iron & steel, ammonia & methanol, cement & lime)	69	627	286	484
Transport (road, shipping, aviation)	595	252	772	534
Electricity consumption in other sectors	-	-	3,004	-
Power*	322	786	-	254
Total	**1,171**	**1,711**	**4,461**	**1,669**

* Demand of biomethane, hydrogen and other describe the fuel use in the power sector. This does not include energy input from variable renewable electricity generation, like solar, wind, and hydropower.

4. Approach to decarbonise EU energy demand

4.1 Introduction

Having established the insights in the potential availability of renewable and low-carbon gas for the energy supply in Chapter 2 and the methodology to determine the value of renewable and low-carbon gas in Chapter 3, this section describes the role and value of gas in the buildings, industry, and transport sectors.

4.2 Buildings

KEY TAKEAWAYS

- In the “optimised gas” scenario, peak demand can be delivered at lower societal costs, replacement costs in existing buildings are lower, and distribution and transmission infrastructure cost are lower compared to the “minimal gas” scenario.
- The buildings sector could be a key demand sector for renewable and low-carbon gas based on the financial and practical impact on home owners and the existence of competing technologies with and without renewable gas.
- Deployment of hybrid heat pumps has the potential to save up to €61 billion per year (excluding infrastructure costs).

4.2.1 Introduction

Buildings are responsible for approximately 40% of EU energy consumption and 36% of greenhouse gas emissions.[83] Over 60% of household energy is used for space heating, about 15% for water heating, and about 5% for cooking. The remainder, about 15%, is used for lighting and appliances, amongst others.[84] This study focuses on the role of renewable and low-carbon gas in space heating and excludes its potential use for hot water and cooling. It is expected that the total energy demand for heating of buildings will be 787–1,026 TWh in 2050.

> Buildings are responsible for 40% of EU energy consumption today

Today, the main energy sources used for space heating in the EU include natural gas, petroleum products, renewables and wastes, derived heat, and electricity.[84] At the EU level, natural gas consumption as a proportion of buildings’ total final energy consumption rose between 1990 and 2012 to 37% for residential and to 31% for non-residential buildings. Electricity consumption grew 59% over the same period, reaching 25% of the total final energy consumption of residential and almost twice that in non-residential buildings.[85] Currently, about 35% of the EU's buildings are over 50 years old and almost 75% of the building stock is energy inefficient, while only 0.4–1.2% (depending on the country) of the building stock is renovated each year.[86]

[83] European Commission (2018), Energy Efficient Buildings, https://ec.europa.eu/energy/en/topics/energy-efficiency/buildings

[84] Eurostat (2018), Energy consumption in households, https://ec.europa.eu/eurostat/statistics-explained/index.php/Energy_consumption_in_households

[85] European Commission Joint Research Centre (2015). *Energy Renovation: The Trump Card for the New Start for Europe*. URL: https://elperiodicodelaenergia.com/wp-content/uploads/2017/01/Energy-renovation-2016.pdf

[86] European Commission (2018) Energy Efficiency in Buildings. Retrieved from:https://ec.europa.eu/energy/en/topics/energy-efficiency/buildings

There are several options to decarbonise the building sector:

- Use of renewable and low-carbon gases like biomethane or blue and green hydrogen in gas-fired boilers or hybrid heat pumps, combining electricity and gas. Gas fired heat pumps are another possibility but not included because they are a less optimal option from a system perspective.[87]
- Electrification with air-source or ground-source heat pumps, or partial electrification using hybrid heat pumps.
- Use of district heating with heat from (industrial) waste heat recovery, geothermal sources or from bioenergy.

Electrifying heating in buildings requires high levels of insulation to maintain comfort levels on cold days. These high levels of insulation are needed because heat pumps[88] work with low capacities (in view of investment cost) and low temperature heat delivery systems (in view of performance), both limiting the amount of heat loss that can be compensated for. Furthermore, the heating system should not only be able to cope with normal winter weeks, but also with the most extreme cold spells over multiple decades. Besides the heating system itself, the supply, transport, and distribution infrastructure should be able to meet high energy demand peaks. For all-electric options this would result in substantial investments in electricity generation, as well as in transmission and distribution infrastructure.

4.2.2 Space heating and insulation

Decarbonisation of space heating requires major changes in the energy system. A comfortable temperature of 20°C has become part of the expected standard of living for EU countries. The challenge is to decarbonise the energy system while maintaining this comfort level in all circumstances. There are several possible solutions that are listed below:

- **Gas-fired boilers** are ubiquitous in the current energy system, using a significant amount of natural gas. They might be replaced with biomethane- or hydrogen-fired boilers or fuel cells.
- **Hybrid heat pumps** require less rigorous insulation than all-electric heat pumps, as the integrated gas heaters provide peak heating demand.
- **All-electric heat pumps** can provide space heating. There are two types of all-electric heat pumps available: air-source heat pumps (ASHPs) and ground-source heat pumps (GSHPs).[89]
- **District heating** can supply (industrial) waste heat, geothermal heat, or renewable heat from heat pumps or renewable and low-carbon gases to homes and buildings in densely populated areas.[90]

---

[87] Gas-fired heat pumps provide another option to use renewable gas for heating in the build environment. While gas-fired heat pumps are more efficient compare to gas-fired heat pumps, they lack the possibility to use renewable gas only at moments on which gas has most value. Hybrid heat pumps have this optionality to use renewable electricity when sufficiently available and gas at moments of high heating demand or low availability of renewable electricity. For that reason, we do not consider gas-fired heat pumps in our scenario. A further comparison between hybrid heat pumps and gas heat pumps is provided in the Gas for Climate 2018 study, available at: https://gasforclimate2050.eu/files/files/Ecofys_Gas_for_Climate_Report_Study_March18.pdf

[88] When direct electricity heating would be applied, the potential impact on electricity infrastructure would be even larger.

[89] For more information on the different type of heat pumps, please see Appendix G.1

[90] Within this analysis the district heating potential is assumed to be not based on renewable gas or electricity. This potential must be obtained from sources such as excess industrial heat, waste incineration, solar thermal heat and geothermal heat. The potential of these sources is very large, but for district heating it is required that supply and demand are located close to each other. In our scenario's the demand for district heating is 396 TWh. For comparison, the Horizon 2020 project Heat Roadmap Europe (http://vbn.aau.dk/files/288075507/Heat_Roadmap_Europe_4_Quantifying_the_Impact_of_Low_Carbon_Heating_and_Cooling_Roadmaps..pdf) estimates a potential for these sources of between 260 and 555 TWh, while the Euroheat and Power Heat Roadmap Europe 2050 (https://www.euroheat.org/wp-content/uploads/2016/04/Heat-Roadmap-Europe-I-2012.pdf) estimates between 500 and 800 TWh.

From the analysis as provided in detail in Appendix G, we conclude that hybrid heat pumps are the most promising heating option for buildings with an already existing gas connection, and are therefore including in the "optimised gas" scenario, because:

Hybrid heat pumps are the most promising option for buildings

- They can make use of the existing gas infrastructure in the buildings sector, reducing the required expansion of electricity grids.
- They can deliver heat using the existing heat delivery systems, avoiding replacement of existing heat delivery systems.
- They deliver peak demand efficiently and at limited additional cost.
- The equipment is relatively low cost, because the expensive part of the heat pump capacity (at low temperatures) is replaced with low-cost gas boiler capacity.
- Hybrid heat pumps can be introduced relatively fast because no expansion of the existing gas and electricity networks is required.
- Hybrid heat pumps heating requires less extreme insulation of buildings compared to installing all-electric heat pumps.

Box 4 Potential role of hydrogen in the buildings sector

Using hydrogen in buildings requires adjustments to the distribution network and its auxiliaries, like compressors, as the amount of hydrogen that can be mixed with natural gas is limited (approximately 5–20% depending on the pipeline network system, the local natural gas composition and type of domestic burner). The necessary requirements to upgrade of possibly to replace parts of the distribution network to use 100% hydrogen are still being assessed in a number of ongoing projects, like the Leeds project described below and the SGN Hydrogen 100 project.[91] Since using hydrogen in the buildings sector could be a viable option in specific areas, for example in cases where supply of biomethane is limited, we assume that 20% of the gas used in our "optimised gas" scenario is hydrogen. The hydrogen can be either used in pure form in dedicated areas, or to some extend be mixed with biomethane.

Leeds (UK) is aiming to progressively convert all households to 100% hydrogen before 2030.[92] Beyond the Leeds transition, Northern Gas Networks (UK) is currently assessing scenarios in which 10 times the equivalent of Leeds is converted between 2025 and 2035, and 50 times the equivalent of Leeds is converted between 2025 and 2045. This could provide a blueprint for a rollout in other countries and regions.[93]

It is conceivable that if a proof-of-concept for the broad use of the existing DSO infrastructure with 100% hydrogen can be achieved in the coming years, a real alternative technology might be available in wind-prone regions in Europe where blue hydrogen could be accessible e.g. from Norway and where very fortunate wind conditions allow for a dedicated hydrogen production from wind power.

H21 Leeds City Gate

The city of 750,000 inhabitants is assessing the technical feasibility and preparing the regulatory and financial framework to progressively convert all households to 100% hydrogen between 2026 and 2029. The project will replace natural gas with hydrogen from four steam methane reformers with a capacity of 1 GW, or about 150,000 tons of hydrogen per year, equipped with 90% carbon capture. The produced hydrogen, about 700 GWh will be stored in salt caverns and fed into the existing gas distribution network through a hydrogen transmission system. The city will be converted in waves of about 2,500 homes, disconnected for about 5 days during the summer months before being fully on the hydrogen network.

[91] SGN (2019), Hydrogen 100 Project. https://www.sgn.co.uk/Hydrogen-100/

[92] Leeds City Gate (2017). H21. https://www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Report-Interactive-PDF-July-2016.compressed.pdf

[93] Northern Gas Networks (2018). H21 North of England, https://northerngasnetworks.co.uk/h21-noe/H21-NoE-23Nov18-v1.0.pdf

4.2.3 Value of renewable and low-carbon gas in the buildings sector

The potential role of renewable and low-carbon gas in the buildings sector as part of the allocation and societal cost savings calculation is described in detail in Chapter 3. The impact of space heating on the energy system is largely determined by the heating equipment used, the local climate characteristics, and the characteristics of the buildings. The insulation level of the buildings strongly affects the heat loss during cold weather and therefore also impacts the required capacity of the heating system. In the modelling, the building stock and energy consumption for heating is differentiated in five geographical regions (Northern, Western, North Eastern, South Eastern, and Southern Europe).

In the “optimised gas” scenario, all-electric and hybrid heat pumps (80%) are the most important options for supplying heat in buildings, complemented by 20% district heating (Table 4). The share of hybrid heat pumps (37%) is restricted by the existing connections to the gas grid. Navigant assumes that all buildings that currently have a gas connection will still use it by 2050, whereas most new buildings (constructed between 2016–2050) will mostly use all-electric heat pumps plus some district heating. All buildings without gas connections will switch to all-electric heat pumps and some district heating.[94] The deployment of these technologies lead to a renewable gas demand of 231 TWh, from which 185 TWh is biomethane, 46 TWh is hydrogen, and 399 TWH is electricity (Table 5). Note that insulation is used to lower the energy consumption also in the “optimised gas” scenario.

In the “minimal gas” scenario, the technologies based on renewable and low-carbon gas are limited, resulting in the deployment of all-electric heat pumps (80%), again complemented by district heating (20%). As a result, electricity demand in the “minimal gas” scenario is 390 TWh, while renewable and low-carbon gas demand is zero.

The chosen insulation level of a building is connected to the selected heating technology. Deep renovation to reach high insulation levels is required for the households with all-electric heat pumps, while less deep renovation is sufficient for district heating and gas-fired heating technologies.[95] As a consequence, total electricity demand in both scenarios is similar because the lower insulation level in the “optimised gas” scenario, but peak electricity demand will be higher in the minimal gas scenario due to the inefficiency of air sourced heat pumps with low outside temperatures. The lower insulation level in the “optimised gas” scenario results in an overall higher energy demand for space heating. Nevertheless, the additional energy costs related to that in the “optimised gas” scenario are much smaller than the additional costs related to the deep renovation, additional electricity distribution networks, and expensive peak electricity generation in the “minimal gas” scenario. Appendix G provides a more detailed description of the assumptions behind the building stock distribution and renovation levels.

Table 4 provides insight into the technology assumptions. The hybrid heat pumps are restricted by the current number of households connected to the grid. GSHP is mainly limited to newly build buildings, which will be about 20% of the future stock. Table 5 provides insight into energy demand results for both scenarios.

---

[94] Navigant assumes the role for district heating to increase by four-fold towards 2050.

[95] Appendix G provides a more detailed definition of the assumptions and costs of medium and high levels of insulation.

Table 4 Technology deployment in the buildings sector in 2050 (%)

Technology	"Optimised gas"	"Minimal gas"
Air-source heat pump (ASHP)	23%	60%
Ground-source heat pump (GSHP)	20%	20%
Hybrid heat pump	37%	0%
District heating	20%	20%

Table 5 Energy demand in the buildings sector in 2050 (TWh)

Technology	"Optimised gas"	"Minimal gas"
Biomethane	185	0
Hydrogen	46	0
Electricity (via heat pumps)	399	390
Heat (via district heating)	396	396
Total	**1,026**	**787**

Full electrification of space heating will lead to higher costs due to high insulation of buildings and heating technology costs. An increasing share of hybrid heat pumps has the potential to save up to €61 billion per year in the "optimised gas" scenario compared to the "minimal gas" scenario. These savings exclude any infrastructure costs, which we further describe in Chapter 6. Table 6 provides an overview of the potential savings connected to the buildings sector.

The highest savings are due lower insulation costs as hybrid heat pumps do not necessarily require deep insulation. However, the overall energy demand in the "optimised gas" scenario is higher because of the lower insulation level, also resulting in higher energy costs.

Table 6 Potential savings through renewable and low-carbon gas in the buildings sector om 2050 (€ billion)

Cost category	"Optimised gas"	"Minimal gas"	Savings
Heating technology costs	207	253	47
Insulation costs	159	180	21
Energy costs	63	57	-7
Total cost savings			**61**

Box 5 Comparison with other scenarios: Buildings

In the 1.5TECH scenario from the EC, the share of electricity in space heating increases from about 10% currently to 30–50% in 2050. In our scenario, the *electrification rate* (final electricity demand divided by total final demand) for space heating ranges from 39% in the "optimised gas" scenario to 50% in the "minimal gas" scenario. Rates range from 21–44% in the Eurelectric scenarios. The remaining demand of non-electricity fuel consumption in the 1.5TECH scenario is about 800 TWh, consisting of a mix of various fuels, like natural gas, biogas, synthetic methane, hydrogen, solid biomass, district heating and other renewables. In our scenarios, the remaining demand is lower, with around 600 TWh of biomethane, hydrogen and district heating in the "optimised gas" scenario and around 400 TWh of district heating in the "minimal gas" scenario. Eurelectric does not specify how much non-electricity based space heating it expects.

4.3 Industry

KEY TAKEAWAYS

- Renewable and low-carbon gasses have added value in facilitating the full decarbonisation of industry. They are needed to significantly reduce greenhouse gas emissions from high temperature heat processes in the industry and to replace fossil feedstocks. The challenge is to boost the share of renewables as much as possible and to ensure that remaining gas demand is met with low-carbon gases.
- Green or blue hydrogen is the key to reduce emissions from ammonia and methanol production in the chemical industry. Implementation will not lead to significant changes of current production processes as hydrogen produced from natural gas is already used today.
- Hydrogen also plays an important role in mitigating emissions from the steel sector. However, significant investments in new production processes and further research are needed before deployment in the long term. The use of CCS/CCU and biomethane presents a greenhouse gas reduction option that can be implemented sooner.

4.3.1 Introduction

Industry is an important part of the EU economy in terms of added value. The sector also has high energy demands and greenhouse gas emissions. In 2015, industry accounted for a quarter of the EU's final energy consumption. Electricity (1035 TWh), natural gas (1012 TWh), oil products (663 TWh), and solid fuels (384 TWh) are the most important energy sources.[96] However, some energy sources are used as feedstocks. Feedstocks refer to raw materials fed into a process for conversion into another product. For example, hydrogen is a feedstock raw material for fertiliser production. Most of the greenhouse gas emissions associated with the industry sector come from natural gas, oil products, and solid fuels (e.g., coal) to provide heat and feedstocks. While emissions from thermal processes are released on the industrial production sites, feedstock emissions typically occur during the use phase of the industrial product, e.g. when fertilizer is used in agriculture. Processes emissions (i.e., emissions from industrial processes involving chemical or physical reactions other than combustion) are another major source of industrial greenhouse gas emissions. For example, in the cement industry, process emissions account for two-thirds of total emissions.

> High temperature industrial heat can be decarbonised either by applying CCS or by renewable or low carbon gas

Decarbonising the industry sector is a challenge, particularly for feedstocks and high temperature processes. When electricity is used by industrial processes, decarbonising is carried out in the power sector. Additional electrification potential exists for low/medium temperature heat processes. Temperature levels below 150°C can be decarbonised by geothermal energy, heat pumps and solar thermal energy. Decarbonisation options for high temperature industrial heat are limited. In addition to applying CCS, renewable and low-carbon gas can be used. Replacing fossil feedstocks (e.g., natural gas, crude oil, coal) with renewable feedstocks (e.g., biomethane or green hydrogen) mitigates emissions.

[96] CIEP (2017). European Union industrial energy use with a focus on natural gas.

The chemical and petrochemical sector is the most energy-consuming industry sector, followed by iron and steel, and non-metallic minerals (mainly cement). Together, they account for almost half of industry's final energy consumption (Figure 22). These three sectors use high temperature processes, have significant shares of process emissions, and use fossil feedstocks. As electrification is only possible to a limited extent, renewable and low-carbon gases are needed to achieve decarbonisation. Therefore, the study analysis focuses on chemicals, iron and steel, and cement and lime.

Other major energy-consuming sectors include paper, pulp and printing, and food, beverages, and tobacco. These sectors use mainly low and medium temperature processes and can significantly reduce emissions through process innovation (e.g., electrification). The pulp, paper, and printing industry also use woody biomass. As we see limited demand for hydrogen in these sectors, we chose not to focus on them.

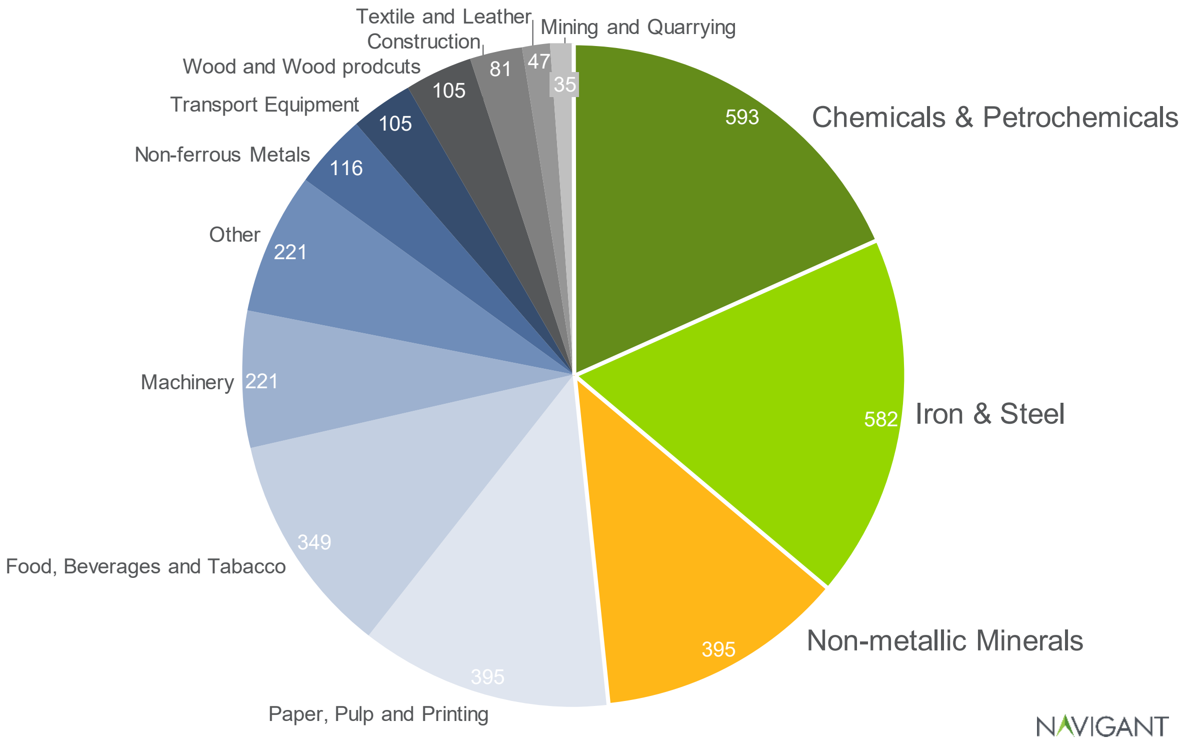

Figure 22 Final energy consumption in TWh of the industry in EU27 in different industry sectors in 2016[97]

In this study, Navigant differentiates between two industrial decarbonisation scenarios: "minimal gas" and "optimised gas." In the "optimised gas" scenario, we assume the existence of a gas infrastructure to transport biomethane and centrally produced hydrogen. In the "minimal gas" scenario, hydrogen is fully produced onsite, resulting in a substantial increase in industrial electricity demand.

The following sections discuss the energy needs in the chemical, iron and steel, and cement and lime industries, and analyse decarbonisation options in an "optimised gas" and "minimal gas" scenario. In a first step, we describe emissions and energy-intensive processes in each of these sectors and, in a second step, identify greenhouse gas emissions reduction technologies.

[97] Eurostat (2018). Energy balance sheets - 2018 edition

4.3.2 Chemicals

The chemical industry provides essential products and materials to many different downstream sectors. It requires energy for running its processes, and feedstocks—often carbon feedstock—eventually embedded in chemical products and materials like plastics. In 2016, the chemical sector (including pharmaceuticals) accounted for 126 million tonnes of CO_2 emissions, down from 325 million tonnes in 1990.[98] The chemical industry is the third-largest industrial emitter of greenhouse gases in Europe and the largest industrial energy consumer with 19% of total industrial consumption.[99] Iron and steel and non-metallic minerals consume less energy but have higher greenhouse gas emissions due to their large share of process emissions. Gas (natural gas and derived gas[100]) accounts for one-third (163 TWh) of total energy consumption (including use as feedstock) in the EU chemical sector. Also, around 20% of current natural gas demand in industry goes to this sector. Electricity is the second most important energy source (140 TWh), followed by crude oil and petroleum products (74 TWh), and derived heat (66 TWh) (see Figure 23). Solid fossil fuels, waste, and biomass provide around 27 TWh.

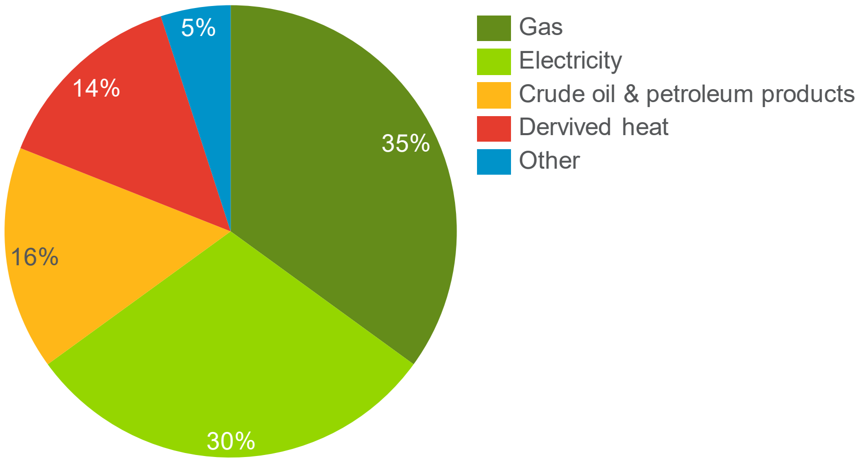

Figure 23 Energy mix in the chemical and petrochemical industry in the EU in 2016[101]

The chemical industry has a heterogeneous structure due to the large variety of products including fuels (petrochemicals), plastics (base chemicals), fertilisers (agrochemicals), and drugs (pharmaceuticals). The following sections focus on the production of two important chemicals in terms of production volume and natural gas use: ammonia (agrochemical) and methanol (base chemical). The current production processes for both chemicals are energy-intensive (particularly natural gas) and emissions-intensive. Ammonia production alone was responsible for 19% of greenhouse gas emissions (23.9 million tonnes of CO_2) in chemical sector in 2016.[102] Like ammonia, methanol requires natural gas as a feedstock.

[98] CEFIC (2018). Facts & Figures 2018.

[99] Bosseboeuf, Didier et. al. (2015). Energy Efficiency Trends and Policies in Industry.

[100] Derived gases are manufactured gases, comprising coke-oven gas, blast furnace gas and gasworks gas.

[101] Eurostat (2018). Energy balance sheets - 2018 edition.

[102] CEFIC (2018). Facts & Figures 2018.

4.3.2.1 Ammonia production

Ammonia is the foundation for the fertiliser industry and ranks second to sulfuric acid as the chemical with the largest tonnage of the global chemical industry.[103] Producing hydrogen from natural gas via steam methane reforming (SMR) is usually the first step in ammonia production, where high temperature steam is used. Hydrogen is then combined with nitrogen to produce ammonia via the Haber-Bosch process.

Although global production of ammonia is expected to grow by 65% in the period up to 2050, driven mainly by population growth (over 80% of the ammonia produced worldwide is utilised in fertilisers), growth, along with the production, is expected outside of Europe. Accordingly, we assume constant ammonia production in Europe of around 19.8 million tonnes a year.

Current emissions are around 1.83 tonnes of CO_2 per tonne of produced ammonia. The upstream production of hydrogen via SMR accounts for approximately two-thirds of the emissions (i.e., process emissions). The remaining emissions result from the combustion of fuel for heat and compression. In our analysis we distinguish between three different decarbonisation technologies: applying CCS to the existing SMR process, sourcing centrally produced green or blue hydrogen via dedicated hydrogen pipelines, and switching to electrolysis-derived hydrogen produced onsite.

Natural gas with CCS: Applying CCS to SMR can reduce emissions from ammonia production by up to 90%. The nearly pure stream of CO_2 from SMR can be captured at relatively low cost. However, CCS increases the electricity demand.[104,105] Additional electricity is required for compression, transport, and storage of CO_2.

Green or blue H_2 (centralised H_2 production): SMR can be omitted as the 178 kg of hydrogen required per tonne of ammonia is sourced centrally via hydrogen pipelines. Process heat is no longer needed and renewable electricity is used for compression and the air separation unit (ASU)[106]. Therefore, total emissions are reduced to zero.

Electricity (decentralised H_2 production): Switching to electrolysis-derived hydrogen as a feedstock eliminates the emissions associated with making hydrogen via SMR. Water electrolysis is the main energy-intensive step[107], accounting for around 10.8 MWh_{el} per tonne of ammonia.[108] Assuming the use of renewable electricity for the electrolysis, compressors and the ASU, total emissions are reduced to zero.

Appendix H.1.1 details the energy consumption of the current and the decarbonised ammonia production routes.

[103] Dechema (2017). Low carbon energy and feedstock for the European chemical industry.

[104] In some cases, CCS can also lead to a limited increase in fuel demand. However, in our analysis we did not consider an increased fuel demand.

[105] CEFIC (2013). European chemistry for growth - Unlocking a competitive, low carbon and energy efficient future.

[106] Nitrogen is needed for the ammonia synthesis. In the conventional ammonia production processes, nitrogen is a by-product of SMR. For low carbon ammonia production, an air separation unit is needed to supply the required nitrogen.

[107] Approximately 1.4 MWh per tonne of ammonia are required for compressors, 0.33 MWh for the ASU.

[108] Dechema (2017). Low carbon energy and feedstock for the European chemical industry.

4.3.2.2 Methanol production

Methanol ranks among the top 10 chemicals in the world in volume and is a source for various compounds such as formaldehyde or acetic acid. Global methanol production capacity is currently at around 110 million tonnes, methanol demand is estimated to be 75 million tonnes.[109] The demand for methanol could increase significantly in the coming decades. Olefins (e.g., ethylene, propylene) and BTX (benzene, toluene, xylene),[110] all of which are important building blocks for plastics, can be produced from methanol. Currently they are produced in steam crackers using naphtha as a feedstock and energy source. Steam cracking is an emissions-intensive process that is difficult to decarbonise. Electrification would require significant changes to the current production chain and is only in an early development stage.[111] Bio-based options are also limited. Switching from steam cracking to production of olefins and BTX via low-carbon methanol, would be a viable decarbonisation option. By 2050, we assume 50% of all olefins and BTX are produced from low-carbon methanol. This would increase European methanol demand from around 10 million tonnes today to 74 million tonnes by 2050.

To produce methanol, feedstock natural gas is first converted to a synthesis gas stream consisting of carbon monoxide (CO), CO_2, water, and hydrogen. This is usually accomplished by the catalytic reforming of feed gas (methane) and steam with partial oxidation as an alternative route. The second step is the catalytic synthesis of methanol from the synthesis gas. This conventional methanol production process results in emissions of around 1.5 tonnes of CO_2 per tonne of methanol. Two-thirds of the emissions can be allocated to the use of natural gas as feedstock, the remainder originate from combustion for heat production. To reduce emissions from the current methanol production process, CCS can be applied, or biomethane instead of natural gas for feedstock and energy can be used. Alternatively, methanol can be produced directly from hydrogen and CO_2. To ensure a substantial reduction of CO_2 emissions, it is required to use green or blue hydrogen, rather than natural gas. The CO_2 that is used in the final step of the low-carbon methanol production is supplied from the combustion of biofuels.

Natural gas with CCS: Like in ammonia production, applying CCS to SMR can reduce emissions from methanol production by up to 90%. The nearly pure stream of CO_2 from SMR can be captured at relatively low cost. However, CCS increases the electricity demand.[112] [113] The additional electricity is required for compression, transport, and storage of CO_2.

Biomethane: Instead of natural gas, biomethane can be used in the conventional methanol production process. In combination with the use of renewable electricity for the utilities, greenhouse gas emissions are reduced to zero.

---

[109] Methanol Industry (2018). Methanol. https://www.methanol.org/the-methanol-industry/

[110] BTX refers to mixtures of benzene, toluene, and the three xylene isomers, all of which are aromatic hydrocarbons used for the production of synthetic fibers, resins, detergent, and polymers.

[111] McKinsey (2018). Decarbonization of industrial sectors: the next frontier.

[112] In some cases, CCS can also lead to a limited increase in fuel demand. However, in our analysis we did not consider an increased fuel demand.

[113] CEFIC (2013). European chemistry for growth - Unlocking a competitive, low carbon and energy efficient future.

Green or blue H_2 (centralised H_2 production): The 189 kg of hydrogen needed per tonne of methanol is sourced centrally via hydrogen pipelines. 1.37 tonnes of feedstock CO_2 are required per tonne of methanol for the synthesis. Compared to the conventional route, additional electricity is needed for utilities (compressor, distillation). Assuming renewable electricity, replacing one tonne of methanol from natural gas with this technology reduces emissions by 2.86[114] tonnes of CO_2.[115,116,117]

Electricity (onsite H_2 production): The only difference to the centralised H_2 production technology described above is that water electrolysis is used to produce hydrogen onsite. This is also the main energy-intensive step, accounting for approximately 9.5 MWh_{el} per tonnes of methanol. Assuming renewable electricity, emissions are reduced by 2.86 tonnes of CO_2 per tonne of methanol.

Appendix H.1.2 details the energy consumption of the current and the decarbonised methanol production routes.

4.3.3 Iron and steel

Like the chemical industry, the steel sector delivers key materials and products to downstream sectors such as the automotive and machinery industries. It is one of the most carbon-emitting and energy-consuming sectors in Europe, and accounted for 216 million tonnes of CO_2 emissions in 2015, down from 298 million tonnes in 1990.[118] The main energy carriers used are solid fossil fuel (mainly coke and coal) (268 TWh), gas (172 TWh), and electricity (115 TWh) (see Figure 24). Gas not only refers to natural gas but also to off-gases produced during the steelmaking process. Integrated steel mills (primary route) meet most of their electricity demand through onsite-generation by burning off-gases from the blast furnace.

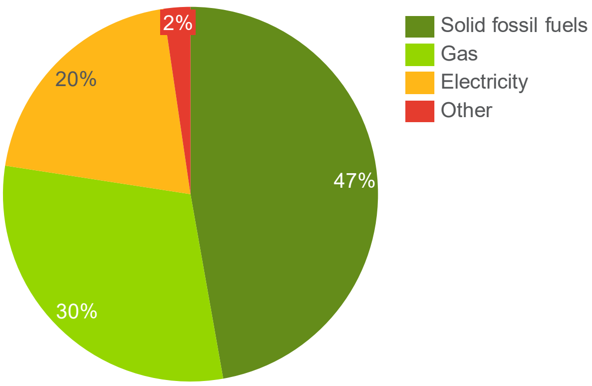

Figure 24 Energy mix in the iron and steel industry in the EU in 2016 [119]

[114] Methanol production via electrolysis and air capture of CO_2 results in negative emissions of -1.37 t CO_2/ t methanol. However, the negative emissions are released back into the atmosphere during the use phase of methanol. Therefore, the negative emissions are not permanent and can only be attributed to the production processes of methanol.

[115] Dechema (2017). Low carbon energy and feedstock for the European chemical industry.

[116] CEFIC (2013). Unlocking a competitive, low carbon and energy efficient future.

[117] Own calculations.

[118] Eurofer (2018).

[119] Eurostat (2018). Energy balance sheets - 2018 edition.

Modern steelmaking has two distinct process routes: primary and secondary steelmaking. Whereas primary steelmaking uses mainly iron ore, secondary steelmaking uses scrap steel as feedstock. In Europe, primary steelmaking is heavily dominated by the Blast Furnace/Basic Oxygen Furnace (BF-BOF) process, the secondary route by the Scrap-Electric Arc Furnace (Scrap-EAF) process. BF-BOF produced 60.5% of the EU-28 crude-steel production in 2015, while scrap-EAF accounted for 39.5% of the production.[120]

Today, primary steel is about five times more emissions-intensive than the production of secondary steel due to the use of carbon-based reducing agents such as coal, coke, and natural gas (which also provide the required heat).

Scrap-EAF uses mainly ferrous scrap as a feedstock which is melted by the electric arc (up to 3,500°C). The production volume and steel quality of the Scrap-EAF process route is limited by the availability and the quality of the feedstock, respectively. Depending on the plant configuration and availability of recycled steel, other sources of metallic iron such as direct-reduced iron (DRI) can also be used. Figure 25 compares the main steel making routes.

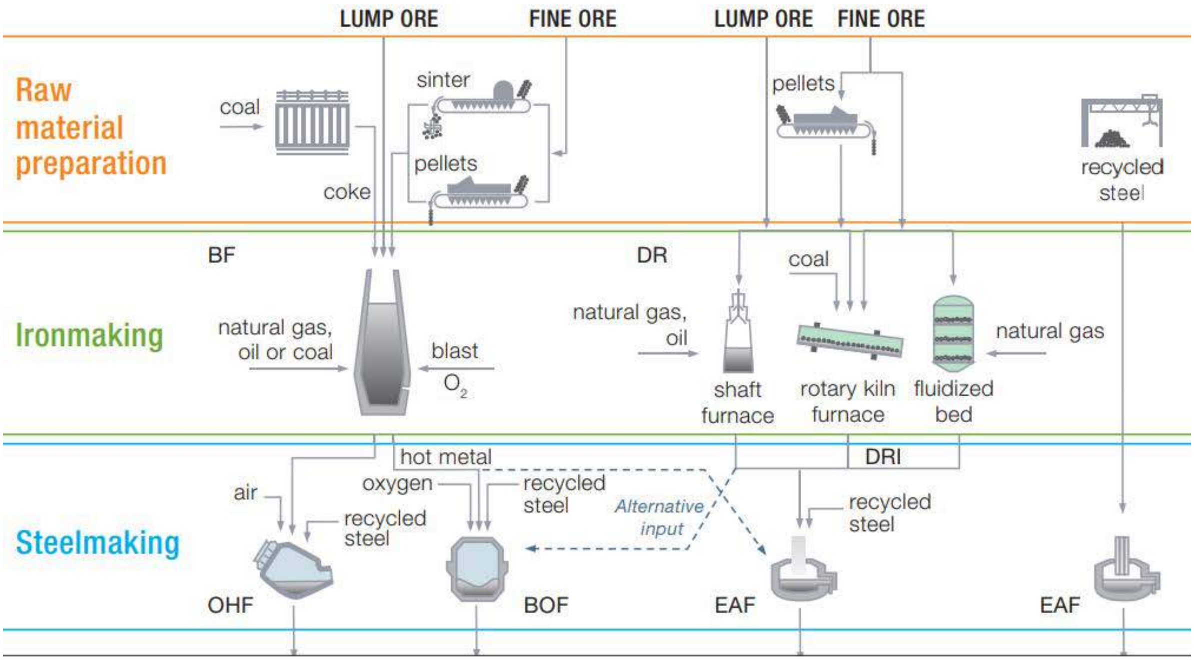

Figure 25 Steelmaking routes[121]

In 2050, European crude-steel demand is expected to be in the range of 200 million tonnes.[122] This presents an increase of over 40 million tonnes compared to 2015 levels. We assume that 50% of the demand in 2050 (up from 39.5% in 2015) will be covered by the Scrap-EAF route.[123] The remaining 50% of crude-steel demand in 2050 is produced via the primary process route with CCS.

Decarbonising secondary steel making is relatively easy and only requires switching to renewable electricity. Replacing fossil feedstocks and energy carriers in primary steelmaking is more challenging. Using hydrogen or biomethane to directly reduce iron ore would substitute fossil reducing agents such as natural gas or oil. The Iron Bath Reactor Smelting Reduction (IBRSR) processes in combination with CCS presents another promising low-carbon steel making technology.

[120] Worldsteel (2017): Steel Statistical Yearbook.

[121] Worldsteel (2018). Fact sheet – energy use in the steel industry.

[122] EUROFER (2018).

[123] EUROFER (2018).

Green or blue H_2 DRI-EAF (centralised H_2 production): During direct reduction, solid primary iron is obtained directly from oxidic iron ores with the aid of a reducing agent. Centrally produced green hydrogen is used as a reducing agent instead of a fossil-based one such as coke. The DRI is in a second step applied as a feedstock in the EAF. Limiting fossil energy carriers reduces the specific emissions to about 0.13 tonnes of CO_2 per tonne of steel.[124] The remaining emissions relate to lime burning and required carbon-bearing materials in the process required to get to the sufficient steel quality.

The same production route can also be realised with biomethane instead of hydrogen. The resulting emissions are also 0.13 tonnes of CO_2 per tonne of steel.

Electricity DRI-EAF (onsite H_2 production): In contrast to the decarbonisation option, here, hydrogen is produced onsite via water electrolysis. An additional 2.68 MWh of electricity is needed to produce the 64 kg of hydrogen required per tonne of crude steel. The specific emissions for this technology are 0.13 tonnes of CO_2 per tonne of steel.

IBRSR-CCS: Applying CCS to the innovative IBRSR process route could reduce CO_2 emissions of primary steelmaking by 80%. In contrast to the conventional BF-BOF process, raw material preparation (coke, sinter, and pellets production) is no longer required, which reduces emissions. Instead, coal and ore are used directly. Process and energy related emissions from the iron bath reactor are captured and stored. As a result, specific CO_2 emissions are reduced to 0.36 tonnes of CO_2 per tonne of steel.[125] Capturing all emissions is technically not feasible.

Appendix H.2 provides and overview of the energy consumption of the low-carbon steel production routes.

4.3.4 Cement and lime

The non-metallic minerals industry encompasses a wide variety of sub-industries such as cement, lime, glass, and ceramics. In terms of total greenhouse gas emissions and energy consumption, cement is by far the most important sub-industry, accounting for half of the energy consumption in the non-metallic minerals sector in the EU in 2005.[126] As the manufacture of lime is somewhat similar to cement, both are included in the analysis. Due to the high share of process emissions, the cement and lime industry are particularly difficult to decarbonise.

4.3.4.1 Cement

In 2011, the European cement industry accounted for 122 million tonnes of direct CO_2 emissions.[127] Only one-third of the emissions come from combustion processes, while the bulk of emissions come from the chemical reactions during calcination.[128] In the cement industry, the most commonly used fuels are solid fossil fuels (coal and lignite), alternative fossil fuels (waste, tyres, solvents, etc.), biomass, and electricity (see Figure 26).

[124] EUROFER (2018) and own calculations.

[125] EUROFER (2018) and own calculations.

[126] Moya J. A., Pardo N., Mercier A. (2010). Energy Efficiency and CO_2 Emissions: Prospective Scenarios for the Cement Industry.

[127] CEMBUREAU (2013). The role of cement in the 2050 low carbon economy.

[128] Calcination is the transformation of limestone into lime. Here, the chemical decomposition of limestone, generating typically 60% of total CO_2 emissions of the cement manufacturing process occurs.

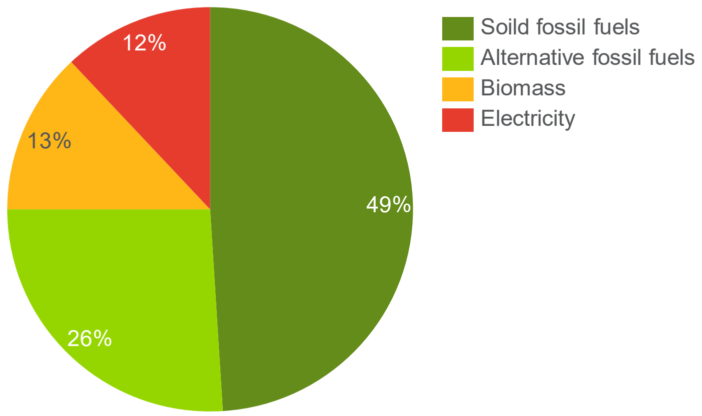

Figure 26 Fuel mix for the manufacture of cement[129]

Renewable and low-carbon gases play no significant role in the decarbonisation efforts of the cement industry. Hydrogen or biomethane have no added value compared to the cheap alternative fuels already in use. An extensive redesign of the furnace would be required given the differences in heat transfer from hydrogen burners compared to burners that today use predominantly fossil fuels. Electrification is not yet a viable option. Industrial-scale electric cement kilns are not yet available and are only at a very early research and development stage.

According to the CEMBUREAU Roadmap 2050,[130] switching to biomass and applying CCS are the main decarbonisation options for the cement industry. Increasing the share of biomass to around 40% mitigates fossil emissions from combustion. Only a modest retrofit of the kiln is required. Clinker, the main constituent of cement, is produced trough calcination. When using biomass, it is essential that biomass lifecycle emissions are mitigated as well. Substitution of clinker and novel cements can reduce processes emissions. To address the remaining emissions from both fuel combustion and calcination, CCS can be applied to the exhaust gases of kilns. In the cement industry, capture rates of 80% can be achieved.

4.3.4.2 Lime

In 2010, the European lime industry accounted for 26 million tonnes of CO_2 emissions.[131] Like cement, about two-thirds of the emissions are process emissions from the calcination process. Solid fossil fuels and natural gas are the main energy carriers (see Figure 27).

---

[129] Own calculation based on figures by CEMBUREAU (https://betoni.com/wp-content/uploads/2018/11/11.-Cement-and-Concrete-in-a-Low-Carbon-Economy-Chief-Executive-Koen-Coppenholle-CEMBUREAU-%E2%80%93-The-European-Cement-Association.pdf)

[130] CEMBUREAU (2013). The role of cement in the 2050 low carbon economy.

[131] Ecofys (2014). A competitive and efficient lime industry.

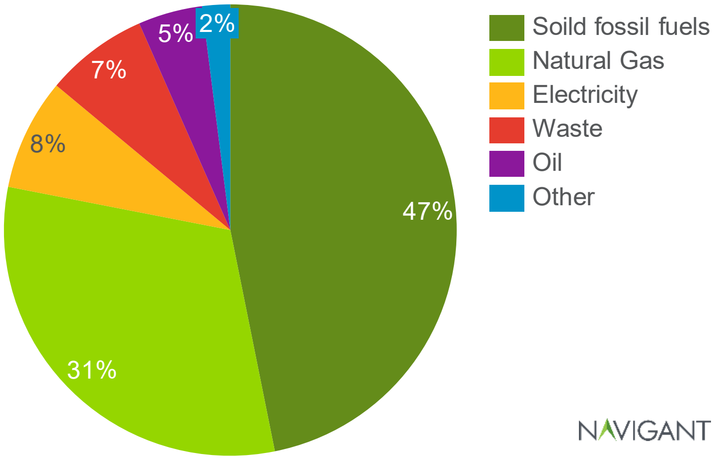

Figure 27 Fuel mix for the manufacture of lime[132]

Similar to the cement industry, the role or renewable and low-carbon gas is limited. Switching to biomass would reduce fossil emissions by about 30%. CCS should be applied to avoid the remaining 70% process emissions, as indicated in EuLA roadmap 2050[133].

Decarbonisation of both cement and lime is predominately based on biomass and post-combustion CCS. Renewable and low-carbon gasses play no significant role.

4.3.5 Value of renewable and low-carbon gas in the industry sector

The chemical, iron and steel, and cement and lime industries are relatively difficult to decarbonise. Our analysis shows that by replacing fossil feedstock with renewable and low-carbon gases, significant reductions of process-related CO_2 emissions are feasible except for the cement and lime industry. Low-carbon feedstocks can be integrated well into the existing process without the need of substantial investment. Pre- and post-combustion CCS and CCU and innovative processes such as direct-reduced iron can also mitigate emissions. The benefits of applying CCS, is the possibility to generate negative emissions if the CCS is eventually combined with the use of biomethane instead of natural gas.

The potential role of renewable and low-carbon gas as part of the allocation and societal cost savings calculation is described in detail in Chapter 3.

In the "optimised gas" scenario, iron and steel production is based on the IBRSR and Scrap-EAF production routes, with a small role for H_2-DRI-EAF. In the "minimal gas" scenario, these options are also favourable (see Table 7). For ammonia and methanol, production from hydrogen (produced centrally) is the most important option in the "optimised gas" scenario. In the "minimal gas" scenarios, only production based on electricity (decentralised H_2 production) is considered. The decarbonisation technologies of cement and lime remain the same in both a "minimal gas" and an "optimised gas" scenario, since gases are not considered a decarbonisation option. In our "optimised gas" scenario, hydrogen plays an important role in industry. While the use of biomethane, especially for methanol production, is possible as well, the limited availability of biomethane makes Navigant to choose for hydrogen in industry. Nevertheless, there can be regional differences. Where biomethane is available in larger quantities, use biomethane in industry is likely as well. Deploying hydrogen technologies in industry also enable accelerated decarbonisation when first blue hydrogen is applied. It is eventually replaced by green hydrogen when this is sufficiently available to get to a fully renewable energy system.

[132] Ecofys (2014). A competitive and efficient lime industry.

[133] Ecofys (2014). A competitive and efficient lime industry.

The deployment of these technologies in the “optimised gas” scenario lead to a biomethane demand of 69 TWh, a hydrogen demand of 627 TWh, and an electricity demand of 286 TWh (see Table 8). In the “minimal gas” scenario, electricity demand is 1,265 TWh, while renewable and low-carbon gas demand is only 69 TWh.

Table 7 Technology deployment in some industry sectors (%)

Sector	Technology	“Optimised gas”	“Minimal gas”
Chemicals | Ammonia	Electricity (decentralised H_2 production)	0%	100%
	Green or blue H_2 (centralised H_2 production)	100%	0%
	Natural gas with CCS	0%	0%
Chemicals | Methanol	Electricity (decentralised H_2 production)	0%	100%
	Green or blue H_2 (centralised H_2 production)	100%	0%
	Natural gas with CCS	0%	0%
	Biomethane	0%	0%
Iron and Steel	IBRSR with CCS	40%	40%
	Green or blue H_2 DRI-EAF (centralised H_2 production)	10%	0%
	Electricity DRI-EAF (decentralised H_2 production)	0%	10%
	Scrap-EAF	50%	50%
Cement and Lime	Biomass, alternative fuels, CCS	100%	100%

Table 8 Energy demand in some industry sectors (TWh)

Energy Carrier	“Optimised gas”	“Minimal gas”
Biomethane	69	69
Hydrogen	627	0
Electricity	286	1,265
Natural gas	0	0
Coal	355	355
Biomass	84	84
Other (alternative fuels, petcoke)	45	45
Total	**1,466**	**1,818**

The “optimised gas” scenario decarbonises heavy industry at €70 billion lower cost compared to a “minimal gas” scenario. The main reasons are the higher cost of energy if hydrogen is produced on site (Table 9).[134]

[134] For iron and steel, base investments were taken into account, for the chemical sector additional investments.

Table 9 Potential savings through renewable and low-carbon gas in some industry sectors (€ billion)

Sector	Cost Category	"Optimised gas"	"Minimal gas"	Savings
Chemicals | Ammonia	Technology costs	0	2	2
	Energy costs	8	22	13
Chemicals | Methanol	Technology costs	7	18	11
	Energy costs	32	71	39
Iron and Steel	Technology costs	4	5	0
	Energy costs	17	21	4
Cement and Lime	Technology costs	n/a	n/a	n/a
	Energy costs	n/a	n/a	n/a
Total costs savings				**70**

> Using hydrogen transported through gas infrastructure to decarbonise high temperature industrial heat saves €70bn annually compared to hydrogen produced on-site

Box 6 Comparison with other scenarios: Industry

The overall electrification rate (final electricity demand divided by total final energy demand) for the industrial sectors (chemicals, iron and steel, and cement and lime) that are explicitly analysed in our scenarios shows a large range from 20% in our "optimised gas" scenario to 70% in our "minimal gas" scenario.. The current electrification rate of the total European industry sector is around 33%. In the Eurelectric scenario, direct electrification rates for the chemical sector are 35–39% and for iron and steel are 38–42%. Differences are largely due to the fact that, in the "minimal gas" scenario, the hydrogen required for ammonia and methanol production is fully produced onsite, resulting in a substantial electricity demand. In the "optimised gas" scenario, electrification is limited in the sectors in scope. For the remaining sectors, mostly low and medium temperature heat industrial sector, Eurelectric assumes higher direct electrification rates of 39-55%. Lower temperatures can be electrified more easily. In the 1.5TECH scenario by the EC, there is a strong increase in electricity and hydrogen use and a strong decrease in natural gas use, although the 1.5 TECH scenario is not very specific on how industry will be decarbonised

4.4 Transport

KEY TAKEAWAYS

- Transport will remain an important energy demand sector, using over 35% of EU energy in 2050.
- In 2050, light road transport (passenger cars, light commercial vehicles) and domestic shipping will be primarily electric. In heavy road transport and international shipping, hydrogen, and biodiesel may become most important. Aviation will continue to use kerosene, but from biogenic (bio jet fuel) or synthetic origin (synthetic kerosene).
- The fuel mix in the “optimised gas” scenario for transport in 2050 consists of 252 TWh of hydrogen primarily for heavy road transport, 595 TWh of bio-LNG for shipping, and 267 TWh for bio jet fuel and synthetic kerosene for aviation. The remaining energy demand in the transport sector is 772 TWh of electricity, which is primarily used in light road transport, short-haul heavy road transport, and domestic shipping.

4.4.1 Introduction

The transport sector contributed 26% to the total EU greenhouse gas emissions in 2015, and its emissions were 23% above 1990 levels. Road transport was responsible for nearly 73% of the total sector emissions, followed by aviation and maritime transport with around 13% share each. Railways only contributed 0.5% to the total sector emissions.[135] By 2050, a full decarbonisation of the transport sector in the EU is required to meet commitments to reach net-zero CO_2 emissions.

In this section details the high-level, bottom-up analysis of the optimal renewable and low-carbon transport fuel mix in the “optimised gas” and “minimal gas” scenarios. The “minimal gas” scenario is characterised by a limited role for hydrogen, bio-LNG, and bio-CNG. We analyse the options with lowest societal costs and that fit the users’ requirements. In the analysis Navigant assumes that policies are technology neutral and the impact of taxation in evaluation of costs is not included.

The analysis covers the three major transport subsectors: road transport (passenger cars, trucks, and buses), shipping (domestic, intra-EU, and intercontinental), and aviation. Rail transport is not covered in our analysis because of its relatively low energy demand. While large part of rail transport is already electrified, hydrogen-powered trains could be a possibility for trains currently using diesel.[136]

For this analysis, the primary source of energy is either renewable electricity (directly supplied to vehicle batteries, or in the form of electric fuels such as green hydrogen and synthetic kerosene), decarbonised natural gas (blue hydrogen), or bioenergy (bio-CNG, bio-LNG, biodiesel, or bio jet fuel). In some transport sectors energy density of fuels is more important than in others, in particular heavy-duty transport, international shipping, and aviation. This means that these sectors could be potential sweet spots for the use of renewable gas, rather than passenger cars where fuel energy density is less important than in other transport sectors.

Most of the energy uses in passenger transport is caused by passenger cars and aviation (Figure 28). Energy use in freight transport is dominated by trucks and shipping. The final energy demand is heavily dependent on the fuel type, as fuel efficiencies can differ by as much as a factor of three.[137]

---

[135] European Environment Agency (2017). Greenhouse gas emissions from transport. URL: https://www.eea.europa.eu/data-and-maps/indicators/transport-emissions-of-greenhouse-gases/transport-emissions-of-greenhouse-gases-10

[136] Alstom (2018) Coradia iLint – the world's 1st hydrogen powered train. https://www.alstom.com/coradia-ilint-worlds-1st-hydrogen-powered-train

[137] IEA MoMo.

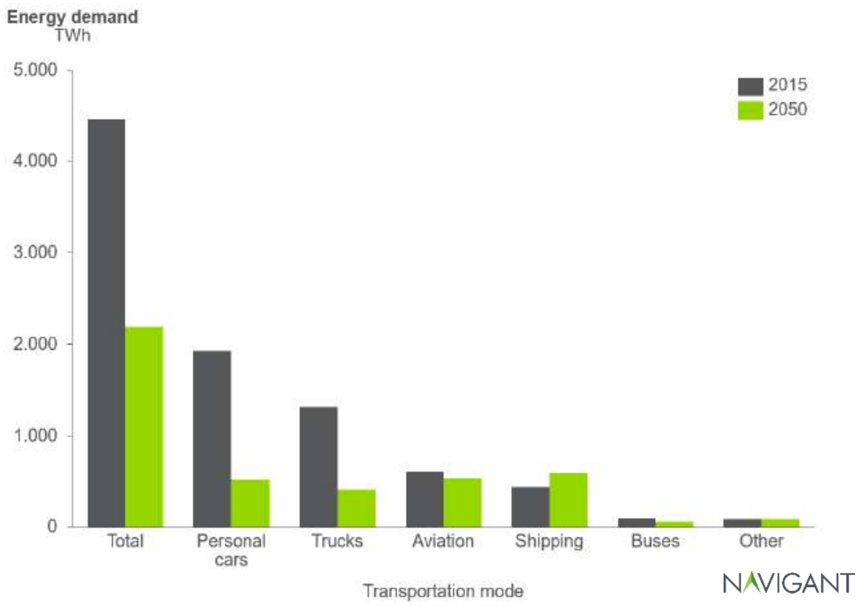

Figure 28 EU energy use in the transport sector for various subsectors in both 2015[138] and 2050. Energy use in 2050 is determined from the optimal fuel mix in Section 4.4.5.

Road transport, shipping, and aviation have their own fuelling infrastructure. It will not be cost-effective to develop fuel types for all subsectors, as it would require investment in parallel infrastructures. The fuel choice and the required infrastructure need to be similar across Europe to ensure freight and transport will be able to operate internationally. For aviation and shipping intercontinental alignment is required. Rail is excluded from the analysis as it accounts for a small part of the energy demand in transport. Besides that, most rail transport already takes place over electric rail lines. We foresee only a minor role for renewable and low-carbon gases, for example hydrogen, in a small subsection of total rail, for instance in rural areas.

Considering the costs of renewable methane and blue and green hydrogen and taking into account the available supply of renewable methane, we compare the relative value of renewable and low-carbon fuel options compared to other fuel options in the “optimised gas” scenario versus the “minimal gas” scenario. The latter scenario limits the use of hydrogen, bio-CNG, and bio-LNG and only allows electricity, advanced biofuel and synthetic kerosine.

4.4.2 Road transport

To ensure a net-zero emissions energy system by 2050, only renewable and low-carbon fuels are considered, including renewable electricity, bio-CNG, bio-LNG, biodiesel, and blue or green hydrogen.

> Road transport energy demand can decrease from 3340 TWh to 1000-2200 TWh per year, depending on the fuel mix

The future demand for fuels is strongly linked to the types of vehicles in 2050. Current energy demand of EU road transport is 3,340 TWh per year. Depending on the fuel mix the energy demand for EU road transport in 2050 is in the range of 1,000–2,200 TWh per year.

Assessing the total societal costs for vehicles to predict which vehicle fuel option will be most economic determines the vehicle stock. Other factors that determine the uptake of renewable and low-carbon fuels towards 2050 are also considered. The road transport sector is broken down into three main vehicle types: trucks, buses, and passenger cars.

[138] Navigant calculations based on IEA MoMo and EU reference scenario 2016.

We evaluated several sources on future vehicle stock, fuel consumption, and costs for vehicles, fuel stations, and energy infrastructure, including public reports, expert assumptions, and the IEA Mobility Model (MoMo). More detailed descriptions of the methodology, sources of data, and assumptions are included in Appendix I.1. This appendix also details total energy system costs for the various fuels are quite comparable, especially considering the uncertainties in technological and societal developments over the next decades.

The comparable costs for different fuel options indicate that non-cost factors will most likely determine the optimal fuel mix. These factors include the availability of an EU-wide refuelling infrastructure, the impact of the fuel type on available transport payload and volumes and the existence of specific policies, taxes, and levies that push a specific technology. Potentially there could also be limitations through the upscaling speed in resources and supply availability for the development of batteries and fuel cells. There are, however, enough raw material resources available globally and supply can be boosted by different battery designs and material recycling and re-use.[139]

In the light vehicle segment (cars and light commercial vehicles, or LCVs), and in public transportation (buses), battery, and fuel cell EVs (FCEVs) are expected to play a major role. The cost difference between battery electric and FCEVs is not very large.

In heavy-duty and long-haul transportation in trucks (medium and heavy freight trucks, or MFTs and HFTs) and long-distance bus transport, lighter or more compact fuels are required, or fuels that can be refuelled faster than with batteries. Hydrogen provides a faster refuelling time than batteries. While (bio-)CNG is an attractive option to lower the greenhouse gas intensity of transport today, no large role for bio-CNG in 2050 road transport is expected because of the better fuel performance and rapidly dropping purchase costs of FCEVs. We therefore expect that a large share of trucks cannot be electrified and will be FCEV. For a small section of long-distance heavy freight trucks, bio-LNG will be the preferred option, providing long-distance driving and fast refill, despite the higher variable costs compared to FCEV.

Markets for biomethane, hydrogen, and biodiesel are still in development, which means that future price levels are still uncertain and could be impacted heavily by the amount of policy support, attractiveness for the fuel producer and potential over- or under-supply compared to market demand. The use of pipeline infrastructure to transport gases to fuelling stations will lower societal costs compared to the delivery by trucks. There could be a role for gas transport and distribution companies to facilitate this development.

Development of overhead electricity lines to provide electrical energy to vehicles while driving (catenary lines) along the major transportation routes in Europe would increase the adoption of hybrid electric trucks, mostly HFTs and potentially also long-distance hybrid electric coaches. This shift would further increase the use of electricity and would reduce the demand for other fuels. We expect that the development of new transportation models, such as automated driving and carsharing, would improve the business case for the use of electricity in urban travel due to the low variable costs for EVs. For automated long-haul trucks and buses, hydrogen or hybrid fuel cell electric trucks using catenary lines would be more advantageous due to the shorter refuelling times than battery EVs. The full results of the allocation and societal costs calculation for road transport are provided in Section 4.4.5.

[139] However, the vulnerability of the supply markets is the main challenge especially since Europe heavily depends on importing raw materials mostly from third countries. European Commission, *Critical Raw Materials* (2017) & *Report on Raw Materials for Battery Applications* (2018), Agora, *Ensuring a Sustainable Supply of Raw Materials for Electric Vehicles A Synthesis Paper on Raw Material Needs for Batteries and Fuel Cells* (2017).

4.4.3 Shipping

In April 2018, the International Maritime Organization (IMO) set a target to halve total greenhouse gas emissions of the global shipping sector in 2050 compared to 2008 and outlined a vision to fully decarbonise shipping between 2050 and 2100.[140] We assume full decarbonisation of EU shipping in 2050, meaning ships fuelling in the EU by 2050. Current energy demand of EU shipping is 639 TWh, including inbound-EU shipping. Energy demand for domestic, intra-EU, and outbound EU shipping is 433 TWh.[141] Depending on the fuel mix we estimate an energy demand for EU shipping in 2050 between 439 TWh and 588 TWh, assuming 100% electrification of domestic shipping. The difference results from the fuel efficiency for intra-EU and outbound EU.

We build upon data from Transport and Environment (T&E) regarding energy demand in 2050 for domestic, intra-EU and outbound EU shipping. Our assumptions on fuel costs, fuel stations, and infrastructure are used estimate the most cost-optimal net-zero emissions energy mix in 2050.[142] Due to the large variety of vessels calling at EU ports, a simple cost assumption for vessels with different fuels and engines is out of scope.

To identify the most cost-optimal fuel, comparable fuel costs are calculated. Comparable fuel costs are calculated as the sum of fuel cost, infrastructure and distribution costs, as well as fuelling infrastructure costs, divided by the efficiency of the fuel.

Battery electric ships are almost twice more efficient than ships with an internal combustion engine (ICE): hydrogen fuel cells have a 30% higher efficiency and bio-LNG ships are around 13% less efficient. As biodiesel can be used in a conventional marine ICE, so its use does not lead to efficiency gains or losses. We use the efficiency as a ratio to ICEs as provided by T&E but adjusted the efficiency of fuel cells from 50% to 60% and add the efficiency for LNG respectively bio-LNG.

> Due to its high efficiency, electricity is the cheapest shipping fuel, but its use is limited to short routes due to the low energy density of batteries

Due to its high efficiency, electricity is the most cost-optimal shipping fuel, but its use is limited to short routes due to low energy density of batteries. Following the assumption from T&E, it is therefore estimated that it is only possible to 100% electrify domestic shipping, characterised by smaller ships and shorter routes, for example ferries with regular schedule and time for charging while embarking or debarking. 50% of intra-EU shipping has similar characteristics as domestic shipping and can also be fully electrified.

Several European states are testing battery electric ships for domestic shipping. For example, the Norwegian ferry sector will operate 60 battery electric ships in the next few years.[143] There have been several tests for hydrogen fuel cell ships, but no commercial application yet. Aside from small ferries and demonstration projects there are hardly any commercial hydrogen-fuelled ships. In 2017, Swedish Viking Cruises announced plans to build the first hydrogen-fuelled cruise ship.[144]

[140] The International Maritime Organisation (IMO) is a specialised agency of the United Nations for regulating shipping.

[141] Transport & Environment, Roadmap to decarbonising European shipping, 2018.

[142] Cost of fuels are not covered in the Transport & Environment roadmap for EU shipping. As our assessment is guided by the most cost-optimal net zero emission fuel, our conclusion is different from Transport & Environment.

[143] DNV GL (2018). Maritime forecast

[144] The Maritime Executive (2017). Worlds First Hydrogen-Powered Cruise Ship Scheduled. https://www.maritime-executive.com/article/worlds-first-hydrogen-powered-cruise-ship-scheduled

In addition to the cost aspect the current technological advantages of electric ships over hydrogen ships and the limited availability of biomass, there are further arguments to strive for electrifying shipping where possible.

International shipping on long-distance routes, often without regular schedules, requires a uniform fuelling option with a fuel that is globally available in sufficient quantities. Deploying multiple fuelling options would be costly from a vessel technology perspective and from an infrastructure perspective. As fuel cost is the main driver, it is expected one dominant fuel for outbound-EU shipping in 2050. The fuel choice for international shipping will also impact the fuel choice for intra-EU shipping, as international shipping will drive the fuelling infrastructure.

For long-distance routes, bio-LNG is the most competitive low-carbon fuel in 2050, despite its lower efficiency compared to biodiesel. Following the implementation of the Alternative Fuel Infrastructure Directive, LNG will be available in all EU TEN-T core ports[145] by 2025,[146] so no additional investments is needed in fuel stations and infrastructure for bio-LNG which enables a smooth transition from LNG to bio-LNG. This is especially relevant considering the long lifetimes of ships. This contrasts with hydrogen for which fuel stations and infrastructure would have to be deployed. ICE ships running on marine diesel can easily be adjusted for using biodiesel and the existing fuelling infrastructure can be reused, so the investments costs for ships and infrastructure will be limited for advanced biodiesel. However, biodiesel at 79 €/MWh is more expensive than bio-LNG.

> Bio-LNG is the most cost optimal 2050 shipping fuel for long distance transport

Shore side electricity enables ships to switch off the auxiliary engines at berth and therefore reduces the overall fuel demand for EU shipping. In a previous study however, Ecofys, now a part of Navigant, estimated that shore side electricity for all seagoing and domestic ships in European harbours in 2020 is only around 3.5 TWh annually.[147]

The full results of the fuel allocation and societal cost analysis for shipping are given in Section 4.4.5.

4.4.4 Aviation

In 2015, energy demand for intra-EU and outbound flights was 620 TWh. With increased consumer affluence, the sector continues to see strong demand growth. The EU-28 baseline scenario[148] expects almost a doubling of passenger kilometres in 2050 compared to 2015. To meet aviation's resulting energy demand in a sustainable way is challenging. With stringent requirements on gravimetric energy density and safety, no deployment of non-kerosene fuel types, such as all-electric or direct applications of hydrogen, are expected in the near future for long-haul flights. In contrast to passenger cars, where several technologies (e.g., hydrogen, electrification, biogas) can compete at the same time, aviation requires one fuel that is available at all airports. Keeping different technologies in parallel would require investing in and facilitating multiple aircraft and refuelling infrastructure types, which is cost-prohibitive. All-electric aircraft are at an early development stage and still constrained by their limited range.

---

[145] The overview of ports in the Trans-European Transportation Network (TEN-T) is available here: http://ec.europa.eu/transport/infrastructure/tentec/tentec-portal/site/en/maps.html

[146] CE Delft, TNO (2017). Study on the completion of an EU Framework on LNG-fueled ships and its relevant provision infrastructure, Lot 3 Analysis of the LNG market development in the EU.

[147] Ecofys (2015). Potential for shore side electricity in Europe.

[148] EC (2016). EU reference scenario 2016.

Because of this and the relatively slow replacement rate of aircrafts in the EU in general, commercially available long-haul all-electric aircraft are not expected at scale before 2050.[149]

Full decarbonisation of aviation is possible, requiring demand curtailment and use of expensive synthetic kerosene and biokerosene

Against this background, fully decarbonising aviation by 2050 is ambitious. The current focus in aviation is on carbon offsetting.[150] The International Air Transport Association (IATA) has a climate target to cut net aviation CO_2 emissions by half by 2050, relative to 2005 levels.[151] A recent analysis by T&E[152] curtails demand in 2050 compared to its business-as-usual (BAU) projection for that same year through a modest modal shift to High-Speed Rail (HSR) for short-haul intra-EU flight and increased ticket prices (caused by higher fuel prices). It further relies on several efficiency measures to reduce energy demand: 829 TWh in a BAU scenario in 2050 to 534 TWh by 2050 for EU outbound and intra-EU air transport (see Figure 29).

