# Gas in European decarbonisation pathways: future infrastructure challenges

Master's thesis report

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## Abstract

The European Union's target to reach net-carbon neutrality by 2050 calls for deep changes to energy supply, including a sharp decrease in the consumption of natural gas. This master's thesis evaluates the impact of carbon neutrality on the gas system, taking France and Germany as two case studies. It first identifies the gas trajectory in French and German decarbonisation scenarios, then explores the consequences of carbon neutrality on gas infrastructure and estimates the changes in methane price due to the increase in methane production cost and the decreased use of existing methane infrastructure. Our results show that gas supply and demand will radically change by mid-century, with biomethane, synthetic methane and hydrogen emerging as major energy carriers and input to industrial processes at the expense of natural gas. It appears that infrastructure planning is paramount to the achievement of carbon neutrality, all the while the issue of infrastructure is little addressed in decarbonisation pathways. A cost simulation is conducted taking two extreme cases for distribution network development. It suggests that methane price could increase up to 72% in France and 98% in Germany between 2030 and 2050 with the increase in methane production cost and in specific infrastructure costs.

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# Contents

# 1 Introduction

The European Union (EU) aims to be climate-neutral, meaning to emit net zero greenhouse gas (GHG), by 2050. According to the Commission's strategy, the shift should be achieved primarily by reducing energy demand through increased energy efficiency, electrification and the use of low-carbon energy technologies such as wind, solar, nuclear, biomass, and carbon capture and storage (CCS) (European Commission, 2018a). Additionally, the transition to a carbon-zero energy system will require that the use of fossil fuels, namely oil, coal and natural gas, is reduced to (near) zero.

The 2015 Paris Agreement identifies carbon neutrality as the main way to limit global warming to 2°C or less, in accordance with the 1.5°C special report by the International Panel on Climate Change (IPCC) (Rankovic et al., 2018). It consists in balancing the emissions of greenhouse gases with its absorption from the atmosphere by carbon sinks. Reducing emissions as early as possible will reduce the need for carbon removal technologies such as CCS later on, and avoid possible cost escalation (European Commission, 2018b). This justifies acting today to reduce emissions and the burning of fossil fuels (Rankovic et al., 2018).

Among fossil fuels, natural gas holds a special place. Although it does emit GHG emissions in its mining and combustion phase, it has been praised as a "bridge" fuel as it would help bringing down emissions quickly and at a relatively low cost, waiting for carbon-free technologies to be developed (Zhang et al., 2016). Natural gas – which is mostly methane ($CH_4$) – made up almost 25% of the EU's total primary energy supply in 2017 (IEA, 2017). It can be used to produce (flexible) power, for space and industrial heat or as a fuel in the transport sector. Most of our consumption owes to the residential sector, closely followed by the industry (IEA, 2017). The relatively low emissions of natural gas have been a strong argument in favour of continued policy support in the European Union (Gaventa et al., 2016). It will likely remain a large share of the European energy mix until 2030 (European Commission, 2018b). However, the target of reaching carbon neutrality by mid-century is calling for an almost total phaseout of natural gas between 2030 and 2050. Although multiple technologies are recognised to be part of the solution to bring natural gas consumption to zero, there is little consensus on the pathway to reach that goal.

## 1.1 Phasing out natural gas

The advantages of natural gas, as compared to other energy carriers, include its high energy density, the fact that it can be used in many energy applications, in particular for cheap energy storage with regards to electricity (négawatt, 2017; Speirs et al., 2018; Gas for Climate, 2020).

To decrease natural gas consumption to near-zero, three main strategies could be implemented. Efforts on behaviours (e.g. space heating at a lower temperature) and energy efficiency improvements could significantly decrease natural gas demand without major technological changes. Some end uses of gas, especially low-temperature heat in buildings or in the industry, could be electrified (European Commission, 2018b). The extent to which electrification is technologically possible is much debated. At the aggregate level, the study Gas for Climate (2020) is an example of a conservative estimate, while the works by Electrification Alliance (2020); European Climate Foundation (2019) are more optimistic. Studies agree on the fact that some other applications using natural gas are very difficult to electrify, particularly high-temperature heat for the industry and long-haul road transport (Åhman, 2010; Frontier Economics et al., 2017; European Commission, 2018b; Gas for Climate, 2020). Residual natural gas consumption could continue until 2050, since the EU is envisioning net rather than absolute zero emissions. Natural gas could also be substituted with low-carbon types of methane such as biomethane and synthetic methane or coupled with carbon capture and storage (CCS) (Gas for Climate, 2018; European Commission, 2018b; Speirs et al., 2018). In some of its uses, especially in the industry, it could be replaced with hydrogen ($H_2$) (IEA, 2019; Bataille et al., 2018).

On the other hand, new uses for gas (either methane or hydrogen) might develop in some sectors as a lower-carbon replacement for coal or oil, notably for energy-intensive industries and transportation, or for flexible power generation (Cornot-Gandolphe, 2018; IEA, 2017, 2019; Bataille et al., 2018).

Energy efficiency requires limited changes to appliances and processes. Today, electricity is generally cheaper than low-carbon gases, however, for most end uses, electrification requires new equipment (e.g. replacing gas boilers with heat pumps). Low-carbon gases are more expensive than conventional gas; their cost will decrease in the future although the extent to which this is the case is uncertain and will depend on the cost of $CO_2$, electricity, and the utilisation rate of conversion plants (Agora Verkehrswende et al., 2018). The higher cost of low-carbon methane and hydrogen might overturn the business case of gas for some end-uses (Trinomics, 2016). Switching from methane to hydrogen calls for the upgrade of appliances. Finally, natural gas infrastructure will undergo significant changes as the demand for methane decreases, new supply chains are built for methane and hydrogen emerges as an energy carrier in some places (Speirs et al., 2018; Trinomics et al., 2019; Wachsmuth et al., 2019b).

## 1.2 The fate of gas infrastructure

Choices in terms of gaseous vectors and gas demand will condition the future of gas infrastructure.

The EU has been funding large gas import infrastructure to ensure security of supply (European Commission, 2018c). For example, the 2019 list of Projects of Common Interest (PCI) includes several gas projects, which are then by definition eligible to EU funding (European Commission, 2019b). A number of stakeholders warn that continued support for natural gas infrastructure is at odds with climate objectives (Inman, 2020; WWF et al., 2017), while security of supply is already ensured by existing infrastructure in the EU (Artelys, 2019, 2020). Adequate planning of gas infrastructure is crucial in order to ensure that climate objectives are met while optimising the use of existing assets (Duscha et al., 2019).

The switch to transport hydrogen and to a lesser extent biomethane would require adaptations to the methane grid (Element Energy, 2018b; Trinomics et al., 2019; ADEME, 2018). For example, hydrogen demands significant retrofit of pipelines and adaptation of end-use appliances (Trinomics et al., 2019).

A decrease in methane demand may also bring economic challenges to the gas infrastructure. Transportation costs per unit gas will also increase and would then increase the price of methane (Wachsmuth et al., 2019b). Parts of the existing distribution and transmission network could become too expensive to maintain, meaning that the gas infrastructure built in the next decade might not be used up till the end of its lifetime, which is typically around 50 years (Energy Union Choices, 2016; Artelys, 2020). Trinomics et al. (2019) warn that these changes will impact the business case of gas network operators, especially at the distribution level. This will likely impact the pricing of methane, as infrastructure costs make up around half of its price without tax (CRE, 2017). Finally, the conversion of part of the network to accommodate for hydrogen or the building of a hydrogen network from scratch would generate large investment costs (Enagás et al., 2020).

## 1.3 Knowledge gap

A number of studies have pointed out the need to better integrate climate objectives to infrastructure planning and projections (Energy Union Choices, 2016; Duscha et al., 2019; Inman, 2020).

Some research has already explored the challenges faced by European gas infrastructure **(1)** from the perspective of a changing gas demand to reduce emissions (Policy Connect and Carbon Connect, 2017; Speirs et al., 2018; ENTSOG, 2019) or **(2)** from the angle of energy security (Energy Union Choices, 2016; Dutton et al., 2017; Artelys, 2020). Other papers focus on the technical requirements to integrate low-carbon gases to the existing grid: Trinomics et al. (2019) study the impact of hydrogen and biomethane on European gas networks, Dodds and Demoullin (2013); Element Energy (2018b) explore the implications of a hydrogen-based gas system; ADEME (2018) look at the potential for a 100% renewable gas demand by 2050 in France; Wachsmuth et al. (2019b) investigate the challenges for gas infrastructure associated with different levels of greenhouse gas reduction in Germany. Additionally, many existing climate neutrality scenarios for the EU include gas supply and demand to their projections such as European Commission (2018b); Duscha et al. (2019); Gas for Climate (2020); European Climate Foundation (2019) .

However, to the best of our knowledge, no research has carried out detailed, independent analysis of the consequences of carbon neutrality on gas infrastructure in a comparative perspective for different European countries. Only one study, Wachsmuth et al. (2019b), links deep cuts to GHG emissions to transformations of the gas infrastructure (for the case of Germany). Additionally, there is no literature on the extent to which infrastructure changes in the transition could transform methane pricing. In order to ensure infrastructure planning in line with climate objectives, in-depth analysis of decarbonisation pathways for the EU to identify the consequences of carbon neutrality on the gas system should be carried out. This would enable appropriate projections for the changes to methane pricing.

## 1.4 Research aim

This thesis aims to evaluate the impact of carbon neutrality on gas infrastructure by assessing the trajectory for gas in decarbonisation pathways and giving a rough estimate the associated change in gas price. The change in gas price will indicate the possible changes to the business model of gas system operators.

## 1.5 Research questions

How will carbon neutrality in Europe affect the gas system?

1. What transformations will gas supply and demand undergo until mid-century?
2. What changes of gas infrastructure will carbon neutrality trigger?
3. How will infrastructure changes brought by carbon neutrality affect end-user price of methane[1] by 2050?

## 1.6 Study area

This study focuses on the European Union (EU). Considering the time frame of the study, in-depth analysis is only conducted for two member states of the EU: France and Germany. Focusing on a selection of member states allows for a fine level of analysis while enabling comparison between countries. These states in particular were chosen as they are the two largest energy consumers in the European Union and have significant political weight regarding European policy.

[1]Throughout the report, "methane" refers to all types of methane, including of fossil, biogenic and synthetic origin. More detail on the definitions of gases in section 2.1.

France and Germany show fundamentally different energy systems which allow for a rich comparison. France uses gas mostly as a final energy carrier for heat. Since the share of variable renewables in the electricity mix is small, little flexibility is needed and gas turbines are not crucial for security of supply. Biogas is seen as a way to improve livelihoods for farmers (Auverlot and Beeker, 2018). Germany has historically relied largely on coal and considered natural gas as a transition fuel for the power sector, while it is also central to its industry (BMUB, 2016). The share of variable renewables in the power mix is much higher. Natural gas use is tied to geopolitical concerns since it is mostly imported from Russia.

## 1.7 Policy relevance of the study

By analysing decarbonisation pathways, this study will bring to light existing narratives for the role of gas in the energy transition in the EU, in France and in Germany. It will further help cooperation and coordination between member states to achieve EU energy and climate goals. The framework produced by this study to identify narratives can be used later to analyse gas trajectories in other decarbonisation scenarios.

Taking the perspective of gas infrastructure on the issue of climate neutrality helps raise awareness among decision-makers and the scientific community on the importance of including infrastructure aspects to projections of the energy system. On top of its policy relevance, the study will help fill the scientific knowledge gap regarding the consequences of climate neutrality on the gas grid.

# 2 Theoretical framework

This chapter lays out the concepts forming the theoretical basis of the study. The definitions chosen for low-carbon gases (section 2.1), for sectors of the energy system (section 2.2) and for gas infrastructure (section 2.4) are given. The framework to analyse and compare decarbonisation scenarios is presented.

## 2.1 Low-carbon gas

This section presents the definitions chosen for low-carbon gases. Two main molecules are used as gas in the energy system: methane ($CH_4$) and hydrogen ($H_2$). In this report, the word "gas" refers to methane and hydrogen; when relevant, the difference is distinguished.

Methane can be of biogenic origin (biomethane), fossil (fossil methane i.e. natural gas) or synthetic. Whatever its origin, methane can be used in the same applications with the same equipment. Production routes for low-carbon methane are shown in Figure 2 (together with production routes for hydrogen).

There are two main routes to produce biomethane (ADEME, 2018):

- Anaerobic digestion: microorganisms break down organic matter into gas, which is called *biogas*. Biogas is upgraded ($CO_2$ is cleared) to form biomethane. It can also be used directly for heat generation but not in most methane applications (Policy Connect and Carbon Connect, 2017);
- Thermal gasification: organic matter (mostly ligno-cellulosic) is heated up and thus transformed into biogas, which is purified into biomethane.

Some authors warn that not all biomethane is low-carbon; its GHG emissions depend on the feedstock and production process (Boulamanti et al., 2013). In this research project, it is assumed that all biomethane is low-carbon: the emphasis is put on the coherence of decarbonisation pathways with infrastructure rather than with climate neutrality itself.

Synthetic methane is produced through the power-to-methane process, which synthesises methane from hydrogen and carbon dioxide during the methanation process. Carbon dioxide can originate from industrial processes, from biogas upgrade or from direct air capture. In a carbon-neutral system where $CO_2$ emissions are low, supplying $CO_2$ to synthetise methane can become problematic. However, this issue is left out of the scope of the study. Synthetic methane is sometimes categorised as biogenic when it is made from $CO_2$ from biogas upgrade (ADEME, 2018; Gas for Climate, 2020). However, for clarity, in this study synthetic methane is called synthetic whatever its production route. Synthetic methane is low-carbon as long as the hydrogen used for its production is low-carbon.

Technologies using natural gas (NG) can be associated with carbon capture and storage (CCS), allowing for much lower emissions from the energy conversion process (to heat or to electricity). However, the CCS technology does not eliminate all emissions. Natural gas with CCS is also considered a low-carbon gas.

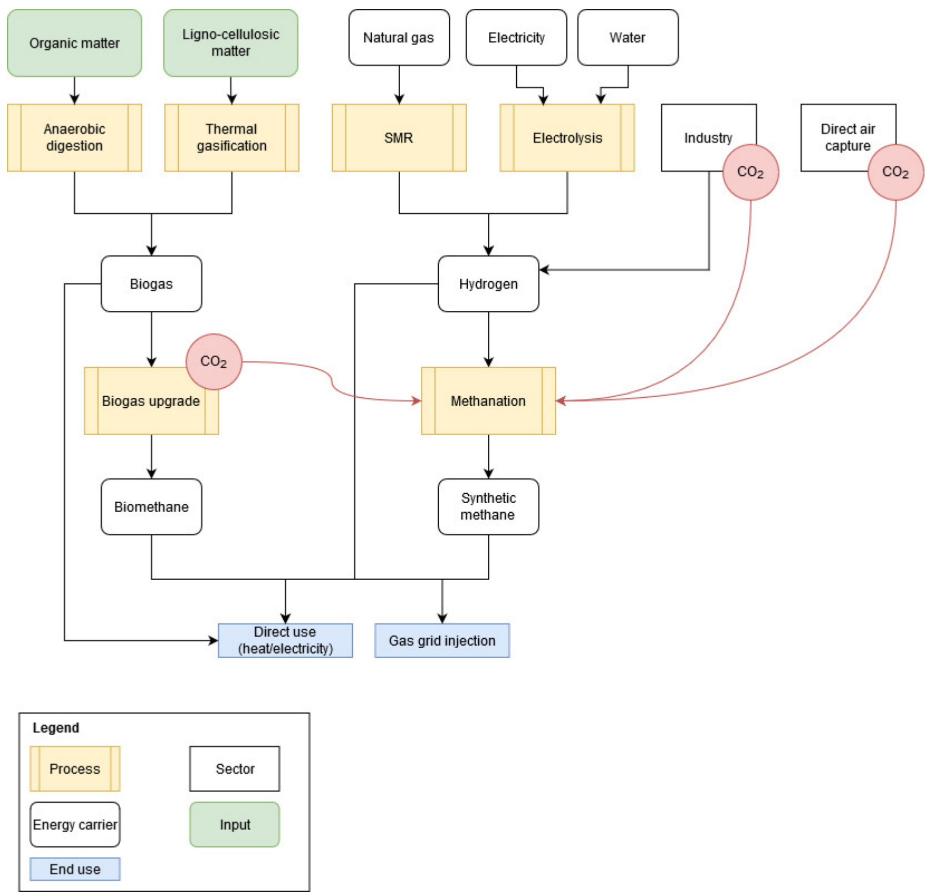


Figure 2: Production routes for low-carbon methane and hydrogen. Source: ADEME (2018), own translation.

Today, hydrogen is mainly produced from natural gas, using steam methane reforming (SMR) and to a lesser extent autothermal reforming (ATR). It can also be produced from coal or biomass (IEA, 2019). All of these processes emit greenhouse gas (GHG) emissions. SMR and ATR coupled with CCS are explored as technologies which could provide large amounts of low-carbon hydrogen (IEA, 2019); however the issue of public acceptance of carbon storage projects and the fact that even with CCS, hydrogen production from fossil fuels is not carbon-free has made some European stakeholders reluctant to develop SMR or ATR with CCS at a large scale (MEZK, 2020a; BMWi, 2019; European Commission, 2020a). Hydrogen can also be produced using carbon-free, renewable electricity for water electrolysis (IEA, 2019); such hydrogen is also renewable and carbon-free. Production routes for hydrogen are shown in Figure 2. Although electrolysed hydrogen will likely prevail after 2030, according to the European Commission Hydrogen Strategy, low-carbon hydrogen based on natural gas will play a role until 2030 (European Commission, 2020b).

## 2.2 Sectors

The challenges for the future role of gas in the energy system will depend on its end use and on the sectors in which it is used. This section articulates the sectors chosen in this study.

The energy system consists in the supply sector and the consuming sectors. In the literature, including in the European Commission's Clean Planet for All strategy, the energy-consuming sectors are usually defined as buildings, industry, transportation (European Commission, 2018b). We will also consider these four end-user sectors. We define subsectors to allow for finer analysis of the role of gas and to better match the data presented in decarbonisation scenarios. Buildings are either residential or non-residential; non-residential buildings include mostly commercial and services buildings but also industrial buildings but for simplicity they are referred to as service buildings further in the report. The transport sector is composed of freight or passenger transport. On the supply side, both power generation and gas supply are defined as sectors. The power sector includes gas-fired power plants and hydrogen electrolysers. The gas supply sector includes supply routes of gas to Europe.

Today's uses of gas in Europe per sector are as follows:

- Buildings use gas exclusively for heat. Gas is mostly used for space heating (44% of space heating is supplied by natural gas) and hot water, with a smaller amount dedicated to cooking heat.
- In the industry, gas is also essentially used for heat. Natural gas supplies 31% of the final energy consumption in the industrial sector (Eurostat, 2017), mostly to fire steam boilers and steam systems and furnaces and kilns (Chan and Kantamaneni, 2015). It is also used as a feedstock for a number of processes: methane is an input for the chemical industry; hydrogen for oil refinement (Duscha et al., 2019; IEA, 2019).
- In the power sector, natural gas provides 23% of the primary energy supply (IEA, 2017). In particular, it is used to provide stability to the system using gas-fired generation and underground storage (Gas for Climate, 2018).
- In transportation, gas is used essentially as natural gas. It only represents about 1% of final energy consumption in transportation (IEA, 2017;

Arteconi et al., 2017). The use of hydrogen for transportation is marginal (IEA, 2019).

- Gas supply mostly relies on imports, which make up about 75% of natural gas supply (IEA, 2017). Both hydrogen and biomethane make up a small share of gas consumption and are only produced domestically. Synthetic methane and natural gas with CCS are at the development phase.

All of these uses of gas are part of the scope of this study.

## 2.3 Challenges facing gas for carbon neutrality

In order to investigate the trajectory planned for gas by decarbonisation pathways, it is crucial to define the framework against which the scenarios are analysed. This section outlines the concepts which underlay the analysis of scenarios.

Turning points in the pathway for the gas system were identified thanks to a literature review. The following types of documents were analysed:

- Policy documents of the EU focusing on the transition to a climate-neutral system, in particular the Commission's Clean Planet for All communication (European Commission, 2018b) but also Trinomics (2016); Trinomics et al. (2019); European Commission (2012); Cambridge Econometrics and Element Energy (2018a); Heat Roadmap Europe documents (Paardekooper et al., 2018; Harmsen et al., 2018; Connolly et al., 2014).

- National-level policy documents, such as the Dutch and the German plans for hydrogen (BMWi, 2019; MEZK, 2020c) and the German Environment Agency's Gas Roadmap for the Energy Transition in Germany (Wachsmuth et al., 2019b).

- Publications from the grey literature which offer insight on the ongoing debates around the question of gas (European Climate Foundation, 2019; Inman, 2020; Dutton et al., 2017; Gaventa et al., 2019). In particular, studies commissioned by European gas producers and facilities were analysed: Gas for Climate (2018, 2020); ENTSOG and ENTSO-E (2020); CE Delft (2017).

- Academic literature on specific technological issues was also reviewed, e.g. Åhman (2010); Arteconi et al. (2017) for biomethane in transportation, Chan and Kantamaneni (2015); Chan et al. (2019); Bataille et al. (2018); Lechtenböhmer et al. (2016) for decarbonisation of industry.

The next section identifies six *aspects* of the energy system in which gas will play a role if carbon neutrality is to be achieved. These aspects are decomposed in the following section into *key factors* for each sector which capture the main technological, socio-economic and environmental factors which determine the place of gas in the deep decarbonisation of the European energy system. These factors will help determine a framework in which to analyse decarbonisation pathways.

### 2.3.1 Aspects of the role of gas in the transition

Six main aspects for the role of gas in the energy transition were identified.

1. **Volume of heat demand**. In Europe, natural gas today is mostly used for heat in both buildings and the industry (IEA, 2017). Moderation of demand has a number of environmental and economic benefits (European Commission, 2015) and will play a key role in deep decarbonisation. The issue of future methane consumption will depend for a large part on the proportion of heat demand which can be abated with energy efficiency measures. The Heat Roadmap Europe 4 claims that heat demand could be cost-effectively reduced by 30 to 50% with energy efficiency (Paardekooper et al., 2018).

