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Carbon neutrality in Europe: future challenges for the gas infrastructure

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Bringing the European energy system to climate neutrality by 2050 will call for substantial transformations to the energy system, including a sharp decrease in the consumption of natural gas. This shift could require very significant changes to today's gas infrastructure and might jeopardise the cost-effectiveness of investments in gas infrastructure, constituting stranded assets. This study aims to identify key challenges delineating the impacts of carbon neutrality on the gas system. First, it investigates how the role of gas is depicted in existing deep decarbonisation scenarios, and then identifies the potential consequences on the gas network. It focuses on the cases of France and Germany.

Our analysis suggests that the gas infrastructure could be significantly affected by carbon neutrality. The key determinants for gas infrastructure needs are heat demand, the role of gas in transportation, the relationship between gas and electricity and the degree of substitution of natural gas with low-carbon gas. Although decarbonisation pathways draw different pictures for 2050, it is highly likely that technical adaptation to the existing network will be needed to accommodate for the transport of biomethane and hydrogen, while the redefinition of demand through space might require the geographical redistribution of the distribution network. To optimise system costs and to ensure that carbon neutrality is achieved, integrated multi-energy infrastructure planning both at the national and European level is paramount.

KEY MESSAGES

Deep decarbonisation scenarios suggest that the role of gas in the energy system will drastically change between 2030 and 2050. Unabated natural gas demand should be phased-out and replaced with low-carbon gas (methane or hydrogen). Total volumes of gaseous carriers should decrease; however the gas system could continue to play a key role at moments of high energy demand or low renewable electricity production. As a consequence, the service provided by gas networks will increasingly evolve towards providing capacity for the security of supply in a more integrated and low-carbon energy system.

Deep decarbonisation scenarios show significant differences between France and Germany, especially with regards to the respective role of gaseous carriers and the contribution of imports to gas supply. However, national decarbonisation scenarios tend to leave out neighbour countries' role in their own decarbonisation. Integrated, long-term infrastructure planning requires more cooperation between member states regarding their vision of the role of gas and hydrogen in the European energy system.

Deep decarbonisation scenarios consistently show a lack of detail regarding the development of end uses of gas in a climate-neutral energy system while important transformations are taking place, from the development of transport applications to the reduction or phase-out of gas use in buildings. These knowledge gaps need to be addressed for the adequate planning of gas transport, distribution and storage infrastructure.

Existing decarbonisation scenarios aiming for net neutrality do not take into account the economic consequences of carbon neutrality on the gas system. Yet these impacts could be significant and involve extra costs for the energy system. Better studying them would help avoid sunken costs for infrastructure assets and slowing down decarbonisation of the energy supply. In particular, long-term scenarios should consider potential stark reductions to imported methane and to gas demand in the distribution network as early as 2030.

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1. INTRODUCTION

1.1. Gas and carbon neutrality

The European Union (EU) aims to be climate-neutral, meaning to emit net zero greenhouse gas (GHG), by 2050. This shift should be achieved primarily by reducing energy demand through increased energy efficiency and the switch to decarbonised energy carriers. 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 (European Commission, 2018a).

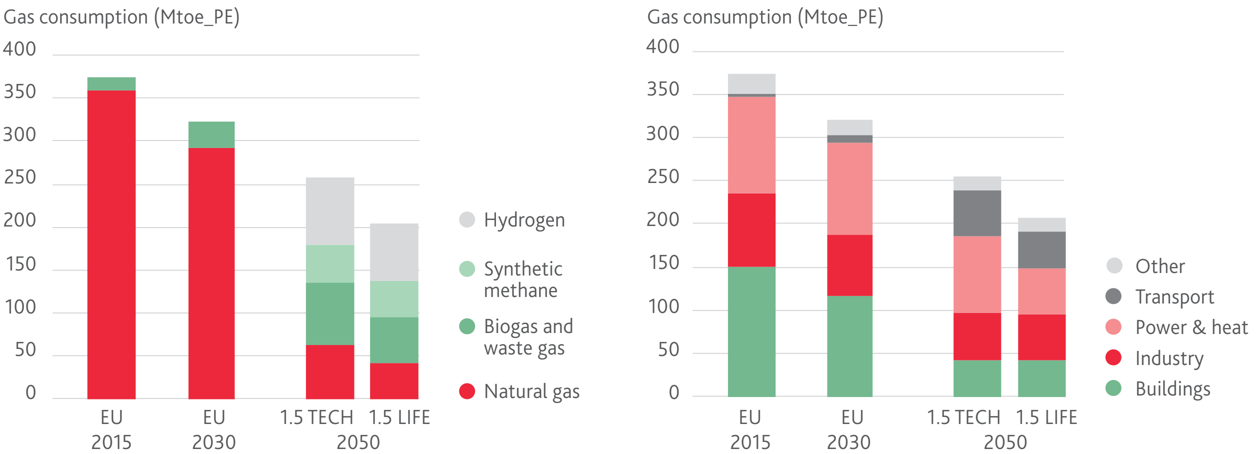
Natural gas—which is mostly methane (CH_4)—made up almost 25% of the EU's total primary energy supply in 2017. It can be used to produce (flexible) power, for space and industrial heat, as an industrial feedstock for i.a. chemicals production or as a fuel in the transport sector. Most of our consumption owes to the residential sector, closely followed by the industry (IEA, 2017). According to the EU's reference Paris-compatible decarbonisation pathways 1.5TECH and 1.5LIFE, gas demand is likely to decrease until 2050, driven by a drop in demand in buildings, power and the industry, despite rising demand in transportation (**Figure 1**, right-hand side). Additionally, gas supply would diversify, with low-carbon gas (biogas, synthetic methane and hydrogen) developing at the expense of natural gas[1] (**Figure 1**, left-hand side).

1.2. The future of gas infrastructure

On the path to carbon neutrality, choices taken for the energy mix could greatly affect the gas infrastructure, which today is mostly dedicated to methane, although a few hydrogen

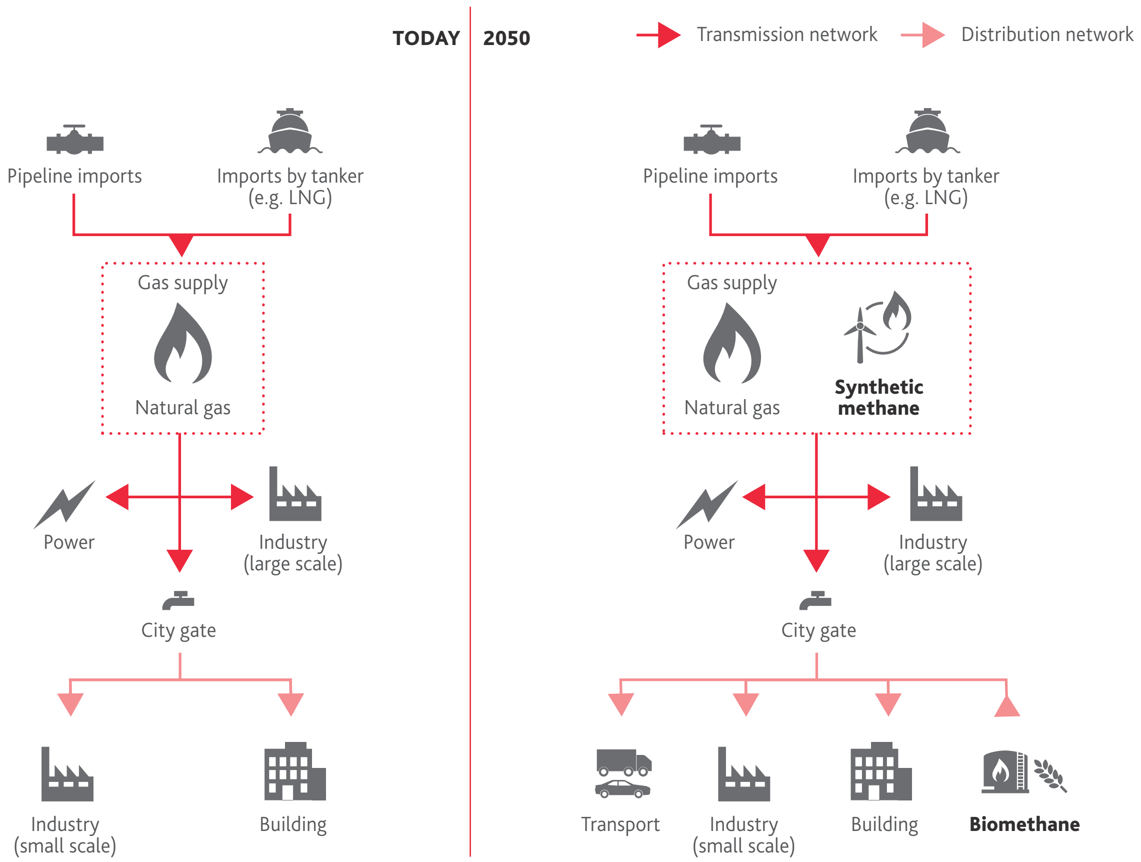
1 Carbon dioxide (CO_2) capture and transport could also play an important role in the shift away from natural gas, especially in the industry to reduce process emissions, in hydrogen production from natural gas and power-to-methane or power-to-liquid processes and in power generation (European Commission, 2018a) However, it is not discussed in this study because it does not relate directly to natural gas end uses.

FIGURE 1. Gas consumption (methane and hydrogen) in the European Union in 2015, 2030 and 2050 per type (left) and sector (right), according to the European Union 1.5TECH and 1.5LIFE scenarios. Includes non-energy uses



Source: European Commission (2018a).

FIGURE 2. Simple sketch of the gas infrastructure in Europe today and by 2050



pipelines exist at the local level. The part of the gas grid involved in gas transport is made of a transmission (or transport) and a 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 conducts natural gas down to each small customer at a lower pressure (Speirs *et al.*, 2018). 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 (Agence ORE, 2020; ENTSOG, 2019; Wachsmuth *et al.*, 2019). This setup is shown in **Figure 2**.

