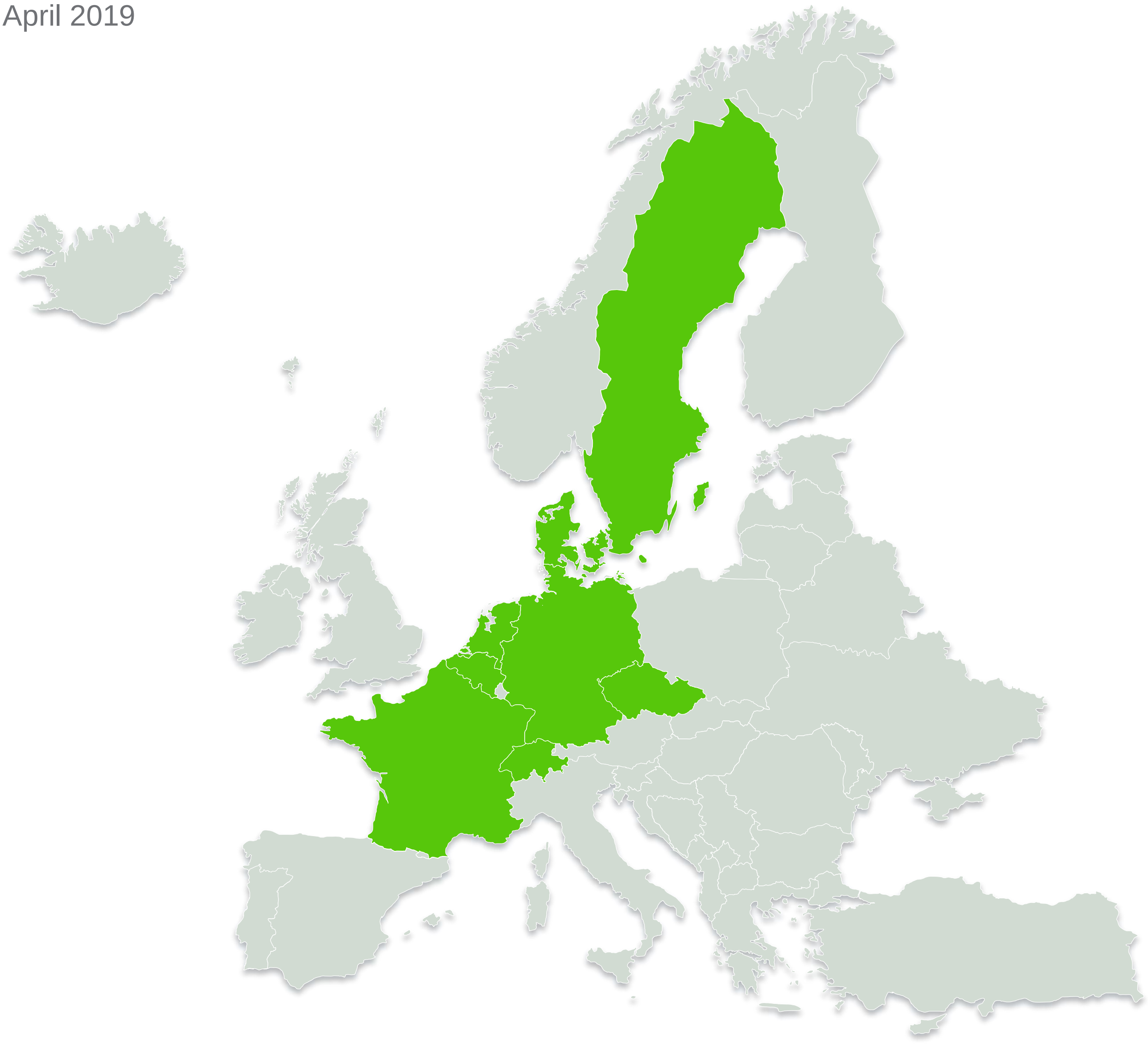
THE VALUE OF GAS INFRASTRUCTURE IN A CLIMATE-NEUTRAL EUROPE

A study based on eight European countries

April 2019



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ABBREVIATIONS

AC	Alternating current
AD	Anaerobic digestion
ATR	Autothermal reforming
BEV	Battery electric vehicles
CAPEX	Capital expenditure
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CCU	Carbon capture and utilization
CH_4	Methane
CHP	Combined heat and power (plant)
CNG	Compressed natural gas
CO_2	Carbon dioxide
DAC	Direct air capture
DC	Direct current
DSM	Demand-side management
EU ETS	European Union Emission Trading Scheme
FCEV	Fuel cell electric vehicles
GGI	Green Gas Initiative
GHG	Greenhouse gas
H_2	Hydrogen
HVDC	High-voltage direct current
ICT	Information and communications technology
LNG	Liquefied natural gas
LPG	Liquified petroleum gas
OCGT	Open cycle gas turbine
OEM	Original equipment manufacturer
OPEX	Operational expenditure
PEM	Polymer electrolyte membrane
PHS	Pumped hydro energy storage
$PtCH_4$	Power-to-methane
PtG	Power-to-gas
PtH_2	Power-to-hydrogen

PtL	Power-to-liquids
PtX	Power-to-X
PV	Photovoltaics
R&D	Research and development
RES	Renewable energy source
SMR	Steam methane reforming
SNG	Substitute natural gas (also: synthetic natural gas)
TSO	Transmission system operator
TYNDP	Ten-Year-Network-Development-Plan

EXECUTIVE SUMMARY

Background and objective

The 2015 Paris Agreement aims to limit the increase in the global average temperature to well below 2°C above pre-industrial levels. To achieve this objective, global greenhouse gas (GHG) emissions, particularly carbon dioxide (CO_2), will need to be reduced substantially. In this context, the European Union has made important progress over the last years. The Clean Energy Package has been a milestone in setting the EU's energy sector on the ambitious decarbonisation trajectory set out by the Paris Agreement.

However, it is clear that efforts targeting reduction in energy sector emissions alone are not sufficient and a concerted cross-sector emissions reduction strategy – referred to as sector coupling – will be required to achieve the Paris Agreement aspirations. In effect, energy-related GHG emissions in the electricity, heat, transport and industrial sectors will have to be reduced to nearly zero by 2050. This study seeks to enrich the debate on sector coupling by focusing on the role and potentials of infrastructure coupling.

In particular, this study analyses the role gas infrastructure could play on the path to a climate-neutral Europe, with a regional focus on Belgium, the Czech Republic, Germany, Denmark, France, the Netherlands, Sweden and Switzerland.[1]

The challenge: Generation, storage and transport of energy in an increasingly decarbonised Europe

Besides a boost in energy efficiency to reduce energy consumption in the first place, the core element of decarbonisation will be replacing fossil fuels with energy from renewable sources such as wind, solar and biomass (or with nuclear energy in those member states that opt for it). Transitioning to this system, as well as maintaining it, will create enormous challenges as it requires:

- **generating** vast amounts of renewable (and low-carbon) energy, and so overcoming the difficulty of finding appropriate and publicly accepted generation locations within Europe;
- **storing** large energy volumes over weeks, months and seasons, to match intermittent renewable supply with the pattern of energy demand (which peaks in most of Europe in winter, driven by demand for heat); and
- **transporting** renewable energy from where it can be most efficiently and feasibly produced to where it is consumed – encompassing both long-distance transport, for example from offshore wind facilities to demand centres, and local distribution.

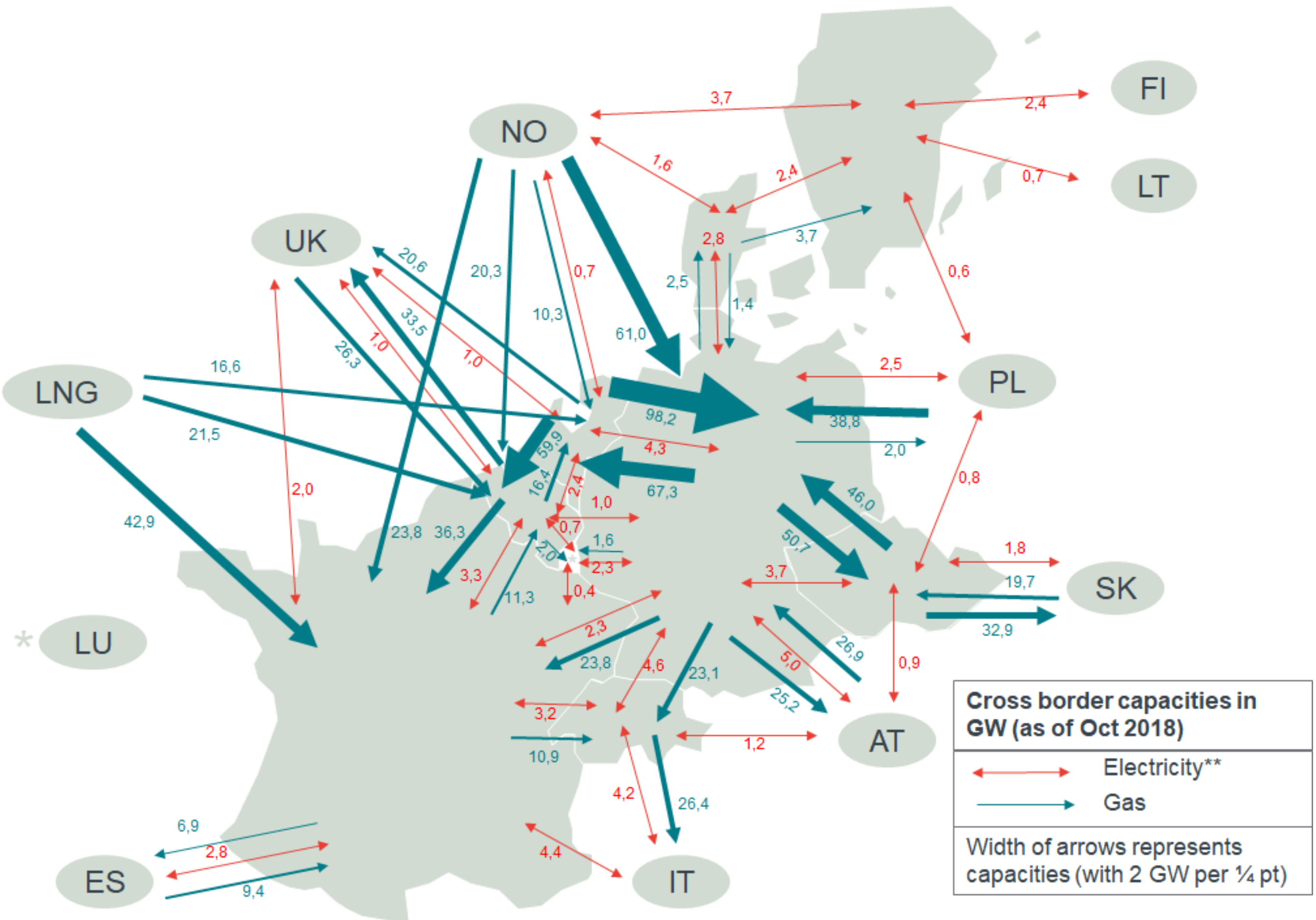
[1] Parts of this analysis are based on a previous study on the value of gas infrastructure in Germany for the association of gas TSOs in Germany (FNB Gas), see Frontier Economics et al. (2017).

Gas infrastructure well positioned to help overcome the challenges of decarbonisation

Existing gas infrastructure has lots to offer to overcome these challenges:

- **Existing gas infrastructure** is extensive and already helps address many of the challenges of generation, transport and storage of energy at present:
  - **Transport**: Gas infrastructure has historically been designed to bridge long-distances between points of production and consumption at low cost and with low energy losses. Accordingly, there is a wide-ranging and well-established Europe-wide gas transportation system, with gas transmission capacity greatly exceeding electricity transmission capacity, not only nationally but also internationally (Figure 1).

Figure 1 Cross-border transport capacities for gas exceed those of electricity by large



Source: Frontier Economics based on ENTSO-E and ENTSOG

*Note: ** In some cases published capacities vary slightly between flow directions. In such cases, the higher figures are shown above.*

- **Storage**: Given the fact that gas demand has always been largely temperature-driven, significant gas storage capacity (550 TWh) exists in the eight countries analysed. This is sufficient to cover today's average gas demand in these countries for more than three months. In comparison, today's total electricity storage (including pump hydro storage) of less than 0.6 TWh suffices only to meet average electricity demand for fewer than four hours.

Storage

Existing gas storage volumes allow to cover gas demand for months, and exceed electricity storage volumes by almost a factor of 1,000 in the eight analysed countries.

- **Overseas sources**: Finally, gas infrastructure could also help to overcome the third identified challenge of decarbonising Europe - the difficulty of exploiting sufficient renewable energy potential within the continent. Existing transport capacity (via pipelines and liquified natural gas (LNG)) and the international trade infrastructure can provide access to low-cost renewable energy sources outside European territory. This can help ensuring that Europe stays part of the global energy market, avoiding a price decorrelation that negatively impacts Europe's competitiveness (and triggering carbon leakage to non-European countries).

- There are **various renewable and low-carbon gases** available, which justify to pursue the usage of the gas infrastructure in a decarbonised Europe. These include biomethane, green hydrogen or synthetic (green) methane from electrolysis (power-to-gas, PtG) and "blue hydrogen", i.e. natural gas decarbonised by carbon capture and storage (CCS) or carbon capture and usage (CCU). All these renewable and low-carbon gases have in common that they either do not emit GHG when being burnt (hydrogen), or only emit the amount of GHG they have captured from the atmosphere recently (biomethane and synthetic methane), in contrast to natural gas or other fossil fuels that, when being burnt, release GHG that has been captured over millions of years.

- Significant shares of **energy consumption** can be switched to (or kept with) renewable and low-carbon gases as energy carriers. For example, such gases could serve as a reliable fuel for **electricity generation** and thus serve as back-up capacity to balance intermittency of renewable electricity supply, cover seasonal **heating** demand, contribute towards decarbonising the **transport** sector (particularly in heavy-duty transport), and provide a low-carbon solution for **industry** heat and feedstock needs.

Methodology of our approach: We perform a system-wide analysis of using gas infrastructure

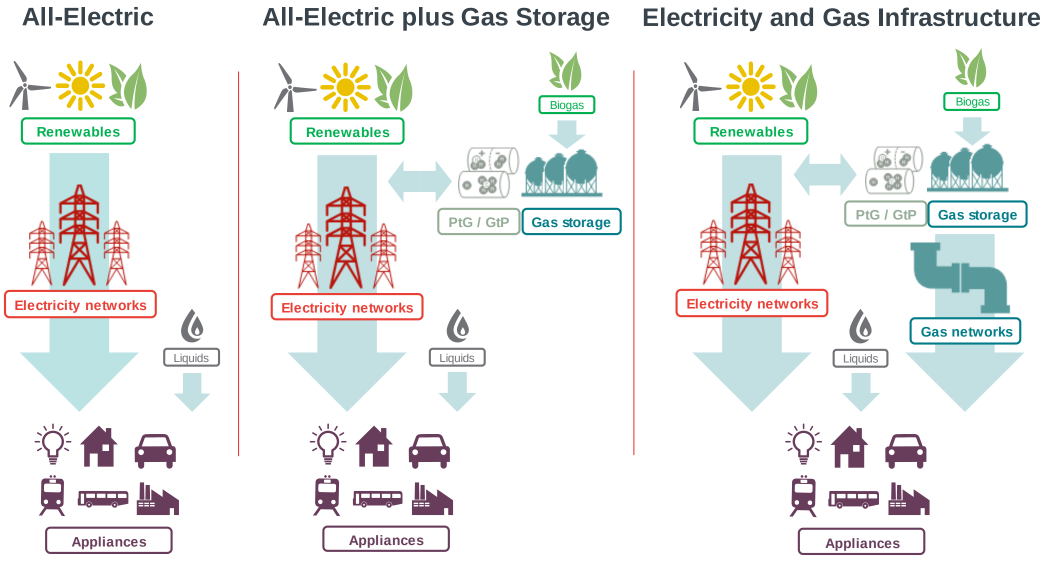
To analyse the role that gas infrastructure could play on the path to a climate-neutral Europe, we take the following steps:

- **We compare three scenarios to achieve the 2050 decarbonisation** targets,[2] (see Figure 2):
  - An **"All-Electric" scenario**, where end consumers in all sectors primarily use electric appliances such as heat pumps and electric vehicles ("direct electrification") and, accordingly, energy infrastructure (transport, distribution, storage) is all-electric;
  - An **"All-Electric plus Gas Storage" scenario**, where the "All-Electric" scenario is supplemented by the opportunity to use gas storage to temporarily store renewable energy/electricity in the form of gas and to convert the gas back into electricity using gas-fired power plants, to cope with intermittent renewable energy supply and seasonal energy demand. However, electricity networks remain the sole means of energy transport and end-user appliances are all-electric similar to the previous scenario; and
  - An **"Electricity and Gas Infrastructure" scenario**, where the electrification of parts of final energy use is complemented with use of end-user appliances that can operate on renewable and low-carbon gas. Accordingly, in addition to electricity networks, gas transmission and distribution networks (along with gas storage) may still remain in use. This scenario therefore forms a "hybrid" scenario with both electricity and gas being used in end-appliances.
- We analyse a **subset of eight European** countries:[3] This helps to identify commonalities and differences in external conditions as well as current status and discussions with regards to gas infrastructure usage across countries as a basis to developing the political and regulatory framework for renewable and low-carbon gas.
- **We take into account various potential renewable and low-carbon gases** that can be deployed within existing gas infrastructure, including biomethane, hydrogen and synthetic methane based on electrolysis as well as blue hydrogen converted from natural gas with CCU or CCS.
- We take into account **all major energy-consuming sectors**, including electricity generation, heating, transport and industry.
- We analyse the costs and benefits of using gas **across the entire energy supply chain**, i.e. we analyse the costs of generating renewable electricity and various renewable and low-carbon gases, storage, end-user appliances, and transmission and distribution of electricity and gas.

[2] This approach is similar to the one adopted in our previous study on the value of gas infrastructure in Germany: Frontier Economics et al. (2017).

[3] Please note that quantitative estimates on potential costs savings of gas infrastructure are limited to Belgium, the Czech Republic, Germany, Denmark, France, the Netherlands and Switzerland, i.e. Sweden is not in the scope of the quantifications.

Figure 2 Three scenarios to achieve the 2050 targets (schematic overview)



Source: Frontier Economics

Note: We assume that there is an identical role for renewable liquid fuels in all scenarios and do therefore not consider liquid fuels in the quantitative comparison between the scenarios.

Results: Use of gas through existing infrastructures saves costs and increases security of supply as well as public acceptance

Achieving decarbonisation targets without gas storage is technically challenging and would be prohibitively expensive

Storing energy over seasonal timespans – particularly to match intermittent renewable electricity supply with winter peak demand for heat – remains a key challenge of decarbonisation.

Electricity storage solutions existing at present are either limited in scale (e.g. pumped hydro storage), or only suited for short-term storage (e.g. many battery technologies). Technology developments are underway, e.g. for compressed air storage that may be used for longer-term storage, but in a foreseeable future costs will be prohibitively high, even assuming significant cost reductions compared to today. This leaves the storing of energy in gas storage facilities as the most cost efficient technology for seasonal storage. Accordingly, gas storage has been used for decades to match comparably constant energy supply with very seasonal und unpredictable energy demand.

Therefore, an "All-Electric" scenario without the use of gas storage – at least for seasonal storage and for providing energy during cold, dark periods with low wind – would be prohibitively expensive and unrealistic. A view that is supported by many other studies and is becoming more commonly understood in the political sphere.

The quantitative analysis of this study, thus, focuses on the second (All-Electric plus Gas Storage) and third (Electricity and Gas Infrastructure) scenarios above, and seeks to evaluate whether using the gas network infrastructure in addition to gas storage can have incremental societal benefits.

Use of gas networks to transport gas to final consumers leads to savings in system costs

The continued use of gas networks avoids substantial investments related to electrifying end-user appliances, expanding electricity networks and requiring an even higher mobilisation of renewable energy potential.

Calculations show that the eight countries analysed together can save **EUR 30 billion to 49 billion per year** in 2050 through the continued use of gas networks.[4] If we assume a linear development path between today and 2050, these would elicit total cost savings of **EUR 487 billion to 802 billion between today and 2050** (real values; undiscounted). Assuming equal per-capita savings in other European countries, total cost savings in the EU-28 would be equivalent to **EUR 76 billion to 125 billion per year** in 2050, or approximately **EUR 1,300 billion to 2,100 billion between today and 2050 –** again assuming a linear path.[5]

487-802bn €

Savings until 2050 through the continued use of gas networks in the eight analysed countries.

To compare energy system costs between both scenarios, our analysis has taken into account all relevant direct[6] cost factors along the energy supply chain. To capture uncertainty about the future development of key parameters such as gas and electricity demand or renewable gas generation costs in 2050, we have repeated the calculations for a number of different parameter sets, resulting in cost saving intervals on each stage of the value chain.

Our analysis for the eight countries shows the following key sources for the above described total savings:

- **Large cost savings through gas-based end-user appliances** in **heating** (EUR 11.7 - 13.3 billion per year), **industrial processes** (EUR 4.1 - 4.6 billion per year) and in the **transport** sector (EUR 3.5 - 5.5 billion per year);
- **Substantial cost savings** of **using gas networks by avoiding investments in electricity transmission** (EUR 2.5 - 3.2 billion per year) and **distribution** (EUR 7.6 - 9.2 billion per year) **networks**;
- **Moderate additional costs** (EUR 0.7 billion per year) of **maintaining gas networks** and adjusting or converting them to hydrogen where required, compared to having to dismantle them in the "All-Electric plus Gas Storage" scenario without gas networks; and

4 That is based on a comparison of system costs in the "Electricity and Gas Infrastructure scenario" with system costs in the "All-Electric plus Gas Storage", where gas networks are no longer used.

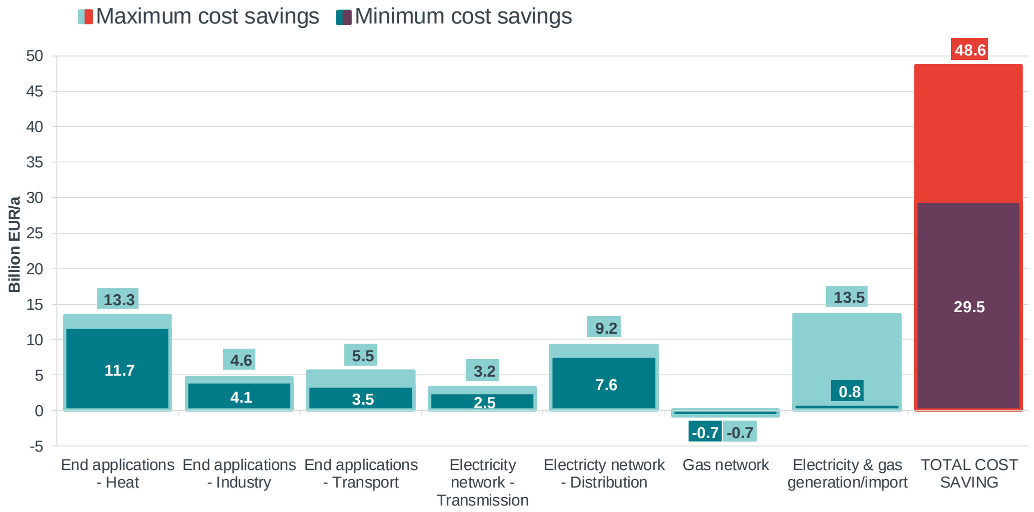
5 Please note that both assumptions, i.e. a linear development of cost savings and per-capita cost savings for non-analysed EU-28 countries that are equal to those of the countries analysed, are simplifying. The resulting numbers serve to give a rough estimate of total cumulated cost savings by 2050 and total cost savings for EU-28.

6 We do not take into account any externalities such as the impact on jobs or emissions in related sectors.

- Further **significant cost savings through cheaper energy generation** (EUR 0.8 - 13.5 billion per year), particularly through using inexpensive domestic biomethane and imported renewable gas from regions with good renewable energy conditions.

Figure 3 illustrates the minimum and maximum benefit that each of these areas contributes to total cost savings.

Figure 3 Minimum and maximum cost savings of a continued use of gas networks per year in 2050 along the supply chain (cumulated for the eight countries analysed)



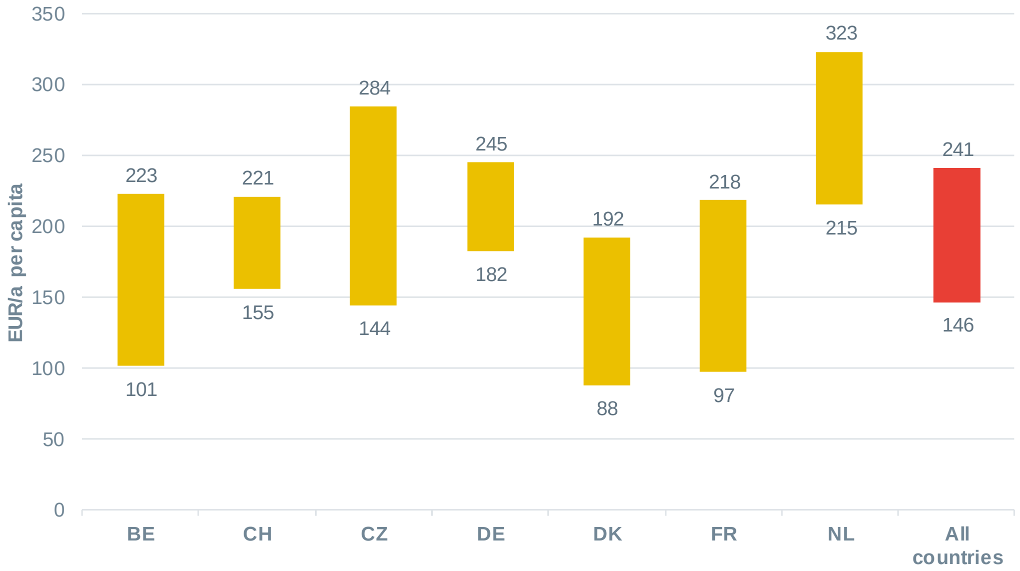
Source: Frontier Economics/IAEW

Note: The values illustrate the difference in annual costs between the "All-Electric plus Gas Storage" scenario and the "Electricity and Gas Infrastructure" scenario. A positive value reflects cost savings in the "Electricity and Gas Infrastructure" scenario, where parts of end energy are supplied by renewable and low-carbon gas[7] via gas networks, compared to the "All-Electric plus Gas Storage" scenario, where end energy is primarily supplied by electricity and gas networks are no longer needed. Minimum and maximum savings refer to varied assumptions on key parameters that are uncertain from today's perspective, such as production prices of different renewable gases, the assumed share of gas imports or the development of final energy demand until 2050.

Cost savings vary between countries due to various country-specific factors like generation potentials, network structures and/or the historic penetration of gas (Figure 4).

[7] For the Czech Republic we also assume a small remaining amount of natural gas.

Figure 4 Annual cost savings [in EUR per capita] of the continued use of gas networks in the countries analysed in 2050



Source: Frontier Economics / IAEW

Note: The values illustrate annual cost savings per capita in the "Electricity and Gas Infrastructure" scenario compared to the "All-Electric plus Gas Storage" scenario.
If these savings are related to the number of households, this corresponds to cost savings per household of 316 to 520 on average over all countries analysed. Please note, though, that we calculate cost savings for all sectors (including e.g. industry) and not only households, so these numbers are not to be interpreted as individual energy bill cost savings per household.
The range of cost savings per country is caused by varied assumptions on key parameters that are uncertain from today's perspective, such as production prices of different renewable gases, the assumed share of gas imports or the development of final energy demand until 2050.

Use of gas storage and import capacity enhances security of energy supply

In addition to cost savings, the use of gas infrastructure can boost the security of energy supply in Europe:

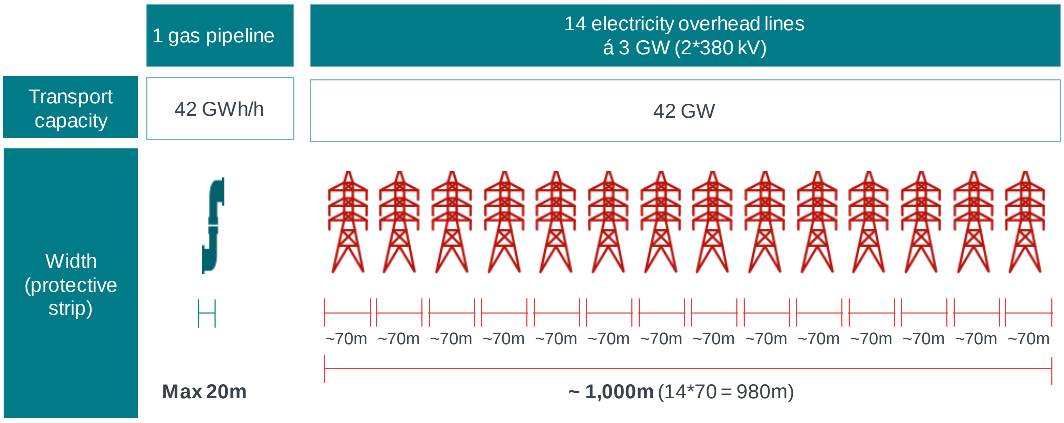
- The **significant existing gas storage capacity** in Europe not only helps to cover seasonal swings in energy demand; it also serves to cover energy demand in the case of one-off supply shortfalls and/or extreme demand situations, for example during a prolonged cold spell with high heat demand and low PV feed-in or during dry years where pumped storage hydro power stations no longer work.
- The high interconnectivity of the European gas network and its LNG infrastructure also **allow for a diversified supply portfolio,** thus further contributing to security of energy supply in Europe.

Use of gas infrastructure benefits public acceptance of decarbonisation

For many years, the required expansion of the electricity infrastructure (both generation and network) in Europe has been significantly hampered by significant opposition in affected regions due to concerns about adverse environmental impacts, effects on health and economic costs. With ongoing decarbonisation, the need for new infrastructure such as network expansions will grow. Our analysis for the eight countries, for example, indicates that decarbonisation mainly via direct electrification as in the "All-Electric plus Gas Storage" scenario is likely to increase today's electricity peak demand by a factor of three by 2050, inducing the need for major electricity network extensions.

In contrast, a comprehensive gas infrastructure that satisfies the required energy demand already exists. And since both gas transmission and distribution networks are typically laid underground, they often have only limited impact on the environment and land use (see Figure 5 for an illustrative comparison of the space requirement for 42 GW gas and electricity transport capacity respectively). Retaining existing gas infrastructure could therefore be key to enhancing public acceptance for an effective energy transition in Europe.

Figure 5 Space requirement of gas vs. electricity transmission



Source: Frontier Economics

Note: The gas pipeline capacity is based on the OPAL pipeline, with a transport capacity of 36 billion cubic meters gas per year (or, in energy-terms approximately 42 GWh/h) North-West Europe's largest gas pipeline, see OPAL (2019). While the pipeline is laid underground and has a diameter of 1.4 m, pipelines of this size are usually assigned a "protection strip" of max. 20m width, where land use is restricted (e.g. no buildings), see Frontier Economics and White & Case (2017).
To accommodate the same energy transport capacity, a hypothetical number of 14 overhead lines with a capacity of 3 GW each would be needed. Transmission overhead lines are typically assigned with a protection strip of 60 to 80m, see Frontier Economics and White & Case (2017).

Implication: Policy change needed to allow gas to underpin decarbonisation

In all countries analysed in this study, the use of renewable and low-carbon gas via existing gas infrastructure will have substantial societal benefits within a 2050 energy system that meets the Paris Agreement targets. However, the path towards a green energy system is challenging and requires parallel policy developments and coordination. Hence there is a need for swift policy adjustments where renewable gas can valuably complement renewable electricity and other forms of renewable energy. We identify the following key areas for policy change:

- **Keep options open to allow for a mix of energy sources and technologies.** Given uncertainty around future technology developments, policymakers should keep as many options open as possible to allow for an intense competition of technologies and innovative concepts that will make the energy transition happen in a cost effective way. Diversification is also key for the resilience of the future energy mix. Therefore:

- **no technology option should be prescribed or precluded** unless sufficient certainty regarding their future value exists;
- **allowance for diverse solutions** within Europe should be made to reflect structural differences between the countries and regions; and
- **R&D in new technologies and feasibility studies should be supported** to address technological spill-overs and help establish which solutions could be of practical value.

- **Create a level playing field for all technologies.** As well as having a fair chance to contribute to the energy transition, technologies should also play by the same rules. Accordingly, it is important to ensure that:
  - the contribution to the energy transition is valued for each climate-neutral energy carrier – in particular, the **positive climate impact of renewable and low-carbon gas needs to be reflected** in the policy framework;
  - **distortions arising from energy carriers are minimised** - for instance, power-based gas is today treated as final consumption in most countries, and thus PtG facilities bear significant extra costs in the form of taxes, levies and grid fees. As this does not reflect the system benefits of PtG, further research is necessary to evaluate which tax and levy structure is appropriate; and
  - **electricity and gas network planning takes place in an integrated way** – this is essential in preventing bias towards one type of network versus the other that would induce unnecessary system costs.
- **Consider explicit (temporary) support for renewable gas.** Renewable and low-carbon gas technologies are today produced on a comparatively low scale, implying relatively high investment and thus gas production costs. Policy could therefore help ensure market build-up and economies of scale through **temporary production and investment support to generate scale effects**.
- **Clarify the role of stakeholders regarding renewable and low-carbon gases**. Sector coupling in a hybrid energy system requires the rights and obligations of relevant stakeholders to be redefined. In particular, there is a need to challenge the established distinction between "market" and "infrastructure" when it comes to creating new technologies and business models:
  - **Electricity and gas sector coupling requires the (re)definition of infrastructure operators:** Today, considerable uncertainty persists, for instance, as to who is eligible to own and operate storage and conversion facilities such as PtG plants – only merchant players, or gas network operators and/or electricity network operators as well?
  - **Electricity and gas sector coupling will change the way the gas infrastructure cost is allocated and encourage efficient gas tariff setting**: Efficient tariff setting needs to be compatible with future gas infrastructure. Specifically, the tariff needs to avoid anti-competitive effects on renewable gas, e.g. through burdening costs for stranded assets to renewable gas.

- **Enable cross-border trade in renewable gas** – Transportability in bulk over long distances is a key advantage of renewable or low-carbon gas over electricity. This also provides unique opportunities to bridge geographic gaps between supply and demand, e.g. due to the uneven distribution of renewable energy sources across Europe and beyond. Countries should therefore strive to foster international trade cooperation, given the benefits of international renewable gas trade.
- **Ensure interoperability of (international) systems** – Gas systems are likely to vary between regions and, given the diversity of renewable or low-carbon gas options and their heterogeneous distribution Europe-wide, the differences in the gas system might even intensify in a renewable or low-carbon gas world. To interoperate smoothly, the following actions are required:
  - **Establish a gas quality standardisation** to accommodate multiple gas sources, for example by implementing harmonised system of certificates of origin.
  - **Introduce a binding international sustainability regulation** to boost acceptance of international renewable or low-carbon gas products.
  - **Harmonise key characteristics of EU support schemes** to prevent inefficient funding due to a range of support system set-ups in European countries.

1 THE AIM OF THIS STUDY: ANALYSE THE VALUE OF GAS INFRASTRUCTURE IN A CLIMATE-NEUTRAL EUROPE

This study analyses the value and potential role of the gas infrastructure in a climate-neutral Europe. In this introductory section we

- conclude that the ambitious climate protection ambitions in Europe require full decarbonisation of the energy supply in the long run (Section 1.1);
- summarise our objective to analyse the potential contribution of gas infrastructure to decarbonising Europe (Section 1.2);
- provide an overview of the scenarios reviewed (Section 1.3); and finally
- lay out the structure of our report (Section 1.4).

1.1 Background: Climate protection ambitions in Europe require full decarbonisation of the energy supply by 2050

The Paris Agreement is setting the global basis for decarbonisation targets

The 2015 Paris Agreement aims to limit increase in the global average temperature to well below 2°C above pre-industrial levels. To achieve this objective, global greenhouse gas (GHG) emissions, particularly carbon dioxide (CO_2), will need to be reduced substantially.[8]

Ambitious climate targets on EU level to contribute to the Paris Agreement

The European Union is willing to make an ambitious contribution towards achieving this objective by aiming for the following GHG emission reductions within EU territory (see Figure 6):

- At least 40% below 1990 levels by 2030 (binding target).[9]
- **80 to 95% below 1990 levels by 2050** (non-binding ambition).[10]

80-95%

of GHG emissions to be cut in the EU by 2050, as compared to 1990 levels.

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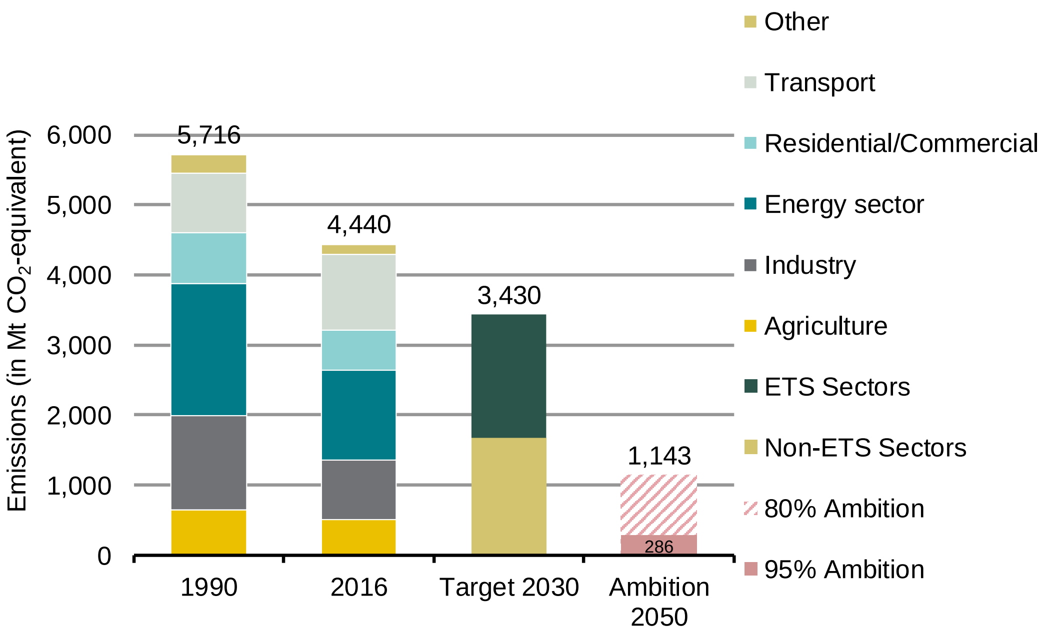
8 Greenhouse gases include a variety of different gases such as CO_2, methane (CH4), water vapor, nitrous oxide or ozone. The chunk of global greenhouse gas emissions is CO2 emissions. To make different greenhouse gas emissions comparable, these can be measured in "CO_2 equivalent". For any quantity and type of greenhouse gas, CO_2 equivalent signifies the amount of CO_2 which would have the equivalent global warming impact. For simplicity, we use the terms GHG and CO_2 interchangeably throughout this report. GHG emissions are always measured in CO_2 equivalent.

9 See European Commission (2018a). Adopted by EU leaders in October 2014, European Council (2014).

10 See 2050 long-term strategy "A Clean Planet for all" of the European Commission, European Commission (2018b).

Over the last years the European Union has made important progress towards reaching these targets. The Clean Energy Package, for instance, has been a milestone in setting the EU's energy sector on the ambitious decarbonisation trajectory set out by the Paris Agreement.

Figure 6 Greenhouse gas emissions in EU-28



Source: Frontier Economics based on the European Environment Agency

Single countries are setting additional national decarbonisation targets

In addition to the targets on EU level, several European countries are setting themselves own national GHG reduction targets. For example, the administrations of many EU member states have committed to achieve a reduction in national GHG emissions of 80-95% by 2050 as compared to 1990 levels, in line with wider EU ambitions. These countries include, for example, most of the member nations of the Green Gas Initiative (GGI). Likewise, Switzerland is currently discussing plans to set a national target to reduce GHG emissions by 70-85% as compared to 1990 levels by 2050 and reach climate-neutrality after 2050.[11]

Achieving these climate targets requires full decarbonisation of energy supply in all sectors by 2050

In recent years, most efforts on European and national level to reduce GHG emissions have been focussed on the energy sector, mainly on replacing fossil-fuelled by renewable electricity generation. However, given the significant share of carbon emissions in the transport, residential, industry and agricultural sectors (see

[11] See Bundesamt für Umwelt BAFU (2017). Other countries, particularly in Central and Eastern Europe, with a more challenging heating and industry heritage in terms of CO_2 emissions, have not yet committed to national targets but are currently identifying pathways for decarbonisation. In the Czech Republic, for instance, a combination of expensive but so far ineffective solar subsidies, the unclear future role of nuclear energy and the heritage of central coal/gas based heating municipality systems make the clear formulation of a decarbonisation strategy difficult.

Figure 6), and the fact that a significant share of emissions in the agricultural and industrial sector are non-energy related and as such hardly avoidable, achieving a reduction of 1990 level emissions by 80-95% requires that energy-related emissions in all sectors will have to be largely decarbonised by 2050.

1.2 Objective: Analyse the role that gas infrastructure could play in decarbonising Europe

Decarbonisation of large parts of the energy, heat and transport sector will require a fundamental change in today’s energy system. As depicted in Figure 7, the European energy systems today consists of:

- A heterogenous mix of primary energy sources, ranging from fossil hydrocarbons to nuclear and renewables;
- (at least) three main pillars of infrastructure to transport and distribute energy: the power grid, the gas network and an infrastructure for distributing liquid fuels;
- and a variety of end appliances in all sectors.

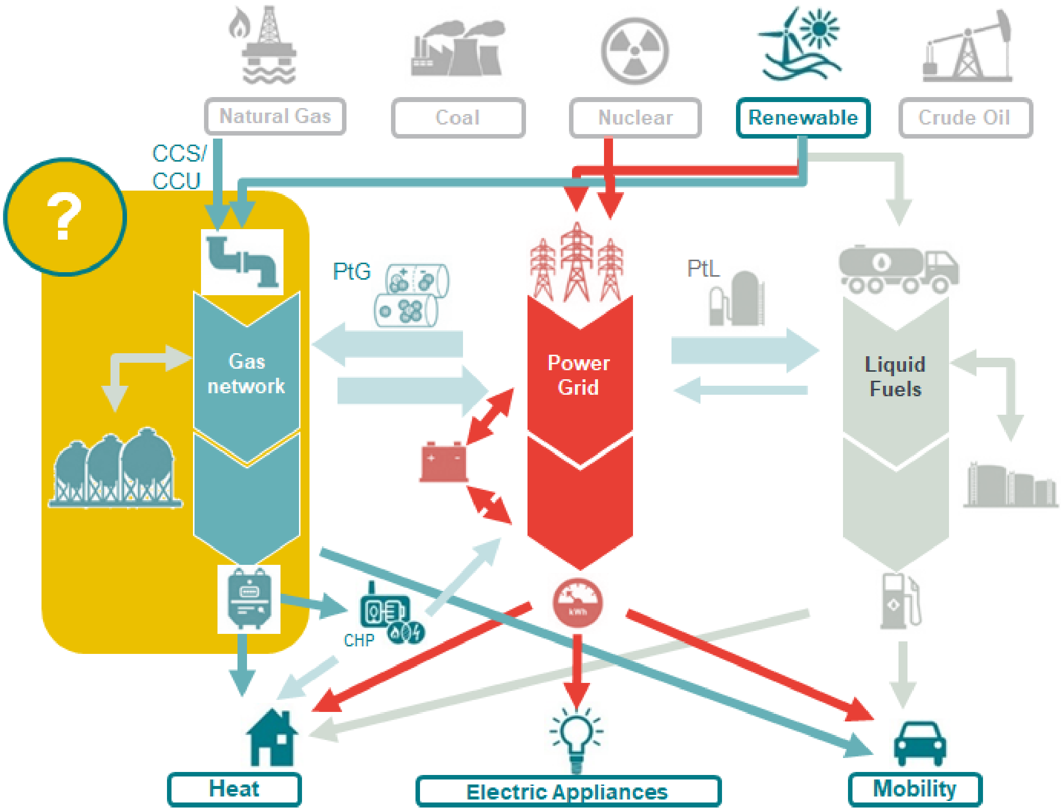
The need to decarbonise will require a fundamental change to the primary energy supply. Most of the fossil energy sources will have to be replaced by large volumes of – mostly intermittent – renewables and other low-carbon sources (such as nuclear in those countries that opt for it). As we discuss in Section 2, integration of intermittent renewable energy sources like wind and solar pose significant challenges to the system.

It therefore remains a key question to which degree the current three pillars constituting large parts of the energy system’s infrastructure will have to be adapted or even substituted to accommodate large shares of renewable energy sources.

In this study we specifically **focus on the role that gas infrastructure could play** on the path to a climate-neutral Europe, and will attempt to answer questions including:

- Is there a long term role for gas infrastructure, given the limitation of natural gas for decarbonising Europe?
- What value can gas infrastructure have given a rising trend in electrification of end-user appliances?
- What sorts of renewable and low-carbon gases can contribute to decarbonising Europe, and what are the sectors where this is most sensible?

Figure 7 The energy supply in a decarbonised economy has to foster sector coupling. What role can and should gas infrastructure play?



Source: Frontier Economics

Note: This schematic illustration focuses on the energy supply and excludes the use of fuels or gases as raw materials ("feedstock") in the industry.

While the potential future role of gas has been assessed in several studies already, most of the previous research was limited to certain aspects of this complex question. In this study, we are aiming for a more comprehensive analysis through:

- **Conducting a multi-country study.**
  - There have been several assessments of the future role and benefits of gas infrastructure in **single European countries**: For Germany alone, the frontrunner in applying intermittent renewables in Europe, a wide range of studies has emerged within the past years.[12] Likewise, there has been significant research conducted on this topic in the UK[13], Denmark[14], France[15] and the Netherlands[16]. What remains pending is an analysis of multiple countries that also identifies commonalities and differences between the countries.

[12] See for example Frontier Economics et al. (2017), Dena (2017), Dena (2018), Enervis (2017a), Enervis (2018), EWI (2017) or Nymoen Strategieberatung (2017).

[13] For example KPMG (2016), Dodds, P. and McDowall, W. (2013) and Northern Gas Networks (2016).

[14] For example Energi Styrelsen (2013) and Energinet (2015a).

[15] For example ADEME (2018).

[16] For example Netbeheer Nederland (2017) and Gasunie (2018).

- Other research has been examining this topic on a **European level**, for example Ecofys (2018), Eurelectric (2018) or Eurogas (2018). These European-scale studies have not looked at single countries in detail.
- **In this study, we analyse a subset of European countries in more detail**, namely, the countries of origin of the seven TSOs that have formed the Green Gas Initiative (GGI), i.e. Belgium (BE), Switzerland (CH), Germany (DE), Denmark (DK), France (FR), the Netherlands (NL) and Sweden (SE), as well as the Czech Republic (CZ) (see Figure 8).[17] Within the study, we reviewed and analysed existing literature and country-specific structural data, which was then discussed in country workshops with relevant key stakeholders. We provide some of these insights in the main part of the report and further details in the country briefs in the Annex to this report.

  Country-specific analysis helps to identify commonalities and differences in external conditions as well as current trends in gas infrastructure usage across countries. This additional perspective is essential for the process of developing the political and regulatory framework for renewable gas at a European level, to guarantee that the framework is appropriately suited for all countries it is applied to.

[17] Please note: To support decarbonisation efforts in Europe, all seven members of the Green Gas Initiative (GGI), i.e. Energinet (Denmark), Fluxys (Belgium), Gasunie (the Netherlands), Gaznat (Switzerland), GRTgaz (France), Ontras (Germany) and Swedegas (Sweden) have committed to the main objective of contributing to a CO_2-neutral gas supply by 2050, see http://www.greengasinitiative.eu/mission.

Figure 8 The regional focus of the study is on the countries of origin of the sponsoring gas TSOs: Seven countries represented by TSOs in the Green Gas Initiative plus the Czech Republic

Source: Frontier Economics

- **For various potential renewable and low-carbon gases**:
  - Most existing research on the future of gas infrastructure focuses on a particular type of gas: For instance, considerable research exists on the benefits of using natural gas to substitute coal and oil during a transition phase.[18] Likewise, some studies, such as Ecofys (2018), emphasise the role of biomethane, while others, such as Frontier Economics et al. (2017),

[18] For example Enervis (2017a).

focus on synthetic gas produced by power-to-gas. There is also some analysis of the benefits of producing (blue) hydrogen from natural gas.[19]

  - In this study, we analyse the benefits of the ongoing use of **gas infrastructure**, taking various renewable and low-carbon gases into account, namely biomethane, synthetic methane and green hydrogen from power-to-gas, blue hydrogen and natural gas (particularly for a transition period), see Section 3.2. We also analyse the various roles these gases may play in different countries.

- **For all major energy-consuming sectors**:
  - Many existing studies analyse the potential role of gas in one (or part of one) sector in detail, e.g. heating/buildings, transport or industry.
  - Again, as we are interested in the benefits of the continued use of gas **infrastructure**, in this study we examine the role of gas in all major energy-consuming sectors, i.e. heating, transport, industry and electricity generation, see Section 3.3.

- **Across the energy supply chain**:
  - Previous research often focused on particular stages in the energy supply chain such as the impact of electric mobility on electricity networks.
  - To cover the overall effects of the use of gas infrastructure on society, we intend to cover **all major stages in the energy supply chain**: In Section 4 we estimate the cost savings that can be elicited from the ongoing use of gas infrastructure in 2050 within the analysed countries,[20] based on estimations of:
    - Costs of **end-user appliances**, i.e. basically investment costs for different heating systems and vehicles;
    - Costs of **transmitting and distributing electricity and gas**; and
    - Costs of **generating electricity and gas**, including **storage** costs.

Given this comprehensive approach, this study is well-positioned to demonstrate the full value of gas infrastructure for decarbonising Europe.

1.3 Scenarios: Assessing different roles for gas infrastructure in a decarbonised Europe

The question as to which energy system will emerge during the energy transition towards a high share of renewables is obviously a complex one, and clearly a wide range of developments are possible, not least because of the uncertainties associated with the long timeframe for the analysis (until 2050).

We therefore focus our analysis on three basic scenarios, which span the full range of potential long-term roles of the gas infrastructure (see Figure 9):

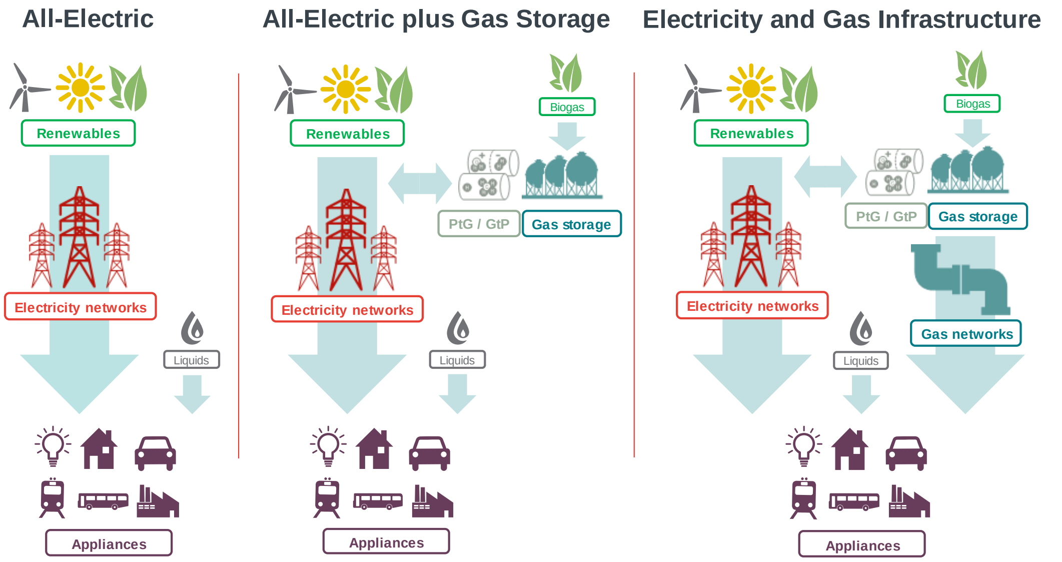
[19] For example Berenschot (2018).

[20] Cost savings are quantified for all countries analysed excluding Sweden. Please refer to the Swedish country report in the Annex for a brief qualitative assessment of the value of gas infrastructure in Sweden.

- **“All-Electric”** – In this scenario, end consumers primarily use electrical appliances such as heat pumps and electric cars (“direct electrification”). The connection between energy generation and final energy use is only made by electricity networks and electricity storage systems. The existing gas infrastructure comprising gas pipelines and storage facilities is no longer required and must accordingly be decommissioned.
- **“All-Electric plus Gas Storage”** – In this scenario, the “All-Electric” scenario is expanded to cope with the seasonality of peak demand by temporarily storing renewable gas and converting it into electricity using gas-fired power plants. The connection between energy generation and final energy use is, however, only made by electricity networks. This means that gas transportation and distribution networks, apart from connections to and from gas storage and power plants, are no longer in use and must accordingly be decommissioned, secured and partially dismantled.
- **“Electricity and Gas Infrastructure”** – In this scenario, the electrification of parts of final energy use (e.g. electric heat pumps in new buildings) is complemented by end-user appliances that can be operated on renewable gas (e.g. gas boilers in existing buildings or gas-based vehicles). Accordingly and in parallel to the electricity network, the existing gas infrastructure, including gas storage, gas transmission and distribution networks, will remain in use.

As discussed in more detail in Section 4.1, for various reasons and particularly because of the inability to feasibly store electricity for longer durations, the All-Electric scenario is without much practical relevance. The main focus of our quantitative analysis (Section 4.2) will therefore rest on a comparison of the latter two scenarios.

Figure 9 Three scenarios to achieve the 2050 targets (schematic overview)



Source: Frontier Economics

Note: We assume that there is an identical role for renewable liquid fuels in all scenarios and therefore do not consider it in the quantitative comparison.

Carbon neutral gas can stem from various sources

While the analysed scenarios differ with respect to the extent of the role of gas infrastructure in the future energy system, they all target the same level of decarbonisation. This requires that most of the gas transported via the gas infrastructure in the long run is carbon neutral.

In today's still fossil-fuel dominated energy world, the term "gas" is often used as a synonym for "natural gas". When we think of decarbonisation, however, various different gases are likely to play a role. There is no consistent use of terms of these gases in the public debate, yet.

Throughout this report, we therefore use the following terms (see Section 3.2 and Annex A for more details):

- **Renewable gas**, i.e. gas made of renewable sources, comprising:
  - **Biogas and biomethane** made from biomass. While CO_2 is released when biogas or biomethane is combusted, this comes from plant matter having captured atmospheric CO_2 via photosynthesis over its (relatively short) lifetime, and thus widely viewed as carbon neutral; and
  - Gas converted from renewable electricity via "**power-to-gas**" (PtG),[21] either
    - "**Green hydrogen**", i.e. hydrogen converted from electricity via electrolysis if the electricity source is renewable. This is the case either if it is located on-site of a renewable generation facility such as a wind park, or, in case it uses electricity from the public electricity grid, if the underlying electricity mix is 100% renewable (which will increasingly be the case if we think of full decarbonisation by 2050).
    - **Synthetic (green) methane**, i.e. green hydrogen further processed through methanation if the carbon source is taken from biomass, from the air ("direct air capture", DAC) or represents a second use of unavoidable CO_2 emissions in industrial processes.
- **Low-carbon gas**, which is basically hydrogen produced from natural gas where the CO_2 is prevented from being released into the atmosphere by carbon capture and storage (CCS) or carbon capture and utilization (CCU). As many others in the literature and in public debate, in this study we refer to this as "**blue hydrogen**", reflecting the fact that it is not "grey" (given that no or only limited CO_2 is emitted), but not "green" (i.e. based on renewable energy) either.

All of these gases can, in principle, be transported, stored and distributed within the existing gas infrastructure.

[21] Another principle option for carbon-free gas is power-to-gas based on nuclear power, which is of course restricted to countries that still allow for nuclear power.

1.4 Structure of this report

We structure the remainder of our report as follows:

- In Section 2, we set out the challenges imposed by decarbonisation in relation to generating, storing and transporting energy.
- In Section 3, we describe how the existing gas infrastructure is already handling many of these challenges today. It becomes evident that the existing gas infrastructure is suited for various kinds of renewable and low-carbon gases and that renewable and low-carbon gases are likely to have a role in all major demand sectors.
- In Section 4, we assess the benefits of continued use of gas infrastructure in a decarbonised Europe. This includes an estimate of cost savings associated with the continued use of gas infrastructure compared to a scenario where only some parts of the gas infrastructure (i.e. gas storage) are needed .
- In Section 5, we provide an initial list of areas where policy changes are required to allow gas infrastructure to play an essential role in decarbonisation.

The appendices to this report provide further details on the analysis conducted:

- In Annex A, we set out our assessment of the renewable and low-carbon energy carriers that are available and would allow the integration and continued use of the gas infrastructure within a decarbonised Europe.
- In Annex B, we describe our analysis of whether sufficient shares of energy consumption can be sensibly switched to (or kept with) renewable or low-carbon gases as energy carriers.
- In Annex C to Annex J we provide separate case studies for all eight countries analysed.

2 GENERATION, STORAGE AND TRANSPORT OF ENERGY PRESENT SIGNIFICANT CHALLENGES WHEN DECARBONISING EUROPE

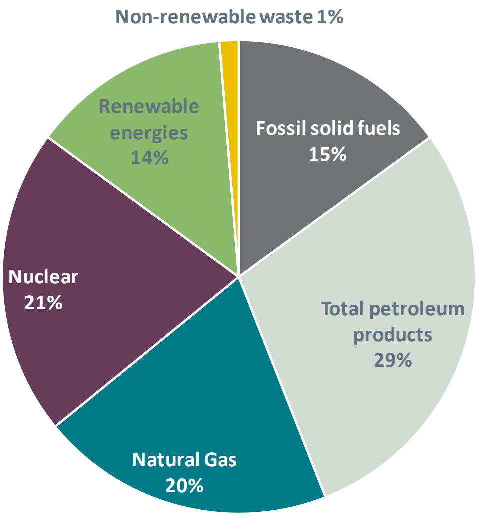
Replacing fossil fuel with renewable sources and particularly renewable electricity generation creates enormous challenges for Europe's long term energy systems. These include:

- How can we **generate** the required amount of renewable energy and where can this generation take place (Section 2.1)?
- How do we **store** renewable electricity seasonally (from summer to winter) to keep supply and demand in balance at all times (Section 2.2)?
- How do we **transport** renewable electricity from point of generation to point of consumption (Section 2.3)?

2.1 Need for renewable energy generation will be substantial, creating the challenge of finding appropriate and accepted generation locations within Europe

While there has been significant growth in renewable energy sources over the last two decades, fossil fuels still dominate energy supply in the eight countries analysed in this study (see Figure 10).

Figure 10 Primary energy supply by energy carrier in the countries analysed (2016)



Source: Frontier Economics based on Eurostat (2018) and Swiss Federal Office of Energy

Accordingly, a key element of decarbonising Europe will involve either switching away from fossil fuel sources or offsetting/reducing the carbon produced from using these sources. Given the limited scope of nuclear energy as many countries are striving to phase it out, the bulk of the 2050 energy supply in Europe across all sectors will have to come from (new) renewable energy sources.

Given the need to also seek out renewable energy supply for sectors like transport and heating, the format and carrier of these additional renewable sources becomes critical. While some appliances would allow fossil-based fuels to be replaced directly by (unconverted) renewable energy sources such as wood or ambient heat, these options remain limited for two main reasons.

- First, the *production and provision* of direct renewables, e.g. solid biomass, is often limited due to the lack of easily accessible and sustainable sources.
- Second, many *end-consumer appliances* are technically non-substitutable when it comes to the direct use of renewable energy. For instance, ambient heat can often only be utilised in combination with other energy carriers like electricity or gas (e.g. in heat pumps) and even then it is well-suited for low-temperature appliances in domestic households, but less as a replacement, for instance, of high-temperature processes in the industrial sector.

Given these limitations, a significant share of today's fossil fuel-based energy demand will have to be replaced by (converted) energy carriers and fuels derived from renewable sources.[22] In many regions and sectors this implies using electricity generated from wind and solar – often the only relatively more widely available renewable energy sources. In this manner, the process of decarbonising the transport and heating sectors will rely on changes to the energy sector. This is referred to as "sector integration" or "sector coupling" and reflect how decarbonising the European economy will inevitably require a cross-sectoral approach. Since renewable energy sources such as wind and solar will provide energy in the form of electricity ultimately used in the transport and heat sector, this form of sector coupling is often referred to as "electrification".

However, even if the detailed technicalities governing which energy carriers to use are set aside, it is important to understand the magnitude of the underlying challenge of such a large-scale Europe-wide replacement of fossil energy sources by renewables such as wind and solar. Already for 2030, the new EU renewable energy directive RED II,[23] includes a binding renewable energy target for the EU of 32% (of gross final energy

> Achieving the reality of a decarbonised Europe based on domestic renewable electricity sources will be a major challenge, simply in terms of energy volumes

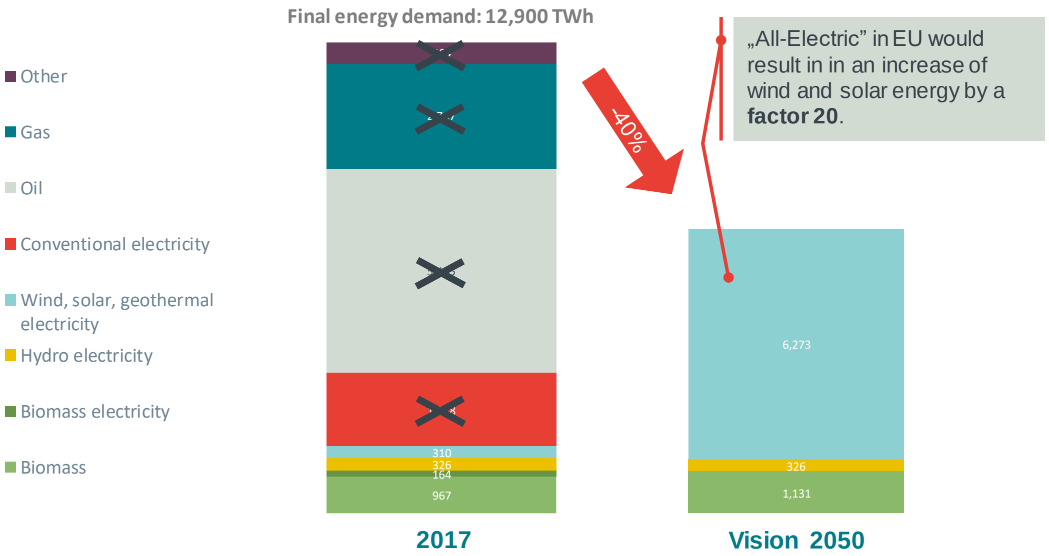
[22] Or nuclear, in countries with limited renewable potentials such as the Czech Republic.

[23] European Council (2018).

consumption) with an upwards revision clause by 2023. For comparison, today's share is only 14%.

And this would only be the start: Figure 11 reveals that decarbonising Europe's energy supply by switching to green electricity by 2050 would require around a 20-fold increase in wind and solar energy. This is based on the assumptions of a 40% reduction in final energy demand, a constant amount of biomass and water potentials, and a full replacement of fossil- and nuclear-fuelled energy generation by wind and solar.

Figure 11 The share of renewable electricity as a portion of final energy demand in the EU in 2016 has to be multiplied 20-fold to meet 2050 demand



Source: Frontier Economics based on Eurostat and IEA (2016)

Note: This assumes a 40% reduction in final energy demand and a constant amount of biomass and water potentials. The remaining demand has to be met by wind and solar.

Consequently, to achieve the 2030 targets and eventually the 2050 ambition, sector coupling underpinned by renewable electricity requires substantial additional generation capacity – even if we assume significantly lower energy demand, e.g. through improved insulation and more efficient end appliances such as electric heat pumps and electrical vehicles.

These figures demonstrate that identifying and providing locations capable of facilitating such installations within densely populated Europe will be far from easy. Already today, many installations such as onshore wind parks face considerable local opposition. Accordingly, finding appropriate and accepted locations for renewable energy in Europe will be crucial to reach a social consensus on the energy transition of Europe. As these will often be remote to populated areas (and hence energy demand), it will increase the need to bridge geographic distances between generation and demand and imposes further strain on the energy transport infrastructure (see Section 2.3).

In conclusion, even if we take energy production alone, it becomes obvious that decarbonising Europe based on domestic renewable electricity sources will prove to be a great challenge.

2.2 Intermittent renewables and seasonal heat demand require vast seasonal energy storage

The challenge of securing large volumes of renewable energy is further aggravated if we take seasonal variation in energy demand into account, particularly for space heating. Consequently, as well as finding sufficient renewable energy sources to replace fossil energy, renewable energy sources will also need to be available on an as-required basis.

This is one area where fossil fuels have been invaluable from an energy system perspective. Given sufficient grid capacity, storage and production facilities, natural gas (and other fossil sources) can instantly be supplied whenever demand arises.

As fossil fuels are phased out and replaced with intermittent renewable energy sources, we will not only lose their flexibility to easily follow demand patterns but also end up with inherently volatile renewable electricity supply in its place.

To complicate matters further, fluctuations in demand and supply are often negatively correlated. Wind turbines and PV panels can generate renewable electricity in hours with a lot of wind and sun which may not always be hours with high demand. For instance, one predictable demand peak occurs during cold and dark winter periods when solar energy is scarce. Accordingly, meeting energy demand directly through renewable electricity seems unrealistic.

> “At times when we need the energy system to provide more flexibility to deal with renewable intermittency, electrification triggers the roll-out of an energy infrastructure which is, itself, more fragile to imbalances between supply and demand

This increases the burden on the energy system to match supply and demand at all times. At the same time, the aforementioned tendency towards electrification of heat and transport sectors places the electricity grid increasingly at the centre of the energy system. Unfortunately, of all three pillars of present-day energy systems (liquid fuels infrastructure, gas networks, electricity grids; see Figure 7), the electricity grid is the most fragile, as it depends on instantaneous balancing of supply and demand. At any point in time, the amount of energy fed into the system must equal current demand, which necessitates the use of costly system balancing mechanisms. With rising shares of electricity supply coming from intermittent renewable sources, the costs of balancing will increase in the future.

In essence, therefore, decarbonising Europe by substituting fossil fuels with renewable electricity triples the flexibility requirements:

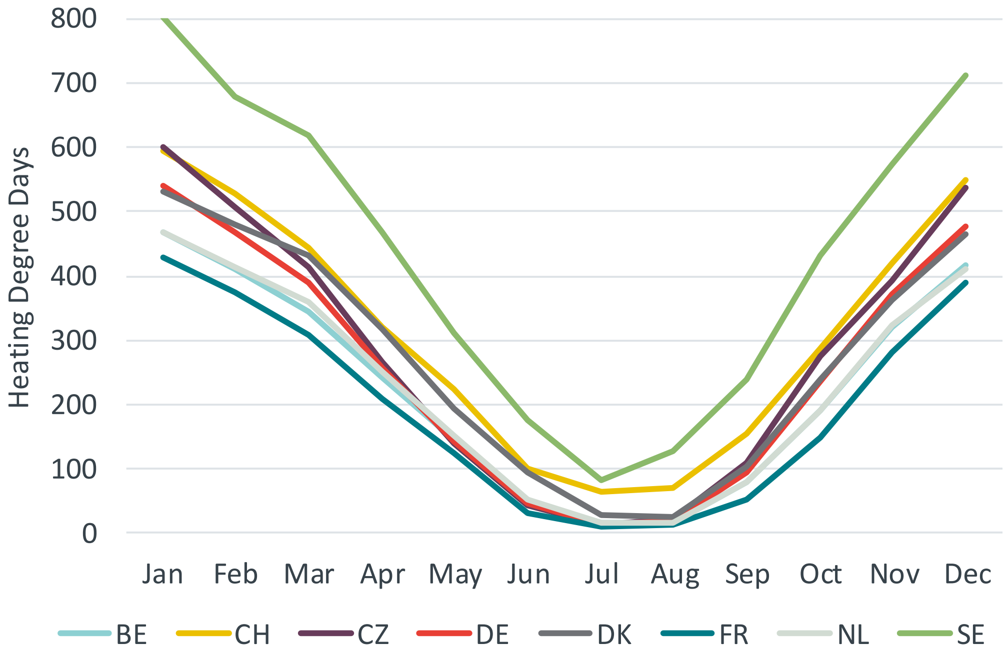
- The system widely "loses" the capability of fossil energy sources to flexibly follow demand changes;
- Renewable generation is volatile in itself; and
- The grid physics means electrification imposes even higher demands on the system to always remain "in balance".

One way to overcome these challenges would be to install spare capacity in bulk, ensuring that even in worst-case scenarios, sufficient generation and grid capacity would remain available to satisfy demand. However, such an approach would be virtually infeasible in technical terms because installing capacity on such scale would likely exceed both resources and available (publicly acceptable) sites. Moreover, the installation of spare generation capacity would be very inefficient if a large amount of fixed-cost assets have to be built solely to handle rare occasions.

So from a practical perspective, the primary remaining option will involve adding flexibility to the system in storage terms – particularly large seasonal storage. As Figure 12 illustrates, even when assuming that short-term flexible resources (e.g. through battery storage and demand side flexibility) will be capable of eliminating hourly and daily fluctuation, the seasonal heat requirement will inevitably require the storage of energy in bulk (in the magnitude of several hundreds of TWh) for extended periods of time (several months).

> Seasonal demand patterns will inevitably require the storage of large volumes of energy over long periods

Figure 12 Seasonality of heat demand in the countries analysed



Source: *Frontier Economics based on Eurostat, Cooling and heating degree days by country - monthly data [nrg_chdd_m], retrieved in April 2018*

Note: *For each country we show the monthly average of heating degree days (HDD) over the years 2010 to 2017. HDD is a measurement derived from outside air temperatures designed to quantify the demand for energy needed to heat a building The statistic assumes that buildings only start to heat when the mean air temperature of a day is 15 °C or lower. In that case buildings heat to achieve and maintain a room temperature of 18 °C. For illustration: If the outside temperature is 8 °C, the HDD is equal to 10. Assuming this holds over a month with 30 days like April, the HDD value for April is 10 * 30 days = 300 HDD.*

For the time being such electricity storage options remain unfeasible. For illustration, total electricity storage currently installed in the countries analysed (including pumped hydro energy storage, the only large-scale electricity storage option available today) would not be sufficient to store even today's comparably low average electricity consumption for more than four hours.[24]

2.3 Effective energy transport and distribution is crucial when exploring more and more renewables

As well as dealing with overall energy volumes and storage requirements, the transition to renewable energy will impose major new challenges when it comes to transporting electricity from point of generation to point of consumption.

Like the convenient ability of fossil fuels such as natural gas to flexibly follow demand patterns over time, they also have the benefit of being easily transportable to supply *whenever* and *wherever* demand emerges. Natural gas (and other fossil fuels) can for instance easily be transported in bulk over long distances to reach end consumers. The same, however, cannot be said of renewable energy sources, which have higher constraints in terms of spatial availability (on both macro and micro levels):

- **Macro level – the major part of renewable generation is distant from the load, necessitating transmission grid expansion:** Energy demand is typically closely correlated to population, which is why fossil energy is typically transported to and harnessed (e.g. in power plants) comparably close to load. Renewable energy means this will have to change: The availability of sites with high renewable supply (e.g. wind-yield) and public acceptance will force large installations such as wind parks to be erected far from densely populated areas – and therefore far from loads. High-capacity transmission grids will therefore have to transport renewable energy from areas where it is not needed to load centres. This is what happens in the North Sea offshore wind parks or renewable energy generation in Scandinavia. Figure 13 illustrates the need for new large-scale Europe-wide transportation

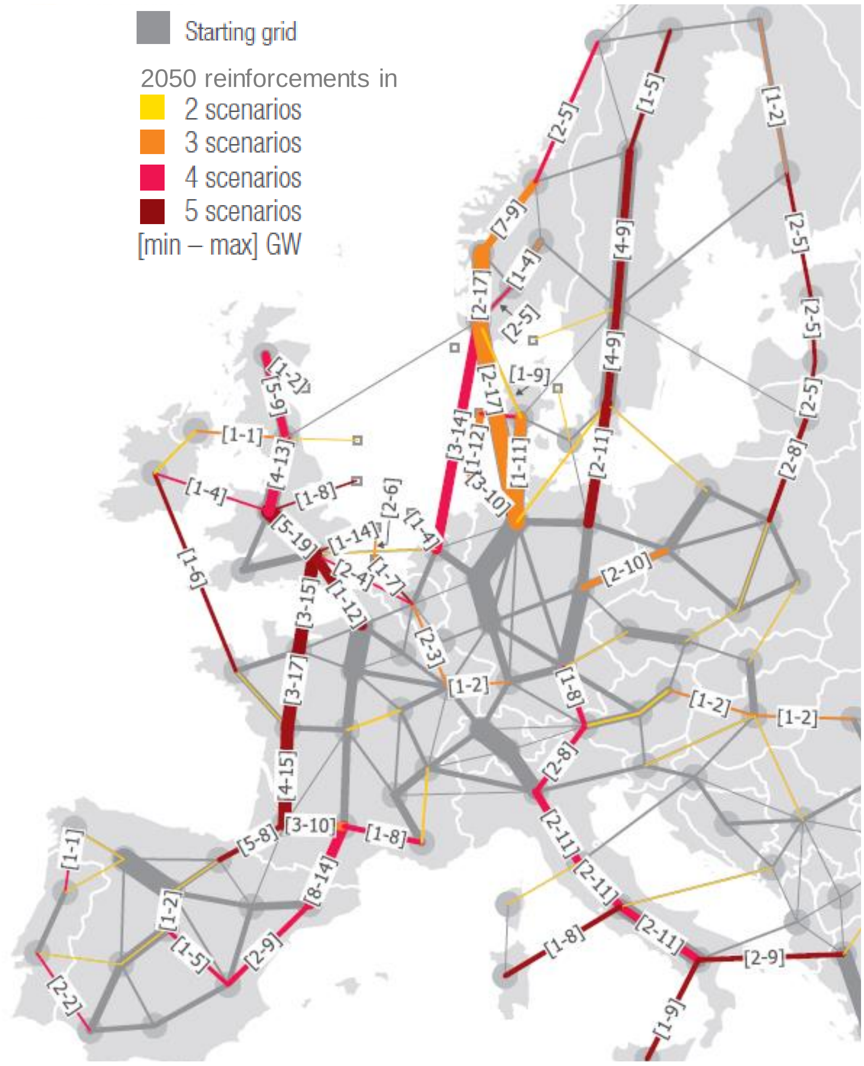
> “
>
> Wind supply and public acceptance means wind parks will have to be erected far away from load centres, for example offshore.