2. **Uptake of gas for new uses**. Despite overall decreasing gas demand, gas use might increase in two sectors: transportation and power generation. The uptake of low-carbon methane and hydrogen in the industry for energy and non-energy uses (e.g. hydrogen instead of coal for direct reduction in steel-making) could be considered as new uses but in this report these uses are included in ”substitution with low-carbon gases” for simplicity. For example, hydrogen in steel-making could substitute coal but it could also substitute natural gas and the difference is often not made in decarbonisation strategies.

    (a) Transport, especially long-haul, heavy goods transport, is one of most difficult sectors to decarbonise, mainly because transport demand is growing and no technology stands out as a clear decarbonisation solution (European Commission, 2018b). Gas in the form of low-carbon methane and hydrogen is considered as a long-term solution to abate emissions for long-haul transport (Pääkkönen et al., 2019; Boulamanti et al., 2013; European Commission, 2018b; Arteconi et al., 2017; Gas for Climate, 2018).

    (b) Today, natural gas is a major energy carrier for the European power sector, supplying 23% of the primary energy supply to EU electricity plants (IEA, 2017). Gas-fired power plants can be turned on and off quite quickly and are typically used for peak moments in the day and the year (Gaventa et al., 2019; Gas for Climate, 2018). In a carbon-neutral system, most of the electricity supply will be based on variable renewable energy sources (VRES), which require other generation sources on the supply or demand side (European Commission, 2018b). Many studies have pointed out the increasing co-dependence between the electricity and gas systems (Artelys, 2019, 2020; Gas for Climate, 2018).

3. **Electrification of current gas uses**. Electrification is admittedly one of the core decarbonisation strategies in Europe (European Commission, 2018b; Gas for Climate, 2018). In buildings and industry, electrification

will take place at the expense of natural gas for a large part. Therefore, the degree to which these two sectors electrify will be central in determining the residual role for methane.

4. **Substitution of natural gas with low-carbon gas**. Low-carbon methane can substitute natural gas in all of its applications. Hydrogen can substitute methane for heat and sometimes as a feedstock. Both low-carbon methane and hydrogen mobilise expensive, new technologies and will strongly compete with electricity to substitute natural gas.

5. **International energy trade**. Electricity imports and exports between neighbouring countries often play the role of flexible power supply for the power grid, meaning that the role of gas power plants in the mix will also interact with the size of electricity exchange. For methane, the EU is heavily dependent on imports to meet its demand (IEA, 2017). Volumes of imports are likely to decrease as gas supply is transformed, which will affect requirements for gas infrastructure.

### 2.3.2 Key factors per sector

In this section, the key factors determining the role of gas in each of the six aspects identified in the previous section are outlined, per sector as defined in section 2.2.

**Buildings**. The role of gas in buildings relates to three main aspects: volume of heat demand, degree of electrification, and degree of substitution of natural gas demand with low-carbon gas. The following key factors will be determining for gas demand:

- Insulation of the existing building stock to reduce heat demand. It has been a policy priority at the EU level but the rate (speed) of renovations has been too slow (European Commission, 2018b). It is also often unclear how deep renovations should be (Wachsmuth et al., 2019a). EU policies and targets in this area are ambitious; the challenge lies in their actual implementation.

- Size and structure of population. They influence demand for housing and therefore energy demand in buildings. Lifestyles also play a key role in energy consumption of buildings, notwithstanding physical conditions (Santangelo and Tondelli, 2017; Lopes et al., 2017; Steemers and Yun, 2009).

- Switch to district heat. Heat networks improve efficiency of the heat system by creating synergies with other sectors and by centralising heat supply (Paardekooper et al., 2018; Gas for Climate, 2018). District heat can be fuelled with large-scale heat pumps, solid biomass, gas-CHP plants, hydrogen. The Heat Roadmap Europe 4 claims that they could supply

50% of heat demand of buildings by 2050 in Europe (Paardekooper et al., 2018).

- Uptake of individual heat pumps and electric heating. The two main barriers for heat pump deployment are their high upfront cost and their low efficiency in cold temperatures, which requires complementary direct electric heating and thus increases peak electricity demand (Gas for Climate, 2018; European Commission, 2018b; Element Energy, 2018a). Only using direct electric heating is less cost-efficient but has a lower upfront cost.

- Ability of the grid to cope with extra electricity demand. Wide electrification of buildings will require extra electricity capacity and flexible storage to meet daily and seasonal peak demand (heat demand does not follow VRES electricity production). Some authors stress the necessity to keep methane for space heat in some buildings to shave off peak electricity demand, which could be very costly as it would require extra generation capacity (Gas for Climate, 2018, 2020; Trinomics et al., 2019; Coénove, 2020).

Most studies do not project a wide use of hydrogen for heat in buildings, because of safety and cost concerns, as a hydrogen-specific distribution network should be built and end-use appliances should be replaced to accommodate for hydrogen (Duscha et al., 2019; European Commission, 2018b; Gas for Climate, 2018; Speirs et al., 2018; IEA, 2019).

**Industry**. In the industry, the role of gas will similarly depend on the volume of heat demand, on the degree of electrification and on the degree to which low-carbon gases are developed to replace natural gas.

- Industrial-sector strategies to implement energy efficiency measures. European policy has been less ambitious with the reduction of heat demand for process heating than with space heating. Consequently, current policies cannot reach the emission reduction targets (European Commission, 2018b; Paardekooper et al., 2018). Some authors have stressed the need to involve industry stakeholders more closely (Trianni et al., 2013; Chan and Kantamaneni, 2015).

- Consumer demand and economic activity. Industrial output and energy demand are closely linked to demand for goods. Often, scenarios link industrial output to economic activity and do not explore potentials of lifestyle shifts in reducing emissions.

- Amount of methane/hydrogen as feedstock in processes. Non-energy use of natural gas is not part of heat demand; today, it makes up a low share of natural gas demand. However, as industry decarbonises its energy supply, gas as feedstock could weigh heavier in favour of maintaining natural gas supply to some industrial sites as both uses require the same transport network. For hydrogen, non-energy use could develop as a replacement for fossil fuels, typically in the chemical sector (Agora Energiewende and Wuppertal Institut, 2019).

- Technical potential to replace low-temperature heat (LTH) with district heating and direct electricity. Industry is characterised by great variation between subsectors and processes in terms of electrification potential (Lechtenböhmer et al., 2016; Chan and Kantamaneni, 2015). Low-temperature heat is cheaper to electrify (Wachsmuth et al., 2019b; Bataille et al., 2018). The matter of how deep electrification can be is debated and will depend for a large part on the carbon price (Lechtenböhmer et al., 2016). Gas demand is also conditioned by the adoption of electrification strategies by industrial producers, which is strongly dependent on their economic cost. The potential for district heating will derive from the location of the plant and the density of heat demand around it.

- Technical potential to replace high-temperature heat (HTH) with district heating and direct electricity. In some cases, it closely competes with the substitution of NG by hydrogen or low-carbon methane and with CCS as costs are similar (Bataille et al., 2018; Chan et al., 2019). The high cost of electrifying HTH will be more deeply impacted by the $CO_2$ price (Wachsmuth et al., 2019b). Studies usually explore the potential for decarbonisation options at the sector-level since the technical feasibility of electrifying HTH depends a lot on the processes and the industrial subsectors, e.g. Lechtenböhmer et al. (2016) for basic materials, Schiffer and Manthiram (2017) for chemicals.

**Power system**. The key factors defining the role for gas in the power system are the following:

- Deployment of gas-fired power plants to displace coal. Natural gas (NG) is sometimes framed as a potential "bridge fuel" to reduce emissions from the power sector in the short- to mid-term if it replaces coal (Howarth et al., 2011; IEA, 2019c). To comply with carbon neutrality, by 2050 existing NG-fired power plants will have been displaced by renewable power plants or natural gas with CCS (Gas for Climate, 2018), and no new plants should be built until then as their lifetime is 20 to 25 years. The main issue is whether and to what extent gas-fired power would increase in share until 2030.

- Deployment of carbon capture and storage (CCS) technology. CCS could be associated with existing natural gas power plants to provide near-zero carbon power. The development of CCS is still highly uncertain because of strong public opinion reluctance, technological barriers (esp. storage) and high cost (European Commission, 2018b; Gas for Climate, 2018).

- Need of the power grid for gas as flexible and long-term energy storage. Gas can provide flexibility to the power system in two main ways: (1)

methane-fired turbines provide flexible backup to the power system typically at times of peak demand (Gaventa et al., 2019; Gas for Climate, 2018); (2) hydrogen production by electrolysis helps to avoid curtailed electricity when variable electricity production exceeds consumption (European Climate Foundation, 2019). Importantly, the amount of curtailed electricity is likely to not cover future needs for hydrogen and synthetic fuels based on hydrogen, and additional electricity capacity would need to be built for hydrogen electrolysis (Agora Verkehrswende et al., 2018). The first role is likely to become more prominent as the share of variable renewable electricity increases in the power mix. Electrolysed hydrogen is virtually not developed commercially today but it will grow in the future (European Commission, 2020b). The cost of electrolysis will be a limiting factor to the development of hydrogen.

- Import dependence on electricity. Large-scale aggregation of the power system tends to smooth out geographical discrepancies, which suggests that the need for backup electricity generation (incl. gas turbines) decreases if countries with large shares of variable renewable power generation share their backup capacity (Schlachtberger et al., 2016). However, countries tend to plan decarbonisation strategies at the national level.

**Transportation**. Three key factors determining the level to which gas will be developed as a transport fuel are the following:

- Level of transport activity. It has been the main driver of transport emissions in Europe in the past few decades (Duscha et al., 2019). The development of demand for transport - both passenger and freight - will partly determine gas demand.

- Degree of electrification in transport. Gas technologies compete with electricity to decarbonise transportation, as electric powertrains are a cheaper and more mature technology (Cambridge Econometrics and Element Energy, 2018b; European Commission, 2018b). The competition will likely be fiercer in long-haul, heavy goods transport, where electric powertrains are less adapted due to the need for large batteries (IEA, 2017, 2019). On the other hand, the development of overhead lines to allow for hybrid powertrains heavy duty vehicles is considered a serious option in Germany and might result in a higher share of electricity (Wietschel et al., 2017).

- Development of refuelling infrastructure ($H_2$ and $CH_4$). There are currently very few gas refuelling stations in Europe (exc. in Italy). Their deployment conditions the development of gas-based powertrain technologies (capacity, location and density) (IEA, 2019; European Commission, 2018b).

**Gas supply**. The gas mix will depend on the extent to which low-carbon gas is deployed and the role of international energy trade in ensuring supply.

- Production potential for biomethane. Biomethane is the cheapest low-carbon methane. However, the volume of biomethane that can be produced depends on amounts of organic matter and competition for land use (Arteconi et al., 2017; European Commission, 2018b). The amount of biomethane which can be produced will condition the level of synthetic methane demand.

- Size of synthetic methane demand. If synthetic methane demand is large enough, imports from regions with cheap renewable electricity (e.g. North Africa, Chile) will become cost-competitive with domestic production (Agora Verkehrswende et al., 2018). New import routes and infrastructure might develop (Frontier Economics, 2018)

- Net imports of hydrogen. Like synthetic methane, hydrogen could be produced in regions with large wind and solar potential and be imported to Europe via new import routes (Agora Verkehrswende et al., 2018).

- Cost of domestic/imported synthetic methane. While the use of biomethane is essentially bounded by its technical potential, synthetic methane development is essentially constrained by its cost. The development path of the technology will determine in what end uses it can be deployed cost-efficient.

- Volume of gas transiting through the national network. National gas infrastructure should also be considered together with decarbonisation pathways of countries whose gas infrastructure is connected to it (Wachsmuth et al., 2019b). Decreasing domestic gas demand might not require the decommissioning of the infrastructure if other countries using the national infrastructure see their demand remain stable or increase.

This section has presented the main aspects of the role of gas in the transition to climate neutrality. The key factors per sector and per aspect are summarised in Table 1. The key factors will be the starting point for selecting indicators to analyse decarbonisation scenarios.

Table 1: Key factors for the use of gas per sector and aspect.

| *Sector/Aspect* | **Volume of heat demand** | **New uses of gas** | **Electrification of current gas uses** | **Substitution of existing gas demand with low-carbon gas** | **International energy trade** |
|---|---|---|---|---|---|
| **Buildings** | Insulation of existing building stock<br>Size and structure of population | | Switch to district heat<br>Uptake of individual heat pumps and electric heating<br>Ability of the grid to cope with extra electricity demand | Switch to district heat | |
| **Industry** | Industrial-sector strategies to adopt EE measures<br>Consumer demand | | Technical potential to electrify LTH/HTH<br>Technical potential to supply LTH with district heat | Amount of methane/hydrogen used as feedstock<br>Technical potential to replace non-energy use of fossil fuels with hydrogen | |
| **Power** | | Deployment of gas power plants to displace coal<br>Deployment of CCS<br>Need for flexibility in the power grid | | | |
| **Transportation** | | Level of transport activity<br>Degree of electrification<br>Development of refuelling stations | | | |
| **Gas supply** | | | | Potential for domestic biomethane<br>Cost of synthetic methane domestic/imports | Size of synthetic methane demand<br>Net imports of hydrogen<br>Demand for hydrogen and methane transit on national grid |

## 2.4 Gas infrastructure

This section lays out the definitions and the system boundaries used for gas infrastructure. Figure 3 presents the model of gas network used in this study.

Today, gas infrastructure is mostly dedicated to methane, although some hydrogen pipelines exist at the local level, e.g. in Germany (Baufumé et al., 2013). Additionally, hydrogen is added to the methane mix in some countries to create demand for hydrogen; admittedly, up to 10% of the gas mix in methane pipelines could safely be hydrogen (IEA, 2019; Judd and Pinchbeck, 2016; GRTGaz, 2019).

Gas infrastructure is the set of pipelines, storage sites and compressors which convey gas from production sites and import terminals to consumers (power stations, industries, commercial and residential buildings). The part of the gas grid involving gas transportation is made of a transmission (or transport) and a distribution grid. In this study, the term "gas network" encompasses the transmission and distribution grid. The transmission network (TN) transports gas at high and medium pressure between production sites, to large customers directly connected to the TN and feeds into the distribution network (DN), while the distribution grid (DN) conducts natural gas down to each small customer at a lower pressure (Speirs et al., 2017). Gas-fired power plants and most industrial consumers are connected to the transmission grid. Buildings, smaller industrial consumers and gas refuelling stations are connected to the distribution grid (Wachsmuth et al., 2019b; ENTSOG, 2019; Agence ORE, 2020).

Import infrastructure is composed of transmission pipelines and Liquefied Natural Gas (LNG) import terminals (ENTSOG and GIE, 2019). Cross-border transmission pipelines are part of the transport grid and take gas from foreign countries to the national network. Cross-border pipelines exist both within the EU between member states and between member states and non-EU countries (esp. Norway, Algeria, Libya). LNG is conveyed by boat from around the world.

Gas is conveyed to Europe via pipelines, although a minor share comes in the form of LNG. Import infrastructure is connected to the transmission network. Biogas is only produced domestically and biomethane is usually directly injected to the grid, always in the distribution part (Müller-Lohse, 2019). Today, biomethane production represents a very small part of gas supply but its share and volume will likely increase until mid-century (European Commission, 2018b). Past some threshold, biomethane can be cost-effectively injected directly in the transmission grid (ADEME, 2018). In this study, it is assumed that the volume of biomethane production does not cross that threshold and is only injected in the distribution grid for simplicity.

The system boundaries for the gas network (distribution and transmission) chosen in this study are shown in Figure 3.

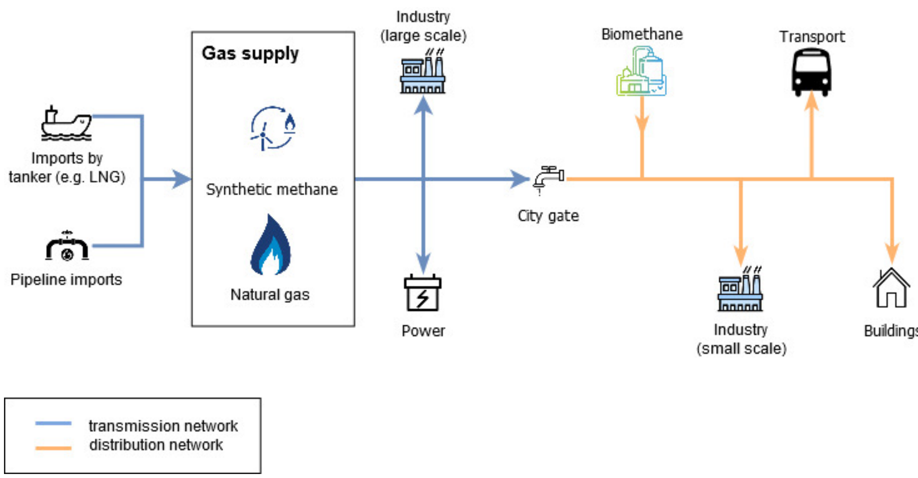


Figure 3: Simplified model of the gas infrastructure used in this study.

## 2.5 Price of methane

This section presents the components of the price of methane. Defining these concepts will provide a theoretical basis to answer subquestion 3.

Most consumed methane is conveyed by the grid. The remaining part is consumed locally (e.g. by CHP plant next to biogas production units) or transported by trailer. The components of methane price from the grid are usually described as follows: energy (the cost of purchasing gas molecules on the wholesale market), marketing and management (the cost for gas facilities to exist as companies), infrastructure (transporting gas between supply and demand), and taxes, which in the EU depend on the member state (CRE, 2017; Grave et al., 2016). The cost structure for methane price without tax given by CRE (2017) and summarised on Figure 4 will be used throughout the analysis. It excludes tax because the level of taxation is not directly dependent on costs.

In particular, infrastructure costs include the cost for distribution, transmission and storage of gas (CRE, 2017). Storage costs are left out of the analysis because they represent a small share of the price of methane. Distribution and transmission costs are composed of investment, operational and decommissioning costs, as shown in Figure 5. Investment costs involve either replacing existing parts of the network which have reached the end of their lifetime (upkeep and renovation, or re-investment) or installing new parts of the network (new build) (Wachsmuth et al., 2019b). In a future with smaller gas demand, investment on the network would be focused on replacing existing equipment, which justifies why only re-investment is depicted in the figure. Operational costs have a fixed and a variable component: the variable component depends on the amount of gas that is transported while the fixed component is primar-

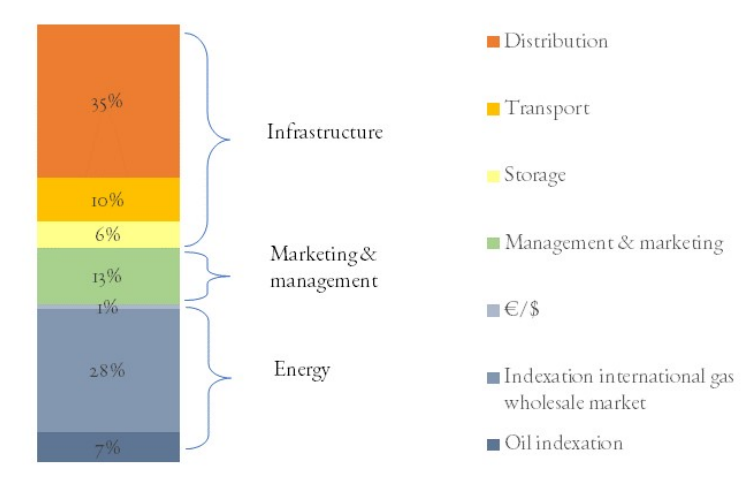


Figure 4: Price components (without tax) of average bill for gas provided by Engie in 2017. Source: CRE (2017), own translation.

ily related to the size of the network. In the distribution network, operational costs include leakage prevention, adding an odorizer, dispatching and the maintenance of equipment. The variable component is negligible (Wachsmuth et al., 2019b). In the transmission network, operational costs relate to each of the five elements it is composed of: pipelines, compressors, pressure regulators, volume flow meters, and process gas chromatographs. Compressors use energy to function, meaning that the variable component of operational costs is not negligible and depends on the gas price (Wachsmuth et al., 2019b). Decommissioning costs describe the cost of getting the distribution and transmission equipment off service in a way ensuring safety. For pipelines, it consists in either demolishing the pipelines, sealing them and cutting access to them (Wachsmuth et al., 2019b). Total decommissioning costs depend on the share of the grid being decommissioned.

The respective weight of investment, re-investment and operational costs in the total costs is different between the distribution and the transmission grid. Wachsmuth et al. (2019b) find from data of the German gas network system operators that operational costs make up resp. 51% and 28% of of overall infrastructure costs for the distribution and the transmission grid, the rest being investment costs. Among investment costs, new build weighs heavier than upkeep and renovation, making up 30% and 50% of overall costs in resp. distribution and transmission, while upkeep only makes up resp. 19% and 23%. No specific data for the French networks was found.