The switch to transport hydrogen and biomethane would require adaptation to the methane grid, as shown in **Figure 2**. For example, hydrogen demands significant retrofit of pipelines and adaptation of end-use appliances, while biomethane injection needs specific connection points (ADEME, 2018; Element Energy, 2018b; Trinomics *et al.*, 2019).

Additionally, the reduced demand in methane could put the size of the network in question. It depends for a large part on maximum peak demand rather than on the volume of demand as the grid should be able to ensure timely supply even when demand is high. Gas storage capacity also factors in as gas pipelines are used as extra storage capacity through a process called line packing (Ríos-Mercado & Borraz-Sánchez, 2015). Finally, the number of customers of the network, which are not uniformly distributed in space, is a strong determinant for the length of the network (Dodds & McDowall, 2013). All three metrics will play an important role in determining the size of the network in a carbon-neutral future.

A decrease in methane demand may bring economic challenges to the infrastructure. In the face of decreasing gas demand, transportation costs per unit gas could increase as these costs depend on the length of the network rather than on the volume of gas being transported (Wachsmuth *et al.*, 2019). Yet, gas infrastructure is mostly financed by revenues determined on volumes of gas and the number of clients (CRE, 2017; Grave *et al.*, 2016). This suggests that the business case of gas network operators could be severely affected, especially at the distribution level (Trinomics *et al.*, 2019). In particular, parts of the existing distribution and transmission network could become too expensive to maintain in the face of lower gas demand. Gas infrastructure built in the next decade might not be used up until the end of its lifetime—typically around fifty years—and could constitute stranded assets (Artelys, 2020a, 2020b; Energy Union Choices, 2016). The end-consumer price of methane could adjust to reflect these higher infrastructure costs. However, the subsequent price increase, together with the higher production cost of low-carbon gases, could redesign some end uses of gas, for example in favour of electrification.

This shows the importance of including the end-user perspective in planning the role of gas in the transition and in infrastructure planning.

Interestingly, the issue of infrastructure is usually left out of decarbonisation pathways. Although the contribution of gaseous vectors to the energy mix is usually presented, little is known about the way infrastructure issues are included in the trade-offs and the impact of decarbonisation on the gas network.

1.3. Objective of the study

This study aims to flag the key challenges for the gas system in the face of carbon neutrality in Europe, including the shifts to gas supply and demand and the effects they could trigger for gas infrastructure. By doing that, we hope to provide some answers regarding how gas infrastructure aspects could be better integrated into decarbonisation pathways and strategies. This study is designed as a tool for discussion among stakeholders working on the gas transition in France and in the EU. Additionally, it aims to help cooperation between EU member states (MS) on efficiently meeting climate neutrality.

2. FOUR MAIN CHALLENGES FOR THE ROLE OF GAS IN REACHING A CARBON-NEUTRAL SYSTEM

Using a literature review, we identify four main aspects of the role of gas in the transition which constitute turning points for the gas system on decarbonisation pathways: (1) heat demand, (2) the use of gas in transportation, (3) gas-electricity interaction, (4) substitution of current gas use with low-carbon gas. These four aspects will play a key role in determining future infrastructure needs. They are decomposed into key factors, which are the main technological, socio-economic and environmental factors determining the role of gas. These key factors are then used to build a framework to analyse decarbonisation pathways. Four decarbonisation pathways are analysed (see Box 1). For more detail on the methodology, see Annex (section 6).

2.1. Gas for 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 and will play a key role in deep decarbonisation (European Commission, 2015). 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.

Buildings. Over 40% of the EU's natural gas consumption is used by buildings (IEA, 2017). Gas demand in buildings goes mostly to space heating (44% of space heating is supplied by NG) and hot water, with a smaller amount dedicated to cooking heat (Paardekooper *et al.*, 2018). There seems to be a consensus across academic literature and decarbonisation pathways that natural gas consumption in buildings will decrease significantly due to improvements to the thermal insulation level of buildings and subsequent reduction of heat demand (Bründlinger *et al.*, 2018; European Commission, 2018a; MTES, 2020b; Paardekooper *et al.*, 2018). Building renovation has been a policy priority at the EU level but the rate of renovations has been too slow (European Commission, 2018a). One major challenge in reaching carbon neutrality lies in the actual implementation of renovation objectives for the building envelope. This issue interacts strongly with the level of electrification of space heating and the size of the remaining methane demand: electrification takes place in priority in buildings with a high energy performance and lower insulation levels in the built environment might correlate with higher residual methane demand (Gas for Climate, 2020; RTE & ADEME, 2020; Union Française de l'Électricité, 2020). In the transition phase, hybrid solutions (using both electricity and methane) might be implemented (Union Française de l'Électricité, 2020).

Industry. In the EU, 32% of NG consumption is used by the industry mostly to fire steam boilers and steam systems and furnaces and kilns (Chan & Kantamaneni, 2015; IEA, 2017). Energy efficiency measures include heat recovery, replacing existing equipment with more efficient ones, using different feedstocks and improving motor systems efficiency (Napp *et al.*, 2014). Although heat demand reduction does not necessarily affect all energy carriers equally, heat demand conditions the size of gas demand. Industrial heat demand is also strongly linked to the level of output and to demand for goods. Heat demand reduction potential varies a lot across subsectors and processes (Gerres *et al.*, 2019). Cuts to heat demand in the industry are likely to be less stark than in buildings as technological solutions are less advanced, policy objectives have been less ambitious and less progress has been achieved (Chan & Kantamaneni, 2015; Paardekooper *et al.*, 2018).

For example, all four of the analysed pathways envision cuts to industrial energy demand[2] but to different degrees: Négawatt projects the largest decrease with -46% between 2015 and 2050, while EL95 only plans a 5% decrease. The two 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. Energy demand decrease (incl. methane) shows great variation between industrial subsectors and across scenarios. In TM95, while the aluminium & copper sector see their energy consumption increase by close to 40%, iron & steel reduce their consumption by 44%. On the other hand, while the French National Low-Carbon Strategy (SNBC) projects decreasing energy demand in chemicals (-39% between 2015 and 2050), it increases by almost 70% in EL95. Even though these figures could only be truly comparable if they referred to energy intensity rather than volume, the gap in order

2 Little data was available for heat demand so energy demand was used as an approximation.

of magnitude suggests that the scenarios envision different pathways for these sectors.

To conclude, it appears likely that heat demand will reduce dramatically in buildings and the industry until mid-century, which would drive down methane demand. The drop will likely be sharper in buildings than in the industry. For the industry, there is a knowledge gap in most decarbonisation scenarios regarding the future level of heat demand, which limits our understanding of future gas demand. Additionally, little is said on the development of demand in terms of capacity and in particular peak demand, as well as on the development of the number of customers. These gaps make it difficult to evaluate the consequences of heat demand reduction for the network.

BOX 1. SELECTION OF DEEP DECARBONISATION SCENARIOS

Four scenarios were selected for France and Germany. They were selected so that a diversity of perspectives are represented. All of these scenarios aim for (near) carbon neutrality at 2050.

- The French National Low-Carbon Strategy, also called SNBC (MTES, 2020b). It is the French government's roadmap to reach carbon net neutrality by 2050.
- 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.
- 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.
- 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, but TM95 uses a broader range of technologies and end-use energy carriers.

2.2. Gas in the transport sector: a new role

Despite overall decreasing gas demand, the use of gas could increase in transportation. Transport, especially long-haul heavy goods transport, is one of the most difficult sectors to decarbonise (European Commission, 2018a). Low-carbon methane and hydrogen are considered as a long-term solution to abate emissions for long-haul and heavy transport because gas has higher energy density than battery-stored electricity, which gives them comparative advantage, even though their role in today's mix is very small (Arteconi *et al.*, 2017; European Commission, 2018a; Gas for Climate, 2018). Therefore, it is likely that methane and hydrogen will be developed as energy carriers at least to some extent, especially in freight road transport. However, the respective role of methane and hydrogen is still uncertain and will depend on a number of factors.

Accordingly, decarbonisation scenarios show very different rates of penetration of each vector—electricity, methane and hydrogen—into the transportation fuel mix, although the rationale behind these choices is often unclear (**Figure 3**, **Figure 4**). In particular, it lacks detail regarding the transport segment where each of these vectors would develop, and evaluation of the gas transport and storage infrastructure needs to be associated to their development. German scenarios develop hydrogen by 2050 more than their French and European counterparts, especially in the electrification scenario, while the EU scenarios stand somewhat in the middle (120 TWh by 2050 corresponding to 36% of transport FE demand in EL95 vs. only 1 TWh in each French scenario). Négawatt projects a much more important role for gas (methane) than other scenarios, making 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.

Synthetic methane and hydrogen are likely to be more expensive as a transport fuel than electricity from a battery. Biomethane is closer to cost parity with battery electricity, but future cost reduction is likely to be limited, especially as compared to the ones for electricity (see Section 2.4). Additionally, the potential for biogas production being strongly constrained by physical limitations means that it will be allocated to sectors needing it most. On that level, the transport sector would be competing with industrial uses. This would suggest that in transportation, low-carbon gas could only be developed in uses where the lower costs of infrastructure of gas solutions and its higher energy density as compared to direct electrification would compensate for higher fuel cost (Moultak *et al.*, 2017). The shorter refuelling time for vehicles running on low-carbon gas could be an advantage over battery vehicles (Carbone 4, 2020; Moultak *et al.*, 2017). However, some authors mention that long-haul battery electric trucks could still be technically and economically feasible if a dense charging infrastructure is implemented or using fast charging or dynamic inductive charging (Earl *et al.*, 2018; Forrest *et al.*, 2020). Additionally, developing fully electric or hybrid trucks being powered with overhead catenary lines is explored in Sweden and Germany. One main limitation of this option is the need for heavy infrastructure deployment before it can be rolled out. Several studies for the German case claim that around 3,000 km of highways could cost-efficiently be equipped with overhead lines by 2030 (Jöhrens *et al.*, 2020; Wietschel *et al.*, 2019). Overhead lines would need to combine with other technologies when trucks are off main highways.