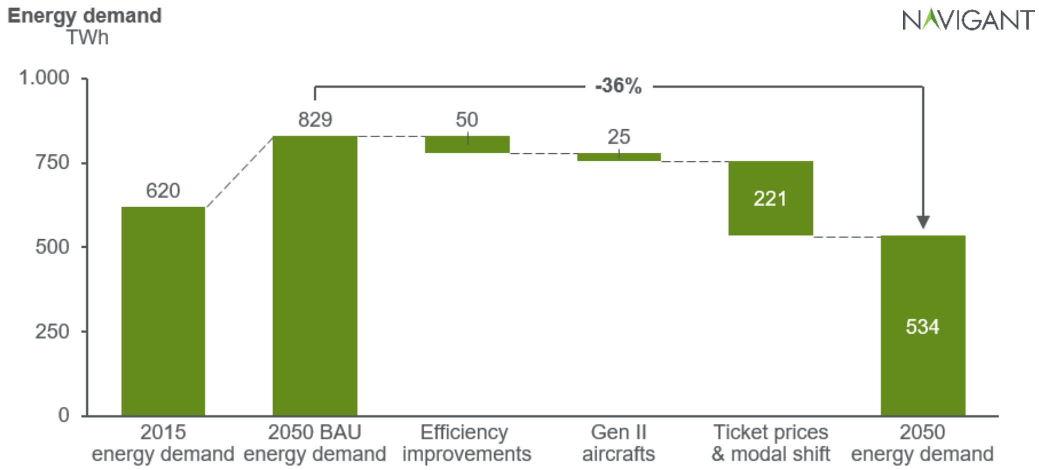

Figure 29 Energy demand and saving options in the aviation sector in TWh. Adopted from Transport & Environment.

Navigant relies heavily on the T&E roadmap, as there are few other scenarios to fully decarbonise European aviation that exist today. Limiting energy demand growth is key to all low-carbon scenarios, but approaches differ slightly. IEA's B2DS[153] scenario assumes 10% growth in of passenger kilometres. The T&E roadmap assumes and 88% in its BAU scenario.

Numerous efficiency measures can still take place between 2019 and 2050. Lightweight materials, electric assistance on the ground, improving air traffic management, and increasing load levels could reduce energy demand by 6%. A new generation of aircraft (Gen II), such as a blended wing body aircraft, could deliver further demand reduction mid-century. If older generation aircrafts are retired before the end of their EU working life this could be achieved sooner. T&E expects additional efficiency measures on new generations of aircrafts to reduce energy demand by another 3%.

[149] Roland Berger, Aircraft electrical propulsion, September 2017 provides a good sense of what these developments might ultimately deliver – and where we are today.

[150] See for example the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA).

[151] https://www.iata.org/policy/environment/Pages/climate-change.aspx, retrieved December 2018.

[152] T&E (2018). Roadmap to decarbonizing European Aviation.

[153] IEA ETP (2017). MoMo

International aviation requires one fuel available at airports worldwide. The remaining energy demand is assumed to be based on Sustainable Aviation Fuels (SAF) only.[154] We define SAF here as renewable kerosene, which mainly comes from two sources: electricity-based synthetic fuels and biofuels. Despite numerous production routes, they are interchangeable "drop-in" fuels as indicated in Figure 30. We assume that these fuels are produced in equal quantities; the sector will take a leading role in developing synthetic fuels, but biofuels are expected to remain more cost competitive towards 2050.

Biofuels make up 267 TWh of fuel supply by 2050, from various forms of biomass. Synthetic fuels, based partly on hydrogen, make up 381 TWh of hydrogen. The full results of the allocation and societal costs calculation for aviation are provided in Section 4.4.5 on the value of renewable and low-carbon gas in transport.

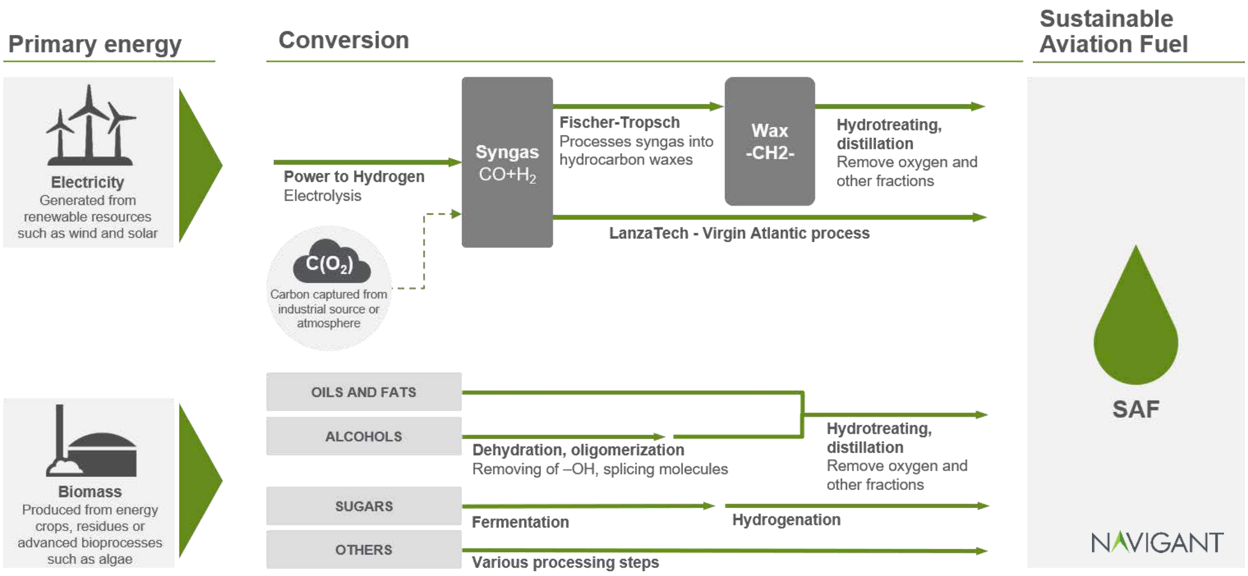

Figure 30 Sustainable aviation fuels can be produced from electricity or bioenergy through numerous different production pathways

There are numerous pathways to producing bio-kerosene.[155] We select biofuels that are not in competition with the production of biomethane as the mostly come from waste and residual oils and short-rotation plantation wood cultivated on abandoned agricultural land.[156] In this projection, synthetic fuels are more expensive than conventional kerosene, ranging from 1,056–1,299 €/t based on our range of hydrogen costs compared to around 600 €/t by 2050 for conventional kerosene as projected by T&E. The higher price for synthetic fuels than conventional fuels increases ticket price and therefore lowers demand. T&E accounts for the price-elasticity effect to reduce final energy demand growth, which Navigant adopted for its analysis and is illustrated in Figure 29. In the analysis, Navigant assumes a smaller share of the expensive synthetic kerosene compared to T&E (50% compared to 85%). This may impact the energy demand in the sector through increased demand for aviation, as ticket prices will generally be lower than assumed by T&E.

[154] The sector already started using SAF. Between 2008-2015 more than 2000 commercial flights with SAF blends have taken place. In January 2016 Oslo Airport become the first airport that integrated biojet fuel in its regular supply. Lufthansa, KLM and SAS have committed to purchase biojet fuels at Oslo.

[155] See for instance http://skynrg.com/technology-section/ for an overview.

[156] See Appendix D for a detailed description of biofuel origins.

Meeting aviation energy demand by biofuels and synthetic fuels as projected here is by no means an end-state for the sector. Ultimately, full-electric or liquid hydrogen fuelled[157] aircraft may play a significant role in the longer-term future of aviation. However, despite ground-breaking developments, major hurdles for this technology are still in place today. In the high-level analysis Navigant does not foresee a significant role for full-electric aircraft towards 2050.

Box 7 There are non-CO_2 warming effects of air travel that are not accounted for in this analysis [158]
Besides the direct climate impact of emitting CO_2 by burning jet fuel, air travel has additional effects on global warming amongst others by the formation of contrails, ozone and aerosols. These effects are believed to be significant and reported to be potentially twice the effect of CO_2 alone. More precise scientific efforts to quantify these effects are ongoing. Switching to climate-neutral fuels will not address all of these non-CO_2 warming effects.

4.4.5 Value of renewable and low-carbon gas in the transport sector

Navigant analysed the potential role of renewable and low-carbon gas in the transport sector as part of the overarching allocation and societal cost savings calculation (described in detail in Chapter 3). In case gas fuels are not available, as in the “minimal gas” scenario different fuels are allocated to the various transport modes. This section describes the results of the allocation of fuels and the impact of the “minimal gas” and the “optimised gas” scenarios on energy demand in transport.

Road transport
In both the “optimised gas” and the “minimal gas” scenarios, electrification of road transport is the key decarbonisation measure. Next that, hydrogen (freight trucks) is the most important energy carrier in the 2050 “optimised gas” scenario. When these carriers are not available, energy demand will be electrified further, or be covered by advanced biodiesel, which is available in a limited quantity. While (bio-)CNG is an attractive option to lower the greenhouse gas intensity of transport today, no large role for bio-CNG in 2050 road transport is expected.

Societal costs for various fuel options in vehicles are comparable, which means that non-cost factors will most likely determine the optimal fuel mix. These factors include the availability of an EU-wide refuelling infrastructure, the impact of the fuel type on available transport payload, and volumes and the existence of specific policies, taxes, and levies that push a specific technology.

Based on the analysis Navigant expects the energy demand in road transport to be around 1,000 TWh in 2050, or close to half of total energy demand in transport. Large-scale adoption of electric drivetrains in 2050 reduces energy demand by roughly 50% compared to a situation in which only conventional drivetrains are used.

The deployment of renewable and low-carbon gas technologies lead to a hydrogen demand of 252 TWh, a bio-LNG demand of 134 TWh and an electricity demand of 648 TWh in 2050. In the “minimal gas” scenario, the technologies based on hydrogen are limited, resulting in the use of advanced biodiesel and an even larger share of electricity. As a result, electricity demand in the “minimal gas” scenario is 729 TWh and the demand for advanced biodiesel is 312 TWh.

---

[157] Liquid hydrogen may be a promising future aviation fuel, as described in Hermans, J. (2017). The challenge of energy-efficient transportation. MRS Energy & Sustainability, 4, E1. doi:10.1557/mre.2017.2 see: https://www.cambridge.org/core/journals/mrs-energy-and-sustainability/article/challenge-of-energyefficient-transportation/497CEECAC514E4B5BA10074A59F4B30B/core-reader

[158] https://www.nature.com/articles/s41467-018-04068-0, https://www.ipcc.ch/site/assets/uploads/2018/05/ar4_wg1_full_report-1.pdf (IPCC, 2007: Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change).

Shipping
In the “optimised gas” scenario, electrification (where possible) and the use of bio-LNG are the most important decarbonisation options for shipping from an overall energy system perspective (Table 10). The deployment of these technologies lead to a bio-LNG demand of 461 TWh and an electricity demand of 124 TWh. In the “minimal gas” scenario, renewable and low-carbon gas are limited, resulting in a demand for advanced biodiesel to replace bio-LNG. As a result, demand for advanced biodiesel in the “minimal gas” scenario is 406 TWh.

Aviation
Through efficiency measures and demand growth reduction, energy demand for aviation is expected to be around 534 TWh of SAF by 2050. Both in the “optimised gas” scenario and in the “minimal gas” scenario, this demand will be met by 267 TWh of bio jet fuel and 267 TWh of synthetic jet fuels based on hydrogen from electrolysis.

Table 10 Technology deployment in the transport sector (%)

Sector	Technology	“Optimised gas”	“Minimal gas”
Passenger cars	BEV	95%	100%
	FCEV	5%	0%
Light commercial vehicles	BEV	90%	100%
	FCEV	10%	0%
Freight trucks	BEV	30%	50%
	FCEV	50%	0%
	Bio-LNG	20%	0%
	Advanced biodiesel	0%	50%
Buses	BEV	75%	87.5%
	FCEV	25%	0%
	Advanced biodiesel	0%	12.5%
Aviation	Synthetic kerosene	50%	50%
	Biojet fuel	50%	50%
Shipping | Domestic	Electricity	100%	100%
Shipping | Intra EU	Electricity	50%	50%
	Bio-LNG	50%	0%
	Advanced biodiesel	0%	50%
Shipping | Outbound EU	Bio-LNG	100%	0%
	Advanced biodiesel	0%	100%

Table 11 Energy demand in the transport sector (TWh)

Energy carrier	“Optimised gas”	“Minimal gas”
Bio-LNG	595	0
Hydrogen	252	0
Electricity	772	853
Biofuel	267	985
Synthetic kerosene	267	267
Total	**2,172**	**2,105**

Looking at all transport modes, the “optimised gas” scenario has comparable costs to the “minimal gas scenario”, except for transportation in which advanced biodiesel is used in the “minimal gas” scenario, as can be seen in Table 12 for freight trucks. This is due to the availability of hydrogen as a fuel, which drives down costs for freight trucks.

For passenger cars, the lower energy costs are predominantly resulting from the reduction in in electricity costs because of the ability to use gas in the power sector as dispatchable power. For shipping, the availability of bio-LNG results in cost reductions compared to the use of advanced biodiesel in the “minimal gas” scenario. In the other transport modes, cost differences are limited, which also explains the resulting small relative cost savings. A limited role for hydrogen and bio-LNG in transport would lead to a steep increase in biofuel demand, for which the potential in the EU is limited.

> Using gas in transport saves some costs compared to a minimal role for gas. Not using gas requires larger volumes of biodiesel

Table 12 Potential savings through renewable and low-carbon gas in the transport sector (€ billion)

Sector	Cost Category	“Optimised gas”	“Minimal gas”	Savings
Passenger cars	Technology costs	779	776	-3
Passenger cars	Energy costs	36	44	9
Light commercial vehicles	Technology costs	90	89	0
Light commercial vehicles	Energy costs	5	6	1
Freight trucks	Technology costs	71	62	-9
Freight trucks	Energy costs	23	34	11
Buses	Technology costs	58	57	0
Buses	Energy costs	4	5	2
Aviation	Technology costs	0	0	0
Aviation	Energy costs	45	45	0
Shipping Domestic	Technology costs	1	1	0
Shipping Domestic	Energy costs	4	5	1
Shipping Intra EU	Technology costs	1	1	0
Shipping Intra EU	Energy costs	14	16	2
Shipping Outbound EU	Technology costs	0	0	0
Shipping Outbound EU	Energy costs	23	24	2
Total cost savings				**14**

Box 8 Comparison with other scenarios: Transport

The *electrification rate* (final electricity demand divided by final energy demand) for passenger cars, freight trucks, and busses in the Navigant and Eurelectric scenarios are comparable. However, because of the broad scope for the shipping and aviation sectors (all fuel bunkered in the EU) as included in the Navigant scenarios, Navigant has a considerable share of bio-LNG, advanced biofuels, biojet, or synthetic kerosene for both sectors. This results in an overall direct electrification rate of 34–41%, while this ranges 29–63% in the Eurelectric scenarios. The exact scope of shipping and aviation in the Eurelectric scenarios is not completely clear, so direct comparison of these numbers is not possible.

In the 1.5TECH scenario by the EC, electricity is the dominant energy carrier (>80% share) in passenger cars and light commercial vehicles. Navigant has similar expectations in both of its scenarios. The fuel mix for heavy duty vehicles is very diverse in the 1.5TECH scenario (ICE diesel, ICE gaseous, hybrid, electric, fuel cell). In both of its scenarios, Navigant expects steeper decarbonisation in the road transport sector, resulting in a much larger role for electricity and hydrogen for heavy duty vehicles. For busses, we see similar trends, with strong electrification (79–88%) in the 1.5TECH scenario and some role for hydrogen as well as gas-fuelled and liquid-fuelled vehicles. In the various scenarios presented by the EC for shipping, fossil fuels still play a significant role, especially in global international shipping. Nevertheless, there is also a significant increase in demand for liquid biofuels, synthetic methane, e-liquids, and hydrogen. In its scenario, Navigant sees a steep increase in bio-LNG in the “optimised gas” scenario and liquid biofuels in the “minimal gas” scenario. For aviation the 1.5TECH scenario shows still a substantial role for fossil jet fuels (about 35%) the remainder being a mix of synthetic kerosene (about 30%), bio jet fuel (about 25%), and electricity to a very limited extend. In its scenarios Navigant assumes that synthetic kerosene and bio jet fuel cover the full kerosene demand in equal shares.

5. Approach to decarbonise the EU power sector

KEY TAKEAWAYS

- In a decarbonised energy system without renewable gas, residual demand is met by large-scale power storage, natural gas- or coal-fired power plants with CCS, and biomass plants.
- With renewable and low-carbon gas, efficient gas-fired power plants can be used to provide backup capacity in combination with storage of renewable and low-carbon gas. Existing gas infrastructure is better used and less investment in replacement electricity infrastructure.

5.1 Introduction

In both the “optimised gas” and “minimal gas” scenarios, electrification of the energy system will play an important role in achieving a net-zero emissions EU energy system. The electrification of the energy system requires a significant increase in the production of electricity. At the same time, all production of electricity must be decarbonised. This implies fundamental changes in the power system. This section briefly describes electricity production in a decarbonised EU energy system, followed by the assessment of the value of renewable and low-carbon gas.

> Wind and solar will dominate EU power production by 2050, requiring flexibility from hydro, biomass power or renewable and low carbon gas

Wind and solar will be the mainstay of the EU renewable electricity production in the future. However, the intermittency of these renewable electricity generation sources requires smarter electricity grids, wide-spread introduction of flexibility measures, and higher levels of (seasonal) storage and backup capacity. Increasing electrification would also require the upgrading of electricity distribution and transmission infrastructure to meet demand increase, as well as more frequent, less predictable, and higher peaks on the demand side.

In a decarbonised energy system without renewable and low-carbon gas, residual demand must be met by large-scale power storage, pumped hydropower plants, biomass power plants.[159] Also, renewable gas and low-carbon gas can be used in efficient gas-fired power plants to provide backup capacity in combination with storage of renewable gas. The existing well-developed gas transmission and distribution infrastructures can be used efficiently in large parts of the EU and has a remaining lifetime far beyond 2050.

5.2 Power system modelling

The most advanced technologies for the expansion of renewable electricity, wind, and solar are intermittent because their production is weather dependent. Meanwhile, electricity demand also varies over time. This variability will increase with further electrification of energy demand, because heating demand peaks only in cold periods.

[159] Navigant assumes nuclear power is not an option in the long term, due to the high cost, especially when running at low capacity factors. Most of the present nuclear capacity in the EU will be out of service by 2050, and not a lot of new capacity is being built.

The difference between intermittent renewable electricity production and electricity demand is called the residual load. If intermittent electricity production is not sufficient to cover demand, additional dispatchable electricity sources will be required. As the electricity system should be efficient (supply meets most of demand on a yearly basis) and carbon neutral, renewable electricity production will often exceed the power demand and surplus electricity must be stored mechanically (pumped hydro) or chemically (batteries), converted (power-to-gas) or curtailed. Navigant analysed the future power system through the following steps:

1. **Demand profile:** Navigant constructed the electricity demand profile, consisting of a base profile as well as profiles for buildings, industry, and transport. The base profile is based on the EU demand profile for 2015,[160] extrapolated using the population growth forecast towards 2050 (7%). For the buildings, industry and transport sectors we developed sectoral profiles. For buildings, this represents the variation in hourly heating demand in buildings, also including very cold periods throughout the year. For transport, we apply modal specific charging profiles. For industry, it is full time operation is assumed, which results in a flat profile.

Box 9 Electrification in industry

Our industry analysis focuses on the production of iron and steel, ammonia and methanol, and cement and lime. In our analysis we compare various decarbonisation options for the industry, using renewable and low-carbon gas or other energy carriers. Electrification of heat using renewable electricity is an option to further decarbonise sectors where industrial processes do not require temperatures above 150°C.[161] Major industrial users are paper and pulp and the food and tobacco industry, followed by the textile, glass, and ceramic sector. Electric heat pumps, solar, or geothermal heating technologies have the biggest technical potential to provide low temperature heat, while electric boilers are good alternatives for medium temperature heat (150°C–500°C). Additionally, hybrid boiler with electricity or renewable and low carbon can provide low and medium heat.[162] To incorporate increasing electricity demand in industry in the power sector, we estimate the increase in electricity in the industrial sectors not in scope as well.

Current electricity demand in industry is 1035 TWh, from which 115 TWh is related to the production of iron & steel, 43 TWh to methanol & ammonia, and 20 TWh to cement & lime. The electricity demand in the other industry (industries other than those subsectors mentioned) is expected to increase from around 857 TWh today to about 1028 TWh, because of increased electrification of industry.[163]

2. **Variable renewable electricity supply profile:** Navigant estimated the potential capacity of onshore and offshore wind, solar PV, and hydropower. The capacity is adjusted to meet 85% of yearly electricity demand in both scenarios. [164] Both renewable power generation and electricity demand have hourly profiles for an average year in Europe.
3. **Residual load profile:** Navigant determined the residual load profile, which is the difference between the demand profile and the variable renewable electricity supply profile.

[160] The EU demand profile for 2015 was extrapolated from the demand profile for NW-Europe developed in Ecofys, 2017. Translate COP21: 2045 Outlook and implications for offshore wind in the North Seas.

[161] Parsons Brinckerhoff, WSP and DNV GL of UK: *Industrial decarbonization and energy efficiency roadmaps to 2050 – cross-sector report* (2015). https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/419912/Cross_Sector_Summary_Report.pdf (p18)

[162] McKinsey: *Decarbonization of industrial sectors: the next frontier* (2018) https://www.mckinsey.com/~/media/mckinsey/business%20functions/sustainability%20and%20resource%20productivity/our%20insights/how%20industry%20can%20move%20toward%20a%20low%20carbon%20future/decarbonization-of-industrial-sectors-the-next-frontier.a

[163] Navigant analysis based on: Eurostat. Energy balance sheets — 2016 data — 2018 edition (current electricity demand: 1035 TWh, steel electricity demand); Dechema. Low carbon energy and feedstock for the European chemical industry (own calculations for ammonia and methanol), Cembureau. The role of CEMENT in the 2050 LOW CARBON ECONOM; https://cembureau.eu/cement-101/key-facts-figures/ (cement), https://www.eula.eu/documents/competitive-and-efficient-lime-industry-cornerstone-sustainable-europe-lime-roadmap-1 (lime), https://www.energinorge.no/contentassets/bbdfe49e19f04c5c8b8b1d3cf6377d85/decarbonisation-pathways-electrificatino-part-study-results-h-ad171ccc.pdf (electrification scenario).

[164] Ecofys (2017). Translate COP21: 2045 Outlook and implications for offshore wind in the North Seas.

Before Navigant determined the dispatchable power capacity requirements to cover the residual load curve, the team assessed the role of storage (batteries) and conversion (power-to-gas) of excess electricity. The advantage of power-to-gas over batteries is that gasses are much cheaper to store than electricity. The disadvantage of power-to-gas is the lower efficiency of the power-to-gas-to-electricity cycle compared to battery storage. However, the advantage of power-to-gas over batteries is that investment costs are substantially lower.

Therefore, batteries are more suitable for short-term multi-cycle storage, whereas power-to-gas is more suitable for single- cycle long- term storage. These characteristics mean that battery storage is well-suited for intraday and intra-week storage, while gas-to-power is well-suited for seasonal storage.

> Batteries are suitable for short term storage while gas is well placed to provide decarbonised seasonal storage

4. **Batteries:** Navigant used battery storage where economically viable for short-term balancing—within the limitations of battery storage capacity. When they are fully charged (in case of long surplus of electricity) or fully discharged (in case of long shortfall of electricity), power-to-gas or gas-to-power steps in.
5. **Power-to-gas:** In the “minimal gas” scenario Navigant does not assume any power-to-gas as the required gas infrastructure would be limited. Consequently, the options for storing surplus electricity are limited as well. In addition to pumped hydro, high capacities of expensive battery storage are needed to reduce curtailment. It is not viable to use batteries for seasonal storage due to the high costs of storage. Seasonal variations in the “minimal gas” scenario should be partly supplied by expensive solid biomass backup plants.
6. **Dispatchable power:** Finally, Navigant determined supply by dispatchable power. The residual load profile is supplied with dispatchable power when demand exceeds supply or can be used for producing green hydrogen if supply exceeds demand. The electricity surplus that remains after using battery storage and green hydrogen production is curtailed as a last resort. If a residual load remains after battery storage, dispatchable generation is needed to produce this power. In periods when for several days there is little renewable supply at high demand, for instance due to low temperatures (the so-called “Dunkelflaute”), stored gas offers the necessary flexibility to guarantee security of supply.

Figure 31 provides a schematic overview of the steps described above.

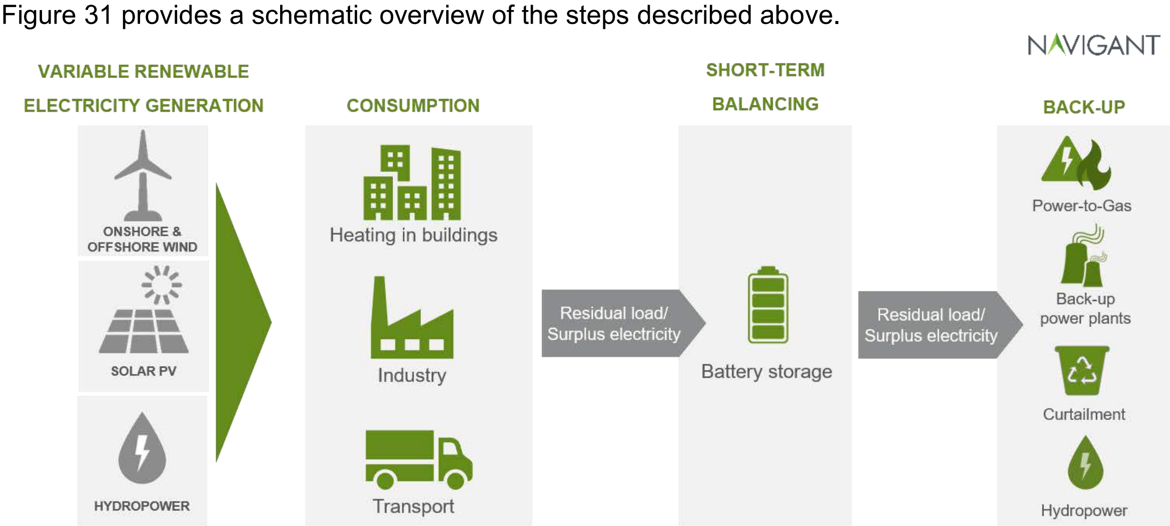

Figure 31 Schematic overview of energy production modelling

In order to estimate the costs related to meeting residual demand with dispatchable electricity generation, Navigant developed an electricity dispatch cost model. This model uses the fixed and variable generation costs to calculate the lowest cost combination of generation technologies to provide the required electricity at all times. The possible dispatchable generation technologies are biomass power plants, hydropower plants, gas power plants[165] on biomethane, as well as a gas turbine on hydrogen. It results in installed capacities per technology and their related costs for capital and operational expenditures. The technology cost assumptions are provided in Appendix J.

Figure 32 shows the outcome of the residual load profile with the various technologies that are dispatched in the "optimised gas" scenario.

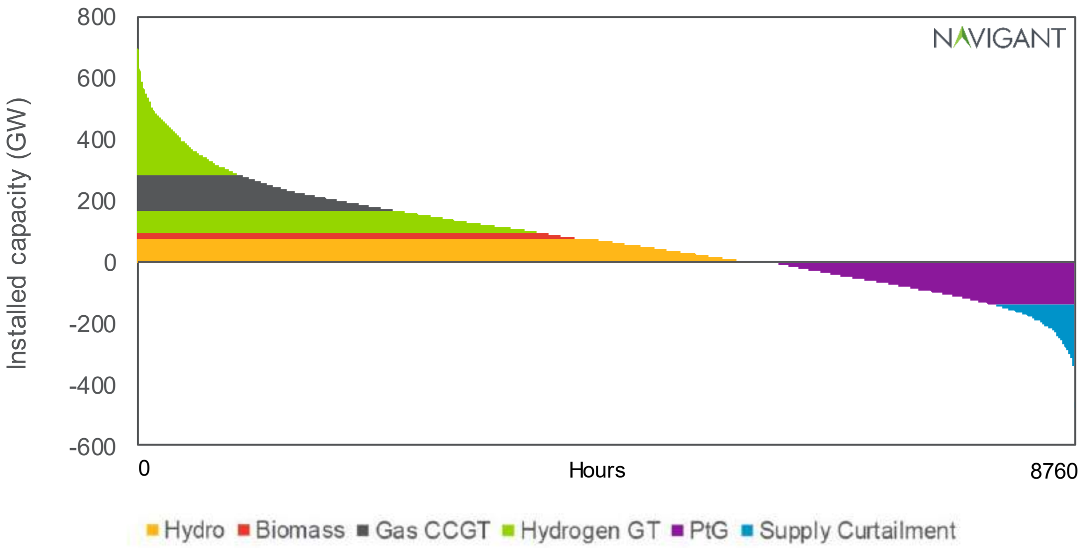

Figure 32 Example of residual load curve in scenario with renewable gas

Biomethane-fired combined cycle gas turbines (Gas CCGT) and hydrogen-fired gas turbines (Hydrogen GT) are used to provide the peak capacity. Hydropower plants and biomass plants are used as baseload plants to provide the remaining supply requirements (left side of the chart, up to 5,750 hours). When there is an electricity surplus (right side of the chart, from 5,750 hours onwards), part of the surplus capacity is used for power-to-gas to produce green hydrogen.
Curtailment takes place only with very large amounts of surplus electricity. During these hours, power-to-gas is not economical because the running hours are too low to cover the capital expenses.

5.3 Value of renewable and low-carbon gas in the power sector

The potential role of renewable and low-carbon gas in the power sector as part of the allocation and societal cost savings calculation is described in detail in Chapter 3. Both the "minimal gas" and "optimised" gas scenario show an enormous growth of electricity demand. In the "minimal gas" scenario this is because of increased electrification, in the "optimised gas" scenario this is because increased electrification, but also because of the production of green hydrogen from dedicated wind and solar power.

> Using gas to produce electricity lowers peak electricity demand, meaning that less dispatchable power generation is needed

[165] We consider both Open Cycle Gas Turbines (OCGT) and Combined Cycle Gas Turbines (CCGT) for biomethane.

To estimate the value of renewable gas in electricity production, Navigant compared the overall generation costs of the “minimal gas” and the “optimised gas” scenarios. Due to full electrification, the peak demand in the “minimal gas” scenario is higher. This increased the need for dispatchable generation. In this scenario, residual load is covered by batteries, hydropower, and solid biomass generation, increasing capital and operational expenditure related to power generation.

Figure 33 and Figure 34 provide the overall electricity generation mix. In the “optimised gas” scenario 4,820 TWh of the electricity is used for buildings, industry, and transport. 2,610 TWh is dedicated to green hydrogen production. The total electricity generation amounts to 7,430 TWh. 88% of the grid connected electricity generation and 100% of the electricity generation dedicated for hydrogen production is from variable renewable electricity options, including dispatchable hydropower plants (6,830 TWh). The remainder is provided by other dispatchable power plants (600 TWh). While covering only about 12% of the electricity supply, dispatchable power plants cover about 29% of the total installed grid connected capacity.

Total electricity demand for buildings, industry and transport in the “minimal gas” scenario is 24% higher compared to the “optimised gas” scenario. However, because of the large role of dedicated green hydrogen production in the “optimised gas” scenario, the total generation for both direct electricity and electricity for hydrogen is 16% higher.

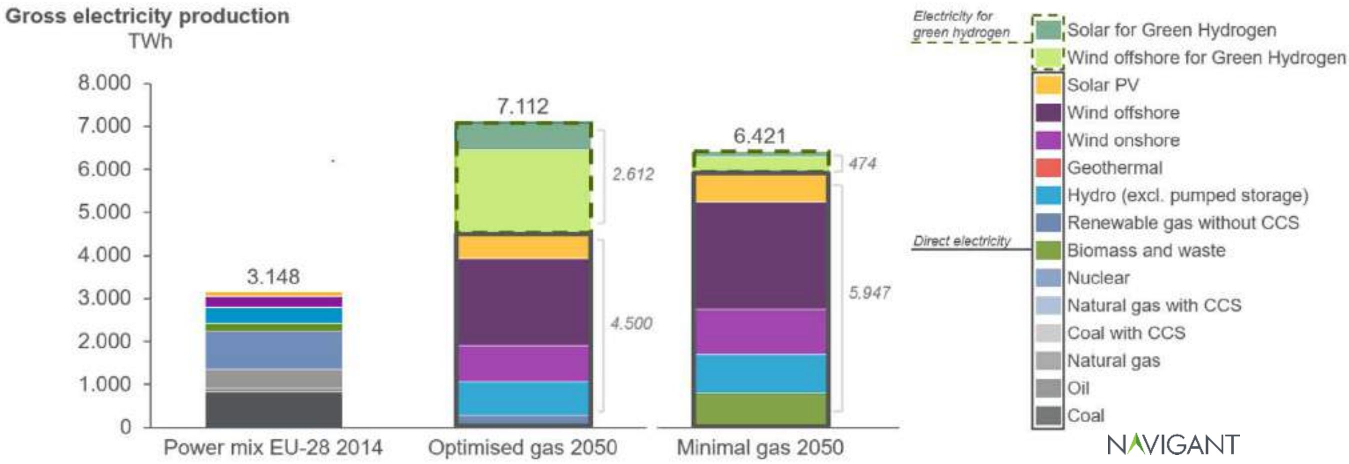

Figure 33 Gross electricity generation in both scenarios compared to EU-28 power mix in 2014

The total installed capacity of variable renewable electricity, including dispatchable hydropower, in the “optimised gas” scenario is 2,650 GW. 1,160 GW is solar PV, focussing on rooftop solar, to avoid the conversion of agricultural land to large-scale solar PV plants. The maximum EU-potential for rooftop solar is over 1,200 GW.[166] The installed capacity for wind power is 1,290 GW, from which 1,010 GW offshore. A considerable part of the installed offshore wind capacity is dedicated for green hydrogen production (49%, 500 GW). The maximum EU-potential for offshore wind up to 1,500 GW.[167]

In the “minimal gas” scenario, the installed variable renewable electricity capacities are lower because of the lower production of green hydrogen from dedicated renewable electricity.

---

[166] In the scenario developed by the Lappeenranta University of Technology and the Energy Watch Group as part of the “Global Energy System based on 100% Renewable Energy – Power Sector” the installed capacity for rooftop solar is 1,268 GW. According to the analysis on http://www.europeanenergyinnovation.eu/Articles/Spring-2018/The-Rooftop-Potential-for-PV-Systems-in-the-European-Union-to-deliver-the-Paris-Agreement the potential for rooftop solar could be up to 1,500 TWh. According to Shell this could be even substantially higher (3,448 TWh) (http://energywatchgroup.org/wp-content/uploads/2017/11/Full-Study-100-Renewable-Energy-Worldwide-Power-Sector.pdf)

[167] According to Wind Europe in their report “Unleashing Europe’s offshore wind potential, the potential for offshore wind on the North Sea, the Atlantic and the Baltic is 5,973 TWh (economic potential with LCEO below 60-65 euro/MWh), this equals about 1,500 GW (http://energywatchgroup.org/wp-content/uploads/2017/11/Full-Study-100-Renewable-Energy-Worldwide-Power-Sector.pdf)

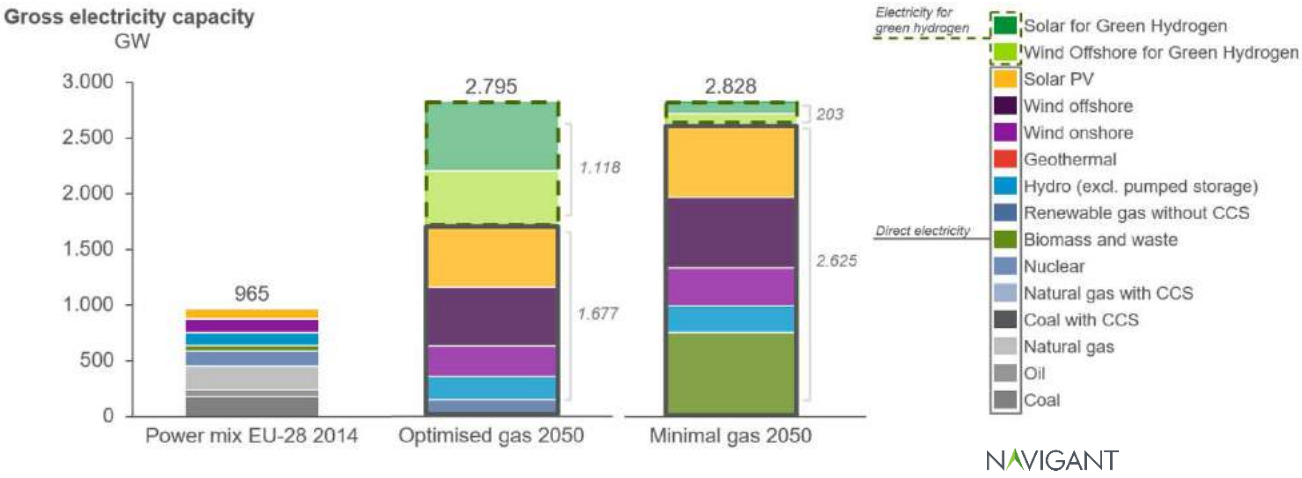

Figure 34 Gross electricity capacity in both scenarios compared to EU-28 power mix in 2014

In the “optimised gas” scenario, 322 TWh of biomethane and 786 TWh is used for gas power plants to provide dispatchable power (Table 13 and Table 14). In the “minimal gas” scenario, the technologies based on renewable and low-carbon gas are limited, resulting in the deployment of only biomass plants. As a result, biomass demand in the “minimal gas” scenario is 2,310 TWh, producing 809TWh of electricity, while renewable and low-carbon gas demand is zero. Because of the high biomass demand, the “minimal gas” scenario is more import dependent, as such amount of solid biomass is not likely to be produced within the EU. Such large supply of solid biomass would require strict criteria to mitigate possible sustainability risks including biodiversity, soil health and carbon debt.

Table 13 Dispatchable power generation deployment in the power sector (GW)

Technology	“optimised gas”	“minimal gas”
Hydro	209	241
Gas CCGT	120	0
Hydrogen OCGT	491	0
Biomass	23	747

Table 14 Energy demand for dispatchable power generation in the power sector (TWh)

Technology	“optimised gas”	“minimal gas”
Biomethane	322	0
Hydrogen	786	0
Biomass	254	2310

The “optimised gas” scenario leads to significantly lower costs (€171 billion per year, from which part is also included in the cost savings for sectors in scope, Table 15 and Table 16) compared to the “minimal gas” scenario because of the higher capital costs for solid biomass plants in the “minimal gas” scenario. The lower capital costs of gas-fired power plants make them better from a societal perspective as dispatchable power plants.

Using gas in electricity production saves €171bn euro annually in energy system costs compared to large-scale use of solid biomass power

Table 15 Potential savings through renewable and low-carbon gas in the power sector (billion € per year)*

Cost category	“Optimised gas”	“Minimal gas”	Savings
Variable renewable electricity generation costs	215	265	50
Dispatchable electricity generation costs; from which:	94	214	120
Hydro	8	8	0
Gas CCGT	26	0	-26
Hydrogen OCGT	55	0	-55
Biomass	12	207	195
Power-to-gas (benefits)	-7	0	7
Battery costs	1	1	0
Total	**310**	**481**	**171**

Table 16 Allocation of potential savings through renewable and low-carbon gas in the power sector to sectors in scope and sectors not in scope (billion € per year)*

Cost category	“Optimised gas”	“Minimal gas”	Savings
Total power system cost allocated to sectors in scope**	100	217	117
Total power system cost not allocated to sectors in scope	210	264	54
Total	**310**	**481**	**171**

** In the overall energy system cost savings provided in Chapter 7, part of the power system costs are included in the buildings, industry and transport demand sectors as part of the electricity cost in the energy costs.*
*** Costs are included as energy costs of individual sectors (buildings, transport and industry). These costs savings are thus also accounted for in individual sectors.*

Box 10 Comparison with other scenarios: Power

Total electricity generation in Navigant scenarios (6,400–7,500 TWh) is in line with the Eurelectric scenarios (about 5,000–7,000 TWh). Generation capacities are largely comparable, though in Navigant’s scenarios the share of onshore and offshore wind is slightly higher because of its extensive use for dedicated green hydrogen production. The share of solar PV is lower because of the focus on rooftop solar PV in Navigant’s scenarios. The installed capacities of dispatchable resources is slightly lower in the Navigant scenario (600–800 GW) compared to the Eurelectric scenario (1,000–1,300 GW). Installed capacities of gas power plants are higher in Navigant’s “optimised gas” scenario (600 GW) compared to the Eurelectric scenario (about 400 GW), but lower in the “minimal gas” scenario (0 GW), where about 750 GW of solid biomass plants are deployed. Because of the large role for hydrogen in the Navigant “optimised gas” scenario, electricity consumption for so-called indirect electrification is higher (about 2,600 TWh, including hydrogen for synthetic kerosene production) compared to the Eurelectric scenarios (600–1,200 TWh).

The 1.5TECH scenario by the EC shows a similar growth in electricity generation (more than doubling by 2050). In addition, installed capacities are similar to Navigant’s “minimal gas” scenario (about 2,800 GW in total). However, solar and wind is larger with up to 1,000 GW solar and slightly above 1,200 GW wind in the 1.5TECH scenario, compared to around 800 GW and 1,100 GW, respectively, in Navigant’s “minimal gas” scenarios. Because of the high hydrogen demand in the “optimised gas” scenario, installed capacities are higher. Other options than wind and solar PV cover about 600 GW in the 1.5TECH scenario, while the dispatchable power generation in our scenarios alone already covers 700–900 GW. This could partly be explained by the larger role of energy storage in the 1.5TECH scenario. While Navigant scenarios do not include nuclear power installed nuclear capacity in the 1.5TECH scenario is around 100 GW.

6. The role and value of gas infrastructure towards 2050

KEY TAKEAWAYS

- Today, EU gas infrastructure ensures the reliability and flexibility of the energy system.
- Towards 2050, flexibility becomes even more important due to increased fluctuations in supply and demand of electricity. Gas infrastructure plays an important role in enabling decarbonisation and the infrastructure will evolve as natural gas is gradually phased out and replaced by low-carbon gas and renewable gas.
- The "optimised gas" scenario results in €19 billion of lower energy infrastructure costs compared to "minimal gas." annually by 2050 due to prolonged utilisation of gas infrastructure. Much higher additional cost savings associated with "optimised gas" are achieved elsewhere in the energy system.
- Both the "minimal gas" and the "optimised gas" scenarios require high investments in electricity infrastructure, albeit lower if gas infrastructure is maintained.
- The complete or almost complete current gas transmission grid adds value when used to transmit renewable and low-carbon gas. The existing transmission grid will be used for intra-regional and cross-border transport of hydrogen and mainly intra-regional transport of renewable methane in parallel. The existing distribution grid will be used to distribute modest quantities of gas to buildings, with high net system cost savings per cubic metre of gas.

6.1 Introduction

This chapter describes the current roles of gas and electricity networks and how both infrastructures are impacted by the transition towards a net-zero emissions EU energy system by 2050. It starts by describing the current roles of the gas and electricity infrastructures. This description is followed by an analysis of how the "minimal gas" and "optimised gas" scenarios will impact the role of both infrastructures, including analysis on how existing gas infrastructure can be used to transport and distribute green and blue hydrogen, biomethane, and synthetic methane. Subsequently, the costs of using existing gas and electricity infrastructures are analysed for both scenarios, leading to a comparative assessment of infrastructure costs in both scenarios.

6.2 The role of gas grids in Europe today

Gas infrastructure plays a key role in the current EU energy system, connecting European gas production sites in Europe as well as import points on the EU borders and LNG terminal's entry points with demand centers all over Europe. Gas infrastructure is currently used to transport and distribute 20% of EU's primary energy consumption, or 5,000 TWh equalling about 470 bcm of natural gas.[168]

Gas transported through gas infrastructure provides a flexible, storable form of energy that is mainly used for the heating of building and industrial heating, gas-fired power plants, and chemicals production. Close to 30% of current natural gas is transported and distributed to end consumers from indigenous sources, the rest is imported through large gas import pipelines from Russia, Norway, north-Africa (including Algeria), and some LNG imports from the rest of the world.[169] The grids foster security of supply and diversification of energy sources.

[168] Eurostat, Natural gas supply statistics, gross inland consumption of natural gas in 2017.

[169] BEIS, Physical gas flows across Europe and diversity of gas supply in 2016, page 79-80 (2018)

Long-distance gas transport takes place through large diameter transmission lines operated at “high pressure” (from 40 up to 100 bar, differing per country). This network is used to import gas from outside the EU and to interconnect EU Member States national gas networks. “Medium pressure” pipelines (between 8 and 40 bar) are used to distribute gas to a dense network of “low-pressure” distribution grids (up to 16 bar) which delivers gas to end consumers.[170] The transmission network consists of about 260,000 km of high-pressure transmission pipelines[171], most of which are operated by around 450 transmission system operators (TSOs). This network is shown in Figure 35 below. Many transmission lines consist of multiple, parallel pipelines to provide enough transmission capacity when required. The much more refined network of medium and low-pressure networks consists of about 1.4 million km of pipelines[172], operated mainly by distribution system operators (DSOs). The operation of the medium pressure pipelines varies between countries and regions and can be done by either TSOs or DSOs.

> The EU gas grid consists of 270,000km of high pressure pipelines operated by about 50 transmission system operators plus about 1.4 million kilometres of gas distribution grids

Gas storage is required to ensure security of energy supply and enable the system to deal with significant variations in gas demand between summer and winter. Also, storage is needed to provide flexibility to react on short-term variations in demand. Regional gas storages are available, mostly connected to high and/or medium pressure transmission systems. In some regions (small) gas storages are directly linked to the low-pressure grid.

[170] What low, medium and high mean varies depending on the country

[171] Austria: 2900km, Belgium: 4100km, Bulgaria: 2645km, Czech Republic: 3810km, Denmark: 860km, Estonia: 880, Finland: 1187km, France: 38,000km, Germany: 117,000km of which 46,000 managed by TSOs, Greece: 1218km, Hungary: 5784km, Ireland: 2149km, Italy: 23,947km, Latvia: 1239km, Lithuania: 1900km, Luxembourg: 410km, Netherlands: 12,000km, Poland: 10,600km, Portugal: 1300km, Romania: 13,336km, Slovakia: 2270km, Slovenia: 1054km, Spain: 13,000km, Sweden: 620km, United Kingdom: 7600km. Based on based on DNV KEMA, Country Factsheets. Entry-Exit Regimes in Gas (2013), see: https://ec.europa.eu/energy/sites/ener/files/documents/201307-entry-exit-regimes-in-gas-parta-appendix.pdf. Where possible, numbers have been cross checked with network length numbers as stated on the Green Gas Grids website: http://www.greengasgrids.eu/index.html. Data for Croatia, Malta and Cyprus are not available.

[172] Austria: 39,500km, Estonia: 2035km, France: 195,000km, Germany: 319,000km, Greece: 3800km, Italy: 271,935km, Latvia: 4800km, Netherlands: 123,000km, Slovakia: 33,000km, Spain: 74,000km, Sweden: 2700km. Numbers based on DNV KEMA, Country Factsheets. Entry-Exit Regimes in Gas (2013). In total the 11 Member States listed here have a combined low and medium pressure gas grids of 1,054,770km. No numbers are available for other EU Member States. Navigant extrapolated this number to the entire EU to derive a total estimate of 1.4mln km.

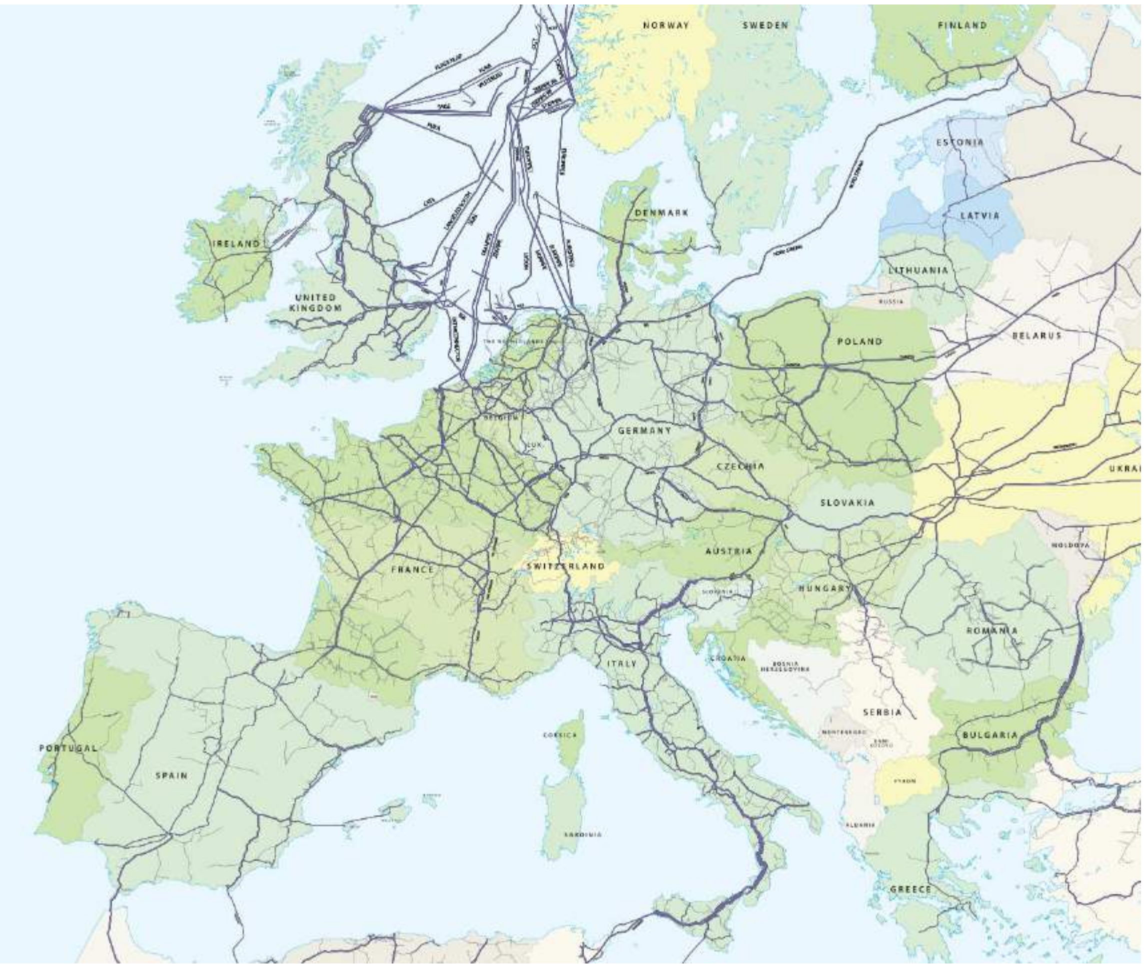

Figure 35 Natural gas transmission networks in Europe[173]

Compressor stations ensure that the required pressure in gas grids is maintained. Typically, the EU gas transmission network requires one compressor station per 200 km of pipeline. Import pipelines transport gas over long distances at a high pressure of 100 to 200 bar. These pipelines can require a compressor station per 100 km. Import pipelines constitute a small share of the total EU gas transmission infrastructure. In some cases, like for subsea pipelines, compressor stations are not available. These pipelines are operated at a high inlet pressure of up to 220 bar.[174]

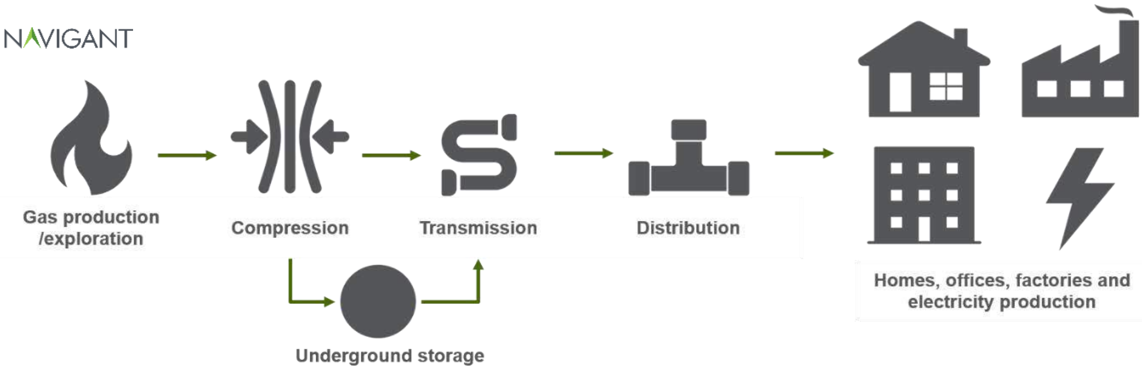

Figure 36 Structure of the gas infrastructure

[173] ENTSOG, see https://transparency.entsog.eu/

[174] The Nordstream pipeline has an inlet pressure of 220 bar, see http://www.gazprom.com/projects/nord-stream/

Gas network offers flexibility and can deal with widely differing volumes of gas

Most natural gas today is used to produce industrial heat, to heat buildings and to produce flexible electricity in gas-fired power plants. Demand for energy fluctuates strongly from year to year, season to season, and over a single day. The gas transport system, with large and flexible pipeline and gas compression capacities and underground gas storage sites and regasification plants across the European grid, can cope with these fluctuations. The gas grid can deal with low overall transported volumes which today occur during summer time.

No minimum technical threshold exists below which the gas network can no longer be operated and reduced gas volumes could require less compressor energy consumption.

> Existing gas grids can deal with lower quantities of gas in the future

6.3 Gas supply and demand in "minimal" and "optimised gas" scenarios

Chapters 2 and 4 of this study show that significant supply and demand for renewable and low-carbon gas is likely to exist in the EU by 2050. Gas infrastructure is of vital importance to connecting gas supply and demand and thereby facilitating large energy system cost savings, as further detailed below and in Chapter 6.6. This section briefly recaps the main conclusions on gas supply and demand by 2050 and subsequently describes how this will impact the role of existing gas infrastructure.

The "optimised gas" scenario assumes, like the "minimal gas" scenario, a substantial increase in the direct use of electricity in the energy system. Electricity production more than doubles compared to today in both scenarios and renewable electricity generation increases more than ten-fold. This requires substantial investments in additional electricity infrastructure.

The "minimal gas" scenario includes a quantity of 69 TWh of biomethane (6.5 bcm of natural gas equivalent in energy content) to provide high temperature industrial heat and feedstock. No gas is used in electricity production, heating of buildings, and transport.

The "optimised gas" scenario foresees that 1710 TWh of green and blue hydrogen and 1170 TWh of renewable methane will be used in all economic sectors. This equals a quantity of 272 bcm of natural gas equivalent (energy content), or about 60% of today's EU natural gas consumption.[175] In Chapter 4, Navigant concludes that biomethane will be used mostly for electricity production and the heating of existing buildings that already have a gas connection. Bio-LNG is used in international shipping and heavy road transport, while hydrogen is mainly used in heavy industry and as fuel in road transport. A small quantity of renewable methane is used in industry as feedstock for e.g., methanol production. Using this gas through existing gas infrastructure will, as described in Section 6.6 and Chapter 7, result in significant net energy system cost savings compared to the "minimal gas" scenario.

[175] On a per energy unit basis, volumes of hydrogen are much higher compared to natural gas. Hydrogen also flows faster through gas pipelines than methane. The net effect of these two elements is that transporting hydrogen through gas infrastructure requires 20% more capacity compared to natural gas. This means that the quantity of 1710TWh of hydrogen requires a pipeline capacity equal to 194 bcm (161 bcm of hydrogen in bcm natural gas energy content plus 20%). In addition, out of 110 bcm biomethane and power to methane, 91bcm is pipeline transported, the remainder being truck-transported. This means that by 2050 a total gas grid capacity is required for a volume of 285 bcm in the "optimised gas" scenario, equalling 60% of today's natural gas volume.

6.4 Future role of gas grids

In both scenarios quantities of gas transported in 2050 decrease compared to current volumes. The "minimal gas" scenario phases out gas demand in the EU energy system except for some biomethane used in heavy industry. This requires some biomethane to be transported to industrial sites in transmission pipelines. Yet given the limited scale of this gas demand, most of the existing gas transmission infrastructure and the entire gas distribution infrastructure would no longer be used and may therefore be decommissioned. This results in decommissioning costs as quantified in Section 6.6.

In the "optimised gas" scenario existing gas infrastructure by 2050 is used to transport and distribute renewable methane, green hydrogen plus remaining blue hydrogen with a 40/60 methane versus hydrogen ratio.

In general, the current gas grid will have enough capacity to transport and distribute the required volumes of gas in 2050, with exception to specific local situations in which gas grids need to be expanded because of increased local economic activity Keeping this general perspective in mind, the way renewable methane and hydrogen are expected to be transported and distributed through gas infrastructure is discussed below.

Biomethane and power to methane is produced throughout the EU, yet mainly in Member States with high potentials of woody and agricultural biomass (e.g., Germany, France, Poland, Italy, Sweden, Finland, Romania). Biomethane is used in all sectors with the highest energy cost saving per cubic metres being achieved in the heating of buildings. Only a small quantity of biomethane is required to satisfy demand in buildings with existing gas grid connection using hybrid heat pumps. Navigant expects that each EU Member State can produce sufficient biomethane to meet demand in buildings. This means that distribution grids will be used for biomethane, regional transport pipes are required to transport biomethane supply in the agricultural regions to the cities. Some transport capacity is also required to connect the grids to seasonal storage locations and to other countries. Existing distribution grids will predominantly distribute biomethane. However, in some cases there will be the conversion of (part of) the existing distribution grid to hydrogen distribution because of regional availability or demand

> Renewable methane and hydrogen can best be transported non-blended through pipelines. It is possible to create separate parallel networks based on existing gas infrastructure with limited need for additional dedicated hydrogen pipelines

Hydrogen transport is most cost-effective through pipelines as it avoids the need for high-pressure compression or liquefaction to allow transport by truck, rail, or ship. This is further discussed in Section 6.6. Modifying existing gas pipelines is expected to be cheaper due to the higher land opportunity costs, permitting and regulation, and pipeline construction costs for new pipelines. It also provides a second life to existing assets, which prevents possible decommissioning costs. In some cases, additional pipelines will need to be constructed to connect transmission infrastructures or to make dedicated connections to hydrogen supply and demand centers.

As current transport grids often consist of parallel pipelines, the "optimised gas" scenario assumes that part of existing pipelines can be used for renewable methane and part for hydrogen transmission.

Whether existing natural gas **transmission** infrastructure can be repurposed to carry 100% hydrogen depends on the type of steel and pipeline pressure. Research in the Netherlands by TSO Gasunie showed that long-distance networks could be repurposed to create a "backbone for a hydrogen transmission system."[176] Most of the refurbishment costs are for replacement of compressor stations, valves, and metering stations. These costs vary from location to location depending on the current gas grid characteristics and on the landscape (urban versus non urban).

Typically, carbon steel pipelines could carry hydrogen without suffering from hydrogen embrittlement or hydrogen stress cracking, provided current pressure levels are not significantly increased. For the different pressure levels, each steel grade needs to be tested thoroughly before a definitive statement of its suitability can be made. Alternatively, fiber-reinforced polymer pipelines are applicable for hydrogen transport, yet these are currently only available in smaller diameters (6"), compared to much bigger steel pipelines (56").

Studies from the UK[177] and Netherlands[178] indicate that it is technically possible to re-use existing natural gas **distribution** networks for hydrogen; however, the costs and effort will be regionally dependent. The logistics of converting the existing natural gas distribution network are well documented in the proposal for the City of Leeds in the H21 report.[179] Navigant expects that having two completely parallel distribution grids will not be feasible given the higher development and maintenance costs of parallel infrastructures compared to a single grid. Most hydrogen distribution grids will likely be less dense than the methane distribution grids and have more of an ad hoc character, connecting specific users to a backbone; for instance, users in industrial areas or hydrogen fuel stations along major routes.

Blending hydrogen with (bio)methane

Hydrogen can be blended with biomethane (or natural gas) in the existing infrastructure. However, Navigant does not expect blended hydrogen-methane transport and distribution to have substantial roles in 2050 because of technical and economic difficulties.

With supply of renewable methane coming from thousands of small production installations and large volumes of hydrogen entering the system on specific locations, it will be difficult to ensure a relatively constant blend of hydrogen and methane across the grid. Not only will the blend vary from location to location, but also during the year due to the seasonal dependence of biomethane and hydrogen production. This results in different optimal blends of hydrogen and methane in different countries at different times. Gas compressors in the grid can be designed to deal with varying blends of hydrogen and methane as long as they are predictable, for instance due to seasonal dependency or local differences. (Un)predictability will, however, vary from location to location. For gas users varying blends would require different and flexible specifications for end-use technologies, which is both impractical and expensive. Some users, such as in chemical industries, require pure hydrogen, which requires them to separate hydrogen. Separating blends of hydrogen and methane, for instance, using membranes at end-of-pipe, is expensive and will at best only be economically feasible for long distance transport of large volumes of hydrogen and methane.

---

[176] Gasunie (2018): Hydrogen Coalition: concrete plans for a flying start of the hydrogen economy, https://www.gasunie.nl/nieuws/waterstof-coalitie-concrete-plannen-voor-een-vliegende-start-van.

[177] Northern Gas Networks (2016). H21 Report, https://www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Report-Interactive-PDF-July-2016.compressed.pdf.

[178] The total costs to make the Dutch distribution networks usable for hydrogen were estimated at 700 million €, resulting in network cost increase per individual household of 10%-50%. Source: (In Dutch) Kiwa (2018). Toekomstbestendige gasdistributienetten, https://www.netbeheernederland.nl/_upload/RadFiles/New/Documents/Kiwa%20-Toekomstbestendige%20gasdistributienetten%20-%20GT170272%20-%202018-07-05%20-D..._.pdf.

[179] The H21 report assumes upfront conversion of the distribution network to a hydrogen-ready grid in course of a modernization program that is due to be undertaken anyhow. See Northern Gas Networks (2016). H21 Report, https://www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Report-Interactive-PDF-July-2016.compressed.pdf.

There may be regional or niche situations in 2050 where there is an economic or technical rationale for hydrogen and methane blending. In the transition phase towards net-zero emission economy, blending can help to scale up hydrogen production, for instance, by creating additional revenue streams for energy producers that aim to prevent curtailment. Although blending hydrogen with natural gas will reduce CO_2 emissions when burning the gas, the societal value of the hydrogen will probably be lower than when used purely in fuel cell vehicles or in the chemical industry.

Oil pipeline system could be used to transport gas

A substantial network of oil pipelines exists in Europe, consisting of 33,000 km of connected pipelines through many EU Member States. Depending on whether liquid oil products will still play a role in a net-zero emissions energy system, this network may be obsolete by 2050. If this happens, instead of decommissioning this network, it could be repurposed to transport hydrogen.

Gas grid offers cost-effective energy seasonal storage. Alternative would be biomass

Gas infrastructure offers flexibility and can deal with widely differing volumes of gas, e.g. between summer and winter. This makes gas a valuable companion of variable renewable electricity in our “optimised gas” scenario. Existing gas storage facilities can be used for biomethane.

With growing supply and demand for hydrogen and biomethane, storage is also required. Due to the low volumetric energy density of hydrogen, high-pressure compression, liquefaction, or chemical conversion is required to keep the storage volume small. The size of the storage also depends on its function in the energy system, i.e., its required storage duration: large volumes for inter-seasonal storage facilities and smaller volumes for intraday storage facilities.

Biomethane will be used mostly for electricity production and the heating of existing buildings that already have a gas connection and hydrogen is mainly used in heavy industry and as fuel in road transport. Therefore, inter-seasonal storage is mainly needed for biomethane, whereas hydrogen mainly needs intraday or intra-week storage and limited large-scale storage.

Smaller hydrogen volumes, e.g., for intraday storage are typically stored in pressurized tanks. In the future storage in metal hydrates presents a possible cost-competitive alternative. For large-scale hydrogen storage, underground salt caverns are typically considered, but this method is limited by its geographical availability. Geologic storage needs cushion gas (minimum amount of gas that needs to be left in storage), which for natural gas is between 20%-30% of the storage working capacity. The reduced volumes of methane that are used in the system will free up storage capacity that can be utilised for hydrogen. Additional hydrogen storage sites may need to be developed depending on whether hydrogen will be used for building heating, and such sites experience large seasonal demand fluctuations and weather large temporal mismatches expected between demand and supply. The costs for hydrogen or methane storage are not explicitly assessed in Navigant’s cost analysis

In the “minimal gas” scenario, we assume that seasonal peaks in demand are covered by biomass power plants, which is a costly solution. And while battery storage is a feasible option for load balancing on short timescales (e.g. hourly, or intraday), for long-term storage it becomes extremely expensive. In comparison, the existing natural gas infrastructure has the benefit of providing this inter-seasonal flexibility at relatively low cost, as shown in our “optimised gas” scenario.

6.5 The role of electricity infrastructure today and towards 2050

Reliable electricity infrastructure is essential for a power system to work. The electric grid must always ensure sufficient capacity is available to match demand and supply. Comparable to the gas grids, there are two main levels in the electricity grid, the transmission grid and the distribution grid. The transmission grid transports electricity over long distances with cables connected to large overground pylons and sometimes underground cables. The distribution grid delivers electricity to households and smaller commercial users through underground electricity cables or cables connected to small overground pylons. Large (industrial) consumers and power plants are connected to the transmission grid. The grids must be dimensioned to meet peak transportation and distribution needs. Figure 37 illustrates the main components of the electricity grid.

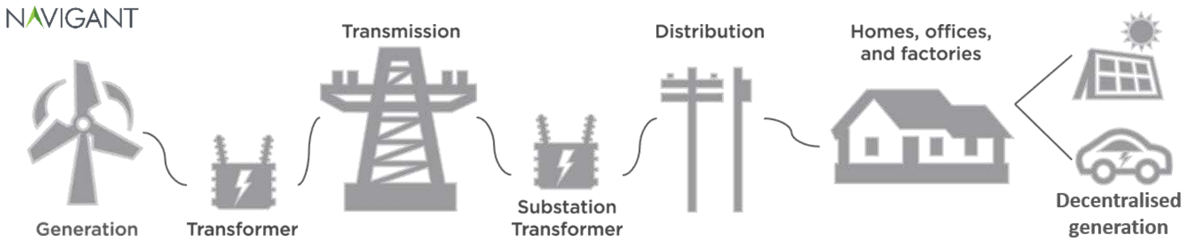

Figure 37 Power system components

The electricity grid is designed to match power demand and supply at any time. This balancing is currently done by large-scale dispatchable electricity generation which is provided by natural gas-fired power plants. Different to gas networks, electricity networks are not suitable to store large quantities of electricity over large periods of time.

Increased electrification of the energy system in the form of electric heat pumps in buildings and electric passenger cars, buses, and light trucks, will increase the volume of electricity demand as well as peak demand. These changes all impact the distribution grid, which will need to be upgraded to facilitate higher peak demand. Meanwhile, more distributed generation, such as rooftop solar PV, is being introduced, which leads to an irregular supply of electricity to distribution grids. The current average distribution grid capacity in the EU is about 1 kW per household. This is expected to grow up to 5 kW in 2050 if heat and other energy consumption is electrified. Investments in the power distribution grids are required to deliver the required peak demand.

Due to electrification at end-users, the total electricity demand, and thereby the potential for renewable electricity, increases. Much of this will be generated in large wind and solar farms often far from the high demand regions (i.e., cities). Higher transmission capacity will therefore be necessary to transport the generated electricity to the place of demand. This will also lead to additional required investments.

This study does not include a bottom-up analysis of the required expansion of the electricity transmission capacity because of large-scale electrification by 2050. Rather, Navigant relies on results of the E-Highway 2050, an EU-funded study performed by a consortium of research institutes and electricity TSOs, various industry associations, and consultants.[180] E-Highway 2050 analyses the required infrastructural investments associated with various 2050 electrification scenarios.

[180] e-Highway 2050. Modular Development Plan of the Pan-European Transmission System 2050 (2015). The consortium includes sixteen TSOs including Amproin, Elia, REN, RED Eléctrica and Terna, ENTSO-E, four industry associations including Eurelectric, ten research institutes including ECN and Brunel University London and five experts including DENA, E3G and Pöyry.