[24] Electricity storage volume of 0.6 TWh compared to yearly electricity demand in these countries of 1,420 TWh (Eurostat and Swiss Federal Office of Energy).

grids by 2050 under various scenarios, as identified in the e-Highways 2050 study.

- **Micro level – More decentralised energy generation relative to today will increase the need to expand the distribution grid:** Decentralised small-scale generation such as PV offers an alternative to large-scale renewable electricity generation such as wind offshore, although with comparably low energy density. Accordingly, replacing fossil-based generation (typically allowing for a high concentration of power in a single site) with renewables requires generation to be spread out over wider areas. Accordingly, a large share of required grid extensions will also occur in the distribution grids. Studies have already demonstrated how investment needs on a distribution level could easily exceed those at a transmission level.[25]

Figure 13 EU map from the e-Highways study underlines the need for new electricity lines



Source: e-Highway 2050 (2015)

Note: The study defines five scenarios; all with differing assumptions on electricity demand, supply technologies, exchanges, policy intervention and social behaviour.

[25] See for instance Frontier Economics et al. (2017).

Accordingly, while the switch to renewable energy sources is directly linked with a need for grid reinforcement to connect the new generation with load, challenges to the grid will intensify as further sectors are electrified. The scope to switch end appliances from fossil fuels to electricity is contingent on available grid connectivity. An obvious example is switching from fuel-based vehicles to battery electric vehicles (BEV). The limited range of the latter requires a dense network of charging stations which must, at the same time, have a high (fast charging) capacity to foster acceptance of BEV. However, this in itself requires grid extensions to provide sufficient system capacities to supply such a network of charging stations. Similar effects are to be expected for example if heat pumps are set to replace gas-fired heating systems on a large scale.

Replacing fossil energy sources with renewable sources thus inevitably means reinforced energy grids become crucial – for local distribution as well as long-distance transport.

While some needs might be alleviated through new technologies further streamlining network usage, these will clearly be limited, as technologies counteracting the expansion of the electricity grid expansion cannot offset the growing need to transport electricity:

- While **demand side management** will provide some short-term flexibility, significant technical and economic constraints remain. For example, energy-intensive industries like aluminium generation cannot be switched off in winter for summer-only operation without enormous technical and economic inefficiencies. Medium- and small-scale demand side management (e.g. for household customers) is often inefficient, given the small volumes per unit.

- **Decentral storage** can smooth daily demand peaks but does nothing to alleviate generalised peaks in electricity demand, let alone winter demand. New electric appliances often bring local storage with themselves, for example owners of battery electric vehicles (BEV) may be able to choose to charge their car during off-peak hours and thus help smooth daily peak loads. Distribution system operators can control heat pumps or refrigerators to function in a grid-compatible way, by letting them work more strongly when the grid is relieved and storing heat/cold without using the grid for subsequent next hours. However, the positive contribution of decentral storage is dwarfed by general soaring electricity demand due to electrification of vehicles among others, not to mention the very seasonal additional demand if the heating sector is electrified.

A trifecta of challenges when switching to renewables:

- Finding sufficient energy sources
- Balancing demand and supply with seasonal storage
- Transporting energy over distance with sufficient grid capacities

In effect these new technologies tend to complement the task of reinforcing the network rather than substituting numerous investment needs. No surprise given the above fundamental drivers of network expansion needs: switching from fossil to renewable generation will inevitability bolster the need to transport energy through the grid because of pure geographic requirements; and the simple fact that some of the existing transportation and distribution channels for fossil fuels will have to be replaced creates a need for grid investments.

That leaves the need for grid reinforcements to bridge spatial differences between energy sources and demand as the third big challenge for decarbonising Europe, in addition to the need to harness sufficient renewable sources (see Section 2.1) and solve the storage challenge (see Section 2.2).

3 GAS INFRASTRUCTURE WELL SUITED TO HELP OVERCOME THE CHALLENGES OF DECARBONISATION

Following on from the description of the challenges of decarbonisation in the previous section, below we summarise the key findings of an analysis of the contribution that the existing gas infrastructure can make to overcoming these challenges:

- The **existing gas infrastructure** is extensive, and helps to handle many of the challenges of generation, transport and storage of energy already today (Section 3.1);
- There are **various renewable and low-carbon gases** available, that allow the integration and continued usage of the gas infrastructure in a decarbonised Europe (Section 3.2; further details provided Annex A; and
- Sufficient shares of **energy consumption** can be switched to (or kept with) renewable and low-carbon gases as energy carriers (Section 3.3; further details provided in Annex B).

In Section 4, we will subsequently analyse whether an integration of gas infrastructure is indeed beneficial compared to an all-electric decarbonisation path without significant gas infrastructure.

3.1 The existing gas transport, distribution and storage infrastructure is extensive

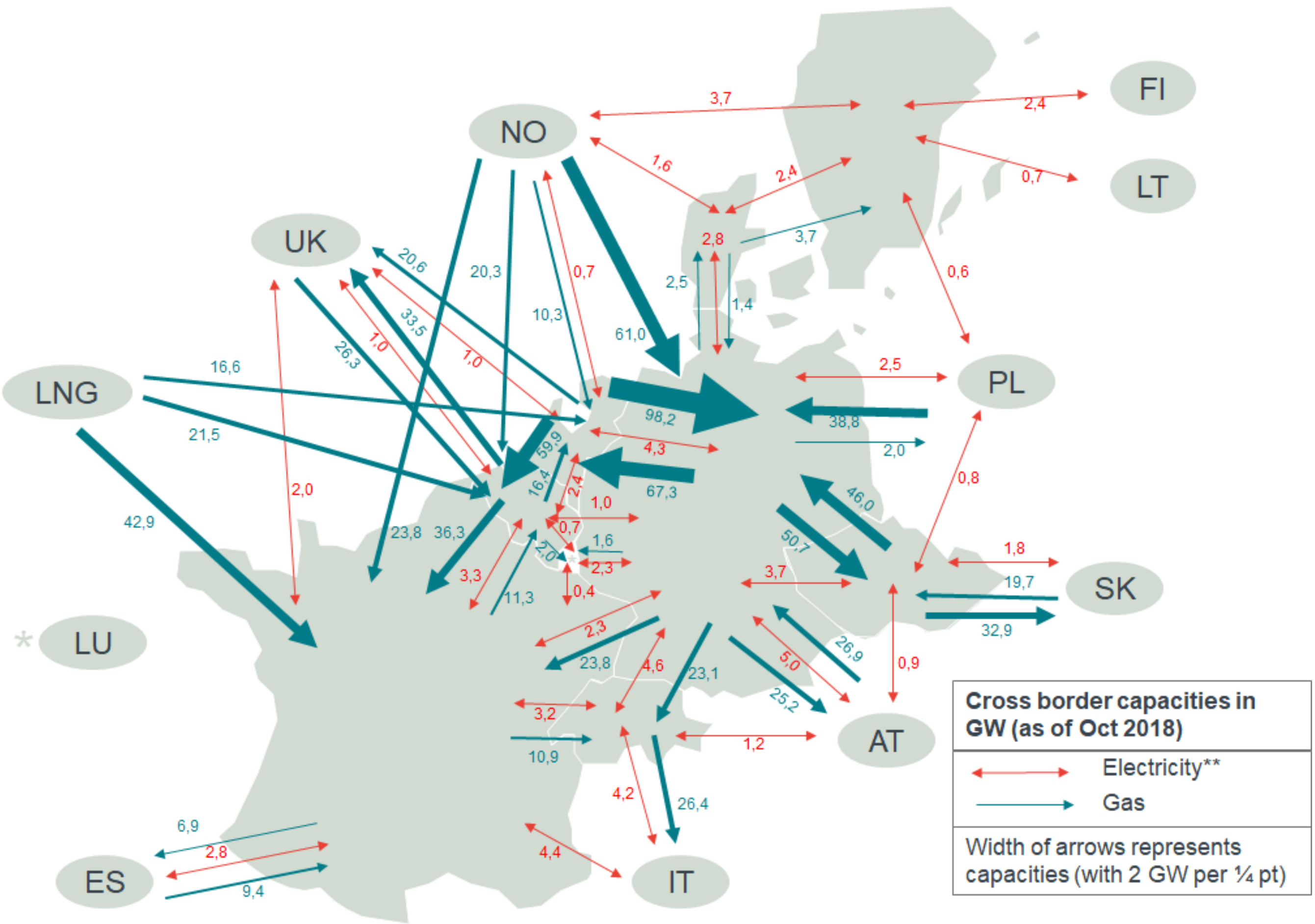
While overcoming the three fundamental challenges identified will be key to successfully decarbonising Europe and switching to renewable energies, challenges such as storing energy or transporting energy in bulk are far from entirely new. Today, the gas infrastructure is actually helping to handle many of these challenges, as we explain below.

3.1.1 Energy transport via existing gas networks significantly exceeds the electricity system capacity

A key challenge identified to reach a decarbonised Europe has been the need to bridge the growing distance between (renewable) energy sources and demand regions (see Section 2.3). This is something the (natural) gas infrastructure has been designed to provide from the outset, which is evident by looking at the wide-ranging and well-established Europe-wide gas transport system:

- The **existing transmission capacity** of the gas network is huge, exceeding electricity transmission levels not only nationally but also internationally. Figure 14 shows the higher international transmission capacity of gas compared to electricity to/from and between the analysed countries.

Figure 14 Cross-border transport capacities for gas exceed those of electricity by large



Source: Frontier Economics based on Entso-E and Entso-G

*Note: ** In some cases published capacities vary slightly between flow directions. In that cases, the higher figures are depicted.*

- Similarly, the gas system also plays an important role on a **distribution level**: Within the EU almost half of household end-energy consumers are connected to the gas distribution network.[26] On EU average, the volume delivered via the distribution grid to households is around four times higher for gas than for electricity.[27]

> Almost half of household end-energy consumers in the EU are connected to a gas distribution network

Gas can even help with decarbonisation beyond existing infrastructure, i.e. islands or isolated regions

Recently, technological development has made gas even more widely available, as it can be increasingly provided to end customers even beyond the coverage of

[26] Namely ca. 110 million household gas connections out of ca. 250 million household end-consumers. Source: CEER (2017), pp. 10, 11.

[27] Based on nearly 11,000 kWh/year for gas and nearly 2,800 kWh/year for electricity. CEER (2017), pp. 22, 23.

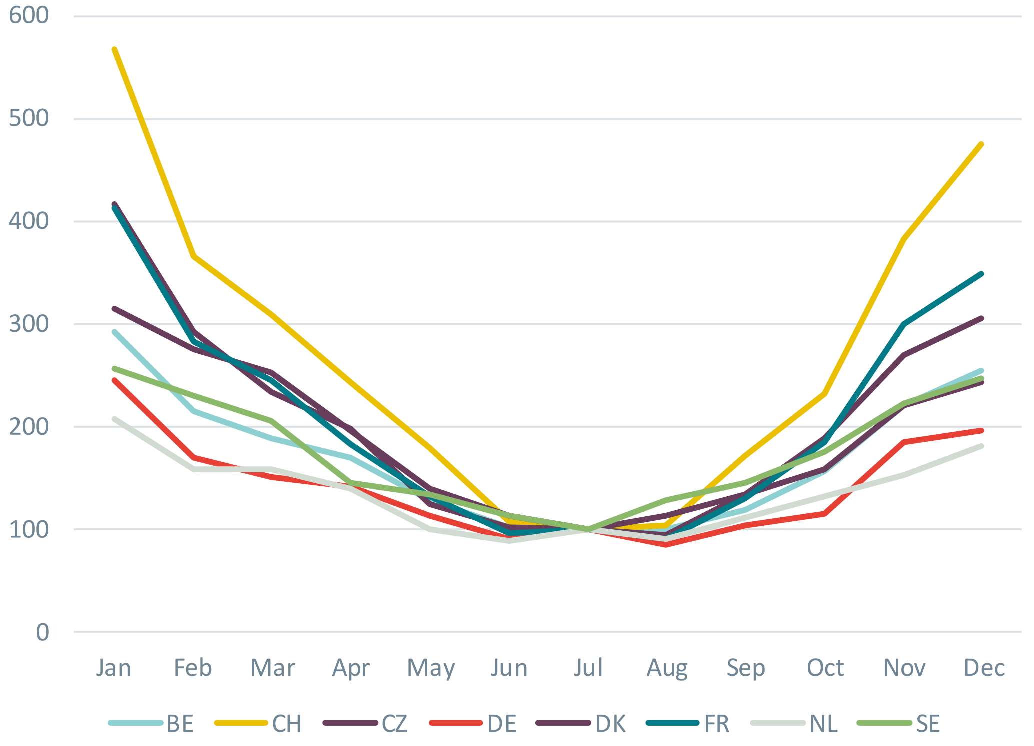
the existing (pipeline) infrastructure. Development is ongoing, now heralding a new wave of gasification based on regional liquified natural gas (LNG) transport ("small-scale LNG"), which opens up new opportunities to gasify new sectors/regions; similar to the established usage of liquified petroleum gas (LPG). In Belgium, for instance, there are plans to supply isolated regions that would be costly to connect to the transmission grid by compressed natural gas (CNG) or LNG trucks, injecting (natural) gas into local distribution grids. Gas therefore increasingly becomes a suitable energy carrier to supply areas without access to gas networks. Examples are isolated regions, industrial sites in rural areas, islands or countries with little gas infrastructure such as Sweden.

3.1.2 Gas is easily storable and already stored in bulk

In Section 2.2, we identified the need to store energy in bulk and for extended periods ("seasonal storage") as a key challenge of decarbonising Europe. While the magnitude and catalysts for this future requirement might be new, the task of providing seasonal energy on a large scale in itself is not. Quite the opposite: Gas systems have centred on storing energy in bulk and close to areas of demand as part of their day-to-day business for decades.

A large portion of gas demand has always been temperature-driven, reflecting the way gas is chiefly used in many countries for heating purposes. In response, the entire system has been designed to handle seasonal demand patterns: As Figure 15 shows, even average monthly gas demand fluctuates between summer and winter by a factor of 2 to 6 in many countries.

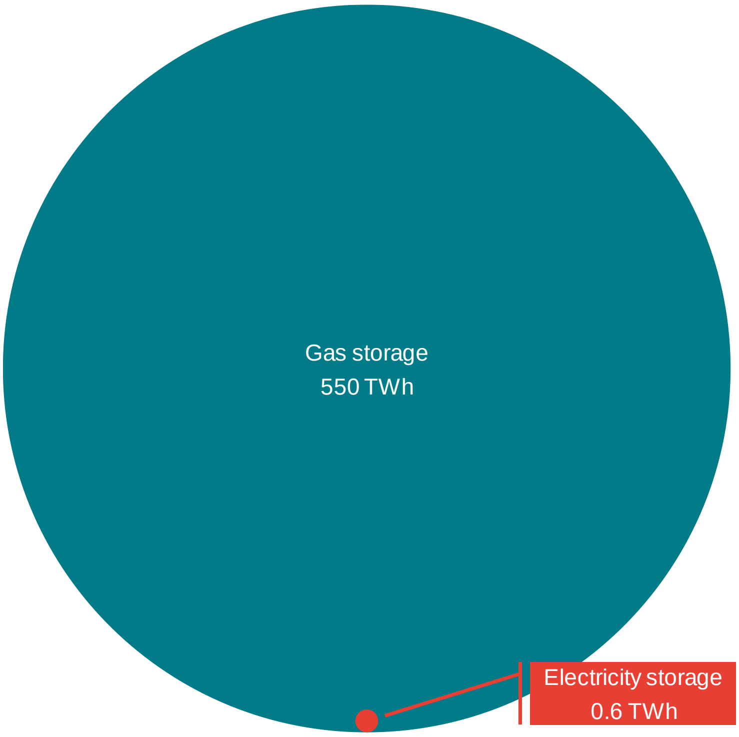
Figure 15 Seasonal gas demand in countries analysed in 2017 (indexed monthly demand, July = 100)



Source: Frontier Economics based on IEA Monthly Gas Statistics 2017

In principle, while gas production can, to some extent, follow demand, this is restricted by limited flexibility in capital cost-intensive production sites and long-distance transportation. These limitations, combined with the requirement of the system to be prepared for rare weather events (e.g. the "1 in 20" winter), have spawned the development and integration of large gas storage facilities (mainly underground) within the gas system. In the analysed countries alone, a gas storage volume of 550 TWh is available as of today (see Figure 16), which is sufficient to cover today's average gas demand in these countries for more than three months.[28] In comparison, today's total electricity storage suffices only to meet the average electricity demand for fewer than four hours.[29]

Figure 16 Gas storage volume is almost 1000 times as large as electricity storage volume in analysed countries



Source: Frontier Economics based on Gas Infrastructure Europe and Geth et al. (2015).

While we have identified the seasonal storability of energy in bulk as one of the three main challenges of decarbonisation, it is worth noting that such capabilities do exist in the gas infrastructure as of today.

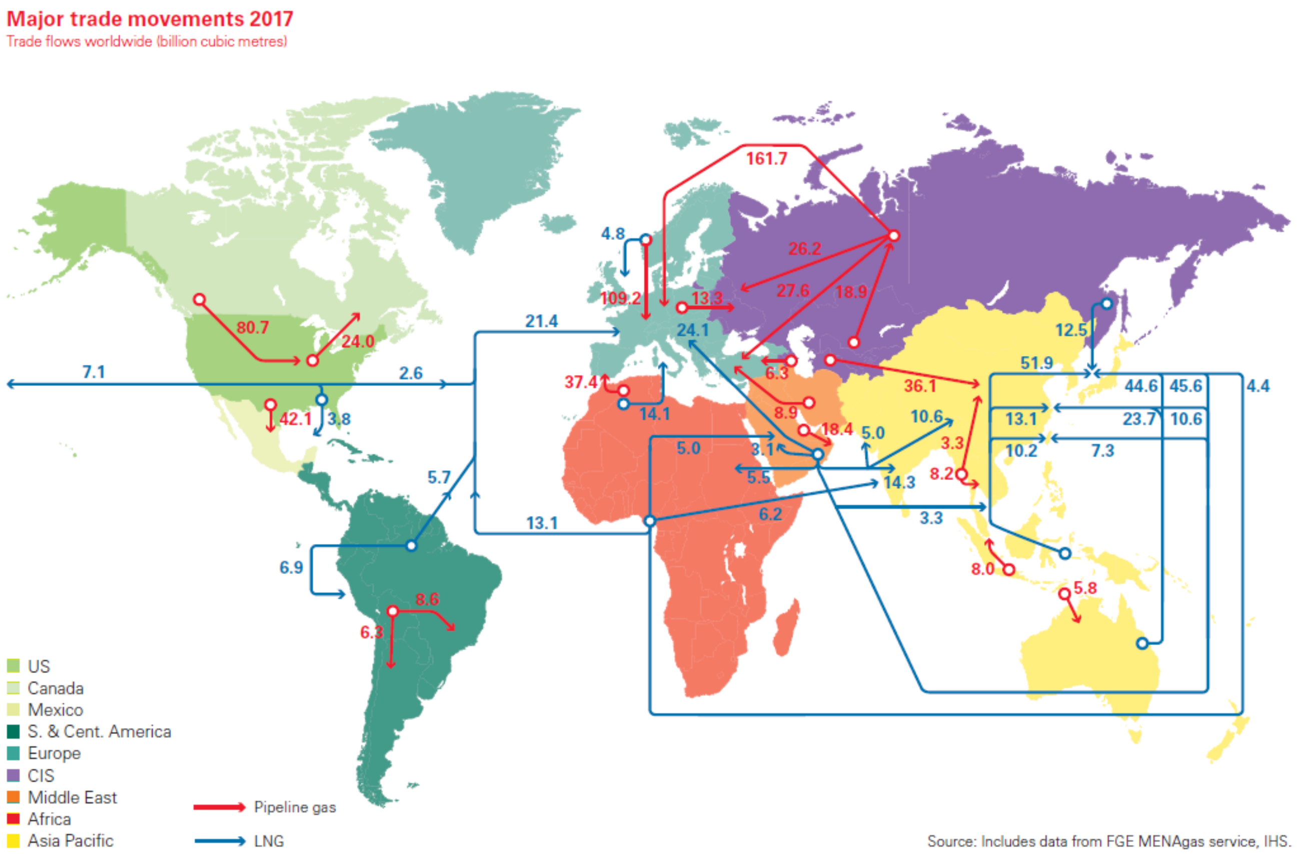
[28] Gas storage of 550 TWh compared to yearly gas demand in these countries of 1,940 TWh (Eurostat and Swiss Federal Office of Energy).

[29] Electricity storage of 0.6 TWh (including pump hydro storage) compared to yearly electricity demand in these countries of 1,420 TWh (Eurostat and Swiss Federal Office of Energy).

3.1.3 The international gas trade allows Europe to tap into overseas energy sources

Finally, also with regard to the third identified challenge of decarbonising Europe - covering the need for sufficient renewable energy sources on the continent (Section 2.1) - gas infrastructure has something to offer. Although demand for natural gas in Europe was initially met through domestic supply, reserves from outside Europe were soon harnessed to supply gas to European customers. In North Africa, West Asia, the Middle East and, via LNG shipping, ultimately worldwide sources are being used to provide European customers with energy, which puts Europe at the centre of a pan-global gas trade today (see Figure 17).

Figure 17 Global trade flows for gas



Source: BP Statistical Review of World Energy (2017)

Two main factors drive the extensive present-day international trade:

- the ability for long-distance transport based on an existing highly developed infrastructure; and
- globally spread gas sources, that could provide gas at comparably low cost.

While the importance of the latter might fade with Europe moving more and more away from fossil sources, the international trade infrastructure will prevail and could be used to give Europe the access to renewable energy sources outside its mainland. In the following subsection, we will discuss the various options and technologies to provide renewable gases. Based on the existing infrastructure it will be possible to use sources abroad whenever these are more cost effective than the usage of domestic sources – in the same manner in which Europe has in the past optimised and diversified its supply mix of natural gas.

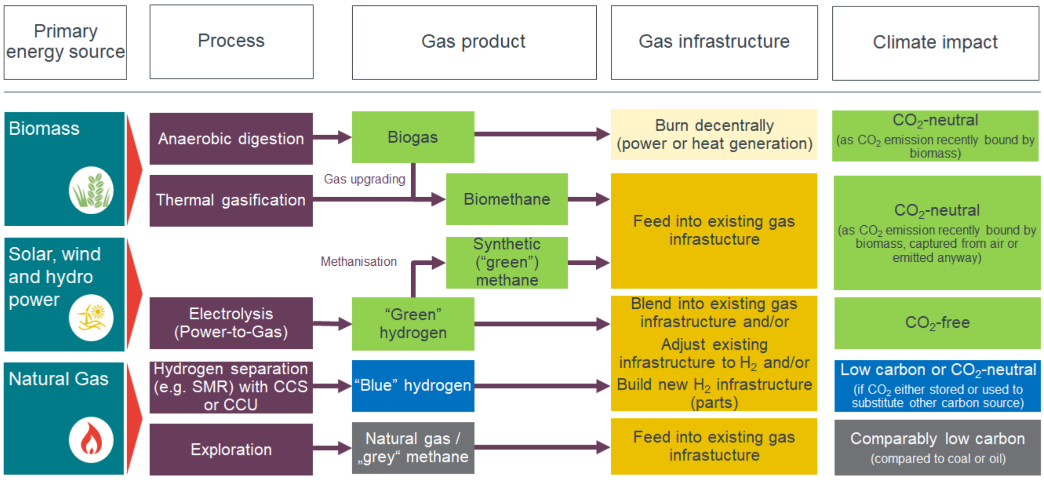
3.2 The existing gas infrastructure is suited for a variety of renewable and low-carbon gases

While today gas infrastructure is mostly used by fossil natural gas, there are various renewable and low-carbon gases available that can increasingly be used to support reducing greenhouse gas emissions. We summarise the essential features of the most important renewable and low-carbon gases in Figure 18 and the following subsections (see Annex A for more details):

- **Biomethane** as a natural renewable gas (Section 3.2.1);
- **Green hydrogen or synthetic (green) methane** from electrolysis on the basis of renewable electricity (power-to-gas) (Section 3.2.2);
- **"Blue hydrogen"**, that is natural gas decarbonised by carbon capture and storage (CCS) or carbon capture and usage (CCU) (Section 3.2.3);

In addition, natural gas can help to substitute dirtier fossil energy sources such as oil or coal in the transition to a full switch to green renewable or low-carbon gases (Section 3.2.4).

Figure 18 Overview of gases supporting decarbonisation in the scope of the study

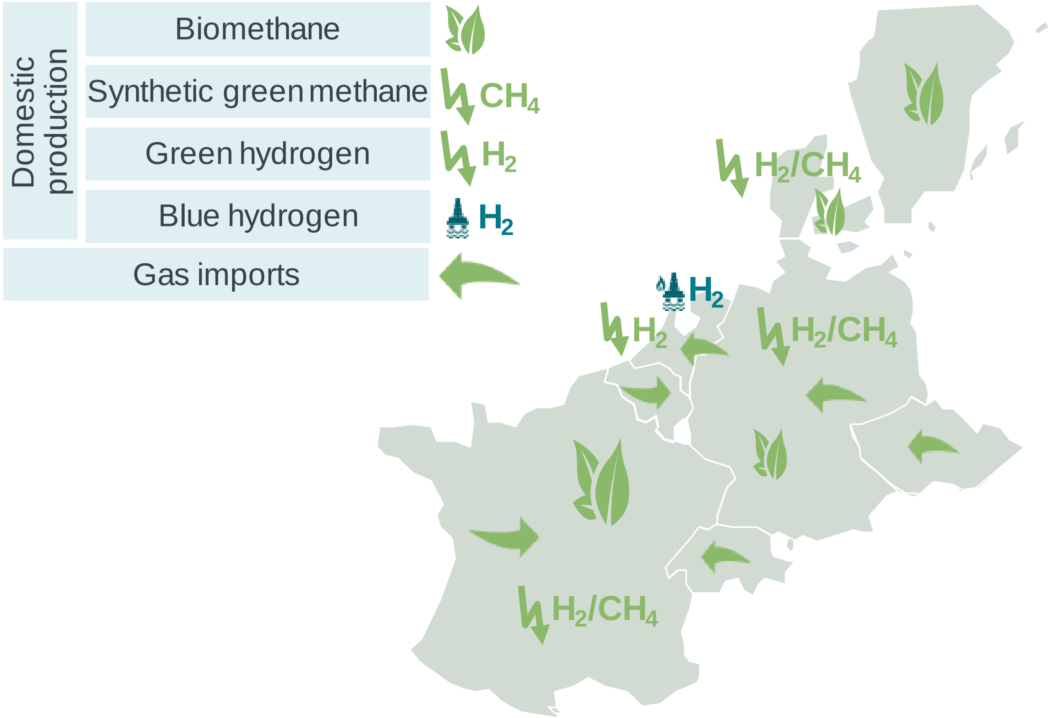


Source: Frontier Economics, E3G (2018)

Note: See subsections below and Annex A for a more detailed discussion of the climate impact of each of the gases.

Thanks to the differences in resource potentials, public attitudes and stakeholder strategies, very different approaches to renewable gases have emerged in the countries analysed, leading to a very heterogenous policy focus today (see Figure 19 for an stylised overview).

Figure 19 Main sources of renewable and low-carbon gas are likely to differ between countries (stylised overview)



Source: Frontier Economics

3.2.1 Biomethane as a natural renewable gas with significant growth potential

A number of different gases sourced from biological materials are included in the definition of “biogases”. In this report where the value of gas transport, storage and distribution infrastructure is highlighted, we focus on biomethane. Biomethane is a climate-neutral gas produced from biological sources,[30] with a composition and properties resembling those of natural gas. This also means that biomethane can be fed into the existing gas infrastructure just like natural gas – without the need for any adjustments of the infrastructure.

There are two main technologies to produce biomethane: **Anaerobic digestion (AD)**, the most common production method of biogas, with upgrading to biomethane, and **thermal gasification**, which is at an earlier development stage than AD, but can operate on a larger scale.

[30] See Annex A for a thorough discussion of the climate impact of biomethane. In any case, thorough and consistent monitoring and accounting methods need to be applied to appropriately reflect the climate impact of biomethane along the value chain.

Biomethane today

Biogas has been exploited for energy usage for decades. In the EU-28 (plus Switzerland), more than 190 TWh of biogas have been produced in 2016,[31] of which more than 90% is used for on-site electricity production.[32]

Biomethane production is still in its infancy, but recent years have seen it soar. While in 2011 fewer than 200 plants produced less than 0.8 TWh of biomethane, there are now around 500 plants in the EU, having produced more than 17 TWh of biomethane in 2016. Accordingly, biomethane production in biogas plants with upgrading facilities has boosted production more than 20fold in only five years.

Biomethane future potentials

A long-running and contentious debate exists over how sustainable and socially acceptable different sources of bioenergy are, centring on the conflict between agricultural land use for energy crops versus food production.

However, several potential sources for further biomethane production exist without conflicting with food production purposes, including for instance, further upgrading of biogas to biomethane, increased use of waste, the use of sequential crops or an increase in biomethane imports from countries with even better geographical conditions, such as the Ukraine or Belarus.

When analysing the countries within this study, quite a few different views emerged on the future of biomethane:

- **Large biogas and biomethane growth potentials in Denmark, France and Sweden**: In some countries domestic biomethane production is likely to play a key role in decarbonising gas supply, for example in Denmark, France and Sweden. One key driver here is the availability of farmlands and woods, which is naturally higher in these countries with comparably low population density.
- **Limited biogas growth potentials, but potentially more biomethane production in Belgium, the Czech Republic, Germany, the Netherlands and Switzerland**: Other more densely populated countries such as Belgium, the Czech Republic or the Netherlands already exploit a significant portion of their available feedstock for biogas production. Therefore, these countries have limited growth potentials for further sustainable biogas production. However, within these countries the option for further biomethane upgrading exists, a trend which we have already observed in recent years.

3.2.2 Power-to-gas offers the opportunity to integrate large volumes of intermittent renewable electricity production

Another opportunity to generate renewable gas is to convert renewable electricity into gas via electrolysis ("power-to-gas", PtG). While power-to-gas is associated with additional energy conversion and hence energy losses, this offers the opportunity to integrate intermittent wind and solar power and thus provides

[31] See Eurostat.

[32] See IRENA (2017b).

substantial societal benefits, for instance by avoiding costly and unpopular electricity network extensions and providing storage opportunities.

The basis of power-to-gas is electrolysis, where electricity is used to split water into hydrogen and oxygen. There are two basic pathways of power-to-gas in the centre of the current debate:

- **Power-to-hydrogen (PtH$_2$)**: The first product of electrolysis is hydrogen. This is often called "green hydrogen" if the electricity source is renewable. This is the case either if it is located on-site a renewable generation facility, such as a wind park, or, in case it uses electricity from the public electricity grid if the underlying electricity mix is 100% renewable (which will increasingly be the case if we move towards decarbonisation by 2050). Hydrogen can be directly used, e.g. to supply industrial processes that require hydrogen, transport, heating or electricity or be injected into the gas grid. As the chemical composition of hydrogen differs from that of natural gas, the use of hydrogen in the existing gas infrastructure requires some adjustment of pipelines, storage and end appliances.[33]
- **Power-to-methane (PtCH$_4$)**: Alternatively, hydrogen can be converted with an external CO or CO_2 source to CH_4 via methanation. The resulting CH_4 is often called synthetic (green) methane, synthetic natural gas or substitute natural gas (SNG), reflecting that it is of the same composition as natural gas.

Both power-to-gas pathways have their advantages and disadvantages. Whether one or the other power-to-gas pathway will prevail in the future can hardly be answered at this stage (or in this study). In our country analyses we observed very different views on this question. In Germany, for instance, the public debate has been focussing on synthetic methane for quite a while (however, the hydrogen path is recently gaining momentum), while the Netherlands is very focussed on hydrogen (as are the UK). In many other countries, key stakeholders have not yet formed a clear view on this question. Further research and trialling will be needed to explore both pathways further and inform the political debate.

Power-to-gas is still costly, but significant cost reductions expected with large-scale production

Although electrolysis in principle is a long-tested and mature process (which has been used e.g. in the copper industry for decades), hydrogen electrolysis is still in its infancy. Therefore, costs are still comparably high. However, this is likely to change once production of electrolysers, particularly polymer electrolyte membrane (PEM) electrolysers, is implemented on industrial mass-scale. In fact, there are many pilot projects ongoing or announced all over Europe, with a focal point in Germany. [34]

[33] See Annex A for more details on hydrogen infrastructure.

[34] See Annex A for more details on expected developments of electrolysis costs as well as current or planned PtG projects.

3.2.3 "Blue hydrogen" as another opportunity to provide low-carbon gas, with large import potentials

Another opportunity to provide low-carbon gas is "blue hydrogen", which is hydrogen produced from natural gas where the CO_2 is prevented from being released into the atmosphere by carbon capture and storage (CCS) or carbon capture and utilization (CCU). In this study we refer to this as "**blue hydrogen**", reflecting the fact that it is not "grey" (given that no or only a little CO_2 is emitted), but not "green" (i.e. based on renewable energy) either.

There are two main technologies to convert natural gas to hydrogen; steam methane reforming (SMR), a complex chemical process to produce H_2 from a methane (CH_4) source, that has been well-established for decades, and methane cracking (also called pyrolysis), a recently developed process for thermal decomposition of natural gas into carbon (C) and hydrogen (H_2) in an endothermic reaction.

Climate impact of blue hydrogen

While blue hydrogen is often referred to as "decarbonised gas" or "climate-neutral" gas, the concrete climate impact depends on the actual degree to which CO_2 is captured and stored. Similarly to biomethane, assessing the climate impact of blue hydrogen production fairly requires the implementation of a thorough and consistent monitoring, accounting and certification process.[35]

Potentials and infrastructure for blue hydrogen

The theoretical potential for blue hydrogen production remains great, given the enormous remaining natural gas resources (e.g. in Norway or Russia, but also elsewhere in the world). The use of blue hydrogen, however, poses some infrastructure challenges. The resulting hydrogen needs to be transported, which can in principle be done using the existing gas infrastructure (analogously to "green hydrogen"), and – in the case of CCS – CO_2 has to be transported and stored. CO_2 can be transported by pipeline or ship and be stored, for instance, in depleted oil and gas fields like those that exist in large volumes under the Norwegian continental shelf.

Differences between countries

Our analysis and discussions with stakeholders in various countries reveal significant differences in thinking and the expectations between them:

- **Methane cracking in Russia**: Russia's gas major Gazprom is scrutinizing methane cracking, building in particular on its vast natural gas resources.[36]
- **SMR with CCS in Norway**: Norway's oil and gas major Equinor has been very actively investigating SMR technology in combination with CCS, based on extensive natural gas resources and existing underwater storage opportunities

35 See Annex A for more details on the climate impact of blue hydrogen.

36 Bloomberg (2018a).

for CO_2.[37] Key stakeholders in the UK are keen to explore the possibilities for blue hydrogen supply to the UK, with the H21 North of England ambition being the most prominent example underpinning this interest.

- **Domestic CCS in addition to green hydrogen in the Netherlands**: Many key stakeholders in the Netherlands, which has a very high natural gas penetration today, consider hydrogen as key to decarbonisation for the Netherlands. A significant part of this may stem from electrolysis (particularly from wind offshore and onshore), but blue hydrogen is also seen as an option, both as a domestic solution, based on the availability of offshore CO_2 storage, and an import solution (e.g. from Norway).
- **Imports of blue hydrogen as an option in other countries** – In most other countries analysed in this study, domestic CCS is not seen as a key option. In Germany, for instance, storage of CO_2 is subject to significant public opposition and is thus unlikely to be an option in the near future. Other countries such as the Czech Republic, Switzerland or Belgium lack opportunities for offshore CO_2 storage. However, onshore CCS opportunities are currently investigated in Switzerland, and there are plans to capture CO_2 in Belgium and transport it to depleted fields in Norway or the Netherlands where it can be stored.

Although all of this remains at a comparably early development stage, we expect a further massive increase in research and trialling, given the large volumes of available natural gas resources that could – if decarbonised – contribute to decarbonisation, at least during a period of transition to a fully renewable energy supply.

3.2.4 Comparably low carbon-intensive natural gas helps to reduce carbon emissions in the short and medium turn

In contrast to the renewable and low-carbon gases mentioned above, natural gas will, ultimately need to disappear from the energy mix. It could, nevertheless, constitute a "bridge" from the current still fossil-dominated world to a long-term zero emissions future.

This potential role as a transition technology is based on its key advantage of relatively low carbon intensity (1 kWh of natural gas contains around 200g CO_2) compared to other fossil fuels such as lignite (400g CO_2 per kWh) or hard coal (340g CO_2 per kWh).[38] Accordingly, a fuel switch from these sources to natural gas may, in some regions and sectors, be a comparably cost-effective way to reduce CO_2 emissions in the transition towards a zero emission world in the long-term.

3.3 Renewable and low-carbon gases can play an essential role in all energy-consuming sectors

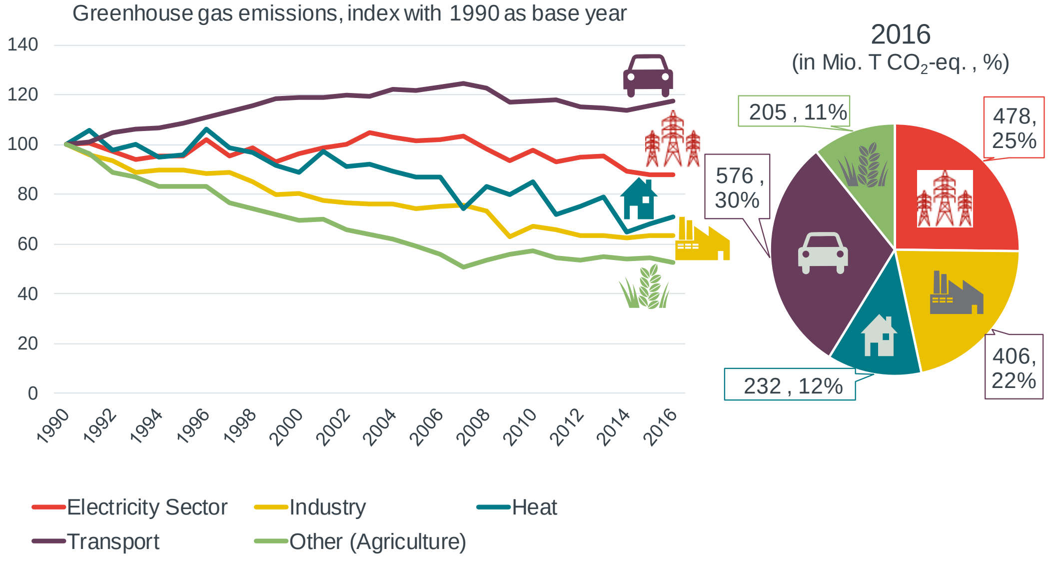
As explained in Section 1, achieving the target of reducing CO_2 emissions by 80 to 95% of 1990 levels by 2050 requires all energy-consuming sectors to contribute substantially. Today, around 30% of emissions in the analysed countries are

[37] See Northern Gas Networks (2018) and Norskpetroleum (2018).

[38] Cf. UBA (2018).

incurred in transport, 25% in electricity production, 22% in industry (including process heat), 12% in heating and 11% in other sectors (most of which in agriculture) (Figure 20, right hand side). A look at how emissions have progressed since 1990 reveals progress in some sectors such as agriculture, industry and heating, while CO_2 emissions in electricity production are almost flat and transportation sector emissions have even increased (Figure 20, left hand side).

Figure 20 Development of emissions differs between sectors (for the eight countries analysed)



Source: Frontier Economics based on EEA

Note: Industry including energy used for refinery processes

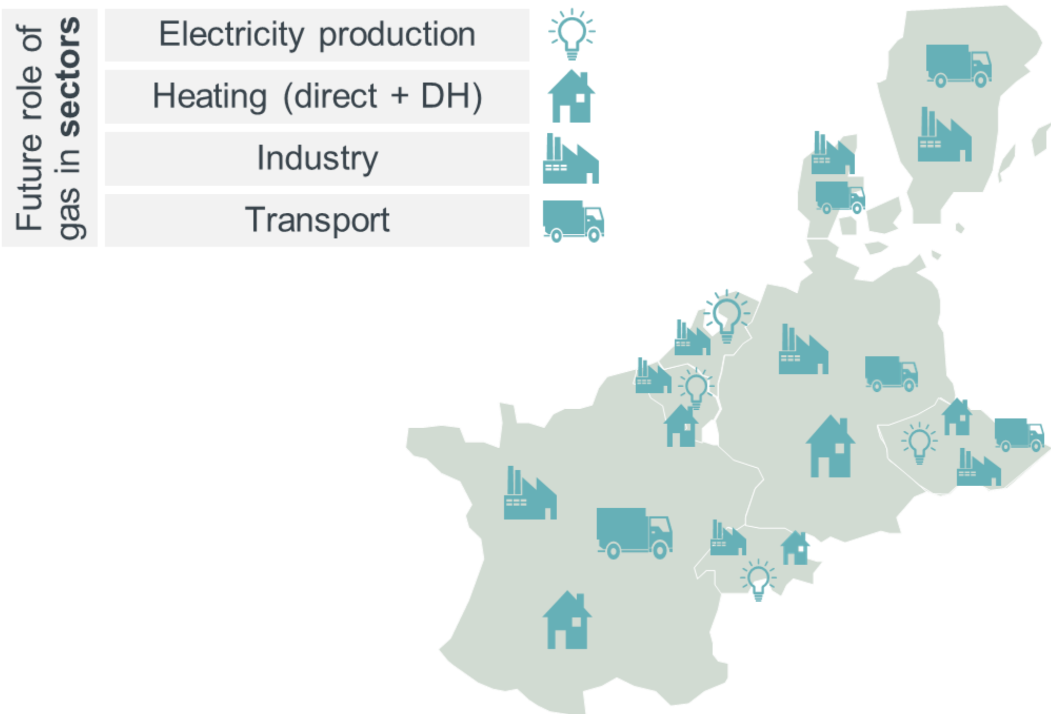
Based on the characteristics of (renewable) gas as described in the previous subsection, gas can serve as a complementing renewable energy carrier alongside renewable electricity and help overcome the enormous challenges of decarbonisation.

While electrification of the different sectors entails the benefit of higher energy efficiency, which in many cases make it the most advantageous technology option, limitations such as low density, limited storability, high capital costs of end appliances and a lack of grid capacity in most regions still apply. Depending on the sector, different challenges call for gas and the gas infrastructure as a complement, with varying relevance for the countries we analysed (see Figure 21 for a stylised overview; see Annex B for details on the sectors):

- Gas is a reliable, permanently available source of **electricity generation** to supplement intermittent electricity from wind and solar power in the absence of coal, oil and - in many countries - also nuclear.
  - This is of particular relevance in countries that are characterised by a high penetration of gas and coal-fired power generation and/or phasing-out nuclear power and/or with limited natural potentials for hydro power (storage), as these are the main carbon neutral and dispatchable alternatives. This is, for example, particularly relevant in the Netherlands, Germany and in Switzerland.

- Gas helps cover **seasonal energy** demand (e.g. in heating) via existing grids and storage facilities.
  - Countries with a high penetration of gas heating today are likely to benefit most from using renewable and low-carbon gas in the future, including, for example, Germany, France and the Czech Republic. In the Netherlands, that has by far the highest penetration of gas in residual heating, key stakeholders such as gas TSO Gasunie are expecting gas to accompany electric heat pumps in hybrid heating systems, so that, although gas distribution capacity equivalent to today will still be needed, gas volumes consumed are expected to decrease strongly.
- Gas can be one element used to decarbonise the **transport** sector, particularly in heavy-duty transport.
  - Gas in transport is even more likely to play a substantial role in countries with significant potential for domestic biomethane production, such as Denmark, France or Sweden, where extensive plans exist to roll out (bio-)LNG fuelling stations in the coming years.
- Gas is a low-carbon solution for combustion processes and as feedstock for **industry.**
  - This is relevant in all analysed countries, in which gas has a significant share in industry today and where alternatives are either limited or very costly.

Figure 21 Stylised overview of key sectors for gas use in a decarbonised future in analysed countries



Source: Frontier Economics

4 USE OF EXISTING GAS INFRASTRUCTURE SAVES COSTS AND INCREASES SECURITY OF SUPPLY AND PUBLIC ACCEPTANCE

Based on the characteristics of renewable and low-carbon gas as described in the previous sections, gas infrastructure can help overcome the enormous challenges of decarbonisation described in Section 2. In particular:

- **Gas storage is indispensable** (Section 4.1) – Decarbonising Europe's economy without large-scale gas storage will hardly be possible and prohibitively expensive, rendering an "all-electric" scenario unrealistic;
- **Gas networks save costs** (Section 4.2) – The continued use of gas in end appliances via gas networks can achieve substantial cost savings throughout the entire energy supply chain compared to a scenario where most end appliances are electrified;
- **Gas infrastructure enhances security of supply** (Section 4.3) – A secure energy supply is essential for residential, commercial and industrial customers. Gas infrastructure can help maintain Europe's high level of security of supply through massive storage volumes, a diversified renewable gas supply portfolio and an internationally highly-connected network;
- **Gas infrastructure safeguards public acceptance** (Section 4.4) – Public acceptance of energy infrastructure will be key to successful decarbonisation. Using gas infrastructure can help safeguard public opinion, particularly by avoiding large portions of electricity network extensions, which would otherwise be required.

4.1 Decarbonisation without gas storage is hardly possible and prohibitively expensive

As laid out before, storing energy over seasonal time spans – particularly to match intermittent renewable electricity supply with winter peak demand for heat – remains a key decarbonisation challenge.

Gas storage solutions are thereby the only affordable large scale technical solution to meet the seasonal storage needs, as electricity storage solutions are either limited in scale, or only suited for short-term storage, even assuming significant cost digression in the future:

- **Pumped hydro energy storage (PHS) limited** – PHS is a widely deployed and mature large-scale energy storage technology. The basic principle sees water pumped from a lower water reservoir to a higher one, when residual power demand is low and released to flow into the lower reservoir to generate electricity in a turbine system when residual demand is high. However;
  - water reservoirs of pumped hydro energy storages are relatively small compared to their turbine capacities (and capacity cost). For illustration:

Although this is by far the most widely deployed electricity storage technology, total energy volumes of all PHS in the countries analysed constitute to approximately 0.6 TWh. This compares to a gas-storage energy volume in these countries of around 550 TWh (see Section 3.1.2).

- PHS is consequently suitable for use in a number of storage cycles per year where energy is stored for a few hours or days at a time, typically to shift energy from off-peak demand overnight to peak-demand during daytime. Given high investment costs per energy capacity energy volumes, PHS is unsuitable both for use in only a couple of storage cycles per year and to store energy for several months to shift energy from supply peaks during the spring and summer to demand peaks in winter.
- the potential for new or extended hydro storage remains limited due to geographical restrictions (PHS require significant land use) and substantial environmental impacts.

- **Batteries suited only for short-term storage** – We have been observing considerable developments in battery technology over the last few years and experts expect further substantial developments in future, including significant cost digression. Because charging and discharging happens quickly and most battery technologies allow several thousand storage cycles over their lifetime, batteries are ideal for short-term storage, e.g. to integrate intermittent PV feed-in into the system.

However, batteries are not suitable for seasonal storage. Even assuming optimistic cost developments down to approximately 80 EUR/kWh,[39] energy storage volume in batteries is still 100 to 1000 times more expensive than energy storage volume in gas storage facilities (Figure 22). For batteries to compete with other flexibility options, they need to be employed in multiple storage cycles per year, rather than only once or twice, to shift energy from spring or summer to cover winter peak heat demand.

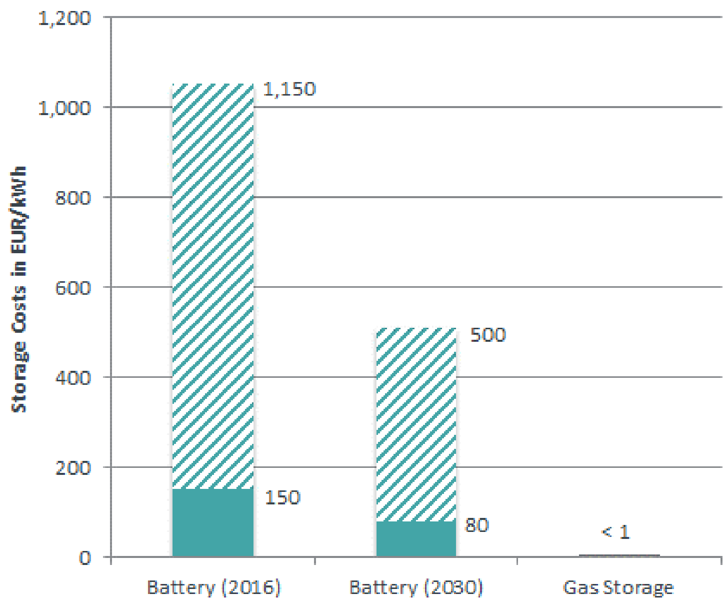
> Energy storage volume in batteries is still 100 to 1000 times more expensive than energy storage volume in gas storage facilities

What is more, for purely practical reasons, battery storages are not a suitable replacement for gas storages: Due to the lower energy density, providing the aforementioned 550 TWh with batteries instead of gas storage would require a storage volume equivalent to almost 500 million standard containers[40] – which, if placed side by side, would cover a land area as large as half of Luxembourg.

[39] Minimum costs of 80 EUR/kWh for flooded lead acid batteries as the lowest-cost battery option are forecast by IRENA for 2030, see IRENA (2017a).

[40] Assuming an energy density of 12 MWh per 40 ft container.

Figure 22 Comparison of battery and gas storage costs in EUR/kWh



Source: *Frontier Economics based on IRENA (2017a) and Le Fevre, C. (2013)*

Note: *Costs for batteries are illustrated for a range of different lead acid, high-temperature, flow and lithium-ion battery technology types. The minimum costs are based on flooded lead acid batteries in 2016 (~EUR 150/kWh) and 2030 (~ EUR 80/kWh). Gas storage costs are based on investment costs for gas storage in caverns, aquifers and depleted oil and gas fields, which are around EUR 0.1 to 0.3/kWh, see e.g. Stronzik, M., Rammerstorfer, M. and Neumann, A. (2008), Le Fevre, C. (2013).*

- **Other forms of storage are equally unsuitable for seasonal storage and flexible demand is not an option either.** – Various other electricity storage options exist, such as flywheel energy storage or compressed air storage. However, all of these are characterised by high investment costs, low energy density and/or high self-discharging rates, which disqualifies them for seasonal storage purposes. Equally, making electricity demand flexible by implementing demand-side management (DSM) and intermediate product storage is a promising and probably necessary path to integrate intermittent renewable electricity, but it will hardly be sufficient to bridge periods lasting several weeks and months.

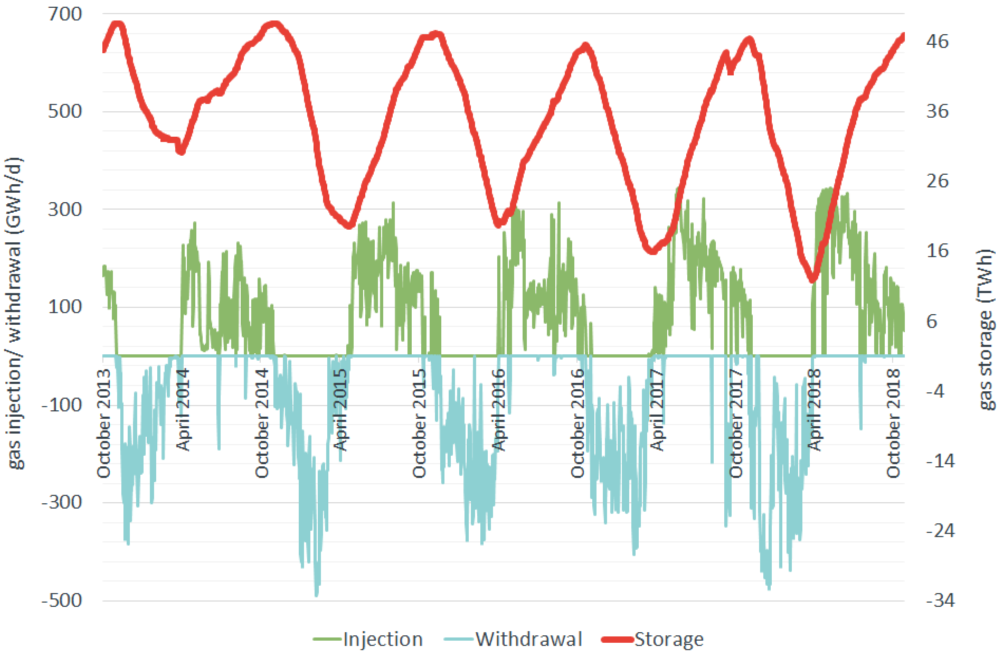
Figure 24 provides a schematic overview of energy storage technologies, illustrating how there is (still) no alternative to gas storage when it comes to storing large energy volumes of several TWh over longer periods like weeks and months.

“

Gas storage is the only technology available which is ideally suited for seasonal storage

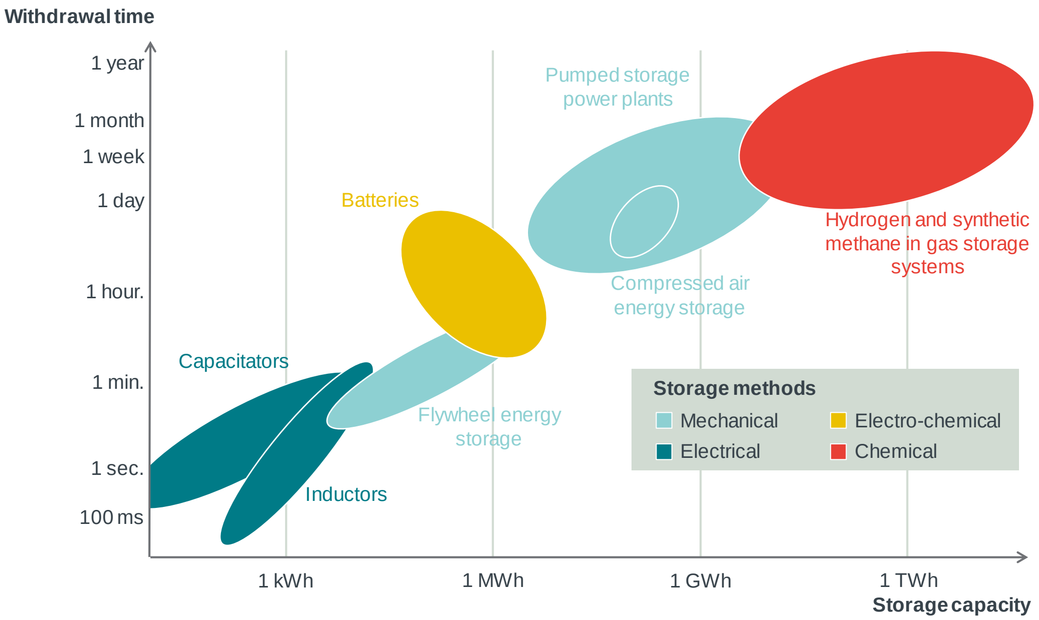
That leaves gas storage as the only available technology feasibly suited for seasonal storage. Gas storage is ideally suited and has been used for decades to match comparably constant natural supply with very seasonal energy demand (see for an example Figure 23). And while present-day gas storage facilities are basically filled with natural gas (and small biomethane shares), they could also be filled with different sorts of renewable gases. Biomethane and synthetic methane are obvious examples, given the virtually identical chemical characteristics of biomethane, synthetic methane and natural gas. However, any assessment of the suitability of existing gas storage to store hydrogen needs to distinguish between technologies: While today limits apply to the share of hydrogen that can be stored in depleted fields (research to overcome these limits is ongoing), hydrogen storage in salt caverns and in over-ground storage facilities is a proven and tested approach.

Figure 23 Storage cycle in the Rehden gas storage facility for the period 2013 to 2018 as an example for seasonal gas storage use



Source: Frontier Economics based on Gas Infrastructure Europe (gie)
Note: Data available as of October 2013.

Figure 24 **Schematic comparison of energy storage technologies**



Source: Frontier Economics based on Sterner and Stadler (2014), p. 19.

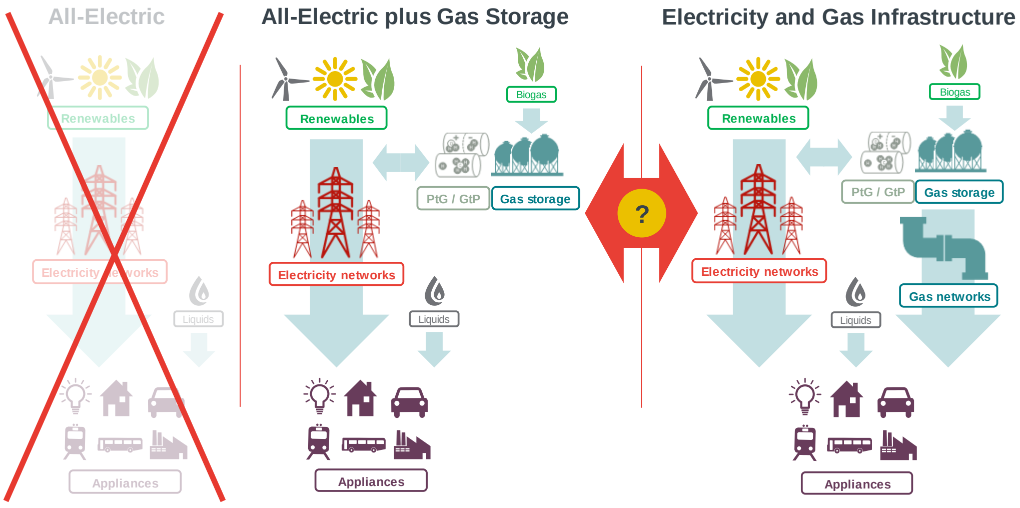
Because of this lack of alternatives to gas storage for long-term high-volume energy storage, an "all-electric" scenario without gas storage would be prohibitively expensive and unrealistic. A view that is supported by many other studies and seems to become common understanding also in the political sphere.

Our quantitative analysis in the following subsection focusses on the question whether, in addition to the gas *storage* infrastructure, also using the gas *network* infrastructure entails societal benefits.

4.2 Use of gas networks to transport gas to final consumers leads to savings in system costs

The previous section has shown that the "All-Electric" scenario without gas storage is not feasible. This section analyses the additional benefit of the continued use of gas networks, **comparing the scenarios "All-Electric plus Gas Storage" and "Electricity and Gas Infrastructure" (Figure 25)**.

Figure 25 Comparison of scenarios "All-Electric plus Gas Storage" and "Electricity and Gas Infrastructure"



Source: Frontier Economics

Note: We assume that there is an identical role for renewable liquid fuels in all scenarios and do therefore not consider it in the quantitative comparison.

It shows that gas networks can help avoid large investments related to electrifying end-user appliances, expanding electricity networks and generating additional electricity from renewable sources.

The usage of gas networks can therefore contribute to reaching a decarbonised Europe at far lower costs than in a scenario which relies to a large degree on electrification.

In the following sections we provide an overview of our calculations and key insights of our analysis:

- In Section 4.2.1 we briefly describe our quantitative approach and the scope of our analysis;
- Section 4.2.2 presents an overview of the results and discusses the identified differences between the various countries; and
- In the four subsequent sections we present our analysis for each element of the value chain in detail, i.e. the cost/benefit effects of a usage of gas networks on
  - end-user appliances (Section 4.2.3);
  - the electricity transmission and distribution grids (Section 4.2.4);
  - the gas networks themselves (Section 4.2.5); and
  - the provision and generation of energy (Section 4.2.6).

4.2.1 Our approach: Calculate cost savings of gas network use along the entire supply chain in the different countries

In line with the objectives of our study (see Section 1.2), we apply a differentiated approach, which is capable of quantifying potential cost savings of a continued usage of gas networks in a decarbonised Europe.[41] Our analysis

- **is differentiated for the eight countries in focus of this study,** reflecting the individual structural differences in each country, including its
  - energy supply mix and national resources,
  - respective infrastructure for electricity and gas; and
  - industry and demand structure.

  To do so, we reviewed and analysed existing literature and country-specific structural data, which was then discussed in country workshops with relevant key stakeholders. This country-specific analysis helped us to identify commonalities and differences in external conditions as well as current trends with regards to gas infrastructure usage across countries.
- **considers a broad range of potential renewable and low-carbon gases –** we do not restrict our analysis to specific technologies (e.g. power-to-gas) but take all renewable sources for gas into account (as they have been described in Section 3.2); namely biomethane, synthetic methane and green hydrogen from power-to-gas, blue hydrogen and natural gas (particularly for a transition period). We also analyse the various roles these gases may play in different countries.
- **includes all major energy-consuming sectors**, i.e. heating, transport, industry and electricity generation (see Section 3.3);
- **considers the entire energy supply chain,** covering energy sources and generation; transport and distribution; as well as end-user appliances;
- **is based on a common, but sufficiently differentiated approach,** which is suitable to generate comparable values across all countries while at the same time can capture significant differences in countries' sector structures: Where important differences across countries warrant country-specific approaches, we have carried out comprehensive bottom-up calculations. In areas where results from our earlier studies are generally transferrable to other countries, we have applied those results to the countries analysed, adjusting for a variety of country-specific factors such as future renewable electricity mix, future gas mix or heat demand seasonality.
- **produces robust and reliable results:** To capture uncertainty about the future development of key parameters such as gas and electricity demand or renewable gas generation costs in 2050, we have repeated the calculations for a number of different parameter sets, leading to robust estimations of cost saving intervals.

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41 See Sections 4.2.3 to 4.2.6 for further details on our approach.

Based on this approach we are capable of providing differentiated values for all countries analysed and all steps of the supply chain.

4.2.2 Results: Gas infrastructure saves costs in all countries, though to a different degree

Aggregated for all eight countries analysed, our calculations show that

- cost savings reach **EUR 30 billion to 49 billion per year** in 2050 (real values; undiscounted).
- If we assume a linear development path between today and 2050, these would elicit total cost savings of **EUR 487 billion to 802 billion between today and 2050** (real values; undiscounted).[42]

487-802 bn €

Savings until 2050 through the continued use of gas networks in the eight analysed countries.

If these findings are extrapolated to all of Europe (assuming equal per-capita savings in other European countries)

- total cost savings in the EU-28 plus Switzerland could be equivalent to **EUR 76 billion to 125 billion per year** in 2050,
- or approximately **EUR 1,300 billion to 2,100 billion between today and 2050** (again assuming a linear path).[43]

These savings are driven through varying effects of a continued usage of gas infrastructure of the **various elements on the supply chain**:

- **Large cost savings through still allowing for gas-based end-user appliances** in **heating** (EUR 11.7 - 13.3 billion per year), **industrial processes** (EUR 4.1 - 4.6 billion per year) and in the **transport** sector (EUR 3.5 - 5.5 billion per year);
- **Substantial cost savings of using gas networks by avoiding investments in electricity transmission** (EUR 2.5 - 3.2 billion per year) and **distribution** (EUR 7.6 - 9.2 billion per year) **networks**;
- **Moderate additional costs** (EUR 0.7 billion per year) of **maintaining gas networks** and adjusting or converting them to hydrogen where required, compared to having to dismantle them in the “All-Electric plus Gas Storage” scenario without gas networks; and
- **Further, possibly significant, cost savings through cheaper energy generation** (EUR 0.8 - 13.5 billion per year). As explained in Section 4.2.6, the wide range of possible cost savings in this area is caused by a number of uncertainties such as the future origin of gas (domestic or imported from

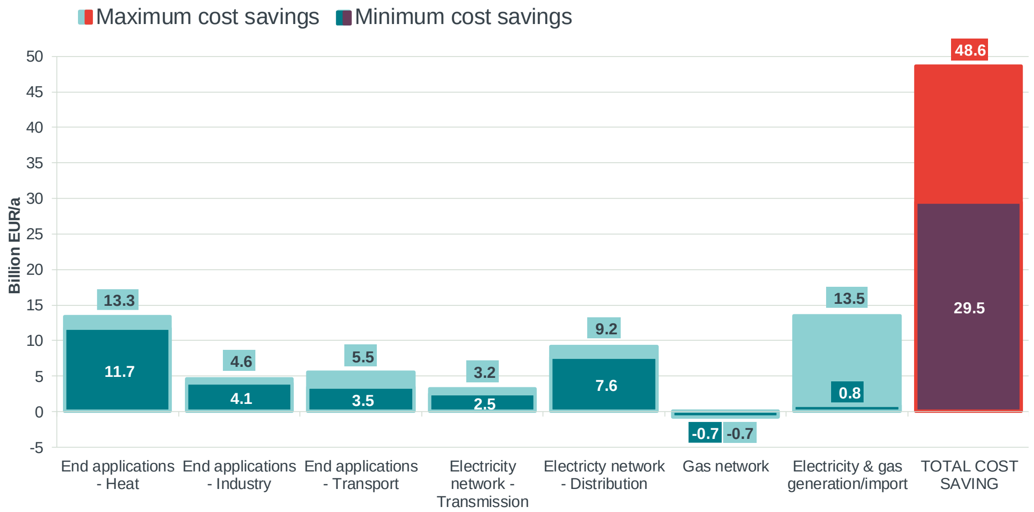
[42] With a linear development path, we refer to linearly increasing cost savings each year through gradual (avoided) infrastructure modification (or electrification), starting from zero cost savings today.

[43] Please note that both a linear development of cost savings and per-capita cost savings for non-analysed EU-28 countries that are equal to those of the analysed countries are simplifying assumptions. The resulting numbers give only a rough estimate of total cumulated cost savings by 2050 and total cost savings for EU-28. They have to be interpreted carefully, acknowledging the shortcomings of the underlying simple scaling approach.

regions with good renewable energy conditions) or the future costs of biomethane production.

The ranges of cost savings reflect the uncertainty about the future development of various parameters. Figure 26 illustrates the minimum and maximum possible cost savings in each of the areas.

Figure 26 Min and max cost savings of a continued use of gas per year in 2050 along the supply chain for the countries analysed



Source: Frontier Economics/IAEW

Note: The values illustrate the difference in annual costs between the "All-Electric plus Gas Storage" scenario and the "Electricity and Gas Infrastructure" scenario. A positive value reflects cost savings in the "Electricity and Gas Infrastructure" scenario, where parts of end energy are supplied by renewable and low-carbon gas[44] via gas networks, compared to the "All-Electric plus Gas Storage" scenario, where end energy is primarily supplied by electricity and gas networks are no longer needed. Minimum and maximum savings refer to varied assumptions on key parameters that are uncertain from today's perspective, such as production prices of different renewable gases, the assumed share of gas imports or the development of final energy demand until 2050.

Cost savings **differ between countries** due to various country-specific factors like renewable generation potentials, electricity and gas network structures or the historic penetration of gas (Figure 27).

[44] For the Czech Republic we also assume a small remaining amount of natural gas.

Figure 27 Annual cost savings [in EUR per capita] of the continued use of gas in the countries analysed in 2050

Source: Frontier Economics/IAEW

Note: The values illustrate annual cost savings per capita in the “Electricity and Gas Infrastructure” scenario compared to the “All-Electric plus Gas Storage” scenario.
If these savings are related to the number of households, this corresponds to cost savings per household of 316 to 520 on average over all countries analysed. Please note, though, that we calculate cost savings for all sectors (including e.g. industry) and not only households, so these numbers are not to be interpreted as individual energy bill cost savings per household.
The range of cost savings per country is caused by varied assumptions on key parameters that are uncertain from today’s perspective, such as production prices of different renewable gases, the assumed share of gas imports or the development of final energy demand until 2050.

In brief, cost savings of continued gas network use in the analysed countries can be explained as such:

- In **Belgium**, gas plays a substantial role particularly in residential heating (where 49% of final energy demand is supplied by gas) and in industry (34%) today and we expect that in a world with gas networks, this will remain the case in 2050: While some gas appliances will be replaced by electric appliances such as heat pumps, significant energy demand will be shifted from oil (e.g. in heating or industry) to renewable gas, leading to comparably constant gas demand if gas networks are available.

  Accordingly, substantial cost saving potentials stem from **lower purchasing costs in space and water heating and process heating appliances**. Further savings are to be expected by releasing pressure on the expansion requirement in the otherwise stretched **electricity and transmission network**. There is considerable uncertainty in Belgium regarding the future origin and cost of both renewable electricity and renewable gas, given very limited domestic renewable potentials, Belgium will **depend on imports** in both scenarios. However, the continued availability of gas networks would allow the import of renewable gas also from overseas, while an electrification-led path would limit imports to renewable sources and costs of neighbouring countries, which would also entail a substantial reinforcement of electricity cross-border interconnections.

- **Switzerland** is characterised by strong seasonality and limited RES generation potentials**.** It boasts a substantial gas network, covering all densely-populated areas and including exclusive access to storage in neighbouring countries. Gas supplies 26% of final energy demand in both industry and heating, which is expected to remain similar (and cost-effective) if gas networks remain in use in 2050.

  Consequently, the continued use of gas networks generates substantial cost savings by **reducing appliance purchasing costs and the costs of upgrading buildings in space and water heating**. Moreover, electrifying large parts of heat demand would import the heat demand seasonality to the electricity sector, imposing extraordinary challenges both for generation/storage, as well as the transmission and distribution network. **Further savings therefore stem from easing of pressure on the electricity distribution and transmission grid**, the latter of which is already congested today and its expansion is expensive due to challenging geographical conditions and high labour costs. Moreover, beyond its hydro storage potential Switzerland has not enough intermittent RES and biomass capacities, which means it will **depend on imports** in future. The continued use of gas networks would also allow gas imports from outside Europe, where production costs are lower, while the “All-Electric plus Gas Storage” scenario would force Switzerland to import electricity from neighbouring countries, necessitating a significant expansion of interconnector capacities.

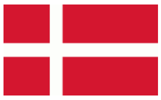
- The gas infrastructure in the **Czech Republic** currently supplies gas to large parts of the EU. Moreover, the country is largely dependent on gas itself, which comprises 22% of total final energy demand. Another important source of energy in the Czech Republic is electricity generated by nuclear power plants. In contrast, RES are comparatively little developed and their geographic potential is limited, meaning an electrification-led energy transition towards “green” energy is likely to be challenging. This is also why no binding climate goals for 2050 have yet been defined.

  The largest savings through the continued use of gas networks stem from **lower purchasing and upgrading costs in space and water heating appliances**, with further benefits expected in areas of electricity generation and transformation. While PV may actually have some potential in CZ, wind load factors are rather low. It would therefore be **expensive to generate sufficient electricity to cover the additional demand in the “All-Electric plus Gas Storage” scenario.** Renewable gas, conversely, could be easily imported, given the current cross-border transmission capacities. The fact that most new RES is likely to be small-scale and connected to the distribution grid would also have important consequences for distribution grids. Given the low penetration of intermittent RES today, the **distribution grids are not yet fit to deal with large capacities of decentralised PV and onshore plants**. Through the reduced final electricity demand and the implementation of power-to-gas plants that could deal with surplus generation, continued use of gas networks could therefore avoid substantial investments in the electricity distribution grids.

- 

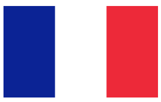
  In **Germany**, gas plays an important role at present, particularly in industry (35%) and residential heating (46%). While RES expansion is already well developed, the question remains how to transport electricity from the major generation sources in the north to load centres in the south and west of the country. The continued use of gas networks could help overcome this challenge.

  In fact, **substantial cost savings would emerge on all steps along the supply chain**. In space and water heating, purchase costs of capital-intensive end appliances could be avoided; in industry, ongoing use of gas would prevent the inefficient use of electricity for high temperature process heat generation; and in the transport sector, lower unit costs of gas-fuelled vehicles (compared to electric vehicles) could elicit substantial cost savings. Additional benefits arise from the **reduced expansion requirement of transmission (North-South) and distribution grids** as far-reaching electrification would otherwise lead to considerable congestion. Finally, considerable uncertainty exists about the future origin of renewable gas. If the import of inexpensive synthetic methane or hydrogen is assumed, **substantial savings can be realised in electricity and renewable gas generation**.

- 

  Denmark has the lowest share of gas in final energy demand of all countries considered (approximately 10%), which is, inter alia, attributable to the predominance of district heating. It may also require less gas for seasonal storage than other countries because of heat storage options that are currently being implemented and probably expanded in future. The benefits of continuing to use gas networks are therefore slightly smaller in Denmark than in the other countries analysed.

  Despite the relatively small role in heating, **considerable cost savings stem from lower purchase costs in space and water heating appliances**. While some cost savings can be generated in the transport sector and by avoiding investments in the electricity distribution network, the **largest cost savings are likely to come from electricity generation and renewable gas generation**. This is because Denmark has both the potential to produce synthetic methane and hydrogen from offshore wind and the possibility to produce biomethane from its **large biomass potential**. While some **uncertainty remains around biomethane production costs** in future, they may fall to such low levels to make renewable gas costs (per TWh) for Denmark comparable to electricity costs. In combination with the flexibility value of gas, this can generate a significant cost advantage in the “Electricity and Gas Infrastructure” scenario compared to the “All-Electric plus Gas Storage” scenario.

- 

  Today **France** is significantly reliant on nuclear power and there is significant uncertainty whether and when this will need to be replaced by other sources. Moreover, given the significant penetration of electric heating, the French electricity system already manages significant swings in demand and further electrification would accentuate the peaks, though this may be partly mitigated by energy efficiency improvements. Gas also plays a significant role today, supplying 36% of final demand in industry and 38% of household space heating. The gas network reaches 80%

of the population. We therefore expect gas to continue playing an important role in future if gas networks remain in use.