For freight road transport, the adoption of low-carbon gas will depend for a large part on the techno-economic possibilities of direct electrification. Biomethane might also be used as a transport fuel locally (e.g. public buses) when it is not economic to transport it elsewhere. In addition, vehicle manufacturers should produce a sufficient portfolio of gas or hydrogen-based vehicles and an adequate distribution infrastructure should be planned and developed (see part on infra) to ensure consumer adoption.

FIGURE 3. Energy demand and fuel mix in transportation in France (left) and Germany (right), 2015-2050

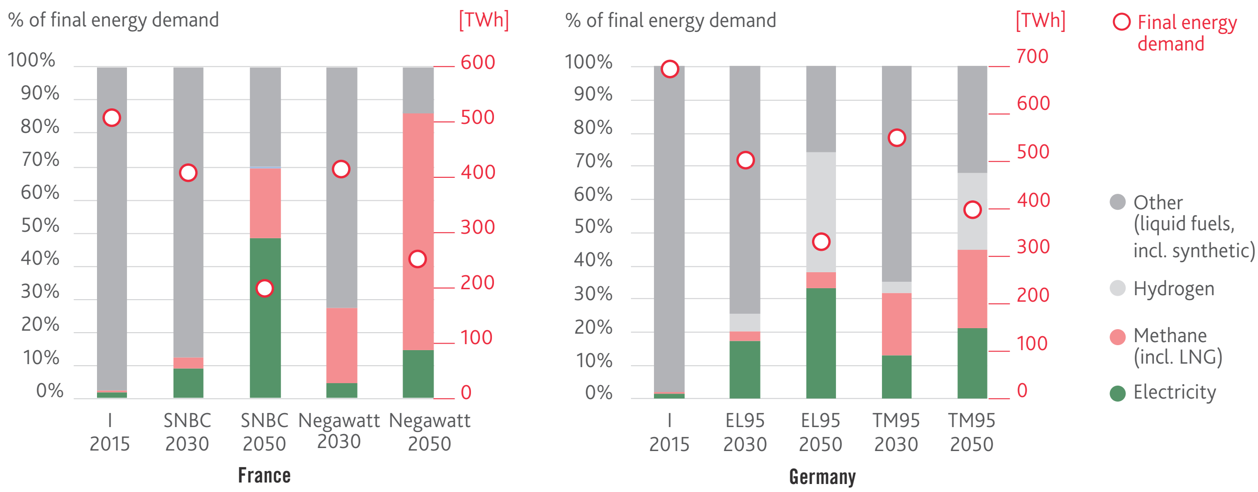
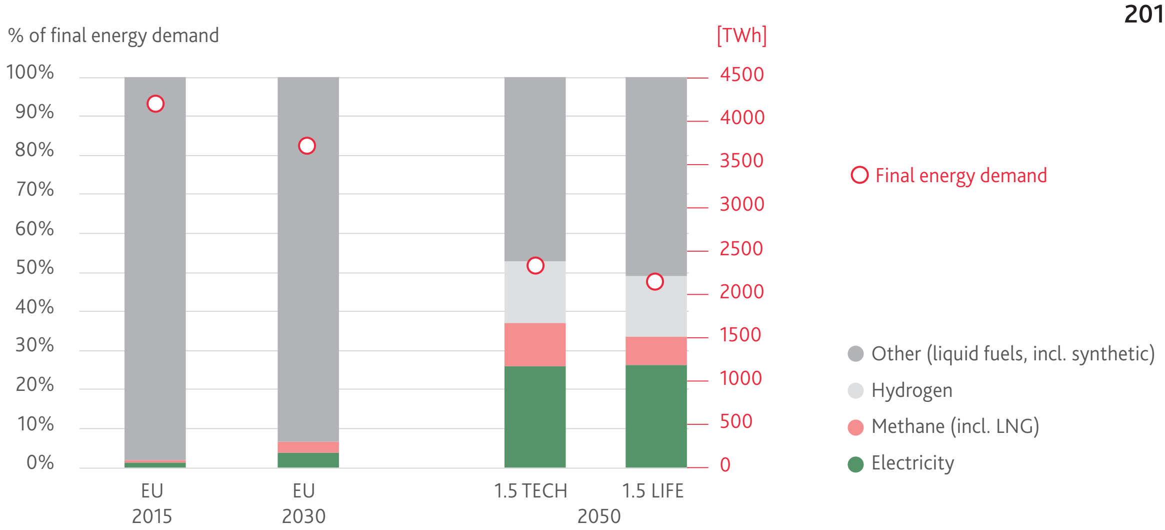


FIGURE 4. Energy demand and fuel mix in transportation in the European Union according to 1.5TECH and 1.5LIFE 2015-2050



On that level, path dependency is likely to be important: for example, refuelling infrastructure would not likely be built for both hydrogen and biogas everywhere across Europe. This is to be put in perspective with the constraints on biogas production potential that might jeopardise its use at a large scale for transportation.

Low-carbon gases and synthetic fuels could also play a role for maritime transport and aviation (Halim *et al.*, 2018; Nistor *et al.*, 2018), where they compete less strongly with direct electrification since it is not technically possible for most of these sectors' consumption. The development of synthetic fuels in these sectors will depend for a large part on the availability of CO_2 (Drünert *et al.*, 2020; Halim *et al.*, 2018).

2.3. Interaction between gas and electricity

The gas system is increasingly interlinked with the power system and that trend will continue on the pathway to carbon neutrality. The electrification of (natural gas) end uses pushed by decarbonisation raises concerns about security of supply as peak electricity demand may increase. This strongly influences the role of gas in power production since gas often provides peak supply to the electricity system in times of high demand.

2.3.1. Electrification of current gas uses

A large part of current natural gas end uses in buildings and the industry can be electrified, especially low-temperature heat. However, electrification is not technically feasible for all uses, and there is uncertainty around the extent to which it should happen. The issue of electrification of end uses relates directly to the size of residual methane demand.

Buildings. In a carbon-neutral energy system, space heating will likely be largely electrified. In all four scenarios analysed here, buildings undergo some electrification up to 2050, especially in residential, which relies on all-electric heat pumps. As a result, the share of electricity for space heating increases significantly and it becomes the largest energy carrier. However, the slow rate of renovations so far and the uncertainty around the size of peak electricity demand with higher penetration of heat pumps results in varied estimates for the extent of electrification in buildings heat. In the four scenarios, more electrification takes place when renovation is more extensive. Additionally, some recent studies have pointed out to the system benefits of installing hybrid heat pumps (using both electricity and gas); this technology could be deployed more widely in future decarbonisation pathways (Gas for Climate, 2020; RTE & ADEME, 2020; Union Française de l'Électricité, 2020). Electrification of building heat also competes with district heat in areas with a high density of demand, typically dense areas.

Industry. There is still technological uncertainty as well as a gap in implementation of decarbonisation strategies in the industry, especially for the energy-intensive industry, even though it is recognised that breakthrough innovations are needed (Agora Energiewende & Wuppertal Institut, 2019; Gerres *et al.*, 2019). It is also agreed upon that some industrial processes are very difficult to electrify, especially high-temperature heat (Bataille *et al.*, 2018; Chan *et al.*, 2019), even though recent progress in high-temperature heat pumps is encouraging (Fourmigué, 2020). This means that there are wide differences between subsectors as regards to electrification potentials. It might result in large differences of electrification potential between European countries due to subsector variations. Overall, decarbonisation strategies aiming for net neutrality agree that the share of electricity in final energy demand in the industry could reach 40 to 50% by 2050 in Europe (ENTSOG & ENTSO-E, 2020; Eurelectric, 2018; European Commission, 2018a).

All four scenarios under study see an increase in the share of electricity in the industry, partly displacing methane demand. This is especially visible in the 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 Dena decarbonisation pathways, some sectors have little electrification potential (iron and steel, non-metallic minerals), whereas others see wide electrification (paper, business/commerce/services). Overall, decarbonisation pathways make it difficult to identify which fuels are displaced by increased electrification as the changes in processes are often not explicit.

2.3.2. Power generation

Today, natural gas is a major energy carrier for the European power sector, making up 20% of electricity generation in the EU (IEA, 2017). Methane-fired power plants provide baseload or peak power (Gas for Climate, 2018; Gaventa *et al.*, 2019). The role of gas differs in countries depending on the structure of their mix; for example, France relies quite little on natural gas as nuclear plants provide the bulk of baseload power and little variable renewable is used, whereas Germany is increasingly developing gas for flexibility as its share of variable renewables is growing and coal and nuclear phase-outs are already planned.

In a carbon-neutral system, unabated electricity production from natural gas should be almost phased out[3] but low-carbon synthetic gas or biogas could still play an important role in two main ways:

- With the electrification of many end uses, electricity demand will likely increase until 2050. Some of this new demand (e.g. for space heating and cooling or electro-mobility) shows large temporal (daily, weekly or seasonal) variation that will change the electricity demand profiles and could result in an increase of peak demand. The development of peak demand will depend on the implementation of insulation upgrades in buildings and the deployment of flexible charging for electric vehicles (RTE & ADEME, 2020).
- The power system will likely see increasing penetration of variable renewable power sources that will require to develop flexibility in the electricity system.

Methane can provide flexibility and long-term storage to the power system using existing or new methane-fired turbines, transmission networks and storage. Flexibility can also be provided by other technologies, such as power interconnections, batteries, pumped storage or vehicle-to-grid services. The advantage of methane-fired power plants as compared to other technologies is they can play on the daily, weekly and seasonal timeframe and have high ramp-up rates and a large potential (Bossmann *et al.*, 2018; European Commission, 2017b). In particular, with the electrification of heat, the role of methane in seasonal storage will be crucial in the future energy system; hydrogen could also play an important role (Child *et al.*, 2019). Yet their use will be limited by the cost of CO_2 for fossil methane and the cost of generation for power-to-X (PtX) (Bossmann *et al.*, 2018).