Navigant selected the "100% renewables scenario"[181] which most closely resembles the "optimised gas" scenario as developed in this study and scaled the level of peak capacity of the "100% renewable scenario" to the peak capacity resulting from the electricity generation in Navigant's "optimised gas" scenario.

6.6 Infrastructure costs analysis for "minimal" and "optimised gas"

This section compares the gas and electricity infrastructure costs in the "minimal gas" scenario with those included in the "optimised gas" scenario. The section clarifies the various cost items associated with the energy infrastructure in both scenarios and subsequently determines these costs by considering the required investments, operation, and maintenance costs for both scenarios in the gas and electricity T&D grids.

6.6.1 Costs to maintain or decommission the current gas grids

Navigant expects that the existing gas grid has sufficient capacity to transport and distribute the future gas volumes in the EU and on average. Existing gas infrastructure has a lifetime beyond 2050, and a relatively low level of investments is required to keep the system in operation, related solely to the replacements of parts of the infrastructure that have a shorter lifespan, such as compressors. Although gas infrastructure is relatively low cost (in comparison with the alternatives to transport energy), with low maintenance costs and long economic lifetimes, the EU gas grids, both TSO and DSO are extensive in length.[182] In many EU countries the legislation requires the natural gas grid to be decommissioned when no longer in use, which could result into substantial costs in case the gas infrastructure is no longer required.

> The cost to decommission existing gas grids are uncertain but may cost many billions of euros

In the "minimal gas" scenario there will be little gas infrastructure required. Merely some transmission pipelines to transport natural gas to industrial sites to produce blue hydrogen. In this scenario, most of the existing gas grid will need to be decommissioned. Based on Navigant's experience with TSO gas infrastructure decommissioning, we assume associated costs of around 30% of the CAPEX initially required to erect the infrastructure. The total decommissioning cost for the TSO gas infrastructure would be €156 billion. To allow for comparison with other infrastructure investment costs in our scenarios, we annualized these costs over a period of 10 years, which results to €15.6 billion per year. Importantly, the DSO network is even more extensive than its TSO counterpart and might pose decommissioning complications in urban areas. Given the variability of DSO networks in EU member countries, Navigant has not estimated the costs associated with decommissioning of the DSO networks but expect these to be potentially substantial and higher than the total TSO decommissioning costs.

In the "optimised gas" scenario, the existing infrastructure will need to be maintained, which results in annual costs of around €5.7 billion, based on gas infrastructure maintenance costs reported by TSOs.

[181] More information on the '100% renewables scenario' can be found in e-Highway 2050 deliverable D.4.4. Modular Development Plan from 2020 to 2050.

[182] Navigant estimates the total length of the EU TSO gas network at 260,000 km and the DSO gas network at 1,400,000 km.

6.6.2 Costs to integrate biomethane in existing gas grids

In the “optimised gas” scenario, Navigant anticipates integration costs for biomethane production units and maintenance costs for the current new infrastructure.

In Chapter 2 we concluded that our “optimised gas” scenario includes a power to methane potential of 15 bcm (natural gas equivalent) plus a biomethane potential of 95 bcm, of which 33 bcm is produced in 228 large-scale thermal gasification plants located close to existing gas grids and 62 bcm is produced in 31,000 small biogas digesters with raw biogas of which 43 bcm is subsequently being upgraded to biomethane and 19 bcm is liquefied to bio-LNG at locations far from gas grids. From a cost perspective it makes sense to feed the output of two neighbouring biogas digesters into a single centralised upgrading unit where biomethane is produced. We assume that by 2050 5150 of such installations are operational. Centralised upgrading plants reduce the required pipeline infrastructure compared less centralised biomethane production. The pipelines that carry biogas to upgrading plants can be made of inexpensive PVC (€200,000 per kilometre), with a small diameter at low pressure (below 8 bar). The cost of steel piping is about 2.5 times higher than the PVC pipes.

> Transporting raw biogas through low pressure PVC pipes to central biomethane installations is a cost optimal way to supply large volumes of biomethane through gas grids

As described in Chapter 2, some biogas plants produce additional methane by injecting green hydrogen produced onsite into methanation units. We assume that by 2050 a total of 5700 of such methanation installations would be operational. These methanation units produce an additional quantity of 15 bcm (natural gas equivalent) of renewable methane. At locations further than 15 kilometres away from gas grids the costs of connecting plant to existing gas grids become high and it may become cost-efficient to produce bio-LNG onsite and transport this to either existing gas grids or to fuelling stations by truck. We assume that 4650 bio-LNG plants will be operational by 2050.

The resulting set-up of biogas integration into existing gas grids is pictured below. It should be noted that Navigant did not perform a bottom-up analysis of regional and local biomethane production potentials throughout the EU and match this with the topology of existing gas transmission and distribution grids. Therefore, our assumed split between ‘grid transported’ biomethane and ‘truck transported’ bio-LNG is a rough estimate that could be further refined. In our estimate of an average 15 km distance to existing gas grids for ‘grid transported’ biomethane we assume that biomethane can be injected in both the low, medium and high-pressure gas grids.

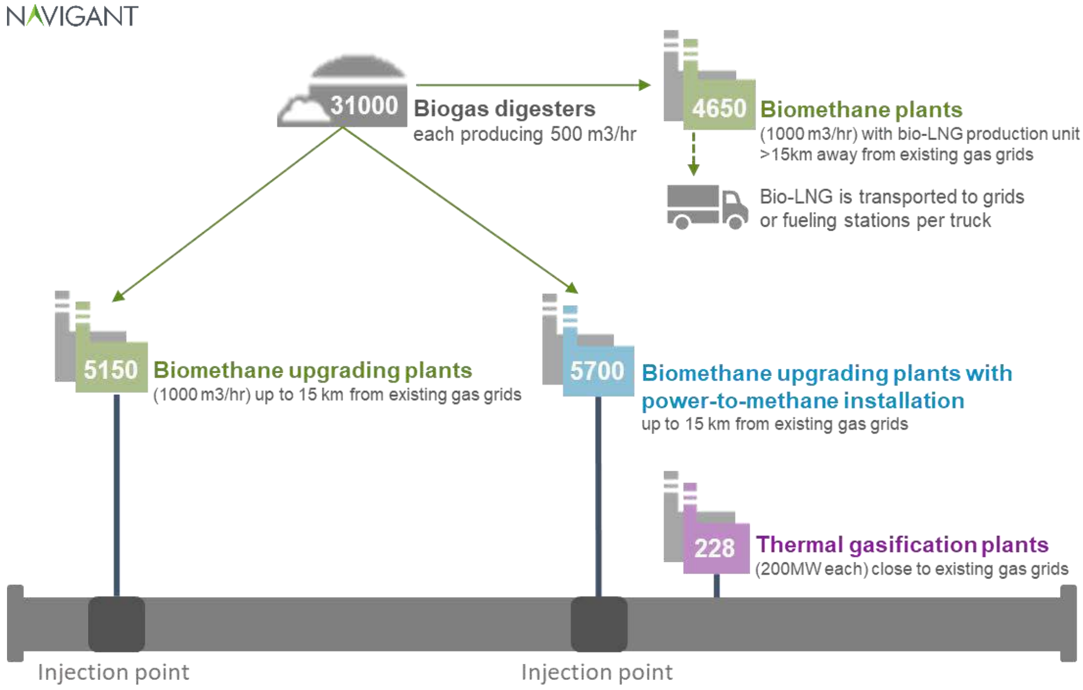

Figure 38 Number of renewable methane plants connected to existing gas grids

In this set-up, a total of 5150 biomethane installations plus 5700 combined biomethane and power to methane installations would exist, which means that 10,850 renewable methane installations have to be connected to existing gas grids. In addition, 228 injection points are required to connect biomethane produced in large-scale thermal gasification plants to existing gas grids.

For thermal gasification based biomethane, it is assumed that the grid injection and connection costs would be marginal since the biomethane produced at natural gas quality will come out at high pressure and could be injected into the grid with little effort. In addition, the thermal gasification plants are assumed to be deployed closer to the existing gas grid leading to negligible pipeline costs. The calculated costs for grid injection of gasification based biomethane amounts to €2/MWh annually.

For anaerobic digestion-based biomethane the network costs are calculated assuming a biogas pipeline with an average length of 9 km per digester. This way, a considerable quantity of biomass feedstock can be used to produce biomethane that can be fed to gas grids. The upgrading facilities are located close to existing gas grids. Navigant assumes an average of 1 km of additional steel piping to connect the biomethane installation to the grid. The total biomethane network costs are estimated to be €9.7/MWh of which biogas pipes cover €5.0/MWh and grid injection and connection costs add €4.7 /MWh per year, as is illustrated in the graph below. The total costs to integrate all biomethane and power to methane are around €5.7 billion annually. On top of this, we include €2.3/MWh methane as OPEX for the gas grid, this is mainly for compression throughout the gas grid. In total, this amounts to €2.7 billion annually.

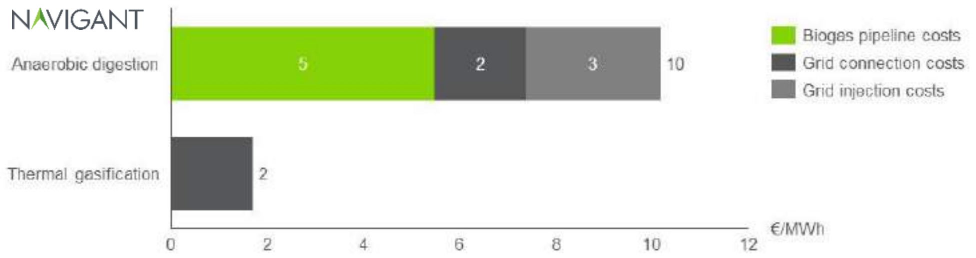

Figure 39 Total biomethane network costs

6.6.3 Costs for hydrogen integration, transport, distribution and storage

Hydrogen can be produced either centrally (i.e., close to the point of power source) or de-centrally (i.e., close to the point of consumption). Decentral hydrogen production does not require extensive hydrogen infrastructure; however, either a grid connection or renewable power generation in the case of green hydrogen, or an (existing) gas connection and CO_2 infrastructure in the case of blue hydrogen production is required. In case hydrogen is produced centrally, hydrogen infrastructure needs to be developed either by refurbishing existing natural gas infrastructure or by deploying new infrastructure.

Hydrogen can be transported in various ways. Typically, it is either compressed or liquefied. Less common options include conversion of hydrogen to a more complex chemical that allows for easier transport (e.g., NH_3, CH_4, CH_3OH) or the utilisation of hydrogen carriers (e.g., metal hydrides or liquid hydrogen organic carriers). The compression of hydrogen entails additional equipment costs as well as energy and hydrogen losses. The costs associated with the most common transportation modes are listed in Table 17, ordered by their technological and commercial maturity. Navigant concludes that transportation via pipelines, either new or retrofitted, is the most cost-effective option for large volumes of hydrogen.

Table 17 Hydrogen conversion, transport and distribution options and estimates of their costs[183]

Delivery option	Costs [€/MWh/ 600km]	Technology maturity	Comments
Retrofitting existing gas infrastructure for 100% hydrogen	3.7	Pilot-tested	Calculated by Navigant based on literature
New hydrogen pipelines	4.6	Commercial	Calculated by Navigant based on literature
Liquid organic hydrogen carriers (LOHC) per pipeline	19[184]	Pilot-tested	Not yet commercial. LOHC could be an option to transport hydrogen but more expensive than gas pipes
Liquified transport per truck, train, ship	58-62 (ship)[185]	Commercial with trucks, trains; ship-bound under development	Not deemed a promising option as major additional energy losses are incurred by liquefaction (over 30% of the hydrogen LHV)[186] and this option is currently very expensive.
Compressed gas containers per truck	Not considered[187]	Commercial	Not suitable for large-scale hydrogen transport.
Hydrogen blending with methane per pipeline	Low cost at <10% blends, at higher blends costs depend on pipeline quality/topology.[188]	Pilot-tested	Assumed only to play a role up to 2030 or 2040 with small shares of hydrogen blended in methane.
Metal Hydrides per truck or train	Unknown at industrial scale	Under development	Becoming commercially available to store small quantities of hydrogen. Large-scale storage costs unknown.

A total supply of around 1,700 TWh of hydrogen is required to fulfill demand in 2050. We assume that all required connections can be can made by a partial retrofit of existing natural gas transmission infrastructure. While gas transmission pipelines should typically be able to carry hydrogen at pressures below 100 bar without major costs,[189] adjustments to or construction of new compression and metering stations will require investments.

[183] Unless specified otherwise, the "Costs" column refers to a sum of levelized CAPEX investments (or retrofitting investments, where applicable) and levelized OPEX costs.

ments/Kiwa%20-Toekomstbestendige%20gasdistributienetten%20-%20GT170272%20-%202018-07-05%20-D.._.pdf.

[184] The H21 report assumes upfront conversion of the distribution network to a hydrogen-ready grid in course of a modernization program that is due to be undertaken anyhow. See Northern Gas Networks (2016). H21 Report, https://www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Report-Interactive-P

DF-July-2016.compressed.pdf.

n Ogden (1999). Prospects for building a hydrogen energy infrastructure, https://www.annualreviews.org/doi/abs/10.1146/annurev.energy.24.1.227?journalCode=energy.2 and NREL (1998). Costs of Storing and Transporting Hydrogen, https://www.nrel.gov/docs/fy99osti/25106.pdf.

[186] The long-term realistic target for hydrogen liquefaction energy consumption is around 6.5 kWh/kg H_2, hence around 20% of hydrogen LHV. Based on Stolten & Emonts eds (2016). Hydrogen Science and Engineering – Materials, Processes, Systems and Technology. There is an on-going research to reduce the cost of liquefaction in future however this has not been evaluated here (see Cardella et al. (2017). Economically viable large-scale hydrogen liquefaction, http://iopscience.iop.org/article/10.1088/1757-899X/171/1/012013.

[187] This transport option is only suitable for smaller quantities of hydrogen up to ~350 km from the production facility and hence not analyzed here. Based on Stolten & Emonts eds (2016). Hydrogen Science and Engineering – Materials, Processes, Systems and Technology.

[188] IRENA (2018): Hydrogen from renewable power: Technology outlook for the energy transition, https://www.irena.org/publications/2018/Sep/Hydrogen-from-renewable-power and NREL (2013): Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues, https://www.nrel.gov/docs/fy13osti/51995.pdf.

[189] Depending on the exact specifics of the materials used for the pipelines.

We estimate that on average, a compression or boosting station has to be placed every 200 km of a pipeline to maintain safe and economically efficient pressures. Including replacement of the required compressors for hydrogen and metering, Navigant evaluates the levelized costs of hydrogen infrastructure, including operational costs, to be around 4.15 €/MWh for typical average transport distances of 600 km. The total annual costs for the hydrogen infrastructure will be €9.5 billion annually by 2050.

6.6.4 Costs of the electricity infrastructure

Both our "minimal gas" and "optimised gas" scenarios require a very large increase in electricity production, as explained in Chapter 5. This requires large investments in electricity generation capacity but also in upgrading and expanding electricity transmission and distribution infrastructure. this section describes how these infrastructure investments are quantified for both scenarios.

To calculate the costs for upgrading the electricity infrastructure, we apply different approaches for high voltage, medium voltage, and low voltage grids.

The necessary reinforcement of the high-voltage transmission grids depends on a wide range of factors, among them the location of electricity production means, the volatility of electricity supply and demand and the type of cables used (e.g., overhead cables vs. underground cables).

The e-Highway 2050 project calculated the necessary investments into the pan-European transmission grid for different scenarios.[190] The study focused mainly on the requirements for bulk capacities between different clusters within the EU. The "100% RES" scenario of the e-Highway study includes high levels of electrification across the EU. In this scenario large numbers of renewable electricity generation are installed that require investments in new electricity infrastructures, such as reinforced links, and increased power transmission capacity. Navigant adopted the costs developed in this 100% RES scenario. These costs are around €12 billion annually, distributed over a period of 10 years around 2050.

Large investments will need to be made to integrate renewable energy into the system. In the "minimal gas" scenario, practically all produced and consumed electricity will need to be connected to the power transmission grid infrastructure. These costs are estimated to be around €60 billion annually, based on a 30 €/MWh[191] cost for offshore wind integration.

In the "optimised gas" scenario, a large part of the renewable electricity will be converted into green hydrogen and then transported via dedicated hydrogen infrastructure. In the "optimised gas" scenario, the electricity transmission costs are expected to be lower than in the "minimal gas" scenario for two reasons:

1. Transport of solid biomass is costlier than transport of biomethane, therefore power plants that run on biomass will be built closer to ports and rivers and further away from demand centers. In contrast, power plants running on biomethane in the "optimised gas" scenario, can be more distributed and located more closely to areas with a high demand for electricity demand.

2. The use of power-to-gas allows useful exploitation of excess renewable generation capacity and generation capacity in remote areas. Instead of the construction of expensive transmission lines, the existing gas grid can be used for transporting the energy. Therefore, in the "optimised gas" scenario we adopt the cost estimates based on the "small and local" scenario from the e-Highway study to estimate the electricity transmission costs.

---

[190] www.e-highway2050.eu/e-highway2050/

[191] Agora Energiewende, Integrations costs of wind and solar power, p.36-38

Using gas in times of peak demand in electricity production and heating of buildings, reduces the required investment to upgrade the electricity infrastructure to deal with peak demand. This reduces peak electricity demand and thereby reduces the required investment in electricity grids to deal with peak demand. The medium and low voltage grids will require reinforcements to cope with increased electrification. In Navigant's "optimised gas" scenario, the lower need for electrification in the building sector (due to deployment of hybrid heat pumps) is partly offset by a higher electricity demand for heating due to lower insulation levels in buildings. The resulting electricity demand, peak load, and amount of installed renewable energy generation is higher in the "minimal gas" scenario compared to the "optimal gas" scenario, being 1,000 GW versus 870 GW.

To calculate the costs for medium voltage grid reinforcements, Navigant assumes that the costs depend on peak demand and on the costs per capacity unit for different locations (urban/intermediate/rural areas). These annual medium voltage grid reinforcement costs vary between €21/kW for urban areas and €57/kW[11] for rural areas. The average costs per capacity unit were calculated based on the trend of population growth and the distribution of the population within urban, intermediate, and rural areas and is €26/kW. The peak demands are based on the profiles created to represent energy required for the heating of buildings. Full electrification increases peak electricity demands, meaning higher transport capacity is required. On the medium voltage level, an indication of the average cost for additional grid capacity is available for the urban, suburban, and rural areas from a previous study on the value of congestion management in the Netherlands.[192] This study used these costs as a rough estimate for the Europe-wide electricity grid extension cost. The average medium voltage electricity costs are calculated based on the expected density of the European network in 2050.

Navigant estimated the costs to upgrade the medium and low voltage grids to be around €31 billion for both scenarios,[192] including €8.4 billion to integrate onshore wind and solar power production, based on an estimated 6 €/MWh.[193]

6.7 Conclusions

The EU gas and electricity infrastructures are both significant assets that provide large energy systems the service of a secure and reliable energy supply. The gas transmission and distribution (T&D) network consists of approximately 266,000 km of high-pressure network of which 200,000 km are operated (mainly) by TSOs, plus approximately 1.4 million km of medium and low-pressure pipelines operated (mainly) by DSOs. Gas infrastructure ensures the reliability and flexibility of the energy system.

Navigant analysed the impact of the "minimal gas" and "optimised gas" scenarios on the role of the future gas and electricity grids. We conclude that both scenarios require very large investments in additional electricity networks resulting from a large increase in variable renewable electricity.

> Continued use of gas infrastructure saves at least €19 billion annually by 2050, plus much larger savings elsewhere in the energy system

We assume that in the "minimal gas" scenario gas will be phased out except a relatively small quantity required to fully decarbonise EU industry. This could mean that the total gas distribution network and almost the entire gas transmission network may have to be decommissioned. Towards 2050, Navigant expects gas T&D networks to continue to have a valuable role in the energy system in the "optimised gas" scenario.

[192] Ecofys (now part of Navigant), Waarde van congestiemanagement, table 9 (available in Dutch) (2016).

[193] Agora Energiewende, Integrations costs of wind and solar power, p.36-38.

Instead of natural gas, the pipelines will be used to transmit and distribute hydrogen and renewable methane (biomethane and power to methane). In the “optimised gas” scenario, existing gas grids will be used to transport and distribute renewable methane and hydrogen.

Navigant concludes that the “optimised gas” scenario results in significant energy infrastructure cost savings of €19 billion as per the table below. These cost savings constitute only a fraction of the total energy cost savings resulting from a continued use of existing gas infrastructure to allow a role for renewable and low-carbon gas. These additional energy cost savings are described in Chapter 7.

The lower costs for the energy infrastructure in the “optimised gas” scenario can be attributed to the lower costs of the electricity infrastructure, which more than offsets the costs for the gas infrastructure. Please note that the costs to transport biomass to solid biomass power plants in the “minimal gas” scenario are not included in the cost overview below since these are included in energy production costs as shown in Table 15 in Chapter 5.

Table 18 Annual costs of the gas and electricity infrastructure in the “minimal gas” and “optimised” gas scenarios and the cost difference between the scenarios by 2050 (billion € per year).

Costs for	“Optimised gas”	“Minimal gas”	Savings
renewable methane infrastructure maintenance	6	0	-6
Gas infrastructure decommissioning	0	16	16
Biomethane connection to gas grid	9	0	-9
Transporting hydrogen in retrofitted gas infrastructure	10	0	-10
Electricity distribution infrastructure	31	37	6
Electricity transmission infrastructure	73	95	22
Total infrastructure costs			**19**

In the “optimised gas” scenario, the existing transmission grid will be used to transport hydrogen and renewable methane in parallel. The existing distribution grid will be used to distribute modest quantities of gas to buildings, with high net system cost savings per cubic metre of gas.

Navigant assumes that renewable methane will be transported and distributed through existing gas grids and that increasing yet still small quantities of hydrogen will up to 2030 be transported through existing gas grids blended with methane. By 2050, separate networks for renewable methane and renewable and low-carbon hydrogen will exist, both based on existing gas grids as available today.

This study does not contain a bottom-up assessment of future gas production and demand locations, nor an assessment on how they match with existing gas infrastructure. There will be regional differences in demand and supply that determine whether it is more favourable to use biomethane, hydrogen, or perhaps a combination of the two. Navigant estimates that hydrogen will often be used within 600 km of production locations and based on analysis we conclude that part of the existing gas transmission grids will be retrofitted to enable hydrogen transport. Further analysis is required to establish a more refined picture of future T&D requirements for hydrogen and renewable methane.

7. The final picture

This study's purpose is to assess the possible role and value for renewable and low-carbon gas used in existing gas infrastructure in a net-zero emissions EU energy system, compared to a situation in which a minimal quantity of gas would be used. This chapter summarises the results of this analysis.

Based on the sectoral analysis and taking into account the most cost-efficient net-zero emissions EU energy system, this study allocates the available renewable and low-carbon gas to the various demand sectors (Figure 40). Biomethane is used mainly for dispatchable electricity production and for the heating of buildings. Since part of the biomethane production takes place more than 15 km from the nearest gas grid and therefore cannot be easily integrated in existing gas infrastructure, it will be transported as bio-LNG, which can subsequently be used for shipping. Hydrogen is a valuable form of renewable gas that can be used in all demand sectors. In our "optimised gas" scenario it will be used mainly in industry and to some extent in heavy truck transport but can also play a valuable role in electricity production and the heating of buildings.

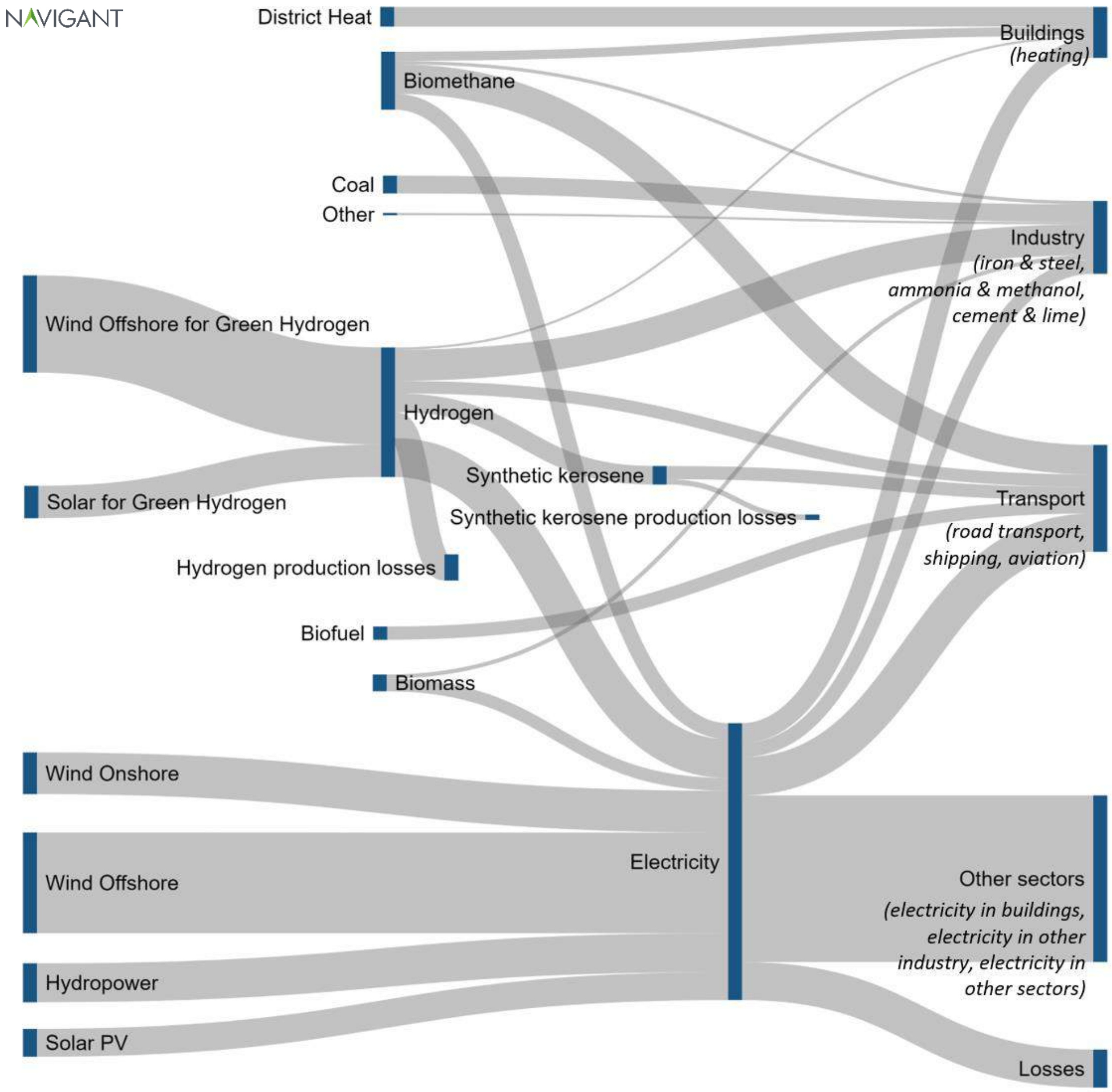

Figure 40 Overview of energy flows in the "optimised gas" scenario

The "optimised gas" scenario as pictured above includes only renewable gas and no low carbon gas. Nevertheless, because the costs of green and blue hydrogen can be similar by 2050, blue hydrogen can still play a role by that year. Blue hydrogen can grow hydrogen demand in coming years, allowing faster decarbonisation. Towards 2050, natural gas will be phased out and blue hydrogen increasingly being replaced by green hydrogen and renewable methane. The speed by which green hydrogen can replace blue hydrogen depends on how fast all direct electricity demand can be produced from renewables and beyond that additional renewable electricity generation capacity is constructed. It furthermore depends on whether policy makers will limit the use of blue hydrogen by 2050. Any large scale-up of green hydrogen production prior to the moment when all demand for direct electricity is covered by renewable power results in indirect increases in fossil electricity generation.

> The future energy system can be expected to be fully renewable.

All renewable gas could be EU-produced, although the option to cost-effectively produce solar PV-based green hydrogen in Northern Africa and transport it to Europe by (existing) pipelines has similar costs. It is difficult to establish the degree of green hydrogen imports or the degree of green versus blue hydrogen by 2050. In the long run the full energy system can be expected to be fully renewables based, whether that being 2050 or somewhat later depends on the penetration rate of renewable electricity and cost decreases of renewable gases. The Box below describes a possible hydrogen scale up pathway.

> The logical moment for large-scale replacing of blue by green hydrogen is the moment that all demand for direct electricity is met with renewable power

Box 11 A hydrogen scale-up pathway up to 2060

2030: Blue hydrogen replacing grey hydrogen in existing hydrogen applications and green hydrogen testing

Up to 2030, increasing quantities of blue hydrogen are expected, with natural gas being transported through the existing gas transmission infrastructure to blue hydrogen production locations. Volumes will still be relatively low, and hydrogen will mainly be used to replace existing grey hydrogen demand in industry in specific regions. Blue hydrogen will either be produced on industrial sites close to demand without a need to transport or produced on a location for which gas pipelines need to be developed or retrofitted for hydrogen transport. In some regions, the already existing hydrogen infrastructure can be used, such as in France, Belgium, Germany, and the Netherlands. Regions with CO_2 storage locations and industries with hydrogen production and demand, such as along the North Sea coast will be the first to develop a hydrogen infrastructure. In this period, green hydrogen production is tested in large-scale demonstration projects.

2030-2040: Further scale up of blue hydrogen, green hydrogen starts to replace blue hydrogen

As costs for green hydrogen are dropping and demand grows, a flow of green hydrogen is produced from offshore wind in theNorth Sea, Baltic Sea, and floating offshore in the Mediterranean plus from rooftop solar-PV in Southern Europe. Green hydrogen can be imported from north-Africa. Volumes of green hydrogen are still relatively small compared to blue hydrogen and most is used close to where it is produced. A dedicated hydrogen network is being constructed mainly by retrofitting part of existing grids from natural gas to hydrogen transport. Transmission pipeline lengths of several hundreds of kilometres may be enough. Blue hydrogen production can be scaled up relatively easily and large-scale CCS takes place. All grey hydrogen has since long been phased out. Hydrogen starts to be used in heavy industry, long distance transport and other sectors at larger scales.

2040-2050: Large scale-up of green hydrogen, EU-produced plus imported from North Africa

Very low cost renewable electricity and strong development of hydrogen demand in heavy industries will push costs for green hydrogen further down to a similar level as blue hydrogen and in some cases even below blue hydrogen costs. As the production of both green and blue hydrogen is strongly linked to locations with large amounts of renewable electricity potential and CO_2 storage capacity, respectively, it can be expected that more transmission capacity will be required to connect these supply centres to the increasing demand beyond the first adoption regions. Existing gas import pipelines can be used to import green hydrogen from Algeria and Morocco.

Around 2060: Green hydrogen can be the dominant form of hydrogen; blue hydrogen being phased out

Strong competition between blue and green hydrogen with the latter gaining more market share because of lower CO_2 emissions and energy demand. Pushed by policy, blue hydrogen will be phased out and replaced by green hydrogen.

Navigant allocated 1,170 TWh of biomethane and 1,710 TWh of hydrogen to the buildings, industry, transport, and power sectors in the "optimised gas" scenario (see Table 19). Compared to the "minimal gas" scenario (for a description of the scenarios see Chapter 3), this scenario saves a total of €217 billion annually in all sectors together (see Table 20). Furthermore, Figure 41 provides the complete overview of the cost savings per sector and the production and integration costs.

Table 19 Allocation of gas, electricity and other energy in the "optimised gas" scenario in 2050 (TWh)

Sector	Biomethane	Hydrogen	Electricity	Other
Buildings (heating)	185	46	399	396
Industry (iron & steel, ammonia & methanol, cement & lime)	69	627	286	484
Transport (road, shipping, aviation)	595	252	772	534
Electricity consumption in other sectors	-	-	3,004	-
Power*	322	786	-	254
Total	**1,170**	**1,710**	**4,460**	**1,670**

* Demand of biomethane, hydrogen and other describe the fuel use in the power sector. This does not include energy input from variable renewable electricity generation, like solar, wind, and hydropower.

Table 20 Overview of cost savings on energy cost and other cost for each sector between the "minimal gas" scenario and the "optimised gas" scenario (billion euro per year)

Sector	"Optimised gas"	"Minimal gas"	Savings
Buildings	429	490	61
Industry	69	139	70
Transport	1,153	1,167	14
Power	210	264	54
Infrastructure	166	184	19
Total cost savings in the "optimised gas" scenario compared to the "minimal gas" scenario	**2,026**	**2,243**	**217**

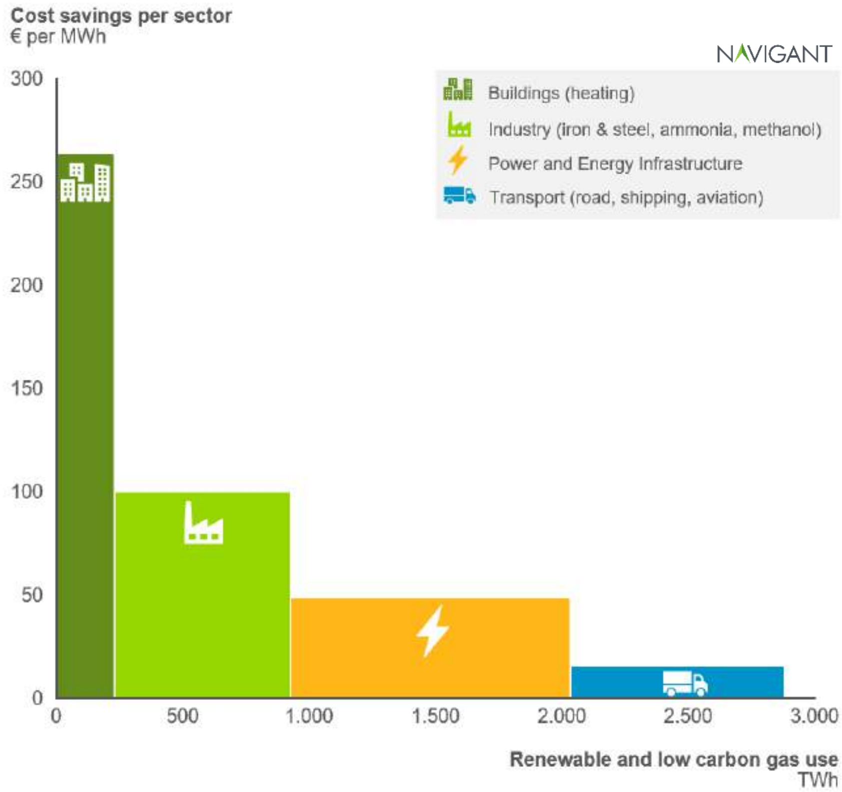

Figure 41 Energy system cost savings generated by the "optimised gas" scenario versus the "minimal gas" scenario[194].

Using 272 bcm (natural gas equivalent) of green hydrogen and renewable methane through existing gas infrastructure saves society €217 billion annually across the energy system compared to an energy system using a minimal amount of gas. Molecules are indispensable to achieve full decarbonisation of the energy system, in a smart combination with increasing amounts of renewable electricity.

> The EU can save €217bn annually by scaling-up renewable gas by 2050

[194] Total savings in the power sector are higher than 54 bn euro because a substantial part of these savings are included in the savings on energy costs in buildings, industry and transport. Energy cost savings in these sectors result from using different energy carriers, but also because of lower electricity prices in the "optimised gas" scenario as compared to the "minimal gas" scenario.

Appendix A. Energy demand in the scenarios

This appendix provides the annual supply and demand of EU energy by 2050, outlined in tables and Sankey diagrams.

A.1 Energy demand in the "optimised gas" scenario

Table 21 Allocation of gas, electricity and other energy in the "optimised gas" scenario in 2050 (TWh)

Sector	Buildings (heating)	Industry (iron & steel, ammonia & methanol, cement & lime)	Transport (road, shipping, aviation)	Electricity consumption in other sectors	Power*	Total
Biomethane	185	69	595	-	322	**1,171**
Hydrogen	46	627	252	-	786	**1,711**
Electricity	399	286	772	3,004	-	**4.461**
Biomass	-	84	-	-	254	**338**
Biofuel	-	-	267	-	-	**267**
Synthetic kerosene	-	-	267	-	-	**267**
Heat	396	-	-	-	-	**396**
Fossil fuels	-	355	-	-	-	**355**
Other	-	45	-	-	-	**45**
Total	**1,026**	**1,466**	**2,153**	**3,004**	**1,363**	

* Demand of biomethane, hydrogen and other describe the fuel use in the power sector. This does not include energy input from variable renewable electricity generation, like solar, wind, and hydropower.

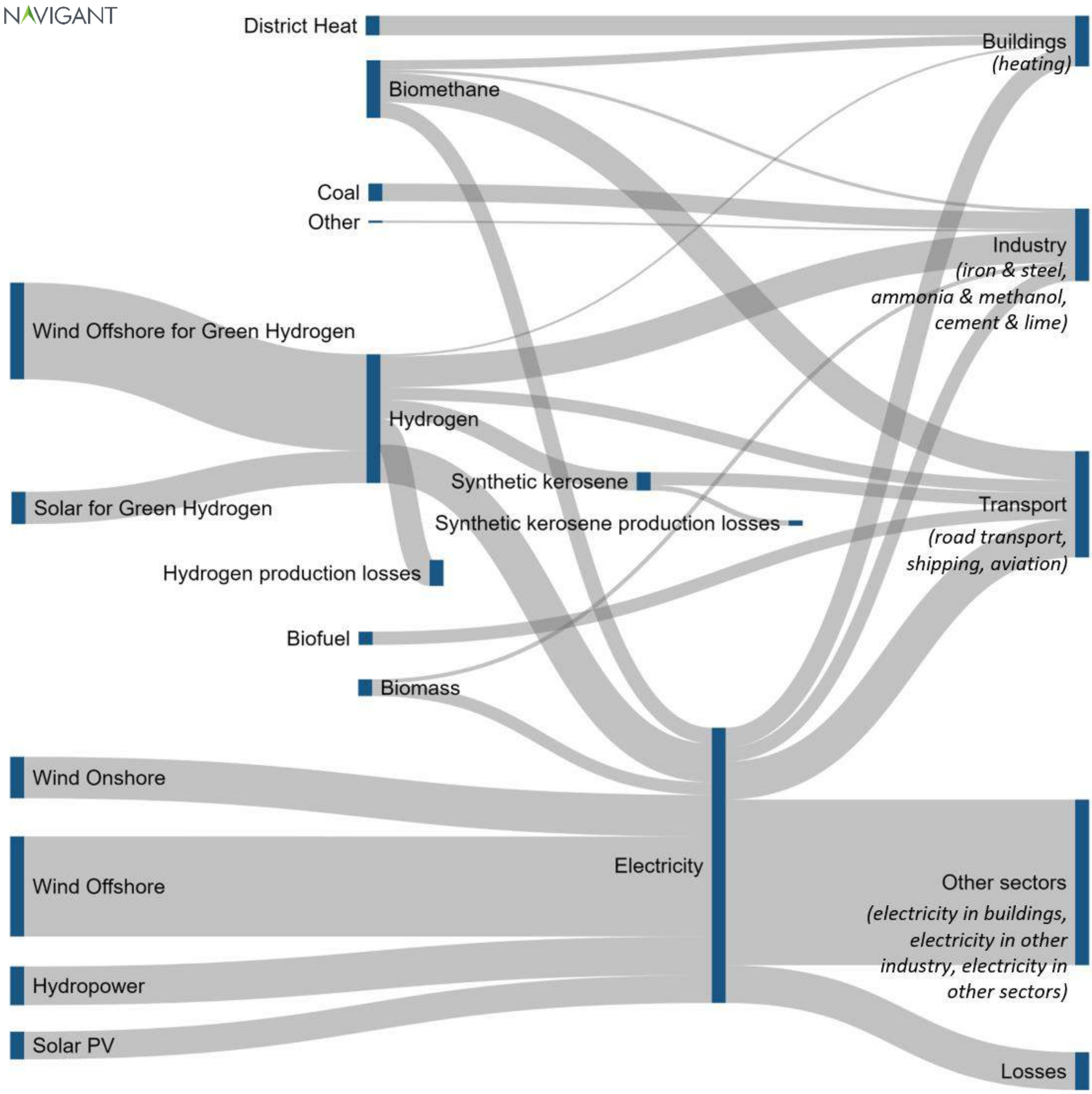

Figure 42 Energy flows in the “optimised gas” scenarios.

A.2 Energy demand in the "minimal gas" scenario

Table 22 Allocation of gas, electricity and other energy in the "minimal gas" scenario in 2050 (TWh)

Sector	Buildings (heating)	Industry (iron & steel, ammonia & methanol, cement & lime)	Transport (road, shipping, aviation)	Electricity consumption in other sectors	Power*	Total
Biomethane	-	69	-	-		**69**
Hydrogen	-	-	-	-		**0**
Electricity	390	1,265	853	-	3,004	**5,513**
Biomass	-	84	-	2,310		**2,394**
Biofuel	-	-	985	-		**985**
Synthetic kerosene	-	-	267	-		**267**
Heat	396	-	-	-		**396**
Fossil fuels	-	355	-	-		**355**
Other	-	45	-	-		**45**
Total	**787**	**1,818**	**2,105**	**2,310**	**3,004**	

* Demand of biomethane, hydrogen and other describe the fuel use in the power sector. This does not include energy input from variable renewable electricity generation, like solar, wind, and hydropower.

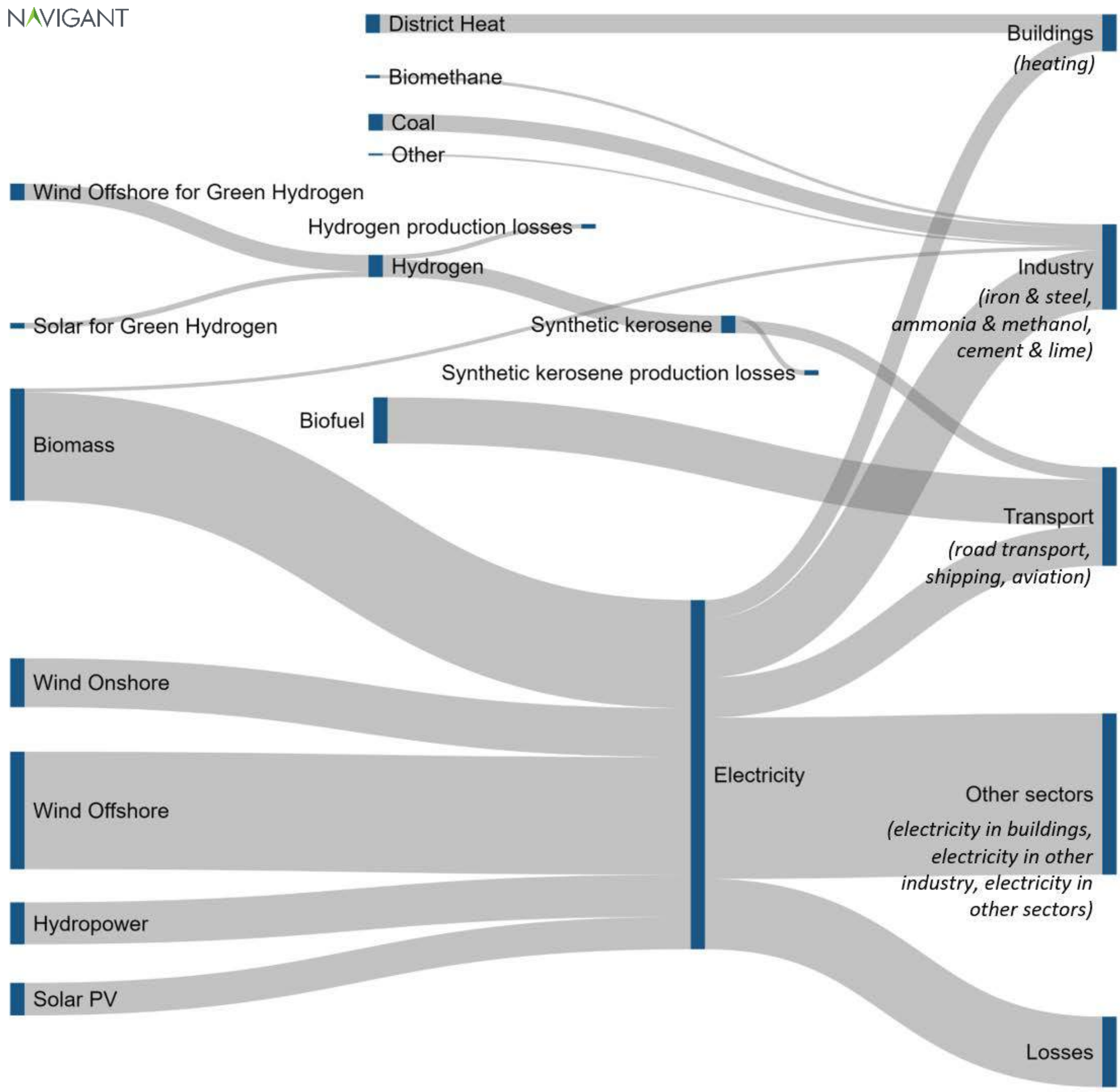

Figure 43 Energy flows in the “minimal gas” scenarios.

Appendix B. General assumptions on the quantification of the value of gas

B.1 Societal cost calculation

All costs are calculated on an annual basis (using an annuity factor) per household and for the European Union (EU-28). The outcome reflects the overall annual costs in 2050, combining operational and capital costs in a single yearly amount. The value is expressed in 2018 euros.

$$Annual\ costs = Investment\ costs * Annuity\ factor + Fixed\ operating\ costs + Variable\ operating\ costs$$

The annuity factor corresponds to the economic lifetime of the investment and the social discount rate (SDR). In the analysis, a SDR of 5% for the energy system is assumed. The annuity factor is defined as:

$$Annuity\ factor = \frac{SDR}{1-(1+WACC)^{-n}}$$

With *n* corresponding to the economic lifetime.

B.2 Population growth

The number of households in the EU is based on the projection of the population in the EU-28 based on the Eurostat Convergence scenario and the average household size for the most current year available, 2015 (Eurostat). The Convergence scenario is based on the assumption that the population will rise by around 5% between 2010 and 2050. The population number is in line with the e-Highway2050 scenarios.[195]

B.3 Energy carrier costs

Table 23 Energy carrier costs in the "minimal gas" and the "optimised gas" scenarios (€/MWh).

Energy carrier	Optimised gas	Minimal gas
Biomethane	57	47
Bio-LNG	69	59
Hydrogen	52	52
Natural Gas	30	30
Electricity	69	87
Biomass	29	29
Advanced Biodiesel	83	85
Bio Jet	75	75
Heat	57	57
Coal	9	9
Synthetic Kerosene	94	94

[195] Note that in this analysis only all current members of the European Union were taken into account whereas the EU Energy Roadmap 2050 and e-Highway2050 also include Switzerland and Norway.

Some fuel costs in the table above differ between the “optimised gas” and “minimal gas” scenario. For example, in the “minimal gas” only a limited amount of biomethane is used, which means that only the cheapest biomethane is used, resulting in a lower average cost per MWh. For electricity, we observe higher costs in the “minimal gas” scenario because of the more expensive backup capacity in the power sector.

B.4 Minimum and maximum shares

Table 24 Minimum and maximum shares in the “minimal gas” and “optimised gas” scenarios.

Technology type	“Optimised gas”		“Minimal gas	
	Min	Max	Min	Max
Air-Source Heat Pump	0%	80%	0%	80%
Ground-Source Heat Pump	0%	20%	0%	20%
Hybrid Heat Pump	0%	37%	0%	0%
District Heating	20%	20%	20%	20%
Water Source Heat Pump	0%	0%	0%	0%
NG-IBRSR-CCS	0%	0%	0%	0%
BM-IBRSR-CCS	0%	100%	0%	100%
BM-DRI-EAF	0%	100%	0%	0%
Dec-H2-DRI-EAF	0%	100%	10%	100%
BM-H2-DRI-EAF	10%	100%	0%	0%
NG-Scrap-EAF	0%	0%	0%	0%
BM-Scrap-EAF	40%	50%	40%	50%
Ammonia_Decentralised H2 (electrolyser)	0%	100%	0%	100%
Ammonia_Centralised H2	0%	100%	0%	0%
Ammonia_CCS	0%	0%	0%	0%
Methanol_Decentralised H2 (electrolyser)	0%	100%	0%	100%
Methanol_Centralised H2	0%	100%	0%	0%
Methanol_CCS	0%	0%	0%	0%
Methanol_Biomethane	0%	100%	0%	0%
LCV - BEV - Electricity	0%	90%	0%	100%
LCV - FCEV - Hydrogen	0%	100%	0%	0%
LCV - Bio-CNG	0%	100%	0%	0%
LCV - Bio-LNG	0%	100%	0%	0%
LCV - Advanced Biodiesel	0%	100%	0%	100%
Bus - BEV - Electricity	0%	75%	87.5%	87.5%
Bus - FCEV - Hydrogen	0%	100%	0%	0%
Bus - Bio-CNG	0%	100%	0%	0%
Bus - Bio-LNG	0%	100%	0%	0%
Bus – Advanced Biodiesel	0%	100%	0%	100%
Car - BEV - Electricity	50%	95%	100%	100%
Car - FCEV - Hydrogen	5%	50%	0%	0%
Car - Bio-CNG	0%	50%	0%	0%
FT - BEV - Electricity	0%	30%	0%	50%
FT - FCEV - Hydrogen	0%	100%	0%	0%
FT - Bio-CNG	0%	100%	0%	0%

Technology type	"Optimised gas"		"Minimal gas	
	Min	Max	Min	Max
FT - Bio-LNG	20%	100%	0%	0%
FT - Advanced Biodiesel	0%	100%	0%	100%
Aviation - Electricity	0%	0%	0%	0%
Aviation - Synthetic Kerosene	50%	50%	50%	50%
Aviation - Bio Jet fuel	50%	50%	50%	50%
Aviation - Kerosene	0%	0%	0%	0%
Shipping Intra - BEV - Electricity	0%	50%	0%	50%
Shipping Intra - Hydrogen	0%	100%	0%	0%
Shipping Intra - Bio-LNG	0%	100%	0%	0%
Shipping Intra - Advanced biodiesel	0%	100%	0%	100%
Shipping Intra - Diesel	0%	0%	0%	0%
Shipping Domestic - BEV - Electricity	100%	100%	100%	100%
Shipping Outbound - Hydrogen	0%	100%	0%	0%
Shipping Outbound - Bio-LNG	0%	100%	0%	0%
Shipping Outbound - Advanced Biodiesel	0%	100%	0%	100%
Shipping Outbound - Diesel	0%	0%	0%	0%

Appendix C. The potential and costs of biomethane and power to methane

C.1 Overview of feedstocks and feedstock potentials for biomethane production

The table below provides an overview of agricultural, waste and woody biomass feedstocks with descriptions and an overview of their availability and the extent to which their availability to produce biomethane is limited by other competing biomass uses or by the need to mitigate sustainability risks.

Table 25 Biomethane feedstock categories and their estimated availability to produce biomethane

Feedstock category	Description	Assumptions	EU-availability (dry tonnes)
Sequential crops	Wheat, triticale, sorghum, or ryegrass silage produced as additional (second) crop before or after the harvest of main crops on the same agricultural land.	Assumed that on average 10% of the current EU Utilised Agricultural Area[196] (UAA) will be used for sequential cropping in 2050. The assumed crop yield for sequential crops is 60% of the main silage crop yield in Southern Europe and 30% in the rest of the EU. No sequential cropping is assumed in the Nordics and Baltics.	147 million tonnes
Agricultural residues	Plant residues from the harvesting of agricultural crops: straw from cereal (wheat, barley, rye, and oat) and oil crops (rape seed, sunflower), maize stover and cobs, and sugar beet leaves. Prunings and cuttings from permanent crops (apples, pears, cherries, apricots, peach, vineyards, olives, and citrus). The category also includes potential from olive pits but excludes grass.	The potential is calculated using a realistic sustainable removal rate that ranges between 40%-60% depending upon the crop. Of the available sustainable potential, 30% of the straw from cereal crops and 50% of the straw from oil crops is considered for biomethane production. The potential from prunings and cuttings is considerably smaller compared to straw. Alternative uses of prunings other than for nutrient and soil conservation are scarce. After accounting for competing uses, all the remaining potential that is available for energy purposes is allocated to biomethane.[197]	36 million tonnes[198,199,200]
Biodegradable waste	Food waste: includes animal and mixed food waste plus vegetable waste categories as defined by Eurostat.	Estimates are developed according to population and GDP developments. The projections also consider the impact of expected increased MSW separation into different waste streams such as wood waste, animal, and mixed food waste as well as vegetable waste. Eurostat waste treatment levels were used to identify conventional competing uses and recycle rate to arrive at the potential. .	5.6 million tonnes[199]

[196] Total Utilised Agricultural Area (UAA) in the EU is around 175 million hectares. https://ec.europa.eu/eurostat/statistics-explained/index.php/Farm_structure_statistics

[197] In the previous Gas for Climate study (Feb 2018), 67% of the sustainable collectable potential of agricultural residues was allocated to biomethane production. Having reassessed the existing uses, we conclude that a smaller share of 30 to 50% of available residues is available for biomethane production without displacing existing other material uses. This reduced the assumed availability of agricultural residues for biomethane production.

[198] Iqbal et al., 2016. Maximising the yield of biomass from residues of agricultural crops and biomass from forestry. https://ec.europa.eu/energy/sites/ener/files/documents/Ecofys%20-%20Final_%20report_%20EC_max%20yield%20biomass%20residues%2020151214.pdf

[199] Elbersen et al., 2016. Outlook of spatial biomass value chains in EU28: Deliverable 2.3 of the Biomass Policies project.

[200] Spöttle et al., 2013. Low ILUC potential of wastes and residues for biofuels: Straw, forestry residues, UCO, corn cobs. https://www.ecofys.com/files/files/ecofys-2013-low-iluc-potential-of-wastes-and-residues.pdf

Feedstock category	Description	Assumptions	EU-availability (dry tonnes)
	Manure: includes solid manure from cattle, pig, poultry, and sheep, and liquid manure from cattle and pig.	Only the manure that is produced in stables is considered since this is the manure fraction that can be collected out of the total manure that is produced on a farm. The manure availability is estimated for farms with a size threshold above 100 livestock units (LU).	87 million tonnes[199,201]
	Sewage sludge: includes sludges and liquid wastes from urban and industrial waste treatment.	Sewage sludge volumes are expected to largely remain stable in the future which means that there will be no large feedstock potential for increase in biogas production from sewage sludge.	1.7 million tonnes[202]
Woody residues	Bark: These are the outermost layer of stems and roots of trees. Debarking of trees usually takes place at saw or paper mills, rather than in forests.	Typically, bark is left on trees and travels with the round wood from the forest to the next processing stage, i.e., saw and paper mills. It is assumed that bark will be used to meet the energy needs of saw mills in 2050. Barks are, therefore, not considered for biomethane production in this assessment.	None[200a]
	Branches and tops are tree parts that are left as residues from the harvesting of trees in forests.	It is assumed that 80% of these forestry residues stay on the forest floor to ensure soil health and biodiversity. An increase of 10% in forestry residue potential is assumed due to expected increase in the EU roundwood harvest. For branches and tops, a moisture content of 20% is factored in for seasoned dry wood to arrive at dry tonnes.	12.6 million tonnes[200]
	Early thinnings: Smaller trees that are cut to make forests less dense and thereby create space for other trees to further growth.	Thinnings usually account for one-third of the existing number of trees. 5% of the total volume of Roundwood harvested in the EU is assumed to be available as thinnings suitable for biomethane production"? For thinnings, we correct for a moisture content of 20% from seasoned dry wood. Estimates are developed by considering an increased roundwood harvest of 20% and yield increase of 10% by 2050.	13 million tonnes[198,203,204]
	Landscape care wood and road side verge grass: covers landscape care wood potential outside of agricultural permanent cropland.	Around 90% of the total assumed collectable quantity is considered to be used for biomethane production. No significant changes in potentials are expected towards 2050. The biomass potentials are linked to land territory. We correct for a moisture content of 25% from the collected biomass	21.5 million tonnes[199]
Residual and post-consumer waste	Municipal solid waste (MSW): includes the organic fraction of total waste generated from municipality.	About 30% of the organic fraction is allocated to biomethane in 2050. MSW volumes are assumed to decrease by 30% compared to today due to increased recycling and MSW separation.	17 million tonnes[205]

[201] In the previous Gas for Climate study (Feb 2018), only wet manure from cattle and pig stables was considered. Having re-assessed this point, the current estimate also includes the solid fraction of manure. This significantly increased the potential.

[202] Kampman et al., 2017. Optimal use of biogas from waste streams. https://ec.europa.eu/energy/sites/ener/files/documents/ce_delft_3g84_biogas_beyond_2020_final_report.pdf

[203] Ecofys, 2017. Beschikbaarheid houtige biomassa voor energie in Nederland. https://www.rvo.nl/sites/default/files/2017/09/Beschikbaarheid%20houtige%20biomassa%20voor%20energie%20in%20Nederland.pdf

[204] In the previous Gas for Climate study (Feb 2018), we assumed that thinnings constitute 2% of the total EU roundwood harvest. We re-assessed this and conclude that early thinnings constitute 5% of the total EU roundwood harvest. See here: https://www.gasforclimate2050.eu/files/files/GfC_Memo_Rethinking_the_EU_biomethane_potential_from_woody_biomass_residues.pdf

[205] Eurostat, 2018. Municipal waste by waste management operations. http://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=env_wasmun&lang=en

Feedstock category	Description	Assumptions	EU-availability (dry tonnes)
	Solid recovered fuel (SRF) and refuse derived fuel (RDF): These fuels are derived from MSW, commercial and industrial (C&I) waste as well as construction and demolition (C&D) waste.	No significant changes in volumes are expected towards 2050. A large fraction of these fuels is used in cement kilns and waste incinerators. Only 10% of the total quantity is considered for biomethane production.	1 million tonnes[206]
	Wood waste: It covers wood from wood processing, paper and pulp, and forestry.	Wood waste volumes are assumed to remain stable towards 2050. About half of the available potential is allocated to biomethane.	20 million tonnes[207,208]

Woody residues

In our memo "Rethinking the EU-potential of biomethane from woody residues," published September 2018, we describe the various types of woody residues, the quantities that can be sustainably harvested, their non-energy uses and availability for bioenergy. This Appendix captures the main messages from the memo.[209]

The following are considered types of woody residue:

- **Bark** is the skin of stemwood that is shaven off after the harvest of roundwood.
- **Branches and tops** are parts of whole trees that are cut off the stemwood shortly after harvesting of roundwood.
- **Thinning** is the cutting of young whole trees. Most of the biomass harvested during the 40–140 years of a forest rotation result from thinning. Thinning can improve the growth rate and increase structural diversity. Increasing the canopy complexity by selecting trees with different heights promotes more efficient use of light and nutrients and improves the overall yield and wood quality as well as health and resilience of the stand. Regular thinning is controlled by tree height (thinning measures in Europe are site dependent and usually conducted every 5–10 years) and combined with the selection and facilitation of potential crop trees mainly from the target species. The number of thinning depends on the rotation cycle. Short-rotation trees have only thinned few times, whereas long-rotation trees are thinned several times.
- **Landscape care wood** is collected during the maintenance operations of certain urban areas and treated as waste. It includes tree cutting and pruning activities in horticulture, arboricultural activity in parks and cemeteries, and tree management operations performed along roadsides, railways, water ways, orchards, etc. to keep plantations in the desired state and wood collection from private gardens. Roadside verge grass is also included in this category.
- **Wood waste** is a source of secondary woody biomass in the EU that includes waste wood from wood processing, wood from paper and pulp production, construction and demolition waste, as well as waste collected from households and industries.

The sustainable availability of each feedstock is provided in Table 26. These potentials consider the fact that important shares of primary forestry residues should be left on the forest floor.

[206] CEMBUREAU & ERFO, 2015. Markets for Solid Recovered Fuel: Data and assessments on markets for SRF. https://www.erfo.info/images/PDF/ERFO-CEMBUREAU_report_SRF_2015.pdf

[207] Eurostat, 2018. Generation of waste by waste category. http://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=env_wasgen&lang=en

[208] In the previous Gas for Climate study (Feb 2018), we assumed a 30% reduction in waste wood availability by 2050 and we allocated 20% of available wood waste to biomethane. We re-assessed this and conclude that wood waste availability is likely to remain stable and, considering existing competing uses of wood waste, 50% can be allocated to biomethane production. See here: https://www.gasforclimate2050.eu/files/files/GfC_Memo_Rethinking_the_EU_biomethane_potential_from_woody_biomass_residues.pdf

[209] https://www.gasforclimate2050.eu/files/files/GfC_Memo_Rethinking_the_EU_biomethane_potential_from_woody_biomass_residues.pdf

Table 26 Overview of different woody residue potentials (all units in million tonnes of dry biomass)

Feedstock	2050 potential GfC study	Updated 2050 potential
Barks	34.1	24.5
Branches and tops	15.7	12.6
Thinning for energy production	6.5	13.0
Landscape care wood	23.9*	23.9
Wood waste	28.1*	40.2
Total (mln tonnes)	**108.3**	**114.2**

** We converted tonnes of biomass "as received" as reported in Eurostat into dry biomass assuming 25% moisture content in landscape care wood and 20% in wood waste*

A part of the woody residue potential will not reach the market and will continue to be directly used for electricity and heat production onsite at saw mills. Electricity consumption of EU saw mills is around 40 TWh at present.[210] If all of this electricity is produced using dedicated bio-CHPs, then around 24 million tonnes of locally available woody feedstock is required. We assume that the EU saw mill industry's process energy needs remain stable towards 2050, and that this woody residue potential cannot become available for energy market. We do not assume paper mills will have large onsite energy consumption by 2050.[211]

Therefore, out of a total 114 million tonnes, only 24 million tonnes will continue to be used for electricity and heat production (in saw mills) and the remaining 90 million tonnes could then be used to produce biomethane and make electricity or heat, be used as industrial feedstock, or be used to produce advanced liquid biofuel.

C.2 Costs of biomethane from anaerobic digestion

The costs of biomethane from anaerobic digestion are calculated on the basis of two biogas plants each producing 500m3 of raw biogas per hour feeding into on centralised biomethane upgrading installation located close to existing gas grids.

The raw biogas is transported to the upgrading unit via inexpensive PVC pipes (€200,000/km) at relatively low pressure (8 bar). The average distance between a digester and the upgrading facility is assumed to be 9 km. This set-up means that a large share of biomethane feedstocks can be used to produce biomethane that can be injected in gas grids. Still, as described in Section 2.2.3, not all biomass can be harvested close enough to existing gas grids and it is assumed that biogas produced far away from gas grids will be transported per truck in the form of bio-LNG. .

The costs for grid-bound biomethane are estimated using the CAPEX and OPEX figures for a 500 m^3/hr biogas plant. This excludes the costs of upgrading as upgrading costs were separately calculated for a 1000 m^3/hr upgrading facility.

[210] http://www.ecoinflow.com/Portals/0/PROR_final_26_06_final-compressed_web.pdf

[211] The Confederation of European Paper industries (CEPI) aims to reduce CO_2 emissions by 80% before 2050. Currently, around 14 EU paper producers together with TU Eindhoven are developing an innovative technology that allows the separation of lignin and cellulose using a solvent that is biodegradable211. This innovation would drastically reduce the process energy that is currently needed to separate lignocellulosic materials into different components. Large scale application is expected in 15 years, well before 2050. With this technology maturity, we expect that the woody biomass that is used to meet process energy needs would be available in the market.

The table below gives an overview of biomethane feedstock costs.

Table 27 Feedstock costs[212] per feedstock type

Feedstock category	Feedstock type	Feedstock cost 2050 (€/tonne-dry matter)
Sequential crops	Triticale, wheat, or ryegrass silage	78
Agricultural residues	Cereal crop residues	47
	Oil crop residues	47
Biodegradable waste[213]	Manure	5-50
Woody residues	Barks	92
	Branches and tops	92
	Early thinnings	92
	Landscape care wood	92
	Road side verge grass	92
Residual and post-consumer waste	MSW	12
	Wood waste	12

Table 28 below provides the CAPEX and OPEX figures for the biogas plant and the upgrading unit. The cost data for the 500 m^3/hr biogas plant was provided by CIB whereas the costs for the upgrading facility were obtained from the Biosurf (2015)[214] study. The production costs in the decentralised scenario are estimated to be €57/MWh. The grid injection and connection costs are about €2.8/MWh and €1.9/MWh (assuming 1 km steel pipes), respectively while the costs for biogas pipelines are estimated to be at €5/MWh.

Table 28 CAPEX and OPEX for anaerobic digestion

Technology	Plant size (m3/h)	CAPEX (M€)	OPEX (M€/yr)	Biomethane yield (m3/t DM)
Anaerobic digestion	500	5.86	0.60	Feedstock specific
Anaerobic digestion	1000	9.89	0.63	Feedstock specific
Anaerobic digestion (upgrading unit only)	1000	2.00	0.11	NA

C.3 Costs of biomethane from thermal gasification

Thermal gasification for biomethane synthesis is in early commercial stage of development. There are around 50 - 100 biomass and/or waste gasifiers in operation globally but only a small sub set of these are targeting Bio-SNG production[215]. In the EU, however, there are a few noteworthy projects for biomethane synthesis such as the Ambigo project in the Netherlands, GoGreenGas project in the UK and the Gussing project in Austria. These projects are running small plants of less than 3 MW_{th} capacity but have ambitions to scale up[216].

[212] Feedstock costs are based on current feedstock prices and an expert judgement on how today's prices may develop in the future. Based on the Italian experience, we expect that the production cost of silage cultivated as second crop would be significantly lower compared to silage cultivated as main crop.

[213] Weighted average feedstock costs in €/MWh for anaerobic digestion are mainly determined by silage, manure and agricultural residues due to their large share in biomethane potential. Costs for sewage sludge and food waste were, therefore, not considered in feedstock cost assessment.

[214] Sturmer et al (2016). Technical-economic analysis for determining the feasibility threshold for tradable biomethane certificates. http://www.ergar.org/wp-content/uploads/2018/07/BIOSURF-D3.4.pdf

[215] https://www.globalsyngas.org/resources/the-gasification-industry

[216] E4tech & Ecofys, 2018. Innovation Needs Assessment for Biomass Heat. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/699669/BE2_Innovation_Needs_Final_report_Jan18.pdf

Biomethane production from thermal gasification is expensive, currently around €100/MWh[217]. However, there are various innovations that can reduce the cost of producing biomethane and are expected to materialize in future. The previous study estimated very low 2050 costs of €37/MWh based on a UK study by Ricardo. Having further assessed this study we found its methodology not sufficiently clear and Navigant performed additional analysis. Based on further literature research, Table 29 shares the impact of some of the key innovations to arrive at biomethane costs for 2050. Continuous deployment and technology scale up as the key factors contributing to cost reduction. Improved plant integration, innovative gas cleaning methods and high-pressure gasification could further reduce the overall system costs and offer some efficiency benefits.

Table 29 Impact of innovations on biomethane costs from thermal gasification[218,219,220]

	Description	Impact
Deployment of multiple plants	First of a kind 42.3 MW_{th} plant to Nth of a kind 42.3 MW_{th} plant	15% reduction in CAPEX, 6% reduction in OPEX
Plant scale up 1	Capacity increase from 42.3 MW_{th} to 84.35 MW_{th}	18% reduction in CAPEX, 14% reduction in OPEX
Plant scale up 2	Capacity increase from 84.35 MW_{th} to 200 MW_{th}	29% reduction in CAPEX, 29% reduction in OPEX
Efficiency improvement	Combined effect of more efficient hot gas cleanup, improved plant integration and high-pressure gasification. Expected energy conversion efficiency increase from 64% to 75%	16% reduction in feedstock costs

We quantified the impact of these innovations on biomethane costs as shared in the Table 30,and it turns out that biomethane can be produced at around 47 €/MWh. The grid connection and injection costs are marginal, only €2/MWh. These costs are estimated against a plant size of 200 MW_{th} at current feedstock prices using our estimated feedstock mix for 2050. Production installations larger than 200 MW_{th} might not be appropriate because of the issues related to feedstock availability and increased costs of feedstock delivery and transport. The estimated costs are social costs of biomethane production calculated using a social discount rate of 5%. Additional cost reductions are possible, e.g. through improved feedstock handling and flexibility, reduced plant complexity and advanced air separation techniques but the impact of these innovations on system costs remains uncertain and were not quantified in our assessment.