Accordingly, **substantial cost savings can be realised by avoiding electrification of some of the end appliances in space and water heating and industry**. In addition, while France has good RES potentials (solar, onshore and offshore), **extending the distribution grid to meet supply-driven grid requirements would be costly**. Some of these investments could be avoided through the continued use of gas networks. **One important uncertainty in France is around biomethane production costs**. Given the large potential, these impact considerably on the costs of renewable gas for France. If biomethane production costs fall sufficiently, renewable gas becomes a cheaper energy source than electricity, leading to substantial cost savings in the "Electricity and Gas Infrastructure" scenario.

- Due to historic production potentials, gas penetration in **the Netherlands** is particularly high; gas covers 36% of final energy demand and also plays a key role in industry, both as a source of energy and feedstock. The existing gas storage options offer large seasonal flexibility. Yet, there is some uncertainty about the future penetration, impacting expected cost savings.

  Elsewhere, **considerable cost savings are likely to come from lower purchasing costs for space and water heating appliances**. Moreover, the continued use of gas networks avoids the use of inefficient electric appliances for generating high-temperature process heat. By far the **largest cost savings stem from electricity generation and renewable gas production**. Ahead of other countries, the Netherlands is already considering a range of alternatives for natural gas, planning for the large-scale use of hydrogen and planning to **construct dedicated power-to-gas production plants from offshore wind**, amongst others.

Further details on each country analysed can be found in the country reports in the Annex.

In the following sections we go into details of the methodology used as well as the estimation results on each stage of the supply chain, highlighting the major differences between countries.

4.2.3 Avoided cost-intensive end-user appliances

One area in which the continued use of gas networks yields substantial cost savings is end-user appliances. In a scenario without gas networks, end-users will have to switch to end appliances based on other energy carriers. Options are renewable electricity, renewable liquids or the direct use of renewables (e.g. solar thermal or wood pellets). In contrast, in a gas scenario end-consumers have the opportunity to use gas-based end appliances such as gas boilers.

Assuming that liquids and direct renewables are equally used in both scenarios, the "All-Electric plus Gas Storage" and the "Electricity and Gas Infrastructure" scenario are distinct in terms of their penetration of electricity- vs. gas-based end appliances. While we take different fuel efficiency rates of these appliances into account when estimating the electricity and gas generation costs (see Section 4.2.6), in this section we focus on differences in costs for purchasing end appliances between the two scenarios.

The assumptions made on the costs of purchasing individual end-user appliances are taken from various established studies. To facilitate comparison with the other cost items (e.g. electricity or gas networks) with different amortisation periods, the costs of end-user appliances are annuitized based on the specific lifetimes of the appliances.

We focus on the three areas of end-user appliances with the largest final energy demand,

- space and water heating;
- process heating in industry; and
- transport.

Space and water heating[45]

While the penetration of electric heat pumps in Europe is still low today, we expect the majority of newly constructed buildings to be equipped with electric heat pumps in the run-up to 2050. When combined with thorough heat insulation and appropriate large surface heaters (e.g. floor heating), electric heat pumps are very efficient in supplying space heat in most times of the year. We therefore expect a high penetration of electric heat pumps in both scenarios, i.e. also in the "Electricity and Gas Infrastructure scenario" in which heat pumps in particular replace oil heaters that are still predominant in many European countries.

However, a considerable share of the existing building stock will not have been replaced until 2050:

- In a scenario with gas networks, large chunks of these buildings can be supplied by renewable and low-carbon gas in 2050, enabling the use of gas boilers that replace e.g. old gas boilers or oil heaters.
- In the "All-Electric plus Gas Storage" scenario without gas networks, however, the old building stock has to be supplied by either electric heat pumps or direct electric heating. Assuming that part of the existing building stock will also be equipped with electric heat pumps, in order to avoid too much of the challenge of increased electricity peak demand through very low energy efficiency of direct electric heating, this leads to substantial costs for insulation, substitution of radiators, and significantly higher costs for the heating itself;

The continued use of gas in heating can therefore avoid purchasing costs in end-user appliances of **EUR 11.7 billion - EUR 13.3 billion per year** in the countries analysed in 2050.

These results are based on an application of the comprehensive approach that we have developed for Germany[46] to the countries analysed, adjusting for

[45] We have focused on space and water heating in the residential and commercial sector, abstracting from space and water heating in industry.

[46] See for details Frontier Economics et al (2017), Section 4.2.1, Annex A and Annex B.2.

- the share of residential and services in final energy demand;
- the expected 2050 final demand for gas and electricity in the "Electricity and Gas Infrastructure" scenario; and
  - Seasonality of heat demand (based on the distribution of heating degree days[47] over the course of the year).

Annual cost savings in 2050 from the continued use of gas networks in most countries are roughly similar, ranging from EUR 35 to EUR 63 per capita. The Czech Republic and Germany stand out because they "score" highest in the combination of the above factors, even though other countries may show higher values in individual areas. Switzerland, Denmark and France, for instance, have higher shares of residential and services in final energy demand and Belgium and Netherlands are characterised by their larger expected role of gas in 2050 (for some possible demand growth paths).

Figure 28 Space and water heating: Annual cost savings in 2050 [in EUR per capita] of a continued use of gas in the countries analysed

Source: Frontier Economics/IAEW

Note: The values illustrate the annual cost savings per capita in the "Electricity and Gas Infrastructure" scenario compared to the "All-Electric plus Gas Storage" scenario.

Process heat[48]

For the same reasons as for space heating, there are substantial benefits from the continued use of gas boilers in industry. While low temperature process heat could technically be supplied by heat pumps and electric heaters in the "All-Electric plus

[47] A heating degree day (HDD) is a measurement derived from outside air temperatures designed to quantify the demand for energy needed to heat a building, see Figure 12 for more details.

[48] We have focused on process heat in industry, since the industry sector is the predominant generator and user of process heat across all sectors.

Gas Storage" scenario, using such technologies for medium- to high-temperature processes is rather inefficient.

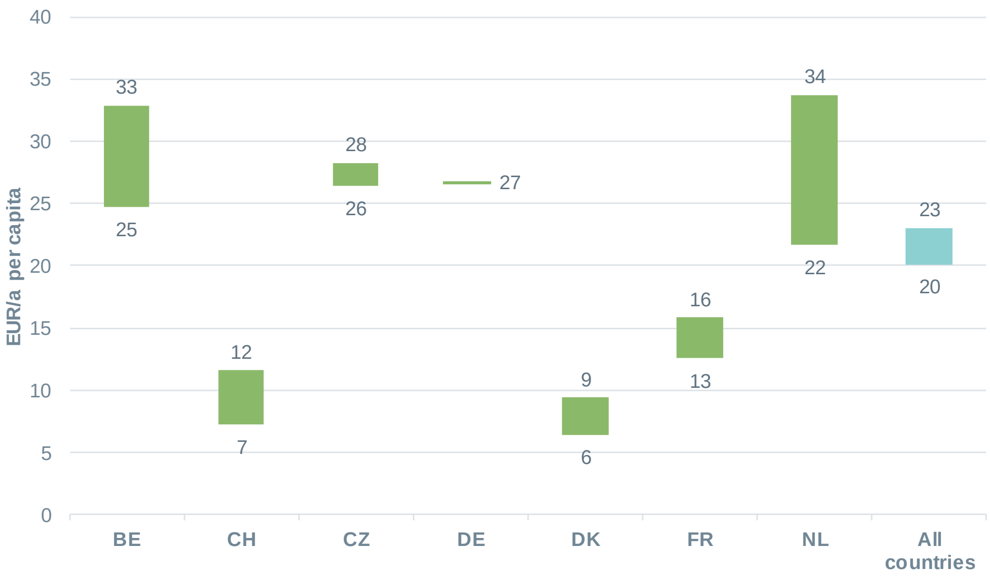
The countries analysed could therefore save electrification costs of **EUR 4.1 billion - EUR 4.6 billion per year** by continuing to use gas for process heat in industry.

In order to reach these results we have transferred the results for Germany to the other countries analysed, adjusting for

- the expected 2050 final demand for gas and electricity in the "Electricity and Gas Infrastructure" scenario in 2050 (rationale analogous to space and water heating, see above); and
- today's share of industry in final energy demand: The higher a country's share of industry in final energy demand (e.g. through a dominance of energy-intensive industries), the higher potential savings of a continued opportunity to use gas in the industry.

Differences in these factors across countries lead to notable differences in per capita cost savings. In Belgium and the Netherlands, for instance, where industry makes up 34% and 30% of final energy demand respectively and where gas is expected to play a major role in 2050, annual cost savings can reach more than EUR 30 per capita. Cost savings are less pronounced in Switzerland or Denmark where the share of industry in final energy demand is comparatively low (18% and 15%, respectively), and where the expected role of gas in 2050 is more limited.

Figure 29 Process heat: Annual cost savings in 2050 [in EUR per capita] of a continued use of gas networks in the countries analysed



Source: Frontier Economics/IAEW

Note: The values illustrate the annual cost savings per capita in the "Electricity and Gas Infrastructure" scenario compared to the "All-Electric plus Gas Storage" scenario.

Transport

Further cost savings of gas usage are to be expected through lower purchasing costs in the transport sector.

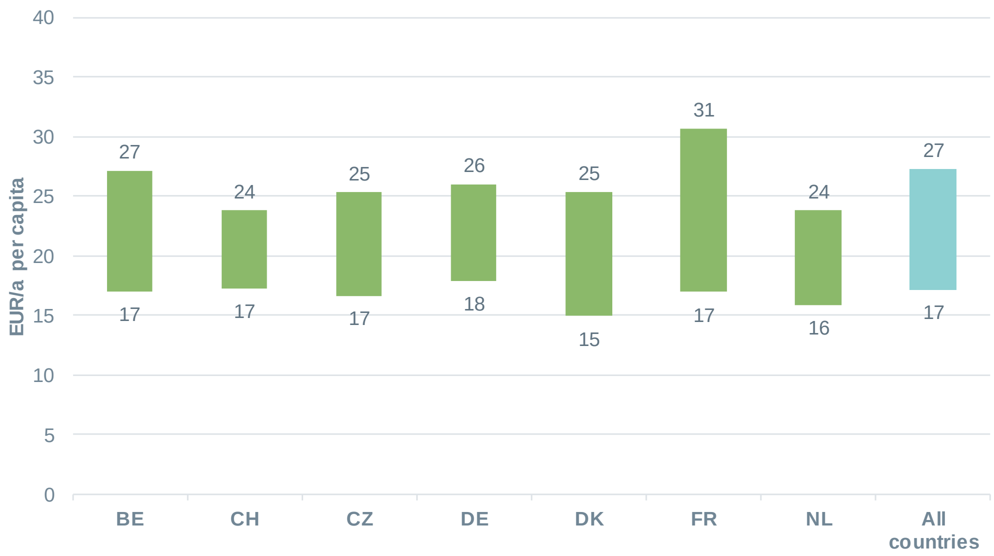
We assume that by 2050 rail transport will be fully electrified, while climate-neutral liquid fuels will be used in aviation and shipping.[49] In these sectors there are therefore no differences between the “All-Electric plus Gas Storage” scenario and one in which gas networks are still used.

In road transport, however, a continued use of gas enables cost savings through less expensive unit costs for passenger cars and particularly in heavy duty transport, compared to electric vehicles. In total, the countries analysed could save **EUR 3.5 billion - EUR 5.5 billion per year** in an “Electricity and Gas Infrastructure” scenario compared to the “All-Electric plus Gas Storage” scenario.

These estimates are based on assumptions in relation to the expected number of vehicles in each country in 2050[50], the expected unit costs for gas-fuelled and electric vehicles in 2050, and the number of electric vehicles in both scenarios.[51]

Given that the same unit costs are assumed for vehicles in all countries, annual cost savings per capita in 2050 are relatively similar between them. On average across all countries analysed, they range from EUR 17 to EUR 27 per capita.

Figure 30 Transport: Annual cost savings in 2050 [in EUR per capita] of a continued use of gas networks in the countries analysed



Source: Frontier Economics/IAEW

Note: The values illustrate the annual cost savings per capita in the “Electricity and Gas Infrastructure” scenario compared to the “All-Electric plus Gas Storage” scenario.

49 Note that this is a conservative approach, as some of today’s diesel-fired trains may well be replaced by hydrogen-based trains, and gas (e.g. in the form of bio-LNG) may well play a role in aviation and particularly shipping (see Section 3.3), which could lead to further cost savings of gas usage. However, for a lack of available data, we abstract from calculating these potential cost savings.

50 The number of expected vehicles is derived from today’s numbers per country and a projected increase in passenger- and tonne-kilometres of 10.3% for passenger cars, 50.6% for road transport of goods and 11.9% of public transport (based on UBA (2016a)).

51 We assume that 50% of road transport will be fuelled by climate-neutral liquid fuels in both scenarios. In the “All-Electric plus Gas Storage” scenario the other 50% of vehicles will be electric. In the “Electricity and Gas Infrastructure” scenario, only 20% of vehicles will be electric while the rest will run with fuel cells, using hydrogen, or run on CNG or LNG basis. This is consistent with our approach in the study for FNB Gas; see for details Frontier Economics et al. (2017).

4.2.4 Reduced requirement to reinforce electricity transmission and distribution networks

One obvious consequence of full electrification is the challenge it poses for electricity networks. If electricity networks are the only means to transport energy from generation to final use in 2050, substantial investments in the infrastructure are required, far beyond what is currently foreseen in the TYNDP.

Transmission

Due to the increase in renewable capacities and the resulting supply peaks, transmission networks need to be expanded in both scenarios. In the “Electricity and Gas Infrastructure” scenario, however, higher PtG capacities help absorb surplus electricity during hours of high wind energy and PV feed-in. Moreover, the continued use of gas networks means that consumers can continue using gas in end appliances and therefore require less final energy in the form of electricity in the first place. The continued use of the gas infrastructure therefore leads to annual cost savings of about **EUR 2.5 billion - EUR 3.2 billion** in the countries analysed in 2050.

We reached this estimate by drawing on insights from our previous analysis for Germany in which we approximated the network expansion costs by

- conducting a simulation of network operation on an hourly time frame, including dispatches of generation in all market areas
- identifying critical hours and network bottlenecks
- determining the necessary network upgrading and expansion measures to eliminate bottlenecks
- estimating the corresponding costs.

For the purpose of this study, we have adjusted savings per capita from existing national studies for the other analysed countries according to structural differences between countries. In particular, we have considered

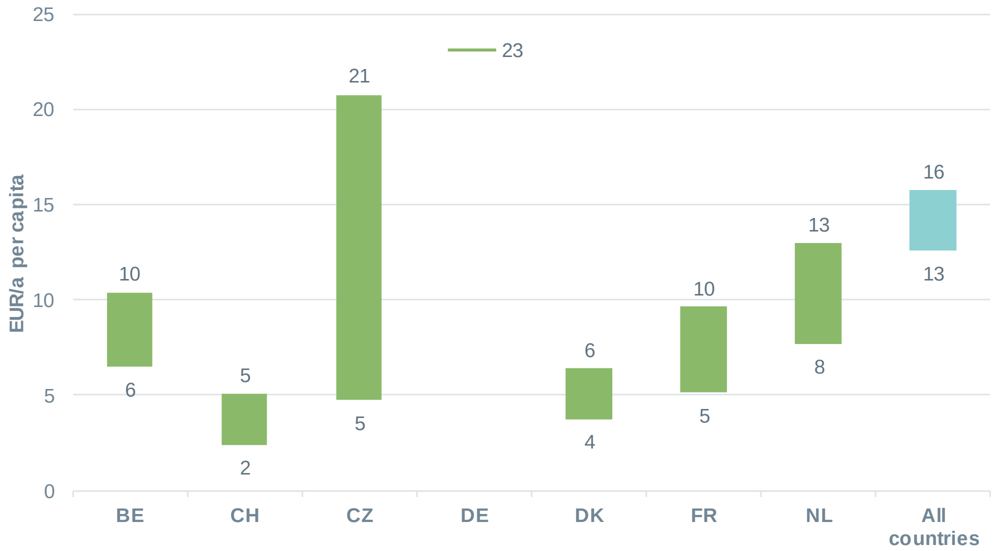
- the future role of gas in each country, approximated by the share of gas in final electricity and gas demand in 2050[52] – The higher the share of gas, the more load would have to be carried by power grids in the “All-Electric plus Gas Storage” scenario compared to the “Electricity and Gas Infrastructure” scenario, thus the more would have to be invested in the electricity infrastructure;
- the costs of grid extension measures relative to Germany’s – These are based on per km costs of planned and commissioned projects of the TYNDP and thus take into account country-specific circumstances such as planned DC (direct current) lines, labour costs and geographical characteristics like mountains or access to the ocean;
- the required grid extension until 2050 caused by RES expansion and today’s grid “preparedness” – This is based on the planned and commissioned grid

[52] In line with the other cost savings calculations, we consider different possible development paths for electricity and gas demand between now and 2050.

extension of the TYNDP, standardised across the countries by today's grid length as well as the expected RES increase over the same period and finally projected by the expected RES growth until 2050.[53]

Due to these factors, cost savings vary considerably between countries. While it is relatively expensive to build new transmission lines in Switzerland, the RES potential is so limited that it would be nearly exhausted in both scenarios. This in turn means that there are no large differences in terms of the required grid extension, leading to annual cost savings of only EUR 2-5 per capita in the "Electricity and Gas Infrastructure" scenario. In contrast, the Czech Republic currently has such a low penetration of RES and may need to expand the capacity so strongly to cover its electricity demand for certain plausible development paths in the "All-Electric plus Gas Storage" scenario, that the continued use of gas networks could generate annual cost savings of up to EUR 21 per capita. This is only surpassed by Germany where both the required grid expansion and per-km-line costs are relatively high.

Figure 31 Electricity transmission networks: Annual cost savings in 2050 [in EUR per capita] of a continued use of gas networks in the countries analysed



Source: Frontier Economics/IAEW

Note: The values illustrate the annual cost savings per capita in the "Electricity and Gas Infrastructure" scenario compared to the "All-Electric plus Gas Storage" scenario.

Distribution

As the level of electrification increases, distribution networks need to be able to handle increasing RES capacities connected to the distribution grid as well as increasing peak loads due to electrification of end-user appliances. This requires substantial investments in the electricity infrastructure.

The continued use of gas networks helps to alleviate this challenge. On the one hand, peak electricity demand will be lower (mainly because households can

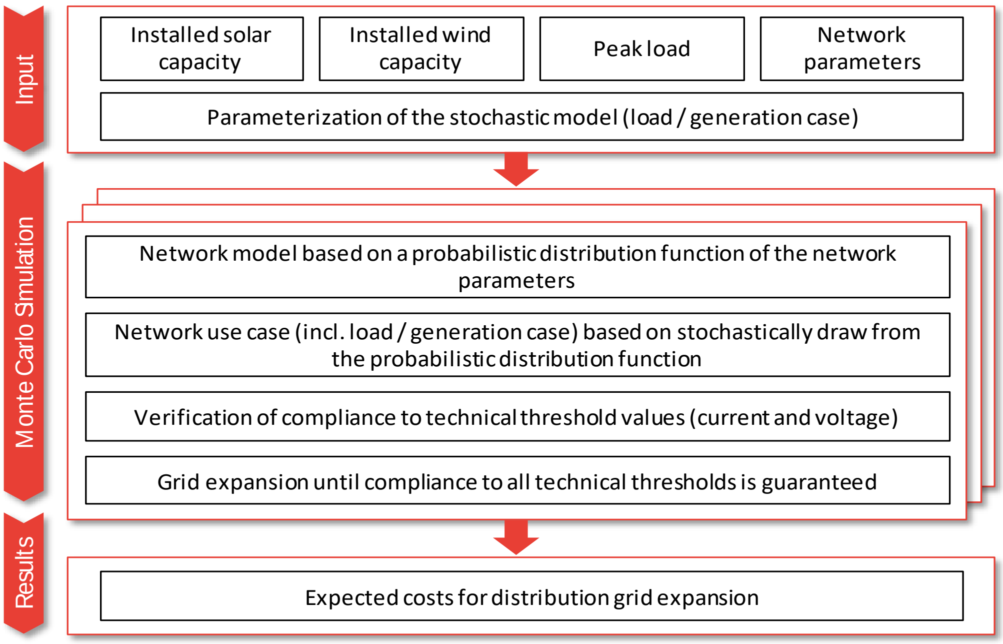
[53] We assume that wind (on- and offshore) integration causes twice the necessary grid extension as PV on TSO level, therefore RES growth is weighted accordingly.

continue heating with gas), which reduces the load-driven expansion requirement. On the other hand, it reduces the RES-driven expansion because more PtG plants will be connected to the network that can help manage the peaks in generation. In sum, the continued use of gas networks avoids investments in electricity distribution networks of **EUR 7.6 billion - EUR 9.2 billion per year** in the analysed countries in 2050.

We use a Monte Carlo approach to simulate the necessary distribution grid expansion for the two scenarios "Electricity and Gas Infrastructure" and “All-Electric plus Gas Storage" in each country. Taking into account country-specific structural characteristics[54] like the share of urban vs. rural networks, we carry out load flow simulations with varying input parameters, particularly the installed RES capacity connected to the grid, the peak load and the grid location of electrical loads, to identify voltage and current limit violations. Our focus lies both on situations of low load and high RES generation on the one hand, and low RES generation and peak load on the other hand. Where constrains are violated, grid expansion measures, such as building of new lines and cables, are carried out until all technical thresholds are met.[55]

Figure 32 visualizes the methodology.

Figure 32 Monte Carlo approach for the determination of necessary grid extension in the distribution network



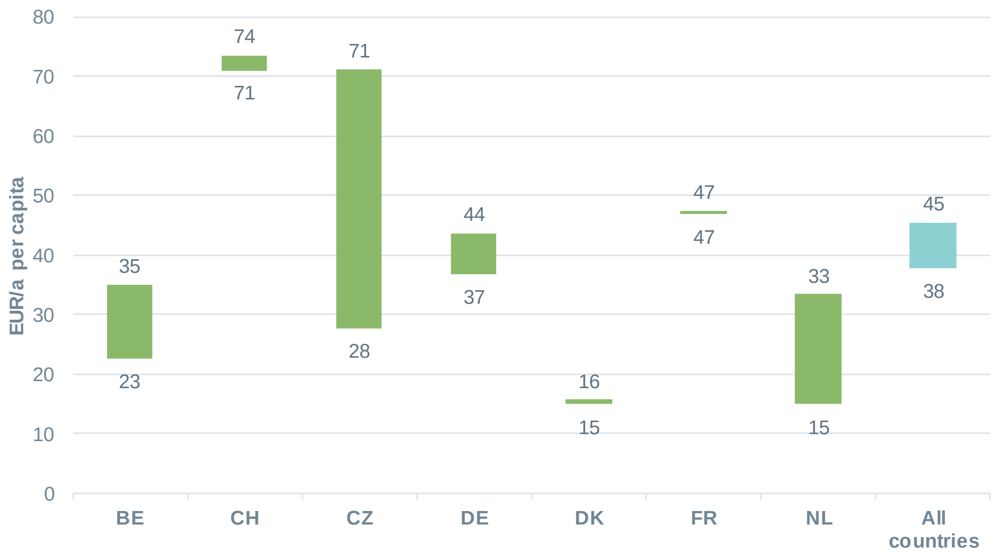
Source: Frontier Economics/IAEW

54 We use published data to analyse the structure of the considered European distribution grids. Present network lengths of the considered distribution grids are obtained from CEER (2015) and Eurelectric (2013). For the distinction between distribution grids serving urban or rural areas their respective share in the total network length is estimated based on the use of area defined by the Corine Land Cover Project. For the distinction between urban and rural networks specific costs for cables and overhead-lines are obtained from BMWi (2014).

55 This is realized in a two-step approach. At first the adherence of the maximum admissible current is validated and if necessary additional lines are put into place parallel to the existing line. Subsequently potential voltage threshold infringements are identified and addressed by implementing an additional line in parallel to the network feeder.

As for transmission networks, there are notable differences in cost savings across countries. Switzerland, where the electrification of heating would substantially increase the demand-driven peak load in cold winters, would need to materially upgrade the distribution grid in an “All-Electric plus Gas Storage” scenario compared to an “Electricity and Gas Infrastructure” scenario. In the latter scenario, savings would amount to 65% - 67% of current network length. Annual cost savings from the continued use of gas networks are therefore as high as EUR 71 - EUR 74 per capita. In contrast, in Denmark the “All-Electric plus Gas Storage” scenario would only require additional distribution grid expansions of around 8% of current network length compared to the “Electricity and Gas Infrastructure” scenario, leading to correspondingly small cost savings. The wide range of possible cost savings in the Czech Republic is again driven by the uncertainty around demand growth and the resulting need for RES expansion.

Figure 33 Electricity distribution networks: Annual cost savings in 2050 [in EUR per capita] of a continued use of gas networks in the countries analysed



Source: Frontier Economics/IAEW

Note: The values illustrate the annual cost savings per capita in the “Electricity and Gas Infrastructure” scenario compared to the “All-Electric plus Gas Storage” scenario.

4.2.5 Moderate additional costs to maintain and adjust gas networks

In the “Electricity and Gas Infrastructure” scenario the existing gas network would continue to operate. While TSOs would no longer construct and expand networks to a significant extent in 2050, they would continue to incur expenses for maintaining and upgrading them. In addition, adjusting and/or converting existing natural gas pipelines to hydrogen entails further cost. In the scenario where gas is only used for temporal storage, on the other hand, gas pipelines would have to be either physically dismantled (which we assume for a low proportion of the pipelines) or at least sealed and secured, which also does incur substantial cost.

On balance, the maintenance and adjusting costs in the “All-Electric plus Gas Storage” scenario exceed the dismantling/securing costs in the “All-Electric plus Gas Storage” scenario moderately, leading to additional costs of **EUR 0.7 billion per year** for the countries analysed in 2050.

We have followed a bottom-up approach to determine the costs for maintenance and upgrading, on the one hand, and securing and dismantling of gas pipelines, on the other hand. In particular, we have also drawn on insights from our study on Germany to calculate operations and maintenance costs as well as dismantling costs per km and calculated total costs per country based on the country’s transmission and distribution network length.

Differences between countries are moderate, driven only by a different mix of transmission and distribution pipeline kilometres. They range from EUR 1 per capita and year in Germany and Denmark where the transmission grid only covers 4% - 5% of the total grid to EUR 7 per capita and year in France where it makes up 16% of the total grid.

4.2.6 Cost savings in energy generation through using renewable and low-carbon gas[56]

The cost savings that are generated by a continued use of gas networks already begin to materialise on the first step of the supply chain. That is primary energy supply, electricity generation and gas production.

In general, gas demand in the “Electricity and Gas Infrastructure” scenario is higher because gas is still used for the supply of energy to end-customers. In the “All-Electric plus Gas Storage” scenario, where most end-user appliances are electrified, there is no final gas demand. As a consequence the electricity demand is much higher and more seasonal.

At first glance, this may suggest extra costs in the “Electricity and Gas Infrastructure” scenario because supplying final consumers with electricity in the “All-Electric plus Gas Storage” scenario saves conversion losses of power-to-gas (if otherwise gas is produced from renewable electricity via power-to-gas), and because electric end appliances are often more energy-efficient, i.e. require less final energy e.g. to heat a home or fuel a vehicle, saving further conversion losses. In a thorough system analysis, however, this is not necessarily the case for the following reasons:

- **Demand and supply is not evenly distributed over the year**. In contrast, heat demand is very seasonal with high peak demand in winter, while e.g. PV supply is comparably low in winter. In the “All-Electric plus Gas Storage” scenario, the seasonality from the heating sector is imported into the electricity sector, making electricity demand peakier. Electricity would now have to cover extreme demand situations, especially caused by cold winters, that were previously covered by gas and oil.
- Given that **electricity is much more expensive to store in large volumes over a seasonal time period** than gas (as explained in Section 3.1.2), even in

[56] Please note that an exception is made for the Czech Republic. Given that it has not formulated specific decarbonisation targets for 2050, we assume that natural gas will continue to play a minor role in 2050.

a scenario where end-customers no longer use gas, it is cost-effective to store large volumes of gas in order to generate electricity in gas-fired power plants in situations of peak demand. The alternative – expanding RES capacity even further or using electricity storages like batteries – would be substantially more expensive.

- In a scenario with gas networks, **gas storage does likewise serve to bridge intermittent renewable supply and seasonal heat** demand. But because gas networks allow to supply end consumers with gas, there is less need to transform gas to power, thus saving conversion losses that are incurred in gas-fired power plants in the “All-Electric plus Gas Storage” scenario.
- There are other, **cheaper renewable and low-carbon gas sources than domestic power-to-gas**. One possible source is the relatively cost-effective production of biomethane from domestic biomass potentials. Another possibility is producing blue hydrogen from natural gas, using CCS. A further possibility is importing gas converted from renewable electricity from outside of Europe (e.g. Northern Africa) where electricity generation and hence power-to-gas production is substantially cheaper than in Europe. Existing transnational gas pipelines and LNG facilities could facilitate these imports, whereas the import of electricity would require major additional investments in long-distance interconnections.

On balance, the cost advantages of electricity and renewable and low-carbon gas generation outweigh the cost disadvantage (caused by conversion losses and CAPEX needed for more power-to-gas in the “Electricity and Gas Infrastructure” scenario), so that total generation and gas production costs are lower in this scenario compared to the “All-Electric plus Gas Storage” scenario. In the countries analysed, this leads to total annual cost savings of **EUR 0.8 billion - EUR 13.5 billion** in 2050.

The wide range reflects uncertainties around a number of factors, in particular

- the development of electricity and gas demand until 2050,
- renewable gas costs, especially biomethane,
- and the share of imports compared to domestically produced synthetic methane/hydrogen.

Given that the development of demand until 2050 is hard to predict, we consider two different sources: Country studies/TSO information and growth paths as calculated in our comprehensive study on Germany. The values for each country are presented below.

Figure 34 Different possible gas and electricity demand development paths (TWh) and changes compared to 2016

		BE	CH	CZ	DE	DK	FR	NL
	Gas demand 2016	**166**	**33**	**82**	**818**	**34**	**445**	**350**
Country studies / Gas TSOs	**Gas demand "Electricity and Gas Infrastructure"**	**85**	**19**	**113**	**665**	**20**	**248**	**142**
	% change	*-49%*	*-41%*	*38%*	*-19%*	*-40%*	*-44%*	*-59%*
	Gas demand for end-usage	81	17	109	645	18	233	135
	Gas demand for storage/generation	4	2	4	19	2	15	7
	Gas demand "All-Electric + Gas Storage"	**39**	**15**	**54**	**262**	**13**	**130**	**63**
	% change	*-76%*	*-55%*	*-34%*	*-68%*	*-61%*	*-71%*	*-82%*
Top-down	**Gas demand "Electricity and Gas Infrastructure"**	**119**	**36**	**69**	**665**	**19**	**373**	**218**
	% change	*-29%*	*11%*	*-15%*	*-19%*	*-43%*	*-16%*	*-38%*
	Gas demand for end-usage	115	34	68	645	18	357	214
	Gas demand for storage/generation	3	2	2	19	1	17	4
	Gas demand "All-Electric + Gas Storage"	**41**	**18**	**31**	**262**	**9**	**155**	**60**
	% change	*-76%*	*-46%*	*-62%*	*-68%*	*-74%*	*-65%*	*-83%*
	Electricity demand 2016	**82**	**58**	**56**	**517**	**31**	**442**	**106**
Country studies / Gas TSOs	**Final electricity demand "Electricity and Gas Infrastructure"**	**99**	**53**	**92**	**468**	**50**	**372**	**167**
	% change	*21%*	*-9%*	*64%*	*-10%*	*60%*	*-16%*	*58%*
	Final elec. demand "All-Electric + Gas Storage"	**161**	**66**	**176**	**965**	**64**	**551**	**271**
	% change	*97%*	*13%*	*214%*	*86%*	*105%*	*25%*	*157%*
Top-down	**Final electricity demand "Electricity and Gas Infrastructure"**	**78**	**53**	**49**	**468**	**29**	**381**	**94**
	% change	*-5%*	*-9%*	*-13%*	*-10%*	*-8%*	*-14%*	*-11%*
	Final elec. demand "All-Electric + Gas Storage"	**166**	**79**	**101**	**965**	**43**	**656**	**258**
	% change	*103%*	*36%*	*80%*	*86%*	*37%*	*48%*	*145%*

Source: Frontier Economics, Eurostat and Swiss Federal Office of Energy

Note: Demands in the "Electricity and Gas Infrastructure" scenario are based on country studies or top-down calculations using 2015 values and insights from Frontier Economics et al. (2017). Demands in the "All-Electric plus Gas Storage" scenario are calculated based on the "Electricity and Gas Infrastructure" values: The electricity demand is calculated so that it covers that electricity demand in the "Electricity and Gas Infrastructure" scenario and replaces its final gas demand; the gas demand is *calculated as the back-up capacity needed in a system where all end appliances have been electrified and the majority of electricity demand is covered by intermittent renewables.*

For renewable, low-carbon (and natural) gas costs we rely on long-run cost estimates from established studies (Figure 35).

Figure 35 Renewable, low-carbon (and natural) gas costs in 2050

Gas	€/MWh	Source and comment
Domestic synthetic (green) methane	129	Agora and Frontier study[57]. “Domestic” refers to PtG production from offshore wind in the North and Baltic Sea, using CO_2 captured from the cement industry.
Domestic green hydrogen	93	Agora and Frontier study. “Domestic” refers to PtG production from offshore wind in the North and Baltic Sea.
Imported synthetic (green) methane	111	Agora and Frontier study. “Imported” refers to imports from North Africa where the gas is produced from PV, using CO_2 from Direct Air Capture.
Imported green hydrogen	72	Agora and Frontier study. “Imported” refers to imports from North Africa where the gas is produced from PV.
Domestic biomethane (methanation or gasification)	52-80	Different studies give a range of plausible biomethane costs. While ADEME[58] assume average production costs of 80€, Ecofys[59] estimates costs of only 52€. We conservatively include 80 €/MWh in our reference scenario, and consider 52 €/MWh in a corresponding sensitivity parameter set.
Blue hydrogen	60	Price based on the “total cost of hydrogen” including production, natural gas and CCS costs in Northern Gas Networks, p. 261, converted into EUR.
Natural gas	31	Price based on the WEO forecast for gas import prices into the EU in 2040 in the 450 scenario.

Source: Agora and Frontier Economics (2018), Ecofys (2018), ADEME (2018) and Northern Gas Networks (2016)

There are different possibilities regarding the future sources of renewable gas. While in the most expensive scenario each country would produce its own synthetic methane/hydrogen (as far as possible, considering limited domestic potentials), it is also conceivable that a large amount of synthetic gas is imported from North Africa or the Middle East where they can be produced more cheaply from PV electricity. To reflect this uncertainty we consider scenarios with different shares of gas imports between 0% and 50% of total gas supply.[60]

As indicated above, we have calculated cost savings by comparing the volumes of gas and final electricity in both scenarios and calculated the production/generation costs of the differences. In doing so, we took into consideration the national potentials, such as limited space for solar PV in Belgium and substantial biogas potentials in France and Denmark and applied an individual generation/production

[57] Agora and Frontier Economics (2018).

[58] ADEME (2018).

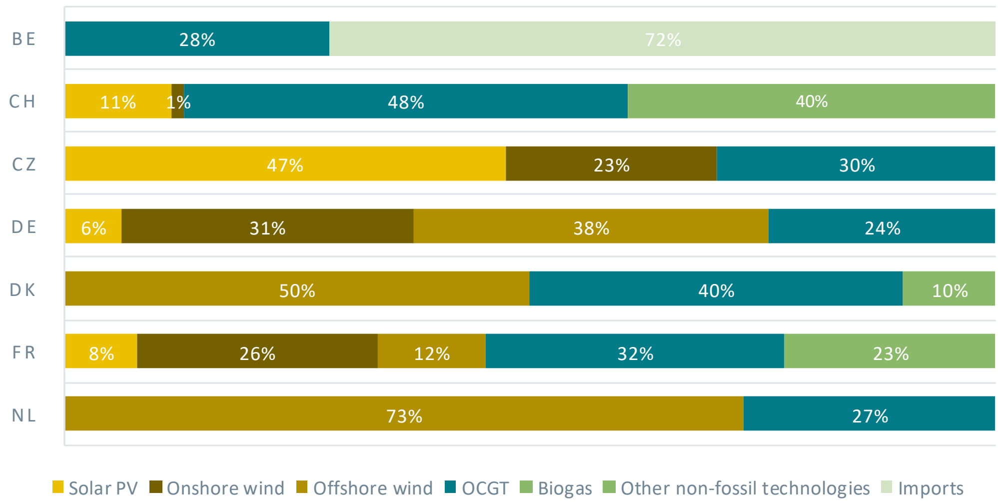
[59] Ecofys (2018).

[60] These import shares relate to "green" methane or hydrogen only. For Switzerland and Belgium the shares are higher, in line with the limited domestic production potentials and the high import share today. In the Netherlands we assume a lower maximum share of imports, which is in line with Gasunie (2018).

mix for each country.[61] Where a country (e.g. Belgium or Switzerland) is unlikely to cover the national demand with national production, we assumed that electricity as well as gas needs to be imported.

As shown for our reference scenario in Figure 36, the generation technologies used to cover the additional electricity demand in the “All-Electric plus Gas Storage” scenario vary substantially across countries. For instance, In France, additional electricity demand is covered by a combination of solar PV, onshore wind, offshore wind, OCGT and biogas. In contrast, in Belgium the only technology available to cover the delta is OCGT – the remaining electricity required to cover the additional national electricity demand has to be imported. (Belgium’s solar PV, onshore and offshore potentials are already exhausted in the “Electricity and Gas Infrastructure” scenario so that they cannot provide additional electricity in the “All-Electric plus Gas Storage” scenario.)

Figure 36 Generation technology mix to cover additional electricity demand in the “All-Electric plus Gas Storage” scenario (for simplicity displayed for one possible parameter setting only)



Source: *Frontier Economics*

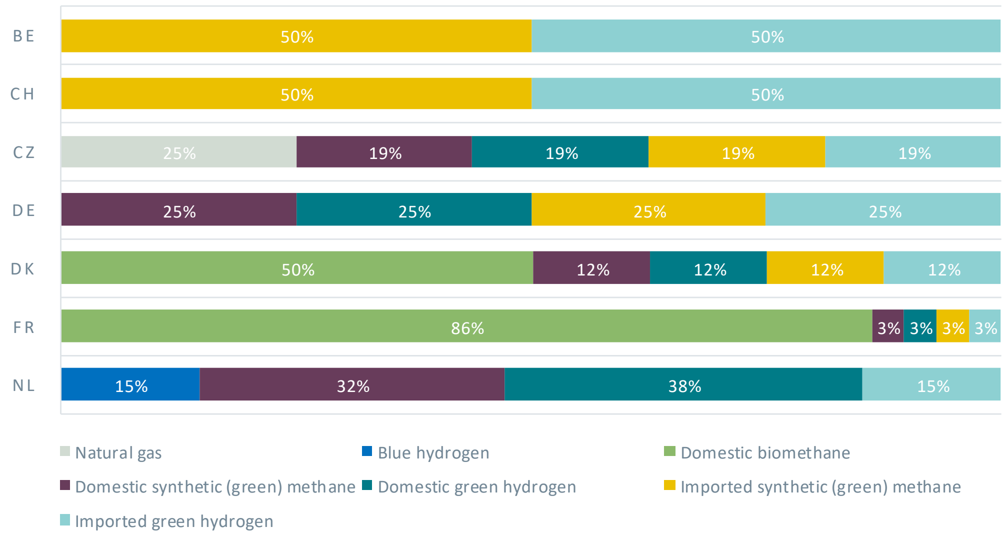
Note: *Due to rounding of the exact values the presented percentages may not add up to exactly 100%. Total quantities are displayed by country in the country annexes.*

Turning to the renewable gas side, differences between countries are even more pronounced. Germany and the Netherlands focus on synthetic methane/hydrogen from PtG in 2050, and the Netherlands also considers the import (from Norway) or domestic production of blue hydrogen. France and Denmark have large biomethane potentials that they can use to cover the additional renewable gas demand in the “Electricity and Gas Infrastructure” scenario. Belgium and Switzerland import large parts of the additional renewable gas. The Czech Republic is the only country that continues to employ natural gas because it does not yet commit to zero CO_2 emissions in 2050. However, it may well be feasible to

61 The mix is the result of a range of country-specific studies and plausibility conversations in country-specific workshops with the gas TSOs. The main studies we considered are: ELIA (2017), FTI Consulting and Compass Lexecon (2018), SFOE (2013), WSL (2017), OTE (2017), Frontier Economics et al. (2017), Energinet (2015b), ADEME (2016), ADEME (2018), Gasunie (2018).

decarbonise these quantities, converting the natural gas into blue hydrogen using CCS.

Figure 37 Gas mix to cover additional gas demand in the "Electricity and Gas Infrastructure" scenario (for simplicity displayed for one possible parameter setting only)



Source: Frontier Economics

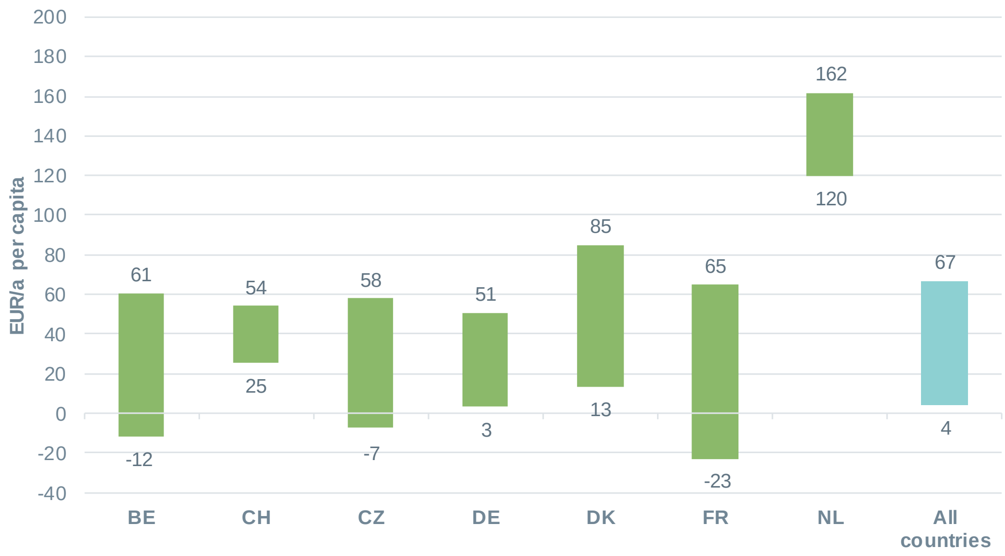
Note: Due to rounding of the exact values the presented percentages may not add up to exactly 100%. Total quantities are displayed for each country in the country annexes.

The individual demand developments and technology/renewable gas mixes generate different cost savings estimates for each country. Furthermore, most countries display a wide range of possible savings due to the uncertainties regarding renewable gas costs, import shares or demand growths until 2050 outlined above. Under extreme assumptions, for example that each country has to produce its required renewable gas itself,[62] as far as possible, electricity generation and transformation could even be more expensive in the "Electricity and Gas Infrastructure" scenario.

However, for most scenarios, generation cost savings through the continued use of gas networks can be substantial for each country, reaching up to 64 EUR per capita and year, on average. The drivers of the upper ends of the range differ across countries, while France and Denmark make the greatest savings when biomethane production costs decrease. Germany and the Czech Republic benefit strongly from being able to import renewable gas, reducing the amount of costly domestic production. The largest savings per capita can be reached in the Netherlands, where even in the "All-Electric plus Gas Storage" scenario large quantities of renewable gas would be required for seasonable storage and where additional electricity would likely be generated by expensive offshore wind and OCGT plants, while blue hydrogen could be produced cost-effectively using SMR.

[62] Note that this was the assumption in Frontier Economics et al. (2017) in Germany, where electricity generation and transformation therefore were more expensive in the "Electricity and Gas Infrastructure" scenario compared to the "All-Electric plus Gas Storage" scenario.

Figure 38 Electricity and gas generation: Annual cost savings in 2050 [in EUR per capita] of a continued use of gas networks in the countries analysed



Source: Frontier Economics/IAEW

Note: The values illustrate the annual cost savings per capita in the "Electricity and Gas Infrastructure" scenario compared to the "All-Electric plus Gas Storage" scenario.

4.3 Use of gas storage and import capacity enhances security of energy supply

Further to cost savings, the use of gas infrastructure can boost the security of energy supply in Europe, due to high energy density of gas, which allows for:

- efficient storage; and
- high transport capacities even over great (up to global) distances.

Gas storage can cover energy demand in the case of supply interruptions or situations involving extreme demand

The extremely large gas storage capacity in Europe not only allows shifting energy from summer to winter, but can also serve to cover energy demand in the case of supply shortfalls and/or extreme demand situations, for example during an extremely cold winter with high heat demand and low PV feed-in.

The gas system has historically dealt with supply security challenges based on temperature-dependent heat demand (e.g. an extreme cold snap as in a "one-in-twenty-years winter" scenario). Consequently, today's gas storage capacity in the countries analysed is sufficient to cover average gas demand for more than three months.[63] In comparison, today's total electricity storage suffices only to meet the average electricity demand for fewer than four hours.[64]

Gas network and renewable LNG infrastructure allow for diversified supply portfolio

As described in Section 3.1, Europe's gas markets are highly interconnected and large capacities also exist to import gas from outside the EU via pipelines and via liquified gas. This has economic benefits, as it allows the matching of demand in countries with low or costly gas production potentials with supply in countries with lower-cost production and lower energy demand, as described in the previous section.

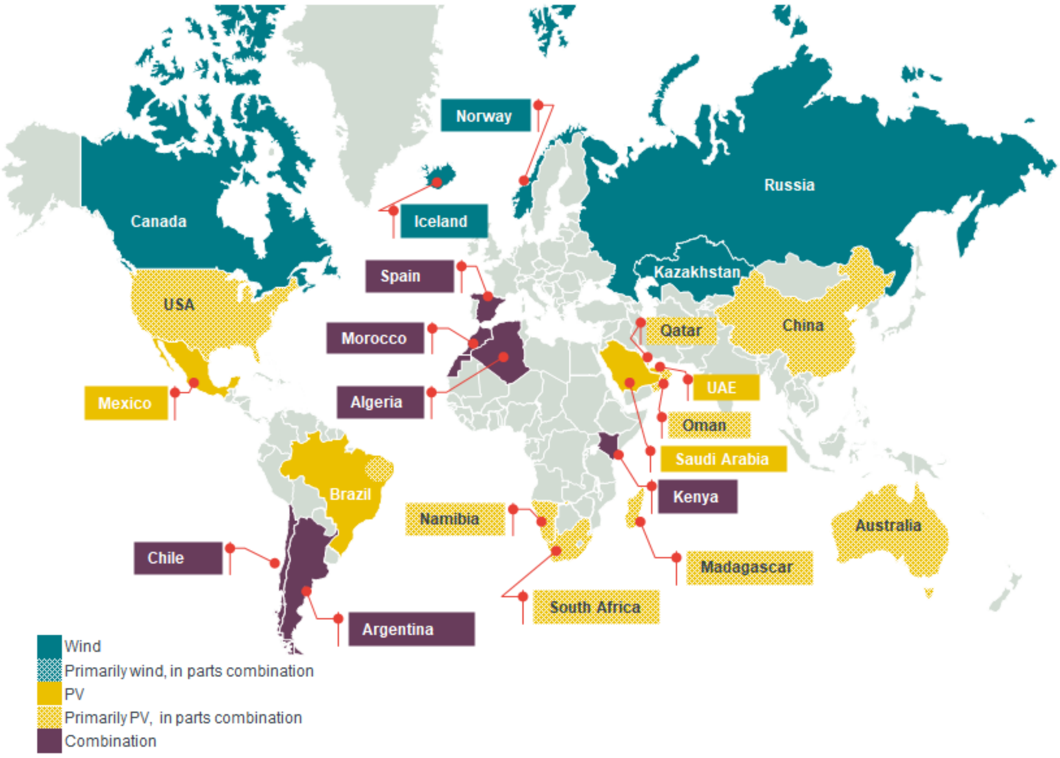
Beyond this economic benefit, the interconnectivity allows for a very diversified supply, contributing to security of energy supply in Europe. The opportunities to diversify the energy supply of renewable gas go far beyond both;

- **What an electricity-only infrastructure can deliver**, given low energy density of electricity and consequently comparably costly long-term transmission capacity; and
- **Today's diversity of natural gas supply.** While natural gas supply to the EU via pipelines is restricted to a small amount of countries – besides domestic supply (e.g. in the Netherlands or Denmark) this is mainly in Russia, Norway and North Africa – LNG has already significantly widened the portfolio of potential suppliers. However, whereas this is still restricted to countries with natural gas resources (de-facto the largest LNG supplier to Europe is Qatar), the future renewable gas supply may become even more diversified. See Figure 39 for a non-exclusive snapshot of potential power-to-gas or power-to-liquids producing countries with a focus outside of the EU.

[63] Gas storage of 550 TWh compared to yearly gas demand in these countries of 1,940 TWh (Eurostat and Swiss Federal Office of Energy).

[64] Electricity storage of 0.6 TWh compared to yearly electricity demand in these countries of 1,420 TWh (Eurostat and Swiss Federal Office of Energy).

Figure 39 Snapshot of the variety and diversity of potential PtX producing countries



Source: *Frontier Economics*

Note: *Illustrative presentation of the strongest RES potentials only; not an exclusive list of all countries.*

4.4 Use of gas infrastructure benefits public acceptance of decarbonisation

Public acceptance is a vital prerequisite underpinning the success of the energy transition towards a decarbonised economy. Equally, a lack of public acceptance, particularly with regard to the urgently required expansion of the electricity network and with regard to renewable electricity generation locations such as onshore wind parks, could quickly put an end to the energy transition. Using gas infrastructure can release the pressure here.

4.4.1 Using existing gas pipelines reduces the need to build new and unpopular electricity lines

Lack of acceptance has already prompted significant delays in network expansion

The need to significantly expand the electricity transmission network in Europe has long been known. While most people in Europe see the energy transition as very positive and support it, concrete electricity network expansion projects regularly encounter significant – and individually quite understandable – opposition in directly affected regions due to concerns about adverse environmental impacts, effects on health and economic disadvantages, especially in the case of overhead lines. Consequently, most big projects involved in the expansion of the electricity network in Europe have been significantly delayed in recent years.

In future, electrification will require even greater network expansion, and a lack of acceptance threatens to block the energy transition.

In recent years electricity TSOs in Europe have identified the need to significantly expand the electricity transmission network. This was, however, mainly the result of a shift in the electricity production structure from fossil power plants located closed to load centres towards increasing capacity of intermittent and often load-distant renewable electricity capacity.

There will, however, be an additional trigger for further network expansions on the demand side, which is not yet included in the Ten-Year-Network-Development-Plans (TYNDP) to a significant extent: Direct electrification of end-user appliances, such as electric vehicles and electric heat pumps, will increase electricity demand, particularly peak demand in winter, where heat demand is high.

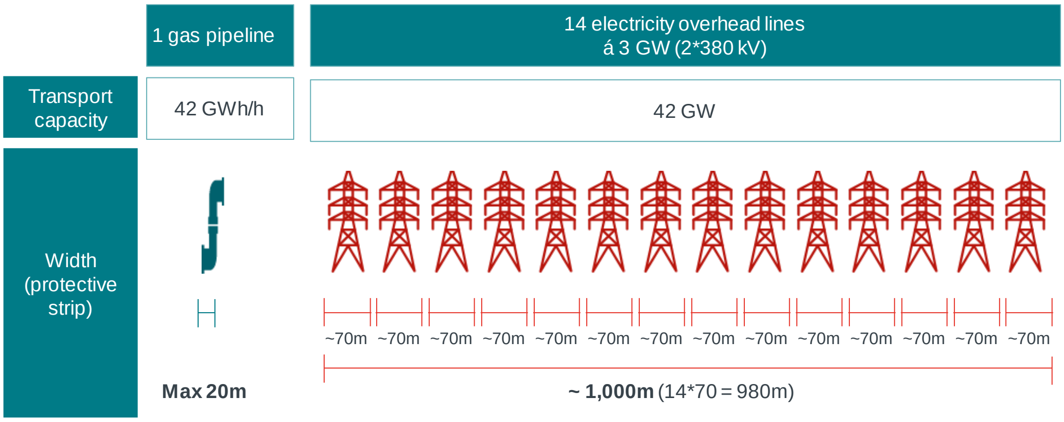
Our analysis indicates, for example, that a scenario based on direct electrification is likely to increase today's electricity peak demand by factor 3 by 2050, inducing the need for large-scale electricity network extensions, on both transmission and distribution levels.

Gas pipelines are already in the ground and can be used to transport energy in bulk without major acceptancy problems

In contrast, a comprehensive gas infrastructure that satisfies the required energy supply for heating and industrial purposes already exists. Both gas transmission and distribution networks are typically laid underground and therefore often have only limited impact on the environment and land use.

For the purpose of illustration (see Figure 40): Replacing one gas pipeline (e.g. OPAL in Eastern Germany) with a capacity of 42 GWh/h and a maximum protective strip (implying restrictions on land use) of 20 m, takes 14 overhead transmission lines with 3 GW capacity (2380 kW) with a protective strip of 70 m per transmission line. This totals almost 1,000 m of directly affected land, equivalent to 50 times the effect of a gas pipeline with the same transport capacity. This comparison does not even include the negative indirect impact through the wide visibility of overhead lines compared to the non-visibility of underground gas pipelines.

Figure 40 Space requirement of gas vs. electricity transmission



Source: Frontier Economics

Note: The gas pipeline capacity is based on the OPAL pipeline, with a transport capacity of 36 billion cubic meters gas per year (or, in energy-terms, approximately 42 GWh/h) it is north-west Europe's largest gas pipeline, see OPAL (2019). While the pipeline is laid underground and has a diameter of 1.4 m, pipelines of this size are usually assigned a "protection strip" of max. 20 m width, where land use is restricted (e.g. no buildings), see Frontier Economics and White & Case (2016).
To accommodate the same energy transport capacity, a hypothetical number of 14 overhead lines with a capacity of 3 GW each would be needed. Transmission overhead lines are typically assigned with a protection strip of 60 to 80 m, see Frontier Economics and White & Case (2016).

In an energy system based on transporting electricity in accordance with the "All-Electric plus Gas Storage" scenario, the use of pre-existing gas networks with wide public acceptance would not be required and the infrastructure would be partially physically dismantled. Instead, electricity networks which are poorly accepted by the public would need to be significantly expanded. Consequently, this situation may be increasingly difficult to achieve in terms of overcoming local resistance in the affected regions.

Alternatively, in an attempt to overcome local resistance against overhead electricity lines, these lines could be laid as underground cables, such as currently done for three high voltage direct current (HVDC) lines in Germany. This, however, increases costs by approximately factor 4 to 8 (according to German electricity TSO Amprion)[65], which bears the risk for wider societal opposition, while not even guaranteeing local acceptance because farmers fear negative impacts on their land.[66]

4.4.2 Using gas infrastructure can release pressure to find local renewable electricity generation sites

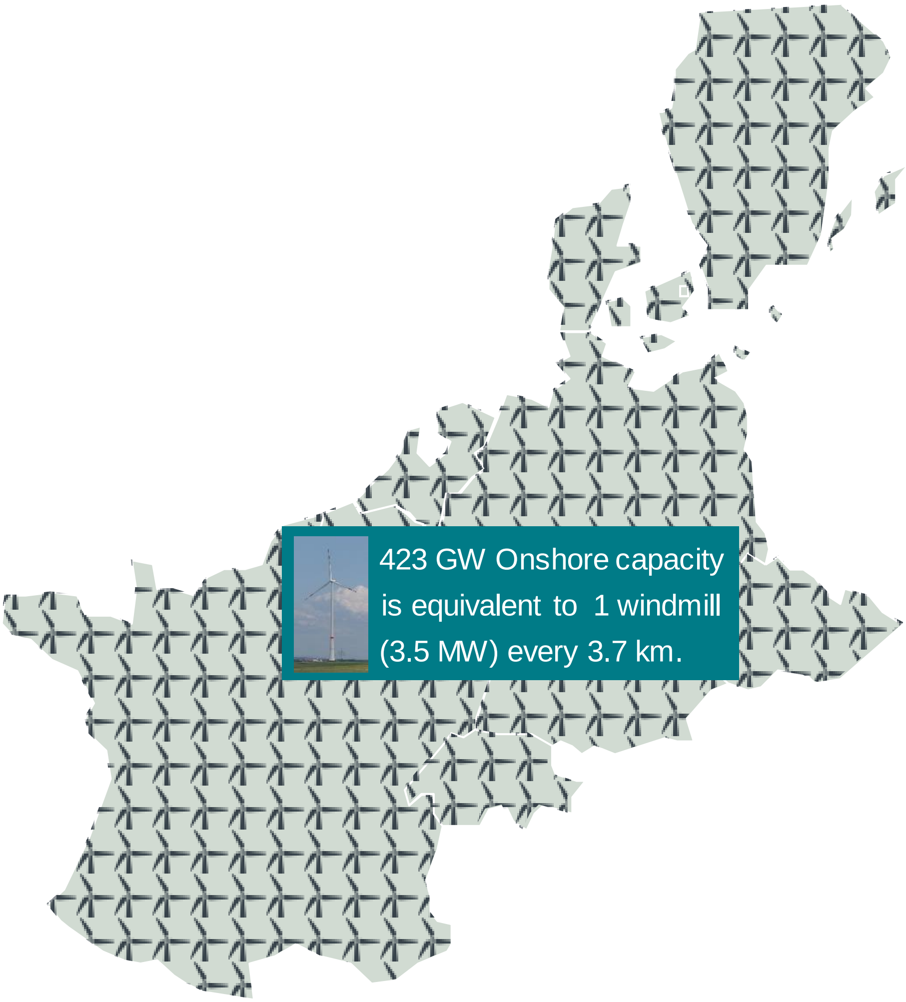
Local opposition to renewable electricity generation sites, particularly wind onshore parks, remains a growing challenge for the success of the energy transition.

Our forecast for the countries analysed suggests an increase of wind onshore generation capacity of up to 423 GW by 2050. This capacity would be equivalent to one windmill of 3.5 MW every 3.7 km.

[65] Compare Handelsblatt (2016).

[66] See for example Agrarheute (2019).

Figure 41 Schematic illustration of wind penetration for the countries analysed



Source: Frontier Economics

*Note: 121,000 windmills (423 GW/3.5 MW) in an area of 1,656,435 km^2. Assuming that each windmill is surrounded by an equally sized quadratic area (of 3.7 km * 3.7 km = 13.71 km^2)*

Maintaining gas infrastructure allows the use of sources with less local resistance:

- Domestic biomethane, as long as it is based on agricultural waste and there are no conflicts with food production;
- Imported green hydrogen or synthetic methane from power-to-gas from sources with better weather conditions and lower local impacts of renewable electricity generation (e.g. in deserted areas); and
- Imported blue hydrogen from natural gas with CCS or CCU, e.g. from Norway or Russia.

In our calculations, for instance, wind onshore capacity in the analysed countries can be reduced by more than 20% by using gas networks (i.e. in the "Electricity and Gas Infrastructure" scenario (with imports) compared to the "All-Electric plus Gas Storage" scenario).

5 POLICY CHANGE NEEDED TO ALLOW GAS INFRASTRUCTURE TO UNDERPIN DECARBONISATION

In all countries analysed in this study, gas infrastructure will have substantial societal benefits within a 2050 energy system that meets the Paris climate targets. By proposing the Clean Energy Package, the European Union has set out the basis of a solid legislative framework for the energy transition. However, the path towards a green energy system continues to be challenging and requires additional policy developments and coordination in order to reach its full potential. Hence, there is a need for swift policy adjustments where renewable gas can valuably complement renewable electricity and other renewable energy.

We identify the following major areas for policy change:

- **Keep options open** to allow for a mix of energy sources and technologies (Section 5.1);
- Create a **level playing field** for all technologies (Section 5.2);
- Consider **explicit temporary support** for renewable gas (Section 5.3);
- Clarify **role of stakeholders** regarding renewable gas (Section 5.4);
- Enable **cross-border trade** in renewable gas (Section 5.5);
- Ensure **interoperability** of (international) systems (Section 5.6).

We focus on areas on the EU policy level, while recognising that there is also need for policy change on national or regional level.

5.1 Keep options open and allow a mix of energy sources and technologies

Work to limit climate change by largely decarbonising today's major energy-consuming sectors of transport, heat, electricity and industry by 2050 is set to prove a daunting socioeconomic challenge. At the same time, of course, future developments remain uncertain, with many technologies possibly facilitating this future energy transition currently immature or even unknown. From today's perspective, we are likely to need a broad mix of different technologies and solutions to make the energy transition happen – and as proven in our analysis presented above, particularly the gas infrastructure could be a valuable, integral part of this technology mix.

> No one-size-fits-all – the suitability of various technologies will vary between regions

As already observed for the eight countries analysed in detail, the suitability of various technologies in each country will also vary regionally depending on prevailing natural conditions, consumer attitudes, public preferences and so on.

Consequently, future policy will have to promote the development of a mix of technology, both mature as well as new:

- **Keep options open, i.e. neither prescribe nor preclude options** unless absolute certainty about their future value exists. For instance, an explicit or de facto ban on gas boilers or combustion engines, as discussed or even implemented in some European countries, may have appealed as an effective means of reducing fossil energy consumption in the past. Now, however, amid emerging new options for renewable gases and liquids, precluding such technology is counterproductive and hinders efforts to achieve Paris targets efficiently. As this example shows, keeping infrastructure open has an added value that policymakers should always take into consideration.
- **Support R&D in new technologies to address technological spill-overs**. Support for technological development, innovation and deployment is key to enable renewable gases to be integrated successfully. Single developers including established market participants such as network operators may not sufficiently engage in research given the risk of failing to recoup their initial investment. However, the actual benefit to society may more than outweigh research costs, as new technological insights boost the productivity and innovative ability of other developers and firms. Accordingly, policy should at least temporarily consider supporting renewable gas development at an initial research stage to support the R&D of immature new technologies, but also at a more developed stage, supporting the development of pilot projects and demonstration plants on a larger industrial scale.
- **Allow for diverse solutions.** To facilitate the integration of new renewable gas sources, the EU regulatory framework should be as flexible as possible. While the gas infrastructure will benefit the energy transition in all countries analysed, it is unlikely that a single framework will fit all countries or regions. On the contrary, a successful energy transition requires a balanced mix of energy sources and technologies. The optimal technology mix may emerge as very region-specific, since differing regional circumstances are likely to spawn:
  - Differing infrastructure utilisation needs; and
  - Differing energy carriers transported via the grid.

  Therefore, giving all technologies in all regions a fair chance to contribute will elicit a mix of technology optimally tailored for the specific region. Analysis regarding their impact and cost-efficiency in the transition is needed to confirm objectives of affordability, sustainability, competitiveness, investment stability and supply security.

5.2 Ensure a level playing field between technologies

As well as having a fair chance to contribute to the energy transition, technologies should also play by the same rules. Therefore, it is important to ensure:

- The contribution to the energy transition is valued for each climate-neutral energy carrier,
- Energy carriers are burdened by taxes and levies fairly,

- Electricity and gas network planning takes place in an integrated way – developing sector coupling into a hybrid energy system.

We explain this in more detail below.

Value the climate-neutrality of renewable gas

Renewable gas is an option to avoid CO_2 emissions and other local pollutants (e.g. if hydrogen rather than diesel is used in vehicles) and foster the use of renewable energies.

Accordingly, renewable gas must be able to monetise these positive environmental and climate values to offset what are often higher costs than, for example, in the case of fossil fuels. Otherwise, there is a danger that negatively discriminating at the expense of renewable gas may lead to society incurring extra costs. Various areas and paths remain to be addressed in this regard, including, but not limited to:

> Renewable gas must be able to monetise its positive environmental contribution

- **Comprehensive carbon pricing to reflect climate effects –** One far-reaching option to guarantee a level playing field between energy carriers with regard to carbon emissions involves implementing a comprehensive pricing mechanism for carbon emissions, e.g. by extending the EU ETS to further sectors such as the heat or transport sector. Assuming an appropriate monitoring mechanism that reflects the carbon emission of energy use, this would ensure that the avoidance of CO_2 emissions by using renewable gas (e.g. compared to oil products or natural gas) can be monetarised by reducing the need to buy carbon certificates. Obviously, this would mean answering a number of open questions, such as who would be committed to provide carbon certificates (e.g. up- vs. mid- vs. downstream) or how to allocate certificates for these new sectors and in which volumes. Another option to price carbon is a tax on energy consumption that reflects the carbon intensity associated with this use. Like an extension of the EU ETS, further research is required to analyse the effects of such a tax solution, including distributional effects that are to be expected.
- **Define climate targets for end consumer sectors with total emissions of an end appliance throughout the entire supply chain in mind.** In other words, emissions should be taken into account from the generation of an energy carrier to the disposal of the end consumer appliance. Two examples illustrate the need to implement the lifetime emission view:
    1. **Renewable gas as a factor in building codes**: Currently, building codes often treat electricity-based heating devices as climate-neutral, even though the electricity may be generated from fossil resources. Conversely, gas appliances like gas boilers are not regarded as climate-neutral, even if renewable gas is used. To account for the correct value to the energy transition, regulation should allow for renewable gas usage to contribute to emission targets in building codes.

2. **Renewable gas as an option to achieve car fleet targets** – Fleet targets incentivise efforts to tackle carbon emissions in the transport sector. However, as it stands, they adopt only a “tank-to-wheel” perspective and fail to examine the whole value chain from “well-to-wheel”. In other words, fleet targets fail to account for the differing carbon intensities of the fuels used, triggering the following regulatory failure:
   - An electric vehicle counts as climate-neutral within a fleet, even if the electricity was generated from 100% coal and generated CO_2 emissions.
   - In contrast, a car with a gas combustion engine driven by 100% renewable gas, e.g. synthetic methane, is categorised as emitting CO_2 emissions of natural gas, despite the fact that the CO_2 emitted from the engine was extracted from the environment beforehand, thereby generating a climate-neutral gas.

Accordingly, to account for the correct impact on the environment, fleet targets should not only take emissions from “tank-to-wheel” into account but rather “well-to-wheel” (cf. textbox below), which would ensure the validation and certification of renewable gas and support market development.

RENEWABLE GAS AS AN OPTION TO FULFIL CO_2 EMISSION TARGETS OF CAR FLEETS

Directive 2009/33/EC defines targets for the average CO_2 emissions for new fleets of the car manufacturers (OEM). Until 2020, the emissions target is 130 g CO_2/km, while from 2021 onwards, regulations become more stringent:

- The emission target is reduced to 95g CO_2/km;
- with a penalty of 95 €/g CO_2 in excess of the target.

The targets must be achieved by technological car-specific improvements (for example more efficient combustion engines) or modifications regarding the composition of the new car fleet (e.g. electric cars or more compact cars).

In the directive, the use of renewable fuels is not included as an option to reduce average car fleet emissions. However, the willingness to pay for renewable fuels of OEMs can be substantial and penalties for OEMs can easily amount to 600 €/t CO_2.

High penalties mean OEMs are more than ready to pay for CO_2-avoidance technologies. Integrating renewable PtX fuels into the directive and crediting PtX against the target for average fleet emissions would represent an important opportunity to scale up the market for PtX products. Furthermore, integrating PtX into OEM regulations would create a level playing field with other CO_2 abatement options for cars (such as costly technological fine-tuning of engines).[67]

- **Establish certificates of origin that account for the green value of gas:** All the above-mentioned options require a monitoring system that tracks the origin and the CO_2 impact of gas used for final consumption; hence the need to

[67] In this section, we explain various options to integrated PtX into sector-specific climate policy regulations. However, if PtX is integrated into various regulations, it is important to eliminate double counting of credits against targets or take the same into account when defining quotas.

develop a system of certificates of origin, allowing renewable and low-carbon gases as renewable (or low-carbon) energy and thus helping those producing and consuming renewable gas to monetise its green value. Denmark, France and Switzerland have already established certificates of origin for biomethane,[68] with others set to follow suit.[69] For green hydrogen/synthetic methane, two sources need to be certified:

- The renewable electricity share is important when converting to synthetic hydrogen or methane: A reliable mechanism to account for the share of renewable electricity is also needed – particularly if a PtG converter is not placed next to the renewable electricity source but connected to the public electricity grid.
- The CO_2 storage/source for synthetic gas generation needs to reliably preclude green washing. In the long term, the role of synthetic methane mainly depends on the availability of CCS/CCU or DAC technologies, and further assessment is necessary to show the potential of these technologies in Europe. More specifically, CO_2 storage operators must properly make up the balance of their CO_2:
  - Blue hydrogen can only count as low-carbon gas if either the CCS ensures infinite storage of CO_2 or the CCU regards the CO_2 as a fossil source in future usage, i.e. positive CO_2 emissions.
  - Similarly, synthetic methane can only count as a renewable gas if its CO_2 comes from negative emissions.

Adjust levies, charges and taxes to reflect societal benefits

Synthetic (green) methane and green hydrogen (i.e. gas produced from renewable electricity) will potentially constitute a significant share of renewable gas, and contribute to system benefits such as reducing the need for transporting electricity. With this in mind, facilitating a conversion of energy carriers is crucial.

[68] See e.g. for Denmark Energinet (2018a) and for Switzerland DETEC (2015).

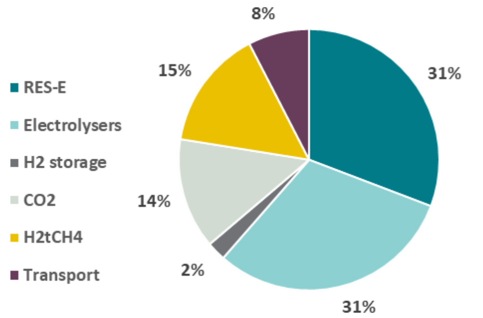
[69] See the CertifHy project as an example for a cross-country initiative to design and trial a certificates of origin scheme for green hydrogen, http://www.certifhy.eu/.

At present, taxes and levies, i.e. non-generation and non-grid components, constitute 2/3 of the average EU retail electricity bill.[70]

Electricity costs are the main cost driver for PtG, amounting to more than 30% for synthetic methane (see Figure 42). The share is even higher for green hydrogen as power is here the only cost-relevant ingredient.

As current regulations dictate that PtG facilities are treated as final end consumers in most countries, PtG facilities bear significant extra costs in the form of taxes and levies. This does not necessarily reflect the system benefits of PtG, such as reduced electricity network expansion requirements, or reduced curtailment of RES. Likewise, the current practice in most countries means that PtG facilities are burdened with renewable levies that are financing the production of renewable electricity.

Figure 42 Electricity is the main cost driver for PtG (example $PtCH_4$)



Source: Agora and Frontier Economics (2018)[71]

Accordingly, further research is necessary to evaluate which tax and levy burden is appropriate. One option would be to focus on taxes and levies on actual end energy consumption rather than pure electricity input into conversion processes.

Integrated planning of electricity and gas networks

Integrated network planning of electricity and gas networks is essential to prevent inefficient bias towards single network types. Rather than viewing electricity and gas networks as competing sectors, they should be understood as interacting systems that should be more closely interlinked for mutual optimisation. Therefore, regulatory means should be used to consolidate and support a coordinated and integrated planning approach to gas and electricity networks.

5.3 Consider explicit support for renewable gas

Renewable gas suppliers have to make capital-intensive investments in conversion capacities and storage and transport infrastructure, which means they require a favourable investment environment and positive prospects for future business models. However, renewable gas technologies, such as biomethane upgrading, electrolysis, CCS or CCU are today produced on a comparatively low scale, implying relatively high investment and thus gas generation costs. Policy could therefore help ensure market build-up and economies of scale through **temporary**

[70] See Eurelectric (2017).

[71] All cost shares (in %) and absolute figures (ct/kWh) are rounded and associated with the following scenario: North Africa, reference scenario 2030, PV-Wind-combination, CO_2 from DAC, 6% Weighted average cost of capital.

production and investment support to generate scale effects. Possibilities include:

- **Renewable gas targets**. In Denmark, for example, 7% of gas demand is covered by biomethane and the 2019 target is 10%. France also targets 10% renewable gas consumption by 2030. To actually create demand for renewable gas and thus revenues for renewable gas producers to generate cost-digression effects though upscaling, a renewable gas target could be enforced, for example, by a quota system or an explicit tendering mechanism, analogously to quota or premium models for renewable electricity.
- **Priority dispatch for renewable gas** through national legislation. Priority dispatch would also facilitate injections of renewable gas into the grid.

5.4 Clarify the role and remuneration of stakeholders regarding renewable gases

Sector coupling into a hybrid energy system and integration requires the rights and obligations of relevant stakeholders to be redefined. In particular, there is a need to challenge the established distinction between “market” and “infrastructure” when it comes to creating new technologies and business models:

- **Electricity and gas sector coupling requires the (re)definition of infrastructure operators:** While the third energy package focussed on unbundling and generating competition in competitive submarkets, currently arising opportunities in “new” sector-coupling technologies such as PtG require EU policy to (re-)think stakeholder roles with regard to electricity-based gases as well as renewable gases in general. Today, considerable market uncertainty persists, for instance, as to who is eligible to own and operate storage and conversion facilities such as PtG plants – only merchant players, or gas network operators and/or electricity network operators as well? Such uncertainty can create substantial investment barriers, which may hinder crucial contributions required to underpin the success of the energy transition.

  There is also a need to regulate the new roles and assess constraints due to unbundling rules.
- **Sector integration calls for clarification of the roles for operating CNG, LNG or hydrogen filling stations**: Some countries envisage that gasoline and diesel in the transport sector will be increasingly substituted for natural gas and later also renewable gas. In France, for example, a specific policy measure aims to reduce GHG emissions by increasing the use of natural gas and expanding the scope to use more renewable gas (biomethane and hydrogen) as fuel. To facilitate this development, there is a need to clarify who is eligible to operate CNG, LNG or hydrogen filling stations for the transport sector and who carries responsibility to meet obligations.
- **Sector coupling will change the way the gas infrastructure cost is allocated and requires efficient gas tariff setting**: Efficient tariff setting needs to be compatible with future gas infrastructure. Specifically, the tariff needs to avoid anti-competitive effects on renewable gas, e.g. through burdening costs for stranded assets to renewable gas. Even in a renewable

gas scenario, the utilisation of some infrastructure assets will decrease in energy terms, e.g. because of

- Changes in transport routes (with renewable gas allowing new sources to be tapped – rendering routes to fossil gas sources partly obsolete);
- Efficiency gains in end-user appliances; or not least
- Changes in the density of energy carriers (e.g. hydrogen vs. methane).