Costs can be expressed as a *total* (in €) or as *specific costs*, that is per unit gas (in €/MWh). For the latter, the total costs are divided by the total amount

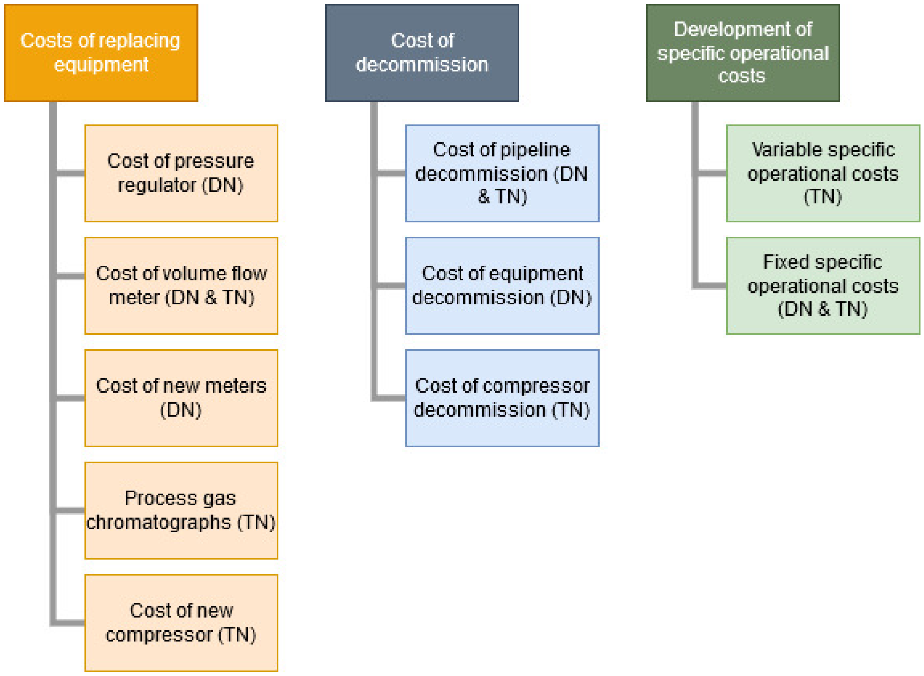


Figure 5: Infrastructure costs: investment in existing network, decommissioning and operational costs. Source: Wachsmuth et al. (2019b), own translation.

of gas they relate to (e.g. total gas demand).

This study aims to propose a rough estimate of the change in methane price by 2050. It will focus on two of the cost components: the cost of energy and operational infrastructure costs. Infrastructure costs and production cost are the components likely to change most fundamentally with the implementation of climate neutrality. Taxes and marketing & management depend on factors largely outside the energy system. Estimating decommissioning costs and investment costs would require a fine modelling of the gas system and gas flows, which is not achievable within the time frame dedicated to this thesis. Up to now, decommissioning costs are virtually zero for French and German networks as gas consumption has remained similar since 1990 (IEA, 2019a,b). They are likely to rise significantly until mid-century: Fraunhofer ISI's Gas Roadmap estimates total decommissioning cost in Germany in a scenario planning a 95% reduction in emissions to range between €3.1 and 17.2 billion (Wachsmuth et al., 2019b).

#### 2.5.1 Cost-demand feedback

Changes to methane price might trigger further changes in demand. A number of studies have explored the relationship between price and consumption of methane. They use the concept of elasticity, which captures the change of demand of a commodity relative to price change (Zhang et al., 2018; DECC, 2016). Elasticity is expressed as shown in eq. (1). The value is usually negative, meaning that an increase in price decreases demand. If the value for elasticity is below 1, demand changes less than proportionally to price and is qualified *inelastic*, conversely for *elastic* demand.

$$\epsilon = \frac{relative\_change\_in\_demand}{relative\_change\_in\_price} \tag{1}$$

A distinction is usually made between short-run (a few months) elasticity and long-run elasticity (a few years). For durable price changes, demand tends to be more elastic in the long term as consumers have time to adapt to new prices.

Estimates for price elasticity of gas demand vary widely. Labandeira et al. (2017) find that energy goods are inelastic in the short- and long-term. Zhang et al. (2018) estimates show elastic demand for power generation, transportation and services. DECC (2016) claim that in the UK residential sector, price elasticity of gas demand is $-0.1$. Similarly, Burke and Yang (2016) find a price elasticity of $-0.9$ and $-0.82$ for residential and industry, with aggregate data from 44 countries.

The fact that price elasticity of gas demand is negative suggests that there is a positive feedback loop between the price of methane, infrastructure costs and the volume of consumer demand for methane, as shown in Figure 6. If infrastructure costs increase because of decreased demand, it might decrease demand even more, creating a vicious circle and exerting pressure on gas infrastructure.

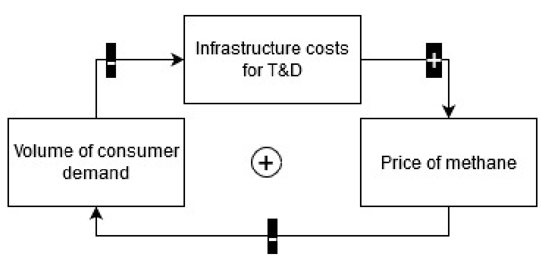


Figure 6: Feedback loop between cost and demand for methane.

Values for price elasticity of demand are highly uncertain. They rely on aggregated data and depend on complex economic feedbacks and trends which are not always accounted for. Most existing studies focus on natural gas prices, yet consumers might react differently when using low-carbon gas. The value for elasticity depends a lot on the availability of substitutes (DECC, 2016). Today's substitutes for natural gas are different than the ones which will be available by mid-century: for example, in industry, hydrogen will likely be much cheaper than today while oil will be more expensive; in residential, the cost of heat pumps or biomass might also decrease a lot. Additionally, price elasticity is defined from historical data and thus only indicates changes associated with price changes within a certain historical range. It can be problematic to apply price elasticity to other ranges of price.

Since this research aims to give only a rough estimate of the possible changes to methane price, the uncertainty of elasticity value is not critical. In any case, values for elasticity and cost feedback should be interpreted with caution.

The theoretical framework presented in this section will be used all throughout the analysis. The relation between the theoretical framework and the rest of the study and the report is shown in Figure 7.

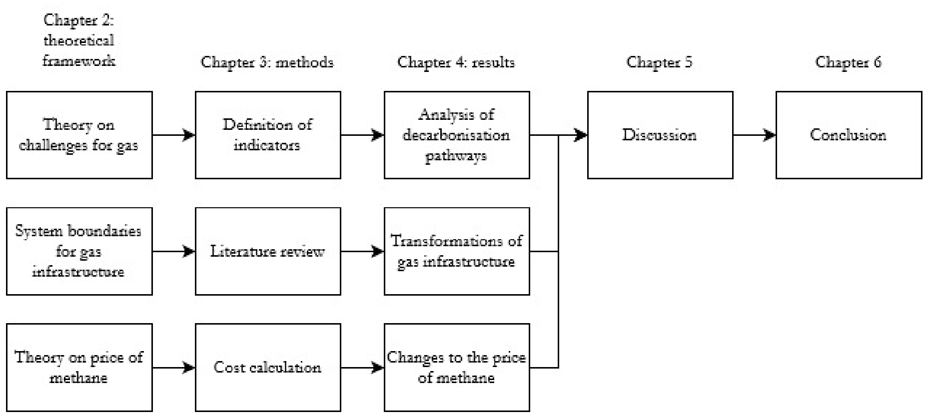


Figure 7: Theoretical framework

# 3 Methods

This section lays out the methods used in this study to answer the research question, detailing first how decarbonisation pathways were analysed (section 3.1), then how the impact of carbon neutrality on gas infrastructure was evaluated (section 3.2), and finally the method used to conduct a cost analysis to determine the consequences on the price of methane (section 3.3). This study uses a mixed-methods approach based on scenario analysis, literature review and cost analysis and relying on both qualitative and quantitative data to best answer the research question. The chapter is structured per research subquestion.

Figure 8 gives an overview of methods used to answer the three research subquestions and the outputs from the research process.

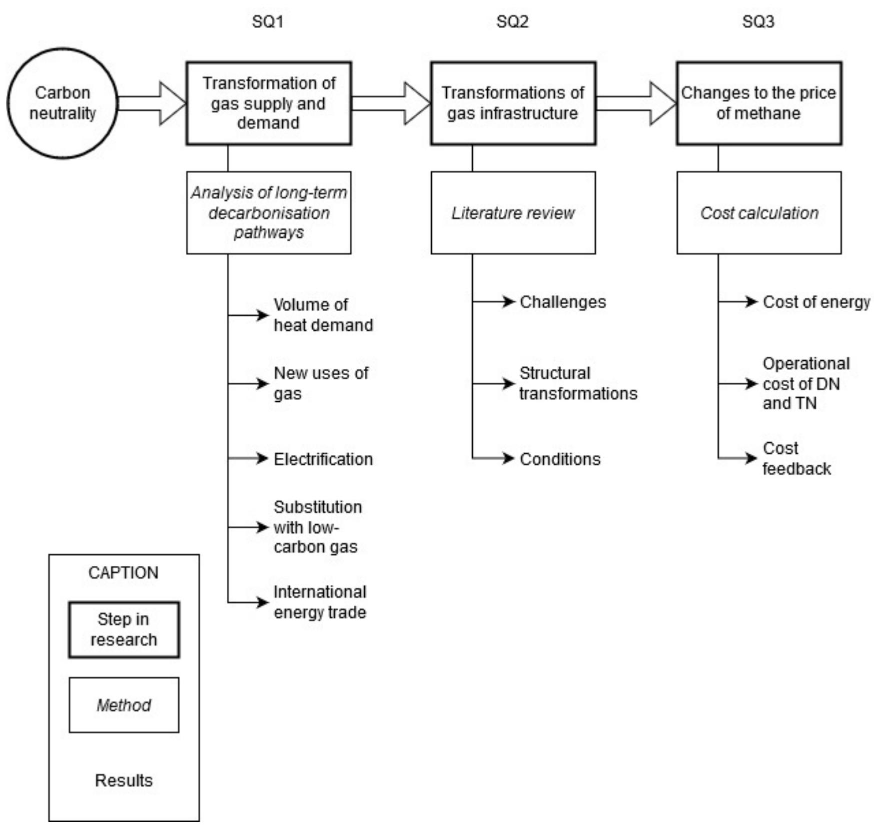


Figure 8: Methodology followed in the study.

## 3.1 Analysis of decarbonisation pathways

To answer subquestion 1, decarbonisation pathways for EU member states are analysed. This section presents the scenarios which are analysed (section 3.1.1) and the indicators used to assess them (section 3.1.2).

### 3.1.1 Scenarios

The scenarios forming the backbone of the analysis are selected based on the following criteria:

- Their time horizon is set at 2050, which is the year set by the European Union to reach net zero emissions (European Commmission, 2019).
- The objective is to reach net-zero emissions by mid-century. Since the net-zero target was only set in 2019, many studies consider the previous target instead, namely a 95% reduction between 1990 and 2050 (European Commmission, 2019). Therefore, decarbonisation pathways aiming for a 95% reduction are also considered if needed.
- Whenever possible, a government-issued scenario is analysed - typically the country's long-term strategy (LTS) to the European Commission. LTSs were submitted in early 2020 to the European Commission and presents countries' vision to reach mid-century climate neutrality in accordance with EU objectives (European Commission, 2018c).

Following these criteria, four scenarios are chosen for France and Germany:

1. The French National Low-Carbon Strategy (MTES, 2020b). It is the French government's roadmap to reach carbon net neutrality by 2050. The SNBC is considered in its final, 2020 version, often named SNBC 2, as laid out in the summary of the underlying scenario (MTES, 2019). It will be referred to with its French acronym "SNBC" in the rest of this study.
2. The négawatt scenario for France to reach net-zero emissions (négawatt, 2017, 2018). Négawatt is a French non-profit organisation aiming to show that alternative energy futures are possible. Their scenario reaches carbon neutrality by 2050 while phasing out nuclear power by 2035 and fossil fuels. The three core principles of the scenario are – by order of priority – sobriety, energy efficiency, renewable energy.
3. dena's EL95 scenario for Germany (Bründlinger et al., 2018). Dena is the German energy agency; its two scenarios EL95 and TM95 were developed in partnership with industry stakeholders. The objective is to reach a 95% reduction in GHG emissions between 1990 and 2050 thanks to quick and extensive electrification of end-use energy applications.

4. dena's TM95 scenario for Germany (Bründlinger et al., 2018). Like EL95, the objective is to reach a 95% reduction in GHG emissions between 1990 and 2050, using however a broader range of technologies and end-use energy carriers.

The German LTS to the EU was left out of the analysis because it is mostly qualitative.

Findings from the analysis of these four scenarios are briefly compared to the European Commission's two carbon neutrality scenarios for the European Union, 1.5TECH and 1.5LIFE (European Commission, 2018b) and put in perspective with elements from the case of the Netherlands, in the discussion section (section 5).

#### 3.1.2 Indicators

In order to assess the gas pathway in decarbonisation scenarios, indicators are defined according to the challenges for gas laid out in our theoretical framework (section 2.3). The indicators are chosen so that they capture the way each key factor is dealt with. Examples of indicators are shown in Table 2 together with the aspect of the role of gas that they relate to. The complete list of indicators with the key factor they relate to are shown in the appendix (section A.1). A list of all indicators per sector is shown in the appendix (section A.2).

Values for each indicator for the year 2015, 2030, 2050 are drawn from the four main scenarios chosen in section 3.1.1. Values for energy indicators are all measured in TWh to be able to easily compare and manipulate the data.

When necessary, values for indicators are calculated from the data in the scenarios so that it matches our indicator framework, using the assumptions shown in the appendix (section A.3). In one case, another indicator was used to make up for the lack of data: in the two dena scenarios, there was not sufficient data available to obtain values for energy demand per carrier per sub-sector in buildings. Therefore, the values for the number of heating systems of each type was used instead.

Scenarios are then compared with each other on the basis of the indicators.

Table 2: Example of indicators used per aspect of the role of gas in achieving carbon neutrality

| Aspect | Indicators (examples) |
|---|---|
| Volume of heat demand | Yearly renovation rate of building stock |
| | Share of gas (methane and hydrogen) in fuel mix (buildings and industry) |
| New uses of gas | Number of refuelling stations for hydrogen and methane |
| | Share of gas in power mix |
| | Volume of electricity used to produce hydrogen |
| Electrification of current gas uses | Share of electricity in fuel mix (buildings and industry) |
| Substitution of existing gas demand with low-carbon gases | Production potential for domestic biomethane |
| | Volume of methane/hydrogen used as feedstock (industry) |
| International energy trade | Volume of methane/hydrogen imports |

## 3.2 Transformations of the gas infrastructure

Decarbonisation scenarios suggest that before 2050, gas demand will undergo dramatic changes, including a large decrease in gas demand in buildings and the rise of gas for backup power generation. This part of the analysis aims to identify the transformations of gas infrastructure which will be required following these changes.

To build a fine estimate of the consequences of carbon neutrality on gas infrastructure, values for gas flow and for the geographical location of the existing grid and of demand are needed, as was done by Wachsmuth et al. (2019b); Trinomics (2016). However in our case, data regarding gas supply and demand, especially its geographical location and sometimes the size of demand per end use is lacking in decarbonisation scenarios. A literature review is conducted instead to determine the range of possible outcomes for the infrastructure.

Academic literature and policy documents are reviewed to determine:

(1) The main challenges that the gas infrastructure will have to face consid-

ering the changes in methane supply and demand which were identified in decarbonisation scenarios;

(2) the associated practical changes for the gas system;

(3) the conditions for these transformations to happen.

Transformations under focus include technical requirements to transport low-carbon gas, the changes in the location of demand and the need for new gas infrastructure. They involve the distribution and transmission grid for methane, methane import infrastructure, hydrogen infrastructure and refuelling infrastructure for vehicles.

Once the main transformations are identified, decarbonisation pathways are scanned to determine whether the challenges facing gas infrastructure changes are taken into account.

## 3.3 Cost analysis

This section lays out the method used to estimate the impact of changes in operational costs and production cost on the price of methane. First, the pathways studied for infrastructure are described (section 3.3.1), then the assumptions for future production cost of methane are outlined (section 3.3.2); finally, the formulas used to calculate operational infrastructure costs are shown (section 3.3.3).

Due to the time constraint, the analysis will focus on only two of the four decarbonisation scenarios: the SNBC and dena's TM95. The SNBC was selected because of its status as the official state roadmap to decarbonisation; as such, it can be considered as a good indication of how carbon neutrality will be achieved in France. For Germany, dena's scenario TM95 offers an interesting counterpoint to the SNBC as it depicts a carbon-neutral future with a large consumption of methane (gas demand increases in all sectors except buildings).

### 3.3.1 Pathways for gas infrastructure

Considering the high uncertainty around future developments for the gas infrastructure, we define two extreme pathways. Using extreme-case pathways allows us to map out the range of change that infrastructure costs might undergo. This section presents the rationale behind the definition of these pathways and the main assumptions.

One crucial variable defining the future development of the transmission and distribution infrastructure is the degree to which the distribution network is decommissioned (Wachsmuth et al., 2019b). That parameter is highly uncertain since the geographical location of future demand is unknown: the criteria determining which buildings are still heated with gas is unclear, as well as demand profiles for gas in the industry, transportation and buildings. Therefore, for each decarbonisation scenario (SNBC and TM95), two extreme pathways for the existing methane (gas) infrastructure are examined:

1. *Infrastructure business-as-usual (BAU)*. Today's infrastructure is kept as is, except that some pipelines are converted to convey hydrogen locally. Infrastructure is overall used much less than today.

2. *Infrastructure optimisation*. The size of the DN is "optimised" according to the volume of demand in buildings. Remaining methane demand in buildings is localised so that the network supplying other buildings is decommissioned. Like in *infrastructure BAU*, part of the transmission network is converted to hydrogen pipelines.

For the import infrastructure, no pathway is defined due to lack of data regarding operational costs of LNG terminals and the use of interconnections in the future.

Each of the two pathways is explored for SNBC and TM95, which are representing respectively the French and the German case. Figure 9 shows the articulation between decarbonisation scenarios used to answer subquestion 1 and the infrastructure pathways drawn to carry out the cost analysis.

The main assumptions for the pathways are as follows:

- The volume of gas transported in the distribution network corresponds to methane demand in buildings, transportation and a third of methane demand of the industry. The one third share for industry stems from the fact that by 2019 in France, one third of industrial methane demand was conveyed by the distribution network (Agence ORE, 2020; MTES, 2019); this share is assumed to remain constant.

- The volume of gas transported in the transport network corresponds to overall methane demand.

- In the transmission network, no decommission takes place and the size of the network does not increase. In the French case, methane demand drops significantly but demand will likely be located all across the country and therefore decommission will be difficult. For the German case, our assumption is coherent with Fraunhofer ISI's Gas Roadmap, which finds that transmission lines are nearly not decommissioned by 2050 (Wachsmuth et al., 2019b). Authors of dena's German scenario find that the increase in methane demand is handled by the existing grid (Bründlinger et al., 2018).

- The assumptions for the length of the distribution network are difference for each pathway:

  - Infrastructure BAU: the length of the network by 2030 and 2050 is the same as in 2015.

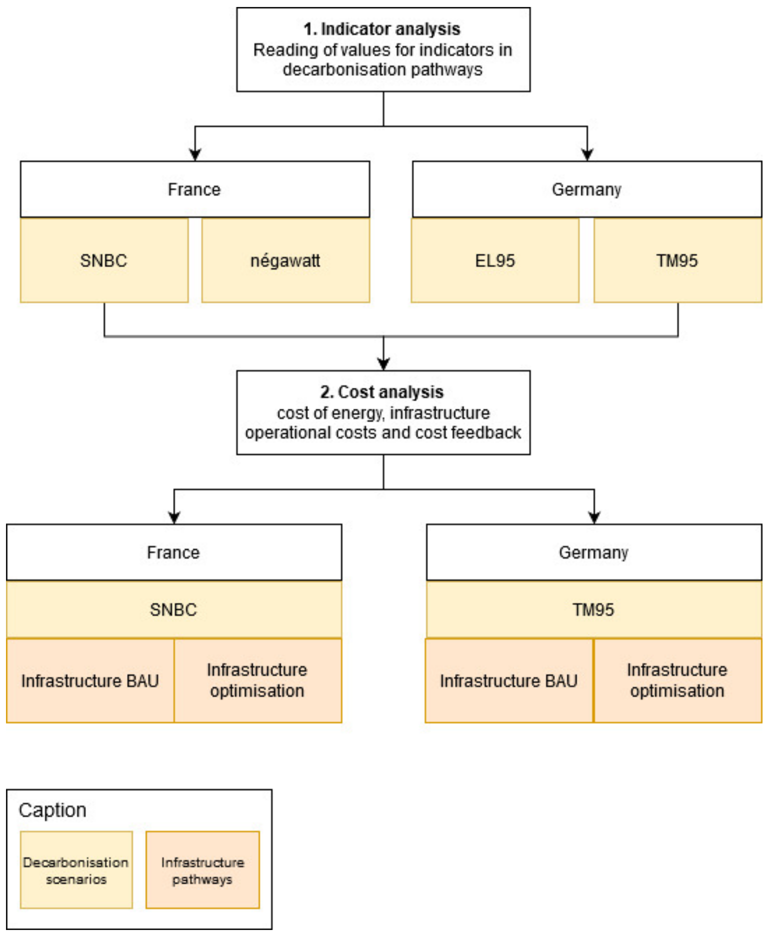


Figure 9: Articulation of decarbonisation scenarios and infrastructure pathways drawn in this study.

– Infrastructure optimisation: the length of the network is proportional to the reduction in methane demand in buildings. Some refuelling stations and industrial consumers are also connected to the distribution grid but their contribution to the size of the network is considered negligible since peak gas demand is mostly caused by buildings. Additionally, part of the decrease in methane demand of buildings is due to energy efficiency; however, we assume that gas buildings are less energy-efficient than the average building stock and therefore the impact of energy efficiency is negligible on gas demand per building.

**Infrastructure use**. To capture the change in use of gas infrastructure depending on our two infrastructure scenarios, we calculate (1) network utilisation [GWh/km] for the distribution and the transmission network and (2) the utilisation rate [%] of import infrastructure for 2015, 2030 and 2050.

Network utilisation for the distribution and transmission network is calculated using eq. (2). $U_{DN,t}$ [GWh/km] is the utilisation of the distribution network in year $t$ with $t = 2015, 2030, 2050$. $V_{DN,t}$ [TWh] is the volume of gas transported in DN in year $t$; $L_{DN,t}$ [1000 km] is the length of the distribution network in year $t$.

$$U_{DN,t} = \frac{V_{DN,t}}{L_{DN,t}} \tag{2}$$

The same formula is used for the transmission network using the respective values for transported volume of gas and length.