---

[217] Larsson et al, 2018. The GoBiGas Project: Demonstration of the Production of Biomethane from Biomass via Gasification. https://www.goteborgenergi.se/Files/Webb20/Kategoriserad%20information/Forskningsprojekt/The%20GoBiGas%20Project%20%20Demonstration%20of%20the%20Production%20of%20Biomethane%20from%20Biomass%20v%20230507_6_0.pdf?TS=636807191662780982

[218] gogreengas, 2015. BioSNG Demonstration Plant. http://gogreengas.com/wp-content/uploads/2015/11/BioSNG-170223-1-Project-Close-Out-Report.pdf

[219] (GoBiGas, 2018). Demonstration of the Production of Biomethane from Biomass via Gasification. https://www.goteborgenergi.se/Files/Webb20/Kategoriserad%20information/Forskningsprojekt/The%20GoBiGas%20Project%20-%20Demonstration%20of%20the%20Production%20of%20Biomethane%20from%20Biomass%20v%20230507_6_0.pdf?TS=636807191662780982

[220] (Ecofys & E4tech, 2018). Innovation Needs Assessment for Biomass Heat. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/699669/BE2_Innovation_Needs_Final_report_Jan18.pdf

Table 30 CAPEX and OPEX for thermal gasification[218,219,220]

Technology	Plant size (MWth)	CAPEX (M€/MWth)	OPEX (M€/MWth/yr)	Energy efficiency %
Thermal gasification (first of a kind)	42	2.83	0.27	64%
Thermal gasification (Nth of a kind)	42	2.41	0.25	64%
Thermal gasification (Nth of a kind)	84	1.98	0.22	64%
Thermal gasification (Nth of a kind)	200	1.4	0.15	75%

C.4 Ensuring that biomethane is a net-zero emissions renewable gas

This study assumes that processing emissions will be mitigated by using zero-carbon fuels in on-farm machinery and by using renewable energy for process energy. Navigant also assume that organic fertilisers are used (biogas digestate) and that where mineral fertilisers are used, these will be fully decarbonised in line with the requirement for EU industry to fully decarbonise by 2050.

Some remaining emissions will however still exist in the form of N_2O (nitrous oxide) emissions. Nitrous oxide is a greenhouse gas with a high global warming potential. The main source of nitrous oxide emissions is in biomass cultivation[221]; it is therefore relevant for crop-based biomethane feedstock (silage) rather than for wastes and residues. Nitrous oxide is produced naturally in the soil through biological and chemical processes[222] that use nitrogen compounds (such as ammonium, nitrate, and nitrite) and is subsequently emitted to the atmosphere. The emissions of nitrous oxide occur through both a direct pathway (directly from the soils to which nitrogen is added; for example, from synthetic nitrogen fertilisers and organic fertilisers such as manure and crop residues)[223] The nitrous oxide emissions from soil can be mitigated by improved agricultural practices such as:[224]

- Using less nitrogen fertilisers;
- Using minimal tillage to minimise the organic matter breakdown and the release of nitrous oxide
- Preventing high water level (waterlogging) to minimise the bacterial growth and activities to form nitrous oxides;
- Reducing nitrate leaching by using nitrification inhibitors.

In addition to these mitigation measures, it is possible to compensate for some of the emissions by including a share of manure in the biomethane feedstock mix. By using methane captured in manure, on-farm methane emissions from manure are avoided. When manure is treated in anaerobic digester to produce biogas, a credit of 45 gCO_{2eq} is allocated per MJ of manure treated[225], which can result in overall negative emissions.

---

[221] Nitrous oxide is also emitted from fossil fuel (or biofuels) combustions in machinery and burning of biomass in boilers and CHP, but most emissions occur from agricultural soils.

[222] These processes are nitrification and denitrification processes. Nitrification is the aerobic microbial oxidation of ammonium to nitrate, and denitrification is the anaerobic microbial reduction of nitrate to nitrogen gas (N2). Nitrous oxide is a gaseous intermediate in the reaction sequence of denitrification and a by-product of nitrification that leaks from microbial cells into the soil and ultimately into the atmosphere (IPCC 2006, Volume 4, Chapter 11).

[223] IPCC, National Greenhouse Gas Inventories, Volume 4, Chapter 11, 2006.

[224] https://www.agric.wa.gov.au/climate-change/reducing-nitrous-oxide-emissions-agricultural-soils

[225] When raw (solid) manure or raw (liquid) slurry is stored, waiting to be spread on the fields, it releases gases in the atmosphere as result of bacterial activity. Methane is the main gas released by manure decomposition, but also nitrogen compounds such as N_2O, NH_3 and nitrogen oxides are released [JRC report 2017, Solid and gaseous bioenergy pathways: input values and GHG emissions].

This credit is due to avoided CH_4 and N_2O emissions (37 and 8 gCO_{2eq}/MJ manure of prevented CH_4 and N_2O emissions, respectively) resulting from improved manure management. It is important to note that this credit is not an intrinsic property of the biogas pathway but "*the result of a common, although less than optimal, agricultural practice,*"[226] and the credit would cease to exist if optimal agricultural practices (such as gas-tight manure tanks for manure storage) become available.

In the Gas for Climate 'Optimised gas' scenario is assumed that by 2050, 27 million tonnes of manure are used to produce biomethane. This generates 1.2 $MtCO_2e$ of manure credit that can be used to offset part of the 8.2 $MtCO_2e$ emissions from nitrous oxide emissions from silage cultivation, with 7 Mt of remaining emissions. These remaining emissions can be compensated for by soil organic carbon accumulation as generated through "Biogasdoneright." (A Box in section 2.2.3 explains the concept). The estimated potential of soil carbon sequestration in the EU by the implementation of Biogasdoneright is estimated to be between 47–73 $MtCO_2$.[227] These negative emissions can be realised mainly by incorporating the solid fraction of biogas digestate into agricultural soils, but also through the additional build-up of organic matter from sequential crops and changing tillage management.

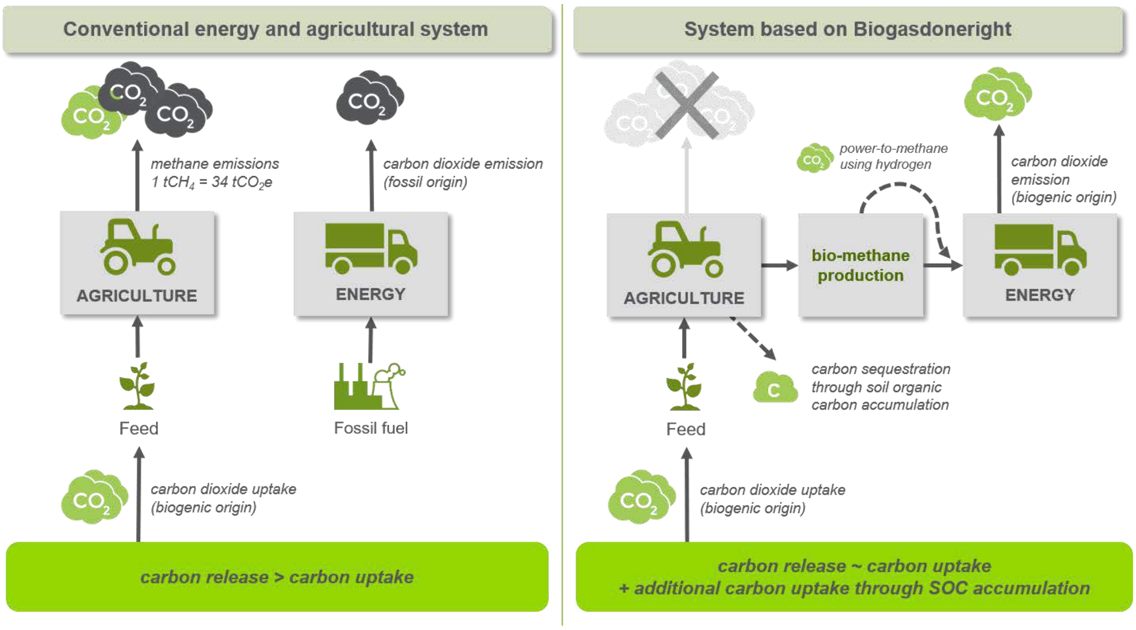

Figure 44 Greenhouse gas emissions benefits of biomethane from anaerobic digestion

Avoiding land use change emissions
The greenhouse gas emission reduction potential of biomethane may be reduced if its production causes land use change in the form of direct or indirect displacement of agricultural production leading to the conversion of forests or other high carbon stock lands to new agricultural land. This study includes only biomethane which does not lead to direct or indirect land use change, to ensure a high greenhouse gas emission reduction from biomethane.

Methane leakage occurs in natural gas and biogas production and transport, leading to unwanted greenhouse gas emissions. Such leakage effects have been widely documented and are not further discussed here. To decarbonise the EU energy system, it is paramount that methane leakage is minimised. Options for this are described in the February 2018 Gas for Climate study.

---

[226] JRC report, 2017, Solid and gaseous bioenergy pathways: input values and GHG emissions.

[227] See separate report by Navigant: *Soil organic carbon sequestration: decarbonising the agriculture sector through the production of renewable gas*. Forthcoming.

C.5 Potential and costs of power to methane

From our overall energy system analysis, 248.75 TWh of excess electricity would be available by 2050 to produce 199 TWh of green hydrogen. To produce power to methane with the same amount of hydrogen, 33 million tonnes of carbon dioxide is required, which requires, in turn, a production of 43 bcm of raw biogas with a CO_2 content of 45% and methane content of 55%. Assuming a methanation reaction efficiency of 80%, this results in total EU-wide production of 147 TWh (HHV) of renewable methane from power to methane. Table 28 gives an overview of the technical assumptions used to derive the methane potential.

Table 31 Technical input parameters of the methanation reaction and power to methane potential

Input parameter	Unit	Value
Hydrogen energy density	MWh/tonne H_2	33.33
Molar ratio in methanation reaction (H_2 : CH_4)	-	4 : 1
Molar mass of hydrogen	grams/mol	2
Molar mass of carbon dioxide	grams/mol	44
Carbon dioxide mass density (25°, 1 bar)	tonnes CO_2/m^3	0.00179
Share of CO_2 in biogas produced	%	42%[228]
Methanation efficiency	%	80%
Molar mass of methane	grams/mol	16
Methane energy density (HHV)	kWh/kg CH_4	15.40
Energy ratio in power to methane process (MWh H_2 produced : MWh CH_4)	MWh H_2/MWh CH_4	1.35[229]

The levelised cost of power to methane in 2050 has been assessed and it is comprised of annualized investment costs, annual operation and maintenance costs and methane feedstock costs.

$$\text{Power to methane } LCoX\ [EUR/MWh\ CH_4] = Investment\ costs + O\&M\ costs + Methane\ feedstock\ costs$$

The methanation process requires additional investment costs, namely a methanation reactor unit. Currently, investment costs for the methanation reactor are very high and there is a large uncertainty on what the investment cost will be for methanation reactors in 2050, mainly due to the lack of commercially deployed units. In the literature different sources report different investment costs ranging between €175/kW to €1000/kW[230]. Navigant assumes a specific methanation reactor CAPEX of €400/$kW_{\text{HHV-SNG output}}$ for a 5 MW plant capacity[231] with a lifetime of 20 years[232] and a 'societal' discount rate of 5%.

[228] Raw biogas has a CO_2 content of 45%. In biogas to biomethane upgrading 42 percentage points of this are captured while 3% of CO_2 is included in grid-fed biomethane

[229] This energy ratio has been calculated as the TWh of H_2 produced from otherwise curtailed power divided by the TWh of CH_4 produced after the methanation reaction. 199 TWh of H_2 are produced from otherwise curtailed power and 147 TWh (HHV) of renewable methane are produced after methanation. This leads to an energy ratio in power to methane process of 1.35.

[230] Götz et al. (2015). Renewable Power-to-Gas: A technological and economic review, page 1383. https://www.sciencedirect.com/science/article/pii/S0960148115301610

[231] Graf et al. (2014). Abschlussbericht "Techno-ökonomische Studie von Power-to-Gas-Konzepten", page 77. https://www.dvgw.de/medien/dvgw/leistungen/forschung/berichte/g3_01_12_tp_b_d.pdf

[232] Enea Consulting (2016). The potential of power-to-gas, page 38. http://www.enea-consulting.com/wp-content/uploads/2016/01/ENEA-Consulting-The-potential-of-power-to-gas.pdf

Additional CAPEX costs of 50% of the reactor's CAPEX have been considered to account for civil works, Balance of Plant (BoP), transport, installation and commissioning of the methanation plant[232].

We assume that the methanation unit will run as twice the amount of time as the electrolyser unit, i.e. 4000 full-load hours, aiming to maintain a continuous operation of the methanation reactor and reduce its specific CAPEX. Next to it, an onsite small-scale hydrogen storage capacity will serve as a hydrogen supply buffer at times when otherwise curtailed power is not available from the grid and therefore hydrogen cannot be produced through electrolysis. With this set-up, the operation of the methanation reactor is optimised.

To calculate the investment costs, we take into account the total CAPEX, both the methanation reactor's specific CAPEX and the additional CAPEX, the methanation reactor's load capacity, the lifetime of the methanation reactor unit and the societal discount rate. Annualized investment costs amount to €12/MWh CH_4.

$$\begin{aligned} &Investment\ costs\ [EUR/MWh\ CH_4] \\ &= \frac{Specific\ CAPEX * (1 + Additional\ CAPEX)}{Methanation\ reactor\ load\ capacity} * Annual\ capacity\ recovery\ factor \end{aligned}$$

Where:

$$Annual\ capacity\ recovery\ factor = \frac{r}{1-(1+r)^{-L}}$$

Where:

r = societal discount rate (default 5%)

L = lifetime of methanation plant

Annual O&M costs are calculated as 8% of the methanation reactor's specific CAPEX[231] and taking into account the methanation reactor's load capacity. Annual O&M costs amount to €8/MWh CH_4.

$$O\&M\ costs\ \left[\frac{EUR}{MWh\ CH_4}\right] = Annual\ OPEX\ of\ methanation\ reactor\ (\%) * Specific\ CAPEX\ \left[\frac{EUR}{kW_{HHV-CH_4}}\right]$$

Methane feedstock costs are calculated based on the hydrogen feedstock cost obtained after the electrolysis production process, onsite hydrogen storage and compression costs, and on the energy ratio that accounts for the MWh of hydrogen required per MWh of methane output[229].

$$\begin{aligned} &Methane\ feedstock\ costs\ \left[\frac{EUR}{MWh\ CH_4}\right] \\ &= (Hydrogen\ feedstock\ cost + Hydrogen\ storage\ \&\ compression\ cost) \\ &* Energy\ ratio\ \left[\frac{MWh\ H_2}{MWh\ CH_4}\right] \end{aligned}$$

After the electrolysis process, a levelised production cost for power-to-hydrogen of €25/MWh of hydrogen is assumed[233]. This cost is based on 2000 full-load hours of the electrolyser unit and €0/MWh of electricity cost. For 350 bar above ground storage, a cost of €13/MWh[234] is assumed on top of €2/MWh for compression costs required to store hydrogen. This study considers a 2050 compression electricity cost of €40/MWh. Overall, a total hydrogen storage cost of €15/MWh is considered. Table 32 gives an overview of all the cost assumptions used. Methane feedstock costs amount to €54/MWh CH_4.

[233] Navigant own power-to-hydrogen analysis.

[234] DOE, figure for 2016: https://www.osti.gov/biblio/1343975

Table 32 Power to methane: Investment, O&M and methane feedstock costs in LCOX assessment

Input parameter	Unit	Value
Methanation investment costs		
Methanation reactor load capacity	hours/year	4,000
Specific CAPEX of methanation reactor unit	EUR/kW$_{HHV\text{-}SNG\ output}$	400
Additional CAPEX of plant[235]	% of specific CAPEX	50%
Lifetime	years	20
Societal discount rate	%	5%
O&M costs		
Annual OPEX of methanation reactor	% of specific CAPEX/year	8%
Methane feedstock costs		
Hydrogen feedstock cost for power to methane	EUR/MWh of H_2	30
Onsite above ground hydrogen storage (350 bar)	EUR/MWh of H_2	13
Electricity cost for hydrogen compression	EUR/MWh	40
Hydrogen compression costs	EUR/MWh of H_2	2
Energy ratio in power to methane process (MWh H_2 produced : MWh CH_4 output)	MWh H_2/MWh CH_4	1.35[229]
Hydrogen feedstock and storage cost	EUR/MWh of CH_4 output	54

Considering all cost assumptions in Table 29 and the EU-wide methane potential of 147 TWh of methane, we estimate a **levelised cost of power to methane** (LCoX) **of €74/MWh in 2050**, comprised of €12/MWh CH_4 of investment costs, €8/MWh CH_4 of O&M costs and €54/MWh of CH_4 feedstock cost.

[235] Additional CAPEX costs account for civil works, Balance of Plant (BoP), transport, installation and commissioning of the methanation plant.

Appendix D. The potential for EU-produced liquid biofuel

Liquid fuels can play a valuable role in heavy transport, where high energy density fuel is required. Especially in aviation there are few alternatives to liquid kerosene. Liquid fuels can use the existing fuelling infrastructure which is cost-efficient. In a net-zero emissions energy system all energy including liquid fuels has to be net-zero emissions energy. This can be achieved by production of renewable liquid fuels such synthetic fuels produced from renewable electricity or biofuels.

Biofuels will be produced from sustainable sources. Such sustainable sources include waste and residue materials, or crops or wood with short rotation that are cultivated in such way that no competition with food and feed takes place. The main sources for sustainable low ILUC liquid biofuel production are:

1. Used cooking oil
2. Animal fats
3. Crude tall oil as far as no competition with non-fuel uses occurs
4. Short-rotation plantation wood cultivated with low indirect land use change (ILUC) impacts.

Additional potentials may be possible from The potential for the oil types 1-3 is defined here as excess availability not competing with other, non-biofuel feedstock uses.

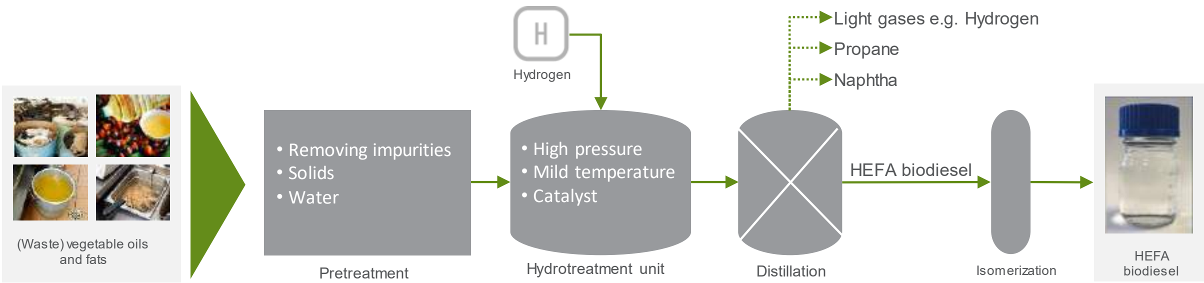

Figure 45 Production of hydrotreated vegetable oil

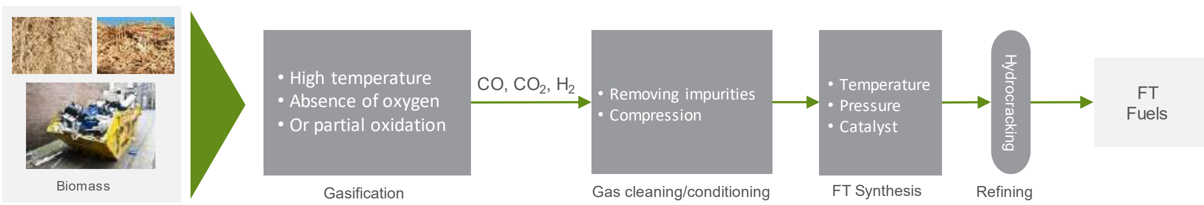

Figure 46 Production of fischer tropsch fuels

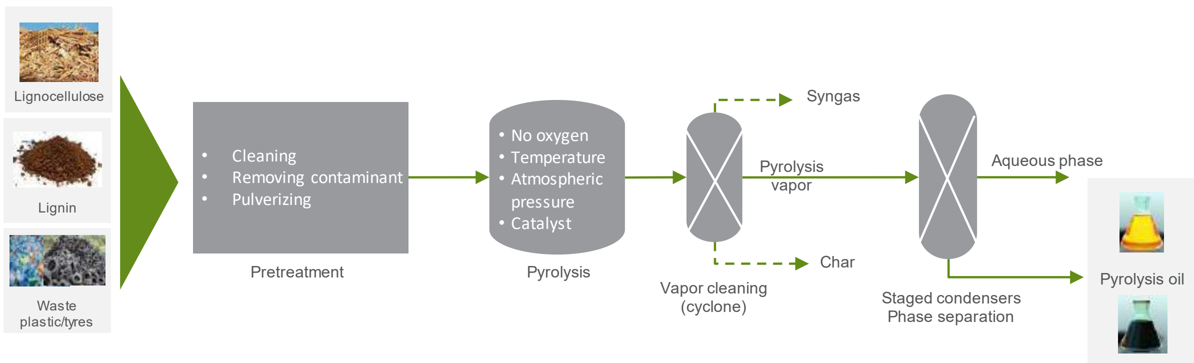

Figure 47 Production of fuels via pyrolysis

The overall annual potential for HVO production is 3.5 million tonnes per year. This biomass can be converted to 3.3 million tonnes of HVO, or 41 TWh. In addition, 60 million tonnes of low ILUC risk short-rotation plantation wood (dry matter) could be produced on 6 million hectares of abandoned agricultural land in the EU. These feedstocks combined can produce a quantity of 16 million tonnes of liquid biofuel, equal to 198 TWh. This means that the total low ILUC-risk potential of liquid biofuel in the EU would be at 239 TWh, consisting of 41 TWh of HVO and 198 TWh of FT diesel. This is a conservative estimate since biofuels produced from additionally produced low ILUC-risk oil crops are not included. We have assessed the following feedstocks:

Used cooking oil:

- **Characterisation:** Used cooking oils (UCOs) are oils and fats that have been used for cooking or frying in the food processing industry, restaurants, or by households.
- **Competing uses:** Of UCOs, 90% are already used for biodiesel production.
- **Low ILUC-risk EU-potential:** 1.7 million tonnes annually.

Animal fats:

- **Characterisation:** Animal parts are separated at the slaughterhouse into parts that are fit for human consumption and those that are prohibited from entering the human food chain (collectively termed “animal by-products”).
- **Competing uses:** Of Cat 1 and 2, 82% is already used for biodiesel production. Cat 3 is used for animal feed (33%), oleochemical products (24%), and biodiesel (20%).
- **Low ILUC-risk EU-potential:** 1 million tonnes annually.[236]

Crude tall oil and tall oil pitch

- **Characterisation:** Crude tall oil (CTO) is generated in the Kraft chemical wood pulping process, mainly from pine trees. Pulping process generates a residue called black liquor which is typically fed back into the pulping process. Crude sulphate soap (CSS) is first removed; it can either be burned as process fuel or further processed into CTO in an acidulation plant (typically co-located with mill). CTO yield is around 1.25%-4% of pulp output. Tall oil pitch (TOP) is the heavy end material left over from CTO distillation.
- **Competing uses:** Of CTO, 80% is distilled into a variety of products and 13% is used for biodiesel production. TOP is mainly used for combustion; some additional supply could be made available
- **Low ILUC-risk EU-potential:** 0.8 million tonnes annually.[237]

Low ILUC-risk oil, sugar, starch crops, short-rotation plantation wood, or short-rotation coppice cultivated with low ILUC impacts

The availability of waste and residue materials available for bioenergy is limited. This is problematic given that biomethane and liquid biofuel can play a valuable role to decarbonise the EU energy system in an affordable way. It is possible to increase the biomass availability by adding low ILUC-risk biomass. Low ILUC risk means that biomass is produced in addition to reference production levels through increased yields, including sequential cropping, or production on unused land. The EU included a possibility for low ILUC-risk biofuels in the updated Renewable Energy Directive (REDII).

The development of low ILUC-risk biofuels is still at its infancy today and experience has to be gained in the credible identification and demonstration of low ILUC-risk biofuels.

---

[236] The information and data for UCO and animal fats are in-house expertise based on a variety of studies.

[237] Ecofys, Crude Tall Oil low ILUC risk potential assessment. Comparing global supply and demand (2017), see: https://www.upmbiofuels.com/siteassets/documents/other-publications/ecofys-crude-tall-oil-low-iluc-risk-assessment-report.pdf

Our EU biomethane potential includes a supply of biomass from additional crop yields resulting from sequential cropping in the sustainable feedstock mix. In our potential for liquid biofuel from EU feedstocks the cultivation of biomass on abandoned land is considered.

Abandoned land is previous agricultural land which is no longer in production. A trend in land abandonment can be observed in the EU. The UAA in the EU-28 has decreased from about 190 million hectares in 2000 to 176 million hectares in 2017.[238] This means that around 14 million hectares of previous agricultural land is no longer in production. Some uncertainty exists on the reliability of these data, given that not all reporting on UAA in specific EU member states matches with data as included in the Farm Structure Survey, another EU database. Still, the order of magnitude seems to be correct.[239] Not all abandoned land is available for biomass production since some of it is converted to forested area or urban area and infrastructure. The European Environmental Agency (EEA) states that about 90,000 hectares of EU land is converted for the purpose of urbanisation annually.[240] This means that the EU urban area has increased by around 1.5 Mha since the year 2000. The EU forested and woodland area has increased significantly in previous decades, growing from 174 Mha to 177 Mha between 2000 and 2010,[241] and reached 182 Mha in 2016.[242] This means that 9.5 million hectares of land has been converted to either urban area or forest since 2000. If all this land is assumed to be recently abandoned agricultural land, a remaining area of 6 million hectares of recently abandoned agricultural land would exist in the EU.

This area of 6 million hectares of currently available recently abandoned land is likely to be not the most fertile land and it may not be feasible to use it for oil crop production while achieving high yields. Most likely, this land could be used to produce either silage crops (e.g., maize, wheat, or triticale silage) or short-rotation plantation wood or coppice (e.g., willow or poplar). Six million hectares of willow plantations generate 60 million tonnes of biomass. We allocate all of this biomass to liquid biofuels, which generates 15 million tonnes of advanced diesel, or 186 TWh.

---

[238] EC (2018, Land cover and Land Use https://ec.europa.eu/agriculture/sites/agriculture/files/statistics/facts-figures/land-cover-use.pdf

[239] For example, Hart et al. (2013) concludes that between 1990 and 2010 agricultural land in the EU-27 declined by approximately 15.7 Mha

[240] European Environmental Agency, https://www.eea.europa.eu/airs/2018/natural-capital/urban-land-expansion

[241] European Commission based on Eurostat (2011), https://ec.europa.eu/eurostat/documents/3217494/5733109/KS-31-11-137-EN.PDF, page 13.

[242] Eurostat 2016, https://ec.europa.eu/eurostat/documents/3217494/7777899/KS-FK-16-001-EN-N.pdf/cae3c56f-53e2-404a-9e9e-fb5f57ab49e3

Appendix E. Carbon capture, storage and utilization

E.1 Summary

The Gas for Climate consortium supports a net-zero emissions energy system in the EU by 2050. This can be achieved through rapid decarbonisation by focusing on energy efficiency, increased use of renewable energy, and by decarbonisation through capturing CO_2 emissions and storing them in the subsurface (CCS) or using them in products or as industrial feedstock (CCU).

In February 2018, Gas for Climate published a study by Ecofys, a Navigant company, on the role of renewable gas in the energy system.[243] This study showed that it is possible to scale up biomethane and green hydrogen and that using this renewable gas in a smart combination with renewable electricity can decarbonise the EU energy system while reducing costs compared to a decarbonisation scenario without any gas. In addition to using renewable gas it is also possible to use the following routes to decarbonise gas demand:

- *Distributed:* using natural gas in industrial processes that are equipped with CCS.
- *Centralised:* producing *blue hydrogen* from natural gas in a hydrogen manufacturing unit that is equipped with CCS, after which the hydrogen can be used in industrial processes to substitute carbon intensive fuels. Sometimes also referred to as *pre-combustion CCS*.

The potential costs and benefits of these two low-carbon gas routes were not explored in the previous study. This study broadens the scope of the Gas for Climate work by exploring the potential of low-carbon gas in the EU. It focuses on the question of how much CCS and CCU can be deployed, and at what cost, to support the decarbonisation of gas in Europe in addition to the scale-up of renewable gas. To understand where CCS and CCU can realistically be applied, we consider various societal and technical boundary conditions, such as public attitudes towards CO_2 storage in EU member states and the emissions that can realistically be captured from industrial sites. To identify the short-term possibilities for CCS and CCU, we illustrate case studies for six industrial clusters.

We identify the following key findings:

1. **Significant potential for CCS exists in Europe based on a vast geological storage potential, with a noteworthy role for CCU under strict boundary conditions.**

   Present gas demand in the industry and energy sector could be decarbonised by applying CCS to a significant extent, considering a significant potential of around 134 $GtCO_2$, including Norway. Biogenic CCU and permanent fossil CCU options can also play a noteworthy role. Storage potential through chemical feedstocks can be significant compared to annual EU emissions but are only stored permanently under strict boundary conditions. Geological storage potential for CO_2 is more significant, and associated costs are not necessarily a limiting factor for the decarbonisation of gas. However, since not all CO_2 can be captured, remaining emissions should be compensated by using bio-based feedstocks in CCS-equipped processes, or by realizing negative emissions elsewhere. Further large-scale demonstration of CCS and CCU, together with supporting policies are required to materialise this potential.

[243] https://gasforclimate2050.eu/files/files/Ecofys_Gas_for_Climate_Report_Study_March18.pdf

2. **Large differences exist across EU member states in allowing geological CO_2 storage**.

   Various member states have introduced bans in national legislation by prohibiting CO_2 storage for a certain period, in certain areas (e.g., onshore) or by limiting the amount of storage in time until the technology is more proven. This would limit the total storage potential in Europe to around 77 $GtCO_2$ (i.e., 57 years of current emissions from industry and gas-fired power). Since CO_2 storage potential is concentrated in some regions, some countries may need to rely on cross-border CO_2 transport and storage if an ambitious CCS scenario were to be pursued and current legislative restrictions in CO_2 storage apply, most notably: Austria, Belgium, Czech Republic, Germany, Greece and Poland.

3. **There is a need for international CO_2 transport and storage networks, and some countries have indicated ambitions to store neighbouring countries' CO_2 emissions.**

   Emissions could be transported either by pipeline or by vessel. Some countries, such as Norway and the Netherlands, have indicated ambitions to store neighbouring countries' CO_2 emissions, which could be a solution to unfavourable attitudes and legislative restrictions on storage in some countries. Long-term national climate strategies generally have a more neutral stance on CO_2 storage, which may allow member states to use more of their domestic storage towards 2050. Discussions around CCS have shifted over time, now focusing more on the perceived risk that CCS can hold back the uptake of renewable energy and prevent further system change. This risk could be mitigated by clearly defining that CCS and CCU are temporary solutions that are required to optimise speed and costs of achieving net-zero emissions.

4. **Costs for CO_2 capture vary depending on the industrial process, from €15–€138/tCO_2 captured, although around half of the carbon capture potential lies between €40–€60/tCO_2.**

   The costs of capturing CO_2 depend highly on process characteristics (e.g., pressure, CO_2 concentration), economies of scale, and financial assumptions. Transport and storage of CO_2 adds another €5-€28/tCO_2 to this cost, depending on the terrain for transport (e.g., onshore/offshore) and type and size of storage (e.g., depleted hydrocarbon fields or aquifers). CO_2 capture in the production of hydrogen, ethylene oxide, and ethanol can generally be done at lowest cost, whereas capture from process heaters, power plants, lime kilns, and petrochemical crackers are the costliest. This difference is largely explained by the additional need for flue gas cleaning, process integration, and CO_2 purification and compression. Whether CCS or CCU will take off in a specific industry will depend largely on the costs of alternative mitigation options and the carbon price.

5. **If the technical potential of CCS is fully deployed in the iron and steel, chemicals and petrochemicals, cement, lime, and energy sectors, gas demand would increase by around 30%**.

   There is no linear relationship between CCS deployment and additional energy demand, since CO_2 from the less concentrated streams requires more thermal energy to capture. Since between 60% and 99% of all the greenhouse gas emissions can be captured from industrial sites, there is a need for negative emissions to achieve our ambition for a net-zero emission energy system in 2050. Using bio-based feedstock to produce biomethane and bioethanol in combination with CCS, a theoretical potential of 112–214 $MtCO_2$ negative emissions could be achieved which could contribute to getting the industrial and agriculture sectors to net-zero emissions. These bio-based fuels can then even be used in industrial CCS installations to realise further negative emissions.

6. **Since CO_2 storage potential is not a constraining factor to produce blue hydrogen, at least 5.8 million tonnes of low-carbon hydrogen (20 bcm) could be produced annually in the short term by retrofitting existing hydrogen manufacturing units with CCS.**

   Costs to produce blue hydrogen vary between €1,290/tH_2–€2,110/tH_2 (€39/MWh–63/MWh) for production in a steam methane reformer (90% capture rate), or €1,190/tH_2–€1,850/tH_2 (€36 MWh–€56/MWh) for production through autothermal reforming (95% capture rate). This cost is highly sensitive to the natural gas price, which will partly determine its competitiveness with green hydrogen. While the production of green hydrogen is not yet cost competitive in most cases, current levels of hydrogen production could be rapidly converted to blue hydrogen production by retrofitting existing production capacity with CCS.

7. **Industrial clusters with a strong chemical and petrochemical industry often provide the best low-cost opportunities for the early upscaling of CCS and CCU.**

   When an industrial cluster is situated close to steel or petrochemical industry, cross-sectoral opportunities arise in the re-use of steel off-gases as a feedstock in the chemical industry. Generally, average costs for CCS in industrial clusters are quite similar across the six that were within the scope of this study,[244] between €70/tCO_2–€90/tCO_2. The influence of low-cost opportunities is rather small on overall cluster costs, since low-cost point-sources are often relatively small in CO_2 amount. The six clusters that were studied together have the potential to capture and store around 57 $MtCO_2$/yr.

E.2 Introduction

To reduce greenhouse gas emissions to net zero by 2050, the EU will need to focus on rapid decarbonisation through accelerated energy efficiency, a transition towards renewable energy, and tackling hard-to-abate emissions by deploying CCS or CCU technologies.[245] By contrast, CCS has had little political incentive to take off and deploy at the speed required to stay well below 2°C of warming by the end of this century. However, with the recent steep increases in the carbon price,[246] and with the prospective ETS Innovation Fund[247] launching around 2021, this may change soon. Signals of CCS deployment are already showing, most notably in the Port of Rotterdam and the Liverpool-Manchester region, mainly to capture emissions originating from the production of hydrogen.[248] CCS and CCU could facilitate the production of blue hydrogen, which can be used to substitute carbon-intensive fuels. CCS and CCU can also be deployed to decarbonise industrial processes that rely on fossil fuels like natural gas and to achieve negative emissions by using biogenic feedstocks in combination with CCS.

---

[244] Port of Antwerp (Belgium), Port of Rotterdam (Netherlands), Krefeld-Uerdingen (Germany), Tarragona (Spain), Marseille-Fos (France), Porto Marghera (Italy).

[245] Haszeldine et al., 2018. *Negative emissions technologies and carbon capture and storage to achieve the Paris Agreement commitments.* http://rsta.royalsocietypublishing.org/content/376/2119/20160447

[246] EU carbon prices could average €35 – 40/tCO_2 over the period 2019 – 2023. Source: Carbon Tracker, 2018. *Carbon Countdown – Prices and Politics in the EU-ETS.*

[247] The Innovation Fund is a fund from the EU emission trading system that will be endowed with 450 million allowances to support large-scale demonstration of activities in CCS, renewable energy and CCU, among others.

[248] Euractiv, 2018. *Meet Europe's two 'most exciting' CO_2 capture and storage projects.*

This study builds on an earlier study by Ecofys, a Navigant company, for the Gas for Climate consortium in which we explored the potential of renewable gas in the EU.[249] This study expands the scope by focusing on low-carbon gas, meaning the use of natural gas in combination with CCS, CCU, or the use of blue hydrogen. It explores how much CCS and CCU can be realised, and at what cost, to support the decarbonisation of gas in Europe alongside renewable gas. We explore a scenario where the technical potential of CCS and CCU is deployed towards 2050, though still considering the public attitudes towards CO_2 storage in EU member states.

Appendix E.3 assesses the potential for geological storage of CO_2 in EU member states. Storage potential in materials such as feedstock through CCU is also assessed in this Appendix. Costs and the impact on energy demand are highlighted. These results are presented in a marginal abatement cost (MAC) curve in Appendix E.3.5. The section further compares options for blue hydrogen production and negative emissions, which can contribute to achieve net-zero emissions in the energy system.

Appendix E.4 investigates public attitudes towards CCS in EU member states by assessing favourability towards CCS in already implemented legislation and long-term energy and climate strategies. Based on this, it aims to determine a realistic potential of available CO_2 storage in the EU and shed light on the needs for cross-border CO_2 transport, since not all CO_2 storage potential is evenly distributed.

Appendix E.5 aims to illustrate the results from the second section by assessing how CCS and CCU can be scaled up in the short term and what the associated costs are on a cluster level, focusing on six European industrial clusters. Since various options for the decarbonisation are discussed in this study, the results will be used as input to our intersectoral model and optimised to achieve lowest societal cost. This will be done after the present study; the results will be published early 2019.[250]

E.3 Sectoral CCS and CCU potential and costs

Carbon capture and storage is widely accepted to be a necessary technology for the rapid decarbonisation of some industries. For the energy sector this is less the case, since renewables provide a good alternative to fossil fuel-fired power plants. However, the value of a dispatchable low-carbon power source may become sufficiently high to still allow low-carbon gas-fired power plants on the grid. Carbon capture and utilisation is also much-discussed and has featured prominently in sector strategies as a method to replace fossil feedstocks. Costs for capturing differ significantly, which means that expensive options may be outcompeted by other mitigation strategies.

This section explores the potential role for CCS and CCU in decarbonising gas if their technical potentials are towards 2050. It does so by assessing two key pathways:

- *Distributed:* Using natural gas in industrial processes (including power generation) that are equipped with CCS.
- *Centralised:* Producing *blue hydrogen* from natural gas in a hydrogen manufacturing unit that is equipped with CCS, after which the hydrogen can be used in industrial processes to substitute carbon intensive fuels. Sometimes also referred to as *pre-combustion CCS*.[251]

---

[249] Ecofys, 2018. *Gas for Climate: how gas can help to achieve the Paris Agreement target in an affordable way*.

[250] Gas for Climate, 2018. *European gas infrastructure companies and renewable gas producers: 'save billions of euros by setting ambitious target for renewable gas'*. https://gasforclimate2050.eu/news

[251] This term is not further used, since this term implies that the hydrogen is later combusted.

This section further explores whether the available CO_2 storage potential in Europe is sufficient to store emissions from the industry and energy sectors, and whether this would limit the extent to which CCS and CCU can be used as a decarbonisation option from a societal cost perspective. Finally, estimates are provided on the cost and options for blue hydrogen production, and on options for negative emissions in industry.

E.3.1 CO_2 Storage Potential

When emissions have been captured, various options exist to store CO_2, in geological reservoirs such as depleted oil & gas fields, saline aquifers, or even coal fields and basaltic rock. Besides storing CO_2 in the subsurface, CO_2 can also be used in products or even locked permanently in products. The latter is generally called CCU (Table 53).

E.3.2 Geological CO_2 Storage

To assess the potential for geological storage of CO_2 in the EU, we consider conservative estimates that were obtained during the GeoCapacity project.[252] If all types of storage reservoirs are considered, the geological storage potential for CO_2 in the EU is around 104 $GtCO_2$.[253] Including Norway, a country that features prominently in European CCS activities, this potential increases to around 134 $GtCO_2$ (Appendix E.6.2, Table 38).

E.3.3 Carbon Capture and Utilisation

CCU technologies that permanently bind CO_2, such as CO_2 mineralisation in aggregates production, can potentially play a noteworthy role in the decarbonisation of industry towards 2050. It is estimated that nearly 70 $MtCO_2$/year can be stored permanently in the form of aggregates and novel construction materials if appropriate calcium or magnesium oxide-containing waste streams are fully recycled and carbonated.[254]

Other CCU technologies that offer either semi-permanent or temporary CO_2 storage (like in case of CO_2 enabled chemicals and fuels production, horticulture, or enhanced oil recovery) do displace feedstock and thereby mitigate emissions. However, the abatement effect for these CCU options can only be quantified through full lifecycle analyses. At the moment, there is no uniform or standardised LCA approach for CCU technologies, and large flexibility in interpreting methodological choices exists which may produce a wide range of results. Therefore, the abatement impacts of these CCU options are often not comparable and can only be determined and compared in a robust way once harmonised LCA standards are defined. These non-permanent CCU options only seem to fit in a net-zero emissions system if either biogenic CO_2 is used or if there are direct air capture systems involved that recycle atmospheric CO_2. No additional CO_2 should be emitted in the process.

---

[252] EU GeoCapacity, 2009. *Assessing European Capacity for Geological Storage of Carbon Dioxide.* http://www.geology.cz/geocapacity/publications/D16%20WP2%20Report%20storage%20capacity-red.pdf

[253] See Appendix 0 for an overview of geological storage potentials in EU Member States. It should be noted that some estimates require more thorough geological research. For example, geologists from Enagás have indicated that the potentials for Spain may be overestimated.

[254] Estimates are developed based on CO_2 binding capacity of different waste volumes in the EU. The following waste categories are incorporated: blast furnace slag, cement kiln dust, mineral construction waste, bauxite residue and air pollution control residue. CO_2 storage capacity via concrete curing is also included in total estimates. Currently, these streams have different end-uses and would be competing with CCU.

Non-permanent CCU options can play an important role in avoiding the use of fossil resources and in enabling a transition of the chemical and fuel sectors towards full decarbonisation. Many technologies required to decarbonise the chemical sector rely heavily on CO_2 as a feedstock. Such technologies include methanol-to-olefins and methanol-to-aromatics to produce BTX, and the production of synthetic fuels. Some estimates mention a requirement of 258 $MtCO_2$/year to decarbonise the chemical sector in 2050.[255] Depending on the end-of-life treatment of these CO_2-based products, some of this CO_2 may be released back into the atmosphere.[256] Together with the estimate for mineralization of CO_2 in aggregates, construction materials, and feedstock could deliver around 328 $MtCO_2$/year of storage potential. This is relatively small compared to the geological storage potential of CO_2 but significant in relation to the EU's industrial emissions of around 1.3 $GtCO_2e$ and could deliver some interesting business cases in the short term.

In many cases, CCU displaces the need for natural gas and replaces this with a need for additional hydrogen and CO_2 to produce fuels or base chemicals. This is because CO_2 is used to substitute fossil feedstocks in the production of chemicals, for example, natural gas in horticulture. For some CCU options, it will depend on how the additional need for hydrogen is met (green or blue hydrogen) to make a conclusion on whether natural gas demand decreases or increases.

E.3.4 Costs of Carbon Capture and Storage in Industrial Processes

The cost of CO_2 capture at an industrial facility depends on numerous factors such as the amount of CO_2 that is captured, the purity of the CO_2 stream, the concentration of CO_2 in flue and off-gases of the process the availability of excess heat, and pressure, among others. Economies of scale and financial assumptions such as discount rates can also strongly affect the cost. Carbon capture can be applied to the majority of industrial processes but are most common for those illustrated in Table 33. The most significant factor determining the spread in costs is the purity of CO_2 in the processed flue gas.

Typically, refineries have complex processes which are associated with numerous point sources of emissions distributed over a large site. This is also true to an extent for chemical production facilities and steel mills. Since there are several sources of CO_2 per site, multiple carbon capture plants or some method of combining flue gas streams would be needed to capture a large fraction of the total site emissions. Generally, the largest point sources of CO_2 emissions are heat and power installations, steel plants, and cement plants, which often exceed 1 $MtCO_2$/year.

At refineries and chemical production sites, the costs of carbon capture for some of the processes is low when compared to other onsite processes. For example, hydrogen and ethylene oxide production have low-carbon capture costs when compared with process heaters, primarily because of the pure CO_2 stream and lower requirements for cleaning and purification. For gas processing, as well as ammonia and ethanol production, a pure stream of CO_2 is emitted that can be captured at relatively little marginal cost. An overview of costs for industrial capture of CO_2 is provided in Figure 48.

---

[255] DECHEMA, 2017. *Technology study: Low carbon energy and feedstock for the European chemical industry.* https://dechema.de/dechema_media/Downloads/Positionspapiere/Technology_study_Low_carbon_energy_and_feedstock_for_the_European_chemical_industry.pdf

[256] If a product that contains carbon is treated in a waste incinerator, the CO_2 will end up in the atmosphere. Ideally, this loop would be closed by capturing that CO_2 from a waste incinerator and storing it or locking it in a product again. Alternatively, the product could be recycled, on the condition that no net CO_2 emissions are created.

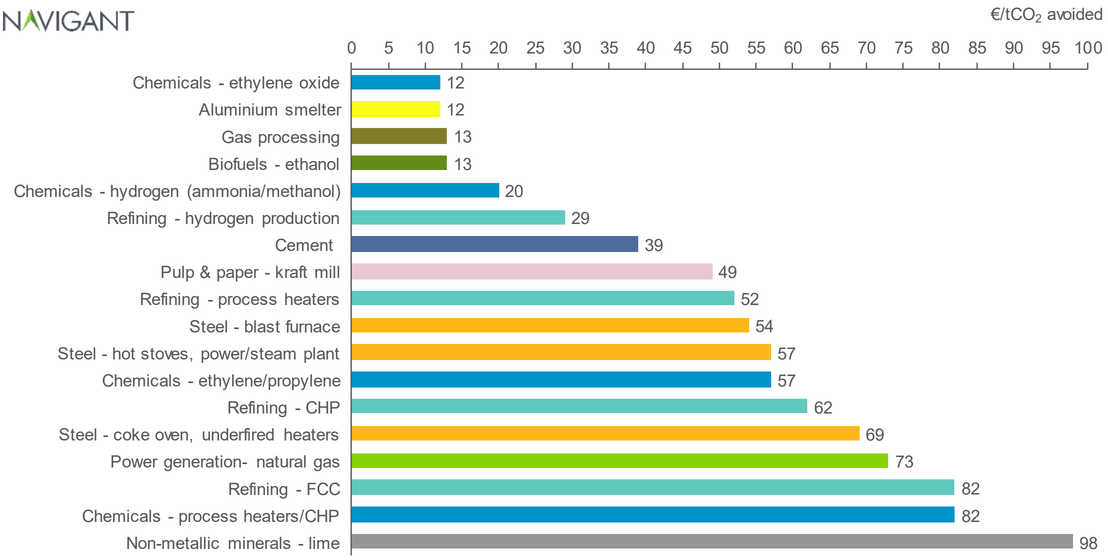

Figure 48 Overview of median carbon capture costs in various industrial processes. Bar colours match for industrial processes in the same industrial sector.[257]

The costs for storage and transport can vary widely. Consequently, the contribution to the overall CCS costs can range from small to significant.[258] There are two major methods of transporting CO_2; by pipelines (onshore and offshore) and by ship. The costs of CO_2 transport depend on the transported distance, CO_2 volumes, method used to transport, and the diameter of pipelines or the size of vessel.[259] Pipeline costs are proportional to the distance transported since more than 90% of the pipeline costs relate to CAPEX. Shipping costs, on the other hand, are marginally influenced by the distance as CAPEX has a significantly lower contribution to the total annual costs. For the transport of CO_2 over distances between 10 km–1,500 km, onshore pipeline costs can range between €0.1–€16/tCO_2, whereas offshore pipelines costs can vary between €2–€29/tCO_2.[260] The ranges are estimated for transported volumes of 2.5, 10, and 20 MtCO_2/year. The first two flow rates assume a one-on-one, point-to-point connection between a source and a sink. The last scenario, with the flow rate of 20 MtCO_2/year, considers a large-scale integrated network of CO_2 sources connected to multiple storage sites. Economies of scale effects are considerable in pipeline transport, while this effect is less significant for ship transport. Costs for ship transport vary between €10–€20/tCO_2 and this method is usually preferable when small volumes (2.5 MtCO_2) need to be transported over long distances (>180 km).

Costs for CO_2 storage can vary widely and are sensitive to various factors such as the type of storage, field capacity and well injection rate, amongst others.[261] Onshore storage is usually less costly compared to offshore storage. Moreover, it is cheaper to store CO_2 in depleted oil & gas fields than in saline aquifers due to pre-existing infrastructure. Costs for storage can vary between €1–€13/tCO_2 onshore, and between €2–€22/tCO_2 offshore.[262]

---

[257] See Appendix 7.E.6.2 for underlying cost figures and an overview of literature sources used. Graph only shows median values.

[258] ZEP (2011). The Costs of CO_2 Capture, Transport and Storage. http://hub.globalccsinstitute.com/sites/default/files/publications/17011/costs-co2-capture-transport-and-storage.pdf

[259] See Appendix 7.E.6.2 for the cost figures on transport under different scenarios.

[260] Excluding a scenario where only 2.5 MtCO_2 is transported over 1500 km offshore.

[261] ZEP (2011). The Costs of CO_2 Storage.

[262] See Appendix 7.E.6.2.

Table 33 Overview of transport and storage costs in €/tCO_2. Transport cost ranges are presented for transport distances of 10 km–1,500 km and transport volumes of 2.5, 10, and 20 MtCO_2/year.[259] Storage cost ranges are given for different storage fields and for field capacities of 40, 66, and 200 MtCO_2, with flow rates of 1, 2, and 5 MtCO_2/year, respectively.[262]

	Onshore	Offshore	Shipping
Transport	0.1–16	2–29	10–20
Storage	1–13	2–22	NA
TOTAL	**1–29**	**4–51**	

E.3.5 Technical potential for CCS and CCU

Distributed decarbonisation (industrial CCS/CCU)

Typically, the most-discussed type of CCS and CCU is the one where capture technology is applied to an individual point-source of CO_2 emissions, after which the CO_2 is transported and sequestered geologically or used in products. The challenge is that not all CO_2 can be realistically captured due to varying site characteristics. Some industrial sites have a significant number of flue gas stacks, whereas others are too small to economically apply CCS to. This means that generally about 60% of the emissions can be captured on an iron and steel site, whereas this might be up to 99% for the production of bioethanol. If we take these capture limitations into account, around 874 MtCO_2/year could be captured and stored from the EU industry sectors (Figure 49). If CCS were scaled up to this level in 2050, only around 15% of the total storage potential would be depleted by that year, with sufficient potential left for the rest of the century.[263]

This approach also has significant implications for the thermal energy demand in the sector. Most carbon capture installations require additional thermal energy for their operation, which is assumed to be met through natural gas. For the sectors within the scope of this study,[264] overall gas demand is expected to increase by 30% compared to current levels if CCS and CCU are deployed to their full technical potential, not taking into account any progress in efficiency. However, there is no linear relationship between CCS deployment and additional energy demand, since CO_2 from less concentrated streams requires more thermal energy to capture. Deploying the full technical potential would mean that the iron and steel, cement, lime, chemicals and petrochemicals, and energy sectors would together have a gas demand of around 219 bcm/year. The role of gas in the energy sector is still significant in the technical potential illustrated in Figure 49, since the assumption is that any additional thermal energy demand would be satisfied with gas-fired power and that current natural gas installations still operate at present-day load hours. It should be taken into account that, due to the penetration of renewables towards 2050, the load factor of gas-fired power plants with CCS would drastically reduce, increasing the cost of this mitigation option beyond what is illustrated in Figure 49.

[263] Assuming that linear scale-up starts by 2025 and the total available potential is 77 GtCO_2. This is the potential that is left if we assume that existing legislative restrictions on geological storage of CO_2 remain.

[264] Based on an analysis of existing gas demand in industrial sectors and suitability of CCS per sector, the following sectors were shortlisted: iron and steel, cement, chemicals and petrochemicals, lime and energy. Jointly, these sectors are responsible for a gas demand of around 6,900 PJ, equivalent to around 180 bcm of gas. This represents around half of the current total gas demand in the EU28. Source: IEA, 2018. *World Energy Balances*.

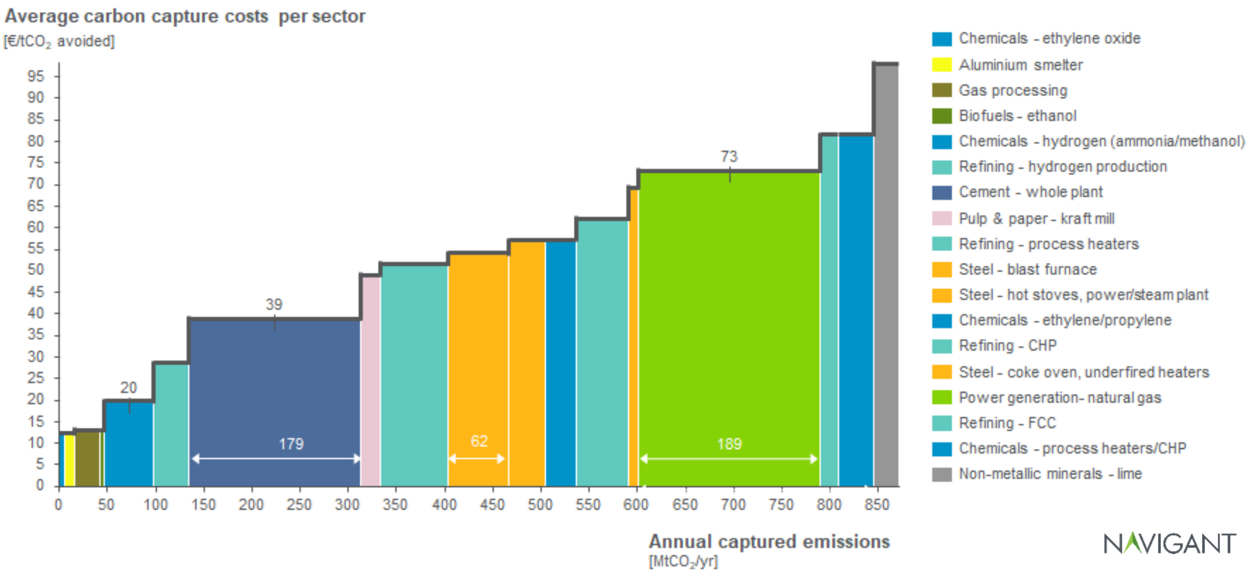

Figure 49 Marginal abatement cost curve for industrial carbon capture in the EU. The curve shows that around 874 $MtCO_2$ can be technically captured from all these sectors if CCS were to be fully deployed. Costs displayed are median values.[265,266,267,268,269,270]

Centralised decarbonisation (blue hydrogen)

Other than applying CCS or CCU to various individual point-sources of industrial CO_2 emissions, we can also consider applying CCS to the large-scale production of hydrogen to turn this into a low-carbon fuel, for subsequent use as a feedstock or fuel to substitute fossil-intensive alternatives. Note that process emissions generally cannot be mitigated through this approach,[271] so industrial processes with a significant share of process emissions such as cement production or petrochemical cracking would benefit more from distributed decarbonisation. The blue hydrogen route could also be interesting for installations that are too small or far off from a CO_2 pipeline network to realistically apply CCS to. In this case it could be more beneficial to decarbonise the use of gas higher up in the value chain in a hydrogen manufacturing unit and to transport that low-carbon thermal energy carrier to the consumption site in question, making use of the already more wide-spread H_2 networks, mainly in Northwest Europe. However, this would then need to compete with existing low-carbon fuel switch alternatives.

265 IEA, 2013. *Technology Roadmap: Carbon capture and storage.* https://www.iea.org/publications/freepublications/publication/TechnologyRoadmapCarbonCaptureandStorage.pdf

266 GCCSI, 2017. *Global costs of carbon capture and storage.* http://hub.globalccsinstitute.com/sites/default/files/publications/201688/global-ccs-cost-updatev4.pdf

267 Leeson et al., 2017. *A Techno-economic analysis and systematic review of carbon capture and storage (CCS) applied to the iron and steel, cement, oil refining and pulp and paper industries, as well as other high purity sources.* https://spiral.imperial.ac.uk/bitstream/10044/1/45768/9/1-s2.0-S175058361730289X-main.pdf

268 DECHEMA, 2017. *Low carbon energy and feedstock for the European chemical industry.* https://dechema.de/dechema_media/Downloads/Positionspapiere/Technology_study_Low_carbon_energy_and_feedstock_for_the_European_chemical_industry.pdf

269 JRC, 2017. *Energy efficiency and GHG emissions: Prospective scenarios for the Chemical and Petrochemical Industry.* http://publications.jrc.ec.europa.eu/repository/bitstream/JRC105767/kj-na-28471-enn.pdf

270 JRC, 2017. *Energy efficiency and GHG emissions: Prospective scenarios for the Paper and Pulp Industry.*

271 Except for the steel industry, through hydrogen-based steelmaking. Although some process emissions would still occur from the use of lime, graphite and preparation of iron ore.

This same approach goes for the production of biofuels. If the emissions originating from biogas or bioethanol production are centrally captured, carbon-negative fuels can be produced, even upon combustion (see Section 'Negative Emissions').

Currently around 8 million tonnes of hydrogen are produced in the EU.[272] An additional 0.2 million tonnes are produced as by-product from the chemical and refinery industries.[273] Nearly all of the steam methane reformers could be retrofitted with CO_2 capture technology if they can realise economies of scale. Whether new capacities will develop depends on the price of natural gas towards 2050, the availability of by-product hydrogen, and the affordability and availability of alternative thermochemical routes such as autothermal reforming, methane cracking, partial oxidation, electrolysis, downhole conversion, or microwave technologies.[274] Since the majority of steam methane reformers are situated in or around industrial clusters, and the purity of the flue gas CO_2 is relatively high, capture costs are among the lowest compared to other industrial processes. Since CO_2 storage potential does not seem to limit production of blue hydrogen (see Appendix E.3.2), the potential role for blue hydrogen could be especially large in the short term when green hydrogen is not expected to be sufficiently competitive. This means that towards 2050, the existing production capacity could be retrofitted with CCS, which would be in the order of 5.8 million tonnes a year (18 bcm natural gas equivalent).[275]

Cost Comparison of Blue Hydrogen Options

This section discusses the costs of blue hydrogen for the two most developed and cost-effective thermochemical routes, steam methane reforming (SMR) and autothermal reforming (ATR). Methane catalytic cracking for large-scale hydrogen production may also turn out to become more cost-effective in the future and could become more interesting due to the eliminated need to remove carbon monoxide, but is currently not considered due to its technology infancy.[276] The costs of producing hydrogen in a steam methane reformer (SMR), optimised to capture 90% of the emissions, is reported to be €1,710/t H_2 (€51/MWh),[277] compared to €1,190/t H_2 (€36/MWh) with a traditional steam methane reformer set-up without CCS.[278] This is however assuming a gas price of €17/MWh. Correcting for the different assumptions used in the Navigant reports and introducing a sensitivity in the gas price of up to €35/MWh,[279] the production cost of blue hydrogen in an optimised SMR would be €1,290–€2,110/tH_2 (€39–€63/MWh).[280] This is an important sensitivity to test when hydrogen from electrolysis becomes more competitive. Hydrogen from SMR is somewhat costlier to produce than through autothermal reforming (ATR), at a production cost of €1,190–€1,850/tH_2 (€36–€56/MWh) (Table 34). It is likely more attractive to extend the lifetime and retrofit existing SMR capacity with CCS than to decommission the installation and build an ATR.

---

[272] CertifHy, 2015. *Overview of the market segmentation for hydrogen across potential customer groups, based on key application areas*. https://www.fch.europa.eu/sites/default/files/project_results_and_deliverables/D%201.2.%20Overview%20of%20the%20market%20segmenatation%20for%20hydrogen%20across%20potential%20customer%20groups%20based%20on%20key%20application%20areas.pdf

[273] Hydrogen Europe, 2015. *Merchant Hydrogen Plant Capacities in Europe*. https://h2tools.org/hyarc/hydrogen-data/merchant-hydrogen-plant-capacities-europe

[274] Royal Society, 2018. Options for producing low-carbon hydrogen at scale. https://royalsociety.org/~/media/policy/projects/hydrogen-production/energy-briefing-green-hydrogen.pdf

[275] Maisonnier et al., 2007. *"European Hydrogen Infrastructure Atlas" and "Industrial Excess Hydrogen Analysis" PART II: Industrial surplus hydrogen and markets and production.* http://citeseerx.ist.psu.edu/viewdoc/download;jsessionid=535A04C6EB3703701C83F6675DDA8CBD?doi=10.1.1.477.3069&rep=rep1&type=pdf

[276] Epling et al., 2011. Review of methane catalytic cracking for hydrogen production. International Journal of Hydrogen Energy 36(4):2904-293.

[277] Using 119.96 MJ LHV.

[278] Based on 500 tonnes of H_2 production per day, delivered at 20 bar. 10% discount rate and 25 year lifetime assumed. Producing H_2 in an SMR with CCS in the "contemporary" set up captures only 70% of emissions. Source: Jakobsen & Åtland, 2016. *Concepts for Large Scale Hydrogen Production*.

[279] I.e. a discount rate of 5% and a lifetime of 30 years. Jakobsen & Åtland assume a discount rate of 10% with a lifetime of 25 years.

[280] For reference, the cost of biomethane was estimated to be €60/MWh.

Costs for retrofitting may even be lower than reported here. However, when capacity expansion is foreseen, ATR will likely be more economically attractive than SMR. Assuming a typical lifetime of 30 years, many SMRs will have seen a replacement cycle by 2050.

Table 34 Comparison between costs for steam methane reforming and autothermal reforming under different financial assumptions.

Hydrogen manufacturing process	Cost (€/tH_2) (source assumptions)	Cost (€/tH_2) (Navigant assumptions)
Steam methane reforming	1,710-2,400	1,290-2,110
Autothermal reforming	1,580-2,240	1,190-1,850

Negative Emissions

Through photosynthesis, living biomass absorbs CO_2 over its lifetime. Biomass can be harvested and used as a feedstock to produce various energy carriers. In this manufacturing process, CO_2 is often co-produced, for example in the production of ethanol or biomethane. When this CO_2 is captured and permanently sequestered, the lifecycle emissions of the fuel can become negative, which can be valuable in compensating hard-to-abate emissions to reach a net-zero economy. Note that the production of biomethane is currently distributed, so for any application of CCS in the future, it needs to be more clustered. This has far-reaching implications and would probably require regional biogas grids to centrally upgrade this to biomethane and capture CO_2.

On a shorter term, biogenic CO_2 from biogas upgrading could alternatively be used to produce additional biomethane in combination with renewable or low-carbon hydrogen. The microbial community formed in the biogas reactors can act as efficient catalysts for the conversion of H_2 and CO_2 to biomethane.[281] This process is called biological methanation.[282] However, in this case, the lifecycle emissions of CO_2 utilisation would be zero instead of negative because biogenic emissions would eventually be released back into the atmosphere upon fuel combustion or product end-of-life. The emissions might even be slightly positive due to the processing steps involved.

The previous Gas for Climate study[283] specifically assessed the potential for the production of biomethane and found a potential of 98 bcm/year. Of this 98 bcm/year, 63 bcm/year was can be produced from biogas through anaerobic digestion and 35 bcm/year from syngas through thermal gasification. The CO_2 content of biogas is typically between 30%–45%,[284,285] whereas this is 16–20% for the syngas produced in the gasification route. Bioethanol has an even higher share at 49%. Capturing all of the process emissions from these processes, assuming the 2017 production of ethanol and the 2050 potential for biomethane, between 112–214 $MtCO_2$/yr negative emissions could be realised (Table 35). This is under the assumption that no additional emissions occur during the production process. Since this is not realistic, the actual level of negative emissions will be lower.

---

[281] Szuhaj et al., 2016. Conversion of H_2 and CO_2 to CH_4 and acetate in fed-batch biogas reactors by mixed biogas community: a novel route for the power-to-gas concept. https://biotechnologyforbiofuels.biomedcentral.com/articles/10.1186/s13068-016-0515-0

[282] Ecofys & Imperial College, 2017. *Assessing the Potential of CO_2 Utilization in the UK.* https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/665580/SISUK17099AssessingCO2_utilisationUK_ReportFinal_260517v2.pdf

[283] Ecofys, 2018. *Gas for Climate: how gas can help to achieve the Paris Agreement target in an affordable way.* https://gasforclimate2050.eu/files/files/Ecofys_Gas_for_Climate_Report_Study_March18.pdf

[284] Ecofys, 2013. *Potential for Biomethane Production and Carbon Dioxide Capture and Storage.* https://ieaghg.org/docs/General_Docs/Reports/2013-11.pdf

[285] Hailong Li et al., 2017. *Capturing CO_2 from biogas plants.* https://reader.elsevier.com/reader/sd/pii/S1876610217319409?token=CD920301D1545DB83D09DDAADD63FC42A99BB13867F962B122F04B7B3165F7CD4F76DFEA2175DE0C66266B20C57B33DC

Including lifecycle emissions associated with the production of these fuels or feedstocks at present technology, negative emissions would be between 53–155 $MtCO_2$/yr.[286]

Alternative pathways for capturing the biogenic fraction of CO_2 are possible. Biogenic CO_2 emissions can also be captured and stored (or utilised) when biogas is used to produce hydrogen in a steam methane reformer. This carbon-negative or low-carbon hydrogen could then be used to substitute carbon-intensive fuels in industry.

Table 35 Overview of biofuel production processes and associated negative emissions potential. For biomethane, industry experts mention the CO_2 content is more towards the upper bound.[287]

Fuel	Process	CO_2 content	Bcm CH_4	CH_4 volume	Bcm CO_2	Negative emissions
Biomethane	Anaerobic digestion	30 – 45%	63	45 – 70%	27 – 63	53 – 125 Mt
Biomethane	Thermal gasification	16 – 20%	35	10 – 12.5%	28 – 44	55 – 87 Mt
Bioethanol	Fermentation	49%	-	-	-	2.8 Mt

E.3.6 Conclusion

The EU possesses a vast geological storage potential for CO_2 of around 134 $GtCO_2$ (including Norway), which would only be around 15% filled by 2050 if the full technical CCS potential is realised. Besides storage in geological reservoirs, CO_2 can also be used to increase the efficiency of manufacturing processes, the production of fuels, feedstocks, or construction materials. Generally, only the latter leads to permanent storage of CO_2 and can continue playing a role in a decarbonised energy system, unless these other options use biogenic CO_2 or recycle the CO_2 in its end-of-life phase. In total, around 328 $MtCO_2$/year could be used in construction material and chemical feedstock, and a circular economy can contribute to the permanency of CO_2 storage in products. CCU has an important role to play in the decarbonisation of some sectors, especially for the chemicals and petrochemicals sector.

Two main routes for the decarbonisation of gas can be identified: 1) distributed, by using natural gas in industrial processes that are equipped with CCS or 2) centralised, where blue hydrogen is produced from natural gas in a hydrogen manufacturing unit that is equipped with CCS, after which the hydrogen can be used in industrial processes to substitute carbon intensive fuels. Generally, CCS on hydrogen production is among the least costly options, although additional costs would be incurred to transport and use this hydrogen in industry. Since not all emissions can realistically be captured, negative emissions can further contribute to the realisation of a net-zero energy system.