If the energy demanded per gas consumer decreases but network operating costs remain unchanged, increased tariffs might undermine the competitiveness of renewable gas. Accordingly, tariffs should be adjusted to reflect true costs, e.g. by differentiating between variable and fixed cost components more strictly.

5.5 Enable cross-border trade in renewable gas

Transportability in bulk over long distances is a key advantage of renewable gas over electricity. [72] This also provides unique opportunities to bridge geographic gaps between supply and demand, e.g. due to the uneven distribution of renewable energy sources within Europe. Countries should therefore strive to foster international trade cooperation, given the benefits of international renewable gas trade that should be recognised by both the public and policy makers alike:

> Gas as energy carrier provides unique opportunities to bridge geographic gaps between supply and demand

- **Cross-border opportunities** could result from the different starting positions of countries – transportation of green energy and blending options with natural gas can help bridge differences between countries and allow streamlined use of renewable gas potential within Europe.
- **Cheaper imports** are likely to emerge from lower input costs for renewable gas generation abroad in the medium term and will render renewable gas more competitive relative to fossil fuels.
- **Easing pressure on domestic wind and solar locations**, particularly in countries with less favourable renewable conditions, will boost acceptance of the energy transition.
- **The feasibility of international renewable gas trade and its benefits over the course of future decades** could be demonstrated by large-scale renewable gas pilot projects, including renewable power production, conversion plants and transport of renewable gas to Europe.

[72] A market for renewable gas requires a monitoring system that tracks the origin and the CO_2 impact of gas used for final consumption; hence the need to develop a system of certificates of origin, see also Section 5.2

5.6 Ensure systems remain interoperable

Gas systems are likely to vary between regions, and given the diversity of renewable gas options and their heterogeneous distribution within Europe, the differences in the gas system might even intensify in a renewable gas world. While only two different gas qualities exist in Europe today (L and H gas), in future we will see systems being run on a mix of natural gas, biomethane, hydrogen and various blends. This underlines the importance – not least because of the cross-border trade benefits as highlighted in the previous section – to keep the gas systems interoperable as far as possible. To interoperate smoothly, the following actions are required:

- Establish a **gas quality standardisation** to accommodate multiple gas sources. At the same time interoperability of different networks should be permitted through converters. Harmonised certificates of origin, possibly including not only environmental but also social standards, allowing cross-border trade in renewable gas as they increase acceptance of international renewable gas production and trade by minimum standards and certification.

> While only two different gas qualities exist in Europe today, the future will see systems run on a diverse mix of various gases

- Introducing a **binding international sustainability regulation to boost acceptance of international renewable gas products**: To ensure the acceptance of renewable gas products in an international market, producers and suppliers must ensure certain standards for producing and distributing renewable gases. These pre-defined standards aim to ensure the acceptance of renewable gas imports in the consumer countries – a crucial element to ensure international trades may evolve and blossom.
- **Harmonise key characteristics of EU support schemes** to prevent inefficient funding due to a range of support system set-ups in European countries. For instance, domestic renewable gas, which is traded nationally, could be hindered if imported renewable gases not only receive support in the destination country but also in the country of origin. To illustrate, in Sweden biogas producers suffer from distorted competition from imported biogas since renewable gas producers receive policy support in some countries. In Sweden, however, support policies target the consumption side, resulting in dual support of imported biogas relative to domestic gas.

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ANNEX A DETAILS ON SOURCES FOR RENEWABLE AND LOW-CARBON GASES

In this Annex we provide more details on our analysis of potential sources for renewable and low carbon gases in the following order:

I. **Biomethane** as a natural renewable gas,

II. **Green hydrogen or synthetic (green) methane** from electrolysis on the basis of renewable electricity (power-to-gas);

III. **"Blue hydrogen"**, that is natural gas decarbonised by CCS or CCU;

IV. **Natural gas**, to substitute dirtier fossil energy sources such as oil or coal in the transition to a full switch to renewable or low-carbon gases.

I. Biomethane

A number of different gases sourced from biological materials are included in the definition of "biogases". In this report, where the value of gas transport, storage and distribution infrastructure is highlighted, we focus on biomethane. Biomethane is a carbon neutral gas produced from biological sources, with a composition and properties resembling those of natural gas. This also means biomethane can be fed into existing gas infrastructure just like natural gas.

Two main technologies to produce biomethane

There are two main technologies to produce biomethane:[73]

- **Anaerobic digestion (AD)** is currently the most common production method of biogas, which can be upgraded to biomethane; and
- **Thermal gasification** of biomass represents another opportunity to generate biomethane. Thermal gasification is at an earlier development stage than AD, but can operate on larger scale and the ability to process dry as well as wet feedstock means greater volumes of sustainable feedstocks than AD can be produced.

Anaerobic digestion with biogas upgrading

Producing biomethane via AD involves a two-step approach:

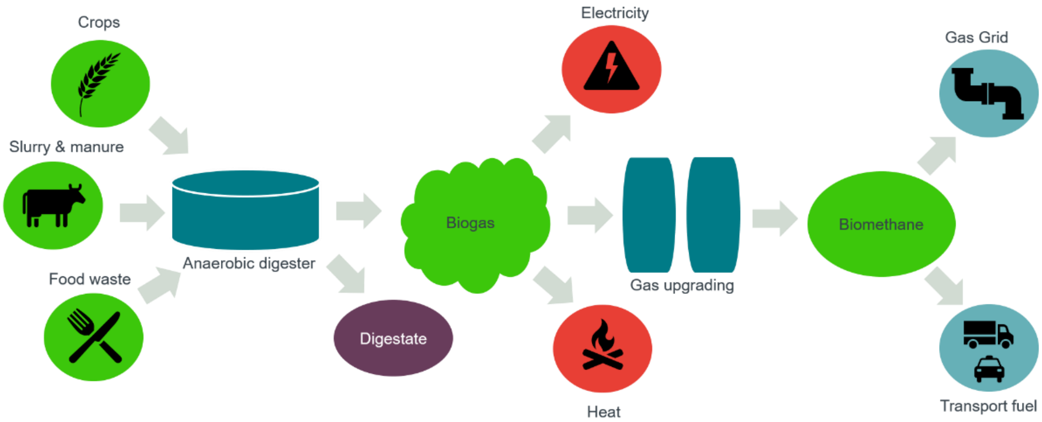
- **Annual digestion** is a biological process which involves the breakdown and fermentation of organic matter by micro-organisms in the absence of oxygen. Various feedstocks can be used to produce biogas through AD, including organic matter from agriculture (farm animal excretions, crop residues, intermediary crops, grass), industry (by-products and waste from food-processing), sludge from urban sewage processing plants and household and

[73] This description of biomethane generation technologies is based, inter alia, on ADEME (2018), E3G (2018), Ecofys (2018), Environmental and Energy Institute (2017), IRENA (2017b) and Policy Connect (2018).

food waste. The resulting product is biogas, which comprises mainly methane (~60%) and carbon dioxide (~40%). This biogas can be used on site to generate heat and/or electricity.

- **Upgrading** – Instead of being used on-site (i.e. usually in rural areas without significant energy demands), biogas can be upgraded or "purified" to biomethane. Upgrading biogas requires specialised facilities, where carbon dioxide and various trace elements are removed and the methane content is increased to approximately 97% methane by volume. The resulting biomethane is then sufficiently close to the properties of fossil-derived natural gas, allowing it to be injected into the gas grid and transported and distributed to load centres to be used interchangeably with natural gas, e.g. to heat buildings or fuel combustion engine vehicles.

Figure 43 Illustration of biomethane production via anaerobic digestion and upgrading



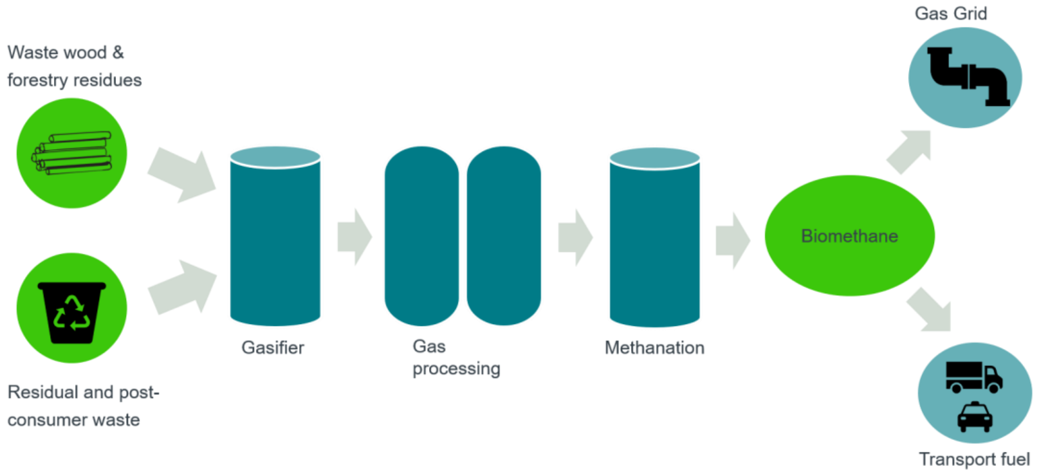
Source: Frontier Economics, based on, inter alia, Ecofys (2018), Environmental and Energy Institute (2017) and Policy Connect (2018).

Thermal gasification

An alternative route to biomethane production is via thermal gasification. Gasification is a thermo-chemical process that converts solid biomass feedstock such as wood and waste into biomethane in what is basically a three-step process:

- **Gasification** – In a gasifier, the biomass is reacted at high temperatures (>700 °C), with a controlled amount of oxygen and/or steam, then converted into a mixture of carbon monoxide, hydrogen and carbon dioxide, called syngas.
- **Gas processing** – The syngas is successively cooled and cleaned to remove pollutants such as sulphur and chlorides.
- **Methanation** – To produce biomethane, with thermodynamic properties equivalent to those of natural gas, the process can be completed by adding carbon dioxide, which may come, for example, from biomethane production in AD facilities or from industrial processes.

Figure 44 Illustration of biomethane production via anaerobic digestion and upgrading



Source: Frontier Economics, based on, inter alia, Ecofys (2018) and Policy Connect (2018).

To distinguish it from AD-derived biomethane, the product of the thermo-chemical route is generally referred to as bio-synthetic or bio-substitute natural gas (bio-SNG). Nevertheless, it can be injected into the existing gas grid in a manner equivalent to AD-derived biomethane and natural gas.

Unlike AD with methanation, thermal gasification is at a comparably early development stage, with mainly only pilot plants implemented and explored across Europe. However, market observers expect substantial technological development in future years, alongside significant cost reductions and higher penetration (see Section 'Biomethane future potentials' below).

Biomethane is climate-neutral

As it is the case with natural gas, when biomethane is combusted, CO_2 is released into the atmosphere, unless it is captured. Since the chemical composition of biomethane is nearly equivalent to that of natural gas, the CO_2 emissions per kWh of gas combusted follow suit.

However, unlike natural gas or other fossil fuels, where the carbon has been stored underground over millions of years before being released at the time it is burned, the carbon in biomethane comes from plant matter having captured atmospheric CO_2 via photosynthesis over its (relatively short) lifetime. Or, where methanation is applied and CO_2 from industrial processes is used – for example when methanising syngas to bio-SNG – the CO_2 would have been emitted anyway, so this "second use" of the CO_2 leaves greenhouse gas emissions unchanged.

Accordingly, biomethane production is widely viewed as carbon neutral and does not add to greenhouse gas emissions.

However, it is essential that thorough and consistent monitoring and accounting methods are being applied to reflect the climate impact along the value chain. For instance, where CO_2 from fossil-fuelled industrial processes is captured and used for methanation, it is important that this "second use" of CO_2 is counted as carbon neutral only once: For the resulting biomethane to be counted as carbon neutral, the industrial process needs to be treated as fossil to avoid double-counting CO_2 reductions and the resulting risks to achieve climate targets.

Biomethane today

Today, the focus is on biogas generation for electricity production

Biogas has been exploited for energy usage for decades and of the technologies mentioned above, AD is by far the most mature. All over the EU-28 (plus Switzerland), there are more than 17,000 biogas plants,[74] which produced more than 190 TWh of biogas in 2016.[75]

The largest biogas producer in Europe is Germany (with approx. 95 TWh or 50% of annual biogas production in EU-28 plus Switzerland), followed by the United Kingdom (16%), Italy (11%), France (5%) and the Czech Republic (4%). The biogas generation share of the other countries analysed is around 2% for the Netherlands, 1% each for Belgium, Denmark and Sweden and 0.5% for Switzerland.[76]

More than 90% of the biogas in Europe is used for on-site electricity production.[77] In 2016 the installed electricity generation capacity of biogas in Europe totalled 9,985 MW, having produced more than 62 TWh of electricity in 2016.[78]

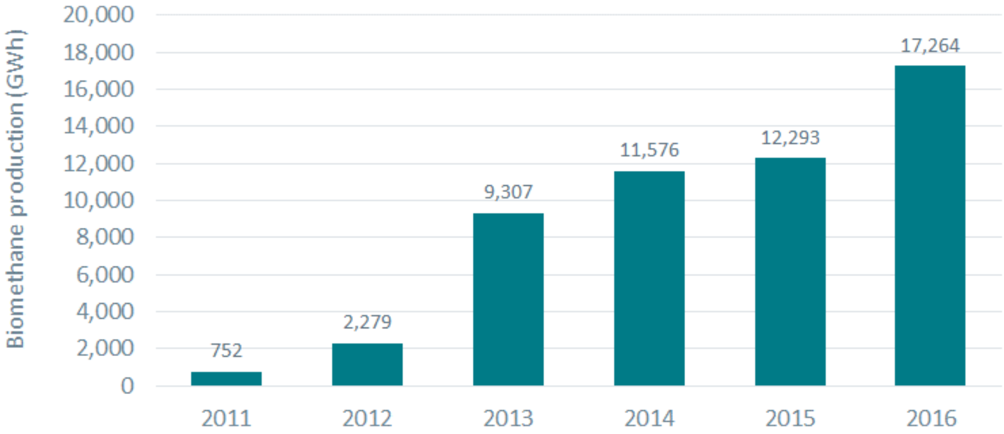
Biomethane generation is still in its infancy, but growing quickly

The biomethane industry in Europe is still in its infancy:

The technology of **biogas upgrading** is well-established, with five different upgrading technologies applied in Europe (pressure swing adsorption, water scrubbing, physical absorption, chemical absorption and membrane separation).[79] However, it remains comparably new: Up to a couple of years ago, biomethane production in Europe remained very limited, but recent years have seen it soar: While in 2011, fewer than 200 plants produced less than 0.8 TWh of biomethane, there are now around 500 plants in the EU, having produced more than 17 TWh of biomethane in 2016 (Figure 45). Accordingly, biomethane production in biogas plants with upgrading has boosted more than 20-fold in only five years.

[74] See European Biogas Association (2017).
[75] See Eurostat.
[76] See Eurostat.
[77] See IRENA (2017b).
[78] See European Biogas Association (2017).
[79] See European Biogas Association (2017).

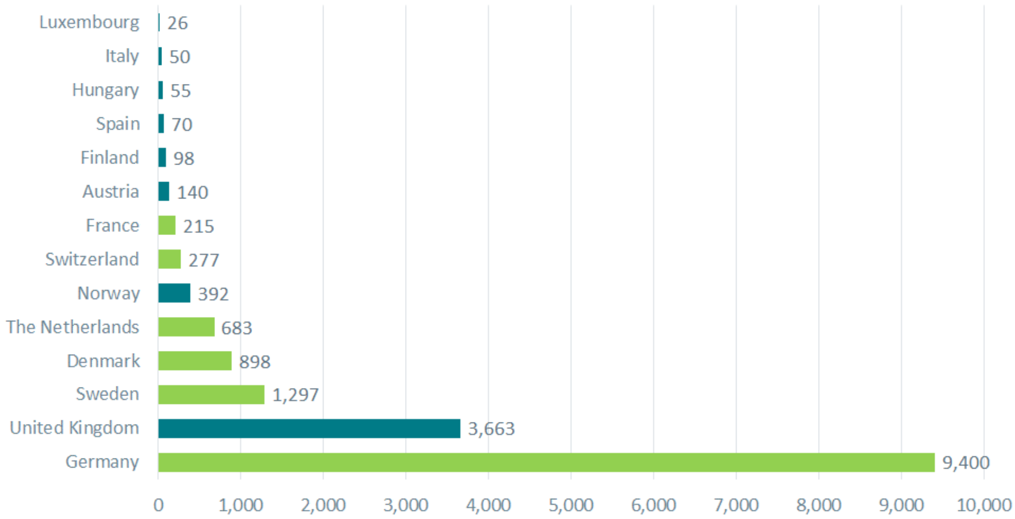
Figure 45 Evolution of biomethane production in Europe (GWh)



Source: Frontier Economics based on European Biogas Association (2017).

There are multiple reasons behind this growth in biomethane production: Changes in national legal frameworks that have corrected the bias towards using biogas for electricity generation (e.g. Germany), growing efforts made by single countries (e.g. France, having increased its biomethane production from 3 GWh in 2011 to 215 GWh in 2016) and the intensified use of biomethane as fuel for transport (e.g. Sweden, where more 88% of biomethane production was used as a fuel in 2016).[80]

Figure 46 Biomethane production in European countries in 2016 (GWh)



Source: Frontier Economics based on data in European Biogas Association (2017).

Biomethane future potentials

Today many of the AD plants used to produce biogas rely heavily on energy crops as feedstock. Based on estimates of the European Biogas Association (2017), for example, 39% of the feedstock in the biogas industry in Europe in 2016 was comprised of energy crops, while another 39% was agricultural residues and the

[80] See European Biogas Association (2017).

residual 22% sewage, industrial food and beverage waste, bio- or municipal waste or other feedstock.

A long-running and contentious debate exists over how sustainable and socially acceptable different sources of bioenergy are, centring on the conflict between agricultural land use for energy crops versus food production.

However, several potential sources for further biomethane production exist without conflicting with food production purposes, including, for instance:

- **Upgrading of biogas** – As set out above, today more than 90% of biogas generated in Europe is used for on-site electricity production, despite the recently observed trend to increasingly upgrade biogas to biomethane. If this persists, substantially more biomethane can be produced and injected into the grid to heat homes or fuel vehicles, while eliminating the need for additional feedstock. The extent to which this is economic, of course, depends on various factors, including transport costs, which are either incurred by transporting biomass from dispersed farms to larger biomethane or gasification plants or by transporting biomethane from smaller plants to the nearest gas distribution network.
- **Increased use of waste** – While some countries are already using most of their agricultural or industry disposal, others retain substantial potential to increase biogas production, even if no energy crops are used. This will be facilitated if and when the technology of thermal gasification matures further, as this allows for feedstock use across the board, even “wet” feedstock that is more difficult to use in AD.
- **Sequential crops** – There is also the opportunity to apply maize silage and triticale produced as sequential crops. These are produced as an additional (second) crop before or after harvesting the main crop on the same agricultural land. Advocates of this technology present it as an innovative and sustainable farming practice, which boosts the agricultural productivity of existing farmland without any negative environmental impacts or any direct or indirect land use change effects. It may even spawn co-benefits such as decreasing soil erosion risks or negative carbon emissions. Ecofys (2018) estimates that these sequential crops will be the single largest contributing biomass for biomethane in 2050.
- **Imports of biomethane** – As well as domestic potential, the existing gas infrastructure allows for imports of biomethane from countries with even better geographical conditions, such as Ukraine or Belarus, which are also effectively connected to the European gas grid via existing import pipelines. Additional imports could be facilitated by transporting biomethane as LNG (bio-LNG) from other sources with favourable conditions around the globe.

A quantitative assessment of the technical and economic potential of biomethane production is beyond the scope of this study. However, previous research has estimated technical biomethane potential in the EU of up to nearly 250 bcm/year (equivalent to approx. 2,500 TWh).[81] This suggests that there is quite substantial

[81] See for estimates of biomethane production potential for example Ecofys (2018) [98 bcm], Institute for Energy and Environment (2007) [151–246 bcm] or Lambert, M. (2017), p. 8 [150 to 250 bcm].

potential for further growth in biomethane production compared to today's less than 2 bcm (17 TWh) in Europe.

Differences between countries

When analysing the countries in focus in this study, different views emerge on the future of biomethane in these countries:

- **Large biogas and biomethane growth potentials in Denmark, France and Sweden**: In some countries domestic biomethane production is likely to play a key role in decarbonising gas supply, for example in Denmark, France and Sweden. One key driver here is the availability of farmlands and woods, which is naturally higher in these countries with comparably low population density. As an indicator, today's biogas production in MWh per square kilometre is 59 in Denmark, 14 in France and only 5 in Sweden. However, the limited penetration of the natural gas pipeline infrastructure in Sweden means biogas will likely either be used for decentralised generation of electricity and heat, or as transport fuel.
- **Limited biogas growth potentials, but potential for more biomethane production in Belgium, the Czech Republic, Germany, the Netherlands and Switzerland**: Other, more densely populated countries such as Belgium, the Czech Republic or the Netherlands already exploit a significant portion of their available feedstock for biogas production: Biogas production equals 86 MWh/km^2 in Belgium and 89 MWh/ km^2 in the Czech Republic and Netherlands. The same applies to Germany, by far the biggest biogas and biomethane producer today, already producing 264 MWh/km^2 of biogas. Accordingly, these countries have limited growth potentials for further sustainable biogas production. Similarly, although only producing 23 MWh biogas per km^2 today, Switzerland has limited potential for (economic) additional biogas generation; given its mountainous landscape. In all of these countries, however, the option for further biomethane upgrading exists, a trend which we have already observed in recent years.

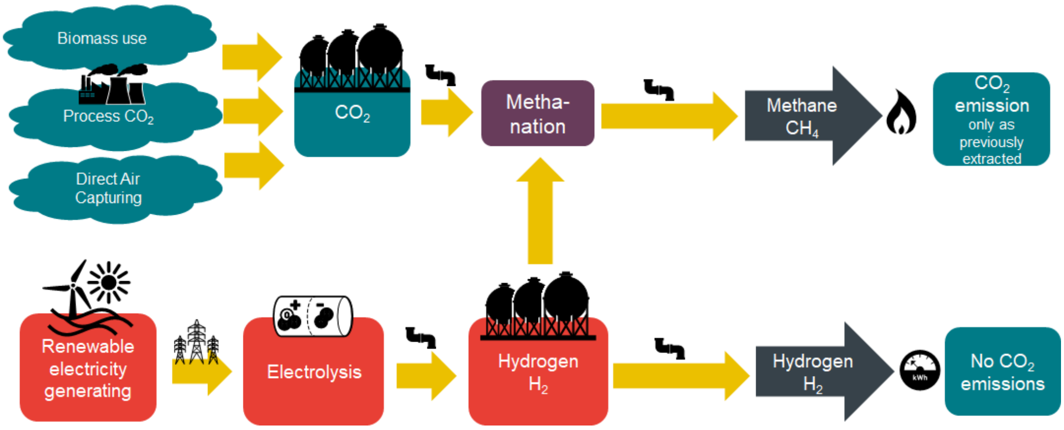
II. Power-to-gas

Another opportunity to generate renewable gas is to convert renewable electricity into gas via electrolysis ("power-to-gas", PtG). While power-to-gas is associated with additional energy conversion and hence energy losses, this offers the opportunity to integrate intermittent wind and solar power and thus provide substantial societal benefits, for instance by avoiding costly and unpopular electricity network extensions and providing storage opportunities.

The basis of power-to-gas is electrolysis, where electricity is used to split water into hydrogen and oxygen. There are two basic pathways of power-to-gas (see Figure 47), which we describe in more detail below:

- **Power-to-hydrogen (PtH_2)**; and
- **Power-to-methane ($PtCH_4$)**.

Figure 47 Schematic overview of power-to-hydrogen and power-to-methane processes



Source: Frontier Economics

Power-to-hydrogen

The first product of electrolysis is hydrogen. This is often called “green hydrogen”, if the electricity source is renewable. This is the case either if it is located on-site of a renewable generation facility such as a wind park, or, in case it uses electricity from the public electricity grid if the underlying electricity mix is 100% renewable (which will increasingly be the case if we assume a decarbonisation by 2050). Hydrogen can be directly used, e.g. to supply industrial process that require hydrogen, in transport, for heating or for electricity generation (either via fuel cell technologies that produce decentralised electricity or via combustion):

- **Hydrogen transport**: Hydrogen can be transported via pipelines, just like natural gas. Since its chemical composition differs from that of natural gas, there are limits to the extent to which hydrogen can be transported in existing gas pipelines. Besides the question of compatibility with the specifications of end-user appliances (see below), there is also the risk of leakage due to hydrogen having smaller molecules than methane. While most gas TSOs consider their transmission pipelines (that are usually steel) to be hydrogen-ready (after adjustment of compressors), some gas distribution networks are not likely to be hydrogen-ready and may need an upgrading to transport substantial degrees of hydrogen. It is worth mentioning that “town gas”, which was supplied to end customers in many (urban) distribution networks in Europe, particularly in the 1960s and 1970s (and still is in some areas of the world, e.g. Hong Kong), comprises around 50% of hydrogen.[82]

- **Hydrogen storage**: Like in the case of transport, hydrogen can be stored like natural gas. While this is comparably easy and tested in salt caverns that prevent smaller hydrogen molecules from leaking, the extent to which depleted oil and gas reservoirs can store hydrogen remains unclear. Hence, there is need for further research and testing, as is currently done by German coal mining corporation RAG in the Underground Sun Storage project in Austria.[83]

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[82] See Towngas (2018).

[83] See Underground Sun Storage (2018).

- **Hydrogen in end-use**: Hydrogen can be used in various appliances and is required as an input to many major industrial processes, mainly in the chemical and refinery industry, which use primarily “grey hydrogen” today. Hydrogen can also be used for power generation, heating or transport, where the fuel cell technology paves the way for high efficiency although further research and cost digression are needed. Hydrogen combustion, meanwhile, is a mature technology but less efficient. Existing end appliances such as combustion engines (that use mostly compressed natural gas (CNG) today) and gas boilers can, in principle, also function on hydrogen, but require at least a change in settings, which limits hydrogen blending within current gas distribution grids.

Looking ahead, plenty of opportunities exist to integrate hydrogen into the energy landscape, with three potential routes:

- **Hydrogen blending –** One potential route to integrate hydrogen is by blending it in within the existing gas grid. Although the above-mentioned pipeline, storage and end-user restrictions impose a physical limit on the possible hydrogen share in existing infrastructure, uncertainty remains as to where this limit actually is. Accordingly, considerable research and discussions are underway to get to the bottom of this. In national legislation and standards, today’s maximal hydrogen blending share ranges from 0 to 10% (by volume).
- **Parallel infrastructures** – When hydrogen volumes increase (even only locally) beyond the maximal blending shares, one option involves having parallel infrastructures for methane and hydrogen. For instance, existing high-pressure natural gas pipelines could be converted to 100% hydrogen pipelines. Logical first candidates for such a conversion are pipelines that are currently transporting low-caloric gas, that are likely to be less and less utilised over the forthcoming years because the generation of low-caloric gas in the Netherlands will be phased out by 2030. Such pure hydrogen pipelines would enable the transport of hydrogen from large-scale production facilities to large industrial sites or central hubs (from where it may be further distributed by truck). While this would require some investments in new compressors on the transmission grid level, it may eliminate the need to invest in the distribution grid and for end-use equipment to make them hydrogen-ready, as end appliances such as residential heating would still be supplied by methane. Nevertheless, this would complicate the nature of the gas infrastructure.
- **Full conversion of infrastructure to hydrogen within entire regions** – Another option to facilitate large-scale hydrogen generation and utilization involves converting the existing infrastructure within entire regions to hydrogen as a whole. An example is the concept underpinning the “H21 North of England” (H21 NoE) project. In this project, the three partners Equinor, Cadent and Northern Gas Networks are developing a detailed engineering solution to convert entire gas networks across the north of England, including Leeds (to which this project was initially limited), Liverpool, Manchester and Newcastle, to hydrogen between 2028 and 2034. Current forecasts suggest the main source for hydrogen will be blue hydrogen produced from either SMR or ATR with CCS.[84]

[84] See Northern Gas Networks (2018).

It is beyond the scope of this study to assess these routes, so further research should be conducted.

Power-to-methane

Alternatively, hydrogen can be converted with an external CO or CO_2 source to CH_4 via methanation. The resulting CH_4 is often called synthetic methane or substitute natural gas (SNG), reflecting that it is of the same composition as natural gas. The main advantage of this additional conversion is that synthetic methane is **compatible with the current gas infrastructure**: It can be injected into the gas grid interchangeably with natural gas and also be stored in existing gas storage facilities. Likewise, there is **no need for adjustment of end appliances** such as gas heating systems.

However, there are also a few disadvantages of this additional conversion

- Methanation **requires additional investment**, (higher capital costs) and **further energy conversion losses** (of around 15 to 20%).
- Methanation also **requires a source for carbon.** This carbon could be taken from biomass (e.g. as a waste product of anaerobic digestion in biogas generation), from unavoidable CO_2 emissions in industrial processes ("second use" of waste product, see discussion in Section I of this Annex on biomethane), or from direct air capture (DAC).
- Unlike Hydrogen, **synthetic methane cannot be used in fuel cells**, that may provide a very efficient decentral conversion to electricity and are of particular relevance for the transport sector (see Section III).

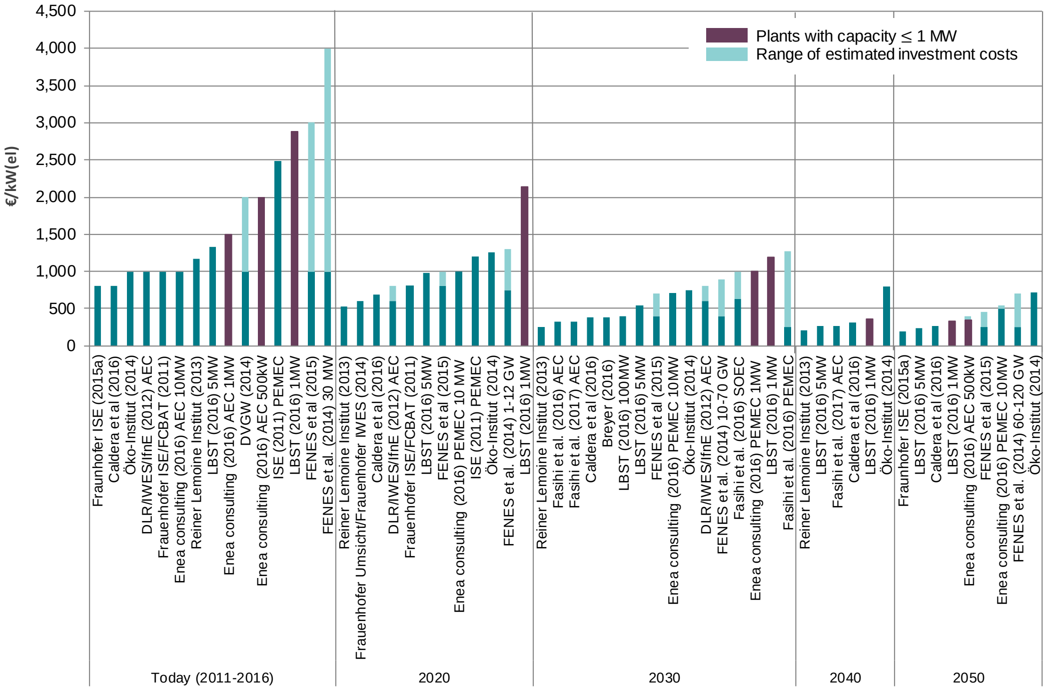
Whether one or the other power-to-gas pathway will prevail in the future remains unclear. In our country analyses we observed very different views on this question. In Germany, for instance, the public debate has been focussing on synthetic methane for quite a while (however, the hydrogen path is recently gaining momentum), while the Netherlands is very focussed on hydrogen (as are the UK). In many other countries, key stakeholders have not yet formed a clear view on this question. Further research and trialling will be needed to explore both pathways further and inform the political debate.

Power-to-gas is still costly, but significant cost reductions expected with large-scale production

Although electrolysis is, in principle, a long-tested and mature process (which has been used e.g. in the copper industry for decades), hydrogen electrolysis is still in its infancy. One of the world's largest operating hydrogen electrolysis plant, located in Mainz, Germany, has an electric capacity of 6 MW. Accordingly, costs are still comparably high.

This is, however, likely to change once production of electrolysers, particularly polymer electrolyte membrane (PEM) electrolysers, will be implemented on industrial mass-scale. Sector experts expect costs to decrease substantially (see Figure 48).

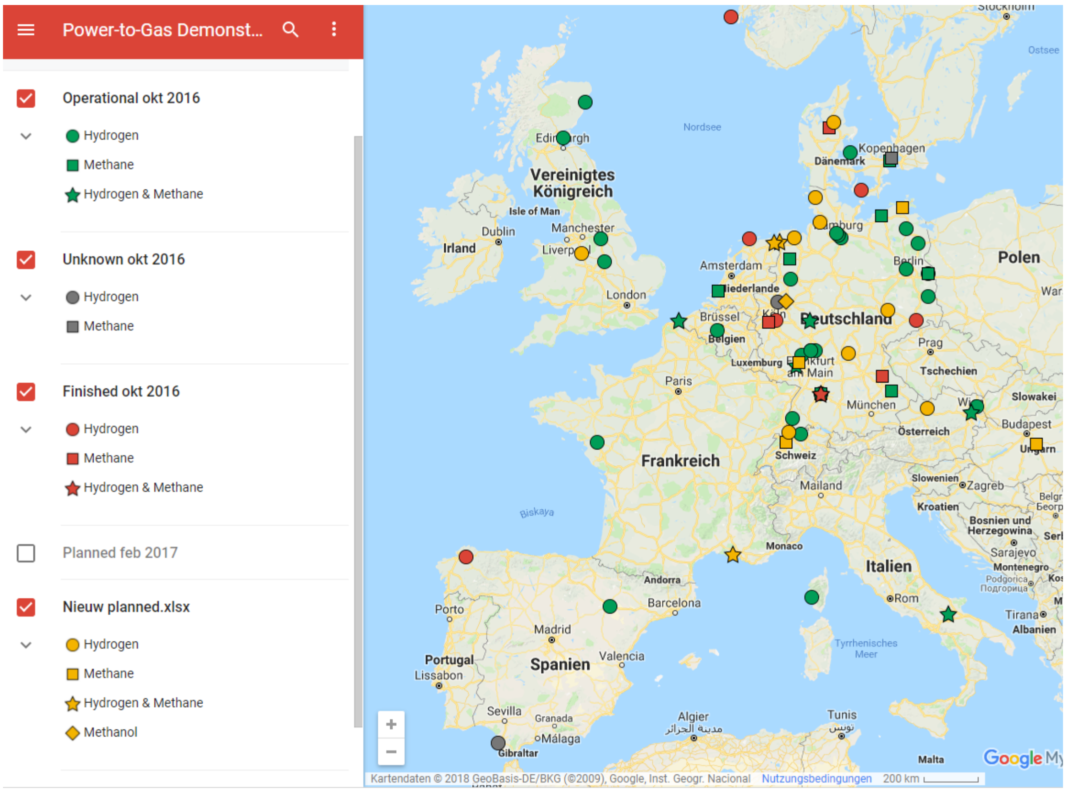
Figure 48 Overview of studies that address investment costs for hydrogen electrolysis



Source: Agora and Frontier Economics (2018)

Currently, there are many pilot projects ongoing or announced all over Europe, with a focal point in Germany (see Figure 49).

Figure 49 Overview of power-to-gas (demonstration) projects in Europe



Source: http://europeanpowertogas.com/projects-in-europe/

Further, large PtG pilot projects with an electrical capacity of 10 to 100 MW have been recently announced, suggesting cost reduction when electrolysis will going to be produced on an industrial scale:

- Shell and ITM Power plan to start operation of its 10 MW PEM-electrolyser in 2020;[85]
- German electricity TSO Amprion and German gas TSO Open Grid Europe are planning to invest into electrolysis with a capacity of 50-100 MW;[86]
- Electricity TSO TenneT and gas TSOs Gasunie and Thyssengas are planning to build a 100-MW power-to-gas plant in Lower Saxony, Germany;[87]
- A Dutch/Danish consortium of TenneT, Gasunie, Energinet and Port of Rotterdam is considering to build an artificial island in the North Sea (North Sea Wind Offshore Power Hub) to accommodate wind offshore capacity of up to 100 GW, and is analysing whether offshore power-to-hydrogen conversion should sensibly be part of this.[88]

III. “Blue hydrogen”

The process of converting natural gas to hydrogen has been well-established for decades, with around half the hydrogen used around the globe today (mainly in the chemical industry and refineries) produced by steam methane reforming (SMR).[89] This is a process that reacts natural gas with steam at high temperatures to generate hydrogen, releasing carbon dioxide as a by-product.

Like hydrogen produced from other fossil fuels (mainly by partial oxidation of oil or coal gasification), hydrogen from SMR is often referred to as “grey hydrogen”, reflecting how the CO_2 by-product is released into the atmosphere.

Technological options to prevent this CO_2 from being released into the atmosphere do, however, exist: Carbon capture and storage (CCS) or carbon capture and utilization (CCU). The resulting hydrogen is often called “blue hydrogen”, reflecting the fact that it is not grey (given that no or only a little CO_2 is emitted), but not green (i.e. based on renewable energy) either. In this study, we use the term “blue hydrogen” for simplicity.

Two main technologies to produce “blue hydrogen”

There are two main technologies to produce blue hydrogen (Figure 50):[90]

- **Steam methane reforming (SMR) with carbon capture and storage (CCS)**.
  - SMR is a mature production process, in which high-temperature steam (700 – 1000 °C) is used to produce H_2 from a methane (CH_4) source; mostly natural gas. SMR is a large chemical process and operates in units on a

[85] See Green Car Congress (2018).

[86] See Clean Energy Wire CLEW (2018).

[87] See TenneT (2018).

[88] See TenneT (2017).

[89] See Policy Connect (2018).

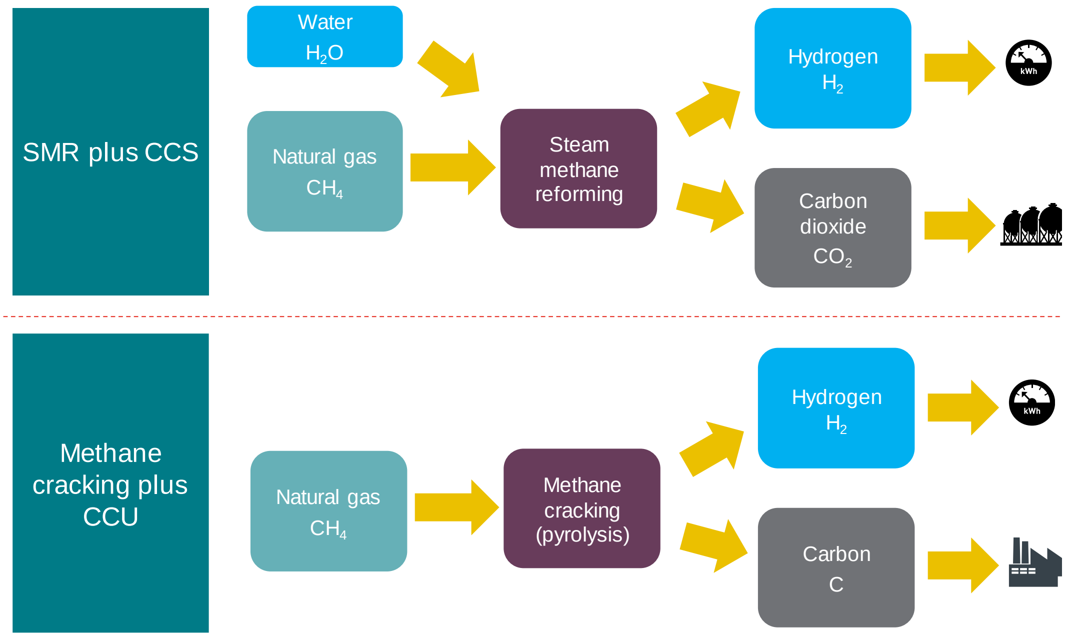
[90] This description of SMR and methane cracking is based, inter alia, on Policy Connect (2018), Argonne and PNNL (2017).

scale of 150-250 MW, or even larger (up to 500 MW, when used to produce methanol).[91]

- To generate carbon savings, it is essential to incorporate CCS into the process and a range of technical options exist to capture CO_2 from SMR (or ATR). Although none have been tested on a large scale, considerable research and numerous pilot projects are underway. Equinor, a Norwegian major energy company (former Statoil), is exploring the potential for SMR/ATR with CCS on a very large scale.

- **Methane cracking (also called pyrolysis) with carbon capture and utilization (CCU)**.
  - Another recently developed option for blue hydrogen production technology involves the thermal decomposition of natural gas into carbon (C) and hydrogen (H_2) in an endothermic reaction. This takes place in low-temperature, non-equilibrium plasma that is exposed to high pressure in a small reactor.
  - The lack of contact with oxygen sees the process form a stream of pure hydrogen, with carbon dropping out as a solid instead of escaping into the air as CO_2. This solid carbon can then be used as a commodity for non-energy industrial appliances.
  - This technology remains in the test phase. In August 2018, Gazprom reported at a conference in Berlin that they were heavily investing in this technology and trialling it in the Siberian town of Tomsk.[92]

Figure 50 Schematic overview of main technologies used to produce blue hydrogen



Source: Frontier Economics

[91] Please note that there is a variation on SMR called autothermal reforming (ATR), where methane and steam are combusted in the presence of oxygen to produce hydrogen. See Policy Connect (2018) for a comparison of SMR and ATR.

[92] See Bloomberg (2018a).

Climate impact of blue hydrogen

While blue hydrogen is often referred to as “climate-neutral”, the concrete climate impact depends on the actual degree to which CO_2 is captured and stored: Today, SMR with CCS has a carbon footprint of around 30-40 g CO2-eq/kWh, compared to 180-230 g CO2-eq/kWh of natural gas.[93] Further research, testing and monitoring of the CO_2 intensity of this process is needed. There is also a need to prove that CO_2 storage is possible without the risk of gas ultimately being released into the atmosphere, which is likely to mean that subsea storage remains the most secure option.

For methane cracking, there are no CO_2 emissions as the carbon is captured as a solid and used in industry. The final greenhouse gas impact ultimately depends on where this carbon is used/reused and finally disposed of.

Similarly to biomethane, assessing the climate impact of blue hydrogen production fairly requires the implementation of a thorough and consistent monitoring, accounting and certification process.

Potentials and infrastructure for blue hydrogen

The theoretical potential for blue hydrogen production remains great, given the enormous remaining natural gas resources (e.g. in Norway or Russia, but also elsewhere in the world).

The use of blue hydrogen poses some infrastructure challenges requiring further research that would go beyond the scope of this study:

- **CO_2 transport**: A SMR/ATR-based process that includes CCS requires the transport of CO_2, which can be transported by pipeline or ship. Whereas transport by ship is better for smaller quantities and greater distances, pipeline transport is the preferred choice for larger quantities and shorter distances. If the carbon-capture process were to be located far from the available storage sources (which are basically depleted fields and mostly offshore), CO_2 transport infrastructure would have to be constructed.
- **CO_2 storage**: Storing CO_2 involves injecting it into geological formations in the subsurface, at depths of one kilometre or more. Geological formations that are suitable for CO_2 storage comprise porous layers allowing CO_2 to move and spread out within the formation as well as one or more solid rocks resting on top like a cap and barrier, thus preventing CO_2 from leaking out.[94] In Europe and elsewhere, large depleted oil and gas fields capable of accommodating CO_2 exist. Under the Norwegian continental shelf, for example, large reservoirs at great depths exist; providing suitable pressure and temperature conditions while preventing the CO_2 from migrating up through the layers of rock and sand towards the seabed.[95] CCS remains in a test phase though and further research and large-scale testing is required.

[93] See Policy Connect (2018).

[94] See Gassnova (2018).

[95] See Norskpetroleum (2018).

IV. Comparably low carbon-intensive natural gas helps to reduce carbon emissions in the short and medium turn

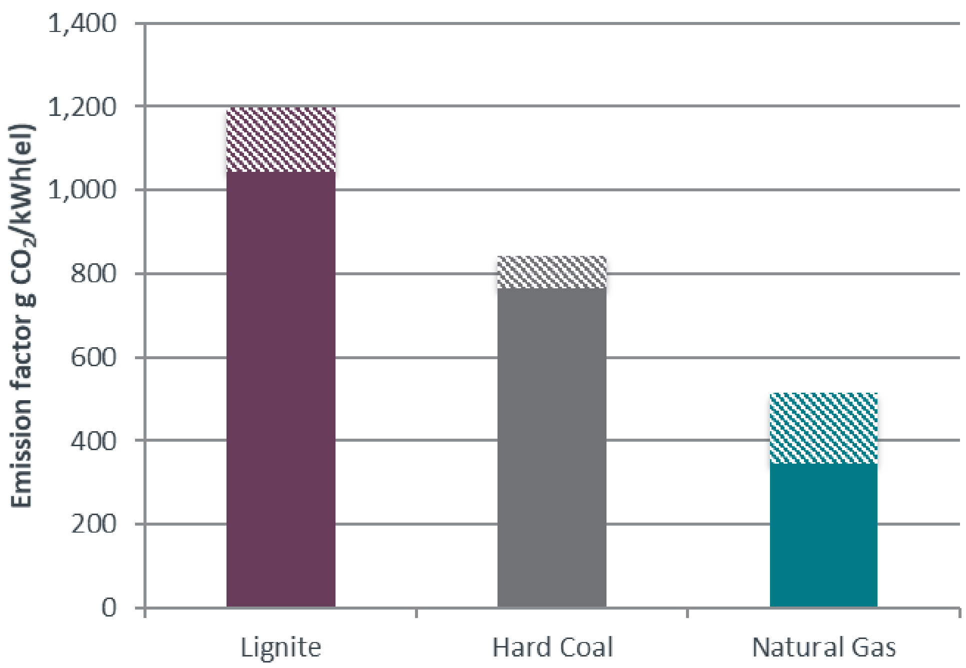
In 2016, 38% of final energy demand in the countries analysed was supplied by petroleum products, another 4% by solid fossil fuels such as lignite and coal (see Annex B). 23% of final energy demand has been supplied by natural gas.

Whereas natural gas is, of course, a fossil fuel that eventually will need to disappear from the energy mix, it could nonetheless constitute a “bridge” from the current still fossil-dominated world to a long-term zero emissions future.

A key advantage of natural gas over other fossils is its comparably low carbon intensity: 1 kWh of natural gas contains around 200g CO_2, compared to 340 g CO_2 for hard coal, and 400 g CO_2 for lignite.[96]

Accordingly, a fuel switch from these sources to natural gas may, in some regions and sectors, be a comparably cost-effective way to reduce CO_2 emissions in the transition towards a zero emission world in the long-term. Figure 51 reveals the substantially lower specific CO_2 emissions of electricity generation by natural gas compared to lignite or hard coal, Figure 52 provides a similar comparison for heat generation.

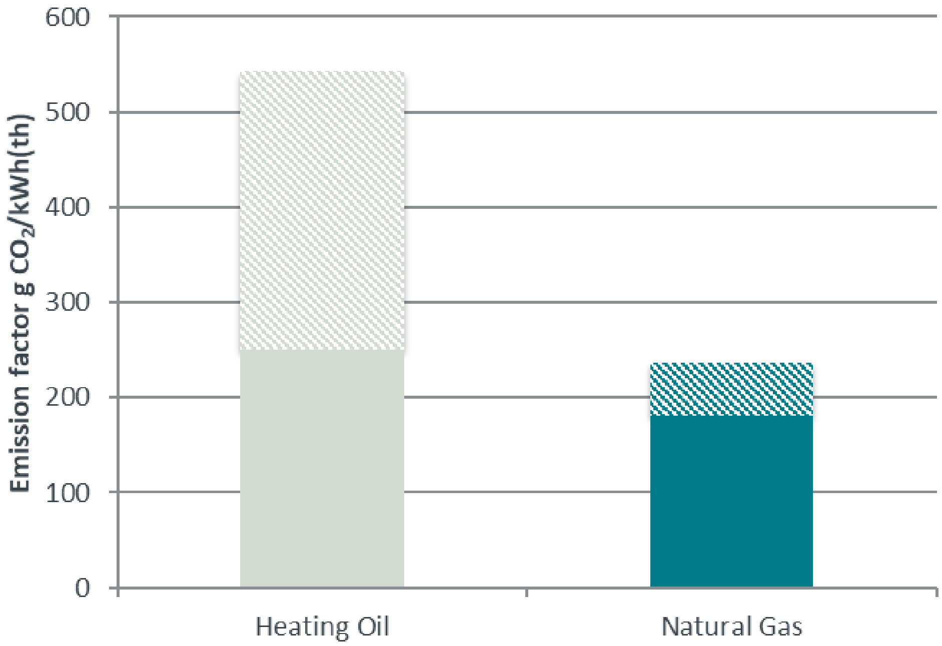
Figure 51 Emission factors for electricity generation by lignite, hard coal and natural gas [g CO_2 / kWh(el)]



Source: Frontier Economics based on UBA (2018) and ranges for typical fuel efficiency of power plants

[96] See UBA (2018).

Figure 52 Emission factors for heat generation by heating oil and natural gas [g CO_2 / kWh(th)]



Source: Frontier Economics based on UBA (2016b) and ranges for typical fuel efficiency of heating

The duration of this "transition" period, within which natural gas can contribute to CO_2 emission reduction, will differ between countries, as it depends on a range of factors, for example:

- **The fuel mix today**: In a country which already generates high shares of energy with renewables, such as Sweden based on its hydro and biomass reservoirs, a significant increase in natural gas consumption may be less sensible. In a country that is still dominated by lignite, coal and oil consumption a switch to natural gas is an opportunity for comparably easy CO_2 emission savings, and also a bridge to the use of renewable and low-carbon gases in the longer-term future. This could be of particular relevance for the Czech Republic or other Central and Eastern European countries.
- **The climate policy ambition**: The EU climate protection ambitions range from 80 to 95% CO_2 emission reductions by 2050 as compared to 1990. While the 95% vision would not allow for significant natural gas shares in 2050 (and thus would require a quicker transition to renewables), natural gas is likely to be a key energy source in an 80% vision. Again, we expect differences between the national ambitions of various countries, reflecting a number of drivers such as different economic conditions, different starting points (see fuel mix above) or different preferences and attitudes of inhabitants.

ANNEX B DETAILS ON THE POTENTIAL USE OF RENEWABLE AND LOW-CARBON GASES IN DEMAND SECTORS

In this section we provide details on the potential contribution of renewable and low-carbon gas to decarbonising energy demand and feedstock in Europe. We look at:

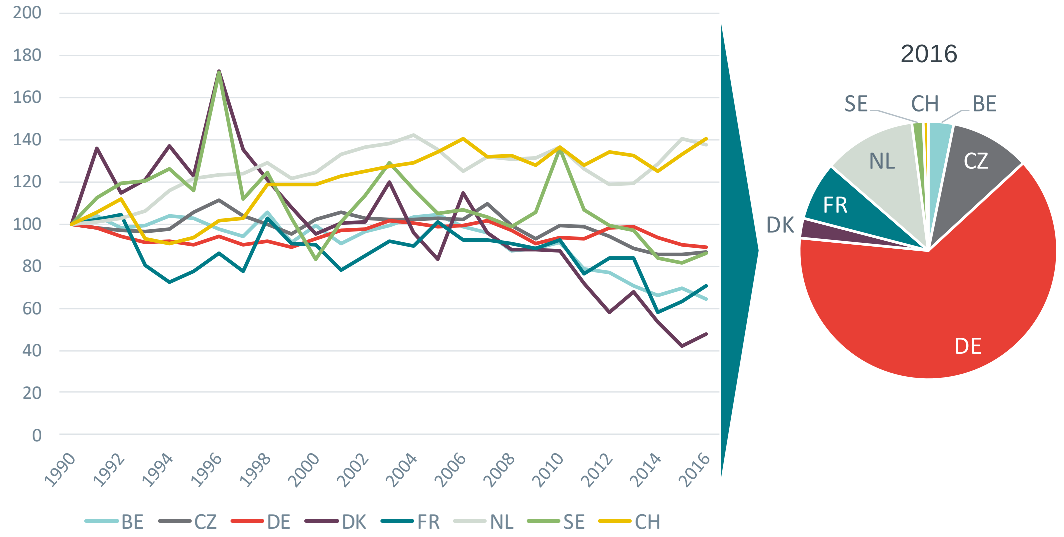
- Gas for reliable electricity production;
- Gas in heating;
- Gas in transport; and
- Gas for the industry.

I. Gas-fired electricity needed as reliable back-up for intermittent renewables in the absence of coal and nuclear power in many countries

Electricity generation sector is the second largest greenhouse gas emitter

The electricity sector is responsible for almost 480 Mio. t CO_2-eq. per year, 25% of total emissions, and thereby is the second largest emitter in the countries analysed after the transport sector, with Germany being by far the largest emitting country with its high share of lignite and hard coal production. Since 1990, electricity generation has decreased greenhouse gas emissions by nearly 70 Mio. t CO_2-eq. (Figure 53), driven mainly by higher renewable shares in Belgium, Denmark, France and Germany, while emissions in the Netherlands and Switzerland even increased.

Figure 53 Electricity generation: Only slightly decreased GHG emissions since 1990



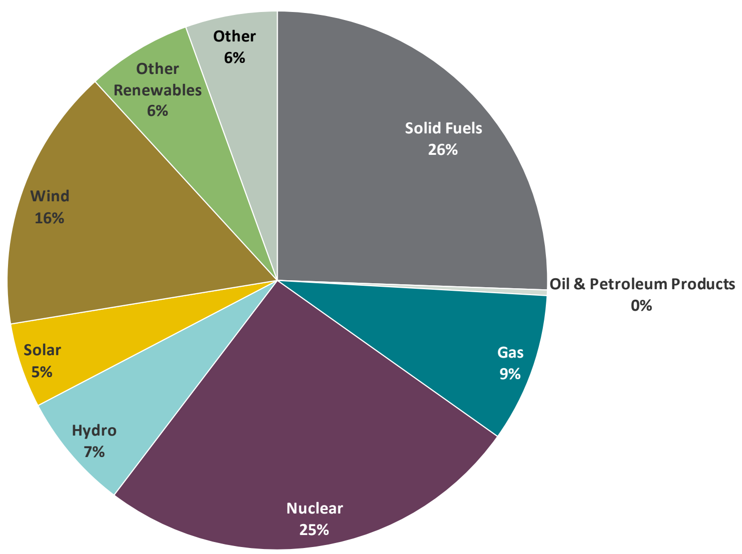
Source: Frontier Economics based on EEA

Note: Emissions depicted as index with 1990 as base year

To decarbonise electricity generation, today's dominating fossil fuels will need to be replaced

In order to decrease greenhouse gas emissions, the fossil resources used to produce electricity need to be replaced by renewables. Currently 40% of electricity in the countries analysed is generated from fossil resources. Thereof, coal, which emits most emissions per given energy unit, accounts for the largest share (26%) (Figure 54).

Figure 54 Electricity generation mix in the countries analysed



Source: Entsoe Transparency Platform (2018)

On a country level, the share of fossil-generated electricity varies due to different shares of renewables and nuclear power:

- Germany, the Czech Republic and the Netherlands have the highest share of fossil-generated electricity (more than 50%), followed by Denmark and Belgium with 31% and 27%, respectively. In the Netherlands, 67% of electricity production is based on gas.
- France and even more so Sweden and Switzerland have a very low share of fossil resources and at the same time the highest nuclear shares, namely 73%, 41%, 54%, respectively – together with Belgium (49%).
- Renewable electricity generation is particularly pronounced in Denmark (71%) with 50% wind, Sweden (54%) with 42% hydro, Switzerland (46%) with 44% hydro, and Germany (38%) with high penetration of wind and solar energy.

Efforts to increase the renewable share in the energy mix will have to be strengthened in order to reduce the significant emissions from fossil resources.

At the same time, many countries phase out nuclear power

At the same time, many national governments are forcing a phase-out of nuclear power generation for safety reasons (see country annexes for more details):

- **Belgium** committed to a nuclear phase-out by 2025. The Belgian nuclear power plants Tihange und Doel have made headlines because of their malfunctions for some years.
- **Denmark** does not have nuclear power production and is not planning to build any nuclear plants.
- **France** will reduce its nuclear share in power mix from 75% today to 50% by 2035. The error-prone nuclear power plant Fessenheim will have to close by 2020.
- In **Germany** nuclear currently still accounts for 13% of power generation, but the phase-out will be completed by 2022.
- In **Switzerland**, existing nuclear plants can continue operation as long as their safety is guaranteed, but there will generally be no new licences for nuclear power plants, implying a de-facto phase-out of nuclear over the decades to come.
- In the **Netherlands**, the Borssele nuclear power plant is the only operational nuclear power plant, covering less than 4% of Dutch power demand. Current government plans provide to close the Borssele station by 2034, while there is still discussion on whether this may be replaced. However, new nuclear power stations (on new sites) are not envisaged.
- The only countries still intending to increase their nuclear share are the **Czech Republic**, in order to replace its large production of lignite and coal-fired power generation, and **Sweden**, that has been discussing a nuclear phase-out since the 1980s, but now decided to allow for new nuclear plants.

(Renewable) gas-fired power plants can serve as reliable back-up for intermittent renewables

Both fossil energy resources and nuclear energy are dispatchable, i.e. its generation output can be flexibly adjusted to demand. This dispatchable generation is mainly replaced by power generation from wind and solar, which is only available when the wind is blowing and the sun is shining. As described in Section 2, the availability of wind and solar power is not aligned with electricity demand. While there are various potential sources to compensate short-term supply fluctuations via the demand side (e.g. demand-side response in the industry, e-mobility or heat storage) and with electricity storage such as pump hydro storage or batteries, there is a need for reliable back-up generation for prolonged periods with low wind and solar availability.

Substantial electrification of heating devices further increases the need for such back-up power generation capacity to ensure reliable power supply during winter periods, where heat demand is high, and at the same time solar power availability is systematically low (see also Section II).

Gas-fired power plants are, based on their comparably low capacity costs and their high flexibility, best placed to provide this back-up service. Besides decentral power generation from biogas, central and large-scale gas-fired power generation could be based on natural gas for a transition period (replacing lignite and coal; see Section IV), with increasing shares of biomethane and synthetic methane or hydrogen in a long-term perspective.

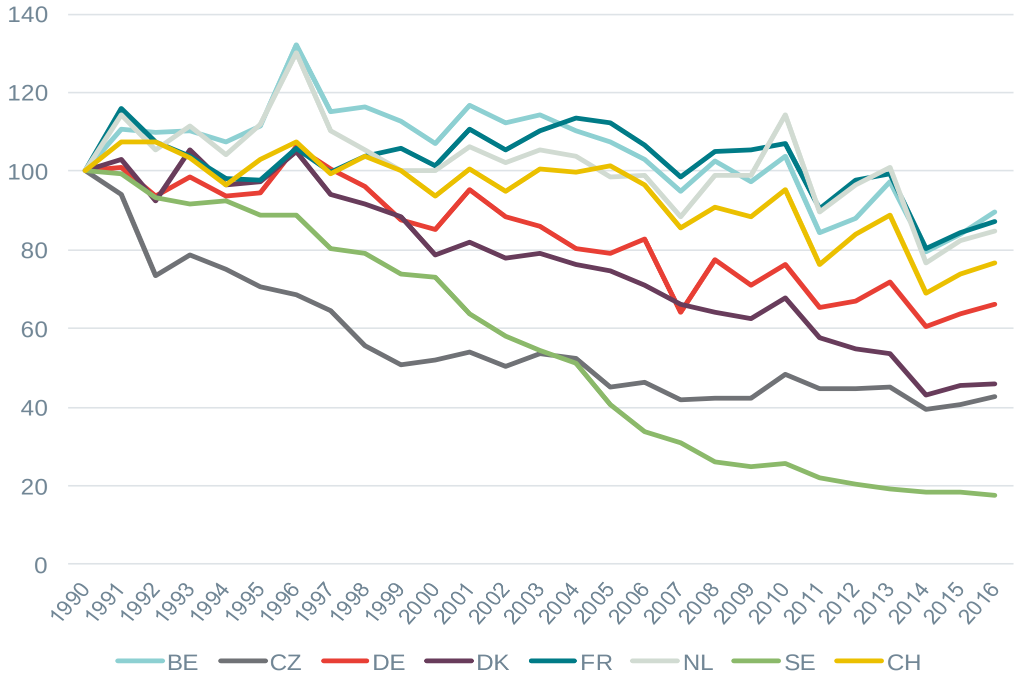
II. Gas in heating allows seasonal heat demand to be covered via existing storage and distribution networks

The heating sector needs to reduce GHG emissions

The heating sector[97] has decreased greenhouse gas emissions by almost 100 million t CO_2-eq. since 1990 and currently contributes to around 12% of emissions overall in the countries analysed (cf. Figure 20). Except for Sweden, which leads the way when it comes to reducing greenhouse gas emissions, all countries need to catch up on emission abatement, as they still need to decarbonise a large share of emissions in the heating sector. While no doubt remains about the necessity to reduce greenhouse gas emissions across the board in the heating sector, there are several possibilities to do so.

[97] Here the heating sector is defined as space and water heating for households, businesses and industry, as well as process heat for household and businesses. Process heat used for industrial purposes is captured in the industry sector.

Figure 55 Space heating: Decreasing GHG emissions, but further efforts are needed



Source: *Frontier Economics based on EEA*

Note: *Data from EEA for Heat for Households and Commercials. Emissions depicted as index with 1990 as base year*

For the heating sector to become climate-neutral by 2050, overall demand has to be reduced by insulating buildings more effectively. Further, electrification is an option often discussed. In fact, supplying the heating sector with electricity produced from renewables has the advantage of efficient energy provision, as electricity-based end appliances that use ambient heat for space heating reduce final energy demand (absent ambient heat) for heating.

However, electrifying the heating sector entails quite specific challenges by its very nature.

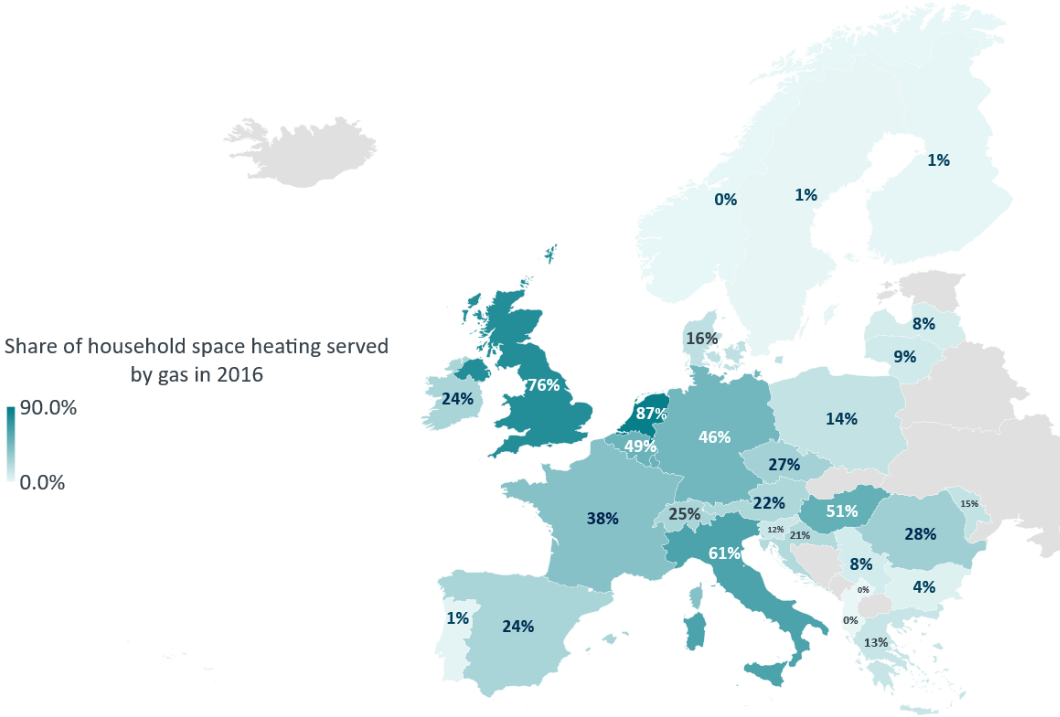
Heating today is dominated by oil and gas – electrification causes a spike in the electricity volumes required

Today's residential space heating in the countries analysed is, to a large extent, dominated by oil and gas. Conversely, electricity still plays a minor role in heating in most countries.

The relatively low share for electricity varies from extremely low shares of below 2% in the Netherlands and Germany to shares peaking at 13% and 31% in France and Sweden, respectively. Gas and oil shares are substantial but vary even more widely (Figure 56). The gas share varies from 0.6% in Sweden, which relies heavily (49%) on district heating, to 87% in the Netherlands. Oil supplies constitute as little as 0.5% in Sweden and as much as 45% in Switzerland.[98]

[98] Eurostat, Share of fuels in the final energy consumption in the residential sector for space heating, 2016.

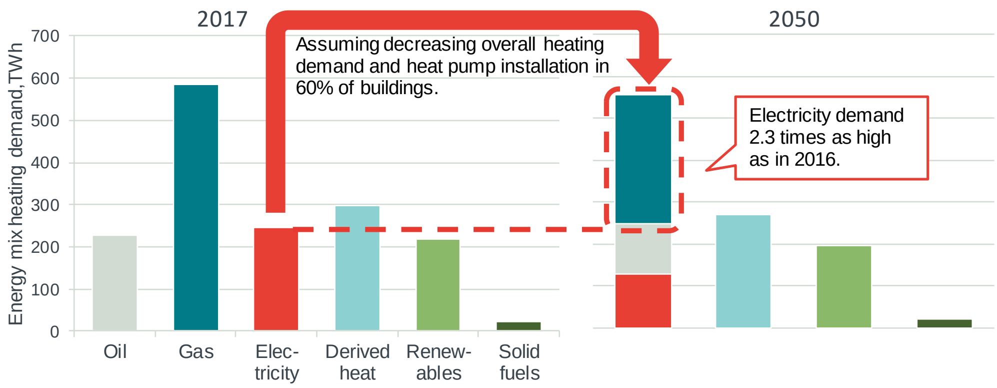
Figure 56 Gas heating prevails in most countries



Source: Eurostat and Swiss Federal Office of Energy

Even assuming continued energy efficiency gains and therefore decreased energy demand, deep electrification of the heating sector will result in substantial additional demand for electricity, as Figure 57 below suggests.

Figure 57 Electricity demand may more than double by 2050, even assuming energy efficiency soars considerably



Source: Frontier Economics based on Eurostat

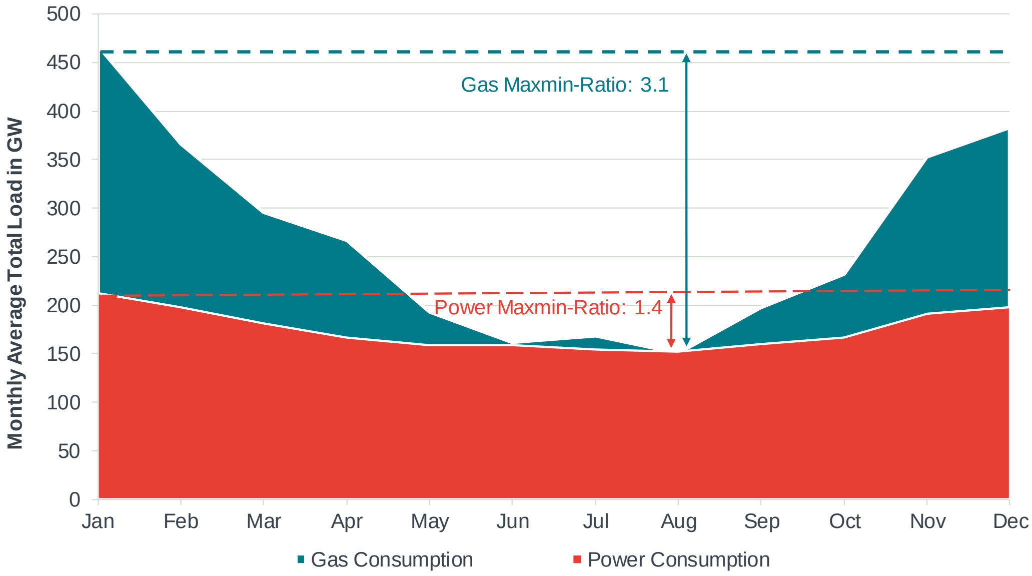
Note: For illustration purposes, we conservatively assume that there are no heat pumps in the electric share of heating demand today. We assume that electric heat pumps with 200% efficiency substitute 60% of the gas, oil and electricity demand and that electric heaters substitute the remaining 40% with an efficiency of 99%. Further we assume a 10% overall decrease in heating demand.

Gas infrastructure is already in place and able to cope with seasonality of heating sector

In addition to the mere volume of heat demand transferred to the electricity sector, seasonality of demand constitutes a further challenge (see Section 2.2), causing electricity demand to peak even higher.

Unlike the seasonal heating demand, today's electricity demand is almost flat year-round (Figure 58). Electricity is mainly used for appliances such as lighting, electric machines, electric mobility (e.g. trains) as well as for information and communications technology (ICT) needs, which are relatively constant over the year: Across the countries analysed, peak demand in January is only 40% higher than the minimum demand in August (cf. Maxmin-Ratio of 1.4). It is evident that under current conditions the electricity sector does not need to respond to fluctuating seasonal demand.

Figure 58 Gas demand is seasonal while electricity demand is (nearly) flat



Source: IEA Statistics, ENTSO-E Transparency Platform

Note: The Maxmin-Ratio is the ratio between the absolute monthly maximum and minimum demand of gas or power, respectively. The unweighted averages across the national Maxmin-Ratios are 1.4 and 3.6 for power and electricity, respectively.

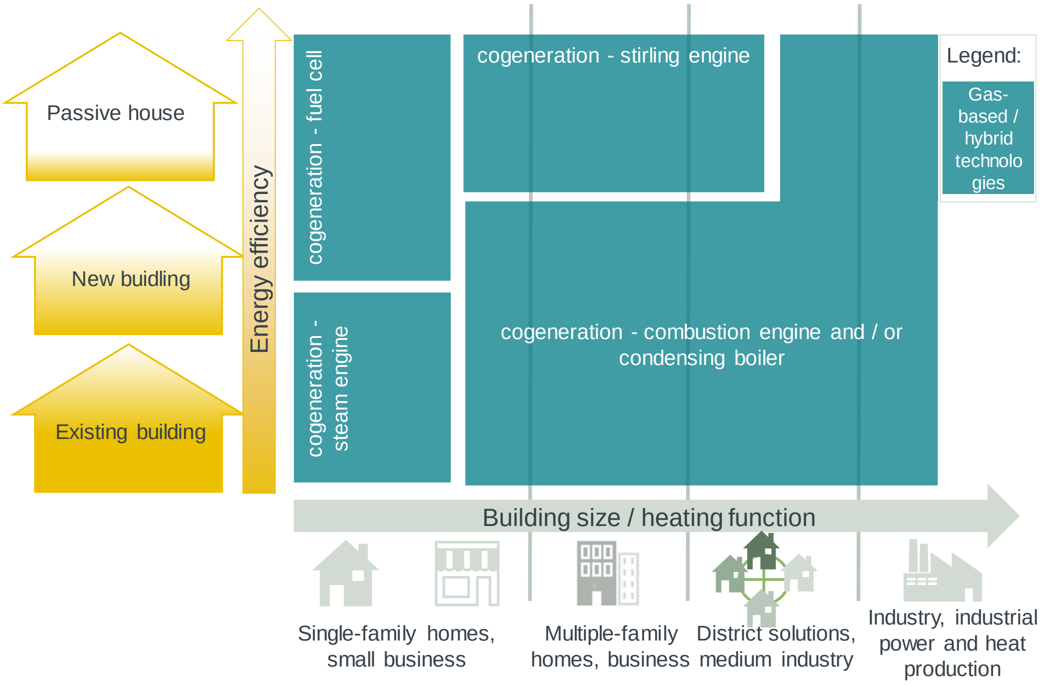
The gas sector, in contrast, has always been dealing with seasonal heating demand. Figure 58 shows how the gas demand pattern largely reflects the seasonality, respectively the heating demand pattern (as illustrated in Section 2.2) and is more than three times higher in January than in July. This ratio even underestimates the average seasonality in each country, as it is spearheaded by Germany and the Netherlands, having the largest gas demand in absolute terms, but the lowest seasonality with Maxmin-Ratios of 2.9 and 2.3, respectively. Countries like Switzerland (5.7), France (4.6) and the Czech Republic (4.4) have even more pronounced seasonality of gas demand. Supplying such seasonal heat demand by gas is facilitated by the existing gas pipeline and storage infrastructure (see Section 3.1.2).

Consequently, despite the undisputed benefits of electrification, substantial challenges remain, calling for gas as a complement. The continued use of gas can therefore mitigate the burden on the electricity sector.

Gas is very versatile and thus lends itself for a range of heating purposes

Gas is versatile and thus suitable for various heating purposes. Figure 59 provides an overview on how gas technologies – either stand-alone or as a hybrid with ambient gas heat pumps and/or electric technologies as electric-heat pumps – can cover numerous heating needs. These differ mainly depending on the actual function (e.g. single-family homes vs. business), which largely determines the heat demand pattern, and the efficiency of the building itself, which is, inter alia, driven by its insulation.[99]

Figure 59 Gas is versatile and suits various heating requirements as a stand-alone or hybrid solution



Source: Frontier Economics based on technology manufacturers as ASUE[100] and Urbansky.

The two key assets of gas for heating are its ability to heat to high temperatures (even during cold spells) and the comparably low investment costs for gas heating systems making it a possibly sensible solution for various heating purposes. Since the largest heating demand comes from the household sector, we give some illustrative examples from household buildings where gas technologies may contribute in the future:

[99] It should be noted that the technologies depicted are not exhaustive and the axes reflect simplified criteria – in fact, in addition to building's heating efficiency and function, many more criteria such as the age of a building, the state of the building's insulation, ground conditions, the availability of energy infrastructure etc. are necessary to assess the exact suitability of technologies.

[100] Arbeitsgemeinschaft für sparsamen und umweltfreundlichen Energieverbrauch (German Association for Economical and Environmentally Compatible Use of Energy).