The utilisation rate of import infrastructure is calculated using eq. (3). $CAP_{imp,t}$ is the capacity of import infrastructure in year $t$ [TWh/y]. Data for existing capacity ($t = 2015$) is drawn from ENTSOG data (ENTSOG and GIE, 2019) and data for planned capacity is drawn from the Europe Gas Tracker (Global Energy Monitor, 2019). It is assumed that import infrastructure which are labelled by the Europe Gas Tracker to be "proposed" and "in construction" are in service from the planned year onward. $V_{imp,t}$ [TWh] is the volume of methane imports in year $t$. Data for gas imports is drawn from the decarbonisation pathways (Bründlinger et al., 2018; MTES, 2019). No data is available regarding the share of methane imports being conveyed as LNG in decarbonisation pathways.

$$r_{utilisation} = \frac{V_{imp,t}}{CAP_{imp,t}} \tag{3}$$

### 3.3.2 Production cost

This section outlines the assumptions regarding the production cost of methane in France and Germany until 2050. The production cost of methane makes up the energy component of methane price.

For each country, the value for the average production price of methane is calculated as the weighted average of the production price of each methane type, based on the following data:

- Fossil methane: projection from IEA's Sustainable Development scenario for the EU, cited by Bründlinger et al. (2018).
- Biomethane: cost reduction reference pathway in France's Multi-year Energy Programme, which sets objectives for up to 2028 (MTES, 2020a). For the period 2028-2050, it is assumed that the price of biomethane production remains at its 2028 value.
- Synthetic methane: for Germany, it is assumed that all of German synthetic methane is imported, which is consistent with projections of the dena scenarios (Bründlinger et al., 2018). Cost data is drawn from the dena study. For France, synthetic methane is only produced domestically; no data is available as to cost assumptions over the period. The cost is assumed to be the same as for imported synthetic methane to Germany, which is consistent with the average value given by ADEME's study for a 100% renewable gas mix in France (ADEME, 2018).

Assumptions for methane production cost are shown in Figure 10.

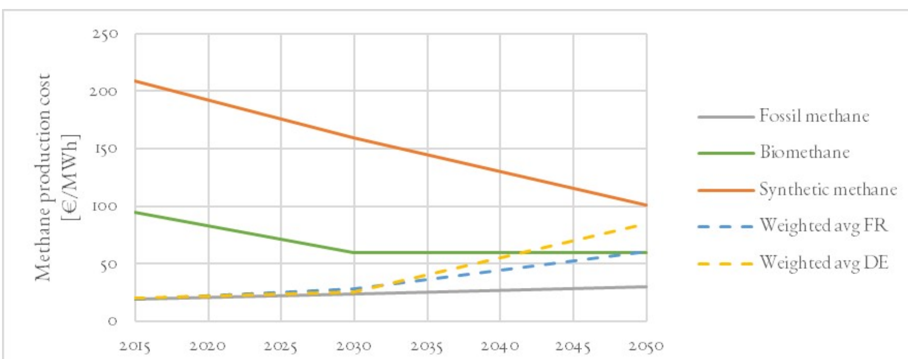


Figure 10: Assumption for average production cost of methane for France and Germany and production cost of methane types between 2015 and 2050. "Weighted avg FR" represents the weighted average for France, resp. "Weighted avg DE" for Germany".

### 3.3.3 Operational infrastructure cost

This section lays out the methodology taken to estimate the future development of operational costs.

A rough estimate of the increase in specific and total operational costs for pipelines is calculated. Operational cost is calculated for the years 2015, 2030 and 2050, separately for distribution and transmission grid and for each infrastructure pathway defined under section 3.3.1. Table 3 shows the data and formulas used to calculate operational costs for the year 2015, 2030 and 2050 in the distribution and transmission grid.

Unless otherwise stated, data is from Fraunhofer ISI's Gas Roadmap for Germany (Wachsmuth et al., 2019b). Data for operational costs of the French transmission system was also available (CRE, 2020) but German data was used instead for simplicity. The values are consistent with each other.

Table 3: Data and formulas to calculate operational costs of the distribution and transmission grid.

| **Data** | **Formulas** |
|---|---|
| Fixed operational costs for DN:<br>$OM_{DN} = 3300$ €/km | Variable operational cost for TN by year t:<br>$OM_{TN,var,t} = Cons_{auto,TN} \cdot p_{gas,t}$ |
| Fixed operational costs for TN:<br>$OM_{TN,fixed} = 9079.3$ €/km | Total operational costs in DN by year t:<br>$OM_{DN,tot,t} = L_{(}DN, t) \cdot OM_{DN}$ |
| Transmission network's own consumption<br>$Cons_{auto,TN} = 2.7$ kWh/MWh | Total operational costs in TN by year t:<br>$OM_{TN,tot,t} = L_{TN,2015} \cdot OM_{TN,fixed}$<br>$+V_{gas,TN,t} \cdot OM_{TN,var,t}$ |
| Fuel price of gas in year $t$: $p_{gas,t}$, see section 3.3.2 | Specific operational costs in DN by year t:<br>$OM_{DN,spec,t} = \frac{OM_{DN,tot,t}}{V_{gas,DN,t}}$ |
| Volume of gas consumed in buildings in year $t$:<br>$V_{gas,buildings,t}$, from decarbonisation pathways | Specific operational costs in TN by year t:<br>$OM_{TN,spec,t} = \frac{OM_{TN,tot,t}}{V_{gas,TN,t}}$ |
| | *For infrastructure optimisation only:* distribution network length in service by year $t$ [km]:<br>$L_{DN,t} = \frac{V_{gas,buildings,t}}{V_{gas,buildings,2015}} \cdot L_{DN,2015}$ |

### 3.3.4 Impact on price

Once the values for operational costs and production costs are calculated, their impact on the price of methane is calculated. The change in price is calculated separately for the period 2015-2030 and for 2030-2050. The cost structure of the methane price is the one given by CRE (2017) and shown in section 2.5.

The breakdown between new build investment, upkeep investment and operational costs in the distribution and transmission cost is drawn from Wachsmuth et al. (2019b). Since in the long term, gas demand will decrease (even though it will slightly increase for Germany), little investment in extending the network will take place between 2030 and 2050. Accordingly, it is assumed that the cost breakdown between investment and operation costs remains the same in the period 2015-2030 but that in the period 2030-2050, investment in new build is brought to zero, as shown in Figure 11. The input data and the formulas used to calculate the impact on price is shown in Table 4.

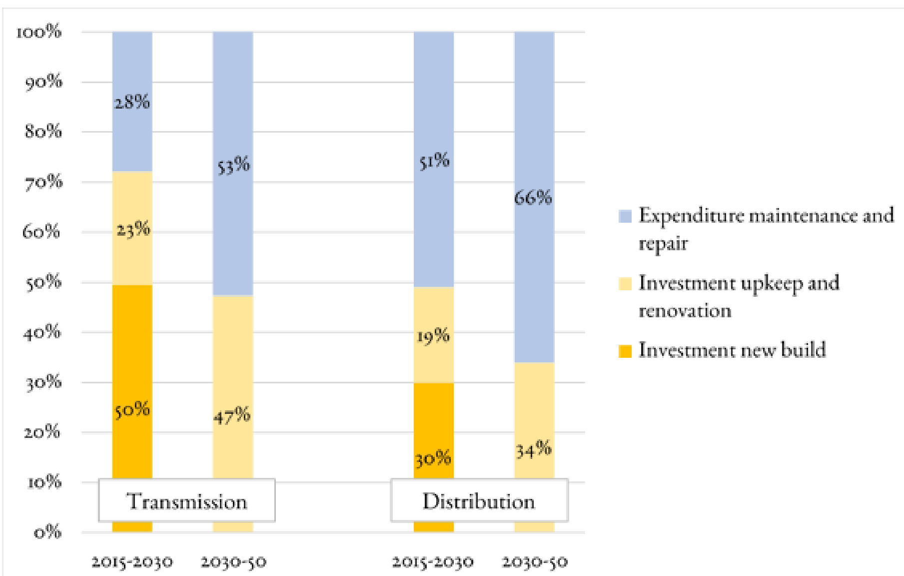


Figure 11: Cost structure of infrastructure cost in 2015-2030 and 2030-2050. Data from Wachsmuth et al. (2019b) and own assumptions.

Table 4: Input data and formulas to calculate the impact of operational costs and production cost changes on methane price.

| **Input data** | **Formulas** |
|---|---|
| Change in price of gas: $\Delta p_{gas}$<br><br>Change in price due to a change in distribution, resp transmission costs: $\Delta p_{DN}$ , $\Delta p_{TN}$<br><br>Change in price due to a change in production cost: $\Delta p_{mol}$<br><br>Change of DN, resp. TN operational costs: $\Delta OM_{DN}$, $\Delta OM_{TN}$<br><br>Change of production cost $\Delta prod_{mol}$<br><br>Share of production cost in methane price $\alpha_{prod,price}$<br><br>Share of operational cost in infrastructure cost for DN, resp. TN: $\alpha_{OM,DN,infra}$ resp. $\alpha_{OM,TN,infra}$<br><br>Share of infrastructure cost in methane price: $\alpha_{infra,price}$ | $\Delta p_{gas} = \Delta p_{DN} + \Delta p_{TN} + \Delta p_{mol}$<br><br>$\Delta p_{DN} = \Delta OM_{DN} \cdot \alpha_{OM,DN,infra} \cdot \alpha_{infra,price}$<br><br>$\Delta p_{TN} = \Delta OM_{TN} \cdot \alpha_{OM,TN,infra} \cdot \alpha_{infra,price}$<br><br>$\Delta p_{mol} = \Delta prod_{mol} \cdot \alpha_{prod,price}$ |

### 3.3.5 Impact on consumer demand

To estimate the feedback between methane price and demand, the additional change in methane demand due to the change in price is calculated. To do so, the concept of price elasticity is used. The change in demand is only calculated for two sectors, residential and industry. These two sectors were chosen because of data availability: since they are the largest consumers of gas today, values for price elasticity are more easily accessible.

The change of price $\Delta p_{gas}$ is the one obtained at the previous step. The associated change in demand in a given sector $\Delta D_{sector}$ is calculated using Equation (4), from Equation (1). $\epsilon_{gas,sector}$ is the price elasticity of gas demand in a given sector.

$$\Delta D_{sector} = \epsilon_{gas,sector} \cdot \Delta p_{gas} \tag{4}$$

Data for price elasticity of methane demand in residential and industry is drawn from the literature. Values for long-term elasticity rather than short-term were chosen since this study considers changes to price in a long-term horizon. Results vary a lot between sources; no study was found on the particular case of France or Germany. To get around some of the uncertainty, two values of elasticity are used: low and high. The low estimate corresponds to the lowest elasticity in terms of effect, which is actually the higher numerical value for elasticity, conversely for the high estimate. The low and high values are the upper and lower bounds of the values found in the literature shown in Table 5. For residential, resp. the low and high estimates are $-0.1$ and $-0.9$. For the industry, they are $-0.82$ and $-0.85$.

Table 5: Values from the literature for price elasticity of natural gas demand in residential and industry

| Source | Elasticity for residential | Elasticity for industry | Notes | Price range |
|---|---|---|---|---|
| Burke and Yang (2016) | -0.9 | -0.82 | Long-run elasticity<br>Data from 44 countries<br>(incl. all EU)<br>for 1978-2011 | 0.04-0.06 €/kWh |
| DECC (2016) | -0.1 | | Long-term elasticity<br>Data from the UK<br>Sample: 2005-2012 | 0.03-0.07 €/kWh |
| Auffhammer and Rubin (2018) | [-0.23;-0.17] | | Data from the US<br>Sample: 2010-2014 | 0.03 €/kWh<br>[SD 0.005] |
| Zeng et al. (2018) | -0.898 | | Data from China | 5.2-31 €/kWh |
| Zhang et al. (2018) | -0.223 | -0.847 | Long-run elasticity<br>Data from China,<br>ex-factory price 1992-2012 | n.a |

# 4 Results

This chapter presents the findings of the study. Results are organised in three parts, first showing the analysis of decarbonisation pathways (section 4.1), then the estimate of changes for infrastructure (section 4.2), finally showing the results of the cost analysis (section 4.3). Results per subquestion constitute building blocks to answer the main subquestion.

## 4.1 Analysis of decarbonisation pathways

This section lays out the results of our analysis of decarbonisation pathways for France and Germany, following the methodology presented in section 3.1. Results are given per sector as defined in section 2.2. For each sector, results include a description of the current situation, an overview of the main transformations up to 2050 per key factor and a highlight of the main gaps in the gas narrative. Values for indicators per scenario are shown in the appendix (section A.2).

### 4.1.1 Buildings

Today, methane is a major energy carrier to supply heat to buildings in both countries, providing over 40% of space heat demand in France in 2015 and making up 55% of residential heating systems in Germany (Figures 12 and 13). The next largest carrier is electricity in France and district heat in Germany. Across decarbonisation pathways, methane consumption decreases dramatically in buildings until 2050: more than -80% for methane demand for space heat in the two French scenarios, -95% and -64% resp. for EL95 and TM95 for the total consumption of methane by buildings between 2015 and 2050. Hydrogen remains unused. Transformations to reach carbon neutrality are the same (house renovations, larger share of district heat, electrification) and all contribute to reducing methane demand, but scenarios show differences in the extent to which each lever is used. As a result, methane demand in buildings decreases dramatically until mid-century, by resp. -83% and -76% in the SNBC and négawatt and by resp. 95% and 64% in EL95 and TM95 between 2015 and 2050.

**Building renovation to reduce heat demand.** All scenarios see a significant reduction (at least $-40\%$) in final energy demand of buildings between 2015 and 2050, which is mostly driven by the renovation of the existing building stock. As shown in Figure 14, renovation rates are similar over the period in France and Germany, although French scenarios assume accelerating rates over the period while their German counterparts are expressed for the whole period. The refurbishment rates of residential buildings in the French SNBC (3.1%/yr of the residential building stock by 2050) have been criticised for being too ambitious, especially considering current rates (Coénove, 2020; The Shift Project, 2020). Despite lower renovation rates, négawatt projects more ambitious space heat demand reduction than SNBC (-65% v. -52% between 2015 and 2050, reaching

150 TWh v. 200 TWh by 2050). One potential reason is that négawatt assumes stricter energy sobriety, e.g. less water use per shower, while the assumptions on the side of SNBC are not explicit.

**District heat to replace methane.** All scenarios project an increasing role for district heat. The trend is stronger in Germany than in France, with district heat making up 9 and 6% of final energy demand of buildings by 2050 in resp. the SNBC and négawatt scenario as compared to 11 and 10% in resp. EL95 and TM95. Contributing factors might be that Germany starts off with a larger proportion of district heat in residential and that it is more densely populated, making district heat potential larger. District heat development participates in the decrease of methane demand.

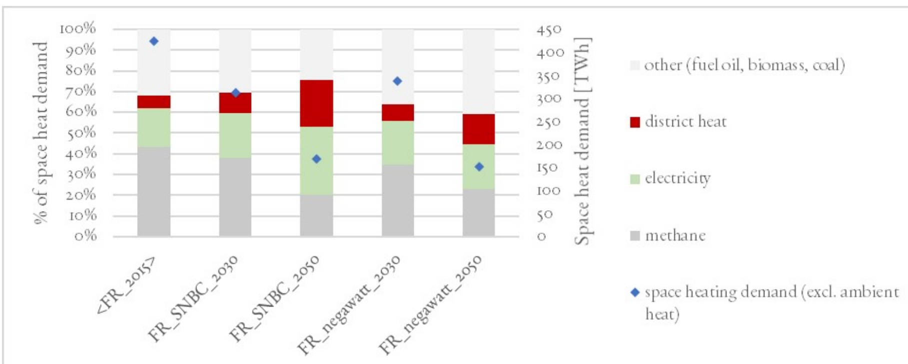


Figure 12: Space heat demand and fuel mix for space heat demand in France, 2015-2050.

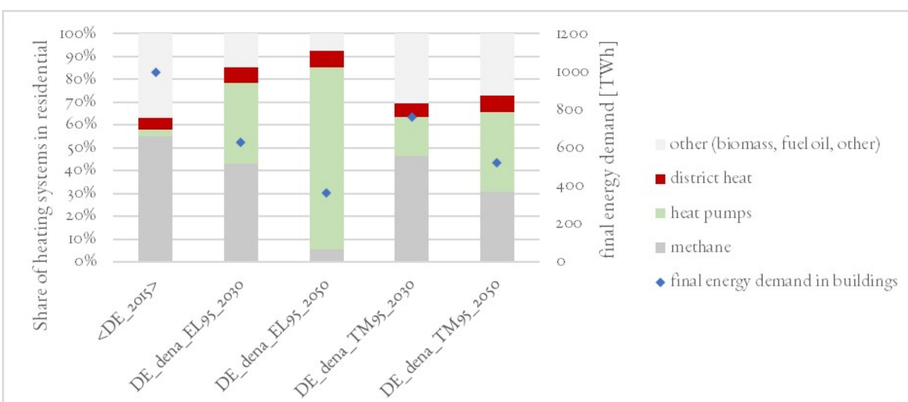


Figure 13: Final energy demand and heating systems per energy carrier in Germany, 2015-2050.

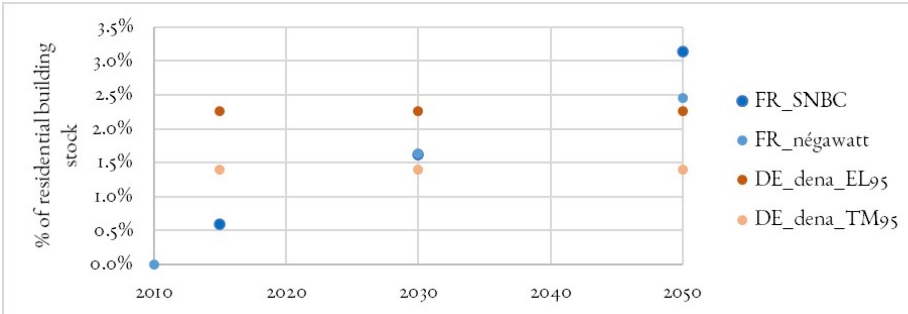


Figure 14: Refurbishment rates of the residential building stock in France and Germany between 2010 and 2050, expressed as the share of the residential building stock going through renovation each year.

**Electrification to replace methane.** In all scenarios, buildings undergo some electrification up to 2050, especially in residential, which relies on heat pumps. As a result, the share of electricity for space heating increases dramatically and it becomes the largest energy carrier, exc. in négawatt where it is a close second. More electrification takes place when renovation is more extensive: the SNBC and EL95 show higher refurbishment rates as well as higher electrification rates than resp. négawatt and TM95. This finding echoes the literature sources stating that improved thermal performance is a pre-requisite for electricity to be used for space heating (Bründlinger et al., 2018; Coénove, 2020; Gas for Climate, 2018).

**Remaining methane demand.** Despite electrification, by 2050 there is still a sizeable methane demand in buildings. Even in EL95, which is the scenario showing the largest electrification, 6% of residential housing still rely on methane. The share of remaining methane demand is larger in residential than in services; probably since it is more difficult to connect to district heat as it tends to be located in less dense areas. It also seems that lower rates of renovation correlate with a larger methane demand (see point above).

**Gaps**. Some aspects in our theoretical framework are consistently not mentioned in the scenarios:

- Demographics and behavioural change: is behavioural change considered in determining the volume of heat demand and how? négawatt's scenario gives values for indicators on living standards but it constitutes a blind spot in other scenarios.
- Rationale behind district heat development: under what conditions are buildings connected to a heat network? what is the fuel mix supplying heat for these networks?

### 4.1.2 Industry

Today, methane is largely used as an energy carrier and as a feedstock for industrial processes, making up 34% of industrial energy demand in France and 25% in Germany, including resp. 13 and 31 TWh for feedstock (see Figures 15 and 16). Yet the largest carrier for energy uses is electricity in both countries. Hydrogen plays virtually no role. The transformations to reach carbon neutrality are the same across scenarios – energy efficiency, new low-carbon industrial processes, electrification, use of low-carbon gases – but they are implemented to very different degrees across scenarios, showing more contrasting perspectives than for the buildings sector. All but one decarbonisation pathway (TM95) project decreasing methane demand over the time period: about -2/3 for the SNBC and négawatt, -38% in EL95, +27% for TM95 in industrial methane demand between 2015 and 2050. Hydrogen demand consistently increases, reaching between 7 TWh in négawatt and 64 TWh in TM95 by 2050.

**Volume of heat demand**. Across decarbonisation pathways, values for heat demand in the industry are not available. All pathways envision deep cuts to industrial energy demand but to different degrees: négawatt projects the largest decrease (-46% between 2015 and 2050), while EL95 only plans a 5% decrease (see Figures 15 and 16). German scenarios assume that energy savings due to efficiency will be compensated by increased output demand and thus project lower absolute reduction of energy demand. The two French scenarios do not clearly state the changes to demand or industry structure underlying the decrease in final energy demand.

- Energy efficiency (EE) measures do not evenly affect all energy carriers. In EL95, overall energy demand decreases by 26% due to EE implementation whereas methane demand decreases by only 18%; most energy savings come at the expense of electricity. Data on EE measures per energy carrier is unavailable in other scenarios.

- Energy demand (incl. methane) transformations show great variation between industrial subsectors and across scenarios. In EL95, residual emissions are only process emissions and are mostly present in chemicals and other industry. On the other hand, while the SNBC projects decreasing energy demand in chemicals (-39% between 2015 and 2050), it increases by almost 70% in EL95 and 14% in TM95.

- Only dena scenarios provide information on the transformations underlying energy demand reduction, indicating that EE is achieved mostly by adopting new processes and fuels.

- Material efficiency assumptions explain some of the differences in final energy demand. They are most ambitious in négawatt's scenario, which projects resp. 90% and 86% of recycling for steel and aluminium from only 57 and 60% today, whereas German scenarios assume more modest improvements for steel's recycling rate and none for aluminium.