The long-term decarbonisation scenarios considered in this study do not always fully disclose choices made for the flexibility mix for the power sector. Only the Dena pathways provide data for peak electricity in Germany and suggest that the future load curve will show larger variation through the year. Across scenarios, the share of methane in the mix is stable—even though in some cases a much larger amount of methane is used for electricity generation. Yet, the power generation capacities per energy source and the contribution of other flexibility solutions are only given in detail in the Négawatt scenario. One scenario, the SNBC, does not rely on hour-by-hour modelling of

3 Larger amounts of natural gas could still be used for power production if coupled with CCS. However, according to the EU's Paris-compatible decarbonisation pathways, it is not likely that this technology is used significantly because of the low cost of renewables (European Commission, 2018a).

the power system, which makes it difficult to understand how the electricity system is balanced. In order to adequately plan transmission and storage infrastructure needs for methane, these knowledge gaps should be bridged.

Additionally, hydrogen production by electrolysis can help avoid curtailed electricity when electricity production exceeds consumption (Bossmann *et al.*, 2018; European Commission, 2017b; Gaventa *et al.*, 2019). However, surplus electricity will likely not be sufficient to cover generation needs for hydrogen and additional capacity would be needed (Agora Verkehrswende *et al.*, 2018). The relationship between hydrogen and power generation is still unknown and will depend on the development of flexibility needs of the power system and of hydrogen demand. For France, a study by the electricity transmission system operator suggests that there is no clear need for hydrogen as flexible power until at least 2035 (RTE, 2020). Hydrogen production is an important driver for electricity demand across scenarios in the two pathways with large hydrogen consumption (Négawatt and TM95), making up resp. 36% and 23% of electricity demand by 2050. Similarly to the role of methane, data in the scenarios regarding the relationship between hydrogen and electricity generation is lacking and its role is difficult to identify.

2.4. Substitution of current gas demand with low-carbon gas

Today, low-carbon gas is virtually not used in European energy systems. It is likely to develop until 2050 but the amount of gas that would be consumed (hydrogen, biomethane, synthetic methane) and for what end uses are still open questions.

On the supply side, the development of low-carbon gas is constrained by two main factors:

Cost. Low-carbon gases are still more expensive than fossil gases (Agora Verkehrswende *et al.*, 2018; Trinomics *et al.*, 2019). In France, public support to biomethane production is conditioned to a production cost decrease from 95 €/MWh today to 60€/MWh by 2028 (MTES, 2020a). A technological breakthrough that would dramatically reduce costs is unlikely and future cost reduction rather depends on some level of economies of scale—although their potential is limited—or on the use of alternative substrates. Some gas producers advocate for a pricing of biomethane production that fully takes positive externalities—such as waste management—into account (Enea, 2018). In any case, there is high uncertainty regarding the feasibility of substantial cost reduction for biomethane production. The production of electrolysed hydrogen and synthetic gas is still at pre-commercial stage. Some studies project that under very favourable conditions (carbon tax, low electricity cost, continued investment in hydrogen and conversion technologies) that the authors deem unlikely, synthetic gases might become competitive with their conventional counterparts by mid-century, although the potential is unclear (Agora Verkehrswende *et al.*, 2018). It means that at least for now, existing end uses of natural gas might have cheaper alternatives than low-carbon gas (e.g. electricity for space heating in buildings). It also means that many end uses of low-carbon gas require public financial support.

Resource availability. Biomethane production is physically restricted by biomass potential and competes with other land uses (European Commission, 2018a), while synthetic methane and hydrogen production require large amounts of low-carbon electricity, which is also needed to decarbonise electricity supply. To overcome constraints on the latter, some studies and policy plans consider importing PtX from countries outside or in Europe with much renewable electricity potential (Agora Verkehrswende *et al.*, 2018; BMWi, 2020; Bründlinger *et al.*, 2018). Associated risks include the high cost of import infrastructure and the potential competition with decarbonising the power sector of these countries.

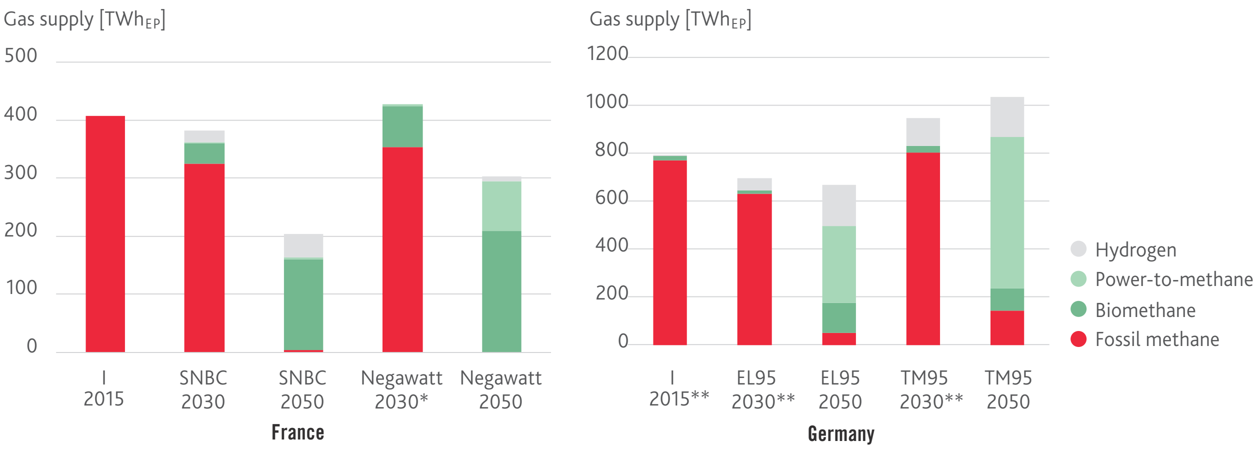
Accordingly, the substitution of natural gas with low-carbon gas is limited across the four analysed scenarios. Substitution with low-carbon methane only when it is economic and technologically possible. This amounts to industrial uses without electrification alternatives, space heating in buildings assumedly when it is more competitive than district heat and electricity (e.g. buildings with low energy performance), and flexible peak power. Despite lower consumption, the role of methane in the energy system remains key to ensure the security of energy supply via power production and storage. Hydrogen replaces natural gas in some industrial applications such as direct reduction of iron ore for steel-making in Germany. Larger substitution with hydrogen takes place in the two German scenarios, partly because German industry is larger and structured differently and because hydrogen development has been a policy priority.

The balance between synthetic methane and biomethane differs in the two countries, as shown in **Figure 5**:

— Biomethane is given more central role in France than Germany in terms of share, making up 77% of gas supply (157 TWh) in SNBC by 2050 and 69% (209 TWh) in Négawatt, while in EL95 and TM95 scenarios it represents respectively 26% (127 TWh) and 11% (96 TWh) of gas supply. The French biogas potential used in both scenarios is based on one seminal study (Solagro & Inddigo, 2013), but other studies have come up with very different values (Carbone 4, 2020; MTES, 2018; Searle *et al.*, 2018). There is uncertainty around the feasibility of mobilising such amounts of bioenergy; were these assumptions not realised, it could jeopardise French gas supply as planned by the two scenarios.

— Synthetic methane takes on a much larger role in Germany than in France, with only 3 TWh in the French SNBC by 2050 and 86 TWh in Négawatt's scenario, compared to 630 TWh in TM95 and half that amount in EL95. The difference between the two French scenarios might stem from a difference in narratives on PtX as the SNBC claims to rely as little as possible on technological breakthroughs (MTES, 2020b). In German scenarios, power-to-methane is a lot more developed. The main reason for that difference is that the two French scenarios aim for complete energy independence and therefore can only rely on domestic synthetic methane, which is very expensive. We see four other factors:

FIGURE 5. Gas supply across scenarios in France (left) and Germany (right), including non-energy use



*in négawatt, no data was available for the hydrogen consumption in 2030, therefore the value is not shown.
**these values only include injected biomethane.

(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 illustrated by most German scenarios including 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 organisation.

All scenarios project some use of hydrogen until 2050, rising especially in the period 2030-2050 (**Figure 5**). 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. It is important to note that in its recent hydrogen strategy for 2030, the French government aims for 6.5 GW capacity of electrolysers to be installed by 2030—which translates to about 25 TWh of hydrogen—suggesting that more than 40 TWh of hydrogen would be consumed by 2050. Reasons for this difference include a lower relative biomass potential, a higher demand for decarbonised gas in Germany and different policy agendas regarding hydrogen.

Long-term decarbonisation pathways still show significant gaps regarding the uses of low-carbon gas, for example regarding the split between the role of gas in low- and high-temperature heat or the respective contribution of gas in volume in freight and passenger transport. They also fail to indicate the location of demand, which is a crucial dimension for infrastructure planning. This lack of data makes it difficult to plan infrastructure needs, including for the refuelling network of methane and hydrogen, the potential need to develop a hydrogen transport infrastructure, and the maximum capacity needed on the methane network.

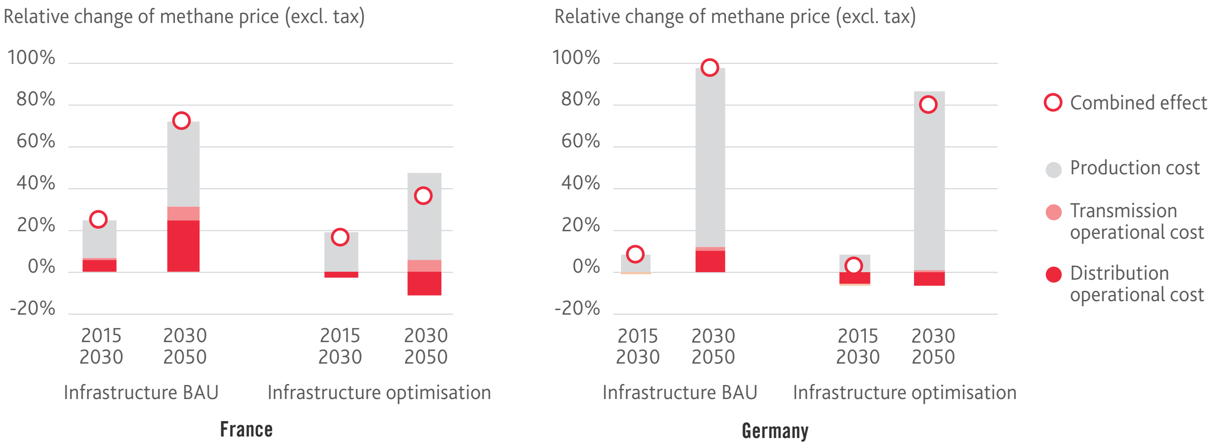
3. OPEN QUESTIONS FOR THE GAS INFRASTRUCTURE

The changes to the role of gas in the energy system brought about by carbon neutrality raise crucial questions for the gas infrastructure. Yet the way deep decarbonisation could affect gas networks is consistently under-investigated in decarbonisation pathways. In this section, we identify four main issues facing gas infrastructure and present which knowledge gaps should be bridged for effective long-term infrastructure planning.