- **Gas as an option for existing – less well insulated – buildings to utilize the gas infrastructure and save costs**:
  - Existing buildings currently using oil require a new heating fuel. Connecting the buildings to the gas grid is a relevant option if the gas grid is accessible, that means in the same or a neighbouring street. In this case, it may make sense to use the gas infrastructure by densifying the grid.
  - Saving on renovation costs: While many buildings need to be renovated by 2050, the renovation costs when sticking to gas heating are substantially lower.
    - Firstly, the building needs to be well insulated for the heat pump to work efficiently. If too much cold air can enter the room, low-temperature technology cannot heat the area.[101]
    - Secondly, heat pumps require heating bodies to be replaced by panel heating and high-temperature pipes by pipes compatible with low-temperature. Oil and gas heat the water to up to 60 °C and can therefore heat buildings swiftly and effectively through traditional heating bodies. Heat pumps, conversely, are a low-temperature technology and only warm the water to 20-40 °C. This means heating the room takes longer and panel heating is necessary, whereupon the building practically needs to be renovated from the shell.
  - Using gas-based technologies may make particular sense in the following cases, namely:
    - Where the outer appearance of a historical building would be altered through insulation measures in preparation of the installation of a heat pump. Further, in multi-family houses the respective national law often prescribes that changes affecting the outer appearance must be unanimously approved by the community of house-owners.[102]
    - When, for geological reasons, it is not possible to apply a deep brine-water or water-water heat pump. To use the heat from ground water, several assessments are necessary, i.e. expert opinions confirming that official requirements have been met. Sometimes the ground water is very deep and therefore inaccessible due to unfavourable soil conditions.
    - When in densely populated areas there is insufficient space to install geothermal heat pumps with horizontal collectors, as these collectors require an area twice as large as that to be heated.
- **Gas as an option in new – well insulated and very efficient – buildings**: New buildings are increasingly characterised by good insulation, high energy efficiency and low energy demand. However, there may still be a role for gas in the following cases:
  - If houses are so efficient that the low energy demand does not justify the high capital costs of a heat pump, less expensive gas technologies are

[101] See for example EWI and The Gas Value Chain Company (2018).

[102] See as an example the German Residential property Act WoEigG.

appropriate. Passive houses are insulated effectively enough to reduce energy demand to a level where additional savings through heat pumps relative to alternative technologies are insufficient to amortise investment costs. Relatively inexpensive gas heating may be an option in these cases.

- Area-wide solutions[103] can elicit further efficiency gains: A cogeneration unit fuelled by hydrogen or methane may supply a whole district with electricity and heat. The advantage is that the thermal energy, produced as a by-product in power generation, is not lost, but used by neighbouring buildings.

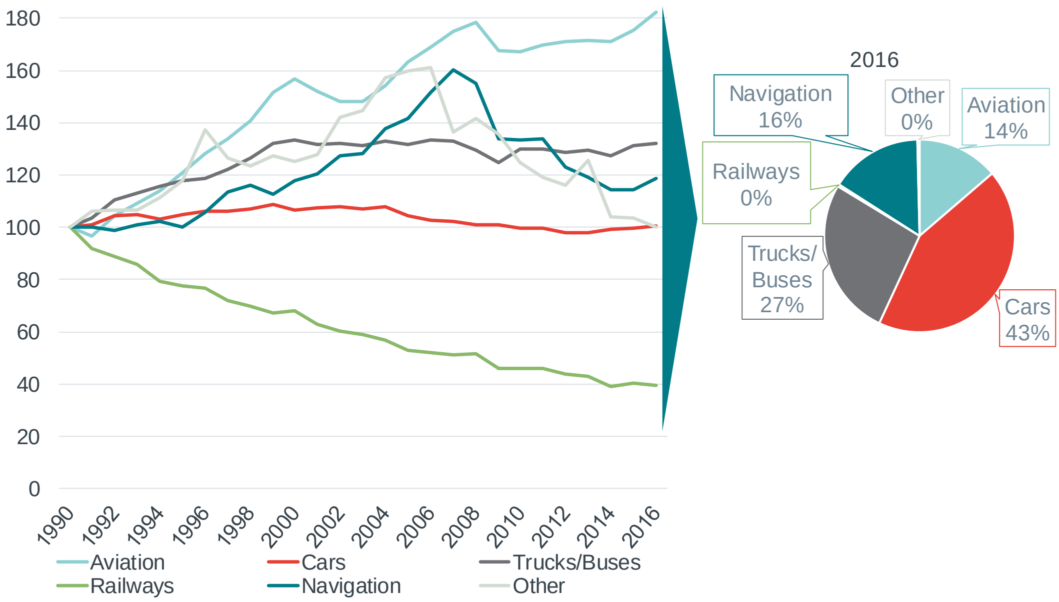
In summary, natural gas currently prevails in most countries analysed and is well able to cope with seasonality. Gas technologies are sufficiently versatile to cope with different heating needs – whether in an existing and less efficient one-family house or a district of very efficient buildings.

III. Gas in transport as a promising decarbonisation option, particularly for heavy-duty road transport

Emissions in the transport sector need to plummet

With more than 500 million t CO_2-eq. the transport sector is responsible for the major share (30%) of total emissions in the countries analysed, and emissions have even grown in this area since 1990 (cf. Figure 20).

Figure 60 Increase in GHG emissions in the countries analysed in the transport sector driven mostly by trucks



Source: Frontier Economics based on EEA

Note: Emissions depicted as index with 1990 as base year

103 An area-wide solution has, for example, been implemented in the project Rummelsburgerstraße, see Technologiestiftung Berlin (2017).

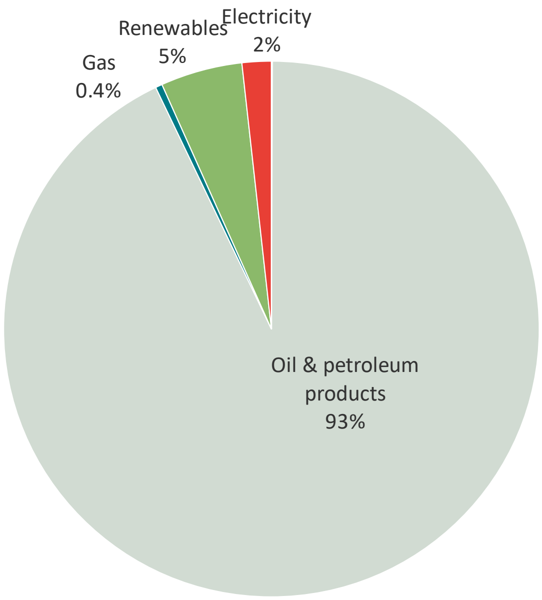
Figure 60 illustrates how the increase in emissions since 1990 in the transport sector stems from trucks (27% of emissions) but also maritime and air transport (16 and 14% respectively). While emissions in the passenger car sector have not increased, they have also not fallen and still constitute the major share of greenhouse gas emissions (43%).

Although emission abatement costs are among the highest in the transport sector[104] and, strictly speaking, no sector-specific climate target exists, decarbonisation of the transport sector is paramount, if the ambitious overall climate targets are to be achieved.

Today transport is dominated by oil, with gas and electricity playing only a minor role

Fossil liquid fuels comprise 93% of transport demand and are responsible for high greenhouse gas emissions. Consequently, fossil liquid fuels, which currently prevail in all transportation areas except for railways (Figure 61), need to be substituted.

Figure 61 Liquids are the predominant transport fuel in the countries analysed



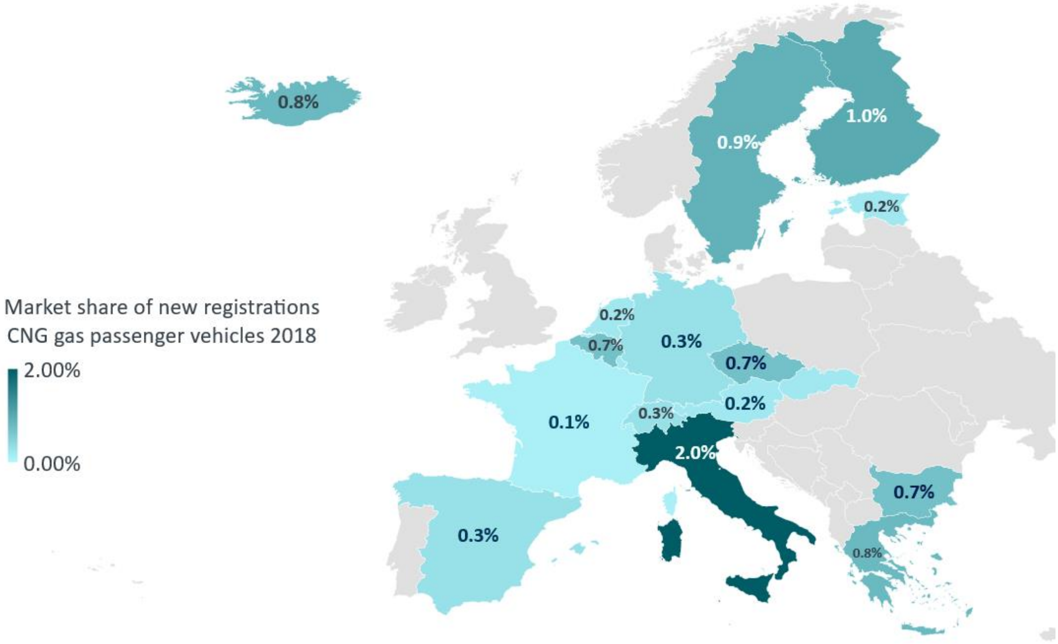
Source: Frontier Economics based on Eurostat and Swiss Federal Office of Energy

Substitution of oil is challenging given transport customer requirements

However, substituting a fuel that currently accounts for 93% of the transport demand is challenging for both electricity and gas, since their respective infrastructures and end-consumer appliances have yet to be rolled out. While Figure 62 illustrates the case of passenger cars, it also applies to remaining transport sectors, except railways, which are largely electricity-driven.

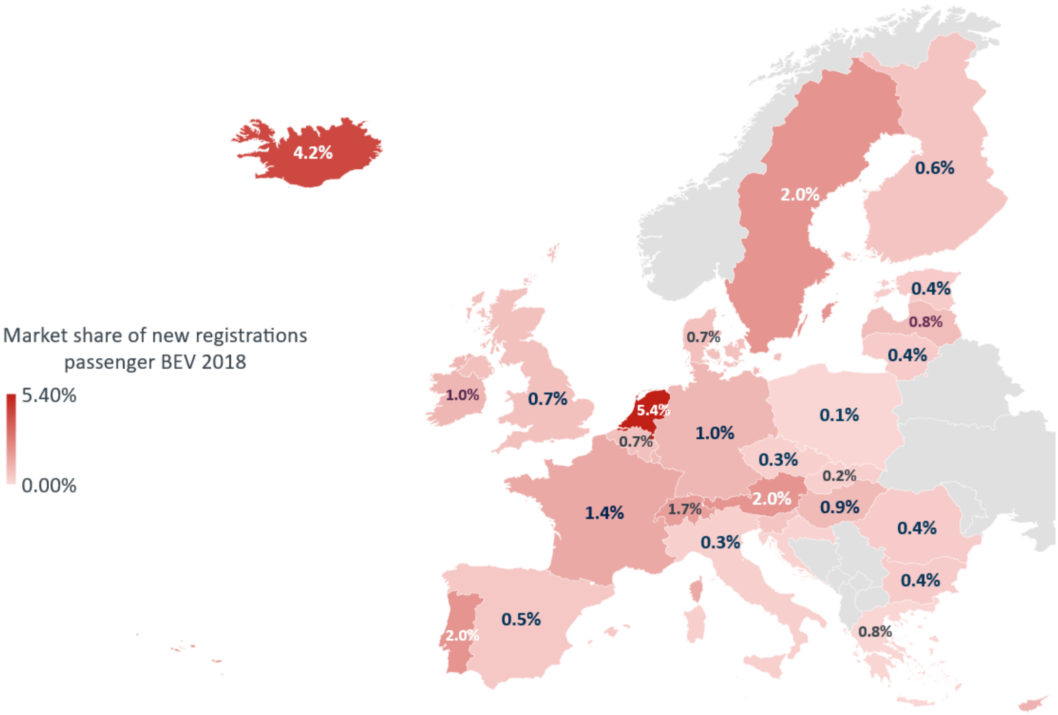
[104] Cf. BDI Study by McKinsey (2018).

Figure 62 Share of CNG vehicles in new registrations (2018)



Source: Frontier Economics based on European Alternative Fuels Observatory

Figure 63 Share of battery electric vehicles in new registrations (2018)



Source: Frontier Economics based on European Alternative Fuels Observatory

Using renewable electricity in the transport sector is a policy envisaged for decarbonising the transport sector, due to direct generation from renewable sources like wind and solar power and the high efficiency of electricity-based end appliances like e-vehicles. Accordingly, for example the German government has targeted 1 million battery electric cars (BEV) in 2020. While this target seems realistic given that there are 46.5 million[105] cars in Germany alone, Germany will fail to meet it by far.

The reason why electrifying the transport sector is more challenging than it appears at first glance is that consumers are used to the advantages of liquids that come with high energy density – something electricity lacks. High energy density is key for a fuel, which functions to provide transport means with mechanical energy on the move. However, as electricity is an energy carrier characterised by low energy density, in the vehicular context, this means that relatively little energy can be stored within a car, which also needs to accommodate passengers alongside the battery. Consequently, the car lacks sufficient reach and often needs to refuel, which is time-consuming and limits acceptance among drivers, who need to travel for longer distances without refuelling frequently. In future, some of the hurdles to electrification will be overcome when electric infrastructure is rolled out in cities and technical solutions shorten recharging periods. However, in some transport sectors like maritime or air transport, there is no foreseeable potential for electrification.

> For the same weight, diesel fuel stores fifty times the energy of a modern battery.
>
> Railengineer, October 2017

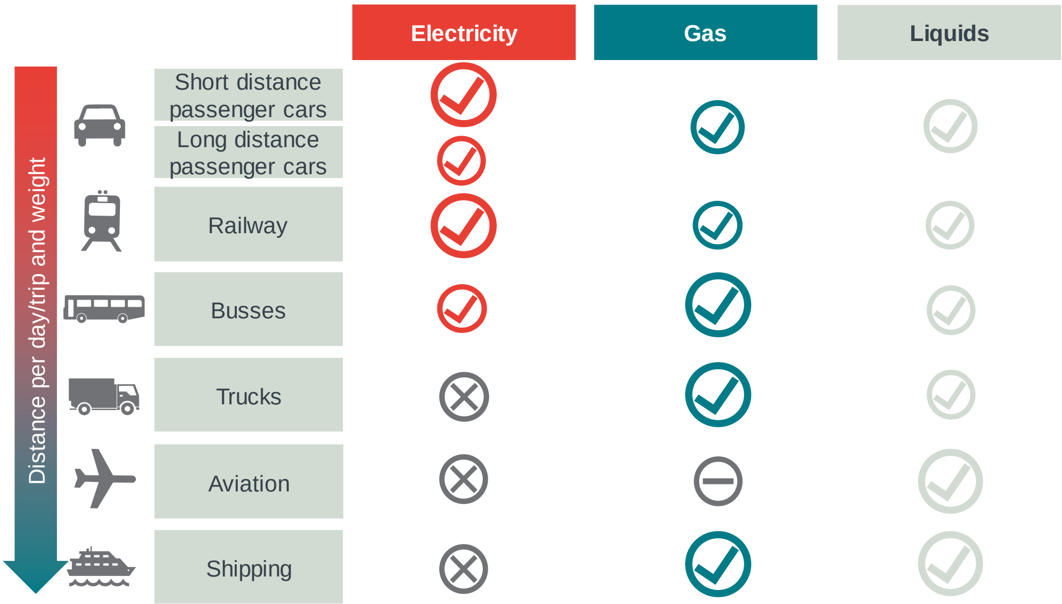
Possible future role for gas, particularly when it comes to long distances and heavy weights

In these cases, gas – although currently with a minor role compared to electricity - becomes a necessary alternative because it:

- Is not only climate-neutral but also mitigates local pollutants: Already in the transition phase substitution of fossil liquid fuels by natural gas reduces greenhouse gas emissions and mitigates local pollutants. In the long run, renewable gases can replace natural gas to completely avoid emissions.
- Also has a high energy density and is very flexible in use: Gas can be used in both gaseous forms, that is as methane or hydrogen, and compressed or liquefied and hence stored and transported as CNG or LNG, respectively, making it crucial for heavy-duty road, maritime and air transport.

[105] Cf. KBA (2018).

Figure 64 Gas in transport as a promising decarbonisation option, particularly in heavy-duty road transport and shipping



Source: Frontier Economics

Figure 64 gives a simplified overview of the transport sub-sectors and shows how the longer distances a vehicle needs to cover and the more weight it needs to carry[106], the more challenging electrification becomes.

- **Passenger road transport** over short distances can be covered by battery electric vehicles, but low energy density of batteries only makes them suitable for such short distances. Over longer distances, hybrid or gas-fuelled cars are necessary.
- **Trains** are largely electricity-driven already. However, the investment costs for electrification are high, meaning current diesel-fuelled trains should not be electrified when lightly trafficked.[107]
- High capital costs are also a factor when it comes to electrifying **buses**. As a general rule, the same reasoning concerning distance applies as for passenger cars: Electric buses are better suited within cities rather than for intercity and country journeys. However, in cities buses generally adhere to a tight schedule. In case the refuelling time remains as it is today, additional buses are necessary to fill the fuelling gap. This means that more electric buses will be necessary relative to those fuelled by gas or liquids.
- **Trucks, ships and aeroplanes** do not only need to travel long distances but also transport heavy load, making gas a crucial alternative fuel in these sectors, allowing them to function properly but also reducing greenhouse gas emissions.

This chapter showed the advantages and disadvantages of gas-fuelled transport means but also that gas is set to play a key role in future, above all in heavy-duty road, maritime and air transport.

[106] See https://www.coriolis.polytechnique.fr/Confs/Heller_conf.pdf.

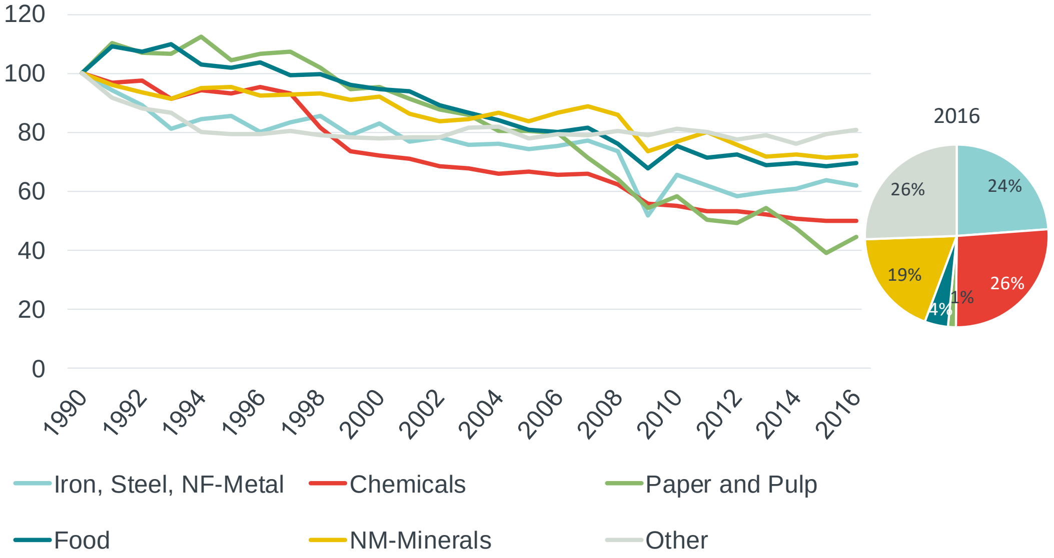
[107] See RailEngineer (2017).

IV. Gas as a low-carbon solution for high-temperature process heat and as feedstock in industry

Industry has decreased greenhouse gas emissions by substituting fossil fuels for natural gas and electricity

While the industry sector has decreased emissions by more than 200 million t CO_2-eq. since 1990 - largely driven by chemicals (see Figure 65) - it has done so on a high absolute level. Currently, industry still comprises more than 400 million t CO_2-eq. and almost 22% of total emissions in the countries analysed, making it the third-largest emitter after the transport and electricity sectors.

Figure 65 Industry has decreased its emissions but is still on a high level

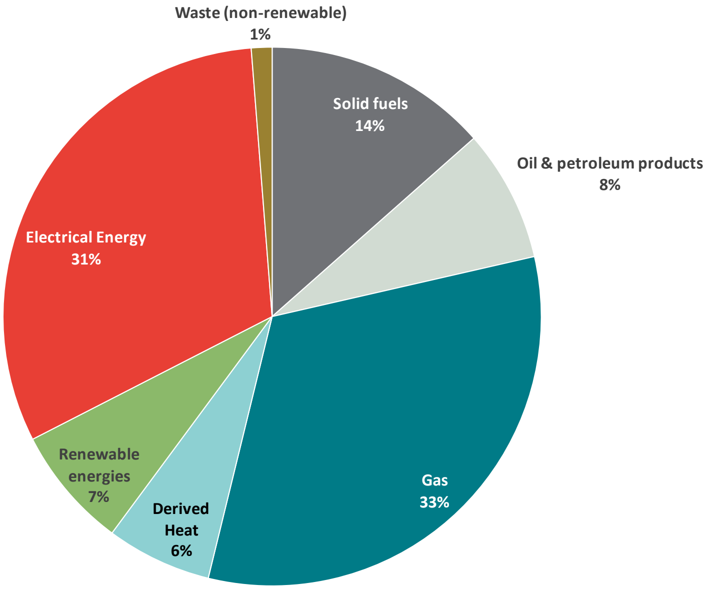


Source: Frontier Economics based on EEA

Note: Emissions depicted as index with 1990 as base year

Currently, gas is the largest energy carrier with 33%, closely followed by electricity with 31% (Figure 66).

Figure 66 Gas and electricity are the major final energy carriers for the industry in the countries analysed (2016)

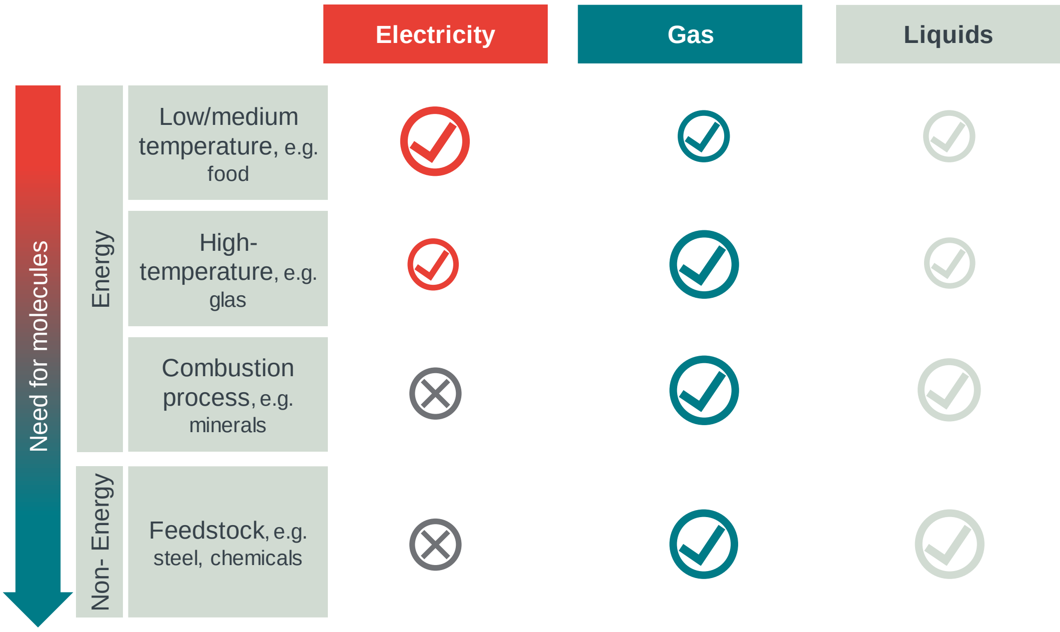


Source: Frontier Economics based on Eurostat

Gas is also well suited to supply the industry sector in the future – particularly in combustion processes and as feedstock

To continue reducing greenhouse gas emissions in the industry, renewable gas and electricity need to increase their share – both replacing natural gas, fossil-generated electricity and other fossil fuels. Figure 67 illustrates where electricity and gas can equally contribute to the decarbonisation but also where molecules are indispensable:

Figure 67 Gas can be used for process heat just like electricity, but is indispensable for combustion processes and feedstock



Source: Frontier Economics

Today, the industry sector requires fuels and electricity for two purposes:

- To power processes (energy demand) and
- As feedstock (non-energy demand).

The versatility of gas makes it a valuable energy carrier for all types of energy processes.

- Gas and electricity can be used for **low- and medium-temperature processes** as in the food industry, which requires temperatures lower than 500 °C and often even below 100 °C as well as **high-temperature processes** like the glass industry, which needs temperatures exceeding 1000 °C. Electricity is also an option in heating processes. Technically, there is no limit to heating, as the electric arc furnace can generate temperatures exceeding 3000 °C, but efficiency decreases substantially at higher temperatures.
- Further, gas is also important for **processes that not only require heat but also combustion**, i.e. fire. Cement, limestone and other minerals are examples where proper combustion is required for production. Gas, i.e. gas combustion, will remain crucial in these appliances for the foreseeable future.
- Some (currently fossil) fuels like oil are essential raw materials for the production of plastic. Chemicals are an example where nearly all fossil fuels could theoretically be replaced by renewable gas as **feedstock**.[108] Renewable methane is a practical substitute due to having the same chemical elements as oil products or coal. Hydrogen often needs more advanced technical process changes such as additional injection of missing C elements - e.g. H_2 combined

[108] Various studies see a very high technical potential for renewable gas, up to 100%, see e.g Enervis (2017b) and Dechema (2017).

with CO_2. Steel production, meanwhile, is a process where gas is both used as feedstock as well as for combustion. Merely for secondary steel, heat suffices and electricity is usable via an electric arc furnace.

Consequently, gas can play an important role in the industry sector, especially if processes require combustion or feedstock.

ANNEX C COUNTRY STUDY BELGIUM

Summary

- **Climate goals –** Belgium aims to reduce CO_2 emissions by at least **80 to 95% by 2050** with respect to 1990. Accordingly, energy-related emissions in transport, industry, households and services need to be avoided almost entirely.
- **Nuclear phase-out** – At the same time, the Belgian government has announced to phase out nuclear power between 2022 and 2025, which provides around half of the electricity produced in Belgium today.
- **The challenge of strong electrification –** Electrification of end appliances to supply consumers with renewable electricity will without doubt be one important pillar to achieve Belgium's 2050 climate target. Our analysis reveals, however, that a primarily electrification-led decarbonisation strategy would create a number of challenges, *inter alia*, by importing the considerable seasonality of Belgian heat demand into the electricity sector, leading to substantial demand for additional adjustable power generation capacity or seasonal storage. The fact that nuclear power is being phased out and domestic renewable generation and hydro storage potentials are very limited in densely-populated Belgium, however, calls for further energy carriers that are storable and easily transportable over large distances.
- **Existing gas infrastructure** – With gas supplying around 27% of final energy demand today, Belgium has a powerful gas infrastructure that is capable of contributing to decarbonisation alongside electrification: The gas network spans the entire country. Being located between major gas countries, Belgium is also well connected to the European gas network. Furthermore, via its LNG terminal capacity it is able to draw on a variety of gas sources around the world. Total gas import capacity to Belgium exceeds the import capacity of electricity by more than factor 22, also providing access to considerable gas storage in neighbouring countries such as Germany or the Netherlands, offering opportunities to bridge the gap between energy supply and seasonal heat demand.
- **Sources for renewable gas –** With domestic renewable potentials being comparably limited, most of future renewable gas will need to be imported. Belgium's large gas network capacity (that is accommodating 100% of natural gas import today and further substantial transits), facilitates renewable gas imports from various sources. Also, offshore conversion of offshore wind power to hydrogen may be an option, facilitated by Belgium having the largest hydrogen network in Europe in place, with a pipeline length of more than 600 km. Further, the idea of CO_2 sequestration of natural gas is emerging. Natural gas could be imported and the resulting CO_2 either be used in industry or transported to Norway or the Netherlands to be stored in former gas fields.
- **Role of renewable gas in consumer sectors –** Renewable gas can play an important role in various energy consuming sectors: In electricity generation, by providing reliable low-carbon back-up for intermittent

renewables and imports. In heating, where gas supplies around half of final energy demand for space heating in residential buildings today and can help to replace oil-based heating in existing buildings in the future. In industry, by reducing CO_2 emissions where electrification is hardly feasible or inefficient, such as for high-temperature process heat or as feedstock. And in transport, particularly by helping to decarbonise heavy-duty and maritime transport.

- **Cost savings of using gas networks** – Our analysis shows that, compared to switching Belgium to an electrification-led energy system, the usage of gas networks based on renewable gas could **reduce Belgian system costs in the magnitude of EUR 1.1 to 2.5 billion in 2050**. A large part of these total savings originates in lower costs for end appliances in residential heating and transport and cost savings through avoided investments in electricity distribution networks. Further savings can come from reduced renewable gas and electricity generation costs, depending on future costs of renewable gas production.
- **In summary, our analysis suggests that usage of Belgium's gas infrastructure is key to reaching Belgium's climate targets in a cost-effective way.**

I. Introduction

In this country study we provide an overview of why the gas infrastructure has a significant societal value for decarbonising Belgium. We follow the same structure as in the main report, and focus on highlighting the particularities in Belgium. Please refer to the main report for a general understanding of the methodology and argumentation.

II. Belgium's challenge: Decarbonisation with low domestic renewable potential while phasing-out nuclear energy

Achieving Belgium's decarbonisation targets presents a major challenge:

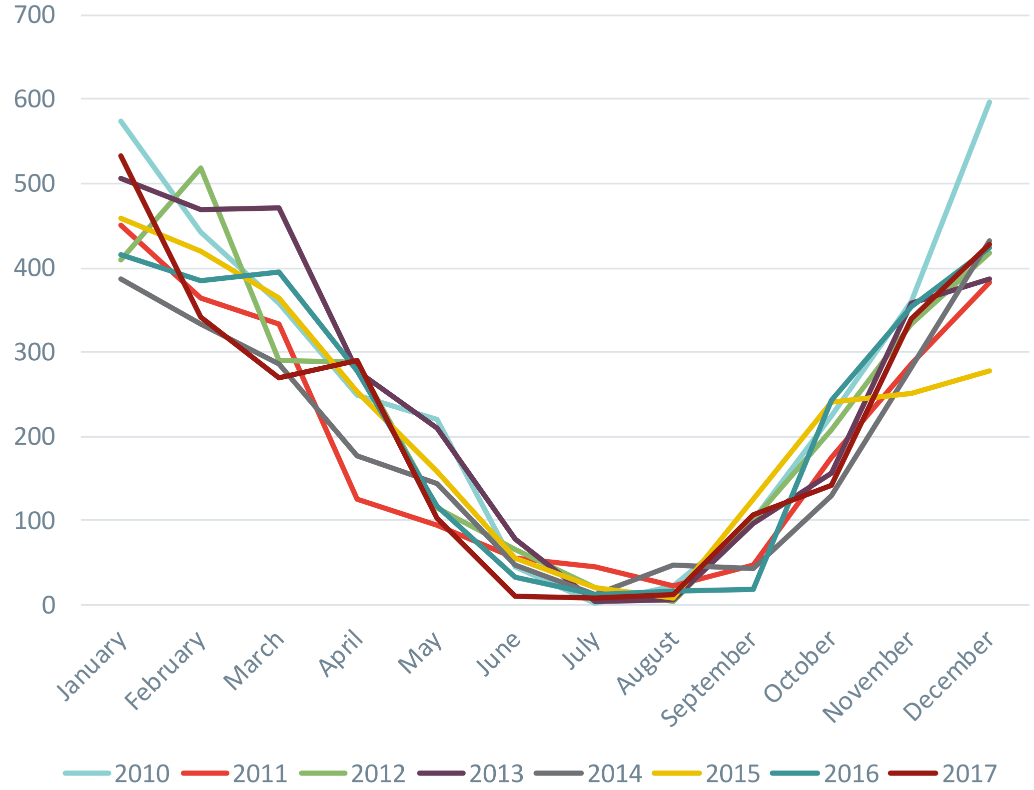
- **Climate protection targets require a massive transition of the energy system –** The Belgian government committed to a reduction of CO_2 emissions by at least **80 to 95% by 2050** as compared to 1990 on the Belgian territory. Given that most non-energy-related CO_2 emissions in agriculture and industry are difficult or costly to avoid, energy-related emissions in transport, industry, households and services need to be avoided almost entirely in order to achieve the 2050 CO_2 target. At the same time, the Belgian government has announced to **phase out nuclear power between 2022 and 2025**, which provides around half of the electricity produced in Belgium today.

- **Reaching these objectives through a high degree of electrification would cause a significant increase in annual and peak electricity demand** – Electrification of end appliances to supply consumers with renewable electricity will without doubt be one important pillar to achieve Belgium's 2050 climate target. Our analysis reveals, however, that a primarily electrification-led decarbonisation strategy would create a number of challenges:

  - **Increase in annual electricity demand –** As of now, less than 20% of final energy demand in Belgium is supplied by electricity. Electrifying large parts of the residual 80% of final energy demand would lead to substantial additional electricity demand, even assuming ambitious energy efficiency gains.

  - **Import of heat demand seasonality to the electricity sector** – Today's electricity demand in Belgium is comparably flat over the course of the year, reflecting that the main use is for purposes with low seasonality such as lighting, ICT or electric engines, but hardly in space or water heating. Electrifying large parts of heat demand, for example through electric heat pumps, would, however, import the considerable seasonality of Belgian heat demand (see Figure 68) into the electricity sector.

Figure 68 Seasonality in Belgium's heat demand (based on number of heating degree days)



Source: *Frontier Economics based on Eurostat - Cooling and heating degree days by country - monthly data*

Note: *Heating degree days are a measure of how much (in degrees) and for how long (in days) outside air temperature was lower than a specific base temperature. Eurostat sets this temperature at 15°C in its calculations.*

- **Additional and peaky electricity demand requires more imports and seasonal storage** – Given Belgium's high population density and its location between France, Germany and the Netherlands, it has a history of being reliant on electricity imports. With nuclear power being phased out by 2025 and domestic renewable potentials being limited,[109] the electricity import dependence is likely to increase, even without electrification of further energy demand. Furthermore, the seasonality of heat demand with high winter peaks, which is not reflected by renewable electricity generation profiles particularly of PV generation with winter being an off-peak season, will require large seasonal storage. Belgium has only two comparably small pumped hydro energy storages, that are used for short-term balancing purposes, and the potential for further hydro storage is limited given the lack of altitude.

[109] Belgian electricity TSO Elia, for example, estimates a theoretical maximum potential of 90 TWh electricity from PV, wind onshore and wind offshore, while acknowledging that this is very optimistic and that there are various factors likely to limiting this potential such as public acceptance and electricity network integration (see ELIA (2017).) Even this very optimistic potential would hardly be sufficient to supply today's electricity demand (of equally around 90 TWh) on an cumulated basis over the year (i.e. ignoring the intermittency of renewable generation and seasonality of demand), let alone further electricity demand from other sectors.

Both limited domestic renewable generation and limited electricity storage capacity calls for further energy carriers that are storable and easily transportable over large distances.

- **Substantial electrification creates further challenges for the (already strained) electricity network** – Already today Belgium's transmission grid passes through significant restructuring to cope with upcoming challenges conditioned on the shift of the energy mix towards renewable energy sources and the enhanced coupling of European energy systems. The biggest challenge today is insufficient grid capacity to transport wind power generate from offshore facilities and coastal onshore plants to load centres in northern and central Belgium. Present grid extension projects aim at the exploitation of offshore wind generation capacities, about 2 GW by 2020, and the increase of transmission capacities towards France, Germany and the Netherlands. For instance, the "Modular Offshore Grid" project, which is expected to be fully operational by 2020, is supposed to connect four future wind farms in the North Sea to a new substation at Zeebrugge via a 220 kV AC (alternating current) cable. Transmission capacities to the neighbouring countries are strengthened through the replacement of conventional transmission lines by high temperature low sag conductors or newly installed HVDC (high-voltage direct current) interconnectors. Exemplary projects consist in an AC cross border interconnector between Avelin (FR) and Avelgem (BE), which is currently under permission, or a HVDC interconnector between Oberzier (DE) and Lixhe (BE), which is already under construction. Overall grid extension projects amount to 593 km, which is equivalent to about 11% of the present transmission grid length.

  An electrification-led decarbonisation pathway is likely to amplify this significantly:

  - **Generation perspective**: Due to Belgian ambitions to phase out nuclear power plants until 2025, in the near future about 50% of the total generation from today has to be shifted towards alternative energy sources. In order to achieve this goal the Belgian government plans to double offshore wind capacity within the next ten to twelve years. In order to integrate the additional wind capacity significant further challenges for the Belgian transmission grid can be expected.

  - **Demand perspective**: Further challenges for the Belgian power system and transmission grid are likely to arise from an on-going electrification of non-electric consumers and, along with that, an increasing future electrical energy consumption and peak load.

III. Belgian gas infrastructure well suited to help overcome the challenges of decarbonisation

Today around 27%[110] of final energy demand in Belgium is supplied by gas. Of this, the majority is consumed in households (mainly for heating), industry and services.

27%

Of Belgium's final energy demand is supplied by gas today.

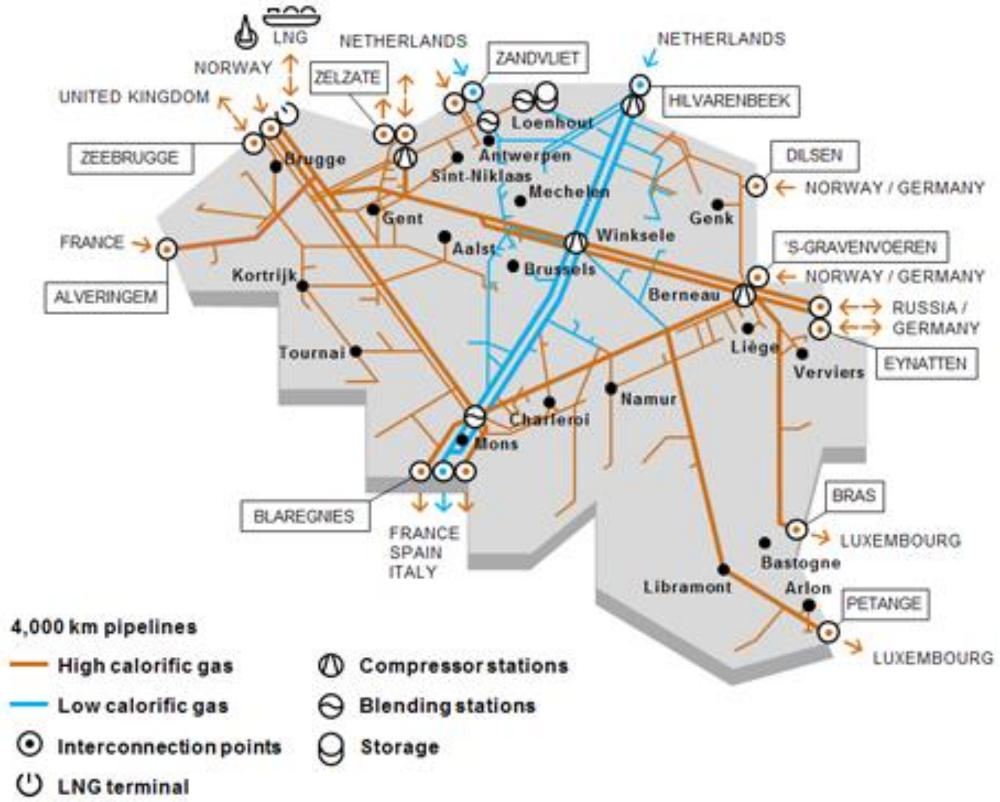
Accordingly, Belgium has a substantial gas infrastructure:

- **Domestic gas network** – Belgium's gas network with 4,000 km transmission pipelines and 70,000 km distribution pipelines spans almost the entire country (Figure 69). While the penetration of gas connections is very high in the densely populated areas in the Flemish part and in Brussels, it is somewhat lower in the Walloon part due to lower population density (and the historic development with gas being mainly supplied from the North). Nevertheless, opportunities exist to feed those regions with satellite solutions based on LNG or CNG and thus, for instance, provide low cost options for replacing oil heating without massive infrastructure investments (e.g. for heat networks, with are associated with high costs in low density areas).

  Given the spread and capacity of the existing gas network and the expected stretch in the electricity network, the gas network can contribute to avoiding large investments in the electricity infrastructure. We outline the potential for the future use of gas in various sectors as well as the cost savings from the continued use of gas networks in subsequent sections.

[110] Based on Eurostat.

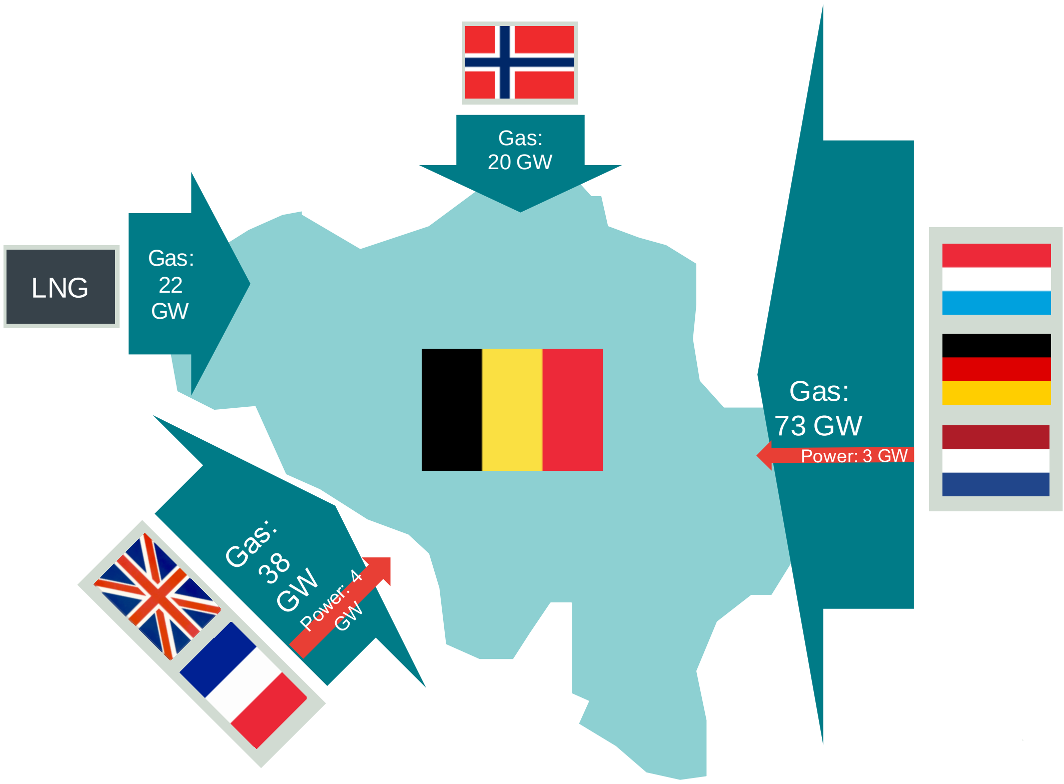
Figure 69 Gas transmission grid Belgium (overview)



Source: Fluxys

- **Gas import capacity** – Located between major gas countries such as the Netherlands, UK, France and Germany, Belgium is well connected to the European gas network. In fact, around 60% of the volumes in the transmission network are used for border-to-border transmission, mainly from the Netherlands to France (and vice versa, depending on the time of the year). There is also significant LNG terminal capacity, that allows to diversify gas supply by drawing on sources around the world. In total, the capacity of gas import to Belgium exceeds the import capacity of electricity by more than factor 22 (Figure 70).

Figure 70 Comparison of total electricity and gas import capacity: Gas import capacity exceeds electricity import capacity by factor 22

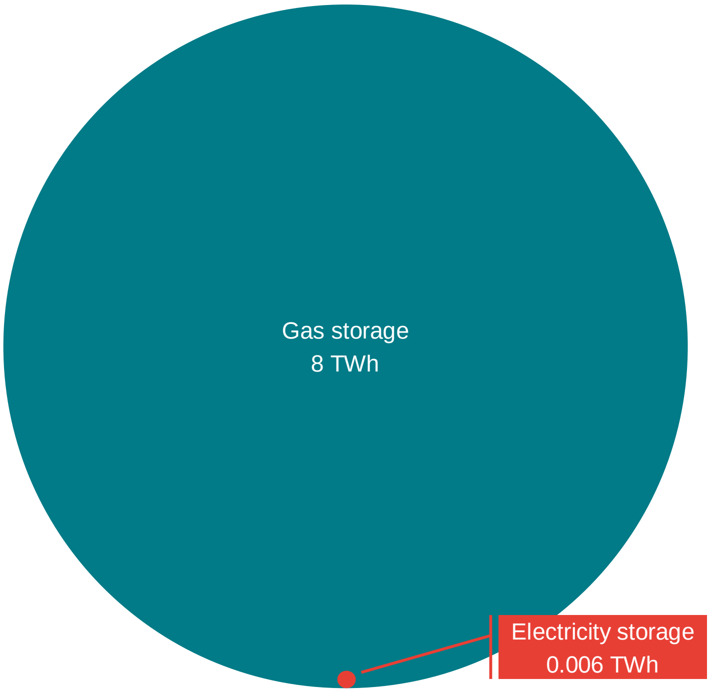


Source: ENTSO-E TYNDP (2018), ENTSO-G Physical Technical Capacity (2018)

Note: Power Import capacities presented are NTCs expected in 2020 according to ENTSO-E TYNDP 2018

- **Gas storage** – As outlined above, one of the major difficulties for decarbonising Belgium will be to supply seasonal demand of heat (which is today primarily supplied by oil and natural gas). While electricity-based storage such as pumped hydro storage or batteries is not suited for this seasonal storage purpose, gas storage is. Although Belgium has only one significant gas storage facility with limited storage capacity, which still exceeds Belgian electricity storage capacity by factor 1,400 (see Figure 71), its well-connected gas network provides the opportunity to benefit from large gas storage capacities for instance in the Netherlands, Germany or UK.

Figure 71 Comparison of total electricity and gas storage volume in Belgium: Gas storage volume is comparably small, but still more than 1,400 times as large as electricity storage volume



Source: Frontier Economics based on Gas Infrastructure Europe and Geth et al. (2015).

IV. Existing gas infrastructure is suited for a variety of renewable and low-carbon gases

While the gas infrastructure in Belgium is currently working on natural gas, there are various potential sources for renewable and low-carbon gas that could be fed into the gas infrastructure in the future, thus contributing to achieving the ambitious climate protection targets:

- **Biomethane** – In 2016, Belgium produced around 1,000 GWh of biogas, which is mainly based on waste (such as waste water from the beets and potato industry in Wallonia), with dedicated energy crops playing only a minor role (5% in Flanders, 10% in Wallonia).[111] At the end of 2018 the first biomethane plant was put into operation and connected to the grid. And several other biogas projects have recently started to investigate purification to biomethane and grid injection as an option.[112]

  Looking ahead, Belgium biomass potential is likely to be limited, mainly due to high population density and public resistance to the use of energy crops. There is, of course, the opportunity that more of the biomass feedstock is gasified or methanised, so that domestic biomethane is likely to contribute to decarbonisation in the future, although presumably limited compared for example to other countries such as France, Denmark or Sweden.

[111] See European Biogas Association (2017).

[112] See Green Gas Initiative (2017).

- **Renewable gas from domestic power-to-gas** – Given limited potentials for renewable electricity production, we do not expect that power-to-gas will play a key role in Belgium when it comes to renewable gas supply. Smartly located power-to-gas facilities can, however, help to release part of the stress on the electricity network. Even offshore conversion of offshore wind power to hydrogen may be an option, analogous to investigations triggered by Belgian and Danish players in the North Sea Wind Power Hub. The usage of green hydrogen could be facilitated by Belgium having the second largest hydrogen network in the world (with a pipeline length of more than 600 km[113]), provided that its currently private access would be opened to the market as it is the case for the gas and electricity grids. Switching parts of the hydrogen production from "grey hydrogen" (on the basis of fossil fuels)[114] to green hydrogen could valuably contribute to decarbonising the industry.

Figure 72 Belgium has the largest hydrogen network in Europe

Source: Air Liquide (2019)

- **Import of renewable gas** – Today, all of the natural gas consumed in Belgium is imported. Given limited renewable potentials in Belgium, not only will electricity be largely imported in the future, but also will renewable gas. There are various potential routes to the import of renewable gas, such as biomethane, synthetic methane or green hydrogen via pipelines or via LNG. This offers the opportunity for a diversified supply portfolio which could not be matched easily by electricity, and can help reduce energy supply costs and enhance security of supply. Where necessary, renewable gas could be

113 Followed by Germany (376 km), France (303 km) and the Netherlands (237 km), see Hydrogen Europe (2017).

114 Main current hydrogen production sources are natural gas (via steam methane reforming), petrochemicals (refining activity in the Port of Antwerp) and hydrogen as a by-product from large chlor-alkali electrolysis (Tessenderlo chemie), see Thomas, D. et al. (2016).

supplemented by natural gas combined with CCU or CCS. Fluxys and the Port of Antwerp, for instance, are currently conducting a feasibility study regarding the capture and use or storage of CO_2 that is emitted by industry in the port.[115] Possible options include

- the direct use of carbon by the industry;
- the transport of CO_2 in pipelines, for instance to Rotterdam where it could be stored in depleted Dutch gas fields;
- or the transport of CO_2as a cooled liquid on vessels to Norway.

V. Renewable gas has a strong potential in various sectors

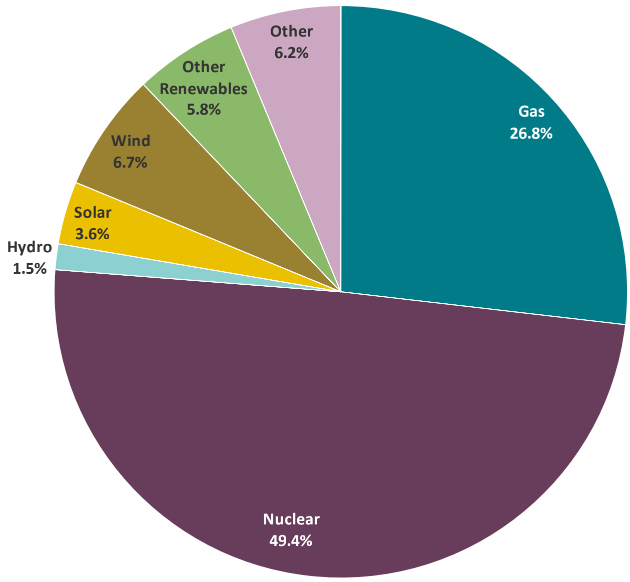
Renewable gas has a strong potential to be used in various energy-consuming sectors in Belgium (see Annex B for more details on the analysis of sectors):

- **Electricity generation** – With nuclear being phased out by 2025 and biomass potentials being limited, gas-fired power plants, which supplied around 27% of electricity generated in Belgium in 2017 (Figure 73), remain the only adjustable technology available within Belgium to back up intermittency from (domestic and imported) renewable generation. Electricity TSO Elia, for example, calculated a need for 3.6 GW of additional adjustable generation capacity by 2025 to cope with the nuclear exit and to guarantee security of supply, in addition to the assumption of 2.3 GW existing gas-fired power stations still operating.[116] According to the study, the requirement for additional adjustable generation capacity would increase by 1 to 2 GW if Belgium's neighbouring countries are not able to ensure their own security of supply.

[115] See Fluxys (2019).

[116] See ELIA (2017).

Figure 73 Electricity generation mix in Belgium (2017)

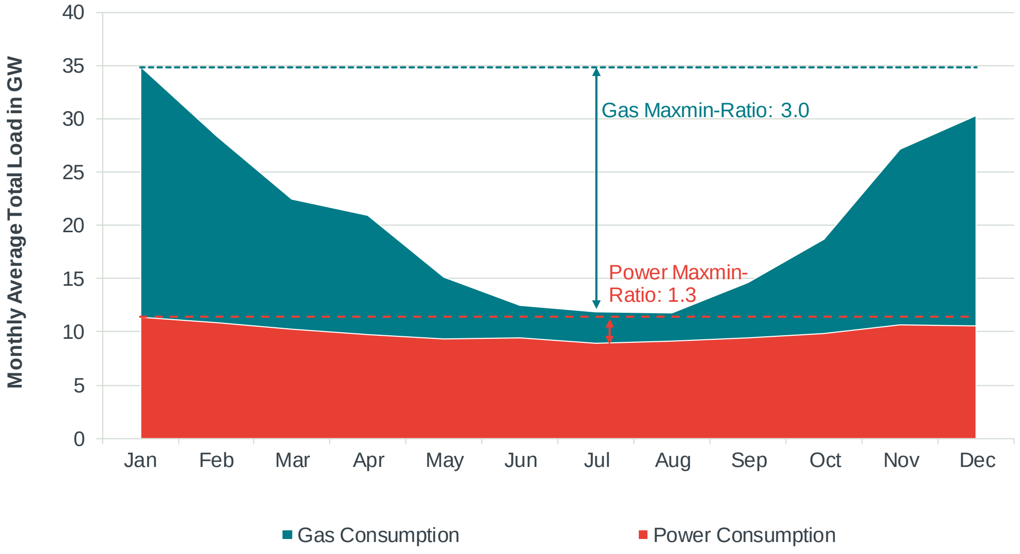


Source: Frontier Economics based on Entso-E Transparency Platform (2018)

- **Heating** – Belgian heating supply is dominated by natural gas: For instance, around 50% of final energy demand for space heating in residential buildings is supplied by natural gas, followed by oil (36%). Only approximately 3% is covered by electricity (Figure 75), and district heating is negligible.

  Accordingly, and because Belgium's heat demand, like that of many other European countries, is characterised by considerable seasonality (see Figure 68), today's gas infrastructure has been built to cope with large seasonality, while the electricity infrastructure deals with demand that is comparably flat over the course of the year (Figure 74). Electrifying large parts of heat demand would import this demand seasonality to the electricity sector. Covering the resulting peaky electricity demand would pose extraordinary challenges both for generation/storage as well as the transmission and distribution network.

Figure 74 Monthly gas vs. electricity load profile in Belgium



Source: *Frontier Economics based on IEA Monthly Gas Statistics for Actual Gas Load (GWh, 2017) and ENTSO-E Transparency Platform for Actual Electricity Total Load (GW, 2017)*

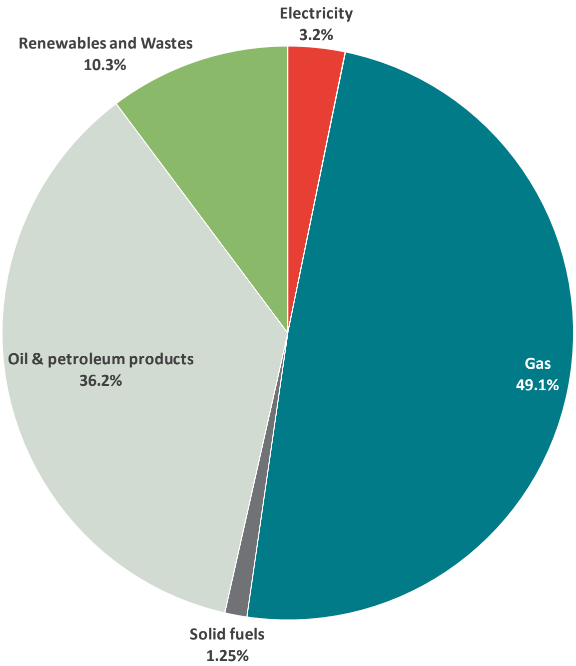
Consequently, there are good arguments to keep existing gas connections active and let households continue to heat with (then renewable) gas.

Furthermore, switching oil-based heating to gas (first natural gas and increasingly renewable gas) can be a cost-effective way forward, particular where oil-dependent households are located close to existing gas networks. For example, according to gas TSO Fluxys 92% of households in Belgium are “connectable” to gas, i.e. within close reach of the gas network, but “only” 72% are actually connected.[117]

In addition, gas network operators are also considering the development of small local grids to supply remote areas with satellite solutions based of LNG or CNG, with the option to connect these local grids to the transmission network at a later stage.

117 For example, even in densely populated Brussels, that is well connected to the gas network, around 10% of the existing building stock is still heated with oil. For these, a switch to gas would not require any major investments.

Figure 75 Final energy demand for space heating in residential buildings by fuel in Belgium (2016)

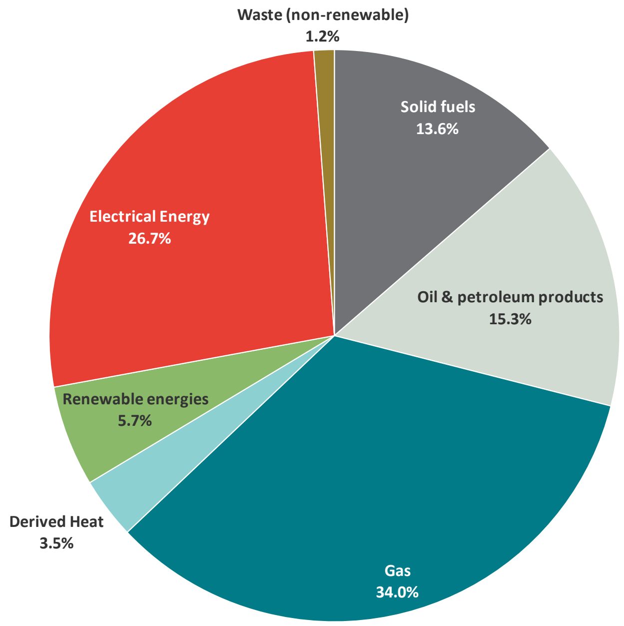


Source: Frontier Economics based on Eurostat

- **Industry –** Energy-intensive industries are of big relevance in Belgium. Accordingly, more than 33% of final energy demand in Belgium is consumed in the industry. Natural gas is supplying the bulk of this (34%), followed by electricity (27%), oil (15%) and solid fuels such as coal (13%). While (fossil) oil and coal will need to be replaced to decarbonise the industry, renewable gas has the potential to complement electrification, particularly where electric supply is difficult or inefficient, such as in high-temperature process heat or as feedstock to supply carbon.

  The industry is likely to be the first sector to be directly supplied with (green or blue) hydrogen, both as a substitute for grey hydrogen where this is already used today (see above), and also as replacement for oil, coal or natural gas to generate process heat. The latter would of course require that machines and processes are adjusted appropriately.

Figure 76 Final energy consumption in industry by fuel in Belgium (2016)



Source: Frontier Economics based on Eurostat

- **Transport** – Like in most other European countries, the Belgian transport sector is dominated by oil products. Gas plays a limited role, supplying 0.4% of final energy demand in transport. Analogously to other countries, though, gas-fuelled (CNG or LNG) or hydrogen-fuelled transport is likely to be one essential pillar of future transport, in particular in transport modes that are difficult to electrify, such as heavy-duty road transport or maritime transport.

VI. Gas networks reduce system costs of energy supply and increase public acceptance

In the previous sections we found that renewable gas is not only important for seasonal storage, where it is practically indispensable, but also potentially a valuable energy carrier to supply various sectors in Belgium directly. This is reflected by our calculations of system costs for two different decarbonisation paths.

In summary, these show that the continued use of gas networks to transport energy to final customers in Belgium in 2050 yields cost benefits of **EUR 1.1 to 2.5 billion per year**. Further, it contributes to the public acceptance of decarbonisation through avoided electricity network expansion.

EUR 1.1-2.5 bn / year

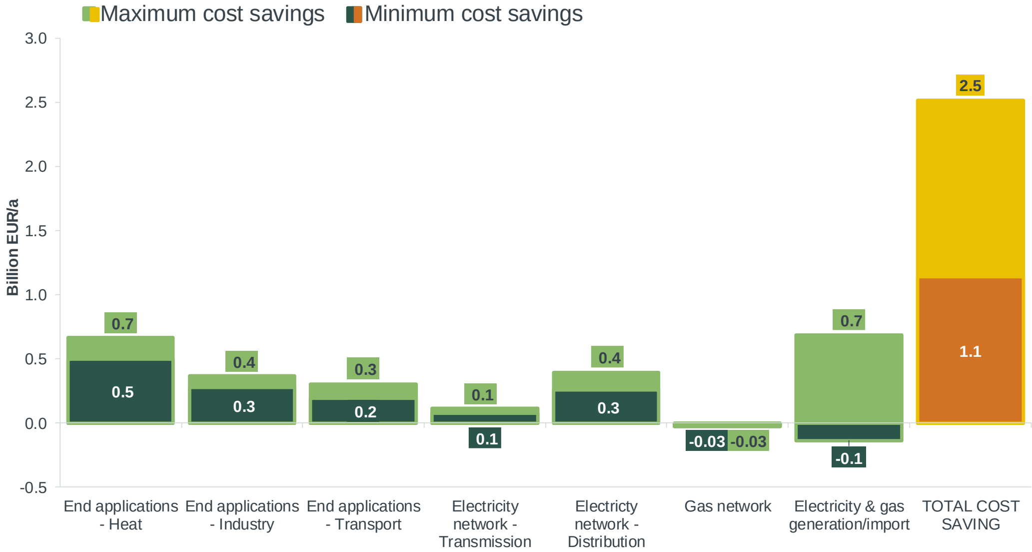
can be saved through the continued use of gas networks in 2050.

The gas network helps save costs across the whole value chain

We have derived these estimates by comparing a scenario in which gas networks are still used to deliver (renewable or low-carbon) gas to end users ("Electricity and Gas Infrastructure" scenario) to a scenario where most end appliances are electrified and gas is only used for seasonal storage with (re-)electrification ("All-Electric plus Gas Storage" scenario) in 2050 (see Section 4.2 for more details).

To compare energy system costs between the two scenarios, our analysis has taken into account costs along the entire energy supply chain. To capture uncertainty about the future development of key parameters such as gas and electricity demand or renewable gas generation costs in 2050, we have executed the calculations for a number of different parameter sets, resulting in the cost saving intervals presented below.

Figure 77 Min and max cost savings of a continued use of gas networks per year in 2050 along the supply chain in Belgium



Source: Frontier Economics/IAEW

Note: The values illustrate the difference in annual costs between the "All-Electric plus Gas Storage" scenario and the "Electricity and Gas Infrastructure" scenario. A positive value reflects cost savings in the "Electricity and Gas Infrastructure" scenario, where parts of end energy are supplied by renewable and low-carbon gas via gas networks, compared to the "All-Electric plus Gas Storage" scenario, where end energy is primarily supplied by electricity and gas networks are no longer needed. Minimum and maximum savings refer to varied assumptions on key parameters that are uncertain from today's perspective, such as production prices of different renewable gases or the development of final energy demand until 2050.

The results reveal that Belgium can benefit considerably from the continued use of gas networks. In 2050 it can save **EUR 1.1 to 2.5 billion per year** in an "Electricity and Gas Infrastructure" scenario compared to the "All-Electric plus Gas Storage" scenario where most end appliances have been electrified and gas is only used for temporal storage. This corresponds to annual cost savings of **EUR 101 to 223 per capita.**

A large part of these total savings originates in lower costs for end appliances in residential heating and transport and cost savings through avoided investments in electricity distribution networks. Further savings can come from reduced renewable gas and electricity generation costs, depending on future costs of renewable gas production. If these sink sufficiently, renewable gas such as (imported) green hydrogen or biomethane can provide an abundance of cheap energy in the "Electricity and Gas Infrastructure" scenario, which will generate substantial cost savings compared to the "All-Electric plus Gas Storage" scenario (see light green column for "Electricity & gas generation/import" in Figure 77). However, if high renewable gas production costs coincide with an unfavourable demand path, the costs of energy generation in the "Electricity and Gas Infrastructure" scenario could be more expensive than those in the "All-Electric plus Gas Storage" scenario (see dark green column for "Electricity & gas generation/import" in Figure 77).

Use of gas networks benefits public acceptance of decarbonisation

As explained above, in the “All-Electric plus Gas Storage” scenario the Belgian electricity grid would have to be expanded substantially. The gas network, on the other hand, is already fit for purpose. Its continued usage would therefore render significant parts of the electricity grid extension obsolete: Based on an extensive network modelling exercise, we previously identified that for the German transmission network this effect is as large as 40% by 2050.[118] Transferring this result to Belgium by taking into account the less significant penetration of gas and the lower extent of RES expansion until 2050, it is likely that Belgium could avoid transmission grid extensions of approximately 20 to 27 % through the continued use of gas networks by 2050, compared to the “All-Electric plus Gas Storage” scenario. In light of the public resistance against the new construction of overhead power lines, gas networks therefore benefit public acceptance of decarbonisation.

[118] See Frontier Economics et al. (2017).

ANNEX D COUNTRY STUDY CZECH REPUBLIC

Summary

- **Climate goals** – While the Czech Republic has not set a binding unilateral decarbonisation goal for 2050 yet, it is clear that substantial reduction of emissions will be necessary to comply with EU targets.
- **Nuclear power** – Today nuclear power is an important pillar of Czech electricity generation. While this is likely to remain the case in the next years, the long-term future of nuclear is uncertain.
- **Fossil fuels phase-out** – State energy policy, currently only spanning the period until 2040, does not foresee a definite phase-out of fossil fuels. Yet, it does plan to lower GHG emissions by a partial fuel switch from coal to gas, amongst other measures.
- **The challenge of strong electrification** – Fossil fuels currently constitute a large share of energy supply in industry, heat and transport. Replacing this share primarily with renewable electricity, without a substantial role of gas infrastructure, imposes challenges for the generation, transport and storage of energy, and is likely to require expensively large amounts of seasonal back-up capacity and renewables capacity. In addition, recent experiences suggest opposition against additional electricity infrastructure developments.
- **Existing gas infrastructure** – The Czech gas infrastructure has a lot to offer to contribute to decarbonisation alongside electrification: Gas supplies around 23% of final energy demand and the gas network covers most parts of the country. Being a major gas transit country, gas import capacity is enormous, exceeding electricity import capacity by factor 18. Likewise, domestic gas storage capacity in the Czech Republic is sufficient to store 35 TWh of energy (which is 6,000 times the energy storage volume of existing electricity storage), with further access to large gas storage in neighbouring countries, providing the basis to bridge the gap between energy supply and seasonal heat demand.
- **Sources for renewable and low-carbon gas** – There are various sources for renewable and low-carbon gas in the Czech Republic. Local production of blue hydrogen from natural gas may be an option. In addition, due to its transit role and geographic location at the heart of the European gas grid, the Czech Republic may play a central role in a new pan-European hydrogen transmission grid.
- **Role of renewable and low-carbon gas in consumer sectors** – Renewable and low-carbon gas can play an important role in various energy consuming sectors, with a focus on heat and, to a lesser extent, industry and transport.
- **Cost savings of using gas networks** – Our analysis shows that, compared to switching the Czech Republic to an electrification-led energy

system, the usage of gas networks based on renewable and low-carbon gas could **reduce Czech system costs in the magnitude of EUR 1.5 to 3.0 billion in 2050**. Main drivers of these savings are avoided investment in capital-intensive heating appliances, avoided electricity distribution grid expansions and a volume effect in electricity generation and gas production/import.

- **In summary, our analysis suggests that usage of the Czech Republic's gas infrastructure is key to reaching the Czech Republic's climate targets in a cost-effective way**.

I. Introduction

In this country study we provide an overview of why the gas infrastructure has a significant value for decarbonising the Czech Republic. We follow the same structure as in the main report, and focus on highlighting the particularities in the Czech Republic. Please refer to the main report for a general understanding of the methodology and argumentation.

II. The Czech Republic's challenge: reducing emissions

Further decarbonisation of the Czech Republic's energy system presents a major challenge

- **Following successful reduction of emissions in the past decades, further action is required** – In large part due to a rapid decrease in heavy industry activities in the early 1990s,[119] overall greenhouse gas (GHG) emissions in the Czech Republic have fallen by 35%[120] on 1990 levels (compared to a target reduction at EU level of 20% by 2020). GHG emissions outside of the 'traded sector' (i.e. those not covered by the EU Emissions Trading System) have fallen by 6%[121] on 2005 levels, meaning that the Czech Republic has effectively already met its target for 2020 (a 9% increase compared to 2005 levels[122]).

  The Czech Republic has not yet set a binding unilateral national target for long-term (i.e. 2050) GHG emissions reductions.[123] While this results in some uncertainty as to the speed and depth of the required energy transition in the Czech Republic, further emissions reductions will likely be required to be consistent with EU policy goals:

  - In the non-traded sector, the Czech Republic will be required to reduce GHG emissions by 14% on 2005 levels by 2030.[124]
  - In the traded sector, the EU-wide emissions cap is due to decline year on year at a set rate (2.2% per year from 2021, with a review clause in 2024).
  - Following the Paris Agreement from 2015 the EU and its member states have committed to reducing overall GHG emissions by 80-95% by 2050 as compared to 1990 levels.[125]

  Due to the predominance of coal (in particular, lignite) in the energy mix, electricity and district heating together represent the single biggest source of GHG emissions in the Czech Republic (see Figure 78). Energy-related emissions from buildings, industry and transport are also significant. In the

119 See, for instance, Ministry of the Environment of the Czech Republic (2015).

120 Based on Eurostat data for 2016.

121 Frontier Economics calculations based on Eurostat data for 2016.

122 See European Commission (2018c).

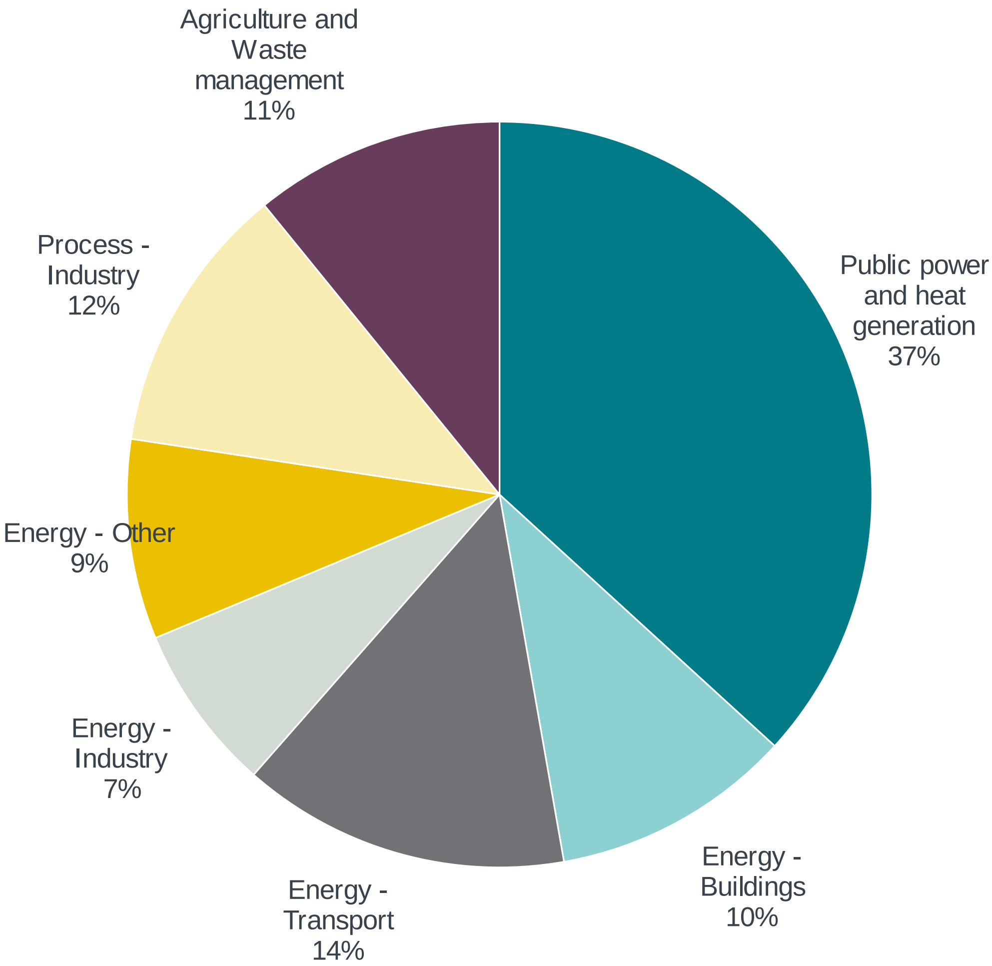
123 The Czech Republic is currently working on its NCEP (National climate-energy plan), which has to be submitted to the EC by all European member states soon. This plan is expected to extend the national planning to 2050 and beyond.

124 See European Commission (2018d).

125 See European Commission (2018b).

long-term, therefore, substantial reductions in energy-related emissions are likely to be needed for EU climate goals to be met.

Figure 78 Sources of GHG emissions in the Czech Republic



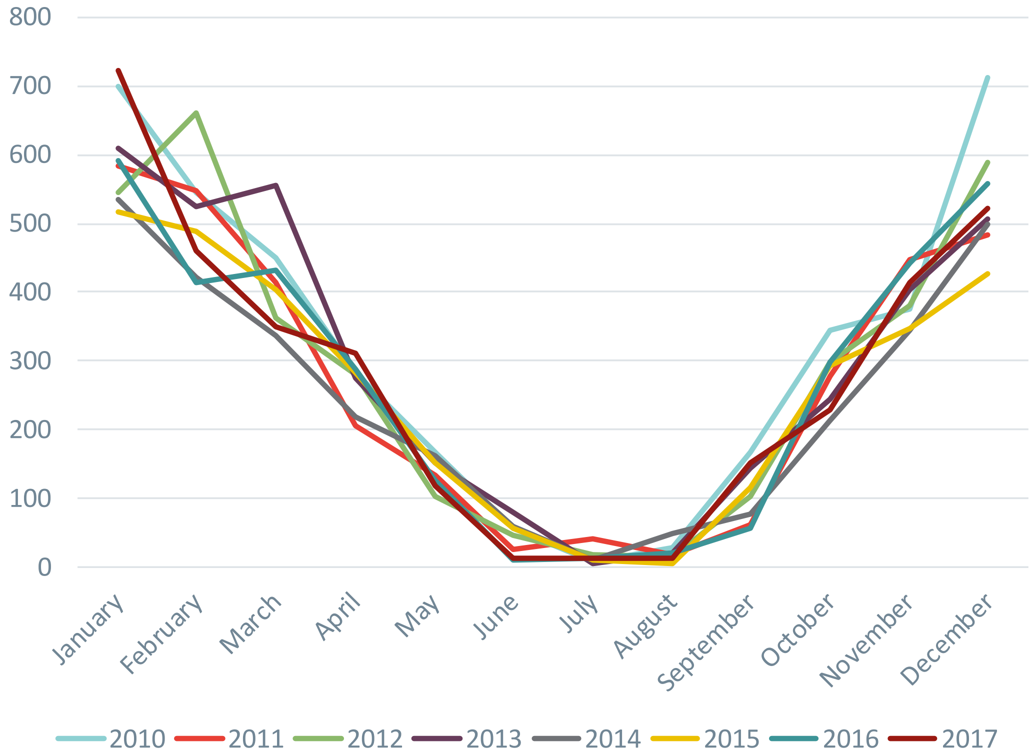
Source: Frontier Economics based on Eurostat data for 2016.