[286] Assuming a weighted average emission factor of 22.58 gCO_2/MJ for bioethanol, based on current production volumes. For biomethane, close digestate with off-gas combustion was assumed, yielding 16.2 gCO_2/MJ. Source: European Commission, 2018. *Proposal for a Directive of the European Parliament and of the Council on the promotion of the use of energy from renewable sources (2016/0382 COD).*

[287] Production of bioethanol was 5.7 Mt in 2017, density 0.81 kg/l. Source: EUBIA, 2018. *Bioethanol*. http://www.eubia.org/cms/wiki-biomass/biofuels/bioethanol/

E.4 CCS Regulation and Cross-Border Cooperation

Storing CO_2 in geological structures (CCS) is regarded in scientific literature to be a safe climate change mitigation option, able to keep 98% of CO_2 for a period of 10,000 years.[288] Despite this, public attitude towards CCS is an important factor that influences its realization and has led to the cancellation of a number of demonstration projects in the EU.[289,290] Notable cancellations include the Shell Barendrecht project in the Netherlands and the Vattenfall Jänschwalde project in Germany, which were cancelled in large part due to public opposition. Unfavourable attitudes are largely projected towards the storage of CO_2 in the subsurface, not so much towards capturing and transporting it. Research also suggests that there is no universal preference for offshore developments compared to onshore storage.[291] Recent analysis has also pointed out that the discussions around CCS have shifted compared to a decade ago, from discussing the safety issues and usefulness of CCS to people questioning whether CCS investments prevent system change (i.e., cause a technology lock-in) and goes at the expense of other climate mitigation options that may have more side benefits.[292] Such risks can be mitigated by positioning CCS as an intermediate solution one among several solutions for industry in their cost-optimal transition towards a fully renewable energy system later this century without a need for fossil fuels.

Various surveys have assessed public attitudes within EU member states towards the geological storage of CO_2, the most comprehensive overview being given by a 2011 Eurobarometer report, requested by the European Commission.[293] The key conclusion from this study was that the European population is generally unaware of CCS and its potential contribution to climate change. It also showed that those that are informed about the technology are more likely to have a favourable attitude towards it. Therefore, to explore what the realistic CO_2 storage potential in the EU could be and whether this is sufficient to store the EU's industrial emissions, existing legislation (Appendix E.4.1) and long-term government strategies on energy and climate are considered (Appendix E.4.2).[294] The result of applying these restrictions on the storage potential are provided in Appendix E.4.3 and an assessment is provided of possible cross-border exchanges of CO_2 in Europe as a result of domestic limitations on CO_2 storage.

---

[288] Alcade et al., 2018. *Estimating geological CO_2 storage security to deliver on climate mitigation.* https://www.nature.com/articles/s41467-018-04423-1

[289] Van Alphen, K., van Voorst tot Voorst, Q., Hekkert, M., Smits, R., 2007. *Societal acceptance of carbon capture and storage technologies*. Energy Policy 35, 4368-4380.

[290] Bäckstrand, K., Meadowcroft, J., Oppenheimer, M., 2011. The Politics and Policy of Carbon Capture and Storage: Framing an Emergent Technology. Global Environmental Change 21, 275-281.

[291] Schumann et al., 2014. *Public perception of CO_2 offshore storage in Germany: regional differences and determinants*. Energy Procedia, 63, 7096-7112.

[292] Leiden University, 2018. *Psychologists test societal acceptance of underground storage of CO_2.* http://www.carboncapturejournal.com/ViewNews.aspx?NewsID=4068

[293] Eurobarometer, 2011. *Public awareness and acceptance of CO_2 capture and storage. Special Eurobarometer 364.* http://ec.europa.eu/public_opinion/archives/ebs/ebs_364_en.pdf

[294] See Appendix 7.E.6 for a more detailed description of the methodology.

E.4.1 Existing national legislation

The European CCS Directive (2009/31/EC)[295] establishes a legal framework for the environmentally safe geological storage of CO_2 and called for countries to implement this Directive into national law. These implementations in national law have been reviewed, and since the framework allows for flexibility in implementing the Directive some member states have introduced bans or restrict the storage of CO_2 within their territory (Table 36). Five German federal states are preparing decisions or have passed legislation that bans or restricts geological storage of CO_2, whereas the German federal government allows a maximum of 4 Mt CO_2 to be stored annually.[296] The Czech Republic does not allow geological storage of CO_2 in rock formations until 2020 and Poland currently only allow storage for demonstration purposes.[297] Finland, Luxembourg, and the Brussels Capital Region restrict CO_2 storage in parts of their areas due to geological unsuitability.[298] These restrictions can be of a temporary nature and amended when CCS is more ubiquitous, though it can be worthwhile to determine the effect should these restrictions on CO_2 storage remain until 2050.

E.4.2 Long-term government strategies

An assessment was also done on existing climate strategies made by national governments to measure the favourability of a certain member state towards CCS in the longer term. A large majority of member states in their climate or energy strategies towards 2030 or 2050 have a neutral or positive attitude towards CCS (Table 36). For example, “Danish government does not rule out a future use of […] CCS”[299] or “obstacles to introduce [CCS] should be removed” (France).[300] Only one-member state is more outspokenly negative about CCS, namely Poland, whereas Austria has no mention of the reduction of industrial emissions in its climate strategy. This generally neutral to positive stance on CCS in long-term strategies makes it more likely that, towards 2050, a larger CO_2 storage potential could be utilised than what would be expected in an “as-is” scenario.

---

[295] European Commission, 2009. *Directive on the geological storage of carbon dioxide.* https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009L0031&from=EN

[296] European Commission, 2017. *Report from the Commission to the European Parliament and the Council on Implementation of Directive 2009/31/EC on the Geological Storage of Carbon Dioxide.* https://ec.europa.eu/commission/sites/beta-political/files/report-carbon-capture-storage_en.pdf

[297] Havercroft, Macrory & Stewart, 2018. *Carbon Capture and Storage: Emerging Legal and Regulatory Issues*. https://bit.ly/2J5uwVs

[298] Ibid.

[299] Danish Government, 2011. Energy Strategy 2050. http://dfcgreenfellows.net/Documents/EnergyStrategy2050_Summary.pdf

[300] French Government, 2013. Pathways 2020-2050 towards a low-carbon economy in France. http://archives.strategie.gouv.fr/cas/system/files/cas_pathways_2020_2050_july2012_0.pdf

Table 36 Overview of public attitude and legislative restrictions in EU28 countries and Norway.[301,302,303]

Country	Long-term government strategy	Current legislative restriction
Austria	Unfavourable	No storage
Belgium	Favourable	Not in Brussels Capital Region
Bulgaria	Favourable	Maximum storage of 160 Mt up to 2030
Croatia	Neutral	No storage
Cyprus	Neutral	-
Czech Republic	Neutral	No storage until 2020
Denmark	Neutral	No onshore storage until 2020
Estonia	Neutral	No storage
Finland	Favourable	Only for demonstration until 2024
France	Favourable	-
Germany	Neutral	Maximum storage of 4 $MtCO_2$/yr. No storage allowed in five federal states
Greece	Favourable	-
Hungary	Favourable	-
Ireland	Neutral	No storage
Italy	Neutral	No storage in seismic areas or unconfined aquifers, no negative impact on maritime traffic and oil and gas exploration
Latvia	Neutral	No storage
Lithuania	Favourable	-
Luxembourg	-	-
Malta	-	-
Netherlands	Favourable	No onshore storage
Poland	Unfavourable	Only for demonstration until 2024
Portugal	Favourable	-
Romania	Favourable	-
Slovakia	Neutral	-
Slovenia	Neutral	No storage
Spain	Favourable	-
Sweden	Neutral	No onshore storage
United Kingdom	Favourable	No onshore storage
Norway	Favourable	No onshore storage

[301] Anthonsen et al., 2012. *CO_2 storage potential in the Nordic region*. https://www.sintef.no/globalassets/sintef-energi/nordiccs/d-6.1.1205-2-co2-storage-potential-in-the-nordic-region_web.pdf

[302] Alla Shogenova et al., 2013. *CCS Directive transposition into national laws in Europe: progress and problems by the end of 2011*. https://core.ac.uk/download/pdf/82544154.pdf

[303] Reiner et al. 2011. *NearCO_2 WP2: Opinion shaping factors towards CCS and local CCS projects: Public and stakeholder survey and focus groups*.

E.4.3 Realistic CO_2 storage potential

Appendix E.3.2 concludes that the conservative CO_2 storage potential in Europe is around 104 $GtCO_2$. When we include Norway, this increases to around 134 $GtCO_2$. If we consider the existing legislative restrictions on storage on a member state level and filter out the storage potentials that currently apply, this potential would decrease to around 77 $GtCO_2$. The largest limitations in storage potential due to legislation are observed in Germany, Croatia, the Netherlands, Poland and Slovenia (see Appendix D.7.2). This does not mean that these countries have a limited storage potential because of these restrictions, but rather that a large part of the potential currently cannot be used. It should also be stressed that these limitations are only applicable to *storage*. Capture in a storage-restricted country and storage elsewhere could still be an option, with one barrier being the London Protocol (Box 12).

Box 12 The London Protocol is a hurdle for shipping CO_2 to subsea storage

Article 6 of the London Protocol, an agreement between fifty states aimed at creating a modern and comprehensive waste management system for the seas, says that: "*Contracting Parties shall not allow the export of wastes or other matter to other countries for dumping or incineration at sea*," thus prohibiting transport of CO_2 from across national boundaries prior to subsea sequestration. An amendment to this article was already devised by 2009, where an exempt is made for CO_2 streams for export. This amendment has however not (yet) been accepted by the two-third majority needed and therefore has not entered into force. During the 39th meeting of the London Convention and the 12th meeting of the London Protocol in 2017, Iran and Finland had ratified, setting the total only 5 of the 32 needed parties to ratify.

E.4.4 Cross-border cooperation on CO_2 infrastructure

As observed in Appendix D.7.2, some European countries have a vast geological CO_2 storage potential, such as the UK, Norway, Romania, France, Portugal, Italy and Slovakia.[304] Other countries with large amounts of industrial emissions but limited storage may want to utilise this available potential. This could be worthwhile due to various reasons: technical, e.g., a lack of geological storage capacity; economic, e.g., domestic storage is costlier; or societal, e.g., due to a negative public attitude towards CO_2 storage.

Based on conservative storage estimates in EU member states and the countries' domestic emissions from industry and gas-fired energy production,[305] some countries have a constrained domestic storage potential towards 2050 if an ambitious CCS scenario is pursued and would need to rely more on cross-border CO_2 transport and storage. These countries are Austria, Belgium, Czech Republic, Germany, Greece and Poland. If legislative restrictions were removed, Czech Republic, Germany and Poland would not require cross-border storage, since domestic storage potential would be sufficient. The list of countries that would have a large surplus of storage available is larger and would include Bulgaria, Denmark, Finland, France, Hungary, Italy, Slovakia, Spain, Sweden, Portugal, Romania, Norway, and UK (see Appendix D.7.2). If legislative restrictions or unfavourable public attitude towards domestic storage persist, it may be worthwhile to pursue cross-border storage with countries that have mentioned that they are open to storing neighbouring countries' emissions. Norway (Equinor) and the Netherlands (Port of Rotterdam Authority) have made such statements.[306,307]

---

[304] Countries with a conservative estimate of > 1 Gt.

[305] EEA, 2018. *Annual European Union greenhouse gas inventory 1990–2016 and inventory report 2018.* CRF Categories assumed: 1.A.1 Energy Industries, 1.A.2 Manufacturing Industries and Construction, 2.A Mineral Industry, 2.B Chemical Industry and 2.C Metal Industry. Only emissions from gas-fired power production are taken into account for 1.A.1.

[306] Reuters, 2018. *Norway invites bids for storing CO_2 on its continental shelf.* https://www.reuters.com/article/us-norway-carboncapture/norway-invites-bids-for-storing-co2-on-its-continental-shelf-idUSKBN1JV1ZY

[307] Euractiv, 2018. *Meet Europe's two 'most exciting' CO_2 capture and storage projects*. https://www.euractiv.com/section/energy/news/meet-europes-two-most-exciting-co2-storage-projects/

European funds are available to finance cross-border CO_2 pipelines, most prominently the CEF Energy Fund (Connecting Europe Facility – Energy) with an available budget of €5.35 billion for the 2014–2020 period.[308] Four CCS projects have received the label of Project of Common Interest (PCI) by the European Commission,[309] which is required to receive funding from the CEF: Porthos CCS – Rotterdam, Statoil – Eemshaven/Teesside-Norway connection, Tees Valley – Teesside CO_2 Hub and Pale Blue Dot – CO_2 SAPLING Infrastructure Project. The first call for funding was launched in November 2018.

E.4.5 Conclusion

Following the implementation of the EU CCS Directive, some member states have introduced bans or restrictions on the storage of CO_2 within their country. Current legislative and regulatory limitations would already have a substantial impact on the CO_2 storage potential, reducing it from 104 $GtCO_2$ (EU only) to around 77 $GtCO_2$. However, the remaining potential is still significant. Unfavourable attitudes towards CO_2 storage might further reduce this potential. This effect could be mitigated by clearly defining that CCS and CCU are temporary solutions that are required to optimise speed and costs of achieving net-zero emissions.

On an individual country basis, some countries will depend on cross-border CO_2 transport and storage if limitations on domestic storage options persist. However, some countries have signalled their potential to store neighbouring countries' emissions, which could be a way to mitigate the effect of public attitudes and legislative restrictions in the short term. This indicates a strong requirement for the development of international CO_2 transport networks, and a beginning is within reach through concrete proposals under the CEF Energy Fund. In the short term, legal barriers such as the London Protocol should also be addressed. Further large-scale demonstration of CCS and CCU, together with supporting policies are required to materialise this potential.

E.5 Promising options for CCS and CCU in selected EU industrial clusters

In their continuous effort to increase production efficiency, energy-intensive industries tend to cluster to enable industrial symbiosis: the exchange of materials and energy from one industrial facility to another. Similarly, clusters may benefit from economies of scale when deploying CCS and CCU infrastructure. This Appendix explores CCS and CCU opportunities through this cluster lens to see where the potentials for CCS and CCU (mentioned in the previous appendices) may develop soonest and at what costs these potentials can be enabled. At the same time, this makes the results from the previous sections more tangible, since those that follow will demonstrate what can be achieved in various industrial clusters.

E.5.1 Distribution and characteristics of EU industrial CO_2 emissions

One quarter of EU industrial and gas-fired energy CO_2 emissions occur in Germany, with the UK and Poland coming in second and third at 11% and 9%, respectively (Figure 50). Over half of EU industrial emissions come from electricity production (of which 22% gas-fired), followed by steel and refineries (both at around 7%). Cement is just behind at 6% of total annual emissions.

[308] European Commission, 2018. *CEF Energy*. https://ec.europa.eu/inea/en/connecting-europe-facility/cef-energy

[309] EERA, 2017. *Adoption of four Projects of Common Interest on cross-border CO_2 infrastructure*. https://www.eera-set.eu/adoption-of-four-projects-of-common-interest-on-cross-border-co2-infrastructure/

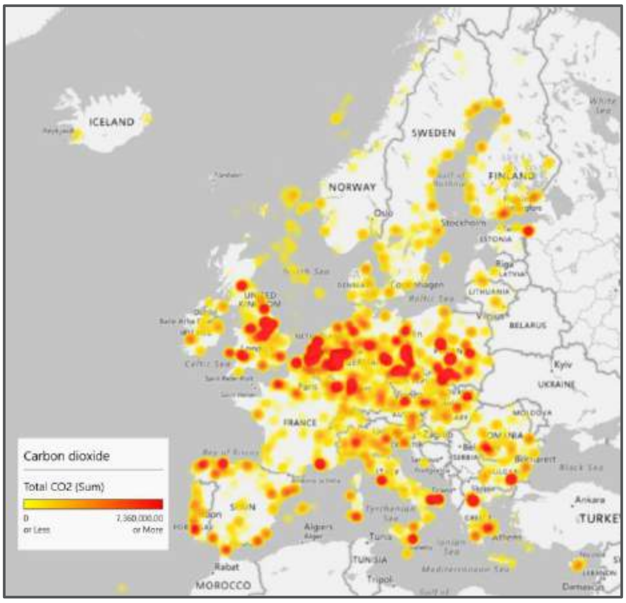

Figure 50 Distribution of CO_2 emissions across EU-28 in 2014. Light yellow and dark red areas represent low and high emissions, respectively[310]

The top 100 emitters represent some 34% of total emissions, the clear majority being in energy and steel production. To get a sense of the level of industrial clustering: out of this top-100, 17 are within a 20 km radius of the mid-point of a cluster, whereas almost half are within 100 km of a cluster. If we focus only on the largest emitters in the chemical industry, 55 of the top 100 are part of a cluster.[311] Clusters are a natural point of focus to explore the early potential for CCS and CCU, since economies of scale potentially can be used here due to the larger concentration of individual CO_2 point-sources.

E.5.2 Industrial clusters

For six European industrial clusters, we sketch how CCS and CCU could be deployed at scale and how this may look in terms of average capture and transport costs and what which pipeline routes may be needed to enable subsurface sequestration of captured CO_2.[312] Capture costs,[313] as presented in the previous section, are used to roughly estimate the costs of CCS per cluster, accounting for the different composition of industrial processes. For transportation, we identify feasible storage solutions[314] in terms of both capacity and proximity and derive a cost range based on pipeline route, construction, art work, and land fall as well as operation and maintenance.[315]

[310] Source: E-PRTR.

[311] Defined here as within a 20 km radius of an identified cluster central coordinate.

[312] See 7.E.6.3 for a more detailed description of the selection methodology.

[313] Please refer to Chapter 7.E.3 for uncertainty ranges in capture costs. These are omitted here to improve readability of charts.

[314] We employ the EU GeoCapacity database to identify subsurface storage potentials.

[315] See Appendix 0 for a detailed description of transport cost estimation method.

E.5.3 Options for CCUS in EU industrial clusters

Per cluster, a marginal capture cost curve is defined for all emitters (defined as 20 km from geographical midpoint). Using the GeoCapacity database, promising carbon sequestration locations (sinks) were identified in the proximity of the cluster. A pipeline trajectory to such locations was modelled to assess a transport cost range.[316] In general, a large range of costs is observed, but in some cases CO_2 capture and storage would already be competitive at the current ETS price of €21/tCO_2.[317]

E.5.4 Port of Rotterdam

- Emissions of 76 known sources are dominated by chemicals and petrochemicals. Note the 20 km radius excludes Moerdijk sources from the analysis. Weighted average capture costs excluding coal-fired power are **€66/tCO_2** for a total of **12.8 MtCO_2/yr** (80% of today's emissions).
- The nearest hydrocarbon injection point is Gaag onshore (8.1 Mt). However, storage would likely start offshore, confirmed by the Porthos pilot which mentions the P18 depleted gas field with a capacity of **39 MtCO_2.**
- A **44 km long pipeline** from the center of the cluster is required to connect to this sink. The transport and storage cost would range from **€10–€21/tCO_2**. The small storage potential of the sink is a key factor leading to these relatively high costs per tonne. The impact of flow rate on transport costs is minute for flow rates above 2 MtCO_2/yr. The cost sensitivity is not visible in **Figure 51** as numbers are rounded.

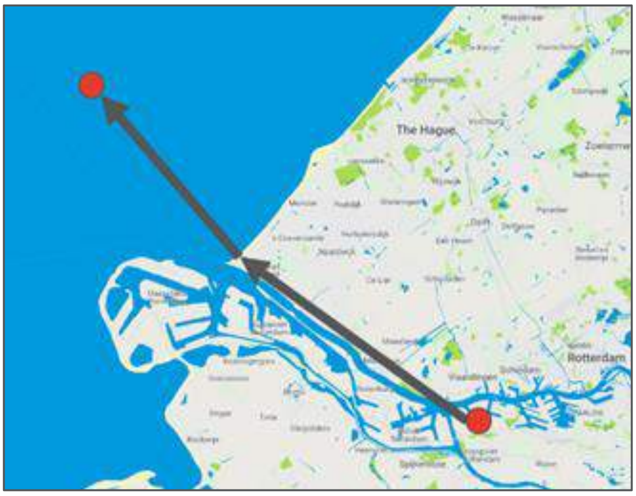

Figure 51 Modelled pipeline trajectory from the Port of Rotterdam to the P18 offshore gas field.

- Average CCS costs are **€76–87/tCO_2** if further uncertainties and spread in capture costs are ignored.
- Relative pipeline costs will be reduced significantly with existing pipeline corridors, potential collaboration in the ARA cluster, and long-term extension to other offshore sinks.
- With the chemical sector being dominant, CCU development may focus on using CO_2 as feedstock. Currently CO_2 from two plants is transported to nearby greenhouses to boost crop yield.

---

[316] Please see Appendix 0 for a more detailed description of the cluster analysis approach.

[317] As of 1 October 2018. Source: EEX, 2018. *EU Emission Allowances | Secondary Market.* https://www.eex.com/en/market-data/environmental-markets/spot-market/european-emission-allowances#!/

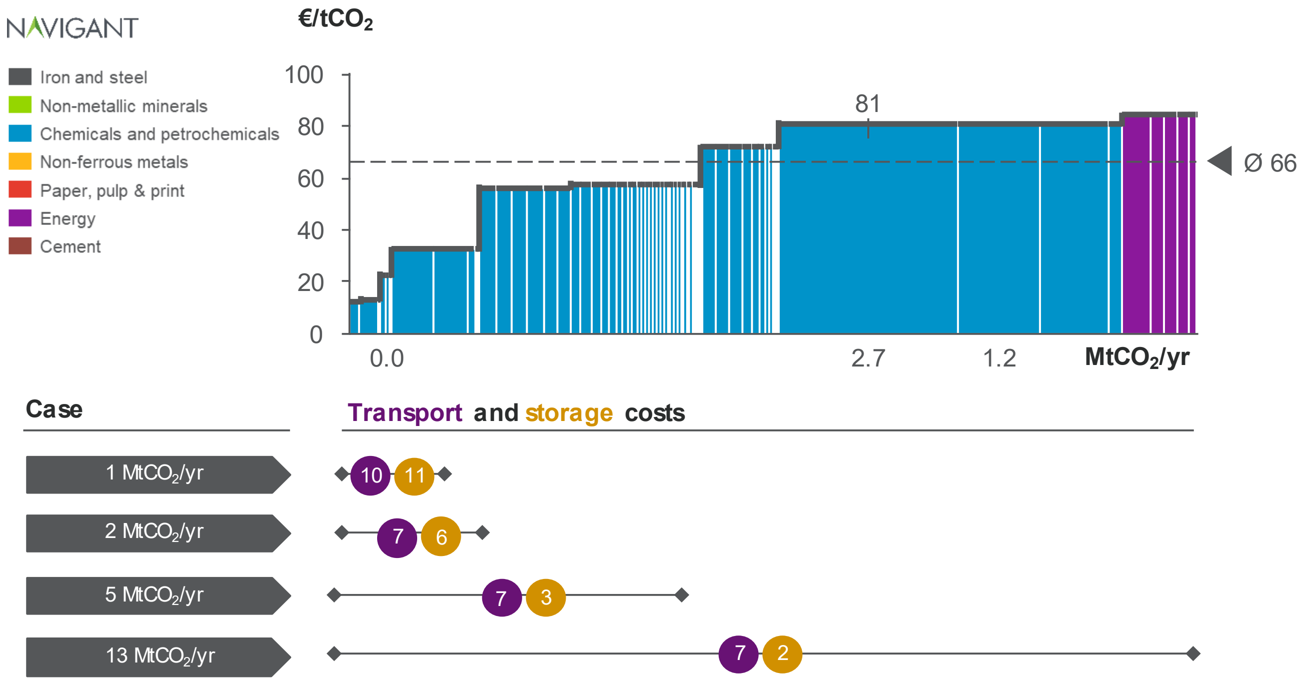

Figure 52 Marginal carbon capture costs for Port of Rotterdam, totalling 12.8 $MtCO_2$/year at a weighted average capture cost of €67/tCO_2. Transport and storage costs differentiated based on CO_2 flow rate.

E.5.5 Chempark Krefeld-Uerdingen

- Emissions of 43 known sources are dominated by iron and steel, chemical, and energy production. Weighted average capture costs excluding coal-fired power are **€63/tCO_2** for a total of **16.9 $MtCO_2$/year**, (51% of today's emissions).
- Ochtrup is the only hydrocarbon injection point in a 100 km radius, and has limited potential. Aquifer injection points show more promise but the closest are in Belgium: a Bundsandstein aquifer has a conservative storage potential of **117 Mt.** In the future, the Krefeld cluster could possibly feed into the Rotterdam network.

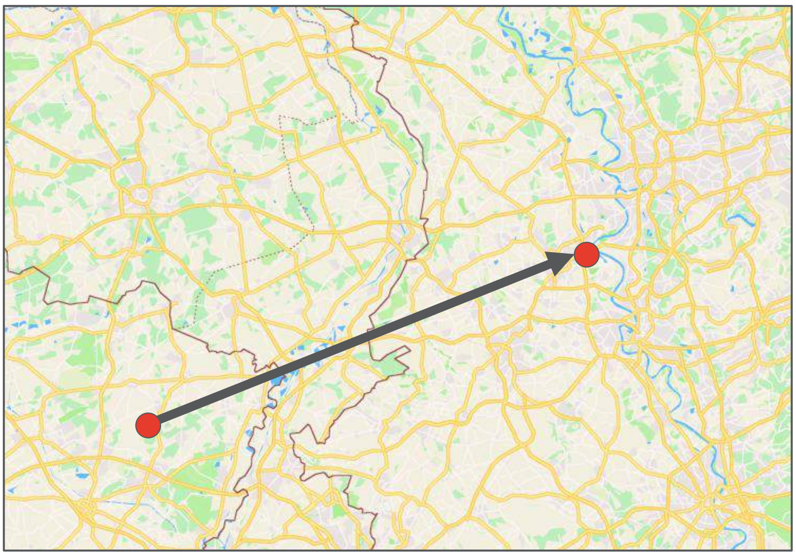

Figure 53 Modelled pipeline trajectory from Krefeld-Uerdingen to an injection point in the Bundsandstein aquifer in Belgium.

- Connecting to this aquifer would require an 80 km long pipeline. The transport and storage costs range from **€4–€21/tCO_2**. Scenarios for transport and storage costs are differentiated by CO_2 flow rate. The costs of transport and storage reduce as the flow rate increases. With increased flow rate the corresponding storage capacity also increases and reaches a maximum threshold of **117 Mt.** With the maximum flow rate of 16 MtCO_2 only seven years of operational emissions will be mitigated.
- Average CCS costs are **€68–€85/tCO_2** if further uncertainties and spread in capture costs are ignored.
- With ten clusters in this same 80 km radius, numerous opportunities may arise to join a larger transnational CO_2 grid, such as a potential one with the Port of Rotterdam as the main hub.
- Iron and steel, chemical, and energy are dominant sectors, which indicates opportunities for CCU focusing on using CO from steelmaking for fuels, feedstock, or otherwise direct use in the production of chemicals.

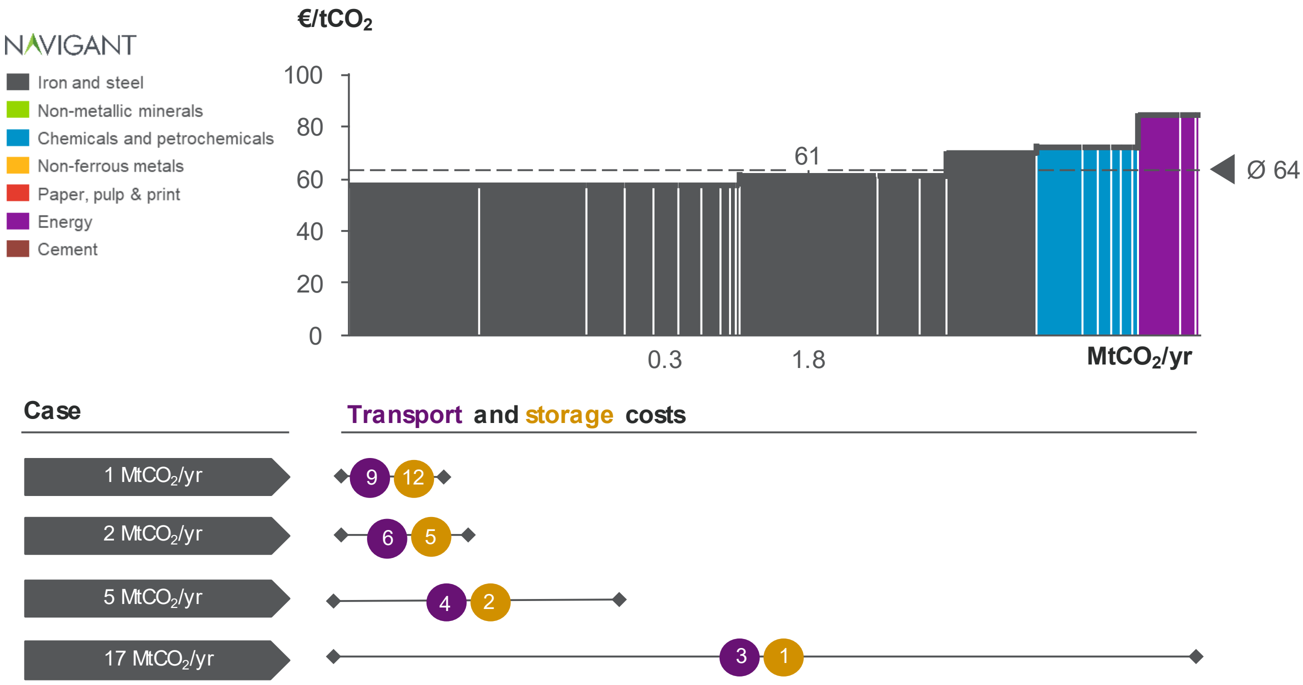

Figure 54 Marginal carbon capture costs for Chempark Krefeld-Uerdingen, totaling 16.3 MtCO_2/yr at a weighted average capture cost of €63/tCO_2. Transport and storage costs differentiated based on CO_2 flow rate.

E.5.6 Marseille-Fos

- Emissions of 27 known sources are dominated by iron and steel and chemicals and petrochemicals production. Weighted average capture costs excluding coal-fired power are **€63/tCO_2** for a total of **10.3 MtCO_2/yr** (69% of today's emissions).

Figure 55 Modelled pipeline trajectory from Marseille-Fos to the Mantes 101 aquifer injection point.

- There are no known hydrocarbon or coal seam injection points in a 100 km radius. Aquifer injection points show more promise, the nearest being a Triassic aquifer called Mantes 101, with a potential of over **200 Mt**.
- **Connecting to this sink would require a 6 km long pipeline from the center of the cluster. The transport and storage cost would range from €2–€13/tCO_2.** The long lifetime of the sink in close proximity to CO_2 sources are two key factors making this low cost. Transport costs for CO_2 flow rates that are greater than €1 progressively reduce below €1/tCO_2 but are rounded to a numeric figure of €1 in Figure 56. The cluster is spread out; connecting all major sources in its vicinity will require an extended pipeline network with a total length of up to 200 km[318].
- Ignoring further uncertainties and spread in capture costs, average CCS costs are **€65–€76/tCO_2**.
- There are no other significant industrial clusters within a 100 km radius of Marseille-Fos. Little opportunity therefore exists to connect to a broader CO_2-network.
- Iron and steel, chemical and petrochemical represent the dominant sectors; hence potential for CCU development focuses on using CO from steelmaking in producing fuels, feedstock, and chemical products. ArcelorMittal leads a study with Covestro to re-use their emissions for polyol production.[319]

---

[318] IEAGHG, 2015. *CCS cluster projects review and future opportunities*.

[319] https://www.carbon4pur.eu/partners/

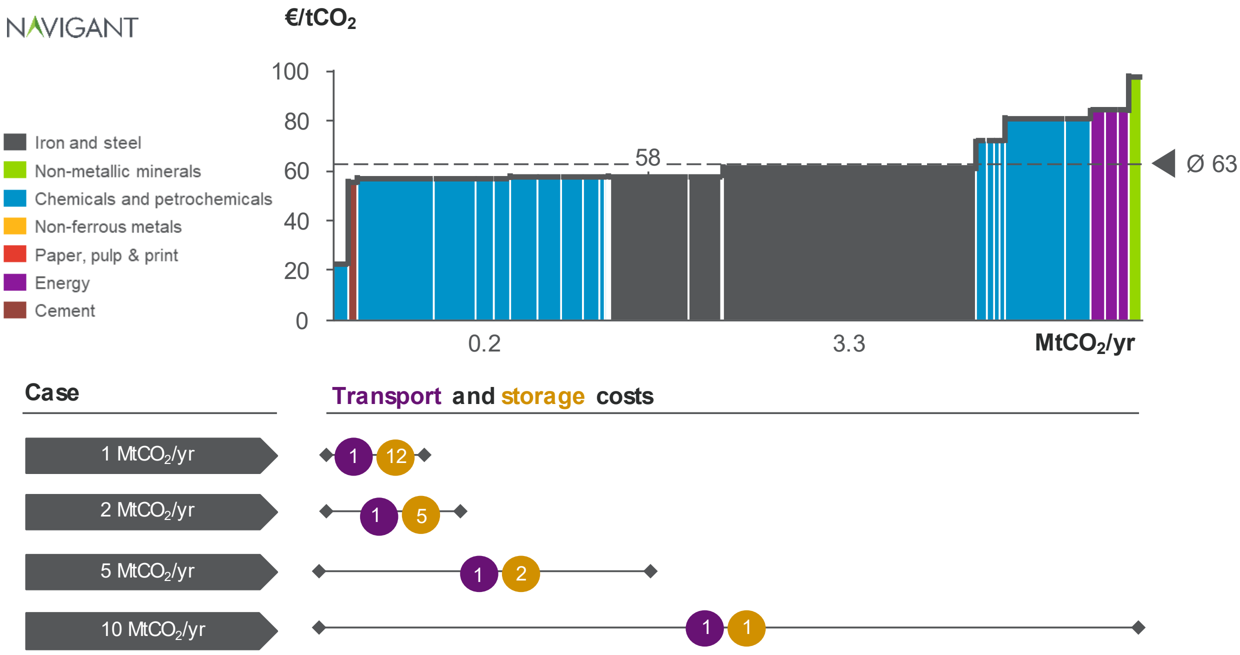

Figure 56 Marginal carbon capture costs for Marseille-Fos, totalling 10.3 $MtCO_2$/year at a weighted average capture cost of €63/tCO_2. Transport and storage costs differentiated based on CO_2 flow rate.

E.5.7 Port of Antwerp

- Emissions of 49 known sources are dominated by chemicals and petrochemicals production within **20 km** radius from the Port of Antwerp. Weighted average capture costs excluding coal-fired power are **€72/tCO_2** for a total of **11.4 $MtCO_2$/year** (84% of today's emissions).
- Within a 50 km radius, there are a few noteworthy emissions sources in Belgium and the Netherlands, with emissions above 1 $MtCO_2$ per point source. The point sources from Belgium include a couple of power production facilities and a steel plant with combined total emissions of around 9 $MtCO_2$/year. These emission sources will most likely be part of a wider CO_2 network but have not been discussed as part of the cluster analysis.

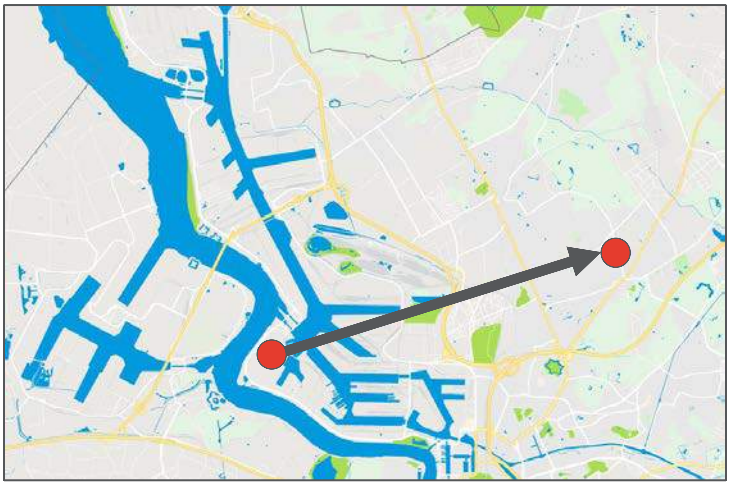

Figure 57 Modelled pipeline trajectory from the Point of Antwerp to an aquifer injection point.

- There are no coal seam injection points in a 100 km radius. The closest hydrocarbon field is Maasdijk which is located in the Netherlands with storage capacity of only 6.5 $MtCO_2$. Aquifer injection points show more promise, the nearest is the Campine aquifer with a capacity of **44 Mt**.

- The cluster can be connected to this onshore aquifer with a 12 km pipeline. The combined costs of CO_2 transport and storage would range from **€7–€19/tCO_2**. Scenarios for transport and storage costs are differentiated by CO_2 flow rate.
- With a maximum flow rate of around 11 MtCO_2/year, the sink can only abate 4 years of operation. There are no major sinks close by that have a potential for long-term storage. It is likely that the cluster will connect with a wider CO_2 network encompassing the Port of Rotterdam, either by pipeline or shipping.
- Ignoring further uncertainties and spread in capture costs, combined average CCS costs are **€79–€91/tCO_2**.
- The chemical and petrochemical sector dominates the cluster, hence potential for CCU development focuses on using CO_2 as a feedstock for making novel chemical products.

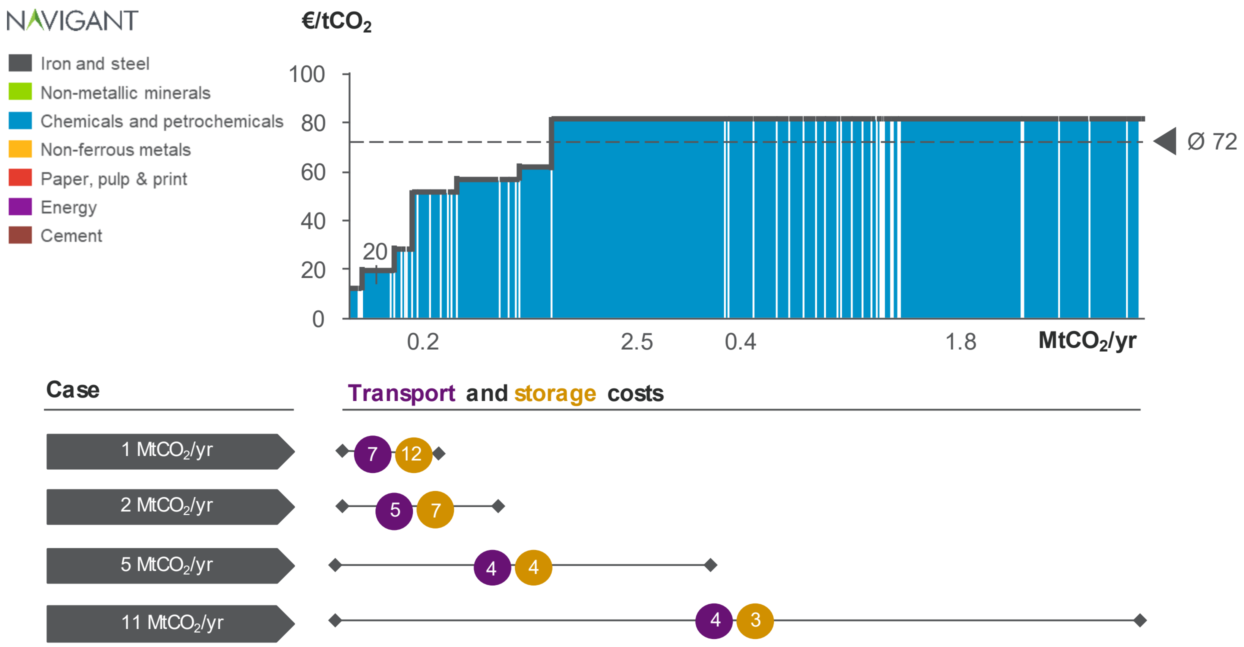

Figure 58 Marginal carbon capture costs for Port of Antwerp, totalling 11.4 MtCO_2/year at a weighted average capture cost of €72/tCO_2. Transport and storage costs differentiated based on CO_2 flow rate.

E.5.8 Porto Marghera

- Emissions of 13 known sources are dominated by power and chemicals and petrochemicals production within **20 km** radius from the Porto Marghera. Weighted average capture costs excluding coal-fired power are **€75/tCO_2** for a total of **1.8 MtCO2/year** (31% of today's emissions). Most of the emissions from the cluster originate from ENEL power plant at Fusina, which largely runs on coal.
- There are no coal seam injection points in a 100 km radius. There are a few aquifer injection points that show promise. The closest considerable storage volumes are **100** and **126 MtCO_2**; the larger sink is Poggio Rusco.

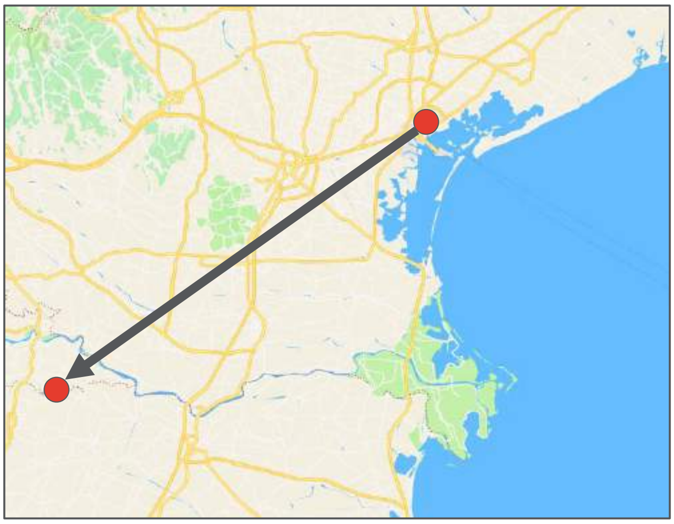

Figure 59 Modelled pipeline trajectory from Porto Marghera to the Poggio Rusco aquifer.

- The cluster can be connected to this onshore aquifer with a 103 km pipeline. The combined costs of CO_2 transport and storage would range from **€17–€29/tCO_2**. Scenarios for transport and storage costs are differentiated by CO_2 flow rate. The costs of transport and storage reduce as the flow rate increases. Transport costs are relatively high, mainly because of low CO_2 volumes being transported over long distances.
- Within 50 km radius, there is one cement and one paper manufacturing facility. The combined emissions from the two facilities roughly amount to 0.5 MtCO_2/year. These emissions sources could also be connected to the main CO_2 pipeline but the allocation of these emissions to an appropriate and cost-effective sink requires further examination which is not part of the scope of this analysis.
- Ignoring further uncertainties and spread in capture costs, combined average CCS costs are **€92–€104/tCO_2**.
- The chemical and petrochemical and power production sectors dominate the cluster, hence potential for CCU development focuses on using CO_2 from power plants to make innovative chemical product.

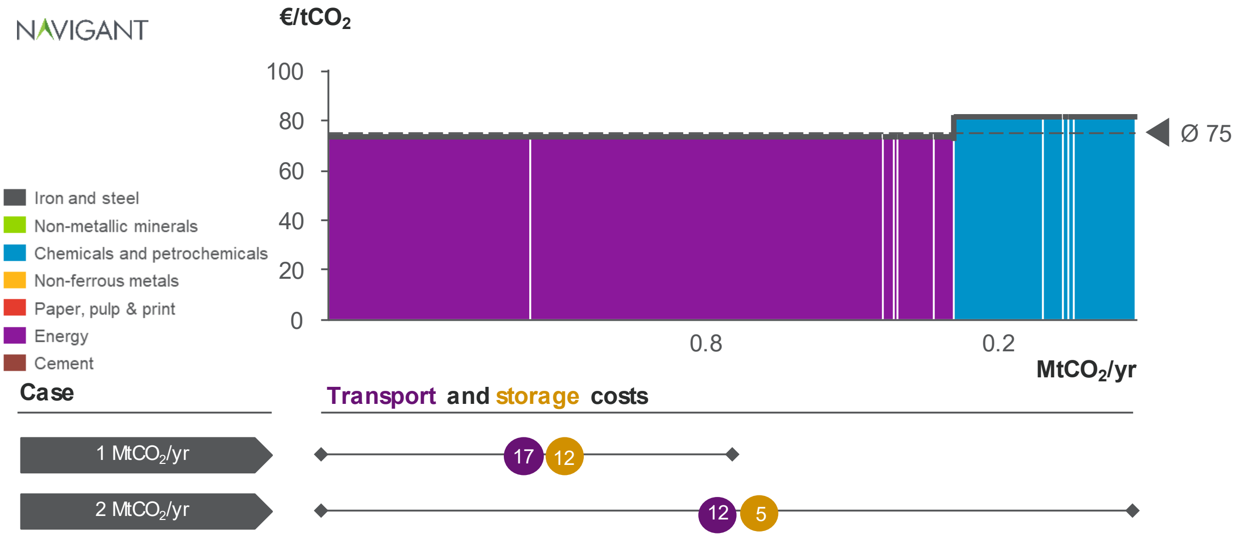

Figure 60 Marginal carbon capture costs for Porto Marghera, totalling 1.8 $MtCO_2$/year at a weighted average capture cost of €75/tCO_2. Transport and storage costs differentiated based on CO_2 flow rate.

E.5.9 Tarragona Chemical Cluster

- Emissions of 13 known sources are dominated by chemicals and petrochemicals production within **20 km** radius from the Tarragona Chemical Cluster. Weighted average capture costs excluding coal-fired power are **€64/tCO_2** for a total of **3.9 $MtCO_2$/year** (90% of today's emissions).
- There are no coal seam injection points in a 100 km radius. There are a few aquifer injection points that offer significant storage volumes.

- The combined costs of CO_2 transport and storage would range from **€10–€27/tCO_2**. Scenarios for transport and storage costs are differentiated by CO_2 flow rate. The costs of transport and storage reduce as the flow rate increases. Storage costs are relatively high which is mainly because of high capital investments needed for an offshore saline aquifer.
- Within 50 km radius, there are no other major energy-intensive industries, only a combined cycle power plant that runs on natural gas and emits around 138 $ktCO_2$/yr.
- Ignoring further uncertainties and spread in capture costs, combined average CCS costs are **€74–€91/tCO_2**.
- The chemical and petrochemical sector dominates the cluster, hence potential for CCU development focuses on using CO_2 for making innovative chemical products.

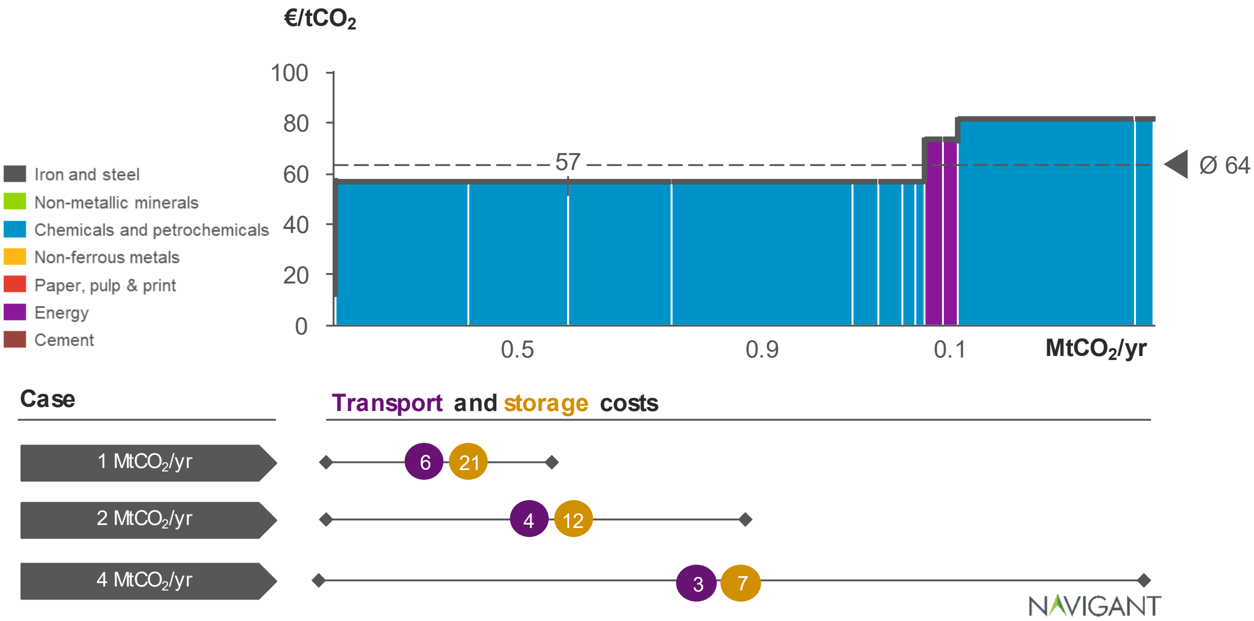

Figure 61 Marginal carbon capture costs for Tarragona Chemical Cluster, totalling 3.9 $MtCO_2$/year at a weighted average capture cost of €64/tCO_2. Transport and storage costs differentiated based on CO_2 flow rate.

E.5.10 Conclusions

Some industries—the chemical industry in particular—form clusters to engage in industrial symbiosis and maximise logistical advantages. This proximity of large point-sources of CO_2 emissions can deliver economies of scale and drive down costs of early CCS and CCU opportunities. This is demonstrated by the recent projects of common interest around CO_2 infrastructure, which are all in and around industrial clusters. Through the analysis of clusters, we observe that when an industrial cluster is situated close to steel or petrochemical industry, cross-sectoral opportunities arise in the re-use of steel off-gases as a feedstock in the chemical industry. Interesting opportunities for CCU also exist between chemical installations themselves, especially when it concerns more concentrated process emissions since this reduces the cost of CO_2 capture.

Although costs of CO_2 capture in the studied industrial clusters can be as low as €15/tCO_2, generally the average cost for CCS for an entire industrial cluster was found to be quite similar, between €70–€90/tCO_2. The influence of low-cost opportunities is rather small on overall cluster costs because low-cost point sources are often relatively small in CO_2 amounts. The six clusters that were studied together have the potential to capture and store around 57 $MtCO_2$/year, which represents around 65% of current emissions in these clusters.

E.6 Methodology and background on CCS potentials and costs

E.6.1 Public attitude towards CCS

Besides consulting reports on the implementation of the CCS Directive in European Member States, long-term strategies were also assessed to arrive at a policy favourability rating per country. The documents that were consulted are listed in Table 37. When a country lists barriers that should be worked on, or demonstrates the potential for a technology, it is rated *favourable*. When it expresses concern and views the deployment of CCS optional depending on the development of the technology it is rated *neutral.* When there are no mentions of CCS or ones that are convincingly sceptic it is rated *unfavourable.* If no government document was found, a non-government document occasionally could be retrieved where government ambitions were quoted.

Table 37 Overview of sources used for long-term government strategy assessment of the EU member states

Country	Rating	Source
Austria	Unfavourable	#mission2030
Belgium	Favourable	Scenarios for a Low-Carbon Belgium
Bulgaria	Favourable	Energy Strategy 2020
Croatia	Neutral	Seventh National Communication to UNFCCC
Cyprus	Neutral	No government source – EU 2050 Energy Strategy Towards Sustainable Energy Systems
Czech Republic	Neutral	Climate Protection Policy of the Czech Republic
Denmark	Neutral	Energy Strategy 2050
Estonia	Neutral	General Principles of Climate Policy until 2050
Finland	Favourable	Energy and Climate Roadmap 2050
France	Favourable	Pathways 2020-2050 Towards a Low-Carbon Economy in France
Germany	Neutral	Climate Action Plan 2050
Greece	Favourable	No government source – National Energy Plan: Roadmap to 2050
Hungary	Favourable	No government source – Climate Change Policy in Hungary
Ireland	Neutral	2050 Low-Carbon Roadmaps
Italy	Neutral	Deep Decarbonization In Italy
Latvia	Neutral	Sustainable Energy Strategy for Latvia: Vision 2050
Lithuania	Favourable	Lithuania Energy Strategy
Luxembourg	-	No sources found
Malta	-	No sources found
Netherlands	Favourable	Key Elements of Climate Agreement
Poland	Unfavourable	No government source – CCS in Poland
Portugal	Favourable	Low Carbon Roadmap for Portugal
Romania	Favourable	ERA-NET ACT

Country	Rating	Source
Slovakia	Neutral	No government document – Slovakia Country Report
Slovenia	Neutral	Sostanj Thermal Power Project
Spain	Favourable	ERA-NET ACT
Sweden	Neutral	Energy Policy and Climate Change in Sweden
UK	Favourable	ERA-NET ACT
Norway	Favourable	Norwegian CCS Strategy

E.6.2 Sectoral CCS and CCU potential and costs

To scope the work that would be conducted in this study, several sectors were selected to estimate the effect on the demand for thermal energy in case CCS is fully deployed in that sector. We apply a threshold that these sectors should represent at least half of the EU's energy demand.

Based on the natural gas demand in 2016, the sectors illustrated in Figure 62 rank highest. However, since individual point-sources of CO_2 are not large enough in the non-ferrous metals, paper, pulp and print, machinery, and food and tobacco sectors, these will not be considered in the analysis. In addition, the energy sector had a natural gas demand of around 5,500 PJ in 2016, which will also be considered given the potentially valuable role of this power source for the grid in backup capacity. Based on this overview, and the availability of specific literature on CCS in these industries, the following industries were selected: iron and steel, cement, lime, chemicals and petrochemicals, and energy.

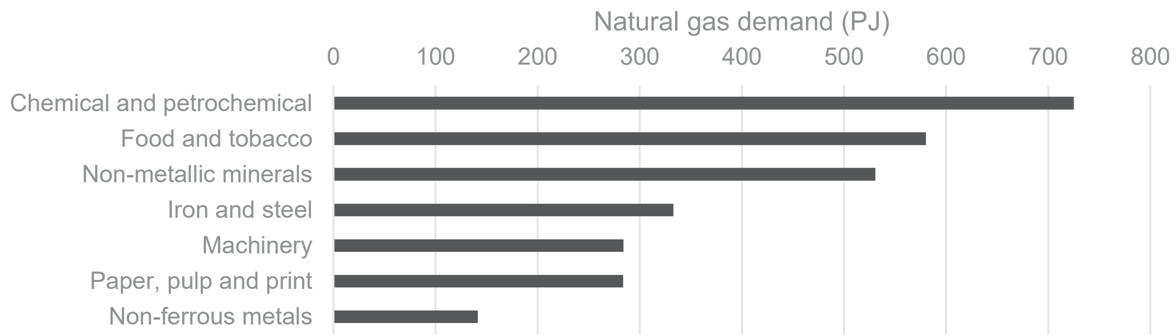

Figure 62 Natural gas demand of industrial sectors with largest gas demand in 2016. Note: chemical and petrochemical also includes non-energy use of natural gas. Source: IEA, 2017.

Jointly, these sectors are responsible for a gas demand of around 6,900 PJ,[320] equivalent to around 180 bcm of gas. This represents about half of the current total gas demand in the EU28.[321]

[320] IEA, 2017. World Energy Statistics and Balances. Note: gas demand from the sectors cement and lime is taken from the category *non-metallic minerals* and are assumed to be equal for the purpose of the selection. This category also includes *glass* and *other*.

[321] 330 Mtoe (13,816 PJ) in 2014. Source: EEA, 2017. *What are the trends concerning the energy mix in gross inland energy consumption in Europe?* https://www.eea.europa.eu/data-and-maps/indicators/primary-energy-consumption-by-fuel-6/assessment-1

European CO_2 storage potential

Table 38 Overview of cumulative CO_2 storage potential in European countries (in $MtCO_2$). Non-EU countries are illustrated in grey italics. Potentials for countries not included in the scope of the GeoCapacity project were taken from other sources. Countries without an entry have no identified storage potentials. Source: EU GeoCapacity (2009).

	Onshore				Offshore	
Country	**Aquifers**	**Hydrocarbon fields**	**Coal fields**	**Mineral trapping**	**Aquifers**	**Hydrocarbon fields**
Albania	*20*	*111*				
Austria						
Belgium	199					
Bosnia-Herzegovina	*197*					
Bulgaria	2,100		17			3
Croatia	2,305	157			405	32
Cyprus						
Czech Republic	766	33	54			
Denmark	1,277				638	203
Estonia						
Finland				2,000		
France	7,922	770				
FYROM	*390*					
Germany	12,000	2,180			2,900	
Greece	37	70			147	
Hungary	140	389	87			
Iceland				*60,000*		
Ireland	210					
Italy	4,436	1,810	71		233	
Latvia	404					
Lithuania	30	7				
Luxembourg						
Malta						
Netherlands	316	1,006	300		24	694
Norway					*26,031*	*3,157*
Poland	1,761	764	415			
Portugal	340				7,260	
Romania	7,500	1,500				
Slovak Republic	1,716					
Slovenia	92	2				
Spain	3,500	34	145		3,500	
Sweden					14,900	
UK					7,100	7,300
TOTAL	47,657	8,833	1,089	62,000	63,139	11,389
TOTAL EU	**47,050**	**8,722**	**1,089**	**2,000**	**37,108**	**8,232**

Carbon capture costs

Literature review was performed to collect cost data on carbon capture for different industrial processes. The processes where the application of CO_2 capture unit is technically feasible and are associated either directly or indirectly with natural gas consumption were included, see Table 39. The majority of literature sources provide costs as cost per tonne of CO_2 avoided rather than captured; therefore, it was decided to use cost data for avoided CO_2 emissions which incorporate the efficiency penalty of integrating a certain capture technology. To allow for cost comparison of an industrial process from multiple sources, costs were converted to constant €$_{2017}$. For the sources that do not report the currency year, it was assumed that the base year is the same as the year of publication of the data source.

Even if cost figures are harmonised for currency, one-on-one comparison of cost data is not possible. This is because the underlying assumptions on plant lifetime, natural gas prices, discount rate, type of capture technology, etc. can vary between sources. To account for this wide variation in assumptions, minimum, median, average, and maximum values were derived from the available list of cost estimates for each industrial process. Table 39 provides an overview of the cost ranges which create an indication of the size of uncertainty in the costs for a tonne of CO_2 that is avoided per industrial process.

Table 39 Minimum, median, average, and maximum costs of a tonne of avoided CO_2 per industrial process. All cost figures are in constant €$_{2017}$. The cost data is obtained from multiple sources.

Industrial processes	Minimum	Median	Average	Maximum
Refining - hydrogen production	16	29	32	63
Refining - process heaters	27	52	58	113
Refining - FCC	45	82	81	106
Refining - CHP	22	62	56	106
Steel - blast furnace	24	54	58	93
Steel - hot stoves, power/steam plant	57	57	61	69
Steel - coke oven, underfired heaters	67	69	70	73
Chemicals - ethylene oxide	12	12	12	12
Chemicals - hydrogen (ammonia/methanol)	16	20	23	33
Chemicals - ethylene/propylene	57	57	57	57
Chemicals - process heaters/CHP	33	82	72	102
Gas processing	8	13	12	15
Pulp and paper - kraft mill	29	49	45	57
Cement	13	39	51	129
Biofuels - ethanol	12	13	13	15
Aluminium smelter	12	12	12	12
Power generation-natural gas	65	73	84	114
Non-metallic minerals - lime	98	98	98	98

List of literature sources for carbon capture costs

Table 40 Capture technologies, costs, and CO_2 emissions per process in the refining sector

Reference	Process	Capture type	Site emissions (Mt CO_2/yr)	Concentration of CO_2	% of the total site emissions	Avoided costs (€/t CO_2)
IEA (2013)	Refining - hydrogen production	Unknown	6.12	Unknown	Unknown	20, 29, 34
GCCSI (2010)	Refining - hydrogen production	Post-combustion new	Unknown	20-99%	5-20%	16-43
Leeson et al. (2017)	Refining - hydrogen production	Post-combustion	Unknown	Unknown	Unknown	22-63
IEA (2013)	Refining - process heaters	Unknown	6.12	Unknown	33%	33, 65,106
GCCSI (2010)	Refining - process heaters	Post-combustion retrofit Pre-combustion retrofit Oxy-combustion retrofit Post-combustion new Oxy-combustion new Chemical looping	Unknown	8-10%	30-60%	63 40 36 78 41 27-34
Leeson et al. (2017)	Refining - process heaters	Chemical looping Oxy-combustion Oxy-combustion Pre-combustion Post-combustion	Unknown	Unknown	Unknow	39-50 51 52 58-59 91-113
IEA (2013)	Refining - FCC	Unknown	6.12	Unknown	8%	65, 82, 106
GCCSI (2010)	Refining - FCC	Oxy-combustion retrofit Post-combustion retrofit	Unknown	10-20%	20-50%	45 69
Leeson et al. (2017)	Refining - FCC	Oxy-combustion Post-combustion	Unknown	Unknown	Unknow	100 100
IEA (2013)	Refining - CHP	Unknown	6.12	Unknown	20%	33, 86, 106
GCCSI (2010)	Refining - CHP	Post-combustion new Pre-combustion new	Unknown	4% (Gas turbine)	20-50%	23-62 22-62

Table 41 Capture technologies, costs and CO_2 emissions per process in the iron and steel sector

Reference	Process	Capture type	Site emissions (Mt CO_2/yr)	Concentration of CO_2	% of the total site emissions	Avoided costs (€/t CO_2)
IEA (2013)	Iron and steel - blast furnace	Unknown	7.5	Unknown	35%	24, 45, 65
GCCSI (2017)	Iron and steel - blast furnace	Unknown	0.62*	Unknown	Unknown	55-91
Leeson et al. (2017)	Iron and steel - blast furnace	Oxy-combustion Post-combustion Post-combustion Post-combustion Post-combustion	Unknown	Unknown	41% 65% 50% 55% 50%	44 42-69 54 61 51-93
IEA (2013)	Iron and steel - hot stoves, power/steam plant	Unknown	7.5	Unknown	30%	57, 57, 69
IEA (2013)	Iron and steel - coke oven, underfired heaters	Unknown	7.5	Unknown	8%	69, 69, 73
Leeson et al. (2017)	Iron and steel - coke oven, underfired heaters	Post-combustion	Unknown	Unknown	20%	67

*Note: Figure with * is estimated using the following data from the source: CO_2 emission factor for steel production and hourly steel production. A capacity factor of 90% is assumed.*

Table 42 Capture technologies, costs and CO_2 emissions per process in the chemicals sector

Reference	Process	Capture type	Site emissions (Mt CO_2/yr)	Concentration of CO_2	% of the total site emissions	Avoided costs (€/tCO_2)
IEA (2013)	Chemicals - ethylene oxide	Unknown	3.6	Unknown	Unknown	12
IEA (2013)	Chemicals - hydrogen (ammonia/methanol)	Unknown	3.6	Unknown	Unknown	16, 29, 33
GCCSI (2017)	Chemicals - hydrogen (ammonia/methanol)	Unknown	0.2*	Unknown	Unknown	16-20
IEA (2013)	Chemicals - ethylene/propylene	Unknown	3.6	Unknown	Unknown	57
IEA (2013)	Chemicals - process heaters/CHP	Unknown	3.6	Unknown	Unknown	33, 82, 102

*Note: Figure with * is estimated using the following data from the source: CO_2 emission factor for hydrogen production and hourly hydrogen production. A capacity factor of 90% is assumed.*

Table 43 Capture technologies, costs and CO_2 emissions per process in the cement sector

Reference	Process	Capture type	Site emissions (Mt CO_2/yr)	Concentration of CO_2	% of the total site emissions	Avoided costs (€/tCO_2)
IEA (2013)	Cement	Unknown	1	Unknown	60%[322]	16, 31, 41
IEA (2013)	Cement	Unknown	1	Unknown	90%[323]	29, 53, 90
IEA GHG (2014)	Cement	Oxy-combustion full Oxy-combustion partial Post-combustion CHP NGCC Post-combustion CHP Coal	1.13	Unknown	90% 60%	29 37 50 85
GCCSI (2017)	Cement	Unknown	0.25*	Unknown	Unknown	33-106
Leeson et al. (2017)	Cement	Oxy-combustion chemical looping Oxy-combustion chemical looping Oxy-combustion chemical looping Oxy-combustion chemical looping Post-combustion Post-combustion	Unknown	Unknown	94% 84% 60% 52% 60% 77%	13 18 32 60 70 129

*Note: Figure with * is estimated using the following data from the source: CO_2 emission factor for cement production and hourly cement production. A capacity factor of 90% is assumed.*

[322] Capture from pre-calciner.

[323] Capture from the whole cement plant.

Table 44 Capture technologies, costs and CO_2 emissions per process in the other industry sectors

Reference	Process	Capture type	Site emissions (Mt CO_2/yr)	Concentration of CO_2	% of the total site emissions	Avoided costs (€/tCO_2)
IEA (2013)	Gas processing	Unknown	2	Unknown	100%	8, 13, 15
IEA (2013)	Pulp & paper - kraft mill	Unknown	1.33	Unknown	75%	29, 49, 57
IEA (2013)	Biofuels - ethanol	Unknown	0.5	Unknown	100%	12
GCCSI (2017)	Biofuels - ethanol	Unknown	0.8	Unknown	Unknown	13-15
IEA (2013)	Aluminium smelter	Unknown	0.25	Unknown	100%	12
Ecofys (2014)	Non-metallic minerals - lime	Unknown	Unknown	Unknown	67%	98
IEA (2013)	Power generation-natural gas	Post-combustion	Unknown	Unknown	100%	65
GCCSI (2017)	Power generation-natural gas	Unknown	~2*	Unknown	100%	73-114

*Note: Figure with * is estimated using the data on plant size from the source. CO_2 emission factor of 0.4 t/ MWh and a capacity factor of 90% is assumed.*

Transport costs

Transport costs depend on CO_2 volumes, transported distance, and the diameter of the pipeline technology used to transport it.[324] These transport cost scenarios are obtained from the ZEP report,[324] which estimates EU-specific transport costs against transport volumes of 2.5, 10, and 20 MtCO_2. For annual flow rates of 2.5 and 10 MtCO_2, point-to-point solutions are considered where a single CO_2 source is connected to a sink located over distances of 10 km, 180 km, 500 km, 750 km, and 1,500 km. Table 45 shows that transport costs for small volumes (2.5 MtCO_2) over long distances (>180 km) via pipeline are not calculated, as it will be an expensive way to transport CO_2. In this scenario transport of CO_2 via ships is a cost-effective alternative.

The large-scale CO_2 capture scenario assumes an annual flow rate of 20 MtCO_2. This solution considers a cluster of CO_2 sources that are linked to multiple storage locations on and offshore. Transport through shipping in this case is also possible but it is more expensive compared to pipeline transport over similar distances. It is worthwhile to note that these cost estimates assume full capacity utilisation of the transport infrastructure from day one, whereas CO_2 volumes would gradually ramp-up to the full capacity in a cluster setting. The unit costs of the pipeline would increase depending upon the maximum flows whereas ramp-up with ships can be achieved by adding more ships when required resulting in only marginal unit cost increases.

These cost estimates do not include the CO_2 compression costs at capture sites. The transport costs in our cluster analysis are calculated using a web-based tool developed by Navigant. For details on transport costs in cluster analysis, reference Appendix A.3.2.

[324] ZEP (2011). The Costs of CO_2 Transport. http://www.zeroemissionsplatform.eu/library/publication/167-zep-cost-report-transport.html

Table 45 CO_2 transport costs via pipelines – onshore vary between 0.1-16€/t CO_2

CO_2 transported	Parameter	Onshore				
2.5 $MtCO_2$/year	Distance (km)	10	180	N/A	N/A	N/A
	Diameter (inch)	12	12	N/A	N/A	N/A
	Costs (€/t CO_2)	0.41	5.38	N/A	N/A	N/A
10 $MtCO_2$/year	Distance (km)	10	180	500	750	1,500
	Diameter (inch)	20	24	24	24	24
	Costs (€/t CO_2)	0.13	2.00	5.34	7.95	15.81
20 $MtCO_2$/year	Distance (km)	10	180	500	750	1,500
	Diameter (inch)	24	32	32	32	32
	Costs (€/t CO_2)	0.08	1.26	3.40	5.04	10.02

**transport costs for small volumes (2.5 $MtCO_2$) over long distances (>180 km) via pipeline are not calculated since it will be an expensive way of CO_2 transport. In this scenario transport of CO_2 via ships is a cost-effective alternative.*

Table 46 CO_2 transport costs via pipelines – offshore vary between 2-29€/t CO_2

CO_2 transported	Parameter	Offshore				
2.5 $MtCO_2$/year	Distance (km)	10	180	500	750	1,500
	Diameter (inch)	N/A	12	16	16	16
	Costs (€/t CO_2)	N/A	9.34	20.42	28.71	51.73*
10 $MtCO_2$/year	Distance (km)	10	180	500	750	1,500
	Diameter (inch)	N/A	22	26	26	30
	Costs (€/t CO_2)	N/A	3.31	7.02	9.75	20.27
20 $MtCO_2$/year	Distance (km)	10	180	500	750	1,500
	Diameter (inch)	N/A	26	32	34	40
	Costs (€/t CO_2)	N/A	2.17	4.74	6.90	15.08

*NOTE: Figure with * sketches a scenario where a very small CO_2 source is transported offshore over 1500 km, which does not seem very practical. It is less likely that such a set-up would be established. The cost figures are shared for comparative purposes only.*

Table 47 CO_2 transport costs via ships (including liquefaction costs) vary between 10-20€/t CO_2[325]

CO_2 transported	Parameter	Ship (including liquefaction)				
2.5 $MtCO_2$/year	Distance (km)	180	500	750	1,500	Liquefaction
	Ship size (m^3)	22,000	29,300	36,600	25,700	
	Costs (€/t CO_2)	13.49	14.76	15.86	19.82	5.31
20 $MtCO_2$/year	Distance (km)	180	500	750	1,500	Liquefaction
	Distance (inch)	35,200	39,100	41,900	41,000	
	Costs (€/t CO_2)	9.87	10.99	12.00	14.88	4.87

325 ZEP report on CO_2 transport costs does not calculate costs of CO_2 transport via shipping against CO_2 volumes of 10 $MtCO_2$/yr.