3.1. Financial management of the gas system

The decrease of gas demand and the integration of low-carbon gas as described in decarbonisation pathways would affect the financial management of gas networks. Since the larger part of operational infrastructure costs does not vary with the amount of transported gas (Wachsmuth *et al.*, 2019), operational costs per unit gas could increase. This could in turn cause a rise in the price of methane if pricing mechanisms are still as they stand today, which might further decrease demand for gas. To overcome this issue, gas network operators could decide to shut down part of the network, especially on the distribution side where demand decrease is likely to be steep. Shutting down the network in some areas requires the coordinated development of low-carbon heating alternatives for building, could take time and entail sunken costs. It can be done incrementally with e.g. banning new natural gas connections in some areas, as pledged by the Netherlands and the United Kingdom, and obligatory connection to a heat grid. On the other hand, would the increase in methane price not impact the business case of methane in its end uses—as compared to district heat and electricity—the network could be kept to its current size but larger costs could occur. In order to investigate this issue, we explore two possible

FIGURE 6-7. Change in methane price in time caused by shifts to production cost, transmission and distribution operational cost, in France and in Germany in 2015-2030 and 2030-2050 for two scenarios: infrastructure BAU (left) and infrastructure optimisation (right).



pathways for the distribution network: business-as-usual and optimisation (see Box 2). More detail on the pathways is provided in the annex (Section 6.2.2).

Our cost analysis finds that the rise in production costs and in operational costs per unit gas could increase the end-user price of methane (**Figure 6**, **Figure 7**). In both France and Germany, most of that increase would take place in the period 2030-2050 rather than in 2015-2030, which follows the timing of changes in gas mix (gas supply still relies mostly on fossil gas by 2030).

— Methane end-user price increases by up to 72% in France and 98% in Germany between 2030 and 2050 in the BAU scenario, while in the optimisation scenario the price increase is lower (resp. 36% and 81% for the same time period).
— The price increase is mostly driven by an increase in production cost due to the shift from natural gas to low-carbon methane. The production cost rises more in Germany in our analysis because a larger use of synthetic methane, which is more expensive to produce, is assumed.
— Operational costs could also drive up the price of methane. In our BAU infrastructure pathway, specific costs[4] increase dramatically in both distribution and transmission between 2015 and 2050: +173% in France between 2015 and 2050, +39% in Germany. On the other hand, if the distribution network is partly decommissioned (resp. 83 and 64% of the network length in France and Germany), specific operational costs remain stable or even decrease because distribution operational costs decrease significantly. As a result, the price of methane is driven up by operational costs in the BAU pathway but down in the optimisation pathway.

BOX 2. TWO POSSIBLE PATHWAYS FOR THE DISTRIBUTION NETWORK

Pathway 1: infrastructure business-as-usual (BAU)
Today's infrastructure is kept at today's size because the number of remaining customers is sufficient despite decreasing volumes of demand. Infrastructure is used less than today.
This could correspond to a situation where some buildings are using hybrid gas heat pumps.[5] It could also occur if the heat transition is not anticipated well and buildings get off natural gas connections in an uncoordinated way.

Pathway 2: infrastructure optimisation
Residual methane demand in buildings is concentrated in space. The size of the distribution network is "optimised": the network is shut down proportionally to the decrease in volume of demand in buildings.
This could correspond to situations such as the one of the United Kingdom, which will ban new house connections to gas from 2025,[6] or the Netherlands.

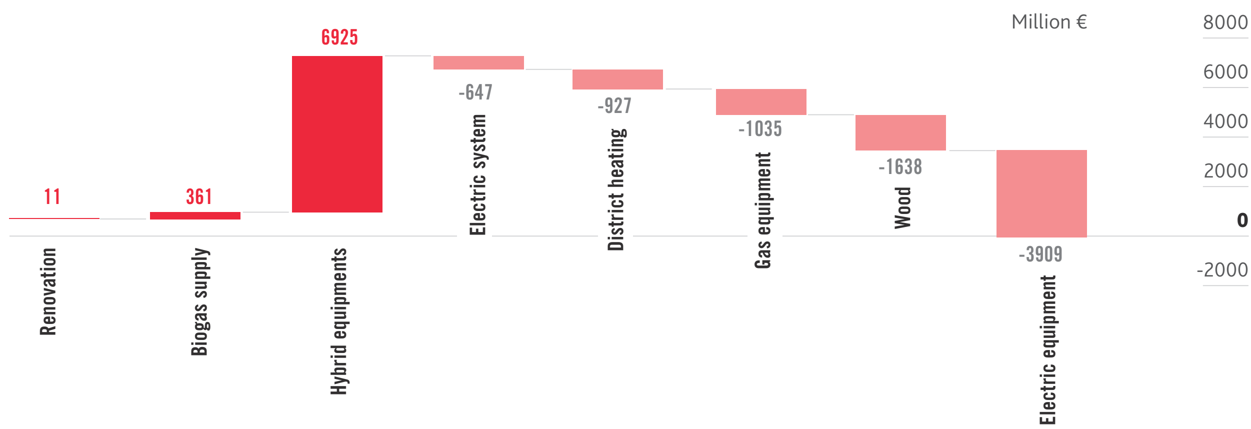
The relative impact of operational costs on the price is influenced by the methane mix. If methane is expensive, whether or not part of the network is decommissioned will not matter much since the rise in price due to high production costs will be

4 Specific costs are the average total costs per unit gas; equivalent to marginal cost. Given in e.g. €/MWh.

5 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).

6 Harrabin, Roger (2019). Gas heating ban for new homes from 2025, BBC News, 13 March 2019. https://www.bbc.com/news/science-environment-47559920

FIGURE 8. Difference in energy system costs for buildings between the SNBC and an alternative scenario using hybrid heat pumps



Source: Coénove (2020)

much larger. In our analysis, this is exemplified by the difference between the French and the German case: in the optimisation scenario, the increase in methane price in France is strongly mitigated by decommissioning part of the network while in Germany, the effect of production cost increase account for a much larger part of the price change.[7]

Even though the higher production cost of low-carbon methane is often mentioned, the potential end-user price increase of grid methane is largely unaccounted for in decarbonisation scenarios. This price increase does not necessarily mean that end-uses of gas would be phased out: that will depend on the cost of alternatives. However, it might redefine the demand for gas in some end uses. For example, decarbonisation pathways often project some residual methane demand in buildings (8% of final energy demand of buildings in France's SNBC, 27% in Germany's TM95), used for a large part for space heating. When actually accounting for gas infrastructure maintenance costs, it could be more cost-efficient to electrify all of that heating demand. On the other hand, there is a possibility that wide electrification increases peak electricity demand (RTE & ADEME, 2020), which could require much larger investments in power generation infrastructure. This could reach the point where system costs are higher when all heating demand is electrified, as some studies have pointed out (coénove, 2020; E-CUBE Strategy Consultants & EWI, 2020), see **Figure 8**. Several studies on the French case have found that assuming that the renovation objectives are achieved for buildings, it is not likely that peak demand would increase due to the electrification heat (Beeker & Hauet, 2019; Carbone 4, 2019; RTE & ADEME, 2020); however, it could happen if insulation objectives would not be achieved (+ 6 GW) (RTE & ADEME, 2020).

Similar factors are at play when assessing the potential benefits of installing gas-electricity hybrid heat pumps. Although they would require to maintain a methane distribution network and could have higher carbon emissions than all-electric ones, they could contribute to electricity peak shaving by providing peak heat demand in buildings with gas, reduce the required investment and the energy consumed to supply peak heat demand (Coénove, 2020; Element Energy, 2018a). The French electricity transmission operator gives a technical potential of a 1.4 GW reduction in peak power demand per million hybrid heat pumps as compared to all-electric ones (RTE & ADEME, 2020), while Coénove claims installing seven million hybrid heat pumps could economically reduce the peak by 5 GW as compared to the SNBC scenario (Coénove, 2020). In poorly-insulated buildings, hybrid heat pumps could be interesting in a transitional phase towards gas-free systems (Union Française de l'Électricité, 2020). These services could improve the case for maintaining a gas connection for some buildings. The techno-economic case for hybrid heat pumps is not known well and should be studied taking into account (1) the costs of extending the electricity network to cope with electrification of energy uses; (2) the costs of maintaining the gas distribution network; (3) the system services that hybrid heat pumps can provide; (4) the uncertainty around the realisation of renovation objectives.

Our price analysis is constrained by data constraints, which limits the significance of results. It uses the length of the network as an indicator for its size. A better indicator would have been the number of customers to the network, which is difficult to estimate considering the data available in decarbonisation scenarios. Additionally, our results only give data in €/MWh, which does not reflect well the economic choices by gas operators or consumers. For end consumers, an important metric is the energy bill, also including the cost of building renovation and new equipment. The revenue of network operators is regulated and it is difficult to estimate their business case by 2050 based on today's regulatory framework. Therefore, for the 2050

7 In the optimisation scenario, between 2030 and 2050, the decrease in operational costs represents 6% of the decrease in production costs in Germany while it amounts to 11% in France.

timeframe, an estimate based on total system costs would be a better indicator on which to base economic decision-making.

The price increase shown by our cost analysis is neither a projection nor a recommendation to shut down respectively 83% and 64% of the gas distribution network in France and Germany; it is an approximate estimate of the order of magnitude that the price increase could have. Most importantly, it reveals some underlying mechanisms defining economic trade-offs between energy infrastructure. It highlights the importance of raising the question of whether shutting down parts of the network would help optimise infrastructure costs. It brings to light the need for complementary research on the economic conditions for gas infrastructure in a carbon-neutral system, especially as compared ot other energy vectors.