Note: Excludes emissions from LULUCF and international aviation. 'Other' energy-related emissions include emissions from refineries, from the manufacture of solid fuels and 'fugitive' emissions.

- **Reaching these objectives through a high degree of electrification would cause a significant increase in annual and peak electricity demand** – Our analysis reveals that meeting these objectives through a primarily electrification-led decarbonisation strategy would create a number of challenges:
  - **Increase in annual electricity demand** – Today, less than 20% of final energy demand in the Czech Republic is supplied by electricity. Electrifying large parts of the residual 80% of final energy demand would lead to substantial additional electricity demand.
  - **Boost in electricity peak demand** – Today, where electricity is mainly used for lighting, ICT or electric engines, but hardly for space or water

heating or cooling, electricity demand in the Czech Republic is comparably flat over the course of the year. While some increase in electricity demand seasonality might be expected regardless of the scenario considered, electrifying large parts of heat demand would import the considerable seasonality of heat demand (see Figure 79) into the electricity sector.

Figure 79 Seasonality in the Czech Republic's heat demand (based on number of heating degree days)



Source: Frontier Economics based on Eurostat - Cooling and heating degree days by country - monthly data

Note: Heating degree days are a measure of how much (in degrees) and for how long (in days) outside air temperature was lower than a specific base temperature. Eurostat sets this temperature at 15°C in its calculations.

- **Replacing fossil fuels by renewable energy sources will be challenging** – Today, fossil fuels are the dominant source of energy in transport (93%), industry (58%) and household space heating (46%).[126] While electrification will be feasible in some areas, it will be close to impossible in others such as high-grade heat in industry.
- **Substantial electrification creates further stress for the (already strained) electricity network –** Already today there is a need for substantial expansion of the Czech electricity transmission grid, especially in the centre of the country and at the borders to Slovakia and Austria. Overall grid extension projects to overcome current congestion amount to about 1,000 km, equivalent to about 18% of present transmission grid length.

  Exemplary projects consist in the implementation of a new 380 kV AC (alternating current) cross border transmission line between Otrokovice (CZ)

[126] Frontier Economics calculations based on Eurostat data for 2016.

and Ladce (Slovakia) or internal projects such as the southwest-east corridor. The southwest-east corridor project combines the replacement of existing 380 kV AC single circuit transmission lines by double circuit transmission lines and the upgrade of substations in Kočín or Přeštice. Further internal projects such as the northwest-south corridor function as reinforcement of the existing infrastructure and as backbone measures in order to facilitate energy exchanges between the Czech Republic and its neighboring countries. As part of this project new lines are going to be built, for instance between Kočín and Mírovka.[127]

Going forward, the strain on the networks is going to increase. OTE[128] notes that in the long-term the electricity distribution networks will need 'considerable strengthening' to deal with increased decentralised generation and electric vehicle charging.[129] To the extent that higher demand in the "All-Electric plus Gas Storage" scenario is met by distributed sources (such as solar PV), this will exacerbate the challenges at distribution level.

- Generation perspective: Today's comparably high level of carbon emissions indicates the necessity of integrating significant low-carbon energy sources capacities into the Czech power system in order to meet European climate goals. As one possible solution, nuclear power may play a larger role in the future.[130] In addition, the comparably low share of renewable energy sources in gross electricity generation (13%) is likely to increase. Renewable energy sources are supported by the Czech government in the form of guaranteed feed-in tariffs or prioritised grid connection. Their integration has already been a challenge in the past, and further challenges, especially through the integration of decentralised small PV capacities and the smart-grid development, are expected.
- Demand perspective: As explained above, the electrification of non-electric consumers is likely to increase future electrical energy consumption and peak load, leading to increased volumes and loading on the grid. To avoid congestion, additional expansion is likely to be necessary.

[127] See ČEPS (2018).

[128] OTE, a.s., the Czech electricity and gas market operator.

[129] See OTE (2017), p. 38.

[130] The current government has to decide within its mandate (until 2022) about the construction of new nuclear blocks of about 2 GW.

III. Czech gas infrastructure well suited to help overcome the challenges of decarbonisation

Today, gas supplies around 23%[131] of final energy demand in the Czech Republic. Of this, the majority is consumed in industry, followed by residential and services.

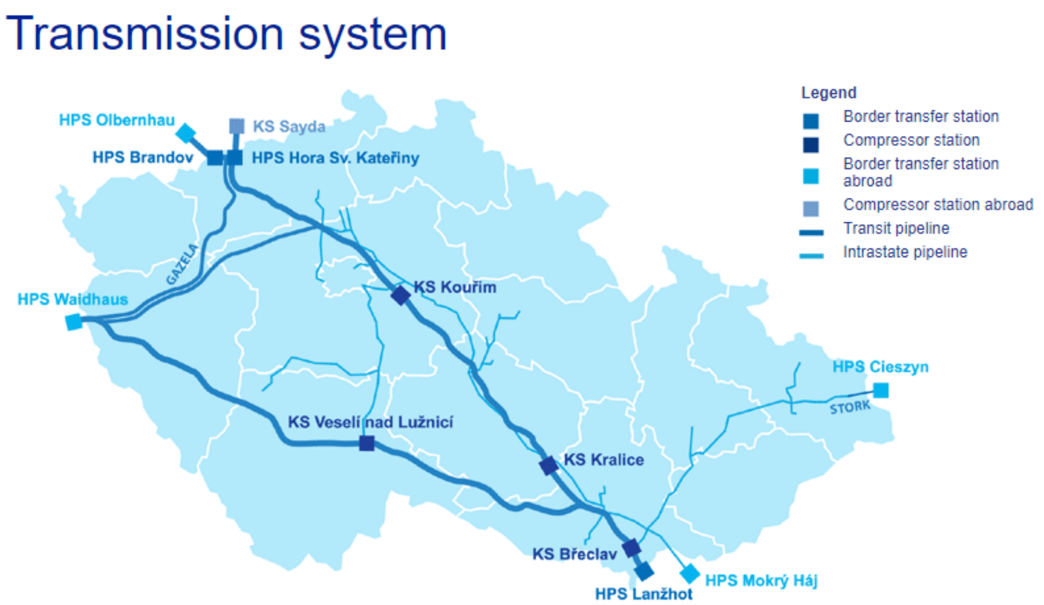
23%

of the Czech Republic's final energy demand is supplied by gas today.

Accordingly, the Czech Republic has a substantial gas infrastructure:

- **Domestic gas network** – The Czech Republic's transmission and distribution gas network covers all densely populated areas. It has more than 78,000 km length, of which the transmission grid accounts for almost 4,000 km. See (Figure 80) for an overview. This network can easily be employed to avoid large investments in the electricity infrastructure. We outline the potential for the use of gas in various sectors as well as the cost savings from the continued use of gas networks in subsequent sections.

Figure 80 Gas transmission grid Czech Republic (overview)

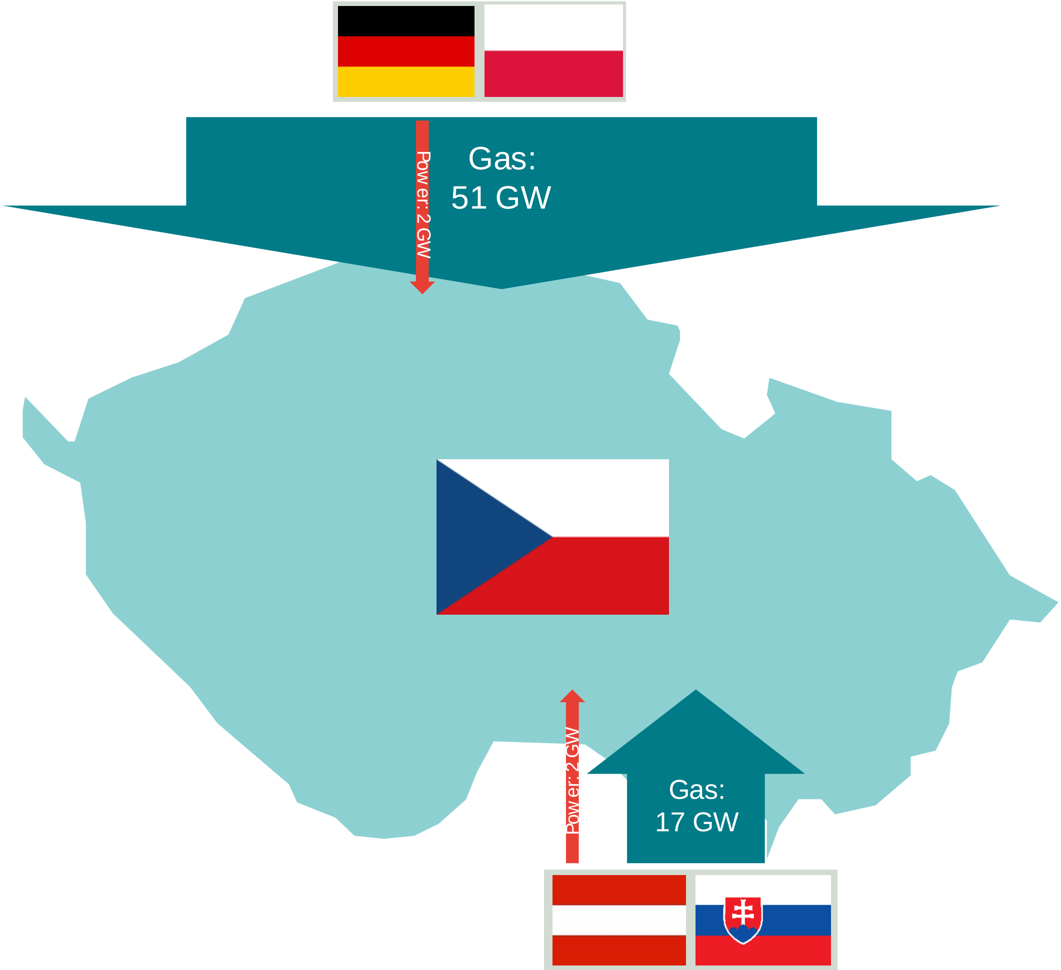


Source: Net4Gas

- **Gas import capacity** – The Czech Republic is at the heart of the European gas system. The high share of import (and export) capacity relative to domestic consumption reflects the country's important role as a transit country for gas within Europe. The capacity of gas pipelines to the Czech Republic exceeds the import capacity of electricity by factor 18 (Figure 81).

[131] Based on Eurostat.

Figure 81 Comparison of total electricity and gas import capacity: Gas exceeds electricity import capacity by factor 18[132]



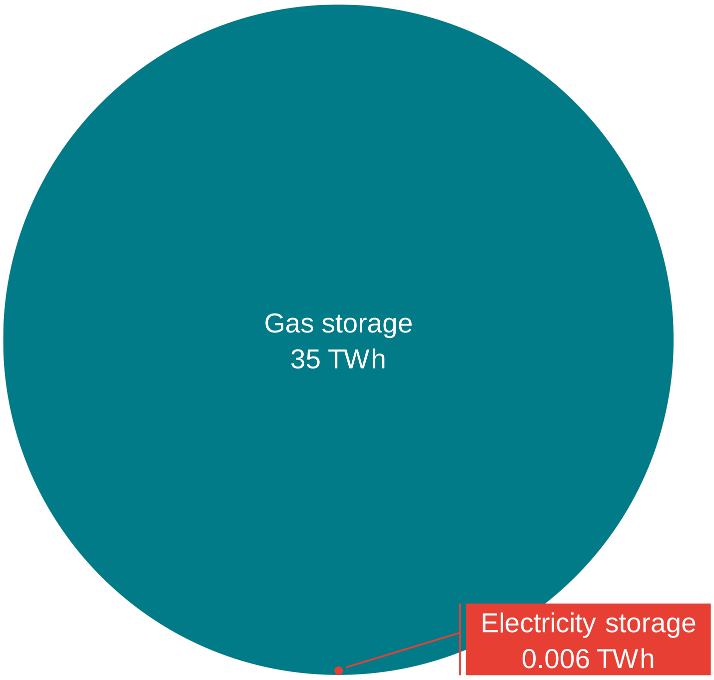
Source: ENTSO-E TYNDP (2018), ENTSO-G Physical Technical Capacity (2018)

Note: Power Import capacities presented are NTCs expected in 2020 according to ENTSOE TYNDP 2018

- **Gas storage** – As outlined above, one of the major difficulties for decarbonising the Czech Republic will be to supply seasonal demand of heat (which is today still supplied to a large part by fossil fuels). While electricity-based storage such as pumped hydro energy storage or batteries is not suited for seasonal storage, gas storage is. Gas storage capacity in the Czech Republic is sufficient to store 35 TWh of energy (which is 6,000 times the energy storage volume of existing electricity storage, Figure 82).

[132] Note that the presented gas import capacities for the Czech Republic are limited by adjacent countries' technical exit capacities. Without these limitations the gas import capacity into the Czech Republic from Slovakia and Germany, for instance, could be more than three times as high.

Figure 82 Comparison of total electricity and gas storage in the Czech Republic: Gas storage volume is more than 6,000 times as large as electricity storage volume



Source: Frontier Economics based on Gas Infrastructure Europe and Geth et al. (2015).

IV. Existing gas infrastructure is suited for a variety of renewable and low-carbon gases

There are various options for future renewable and low-carbon gas supply in the Czech Republic:

- **Biomethane** – In recent years, the Czech Republic has greatly increased its biogas industry, becoming one of the top EU producers with 7 TWh biogas production in 2017.[133] Studies agree that there is scope for further biogas and biomethane production in the Czech Republic. OTE cites a possible figure of 8 TWh overall,[134] consistent with a recent estimate by CE Delft for 2030 for the European Commission.[135]
- **Renewable gas from domestic power-to-gas** – Due to the rather unfavourable conditions for renewable energy production (e.g. absence of a coastal line for high-yield wind parks, limited sunshine duration per year or missing high mountain ridges for hydro plants), the potential for substantial domestic power-to-gas production may be limited. However, OTE considers that after 2030 synthetic methane from photovoltaic could to some extent complement other gas supplies in the country.
- **Domestic blue hydrogen –** Due to the Czech Republic's strong connections to natural supplies, local production of hydrogen from natural gas using steam

133 Eurostat.

134 See OTE (2017), p. 48.

135 See European Commission (2016), Figure 17.

methane would also be an option. Discussion of carbon capture and storage (CCS) technologies that would be needed to make such hydrogen production 'low-carbon' has so far been limited in the Czech Republic. However, it should not be ruled out that certain CCS technologies (such as the 'pyrolysis'[136] solution promoted by some stakeholders) could gain public acceptance.

- **Import of renewable and low-carbon gas** – The Czech Republic could take advantage of its large cross-border capacities and its important role in transit (including parallel pipelines) to become an important part of a possible future pan-European hydrogen transmission grid. This could be fed by blue hydrogen from Norway. But hydrogen (or synthetic methane) from North Africa are other plausible options. Such a diversified import portfolio, which could not be matched easily by electricity, can help to reduce energy supply costs and enhance security of supply.

V. Renewable and low-carbon gas has a strong potential in various sectors

To assess the benefits that the use of gas infrastructure can have in decarbonising the Czech Republic, in the following we analyse which role renewable and low-carbon gas may play in various sectors (see Annex B for more details on the analysis of sectors).

- **Electricity generation** – Currently, coal- and lignite-fired capacity, together with existing nuclear capacity, forms the majority (80%) of the generation mix. Coal's role as an indigenous energy source and source of local employment make it politically challenging for the Czech Republic to commit to a transition away from it. That said, a number of factors are supportive of projections by OTE of around a 70-80% decline in coal-fired capacity by 2050:[137]
  - Limits on mining currently imposed for environmental reasons;[138]
  - The power plants' age;[139]
  - The generally challenging environment for newly-built coal-fired power stations given EU energy and environmental policy.[140]

  The most recent State Energy Policy[141] foresees construction of '1-2 nuclear units' by 2040. However, much of this will go towards compensating for the expected closure of the Dukovany nuclear plant in the 2040s (with a resulting loss of 2 GW of capacity).

[136] Under the 'pyrolysis' approach to CCS, the carbon would be stored in solid, as opposed to gaseous, form.

[137] See, for example, Tables 1 to 3 of OTE (2017).

[138] See OTE (2017), p. 34.

[139] Most Czech coal-fired power plants were built in the 1960s or 1970s. While the majority of them have been modernised in the last three decades, there are already plans to decommission those who have not: In particular, the energy company ČEZ announced that they would phase out all coal plants that have not been modernised or newly built until 2035. This is equivalent to around 3,000 MW or almost two thirds of current capacity. See Hospodářské noviny (2017).

[140] In particular, the risk of a rising carbon price, ever more stringent air quality standards (most recently, the updated 'BREF' limits) and forthcoming rules effectively restricting the participation of coal-fired power stations in capacity remuneration mechanisms.

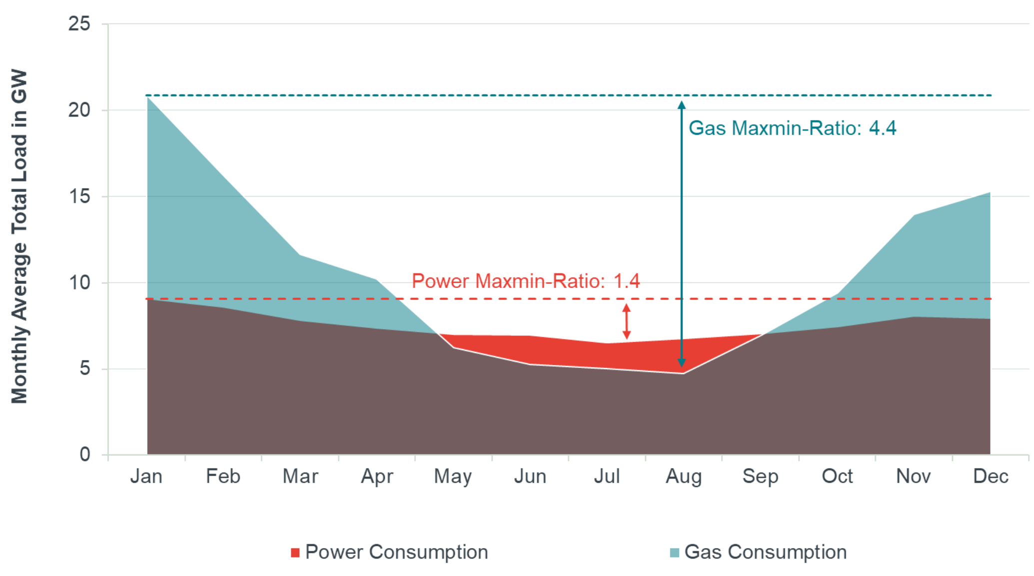
[141] See Ministry of Industry and Trade of the Czech Republic (2014), p. 49.

Gas-fired generation could play a role in ensuring seasonal peaks in electricity demand are met. Indeed, OTE projections generally see an increasing role for gas-fired capacity up to 2050. [142]

- **Heating** – Today, over 40% of energy demand in the Czech Republic is accounted for by residential and commercial buildings. The largest part of this energy is used for space heating, which, in turn, is mainly supplied by renewables and waste (35%), gas (27%) and fossil solid fuels (18%). Only a minor share of 4% is covered by electricity.[143] Accordingly, the seasonal profile of electricity demand in the Czech Republic is currently relatively flat, while the profile for gas demand is highly seasonal (Figure 83).

  Some increase in electricity demand seasonality might be expected going forward, regardless of the scenario considered. According to Net4Gas experts, the default technology for new buildings is electric heating (heat pumps). However, in addition, some district heating networks are being closed and the Czech Republic aims for the use of individual solid fuel heating to be phased out. If heating needs in these properties and those currently fuelled by gas were to be met entirely with electricity in the future, peaks in electricity demand would grow substantially. Covering these peaks would pose extraordinary challenges both for generation/storage, as well as the transmission and distribution network. Amongst others, it would create the need for substantial back-up capacity.

Figure 83 Monthly gas vs. electricity load profile in the Czech Republic



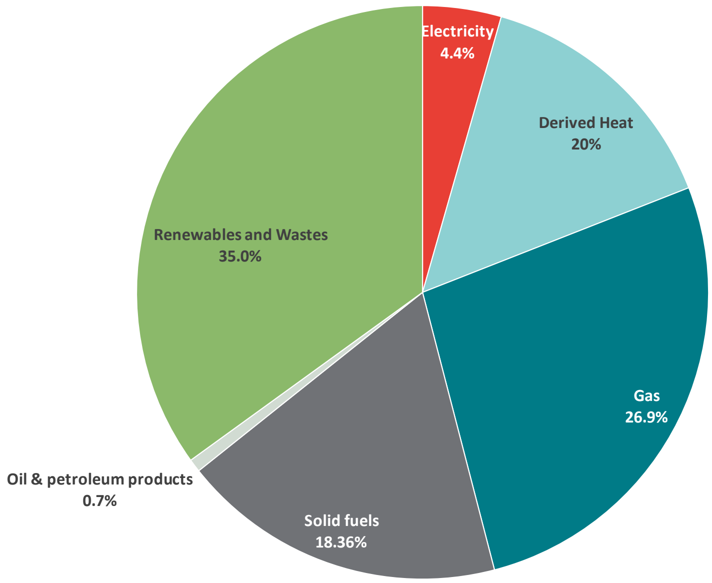
Source: *Frontier Economics based on IEA Monthly Gas Statistics for Actual Gas Load (GWh, 2017) and ENTSO-E Transparency Platform for Actual Electricity Total Load (GW, 2017)*

[142] See OTE (2017), Tables 1 to 3.

[143] Eurostat.

Retaining, or even increasing, the role for gas in heating would avoid the need for this back-up capacity (and additionally avoid capital-intensive investments in heat pumps). Consequently, there are good arguments to keep existing gas connections active and let households continue to heat with (in the future renewable and low-carbon) gas. In addition, we understand from Net4Gas that a substantial proportion (around 10%) of existing gas connections are currently ‘unused’ or ‘under-used’ (e.g. where gas is used for cooking purposes only). Many of these properties may use solid fuels for heating, meaning that there could be a role for gas if solid fuels are to be phased out from heating.

Figure 84 Final energy demand for space heating in residential buildings by fuel in the Czech Republic (2016)



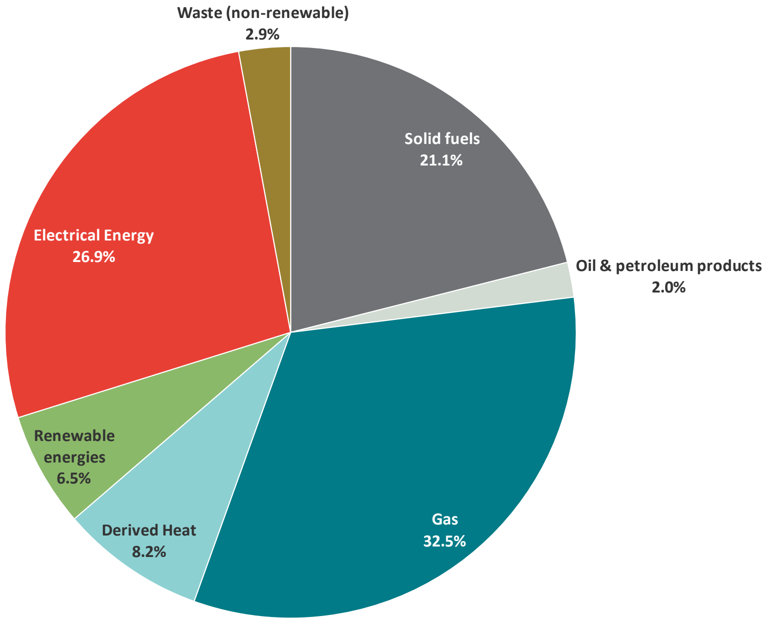
Source: Frontier Economics based on Eurostat

- **Industry** – Today, approximately 30% of final energy demand in the Czech Republic is consumed in the industry. Gas accounts for about a third of demand. The bulk of industrial gas demand (for energy) comes from the iron/steel and non-metallic minerals sectors. These processes often require high-grade heat that can be difficult or expensive to provide through electricity. Renewable and low-carbon gas (or other renewable/low-carbon combustible fuel sources, such as biomass), either directly (i.e. boilers) or used in CHP plants, will therefore be needed to allow these sectors to continue operating in the Czech Republic. A smaller amount of gas (1.4 TWh)[144] is required as feedstock (i.e. for non-energy purposes) in industrial processes (usually in the form of hydrogen). If this gas is not available from the network, it will need to

[144] Eurostat data for 2016.

be produced on site (e.g. using electrolysis), at potential additional cost given the lack of economies of scale.

Figure 85 Final energy consumption in industry by fuel in the Czech Republic (2016)



Source: Frontier Economics based on Eurostat

- **Transport –** Transport constitutes around a quarter of final energy demand (78 TWh in 2016). The share of gas in meeting final energy demand for transport is currently negligible (0.8%). And Net4Gas informed us that public concerns regarding safety of gas vehicles may be hindering their uptake.[145] That said, mobility is one area in which the policy goals are clearer. The Czech Republic has set aims to phase out use of diesel in urban buses by 2040 and to promote the use of alternative fuels, including CNG and hydrogen.[146] We understand from Net4Gas that gas vehicles are increasingly competitive vis-à-vis diesel vehicles, thanks in part to vehicle tax reductions (recently extended to 2025). The National Action Plan for Clean Mobility sets a goal of building 5 LNG filling stations in the Czech Republic by 2025 and 14 by 2030.[147] As a result, gas is likely to play an important role in some areas of transport in the future – Net4Gas believes that it could be reasonable to assume a final demand of 3 TWh for gas in transport by 2030.

[145] Gas vehicles are, for instance, banned from public car parks.

[146] See Ministry of Industry and Trade of the Czech Republic (2014).

[147] See National Action Plan for Clean Mobility, Ministry of Industry and Trade of the Czech Republic (2015).

VI. Gas networks reduce system costs of energy supply and increase public acceptance

In the previous section we found that renewable and low-carbon gas is not only important for seasonal storage, where it is practically indispensable, but also potentially a valuable energy carrier to supply various sectors directly. This is reflected by our calculations of system costs for two different decarbonisation paths.

In summary, the continued use of gas networks to transport energy to final customers in the Czech Republic in 2050 yields cost benefits of **EUR 1.5 to 3.0 billion per year**. Further, it contributes to the public acceptance of decarbonisation through avoided electricity network expansion.

EUR 1.5 to 3.0 bn / year

can be saved through the continued use of gas networks in 2050.

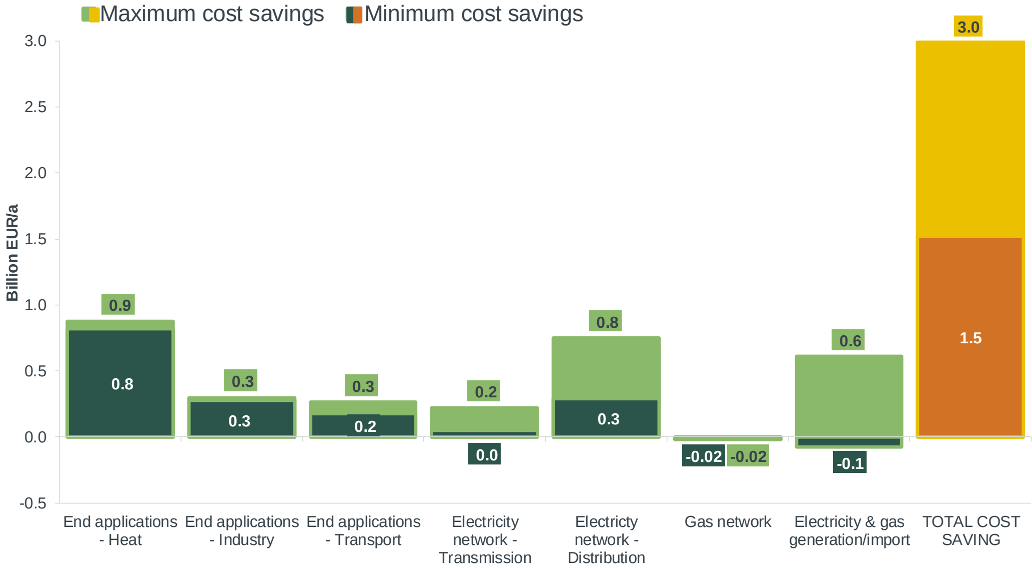
The gas network helps save costs across the whole value chain

We have derived these estimates by comparing a scenario in which gas networks are still used to deliver gas[148] to end users ("Electricity and Gas Infrastructure" scenario) to a scenario where most end appliances are electrified and gas is only used for seasonal storage with (re-)electrification ("All-Electric plus Gas Storage" scenario) in 2050 (see Section 4.2 for more details).

To compare energy system costs between the two scenarios, our analysis has taken into account costs along the entire energy supply chain. To capture uncertainty about the future development of key parameters such as gas and electricity demand or gas generation costs in 2050, we have executed the calculations for a number of different parameter sets, leading to estimations of cost saving intervals.

[148] Given that the Czech Republic has not formulated specific decarbonisation targets for 2050, we assume that natural gas will continue to play a minor role in 2050. However, it may be feasible to reduce its role or replace it entirely with the help of blue hydrogen, which we currently do not consider in our calculations for the Czech Republic.

Figure 86 Min and max cost savings of a continued use of gas networks per year in 2050 along the supply chain in the Czech Republic



Source: Frontier Economics/IAEW

Note: The values illustrate the difference in annual costs between the "All-Electric plus Gas Storage" scenario and the "Electricity and Gas Infrastructure" scenario. A positive value reflects cost savings in the "Electricity and Gas Infrastructure" scenario, where parts of end energy are supplied by renewable and low-carbon gas via gas networks, compared to the "All-Electric plus Gas Storage" scenario, where end energy is primarily supplied by electricity and gas networks are no longer needed. Minimum and maximum savings refer to varied assumptions on key parameters that are uncertain from today's perspective, such as production prices of different gases or the development of final energy demand until 2050.

The results reveal that the Czech Republic can benefit considerably from the continued use of gas networks. In 2050 it can save **EUR 1.5 to 3.0 billion per year** in an "Electricity and Gas Infrastructure" scenario compared to an "All-Electric plus Gas Storage" scenario where most end appliances have been electrified and gas is only used for temporal storage. This corresponds to annual cost savings of **EUR 144 to 285 per capita.**

The bulk of these total savings is resulting from lower costs for end appliances in residential heating and cost savings through avoided investments in electricity distribution networks. Further savings can come from reduced gas and electricity generation costs, depending on future costs of renewable and low-carbon gas production. If these sink sufficiently, renewable gas such as (imported) green hydrogen or biomethane can provide an abundance of cheap energy in the "Electricity and Gas Infrastructure" scenario, which will generate substantial cost savings compared to the "All-Electric plus Gas Storage" scenario (see light green column for "Electricity & gas generation/import" in Figure 86). However, if high renewable gas production costs coincide with an unfavourable demand path, the costs of energy generation in the "Electricity and Gas Infrastructure" scenario could exceed those in the "All-Electric plus Gas Storage" scenario (see dark green column for "Electricity & gas generation/import" in Figure 86).

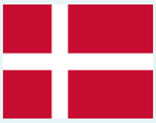
Use of gas networks benefits public acceptance of decarbonisation

As explained above, in the “All-Electric plus Gas Storage” scenario the Czech electricity grid would have to be expanded substantially. The gas network, on the other hand, is already fit for purpose. Its continued usage would therefore render significant parts of the electricity grid extension obsolete: Based on an extensive network modelling exercise, we previously identified that for the German transmission network this effect is as large as 40% by 2050.[149] Transferring this result to the Czech Republic by taking into account the less significant penetration of gas and the lower extent of RES expansion until 2050, it is likely that the Czech Republic could avoid transmission grid extensions of more than 30% through the continued use of gas networks by 2050, compared to the “All-Electric plus Gas Storage” scenario. In light of the public resistance against the new construction of overhead power lines, gas networks therefore benefit public acceptance of decarbonisation.

[149] See Frontier Economics et al. (2017).

ANNEX E COUNTRY STUDY DENMARK

Summary



- **Climate goals –** Denmark is targeting to become a net zero CO_2 emitter by 2050. Due to its vast potential of offshore wind and biomass and a history of district heating, Denmark disposes of good prerequisites to reach this targets. Nonetheless, the energy transition will require substantial changes in all energy-consuming sectors.
- **Challenge of connecting wind power with load –** One particular Danish challenge is to collect the electricity generated in offshore and onshore wind parks on the west coast of the main peninsula Jutland, and connect this with load centres on the islands of Funen and, particularly, Zealand with Denmark's capital Copenhagen. Accordingly, massive electricity grid extensions are needed. Current grid extension projects amount to 1,415 km, equivalent to 27% of today's transmission grid length, and further requirements will be needed when thermal electricity production will be replaced by wind power in the run-up to 2050.
- **Existing gas infrastructure –** The Danish gas infrastructure has a lot to offer to contribute to decarbonisation. The gas network has historically been used to, *inter alia*, connect domestic gas exploration sources in the North Sea on Denmark's west coast with gas demand in the entire country. There are, thus, strong connections between the islands of Jutland, Funen and Zealand, where electricity network capacity is short. By increasingly filling this gas network with renewable gas such as domestically generated biomethane or green hydrogen, it can support the energy transition and help avoiding some investments in the electricity infrastructure. In addition, current gas storage capacity in Denmark is sufficient to store about 10 TWh of energy, corresponding to about one third of Denmark's annual gas consumption, which can contribute to integrating intermittent wind power generation and increasingly seasonal electricity demand if a proportion of heat demand is electrified.
- **Sources for renewable gas –** Denmark has large potentials to produce renewable gas. Major sources of renewable gas in Denmark are likely to be biomethane, which already provides 5% of current gas production with significant growth potential, and power-to-gas, in particular on the basis of wind (onshore or offshore) power, which can help collect the energy on the west coast and transport it to the load centres in the west. Denmark's connection to the German and soon also Norwegian gas network provides an opportunity to diversify and further increase the resilience of renewable gas supply, for example by importing blue hydrogen from Norway or hydrogen / synthetic methane from power-to-gas facilities in the North Sea.
- **Role of renewable gas in consumer sectors –** Renewable gas can play an important role in the decarbonisation of various energy consuming sectors in Denmark: In electricity, by providing reliable low carbon back-up for intermittent renewables especially wind power. In heating, by supplying

existing gas connections with renewable gas instead of natural gas, by replacing existing oil burners by hybrid heat pumps or gas boilers and by replacing district heating supply of coal and natural gas by renewable gas (alongside biomass). In industry, by reducing CO_2 emissions where electrification is hardly feasible or inefficient, such as for high-temperature process heat or as feedstock. And in transport, particularly by decarbonising heavy-duty and maritime transport.

- **Cost savings of using gas networks** – Our analysis shows that, compared to switching Denmark to a primarily electrification-led energy system, the usage of gas networks based on renewable gas could **reduce Danish system costs in the magnitude of EUR 500 to 1,100 million in 2050**. A considerable part of these savings results from avoided investments in new appliances in heating and transport, and from avoided electricity grid expansions. Depending on the development of renewable gas production costs, significant cost savings may also arise from lower energy production costs.
- **In summary, our analysis suggests that usage of Denmark's gas infrastructure is key to reaching Denmark's climate targets in a cost-effective way**.

I. Introduction

In this country study we provide an overview of why the gas infrastructure has a significant societal value for decarbonising Denmark. We follow the same structure as in the main report, and focus on highlighting the particularities in Denmark. Please refer to the main report for a general understanding of the methodology and argumentation.

II. Denmark's challenge: Decarbonising the energy system based on intermittent electricity generation

Achieving Denmark's decarbonisation targets presents a major challenge:

- **Ambitious climate protection targets require a massive transition of the energy system** – Denmark is targeting to become a net zero CO_2 emitter by 2050. Following the government's formulated objective of reaching "independence from fossil fuels" by 2050,[150] the new Danish Energy Agreement from June 2018, supported by all parties in the parliament, aims to bring Denmark a step closer to this goal.[151] Due to its vast potential of offshore wind and biomass and a history of district heating, Denmark disposes of good prerequisites to reach its decarbonisation targets. In fact, it is already on track – the renewable share of final energy consumption is expected to reach 40% in 2020, which is ahead of the EU target of 30%.[152] Nonetheless, the energy transition will require substantial changes in all energy-consuming sectors.

- **Reaching these objectives through a high degree of electrification would cause a significant increase in annual and peak electricity demand** – Our analysis reveals that meeting these objectives through a primarily electrification-led decarbonisation strategy would create a number of challenges:

  - **Increase in annual electricity demand** – Today, less than 19% of final energy demand in Denmark is supplied by electricity. Electrifying large parts of the residual 81% of final energy demand would lead to substantial additional electricity demand, even assuming ambitious energy efficiency gains. The fact that Denmark may continue to be a popular choice for large data centres may accentuate this challenge.

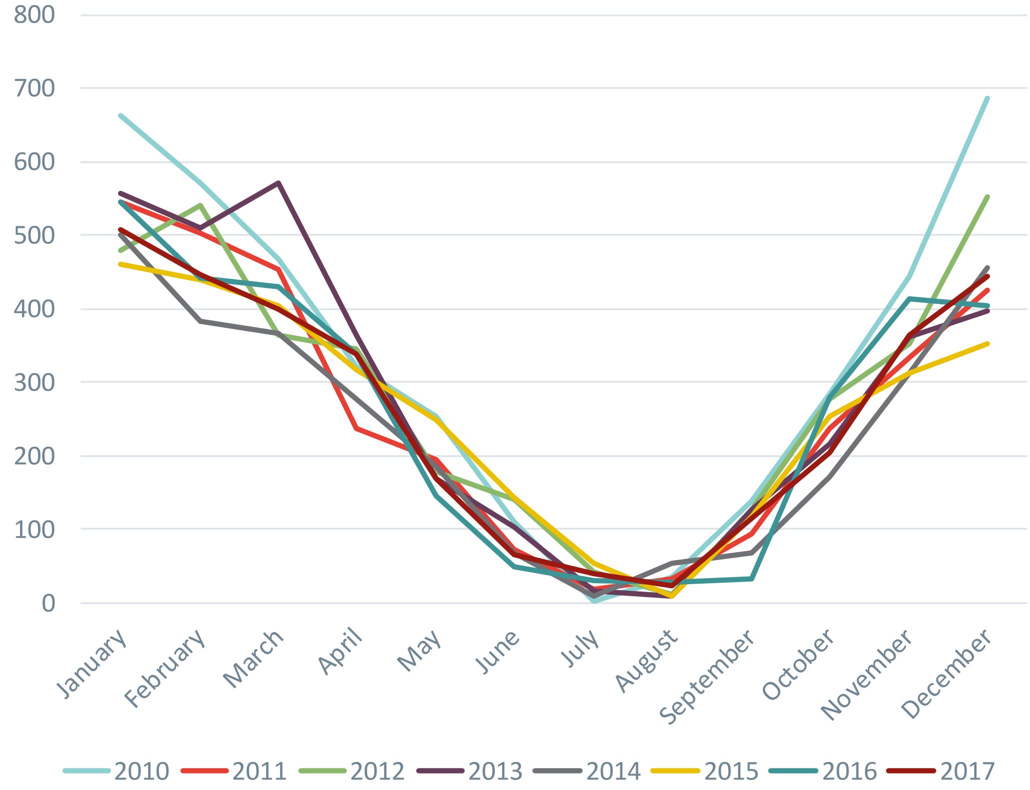
  - **Boost in electricity peak demand** – Today, where electricity is mainly used for lighting, ICT or electric engines, but not for space or water heating, electricity demand in Denmark is comparably flat over the course of the year. Electrifying large parts of the heat demand that is not supplied by district heating would integrate the considerable seasonality of heat demand (see Figure 87) into the electricity sector.

[150] See Regeringsgrundlag Marienborgaften (2016).

[151] See Ministry of Foreign Affairs in Denmark (2018).

[152] See Danish Energy Agency (2017a).

Figure 87 Seasonality in Denmark's heat demand (based on number of heating degree days)



Source: Frontier Economics based on Eurostat - Cooling and heating degree days by country - monthly data

Note: Heating degree days are a measure of how much (in degrees) and for how long (in days) outside air temperature was lower than a specific base temperature. Eurostat sets this temperature at 15°C in its calculations.

- **Challenges ensuring security of supply when integrating large shares of intermittent wind generation into the energy system** – Denmark's interconnector (see below) and CHP capacity currently provide back-up (including on seasonal timescales) to intermittent renewable output. However, significant additional flexible capacity would be needed if peak electricity demand were to grow in parallel with the deployment of intermittent wind and solar PV generation.
- **Substantial electrification creates further challenges for the (already strained) electricity network**
  - The electricity network is already stretched today: The major challenge is to collect the electricity generated in offshore and onshore wind parks on the west coast of the main peninsula Jutland, and connect this with load centres on the islands of Funen and, particularly, Zealand with Denmark's capital Copenhagen. Accordingly, electricity TSO Energinet is about to massively reinforce electricity lines to collect wind (such as the "West Coast line") and connect load centres in eastern Denmark (e.g. by the subsea HVDC (high-voltage direct current) project "Great Belt II" between Malling (western Denmark) and Kyndby (eastern Denmark)). Furthermore, there is a need for increased transmission capacities to neighboring countries. Consequently, a significant share of present grid extension projects

consists of subsea HVDC projects, for example the “Viking” interconnector project between Great Britain and Denmark, which is currently at the permission stage. Transmission capacities towards Germany are going to be increased by the implementation of a 380 kV AC (alternating current) double circuit between Audorf (DE) and Kassoe (DK) as well as a 380 kV AC transmission line between Klixbüll (DE) and Endrup (DK). In total present grid extension projects amount to 1,415 km, equivalent to 27% of today’s transmission grid length.

- Looking further ahead, wind onshore and offshore capacity will replace fossil-fueled dispatchable electricity capacity, accentuating the need for electricity network extensions (see Figure 88). Additional strong electrification of gas-based end appliances would put further stress on the electricity grid.

Figure 88 Plans for electricity network development in Denmark by 2040

Source: Energinet

III. Danish gas infrastructure well suited to help overcome the challenges of decarbonisation

Today, around 10%[153] of final energy demand in Denmark is supplied by gas. Of this the majority is consumed in industry (43%) and in the residential sector (42%).

10%

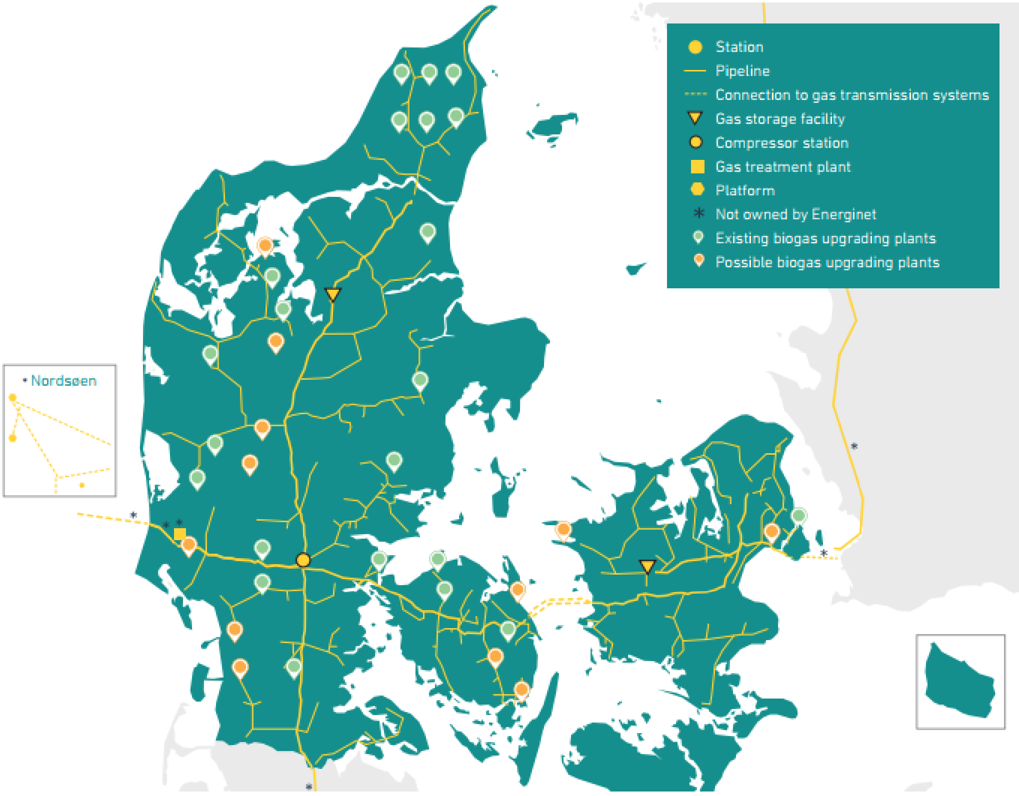
Of Denmark's final energy demand is supplied by gas today.

Accordingly, Denmark has a well-established gas infrastructure.

- **Domestic gas network** – Denmark's transmission and distribution network covers most, though not all, parts of the country. It has around 18,000 km length, of which the high-pressure transmission network accounts for more than 900 km (Figure 89). The network has historically been used to, *inter alia*, connect domestic gas exploration sources in the North Sea on Denmark's west coast with gas demand in the entire country. There is, thus, strong connection between the islands of Jutland, Funen and Zealand, where electricity network capacity is short. By increasingly filling this gas network with renewable gas such as domestically produced biomethane or green hydrogen, it can support the energy transition and help avoid some investments in the electricity infrastructure. We outline the potential for the use of gas in various sectors as well as the cost savings from the continued use of gas networks in subsequent sections.

153 Based on Eurostat.

Figure 89 The Danish gas system (overview)



Source: Energinet (2017a)

- **Gas import capacity –** Historically, the purpose of the Danish gas grid has been to supply Denmark and Sweden with domestic gas from the North Sea or Germany and to connect production facilities in the North Sea with gas storage facilities in central Europe. Accordingly, Denmark has been a net exporter of natural gas in the past.[154] However, in order to improve the Danish security of gas supply, investments in recent years have significantly expanded the import capacity from Germany. Furthermore, the New North Sea pipeline, connecting natural gas fields in Norway with the Baltic States via Denmark, will further increase the Danish import capacity.[155] It will be able to transport energy equivalent to Denmark's total consumption of oil, gas and electricity.[156]
- **Gas storage –** As outlined above, one of the major difficulties for integrating large amounts of intermittent renewable energy sources into the Danish energy system will be to deal with periods of surplus or insufficient energy. While electricity-based storage such as pumped hydro energy storage is unavailable in Denmark and, just like batteries, not suited for longer-term storage anyway, gas storage is. Current gas storage capacity in Denmark is sufficient to store about 10 TWh of energy, corresponding to about one third of Denmark's annual

154 And as a consequence, current capacity to import gas is, with 3 GW, lower than that of electricity (7 GW).

155 See Energinet (2017a).

156 See Energinet (2017b).

gas consumption. And gas storages in neighbouring countries offer further flexibility.

Overall, the Danish gas system is able to receive, store and distribute large amounts of energy, making it a valuable contributor to the Danish energy transition.

IV. Large biogas and power-to-gas potentials offer opportunities to diversify the Danish energy supply

Denmark has large potentials to produce renewable gas. Major sources of renewable gas in Denmark are likely going to be biomethane and power-to-gas (from a predominantly renewable electricity mix). In the following we will describe each of the technologies in further detail.

- **Biomethane** – Denmark has a high biomethane potential. Already today, Denmark produces around 3 TWh of biogas, with agricultural substrates being the most important source (around 50% of produced biogas).[157] Biomethane generation already comprises around a third of this volume.[158] While the first commercial biogas upgrading plants was connected to the grid in 2014, there has been a steady rise in the past few years to around 30 plants today, supplying around 5 per cent of Danish gas consumption in 2017.[159] And the upward trend continues: Biomethane is expected to reach 10-15% of Danish gas consumption shorty.[160] According to recent calculations, there is potential of sustainable domestic biomethane production of up to 27 TWh by 2035.[161]

- **Renewable gas from domestic power-to-gas –** Power-to-gas can play an important role in integrating the growing share of intermittent electricity generation from wind parks in the energy system, particularly to help collecting the energy on the west coast and transporting it to the load centres in the west. Conditions for power-to-gas in Denmark are favourable due to comparably competitive electricity prices, expected periods of surplus RES and the fact that surplus heat from PtG/PtX processes can be used in district heating networks.[162] And the possibility of offshore electrolysis combined with onshore hydrogen refinery is investigated. Given that the Danish gas system would be able to handle the transport of substantial amounts of hydrogen, there may be a case for using hydrogen directly – for instance to complement and stretch the available volumes of biomethane in the grid.[163]

- **Import of renewable gas** – Denmark's connection to the German and soon Norwegian gas network provides the opportunity to diversify and increase the resilience of renewable gas supply. Likely options are imports of blue hydrogen from Norway or hydrogen / synthetic methane from power-to-gas facilities in the North Sea.

157 See European Biogas Association (2017).

158 See European Biogas Association (2017).

159 See Energinet (2017a).

160 See Energinet (2017a).

161 See Grøn Gas Danmark (2017).

162 See Energinet (2018b).

163 See for example the different scenarios in Danish Energy Agency (2014).

In order to achieve the most efficient mix of electricity generation and gas production, different forms of system integration are currently being considered. Between decentralised district heating plants, decentralised energy plants (biogas with PtG/PtX) and large central plants with PtG/PtX, the challenge will be to balance between scale, flexibility and requirement for additional grid expansion.

V. Renewable gas has a strong potential in various sectors

Renewable gas has a strong potential to support the energy transition in various energy-consuming sectors (see Annex B for more details on the analysis of sectors):

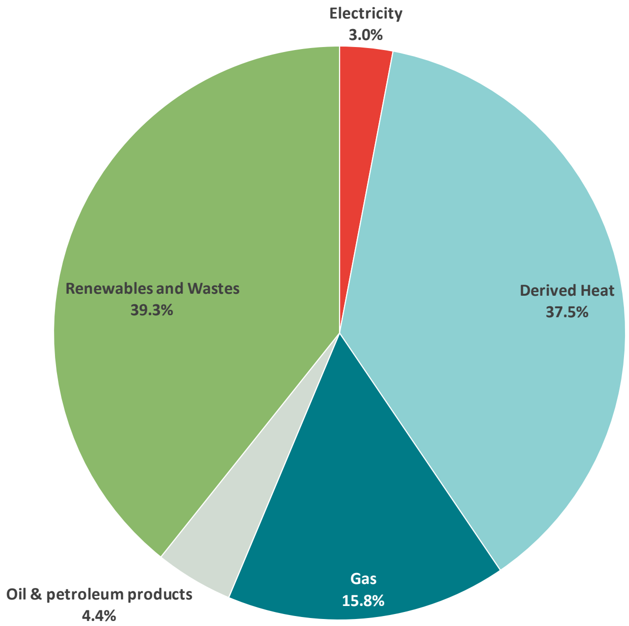
- **Electricity generation** – Renewable energies already constitute more than 70% of the Danish generation mix today. The largest share is wind with 50%. Gas contributes only around 7%.[164] In line with the emission targets of the government, coal is going to be phased out, while the share of biomass, solar and offshore and onshore wind will increase steadily. This increases the challenge of balancing electricity supply and demand. Battery and heat storage is likely to be essential for short- and potentially mid-term balancing, but too expensive for large scale storage over weeks or even months. The same holds for the electricity integration with Nordic hydroelectric power plants, which can contribute to balancing out fluctuating electricity but will not be sufficient on their own.[165] Given Denmark's vast renewable gas potential described above, there may therefore be a role for gas to provide long-term storage and flexibility.
- **Heating** – In Denmark, the biggest part of this is supplied by derived heat (50%), followed by renewable energies and gas (16%). Only a minor share of less than 4% is covered by electricity.[166]

[164] Entsoe Transparency Platform (2018).

[165] See Energinet (2018b).

[166] Eurostat.

Figure 90 Final energy demand for space heating in residential buildings by fuel in Denmark (2016)

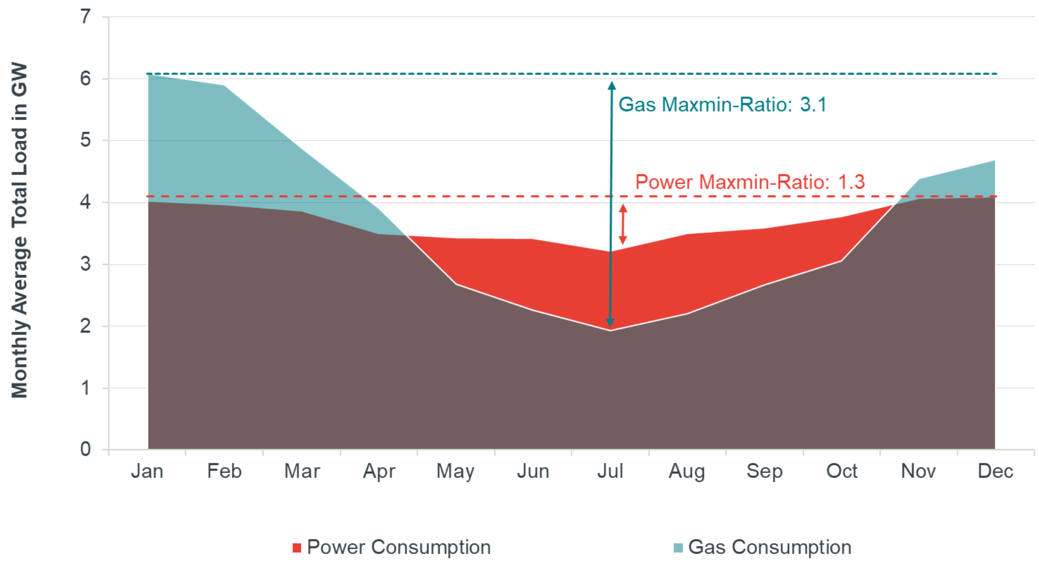


Source: Frontier Economics based on Eurostat

There are two potential future roles for gas in heating.

- Firstly, to achieve the Danish decarbonisation targets, the shares of heating currently supplied by oil and natural gas have to be replaced by renewable sources. Given the seasonality in Danish heat demand (cf. Figure 87), electrifying all of the affected households would considerably accentuate the seasonality in electricity demand, creating challenges for storage and supply. There is therefore a case for keeping existing gas connections in use, supplying them with renewable gas instead of natural gas and, where possible, also for replacing existing oil burners by hybrid heat pumps or gas boilers.

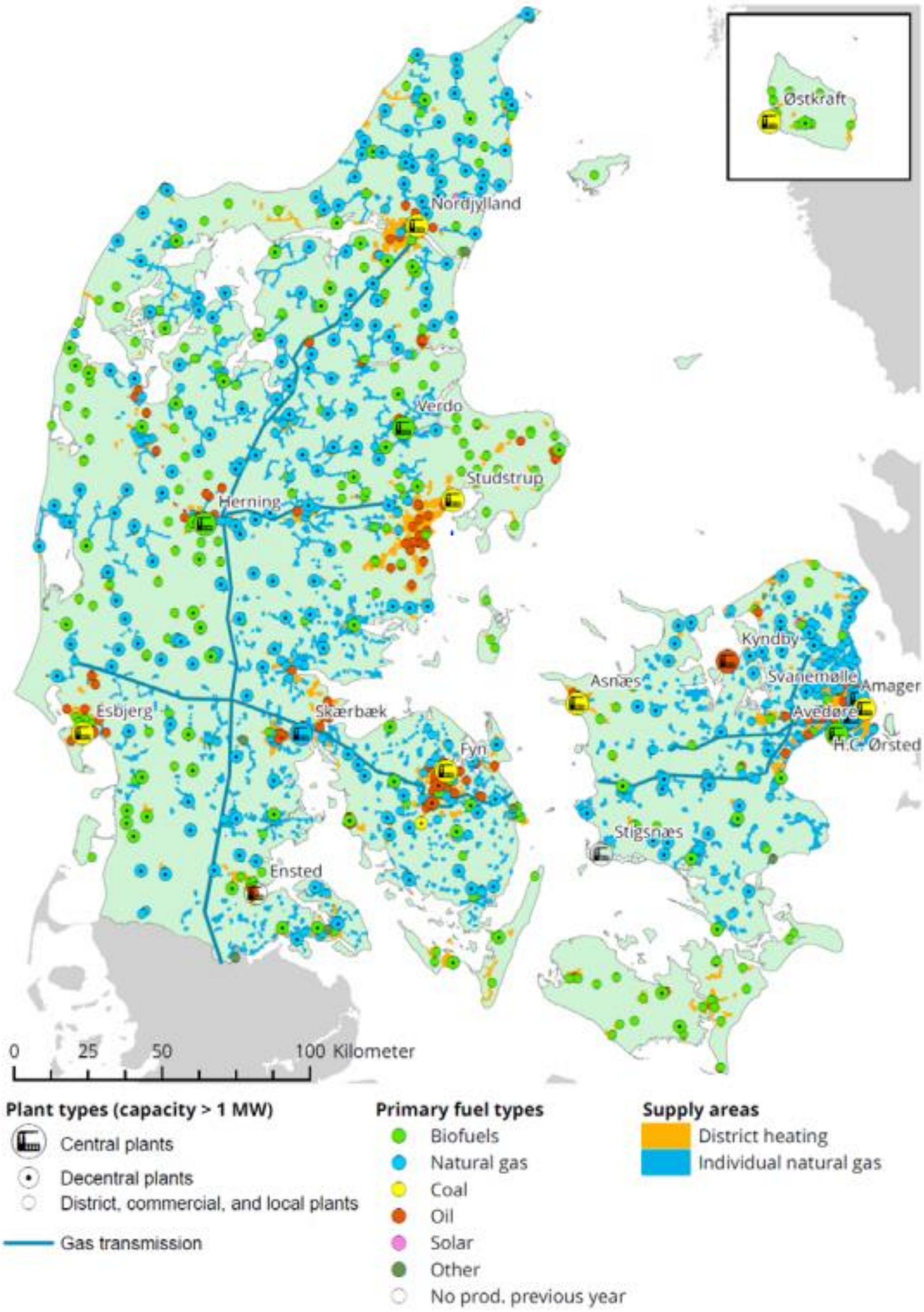
Figure 91 Monthly gas vs. electricity load profile in Denmark



Source: *Frontier Economics based on IEA Monthly Gas Statistics for Actual Gas Load (GWh, 2017) and ENTSO-E Transparency Platform for Actual Electricity Total Load (GW, 2017)*

- Secondly, as shown in Figure 90, 38% of heat in Denmark is supplied by derived heat. Danish district heating networks are concentrated around densely populated areas and are made up of six large central areas and 400 small/medium-sized areas. They cover around 63% of private housing. Currently, the heat is supplied by a combination of coal, gas, gas-fired CHP plants and, increasingly, biomass. Given that coal and natural gas have to be replaced and that without heat storages intermittent technologies would not be able to reliably supply the networks during peak periods, renewable gas may be a viable solution, especially given that gas-fired CHP plants could easily be fuelled by renewable gas.

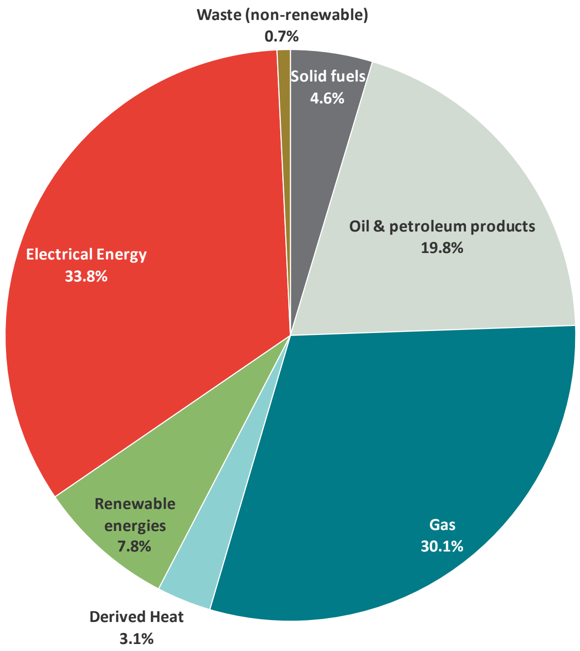
Figure 92 Denmark's Heating Supply



Source: Danish Energy Agency (2017b)

- **Industry** – Today approximately 15% of final energy demand is consumed in the industry. Electricity (34%) and gas (30%) are supplying the bulk of this, followed by oil (20%) and solid fuels such as coal (5%). Also, some industries like the chemistry industry require gas as feedstock. While (fossil) oil and coal will need to be replaced to decarbonise the industry, renewable gas has the potential to complement electrification, particularly where electric supply is difficult or inefficient, such as in high-temperature process heat (as, for example, required by the food industry such as bacon production) or as feedstock to supply carbon. It may therefore be sensible to leave an opportunity for the continued use of gas.

Figure 93 Final energy consumption in industry by fuel in Denmark (2016)



Source: Frontier Economics based on Eurostat

- **Transport** – Today Denmark's transport sector is, similar to that of most other European countries, dominated by oil products (94%). Gas plays a limited role, supplying 0.4% of final energy demand in transport. While Denmark plans to electrify all of rail and nearly all of passenger road transport until 2050, gas or hydrogen is likely to be an essential pillar in future heavy goods / public transport and shipping. Some Danish cities are already pioneering the use of biogas-fuelled buses and refuse collection trucks.[167]

[167] See Energinet (2015a).

VI. Gas networks reduce system costs of energy supply and increase public acceptance

In the previous section we found that renewable gas is not only important for seasonal storage, where it is practically indispensable, but also a valuable energy carrier to supply various sectors directly. This is reflected by our calculations of system costs for two different decarbonisation paths.

In summary, the continued use of gas networks to transport energy to final customers in Denmark in 2050 yields cost benefits of **EUR 500 to 1,100 million per year**. Further, it contributes to the public acceptance of decarbonisation through avoided electricity network expansion.

EUR 500-1,100 mio. / year

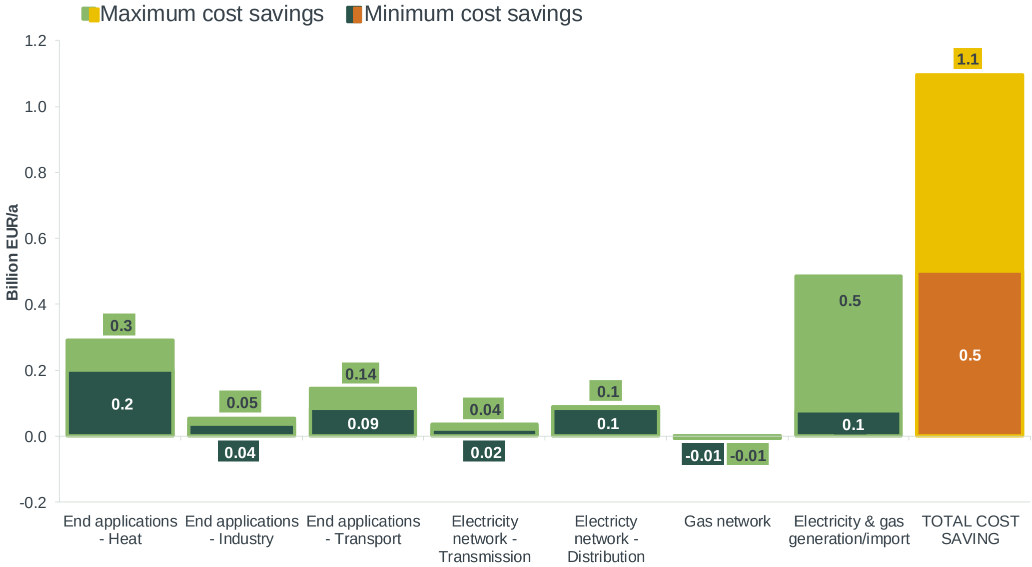
can be saved through the continued use of gas networks in 2050.

The gas network helps save costs across the whole value chain

We have derived these estimates by comparing a scenario in which gas networks are still used to deliver (renewable) gas to end users ("Electricity and Gas Infrastructure" scenario) to a scenario where most end appliances are electrified and gas is only used for seasonal storage with (re-)electrification ("All-Electric plus Gas Storage" scenario) in 2050 (see Section 4.2 for more details).

To compare energy system costs between the two scenarios, our analysis has taken into account costs along the energy supply chain. To capture uncertainty about the future development of key parameters such as gas and electricity demand or renewable gas generation costs in 2050, we have executed the calculations for a number of different parameter sets, resulting in the cost saving intervals presented below.

Figure 94 Min and max cost savings of a continued use of gas networks per year in 2050 along the supply chain in Denmark



Source: Frontier Economics/IAEW

Note: The values illustrate the difference in annual costs between the "All-Electric plus Gas Storage" scenario and the "Electricity and Gas Infrastructure" scenario. A positive value reflects cost savings in the "Electricity and Gas Infrastructure" scenario, where parts of end energy is supplied by renewable and low-carbon gas via gas networks, compared to the "All-Electric plus Gas Storage" scenario, where end energy is primarily supplied by electricity and gas networks are no longer needed. Minimum and maximum savings refer to varied assumptions on key parameters that are uncertain from today's perspective, such as production prices of different renewable gases or the development of final energy demand until 2050.

The results reveal that Denmark can benefit considerably from the continued use of gas networks. In 2050 it can save **EUR 500 to 1100 million per year** in an "Electricity and Gas Infrastructure" scenario compared to an "All-Electric plus Gas Storage" scenario where most end appliances have been electrified and gas is only used for temporal storage. This corresponds to annual cost savings of **EUR 88 to 192 per capita.**

A considerable part of these cost savings result from avoided investments in capital-intensive electric heat pumps, from lower per-unit costs for gas-fuelled vehicles compared to electric vehicles, and – to a lesser extent – from avoided electricity grid expansions. Given Denmark's large biomethane potential, renewable gas costs are to a large extent driven by biomethane costs. If these sink considerably (for instance to 52 €/MWh as expected by Ecofys[168]), this stage of the supply chain can generate the largest cost savings (see light green column for "Electricity & gas generation/import" in Figure 94).

Use of gas networks benefits public acceptance of decarbonisation

As explained above, in the "All-Electric plus Gas Storage" scenario the increase in offshore wind power production, amongst others, would necessitate substantial investments in the Danish electricity network. The gas network, on the other hand, is already fit for purpose. Its continued usage would therefore render significant

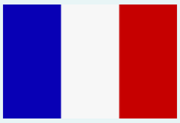
[168] See Ecofys (2018).

parts of the electricity grid extension obsolete: Based on an extensive network modelling exercise, we previously identified that for the German transmission network this effect is as large as 40% by 2050.[169] Transferring this result to Denmark by taking into account the less significant penetration of gas and the lower extent of RES expansion until 2050, it is likely that Denmark could avoid transmission grid extensions of approximately 11 to 15% through the continued use of gas networks by 2050, compared to the “All-Electric plus Gas Storage” scenario. In light of the public resistance against the new construction of overhead power lines, such as the West coast line, gas networks therefore benefit public acceptance of decarbonisation.

[169] See Frontier Economics et al. (2017).

ANNEX F COUNTRY STUDY FRANCE

Summary



- **Climate-neutrality by 2050 –** To achieve its target of climate-neutrality by 2050, France has to decarbonise its heating, overland transport and industry sector entirely. The same applies to the electricity sector, which is comparably low-carbon today, though, thanks to France's high nuclear power share of more than 70% .
- **Reduction of nuclear power –** At the same time, the French government has committed to reduce the share of nuclear power production to 50% by 2035.
- **The challenge of strong electrification –** Reaching the climate objective through a high degree of electrification would impose significant challenges for the generation, transport and storage of energy in France. Electricity consumption may almost double from today's 440 TWh per year. The seasonality of electricity demand, already comparably high in France given its high penetration of electric heating which led, inter alia, to the introduction of a capacity reliability mechanism to guarantee security of electricity supply in recent years, will be accentuated by further electrification of heat demand. With nuclear plants shutting down and natural electricity storage such as from hydro being limited, there will need to be other options to cover winter peak demand.
- **Existing gas infrastructure –** Gas infrastructure in France offers the opportunity to complement electrification in a pathway to decarbonisation: Gas supplies around 20% of final energy demand and the gas network spans the entire country. Gas import capacity is large, both via pipelines and LNG, in total exceeding electricity import capacity by a factor of more than 10. Likewise, domestic gas storage capacity in France is sufficient to store 133 TWh of energy (which is 1,500 times the energy storage volume of existing electricity storage), providing the basis to bridge the gap between energy supply and seasonal heat demand.
- **Sources for renewable gas –** Given large potentials of renewable energy sources such as biomass, wind and solar, France has substantial domestic potential to produce both biomethane and hydrogen or synthetic methane from renewable electricity. According to a recent ADEME study, total domestic renewable gas production potential in 2050 amounts to 460 TWh, which is likely to cover a large part (if not all of) France's future gas demand, enhancing France's energy independence.
- **Role of renewable gas in consumer sectors –** Renewable gas can play an important role in various energy consuming sectors: In electricity production, by complementing intermittent renewables. In heating, by helping to cope with heat demand seasonality, likely to be based on biomethane. In industry, with a focus on hydrogen. And in transport, where there is significant momentum behind the use of hydrogen-driven fuel cells

particularly in heavy goods transport and behind the use of gas in shipping.

- **Cost savings of using gas networks** – Our analysis shows that, compared to following a strongly electrification-led decarbonisation pathway, the complementing usage of gas networks based on renewable gas could **reduce French system costs in the magnitude of EUR 6.5 to 14.5 billion in 2050**. A large part of these total savings will stem from lower costs for end appliances in residential heating and transport and cost savings through avoided investments in electricity distribution networks. Further potentially very large savings can come from lower costs for energy generation. Due to France’s large biomass potential, an important driver of the magnitude of these savings is the development of future biomethane production costs.
- **In summary, our analysis suggests that usage of France’s gas infrastructure is key to reaching France’s climate targets in a cost-effective way**.

I. Introduction

In this country study we provide an overview of why the gas infrastructure has a significant societal value for decarbonising France. We follow the same structure as in the main report, and focus on highlighting the particularities in France. Please refer to the main report for a general understanding of the methodology and argumentation.

II. France's challenge: Carbon neutrality by 2050 while reducing nuclear power generation

Achieving France's decarbonisation targets presents a major challenge:

- **Ambitious climate protection targets** – The climate plan presented by the French government sets out a goal of making the French economy 'carbon neutral' by 2050.[170] This goal is to be formally codified in the revision of the *Stratégie Nationale Bas-Carbone* (SNBC) which has been released by end-2018.[171] According to recent analysis from the French Environment Ministry, available 'carbon sinks' in France will only just about be able to capture difficult-to-avoid greenhouse gas (GHG) emissions from sources such as agriculture, industry and aviation.[172] Hence, carbon neutrality of the French economy also implies (near) complete decarbonisation of all final energy consumption (including transport) by 2050. And while final energy consumption can be expected to fall (due to energy efficiency improvements), it will still remain significant in 2050.

- **Reducing nuclear electricity generation** – At the same time, the French government is keen to reduce electricity production from the ageing nuclear power plant fleet of EDF, the monopoly nuclear operator. While nuclear power supplied 71% of electricity consumption in France in 2017, President Macron just recently unveiled the target to reduce this share to 50% by 2035 in the French multiannual energy framework.[173] This is already delaying the achievement of this goal by 10 years compared to the original ambition to achieve this 50% share by 2025, reflecting the technical and economic challenges resulting from a faster reduction.[174]

- **Reaching these objectives through a high degree of electrification may cause a significant increase in annual and peak electricity demand** – Existing studies as well as our analysis reveal that meeting these objectives through a primarily electrification-led decarbonisation strategy would create a number of challenges:

  - **Increase in annual electricity demand** – While final electricity consumption today in France is around 440 TWh[175], our analysis as well as

[170] Ministére de la Transition écologique et solidaire (2015).

[171] Ministére de la Transition écologique et solidaire (2018).

[172] Ministére de la Transition écologique et solidaire (2018).

[173] See Reuters (2018).

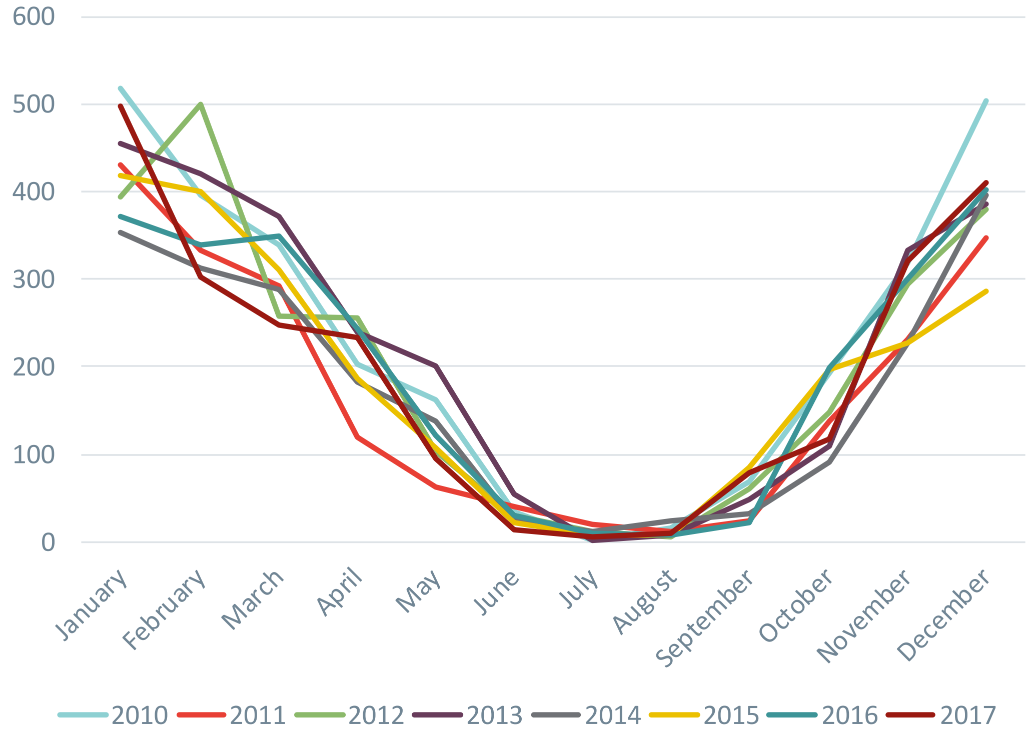
[174] See Financial Times (2018).