Sector Descriptions

Iron and Steel

- In existing integrated steel mills, most of the process off-gases (coke oven gas [COG]), blast furnace gas [BFG], and basic oxygen furnace [BOF]) are recovered and utilised in different steel mill processes, for instance, in coke ovens and blast furnaces. The off-gases are also used in hot stoves, heating furnaces, and power plants. The excess off-gases with no demand are flared for safety reasons. The use of natural gas is around 0.849 GJ/t hot rolled coil (HRC) in an integrated steel mill. This results in total natural gas demand of 86 PJ at current primary steel production of 101 million tonnes[326] in the EU.
- The deployment of a carbon capture unit increases the energy needs of a steel mill in the form of thermal energy and electricity for which additional natural gas or fuel gas is needed. With post-combustion capture at an integrated steel mill with conventional blast furnace, the energy increase is higher compared to a case where CO_2 is captured using chemical absorption[327] from an oxygen blast furnace (OBF) with top gas recycling. The primary reason for this is the reduction of coke consumption because of (CO_2 free) top gas recycling to blast furnace. Less energy increase results in lower CO_2 emission levels per tonne of HRC for the OBF case. It is estimated that around 46% of the site emissions that are avoided can be captured in the OBF case, whereas with post-combustion process the capture rate could be as high as 60%.[328] The natural gas demand in iron and steel sector would increase if the augmented energy needs are met through natural gas. It is reported that the natural gas demand can roughly increase between 5 to 6.5 times with the integration of carbon capture.[328] In a CCS scenario with post-combustion CO_2 capture using MEA solution, the natural gas demand could vary between 430–560 PJ (11–15 bcm) at current primary steel production volumes of 101 million tonnes.
- Our estimates suggest that around 171 Mt CO_2[329] are emitted from the primary production of steel in the EU. In a CCS scenario, these emissions would approximately increase by 10%. Since 60% of site emissions can realistically be captured with CCS, the total captured emissions from iron and steel sector in a CCS scenario will amount to 113 $MtCO_2$.
- Since the share of emissions that are captured at an integrated steel plants[330] can at maximum be 60%, CCS alone cannot guarantee the deep decarbonisation of the steel sector. To fully decarbonise using current technologies, a combination of bio-based fuels and CCS would be required. Looking towards 2050, new processes are being developed. The suitability of carbon capture technologies for new iron and steel production processes, such as direct-reduced iron (DRI), can increase the potential for CCS in the sector and the demand for natural gas. This is because the process requires reduction gas, usually natural gas, which is chemically converted to syngas. Various CO_2 capture technologies such as pre-combustion (gasification), Pressure swing adsorption (PSA), vacuum pressure swing adsorption (VPSA) or chemical adsorption can be used with DRI.[331] In the longer term, hydrogen-based steelmaking could be promising.

---

[326] World Steel Association (2018). *World Steel in Figures 2018*. https://www.worldsteel.org/en/dam/jcr:f9359dff-9546-4d6b-bed0-996201185b12/World+Steel+in+Figures+2018.pdf

[327] Pressure Swing Adsorption (PSA), Vacuum Pressure Swing Adsorption (VPSA) and Cryogenic separation are also being researched for CO_2 capture from Oxygen Blast Furnace (OBF).

[328] IEAGHG (2013). *Iron and Steel CCS Study (Techno-economics Integrated Steel Mill*).

[329] Emissions are obtained from EU GHG Inventory published in May 2018. The inventory includes process emissions as well as emissions from fuel combustion. The reported emissions were then adjusted for additional emissions from onsite power generation.

[330] An integrated steel plant is a site which has all the primary functions for steel production. The processes include iron making from iron ore, steelmaking using pig iron as well as casting and rolling.

[331] IEA (2011). *Technology Roadmap: Carbon Capture and Storage in Industrial Applications*. http://hub.globalccsinstitute.com/sites/default/files/publications/22002/ccs-industry-roadmap-web.pdf

If the hydrogen is produced in a low-carbon manner, significant emissions reductions can be achieved. Currently, the first demonstration project is being prepared by voestalpine in Linz, Austria, with a 6 MW electrolyser to produce hydrogen.[332]

- Other processes that are being researched and further developed are FINEX and HIsarna. With FINEX, almost all of the CO_2 can be captured with no efficiency penalty to the process itself. With HIsarna, around 80% of the CO_2 from liquid iron, which is cultured using iron ore and coke, can be captured.[333]

Cement

- Among EU cement kilns, the weighted average thermal energy consumption was 3.74 GJ/t (grey) clinker in 2016.[334] To cover the necessary energy demand, waste fuels and conventional fossil fuels are used, with the consumption of waste fuels consistently increasing over the last few years.[335] The combined share of waste and biofuels in weighted average thermal energy consumption increased from 18% in 2006 to 45% in 2016.[336] This increasing trend is expected to continue in the coming years. Literature shows that typically used fossil fuels are coal, pet coke, and fuel oil. The share of natural gas in the total thermal energy consumption is marginal in the EU.
- It is possible to capture CO_2 from a cement production facility, but the application of a capture unit would increase the energy needs of the process. The amount of energy needed for sorbent regeneration (in post-combustion process with amine scrubbing) can only be partially supplied from clinker burning. It is reported that 15% of the additional energy needs (4 GJ/t CO_2 for amine scrubbing) can be provided by clinker burning, but to meet the rest of the energy demand additional CHP is required, mainly for the purposes of generating steam.[337] The CHP unit could be coal-fired or gas-fired, the choice depends on numerous factors including local conditions. If a natural gas combined cycle plant is used, then the natural gas demand could be 749 PJ[338] (20 bcm) in a CCS scenario.
- With oxy-combustion CO_2 capture, the role of natural gas would be relatively minor. The technology also requires some re-adjustments to different processes and is relatively less developed when compared with post-combustion technologies. The natural gas demand with post-combustion capture from chemical absorption, therefore, represents the upper limit of the sector's potential gas requirements. Other more energy-efficient carbon capture technologies are also being researched, such as calcium looping and membrane separation. It has been reported that with advanced calcium looping technology it is possible to capture emissions as cheap as €20/tCO_2 avoided.

---

[332] Voestalpine, 2018. http://www.voestalpine.com/group/en/media/press-releases/2018-01-16-voestalpine-and-its-partners-get-the-green-light-to-build-the-worlds-largest-industrial-hydrogen-pilot-plant-in-linz/

[333] Ibid

[334] WBCSD (2018). *GNR Project Reporting CO_2. Thermal energy consumption – Weighted average: including drying of fuels – grey clinker – (MJ/t clinker)*. http://www.wbcsdcement.org/GNR-2016/EU28/GNR-Indicator_93AG-EU28.html

[335] JRC (2013). *Best Available Techniques (BAT) Reference Document for the Production of Cement, Lime and Magnesium Oxide*. http://eippcb.jrc.ec.europa.eu/reference/BREF/CLM_Published_def.pdf

[336] WBCSD (2018). *GNR Project Reporting CO_2. Thermal energy consumption – Weighted average: excluding drying of fuels – grey clinker – by fuel category (%)*. http://www.wbcsdcement.org/GNR-2016/EU28/GNR-Indicator_25aAGFC-EU28.html

[337] IEAGHG (2013). *Deployment of CCS in the Cement Industry*. https://ieaghg.org/docs/General_Docs/Reports/2013-19.pdf

[338] The natural gas demand would be 3.4 GJ/tCO_2 captured in a CCS scenario. This is the residual energy demand for solvent regeneration after using waste heat from clinker burning. Emissions increase by 43% with CCS integration resulting in a CO_2 emission factor of 1.174 tCO_2/t cement. With the new emission factor and the cement production volumes of 169 Mtonnes in the EU, the total natural gas demand is estimated to be 749 PJ. The CO_2 capture rate is 90% and the assumed efficiency of NGCC power plant is 60%.

The technology could also yield negative emissions in case biomass is used as a fuel in the calciner.[339] These technologies require low energy demand for solvent regeneration and, with these technologies, the demand for gas would not increase considerably from the base case.

- Current emissions in the cement sector are estimated to be 139 Mt CO_2 against the cement production volumes of 169 million tonnes per annum[340]. The estimates are developed assuming an emissions factor of 0.82 tCO_2/t cement.[341] With the application of CCS, the energy needs of a cement plant increases. It is estimated that the site emissions would increase by roughly 43% if all the additional energy is supplied through a NGCC CHP unit. Since CCS allows capture of 90% of the site emissions, there will be a CO_2 supply of 179 Mt per annum from the cement sector for geological storage.
- As mentioned earlier, the application of CCS guarantees capture of up to 90% of CO_2 emissions from a cement plant. Therefore, CCS can play a crucial role in the deep decarbonisation of the sector. One of the main reasons for the deployment of CCS is that 55%–60% of the total emissions from cement production arise from the decomposition of limestone in the pre-calciner. However, 20% of the clinker in the EU is replaced by waste materials such as fly ash or blast furnace slag which in turn reduce the process emissions from limestone,[342] the complete replacement of limestone is not expected to materialise anytime soon. A combination of material substitution and CCS could offer the needed emission reductions for achieving the long-term decarbonisation targets in the EU.

Lime

- Emissions reductions through fuel switching and energy efficiency improvements have limited influence on the sector's decarbonisation. Two-thirds of all the carbon emissions are released from raw materials during the production process. CCS could be an effective solution to help the sector achieve deep decarbonisation.[343]
- There are different lime kilns that are operational in the EU, namely long rotary kilns (LRK), rotary kiln with pre-heater (PRK), parallel flow regenerative kiln (PFRK), annular shaft kiln (AFK), mixed feed shaft kiln (MFSK) and other shaft kilns (OSF). The use of kiln and fuel type depends on the end-use of lime. Most kilns can operate on more than one fuel, but others only operate on certain fuel types. The most common fuels in the EU are gaseous, such as natural gas and coke oven gas, solid fuels such as coal, coke/anthracite, and waste that includes used oil, plastics, paper, saw dust, etc. The liquid fuels and biomass have relatively small share in the total fuel consumption.[344]
- In the EU, the total use of gaseous fuels in lime kiln-firing process was around 36 PJ in 2003. The gaseous fuels include mainly natural gas but also coke oven gas and butane/propane gas. The largest share of gaseous fuels was in PFRK (~21 PJ), followed by ASK (~10 PJ) and PRK (~4 PJ).[344] At present, average fuel consumption for heating in lime kilns is around 4.25 GJ/tonne of quicklime. About 34% of this fuel demand is met by natural gas.

---

[339] Martinez et al., 2017. Second generation calcium looping system with biomass combustion in the calciner. https://www.sintef.no/globalassets/project/tccs-9/presentasjoner/b6/11---presentation-tccs9--martinez-et-al.-def.pptx.pdf

[340] CEMBUREAU (2018). Key facts & figures. https://cembureau.eu/cement-101/key-facts-figures/

[341] WBCSD (2018). *GNR Project Reporting CO_2. Gross CO_2 emissions – Weighted average: excluding onsite emissions from power generation – grey clinker*. http://www.wbcsdcement.org/GNR-2016/index.html

[342] CEMBUREAU (2017). *Innovation in the Cement Industry*. https://cembureau.eu/media/1225/10819_cembureau_innovationbooklet_eu-ets_2017-02-01.pdf

[343] EuLA (2014). *A Competitive and Efficient Lime Industry: Corner Stone for a Sustainable Europe*. https://www.eula.eu/file/475/download?token=atvGVNpE

[344] JRC (2013). *Best Available Techniques (BAT) Reference Document for the Production of Cement, Lime and Magnesium Oxide*. http://eippcb.jrc.ec.europa.eu/reference/BREF/CLM_Published_def.pdf

The share of electricity consumption in lime making is very small, in the order of magnitude 0.2 PJ which is less than 5% of the total energy use. Total lime production is 22 million tonnes, making total average natural gas demand around 32 PJ (0.8 bcm) in the EU lime sector.

- With post-combustion CO_2 capture, a part of the additional energy for heating and electricity can come from residual heat of the lime kiln; however, additional fuel volumes would be needed to supply the augmented energy demand. For each tonne of CO_2 that is captured around 3.1 GJ of energy is needed for solvent regeneration in the form of heat. About 0.46 GJ of energy is required in the form of electricity to power the fans and pumps and for CO_2 compression.[343] The demand for natural gas can increase by 88 PJ if no residual heat is used and additional energy is supplied through a gas-fired boiler.[345] The total natural gas demand with CCS is therefore 120 PJ (3 bcm), which is almost 4 times higher compared to a no CCS scenario.
- Lime production is approximately 22 million tonnes, and it is reported that 1.09 $MtCO_2$ are emitted per tonne of quick lime on average.[343] Therefore, the EU lime sector emits around 24 $MtCO_2$/year. With the integration of CCS, it is estimated that direct emissions from lime sector increase by approximately 36% if the additional energy demand is met by natural gas. These estimates do not exclude the share of emissions that would be mitigated by the use of residual heat. With 90% capture of site emissions, around 34 $MtCO_2$ would be available for geological storage.
- A process called Calix's Direction Separation is being investigated. The process is expected to significantly reduce process emissions from lime making with no additional chemicals or processes—resulting in a pure stream of CO_2.[346] For the remaining emissions, which constitute around one-third of the total emissions, fuel switching would allow for emissions reductions. Alternatively, other carbon capture technologies could be deployed. With this technology around 95% of the process emissions can be captured. There is no additional demand for natural gas in Calix's process.
- The process requires minimal changes to the traditional cement production process by simply replacing the calciner. The technology is being researched and further developed under the LEILAC project, which received a grant of €12 million under the Horizon 2020 research and innovation program. The aim is to develop, build, operate, and test a 240 tonne per day pilot plant at Heidelberg Cement's plant in Lixhe, Belgium. The pilot plant is expected to become operational in 2019.[347]

Energy

- Current natural gas demand in the energy sector is around 5,500 PJ (144 bcm). Integration of CCS (post-combustion) can result in an efficiency penalty of 5%–10% due to additional steam or electricity generation for larger flue gas fans, CO_2 compression, and solvent stripping.[348] With CCS, the natural gas demand in the power sector would be approximately 5950 PJ (156 bcm).
- It is technically possible to capture around 85%–95% of site emissions from the gas-fired power plants. This indicates that CCS is an effective way to substantially reduce emissions from the power sector.

---

[345] The natural gas demand is calculated using the specific energy consumption of 3.1 GJ/tCO_2 captured for solvent regeneration. It is assumed that the heat is supplied through a gas fired boiler. The thermal energy efficiency from natural gas to steam is assumed to be 90%.

[346] LEILAC (2018). *The core technology - Direct Separation*. https://www.project-leilac.eu/the-core-technology

[347] Hills et al. (2017). *LEILAC: Low cost CO_2 capture for the cement and lime industries*. https://spiral.imperial.ac.uk/bitstream/10044/1/62582/5/1-s2.0-S1876610217319550-main.pdf

[348] ZEP (2011). *The Costs of CO_2 Capture*.

- Current emissions from natural gas power and heat production are 229 $MtCO_2$.[349] Since some of the emissions from the power sector are allocated to steel, chemical, and refining sectors, these emissions were excluded from the power sector to avoid double counting. This also leads to an adjustment of the energy sector's energy usage to 5,560 PJ. The adjusted emissions for the power sector are estimated to be 191 $MtCO_2$. With an efficiency penalty of 10%, the total site emissions will be 210 $MtCO_2$ in a CCS scenario. With 90% capture of the site emissions, a CO_2 supply of 189 $MtCO_2$/year would be available for geological storage.
- Natural gas is considered to be a transition fuel. With increased penetration of cheap renewables in the electricity sector, the number of operational hours for natural gas-fired power plants would gradually reduce. This reduction in average load factor would make the CCS integration for the natural gas plants even costlier than it is today. In today's situation natural gas plants could achieve a capacity factor of as high as 90%. If this factor was reduced to 50%, the consequent increase in the electricity price from natural gas-fired power plants would be substantial. This increase in unit energy prices would diminish the natural gas demand in the power sector in the future.

Chemicals and Petrochemicals

- Olefins, i.e., ethylene and propylene, are basic buildings blocks for many chemical products. They are typically produced from steam cracking of naphtha, although LPG is also gaining importance in Europe. Around 25% of the feedstock used in steam cracking was LPG in 2015.[350] Naphtha is made from natural gas condensates, petroleum distillates, and the distillation of coal tar and peat. There is no direct natural gas consumption in the production of naphtha, only the by-products of natural gas production such as condensates from raw natural gas are used. The released methane from cracker gases is often used to heat the cracker furnaces, with a marginal amount of external natural gas to start the furnace or provide additional supply.
- It is expected that for all chemical and petrochemical processes considered in this study, the additional thermal energy requirement is 3.2 GJ/tCO_2 for emissions from fuel combustion and 0 GJ/tCO_2 for pure CO_2 sources. Additional electric energy demand is 1.13 GJ/tCO_2 to capture the more diffuse emissions from fuel combustion and 0.33 GJ/tCO_2 for more concentrated process emissions, but this can be supplied with renewable electricity.[351] Emissions from fuel combustion in the chemicals and petrochemicals sector were around 179 $MtCO_2$ in 2016. Including the energy penalty induced, and including onsite power generation, capturing 85% of these emissions (240 $MtCO_2$) would lead to an additional thermal energy demand of 768 PJ, bringing the total sector natural gas demand to 2,058 PJ (54 bcm) for energy and non-energy use.
- Alternative pathways are possible for the chemical and petrochemical industry. Currently, 319 PJ of the generation of heat is met through natural gas in the chemical sector. As the power grid decarbonises, electricity-based steam production could be less emission-intensive between 2030 and 2035.[352] Fossil production routes that rely on the production of hydrogen, such as ammonia and methanol, could gradually be replaced by water electrolysis. No direct pathways are currently known to produce olefins from hydrogen and CO_2, but they can be produced from methanol through the methanol-to-olefins technology.

---

[349] IEA (2018). *IEA Energy Balances*

[350] DECHEMA, 2017. *Technology study: Low carbon energy and feedstock for the European chemical industry.* https://dechema.de/dechema_media/Downloads/Positionspapiere/Technology_study_Low_carbon_energy_and_feedstock_for_the_European_chemical_industry.pdf

[351] CEFIC, 2013. *European chemistry for growth: Unlocking a competitive, low carbon and energy efficient future.* http://www.cefic.org/Documents/RESOURCES/Reports-and-Brochure/Energy-Roadmap-The%20Report-European-chemistry-for-growth.pdf

[352] DECHEMA, 2017. *Technology study: Low carbon energy and feedstock for the European chemical industry.* https://dechema.de/dechema_media/Downloads/Positionspapiere/Technology_study_Low_carbon_energy_and_feedstock_for_the_European_chemical_industry.pdf

It should be noted that many technologies required to decarbonise the chemical sector rely heavily on CO_2 as a feedstock—such as for MTO and methanol-to-aromatics to produce BTX and the production of synthetic fuels. DECHEMA reports a requirement of 258 $MtCO_2$ in 2050.

- Alternatively, biomethanol, bioethanol, bioethylene, and BTX from biomass are also already available at TRLs higher than 6. DECHEMA's most ambitious scenario reports that only natural gas will be needed in 2050. In this scenario, natural gas is used for distillation of methanol to produce HVCs and some for the production of ammonia, thereby almost completely reducing the need for natural gas in the chemical sector.

CO_2 emissions overview of EU countries

Table 48 Greenhouse gas emissions (in $MtCO_2e$) from CRF Category 1.A.1 Energy Industries, 1.A.2 Manufacturing Industries and Construction, 2.A Mineral Industry, 2.B Chemical Industry, and 2.C Metal Industry. Only emissions from gas-fired power production are taken into account for CRF Category 1.A.1 Energy Industries and were estimated by multiplying total emissions by a factor of 22%, which is the share of gas-fired power emissions in the EU from the EU GHG Inventory. Countries with a limited storage potential in any case are marked in bold. Source: UNFCCC.

Country	CO_2 storage potential under legislative restrictions ($MtCO_2$/yr)	CO_2 storage potential without legislative restrictions ($MtCO_2$/yr)	Emissions from gas-fired energy production and industry ($MtCO_2e$/yr)	Emissions captured in 2050 under ambitious CCS scenario ($MtCO_2$/yr)	% storage capacity used by 2050 under legislative restriction	% storage capacity used by 2050 without legislative restriction
Austria	0	0	43	28	100%	100%
Belgium	199	199	50	32	100%	100%
Bulgaria	2,120	2,120	21	13	10%	10%
Croatia	0	2,899	7	5	100%	3%
Cyprus	0	0	3	2	100%	100%
Czech Republic	0	853	55	36	100%	65%
Denmark	841	2,118	10	6	12%	5%
Estonia	0	0	4	2	100%	100%
Finland	2,000	2,000	24	15	12%	12%
France	8,692	8,692	89	58	10%	10%
Germany	120	17,080	335	217	100%	20%
Greece	254	254	27	18	100%	100%
Hungary	616	616	16	11	27%	27%
Ireland	0	210	10	6	100%	48%
Italy	6,550	6,550	91	59	14%	14%
Latvia	0	404	2	1	100%	5%
Lithuania	37	37	5	3	100%	100%
Luxembourg	0	0	2	1	100%	100%
Malta	0	0	0	0	100%	100%
Netherlands	717	2,340	68	44	95%	29%
Poland	0	2,940	126	82	100%	43%
Portugal	7,600	7,600	18	12	2%	2%
Romania	9,000	9,000	41	27	5%	5%
Slovakia	1,716	1,716	25	16	14%	14%
Slovenia	0	94	5	3	100%	54%
Spain	7,179	7,179	106	68	15%	15%
Sweden	14,900	14,900	21	14	1%	1%
UK	14,400	14,400	145	94	10%	10%
TOTAL	**76,942**	**104,201**	**1,349**	**874**		

E.6.3 Promising options for CCS and CCU in EU industrial clusters

Cluster selection

European clusters were selected based on their annual CO_2 emissions volume in a 20 km radius, whilst ensuring geographical spread within the Gas for Climate consortium, sectoral diversity, and whether there are noteworthy recent CCUS developments identified. To ensure this, selection for further analysis was performed in the following order:

1. Select cluster with most annual CO_2 emissions from LCP and E-PRTR databases.
2. Identify next-largest emitting cluster in a different EU member state represented in the consortium. Select if this cluster meets one or more of the following criteria:
    a) Significant emissions from sectors[353] that are not represented in the selection thus far
    b) Noteworthy, recent CCUS developments
    c) It is the last known cluster in this member state
3. Repeat step 2 until six clusters are selected.

European clusters were selected based on their annual CO_2 emissions volume in a 20 km radius, whilst ensuring geographical spread, sectoral diversity,[354,355] and whether there are identifying noteworthy recent CCS and CCU developments.[356,357] Table 49 provides an overview of these attributes for the investigated industrial clusters in the EU.

Table 49 Overview of investigated clusters

	CCU and CCS developments	Country	Annual emissions (20 km radius) [$MtCO_2/y$]	Energy		Manufacturing										Other	
				Gas-fired	Other	Iron and steel	Aluminium	Lime and plaster	Cement	Refined petroleum products	Organic basic chemicals	Plastics in primary forms	Fertilisers and nitrogen	Paper and paper board	Industrial gases	Steam and air conditioning	Waste treatment and disposal
1 Krefeld-Uerdingen	✓	Germany	33.4	✓	✓	✓					✓				✓	✓	✓
2 Port of Rotterdam	✓	Netherlands	16.0	✓	✓		✓			✓	✓				✓		✓
3 Marseille-Fos	✓	France	14.9	✓		✓		✓	✓	✓	✓				✓		✓
4 Port of Antwerp	✓	Belgium	13.6	✓	✓					✓	✓	✓	✓		✓		✓
5 Porto Marghera		Italy	6.0		✓					✓	✓						✓
6 Tarragona		Spain	4.8	✓	✓					✓	✓	✓			✓		

[353] See Table 49 Overview of investigated clusters for the sector list used.

[354] The European Pollutant Release and Transfer Register (E-PRTR).

[355] The Large Combustion Plant database (LCP).

[356] Identifying and Developing European CCS Hubs, ZEP, April 2016.

[357] https://www.carbon4pur.eu/partners/

Capture costs
Weighted average capture costs are calculated by identifying the emitters in a 20 km radius around the central cluster coordinate, de-selecting coal-fired power generation and combining total annual emissions per point source with capture costs per identified industrial process as specified in Table 39. Per process, a capture effectiveness (%) is assumed, and reflects the increasing difficulty of tying in point sources when there are more smaller point sources versus when there are a few very large emission points.[358] Industrial processes from Table 39 are not always explicitly associated in the used LCP and E-PRTR databases. In absence of explicit association, other publicly available sources[359,360,361,362] were used to help identify the process underlying a certain emission point source, including company websites. If no definitive identification could take place based on publicly available sources, expert judgement was used. For example, the distinction between power generation and a blast furnace owned by the same steel plant operator under the same permit was made based on the expected relative emissions difference: in integrated steel plants, blast furnace flue gas is usually diverted to power and steam generation facilities, hence most CO_2 emissions are expected to exit through the power generation exhaust.[363]

Transport costs
We employ a web-based interface[364] to construct and analyse high-level pipeline routes from a central location of the cluster to identified sinks[365] near this cluster. Within this tool, costs of pipeline transport are broken down into capital investments and operation and maintenance cost. Costs of compression of the CO_2 are not included in the cost calculations.

Costs of pipelines are determined by the following variables or cost factors:

- Startup cost and other costs (design and engineering, project management, regulatory filing fees, insurance costs, and right-of-way costs). The startup costs are fixed costs only depending on the diameter of the pipeline. Other costs are cost factors that increase with both the length and diameter of the pipeline.
- Construction costs (material/equipment costs and installation costs).
- Material costs (steel cost and other materials/equipment).
- Labour cost (installation costs).
- Art works and land fall costs: Art works (e.g., river crossings) form important cost elements. The costs are mainly depending on the amount and the size and length of art works. Costs for a single art works can go up to €2-€3 million. Cost of land fall (onshore to offshore crossing or vice versa) also significantly adds to the total costs and depends on the diameter of the pipeline. The estimated costs for a pipeline of 1 meter in diameter are €7 million per crossing.
- Operation and maintenance costs (monitoring, operation, maintenance).

[358] IEA, Technology Roadmap Carbon Capture and Storage, 2013 edition.

[359] CIEP, The European Refining Sector: a diversity of markets? 2017.

[360] Ecofys, Methodology for the free allocation of emission allowances in the EU ETS post 2012, 2009.

[361] EU Transaction Log (EUTL): European Union Emissions Trading System data.

[362] JRC, Best Available Techniques (BAT) Reference Document for the Production of Large Volume Organic Chemicals, 2017.

[363] IEAGHG, Iron and Steel CCS Study (Techno-economics integrated steel mill), 2013.

[364] See http://ccs.ecofys.com/ The methodology explained in the reminder of this section is based on the web tool manual.

[365] We used the EU GeoCapacity GIS database to identify sinks: Project no. SES6-518318 for the European Commission.

The formulae to calculate the costs of pipeline transport are detailed below. Terrain factors and country indices are used to allow for cost inflation due to complex terrain conditions or to correct for high (labour) cost regions. Complex terrain conditions like hilly areas and soggy or unstable soil may increase the investment costs considerably. Another important factor is land use. Crossing populated areas or nature reserves increases costs considerably. Onshore pipeline costs may more than double when the pipeline route is congested and heavily populated. Costs increase in heavily urbanised areas because of accessibility to construction and additional required safety measures.

To calculate the specific transport cost, we calculate first the annual capital costs by determining a capital recovery factor. The capital recovery factor (α) is a function of the discount rate and the lifetime of the project.

$$\alpha = \frac{\mathrm{r}}{1-(1+\mathrm{r})^{-\mathrm{L}}}$$

Where:

α = annual capital recovery factor

r = discount rate (default 10%)

L = lifetime of project (calculated based on total annual emissions and sink potential)

The specific transport costs are then calculated based on the capital investments and annual operation and maintenance costs:

$$specific\ transport\ cost\ [euro/t] = \frac{\alpha * \ Total\ capital\ investments\ [euro] + \ OPEX\ [euro/a]}{Flow\ [\ Mt/a]}$$

Total capital investment costs are calculated as:

$$\begin{aligned} &Total\ capital\ investments\ [euro] \\ &\quad = Start - up\ costs\ pipeline + Material\ costs + Labour\ costs + Other\ costs \\ &\quad + \sum_{i=0}^{n} Art\ work\ costs + \sum_{i=0}^{n} Land\ fall\ costs \end{aligned}$$

Annual operation and maintenance (O&M) cost:

$$\begin{aligned} OPEX\ [euro/a] = &(Capital\ investments\ [euro] * fixed\ OPEX\ factor\ [\%]\ ) + (flow\ (actual)[Mt/a] \\ &* (O\&M\ cost\ factor\ [euro/(Mt/a)]\ *\ country\_index(OPEX)) \end{aligned}$$

Land use (TF)

The Corine land cover maps[366] is used to derive terrain factors. The cover maps contain information on the land use, e.g., grassland, build area, ports. Each land use is associated with a terrain factor, which is a proxy for the relative costs for constructing pipelines, i.e., a land cover with factor 2 implies that the costs for constructing pipelines are twice as high as for land covers with factor 1.[367] Table 50 indicates terrain factors for various land covers.

---

[366] More info on the European Corine land cover database: http://www.eea.europa.eu/publications/technical_report_2007_17

[367] A function has been written which calculates the intersections between the pipelines in the network and the polygons in the land cover database. A weighted average (based on length of pipe) is applied to determine the terrain factor for a certain pipe segment.

Table 50 Terrain factors for various land covers

Type	Terrain Factor (TF)
Non-irrigated arable land	1.2
Pastures	1.2
Complex cultivation patterns	2.0
Discontinuous Urban Fabric	2.5
Water bodies	2.0
Intertidal flats	2.0
Coniferous forests	2.0
Land principally occupied by agriculture	1.2
Mixed forests	2.0
Industrial and commercial units	4.0
Broad-leaved forests	2.0
Stream courses	4.0
Sport and Leisure facilities	4.0
Moors and heathlands	4.0
Inland marshes	4.0
Natural grassland	1.2
Estuaries	4.0
Beaches	1.2
Construction sites	2.5
Sea ports	5.0
Green urban areas	4.0
Peat bogs	2.0
Salt marshes	4.0
Fruit trees and berries plantations	2.0
Airports	10.0
Road and rail networks	4.0
Mineral extraction sites	4.0
Transitional woodland scrub	1.2
Dump	4.0
Sea and ocean	2.0
Unknown	1.7

Storage costs

Storage costs are differentiated for six different CO_2 storage types,[368] as indicated in Table 51. Onshore storage is cheaper than offshore storage, and depleted oil and gas fields (DOGF) are cheaper than saline aquifers (SA). The possibility of using existing wells in DOGF makes them even cheaper than SA. One of the key factors that determines the costs of CO_2 storage is the reservoir capacity, as larger reservoirs are cheaper than smaller ones.

[368] ZEP (2011). The Costs of CO_2 Storage.

Storage costs in Table 51 are obtained from the ZEP report.[368] Three cases are assumed that correspond to storage volumes of typical storage sites in the EU as identified in the GeoCapacity project.[368] The high, medium, and low cases relate to storage capacities of 40, 66, and 200 $MtCO_2$, respectively. Table 51 provides the costs in €/tCO_2, which are calculated by assuming flow rates of 1, 2, and 5 $MtCO_2$/year against high, medium, and low storage capacities. The costs are estimated against a project lifetime of 40 years using a WACC of 8%.

For the cluster analysis typical storage capacities (40, 66, and 200 $MtCO_2$), as identified in the ZEP report on storage costs, were used as reference to estimate the costs of storage. This is done by using the CAPEX and OPEX from Table 52 from one of the three cases (high, medium, and low) that falls in the same range as the capacity of the site identified in cluster analysis. For each cluster a storage site was first identified, and then multiple scenarios were assumed that were differentiated by CO_2 flow rate. The highest flow rate corresponds to the total CO_2 volumes from the cluster.

While estimating the storage costs against different flow rates some adjustments were made to make the scenarios more realistic. In cases where the capacity of a storage site resembled the typical high cost case from Table 52, project life time for scenarios with high flow rates were reduced. For example, if the capacity of a storage site is 40 $MtCO_2$, the scenario with a flow rate of 5 $MtCO_2$/year would exhaust the capacity in just 8 years. The costs were calculated by taking these factors into consideration.

In cases where a storage site had a capacity that matched the typical low-cost scenario from Table 52, the costs for smaller flow rates were calculated using the CAPEX and OPEX from the associated low storage capacities. For example, if the identified storage site had a capacity of 200 $MtCO_2$ then the scenario with a flow rate of 1 $MtCO_2$/year would result in only 40 Mtonnes of CO_2 stored at end of life. Therefore, the storage costs were calculated by using the CAPEX and OPEX of the storage capacity that corresponds to the flow rate. For the above cited example this means that the CAPEX and OPEX against the site with a storage capacity of 40 $MtCO_2$ were used.

Table 51 Storage costs (€/tCO_2) per CO_2 storage type.

Storage type	Low	Medium	High
Onshore depleted oil/gas field with legacy wells	1	3	8
Onshore depleted oil/gas field with no legacy wells	1	4	11
Onshore saline aquifer with no legacy wells	2	5	13
Offshore depleted oil/gas field with legacy wells	2	6	10
Offshore depleted oil/gas field with no legacy wells	3	11	15
Offshore saline aquifer with no legacy wells	6	15	22

Table 52 Cost figures against high, medium, and low capacity scenarios that correspond to a flow rate of 1, 2, and 5 $MtCO_2$/year

Storage type	CAPEX (Million €)			OPEX (Million €/yr)			Storage capacity ($MtCO_2$)		
	Low	Medium	High	Low	Medium	High	Low	Medium	High
Onshore depleted oil/gas field with legacy wells	29	29	31	2	3	4	200	66	40
Onshore depleted oil/gas field with no legacy wells	52	52	74	2	3	4	200	66	40
Onshore saline aquifer with no legacy wells	76	76	96	2	3	4	200	66	40
Offshore depleted oil/gas field with legacy wells	61	52	48	6	6	6	200	66	40
Offshore depleted oil/gas field with no legacy wells	137	130	104	6	6	6	200	66	40
Offshore saline aquifer with no legacy wells	257	215	183	9	8	6	200	66	40

CCU technology selection

Table 53 CCU technology longlist: selection relevance by 2030. Only technologies that are at technology readiness level (TRL) 9 by 2030 will be considered for cluster analysis. [369,370]

CCU category	Specific CCU technology	Storage type	TRL	Timeframe to reach TRL9
Chemicals production	Organic acids		2-9	2030
	Synthetic methanol as feedstock		8-9	2025 or before
	Carbonates		6-8	2030
	Polycarbonates		6-7	2030
	Polyurethanes		6-7	2030
	Epoxides		2-4	beyond 2030
	Polyols		3-7	2030
	Carbamates		9	Already mature
CO_2 mineralisation	Bauxite residue carbonation		9	Already mature
	Carbonate mineralisation/aggregates		4-8	2025
	Concrete curing		7-8	2025
CO_2 to fuels	Algae cultivation		5	beyond 2030
	Formic acid as a fuel		5	beyond 2030
	Hydrogen-based syngas and FT synthesis		5-7	2030
	Synthetic methane as fuel		7-8	2025
	Synthetic methanol as fuel		7-8	2025
Enhanced commodity production	Methanol yield boosting		9	Already mature
	Enhanced oil recovery		9	Already mature
	Urea yield boosting		9	Already mature
Food and drink	Beverage carbonation		9	Already mature
	Food freezing, chilling, and packaging		9	Already mature
	Horticulture (glasshouses)		9	Already mature

Permanent storage
Semi-permanent storage
Temporary storage

The resulting selection in Table 53 illustrates up to 19 technologies that are relevant to consider for cluster decarbonisation over the next decade. Only four of the technologies provide permanent storage, whereas the abatement effect of the other technologies relates to displacing fossil feedstock of fuel, short-term storage, or a combination of both. For most of these technologies no reliable cost estimates can be found in the public domain, and will also prove to be variable as the technologies develop over the coming years. The abatement effect for non-permanent CCU can only be quantified through full lifecycle analyses which are not yet available in most cases. Consequently, in the remainder of our analysis, the contribution and associated costs of these 19 technologies to the decarbonisation of European clusters will be treated qualitatively. We identify the most relevant CCU technologies per cluster, based on prominent industrial sectors and in conjunction with quantitative CCS analysis.

[369] DECHEMA, 2017. *Low carbon energy and feedstock for the European chemical industry*.

[370] Ecofys, 2017. *Assessing the potential of CO_2 utilisation in the UK*.

Appendix F. Hydrogen

The Gas for Climate consortium supports a net-zero emissions energy system in the EU by 2050. This can be achieved through rapid decarbonisation by focusing on energy efficiency, increased use of renewable energy, and using low-carbon energy carriers.

In February 2018, Gas for Climate published a study by Ecofys, a Navigant company, on the role of renewable gas in a decarbonised EU energy system by 2050.[371] This study showed that it is possible to scale up biomethane and green hydrogen. Using this renewable gas in a smart combination with renewable electricity can decarbonise the EU energy system while saving costs compared to a decarbonisation scenario without any gas.

This study builds on the February 2018 study by diving deeper into the future role of green hydrogen from wind and solar power and blue hydrogen which uses hydrocarbons as feedstock and employs carbon capture and storage. First, it analyses the future supply of green and blue hydrogen. Second, different transportation and storage options for hydrogen are assessed.

To compare different hydrogen production routes and storage and transportation options, multiple hydrogen production and delivery scenarios were constructed and analysed. This part of the study mainly focuses on green hydrogen production. A more detailed assessment of blue hydrogen options is available in Appendix E.

We identify the following key findings:

1. **Hydrogen is a scalable and cost-efficient building block in achieving net-zero emissions by 2050.**

   Hydrogen can, to a large extent, replace natural gas and other fossil fuels across all sectors. Green and blue hydrogen can substantially contribute to achieve net-zero emissions by 2050. It is cost competitive with biomethane and can, to a certain degree, be integrated into the existing energy infrastructure without major additional costs.

2. **Green and blue hydrogen can serve as a low-carbon feedstock in the chemical and refining industry. There is also significant demand potential for hydrogen in other industries and the transport sector.**

   In 2015, the annual global hydrogen demand has been estimated at 2,200 TWh (66 million tonnes of H_2) with a total value of $115 billion (€102 billion).[372] The industry sector represents 99% of the hydrogen market. Most of today's hydrogen is produced via natural gas (grey hydrogen). To achieve a net-zero energy system, green and blue hydrogen production needs to be significantly scaled up.

   In future, hydrogen could be used in many applications. Transport (both passenger and cargo, including power to liquids), industrial processes (e.g., direct hydrogen reduction of iron ores, biorefineries) and both residential and industrial heating are all examples of feasible applications for hydrogen.

[371] Ecofys (2018): Gas for Climate: How gas can help to achieve the Paris Agreement target in an affordable way, https://www.gasforclimate2050.eu/files/files/Ecofys_Gas_for_Climate_Feb2018.pdf.

[372] The value of 66 million tonnes of H_2 was obtained using the Lower Heating Value (LHV) of hydrogen (33.3 kWh/kgH_2). Hydrogen Council reports this on the Higher Heating Value (HHV) of hydrogen (39.4 kWh/kgH_2). Hydrogen Council (2017). Hydrogen scaling up: A sustainable pathway for the global energy transition, http://hydrogencouncil.com/wp-content/uploads/2017/11/Hydrogen-scaling-up-Hydrogen-Council.pdf.

3. **Dedicated hydrogen production is needed to satisfy anticipated increase in hydrogen across sectors.**

   We have identified the potential of hydrogen production from curtailed electricity to be 24 bcm (natural gas equivalent). Considerable demand for hydrogen may exist in the EU by 2050. In our "optimised gas" scenario, the demand has been quantified at over 2000 TWh of hydrogen (180 bcm), thus much beyond the 24 bcm which uses otherwise curtailed electricity. Navigant's analysis of the renewable energy potentials in the EU shows that the whole demand could be met only with fully developed offshore wind and rooftop solar PV resources. If the envisioned scale for green hydrogen generation is to be reached by 2050, its implementation and setting of relevant policy framework must begin decades earlier of that. To increase the security of supply, green hydrogen production might then need to be supplemented with domestic non-electric hydrogen production or by imports.

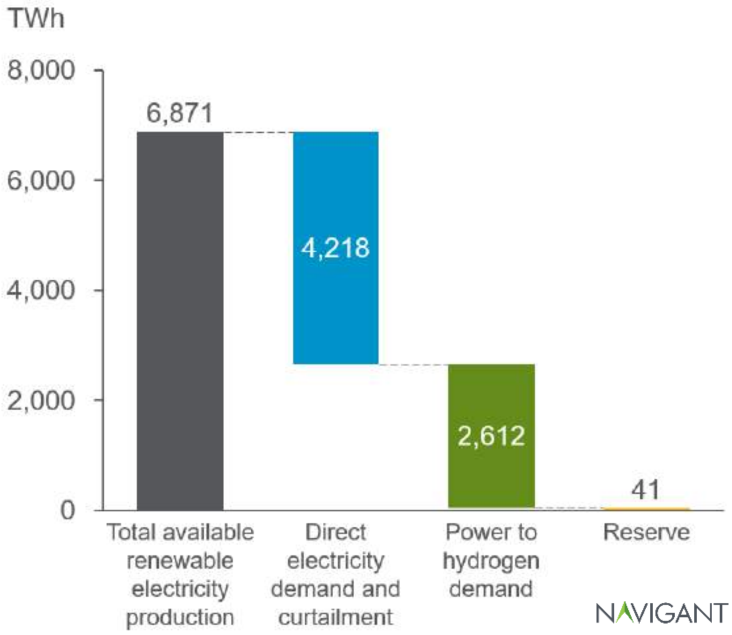

Figure 63 Renewable electricity production vs demand in the "optimised gas" scenario

4. **Hydrogen is cost competitive with other renewable and low-carbon gas options.**
   With expected substantial decrease of investment costs for electrolysis systems, cost of electricity and load factor will be the main drivers behind green hydrogen production costs. Assuming zero costs for curtailed electricity would result in green hydrogen production costs between 17 €/MWh and 71 €/MWh.[373] This would in many cases be considerably cheaper than dedicated green hydrogen, blue hydrogen, and biomethane, but the supply is constrained by the availability of curtailed electricity.

5. **A sizeable blue hydrogen market can be established at relatively fast pace in many locations across Europe.**
   Thanks to the existing natural gas infrastructure in Europe and the existence of SMR facilities, a sizeable blue hydrogen market can be established at a relatively fast pace in many geographical locations. Blue hydrogen via SMR could then be solution for hydrogen market activation from the early 2020s onwards, with blue hydrogen via autothermal reforming (ATR) and dedicated green hydrogen production coming into the picture slightly later, when the hydrogen demand across segments increases.

[373] With average FLH resulting in cost of 29 €/MWh. The range is fully dependent on the full load hours of the assumed electrolyser.

6. **EU-produced hydrogen can be complemented by imported green hydrogen from e.g., North Africa.**
Given its high technical potential for solar green hydrogen (80,000 TWh/year) and its proximity to the EU, North Africa has the potential to meet part of the EU demand, if required. Existing pipelines from North Africa to Europe can potentially be retrofitted to transport pure hydrogen.

7. **Pipelines are the cheapest option to transport hydrogen across long distances.**
Where the pipeline steel quality is sufficient, existing infrastructure can be upgraded to carry 100% hydrogen which would be cheaper than building new, dedicated hydrogen pipelines. Even newly constructed, dedicated hydrogen pipelines are cheaper for long-distance transport than transmission lines for decentralised hydrogen production.

8. **Hydrogen is a storable energy source that can balance fluctuating demand and high shares of intermittent renewable electricity sources. Hydrogen can also provide inter-seasonal storage, both of which are needed in a net-zero energy system.** In a net-zero energy system, balancing between supply of renewable and low-carbon energy sources and demand will be needed. Hydrogen can also be stored between seasons to cover for seasonal variations in supply (wind, solar) and demand (heating). It will be most cost-efficient to use geological formations (such as salt caverns) for bulk hydrogen storage, but these options will be limited by their geographical availability. Complementary solutions such as bulk compressed hydrogen storage or liquefaction may be necessary depending on the regional situation, and the degree of hydrogen interconnection.

F.1 Introduction

Hydrogen is the lightest molecule in the periodic table and the hydrogen atom is the most abundant element in the universe. It is also a possible key enabler of the low-carbon transformation as a chemical feedstock, fuel, and as an energy carrier in in numerous sectors including transport, built environment and power. On Earth, hydrogen only exists in (chemically) bound form, so it must be produced by specific processes. The key differences of using hydrogen versus methane are the added complexity of hydrogen transportation and storage and the fact that hydrogen does not emit greenhouse gases at the point of use.[374]

Hydrogen is used since many years in various industrial processes. In 2003, 96% of the hydrogen produced worldwide came from the thermochemical conversion of fossil fuels, mainly natural gas, and there is no indication this has changed significantly. The remainder is produced via an electrolytic process using electricity.[375] Hydrogen produced from fossil fuels leads to significant greenhouse gas emissions unless CO_2 is captured.[376] (in this case referred to as grey hydrogen), However, demonstration projects are underway for hydrogen production from fossil feedstocks coupled with carbon capture and storage (blue hydrogen). Potentially, blue hydrogen production from natural gas can be coupled with a share of biomass feedstocks that could bring the overall hydrogen greenhouse gas footprint to net zero or even negative. With an increasing share of low-cost renewable electricity, green hydrogen production via electrolysis is also a promising decarbonisation option for the near future.

---

[374] These points are further explained and discussed in the following sections.

[375] International Energy Agency (2005): Prospects for Hydrogen and Fuel Cells, http://ieahydrogen.org/Activities/Subtask-A,-Hydrogen-Resouce-Study-2008,-Resource-S/2005-IEA-Prospects-for-H2-and-FC.aspx.

[376] Depending on the specifics of the supply chain, the total GHG emissions for grey hydrogen have been estimated in a range from 230 gCO_{2eq}/kWh (minimum found for stream methane reforming) to 642 gCO_{2eq}/kWh (maximum for coal gasification). Compare with 210 gCO_{2eq}/kWh for natural gas (all figures are shown before efficiency losses from carriers to electricity or heat). See Balcombe et al. (2018). The carbon credentials of hydrogen gas networks and supply chains, Renewable and Sustainable Energy Reviews, https://www.sciencedirect.com/science/article/pii/S1364032118302983.

This study thus distinguishes between several types of hydrogen, grouped by greenhouse gas emissions from the production process of the gas (hydrogen itself causes no greenhouse gas emissions at point of use):

- **Grey hydrogen** is gas produced by thermochemical conversion of fossil fuels without the capture of CO_2.
- **Blue hydrogen** is a low-carbon gas produced by thermochemical conversion of fossil fuels with added carbon capture and storage.[377]
- **Green hydrogen** is a renewable gas produced from renewable resources such as solar PV, wind or hydropower**.** In this study the focus is put on electrolysis (i.e., electrolytical hydrogen; see below), although many other production methods are available.[378, 379]

Besides the potential climate benefits, the main advantages of using hydrogen in the energy system are its storability, prospective large-scale availability, and wide range of applications. Hydrogen is one of the prime candidates to facilitate sector coupling,[380] and fits well into the efforts for increased electrification by providing long-term storage and possibly also dispatchable power generation, although other, possibly more prominent options exist.[381]

Grey hydrogen is almost exclusively consumed as feedstock for chemical and refining processes (e.g., ammonia and methanol production, hydrogenation of crude oil, etc). In 2015, the total global hydrogen demand was estimated at 2,200 TWh (66 million tonnes of H_2)[382] with a total value of $115 billion (€102 billion).[383] In future, hydrogen could be used in many more applications. Transport (both passenger and cargo), industrial processes (e.g., direct hydrogen reduction of iron ores) and both residential and industrial heating are all examples of feasible applications for hydrogen. Given the substantial variability in which hydrogen can be used in future, the 2050 potential also varies. IRENA estimates additional 2,200 TWh (66 million tonnes of H_2) in addition to existing feedstock uses (total of 4,400 TWh or 122 million tonnes of H_2), while the Hydrogen Council puts the figure at 21,700 TWh (651 million tonnes of H_2).[384]

F.2 Supply potential for European green and blue hydrogen

In this section, we estimate the potential supply of domestic (European) green and blue hydrogen and the associated production costs. Grey hydrogen is not considered as it cannot play a role in a net-zero greenhouse gas emission energy system.

---

[377] Other options, most notably carbon capture and utilization (e.g. via methane cracking) need to be further technically developed and also evaluated for their real greenhouse gas emission reduction potential (i.e. long-term carbon sequestration potential).

[378] For instance, direct photochemical conversion, supercritical wet biomass conversion, biomass gasification, fermentation, etc.

[379] Further specifications (e.g. specific GHG intensity limits in green / blue hydrogen production) on these definitions will be available at the conclusion of the design phase for the green hydrogen guarantees of origin at CertifHy (http://www.certifhy.eu/).

[380] The idea to closely interlink the three-main energy consuming segments, the built environment, industrials and transport and to optimally use energy infrastructure.

[381] This is mainly valid for PEM electrolysis with fast ramp up times that can theoretically be switched from generator to load and vice versa almost immediately. Other options, such as using biomethane in existing gas peaking plants, might however be more prominent.

[382] Value converted using Lower Heating Value of hydrogen.

[383] IRENA (2018). Hydrogen from renewable power: Technology outlook for the energy transition, http://www.irena.org/publications/2018/Sep/Hydrogen-from-renewable-power

[384] All values have been converted using Lower Heating Value of hydrogen. Hydrogen Council (2017). Hydrogen scaling up: A sustainable pathway for the global energy transition, http://hydrogencouncil.com/wp-content/uploads/2017/11/Hydrogen-scaling-up-Hydrogen-Council.pdf.

For green hydrogen we selected four different production routes to characterise the impact of different capacity factors (full-load hours) and feedstock electricity costs on green hydrogen production cost:

1. Production from curtailed electricity
2. Dedicated production from North Sea offshore wind power
3. Dedicated production from Southern European PV
4. Dedicated production from Southern European hybrid sources (PV plus onshore wind power).

We look at two distinct production methods for blue hydrogen: steam methane reforming (SMR) and autothermal reforming (ATR).

Although the scope of this study is European hydrogen, there might be the need for additional hydrogen from outside of Europe if demand cannot be met with domestic sources. Therefore, we also performed a high-level analysis of importing green hydrogen from North Africa.

F.2.1 Green hydrogen

Our analysis of the 2050 EU energy system shows the potential to produce 19 bcm (natural gas equivalent) of green hydrogen assuming conversion of otherwise curtailed wind and solar electricity into hydrogen.[385] This allows excess renewable electricity generation to be stored in a useful form. When quantifying the cost of green hydrogen using curtailed electricity, a zero-cost of power is assumed. The analysis was based on scenarios of the e-Highway2050 project.[386] However, in the case of limited grid expansion the amount of curtailed electricity could be higher.

Considerable demand for hydrogen may exist in the EU by 2050. In our "optimised gas" scenario, the demand has been quantified at 1,710 TWh (161 bcm), thus much beyond the 19 bcm which uses otherwise curtailed electricity. Our analysis of the renewable energy potentials in the EU shows that the whole demand (i.e. 1,710 TWh) could be met if economically feasible offshore wind and buildings solar PV resources. If these were fully developed (with onshore wind and hydropower generation kept at their 2015 levels), a reserve of 680 TWh (64 bcm) would still be available after satisfying all the electricity and power-to-gas demand in our "optimised gas" scenario (Figure 64).[387]

---

[385] This figure has been updated from our previous estimation of 24 bcm. Ecofys (2018): Gas for Climate: How gas can help to achieve the Paris Agreement target in an affordable way, https://www.gasforclimate2050.eu/files/files/Ecofys_Gas_for_Climate_Feb2018.pdf.

[386] e-Highway2050 (2015a). Europe's future secure and sustainable electricity infrastructure e-Highway2050 project results, http://www.e-highway2050.eu/fileadmin/documents/e_highway2050_booklet.pdf.

[387] Note that the reserve has been quantified before power to hydrogen conversion, it is thus shown in TWh of electricity. The analysis assumes development of the economic potential (LCOE below 55-60 EUR/MWh) in the Atlantic, North and Baltic seas for offshore wind (2030 potential) and solar PV potential on buildings across EU (2070 potential). Generation capacity for onshore wind and hydropower are kept at their respective 2015 levels as their further development might be constrained. Sources: Wind Europe (2017): Unleashing Europe's offshore wind potential: A new resource assessment, https://windeurope.org/wp-content/uploads/files/about-wind/reports/Unleashing-Europes-offshore-wind-potential.pdf ; Shell (n.d.): GLOBAL ENERGY RESOURCES DATABASE, https://www.shell.com/energy-and-innovation/the-energy-future/scenarios/shell-scenarios-energy-models/energy-resource-database.html#iframe=L3dlYmFwcHMvRW5lcmd5UmVzb3VyY2VEYXRhYmFzZS8jb3Blbk1vZGFs ; EEA (2009): Europe's onshore and offshore wind energy potential: An assessment of environmental and economic constraints, https://www.energy.eu/publications/a07.pdf ; Ram M., Bogdanov D., Aghahosseni,A., Oyewo A.S., Gulagi A., Child M., Fell H.-J., Breyer C. 2017): Global Energy System based on 100% Renewable Energy – Power Sector, http://energywatchgroup.org/wp-content/uploads/2017/11/Full-Study-100-Renewable-Energy-Worldwide-Power-Sector.pdf.

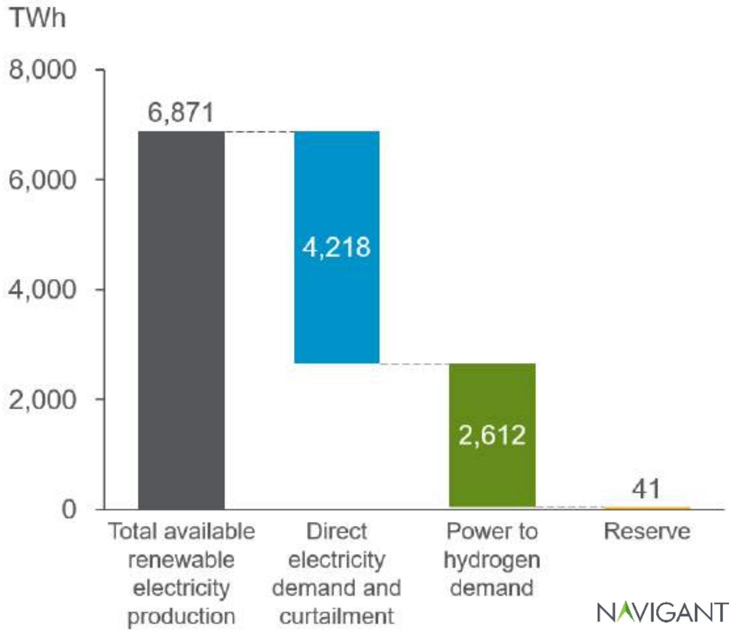

Figure 64 Renewable electricity production vs demand in the "optimised gas" scenario

Competitiveness of the domestically produced green hydrogen using non-zero electricity costs against alternatives (e.g. direct electrification, biomethane, etc.) is then crucial to understand the future role of hydrogen in the EU. We have focused on the regions with the best combination of FLH and LCOE for renewable energy sources: **North Sea** (offshore wind power) and **Southern Europe** (standalone solar PV, or solar PV combined with onshore wind) (Figure 65).

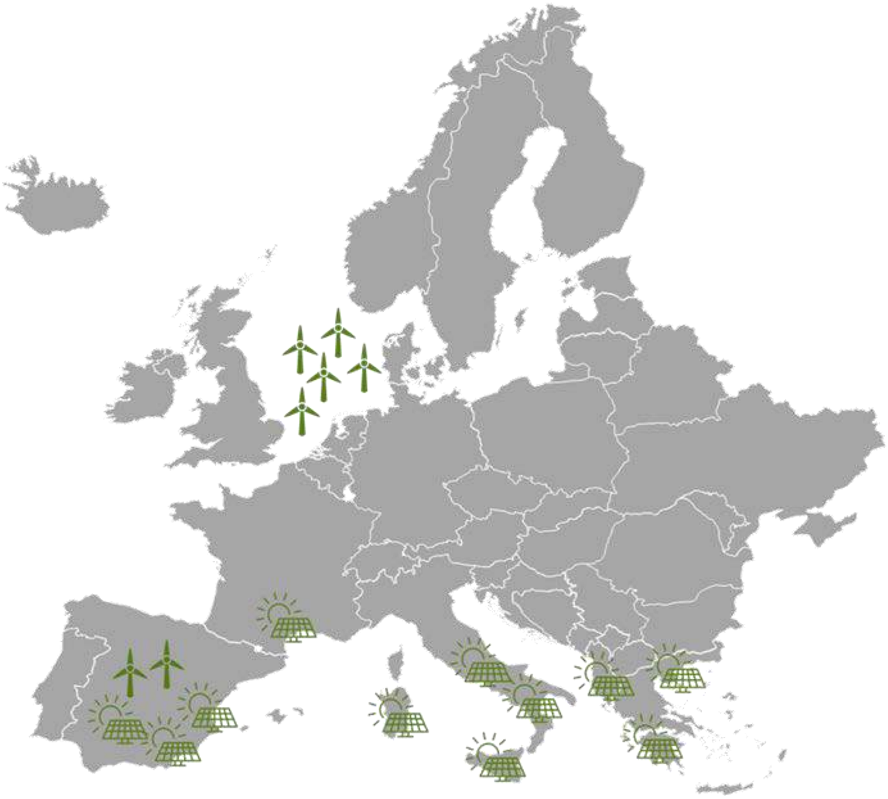

Figure 65 Overview of assessed hydrogen production hubs

F.2.2 Production cost of green hydrogen

Many different green hydrogen production methods are currently under development, from so-called solar fuels (i.e., artificial photosynthesis) to supercritical gasification of wet biomass. However, the most mature and most-discussed green hydrogen production route is via electrolysis of water, which uses decarbonised electricity to split the water molecule (H_2O) into hydrogen (H_2) and oxygen (O_2) molecules. Three main technologies are currently used/in development for electrolysis:

- **Alkaline Electrolysers** (AE) are the most mature and currently cheapest (€/kW) technology option. However, they have limited ability to respond to load changes, which is essential for the flexibility requirements of a power system with high penetration of renewables. Further, the design is complex, implying limited cost-reduction options.
- **Proton Exchange Membrane** (PEM) electrolysers have a simple design, are currently more expensive than alkaline ones, but are assumed to have a high cost-reduction potential. Crucially, they are flexible, with ramp up or down times in seconds, which makes them ideal for a variety of applications in the power sector.
- **The Solid Oxide Electrolysis Cells** (SOECs) apply high temperature electrolysis; they are at an early stage of development and are expected to mature in the long term. Theoretically, solid oxide electrolysis is a ground-breaking technology due to its high efficiency, its ability to recover the heat needed to supply the electrolysis, and its possibility to operate in reverse mode (regenerative electrolysis). The inability to have a flexible load and the high degradation of the membranes are the two major challenges the SOECs are currently facing.[388]

Table 54 provides an overview of the present values for the most important parameters in water electrolysis technologies.

Table 54 Present (2018) values for water electrolysis technology parameters[389]

Technology	Temp. [°C]	Electrolyte	Efficiency [%][390]	System costs 2018 [€/kW]	Service life [h][391]	Maturity level
AE	60–80	Potassium hydroxide	65–82	450-600	60,000 – 90,000	Mature
PEM	60–80	Solid membrane	65–78	800-1,000	20,000 – 60,000	Demonstration level for large systems
SOEC	700–900	Oxide ceramics	85 (lab)	N/A	Ca. 1,000	Laboratory development

[388] ASSET (2018). Sectoral integration – long-term perspective in the EU energy system, https://ec.europa.eu/energy/sites/ener/files/documents/final_draft_asset_study_12.05.pdf.

[389] Based on E4tech (2014). Development of Water Electrolysis in the European Union, http://www.e4tech.com/reports/development-of-water-electrolysis-in-the-european-union/ and Navigant industrial intelligence. We have reviewed several other studies that report similar figures regarding system energy efficiencies and typically somewhat higher values for electrolyser system cost. Please note that the System costs we use come from Navigant Industrial intelligence (i.e. reported in the market). The studies reviewed include: Energy Brainpool (2018; in German): Auf dem Weg in die Wettbewerbsfähigkeit: Elektrolysegase Erneuerbaren Ursprungs, https://www.greenpeace-energy.de/fileadmin/docs/pressematerial/180419_GPE_Kurzanalyse_Kostenentwicklung-erneuerbare-Elektrolysegase_fin....pdf; Agora Energiewende (2018): The Future Cost of Electricity-Based Synthetic Fuels, https://www.agora-energiewende.de/fileadmin2/Projekte/2017/SynKost_2050/Agora_SynKost_Study_EN_WEB.pdf; or Hinico (2017); Study on early business cases for H2 in energy storage and more broadly power to H2 applications, https://www.fch.europa.eu/sites/default/files/P2H_Full_Study_FCHJU.pdf.

[390] System energy efficiency on lower heating value.

[391] Before stack replacement.

For this study, we use PEM electrolysis in our calculations as it possesses the biggest cost-reduction potential and seems to be only at the beginning of its experience curve. The production cost for electrolytical hydrogen is determined by four main factors that can vary significantly based on the business case and proposed set-up:

- System costs for the production facility, including electrolyser CAPEX, and for auxiliary systems (or Balance of Plant, BoP), each constituting roughly 50% of the system costs in current PEM systems.[392]
- Feedstock electricity cost
- Capacity factor, expressed in full-load hours (FLH)
- Electrolyser system energy efficiency

OPEX (excluding energy costs) is a fifth major cost component yet it is relatively constant in different PEM set ups (in its relation to system costs) and hence not investigated in more depth. Major OPEX categories include the labour costs to operate the plant, costs of component replacements, and property tax and insurance.

Whereas system costs and efficiency are largely independent of the location of the electrolyser within the EU, feedstock electricity costs and capacity factors are not. Thus, we defined four distinct green production routes that illustrate what effects differing feedstock electricity costs and FLH have on the production cost of green hydrogen as illustrated in Table 2.

With the expected technology maturity leading to reduced electrolyser system costs of 420 €/kW by 2050[393], green hydrogen costs from dedicated production in Southern Europe (PV or hybrid) were calculated at 44-59 €/MWh and from North Sea wind power at (48-61 €/MWh). Given the uncertainties in calculating the 2050 costs, we can conclude that the cost of producing green hydrogen in either of these set ups will be virtually equal. Production cost from otherwise curtailed electricity (at zero electricity cost) is expectably cheapest at 17 €/MWh at high capacity factor (2,881 FLH) but limited in its availability to the previously mentioned 19 bcm. In case of low capacity factor (709 FLH), the production cost more than quadruples to 71 €/MWh. Table 2 summarises the main input parameters for the different production routes.

[392] We include additional 10% installation costs on top of the system cost. Based on NREL (2018): H2A: Hydrogen Analysis Production Case Studies: Current Central Hydrogen Production from Polymer Electrolyte Membrane (PEM) Electrolysis version 3.2018, https://www.nrel.gov/hydrogen/h2a-production-case-studies.html.

[393] Depreciation period: 30 years; Societal discount rate: 5%; OPEX (Including replacement, maintenance and labour costs): 3% of CAPEX per annum; system energy efficiency: 80%.

Table 55 Main input parameters used for estimating production costs of green hydrogen in 2050

Production route	Full system installation costs ([€/MW_{input}]	Full-load hours (FLH) [hours/yr][394]	Feedstock electricity cost[395] [€/MWh]	Production cost[396] [€/MWh]
Curtailed	420	709-2,881	0	**17-71**
Dedicated - North Sea offshore wind power	420	4,500-5,000	30–40	**48-61**
Dedicated - Southern European PV	420	1,500-2,000	15–20	**44-59**
Dedicated - Southern European hybrid	420	3,500-4,000	25–30	**44-52**

Green hydrogen production costs of 44-61 €/MWh by 2050 present a major reduction from the costs of around 90-210 €/MWh in 2018 (Figure 16).[397] The biggest part of these cost reductions comes from economies of scale driving down the system cost, from cheaper electricity, and from improvements in system energy efficiency.

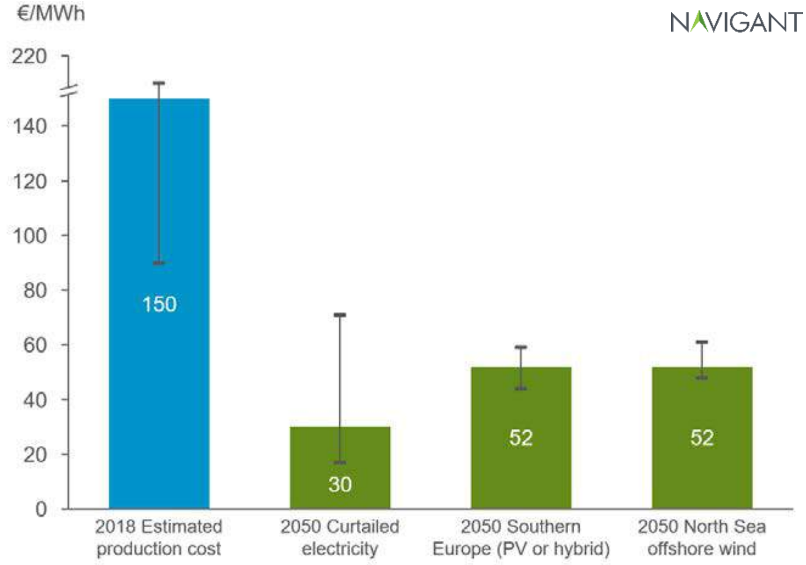

Figure 66 2018 and 2050 green hydrogen production cost estimation

[394] Based on: Ecofys (2018): Gas for Climate: How gas can help to achieve the Paris Agreement target in an affordable way, https://www.gasforclimate2050.eu/files/files/Ecofys_Gas_for_Climate_Feb2018.pdf, Fasihi & Breyer (2018): Synthetic Fuels and Chemicals: Options and Systemic Impact, https://www.strommarkttreffen.org/2018-06-29_Fasihi_Synthetic_fuels&chemicals_options_and_systemic_impact.pdf, and Navigant offshore wind expertise

[395] Navigant scenario

[396] Excluding gross retail margin

[397] 2018 cost range based on: Energy Brainpool (2018; in German): Auf dem Weg in die Wettbewerbsfähigkeit: Elektrolysegase Erneuerbaren Ursprungs, https://www.greenpeace-energy.de/fileadmin/docs/pressematerial/180419_GPE_Kurzanalyse_Kostenentwicklung-erneuerbare-Elektrolysegase_fin....pdf ; Agora Energiewende (2018): The Future Cost of Electricity-Based Synthetic Fuels, https://www.agora-energiewende.de/fileadmin2/Projekte/2017/SynKost_2050/Agora_SynKost_Study_EN_WEB.pdf ; CE Delft (2018; in Dutch): Waterstofroutes Nederland – Blauw, groen en import, https://www.ce.nl/publicaties/2127/waterstofroutes-nederland-blauw-groen-en-import ; and Navigant Research (2017): Power-to-Gas for Renewables Integration, https://www.navigantresearch.com/reports/power-to-gas-for-renewables-integration.