Answers to such questions should build on analyses that consider the multi-energy system, including both electricity and gas, as well as the consumer perspective. Yet, developments and investment for the gas and electricity systems continue to be planned separately, even though progress has been achieved (Gaventa *et al.*, 2016). That means that the financial management in energy networks often follows optimisation of costs at the single network level, despite the fact that gas, heat and electricity are to be increasingly integrated in the energy system (European Commission, 2017a).

3.2. Integrating low-carbon gases to the network

According to decarbonisation pathways, the gas mix will likely shift towards less natural gas, more biomethane, synthetic methane and hydrogen. On the methane side, it is still unclear where synthetic methane would come from but it would probably re-use existing natural gas import routes and would therefore require very limited adaptation to the network. However, biomethane and hydrogen might call for deeper changes to the network.

Biomethane. Much of biomethane production in France and to a lesser extent in Germany has been and will be directly injected in the methane grid (Müller-Lohse, 2019). 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 today, natural gas supply to the grid is injected 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 origin to the methane network would generate costs of 2.9-3.7 €/MWh, while biomethane is expected to cost around 60 €/MWh by 2028 in France (MTES, 2020a).

Additionally, beyond some volume of biomethane injection, gas cannot only be consumed locally and it needs to be transported further in the network; reverse flows are required (ADEME, 2018). The cost of installing equipment to enable reverse flows is relatively low when compared to the cost of biomethane: it would range between 0.11 and 0.18 €/MWh depending on the location (ADEME, 2018).

The integration of biomethane to the network is an issue of network structure optimisation and of implementation. The cost will likely not be a substantial limiting factor.

Hydrogen. The emergence of hydrogen demand will require dedicated infrastructure to convey hydrogen in the gaseous form[8] from production sites to storage sites and then consumers.

Building an adequate hydrogen network is still technically uncertain as only a few hydrogen pipelines exist. 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). Authors seem to agree that the cheapest way to build hydrogen networks is by upgrading natural gas pipelines, as opposed to building new lines (Bründlinger *et al.*, 2018; Cerniauskas *et al.*, 2020; Enagás *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). Little to no distribution network will be needed as demand for hydrogen in buildings is very small. There is still significant uncertainty regarding the technical conditions for upgrading natural gas pipelines and the cost might be significant. In France, the transmission network operators 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 (GRTGaz, 2019). A study by Artelys locates the cost of hydrogen pipelines for interconnections between 5 and 16 €/MWh for new pipelines and 4-8 €/MWh for refurbished ones[9] (Artelys, 2020b). The estimate by Fraunhofer ISI's Gas Roadmap for Germany is higher, ranging between 10 and 19 €/MWh by 2050 (Wachsmuth *et al.*, 2019).

Decarbonisation pathways project relatively small amounts of hydrogen consumption by 2030 at least, which suggests that until then, hydrogen use would be restricted to small clusters where economies of scale can take place and small-scale infrastructure can first be rolled out (GRTGaz, 2019). Lifting some of the uncertainty on hydrogen infrastructure costs will help defining the uses for which it could be used. It is a prerequisite for deciding on the clusters where hydrogen will first be deployed.

Beyond some level of consumption, hydrogen storage will likely be needed to ensure security of supply. Centralised storage of hydrogen is provided mostly by salt caverns and as a liquid e.g. at import terminals; distributed storage provides

8 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.

9 This is assuming that hydrogen pipelines operate 1,000 hours at full load.

intra-day storage and is located close to high demand locations, provided by line packing or 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.*, 2019). In France, it is still unclear whether existing salt caverns and aquifer reservoirs would be fit to store hydrogen; experiments are under way (GRTGaz, 2019; Le Duigou *et al.*, 2017; Tlili *et al.*, 2020). The needs for salt caverns and the potential associated costs are highly uncertain and will depend on electricity sources used after 2035 and techno-economic conditions (RTE, 2020). Storage sites will need to be connected to production and consumption sites.

Hydrogen integration is technically more challenging than biomethane and costs are still little studied. Both hydrogen and biomethane integration need to be taken into account when planning for infrastructure size and costs.

3.3. Geographical organisation of the gas networks

3.3.1. Methane network

The shifts of methane demand coming by 2050 could require adaptation to the spatial organisation of the network. Even though across the system, gas demand is likely to decrease or remain stable until 2050, the sectoral and geographical differences might require shifts to the setup of the network in space.

The development of demand suggests that gas consumption on the distribution network could be concentrated in some areas, for example around industrial areas or biomethane injection sites, and that the grid would be less needed in other zones.

— Today, the distribution network mostly provides buildings (residential and services) and small industrial sites. Demand in these sectors is likely to switch for a large part to electricity, even though some methane demand would remain and could lead to some decommission of the distribution network (see Section 3.1).

— Refuelling stations for transport might be supplied by the distribution network, although it could technically also be supplied by the transmission network or by trailer (Robinius *et al.*, 2018; Uusitalo *et al.*, 2015). Although there is some literature on the technical possibility of using low-carbon gas for air, maritime transport and heavy road transport (Drünert *et al.*, 2020; Nistor *et al.*, 2018; Pääkkönen *et al.*, 2019), little is known on the infrastructure setup required for such uses. Consequently, there is uncertainty regarding the required mesh of the refuelling infrastructure. If low-carbon gas is only used by air, river and maritime transport, or captive fleet in cities, refuelling infrastructure could be quite small and concentrated in space, around cities, ports, main waterways. However if gas is only used by private passenger cars or heavy trucks (only off main roads if overhead lines are used on the former), stations would be needed across space, albeit at a lower density than what is currently deployed for residential buildings (Tlili *et al.*, 2020). For the latter case, cross-European optimisation of the location of refuelling stations would be strategic (Kuby *et al.*, 2017).

— The distribution network is meant to connect biogas production units to the grid, at least in France (see Section 3.2). However, even in the French scenarios (which project more biomethane production), the volume of production would not compensate in volume for the decrease in demand from buildings. This raises the question of the viability of the grid only as a collection network for biogas. Even though the network density required to collect biomethane at injection points would likely be much lower than the one to provide methane to residential buildings, the remaining network could still be difficult to maintain in terms of costs.

The fact that large consumers, such as industrial sites and power plants, will likely maintain a large consumption and that they are spread across the network suggests that the geographical organisation of the transmission network would not need much change. It is however important to note that an increased penetration of variable renewables might require higher capacity of methane-fired CCGT even though consumed volumes of gas remain stable, which could call for extending the gas transmission network locally.

3.3.2.Hydrogen network

Similar questions arise for the hydrogen network, with the significant difference that methane infrastructure is already mature in many European countries—including France and Germany—and therefore less investment is needed (Speirs *et al.*, 2017).

The geographical organisation of the hydrogen network will strongly depend on the uses for which it is developed. We can see two main setups:

— (1) Limited development of hydrogen around production sites. Only some industrial consumers and rail, maritime and air transport would use it. Industrial consumers could use on-site electrolysers, meaning that little to no hydrogen pipelines would be needed. Hydrogen generation sites are located close to demand, forming hydrogen clusters (valleys) where some pipelines are built. In transportation, a limited number of refuelling stations are needed. This is likely to be the initial setup for hydrogen—until at least 2030 (Enagás *et al.*, 2020; GRTGaz, 2019)—and might continue further in time.

— (2) Wider use of hydrogen and relatively centralised hydrogen production. Hydrogen is used substantially for long-haul truck transport, calling for a substantial refuelling network through space. Assuming that at this stage, economies of scale could be achieved by somewhat centralising hydrogen production or that hydrogen imports would be significant, an extended hydrogen network could be needed, as put forward by the European Hydrogen Backbone study (Enagás *et al.*, 2020). Developing hydrogen for such uses would require an extended hydrogen network. In that setup, hydrogen would be competing with methane for some end uses: additional uses of hydrogen (e.g. fuel for light-duty vehicles, passenger cars, hydrogen-to-power) could become economic. The hydrogen network could become the main gas network while methane takes a smaller role.

For adequate, efficient and timely development of hydrogen infrastructure, hydrogen uses need to be anticipated in a finer way than what decarbonisation pathways have disclosed so far. Additionally, choices need to be made regarding the respective role of networks for methane and hydrogen because these roles are associated with sometimes radically different technological, economic and organisation pathways.

3.4. Infrastructure for gas trade within and outside the EU

The transformations of the energy system to reach carbon neutrality and the shift towards new sources of energy could disrupt the respective role of domestic and imported energy, for both electricity and gas. In the analysed scenarios, no major shift is visible for electricity supply; therefore the focus is on gas.

Today, the European Union imports nearly all of its methane supply, mostly by pipeline and ship as LNG (Eurostat, 2020). It has been funding large gas import infrastructure to ensure security of supply (European Commission, 2018b). 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, 2019). The decarbonisation pathways analysed in this study nearly all show decreasing methane imports until 2050, which would affect requirements for gas infrastructure. Existing infrastructure is already under-utilised and is likely to remain so, as shown in **Figure 9**. The analysed scenarios for France and Germany are two extreme cases of the role of gas imports: France relies almost completely on domestic biogas, while Germany meets its gas demand with imports, which make up almost 75% of PtX consumption by 2050 in EL95 and over 80% in TM95 (see Section 2.4). As gas supply evolves towards a lesser reliance on imports and on countries with geopolitical tensions, the risk of stranded assets is high (Inman, 2020; WWF *et al.*, 2017).

The differences between decarbonisation scenarios illustrate the uncertainty regarding the role of gas imports in a carbon-neutral European energy system. Apart from domestic biomethane potential, the respective role of imports and domestic production will depend for a large part on the production cost of low-carbon gas in potential import countries and cross-border transportation costs. For example, in the Dena scenarios for Germany, imports are so large partly because of low cost assumptions for imported synthetic methane, which is one-fourth the cost of the one produced domestically by 2050. The assumptions underlying the cost difference are not specified. Production of such amounts of PtX would require large renewable electricity infrastructure in import countries. There is still uncertainty as to where this synthetic methane would be imported from and how feasible such large imports would be.