[175] Frontier Economics calculations based on Eurostat data for 2016.

research by both ADEME and SNBC reveal that this could nearly double if substantial parts of final demand are electrified.[176]

- **Accentuation of demand seasonality** – Given the significant penetration of electric heating compared to other EU countries, the French electricity system already manages significant seasonal swings in demand, with monthly demand falling nearly as low as 30 TWh during summer months and reaching 50 TWh during winter months.[177] This is, however, facilitated by France's enormous nuclear power fleet of 58 plants that is able to adjust production (and the timing of maintenance) to follow demand, and it is still far from gas seasonality.
- Further electrification of heating will tend to accentuate the peaks[178], given seasonality of heat demand in France (Figure 95).[179] And with nuclear generation being increasingly substituted by intermittent renewables such as wind and solar power, there will need to be other options to cover winter peak demand.

Figure 95 Seasonality in France's heat demand (based on number of heating degree days)



Source: Frontier Economics based on Eurostat - Cooling and heating degree days by country - monthly data

[176] Electrification of all final demand (apart from final demand met directly by renewable energy, carbon neutral solid fuels or liquid fuels) is equal to 761 TWh based on ADEME (2018) and 720-787 TWh based on Ministére de la Transition écologique et solidaire (2019).

[177] Frontier Economics calculations based on ENTSO-E data for 2016 and 2017.

[178] This may be partly compensated if mobility is also electrified, which is characterised by a flat or even counter-seasonal demand over the year.

[179] Which is, however, less pronounced than in North European countries such as Sweden or Denmark (see Figure 12 in Section 2.2 of the main report).

Note: *Heating degree days are a measure of how much (in degrees) and for how long (in days) outside air temperature was lower than a specific base temperature. Eurostat sets this temperature at 15°C in its calculations.*

- **Strong electrification creates further challenges for the (already strained) electricity network** – Already today there is a need for substantial strengthening of the French electricity transmission grid, as the Ten-Year-Network-Development-Plan (TYNDP) of French electricity TSO RTE suggests for the next decade.[180] Already planned or commissioned projects total to 3,100 km, equivalent to about 6% of the current transmission grid length.

  One of the key drivers of the currently planned expansion projects are higher and more volatile energy flows that emerge particularly in north-south direction and as a consequence of the shift towards renewable energy sources that are primarily located in the north (wind) and the south (PV) of France. In order to alleviate transit flows from north to south, reinforcement of existing 400 kV transmission lines e.g. between Cubnezais and Marmagne is under consideration.

  Furthermore, exchange capacities to Spain, Switzerland and Italy are supposed to be increased, indicating current congestion in the cross border areas.

  - Against that background a new HVDC (high-voltage direct current) interconnection between the areas of Grenoble and Turin is under construction.
  - Another HVDC project is planned to provide additional transmissions capacities of 2,000 MW between Cantegrit and Pamplona at the French-Spanish border.
  - An increase of exchange capacities between France and Switzerland is pursued by upgrading an existing 225 kV double circuit between Cornier and Chavalon.

  Looking beyond the next decade, the stress on the electricity network is likely to grow significantly:

  - **Generation perspective**: The gradual substitution of nuclear power and fossil-based generation by wind (with a focus onshore in the north and offshore) and solar power (with a focus in the south) will create a further need for network extensions.
  - **Demand perspective**: As already mentioned, electrification of most non-electric consumers will significantly increase future peak load, volatility and volume of electrical energy consumption most likely accompanied by additional loading and challenges for the French power system, which might be resolved by further grid expansion.

[180] See Rte (2015).

III. French gas infrastructure well suited to help overcome the challenges of decarbonisation

Today, around 20%[181] of final energy demand in France is supplied by gas. Of this, the majority is consumed in the residential sector (40%), the industry (36%) and in services (23%).

Accordingly, France has a substantial gas infrastructure:

20%

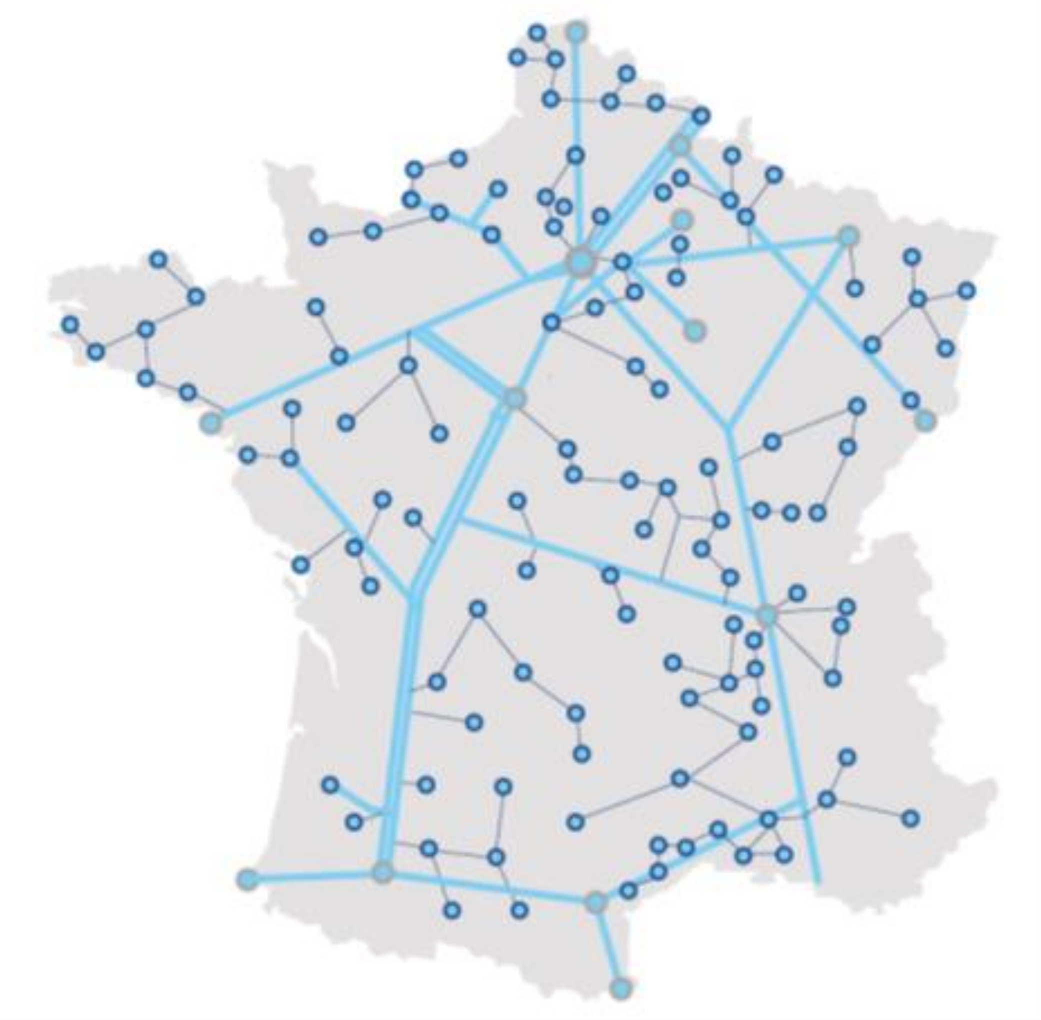
Of France's final energy demand is supplied by gas today.

- **Domestic gas network** – France has a comprehensive gas network of more than 230,000 km length, of which the transmission grid accounts for around 37,000 km. It spans the whole country (Figure 96) and reaches 80% of the French population.[182] This network can be employed to avoid large investments in the electricity infrastructure. We outline the potential for the use of gas in various sectors as well as the cost savings from the continued use of gas networks in subsequent sections.

[181] Based on Eurostat.

[182] See GRDF et al. (2016).

Figure 96 Gas transmission grid France (overview)

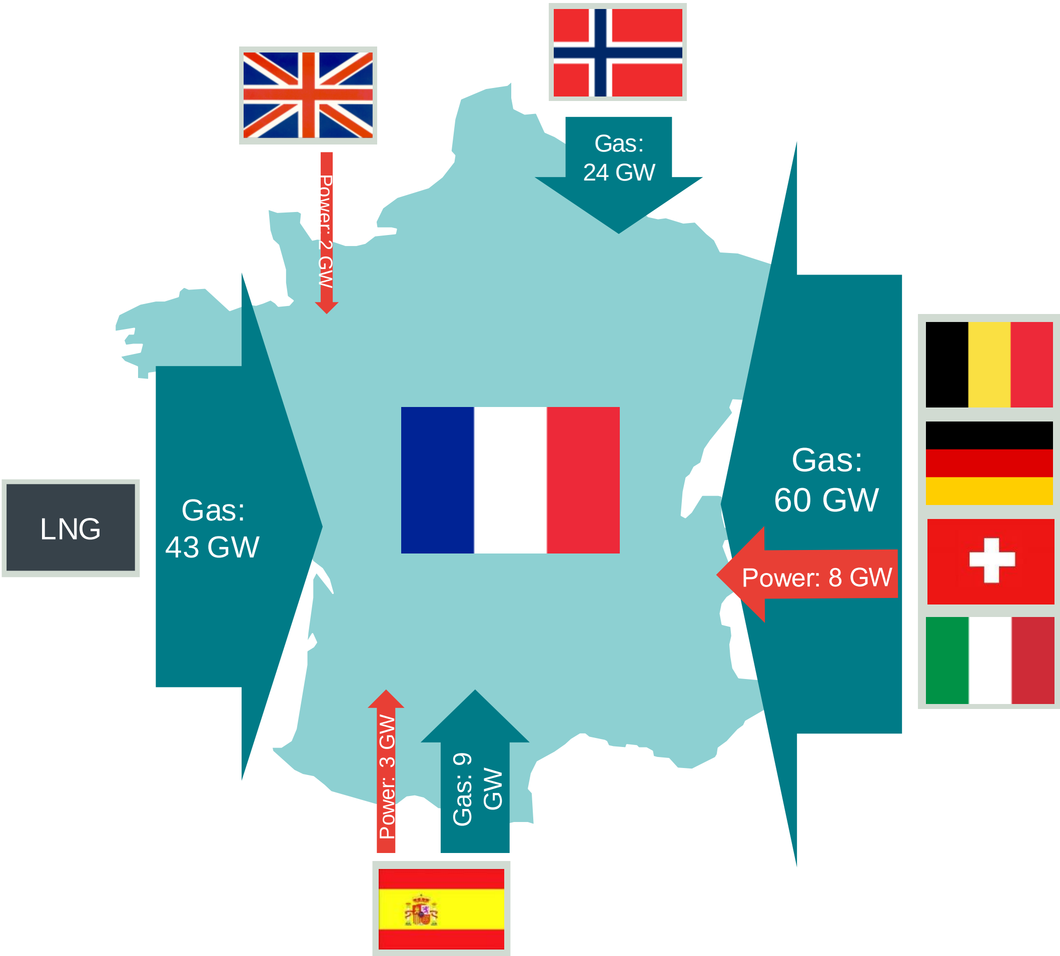


Source: GRDF et al. (2016)

- **Gas import capacity** – Since 2009 France has continued to expand its gas interconnection capacity with neighbouring countries.[183] Likewise, large LNG terminal capacity allows France to import gas from elsewhere around the world. In total, import capacity of gas pipelines and LNG terminals to France amounts to 136 GW, which exceeds the import capacity of electricity by a factor of ca. 11 (Figure 97).

[183] See International Energy Agency (2017).

Figure 97 Comparison of total electricity and gas import capacity: Gas import capacity exceeds electricity import capacity by a factor of 11

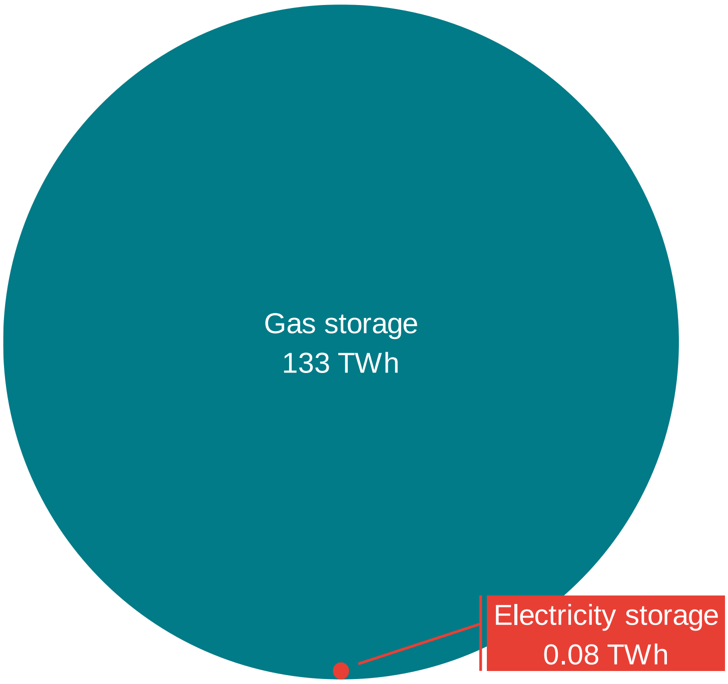


Source: ENTSO-E TYNDP (2018), ENTSO-G Physical Technical Capacity (2018)

Note: Power Import capacities presented are NTCs expected in 2020 according to ENTSOE TYNDP 2018

- **Gas storage capacity –** Likewise, France is well-equipped with gas storage, with a capacity of 133 TWh. This exceeds the existing electricity storage volume by a factor of ca. 1,500 (Figure 98). Additionally, given its high import capacity, France can access significant gas storage capacities in countries such as Germany.

Figure 98 Comparison of total electricity and gas storage volume in France: Gas storage volume is more than 1,500 times as large as electricity storage volume



Source: Frontier Economics based on Gas Infrastructure Europe and Geth et al. (2015).

In sum, the gas infrastructure can help improve overall system flexibility, which will be required to respond to intermittent renewable generation, on the one hand, and peakier demand, on the other hand, especially in light of decreasing nuclear power production.

IV. Existing gas infrastructure is suited for a variety of renewable and low-carbon gases

France has significant domestic production potential for various renewable gases, as set out in recent studies. This potential alone could exceed potential future gas demand, and it could further be augmented by imports from other countries:

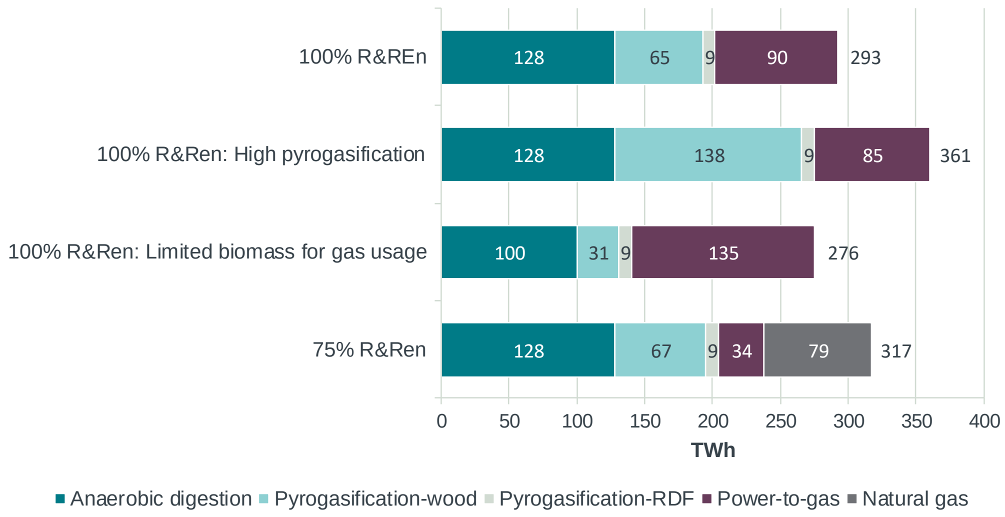
- **Biomethane and synthetic power to gas –** Given large potential of renewable energy sources, there is substantial potential to use electricity to produce synthetic methane or hydrogen. Moreover, France has substantial biomass resources to be employed to meet its decarbonisation targets.[184] In 2015, France produced around 6,000 GWh (or 6 TWh) of biogas, with manure being the main feedstock source. Biomethane generation is still in its infancy, but

[184] See, for instance Ministére de la Transition écologique et solidaire (2018), in which there is a discussion about the necessity to mobilise biomass in order to satisfy carbon free energy demand in 2050. Please note that since then the French government has revised and reduced the support for biomethane generation. Given that this does not affect the physical potential, however, it is not relevant for the remainder of this report.

increased significantly from 3 GWh in 2011 to 215 GWh in 2016.[185] As recently analysed by ADEME,[186] there is substantial scope for further biogas and biomethane production (see Figure 99). Based on four different scenarios for low-carbon gas production in 2050, the study reveals that

- there is significant potential (100-128 TWh) for biogas from anaerobic digestion;
- further biogas production (up to 147 TWh) is possible from pyro-gasification of biomass; and
- power-to-gas is also possible (up to 135 TWh), to produce hydrogen or synthetic methane.

Figure 99 ADEME study, renewable gas mix across four scenarios



Source: Frontier Economics based on ADEME (2018), Figure 3.

According to this study, total domestic renewable gas production (excluding food crops) in 2050 should be at least 270 TWh (in a 100% renewable energies scenario). This potential is likely to cover a large part (if not all of) France's future gas demand, enhancing France's energy independence.

- **Domestic blue hydrogen –** France currently imports natural gas either through pipelines or in the form of LNG. Provided that natural storage reservoirs suited for CO_2 storage can be found in France or nearby producing regions such as the North Sea, hydrogen produced from natural gas could be an additional source of low-carbon gas. This hydrogen could either be produced at centralised facilities before injection into the grid or on-site (e.g. at power stations or industrial locations), as noted by the French hydrogen association.[187]
- **Import of renewable gas –** In addition to the vast domestic potential, France is well interconnected with the global energy market (e.g. through pipelines from North Africa or LNG terminals) and hence has the opportunity to import

[185] See European Biogas Association (2017).

[186] ADEME (2018).

[187] See AFHYPAC (2018).

(renewable) gas from other countries in the case of a positive global equilibrium at the 2050 horizon. This can help ensure that the gas consumed within France is sourced as cost-effectively as possible. Likewise, based on its large domestic production potentials, exporting biomethane or other renewable gases may be an option.

V. Renewable gas has a strong potential in various sectors

Renewable gas a has strong potential to be used in various energy-consuming sectors in France (see Annex B for more details on the analysis of sectors):

- **Electricity** – France has a relatively low-carbon electricity generation mix today, thanks to nuclear power (>70%) and renewables (17%).[188] With the share of nuclear to be reduced to 50% by 2035 and potentially further by 2050, renewables will need to fill the gap. While the hydro potential is nearly exhausted, France has a large potential of solar PV and wind generation[189].[190] The main challenge for France will therefore less be to produce enough electricity but to provide it when it is needed. Technologies such as battery storage and demand-side response are suited for managing short-term fluctuations in supply and demand. However, other solutions will be needed to help manage seasonal fluctuations in demand. (Renewable) gas-fired generation could play an important role in ensuring seasonal peaks are met while at the same time allowing France to meet its GHG emission reduction targets.[191]
- **Heating** – Today, gas accounts for about 38% of the final energy demand for space heating in residential buildings. Renewable energies and waste cover 27% and oil 18% of space heating demand. Despite the high share in overall energy demand, the share of electricity in household space heating is only 13%.[192] As part of the objective to fully decarbonise the building sector until 2050, there are therefore plans to retrofit, renovate or rebuild all buildings, increasing their energy and climate efficiency.[193]

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188 Entsoe Transparency Platform (2018).

189 French wind generation benefits from three strong winds (in the West of France, in the Rhone valley and in the Languedoc area), making France one of the countries with the strongest wind potentials in Europe.

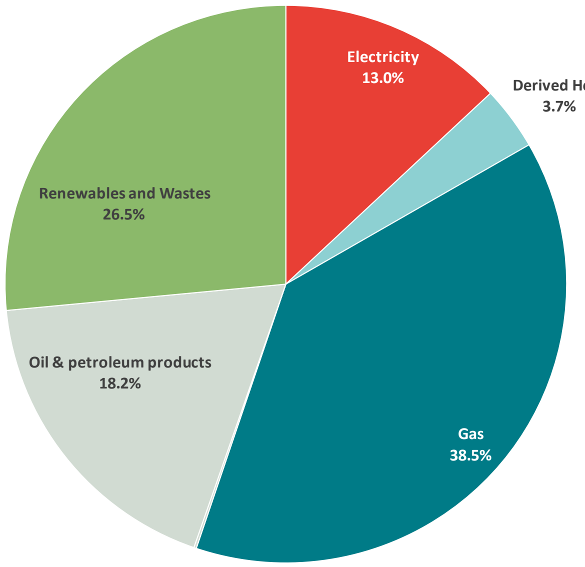
190 According to ADEME (2016) onshore wind could reach a capacity of 174 GW, offshore 66 GW and solar PV 411 GW.

191 See ADEME (2016). For example, with renewables at 95% or 100% of the electricity mix, 9 to 17 GW of 'seasonal storage' (in the form of power-to-gas-to-power facilities) are assumed to be needed to cope with challenging weather conditions. Note that the underlying demand projections still assumed some use of gas in heating; further electrification would likely increase the back-up required. At lower levels of renewables penetration (e.g. 40% or 80%), the study finds that gas-fired generation can provide the required flexibility, with up to 23 GW being needed in the 80% renewables scenario. However, the study is consistent with ADEME (2012), which in turn is based on 75% GHG emissions reduction by 2050 on 1990 levels. Assuming carbon neutrality by 2050, electricity supply would likely need to be completely decarbonised, meaning that (unabated) natural gas-fired generation could not provide the flexibility required (but technologies such as power-to-gas-to-power or biogas generation still could).

192 Eurostat.

193 See Ministére de la Transition écologique et solidaire (2018) and Ministère de la Transition écologique et solidaire (2015).

Figure 100 Final energy demand for space heating in residential buildings by fuel in France (2016)



Source: Frontier Economics based on Eurostat

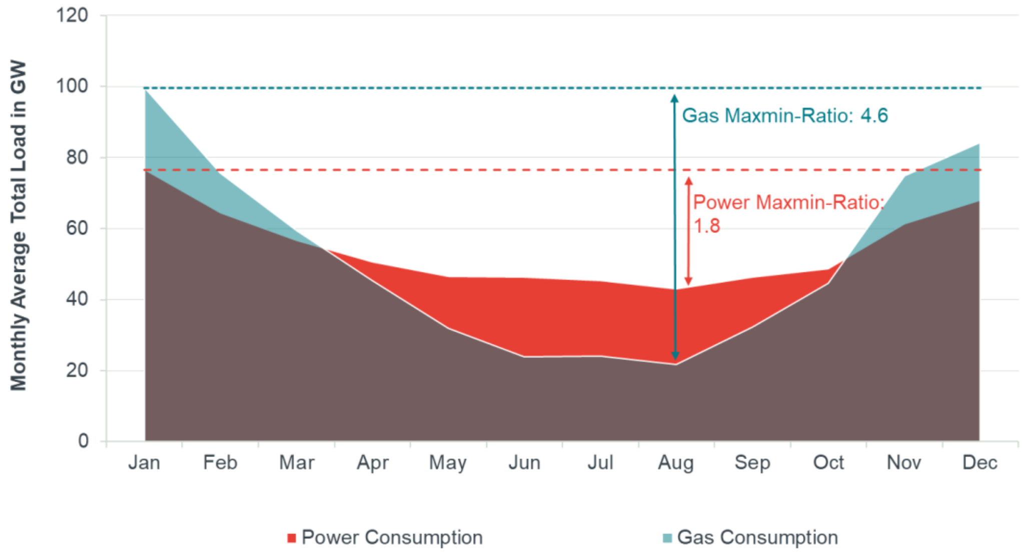
As explained earlier, the French electricity system today manages a comparably large electric heating penetration, although this is largely facilitated by the large nuclear fleet.

Further electrification of heating will accentuate the seasonality of electricity demand, raising the needs for flexible electricity generation or storage. With more and more nuclear plants shutting down and limited possibilities for seasonal electricity storage such as hydro storage, however, there is likely to be a limit to how much further electrification the system can cost-effectively manage.

Given the significant gas storage capacities both within France and within Europe as a whole that are already facilitating to cope with seasonal heat demand, with seasonality in gas consumption being twice as big as in electricity consumption (Figure 101), retaining a role for gas heating is likely to help minimise the costs of the energy transition in France. Accordingly, recent studies assume a remaining gas consumption in buildings in the range of 40 to 100 TWh.[194]

[194] See ADEME (2016), Direction Générale de l'Energie et du Climat (2019) and négaWatt (2018).

Figure 101 Monthly gas vs. electricity load profile in France



Source: *Frontier Economics based on IEA Monthly Gas Statistics for Actual Gas Load (GWh, 2017) and ENTSO-E Transparency Platform for Actual Electricity Total Load (GW, 2017)*

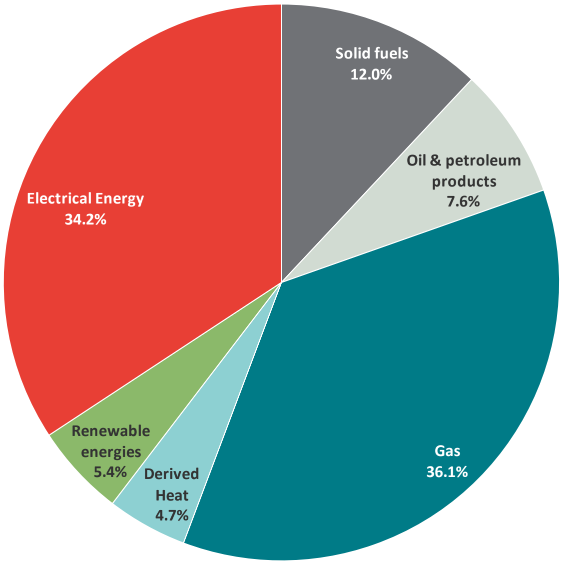
- **Industry** – Today, approximately 20% of final energy demand in France is consumed in the industry, of which 36% is supplied by gas, 34% by electricity and 8% by oil. The bulk of industrial gas demand (for energy) comes from the chemicals (31%) and the food and drink sectors (20%).[195] These processes often require high-grade heat that can be difficult or expensive to provide through electricity. Additionally, a smaller amount of gas (13 TWh)[196] is required as feedstock (i.e. for non-energy purposes) in industrial processes. If this gas is not available from the network, it will need to be produced on site (e.g. using electrolysis), at potential additional cost given the lack of economies of scale. It may therefore be sensible to leave an opportunity for the continued use of renewable gas. As envisioned by the French ministry for ecological and solidary transition, hydrogen produced from electrolysis may play an important role in supplying industry with carbon-free energy.[197]

[195] See GRDF et al. (2016).

[196] Eurostat data for 2016.

[197] See Ministére de la Transition écologique et solidaire (2017).

Figure 102 Final energy consumption in industry by fuel in France (2016)



Source: Frontier Economics based on Eurostat

- **Transport –** Transport is currently the highest CO_2-emitting sector in France. While the share of gas in meeting energy demand for transport is negligible today (0.1%), there is significant momentum behind increasing its future share. Industry has stated an ambition for reaching 20-30% use of gas in heavy goods transport by 2030, where hydrogen-driven fuel cell electric vehicles (FCEV) are particularly well suited due to their range, short refuelling time and weight characteristics[198]. There is also support for the increased use of gas in shipping. Use of gas in road transport (or low-carbon liquid fuels) could, furthermore, reduce pressures on the electricity distribution network.

[198] See AFHYPAC (2018).

VI. Gas networks reduce system costs of energy supply and increase public acceptance

In the previous section we found that renewable gas is not only important for seasonal storage, where it is practically indispensable, but also potentially a valuable energy carrier to supply various sectors directly. This is reflected by our calculations of system costs for two different decarbonisation paths.

In summary, the continued use of gas networks to transport energy to final customers in France in 2050 yields cost benefits of **EUR 6.5 to 14.5 billion per year**. Further, it contributes to the public acceptance of decarbonisation through avoided electricity network expansion.

EUR 6.5 -14.5 bn / year

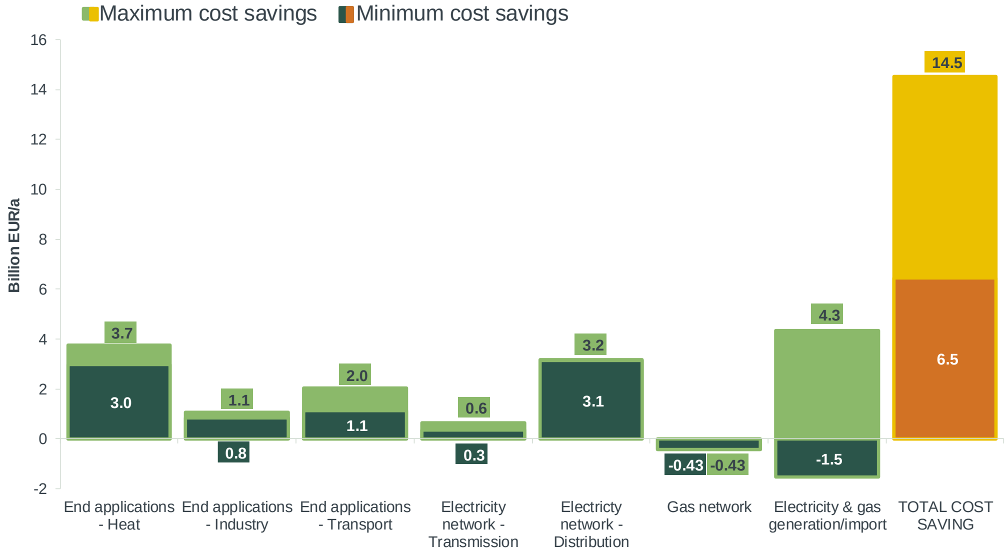
can be saved through the continued use of gas networks in 2050.

The gas network helps save costs across the whole value chain

We have derived these estimates by comparing a scenario in which gas networks are still used to deliver (renewable) gas to end users ("Electricity and Gas Infrastructure" scenario) to a scenario where most end appliances are electrified and gas is only used for seasonal storage with (re-)electrification ("All-Electric plus Gas Storage" scenario) in 2050 (see Section 4.2 for more details).

To compare energy system costs between the two scenarios, our analysis has taken into account costs along the entire energy supply chain. To capture uncertainty about the future development of key parameters such as gas and electricity demand or renewable gas generation costs in 2050, we have executed the calculations for a number of different parameter sets, resulting in the cost saving intervals presented below.

Figure 103 Min and max cost savings of a continued use of gas networks per year in 2050 along the supply chain in France



Source: *Frontier Economics/IAEW*

Note: *The values illustrate the difference in annual costs between the "All-Electric plus Gas Storage" scenario and the "Electricity and Gas Infrastructure" scenario. A positive value reflects cost savings in the "Electricity and Gas Infrastructure" scenario, where parts of end energy are supplied by renewable and low-carbon gas via gas networks, compared to the "All-Electric plus Gas Storage" scenario, where end energy is primarily supplied by electricity and gas networks are no longer needed. Minimum and maximum savings refer to varied assumptions on key parameters that are uncertain from today's perspective, such as production prices of different renewable gases or the development of final energy demand until 2050.*

The analysis shows that France can derive substantial benefits from the continued use of gas networks. In 2050 it can save **EUR 6.5 to 14.5 billion per year** in an "Electricity and Gas Infrastructure" scenario compared to an "All-Electric plus Gas Storage" scenario where most end appliances have been electrified and gas is only used for temporal storage. This is equivalent to annual cost savings of **EUR 97 to 218 per capita.**

A large part of these total savings will stem from lower costs for end appliances in residential heating and transport and cost savings through avoided investments in electricity distribution networks. Further, and in fact potentially the largest, savings can come from reduced renewable gas and electricity generation costs. Due to France's large biomass potential, an important cost driver are biomethane production costs that are currently surrounded by large uncertainty. If these sink sufficiently (for instance to 52 €/MWh for most of biomethane production in 2050 as expected by Ecofys[199]), biomethane can provide an abundance of cheap energy in the "Electricity and Gas Infrastructure" scenario, which will generate substantial cost savings compared to the "All-Electric plus Gas Storage" scenario (see light green column for "Electricity & gas generation/import" in Figure 103). However, if high biomethane production costs coincide with high gas demand and if we demand that gas be produced domestically, the costs of energy generation in the

[199] See Ecofys (2018).

"Electricity and Gas Infrastructure" scenario could be more expensive than generation in the "All-Electric plus Gas Storage" scenario (see Figure 103).

Use of gas networks benefits public acceptance of decarbonisation

The importance of public acceptance for the successful implementation of the energy transition must not be overlooked. ADEME (2016), for instance, shows that reduced social acceptance can substantially increase the costs of a 100% renewable energy mix in 2050.

Here, the underground gas network has something to offer. As explained above, in the "All-Electric plus Gas Storage" scenario the French electricity grid would have to be expanded in order to accommodate increased flows especially from north-south for national and European dispatch purpose. The continued usage of the gas in end appliances would alleviated the expected strains on the network and therefore render some of the investments unnecessary: Based on an extensive network modelling exercise, we previously identified that for the German transmission network this effect is as large as 40% by 2050.[200] This result can be transferred to France: When taking into account France's less significant penetration of gas and the lower extent of RES expansion until 2050 it is likely that France could avoid transmission grid extensions of approximately 8 to 13% through the continued use of gas networks by 2050, compared to the "All-Electric plus Gas Storage" scenario.

[200] See Frontier Economics et al. (2017).

ANNEX G COUNTRY STUDY GERMANY

Summary

- **Climate goals –** By 2050, Germany aims to reduce greenhouse gas emissions by **80% to 95%** as compared to 1990, which is to be achieved by using renewable energy in the heat, transport and industrial sectors. At the same time, Germany **is phasing out nuclear energy** by 2022.
- **The challenge of strong electrification** – Whereas electrification of end appliances to supply consumers with renewable electricity will without doubt be one important pillar to achieve Germany's climate target, our analysis reveals that a primarily electrification-led decarbonisation strategy would create a number of challenges: Not only would the annual volume of electricity consumption increase substantially, but peak demand could also more than double, driven by seasonal heat demand swinging to the electricity sector. The bulk of additional electricity demand will need to be supplied by wind onshore, offshore and PV. Wind and PV generation capacity could roar to more than 550 GW,[201] compared to around 105 GW at the end of 2018.[202] As wind parks will continue to be concentrated in North Germany, there will be an increasing need for energy transport to the load centres in West and South Germany.

  As a result, an electrification-led strategy imposes significant challenges for the generation, transport and storage of energy.
- **Existing gas infrastructure –** The German gas infrastructure can substantially contribute to decarbonisation alongside electrification: Gas supplies around 23% of final energy demand and the gas network has always been transporting large energy volumes from North to West and to South Germany. Gas import capacity is extremely large, exceeding electricity import capacity by factor 13. Likewise, domestic gas storage capacity in Germany is sufficient to store 260 TWh of energy (which is more than 6,000 times the energy storage volume of existing electricity storage), providing the basis to bridge the gap between energy supply and seasonal heat demand.
- **Sources for renewable gas –** There are various sources for renewable gas in Germany. Power-to-gas is a promising solution to facilitate energy transport from North to West and South Germany, and there is some potential for further upgrading biogas to biomethane, which could then be injected into the gas grid. Moreover, the extensive interconnector capacity facilitates imports of renewable gas from various sources in Europe and beyond.
- **Role of renewable gas in consumer sectors –** Renewable gas can play an important role in various energy-consuming sectors: In electricity, by providing reliable low carbon back-up for intermittent renewables. In heating,

201 See Frontier Economics et al. (2017).

202 See Fraunhofer ISE (2019).

by supplying existing gas connections with renewable gas instead of natural gas and by replacing existing oil burners with hybrid heat pumps or gas boilers. In industry, by reducing CO_2 emissions where electrification is hardly feasible or inefficient, such as for high-temperature process heat or as feedstock. And in transport, particularly by decarbonising heavy-duty and maritime transport

- **Cost savings of using gas networks –** Our analysis shows that, compared to switching Germany to an electrification-led energy system, the usage of gas networks based on renewable gas could **reduce German system costs in the magnitude of as much as EUR 20 billion in 2050**. These savings originate in lower costs for end appliances in residential heating, industry and transport and cost savings through avoided investments in transmission electricity distribution networks, as well as cost savings in the area of electricity generation, storage and renewable gas generation, if we allow for the import of less costly renewable gas from abroad.
- **In summary, our analysis suggests that usage of Germany's gas infrastructure is key to reaching Germany's climate targets in a cost-effective way.**

I. Introduction

In this country study we provide an overview of why the gas infrastructure has a significant societal value for decarbonising Germany. We follow the same structure as in the main report, and focus on highlighting the particularities in Germany. Please refer to the main report for a general understanding of the methodology and argumentation.

Please also note that, in 2017, Frontier Economics and IAEW, together with Emcel and 4Management, prepared a comprehensive report for FNB Gas to assess the importance of gas infrastructure for Germany's energy transition, including a sophisticated model-based estimation of cost savings of using gas infrastructure.[203] In the country study below, we build on this earlier report and add further aspects, such as the perspective of renewable gas imports to Germany (while in the 2017 study we assumed that renewable gas supply in 2050 has to originate entirely from domestic renewable sources).

II. Germany's challenge: Decarbonisation based on intermittent renewables without nuclear power and large hydro reservoirs

Achieving Germany's decarbonisation targets presents a major challenge:

- **Climate protection targets require a massive transition of the energy system –** Germany has set itself ambitious climate protection targets: by 2050, greenhouse gas emission levels are to be reduced by **80% to 95%** as compared to 1990. A clear policy requirement in this process is that the majority of the greenhouse gas reduction be achieved using renewable electricity in the heat, transport and industrial sectors. At the same time, Germany **is phasing out nuclear energy**, which provides around 13% of Germany's electricity generation today: The last of seven nuclear plants currently in operation will shut down in 2022.

- **Reaching these objectives through a high degree of electrification would cause a significant increase in annual and peak electricity demand –** Electrification of end appliances to supply consumers with renewable electricity will without doubt be one important pillar to achieve Germany's 2050 climate target. Our analysis reveals, however, that a primarily electrification-led decarbonisation strategy would create a number of challenges:

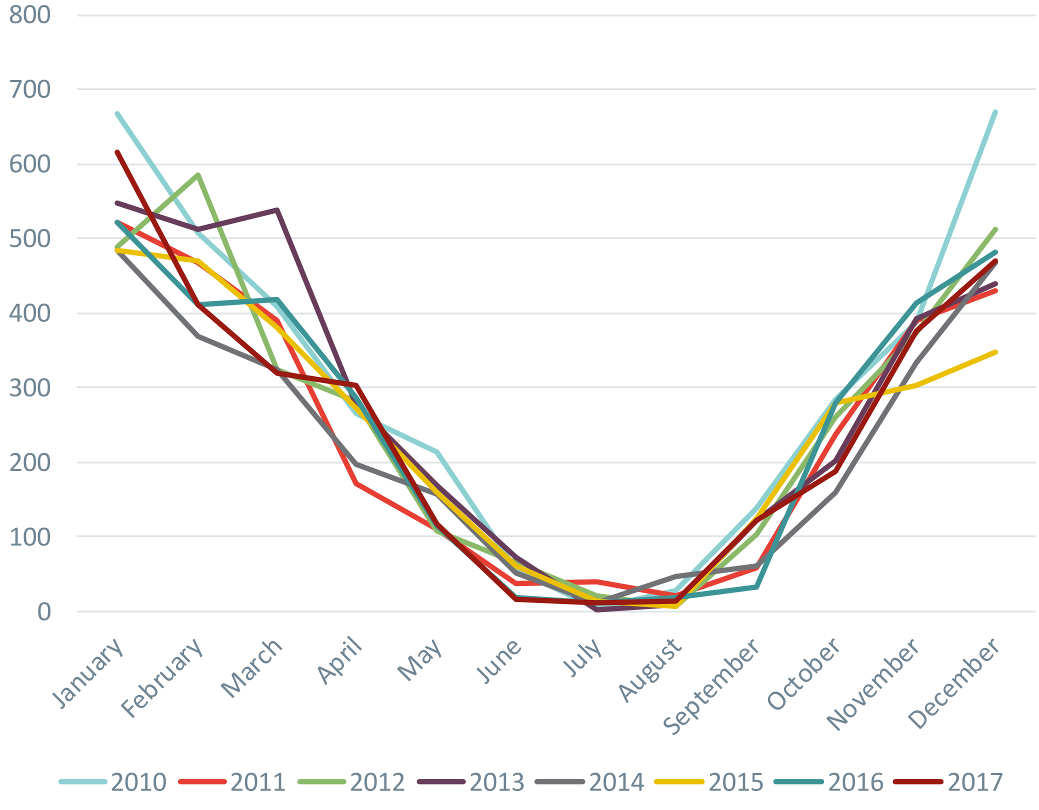
  - **Increase in annual electricity demand –** Today approximately 20% of final energy demand in Germany is supplied by electricity. Electrifying large parts of the residual 80% of final energy demand would lead to substantial additional electricity demand, even assuming ambitious energy efficiency gains. For example, in Frontier Economics et al. (2017) we estimate an increase in electricity consumption in end appliances from around 515 TWh in 2015 to 965 TWh in 2016 if a substantial proportion of energy demand

[203] Frontier Economics et al. (2017).

for space and water heating, for process heat and for mobility is switched from fossil-fuels to electricity-based supply.[204, 205]

- **Boost in electricity peak demand** – Today, where electricity is mainly used for lighting, ICT or electric engines, but not for space or water heating or cooling, electricity demand in Germany is comparably flat over the course of the year. Electrifying large parts of heat demand would import the considerable seasonality of heat demand (see Figure 104) into the electricity sector. When modelling this based on load profiles and fuel efficiencies of all sorts of end appliances in Frontier Economics et al. (2017), for example, winter electricity peak demand more than doubles by 2050 compared to 2015, basically driven by heat demand peaks in January and February (see Figure 105).

Figure 104 Seasonality in Germany's heat demand (based on number of heating degree days)



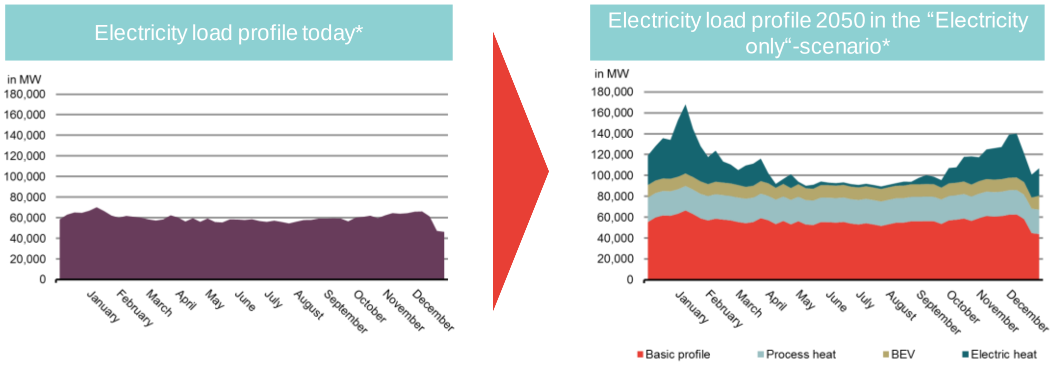
Source: *Frontier Economics based on Eurostat - Cooling and heating degree days by country - monthly data*

Note: *Heating degree days are a measure of how much (in degrees) and for how long (in days) outside air temperature was lower than a specific base temperature. Eurostat sets this temperature at 15°C in its calculations.*

[204] To add to this, our modelling suggests that another 330 TWh of electricity is required to generate synthetic gas via power-to-gas that can later be re-electrified to cope with the challenge of seasonality of heat demand even in an electrification-led scenario in a cost-effective way. See Frontier Economics et al. (2017).

[205] This is already taking into account substantial gains in energy efficiency: Both through lower demand of end-use energy, for example a decrease of space and water heat demand through more effective insulation in existing and new buildings by 34% from 2015 to 2050, and through more efficient end-user appliances, e.g. a high penetration of electric heat pumps that use ambient heat to reach high fuel efficiency.

Figure 105 Electrifying a large proportion of final energy demand increases electricity annual demand and peak demand[206]



* Arithmetic mean of load over one week.

Source: *Frontier Economics et al. (2017)*

- **Electricity demand to be covered by wind and PV, creating challenges to find accepted generation spots –** Given the phase-out of nuclear, restricted potentials for large hydro power stations, strong local opposition to CCS and limited growth potentials for biomass energy use, the bulk of additional electricity demand will need to be supplied by wind onshore, offshore and PV. In Frontier Economics et al. (2017), for instance, the cost-minimising electricity generation mix in the "All-Electric plus Gas Storage" scenario 2050 comprises more than 550 GW of wind and PV generation capacity, up from around 75 GW in 2015.

  Taking into account that public acceptance of especially wind onshore parks is on the decline in recent years, the sheer amount of this capacity imposes a great challenge for a successful energy transition. Further, the intermittency of wind and solar availability creates an additional need for large-scale storage.

- **Substantial electrification creates further challenges for the (already strained) electricity network –** Due to favourable wind power conditions being concentrated near the coast of the North Sea and Baltic Sea in northern and eastern Germany and load centres being concentrated in western and southern Germany, we observe ever increasing power flows from the north/east to the south/west of Germany. This is exacerbated by the nuclear power phase-out, as most nuclear power stations are located in Southern Germany. This has led to significant congestion on multiple network elements of the German transmission grid in recent years. 2017 marked the all-time high of German redispatch measures, with about 20.4 TWh being redispatched. There are four transmission lines that have been subject to redispatch measures in more than 500 hours per year.[207]

  While the need to significantly expand the electricity transmission network to alleviate congestion has been known now for many years, concrete electricity network expansion projects regularly encounter significant local opposition. As a result, almost all major projects involved in the expansion of the electricity

[206] As noted above, this is excluding additional electricity demand for power-to-gas.

[207] These lines are located between Dörpen West and Hanekenfahr, Remptendorf and Redwitz, Sittling and Simbach as well as between Pleinting and St. Peter (Austria).

network have been significantly delayed in recent years. Several legislative attempts to accelerate network expansion have been largely unsuccessful to date.

Nonetheless, a range of grid extension measures is underway now. Projects of highest relevance consist in the implementation of five HVDC[208]-lines between Northern and Southern Germany, which are expected to be fully operational between 2021 and 2025. In total, planned or commissioned grid extension projects of the next decades amount to about 20% of the present grid length.

With additional strong electrification of heating, industrial and mobility appliances, numerous additional electricity lines will be required, for long-distance transport, but also to make distribution networks fit to accommodate the additional demand as well as increasing decentralised electricity feed-in especially from rooftop PV.

III. German gas infrastructure well suited to help overcome the challenges of decarbonisation

Today, around 25%[209] of final energy demand in Germany is supplied by gas. Of this, the majority is consumed in households (mainly for heating), industry, power generation and services.

25%

of Germany's final energy demand is supplied by gas today.

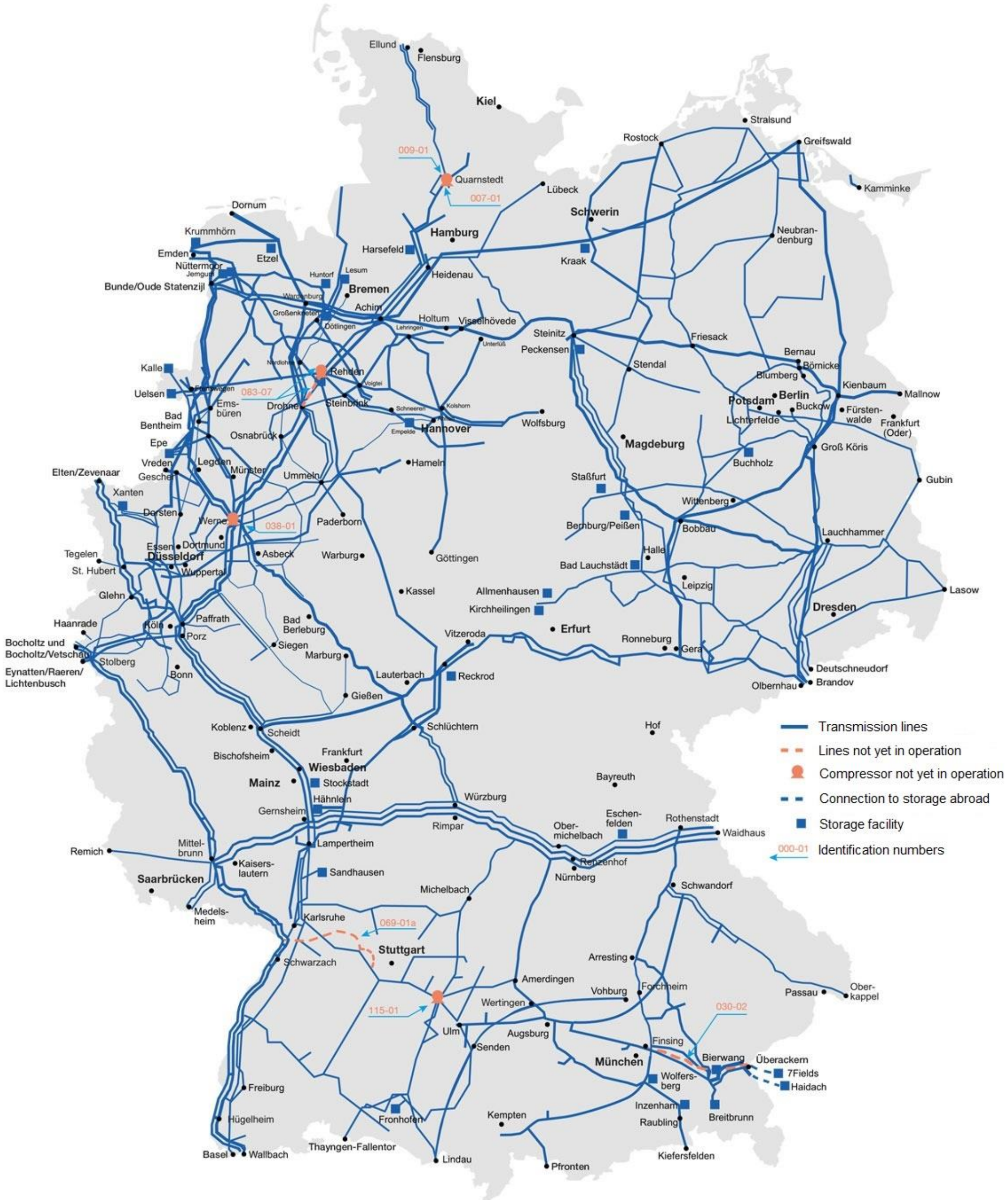
Accordingly, Germany has a substantial gas infrastructure:

- **Gas network** – Germany's gas network with 22,500 km transmission pipelines and 480,000 km distribution pipelines spans the entire country (Figure 106). As natural gas has historically been produced in Northern Germany or, to the largest extent, imported from Russia, Norway or the Netherlands via pipelines that enter Germany in its north, the gas network is well suited to facilitate the transport of energy from north to south, and thus helps avoid investments in electricity infrastructure. We outline the potential for the use of gas in various sectors as well as the cost savings from the continued use of gas networks in subsequent sections.

[208] High-voltage direct current.

[209] Based on Eurostat.

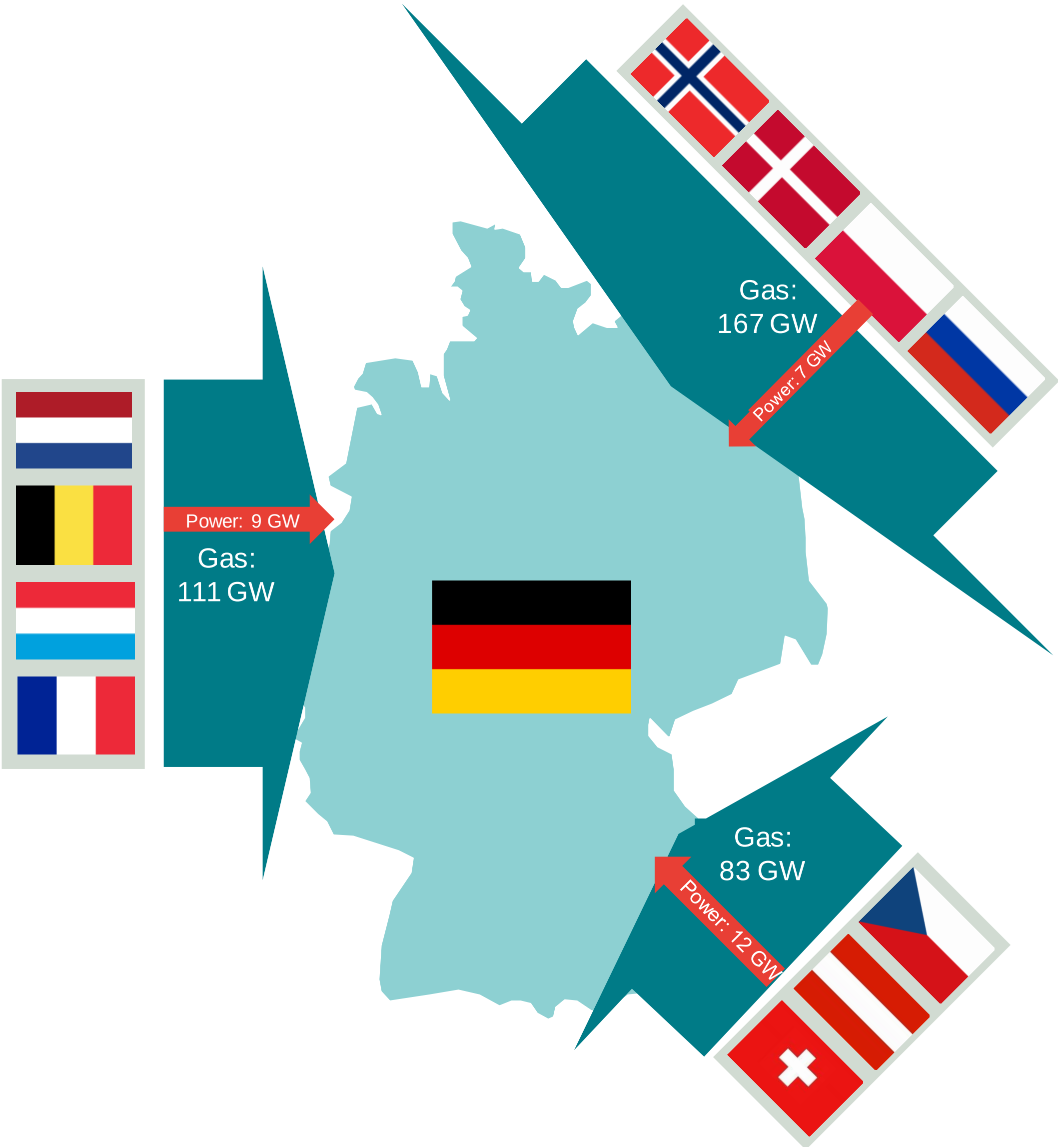
Figure 106 Gas transmission grid Germany (overview)



Source: BMWi (https://www.bmwi.de/Redaktion/DE/Textsammlungen/Energie/gas.html)

- **Gas import capacity** – Germany is well connected to the European gas network. In fact, the import capacity of gas pipelines to Germany exceeds the import capacity of electricity by a factor of 13 (Figure 107).

Figure 107 Comparison of total electricity and gas import capacity: Gas import capacity exceeds electricity import capacity by factor 13

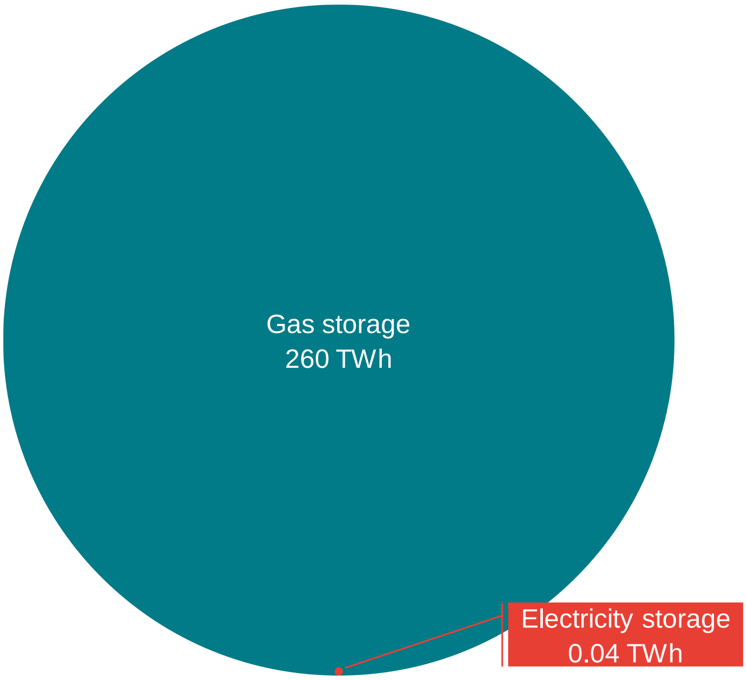


Source: ENTSO-E TYNDP (2018), ENTSO-G Physical Technical Capacity (2018)

Note: Power Import capacities presented are NTCs expected in 2020 according to ENTSOE TYNDP 2018

- **Gas storage –** As outlined above, one of the major difficulties for decarbonising Germany will be to supply seasonal demand of heat (which is today primarily supplied by oil and natural gas). While electricity-based storage such as pumped hydro energy storage or batteries are not suited for this seasonal storage purpose, gas storage is. Gas storage capacity in Germany is sufficient to store 260 TWh of energy (which is more than 6,000 times the energy storage volume of existing electricity storage, see Figure 108).

Figure 108 Comparison of total electricity and gas storage volume in Germany: Gas storage volume is more than 6,000 times as large as electricity storage volume



Source: Frontier Economics based on Gas Infrastructure Europe and Geth et al. (2015).

IV. Existing gas infrastructure is suited for a variety of renewable and low-carbon gases

While the gas infrastructure in Germany is currently working on natural gas, there are various potential sources for renewable and low-carbon gas that could be fed into the gas infrastructure in the future, thus contributing to achieving the ambitious climate protection targets:

- **Renewable gas from domestic power-to-gas –** In Frontier Economics et al. (2017), we focused our analysis on power-to-gas. And indeed, the conditions in Germany render power-to-gas appliances to be a logical solution:
  - Favourable wind conditions in Northern Germany have already led to wind parks being concentrated near the coast. This concentration will be intensified significantly in the years to come, both offshore and onshore.
  - Large-scale electrolysers can thus be built in proximity to wind parks in the north, which enables cost advantages through economies of scale, to convert electricity to hydrogen or (if also methanised) to synthetic methane. Using the existing gas infrastructure, with gas storage also being concentrated in Northern Germany and gas pipelines with large energy transport capacity from north to south, can thus help to avoid some of the unpopular and expensive electricity transmission network extensions.

- Not surprisingly, Germany is the country where we observe the strongest activity of power-to-gas piloting, and further investments in large-scale electrolysers of up to 100 MW being envisaged.[210]

  Nonetheless, there are more potential sources for renewable gas to supply Germany:

- **Biomethane** – Germany is by far the largest biogas producer in Europe, with more than 90 TWh biogas production in 2017, accounting for almost 50% of biogas production in EU28 plus Switzerland.[211] With biogas production being primarily based on energy crops (51% of produced biogas; mainly maize) and agricultural residues (41%), and by far the highest biogas generation per km^2 (264 MWh/km^2, with the UK following on second place with 124 MWh/km^2), growth potentials for biogas in Germany are limited.[212]

  There is, however, potential for additional biogas upgrading and injection of biomethane into the grid. Although Germany is also Europe's frontrunner for biomethane generation with approximately 9.4 TWh in 2016,[213] this is still accounting for only 10% of biogas production, with 90% being used for on-site electricity production.[214]

- **Import of renewable gas** – While in Frontier Economics et al. (2017) we assumed that all gas consumption in 2050 has to be produced within Germany, in practice future renewable gas supply to Germany is likely to be much more diversified. This is facilitated by Germany's strong connections to the European gas network with substantial entry and exit capacities. Potential sources of renewable gas to Germany comprise, for example, biomethane from Denmark, Sweden or France, synthetic methane from North Africa, blue hydrogen from Norway and Russia[215] or bio-LNG from anywhere around the world (facilitated by the expected development of a German LNG terminal at the North Sea coast). Such a diversified import portfolio, which could not be matched easily by electricity, can help reduce energy supply costs and enhance security of supply.

V. Renewable gas has a strong potential in various sectors

Renewable gas has a strong potential to be used in various energy-consuming sectors in Germany (see Annex B for more details on the analysis of sectors):

- **Electricity** – Gas-fired power plants are capable of serving as back-up for intermittent renewable electricity and provide flexibility to cover large demand peaks. In recent years, utilisation of gas power plants has been low due to coal power plants producing large amounts of electricity, facilitated by low prices for CO_2 certificates in the EU ETS. With CO_2 prices rising, German nuclear going

[210] See Annex A Section II. Power-to-gas in the main report of this study.

[211] Eurostat.

[212] Frontier Economics calculations based on Eurostat (2018).

[213] See European Biogas Association (2017).

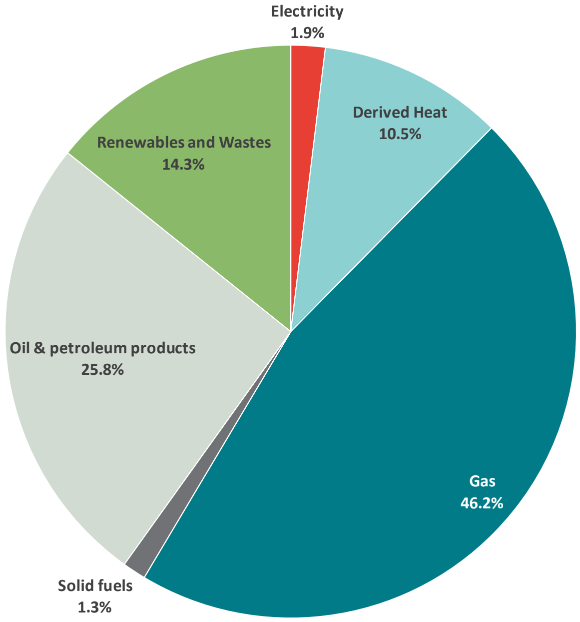
[214] See IRENA (2017b).

[215] Domestic generation of blue hydrogen is unlikely to play a role in Germany, given strong public and political opposition to onshore CO_2 storage and limited offshore storage potential.

offline by 2022 and coal and lignite being phased out by 2038[216], gas power plants may have a more substantial role to play to complement intermittent renewables in Germany in the future.

- **Heating** – Germany's heat demand is dominated by natural gas today. For example, around 46% of final energy demand for space heating in residential buildings is supplied by natural gas, followed by oil (26%). Less than 2% is covered by electricity (Figure 109).

Figure 109 Final energy demand for space heating in residential buildings by fuel in Germany (2016)

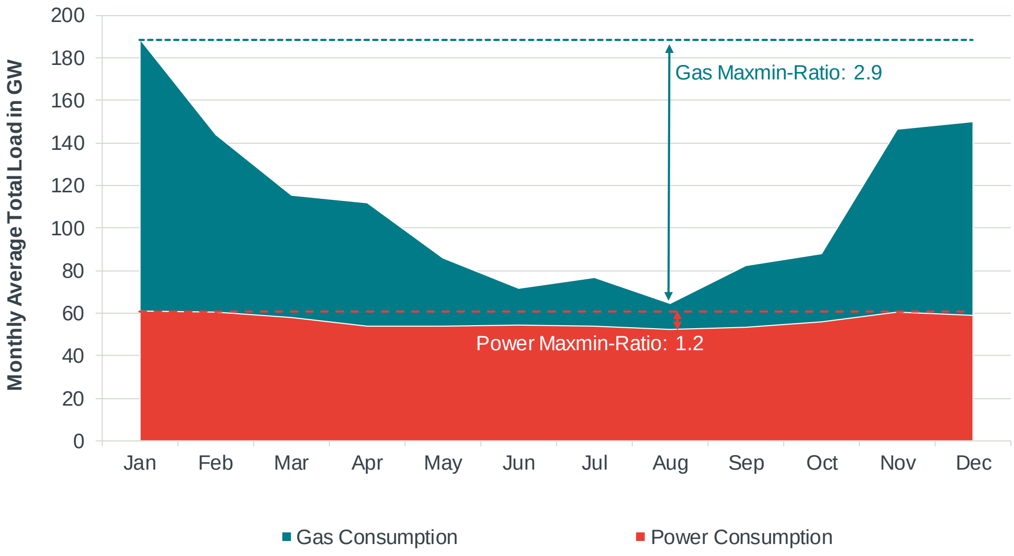


Source: Frontier Economics based on Eurostat

Accordingly, and because Germany's heat demand, like that of many other European countries, is characterised by considerable seasonality (cf. Figure 104), today's gas infrastructure has been built to cope with large seasonality, while electricity infrastructure deals with demand that is comparably flat over the course of the year (Figure 110). Electrifying large parts of heat demand would import this demand seasonality to the electricity sector. Covering the resulting peak electricity demand would pose extraordinary challenges both for generation/storage, as well as for the transmission and distribution network.

[216] Lignite phase-out timing according to the recommendations of the final report of Commission "Growth, Structural Change and Employment", see BMWi (2019).

Figure 110 Monthly gas vs. electricity load profile in Germany



Source: Frontier Economics based on IEA Monthly Gas Statistics for Actual Gas Load (GWh, 2017) and ENTSO-E Transparency Platform for Actual Electricity Total Load (GW, 2017)

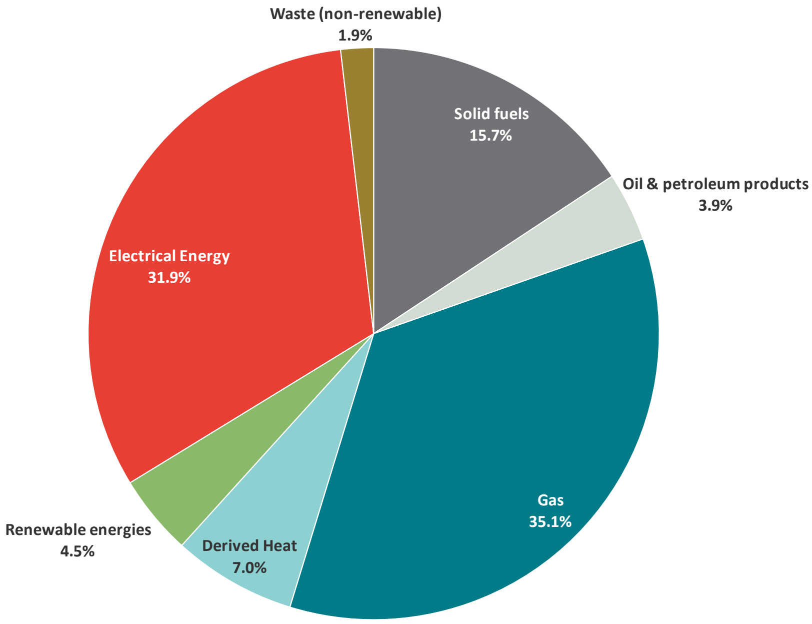
Consequently, there are good arguments to keep existing gas connections active and let households continue to heat with gas.

Furthermore, switching oil-based heating to gas (first natural gas and increasingly renewable gas) can be a cost-effective way forward, particular where oil-dependent households are located close to existing gas networks.

- **Industry** – Energy-intensive industries are of big relevance in Germany. Accordingly, more than 28% of final energy demand in Germany is consumed in the industry. Natural gas is supplying the bulk of this (35%), followed by electricity (32%), solid fuels such as coal (16%), CHP (7%), renewable energies (5%), oil (4%) and waste (2%). While (fossil) oil and coal will need to be replaced to decarbonise the industry, renewable gas has the potential to complement electrification, particularly where electric supply is difficult or inefficient, such as in high-temperature process heat or as feedstock to supply carbon.

  Industry is likely to be the first sector to be directly supplied with (green or blue) hydrogen, both as a substitute for grey hydrogen where there is already substantial demand (e.g. in refineries), and also as a replacement for oil, coal or natural gas to generate process heat. The latter would of course require that machines and processes are adjusted appropriately.

Figure 111 Final energy consumption in industry by fuel in Germany (2016)



Source: Frontier Economics based on Eurostat

- **Transport** – Today Germany's transport sector is, similar to that of most other European countries, dominated by oil products. Gas plays a limited role, supplying 0.7% of final energy demand in transport. Analogous to other countries, though, gas or hydrogen-fuelled transport is likely to be one essential pillar of future transport, in particular in transport modes that are difficult to electrify, such as heavy-duty road transport.

VI. Gas networks reduce system costs of energy supply and increase public acceptance

In the previous section we found that renewable gas is not only important for seasonal storage, where it is practically indispensable, but also potentially a valuable energy carrier to supply various sectors directly. This is reflected by our calculations of system costs for two different decarbonisation paths.

In summary, the continued use of gas networks to transport energy to final customers in Germany in 2050 yields cost benefits of up to **EUR 20.1 billion per year**. Furthermore, it contributes to the public acceptance of decarbonisation through avoided electricity network expansion.

Up to EUR 20 bn / year

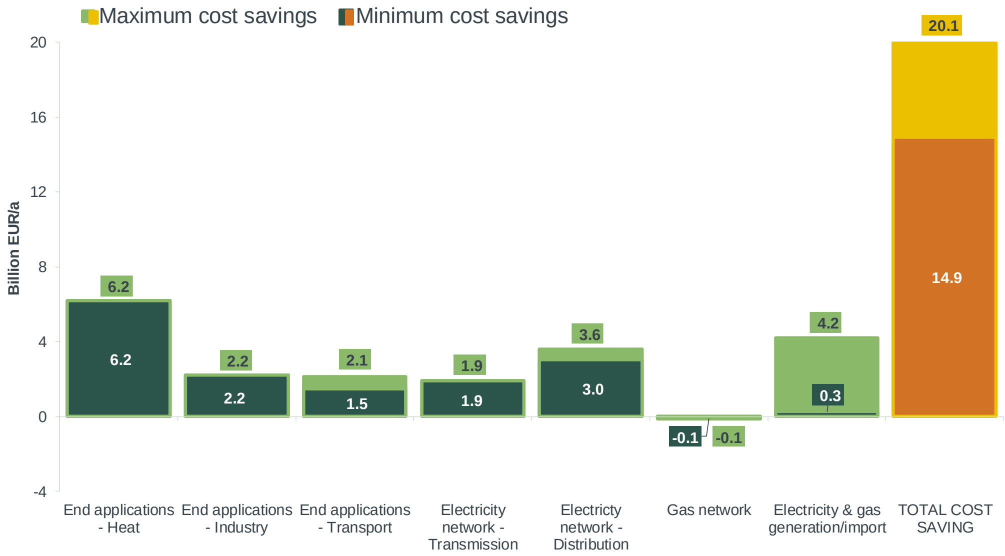
can be saved through the continued use of gas networks in 2050.

The gas network helps save costs across the whole value chain

We developed the basis of these estimates in Frontier Economics et al. (2017), where we compared a scenario in which gas networks are still used to deliver (renewable) gas to end users (“Electricity and Gas Infrastructure” scenario) to a scenario where most end appliances are electrified and gas is only used for seasonal storage with (re-)electrification (“All-Electric plus Gas Storage” scenario) in 2050 (see Frontier Economics et al. (2017) and Section 4.2 of this study for more details).

To compare energy system costs between the two scenarios, our analysis has taken into account costs along the entire energy supply chain. To capture uncertainty about the future development of key parameters such as gas and electricity demand or renewable gas generation costs in 2050, we have executed the calculations for a number of different parameter sets, resulting in the cost saving intervals presented below.

Figure 112 Min and max cost savings of a continued use of gas networks per year in 2050 along the supply chain in Germany



Source: Frontier Economics/IAEW

The results reveal that Germany can benefit considerably from the continued use of gas networks. In 2050 it can save **EUR 14.9 to 20.1 billion per year** in an "Electricity and Gas Infrastructure" scenario compared to an "All-Electric plus Gas Storage" scenario where most end appliances have been electrified and gas is only used for temporal storage. This corresponds to annual cost savings of **EUR 182 to 245 per capita.**

These savings originate in lower costs for end appliances in residential heating, industry and transport and cost savings through avoided investments in transmission and distribution electricity networks.

The difference between cost for electricity generation, storage and gas generation is also worth noting: In Frontier Economics et al. (2017) in 2017, we assumed that renewable gas supply in 2050 has to be generated via power-to-gas within Germany, leading to a cost disadvantage of the "Electricity and Gas Infrastructure" scenario driven by additional costs for electrolysers, conversion losses and costs for CO_2 (for methanation). In this study, we relax this assumption, reflecting that in practice renewable gas supply is likely to be more diverse. We find that a more diversified renewable gas supply portfolio has the potential to lead to cost savings in the area of electricity generation, storage and renewable gas generation. The amount of these cost savings depends mostly on future costs of renewable gas production (including the level of imports we assume). If these decrease sufficiently, renewable gas such as (imported) biomethane or green hydrogen can provide an abundance of cheap energy in the gas-scenario, which will generate substantial cost savings compared to the "All-Electric plus Gas Storage" scenario (see light green column for "Electricity & gas generation/import" in Figure 112).