F.2.3 Blue hydrogen

Blue hydrogen is an alternative low-carbon production route for hydrogen, relying on the use of fossil fuels (typically natural gas) and CCS. Two production technologies are considered, the currently dominant SMR, and ATR, which has integrated carbon capture in its design.

The cost of hydrogen production via SMR that is optimised to capture 90% of the greenhouse gas emissions[398] has been established at 39-63 €/MWh with sensitivity to natural gas prices being responsible for the calculated range.[399] This is somewhat higher than the production cost for ATR with 95% greenhouse gas emissions capture rate at 36-56 €/MWh. However, this comparison is only valid for new greenfield installations. It is likely desirable to first retrofit the existing SMR assets with CCS, which could roughly alleviate the greenhouse gas emissions from currently existing hydrogen demand.[400]

In the Gas for Climate 2050 scenario, a net-zero greenhouse gas energy system and hence hydrogen production is pursued. As noted above, blue hydrogen production either via SMR or ATR will bare residual emissions with lower bound between 11.5-23 gCO_{2eq}/kWh of hydrogen. These emissions would have to be offset elsewhere in the energy system. Further technical, cost and emission details regarding blue hydrogen are further elaborated in Appendix E.

There are several considerations in production of such hydrogen in the EU. Thanks to the existing natural gas infrastructure in Europe and the existence of SMR facilities, a sizeable blue hydrogen market can be established at a relatively fast pace in many geographical locations. Blue hydrogen via SMR could then be the solution for rapid hydrogen market activation between 2020 and 2030, with blue hydrogen via ATR and dedicated green hydrogen production at a considerable scale coming into the picture slightly later, when the hydrogen demand across segments increases and the gas infrastructure has been upgraded to be hydrogen-ready. Hydrogen imports could potentially play a role in this overview, but this is likely only in the long-term, around 2050. Of note, there is a certain dependence of blue hydrogen production on availability of large CO_2 storage locations, yet this does not seem to be a major issue.

F.2.4 Hydrogen from North Africa

The DESERTEC project once envisioned supplying a large part of Europe's energy consumption by a large-scale development of solar energy in North Africa. While the DESERTEC project is yet to come to any significant implementation, the North African region indeed has some of the world's best solar energy resources and is in an excellent position to be one of the hubs for a green hydrogen-based economy.[401] The maximum technical potential for the solar green hydrogen route is tremendous. At some 80,000 TWh it is just below the world final energy consumption in 2015 at 110,000 TWh.[402]

---

[398] The remaining 10% of the GHG emissions can be captured in the post-combustion CCS set up, yet this currently seems very costly.

[399] Assuming 5% discount rate and 30-year lifetime and natural gas prices between 0.17-0.35 €/m^3. Based on: Jakobsen & Åtland, 2016. *Concepts for Large Scale Hydrogen Production*.

[400] According to Navigant estimations, the current SMR production capacity in the EU roughly matches the demand.

[401] Note that this could result into an export of fresh water from arid regions of the world such as North Africa. For instance, Navigant estimates that covering current Germany's industrial demand with green hydrogen would require the equivalent of 0.7% of the annual water consumption in Morocco. Potentially, electrolysis could also be run using sea water, yet this technology is unproven and currently faces technical difficulties.

[402] Green hydrogen potential done by Navigant based on solar PV technical potential for North Africa, using 80% electrolyser system energy efficiency and Lower Heating Value of hydrogen, from IRENA (2014). Estimating the Renewable Energy Potential in Africa - A GIS-based approach, http://www.irena.org/publications/2014/Aug/Estimating-the-Renewable-Energy-Potential-in-Africa-A-GIS-based-approach. World final energy consumption from IEA (2018). Key World Energy Statistics 2018, https://webstore.iea.org/key-world-energy-statistics-2018.

Given the relative geographical proximity of North Africa, the potential of delivering green hydrogen to the EU has been considered. Assuming that hydrogen will become a globally traded commodity, the relative cost of the hydrogen delivered via the North African route versus domestic EU production will become a central issue. Geopolitical considerations will also play a role in such development; however, these are not discussed here.

Solar resources in the North Africa region will have a slight edge in terms of costs over their Southern European counterparts. We anticipate that green hydrogen production cost in North Africa could be between 34-44 €/MWh (1-1.3 €/kg H_2). If such large-scale production would use liquefaction (which is capital intensive and has large energy losses) to deliver the hydrogen to European ports by ships, the cost of delivered hydrogen spikes to 92-160 €/MWh (2.8-4.8 €/kg H_2),[403] rendering such imports virtually uncompetitive to European domestic production. Alternative ways of delivering hydrogen to Europe would have to be considered. The delivery costs could be dramatically reduced in case hydrogen is imported via converted natural gas pipelines that are already in place.[404] There are existing connections to Spain and Italy (via, Sicily, Malta, and possibly, Sardinia[405]) that could serve as a backbone of such transmission system in future (see
Figure 67).

Figure 67 Existing Natural Gas Network between North Africa and Europe[406]

---

[403] The imported cost consists of estimated production cost and shipping of liquefied hydrogen. Figures used in the calculations originate from AGORA (2018): The Future Cost of Electricity-Based Synthetic Fuels, https://www.agora-energiewende.de/fileadmin2/Projekte/2017/SynKost_2050/Agora_SynKost_Study_EN_WEB.pdf, Teichmann et al. (2012). Liquid Organic Hydrogen Carriers as an efficient vector for the transport and storage of renewable energy, https://www.researchgate.net/publication/257175113_Liquid_Organic_Hydrogen_Carriers_as_an_efficient_vector_for_the_transport_and_storage_of_renewable_energy and Ogden (1999). Prospects for building a hydrogen energy infrastructure, https://www.annualreviews.org/doi/abs/10.1146/annurev.energy.24.1.227.

[404] Of note, high operating pressure (close to 200 bar) is required to cross the Mediterranean Sea. Thus, investment and operational cost of compressors have to be accounted for. However, pipeline transport would likely still be the cheapest option of bringing hydrogen from North Africa to Europe.

[405] The Galsi pipeline that would connect Algeria and Italy via Sardinia has been announced in 2003. As of 2018 however, this pipeline has not been developed.

[406] Please note that the Galsi pipeline from Algeria to Italy via Sardinia has not been developed as of 2018. The full map is available at entsog (2017): The European Natural Gas Network, https://www.entsog.eu/public/uploads/files/publications/Maps/2017/ENTSOG_CAP_2017_A0_1189x841_FULL_064.pdf

F.3 Conclusions

Our analysis provides insights into the potential role of hydrogen in a net-zero emissions EU energy system by 2050. It shows that the introduction of hydrogen into the energy system is feasible and likely desirable in 2050.

Renewable and low-carbon gases such as green and blue hydrogen, as well as biomethane, play an important role in achieving net-zero emissions by 2050 and can complement electrification efforts. Significant demand potentials for hydrogen exist in all sectors. In the transport sector, hydrogen-powered vehicles are seen as a promising technology to decarbonise heavy transport (i.e., buses and trucks). In industry, decarbonisation efforts in the chemical, refining, and iron and steel sectors will lead to a significant increase in hydrogen demand. From an energy system perspective, hydrogen is desirable as can balance intermittent wind and solar power and can be stored at a large scale.

In our “optimised gas” scenario, a significant demand for hydrogen is envisioned, far beyond the estimated volume of green hydrogen available from otherwise curtailed electricity (19 bcm). The demand can be met with a mixture of domestically produced green (from dedicated RES) or blue hydrogen, or alternatively imported from regions such as Northern Africa. Importantly, the total electricity demand (i.e. combined direct electricity and power-to-gas) can be fully met by economically sensible development of offshore wind and building solar PV, while keeping onshore wind and hydropower generation at their 2015 levels.

As for green hydrogen, the estimated production cost in 2018 renders it virtually uncompetitive in any of its envisioned uses. However, major production cost reductions are expected by 2050. These are primarily driven by electrolysis system cost decrease due to economies of scale and availability of cheap renewable electricity. The latter will be at least partly determined by the electricity market structure, e.g. by the access of power-to-gas producers to wholesale / low-cost electricity. The success of massive green hydrogen integration into the energy system will thus be dependent on the given legislative framework at large. In sum, if the envisioned scale for green hydrogen generation is to be reached by 2050, its implementation and setting of relevant policy framework must begin decades earlier of that.

Before the green hydrogen market reaches the desired size, the blue hydrogen route seems as a promising option. In the medium term, retrofitting of existing SMR facilities with CCS (blue hydrogen) can meet the growing demand for low-carbon hydrogen in locations that allow for CCS. Beyond the SMR + CCS retrofit capacity, more blue hydrogen can be made available via development of new SMR or ATR assets equipped with CCS, which should be competitive with green hydrogen production.

Our analysis further investigated the possibility of reusing existing natural gas transmission and distribution infrastructure, building a dedicated hydrogen infrastructure and assessed both centralised and decentralized production (for green hydrogen).[407] From a societal perspective, centralised green hydrogen production seems to be the most economic option. Existing natural gas pipelines, given the right steel quality, can be retrofitted to carry 100% hydrogen. Using retrofitted pipelines to transport hydrogen across long distances is cheaper than building transmission lines to transport electricity from the North Sea or Southern Europe to decentral hydrogen production sites. Questions however remain about the potential competition of biomethane vs hydrogen in the gas transmission infrastructure. In places where double natural gas corridors (e.g. one for biomethane and one for hydrogen) do not currently exist and would be necessary, new hydrogen pipeline infrastructure has to be erected.

[407] In other words, hydrogen production at the point of electricity generation with subsequent use of pipelines to transport to demand centers against transmission of electricity to produce hydrogen at the point of demand.

Conversely, a fully enabled hydrogen system will require inter-seasonal storage. The cheapest option, storage in underground geological formations like salt caverns, will be limited by its geographical availability. In-depth engineering studies are required to understand whether other common natural gas storage platforms (e.g. aquifers, depleted gas fields) could also be reused for hydrogen. In terms of natural gas distribution networks (medium and low pressure), their prospective to be refurbished into hydrogen-enabled ones is highly region specific. It will be also highly dependent on the selection for the primary gas used in that region (i.e. biomethane vs hydrogen). While we assess that such refurbishment is technically feasible, other factors, such as the need to adjust / replace end-use gas appliances might prove detrimental to such efforts.

F.4 Additional information

Table 56 Overview of all assessed hydrogen delivery routes

Scenario name	Electricity source	Offshore transport	Onshore transport	Inter-seasonal storage[408]	Intraday storage[409]
(1a) Offshore H_2 production, centralised, North Sea, curtailed, max FLH	Offshore wind (curtailed)	Pipeline	Pipeline	Underground (gaseous)	Above ground (gaseous)
(1b) Offshore H_2 production, centralised, North Sea, curtailed, min FLH	Offshore wind (curtailed)	Pipeline	Pipeline	Underground (gaseous)	Above ground (gaseous)
(1c) Offshore H_2 production, centralised, North Sea, dedicated, max FLH, min LCOE	Offshore wind (dedicated)	Pipeline	Pipeline	Underground (gaseous)	Above ground (gaseous)
(1d) Offshore H_2 production, centralised, North Sea, dedicated, min FLH, max LCOE	Offshore wind (dedicated)	Pipeline	Pipeline	Underground (gaseous)	Above ground (gaseous)
(2a) Onshore H_2 production, centralised, North Sea, curtailed, max FLH	Offshore wind (curtailed)	Underwater cable	Pipeline	Underground (gaseous)	Above ground (gaseous)
(2b) Onshore H_2 production, centralised, North Sea, curtailed, min FLH	Offshore wind (curtailed)	Underwater cable	Pipeline	Underground (gaseous)	Above ground (gaseous)
(2c) Onshore H_2 production, centralised, North Sea, dedicated, max FLH, min LCOE	Offshore wind (dedicated)	Underwater cable	Pipeline	Underground (gaseous)	Above ground (gaseous)
(2d) Onshore H_2 production, centralised, North Sea, dedicated, min FLH, max LCOE	Offshore wind (dedicated)	Underwater cable	Pipeline	Underground (gaseous)	Above ground (gaseous)
(3a) Onshore H_2 production, decentralised, North Sea, curtailed, max FLH	Offshore wind (curtailed)	Underwater cable	Cable	Not included	Above ground (gaseous)
(3b) Onshore H_2 production, decentralised, North Sea, curtailed, min FLH	Offshore wind (curtailed)	Underwater cable	Cable	Not included	Above ground (gaseous)
(3c) Onshore H_2 production, decentralised, North Sea, dedicated, max FLH, min LCOE	Offshore wind (dedicated)	Underwater cable	Cable	Not included	Above ground (gaseous)
(3d) Onshore H_2 production, decentralised, North Sea, dedicated, min FLH, max LCOE	Offshore wind (dedicated)	Underwater cable	Cable	Not included	Above ground (gaseous)
(4a) PV H_2 production, centralised, Southern Europe, curtailed, max FLH	PV (curtailed)	-	Pipeline	Underground (gaseous)	Above ground (gaseous)

408 Where included, it is assumed that 30% of the total hydrogen production volume will go through the inter-seasonal storage.

409 It is assumed that 5% of the total hydrogen production volume will go through the intraday storage.

Scenario name	Electricity source	Offshore transport	Onshore transport	Inter-seasonal storage[408]	Intraday storage[409]
(4b) PV H_2 production, centralised, Southern Europe, curtailed, min FLH	PV (curtailed)	-	Pipeline	Underground (gaseous)	Above ground (gaseous)
(4c) PV H_2 production, centralised, Southern Europe, dedicated, max FLH, min LCOE	PV (dedicated)	-	Pipeline	Underground (gaseous)	Above ground (gaseous)
(4d) PV H_2 production, centralised, Southern Europe, dedicated, min FLH, max LCOE	PV (dedicated)	-	Pipeline	Underground (gaseous)	Above ground (gaseous)
(4e) PV + onshore wind H_2 production, centralised, Southern Europe, dedicated, max FLH, min LCOE	PV + onshore wind (dedicated)	-	Pipeline	Underground (gaseous)	Above ground (gaseous)
(4f) PV + onshore wind H_2 production, centralised, Southern Europe, dedicated, min FLH, max LCOE	PV + onshore wind (dedicated)	-	Pipeline	Underground (gaseous)	Above ground (gaseous)
(5a) PV H_2 production, decentralised, Southern Europe, curtailed, max FLH	PV (curtailed)	-	Cable	Not included	Above ground (gaseous)
(5b) PV H_2 production, decentralised, Southern Europe, curtailed, min FLH	PV (curtailed)	-	Cable	Not included	Above ground (gaseous)
(5c) PV H_2 production, decentralised, Southern Europe, dedicated, max FLH, min LCOE	PV (dedicated)	-	Cable	Not included	Above ground (gaseous)
(5d) PV H_2 production, decentralised, Southern Europe, dedicated, min FLH, max LCOE	PV (dedicated)	-	Cable	Not included	Above ground (gaseous)
(5e) PV + onshore wind H_2 production, decentralised, Southern Europe, dedicated, max FLH, min LCOE	PV + onshore wind (dedicated)	-	Cable	Not included	Above ground (gaseous)
(5f) PV + onshore wind H_2 production, decentralised, Southern Europe, dedicated, min FLH, max LCOE	PV + onshore wind (dedicated)	-	Cable	Not included	Above ground (gaseous)

Appendix G. Buildings

G.1 Different solutions for space heating and insulation

Decarbonisation of space heating requires major changes in the energy system. A comfortable temperature of 20°C has become the expected standard of living for developed countries. The challenge is to decarbonise the energy system while maintaining this comfort level in all circumstances. There are several solutions.

District heating can provide waste heat, geothermal heat, or renewable heat from heat pumps or biogenic sources to homes and buildings in densely populated areas. However, this is not a solution for areas where renewable sources are not available, as heat cannot be transported over long distances like electricity and gas.

Another solution is to provide space heating with **all-electric heat pumps**. There are two all-electric heat pumps available: electric ASHPs and GSHPs. Electric heat pumps work in the same way as a refrigerator, transferring heat from one space to another by using electricity. The heat pump absorbs heat from outside and transfers it to the space that needs heating. The difference between ASHPs and GSHPs is that ASHPs absorb the heat from outside air while GSHPs absorb the heat from the ground. GSHPs have better performance at ambient temperatures below zero than ASHPs, but they are significantly more expensive. Heat pumps can be both a space heater and cooler.

Generally, all-electric heat pumps are more efficient than conventional electric heating and gas boilers. ASHPs allow the harvesting of ambient heat even in circumstances where the ambient temperature is lower than the indoor temperature. The ratio between the energy that can be harvested, and the electricity required is called the Coefficient of Performance (COP). In cold spells the COP of ASHPs goes down significantly[410] because of the larger difference between source temperature and heating system temperature. This negatively affects their efficiency. Unfortunately, this means that peak heat demand coincides with low efficiencies, causing high demand for electricity. While this does not occur often, the overall system must be designed to accommodate them to prevent loss of load in periods of cold weather.

To achieve high performance, all-electric heat pumps require low temperature heating, meaning that the buildings will need to be well insulated, and that their heat delivery systems will need to be replaced in many cases. The necessary renovation of existing buildings requires a large effort with high impact on residents and owners. The required renovation for using all-electric heat pumps is referred to as **deep renovation**.

Renewable gas allows zero emissions use of gas boilers, gas-fired heat pumps, and hybrid heat pumps. **Gas boilers** are ubiquitous in the current energy system, using a significant amount of natural gas. As renewable gas will be scarcer than natural gas, it is not feasible to use them for all of the heat demand in the long-term as volumes are significant.

Gas-fired heat pumps would reduce demand for gas by using ambient heat, but in our estimation the remaining demand for gas would be too high to be met with renewable gas. Gas-fired heating requires less rigorous insulation as the gas heaters are better suited to meet peak demand. In this study, the required renovation for gas-fired heating is referred to as **less deep renovation.**

[410] As low as 1 with temperatures of -15°C.

Gas-fired heat pumps versus hybrid heat pumps Gas-fired heat pumps are being developed as a heating solution which reduces gas demand while avoiding expensive building adjustments and electricity peak supply problems. To make a choice between the technologies, we carried out a short comparison between gas-fired heat pumps and hybrid heat pumps. To gain some insight, we compared the volume of gas required for installing either hybrid heat pumps or gas-fired heat pumps in one-sixth of all households and commercial buildings.

Hybrid heat pumps are the most promising alternative for all-electric heat pumps. A hybrid heat pump is a relatively small electric heat pump with a gas boiler to meet peak demand. The gas boiler is deployed in the few occurrences where peak supply is required. It is assumed that the electric heat pump is an air-source heat pump with a comparable performance and the same COPs as the all-electric air-source heat pumps. The advantages of hybrid heat pumps are:

- They can make use of the existing gas infrastructure in the buildings sector, reducing the required expansion of electricity grids;
- They can deliver heat using the existing heat delivery systems, avoiding replacement of existing heat delivery systems;
- They require less deep renovation as they can deliver peak demand efficiently and at limited additional cost;
- The equipment is relatively low cost, because expensive heat pump capacity is replaced with low-cost gas boiler capacity;
- Because of the usage of existing networks and the requirement of less deep renovation, the introduction of hybrid heat pumps can occur much faster than other techniques to reduce CO_2.

G.2 Assumptions used for space heating and insulation

Table 57 shows the range of insulation costs between medium to high levels of insulation.

Table 57 Overview of the range of annual insulation cost depending on the renovation level per region and building type[411]

Region	Building	Annual costs related to insulation (€1,000 per building)
Northern Europe	Single-family home[412]	2.9 – 4.2
	Multifamily home[413]	42.0 – 58.9
	Commercial building	21.7 – 30.5
Western Europe	Single-family home	1.0 – 1.4
	Multifamily home	13.8 – 19.8
	Commercial building	7.2 – 10.2
Southern Europe	Single-family home	1.0 – 1.2
	Multifamily home	13.5 – 17.5
	Commercial building	7.0 – 9.1
North-East Europe	Single-family home	0.5 – 0.6
	Multifamily home	6.1 – 7.8
	Commercial building	4.3 – 5.4
South-East Europe	Single-family home	0.6 – 0.8
	Multifamily home	11.0 – 14.1
	Commercial building	4.5 – 5.8

In the “minimal gas” scenario it is assumed that most of the heating demand (including domestic hot water) will be provided by electric heat pumps. As the use of electric heat pumps requires a high insulation, it is assumed that all buildings are compliant with the highest insulation standards (or deep renovation). For the houses which are connected to district heating a medium insulation level is sufficient (also called shallow renovation).

In the “optimised gas” a high insulation is also needed in the case of electric heat pumps (with exemption of hybrid heat pumps), but these constitute a substantially lower share than in the electrification scenario. In the Ecofys EPBD study, the cost for deep and shallow renovations were calculated taking into account differences in the building stock and weather conditions. Therefore, the terms “shallow” and “deep” renovation have been defined for every region separately. The U-values for the various renovation levels in the different regions are given in Table 58.[414] The data on the insultation and technology costs per region, building type and renovation level is found in Table 59 and Table 60. Table 61 provides an overview of cost reductions of insultation and heating technologies.

[411] Ecofys (2012). Renovation Tracks for Europe up to 2050. Building renovation in Europe, what are the choices?

[412] Living area per building type:

Single-family home: 125 m² for all areas

Multifamily home: 3,811 m² for NO, WE, SO, 2,825 m² for NE and 4796 m² for SE

Commercial building: 1,972 m² for all areas

[413] About 40 homes

[414] The U-values for deep renovated buildings and new building standards are identical; however, we are still assessing with the quantification group whether this is justified.

Table 58 U-values (in W/m²K) for various renovation levels of the residential reference buildings

		Northern Europe	Western Europe	Southern Europe	North eastern Europe	South eastern Europe
Shallow renovation	**Ambient wall**	not replaced	not replaced	not replaced	not replaced	not replaced
	Roof	0.26	0.3	0.43	0.34	0.39
	Cellar	not replaced	not replaced	not replaced	not replaced	not replaced
	Windows	1.3	1.3	1.3	1.3	1.3
Deep renovation	**Ambient wall**	0.11	0.12	0.15	0.12	0.15
	Roof	0.11	0.12	0.15	0.12	0.15
	Cellar	0.11	0.12	0.15	0.12	0.15
	Windows	0.85	0.85	1.8	0.85	1.8
New building standards	**Ambient wall**	0.11	0.12	0.15	0.12	0.15
	Roof	0.11	0.12	0.15	0.12	0.15
	Cellar	0.11	0.12	0.15	0.12	0.15
	Windows	0.85	0.85	1.8	0.85	1.8

Table 59 Overview of annual insulation cost per region, building type and renovation level[415]

Region	Building	Renovation level	Investment costs
			€/(m²a)
Northern Europe	Single-family home	Shallow renovation	23.2
		Deep renovation	33.4
	Multifamily home	Shallow renovation	11.0
		Deep renovation	15.5
	Commercial building	Shallow renovation	11.0
		Deep renovation	15.5
Western Europe	Single-family home	Shallow renovation	7.8
		Deep renovation	11.4
	Multifamily home	Shallow renovation	3.6
		Deep renovation	5.2
	Commercial building	Shallow renovation	3.6
		Deep renovation	5.2
Southern Europe	Single-family home	Shallow renovation	7.5
		Deep renovation	9.7
	Multifamily home	Shallow renovation	3.5
		Deep renovation	4.6
	Commercial building	Shallow renovation	3.5
		Deep renovation	4.6
North-East Europe	Single-family home	Shallow renovation	3.8
		Deep renovation	4.8
	Multifamily home	Shallow renovation	2.2
		Deep renovation	2.7
	Commercial building	Shallow renovation	2.2
		Deep renovation	2.7
South-East Europe	Single-family home	Shallow renovation	4.6
		Deep renovation	6.0
	Multifamily home	Shallow renovation	2.3

[415] Ecofys, 2012: Renovation Tracks for Europe up to 2050. Building renovation in Europe- what are the choices?

Region	Building	Renovation level	Investment costs
		Deep renovation	2.9
	Commercial building	Shallow renovation	2.3
		Deep renovation	2.9

Table 60 Technology costs per region and square meter (Ecofys, 2012: Renovation Tracks for Europe up to 2050. Building renovation in Europe- what are the choices?)

Region	Technology	Unit	SFH		MFH		CB	
			Retrofit	New built	Retrofit	New built	Retrofit	New built
NO	GB	€/m² floor area	77	85	31	30	31	30
	ASHP	€/m² floor area	197	225	109	72	109	72
	GSHP	€/m² floor area	242	258	109	72	109	72
	HHP	€/m² floor area	99	113	55	36	55	36
	DH	€/m² floor area	73	144	36	20	36	20
WE	GB	€/m² floor area	60	66	24	23	24	23
	ASHP	€/m² floor area	154	176	85	56	85	56
	GSHP	€/m² floor area	189	202	85	56	85	56
	HHP	€/m² floor area	77	88	43	28	43	28
	DH	€/m² floor area	57	113	28	51	28	51
SO	GB	€/m² floor area	42	46	17	16	17	16
	ASHP	€/m² floor area	107	122	59	39	59	39
	GSHP	€/m² floor area	131	140	59	39	59	39
	HHP	€/m² floor area	54	61	30	20	30	20
	DH	€/m² floor area	39	78	20	11	20	11
NE	GB	€/m² floor area	39	42	15	15	15	15
	ASHP	€/m² floor area	89	112	54	36	54	36
	GSHP	€/m² floor area	98	129	54	36	54	36
	HHP	€/m² floor area	45	56	27	18	27	18
	DH	€/m² floor area	36	72	18	10	18	10
SE	GB	€/m² floor area	30	33	12	12	12	12
	ASHP	€/m² floor area	77	88	42	28	42	28
	GSHP	€/m² floor area	94	100	42	28	42	28
	HHP	€/m² floor area	39	44	21	14	21	14
	DH	€/m² floor area	28	56	14	8	14	8

Table 61 Cost reductions of heating technologies and insulation costs (based on the estimates in Ecofys, 2016: Urban Electrification Report, DECC, 2016: Potential Cost Reductions for Air-Source Heat Pumps and DECC, 2016: Potential Cost Reductions for Ground-Source Heat Pumps)

	Cost-reduction multiplicator
GB	0.90
ASHP	0.80
GSHP	0.82
HHP	0.85
DH	1.00
Insulation	0.70

Appendix H. Industry

H.1 Chemical industry

The chemical industry provides essential products and materials to many different downstream sectors. After China, Europa has the second largest chemical industry, contributing 15.6% of global chemical sales in 2017. Germany and France are the two largest chemical producers in Europe, followed by Italy and the Netherlands.[416] The chemical industry is the largest industrial energy consumer and the third-largest emitter of GREENHOUSE GASs in Europe. In 2015, the chemical sector, including pharmaceuticals, accounted for 126 Mt of CO_2 emissions, down from 325 Mt in 1990.[417] A large share of emissions can be attributed to fossil feedstocks such as natural gas (e.g., for ammonia) or crude oil (e.g., diesel, gasoline).

H.1.1 Ammonia production

Modern ammonia production is based on the Haber-Bosch process. Simplified, the reaction looks like this:

$N_2 + 3H_2 \rightarrow 2NH_3$

The conversion occurs via several steps using an iron catalyst. The first step starts with feed purification (which removes sulphur) and includes steam methane reforming, where feed gas is mixed with process steam. This results in separation of the gas into carbon dioxide, carbon monoxide and hydrogen. The reaction is highly endothermic, which means that a lot of heat must be supplied during the process. In the next step, during the so-called water-gas shift reaction, steam reacts with carbon monoxide and additional hydrogen and carbon dioxide are being formed. The rest of the carbon dioxide, including other impurities such as acid gas is removed by a subsequent reaction. This leaves pure hydrogen readily available for the last reaction with atmospheric nitrogen which happens under high pressure (150-350 bar) and at high temperature (450°C-550°C). The ammonia production process is depicted in Figure 68.

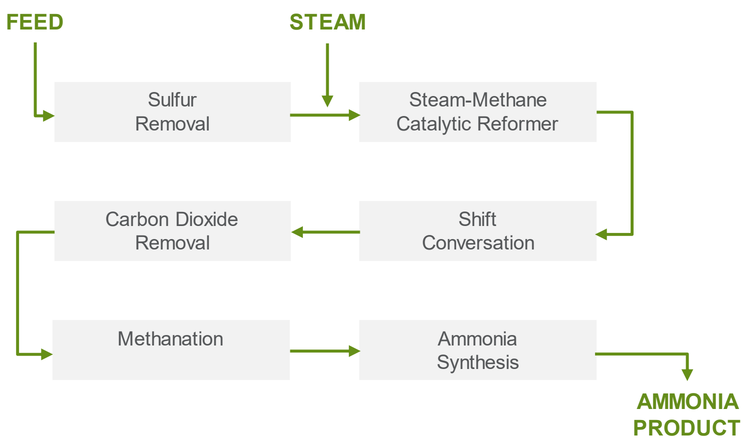

Figure 68 Ammonia production process

[416] CEFIC (2018). Facts & Figures 2018.

[417] Ibid.

Alternatively, ammonia can also be produced via the low-carbon ammonia production route. During this process CO_2 is not formed as a by-product because hydrogen is provided via water electrolysis produced onsite or green or blue hydrogen which is sourced centrally. This means that the first steps of the conventional Haber-Bosch process can be skipped. Additionally, this reaction requires an air separation unit to supply the required nitrogen.[418]

Economics of low-carbon ammonia

In the CCS route, the current ammonia production chain would not have to be changed significantly limiting the need for new investments. The additional specific cost related to CCS on an SMR (capturing 90% of emissions), would be around 380€/t H_2.[419] Given the need for 178 kg of hydrogen per ton of ammonia, the investment costs for low-carbon ammonia production with CCS are **68€/t NH3.**[420]

If centrally produced hydrogen is utilised and ASU is required, we assume investment costs of **27€/t NH3**[421] for the ASU.

For the electricity-based scenario our calculation assumes total investment costs of **863€/t NH3** produced yearly, consisting of hydrogen electrolyser investment costs (423€/kW),[422] assuming 4,500 operating hours and the ASU.

Table 62 presents the specific energy demand, CO_2 emissions, and investment costs for different ammonia production routes.

Table 62 Comparison of low-carbon ammonia production routes

Energy carrier	Production process today	Optimised gas scenario		Minimal gas scenario
	Fossil (SMR + NH3 synthesis)	Natural gas + CCS	Green or blue H_2 (centralised H_2 production)	Electricity (decentral H_2 production)
Natural gas (m^3/tNH_3)	860	860	-	-
Electricity (MWh/tNH_3)	2.1	2.4	1.72	12.53
Hydrogen (t/tNH_3)	-	-	0.18	-
Steam balance (GJ/tNH_3)	-4.3	-4.3	-	-
CO_2 emissions ($t//tNH_3$)	1.83	0.18	0	0
CAPEX (€/tNH_3)	-	68	27	863

[418] Dechema: *Low carbon energy and feedstock for the European chemical industry* (2017).

[419] Based on own calculation.

[420] Ibid.

[421] VNCI (2018). Chemistry for Climate. Acting on the need for speed.

[422] Based on our calculations for the supply of green hydrogen.

H.1.2 Methanol

Methanol is produced from syngas over a catalyst. First and second steps, the feed purification and steam reforming respectively, are same as for ammonia. During step three the methanol gets produced via two production routes, either with hydrogenation of carbon monoxide or CO_2:

1.) $CO + 2\ H_2 \rightarrow CH_3OH$
2.) $CO_2 + 3\ H_2 \rightarrow CH_3OH + H_2O$

In the case of CO_2 hydrogenation, the beforementioned water-gas shift reaction is needed to remove the excess CO_2. In the last step, the methanol needs to be purified by distillation as it includes water and traces of other by-products.

Similar to ammonia, methanol can also be produced via a low-carbon pathway. This route includes green or blue hydrogen, followed by subsequent hydrogenation reaction of CO_2. During the process more water is formed than in the conventional process, which needs to be removed by distillation. The power to methanol process is depicted in the picture below.[418]

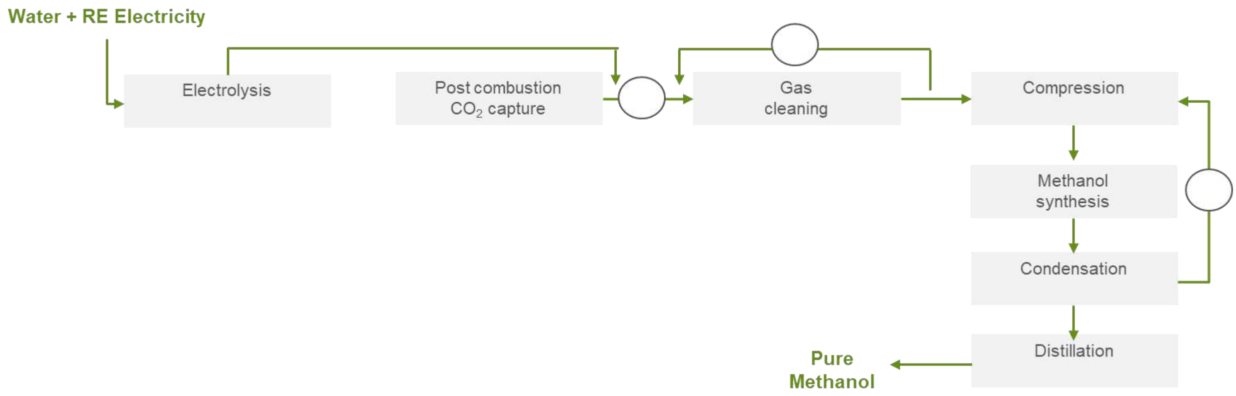

Figure 69 Low-carbon methanol production process

Economics of low-carbon methanol

In the **natural gas + CCS** route, the current methanol production chain would not have to be changed significantly limiting the need for new investments. The additional specific cost related to CCS on an SMR (capturing 90% of emissions), would be around 380€/t H_2.[423] Given the need for 189 kg of hydrogen per ton of ammonia, the investment costs for low-carbon ammonia production with CCS are **72€/t NH_3.**[424]

For the **biomethane** option, no additional investments compared to the already existing methanol production process are needed.

For both alternative low-carbon methanol routes, investments of €229/ t CO_2 captured yearly for CO_2 capture) translating to 315€/t CH_3OH (just capture, no transport or storage) are needed. Additionally, an investment costs of 451€/t CH_3OH produced yearly for the synthesis of methanol from hydrogen and CO_2.[425] Thus, for the **green or blue H_2** option total investments are 766€/t CH_3OH.

[423] Based on own calculation.

[424] Based on own calculation.

[425] VNCI (2018). Chemistry for climate. Acting on the need for speed.

On top of the above-mentioned investments, the **electrification** option requires investments of 889 €/t CH_3OH for the electrolyser. Thus, the total investment costs are €1,655

Table 63 presents the specific energy demand, CO_2 emissions, and investment costs for different ammonia production routes.

Table 63 Comparison of low-carbon methanol production routes

Energy carrier	Production process today	Optimised gas scenario			Minimal gas scenario
	Fossil (SMR + methanol synthesis)	Green or blue H_2 (centralised H_2 production)	Natural gas + CCS	Biomethane	Electrification (decentral H_2 production)
Natural gas (m^3/tCH_3OH)	1049	-	1049	-	-
Natural gas (m^3/tCH_3OH)	-		1049		-
Electricity (MWh/CH_3OH)	0.2	1.5	0.467	0.2	11.03
Hydrogen (t/tCH_3OH)	-	0.19	-	-	-
CO_2 as feedstock (t/tCH_3OH)	-	1.37	-	-	1.37
Steam balance (GJ/tCH_3OH)	-2	-	-2	-2	-
CO_2 emissions (t/tCH_3OH)	1.49	-1.37	0	0	-1.37
CAPEX (€/tCH_3OH)	-	866	72	0	1,655

H.2 Iron and steel

Like the chemical industry, the steel sector delivers key materials and products to downstream sectors, such as the automotive and machinery industries. After China, Europe is the largest steel producer and accounts for 18.5% of crude-steel production. Within Europe, Germany is the largest, followed by Italy and France. The steelmaking industry is one of the most carbon-emitting and energy-consuming sectors in Europe. [426]The European steel sector accounts for 216 Mt of CO_2 emissions in 2015, down from 298 Mt in 1990.[427] The main energy carriers used are coal, gas, and electricity.

Modern steelmaking is characterised by two different process routes: primary and secondary steelmaking. Whereas primary steelmaking uses mainly iron ore, secondary steelmaking uses scrap steel as feedstock. In Europe, primary steelmaking is heavily dominated by the BF-BOF process, the secondary route by the Scrap-EAF process. BF-BOF produced 60.5% of the EU-28 crude-steel production in 2015. Scrap-EAF accounted for 39.5% of the production.[428] Primary steel is more energy intensive than the production of secondary steel due to the chemical energy required to reduce iron ore to iron using carbon-based reducing agents such as coal, coke and natural gas. These energy carriers also provide the required heat.

The Scrap-EAF uses mainly ferrous scrap as feedstock for the electric arc furnace (EAF). The feedstock is melted by the electric arc (up to 3,500°C). The production volume and steel quality of the Scrap-EAF process route is limited to the availability and the quality of the feedstock, respectively.

---

[426] Eurofer (2018). European Steel in Figures.

[427] Eurofer (2018).

[428] Worldsteel (2017): Steel Statistical Yearbook.

Therefore, DRI is also increasingly used due to its lower content of undesirable metals such as copper. In this case, ferrous scrap is often used as additional feedstock to adjust the desired steel quality. In contrast to the BF-BOF route, electricity is the main energy source for Scrap/DRI-EAF.

Several decarbonisation options exist for the BF-BOF (primary) and Scrap-EAF (secondary) process routes, which can be categorised into 1) carbon direct avoidance (CDA) and 2) smart carbon usage (SCU), as explained in Figure 70. The aim of SCU is to reduce the use of carbon in the conventional BF-BOF process route by e.g., injecting low or zero CO_2 emitting energy carriers like natural gas or hydrogen in the BF, and/or by applying CCS and CCU. CDA is based on renewable electricity and green hydrogen. Electricity is used to provide the required energy for the Scrap-EAF process route. In the DRI-EAF process route, green hydrogen is used in direct reduction shaft furnaces (instead of currently used natural gas) for hydrogen-based iron ore reduction to DRI. Afterwards, green electricity provides the required energy for the EAF.

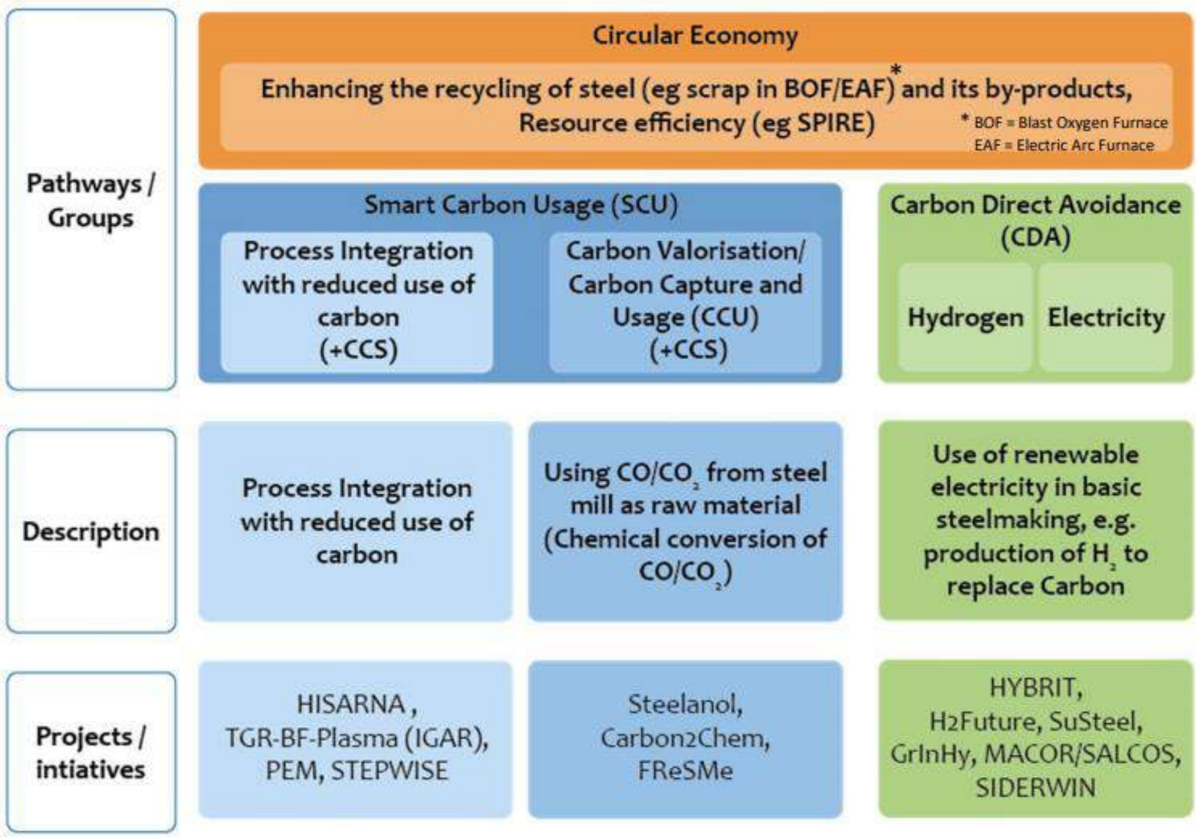

Figure 70 Technological pathways/options for CO_2 emission of the steel sector in Europe[429]

[429] EUROFER (2018b): Framework Programme 9: A Mission for Carbon-Neutral Steel & Towards an EU Masterplan for a Low-Carbon, Competitive European Steel Value Chain.

Table 64 Presents the specific energy demand, CO_2 emissions, and investment costs for different low-carbon steel production routes.

Table 64 Comparison of low-carbon methanol production routes

Energy carrier	Optimised gas scenario			Minimal gas scenario	
	Biomethane DRI-EAF	Green or blue H2 DRI-EAF	IBRSR-CCS	Electrolyser DRI-EAF	Scrap-EAF
Coal (t/tCS)	0.01	0.01	0.46	0.01	0.01
Biomethane (m^3/tCS)	290	39	60	39	36
Electricity (MWh/tCS)	0.86	0.61	0.46	3.5	0.71
Hydrogen (t/tCS)	0	0.064	0	0	0
CO_2 emissions (t/tCS)	0.131	0.131	0.242	0.131	0.128
CAPEX (€/tCS)	415	415	350	666	165

H.3 Cement and lime

Cement and lime are both energy and carbon intensive industries. However, only one-third of their emissions come from combustion processes, while the bulk of emissions come from the chemical reactions that happen during the calcination processes.

Cement is a basic material used for building and construction. The most important use of cement is in the production of concrete. Lime is used in a wide range of products, for example as a fluxing agent in steel refining, as a binder in building and construction, and for the neutralisation of acidic components of industrial effluent and flue gases. The European cement industry accounts for 122 Mt (2011) [430] of CO_2 emissions, the lime industry for around 26 Mt (2010).[431]

Cement and lime manufacturing processes have the mixing of inorganic minerals calcined at high temperatures (>1,000°C) in kilns in common. In the cement industry, the clinker burning process is the most important part of the process in terms of energy use and emissions. CO_2 emissions from combustion are related to fuel use, while emissions due to calcination are generated when the raw materials (mostly limestone and clay) are heated and CO_2 is released from the decomposed limestone. Various conventional fossil and waste fuels are used to provide the thermal energy demand required for the process.

[430] Cembureau (2013). The role of cement in the 2050 low carbon economy.

[431] Ecofys (2014). A competitive and efficient lime industry.

In the lime industry, the lime burning process is also referred to as the calcination process and is both the main source of emissions and the principal user of energy. Solid fossil fuels and natural gas are the main energy carries in the lime industry. Kilns are fired with gaseous fuels (e.g., natural gas, coke oven gas), solid fuels (e.g., coal, coke/anthracite), and liquid fuels (e.g., heavy/light fuel oil). Furthermore, different types of wastes are used as fuels, e.g., oil, plastics, paper, animal meal, sawdust. The secondary processes of lime slaking and grinding can also be of significance. Depending on the specific production processes, lime plants cause emissions to air, water, and land (as waste). The electricity consumption in lime manufacturing is relatively low. Electricity is mainly used for operating some of the kiln equipment and mechanically crushing the limestone.[432]

H.4 Electrification potentials

In our analysis we compare various gas and non-gas decarbonisation options for the industry sector. The non-gas option is mainly electricity-based whereas the gas options include hydrogen, biomethane, and natural gas. Electrification of heat using renewable electricity is an option to further decarbonise sectors where industrial processes do not require temperatures above 150°C.[433] Major industrial users are paper and pulp and the food and tobacco industry, followed by the textile, glass, and ceramic sector. Electric heat pumps, solar, or geothermal heating technologies have the biggest technical potential to provide low temperature heat, while electric boilers are good alternatives for medium temperature heat (150°C–500°C). Additionally, hybrid boiler with electricity or low carbo or renewable gas can provide low and medium heat.[434] High temperature heat can be electrified only to a limited extend. Key technologies to electrify high temperature processes are based on induction, resistance or infrared heating, complemented by other market mature technologies, such as microwave, radio-frequency, electric-arc heating, and ultraviolet curing. Some of the technologies are applied in various industry sectors while others such as electric-arc furnace are limited to only few sectors.

The potential for electrification as identified by the Electric Power Research Institute (EPRI) including the temperature demand for each industry is given in Table 65.

[432] Ecofys (2014). A competitive and efficient lime industry.

[433] Parsons Brinckerhoff, WSP and DNV GL of UK: *Industrial decarbonization and energy efficiency roadmaps to 2050 – cross-sector report* (2015).
https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/419912/Cross_Sector_Summary_Report.pdf (p18)

[434] McKinsey: *Decarbonization of industrial sectors: the next frontier* (2018)
https://www.mckinsey.com/~/media/mckinsey/business%20functions/sustainability%20and%20resource%20productivity/our%20insights/how%20industry%20can%20move%20toward%20a%20low%20carbon%20future/decarbonization-of-industrial-sectors-the-next-frontier.a

Table 65 Temperature range (low: 0-150°C, medium: 150-500°C, high: >500°C) and estimation of the electrification potential for industry subsectors

Industry	Temperature range[435,436]	Electrification potential (GWh)[437]	Electrification potential (%)
Iron and Steel	High	113,867	20%
Food, Drink, and Tobacco	Low/Medium	103,121	30%
Chemical and Petrochemical	High	89,591	15%
Machinery	Low	76,603	35%
Non-Metallic Minerals[438]	Medium	69,499	18%
Paper, Pulp, and Printing	Low/Medium	47,238	12%
Transport Equipment	Low	30,333	30%
Non-Ferrous Metals	High	29,729	25%
Textile, Leather, and Clothing	Low/Medium	17,723	35%
Other industry	Low	15,242	7%
Ore Extraction	Low	6,366	16%
Wood and Wood Products	Low	5,001	5%

[435] Rehfeldt et al.: *A bottom-up estimation of heating and cooling demand in the European industry* (2016). https://www.researchgate.net/publication/312173884_A_bottom-up_estimation_of_heating_and_cooling_demand_in_the_European_industry

[436] Joint Research Centre: *Heat and cooling demand and market perspective* (2012): http://publications.jrc.ec.europa.eu/repository/bitstream/111111111/26989/1/ldna25381enn.pdf

[437] EPRI study calculates the electrification potential based on the estimation of the portion of natural gas that can be converted to electric with an assumed efficiency gain.

[438] Including glass, pottery & building materials (such as cement).

Appendix I. Transport

I.1 Road Transport

In our analysis we aim for a transport sector that has net-zero CO_2 emissions in 2050. This means that we consider fuels that are either renewable or low carbon. The fuels we consider are renewable: electricity, biomethane, biodiesel, and green hydrogen from electrolysis or low carbon: blue hydrogen from reformed methane in combination with CCS.

Future fuel demand is determined by considering the lowest societal costs for fuel type for each transport application. Total societal costs include all investments and operational costs for vehicles and fuels and the costs for fuel station and related energy infrastructure costs. In addition, we take into account non-cost factors that determine the uptake of specific fuels towards 2050. We determine the optimal fuel demand for road transport in terms of lowest societal costs based on an optimisation of fuel demand and availability in overall economic sectors.

To determine the optimal fuel mix, we break down the road transport sector into three main vehicle types: trucks, buses, and passenger cars. Our analysis evaluates a combination of sources containing estimates on future vehicle stock, fuel consumption and costs for vehicles, fuel stations, and energy infrastructure. Based on public reports and expert assumptions we obtain cost figures on vehicles, fuel stations, and required fuel infrastructure to evaluate the total societal costs for each fuel type. The reports and assumptions used are detailed further in the remainder of the appendix.

Future vehicle stock for vehicles and fuel consumption are based on the IEA Mobility Model (MoMo). MoMo is an analytical tool projecting transport activity, energy demand, and CO_2 emissions until 2100.

MoMo modelling framework provides multidimensional transport data and is based on calibration of historical data (collected from various global, national, and regional sources on vehicles), existing databases (such as demographic data, policies, emission related data) and hypothesis (such as GDP, population growth, fuel economies).[439,440] From the model we take the forecasted number of vehicles in Europe up to 2050 and fuel consumption data of vehicles within the below 2°C scenario for the EU 27.[441] Transport modes are split into commercial and passenger transport. Buses and cars are further split into urban and non-urban geographies, their data is extrapolated based on the population density, country-specific parameters, driving patterns, and assumed relationships.

I.1.1 Trucks

Road transport via trucks represent an important part of the freight as can be seen in Figure 71. Typically, trucks are being either used for last mile, or regional delivery and logistics or for long-haul transport between distribution hubs. Truck transport is more flexible than transport via inland shipping and rail, especially in rural regions and for last-mile delivery and doesn't require specific infrastructure[442] beyond roads and the availability of refuelling stations. Some overlap exists with shipping and rail transport especially in container transport.

In our analysis we classify trucks similarly to the IEA Mobility Model (MoMo). MoMo distinguishes between three categories of trucks:[443]

---

[439] IEA, *Data and Modelling for Transport, and Thoughts on Data Collection Needs* (2009).

[440] IEA, *Modelling of the transport sector in the Mobility Model* (2018).

[441] IEA, Mobility Model, https://www.iea.org/etp/etpmodel/transport/

[442] With the exception to when catenary wires are used.

[443] IEA, The future of trucks (2017).

- **Light Commercial Vehicles (LCVs):** These vehicles have a gross vehicle weight (GVW) of less than 3.5 tonne and are primarily used for small scale, last-mile deliveries such as postal and commercial deliveries and for transporting industrial goods and building materials to and from work sites. They are also used to provide services, such as repairs, plumbing and heating, and office support. The category consists of pickup trucks, vans, and small open lorries with typical load carrying capacities in the range of 1-2 t.
- **Medium Freight Trucks (MFTs):** Commercial vehicles with a GVW between 3.5 and 15 tonnes[444] that typically perform a regional function. The type of vehicles in this category is very diverse, includes small lorries, rigid trucks and tractor-trailers, as well as large vans. It also includes public services such as garbage and firefighting trucks. Loads for these vehicles are typically between 4-10 tonnes. On average these vehicles drive 52,000 km a year.
- **Heavy Freight Trucks (HFTs):** Commercial vehicles with a GVW greater than 15 tonnes,[444] including road trains (multiple trailers pulled by a single tractor unit). HFTs typically have a power rating between 200 kW and 600 kW and deliver goods over long distances from central distribution hubs to their final destinations, such as retail firms or for transporting bulk building materials and resources. In countries with less developed infrastructure MFTs effectively perform a similar function as HFTs. HFTs have large annual mileage, averaging around 75,000 km a year. Large differences exist as some vehicles cover close to 200,000 km annually. HFTs are responsible for the majority (about 70%) of road freight activity and about 50% of truck energy use. Loads for HFTs are assumed to fall in the 12 tonne to 16 tonne range.

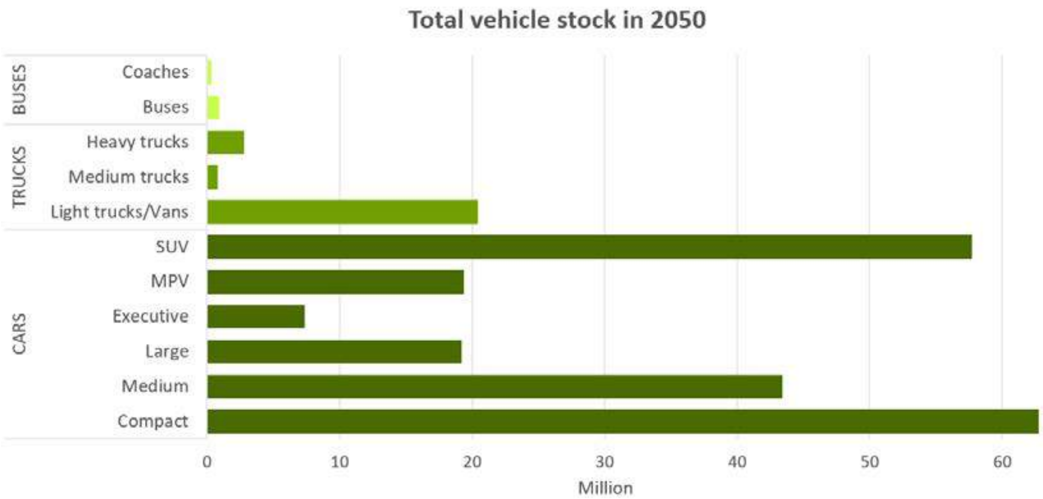

Figure 71 Projected numbers of trucks, buses, and cars in Europe in 2050[445]

I.1.2 Buses

Buses are the most common form of public transport in the European Union, as 55.7% of all public transit service are made by buses. Buses have the lowest carbon footprint per passenger of other form of transportation and when full can replace 30 cars. In 2016, there were almost 900,000 buses on Europe's roads.[446]

Based on the European classification, buses are categorised based on their weight (beneath or above 5 tonnes), but this classification is not useful for predicting their fuel and emissions behaviour. There is no harmonised set of rules differentiating between types of buses that applies to all member states.

[444] EU uses a slightly different truck classification, counting trucks with GVW > 12 tonnes as HFTs.

[445] IEA MoMo, well below 2 degrees scenario (2018).

[446] ACEA - European Automobile Manufacturers Association: *Buses: Factsheet* (2017).

To obtain a comprehensive analysis, we classified buses in following subcategories based on the distances they drive[447,448] :

- **Urban buses.** Are used for short-distance services, mainly for urban and local scheduled transport. They can up to 52 passengers and usually do not have toilets, underfloor storage areas, seat belts, arm rests, or head rests. Passengers can stand or sit. Typical occupancy rate is 14 passenger kilometres per vehicle kilometre with an average of 190 vehicle kilometres per traffic days.[449] This category includes bus rapid transit (BRT) and trolleybuses.
- **Coaches (non-urban buses).** Are used for long-distance services, mainly for non-urban regular and non-regular transport between cities, regions, or countries. They can accept up to 53 passengers and do not have a provision for standing passengers. Typical occupancy rate is 23 passenger kilometres per vehicle kilometres with an average of 300 vehicle kilometres per traffic days.

To determine the vehicle stock up until 2050, we used the distinction between urban and non-urban/intercity buses as defined by the MoMo model, with non-urban buses matching our definition of coaches.

I.1.3 Passenger cars

The European Commission defines passenger cars as vehicles carrying passengers, consisting of up to nine sits (including the driver's sit), having at least four wheels, and not exceeding the maximum weight of 3.5 tonnes.[450] A further breakdown is done into three subcategories, depending on maximum mass and number of seats.[450] There exists other methods of vehicle categorization, such as by size class, vehicle construction, and others.[451] Transport statistics on car segments are not consistent as the borders between individual segments are often blurred and many vehicles fit in multiple categories. Based on the most relevant statistics available,[452,453] we categorised passenger cars into two categories of roughly equal shares in current sales figures, consisting of compact/medium and large/executive cars:

Compact/medium cars:
- **Compact cars.** A- (mini) and B- (small) segment cars, including city cars and superminis (examples: Renault Twizy, Citroën C1, Opel Corsa).
- **Medium cars.** C-segment cars, including small family cars (examples: Toyota Auris, Renault Mégane, Ford Focus).

Large/executive cars:
- **Large cars.** D-segment cars, including large family cars, mid-size, and entry-level luxury cars. (examples: Audi A4, Volkswagen Passat, Mercedes-Benz C-Class).
- **SUV (Sport Utility Vehicles).** J-segment cars, including small and large off-road 4x4 (examples: Citroen C3 Picasso, Volkswagen Touran, Toyota Sienna).

---

[447] Özdemir*: The Future Role of Alternative Powertrains and Fuels in the German Transport Sector: A model-based scenario analysis with respect to technical, economic and environmental aspects with a focus on road transport* (2012).

[448] Steer Davies Gleeve on behalf of DG MOVE: *Comprehensive Study on Passenger Transport by Coach in Europe* (2016).

[449] Traffic days are days when buses operate.

[450] European Commission, *Vehicle Categories* (2018).

[451] See e.g. Euro NCAP (2018), Wikipedia: *Size and usage-based vehicle classification systems worldwide* (2018) & International Council on Clean Transportation Europe: *European vehicle market statistics* (2017).

[452] The international council of clean transportation: *European Vehicle Market Statistics: Pocketbook 2017/18* (2017).

[453] Statista: *Number of car registrations in Europe in November of 2016, by segment* (2016).

- **MPV (Multi-Purpose Vehicles).** M-segment cars, including small and large MVPs (examples: Suzuki Jimny, Honda CR-V, Volkswagen Touareg, Range Rover).
- **Others.** Including executive (E-segment cars, including full-size and mid-size luxury cars, examples: Ford Taurus, Audi A6, Mercedes-Benz E-Class), luxury (F-segment, including full-size luxury cars, examples: BMW 7 Series, Jaguar XJ, Mercedes-Benz S-Class), sport cars (S-segment, including roadsters, convertibles, supercars, and grand tourers, examples: Volvo C70, Mercedes-Benz SLK, LaFerrari, Jaguar XK), pickups and limousines.

To predict the passenger vehicles in Europe in 2050 we used the total forecast stock data from MoMo.[454] To distinguish between different classes of cars we projected 2016 sales figures[455] for each car segment onto the total car stock. We assume that the proportion of car type distribution on European roads will not change extensively.

I.1.4 Renewable and low-carbon fuels in road transport

Current fuel demand in trucks and buses is dominated by diesel, mainly because of their low operational costs, high energy content and well-established infrastructure. Various national taxation schemes exist that are favourable to the use of diesel for long mileage transportation. In passenger cars a mix of different fuels are currently being used, with petrol and diesel being the major fuel options. With smaller shares, also other energy carriers are used such as bio-compressed natural gas (CNG), bio-LNG, bio-liquefied petroleum gas (LPG) and biofuels such as biodiesel, bioethanol, and biomethane.[456] BEVs and FCEVs are also commercially available; however, their deployment is still relatively low. Hydrogen fuel cell technology in vehicles is still maturing and is only deployed on a small scale. For example, in 2016, only 2% of the total bus fleet ran on alternative, non-diesel fuels, such as methane and hydrogen.[457]

In our analysis we assume the fuel options for vehicles in the various transportation modes as indicated by Table 66. We assume that biodiesel and bio-LNG will only be available for heavy or long-haul transportation in trucks and buses. We include biodiesel as a fuel option for buses, although we see a current trend in some European cities towards phasing out diesel buses. For example, the Dutch government explicitly aims to ban combustion engine buses from cities in 2030.[458] It is uncertain whether also future policies will discourage the use of biodiesel in the urban environment.

Table 66 Fuel options considered in our analysis for the various transportation modes

	Trucks	Buses	Passenger cars
Battery electric	X	X	X
Fuel cell electric	X	X	X
Biodiesel	X	X	
Bio-CNG	X	X	X
Bio-LNG	X	X	

---

[454] The MoMo model describe cars as PLDVs (personal light-duty vehicles). PLDVs are split into cars and light trucks, which is done on the basis of country-specific definitions and data availability. “Light-trucks” hereby indicate SUVs and MPV and thus have no overlap with commercial freight vehicles.

[455] European passenger car registration figures as obtained from Statista for November 2016.

[456] CIVITAS, *EU Policy note: Smart choices for cities Alternative Fuel Buses* (2016).

[457] ACEA - European Automobile Manufacturers Association: *Buses: Factsheet* (2017).

[458] Transport and Environment: *Roadmap to climate-friendly land freight and buses in Europe* (2017).

Switching to renewable or low-carbon fuels may be as simple as using a different fuel in case of biodiesel or could require an entirely new infrastructure in the case of hydrogen or electricity use. Although it may be relatively easy to switch to bio-CNG and bio-LNG in current fuel stations, the amount of stations and fuel supply infrastructure will need to increase to accommodate a larger scale adoption of these options.

I.1.5 Fuel energy density

All the fuels considered in this study have a lower energy density than the dominant conventional fuels: diesel and petrol. This means that a similar volume of fuel in a vehicle in 2050 will result in a lower driving range, even when considering differences in fuel efficiencies. While the driving range can be extended by refuelling, the refuelling times for hydrogen, CNG and batteries are generally longer than for LNG and diesel, which may negatively impact business cases for operators.

The other option is to increase the fuel storage space compared to current fuel tanks to achieve a comparable driving range. As can be seen in Figure 72, the lower volumetric density of methane, both compressed to 250 bar (CNG) and liquified (LNG) result in a six and two times larger required fuel tank than for diesel respectively.[459] Battery size and hydrogen storage tanks would need to be even larger than CNG, although this effect is partially offset by the higher energy conversion efficiency of electric motors compared to diesel, CNG, and LNG combustion engines. Fuel storage space is a key factor that will impact the choice between fuel options as it will impact the amount of volume left in vehicles to transport goods.

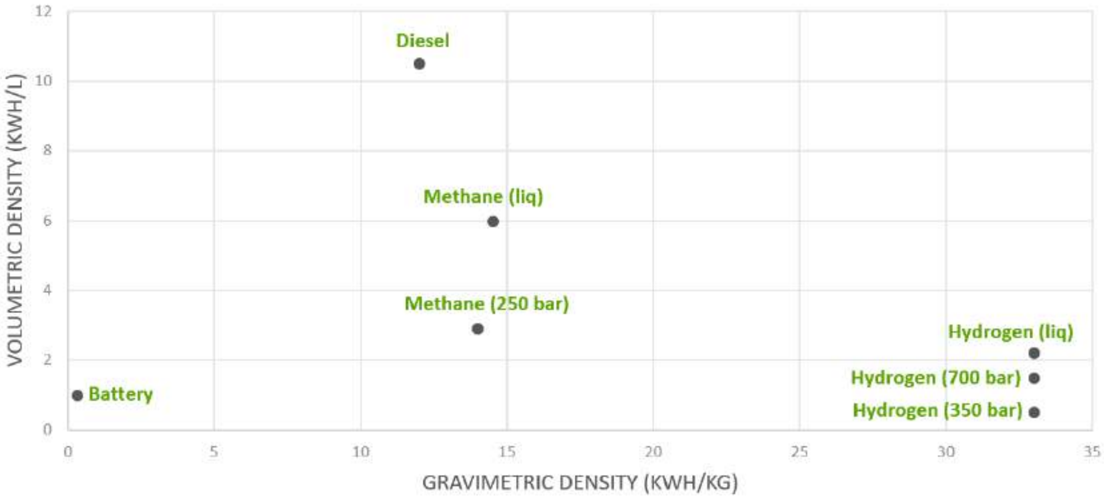

Figure 72 Volumetric and gravimetric energy densities for renewable and low-carbon fuels compared to diesel and petrol[460]

Similar considerations apply to the weight of batteries. To store a similar amount of energy, batteries are heavier than diesel or petrol fuel and will therefore impact the gross vehicle weight. For vehicles gross vehicle weight is restricted to specific categories. Carrying heavy batteries will impact the maximum payload that can be carried.

[459] IEX, The future of trucks (2017).

[460] US Department of Energy, Office of energy efficiency & renewable energy, Hydrogen storage (2018) & Harrison, MaximIntegrated.com, *A look at the latest battery technology from Tesla* (2018) & DNKpower.com, Tesla, mass production of 21700 battery (2018).

Research programmes all around the world focus on optimising key performance parameters for fuel cells and battery and hydrogen storage, focusing on improving energy efficiencies and increasing volumetric and gravimetric densities for storage. Electric car manufacturer Tesla expects that energy density in car batteries will improve over the years, towards a volumetric density of above 1 kWh/L[461] and a gravimetric density of 0.3 kWh/kg.[462] In the next decades we can expect that more developments will take place that improve the energy densities of batteries. Despite these improvements we can expect that the adoption of battery electric and to a lesser extent also CNG and LNG as well as fuel cell vehicles will depend on the type of application and the required vehicle specifications.

I.1.6 Electrification through catenary wires

To overcome the volume and weight issues related to BEVs, some companies are piloting a different approach to transport by implementing overhead electric wires on highways that allow trucks and buses with an installed pantograph to be supplied with power while driving. Currently only Sweden and Germany are considering and piloting these systems for trucks on trial road sections. Historically, some cities have been using similar systems on a local scale for urban bus transport and some mining companies to power heavy-duty trucks on specific point-to-point routes.

This catenary driving system could present a cost-competitive solution especially for long-haul transport road applications[463] or along fixed bus routes. Compared to electrification through rail, the use of catenary wires for transport provides more flexibility. Trucks and buses could be equipped with batteries or hybrid motors that allow them to drive when no catenary lines are available on secondary roads or when overtaking other traffic.

To be an effective solution for European long-haul transport, overhead lines should be installed throughout Europe,[464] at least along the 34,401 km of nine major international routes that are part of the Trans-European Transport Network (TEN-T core network).[465] Development of such an infrastructure would require a huge initial investment, totalling an estimated €70–100 billion for identified TEN-T core network.[466] This is comparable to the cost of roughly 50,000 fuel stations, which is half of all the fuel stations in the EU. Development of an international infrastructure of catenary wires requires policy decisions on EU level and tailored policies that specifically promote this solution, support combined planning and maximised utilisation.[467]

Because of the high investment costs and the need for complex planning instead of step-by-step developments for other renewable and low-carbon transport solutions, we do not consider catenary wires as a potential solution for trucks in 2050 in this study. Catenary wires may potentially present a niche solution for trucks on specific point-to-point routes in industrial clusters or between logistical hubs.
Trolley bus systems have the disadvantage over battery electric buses in that they are less flexible in changing routes compared to fully electric buses. Nevertheless, historic implementation suggests that in some cases trolley bus infrastructure could be interesting.[468]

---

[461] https://www.maximintegrated.com/en/design/blog/tesla-battery-technology.html)/

[462] https://www.dnkpower.com/teslas-mass-production-21700-battery

[463] CE Delft & DLR, *Zero emission trucks* (2013).

[464] DENA & LBST, *E-Fuels – The potential of electricity-based fuels for low emission transport in the EU* (2017).

[465] European Commission, Trans-European Transport Network, TENT-T Core Network Corridors (2013).

[466] Assuming €2-€3 million per km of catenary wires, CE Delft, *Zero emission trucks* (2013).

[467] Ifeu & M-Five, *Roadmap for an overhead catenary system for trucks: SWOT analysis* (2017).

[468] Roland Berger, *Commercialisation Strategy for Fuel Cell Electric Buses in Europe* (2015).

I.1.7 Key cost factors

We include the following cost factors in our cost modelling:

- **Vehicle costs:** Costs for the purchase of a new vehicle
- **Bare fuel costs:** Wholesale costs for the specific fuel
- **Maintenance costs:** Costs associated with the maintenance of the vehicle
- **Fuel station costs:** Costs related to the costs of operating a refuelling station
- **Fuel infrastructure costs:** Costs related to distribution of the fuel from the fuel production site to the fuel station

Our cost analysis does not take into account taxes and levies, as it is not clear what the tax system will look like in 2050. We also do not take into account specific policies that stimulate certain alternative fuel systems. The impact of taxes, levies, and policies can be a determining factor in what fuel system will be chosen by truck operators. This also may not be uniform across the EU.