**Electrification**. All scenarios see an increase in the share of electricity in the industry, which partly displaces methane demand. This is especially visible in SNBC and EL95, which project that electricity will make up two thirds of energy demand in the industry by 2050 from just over one third in 2015. In the SNBC, electrification mostly takes place in the period 2030-2050 and all industrial sectors use at least 60% electricity by 2050. In the dena decarbonisation pathways, some sectors have little electrification potential (iron  steel, non-metallic minerals), whereas others see wide electrification (paper, business/commerce/services). It is difficult to identify which fuels are displaced by increased electrification as the changes in processes are not always made explicit.

**Gas demand**. Overall, gas demand decreases in share and volume, except in TM95. The decrease is stronger in the two French scenarios. Methane as feedstock is consumed in fossil form, making the industry the only sector still using fossil methane by 2050 (3 TWh by 2050 in SNBC, 49 TWh in EL95, 141 TWh in TM95, no data for négawatt). Hydrogen is developed for both energy and non-energy purposes:

- In the two French scenarios, hydrogen is not used for industrial heat but it takes up as a feedstock, supplying resp. 20 and 7 TWh by 2050 in SNBC and négawatt. Methane consumption decreases by about two thirds in both scenarios between 2015 and 2050, especially in the 2030-2050 period. It is unclear in what processes and subsectors gas is used.
- Germany sees a larger uptake of hydrogen (37 and 64 TWh by 2050 in resp. EL95 and TM95), with significant differences between subsectors:
  - *Iron & steel*. Both EL95 and TM95 completely switch to direct reduction and smelting in electric arc furnace (DRI-EAF) by 2050 for primary steel (switch from coal to natural gas and hydrogen – uses lower temperature heat). In TM95, iron & steel use 24 TWh of hydrogen by 2050. In the future, GHG emissions might be further reduced by using more electrolysed hydrogen.
  - *Aluminium & copper*; *non-metallic minerals*: technologies to displace process emissions are still at early development but these two subsectors are projected to use hydrogen by 2050 (12 TWh for non-metallic minerals in TM95).
  - *Chemicals*. TM95 assumes all ammonia is produced using fossil methane (displacing oil) by 2030 and from 2035, fossil methane is used in upstream methane pyrolysis (zero $CO_2$ emissions); in EL95, 2/3 of ammonia is produced using hydrogen between 2030-2050; from 2035 onward, upstream methane pyrolysis is also used with fossil methane. For ethylene production, oil is replaced with fossil methane. In EL95, by 2030, 40% of ethylene produced using methanol-to-olefins (MTO) process, which is based on electrolysis, displacing methane demand. TM95 uses methane instead, incl. synthetic methane when required, as well as hydrogen (19 TWh in TM95 by 2050).

Note that although the share of ”other” in the fuel mix of the industry in négawatt seems to change little between 2015 and 2050, it switches from mostly coal to mostly biomass.

**Gaps**. Many factors conditioning industrial demand for gas are not well-informed across scenarios:

- Characteristics of industrial heat demand. Only négawatt provides data on the volume of industrial heat demand. Additionally, the split between high- and low-temperature heat demand and the fuel mix for each of them is not shown in any of the decarbonisation pathways.
- Consumer demand: is consumer demand projected to fundamentally transform and how négawatt formulates hypotheses regarding the impact of sobriety on consumer demand for some sectors but it is not discussed in the other decarbonisation pathways.
- Geographical structure of industry: will production of European consumer goods relocate domestically and how will it affect heat demand? The shift of industrial activity within Europe is mentioned in négawatt and SNBC scenarios but there is little analysis on the consequences on energy and gas demand.
- Degree of implementation of EE measures in industrial activities: under what conditions will industrial stakeholders put EE strategies in place and how will it affect heat demand? None of the scenarios mentions this aspect of the transition.

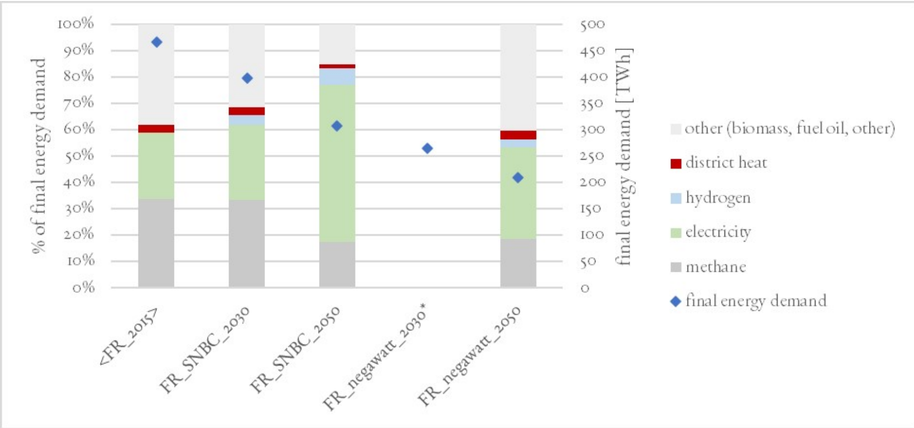


Figure 15: Final energy demand and fuel mix in the industry in France, 2015-2050. Data for the SNBC includes non-energy uses; whether or not non-energy uses are included is unclear for the négawatt scenario.
⋆ in négawatt, no data was available for the industry’s fuel mix in 2030.

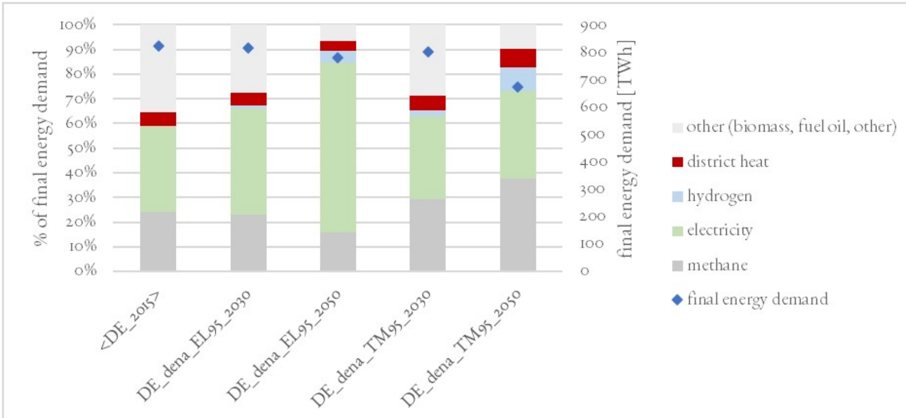


Figure 16: Final energy demand and fuel mix in the industry in Germany, 2015-2050. Whether or not non-energy use is included is unclear from the data.
⋆⋆ Values for biomethane consumption in 2015 and 2030 correspond to injected biomethane only.

#### 4.1.3 Power

Today's relationship between gas and electricity is quite different in France and Germany. France has a low-carbon baseload with nuclear, with lower rates of variable renewable energy sources (VRES) in the power mix. Barely any gas-fired electricity is used. Germany's power mix shows more VRES; gas is increasingly used for flexible backup. Accordingly, the transformations of the role of gas in the power sector are quite different between the two countries, as shown in Figures 17 and 18.

**Impact of electrification of end uses**. Except for négawatt, all scenarios see a significant increase in electricity demand across sectors up to 2050, which raises the question of grid stability, especially for buildings, whose heat demand shows larger seasonal variation. Only dena pathways provide data for sectoral peak electricity throughout the year. It suggests that future load curve will show larger variation through the year calling for seasonal storage, e.g. in the form of gas. This is especially the case in buildings, where peak electricity increases by 100% and 50% in resp. EL95 and TM95. In the industry, in EL95 peak electricity demand increases substantially (+60% between 2015 and 2050) while electricity demand "only" increases by 55%. This echoes the fact that part of industrial electricity demand, e.g. in aluminium & copper sector, is not flexible. On the other hand, in the two French scenarios, electricity demand for space heating actually decreases (-29% in SNBC, -64% in négawatt), and négawatt mentions that winter peak heat demand is reduced thanks to electrification. Coénove (2020) claim that winter peak electricity demand increases by 15% between 2012 and 2050 with the SNBC.

**Deployment of gas-fired power plants**. In all scenarios (exc. négawatt), the volume of methane used in power generation increases: +24% in the SNBC, +105% in EL95, +33% in TM95. Hydrogen also takes up exc. in négawatt, making up between 15 (SNBC) and 40 TWh (EL95 and TM95) of the primary energy used by power plants by 2050. Gas power plants are used for flexible generation; methane is more used than hydrogen. In France, the volume of gas used in power generation remains quite small in the SNBC (less than 40 TWh of gas by 2050) and is totally phased out by 2050 in négawatt's scenario. The fact that Germany will rely on variable renewables by a larger share than in the SNBC already by 2030, while France will still rely on nuclear power, partly explains why gas-fired power generation is more used in Germany. But this argument is not valid when it comes to the négawatt scenario, in which 65% of power generation comes from renewables by 2030 and no nuclear power is used after 2035. It is unclear how flexibility is otherwise provided to the network. Négawatt's scenario does project a nuclear phaseout by 2035 but sobriety and efficiency in end-use sectors reduce the need for flexible power generation, which is ensured by biomass-CHP and a little biogas. Across scenarios, hydrogen is used very little for flexible power generation, which is in line with projections in the EU's 1.5TECH and 1.5 LIFE and in the Dutch plan for hydrogen (European Commission, 2018b; MEZK, 2020a).

**Role of hydrogen in power capacity.** In the two pathways with large hydrogen consumption (négawatt and TM95), hydrogen generation is an important driver for electricity demand, making up resp. 36% and 23% of electricity demand by 2050, but it is unclear whether additional power capacity is required. In the négawatt scenario, hydrogen generation is explicitly sized so that there is no electricity curtailment, which would suggest that this is not the case. In other scenarios, the rationale is less clear; the two dena scenarios seem to be based on end-user demand rather than power demand-supply mismatch.

**Role of electricity imports/exports**. In terms of electricity supply, no major shift takes place. In the SNBC, France remains a net exporter with imports decreasing to zero, although less electricity is exported. Germany becomes a net importer by 2030 in both scenarios; it remains so until 2050 in EL95 while it becomes a net exporter again in TM95 by 2050 (volumes of gross imports and exports are unknown). For Germany, imports are a way to compensate the decreasing coal and gas capacity.

**Gaps.** One main defining factor for the future role of gas in the power system was not addressed sufficiently in the scenarios.

- Impact of carbon neutrality on grid stability, esp. peak electricity. The two dena scenarios do show the values for peak electricity in 2015, 2030 and 2050, which give an indication on the variation in demand through the year and helps determining the size of the power grid. However, they do not mention the role of flexible power storage other than gas, such as battery storage. French scenarios do not mention the precise role of each balancing technology for balancing the grid.

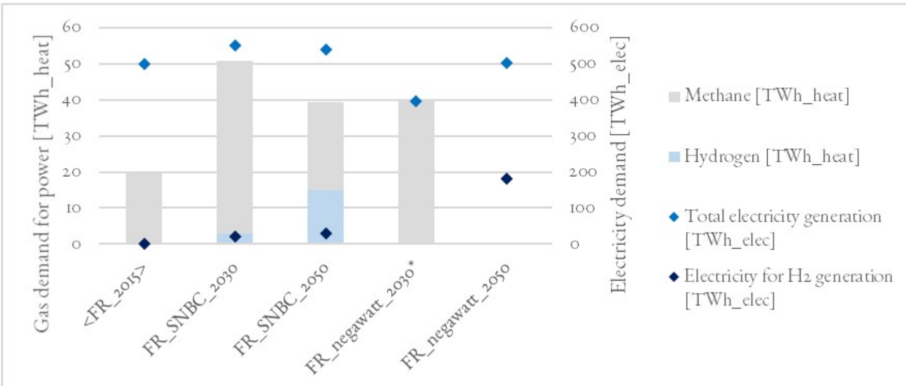


Figure 17: Electricity production, production dedicated to hydrogen generation and the role of gas in the fuel mix in France, 2015-2050.
⋆ in the négawatt scenario, data for the role of hydrogen in the power mix in 2030 was not available.

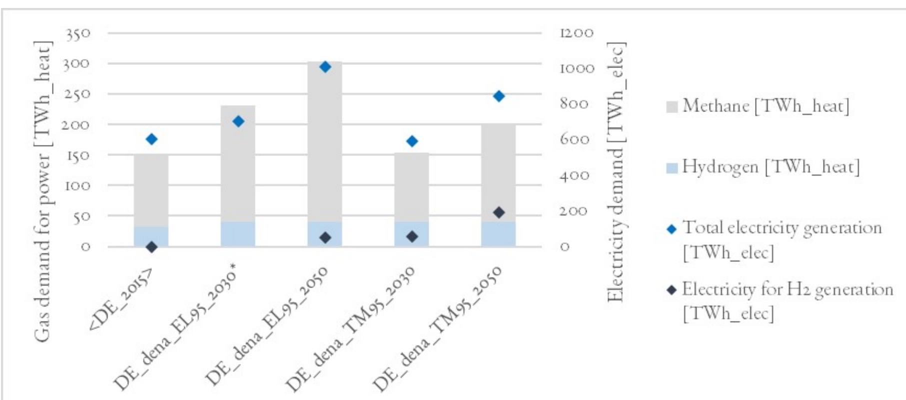


Figure 18: Electricity production, production dedicated to hydrogen generation and the role of gas in the fuel mix in Germany, 2015-2050.
⋆ In EL95, data for the amount of electricity dedicated to hydrogen production was not available for 2030.

### 4.1.4 Transportation

Today, virtually no gas is used for transportation. Both methane and hydrogen become major energy carriers by 2050: final energy demand for methane increases between three- and thirty-five-fold (resp. SNBC and négawatt), while hydrogen consumption develops, reaching between 1 TWh (SNBC and négawatt) and 120 TWh (EL95) by 2050. Transformations take place mostly in the period 2030-2050.

**Transport energy demand**. All scenarios project a sizeable decrease in energy demand (see Figures 19 and 20). It is partly related to higher electrification (electric powertrains are three times as efficient as thermal ones) and to the decrease in transport demand (esp. in passenger transport). Energy demand in transportation decreases similarly in both French scenarios (about 60% between 2015 and 2050) and by about half in German scenarios with a stronger decrease in the electrification scenario. All pathways see a significant increase in freight transport activity (exc. négaWatt) and a small decrease in passenger transport activity (exc. SNBC). SNBC is the least ambitious scenario in terms of transport demand reduction, with also a sizeable increase in passenger transport demand (+26%). Transport demand, esp. in freight, conditions the levels of gas demand.

**Gas uptake as transport fuel**. Both hydrogen and methane take on a larger role in all scenarios, especially in freight transport, assumedly because freight transport requires long ranges with heavy goods, which cannot be ensured by electric powertrains. Only German scenarios widely develop hydrogen as an energy carrier by 2050, more so in the electrification scenario (120 TWh by 2050 corresponding to 36% of transport FE demand in EL95 v. only 1 TWh in each French scenario). négaWatt projects a much more important role for gas (methane) than other scenarios; it makes up 91% of FE demand in 2050 in freight and 57% in passenger transport: since the scenario projects less demand across sectors, relatively more biogas is available for the transport sector.

**Electrification of transportation**. Methane and to a lesser extent hydrogen compete with electricity. All scenarios show a large uptake of electricity in the transport sector, with SNBC and négawatt showing resp. the largest and the lowest share in 2050. The SNBC favours electric powertrains for passenger transport for their energy performance, stressing however that part of the electric vehicles might be powered by fuel cells. On the other hand, négawatt favours biomethane over electricity in general and especially outside urban areas, because of its lower environmental impact over its lifetime, as some studies have suggested (IFP Energies nouvelles, 2019). In Germany, the uptake of electricity is a little higher in EL95, at the expense of methane.

Some gaps regarding the role of gas in transportation remain:

- Refuelling infrastructure: how large will the refuelling infrastructure be? where will it be located?

- Breakdown of fuel mix between freight and passenger transport is not always explicit, when it is essential in understanding the need for refuelling infrastructure. In Germany, overhead lines are mentioned in the dena scenarios and

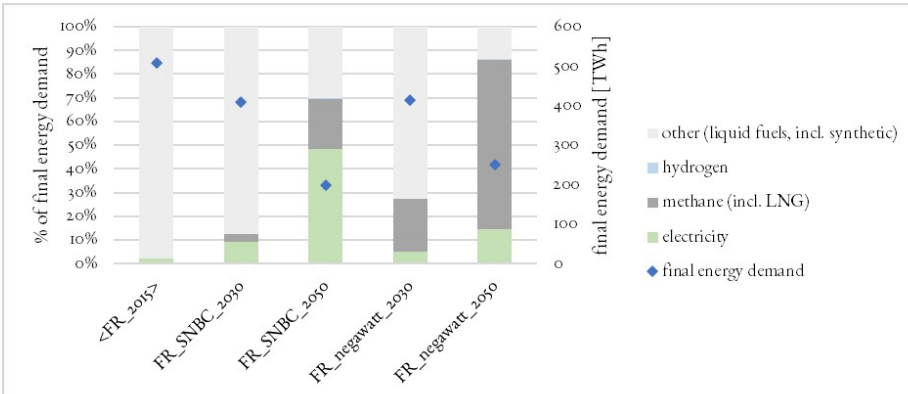


Figure 19: Energy demand and fuel mix in transportation in France, 2015-2050

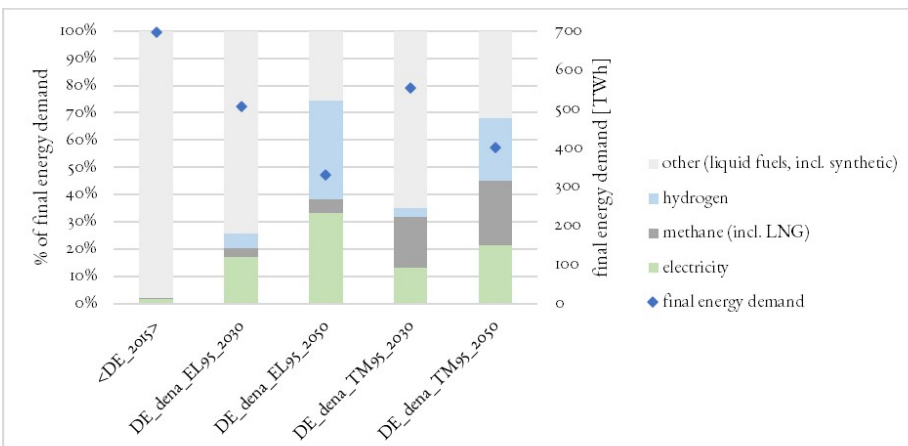


Figure 20: Energy demand and fuel mix in transportation in Germany, 2015-2050

#### 4.1.5 Gas supply

Today, almost all gas consumption in both countries is imported fossil methane. All scenarios see an near-complete fossil gas phaseout by 2050, mostly in the 2030-2050 timeframe, as shown in Figures 21 and 22. Residual consumption remains in the industry for non-energy purposes.

**Methane**. Overall, there is a significant decrease of methane consumption except in TM95 between 2015 and 2050: -60% in the SNBC, -43% in négawatt, -37% in EL95. Fossil methane gas consumption is partly substituted with renewable gas, either as biomethane or synthetic methane and hydrogen.

- Biomethane is given more central role in France than Germany in terms of share, making up 77% of gas supply in SNBC by 2050 and 69% in négaWatt, while in EL95 and TM95 scenarios it represents resp. 26% and 11% of gas supply. However, in absolute amounts the biogas potential is similar (around 200 TWh in France and around 100 TWh in Germany); in both cases biomass is used up to its maximum potential. The French biogas potential is based on one study by Solagro (Solagro and Inddigo, 2013); estimates vary widely between studies (Searle et al., 2018; MTES, 2018).

- Synthetic methane takes on a much larger role in Germany than in France, with only 3 TWh in the French SNBC and 86 TWh in négawatt's scenario by 2050, compared to 630 TWh in TM95 and half that amount in EL95. The difference between the two French scenarios might stem from the rationale to work out PtX potentials. Although the way SNBC works out hydrogen and power-to-methane potentials is not explicit, authors claim to rely as little as possible on technological breakthroughs(MTES, 2020b). On the other hand, négawatt works out the electrolysed hydrogen potential from the amount of curtailed electricity and assumes that all hydrogen which cannot be used directly in the industry or for transportation is converted to methane. In German scenarios, power-to-methane is a lot more developed, possibly because of four main factors: (1) Germany shows a much larger methane demand for power generation and to a lesser extent in industry; (2) the German biogas potential is proportionally and absolutely lower than in France; (3) the narrative in Germany around PtX is less reluctant as shows the fact that most German scenarios include some PtX (Schnuelle et al., 2019); (4) dena scenarios were built with industrial stakeholders while the French ones were developed by resp. the government and an environmental non-profit. In Germany, PtX (incl. power-to-methane) is central to abate the "last" 15% of emissions, as shows the comparison between the two dena scenarios projecting a 95% emission reduction between 1990 and 2050 and the ones only looking at a 80% reduction. In addition to volumes of synthetic methane consumed, German scenarios also stand out in their reliance on imports to supply that methane, making up almost 75% of PtX consumption by 2050 in EL95 and over 80% in TM95. Such imports is partly made possible by low cost assumptions for imported synthetic methane, which is one-fourth the cost of the one produced domestically by 2050.

**Hydrogen**. All scenarios project some use of hydrogen until 2050, rising especially in the period 2030-2050 (Figures 21 and 22). In both countries, hydrogen is mostly produced domestically. The volumes of hydrogen developed in Germany are a lot larger, 169 TWh by 2050 in both scenarios, whereas it only makes up 40 TWh in SNBC and 8 TWh in négawatt. The difference might stem from the method used to estimate the hydrogen potential, which in dena scenarios is based on end-user demand, whereas négawatt is basing its estimate on curtailed electricity (SNBC is not making its rationale explicit). On the other hand, dena scenarios still rely on some hydrogen produced from fossil methane until 2030, while it switches over completely to electrolysers after that date. Some blind spots remain in the decarbonisation strategies:

- Cost development of methane & hydrogen: how will the cost of hydrogen and methane evolve and how will it condition its use?
- Level of biogas consumption: in the two German scenarios, little insight is available regarding the development of biogas: volume of biogas consumption, process used to produce it.