For biomethane, it is likely that no significant amount of biomass would be imported to the EU considering that few countries have biomass resources exceeding their domestic demand and the current EU projections as to biomass imports (European Commission, 2018a). However, for synthetic methane, imports from countries with cheap and abundant renewable electricity resources could be cost-effective. A study for the German case claims that even in the long term, imported synthetic methane would be cheaper than its domestically produced counterpart. Main cost drivers include the cost of electricity production, conversion plant utilisation rates and the cost of CO_2 (Agora Verkehrswende *et al.*, 2018). Import countries around the North and Baltic Sea, in North Africa or in the Middle East are often considered. Although import routes from these countries already exist, today most methane to the EU comes from Eastern Europe. This suggests that the import infrastructure might have to shift towards the Western part of Europe and would re-draw European gas import routes.

FIGURE 9. Utilisation rate of existing and planned import infrastructure in France and Germany, 2015-2050

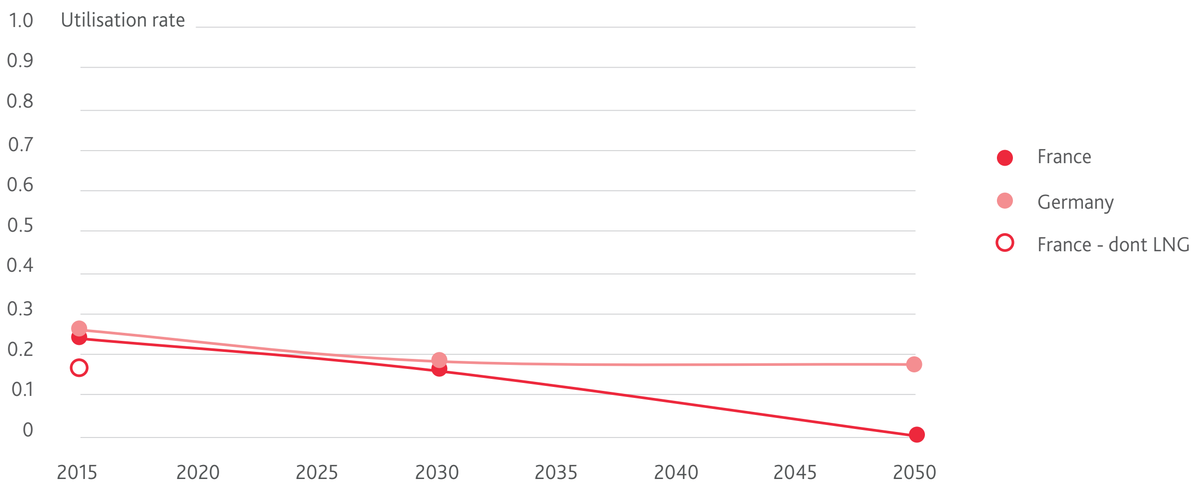
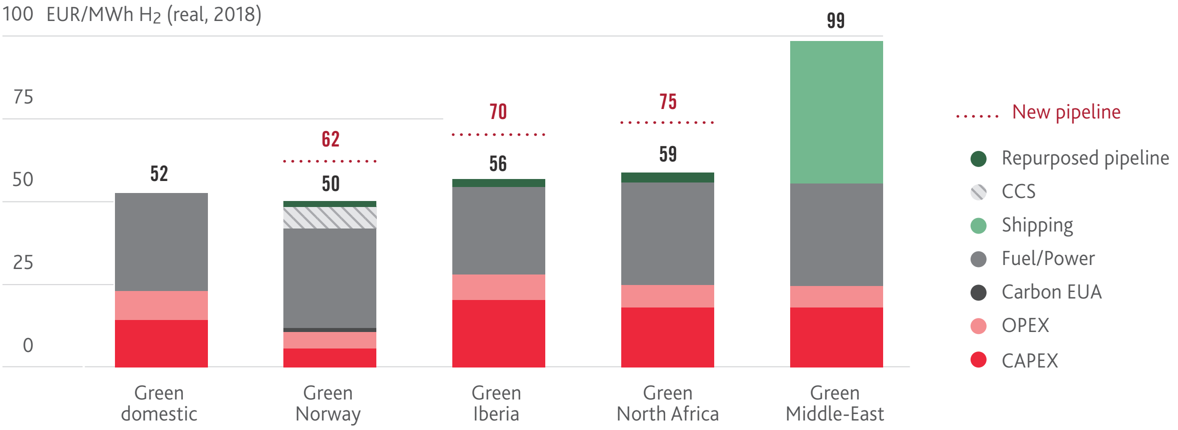


FIGURE 10. Levelised cost of hydrogen (LCOH) by 2040 in Northeast Europe



Source: Aurora Energy Research (2020).

For green hydrogen, the cost of building import pipelines might not counterbalance the fact that electricity is cheaper in potential import countries, as suggests a recent study focusing on hydrogen supply to Northwest Europe, see **Figure 10** (Aurora Energy Research, 2020). It is however likely that domestic production will be limited by the renewable electricity supply; for example, many German stakeholders claim that the domestic hydrogen production potential could not cover the country's hydrogen demand and that hydrogen imports would be needed (BMWi, 2020; Gerhardt *et al.*, 2020). Whether or not blue hydrogen (produced using natural gas and CCS) is considered could change the picture since it is expected to be cheaper than green hydrogen until at least beyond 2030. Yet, the technological feasibility of commercial-scale CCS by that time is much debated, while low social acceptance often hinders pilot projects. In Europe, promising capture sites for carbon are essentially located in the Netherlands and Norway (Aurora Energy Research, 2020; Gas for Climate, 2020); hydrogen import routes from these two countries to the rest of Europe might not coincide with the ones for green hydrogen.

Considering the extent of potential changes to gas supply routes, import infrastructure should be sufficiently included in infrastructure planning exercises:

— At both the EU and Member State level, assessment of the economic viability of import infrastructure projects should include the possibility that methane imports decrease in some countries as early as 2030. That might mean that little to no new capacity is developed or that some import facilities should be shut down. This is at odds with ENTSOG and ENTSO-E's last ten-year network development plan, which assumes increasing imports until 2030 in all of its pathways (ENTSOG & ENTSO-E, 2020).

— National decarbonisation strategies should take into account strategies of other EU Member States. For now, there is great variation between countries in terms of gas supply in the long term. These differences stem from variations not only in circumstances but also in narratives. For example, our comparison of decarbonisation pathways suggested that power-to-X (both hydrogen and methane) would have a larger role in Germany while biogas would be more central in France. Although there is uncertainty around these two technologies, this gap already shows in support policies in the two countries, e.g. with feed-in tariffs for biomethane in France enshrined in the Multi-year Energy Programme (MTES, 2020a) or in the German Hydrogen Strategy (BMWi, 2020). It is important for the two countries to find optimal pathways together: if Germany builds import routes for PtX from Maghreb, should France develop PtX imports rather than biogas? This could translate into the common design of new gas supply routes.

Long-term objectives will have consequences on today's policies. For example, the EU and its Member States are currently defining the objectives and the regulatory framework for the development of hydrogen. The end uses for which hydrogen is encouraged as early as the pilot phase will influence the size of hydrogen demand and the need for infrastructure in the long term. Similarly, objectives for energy efficiency, electrification and deployment of low-carbon gases in the industry will determine future demand for synthetic methane and hydrogen and their imports. Since large-scale natural gas infrastructure tends to have a long lifetime (around 50 years), it is crucial that today's investment plans are in phase with climate objectives.

4 CONCLUSION

The starting point of this study 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. It has provided elements to understand the potential impacts of carbon neutrality on gas infrastructure and to explore ways to better include infrastructure aspects in decarbonisation strategies.

The study highlights the fact that reaching carbon neutrality in the European Union is likely to cause significant shifts to the gas system driven by energy efficiency, electrification, and the development of low-carbon gases. Key challenges for gas which will determine infrastructure needs are the size of heat demand, the role of gas in transportation, the interaction between gas and electricity, and the degree of substitution of natural gas with low-carbon gases. The examples of France and Germany decarbonisation pathways suggest the following trends for European gas systems:

— Methane demand decreases significantly, especially in buildings and the industry;
— The decrease in these two sectors is partly compensated with a demand increase in transport and power;
— Hydrogen emerges as a significant energy carrier (for power generation and in the industry) and feedstock for the industry, although the uses for which it is developed varies between scenarios, especially when it comes to the transport sector.

Some aspects of the role of gas until 2050 are still very uncertain and vary a lot depending on the decarbonisation pathway, in particular with regards to the respective role of low-carbon gases (biomethane, synthetic methane and hydrogen) in the mix. While the role of biomethane is strongly determined by domestic potential, the contribution of hydrogen and synthetic methane seems to be more largely defined by political orientations or narratives.

These shifts are likely to significantly disrupt the way the gas infrastructure is managed and structured today, in four main ways:

— The financial management of the methane network, as the decrease in demand and the rise of more expensive, low-carbon methane could increase methane price and might lead to shut down part of the network;
— The integration of low-carbon gases to the existing network require technical adaptation which are likely to not be economically prohibitive but should be carefully planned;
— The geographical organisation of the network, as the distribution of methane demand in space could become more concentrated and as the development hydrogen could require dedicated infrastructure;
— The development of import infrastructure, as current projects to increase import capacity could result in stranded assets considering the likely decrease of methane imports and the redefinition of supply routes for low-carbon gases.