I.1.8 *Vehicle costs*

In conventional diesel or petrol vehicles the costs of the drivetrain are responsible for a large part of the total vehicle costs (e.g., about 25% in trucks), while costs for energy storage, i.e. the tank, are limited. In addition, diesel trucks will require more extensive post-combustion treatment to comply with tightening emission standards for NO_x, CO and SO_x. Vehicle costs of fuel cell trucks are dominated by the costs of the fuel cell stack and storage tank and costs for electric trucks are dominated mostly by the costs of the battery.

To determine the vehicle purchase costs, we performed a vehicle component differential analysis comparing ICE vehicles and with BEVs and FCEVs. These differential costs are added to costs for ICE vehicles as obtained from MoMo. Our analysis includes the costs of components such as the motor, battery, and hydrogen storage costs and costs for the fuel cell and additional costs for controllers and convertors, as can be seen in Table 67. Unless stated differently cost figures have been based on figures listed in the dissertation of Özdemir on the *Future Role of Alternative Powertrains and Fuels in the German Transport Sector*.[469] Cost figures have been adopted to 2018 values.

Because of rapid cost reductions in both batteries and fuel cells, the costs for trucks running on hydrogen and electricity are expected to drop dramatically over the next decades. Car batteries costed 183 €/kWh in 2017 after having seen a >70% cost drop over in 2010.[470] Extrapolating 5% annual cost reductions, the price of batteries will drop below 100 €/kWh around 2025, which is in line with expectations by market experts[471]. In our evaluation of future battery costs for trucks we adopted a cost figure of 60 €/kWh in 2050 to determine the retail costs for EVs. For fuel cells we see similar cost-reduction speeds.
The US Department of Energy (DOE) set a target cost level at 40 $/kW (35 €/kW) for 2020 and a long-term goal of 30 $/kW (26 €/kW).[472] In our analysis we assume a conservative value of 35 €/kW for 2050. For the costs of hydrogen storage tanks, we used a conservative value of 9 €/kWh based of future price expectations from DOE.[473]

---

[469] Özdemir, *A model-based scenario analysis with respect to technical, economic and environmental aspects with a focus on road transport* (2011).

[470] Navigant Research, *Market Data; EV Market Forecasts 2017* (2017) & Bloomberg New Energy Finance, *Electric Vehicle Outlook 2018* (2018).

[471] Ecofys, *Support to R&D Strategy for battery-based energy storage* (2016) &

[472] US Department of Energy, *2018 Cost Projections of PEM Fuel Cell Systems for Automobiles and Medium-Duty Vehicles* (2018) & Vde, *Batteriespeicher in der Nieder- und Mittelspannungsebene* (2015).

[473] US Department of Energy, *DOE Technical Targets for Onboard Hydrogen Storage for Light-Duty Vehicles* (2018).

Table 67 Cost difference evaluation between battery electric and fuel cell truck compared to internal combustion trucks in 2050[469]

	BEV specifications and differential costs			FC truck specifications and differential costs		
	LCV	MFT	HFT	LCV	MFT	HFT
Battery capacity (kWh)[474]	*100*	*350*	*700*	*5*	*20*	*30*
Motor power (kW)	*120*	*250*	*320*	*120*	*250*	*320*
H_2 capacity (kWh)	-	-	-	*250*	*1,500*	*3,000*
No ICE (k€)	-9.7	-20	-26	-9.7	-20	-26
Diesel storage (k€)	-0.3	-0.5	-0.7	-0.3	-0.5	-0.7
Electric motor (k€)	2.3	4.7	6.0	2.3	4.7	6.0
Battery costs (k€)	6.0	21	42	0.4	1.6	2.4
Hydrogen storage (k€)	-	-	-	2.2	14	27
Fuel cell costs (k€)	-	-	-	4.2	8.8	11
Controllers and convertors (k€)	2.5	5.2	6.7	2	4	5
Total cost difference (k€)	**0.7**	**10**	**28**	**9.7**	**12**	**25**

Table 68 Cost difference evaluation between battery electric and fuel cell buses compared to internal combustion engine diesel buses in 2050[469]

	Battery electric buses		Fuel cell electric buses	
	Urban bus	Coach	Urban bus	Coach
Battery capacity (kWh)	*180*	*637*	*4*	*5*
Motor power (kW)	210	315	210	315
H_2 capacity (kWh)	-	-	*376*	*912*
No ICE (k€)	-17	-26	-17	-26
Diesel storage (k€)	-0.4	-0.7	-0.4	-0.7
Electric motor (k€)	4.0	5.9	4.0	5.9
Battery costs (k€)	11	19	0.3	0.4
Hydrogen storage (k€)	-	-	3.4	8.2
Fuel cell costs (k€)	-	-	7.4	11
Controllers and convertors (k€)	4.4	6.6	3.3	4.9
Total cost difference (k€)	**2.0**	**4.8**	**0.8**	**4.2**

Table 69 Cost difference evaluation between battery electric and fuel cell cars compared to internal combustion engine diesel cars in 2050[469]

	Battery electric cars		Fuel cell electric cars	
	Compact/medium	Large	Compact/medium	Large
Battery capacity (kWh)	*40*	*100*	*4*	*4*
Motor power (kW)	*100*	*150*	*100*	*150*
H_2 capacity (kWh)	-	-	*140*	*180*
No ICE (€)	-6,100	-9,200	-6,100	-9,200
Diesel storage (€)	-200	-200	-200	-200
Electric motor (€)	1,900	2,800	1,900	2,800
Battery costs (€)	2,400	6,000	300	300
Hydrogen storage (€)	-	-	1,300	1,600
Fuel cell costs (€)	-	-	3,500	5,300
Controllers and convertors (€)	2,100	3,100	1,600	2,400
Total cost difference (€)	**100**	**2,700**	**2,300**	**3,100**

[474] Battery capacities for electric trucks are based on specifications for existing cars (Tesla Semi, Chanje V8100, Volkswagen Transporter Electric, EMOSS EMS series and increased for LCVs and MFTs to overcome range issues. FC truck battery size estimated based on Agora, *Ensuring a Sustainable Supply of Raw Materials for Electric Vehicles* (2017) and CE Delft, *Zero Emission trucks* (2013).

Table 70 Vehicle retail costs (k€) and economic lifetimes (years) in 2050

	Trucks			Buses		Passenger cars	
	LCV	MFT	HFT	Urban bus	Coach	Medium/ compact car	Large/ executive car
Electric	30	67	145	373	462	22	38
Fuel cell	30	69	142	372	461	25	39
Biodiesel	29	57	117	375	463	-	-
Bio-CNG/LNG	29	62	126	371	457	24	37
Economic lifetime[475]	11	11	11	12	12	12	12

I.1.9 Maintenance costs

Vehicles with electric drivetrains, such as battery electric and fuel cell, require less maintenance compared to conventional diesel or CNG/LNG vehicles, because there are less moving parts and therefore less wear and tear and need for oil refills. In addition, the regenerative breaking in electric drivetrains not only reduces fuel consumption but also reduces wear of the brakes to allow a longer lifetime. The growing complexity of combustion engines, with fuel injectors and turbochargers, further increases the maintenance cost gap. Element Energy assumes 50% maintenance cost reduction of electric drivetrains compared to a combustion engine.[476] For trucks and buses we assume a more conservative estimate of one-third less maintenance and repair costs, based on interviews with experts done by CE Delft, resulting in 0.04 €/km maintenance costs for electric and fuel cell trucks and buses.[477]

Bio-CNG and bio-LNG trucks are also expected to have less maintenance costs than biodiesel trucks, because gas-based fuels burn cleaner and create less internal engine pollution. However, this difference will mostly impact long-term maintenance and vehicle lifetime.[478] For this study we will assume maintenance spent for CNG and LNG trucks to be at 0.05 €/km.

Batteries have finite lifetimes that depend on the type of battery, ambient temperatures, and number and types of charging cycles. Typically, end of lifetime is defined as the moment a battery capacity drops below 80% of its specified capacity. A battery lifetime that is shorter than the vehicle's lifetime will negatively impact the costs as it will require battery or vehicle replacement. It is, however, not yet clear whether current or future cars will require replacements of their battery packs during the life of the vehicle. Different types of batteries for vehicles have different maximum charging cycles that can range between 800 and 14,000.[479,480]

Currently, various battery electric vehicle manufacturers already provide guarantees on battery capacity for 8-10 years or a mileage of 160,000 km.[481] For its battery electric truck, Tesla announced a battery lifetime exceeding 1 million km, which is comparable to the lifetime of diesel trucks. Although this number is debated, car manufacturers are actively researching ways to improve longevity of batteries both via new battery technologies and by smart, lifetime conserving, charging cycles.

[475] IEA MoMo (2018), Özdemir, *A model-based scenario analysis with respect to technical, economic and environmental aspects with a focus on road transport* (2011) & ACEA - European Automobile Manufacturers Association: *Buses: Factsheet* (2017).

[476] Element Energy, *Low carbon cars in the 2020s: Consumer impacts and EU policy implications* (2016).

[477] CE Delft, *Zero emission trucks* (2013).

[478] Greenfleet magazine, *The Economics of Natural Gas Vehicles* (2015).

[479] European Commission, *FUTURE BRIEF: Towards the battery of the future* (2018).

[480] Technofi & RTE, *E-highway 2050, Modular development plan of the pan-European Transmission system 2050, D3.1* (2013).

[481] See for an overview e.g., greencarreports.com/news/1107864_electric-car-battery-warranties-compared

The impact of battery replacement will depend on whether individual modules or the entire battery pack should be replaced and whether there is a market for second hand car batteries that can reduce replacement costs.[482] It is possible to use second hand batteries from electric vehicles in other applications, such as in stationary energy storage[483], or to reprocess a battery to its original manufacturer specifications.[484,485,486] NREL expects a lifetime of second hand batteries in stationary applications that could be another 10 years.[487]

Considering vehicles that charge daily, such as buses and trucks, a minimum of 4,000 cycles are required over the vehicle's lifetime. In 2050, we assume that batteries will have lifetimes that require only a single replacement during a vehicle's lifetime. We also assume that the residual value of the battery is still considerable, with 75%-80% of the capacity still available for alternative applications. When assuming 50% residual battery value both for the replaced battery and the second battery, the total added costs for battery replacement to the vehicle owner would be zero.

I.1.10 Fuel costs

One of the key criteria for vehicle owners to decide on what type of truck to buy, are the operational costs, or running costs, of the vehicle. This is especially the case for trucks and buses that have large annual mileage. Running costs consist of bare fuel costs, costs that are related to fuel stations, and fuel distribution and costs for vehicle maintenance and operation.

Fuel costs

The costs for hydrogen are based on the midpoints in the projected costs for green and blue ranges as evaluated in Sections 2.4 and 2.5, being 44-61 €/MWh for green hydrogen and 36-63 €/MWh for blue hydrogen. Costs for biodiesel are based on a 75 €/MWh estimate for advanced biodiesel.[488] Cost for biomethane, 48-58 €/MWh, used in CNG and LNG trucks, is based on our analysis in Section 2.2.4.

To evaluate the fuel costs per trucks, buses, and cars, estimates of annual mileage, average payload, and fuel efficiency need to be considered. We adopted predictions on future fuel efficiency of diesel ICE from the IEA MoMo for different vehicles and adopted these for the differential fuel consumption for electric, fuel cell, and CNG/LNG as can be seen in the leftmost column of Table 71. Electric drivetrains are more efficient than conventional ones, which is reflected in the lower fuel consumption in BEVs and FCEVs. On top of that, fuel cells and batteries have a much higher efficiency than conventional engines. The resulting fuel efficiency for all vehicles is shown in Table 71.

---

[482] Element Energy, *Low carbon cars in the 2020s: Consumer impacts and EU policy implications* (2016).

[483] Richa, et al., *Eco-Efficiency Analysis of a Lithium-Ion Battery Waste Hierarchy Inspired by Circular Economy* (2017).

[484] European Commission, *FUTURE BRIEF: Towards the battery of the future* (2018).

[485] Ramoni, et al., End-of life (EOL) issues and options for electric vehicle batteries (2013).

[486] Ganter, et al., *Cathode refunctionalization as a lithium ion battery recycling alternative* (2014).

[487] NREL, Energy storage, *Possibilities for expanding electric grid flexibility* (2016).

[488] Based on a market forecast based on Ecofys, 2018. *Gas for Climate: how gas can help to achieve the Paris Agreement target in an affordable way* (2018) & Peter et al., *How to advance cellulosic biofuels: Assessment of costs, investment options and required policy support* (2015).

Table 71 Fuel consumption and mileage in 2050 for different fuel types (MWh/100km)[489,490]

	Relative fuel consumption	Trucks			Buses	Cars	
		LCV	MFT	HFT		Compact/medium car	Large/Executive car
Battery	0.36	0.034	0.094	0.14	0.11	0.020	0.021
Fuel cell	0.6	0.033	0.11	0.14	0.11	0.022	0.025
Biodiesel	1	0.054	0.19	0.25	-	-	-
Bio-CNG	1.14	0.059	0.20	0.27	0.22	0.045	0.049
Bio-LNG	1.14	0.059	0.20	0.27	0.22	-	-
Mileage (k km/y)		18	52	74	57-60	15	15

While the annual mileage for buses and coaches is comparable at 5,700 km and 60,000 km, respectively, their drive patterns differ strongly.[491] Buses have a large annual utilisation, with less daily driving kilometres, while coaches drive longer distances but at a lower utilisation. Although fuel consumption is comparable for these vehicles, the different driver patterns may impact the choice for the optimal fuel.

For cars, annual mileage of 15,000 km is assumed.[492] Note that the mileage depends on the type of car and whether the car is privately, or company owned. Private cars drive fewer kilometres per year than company owned cars. Mileage is also known to depend on the age of the vehicle and decreases as the car gets older or changes owner.[493] Typically, in cars with higher mileage the running costs have a larger impact on the total costs, whereas buying decisions for cars with low annual mileage depend stronger on the vehicle purchase price.

Fuel station costs

In 2050, we assume that an international encompassing distribution of fuel stations will be available for the fuels that will be used in the road transportation market. The costs of the fuel station will be factored into the fuel prices trucks pay. Actual costs per megawatt-hour of fuel will depend on utilisation of the stations. In our model we assume that stations will be operating in a mature market, which means that utilisation will be similar across the different types of fuels.

Costs for electric charging depend strongly on the charging strategy, which can differ between transport vehicles. We include separate sections on the battery charging strategies and our evaluation of their associated costs. The costs for the other fuels are listed in Table 72.

We evaluated the costs of biodiesel, bio-CNG, and bio-LNG based on the price breakdown estimates for current fuel stations that offer the fossil version. For LNG the costs for liquefaction and fuel distribution are incorporated in the fuel station costs. Costs for hydrogen fuel stations are still uncertain, as empirical data is still lacking, specifically related to operation and maintenance costs.[494]

---

[489] Özdemir, *A model-based scenario analysis with respect to technical, economic and environmental aspects with a focus on road transport* (2011).

[490] IEA Mobility Model.

[491] Özdemir, *A model-based scenario analysis with respect to technical, economic and environmental aspects with a focus on road transport* (2011).

[492] Element Energy, *Low carbon cars in the 2020s: Consumer impacts and EU policy implications* (2016).

[493] Ricardo-AEA, *Improvements to the definition of lifetime mileage of light duty vehicles* (2015).

[494] California Energy Commission & California Air Resources Board, *Joint Agency Staff Report on assembly bill 8: Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California* (2015).

Hydrogen fuel stations are more expensive than CNG because of the higher costs for compression, storage and distribution (CSD), related to the higher required pressure, more expensive storage material and need for refrigeration to support dispensing.[495] NREL estimates the costs for CSD to be around €22/MWh in 2020 under optimistic conditions.[496] Total fuel station costs for hydrogen will be larger when also the other fuel station components are included in the price. In our analysis we use the NREL estimate of €41/MWh for total hydrogen fuel station costs in 2025 for large fuel stations. [497]

The costs for CNG and hydrogen distribution are assumed to be similar and are based on transport via pipeline infrastructure. These costs are estimated to be around €2/MWh, based on the analysis of costs for pipeline infrastructure and gas compression as outlined in Chapter 6.6, and assuming a pipeline length of 150 km.

Table 72 Fuel costs per fuel type (€/MWh)

	Fuel costs	Fuel station	Distribution infrastructure	Total
Hydrogen	52	41[498]	2	**94**
Biodiesel	75	2[499]	Included in fuel station price	**90**
Bio-CNG	57	12[500]	2	**71**
Bio-LNG	57	26[500]	Included in fuel station costs	**83**

Battery charging strategies

Charging EVs can be done via various strategies, ranging from dedicated private charging installations to workplace or public or semi-public (e.g., shopping centres) locations, and at fast charging stations at important intersections or major routes.

We assume that the fast charging stations at major intersections and routes will perform a similar role as current fuel stations, providing opportunity charging when batteries are low. Fast charging capacities at 50 kW are already common in multiple EU countries, beyond that 175 kW and even 350 kW capacities are being implemented. Fastned has already deployed 350 kW chargers on a small scale in the Netherlands and Germany in 2018.[501] We assume that in 2050, fast chargers along highways will be implemented with at least 350 kW to allow short charging times.

[495] National Center for Sustainable Transportation, *The potential to build current national gas infrastructure to accommodate the future conversion to near-zero transportation technology* (2016).

[496] NREL, *Hydrogen Station Compression, Storage and Dispensing Technical Status and Costs* (2014).

[497] NREL, *Hydrogen Station Cost Estimates* (2013).

[498] NREL, *Hydrogen Station Cost Estimates* (2013).

[499] RAC foundation, *Daily pump prices* (2018).

[500] Transport and Travel research, *Biomethane for Transport – HGV cost Modelling* (2011). Costs for liquefaction of methane into LNG are included as fuel station costs.

[501] Electronics weekly, *This is what 350kW charging looks like* (2018).

The investment costs for a 350 kW fast charger are around 250 k€,[502] which evaluates to 21 €/MWh assuming maintenance and operational costs of 3%/capex and 50% utilisation. The electricity infrastructure needs to be reinforced to deliver the required power to the fast charging station, which results in infrastructure costs. We assume there will be multiple fast chargers sharing a single grid connection, and infrastructure related costs around 100 k€ for an individual 350 kW charger,[503] based on Wainwright et al.[502] Assuming annual infrastructure operational costs of around 1.5%/CAPEX and a utilisation level of 50%, the infrastructure costs evaluate to around 5 €/MWh.

At locations where vehicles spend more time, e.g., at parking spaces, the power of the charging station can be less. Which specifications and type of charging is most relevant depends strongly on the type of vehicle and associated charging strategy, and will be discussed for each vehicle type separately. An overview is provided in Table 73.

Table 73 Electricity costs for different charging strategies (€/MWh)[502]

	Fuel costs	Fuel station	Distribution infrastructure	Total
Fast charging	69[504]	15	6	**84**
Overnight charging trucks		14	5	**82**
Depot charging buses		26	14	**103**
Private car charging		23	0	**86**

Charging strategy for trucks

Especially for long-haul medium and heavy freight trucks, opportunity charging at public fast charging stations will not be desirable as it will still take too long to fill the 700 kWh battery. We assume that charging stations will only be frequented in case an extension of the daily range is required and the charging can be combined with required resting times. [505] We assume that batteries for these kinds of trucks will all be charged overnight at public or private overnight parking. Electric truck fleet owners or owners of overnight parking locations will invest in charging stations to accommodate overnight charging. Considering limitations to daily driving timesy as set forth by EU regulation No 561/2006, truck drivers will have at most 10 hours of daily driving and required 45 min resting periods every 4.5 hours. Combined with fast charging during resting hours, a 50 kW charger should be sufficient to charge the vehicle overnight for most trucks, with an exception to special or heavy ones.

The costs for a 50 kW charging station of 20 k€[506,507] are evaluated to be around 15 €/MWh for a 80% utilisation level. Considering grid investment costs of 10 k€[508] per charger, results in 5 €/MWh costs for the electricity infrastructure.

Our cost analysis indicates that private overnight charging and public fast charging have comparable costs/MWh. For the remainder of the study we will assume that for each battery electric truck type a charging strategy will be adopted that result in the lowest total fuel costs or an optimal fit to the vehicle drive pattern. We will take a fuel cost of 100 €/MWh for electric trucks.

---

[502] Wainwright, et al. *Clean Power for Transport Infrastructure Deployment* (2017).

[503] These costs are quite high when compared to the 270€k investment costs for a 10 MW new connection as listed by Dutch DSO Liander.

[504] Based on the analysis performed in Section 5.2.

[505] Earl, et al. European Federation for Transport & Environment, *Analysis of long haul battery electric trucks in EU* (2018).

[506] Ecofys/Navigant research for the TRAN committee of the European Parliament, *Charging infrastructure for electric road vehicles* (2017).

[507] Wainwright, et al. *Clean Power for Transport Infrastructure Deployment* (2017).

[508] Based on Liander tariffs for a new electricity connection.

Charging strategy for buses
The driving pattern for urban buses and coaches is different. Coaches typically have a higher number of passengers and travel longer distances during the day. We assume that coaches will have a charging strategy that is similar to medium and heavy trucks, using low power overnight charging combined with opportunity fast charging to extend the driving range.

Opportunity charging at public fuelling stations will not be a feasible option for urban buses. Waiting times are too long and fuelling stations will not always be located close to the bus routes. We assume that buses will mostly recharge their batteries in the depot during overnight parking. Urban buses are used intensely during the day, which means the number of overnight hours available for charging can be limited. Assuming 5 hours of charging time, a 180 kWh bus requires at least a 36 kWh charger. For our analysis we assume buses will be connected to 50 kW chargers while in the depot. Due to smart software and taking into account the battery status and shift times of individual buses, the charger can charge more than one bus. We assume that a single charger can be used by 1.5 buses on average. This charging strategy results in 25 €/MWh for the charger and 14 €/MWh for the infrastructure.

We consider the cost estimates of overnight charging in the depot to be conservative and believe that costs could go down by carefully designing the charging infrastructure in bus depots against electricity demand and adding smart charging software to optimise use of charging assets. Given the price difference between overnight charging in the depot and fast charging, it may also be cost-effective to change bus shifts to allow public fast charging instead of depot charging.

For our analysis we will use a total electric fuel cost of 101 €/MWh for coaches and a cost of 120 €/MWh for urban buses.

Charging strategies for cars
Expected battery electric vehicle driving ranges are around 250-450 km in 2030,[509] which is sufficient for everyday use of over 95% of all daily driving distances.[510] This range can be extended by charging at work locations for commuting traffic. For occasional long-distance travel, 350 kW fast charging is a convenient solution, allowing a complete refill under 20 minutes, which we believe is sufficiently short when combined with resting times.

This means that overnight private charging will be sufficient for most electric car use. Daily travel beyond the battery driving range will require opportunity fast charging at a public fuel station, or, for commuting traffic, charging at the work location.

A more convenient option for owners of private parking places would be private charging. Considering the average mileage of private cars of 15,000 km, the average daily recharging demand will be under 10 kWh, which can easily be recharged using an existing home electricity grid connection. Assuming a €600 home charger, charging costs are around 23 €/MWh, which is comparable to public fast charging costs. It will depend on the impact of energy taxes and the possibility to consume self-generated electricity whether home charging will become more competitive compared to public fast charging.

---

[509] Element Energy, *Low carbon cars in the 2020s* (2016).

[510] Özdemir, *A model-based scenario analysis with respect to technical, economic and environmental aspects with a focus on road transport* (2011).

A third option for charging passenger cars is to use charging infrastructure at public parking spaces or at the work location for commuting traffic. These charging locations will have low or intermediate powers. We expect charging costs per megawatt-hour to be higher than costs for fast charging and home charging. We expect that new charging strategies will develop for public charging that drive costs down, for instance by using fast chargers at parking spaces near shopping centres that allow smart charging of multiple vehicles, which could make public charging more attractive. For the remainder of the analysis we assume that fast charging will be the charging strategy of choice for private cars at a cost of 101 €/MWh.

I.1.11 Societal costs for road transport for different fuels

Figure 73 shows the societal costs for vehicles for different renewable and low-carbon fuels, based on the evaluation of the cost factors as described in Section I.1.7.

Despite the higher costs/MWh in battery and fuel cell electric vehicles, total running costs are low compared to bio-CNG, bio-LNG and biodiesel because of the higher fuel conversion efficiencies in the electric motors. The impact of this improved efficiency on the societal costs becomes especially large for vehicles that have higher annual mileage, such as medium and heavy trucks and buses. For all transportation modes, the use of electricity in BEVs is the most cost-effective solution from total societal costs perspective, with FCEVs coming second. Overall the differences between fuel options are very small, especially considering the uncertainties in assumptions and potential future impact of taxes and policies. We note that, especially in freight transport, the variety in vehicle types and driving behaviour can be quite different from case to case. For all vehicles a decision on fuel options will not be made on societal costs alone, but also other factors will play an important role, as discussed in Appendix I.1.12.

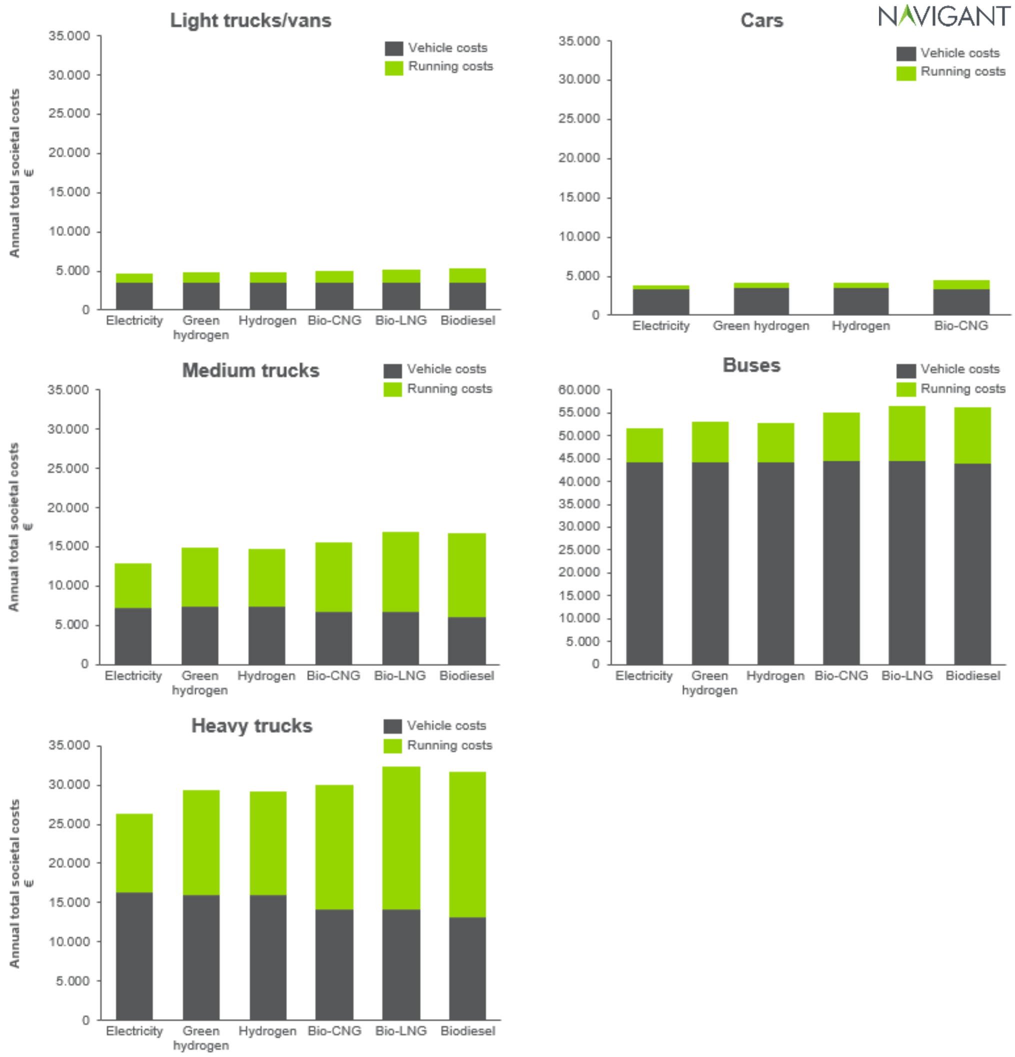

Figure 73 Overview of the total societal costs for different transport modes and different fuel options

I.1.12 Other factors impacting the optimal fuel mix in road transport

The lifetime of road vehicles is relatively short compared to other modes of transport, and ranges between 11-13 years. It will be possible to decarbonise all road transportation in 2050 just by replacing vehicles at their end of life if suitable renewable and low-carbon fuel options and related infrastructure become available before 2040.

The purchase choice depends on a variety of factors. The primary factor is usually cost, which is broken out into purchase and maintenance costs, fuel taxes and duties, and the availability of financial support in terms of subsidies, existence of fuel infrastructure, and availability and readiness of technologies.

The decision on what fuel type a vehicle owner buys will not only depend on the lowest societal costs. Especially since total societal costs are quite comparable for most fuel types, other factors will have a key impact on the future fuel mix. Some of these factors are often expressed as costs by freight operators, such as available payload or transport volume. The costs that are allocated to these factors, however, differs from application to application. Thus, we will only discuss them qualitatively and use that as a correction factor to combine with the societal costs to determine the optimal fuel mix in 2050.

The impact of maximum available payload and storage volume and refuelling times
For BEVs, the battery weight will be an important factor to take into account, especially when combined with the persons or goods that need to be transported, it approaches the maximum gross vehicle weight. Available payloads and freight storage volumes will play an important role in many medium and heavy freight trucks, limiting the applicability of batteries. This is especially the case when considering long-haul transport. For a long-haul electric HFT with a battery pack of 1,000 kWh the battery pack weight would be around 4.1t or 10% of total gross vehicle weight.[511] However, an electricity powered truck will no longer require a diesel engine and transmission system, which reduces the weight by around 3 tonnes. Nevertheless, especially for long-haul transport applications, the reduced maximum payload may be a key reason for not choosing a battery electric truck. Because of the potential limitations batteries may give in terms of maximum available payload, we assumed lower adoption for EVs for HFTs and MFTs compared to what could be assumed based on lowest societal costs. The use of hydrogen in MFTs and HFTs will offset the weight restrictions that BEVs may have for specific long-haul applications. For very demanding applications in terms of driving distance or available freight volume bio-LNG can be an option in MFTs and HFTs.

When considering the factors influencing the choice between hydrogen, bio-CNG, bio-LNG and biodiesel we note that bio-CNG appears to have no advantages over hydrogen for use in vehicles: CNG vehicle fuel efficiency is lower than in fuel cell vehicles and refuelling times for CNG and hydrogen are similar. We expect that in case BEVs are not feasible, FCEVs will be the most attractive alternative option. Despite the higher costs, bio-LNG and biodiesel could also be attractive, based on the advantages they bring in terms of higher energy densities and faster refuelling speeds. However, it will be expensive to deploy and maintain parallel fuel infrastructures, especially if the market demand for them will be limited.

MFTs and HFTs are designed for a wide range of purposes, which require different types, volumes, and payloads and as many required driving ranges.[512] We expect that batteries will be a good and cost-effective option for a share of vehicles in these categories. In situations where EVs can be deployed, their specifications will be tailored to a specific use with a battery that is sized to match its purpose, resulting in even lower societal costs than the vehicle category average evaluated in this study.

The weight of the battery is less important for buses, light commercial vehicles, and cars, as these are designed to move relatively light loads and passengers. In LCVs, costs for BEV and FCEV are comparable, which leads us to assume comparable penetration of BEVs and FCEVs. We expect nearly full electrification for passenger cars and also for urban buses, in line with predictions by Balard that the market for zero emission buses could grow to 10,000 annually by the mid-2020s.[513]

Nearly all urban buses will be battery electric with overnight recharging. In coaches that drive longer distances, we expect a mix between battery electric and hydrogen fuel cell buses due to their higher range and shorter acceptable refilling time.[514,515]

[511] Earl, et al. European Federation for Transport & Environment, *Analysis of long haul battery electric trucks in EU* (2018).

[512] IEA, *The future of trucks* (2017).

[513] Balard Power Systems: *Economic Case for Hydrogen Buses in Europe* (2017).

[514] CIVITAS, *EU Policy note: Smart choices for cities Alternative Fuel Buses* (2016).

[515] Transport and Environment: *Roadmap to climate-friendly land freight and buses in Europe* (2017).

Decision factors on passenger cars
To passenger car owners, the purchase price of a vehicle is the more important factor to determine a purchase than the total societal costs, or even running costs.[516] In fact, some studies suggest that lower running costs are largely ignored by the mass market.[517] Despite this effect, we expect the vehicle purchase costs of passenger cars for different fuel options to be so close in price that running costs will be factored in more than currently and that the majority of people will choose an electric car.

Driving range is a key selection criterium when it comes to considering BEVs over alternatives, even though the maximum vehicle range is only required for less than 5% of all travel. Part of the range anxiety will be taken away be having a mature fast charging infrastructure, consisting slow charging infrastructure and fast charging infrastructure, e.g., 25 minutes of fast charging at 350 kW will be sufficient to fill the battery for another 700 km of driving in a large car.

Automated vehicles
Car manufacturers are developing technologies for automated driving, which could have a large impact on the driving behaviour of vehicles and therefore their optimal fuel choice. In addition, the ownership model of passenger cars could change from personal ownership to carsharing, carpooling, or mobility as a service (MaaS), which hold the potential to revolutionise vehicle use. A common view on these developments is that all favour the use of BEVs because of higher annual mileage and therefore even stronger impact of the low running costs of BEVs.[518] Autonomous driving will also heavily impact the number of available vehicles and required charging points. For automated long-haul trucks and buses, hydrogen or hybrid electric trucks using catenary lines will be more advantageous due to the low running costs and refuel times.

I.1.13 Optimal fuel mix

In determining the optimal fuel mix in vehicles in 2050, we take into account the impact of both costs and other decision factors. Starting with the most cost-effective solution for vehicles: if vehicles can be electrified via batteries, this will be the technology of choice given the lowest societal costs for BEVs. This effectively results in a near full electrification of urban buses, cars, and half of the light commercial vehicles. We expect that the remaining fuel types will be based on hydrogen as the next cheapest option, with less restrictions in available payload and duration of refuelling. A small share of the car market will be based on hydrogen fuel cell vehicles, especially in the large/executive car segment. We estimate the total potential to be around 10% of the large/executive car segment, which is roughly equal to the expected percentage of executive cars in 2050. For coaches that operate both on a regional level and on an international level, we assume that these will be predominantly based on FCEV, resulting in 75% of the total bus stock being battery electric, as can be seen in Table 74.

Table 74 Estimated percentages of vehicle fuel options based on an evaluation of total societal costs and other decision factors

	Trucks			Buses	Cars	
	LCV	MFT	HFT		Compact/ medium car	Large/ Executive car
Battery	90%	30%	30%	75%	100%	90%
Fuel cell	10%	70%	70%	25%	0%	10%
Biodiesel	0%	0%	0%	0%	0%	0%
Bio-CNG	0%	0%	0%	0%	0%	0%
Bio-LNG	0%	0%	0%	0%	0%	0%

516 Element energy, *Electric Vehicles: Strategies for uptake and infrastructure implications* (2009).

517 Kurani, et al., *Driving Plug-In Hybrid Electric Vehicles: Reports from U.S. Drivers of HEVs converted to PHEVs, circa 2006-07* (2008).

518 IEA, *Global EV Outlook 2018, towards cross-modal electrification* (2018).

Determining the future fuel types of freight trucks is more complicated, as these trucks perform a wide variety of services, covering regional and international transport, both dense and heavy and light and voluminous transport with many different drive patterns, ranging from local garbage collection vehicles to international transport of food products and metal ores. The optimal fuel type vehicle will depend heavily on the characteristics of the freight transport application.

Based on an analysis of Eurostat data for 2017, we conclude that the dominant long-haul transport applications in Europe in terms of tonne-km are food and agricultural products transport.[519] IEA MoMo predicts 80% of all MFTs to be predominantly urban[520] and 40% of all tonne-km in 2017 were over a distance of less than 300 km.[521] Considering the distribution of road freight transport distances driven, only in 37% of the cases the distance is more than 500 km and only in 13% more than 1000 km. It seems reasonable to expect that most of that local and regional transport can be done using battery electric trucks, which will be the lowest cost option. This indicates that a driving range of 800 km, as specified by for instance the battery electric Tesla semi on a single charge, is sufficient for most applications.[522]

Despite this we adopt a conservative estimate of the adoption of BEV freight trucks, of just 30%. This number is comparable, but higher than assumed in a report by the German Bundesministerium für Verkehr und digitale Infrastruktur (BMVI), however lower than assumed by Eurelectic in their decarbonization pathways.[523,524] We expect that the remaining trucks will be fuel cell trucks, being the next cheapest option.

Based on the relative vehicle fuel options in 2050, we determine a total fuel demand as shown in Table 75.

Table 75 Fuel demand for vehicles in 2050 (TWh)

	Trucks	Buses	Cars	Total
Electricity	128	37	483	**619**
Hydrogen	189	21	42	**300**
Bio-LNG	134	0	0	**134**
Total	**470**	**58**	**525**	**1,053**

Fuel demand for transport is strongly linked to other various other developments in the transport sector.[525] These developments cannot be predicted for the next 35 years. We provide a qualitative description below of potential developments and how they would impact the results.

As the cost drivers for vehicles on renewable and low-carbon fuels vary with the vehicle type, our results are sensitive for cost developments and innovations that could occur in the next 30 years. Markets for biomethane, hydrogen, and biodiesel are still in development, which means that future price levels are still uncertain and could be impacted heavily by the amount of policy support, attractiveness for the fuel producer, and potential over or under-supply compared to market demand.

---

[519] Eurostat, *Annual road freight transport by distance class with breakdown by type of goods in 2017* (2019).

[520] IEA Mobility Model (2018).

[521] Eurostat, *Road freight transport by journey characteristics in 2017* (2018).

[522] www.Tesla.com

[523] Fraunhofer-Institut & E4tech, *Studie IndWEDe Industrialisierung der Wasserelektrolyse in Deutschland: Chancen und Herausforderungen für nachhaltigen Wasserstoff für Verkehr, Strom und Wärme* (2018).

[524] Eurelectric, *Decarbonisation pathways* (2018).

[525] LBST & DENA, *The potential of electricity-based fuels for low-emission transport in the EU* (2017).

Development of catenary lines along the major transportation routes in Europe would increase the adoption of hybrid electric trucks, mostly HFTs and potentially also long-distance hybrid electric coaches. This shift will further increase the use of electricity and will reduce the demand for other fuels.[526] We expect that implementation of trolley bus infrastructure for urban buses will replace battery electric buses, and therefore not result in a change in the optimal fuel mix for buses.

In the development of a fuelling station infrastructure, a key question is the how the gas-based fuels, biomethane and hydrogen can be delivered to the fuel station. The use of pipeline infrastructure to transport gases to fuel stations over the use of delivery trucks will lower societal costs. As this infrastructure is not yet available there could be a role for gas transport and distribution companies to facilitate and steer this development and enable pipeline infrastructures along major transportation routes.

Availability of raw materials

Batteries and fuel cells are constructed using various materials that have finite global reserves. Assuming that current battery and fuel cell technologies will still be the dominant technology in 2050, the materials nickel, cobalt, lithium, graphite, and rare earth elements in batteries and platinum in fuel cells will be critical in the development of these systems.[527] Agora concluded in 2017 that the projected demand for these materials for the road transport sector in 2050 is much lower than the known reserves and even lower than estimated global resources.[528] Even when assuming much larger amounts of EVs, the material reserves and resources are sufficient by an order of magnitude. A growth in demand will also develop more recycling of materials and additional exploration of yet unknown resources. For lithium-based batteries, the European Commission states that the known lithium reserves are enough to cover the future demand even without its recovery.[529]

There are a number of other materials (rare earths, manganese, tin, magnesium, germanium), that need to be closely monitored in case their role in batteries rapidly increases.[529] Some rare earth materials that are used in electric motors have known supply chain and resource issues; however, in recent years alternatives have been developed that can be implemented when rare earth supply will become insufficient.[530]

While global reserves are sufficient, there could be limitations in the upscaling speed of the supply to accommodate the growth in demand for batteries and fuel cells.[531] We did not take these potential barriers into account in this study.

[526] European Climate Foundation, *Trucking into a Greener Future: the economic impact of decarbonizing goods vehicles in Europe* (2018).

[527] Cobalt, natural graphite, silicon metal, rare earth elements and platinum, which are used in emerging vehicle technologies are listed as critical raw materials (CRMs) by the European Commission. EC, *Critical Raw Materials* (2017).

[528] Agora, *Ensuring a Sustainable Supply of Raw Materials for Electric Vehicles A Synthesis Paper on Raw Material Needs for Batteries and Fuel Cells* (2017).

[529] European Commission, *Report on Raw Materials for Battery Applications* (2018).

[530] Agora, *Ensuring a Sustainable Supply of Raw Materials for Electric Vehicles A Synthesis Paper on Raw Material Needs for Batteries and Fuel Cells* (2017).

[531] The vulnerability of the supply markets is the main challenge especially since Europe heavily depends on importing raw materials mostly from third countries.

I.2 Shipping

I.2.1 Introduction

The EU shipping sector is responsible for 4.5% and 5% of EU greenhouse gas emissions and EU energy demand, respectively.[532,533] According to the International Transport Forum greenhouse gas emissions from international shipping could more than triple if no decarbonisation measures are taken.[534] Together with aviation the shipping sector was not covered in the Paris Agreement. Cheap heavy fuel oil is currently the most used fuel in the shipping sector and in the past the International Maritime Organisation (IMO)[535] focused on reduction of sulphur and NO_x emissions. In April 2018, the IMO set a target to halve the total greenhouse gas emissions of the global shipping sector in 2050 compared to 2008 values and outlined a vision to fully decarbonise shipping between 2050-2100. The process for implementing these targets in regulatory measures is currently ongoing. In addition, relevant shipping companies start to develop climate targets. Maersk, the world's largest container shipping company, has set a target to achieve zero greenhouse gas emissions in its operations by 2050.[536]

The aim of this section is to assess the expected 2050 energy demand in EU shipping and to develop a scenario for a decarbonised shipping energy mix with associated fuel costs, fuel station, and related energy infrastructure cost. Due to the large variety of vessels calling at EU ports a simple cost assumption for vessels with different fuels and engines is out of scope.

Most existing scenarios on future energy demand for shipping do not aim for full decarbonisation in 2050 and often have a global scope not providing figures for the EU. We therefore built our analysis on most ambitious scenarios for decarbonisation with EU scope and add assumptions and explore what is required for full decarbonisation. Changes in three areas can be implemented in parallel to achieve full decarbonisation: 1) Optimising the use of available shipping capacity, 2) Maximising the energy efficiency potential and 3) Using renewable and low-carbon fuels. The focus of this assessment is on renewable and low-carbon fuels with a special focus on renewable gas, i.e., for shipping hydrogen and bio-LNG.

I.2.2 Scope of analysis

The scope of this assessment is EU shipping meaning ships fuelling in the EU. EU shipping is further differentiated in the following subsectors below, each with different fuel requirements for decarbonisation:

- **Domestic shipping** characterised by smaller ships and short routes. Electrification, advanced biodiesel, bio-LNG, and hydrogen are possible fuel options to decarbonise domestic shipping.
- **Intra-EU shipping** covering ships with relatively short routes, typically operating in limited geographical areas with frequent port calls on a regular schedule. The fuel choice will depend on the operating profile of the respective segment. Ships on short routes have the same fuel options for decarbonisation as domestic ships. For ships operating on longer routes electrification is not an option but advanced biodiesel, bio-LNG, and hydrogen are potential fuel options.

---

[532] The reported EU GHG emissions in 2015 are 4.45 $GtCO_2e$ which include emissions from international aviation and shipping but exclude net emissions from the LULUCF sector. https://www.eea.europa.eu/data-and-maps/indicators/greenhouse-gas-emission-trends-6/assessment-1

[533] Total EU energy demand in 2015 is around 12,886 TWh whereas the energy demand in EU shipping sector is 640 TWh.

[534] International Transport Forum, Reducing Shipping Greenhous Gas Emissions, 2018.

[535] The International Maritime Organisation (IMO) is a specialised agency of the United Nations for regulating shipping.

[536] https://www.maersk.com/en/news/2018/12/04/maersk-sets-net-zero-co2-emission-target-by-2050

- **Outbound-EU shipping** including large ocean-going vessels with long routes and often without a regular schedule. International shipping requires a globally available fuel with the right fuelling infrastructure with high energy density to maximise the space available for cargo transport over long distances.[537] We therefore assume one dominant renewable and low-carbon fuel for outbound-EU shipping.
- Inbound-EU shipping is not covered as the bunkering will take place outside the EU.

We build upon data from Transport and Environment (T&E)[538] regarding energy demand in 2050 for these subsectors. Our own fuel cost assumptions will be used to establish the most cost-optimal net-zero emissions energy mix in 2050. The estimated energy demand in 2050 depends on the fuel mix, due to the different efficiencies of the fuels. We will use the efficiency as a ratio to internal combustion engines as provided by T&E but will adjust the efficiency of fuel cells and will add the efficiency for LNG respectively bio-LNG.

I.2.3 Expected energy demand and respective fuel mix in EU shipping by 2050

IEA's Mobility Model (MoMo) reports an energy demand for EU freight shipping of **375 TWh in 2015**, which covers outbound EU shipping and intra EU shipping for selected member states, i.e., Germany, UK, Italy, and France. Any other intra-EU shipping or domestic shipping is not covered. In a below 2°C scenario aiming for carbon neutrality in 2060, the IEA MoMo forecasts an energy demand of **202 TWh in 2050**. Main assumptions are a reduction in trade due to lower demand for trade in fossil fuels, which globally accounts for one-third of maritime trade in volume, and 30% efficiency gains after 2030. IEA forecast that 48% of fuel share will be marine diesel, advanced biodiesel will have the same share, and heavy fuel oil will drastically decline to 4%. Hydrogen is seen as an additional option for CO_2 reduction but not part of the fuel mix 2050. The reasons for excluding hydrogen are "uncertainties on costs of technologies requiring the use of hydrogen as energy carrier" and "expectations for higher barriers for the wide-spread adoption of hydrogen across the energy system." Due to limited greenhouse gas abatement potential, limited current uptake, and the need to significantly invest in an infrastructure with expected high likelihood of being stranded soon, IEA sees a neglectable role for LNG in the fuel mix for 2050.[539] A further disadvantage is limited load capacity of an LNG fuelled ship, as the fuel tank is two to three times bigger than a fossil fuel tank. However, setting up an LNG infrastructure offers a future option for decarbonisation by substituting LNG with bio-LNG.

In a recent study from November 2018, T&E assessed the effects on the demand for renewable electricity in Europe to produce carbon neutral fuels for a full decarbonisation of EU shipping in 2050. The scope of the study is national, intra-EU, and outbound EU shipping for passenger and freight according to the definition of EU-related shipping in the EU 2015 ship MRV Regulation. T&E assumes that despite efficiency gains, energy demand for EU-related shipping will grow by 50% compared to 2010. In total eight technology pathways have been modelled. T&E thinks that using an LNG infrastructure for future distribution of renewable and low-carbon fuel provides "insurmountable regulatory challenges for ports and flag states to ensure compliance," especially as the renewable and low-carbon fuels are much more expensive than their fossil counterpart. In addition, T&E wants to reserve sustainable biofuels for aviation, so biodiesel and bio-LNG are not covered in the future fuel mix. For this study, we consider T&E's "full hydrogen fuel cell" and "technology fuel mix" scenarios.[540]

[537] DNV GL, Maritime forecast, 2018.

[538] Transport & Environment, Roadmap to decarbonising European shipping, 2018.

[539] OECD submission to the IMO Intersessional Working Group on GHG emissions of September 2017.

[540] We have selected these two scenarios as they would have the lowest impact on additional primary energy demand.

The latter assumes 100% battery electric national shipping, 50% battery electric and 50% liquid hydrogen for intra-EU shipping, and 50% hydrogen and 50% ammonia used in fuel cells for outbound EU shipping. Note that T&E assumes liquid hydrogen and liquid ammonia are used due to their benefits in terms of energy storage,[541] whereas we assume gaseous hydrogen due to high energy consumption and costs for liquefaction.

T&E sums up the energy demand from EU shipping and the energy needed to produce the respective fuels. We refer to the energy demand from EU shipping from T&E for the relevant scenarios in

Table 76. Whereas T&E assumes a fuel cell efficiency of 50%, we assume 60%. All other parameters remain unchanged.

Table 76 EU shipping energy demand 2050 in T&E scenarios (TWh)[542]

Sub-sector	Full hydrogen scenario	Technology mix scenario
Domestic shipping EU	91	60
Intra-EU shipping	186	155
Outbound-EU shipping	223	223
Total	**500**	**439**

Table 76 shows that the energy demand in 2050 depends on the respective fuel mix and engine. With **439 TWh–500 TWh** the total energy demand for EU shipping estimated by T&E in the two considered scenarios is higher than the energy demand estimated by IEA. Considering the different scopes, the gap between IEA and T&E is in fact smaller. Domestic shipping is not covered by IEA, nor is intra-EU shipping except for shipping between defined EU member states. For this reason, a comparison between the two is only possible for outbound-EU shipping with a range from 202 TWh(IEA)–223 TWh.

As T&E also covers passenger and freight, whereas IEA only covers freight, we assume that by 2050 energy demand for outbound EU shipping will be **223 TWh.**

When at berth, ships typically use the auxiliary engines of the ship to generate electrical power for communications, lighting, ventilation, and other on-board equipment. Boilers are also used, for instance for hot water supply and heating. Shore side electricity (SSE) is an option for reducing the unwanted environmental impact of ships at berths, i.e., greenhouse gas emissions, air quality emissions, and noise pollution of ships using their auxiliary engines. In a previous study, Ecofys estimated that SSE for all seagoing and domestic ships in European harbours in 2020 would result in 3.5 TWh energy demand annually.[543] Installed SSE at all EU ports and respective equipment at all ships calling at EU ports will reduce overall fuel demand for EU shipping. However, compared to the estimated overall energy demand for EU shipping in 2050 the effect is limited, even assuming an increase for SSE.

[541] Transport & Environment, Roadmap to decarbonising European shipping, 2018.

[542] Own calculations in-line with methodology by T&E, but we assume a fuel cell efficiency of 60%, whereas T&E assumes 50%.

[543] Ecofys, Potential for shore side electricity in Europe, 2015.

I.2.4 Fuel mix in international shipping scenarios for 2050

IMO and DNV GL also published scenarios on shipping in 2050. Due to their scope on international shipping without regional differentiation, we could not use these scenarios for our assessment on EU shipping. We like to outline their respective fuel mixes in 2050.

IMO projects 16 different scenarios for international shipping, which assume an increase in CO_2 emissions by 2050 when compared with the baseline emissions from 2012. It is important to stress that the IMO scenarios have been developed before the announcement for greenhouse gas reduction, which explains the focus on sulphur and NO_X reduction. Carbon reduction is not included. Their high LNG scenario has a share of 25%, while the remaining share is 40% heavy fuel and 35% marine diesel. [544]

The latest annual maritime forecast of DNV GL for international shipping assumes that the target of IMO for halving greenhouse gas emission will be met in 2050. With a share of 39% carbon neutral fuel will have the highest share in the 2050 fuel mix followed by heavy fuel with 34% and LNG and LPG with 23%.[545]

I.2.5 Establishing the most cost-optimal net-zero emissions energy mix

Several European states are testing battery electric ships for domestic shipping. For example, the Norwegian ferry sector will operate 60 battery electric ships in the next few years.[546] Electrification is suitable for domestic shipping due to short routes and small ships. We expect that the current trend will continue and assume **100% electrification for domestic EU shipping in 2050**. Battery electric ships are almost twice as efficient as ships with an ICE. We expect that the higher fuel efficiency will offset the higher price for the vessels, especially considering the average economic lifetime of 20-25 years. Electrification is the preferred option for decarbonisation and should be applied as far as technically possible. Our assumed electricity price in 2050 is 69 €/MWh. Based on data for the first electric ferry[547] and first electric cargo ship,[548] we assume that battery electric ships would require a 1,000 kW charger. We also assume maintenance and operational costs of 3%/CAPEX and 50% utilisation. Although the investment costs for the 1,000 kW charger will be higher than for a 350 kW fast charger for cars, we expect that the cost per megawatt-hour will be the same, as more energy will be consumed. We assume that high power infrastructure will be provided at all EU ports in 2050 due to industry located at ports, so that the additional infrastructure costs for charging battery electric ships will be limited. Therefore, we assume the same fuel station and infrastructure costs as for 350 kW fast charging of cars, i.e., 15 €/MWh fuel stations costs and 6 €/MWh infrastructure costs. The total costs of electricity for shipping sum up to 90 €/MWh. In order to identify the most cost-optimal fuel, we calculate the comparable fuel costs, which are the sum of cost of the fuel, infrastructure and distribution as well as fuel station costs, divided by the efficiency of the fuel. The comparable fuel cost for electricity is 46 €/MWh.

For intra-EU shipping the situation is more complex. Part of intra-EU shipping has similar characteristics as domestic shipping and will also electrify. We follow T&E's assumptions that passenger ferries and smaller cargo ships will prefer battery electric propulsion in short-sea shipping and also assume that in their technology mix scenario that **50% of intra-EU shipping in 2050 will be electrified**. The remaining energy demand will be generated by ships on long routes within intra-EU shipping. A variety of renewable and low-carbon fuels is possible, as are different fuels for different segments or even operators, provided they stick to a regular schedule.

---

[544] IMO, Third IMO GHG Study 2014-Final Report. https://www.cedelft.eu/publicatie/third_imo_ghg_study_2014/1525

[545] DNV GL, Maritime forecast, 2018.

[546] DNV GL, Maritime forecast, 2018.

[547] https://www.ship-technology.com/projects/norled-zerocat-electric-powered-ferry/

[548] https://safety4sea.com/china-launches-first-fully-electric-cargo-ship/

Intra-EU ship operators are expected to choose the most cost-competitive option. The fuel choice for international shipping will also have an effect on the fuel choice for intra-EU shipping, as international shipping will drive the set-up of a designated infrastructure.

International shipping requires a uniform fuelling option with a fuel that is globally available in sufficient quantities to allow fuelling up large ships in every port worldwide. Establishing various different fuelling options would be costly from a vessel technology perspective and from an infrastructure perspective.
We do not see a role for electrification for international shipping due to the long routes, but any other renewable and low-carbon fuel is possible. With fuel costs being the main driver, we expect that there will be **one dominant fuel for outbound-EU shipping in 2050**.

There have been several tests for hydrogen fuel cell ships, but no commercial application yet. Aside from small ferries and demonstration projects there are hardly any commercial hydrogen-fuelled ships. In 2017, Swedish Viking Cruises announced plans to build the first hydrogen-fuelled cruise ship.[549] In addition to zero emissions hydrogen fuel cell ships also reduce noise and vibrations and require less maintenance. The current efficiency of fuel cells is 50%-60%.[550] For 2050, we assume a fuel cell efficiency of 60% which results in a 30% higher efficiency for hydrogen fuel cell ships compared to ICE ships. However high investments in new ships and specifically designed bunkering systems are required. As stated in Section 2.4 the production costs of green hydrogen in 2050 are on average 61 €/MWh (52 €/MWh production, 8.6 €/MWh integration) when produced in dedicated plants. Costs for hydrogen infrastructure and distribution of 2 €/MWh plus 41 €/MWh fuel station costs have to be added. Total cost for hydrogen in 2050 sum up to 104 €/MWh. The comparable fuel cost for hydrogen is 80 €/MWh.

T&E also mentions ammonia in its 2050 fuel mix. The costs for ammonia would be even higher than hydrogen, especially for fuel production, since ammonia is generated using hydrogen as a feedstock. Moreover, ammonia is highly toxic in nature and its transport via pipelines is dangerous. With these considerations we do not see any contribution of ammonia towards the decarbonisation of the shipping sector.

T&E nor IEA see a role for LNG in the future fuel mix, but DNV GL and IMO see an increasing share of LNG. We will include LNG in our assessment as it can be substituted with bio-LNG, which allows full decarbonisation. Furthermore, we expect that the respective infrastructure will be set up by 2050. Following the implementation of the Alternative Fuel Infrastructure Directive, LNG will be available in all EU TEN-T core ports[551] by 2025.[552] We can therefore assume that there are no investment costs for a bio-LNG infrastructure in 2050, still investments costs in LNG ships are needed. LNG ships are around 13% less efficient than ICE ships. Biomethane fuel cost in 2050 are expected to be at 57 €/MWh. Adding costs for liquefaction of 12 €MWh the total costs for bio-LNG in 2050 are 69 €/MWh. The comparable fuel cost for bio-LNG are 78 €/MWh. While these costs are only slightly lower than costs for the use of hydrogen in ships, we believe that bio-LNG will be the preferred option as much of the required infrastructure will be available in 2050, which enables a smooth transition from LNG to bio-LNG. This is especially relevant considering the long lifetimes of ships.

[549] https://www.maritime-executive.com/article/worlds-first-hydrogen-powered-cruise-ship-scheduled

[550] DNV GL, Study on the use of fuel cells in shipping, 2017.

[551] The overview of ports in the Trans-European Transportation Network (TEN-T) is available here: http://ec.europa.eu/transport/infrastructure/tentec/tentec-portal/site/en/maps.html

[552] CE Delft, TNO, Study on the completion of an EU Framework on LNG-fueled ships and its relevant provision infrastructure, Lot 3 Analysis of the LNG market development in the EU, 2017.

In contrast to hydrogen, the investments costs for ships and infrastructure will be limited for biodiesel. We assume that the current policy focus on sulphur reduction will lead to a transition from heavy fuel oil to marine diesel. ICE ships running on marine diesel can easily be adjusted for the use of biodiesel and the diesel infrastructure can also be used for biodiesel. Stranded assets for biodiesel fuelled ships will be avoided compared to a fuel switch which requires specifically designed ships with a new engine. As stated Table 23 we assume an advanced biodiesel price of 83 €/MWh in 2050, which are also the comparable fuel cost, since biodiesel is also used in an ICE.

Electricity is the most cost-optimal shipping fuel, but its use is limited to short routes due to technical constraints. For longer routes bio-LNG is the most cost-competitive fuel in 2050. Aside from costs the main challenge is availability of the fuel. Whereas the green and blue hydrogen potentials could be large, the annual biomass potential is limited. In case biodiesel is produced from waste and residues, there will also be conflicting uses for bio-LNG or biomethane in general. As biomass will be required for decarbonising both the shipping and aviation sector—not to mention possible demands by industry and the heating of buildings—hydrogen could play an important role in decarbonising the shipping sector.

Table 77 provides an overview of the most cost-optimal net-zero emissions fuel mix in EU shipping in 2050 following the reasoning outlined above. The corrected energy demand for the fuel mix is also displayed.

Table 77 Most cost-optimal net-zero emission fuel mix in EU shipping 2050

Sub-sector	Fuel mix	Energy demand	Comparable fuel cost *	Optimal fuel
Domestic shipping EU	100% electric	60 TWh	46 €/MWh	Electricity is the most cost-optimal fuel
Intra-EU shipping	50% electric 50% bio-LNG	63 TWh 136 TWh	46 €/MWh 78 €/MWh	Electrification of all short shipping routes Choice for dominant fuel in international shipping
Outbound-EU shipping	100% bio-LNG	327 TWh	78 €/MWh	Bio-LNG is most cost-optimal fuel for longer routes
Total		585 TWh		

* Comparable fuel costs are the costs for the fuel, infrastructure and distribution as well as fuel station costs divided by the efficiency of the fuel in the respective engine. Fossil fuels and biodiesel in an ICE have an efficiency ratio of 1, battery electric ships 1.94, hydrogen fuel cell ships 1.29 and bio-LNG ships 0.88.

Due to the lower efficiency of bio-LNG the most cost-optimal net-zero emissions fuel mix has a 147 TWh higher energy demand than the T&E technology fuel mix and is still 85 TWh higher than a full hydrogen scenario.

I.3 Aviation

Our high-level analysis for the aviation sector covers intra-EU and outbound flight. For the overall energy demand development, we use the recent roadmap for decarbonising European aviation by T&E, published October 2018. Energy demand and impact of efficiency levers are listed in Table 78.

Table 78 Energy demand profile assumptions for European aviation

Parameter	Unit	2015	2050
Aviation energy demand (BAU)	TWh	620	829
0.2% p.a. improvement	TWh		-50
Gen-II aircraft	TWh		-25
Demand reduction (tickets)	TWh		-221
Total final energy demand	TWh		534
Outbound passenger activity (BAU)	Gpkm	3600	6753
Outbound passenger activity	Gpkm	3600	4853

In this analysis, full-electric aircraft are not expected to play a significant role. To meet the remaining aviation energy demand in a fully decarbonised 2050, we assume either synthetic fuels produced from electricity-based hydrogen or biofuels. Aiming for cost-effective deployment of these fuels across the European economy, we project a share of 50% bio-kerosene. This leads to a distribution of these fuels listed in Table 79. Cost assumptions underpinning this analysis are also listed.

Table 79 Allocation parameters for Sustainable Aviation Fuels (SAF) in 2050

Parameter	Unit	2050
Synthetic kerosene	TWh	267
Bio-kerosene (advanced biofuels from waste and residues)	TWh	267
Hydrogen needed to produce synthetic kerosene[553]	TWh	381
Hydrogen costs (green)	€ / MWh	44-61
Hydrogen costs (blue)	€ / MWh	36-63
CO_2 supply, synthesis, conditioning and transport[554]	€ / MWh	13

Costs associated with infrastructure, fleet modernisation, and associated investments are not quantified. As all fuel types are considered chemically similar to kerosene or drop-in, no distinction in business as usual or either of the scenarios of our study are expected. Fleet modernisation is considered part of the regular sector investment cycle.

[553] Conversion efficiency adopted from Agora Verkehrswende, Agora Energiewende and Frontier Economics (2018): The Future Cost of Electricity-Based Synthetic Fuels.

[554] Umweltbundesamt, Power-to-Liquids, Potentials and Perspectives for the Future Supply of Renewable Aviation Fuel, Sept. 2016.

Appendix J. Power sector

J.1 Electricity production

Table 80 Technology cost assumptions used in this study

Technology	CAPEX	Fixed OPEX	Variable OPEX	Cost of fuel	Efficiency	Load factor	Lifetime
Unit	**€/MW**	**€/MW/a**	**€/MWh**	**€/MWh**			**Years**
Gas CCGT	750,000	11,250	2.7	58-70	60%	N/A[555]	30
Gas OCGT	300,000	7,500	2.7	58-70	40%		30
Hydrogen GT	300,000	7,500	2.7	58-70	40%		30
Gas OCGT with CCS	880,000	15,000	2.7	30	34%		30
Gas CCGT with CCS	1,500,000	22,500	2.7	30	51%		30
PV	893,000[556]	8,935	0	0	n/a	12%	30
Wind onshore	1,195,000	24,443	0	0	n/a	35%	25
Wind offshore	2,400,000	92,500	0	0	n/a	45%	25
Hydro	1,700,000	7,500	0	0	n/a	35%	50
Solid biomass	2,450,000	17,150	9	29	35%	N/A	30
Battery storage costs	N/A[557]	0	0	0	90%	N/A	5
Power-to-hydrogen	423,700	12,173	0	0	86%	N/A	30

J.2 Energy storage

The European gas and electricity systems are among the most stable and reliable in the world. Even in very hot summers or very cold winters the energy system provides the required energy. In the electricity grid, this stability is currently guaranteed by large dispatchable generation capacity. Gas infrastructure has been dimensioned to deliver sufficient energy during cold spells. The stability of the current system relies heavily on gas-fired generation and underground storage for large volumes of gas. In future low-carbon energy systems, one of the main challenges will be to store large volumes of renewable energy.

With increased electrification, this will change. With increased wind and solar generation capacity it is expected that storage of electricity—in some form of energy carrier—will become necessary in large volumes. It is, however, expensive to store large volumes of electricity. Battery systems' efficiencies are improving and large technology companies have invested in scaling up battery production facilities, leading to rapid cost declines.

However, costs are not likely to reach less than €60,000/MWh of storage capacity within the next 35 years.[558] These high costs per unit of volume makes batteries unsuitable for long-term storage.

---

[555] The load factors for dispatchable technologies are not an input, but a result from the modelling.

[556] As the capacities will be installed between now and 2050, these costs represent the average costs between now and 2050. Significant cost reductions are expected for wind and solar energy towards 2050, hence their corresponding costs have been taken as the average between now and forecasted cost for 2050.

[557] Expressed in capacity price per MWh of storage capacity: 60,000 €/MWh.

[558] Ecofys et. al., 2017: Batstorm- Battery-based energy storage roadmap. Cost estimates include the full battery pack and are based on an exponential interpolation of battery costs estimates provided by IRENA, EPRI, Rocky Mountain Institute, Bloomberg, EIA, Roland Berger, Deutsche Bank, Johns Hopkins University, Aalto University, Lazard and JRC.

Another possibility is (pumped) hydro storage. However, a GIS[559]-based study by JRC found EU-28 countries to have a limited realisable pumped hydropower storage (PHS) potential of 37 TWh.[560] This is approximately 4 days of the current EU power consumption.

Gas can provide the remaining storage requirements. Gas is routinely and cheaply stored in large volumes. Investment costs for creating underground gas storage are around €25/MWh. This makes gas suitable for storing large volumes of energy over longer periods, for example, for seasonal storage[561].

J.3 The potential role of hydrogen in the power sector

Today, the EU (electric) power sector is dominated by conventional generation from fossil fuels (hard coal, lignite, oil, natural gas) (45%). However, the share of renewables as a percentage of gross electricity production rose from 20% in 2010 to 30% in 2017. Nuclear accounts for 25%, with a declining tendency, as Germany is executing its nuclear exit program, and some older plants out of the ageing fleet in other countries are shut down, in some cases due to safety concerns.[562]

In June 2018, the EC agreed on a share of renewable energy of at least 32% on the EU's gross final consumption in 2030, which implies a renewable share in EU electricity of well over 50% by that date.[563]

Hydrogen can play a key role to transform fossil fuel dominated power sectors of today towards a 100% electricity supply by renewable energy and hence in decarbonising the European power sector. Due to seasonality of variable renewable energy sources like wind and solar, large-scale seasonal storage is required in addition to other flexibility options such as batteries, pumped-hydro storage (both rather short-term storage options), and demand-side management, to achieve very high shares of renewable energy on annual electricity supply. Hydrogen could be produced when electricity production from variable renewable energy exceeds electricity demand and is stored over several weeks/months until it is converted back to electricity when available variable renewable energy is insufficient to meet electricity demand.

Existing gas-fired power plants can be retrofitted to burn green or blue hydrogen instead of natural gas. This is currently studied for a large-scale combined-cycle gas power plant in Groningen in the Netherlands (Nuon's 1.32 GW Magnum station). Each of the three installed 440 MW combined-cycle gas turbines can emit up to 1.3 million tons of CO_{2eq} per year. Hence, when retrofitted, CO_{2eq} emissions could be reduced by up to 4 million tons per year.[564]

---

559 Geographic Information System.

560 JRC, 2013: Assessment of European potential for pumped hydropower energy storage.

561 Costs based on the replacement costs of the Gasunie storage facilities.

562 Agora, Sandbag (2018). The European Power Sector in 2017. URL: https://sandbag.org.uk/wp-content/uploads/2018/01/EU-power-sector-report-2017.pdf

563 European Parliament (2018): Press release 14 June 2018: Energy: new target of 32% from renewables by 2030 agreed by MEPs and ministers, online: http://www.europarl.europa.eu/news/en/press-room/20180614IPR05810/energy-new-target-of-32-from-renewables-by-2030-agreed-by-meps-and-ministers

564 Power (2018): MHPS Will Convert Dutch CCGT to Run on Hydrogen, online: https://www.powermag.com/mhps-will-convert-dutch-ccgt-to-run-on-hydrogen/

NAVIGANT