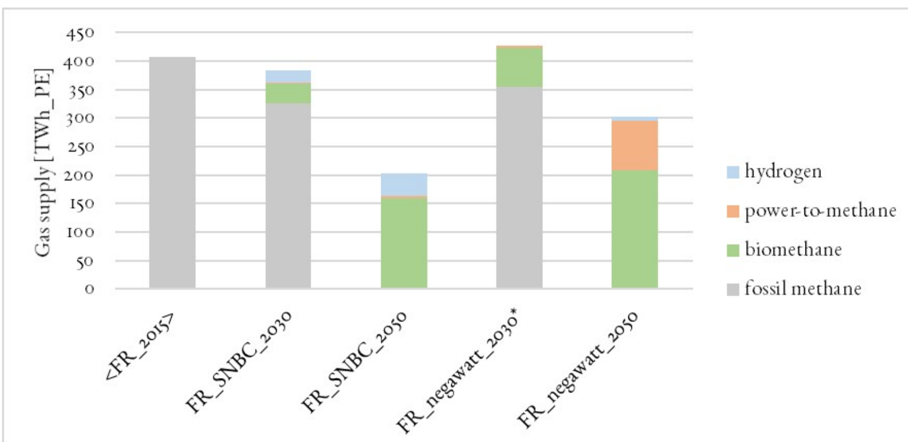


Figure 21: Gas supply in France across scenarios (incl. non-energy use), 2015-2050.
⋆ in négawatt, no data was available for the industry's fuel mix in 2030, meaning that the value for gas consumption in the industry for 2030 is unknown.

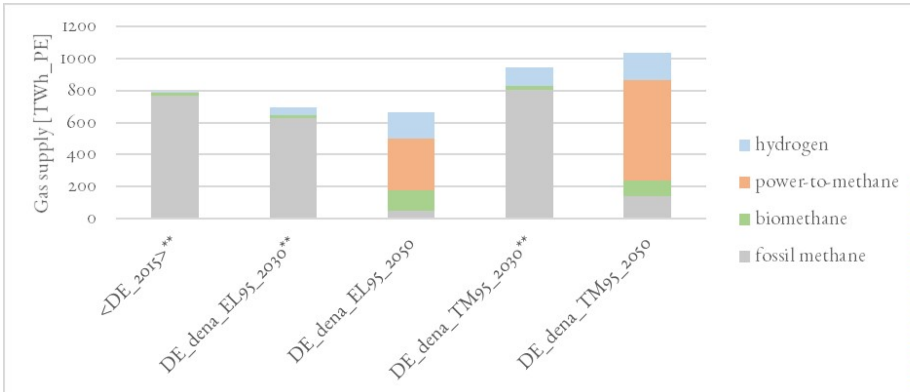


Figure 22: Gas supply in Germany across scenarios (incl. non-energy use), 2015-2050

#### 4.1.6 Summary of findings

According to the decarbonisation pathways analysed in this study, the gas system will undergo significant changes until 2050:

- Methane demand will decrease significantly, as can be seen on Figure 23. The emergence of methane in transportation and the strengthening of the role of methane in power generation does not compensate for energy efficiency and electrification of heat in buildings and the industry. The role of methane is stronger in the industry and in the power sector in Germany, while in the négawatt scenario for France methane is the strongest in transportation. In the SNBC, methane demand decreases more quickly than final energy demand, meaning that the role of gas in the energy system decreases. In the other three scenarios, methane decreases less (increases for TM95) than final energy demand, which suggests that the role of gas increases.

- Methane supply will change completely: natural gas disappears almost completely from the mix and is partly displaced by low-carbon alternatives. The French methane mix relies almost exclusively on domestic biogas (Figure 21) while Germany develops imports of synthetic methane (Figure 22).

- Hydrogen demand develops until 2050 in the industry and power generation (Figure 24). In transportation, hydrogen takes up in both countries but in much larger volumes in Germany. Hydrogen demand is much larger in Germany than in France.

- Hydrogen supply is domestic and is mostly produced with electrolysis. The German scenarios keep the SMR door open.

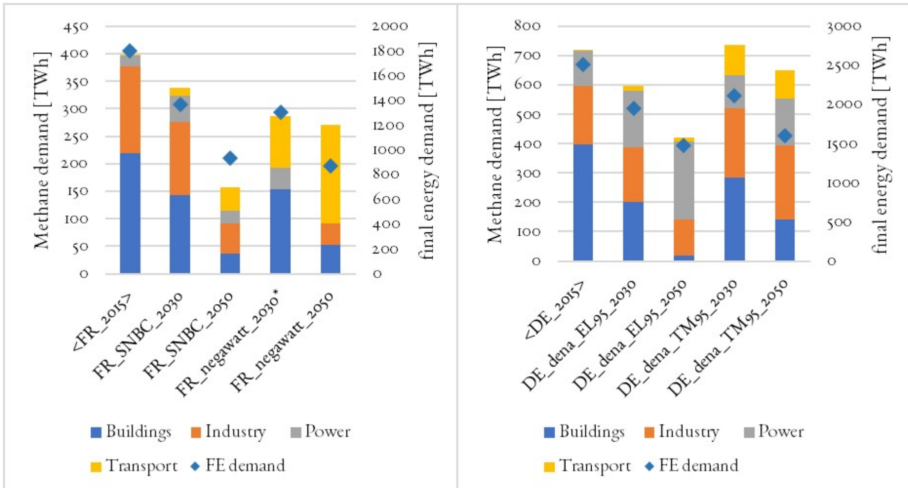


Figure 23: Methane demand per sector (incl. non-energy use) and total final energy demand in France and Germany, 2015-2050.
⋆ in négawatt, no data was available for the industry's fuel mix in 2030.

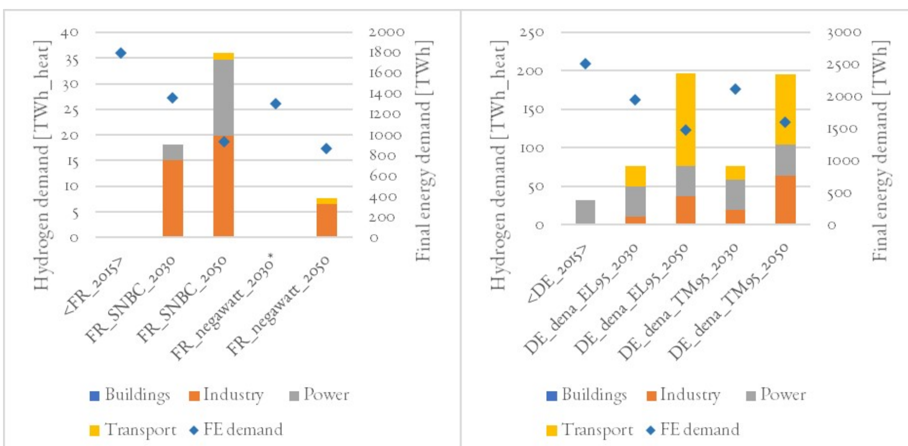


Figure 24: Hydrogen demand per sector (incl. non-energy use) and final energy demand in France and Germany, 2015-2050.
⋆ in négawatt, no data was available for the industry's fuel mix in 2030.

The next section will explore what theses changes might mean for gas infrastructure.

## 4.2 Transformations of the gas infrastructure

This section lays out the results of the literature review regarding the possible transformations of the gas infrastructure. Five main challenges were identified: integrating biomethane, integrating hydrogen, determining the future size of the distribution and transmission network, deciding the future of import infrastructure and building adequate gas refuelling infrastructure. The section is structured following these five aspects. Table 6 summarises the main challenges faced by gas infrastructure and the changes which might ensue, as well as the key factors which will condition these changes.

### 4.2.1 Integration of biomethane

According to the decarbonisation pathways, much of biomethane production in France and Germany will be directly injected in the methane grid. As opposed to natural gas, biomethane production units inject gas in the distribution network rather than the transmission network (ADEME, 2018). Additionally, biomethane supply is located in rural areas whereas natural gas supply to the grid is injected in the grid at LNG terminals and at cross-border interconnections.

To accommodate for the new methane supply, connection points will need to be built. The amount of the additional costs associated with the SNBC scenario is difficult to estimate when no indication is given on the location of supply and demand. ADEME (2018) estimate that connecting biomethane and power-to-methane of biogenic origina to the methane network would generate costs of 2.9-3.7 €/MWh. Additionally, beyond some volume of biomethane injection, gas cannot only be consumed locally and it needs to be transported further in the network (ADEME, 2018). Reverse flows are required to transport the gas in other parts of the network. The cost of installing reverse flows is relatively low when compared to the cost of biomethane: according to ADEME (2018), it would range between 0.11 and 0.18 €/MWh depending on the location, while biomethane is planned to cost around 60 €/MWh by 2028 in France (MTES, 2020a).

Connecting biomethane production units to the grid will need to articulate with the rest of methane demand on the distribution network. If biomethane production is located in areas where buildings are completely electrified, it might be more cost-efficient to put the grid off service and to use biomethane for local applications instead of injecting it.

### 4.2.2 Integration of hydrogen

The emergence of hydrogen demand will require dedicated infrastructure to convey hydrogen from production sites to demand. The main challenge for the gas infrastructure is the cost of making hydrogen-compatible pipelines, which will depend on the amount of pipelines which are needed.

Hydrogen can be transported in gaseous form (in pipelines) in liquid form, or chemically bonded to other molecules, called liquid organic hydrogen carriers (LOHCs). Liquefaction is for now quite expensive and LOHCs are not yet market-ready (Frontier Economics, 2018). For the case of Germany and France, it is safe to assume that hydrogen will mostly be transported in gaseous form in the 2050 timeframe.

The size and location of the hydrogen network which would be necessary to achieve the decarbonisation pathways is uncertain. For the distribution network, demand would only come from refuelling stations since none of the four scenarios projected hydrogen consumption for buildings. This means that no or little distribution network will be needed. The hydrogen transmission network would supply power plants and industrial sites. In the dena scenarios, it is projected that industrial hydrogen demand is essentially supplied with pipelines. For the industry, part of hydrogen demand might be supplied with on-site production and would therefore not require transport infrastructure. In France, the two decarbonisation pathways project quite modest hydrogen consumption (40 TWh by 2050 in the SNBC), only in transport and the industry. This suggests that hydrogen would only be transported by a dedicated network in clusters and not at a diffuse level (GRTGaz, 2019).

Authors seem to agree that the cheapest way to build hydrogen networks is by upgrading natural gas pipelines, as opposed to building new lines (Cerniauskas et al., 2020; Wachsmuth et al., 2019b; Bründlinger et al., 2018). Hydrogen cannot be transported in natural gas pipelines beyond a certain share of hydrogen admixture (under 10%) because it weakens the pipeline structure (hydrogen embrittlement) (Gerhardt et al., 2020). Adapting a natural gas pipeline to transport pure hydrogen requires adding other molecules (e.g. dioxygen) to the gas or a protective layer inside the pipeline. Steel pipelines, which are predominant in the transmission network, might need to be completely replaced (Element Energy, 2018b; GRTGaz, 2019). There is still significant uncertainty regarding the technical conditions for upgrading natural gas pipelines. For non-steel pipelines, which are predominant in the distribution network, hydrogen does not significantly impact the material. Therefore, it is generally easier to convert distribution pipelines to hydrogen (GRTGaz, 2019; Trinomics et al., 2019). The cost might be significant. GRTGaz (2019) claim that costs to adapt enough pipelines to comply with the SNBC (40 TWh by 2050) would cost between 1 and 8 €/MWh by 2050. The estimate by Fraunhofer ISI's Gas Roadmap for Germany is higher, ranging between 10 and 19 €/MWh by 2050.

Hydrogen will typically be produced using VRES, which suggests that its production will not necessarily follow consumption through time. Therefore, long-term hydrogen storage would likely be needed to ensure security of supply. Centralised storage of hydrogen is provided mostly by salt caverns and as a liquid at import terminals; distributed storage provides intra-day storage and is located close to high demand locations, provided by line packing/above-ground storage (Element Energy, 2018b). In Germany, there is potential for long-term hydrogen storage in the North (close to electricity production sites), which would require transport network from the North to the hydrogen-consuming areas (Cerniauskas et al., 2019; Wachsmuth et al., 2019b). In France, it is still unclear whether salt caverns and aquifer reservoirs would be fit to store hydrogen (GRTGaz, 2019; Tlili et al., 2020).

### 4.2.3 Size of the network

All but one of the scenarios analysed in this study for France and Germany envision a decreasing methane demand overall, which is consistent with projections for Europe in the Commission's two scenarios reaching a 95% reduction of emissions (European Commission, 2018b) and with the ENTSOG and entsoe's Ten-Year Network Development Plan (ENTSOG and ENTSO-E, 2020). For the one scenario which projects an increasing methane demand (TM95 for Germany), authors indicate that the existing grid is sufficient to supply the additional demand (Bründlinger et al., 2018). Here, we focus on the case of decreasing methane as it is the most likely development.

With decreasing demand, gas infrastructure will likely be less used than it is now. The fact that most of the distribution and transmission cost is not related to gas demand total costs would not decrease as much as gas demand. As a consequence, part of the network could be decommissioned because it has become too expensive to maintain.

The issue of decommission is depends on parameters which are not described in detail in decarbonisation pathways. It depends on volume of gas demand, which are usually mentioned, but also on the required network capacity, which relates to the maximum gas flow of gas demand (Bründlinger et al., 2018). In the two German scenarios, by 2050 peak gas load is due to consumption in buildings and the power sector. Authors of the scenarios state that existing infrastructure is sufficient to cover the additional peak gas load projected in its scenarios (Bründlinger et al., 2018). Findings from the literature for the UK case indicate that the maximum gas flow is likely to decrease with the electrification of buildings and that intra-day variation of the load will increase Baruah et al. (2014); Qadrdan et al. (2019). This suggests that the size of the distribution network is strongly related to the size of methane demand in buildings. It is consistent with the findings of Wachsmuth et al. (2019b), which finds that one third of the distribution network might be decommissioned in a Germany with 95% less emissions than in 1990. The changes in methane demand of other sectors connected to the DN (transportation and small industry) as well as biomethane injection need to be consistent with changes in demand of buildings. For the transmission network, demand will decrease less (in the case of TM95, slightly increase). Residual demand will be distributed over the country (power plants, industrial sites, etc.). For that reason, it would probably be more difficult to phase out parts of the transmission network, notwithstanding costs.

Aside from the size of demand, decommissioning the network will depend on the location of demand. If residual methane demand is concentrated, other parts of the distribution network will not be used at all and can easily be decommissioned. However, if methane demand remains diffuse, less of the network could be decommissioned.

Decommission could significantly impact the pricing of methane. Infrastructure costs per unit gas would increase, which might mean that it would not be cost-efficient to maintain a gas infrastructure. Financing gas infrastructure today is paid for a large part by consumers (CRE, 2017). In a future with higher infrastructure costs, the corresponding price increase might accelerate the switch away from gas. In this context, the business model of system operators will need to evolve (Wachsmuth et al., 2019b; Trinomics et al., 2019).

### 4.2.4 Import infrastructure of methane

Scenarios all show decreasing methane imports, which raises the question of the future use of import facilities. Today, both countries import nearly all of their methane consumption, mostly by pipeline and ship as LNG (Eurostat, 2020). With decreasing gas demand, import assets might become stranded and generate additional costs.

SNBC and Négawatt both project complete energy independence by 2050 with decreasing imports until then. As a consequence, the country's operating 4500 TWh/yr import capacity might become superfluous. The additional 1260 TWh/yr capacity proposed to be operational from 2024 (Inman, 2020) seems to be at odds with the country's climate roadmap.

Germany plans to purchase nearly all of its methane consumption as PtX on the global market. Dena scenarios do not mention detail on how this synthetic methane would be supplied but it technically can be conveyed as gas in pipelines or as LNG. There is significant uncertainty regarding the potential for such a market to develop by mid-century. Frontier Economics finds that the global market for PtX will become significant in size (medium case: 20 PWh, corresponding to 3-6 TW of electrolyser capacity), with various countries around the world showing large PtX potential (e.g. Norway, Algeria, Mexico). However, it will require technological development, regulation and facilitation (Frontier Economics, 2018). For now, Germany has no LNG import capacity, but a capacity of over 3000 TWh/yr is proposed, including 2400 TWh/yr which would be operational by 2023 (Inman, 2020). This surpasses the volume of synthetic methane imports planned in EL95 and TM95 by 2050, meaning the country's planned import infrastructure seems to be similarly incompatible with their climate plans.

### 4.2.5 Refuelling infrastructure for transportation ($CH_4$ and $H_2$)

Both methane and hydrogen will be deployed as transport fuels in all four scenarios and will require refuelling infrastructure.

Refuelling stations can be supplied with the distribution network; if there is no distribution network, gas can be conveyed by trailer (Uusitalo et al., 2015). Considering that France and Germany both have extensive methane networks, methane stations could likely be supplied by the grid (**?**). Whether or not it is cost-efficient to connect stations to the grid will interact with the issue of the size of the distribution network (section 4.2.3).

In addition to location, the geographical coverage of refuelling stations depends on the types of vehicles which are using gas. Long-haul transport requires stations all around the country but focused on fast roads. On the other hand, gas-fuelled passenger cars could be deployed more densely but in cluster areas. The captive fleet, that is vehicles with predictable demand such as public transportation, uses private refuelling stations which are sized to their demand (Cerniauskas et al., 2019). However, the decarbonisation pathways analysed in this study seem to not include optimising the refuelling infrastructure into account when deciding on trade-offs for the energy mix of transportation.

In the two French scenarios, few hydrogen stations will be needed: hydrogen use in transportation is very small (1 TWh by 2050) and in négawatt's case it will only be used for the captive fleet. For Germany, trailer supply of $H_2$ for passenger cars is more cost-efficient in the introductory phase whereas pipeline supply (transmission and distribution) becomes cost-efficient in the medium- to long-term (Cerniauskas et al., 2019). The dena study projects refuelling stations to be supplied by trucks and not by pipeline; the tank infrastructure is developed proportionally to demand (Bründlinger et al., 2018). Authors point out the importance of early planning of hydrogen demand in transportation to optimise the size of refuelling infrastructure (Baufumé et al., 2013; Cerniauskas et al., 2019).

Results shown in this section indicate that decarbonisation pathways consistently do not fully address infrastructure challenges. The next part of our analysis will address the challenges of the size of the network and the impact on methane price.

Table 6: Challenges, changes and key factors of the transformations of gas infrastructure to reach carbon neutrality. Note: DN = distribution network.

| **Challenge** | **Change** | **Key factors** |
|---|---|---|
| Integration of biomethane | Connection cost<br>Size of DN | Location of biomethane production and methane demand |
| Integration of hydrogen | Cost of upgrading existing pipelines | Location of hydrogen demand<br>Location of hydrogen production and storage |
| Size of the network | Decommission of part of the DN<br>Pricing of methane | Location and size of methane demand on the DN<br>Location and size of biomethane injection |
| Import infrastructure | Decreasing utilisation of existing infrastructure<br>Stranded assets | Existence of large international synthetic methane market |
| Refuelling infrastructure for transportation | Connection of stations by trailer or DN (methane)<br>Connection of stations by trailer (hydrogen) | Size of DN<br>Type of vehicle using methane resp. hydrogen |

## 4.3 Cost analysis

This section presents the results of the cost analysis carried out to estimate some aspects of the transformations of the gas infrastructure. It is structured in four sections each corresponding to one metric, following our method section: infrastructure use, infrastructure cost, impact on price and impact on consumer demand. Values for each metric are calculated for each infrastructure pathway (BAU and optimisation) for each country (France and Germany), according to assumptions shown in the method section (section 3.3.1). Detailed calculations are shown in the appendix (section A.4).

### 4.3.1 Infrastructure use

**Network length**. As can be seen on Figure 25, in the BAU scenario, the length of the network remains the same until mid-century. The transmission network does not change in size across the two scenarios. However, a sharp reduction in network length is visible in the optimisation scenario for the distribution network. The French distribution network shrinks almost completely and makes up only about 34 thousand km by 2050. In Germany, the decrease is less dramatic but still sizeable (-64% between 2015 and 2050).

**Network utilisation**.

- In the BAU scenario, distribution network utilisation decreases significantly until mid-century in both countries (-65% for France, -32% in Germany), as shown in Figure 26. The utilisation of the transmission

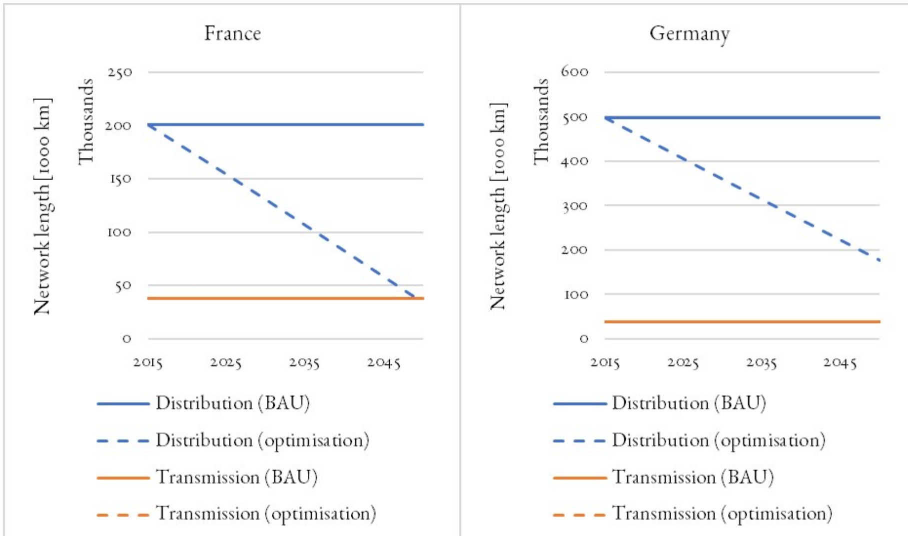


Figure 25: Network length in France (left) and Germany (right) between 2015 and 2050 according to the two pathways. The dashed and solid lines for the transmission network are on top of each other, according to our assumptions.

grid increases slightly in Germany because methane demand increases and conversely decreases in France; the change is less stark than for the DN (Figure 27).