Despite significant challenges, existing decarbonisation pathways tend to leave infrastructure aspects out of the energy mix orientations. Additionally, they do not provide enough information to adequately study how the gas infrastructure could be affected by changes to the energy mix. In particular, the role of gas in transportation per segment, the contribution of gas to flexible power generation, the role of residual methane demand in building heat and associated consequences on the gas network should be explored more. This points out to the need for better integration of long-term infrastructure challenges into decisions about the energy mix. In real terms, decarbonisation pathways should take into account potential methane demand reduction as early as 2030 that is differentiated between sectors, take an integrated outlook on the electricity and gas systems, and include the end-user price perspective. Our study also highlights areas which require further research to adequately inform decisions regarding the energy system. It is of paramount importance that the future of the gas system is studied in an integrated perspective together with other energy carriers, especially electricity, in order to minimise system costs and increase the resilience of the energy system. The European level should be studied more in-depth as there are potential synergies and total cost reduction using cross-border integration, while existing pathways seem to only focus on the national level. Doing so is a prerequisite for infrastructure planning that both avoids sunken costs and ensures that decarbonisation is carried out efficiently and at minimal cost.

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6. ANNEX: METHOD

To achieve the research objective, this study took two main steps: first, the main issues facing gas supply and demand by 2050 were identified; then, the potential associated impacts on gas infrastructure were assessed.

6.1. Mapping the main issues for gas supply and demand until 2050

In order to understand the main transformations of the gas system until 2050, a framework of analysis was built based on the challenges posed by carbon neutrality to gas use and production.

An extensive literature review was conducted to identify the main turning points for gas in decarbonisation strategies. Such turning points are defined as the issues brought to the gas system by carbon neutrality which decarbonisation strategies need to address. A sectoral approach was taken, with a focus on the five following sectors: buildings, industry, power generation, transport, gas supply. These main turning points form the backbone of our analysis framework.

Using the framework, French and German decarbonisation pathways were analysed to illustrate different ways in which each of the challenges is addressed. These two case studies were chosen as they are the two largest energy consumers in the European Union and have significant political weight regarding European policy. France and Germany show fundamentally different energy systems which allow for a rich comparison. Four scenarios were selected so that a diversity of perspectives are represented. All of these scenarios aim for (near) carbon neutrality at 2050.

— The French National Low-Carbon Strategy, also called SNBC (MTES, 2020b). It is the French government's roadmap to reach carbon neutrality by 2050.
— 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.
— 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.
— 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.

6.2. Identifying the associated impacts on gas infrastructure

Using the results of our mapping of the main challenges and the possible developments for gas supply and demand, the associated impacts for gas infrastructure were estimated. A combination of quantitative and qualitative data was used to identify the main open questions when it comes to the future of gas infrastructure and quantify the range of changes.

6.2.1. Literature review

First, we carry out a literature review to identify the main (1) challenges that the gas infrastructure will have to face; (2) associated technical changes to the gas network; (3) conditions for these transformations to take place.

6.2.2. Infrastructure pathways

Once the transformations are identified, a quantitative analysis is carried out to estimate the impact of these changes. As there is high uncertainty on the future size of the network, we explore two infrastructure pathways, which are extreme-case scenarios which aim to give a range rather than project actual developments. It is assumed that the distribution network reduces in length, whereas the transmission system does not change in size. The focus in on the distribution network as the literature review revealed that it could significantly shrink in size (Wachsmuth *et al.*, 2019); the transmission network would reduce less.

— (1) Infrastructure business-as-usual (BAU). Today's infrastructure is kept as it 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 distribution network 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.

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.*, 2019). 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 different for each pathway:

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

The two pathways are examined for France and Germany, using respectively the SNBC and TM95 as reference scenarios for the gas mix until 2050.

The objective is to quantitatively estimate the range of impacts on the infrastructure, using the following metrics:

— The degree of use of the existing infrastructure and in the future according to two infrastructure scenarios.
— The change in price due to the change in production cost and operational cost of the gas distribution and transmission network according to two infrastructure scenarios.

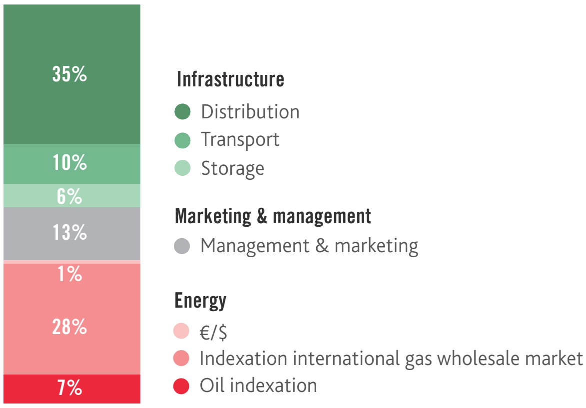
6.2.3. Methane price

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), as shown in **Figure 11**. In particular, infrastructure costs include the cost for distribution, transmission and storage of gas (CRE, 2017), see **Figure 12**.The breakdown between new build investment, upkeep (maintenance) investment and operational costs in the distribution and transmission cost is drawn from Fraunhofer ISI's Roadmap for Gas in Germany (Wachsmuth *et al.*, 2019). As in the long term gas demand is likely to decrease, little investment in extending the network would 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 13**.

This study aims to propose a rough estimate of the change in methane price by 2050. It focuses 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. Storage costs are left out of the analysis as they represent a small share of the price of methane.

Data for existing capacity of import infrastructure is drawn from ENTSOG data (ENTSOG & GIE, 2019) and data for planned

FIGURE 11. Price components (without tax) of average bill for gas provided by Engie in France in 2017



Source: CRE (2017), own translation.

capacity is drawn from the Europe Gas Tracker (Global Energy Monitor, 2019).

Data for the operational costs for distribution and transmission in the two countries is taken from Wachsmuth *et al.*, (2019) on the German case. Operational cost is expressed per unit gas.

For the production cost, the value for the average production price of methane is calculated for each country as the weighted average of the production price of each methane type, based on data from the literature. Assumptions for the production cost of methane depending on their type are as follows and shown in **Figure 14**.

— Fossil methane: projection from IEA's Sustainable Development scenario for the EU, cited by Bründlinger *et al.* (2018). This figure corresponds to the wholesale price, which is higher than the actual production cost; it does not assume any carbon tax. The fact that this is a conservative assumption does not affect our findings: if fossil methane were cheaper, the average cost of production by 2050 would be even more expensive as compared to 2015 and 2030 than it already is with our current assumptions.
— 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. This is a conservative hypothesis; it was chosen because of the uncertainty around the production costs of biomethane and state financial support for it.
— 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).

FIGURE 12. Infrastructure costs: investment in existing network, decommissioning and operational costs

Costs of replacing equipement

- Costs of pressure regulator (DN)
- Costs of volume flow meter (DN & TN)
- Costs of new meters (DN)
- Process gas chromatographs (TN)
- Costs of new compressor (TN)

Costs of decomimission

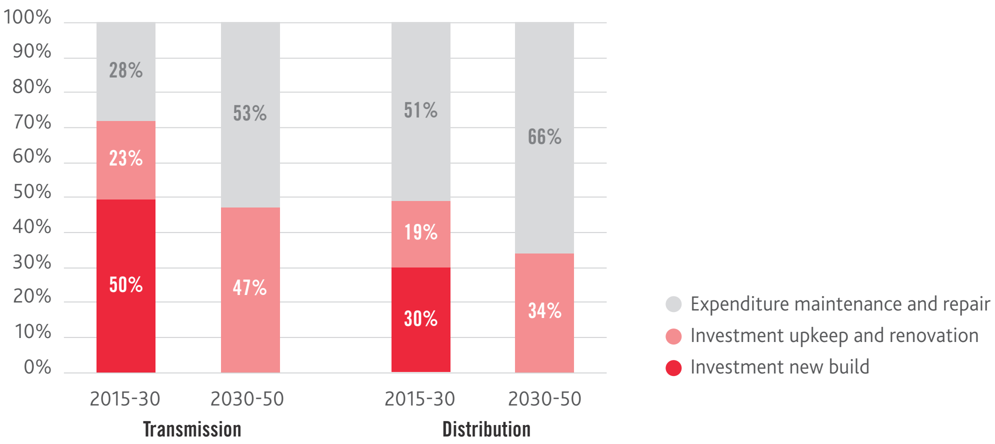
- Costs of pipeline decommission (DN et TN)
- Costs of equipement decommission (DN)
- Costs of compressor decommission (TN)

Development of specific operational costs

- Variable specific operational costs (TN)
- Fixed specific operational costs (DN & TN)

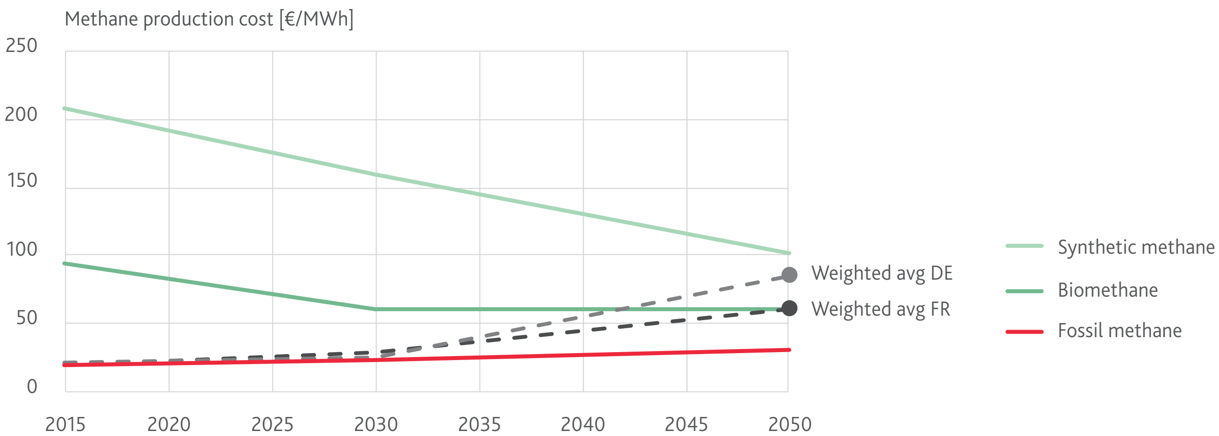
Source: Wachsmuth et al. (2019), own translation.

FIGURE 13. Cost structure of infrastructure cost in 2015-2030 and 2030-2050



Source: data from Wachsmuth et al. (2019) and own assumptions.

FIGURE 14. Assumptions 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"



Carbon neutrality in Europe: future challenges for the gas infrastructure

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