- Optimising the network by phasing out some pipelines increases the utilisation rate of the distribution grid between 2015 and 2050, from 1.4 to 2.9 GWh/km in France, 0.94 to 1.8 GWh/km in Germany. Since the network is decommissioned proportionally to the reduction in methane demand of buildings, the network shrinks faster than the amount of gas transported on the DN, which explains why utilisation rate increases, as can be seen on fig. 26. However, in transmission, there is no decommission so there is no difference in network utilisation between the two scenarios (fig. 27).

**Import capacity utilisation**.

- Both French and German import infrastructure (pipelines and LNG terminals) are found to be under-utilised today: their utilisation rate is below 30% Figures 28 and 29).
- However, projects to expand existing LNG terminals are underway in both countries and import capacity is planned to increase up to 2050, as shows on Figures 28 and 29. On the French side, these projects are at odds with complete energy independence by mid-century as planned in the SNBC. Current German import capacity is likely already sufficient to cover future

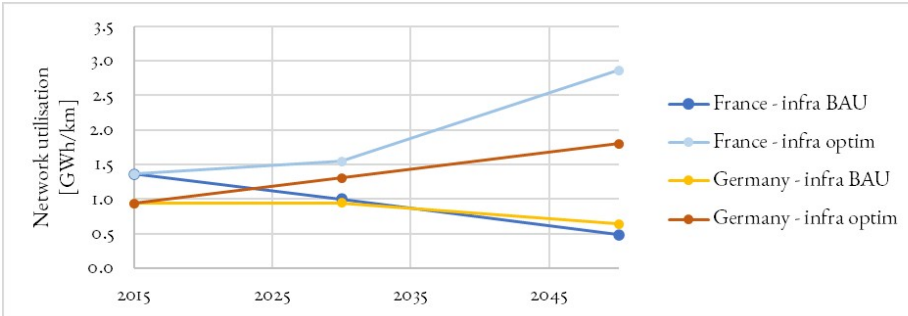


Figure 26: Network utilisation of the distribution network in France and Germany in BAU and optimisation scenarios

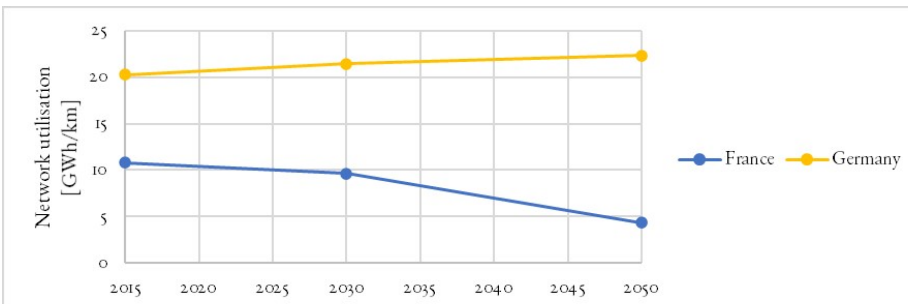


Figure 27: Network utilisation of the transmission network in France and Germany.

imports of synthetic methane: today's infrastructure is already underutilised and future imports will be smaller in volume than current ones.

- Accordingly, utilisation rates of French and German import infrastructure are decreasing until mid-century, as can be seen on Figures 28 and 29.
- Results should be balanced with the fact that new import infrastructure, especially LNG terminals, were built to comply with security of supply standards (European Commission, 2016). It is uncertain how European regulation on this matter will develop as the role of gas in the European energy mix changes.

### 4.3.2 Operational infrastructure cost

This section shows the results for the analysis of future operational costs in the distribution and transmission network. They are shown in Figures 30 and 31.

- In the BAU scenario, specific costs (distribution and transmission) overall increase dramatically between 2015 and 2050: +173% in France between

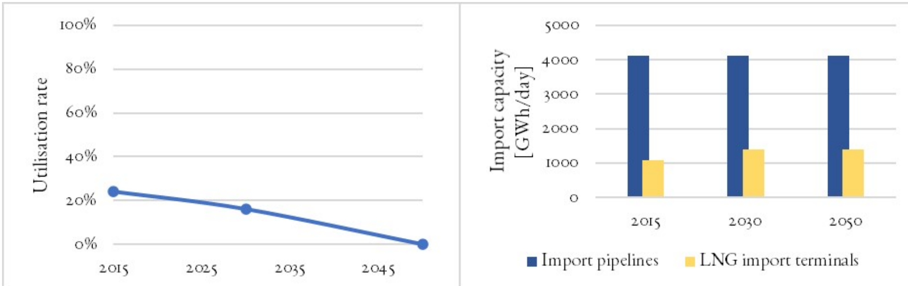


Figure 28: Utilisation rate and capacity of import infrastructure in France, 2015-2050

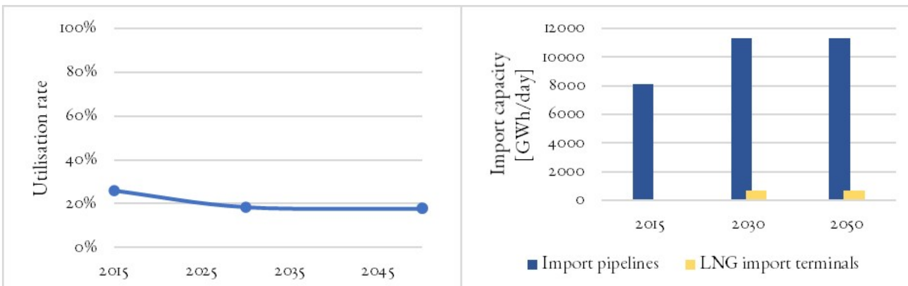


Figure 29: Utilisation rate and capacity of import infrastructure in Germany, 2015-2050

2015 and 2050, +39% in Germany. Specific distribution costs increase because methane demand in the DN decreases while the size of the network remains the same and DN costs depend solely on network length. On the transmission side, costs increase partly for the same reason but also because the increase in methane cost increases the value of specific variable costs. Total operational costs in distribution do not change in both countries since the network remains the same in size. However, in transmission, total costs increase by 2% in France and 39% in Germany. The increase is much larger in Germany since methane demand increases as well, while in France the decrease in methane demand mostly compensates for the increase in specific variable cost.

- In the optimisation scenario, specific costs decrease overall. Specific transmission costs see the same developments as in the BAU, while the distribution network sees its costs halve between 2015 and 2050. This transformation originates in the decommission of resp. 83 and 64% of the network length in France and Germany. As a result, specific operational costs for distribution are similarly lower in the optimisation scenario as compared to the BAU scenario. It is interesting to note that even in Germany, where methane demand overall does not decrease, operational costs decrease significantly when parts of the distribution network are decommissioned. As opposed to the BAU scenario, total operational costs decrease dramatically between 2015 and 2050: total transmission operational costs evolve similarly as in the BAU but distribution costs decrease spectacularly as a large part of the network is decommissioned. In 2050 "optimisation" saves €545 m in France and €1057 m in Germany as compared to the BAU scenario.

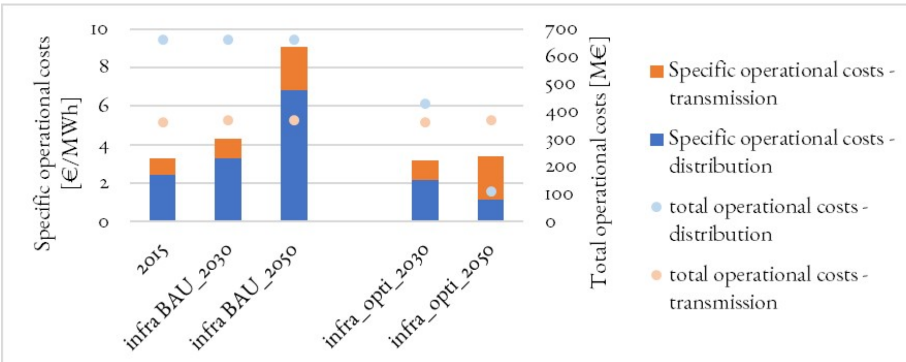


Figure 30: Specific and total operational costs in France between 2015 and 2050 according to the BAU (left) and optimisation (right) scenario

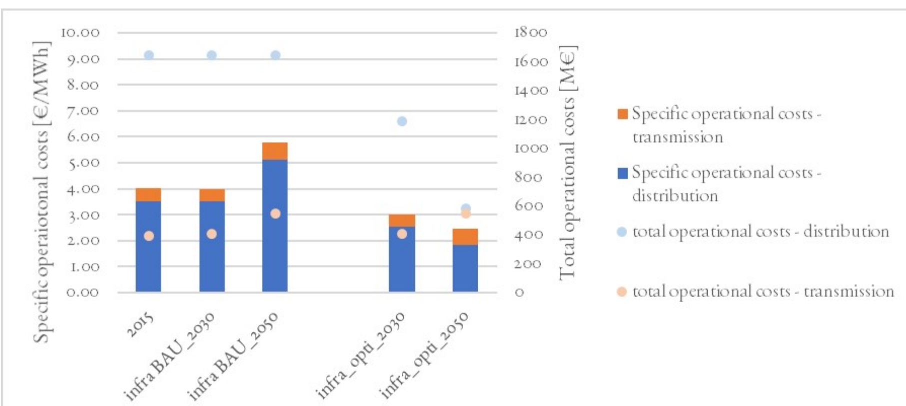


Figure 31: Specific and total operational costs in Germany between 2015 and 2050 according to the BAU (left) and optimisation (right) scenario

### 4.3.3 Impact on price

This section shows the impact of the changes in distribution and transmission operational costs and of production costs on methane price. In France, methane price increases by up to 72% between 2030 and 2050, and in Germany by up to 98%. Results are shown in Figures 32 and 33.

- Across scenarios, the increase in production cost of methane drives up the price of methane, ranging from +8% in the period 2015-2030 to +98% for the period 2030-2050 in Germany. In both countries, the price increase is steeper in the period 2030-2050 than in 2015-2030, which is consistent with the changes in gas mix (gas supply relies mostly on fossil gas by 2030). The change in methane price due to production cost is wider in Germany than in France because its gas mix relies mostly on synthetic methane, while France uses more biomethane, the latter being more expensive than the former.

- Methane price is increased by operational costs in the BAU scenario and decreased in the optimisation scenario, following the increase or decrease of operational costs over time. Changes to methane price due to operational costs range from -21% in 2030-50 for the distribution operational cost in France's BAU to +25% for the distribution operational cost for the same time period in the optimisation scenario.

- The impact of infrastructure operational costs is smaller than of production cost, especially in Germany, where operational costs vary less over the period than in France and where methane production is more expensive. When the two effects mitigate each other (in the optimisation scenario), the decrease in price to operational costs does not match the increase due to production cost.

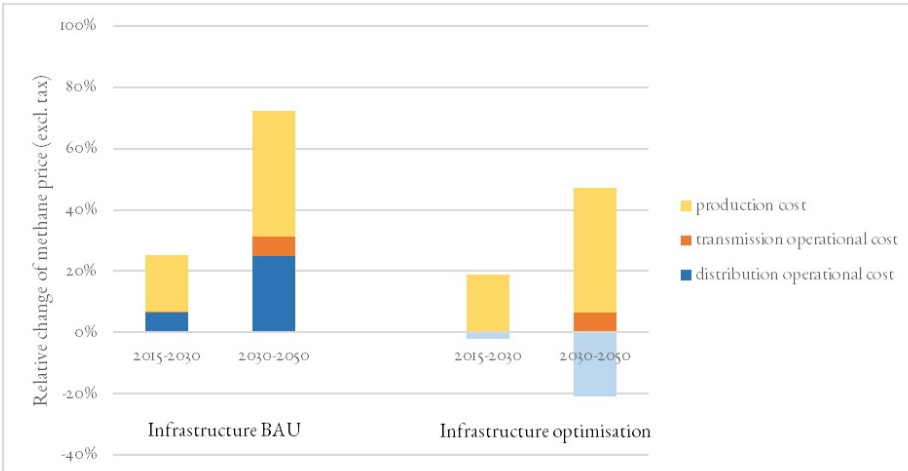


Figure 32: Change in methane price in France in 2015-2030 and 2030-2050 for two scenarios: infrastructure BAU (left) and infrastructure optimisation (right).

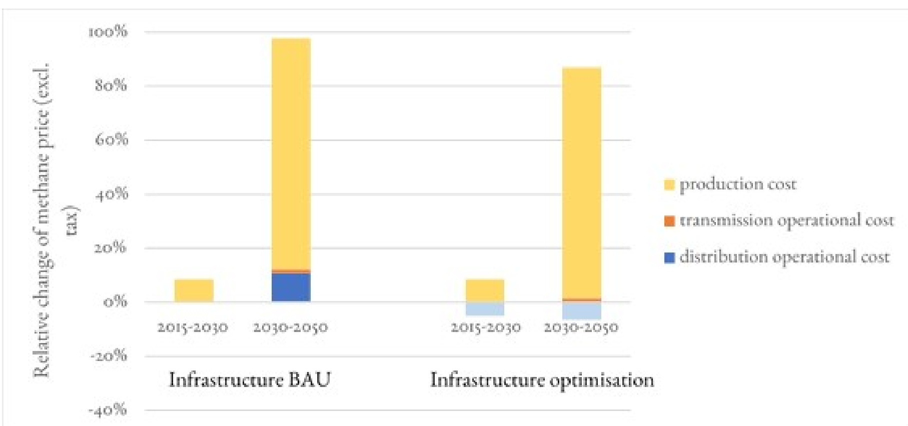


Figure 33: Change in methane price in Germany in 2015-2030 and 2030-2050 for two scenarios: infrastructure BAU (left) and infrastructure optimisation (right).

### 4.3.4 Impact on consumer demand

This section lays out the results of our cost feedback simulation on consumer demand for methane. Figures 34 and 35 show the methane demand in 2050 in resp. residential and industry with and without feedback, with the low and high estimate for elasticity.

The impact of cost feedback on methane demand is significant, ranging for residential from -94% to -33% and for industry from -89% to -31%. The impact of the cost feedback is larger for residential because the values chosen for elasticity are more extreme. It is stronger in the BAU scenario because the change in the price of methane between 2015 and 2030 is higher than in the optimisation scenario.

The results confirm our intuition that price changes could significantly affect methane demand. Even with the lowest price elasticity, that is $\epsilon = -0.1$ (low estimate for residential), which is the least elastic demand in the analysis, methane demand could decrease by 4 to 10%. It is important to note that the significance of our results is constrained by the uncertainty around the value of price elasticity.

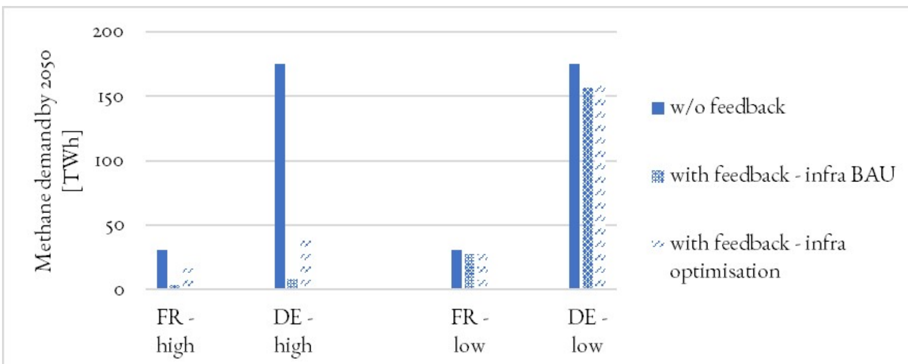


Figure 34: Methane demand by 2050 in France and Germany for residential, with and without including the price feedback. The high estimate to an elasticity ($\epsilon = -0.9$, whereas the low estimate corresponds $\epsilon = -0.1$).

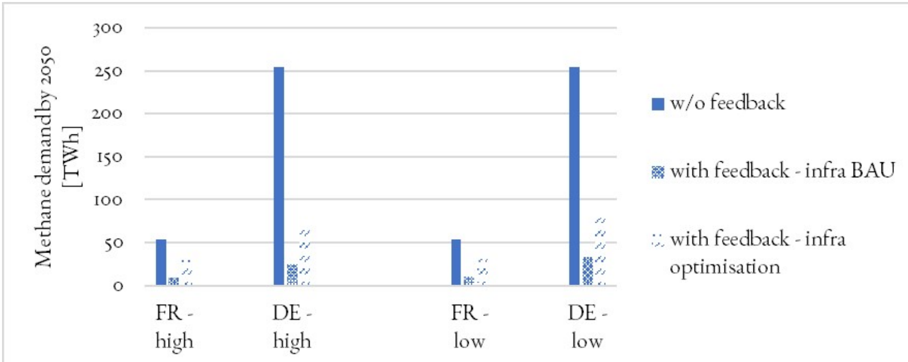


Figure 35: Methane demand by 2050 in France and Germany for industry along the two infrastructure pathways with and without including the price feedback. The high estimate to an elasticity ($\epsilon = -0.85$, whereas the low estimate corresponds $\epsilon = -0.82$).

## 4.4 Summary of findings

The increase in production costs and the change in infrastructure operational costs are likely to cause an increase of methane price until 2050:

- The use of low-carbon methane drives up the production cost of methane and therefore increases methane price.
- The changes in infrastructure operational costs have a significant impact on the price of methane - increase in the BAU scenario, decrease in the optimisation scenario. The range and whether it increases or decreases the price of methane will essentially depend on the extent to which the network is decommissioned to better fit the lower gas demand. Overall, the impact of infrastructure operational costs is lower than the one of production cost.
- The increase in methane price due to higher production costs and when applicable the increase in specific infrastructure costs could trigger a large decrease in methane demand, which might further increase specific costs.
- Part of the increase in methane price is due to the under-utilisation of the existing grid. Additional costs might also arise from the under-utilisation of import capacity.

# 5 Discussion

## 5.1 Perspective on main findings

This study aimed at exploring the impact of carbon neutrality on the gas system in Europe. In this chapter, the answers given to the research question and the subquestions are discussed and put in perspective using findings from other studies.

Our analysis of four decarbonisation scenarios for France and Germany suggests that the gas demand and supply systems will undergo deep transformations as the energy system shifts to carbon neutrality. It finds that according to decarbonisation pathways, methane demand will decrease greatly in buildings and industry, while its use will increase in transportation and for Germany in the power sector. The overall decrease of methane consumption is in line with findings from other sources, although there are differences depending on the sector.

- For the case of France, no alternative deep decarbonisation scenario aiming for an 80% reduction of emissions between 1990 and 2050 was found, making it difficult to put our findings in perspective.

- For Germany, Wachsmuth et al. (2019b) analyse existing decarbonisation pathways aiming for over 90% of emission reduction between 1990 and 2050. Across scenarios, gas (methane and hydrogen) demand decreases sharply in buildings and there are large differences for the transport sector between scenarios regarding the balance between methane and hydrogen; this is consistent with our findings for EL95 and TM95. However, in the Climate Protection 2050 scenario by the German Federal Ministry for Environment "KS95", the decrease in gas demand (methane and hydrogen) is much steeper in the industry, with a -81% decrease between 2015 and 2050 where in EL95 and TM95 are only projecting methane demand in the industry to fall by -38% and -27% in the same time interval. In the power sector, the decarbonisation pathways show a decreasing gas demand, which goes opposed to the projections by the two dena scenarios.

- The 1.5TECH and 1.5LIFE scenarios for the EU see similar decreases of methane per sector, although the respective contribution of levers to this decrease are difficult to identify. Transportation makes less use of gaseous carriers in favour of electric powertrains. In both 1.5TECH and 1.5LIFE, 80% of passenger cars are electric by 2050 – higher than in EL95 (71%) which is one of the most "electrified" scenarios – while methane plays virtually no role. Methane is more developed with heavy goods transport vehicles, making up over 30% of the vehicle fleet by 2050 in 1.5TECH and almost 20% in 1.5LIFE, which fits projections by TM95 and négawatt (data unavailable for the SNBC). Fuel cells play a marginal role in freight transport, as opposed to EL95 and TM95 (European Commission, 2018b).

Buildings see less large electrification than in the SNBC and EL95 but a similar decrease in methane demand (-80% of methane in buildings between 2015 and 2050). While the four scenarios of this study assume that no hydrogen is consumed in buildings, the EU's 1.5TECH and 1.5LIFE project a little hydrogen consumption by 2050 for off-grid areas (European Commission, 2018b). The Dutch Government Strategy for Hydrogen also mentions the use of hydrogen in buildings for space heating beyond 2030 in the form of hybrid heat pumps or for district heat (MEZK, 2020a).

In terms of gas supply, our study found that while biogas is central to the French gas supply by 2050, Germany relies more heavily on pure hydrogen and on imported synthetic methane. The balance between gas carriers varies quite widely between sources.

- For France, estimates for biogas potential are debated. The estimate by the International Council on Clean Transportation (ICCT) is much lower than the one by the ADEME (ADEME, 2018), which is the reference estimate in France, including for the SNBC and négawatt's scenario. In their most recent paper, the ICCT finds a technical potential of 70 TWh by 2050 (Baldino et al., 2019), while the ADEME projects 620 TWh. The difference in estimates mostly stems from different assumptions regarding what constitutes a feedstock for renewable biogas (Baldino et al., 2019). This debate illustrates the uncertainty regarding the technical potential of biogas. With a much lower biogas potential, the energy mix envisioned by the SNBC might include more synthetic methane and/or hydrogen.

- Other scenarios for Germany sometimes balance differently between synthetic methane and hydrogen, relying quite little on synthetic methane: for example, the KS95 scenario by the German Federal Ministry for Environment only projects 15 TWh of synthetic methane by 2050, while dena's EL95 is the most conservative and projects over 300 TWh. Biogas consistently represents a small share of gas supply by 2050 (around 40 TWh) in the scenarios analysed by Wachsmuth et al. (2019b). It is much lower than the potential mobilised in the dena scenarios, which amounts to resp. 127 TWh and 96 TWh in EL95 an TM95. These differences might be explained by a different distribution of the biomass potential over solid, liquid and gaseous biomass. It suggests that although the potential by EL95 and TM95 might be ambitious, the biomass potential in Germany does not seem to be able to cover the country's demand in methane. Accordingly, biomass and biogas are little mentioned in Dutch climate and energy plans (MEZK, 2019, 2020b), while the country has a small domestic biomass potential. In terms of synthetic methane, the scenarios for Germany shown in Wachsmuth et al. (2019b) provide estimates ranging from 15 to 320 TWh for 2050, which suggests that estimates by EL95 and TM95 are very optimistic regarding the synthetic methane consumption (resp. 320 and 630 TWh by 2050). It it not mentioned whether this synthetic methane is imported. The estimate by EL95 and TM95 for hydrogen consumption lies within the range shown by Wachsmuth et al. (2019b), with estimates going from 0 to 280 TWh while EL95 and TM95 foresee about 170 TWh of demand (excl. non-energy uses).

- The EU's 1.5TECH and 1.5LIFE give a larger role to fossil methane than the French and German scenarios: by 2050, methane supply is equally distributed between natural gas, biogas and waste gas, and synthetic methane. The reason for keeping more fossil methane might lie in its role a transition fuel for the energy systems of some member states, e.g. Poland (Polish Ministry of Environment & Energy, 2019).

All four scenarios do not explore in detail the possible cross-border synergies between energy systems. They project decreasing methane imports and no hydrogen imports. On the other hand, the Dutch LTS to the EU is the only decarbonisation pathway examined in this study to mention cross-border cooperation as one of the three red threads of its strategy, which is also stressed in the Government Vision for Hydrogen (MEZK, 2019, 2020a). The importance of cross-border cooperation for gas supply also pointed out by other studies (Artelys, 2019; Gasunie and TenneT, 2020).

This paper also looked into the potential changes in infrastructure following transformations of gas supply and demand. Our findings stress the lack of data regarding location and sometimes size of gas demand (both methane and hydrogen) and the need for such data to precisely determine the impact of carbon neutrality on gas infrastructure. Wachsmuth et al. (2019b) carry out a finer analysis on the future of the German gas infrastructure, including the modelling of gas flows through the existing gas network until 2050. They find that the main challenges lying ahead would be the potential shutdown of distribution lines in some areas if methane demand in buildings decreases a lot, which would generate additional costs, and adapting the network (esp. transport) to accommodate for pure hydrogen. Our findings are consistent with theirs and further echo recommendations by other studies to include more infrastructure aspects to climate plans, to make the most of existing infrastructure, e.g. Trinomics et al. (2019); Gas for Climate (2020).

Finally, our study aimed to contribute to the discussion on the impact of carbon neutrality on the gas system by estimating the change in the price of methane following the shift to low-carbon methane and the change in utilisation rates of existing infrastructure. Our findings indicate that the pricing of methane might call for a new framework to finance methane infrastructure as higher prices might affect the business case for using gas in end-use applications, which is consistent with findings by Trinomics (2016). Our results for infrastructure operational costs lie in the same range as Wachsmuth et al. (2019b), even though our assumption for the proportion of the distribution network being decommissioned by 2050 in the infrastructure optimisation pathway is slightly more extreme. For the case of France, to the best of our knowledge, no publicly available study on the future price of methane considering carbon neutrality exists, which makes it difficult to compare our results. It can be noted that results for France are quite similar to the ones for Germany, with a little larger proportion of the distribution network being decommissioned, in accordance with the difference in methane demand for buildings.

## 5.2 Limitations to the research

Some of the assumptions taken in the research as well as data gaps put limitations on significance of the results. This section goes through the main limitations regarding the scenario analysis, the definition of infrastructure pathways and the cost analysis.

### 5.2.1 Scenario analysis

Findings of the scenario analysis are conditioned by the selection of scenarios. The two case studies are not representative of the whole Union. The analysis has shown that the difference in energy systems between France and Germany can influence the narratives on gas. Many other member states show fundamentally different energy systems as regards to France and Germany. For example, Poland, like Germany, has historically relied on coal and has framed natural gas as a transition carrier. Unlike Germany, the country has shown reluctance in implementing ambitious climate policy that is compatible with the Paris Climate Agreement (European Commission, 2019a). The Polish case would offer an interesting counterpoint to the French and German cases.

### 5.2.2 Infrastructure pathways

The relevance of results of the third subquestion performing a cost analysis on infrastructure is constrained by the way infrastructure pathways are defined.

The high uncertainty regarding the extent to which the distribution network would be decommissioned prompted us to choose two extreme hypotheses, from no decommission at all to very large decommission. The following factors question the relevance of these two extreme pictures:

- The assumption that the size of the distribution network is proportional to methane consumption in buildings assumes that decommissioning is only due to fuel switch and that the energy efficiency of gas-heated buildings remains the same. Fraunhofer's Gas Roadmap takes a less extreme assumption and considers that the distribution network is decommissioned proportionally to the number of buildings switching away from gas (Wachsmuth et al., 2019b). In reality, because of energy efficiency, the remaining number of houses connected to the gas grid per unit consumption would be higher than today. On the other hand, the feasibility of refurbishment objectives in the EU as regards to current rates of renovation are optimistic (Wachsmuth et al., 2019a). It is particularly the case for the two

French scenarios (Coénove, 2020; The Shift Project, 2020). In case these objectives are not met, it is likely that gas-heated buildings would be less energy efficient than their electric counterparts since wide electrification is only possible in energy-efficient buildings. Methane demand per building would be higher than projected in the scenario but lower than with our assumption. Therefore, our hypothesis is an extreme-case scenario and likely overestimates the extent of decommission of the distribution network.

- Subquestion 2 identified that biomethane injection would be a strong determinant for the size of the distribution network (section 4.2). This will especially be the case in France, where biomethane injection is prioritised over cogeneration (Müller-Lohse, 2019). However, it was not included in our assumptions regarding the extent to which the distribution network is decommissioned (section 3.3.1). Considering the uncertainty on the amount of biomethane supply and its location, it was difficult to include that parameter in our assumptions.

- The implicit assumption in the "infrastructure optimisation" pathway that buildings which install heat pumps disconnect from the gas grid leaves out the possibility for hybrid heat pumps. Hybrid heat pumps are designed so that most heat is supplied with a regular air heat pump but part of peak demand is supplied with a methane boiler; it avoids the need for complementary direct electric heating in the winter and decreases peak electricity demand (Gas for Climate, 2020). The decarbonisation pathways in this study do not mention hybrid heat pumps, which is why they were left out of our assumptions. However, some studies have pointed out their role in electricity peak shaving, claiming that the additional costs associated with maintaining gas connections and installing more expensive heat pumps is compensated by lower system costs due to reduced electricity capacity and by the emission reduction in resorting to gas-fired power generation (Coénove, 2020; Element Energy, 2018a; Gas for Climate, 2020).

Our assumptions for the size of the distribution network do not reflect all determinants of gas demand in the distribution grid. According to the formulas for operational costs shown in section 3.3.3, operational costs in the DN are proportional to the length of the network. It follows that a longer or shorter network would mean a proportionally higher or lower amount of operational costs for distribution.

The size of the future transmission network is also quite uncertain. It is quite likely that between 2030 and 2050, part of the methane network will be converted to hydrogen. This would reduce the length of the transmission network and therefore the total operational cost and the weight of fixed costs in the specific infrastructure costs of transmission. There is high uncertainty surrounding the location and the size of the hydrogen network. At an early phase, conversion of natural gas pipelines might only involve "double" pipelines, which would not affect the length of the methane network. These factors make it very challenging to estimate the size of the transmission network which would convert to hydrogen. Therefore, the consequences of the upgrade of part of the methane network to hydrogen was left our of our scope.

It was assumed that the share of industrial methane demand supplied through the distribution network (1/3) remains constant until mid-century. However, industrial customers connected to the distribution grid usually are smaller, less energy-intensive industries. They are likely to electrify more and to use less natural gas than larger industrial consumers, which are connected to the transmission grid. Therefore, the share of 1/3 will likely decrease until mid-century. Yet, decarbonisation pathways usually do not differentiate between low- and high-temperature heat demand in the industry and between distribution- and transmission-grid methane consumers, which makes it challenging to formulate assumptions regarding the share of industrial methane demand supplied by distribution grid. This is why we chose to assume it remains constant.

Finally, throughout the analysis, the size of the network is measured in length. Capacity or peak demand would have been a better metric for network size. Yet, decarbonisation scenarios tend to project energy mixes in volumes rather than capacity, especially for gas. This data constraint justifies our use of network length as a proxy for network capacity.

### 5.2.3 Cost analysis

Some aspects of our methods and assumptions for the cost analysis puts limitations on the significance of our results.

Only two components of the methane price were included in the analysis: operational costs of infrastructure and the cost of energy. The cost of management and marketing, gas storage costs, decommissioning costs and investment cost for infrastructure were left out of the scope. Management & marketing and storage costs per unit gas relate to the size of demand rather than the size of the network, meaning that their specific value would likely not change much with carbon neutrality. However, decommissioning costs would likely increase total system costs for the gas network in the "infrastructure optimisation" pathway, although they are bound to significant uncertainty. Fraunhofer ISI's Gas Roadmap estimates total decommissioning cost in Germany in a scenario planning a 95% reduction in emissions to range between €3.1 and 17.2 billion (Wachsmuth et al., 2019b). Cost of switching parts of the transmission network to hydrogen might range between 10 and 19 €/MWh (Wachsmuth et al., 2019b).

The assumption that the operational costs for the parts of the transmission network which are converted to hydrogen are the same as for methane was taken implicitly. However, specific operational costs are higher for hydrogen (Wachsmuth et al., 2019b; Trinomics et al., 2019); about twice as high in Germany according to Wachsmuth et al. (2019b). This aspect was left out of our analysis for the same reason that the size of the transmission network was assumed to not change (see above).

Price elasticity is bound to a high level of uncertainty by nature and in the particular case of this study, as presented in section 2.5.1. In particular, the price change resulting from the increase in the cost of energy and in operational infrastructure costs found in this study (up to $\times 2$) is much wider than any of the ranges for price elasticity found in the literature. The objective of the calculation of cost feedback was only to show the extent to which the cost feedback could affect the gas mix projected in decarbonisation scenario. The results show that this cost feedback could have significant impact but the numerical range for this impact is too uncertain to be of scientific significance.

## 5.3 Contribution to scientific knowledge and policy-making

The research has provided a useful framework for the analysis of the gas component in decarbonisation pathways aiming for climate neutrality. The fact that it is rooted in an extensive literature review which includes academic sources as well as grey literature and documents from players of the gas industry makes it a solid conceptual tool to analyse the topic of gas in the context of carbon neutrality in the EU. It could be used for further analysis of other decarbonisation scenarios in Europe and be the starting point for analysis frameworks for cases outside Europe.

Only a small number of decarbonisation pathways were analysed to form the basis of the analysis. However, as shown in section 5.1, the gas pathway projected by the chosen decarbonisation scenarios is relatively similar to other pathways found in the literature, which gives more weight to our findings.

This study contributes to policy-making by informing the debate on the role for gas in the decarbonisation of the EU. It captures some of the differences between the narratives of member states and the factors influencing these narratives. It also has relevance for the national level since state-specific decarbonisation pathways were analysed and national determinants were examined. Further, our study has shown that gas infrastructure concerns should be an integral element of emission reduction policies in the EU. Neglecting gas infrastructure aspects in projections for fuel mix might put their feasibility into question. The integration of new gas carriers to the existing methane network will require technical adaptations that come at a cost and call for careful and realistic long-term planning. Additionally, the use of more expensive low-carbon methane and the decrease in network utilisation is likely to put into question the existing pricing framework of methane coming from the grid, as revenues from selling methane would not compensate for the costs. The challenge of methane pricing in a carbon-neutral system will become more pressing until mid-century. In this perspective, our study adds to previous research on the impact of decarbonisation scenarios on gas infrastructure such as the ones by Wachsmuth et al. (2019b); Trinomics et al. (2019) as well as studies pleading for infrastructure planning to be considered together with climate objectives (Energy Union Choices, 2016; Dutton et al., 2017; Artelys, 2020; Inman, 2020).It brings a new light to the issue by taking the specific angle of carbon neutrality and by providing an estimate of methane price.

To conclude, the cost analysis carried out in this study is quite approximate and does not allow to make precise projections for the development of methane price. However, it is a useful first step towards an open discussion about the future of gas infrastructure in an EU aiming for climate neutrality.

## 5.4 Further research

The limitations presented in the previous sections help define orientations for future research regarding the role of gas in achieving climate neutrality and infrastructure analysis.

More decarbonisation pathways should be analysed to increase the number of perspectives on the issue of gas, both from the point of view of more countries and more types of stakeholders. In particular, taking the perspective of the aggregate EU level and confronting it with the member-state perspective would help explain some of the differences laid out in section 5.1. Including energy exchanges between countries would provide a more realistic picture on the potential future developments. For example, the development of synthetic methane import routes from North Africa to Germany might trigger a larger use of synthetic methane in France. Other EU Member States could be added to the analysis, providing a more complete understanding of the European energy system and of country-specific conditions.

Additionally, further research could look at the role of today's methane supplier countries to Europe in the transition to carbon neutrality, including Russia, Algeria, Libya, the Netherlands and Norway (ENTSOG and GIE, 2019). All of these countries have a larger renewable electricity potential and could become suppliers of electricity-based energy carriers, including synthetic methane and electrolysed hydrogen (Frontier Economics, 2018). The orientations for energy production chosen in these countries will partly determine the existence of a global hydrogen and synthetic methane market which could supply amounts of renewable methane as planned by scenarios like dena's EL95 and TM95.

For a finer analysis of infrastructure needs, more research should be conducted to simulate the gas flows in the system through time and across locations. Thus, more precise data on the costs for infrastructure with gas demand in a carbon-neutral system could be produced. Our analysis shows that it should be done for methane. Such investigation should also be carried out for hydrogen, for which technical transformations of the grid a riddled with uncertainty e.g. on the cost and techniques to upgrade pipelines to accommodate for $H_2$. Additionally, the cost of hydrogen production will highly depend on the deployment water electrolysis and its cost, which might influence the business case for hydrogen infrastructure.

# 6 Conclusion

The starting point of this project was the realisation that natural gas consumption would need to decrease dramatically in the European Union by mid-century, and therefore that decarbonisation pathways for the European Union and its member states should address this change. This research has provided elements to estimate the impact of carbon neutrality on the gas system, including methane and hydrogen supply and demand and the existing methane grid.

First, four decarbonisation pathways for France and Germany were analysed. All scenarios find that gas demand decreases significantly until mid-century due to energy efficiency and electrification in buildings and industry; this decrease is partly compensated for by the uptake of gas for some industrial applications and in transportation. Hydrogen emerges as a new gaseous energy carrier and as a feedstock in industry, partly displacing natural gas demand. Methane supply shifts from being all-fossil to near-complete renewable, relying on domestic biomethane in France and imported synthetic methane in Germany. Most shifts take place in the period 2030-2050.

Some fundamental differences between France and Germany can be identified in the scenarios regarding the transformations that their gas system will undergo. Biogas use is much larger in France and more central to the system than in Germany. By mid-century, biogas provides fuel for transportation, residual space heat demand in some buildings and high-temperature heat in the industry. The estimate for biogas potential used in the two scenarios analysed here are debated. For Germany, the dena scenarios foresee that hydrogen and synthetic methane will take on a larger role, providing the industry and the power sector as well as some space heating for buildings. The respective role of hydrogen and synthetic methane seems to vary widely between scenarios for Germany.

Then, a literature review was conducted to determine the effects such changes could have on existing gas infrastructure. It was found that the integration of biomethane and hydrogen to the existing grid, the future size of the network and of import infrastructure and the development of refuelling infrastructure for transportation are likely to constitute significant challenges for gas infrastructure come carbon neutrality. The uncertainty around the impact of these challenges can be partly overcome with finer projection of gas demand until mid-century. Early planning including gas infrastructure is paramount to a cost-effective decarbonisation of the energy system.

Finally, our projections of the energy component and the infrastructure component of the methane price show that the changes in gas supply and infrastructure are likely to increase the price of methane. Low-carbon methane is more expensive than natural gas, meaning that the cost of energy will increase, which would reflect on the price of methane. The increase might further decrease methane demand. It means that methane pricing might need to evolve to account for the new developments of the role of gas and the amounts of gas transiting through the infrastructure.

Despite the limitations due to data availability, this master's thesis provides a useful overview of the challenges which the gas system will be facing by mid-century and the way decarbonisation pathways deal with these challenges. It contributes to the conversation by emphasising on the need for infrastructure aspects to be included in the design of decarbonisation pathways. The research could be improved by including the perspective of more diverse decarbonisation pathways and with and a finer analysis of future infrastructure needs.

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# A Appendix

## A.1 Key factors determining the role of gas and associated indicators to analyse decarbonisation pathways

Table 7: Key factors and associated indicators for the analysis of decarbonisation scenarios

| Key factor | Indicator |
|---|---|
| Cross-sector indicators | Total primary energy supply |
| Cross-sector indicators | Total final energy consumption |
| Cross-sector indicators | GDP |
| Gas supply | Volume of biomethane/fossil methane/synthetic methane consumption across system and per sector |
| Gas supply | Volume of biomethane/fossil methane/synthetic methane imports |
| Gas supply | Volume of hydrogen consumption |
| Insulation of existing building stock | Final energy demand in buildings (residential/services) |
| Size and structure of population | Population size |
| Industrial-sector strategies to adopt EE measures | Final energy demand in industry |
| Consumer demand | GDP<br>recycling rate for basic materials: steel, aluminium, glass |
| Deployment of gas power plants to displace coal | Methane in power mix (volume) |
| Need for flexibility in the power grid | VRES in power mix (share)<br>Electricity peak over the year<br>Share of electricity generation used for $H_2$ production |
| Level of transport activity | Transport activity (passenger/freight) |

**Table 7 continued from previous page**

| Key factor | Indicator |
|---|---|
| Degree of electrification of transportation | Electricity in energy mix of transportation (passenger/freight) |
| Development of refuelling stations | Number of refuelling stations |
| Switch to district heat in buildings | District heat in buildings (residential/services) |
| Technical potential to electrify LTH | Electricity in energy mix of industry LTH |
| Technical potential to electrify HTH | Electricity in energy mix of industry HTH |
| Amount of methane/ hydrogen used as feedstock | Amount of methane/hydrogen used as feedstock in industry |
| Technical potential to replace non-energy use of fossil fuels with hydrogen | Amount of hydrogen used as feedstock in industry |
| Potential for domestic biomethane | Biomethane production |
| Cost of synthetic methane domestic/imports | Cost of synthetic methane domestic/imports in industry |
| Size of synthetic methane demand | Synthetic methane demand |
| Import dependency for electricity supply | Imports/Exports of electricity |
| Net imports of hydrogen | Imports of hydrogen |
| Demand for hydrogen and methane transit on national grid | Amount of hydrogen/methane transiting on national grid |

## A.2 Indicator values for scenario analysis

*Excel sheet "scenario analysis.xlsx" attached to the present document.*

Each sheet corresponds to one of the four scenarios. When the value for an indicator was not found, the cell was left empty. Values which are only used as intermediate steps to calculate the final indicators are shown at the bottom of the sheet, in light grey colour.

## A.3 Assumptions for indicator data in scenario analysis

Table 8: Specific assumptions for the data for indicators when relevant

| Indicator | Scenario | Assumption |
|---|---|---|
| LPG demand | négawatt | Liquefied petroleum gas (LPG) is not included in the value for methane. Unclear what other scenarios do. In négawatt, LPG demand is small enough to be neglected, whatever the sector. |
| Rate of renovation of residential buildings | SNBC | Available data is number of renovations per year. Transformed into rate of renovation using assumptions by négawatt for building stock until 2050. |
| Rate of renovation of residential buildings | négawatt | Calculated as the ratio of full renovations per year and the building stock in the year. |
| Rate of renovation of residential buildings | EL95 | Rate of renovation in residential is different depending on the type of house (one-person, multi-family, large multi-family). Our value is the average of the three values (no data for the breakdown of the building stock was found). |
| Average thermal performance of buildings | négawatt | Available data is surface of service buildings per category [$m^2$] and need for space heating per unit surface per category of service buildings [$kWh/m^2/yr$]. Average thermal performance is the weighted average of the two. |
| Electricity exports | négawatt | Value for electricity exports is excess electricity from the system Sankey diagram |
| Biomethane consumption | EL95; TM95; SNBC | The value for biomethane consumption only includes injected biomethane. Not a problem considering only injected biomethane can have an impact on the gas network. |
| Biomethane consumption | négawatt | Biomethane consumption is assumed to be the same as biogas consumption. Biogas consumption is given separately for biogas from gaseification and anaerobic digestion. |
| Gas consumption in power sector | EL95; TM95 | Figures are given in $TWh_{elec}$. To find $TWh_{heat}$, assume an energy conversion rate of 0.5 for methane (average of the efficiencies of the two types of methane power plants shown in the scenario) and 0.6 for hydrogen (estimate by IEA (2019) for fuel cells in the power sector. |
| Energy demand in transportation (freight and passenger) | EL95; TM95 | Data available: vehicle fleet [nb], fuel consumption of transport modes per carrier [kWh/km], breakdown between transport modes [p-km]. Assume that each German passenger car travels 14,000 km/yr (data from ODYSSEE-MURE). Assume that methane hybrid cars consume no electricity. |

## A.4 Calculations for cost analysis

*Excel sheet "cost analysis.xlsx" attached to the present document.*

The first sheet "ope costs + utilisation" shows calculations for the utilisation rate of the gas network as well as import infrastructure, together with calculations for operational costs. The second sheet "prod costs + impact price" presents the assumptions for the production cost of methane and the impact of infrastructure operational costs and production cost changes on methane price. The last sheet "cost feedback" shows the calculations for the impact of the increase in methane price on demand.