Use of gas networks benefits public acceptance of decarbonisation

As explained above, in the "All-Electric plus Gas Storage" scenario the German electricity grid would have to be expanded substantially. The gas network, on the other hand, is already fit for purpose. Its continued usage would therefore render significant parts of the electricity grid expansion obsolete: Based on our extensive network modelling exercise in Frontier Economics et al. (2017), we previously identified that for the German transmission network, as much as 40% of the electricity grid expansion may be avoidable by 2050. In light of the public resistance against the new construction of power lines, gas networks therefore benefit public acceptance of decarbonisation.

ANNEX H COUNTRY STUDY NETHERLANDS

Summary

- **Climate goals –** The Netherlands aims to reduce its CO_2 emissions by 49% by 2030 and by 95% by 2050 of 1990 levels. To achieve this, energy-related emissions in transport, industry, households and services need to be avoided almost entirely.
- **The challenge of strong electrification** – One important element to achieve these targets will be the electrification of fossil-fuelled end appliances, for example through electric heat pumps to heat new homes. A strong electrification will, however, boost the demand for electricity and at the same time import the pronounced seasonality of heat demand to the electricity sector, creating challenges for the generation, transport and storage of energy, which may require other renewable energy carriers such as renewable gas to complement electricity. Current negotiations in the “klimaatakkoord” hint to an increase in the use of electricity of about 20% in 2030, compared to 2018. This would bring electricity as percentage of final energy to 25% in 2030.
- **Wind offshore** – In the Netherlands, a large proportion of required electricity is likely to be provided by offshore wind: Current government target is to increase wind offshore capacity from 1 GW today to 11.5 GW in 2030. This compares to 19 GW electricity peak demand today.
- **Existing gas infrastructure** – Being the country with the highest penetration of gas of all EU countries, the Dutch gas infrastructure has a lot to offer to contribute to decarbonisation alongside electrification: The transmission and distribution networks span the whole country, with 93% of Dutch households having a gas connection. Likewise, domestic gas storage capacity in the Netherlands is sufficient to store 130 TWh of energy (while existing electricity storage is neglectable), providing the basis to bridge the gap between energy supply and seasonal heat demand.
- **Sources for renewable and low-carbon gas** – There are various sources for renewable and low-carbon gas in the Netherlands. Besides some domestic and imported biomethane, hydrogen is likely to play a key role in the Netherlands. This is based on favourable conditions for both green hydrogen (based primarily on offshore wind) and blue hydrogen (with offshore CO_2 storage) and large potential for near shore hydrogen demand e.g. in the industry and in power plants.
- **Role of gas in consumer sectors** – Based on high gas penetration today, renewable and low-carbon gas can play an important role in various energy consuming sectors such as electricity generation, industry, heating and transport.

- **Cost savings of using gas networks** – Our analysis shows that, compared to switching the Netherlands to an electrification-led energy system, the usage of gas networks based on renewable and low-carbon gas could **reduce Dutch energy system costs in the magnitude of EUR 3.6 to 5.5 billion in 2050 per year**. These savings comprise of savings from substituting expensive additional electricity generation capacity through lower cost gas, cost savings for end appliances in heating, industry and transport, as well as cost savings through avoided investments in electricity transmission and distribution networks.
- **To summarise, our analysis suggests that usage of the Netherlands's gas infrastructure is indispensable to reaching the Netherlands's climate targets in a cost-effective way.**

I. Introduction

In this country study we provide an overview of why the gas infrastructure has a significant societal value for decarbonising the Netherlands. We follow the same structure as in the main report, and focus on highlighting the particularities in the Netherlands. Please refer to the main report for a general understanding of the methodology and argumentation.

II. The challenge for the Netherlands: Decarbonisation based largely on offshore wind

Achieving the Netherlands's decarbonisation targets presents a major challenge:

- **Ambitious climate protection targets require energy-related greenhouse gas (GHG) emissions to plummet by 2050** – The Dutch government has confirmed its commitment to the Paris Climate Targets for 2050. On that basis, the Netherlands aims to reduce its 1990 GHG emissions by 49% by 2030[217] and by 95% by 2050.[218] That compares to a decrease in emissions of only 11% between 1990 and 2015.[219]

  Given that some greenhouse gas emissions in the Netherlands are difficult to reduce, particularly non-energy-related emissions within the Food and Nature functionality, energy-related emissions in transport, industry, households and services need to be avoided almost entirely in order to achieve the 2050 GHG reduction target, unless substantial amounts of "negative" emissions are achieved in certain sectors, e.g with the production of biogas or in waste incinerators (as actually proposed by Dutch government).
- **Reaching these objectives through a high degree of electrification would cause a significant increase in annual and peak electricity demand** – Our analysis reveals that meeting these objectives through a primarily

[217] See Coalition Agreement (2017).

[218] The climate law proposal was presented in June 2018 and is backed by seven political parties and a three quarter majority in the Dutch parliament. The law will probably be enacted in 2019, see Groenlinks (2018).

[219] See Rijksoverheid (2016).

electrification-led decarbonisation strategy would create a number of challenges:

- **Increase in annual electricity demand** – Today, less than 19% of final energy demand in the Netherlands is supplied by electricity, equivalent to around 105 TWh electricity consumption per year (2016).[220] Electrifying large parts of the residual 81% of final energy demand would lead to substantial additional electricity demand, even assuming ambitious energy efficiency gains.[221]

- **Boost in electricity peak demand** – Today, where electricity is mainly used for lighting, ICT or electric engines, but not for space or water heating or cooling, electricity demand in the Netherlands is comparably flat over the course of the year. For example, energy consumption in peak month January is only around 20% above that in off-peak month August.[222] Consequently, the capacity of electric grids in the Netherlands is based on about 1.2 - 1.3 kW per household. Electrifying large parts of heat demand would integrate the considerable seasonality of heat demand (see Figure 113) into the electricity sector [223]

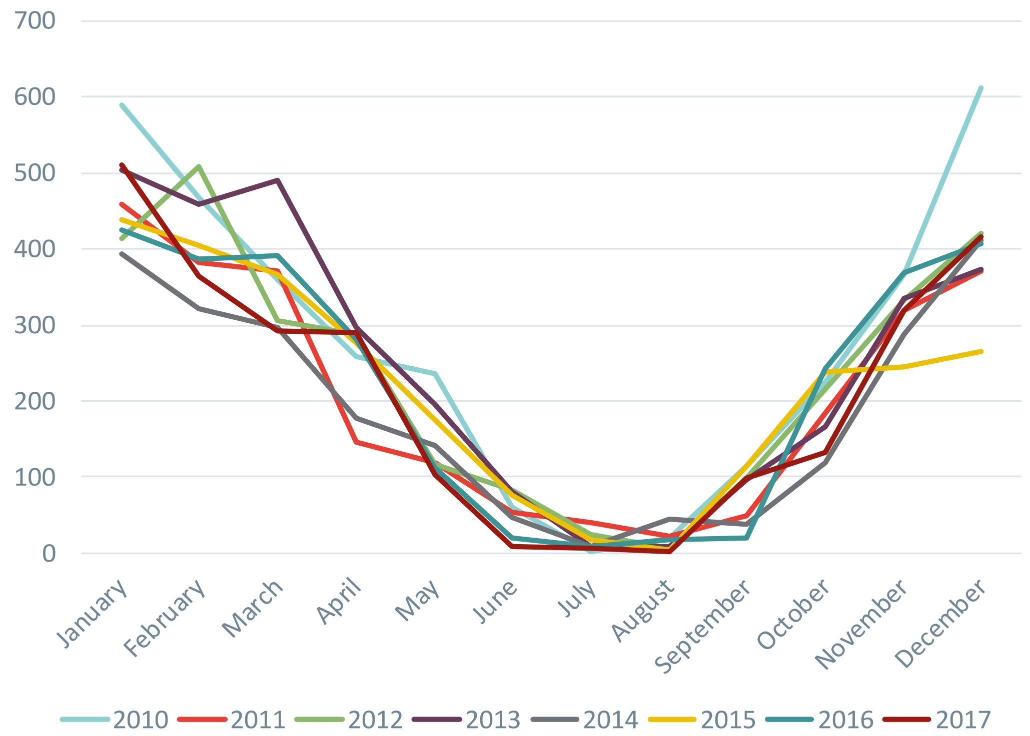
[220] Based on Eurostat.

[221] For example, Gasunie (2018) calculates an increase of electricity demand to 167 TWh by 2050, despite a substantial role of gas (partly generated from natural gas).

[222] See Figure 118.

[223] For example, Gasunie (2018) calculates an increase of electricity peak demand to 35 GW by 2050, compared to 18 GW today, despite a substantial role of gas (partly generated from natural gas).

Figure 113 Seasonality in the Netherlands' heat demand (based on number of heating degree days)[224]



Source: *Frontier Economics based on Eurostat - Cooling and heating degree days by country - monthly data*

Note: *Heating degree days are a measure of how much (in degrees) and for how long (in days) outside air temperature was lower than a specific base temperature. Eurostat sets this temperature at 15°C in its calculations.*

- **The bulk of renewable electricity will be from offshore wind** – Due to high population density in the Netherlands on the one hand, and the fact that the Dutch part of the North Sea is over one and a half times the size of the surface of the country on the other hand, a large proportion of required electricity is likely to be provided by offshore wind.

[224] Note that these are average monthly data. In the Netherlands, a very cold period usually lasts no longer than a few days or a week. Hence, for the coldest days, the heat demand is considerably higher than the average for a cold month.

In its coalition agreement, the current government foresees to build another 7 GW of wind offshore capacity in the Dutch part of the North Sea between 2024 and 2030. Taking into account the existing wind farms (with a capacity of approx. 1 GW) and the wind farms to be realised under the current offshore wind energy roadmap to 2023 (approx. 3.5 GW), this translates into a total scale of offshore wind farms of approximately 11.5 GW by 2030.[225] Forecasts of how much offshore wind energy will be needed to achieve 2050 climate goals vary widely. The scenarios of the Netherlands Environmental Assessment Agency (PBL), for instance, range from 12 to 60 or even 75 Gigawatts in 2050.[226]

Wind offshore capacity in the Netherlands

intended to increase from 1 GW today to 11.5 GW in 2030. Until 2050 this could even go up to 75 GW. This compares to 19 GW electricity peak demand today.

To understand the dimension of this, please note that Dutch electricity peak load today is 19 GW.

- **Substantial electrification creates further challenges for the (already strained) electricity network** – Today's planned grid expansion projects indicate congestion in the Dutch power grid and the necessity for increased transmission capacity to North West European countries. Various expansion projects in the centre of the Netherlands consist in the implementation of new 380 kV AC (alternating current) transmission lines as well as the reinforcement of existing transmission lines. Exemplary projects involve new transmission lines between Eemshaven and Diemen or between Zwolle and Maasbracht. A new 380 kV transmission line between Doetinchem (NL) and Niederrhein (DE) is built to significantly increase future exchange capacities between the Netherlands and Germany. Extension of exchange capacities to Denmark is assured by the implementation of a DC (direct current) subsea cable between Eemshaven and Endrup. Overall grid extension projects amount to 1,230 km, equivalent to about 12% of the present transmission grid length.

  An electrification-led decarbonisation pathway is likely to amplify this significantly:

  - Generation perspective: An installation of 11.5 GW of offshore wind capacity by 2030, and potentially much more by 2050, does not only induce a substantial challenge for the offshore connection of these parks, but also for the subsequent mainland electricity network. As the current network is not suited to integrate such amounts of wind offshore electricity, major network congestion is likely to occur, which causes the need to strengthen the network substantially, not only in the Netherlands, but also far into Europe. After all, when there is strong wind in the Dutch part of the North

[225] See Ministerie van Economische Zaken en Klimaat (2018).

[226] See PBL and ECN (2017) and PBL (2018).

sea, there will also be a lot of wind energy in the Belgian, UK, German and Danish areas.[227]

- Demand perspective: An on-going electrification of most non-electric consumers will significantly increase the future electrical energy consumption, volatility and peak load. This might lead to further congestion and challenges for the Dutch power system and thus to additional grid expansion, also in the distribution grid.

III. Dutch gas infrastructure well suited to help overcome the challenges of decarbonisation

The Netherlands is the country with the highest gas penetration of all EU28 countries: In 2016, more than 36% of final energy demand in the Netherlands was supplied by gas.[228] This spans across electricity production, households (mainly for heating), industry and services.

36%

of Dutch final energy demand is supplied by gas today. This is the highest gas penetration of all EU28 countries.

Consequently, the Netherlands has a substantial gas infrastructure:

- **Domestic gas network** – The gas transmission network of 11,000 km length spans across the whole country (Figure 114). The distribution network with a length of 135,000 km facilitates, for example, that 93% of Dutch households have a gas connection.[229] There is no significant congestion in the gas grids today, neither are bottlenecks foreseeable as gas consumption and the number of connections are in decline.

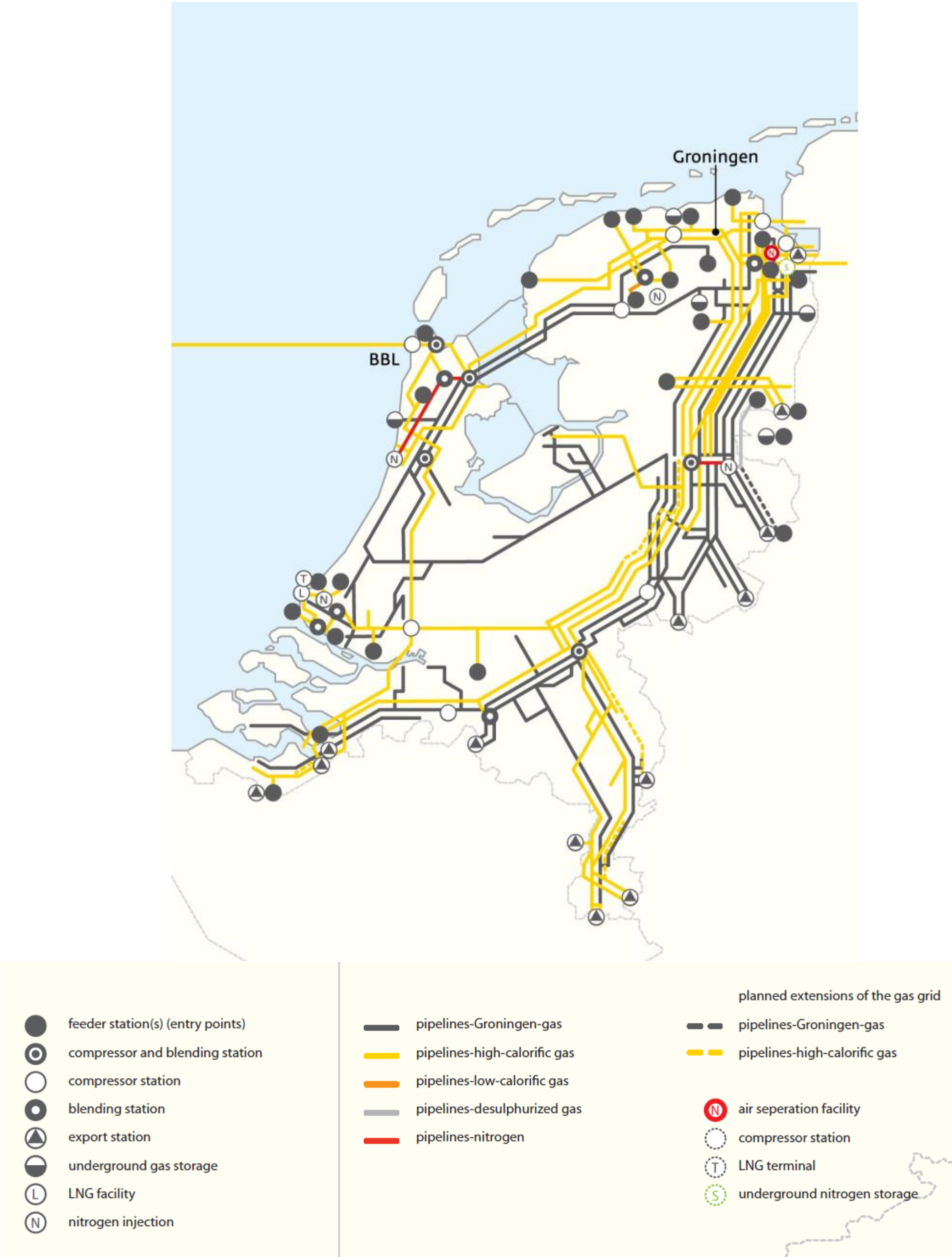
  This network can easily be employed to avoid large investments in the electricity infrastructure. We outline the potential for the use of gas in various sectors as well as the cost savings from the continued use of gas networks in subsequent sections.

[227] See also Energeia (2018).

[228] Based on Eurostat.

[229] See PBL (2017), page 144.

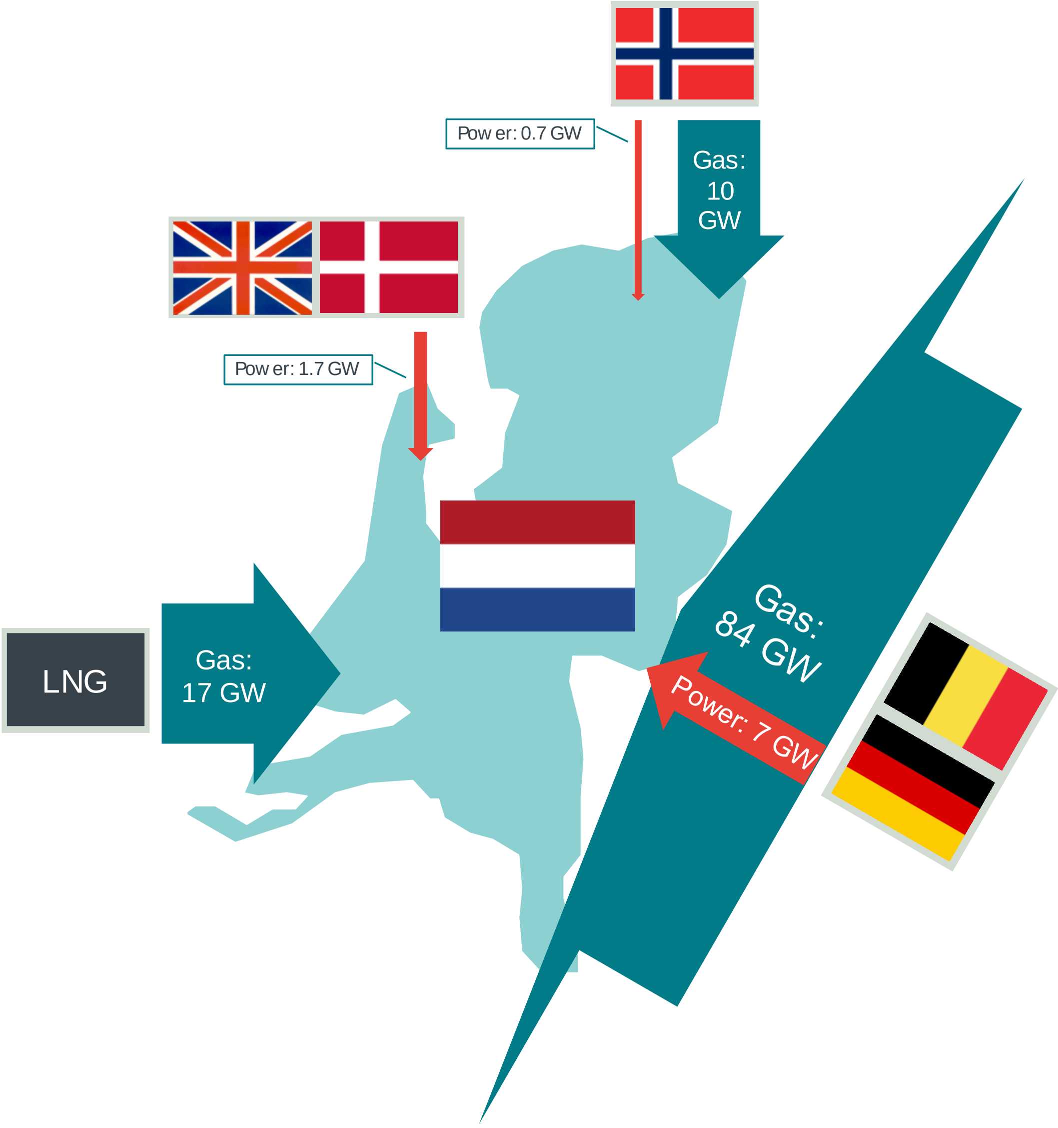
Figure 114 Gas transmission grid in the Netherlands



Source: Gasunie

- **Gas import capacity** – With a history of being a large natural gas exporter, and at the same time located between major gas consuming countries such as UK, Germany and France, the Netherlands is well connected to the European gas network. As an example, the capacity of gas pipelines to the Netherlands exceeds the import capacity of electricity by more than factor 12 (Figure 115).

Figure 115 Comparison of total electricity and gas import capacity: Gas import capacity exceeds electricity import capacity by factor 12

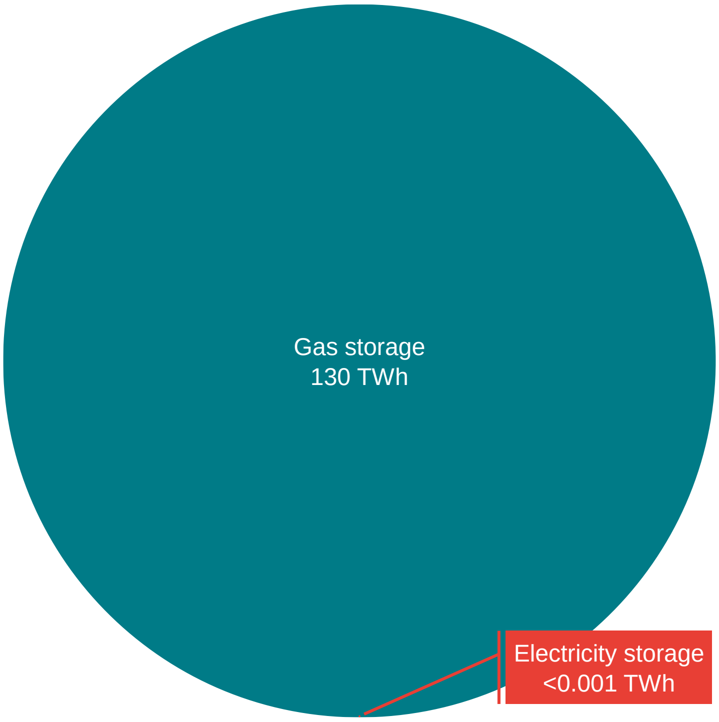


Source: ENTSO-E TYNDP (2018), ENTSO-G Physical Technical Capacity (2018)

Note: Power Import capacities presented are NTCs expected in 2020 according to ENTSOE TYNDP 2018

- **Gas storage –** As outlined above, one of the major difficulties for decarbonising the Netherlands will be to supply seasonal demand of heat. Currently, this is primarily supplied by natural gas, facilitated by considerable domestic gas storage capacity that is sufficient to store 130 TWh of energy (Figure 116). Consequently, gas storage in the Netherlands is well suited to bridge the gap between gas supply, which is comparably flat over the year, and winter peak demand of heat in particular. There is nothing like this in the electricity sector today, where storage volumes are negligible, reflecting that there is no potential for pumped hydro energy storage given the lack of altitude.

Figure 116 Gas storage volume in the Netherlands compared to almost zero electricity storage volume



Source: Frontier Economics based on Gas Infrastructure Europe and Geth et al. (2015).

IV. Dutch gas infrastructure is suited for various renewable and low-carbon gases

While the gas infrastructure in the Netherlands is currently working on natural gas, there are various potential sources for renewable and low-carbon gas that could be fed into the gas infrastructure in the future, thus contributing to achieving the ambitious climate protection targets:

- **Biomethane** – In 2016, the Netherlands produced around 3,700 GWh of biogas.[230] Of that, approximately 1,100 GWh was biomethane, having increased by approximately 30% within four years.[231]

  Looking ahead, the potential for additional domestic biogas production is somewhat limited, given the high population density. As an indicator, the Netherlands is producing 89 MWh biogas per km^2 today. This compares to 5 MWh/km^2 in sparsely populated Sweden on one end of the spectrum, and 264 MWh/km^2 in Germany, the European biogas frontrunner, on the other end of the spectrum. There is, on the other hand, potential for increased biogas upgrading to biomethane, a trend that is already going on, and we observe new demonstration projects to go online such as the Ambigo project, a 4 MW biomass research and demonstration gasification plant in Alkmaar that can be

[230] Eurostat.

[231] See Green Gas Initiative (2017).

used to convert residual flows of biomass, such as waste wood, into renewable gas.[232]

- **Green hydrogen –** The Netherlands has favourable conditions for (renewable) power-to-gas:
  - Substantial amounts of large-scale offshore wind parks with comparably high numbers of full load hours (see above);
  - Substantial demand for gas by industry and power generation sectors that can be substituted by hydrogen. These consumers are also often located close to the seaside.
  - A gas pipeline that is well suited for potential future hydrogen use. According to gas TSO Gasunie, only limited investment would be required to make the transmission network suitable for hydrogen transport, with investment mainly relating to compressors.[233]
  - The facts that the Groningen field needs to phase out natural gas production by 2030 and that the separate pipeline for low-caloric gas will consequently be decreasingly utilised, could also facilitate the transformation to hydrogen by operating two parallel networks: One (bio-)methane-based network to supply households and industry feedstock, and one hydrogen-based network to supply power plants, industry, transport fuelling stations for transport and more.

  Synthetic methane is less likely to play a key role.

  Accordingly, there is a number of power-to-gas conceptions and pilot projects out there, such as (see also PtG pilot project in Rozenburg, as described in Section V of this Annex):
  - The North Sea Wind Power Hub, a consortium of TenneT, Gasunie, Energinet and Ports of Rotterdam, studies and investigates the possible development of a large-scale artificial island in the North Sea to accommodate dozens GW of offshore wind. It is also investigating the possibility of offshore conversion of electricity to hydrogen via large-scale electrolysis and the possibility to transport energy as hydrogen to the final customer, in order to overcome the challenge of electricity transport and reduce system costs.
  - Pilot project HyStock, Netherlands' first MW-sized power-to-gas installation, built by Gasunie subsidiaries Gasunie New Energy and Gasunie EnergyStock. Located at the company's underground gas storage facility at Zuidwending in the province of Groningen, a photovoltaic array of 5,000 solar modules will generate power for the production of hydrogen through electrolysis.[234]
- **Blue hydrogen –** Likewise, the conditions in the Netherlands facilitate the use of blue hydrogen, i.e. hydrogen generated from natural gas while capturing and storing or using the carbon (dioxide):

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[232] See ECN (2017).

[233] See Gasunie (2018).

[234] See EnergyStock (2019).

- The gas infrastructure is well suited for hydrogen (see green hydrogen above);
- While onshore carbon storage would hardly find public acceptance (similar to other countries such as Germany), offshore storage would face less scrutiny. Further, there are natural storage potentials in the North Sea and, as explained above, most industry and many power plants in the Netherlands are located close to the seaside, which would facilitate hydrogen transport.
- Imports of blue hydrogen from Norway, for instance, which has both the necessary natural gas and the offshore CO_2 storage capabilities, is another realistic option, facilitated by the proximity to Norway.

- **Natural gas for the transition** – Obviously, given the high penetration of natural gas in the Netherlands today, it is likely to play a key role for the transition period.[235] It can also have a role in achieving short- or medium-term climate targets, for example by substituting coal in the power generation.

V. Renewable and low-carbon gas has a strong potential in various sectors

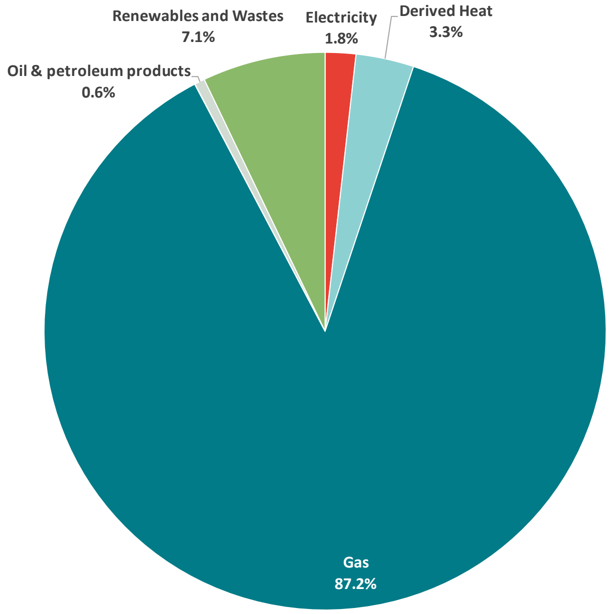
On the back of today's high penetration of natural gas in the Netherlands, renewable and low-carbon gas has strong potential to be used in various energy-consuming sectors in the future (see Annex B for more details on the analysis of sectors):

- **Electricity** – The Dutch electricity generation mix today is dominated by coal- and gas-fired generation. The Dutch government has announced to phase out coal-fired electricity generation by 2030.[236] Given an uncertain future of nuclear power in the Netherlands, this leaves basically gas-fired electricity as a reliable back-up for intermittent renewable electricity generation from, especially, wind onshore and offshore. Because an increase in electricity demand can be expected through electrification of end appliances particularly in heating and transport, gas-fired electricity generation is likely to play a key role in decarbonising the Netherlands. Of course, this will increasingly be renewable and low-carbon gas, with hydrogen being the most obvious solution given the characteristics explained above.
- **Heating** – The Netherlands is the country with the highest gas penetration in heating in Europe. For example, 87% of final energy demand for space heating in households is supplied by gas and 93% of households have a connection to the gas network. Less than 2% is covered by electricity (Figure 117).

[235] See for example Centre for Energy Economics Research at the University of Groningen (2018).

[236] See Rijksoverheid (2018).

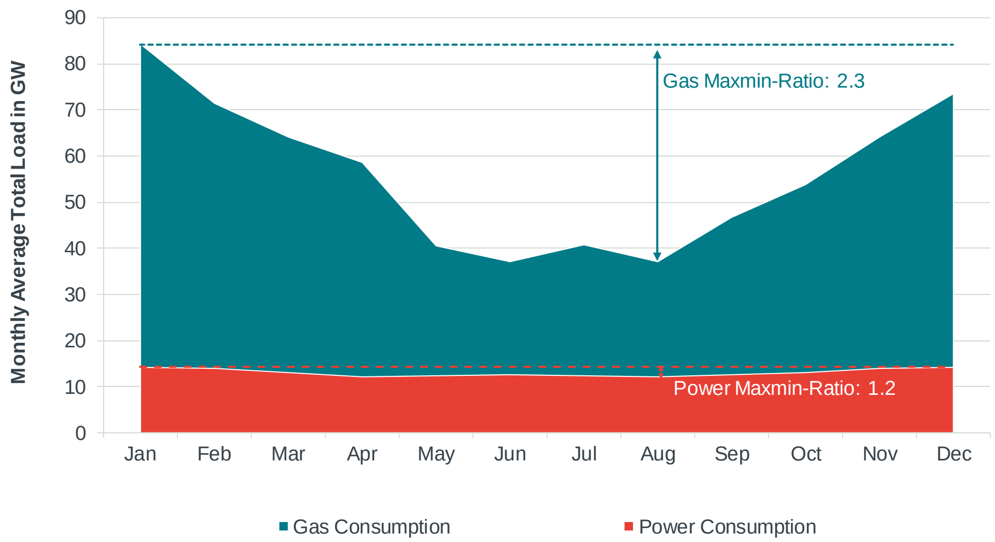
Figure 117 Final energy demand for space heating in residential buildings by fuel in the Netherlands (2016)



Source: Frontier Economics based on Eurostat

Accordingly, and because the Netherlands's heat demand, like that of many other European countries, is characterised by considerable seasonality (cf. Figure 113), today's gas infrastructure has been built to cope with large seasonality, while electricity infrastructure deals with demand that is comparably flat over the course of the year (Figure 118). Electrifying large parts of heat demand would import this demand seasonality to the electricity sector. Covering the resulting peaky electricity demand would pose extraordinary challenges both for generation/storage, as well as the transmission and distribution network.

Figure 118 Monthly gas vs. electricity load profile in the Netherlands



Source: *Frontier Economics based on IEA Monthly Gas Statistics for Actual Gas Load (GWh, 2017) and ENTSO-E Transparency Platform for Actual Electricity Total Load (GW, 2017)*

In this figure, the base load is mainly the usage of gas in industry. This includes gas used as feedstock, which represents a baseload of roughly 3 GW.

Thus, there is a case for gas to supply part of the energy for heating purposes also in the long-term vision of a low or zero emission Netherlands. There is different views of how this contribution may look like:

- **Biomethane for hybrid heat pumps**: Gasunie, for example, expects that most building will run on electric heat pumps by 2050, based on the assumption of substantially increased minimum efficiency requirements for heating devices, but that there will be need for a hybrid solution (at least in existing buildings) where condensing gas-boilers provide the necessary energy on cold days, when e-heat pumps are not capable of (efficiently) providing the required heat. Thus, even though stand-alone gas boilers will be a rarity, the gas transmission and distribution network will still be needed as a backbone for supplying security of heat supply, while the need for electricity network extensions is reduced largely, and costs for the electric heating system (including insulation and radiators) are far lower than in an all-electric solution.[237] This hybrid heating system is likely to be fuelled with biomethane rather than hydrogen.
- **Hydrogen for central or decentral heating boilers**: Other stakeholders are investigating the possibilities to use hydrogen also for heating, for instance currently trialled by Stedin, the network operator for gas and electricity in South Holland, in Rotterdam district Rozenburg.[238]

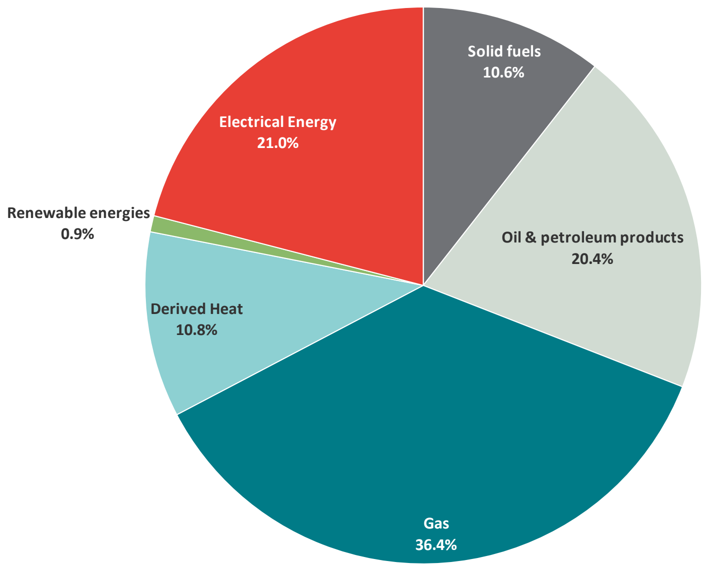
[237] See Gasunie (2018).

[238] See New Mobility News (2018).

- **Industry** – Energy use in the Dutch industry is dominated by gas: In 2016, around 36% of final energy demand in the industry was supplied by gas, another 20% by oil & petroleum products (Figure 119). Likewise, natural gas as has a key role in supplying the required feedstock for industrial processes.

  To achieve Dutch climate targets, there is likely to be a combination of electrification of processes (e.g. where comparably low temperature process heat is needed), adjusting machines and processes to hydrogen and using biomethane or fossil fuels such as natural gas or oil with CCS to supply the required carbon feedstock. The location of the bulk of industry near the seaside facilitates supply of green hydrogen (based on offshore electrolysis) and application of CCS where the CO_2 can be stored offshore.

Figure 119 Final energy consumption in industry by fuel in the Netherlands (2016)



Source: Frontier Economics based on Eurostat

- **Transport** – Today the Netherlands's transport sector is, similar to that of most other European countries, dominated by oil products. Gas plays a limited role, supplying 0.3% of final energy demand in transport. Analogously to other countries, however, gas or hydrogen-fuelled transport is likely to be one essential pillar of future transport, in particular in transport modes that are difficult to electrify, such as heavy-duty road transport.

VI. Gas networks reduce system costs of energy supply and increase public acceptance

In the previous section we found that renewable and low-carbon gas is not only important for seasonal storage, where it is practically indispensable, but also potentially a valuable energy carrier to supply various sectors directly. This is reflected by our calculations of system costs for two different decarbonisation paths.

In summary, the continued use of gas networks to transport energy to final customers in the Netherlands in 2050 yields cost benefits of **EUR 3.6 to 5.5 billion per year**. Further, it contributes to the public acceptance of decarbonisation through avoided electricity network expansion.

EUR 3.6-5.5 bn / year

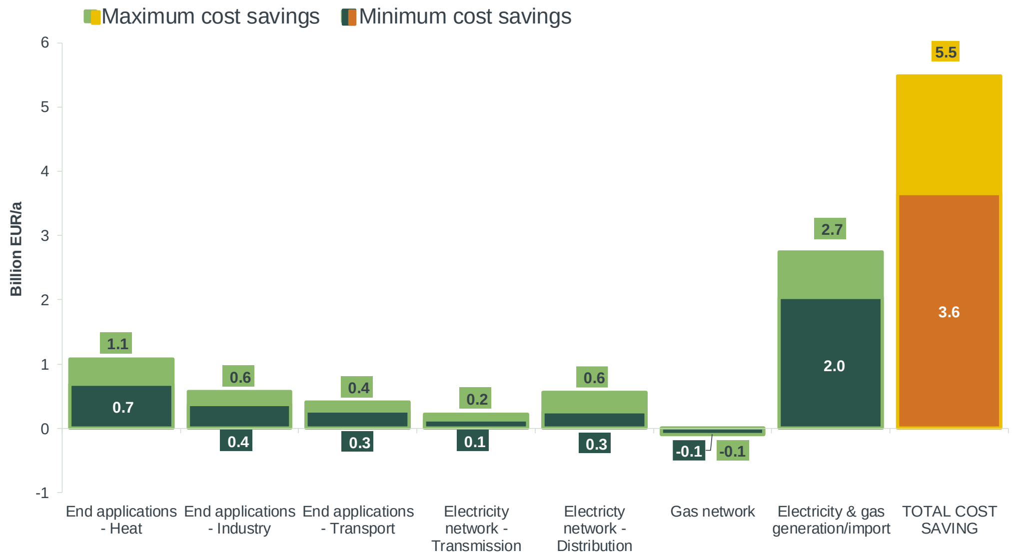
can be saved through the continued use of gas networks in 2050.

The gas network helps save costs across the whole value chain

We have derived these estimates by comparing a scenario in which gas networks are still used to deliver (renewable and low-carbon) gas to end users ("Electricity and Gas Infrastructure" scenario) to a scenario where most end appliances are electrified and gas is only used for seasonal storage with (re-)electrification ("All-Electric plus Gas Storage" scenario) in 2050 (see Section 4.2 for more details).

To compare energy system costs between the two scenarios, our analysis has taken into account costs along the entire energy supply chain. To capture uncertainty about the future development of key parameters such as gas and electricity demand or renewable and low-carbon gas generation costs in 2050, we have executed the calculations for a number of different parameter sets, resulting in the cost saving intervals presented below.

Figure 120 Min and max cost savings of a continued use of gas networks per year in 2050 along the supply chain in the Netherlands



Source: Frontier Economics/IAEW

Note: The values illustrate the difference in annual costs between the "All-Electric plus Gas Storage" scenario and the "Electricity and Gas Infrastructure" scenario. A positive value reflects cost savings in the "Electricity and Gas Infrastructure" scenario, where parts of end energy are supplied by renewable and low-carbon gas via gas networks, compared to the "All-Electric plus Gas Storage" scenario, where end energy is primarily supplied by electricity and gas networks are no longer needed. Minimum and maximum savings refer to varied assumptions on key parameters that are uncertain from today's perspective, such as production prices of different gases or the development of final energy demand until 2050.

The results reveal that the Netherlands can benefit considerably from the continued use of gas networks. In 2050 it can save **EUR 3.6 to 5.5 billion per year** in an "Electricity and Gas Infrastructure" scenario compared to an "All-Electric plus Gas Storage" scenario where most end appliances have been electrified and gas is only used for temporal storage. This corresponds to annual cost savings of **EUR 215 to 323 per capita.**

These savings comprise of savings from lower costs for end appliances in heating, industry and transport, cost savings through avoided investments in electricity transmission and distribution networks as well as from replacing expensive additional electricity generation capacity by lower cost renewable and low-carbon gas. In particular, an expected use of comparably inexpensive blue hydrogen in the Netherlands leads to electricity and gas generation being substantially cheaper in the "Electricity and Gas Infrastructure" scenario than the "All-Electric plus Gas Storage" scenario for all tested parameter sets.

Use of gas networks benefits public acceptance of decarbonisation

As explained above, in the "All-Electric plus Gas Storage" scenario the Dutch electricity grid would have to be expanded substantially. The gas network, on the other hand, is already fit for purpose. Its continued usage would therefore render significant parts of the electricity grid extension obsolete: Based on an extensive network modelling exercise, we previously identified that for the German transmission network this effect is as large as 40% by 2050.[239] Transferring this result to the Netherlands by taking into account the higher penetration of gas on the one hand, but the possibly lower grid extension needs per added GW of RES expansion until 2050 on the other hand[240], it is likely that the Netherlands could avoid transmission grid extensions of approximately 28 to 42% through the continued use of gas networks by 2050, compared to the “All-Electric plus Gas Storage” scenario. In light of the public resistance against the new construction of overhead power lines, gas networks therefore benefit public acceptance of decarbonisation.

239 See Frontier Economics et al. (2017).

240 Basically driven by the higher population density.

ANNEX I COUNTRY STUDY SWEDEN

I. Introduction

In this country study we provide an overview of the situation and perspectives of gas infrastructure in Sweden. As the Swedish gas infrastructure differs largely from that in other countries, we apply a different structure and methodology than for the other countries.[241]

II. Decarbonisation in Sweden facilitated by abundance of renewable energy sources

Sweden has ambitious climate protection targets:

- Zero net emissions of greenhouse gases by 2045, implying that the emissions from Swedish territory are to be 85% lower than in 1990.[242]
- Sweden also committed to certain sector sub-targets, such as:
  - 70% reduction of CO_2 emissions in the transport sector by 2030 (update of the initial target of a fossil-free road vehicle fleet in 2030);
  - 100% renewable electricity production by 2040 (including nuclear power).

With respect to decarbonisation, however, Sweden is different to most other European countries in that there is an abundance of renewable energy resources, especially of hydro and of biomass. Furthermore, as one of only few countries in Europe, there are no plans to phase out nuclear power in the foreseeable future, that with its eight operating plants provides around 40% of electricity consumed in Sweden. The 2016 energy accord, supported across all major parties, ended more than 30 years of discussions over nuclear power, and effectively extended the lives of the nation's six newest reactors until at least 2040, and even allowed new units to be built, even if only at the existing sites.[243] Discussions on rethinking this deal, however, are emerging, imposing an uncertain future for nuclear power.[244]

III. Sweden's gas infrastructure is focussed regionally

Being blessed with renewable energy potential, natural gas was introduced rather late into the Swedish market in the 1980s, basically as a mean to lower the dependency from oil after the oil price crises of the 1970s. Therefore, and because population density in Sweden is very low, there is nothing like a nation-wide gas network in Sweden, and gas supplies only around 2% of final energy demand in Sweden. Gas infrastructure in Sweden comprises of

- The main gas grid, operated by Swedegas, which is located in West and South Sweden, mainly around the urban areas of Malmö and Gothenburg (Figure

[241] Likewise, it was not in the scope of the study to calculate potential cost savings of using gas infrastructure for Sweden.

[242] See Swedish Environmental Protection Agency (2018).

[243] See Government Offices of Sweden (2016).

[244] See Bloomberg (2018b).

121). Swedegas estimates that the share of gas in energy consumption only in this area is about 20%;

- Several smaller gas networks all over Sweden ("offgrid solutions"), mostly run with biogas. In fact, Stockholm even has two separate gas networks: An old city gas grid which provides gas for heating and cooking and is partly served by regasified LNG, and a smaller grid for biogas for vehicles (mainly busses).

Figure 121 Gas transmission grid in West and South Sweden

Source: Swedegas

IV. Value of renewable gas particularly in the industry and in transport

Despite the limited scope of gas infrastructure today, it can contribute to decarbonisation in various sectors:

- **Electricity** – Electricity generation in Sweden is dominated by nuclear and hydro power, with a share of around 40% in electricity generation each, followed by wind with approximately 10%.[245] Gas-fired CHPs are available in Gothenburg and Malmö, but market conditions are currently challenging. Southern Sweden is a deficit area, and the power balance will further worsen when more nuclear reactors are decommissioned in 2019/20, which may provide opportunities for gas-fired plants during coming years. Their role may

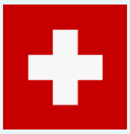
[245] Entso-E transparency platform for 2017.

become more relevant in case the agreement on nuclear power lifetime is changed.

- **Heating** – Sweden's heating is dominated by district heating in densely populated areas, mainly based on biomass, electricity, facilitated by adjustable production from nuclear and reservoir hydro power, and direct renewables such as wood pellets. Given the lack of an existing comprehensive gas network and the low population density in most parts of Sweden, gas is unlikely to play a major role in (further) decarbonising Sweden's heat supply.
- **Industry** – Swedish gas consumption is dominated by the industrial sector, where around 4% of the final energy consumption is supplied by gas, plus a comparably high non-energy demand of gas as feedstock. Looking ahead, gas infrastructure has the potential to contribute to further reducing greenhouse gas emissions in Sweden's industry sector, e.g. by
  - substituting natural gas with renewable gas, especially biomethane, in existing facilities;
  - replacing oil-fired industrial processes with natural gas (and increasingly renewable gas) by densifying the existing gas network in South and West Sweden;
  - supplying remote industrial sites with LNG or bio-LNG.
- **Transport** – Substantial efforts are required to achieve Sweden's target to reduce CO_2 emissions in the transport sector by 70% until 2030. Passenger cars and light-duty vehicles will likely be almost completely electrified. For other types of vehicles biofuels and LNG technologies will possibly play a role in the foreseeable future. In cities like Malmö and Stockholm public transport is already close to being fossil fuel free by focussing on electrification, liquid biofuels and biogas solutions. Some small local biogas pipeline networks are already in place.

ANNEX J COUNTRY STUDY SWITZERLAND

Summary



- **Climate goals –** By 2050, Switzerland has to decarbonise its heating, transport and parts of its industry sector almost entirely, given its ambitious climate targets (minus 70 to 85 % by 2050).
- **Nuclear phase-out** – At the same time, Switzerland is phasing out nuclear power and potentials for an extension of domestic renewable electricity generation are limited.
- **The challenge of strong electrification** – Thus, an electrification-led decarbonisation path in Switzerland is imposing challenges for the generation, transport and storage of energy, and is very likely to require a substantial increase of electricity imports from neighbouring countries. This would require significant new interconnector capacity and strengthened domestic transmission and distribution networks.
- **Existing gas infrastructure** – The Swiss gas infrastructure has a lot to offer to contribute to decarbonisation alongside electrification: Gas supplies around 14% of final energy demand and the gas network covers all densely-populated areas. Gas import capacity is large, exceeding electricity import capacity by factor 4. Also, although Switzerland's domestic gas storage is small, Switzerland has exclusive access to gas storage in neighbouring countries, providing the basis to bridge the gap between energy supply and seasonal heat demand. Additionally, some studies are underway for developing storages (e.g. lined rock cavern, LNG) in Switzerland.
- **Sources for renewable gas –** There are various sources for renewable gas in Switzerland. It could either be produced from domestic biomass or imported from countries with better conditions for biogas or synthetic gas production. Such imports are facilitated by large existing gas import capacity.
- **Role of renewable gas in consumer sectors –** Renewable gas can play an important role in various energy consuming sectors:
  - **Electricity production**, by substituting dispatchable generation from nuclear energy;
  - **Heating**, where existing gas infrastructure has always been used to cover heat demand peaks (e.g. gas demand in January is six times higher than average summer demand);
  - **Industry**, where renewable gas could substitute natural gas (for heating and as feedstock);
  - **Transport**, where CNG, hydrogen or LNG can contribute to efficient decarbonisation, particularly in heavy duty road and public transport,.

- **Cost savings of using gas networks** – Our analysis shows that, compared to switching Switzerland to an electrification-led energy system, the usage of gas networks based on renewable gas could **reduce Swiss system costs in the magnitude of EUR 1.3 to 1.9 billion in 2050**. Main drivers of these savings are the avoided investment in capital-intensive heating appliances, avoided electricity distribution grid expansions and a volume effect in electricity generation and renewable gas production/import.
- **In summary, our analysis suggests that usage of Switzerland's gas infrastructure is key to reaching Switzerland's climate targets in a cost-effective way**.

I. Introduction

In this country study we provide an overview of why the gas infrastructure has a significant societal value for decarbonising Switzerland. We follow the same structure as in the main report, and focus on highlighting the particularities in Switzerland. Please refer to the main report to understand the general methodology and argumentation.

II. Switzerland's challenge: Decarbonisation of a complex energy system while phasing-out nuclear energy

Achieving Switzerland's decarbonisation targets presents a major challenge:

- **Climate protection targets and nuclear phase-out require a massive transition of the energy system** – On the back of its Energy Strategy 2050,[246] Switzerland is targeting a reduction of 1990-levels of CO_2-emissions by 50% by 2030 (including non-domestic measures), by **70-85 % by 2050**, and climate-neutrality beyond 2050.[247] Further, the **New Energy Act implies a (soft) nuclear phase-out**, i.e. existing nuclear plants can continue operation as long as their safety is guaranteed, but there will generally be no new licences for nuclear power plants.[248] Given that most non-energy-related CO_2 emissions in agriculture and industry are difficult or costly to avoid, energy-related emissions in transport, industry, households and services need to be avoided or compensated almost entirely in order to achieve the 2050 CO_2 target.
- **Reaching these objectives through a high degree of electrification would cause a significant increase in annual and peak electricity demand** – Our analysis reveals that meeting these objectives through a primarily electrification-led decarbonisation strategy would create a number of challenges:

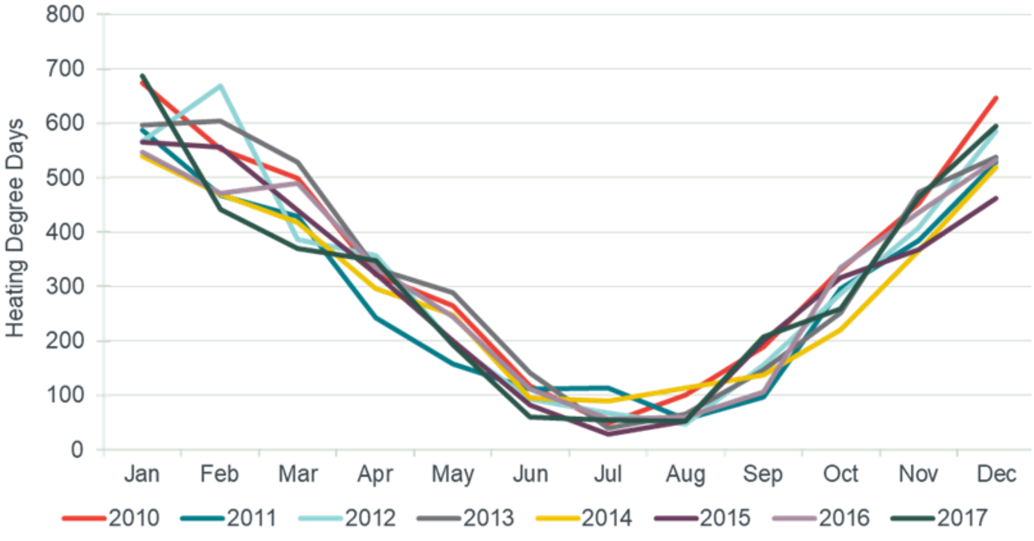
246 See SFOE (2018a).

247 See current draft of CO_2-law FOEN (2017).

248 As stipulated in the Swiss Energy Act from 2016, see The Federal Council (2018).

- **Increase in annual electricity demand** – Today, less than 25 % of final energy demand in Switzerland is supplied by electricity, which is equivalent to a final electricity consumption of 58 TWh[249] per year and a peak load of 10 GW.[250] Electrifying large parts of the residual 75% of final energy demand would lead to substantial additional electricity demand, even assuming ambitious energy efficiency gains.[251]
- **Boost in electricity peak demand** – Today, where electricity is mainly used for lighting, ICT or electric devices, but not for space or water heating or cooling, electricity demand in Switzerland is comparably flat over the course of the year. Electrifying large parts of heat demand would import the considerable seasonality of heat demand (see Figure 122) into the electricity sector.

Figure 122 Seasonality in Switzerland's heat demand (based on number of heating degree days)



Source: Frontier Economics based on Eurostat - Cooling and heating degree days by country - monthly data

Note: Heating Degree Days are defined as days on which the mean air temperature is so low that indoor heating is required. Eurostat sets this temperature at 15 °C in its calculations.

- **The additional demand may need to be met through increased imports, intensifying already existing concerns about security of supply** – This additional electricity demand of electrification, particularly in winter, needs to be supplied. However, **potentials for low-carbon electricity generation in Switzerland are limited:**
  - Nuclear, today producing almost 20 TWh electricity per year or more than 30 % of Switzerland's electricity generation, is phasing-out;
  - For hydro power, which produces 60% of Switzerland's electricity today, there are no substantial expansion potentials.

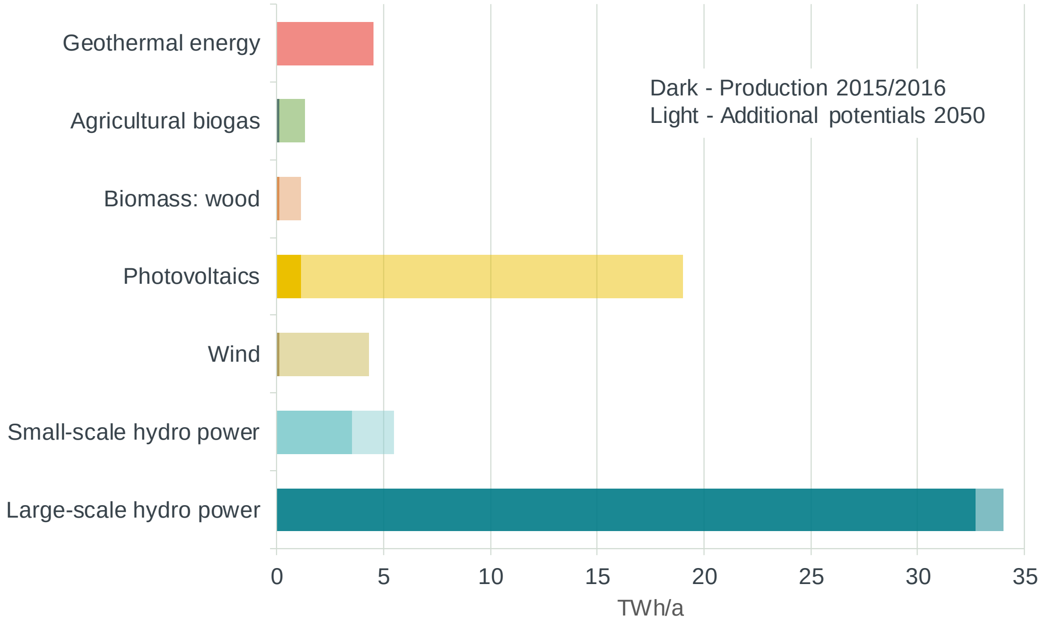
[249] See SFOE (2017).

[250] See ENTSO-E (2018).

[251] These efficiency gains were actually expected to lead to a substantial decline in overall energy demand until 2050, see DETEC (2016).

- And potentials for "new renewables" such as wind and solar power, which today produce less than 3% of electricity in Switzerland, are also limited. A recent study for the Swiss Federal Office of Energy (SFOE) estimates a maximum additional potential of 32 TWh of renewable electricity production in 2050, compared to 38 TWh today (see Figure 123).

Figure 123 Current production and estimated maximum potentials for renewable electricity generation in Switzerland in 2050 (in TWh/a)



Source: Frontier Economics based on Paul Scherrer Institut for SFOE (2017)

Of the "new renewables", photovoltaics have the largest potential in Switzerland due geographic conditions and public acceptance. However, solar power can contribute only little to electricity supply in winter where electricity demand is highest. As a result, there would be a substantial generation gap in winter that would need to be covered by imports.

Given similar challenges in neighbouring countries, a substantial **increase in required imports** would **intensify already existing concerns about security of electricity supply in Switzerland**, triggered by the heavy dependency on electricity imports caused by low production from run-of-river plants and low water reservoir levels in winter that is already prevalent today.[252]

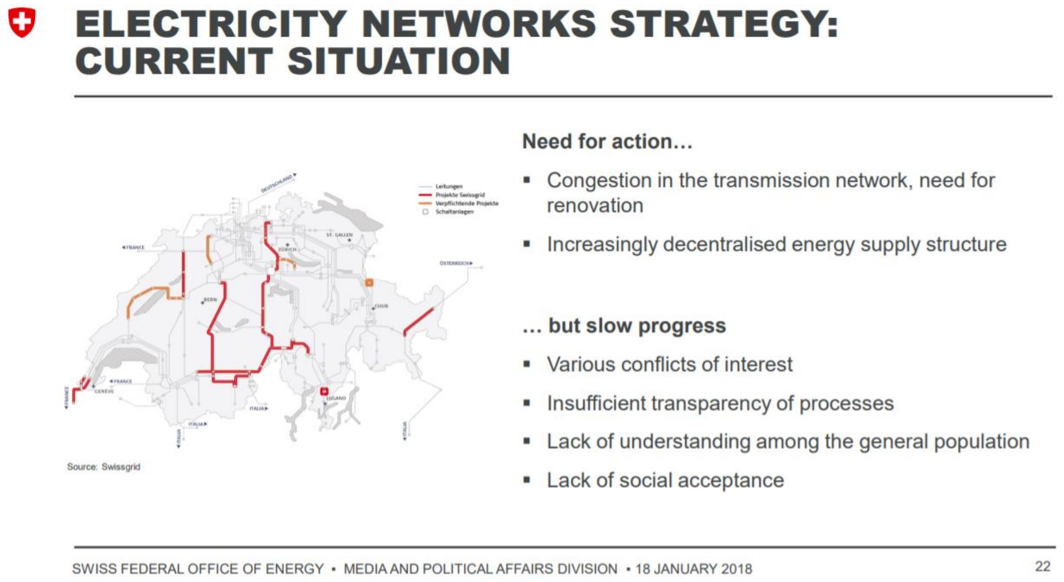
- **Substantial electrification creates further challenges for the (already strained) electricity network** – Likewise, direct electrification creates additional challenges for the electricity network, which is already suffering from substantial congestion today:
  - The power flow from the north to the south creates congestion in the so-called "Mittelland" of Switzerland. Expansion projects to alleviate these are

[252] See for example Frontier Economics (2017).

already underway. Additionally, the transmission capacity between Chippis and Lavorgo is to be increased, indicating congestion in this area. Further local congestion occurs in the northwest as well as in the east of Switzerland. The already planned or commissioned expansion projects in the transmission grid amount to a length of 525 km, which is around 8 % of the current transmission grid length of Switzerland.

- Substantial electrification will likely necessitate further network expansions due to changes on the generation and the demand side.
  - Generation perspective: As nuclear is to be phased out and partly replaced by renewable sources, the share of solar PV and wind in the generation mix will increase. Solar systems are mainly connected to the distribution grid, the dimensioning of which historically evolved from the demand perspective. Increasing feed-in of solar systems on distribution level might therefore lead to significant need for restructuring and extension of the distribution grid. In contrast, future wind farms result in the necessity of long distance electricity transport. Consequently, the loading of the transmission network will be affected and network extension measures of the transmission grid are likely to increase, too.
  - Demand perspective: The electrification of mobility most non-electric consumers will significantly increase the future peak load, volatility and volume of electrical energy consumption. The likely additional future electricity imports, caused by the aforementioned limitations of additional sustainable generation capacity, are likely to further increase the loading of the power grid. All of these changes are likely to cause further congestion in the Swiss power grid. That would have to be compensated by network expansions.
- This is likely to create difficulties given that already today the process of renovating existing lines or building new lines turns out to be a major challenge due to various conflicts of interest and a lack of social acceptance (see government information in Figure 124).

Figure 124 Need for action but slow progress in the Swiss electricity transmission network



Source: SFOE (2018a)

III. Swiss gas infrastructure well suited to help overcome the challenges of decarbonisation

Today, around 14 %[253] of final energy demand in Switzerland is supplied by gas. Of this, the majority is consumed in households (mainly for heating), industry and services.

14 %

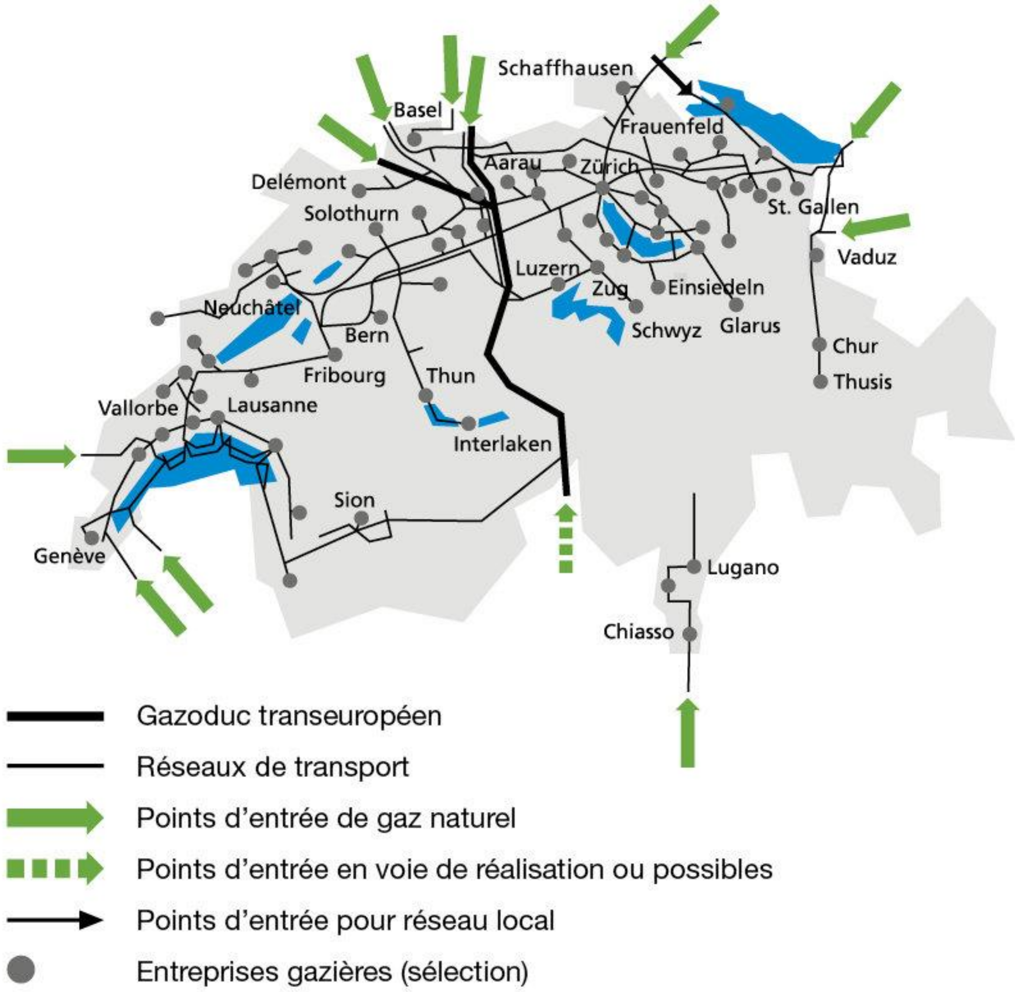
Of Switzerland's final energy demand is supplied by gas today.

Accordingly, Switzerland has a substantial gas infrastructure:

- **Domestic gas network** – Switzerland's transmission and distribution gas network covers all densely populated areas. It has more than 19,000 km length, of which the high-pressure (> 5 bar) transmission network accounts for more than 2,200 km. It covers the whole so-called "Mittelland", ranging from Geneva in the far west via all major cities such as Lausanne, Bern, Basel or Zurich to St. Gallen in the north-east (Figure 125). This network can easily be employed to avoid large investments in the electricity infrastructure. We outline the potential for the use of gas in various sectors as well as the cost savings from the continued use of gas networks in subsequent sections.

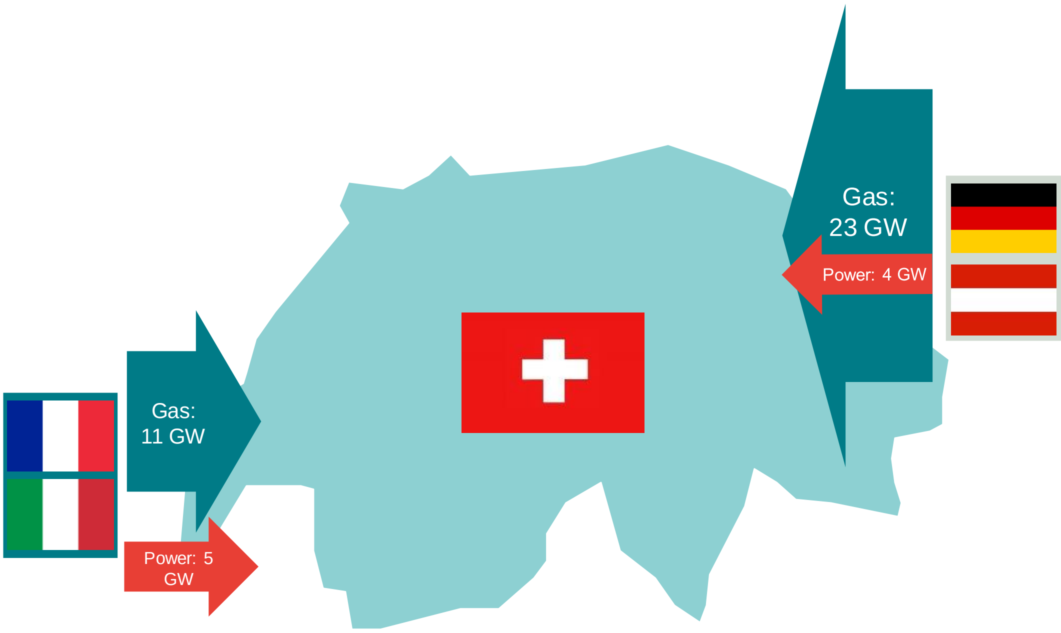
[253] See SFOE (2018c).

Figure 125 Gas transmission grid Switzerland (overview)



- **Gas import capacity –** Due to its geographic location in the middle of Europe, Switzerland is well connected to the European gas network. For instance, the Transit pipeline that connects Germany and Italy runs through Switzerland. In fact, the capacity of gas pipelines to Switzerland exceeds the import capacity of electricity by more than factor 4 (Figure 126).

Figure 126 Comparison of total electricity and gas import capacity: Gas import capacity exceeds electricity import capacity by factor 4



Source: ENTSO-E TYNDP (2018), ENTSO-G Physical Technical Capacity (2018)

Note: Power Import capacities presented are NTCs expected in 2020 according to ENTSOE TYNDP 2018

- **Gas storage –** As outlined above, one of the major difficulties for decarbonising Switzerland will be to supply seasonal demand of heat (which is today primarily supplied by oil and natural gas). While electricity-based storage such as pumped hydro energy storage or batteries are not suited for this seasonal storage purpose, renewable gas storage is. Switzerland's own gas storage facilities are currently limited (below 100 GWh).[254] However, Switzerland's physical gas interconnection with neighbouring countries provides access to considerable gas storages. As an example, Switzerland has contracted access to the French storage facilities in Etrez with exclusive delivery (1,500 GWh), which can be used for strategic and seasonal storage. In addition, there are a few pilot projects to explore underground storage in Switzerland: For instance, Gaznat is exploring a potential site for gas storage of more than 600 GWh in the Valais canton. LNG could also be a solution for future energy storage systems.

IV. Existing gas infrastructure is suited for a variety of renewable and low-carbon gases

In Switzerland the gas industry is already driving the transition: It has committed to a target share of at least 30% renewable gas for heating in the grid by 2030.[255]

In the long-term, there is a variety of different renewable gases that are likely to play a role:

[254] See Institut für Energietechnik (2017).

[255] See VSG (2017).

- **Biomethane** – In 2016, Switzerland produced 950 GWh of biogas, with sewage sludge being the most important source (almost 50% of produced biogas). Biomethane generation is still in its infancy, but increased significantly from 15 GWh in 2011 to 277 GWh in 2016. In addition, there is already substantial demand for biomethane in the country: Approximately 200 GWh of biomethane was imported mainly from Germany for heating purposes in 2016.[256]

  There is scope for further biogas and biomethane production in Switzerland. As an indicator, Switzerland is only producing 23 MWh biogas per km^2 today, compared to, for example, 264 MWh/km^2 in Germany. However, given its hilly landscape, there are limits to additional (economic) biogas generation. Nevertheless, there is also the option for further biomethane upgrading of today's biogas generation (which could be stretched with the help of direct methanation using power to gas,[257] which increases the biomethane yield by 60%.[258] One major difficulty in producing biomethane in Switzerland, however, are transport costs, either incurred through the transport of biomass from dispersed farms to larger plants or through the transport of biomethane from smaller plants to the nearest gas distribution network. In sum, Hanser Consulting (2018) estimates the cost-effective domestic biomethane potential in Switzerland to be below 3 TWh/a.

- **Renewable gas from domestic power-to-gas** – In light of the limited Swiss renewable potentials, there is not likely to be a substantial systematic power to gas production in Switzerland. However, it would be feasible to convert electricity to gas in periods of excess generation, such as from hydro or photovoltaic in summer. In addition to facilitating storage, this would help to relieve the strain on electricity networks.

- **Domestic blue hydrogen** – Switzerland has substantial shale gas potential, but political considerations make its exploration difficult. In addition, Switzerland has some underground storage which could potentially be used to store CO_2 (tests are currently undertaken). The generation of hydrogen from natural gas would therefore likely be feasible in Switzerland, but its future scale and role is uncertain.

- **Import of renewable gas** – Switzerland's strong connections to the European gas network with substantial entry and exit capacities provide the opportunity to diversify renewable gas supply: For example via the import of biomethane from France or Italy, synthetic methane from North Africa, where the abundance of solar energy allows for very inexpensive synthetic methane production, or blue hydrogen from Norway or Russia, that may benefit from large natural gas resources and the availability of depleted gas or oil fields to store large volumes of CO_2. Such a diversified import portfolio, which could not be matched easily by electricity, can help reduce energy supply costs and enhance security of supply.

[256] See European Biogas Association (2017).

[257] Direct methanation is the process of combining hydrogen from electrolysis with the CO_2 that is produced as a by-product during the upgrading of biogas to biomethane.

[258] See Hanser Consulting (2018)

V. Renewable gas has a strong potential in various sectors

Renewable gas has a strong potential to be used in various energy-consuming sectors in Switzerland (see Annex B for more details on the analysis of sectors):

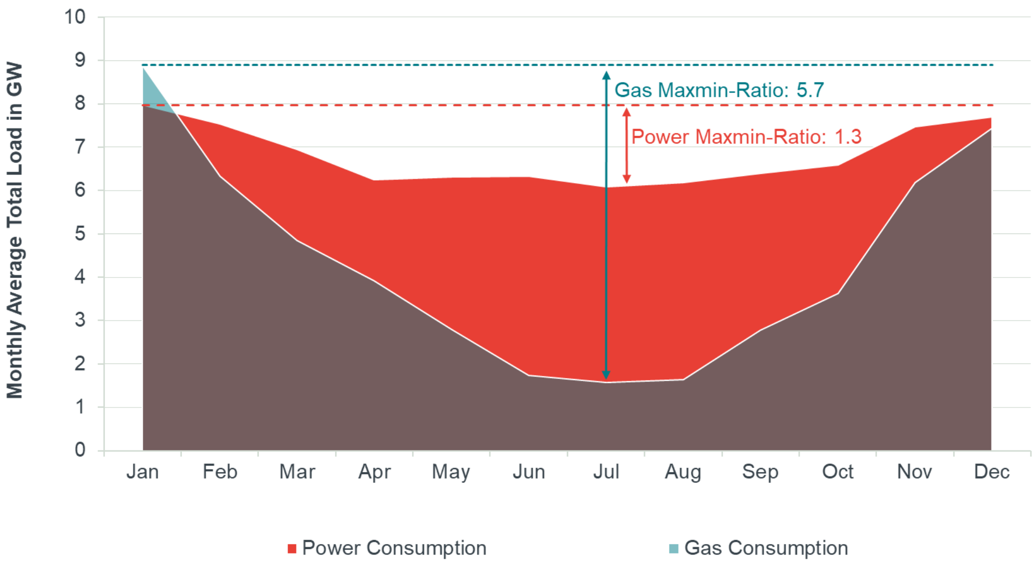
- **Electricity** – While today's gas share in Switzerland's electricity generation mix is negligible, this may change in the future: Given the phase-out of dispatchable nuclear power and the increase in intermittent renewable electricity generation, in particular from solar power, centralised power stations fired by renewable gas or small decentralised CHPs are likely to be required to supply peak electricity demand in times of low hydro and solar power supply in the winter period.

- **Heating** – Today, more than 35% of final energy demand in Switzerland is used for space and water heating. The biggest part of this is supplied by fossil fuels, mainly oil (41%) and gas (26%). Only a minor share of about 10% is covered by electricity. District heat covers approximately 5% of space and water heating demand in buildings (see Figure 128).[259]

  Accordingly, and because Switzerland's heat demand, like that of many other European countries, is characterised by considerable seasonality (cf. Figure 122), today's gas infrastructure has been built to cope with large seasonality, while electricity infrastructure deals with demand that is comparably flat over the course of the year (Figure 127). Electrifying large parts of heat demand would import this demand seasonality into the electricity sector. Covering the resulting peaky electricity demand would pose extraordinary challenges both for generation/storage, as well as the transmission and distribution network.

[259] Calculation by Frontier Economics based on SFOE (2018b).

Figure 127 Monthly gas vs. electricity load profile – Switzerland



Source: *Frontier Economics based on IEA Monthly Gas Statistics for Actual Gas Load (GWh, 2017) and ENTSO-E Transparency Platform for Actual Electricity Total Load (GW, 2017)*

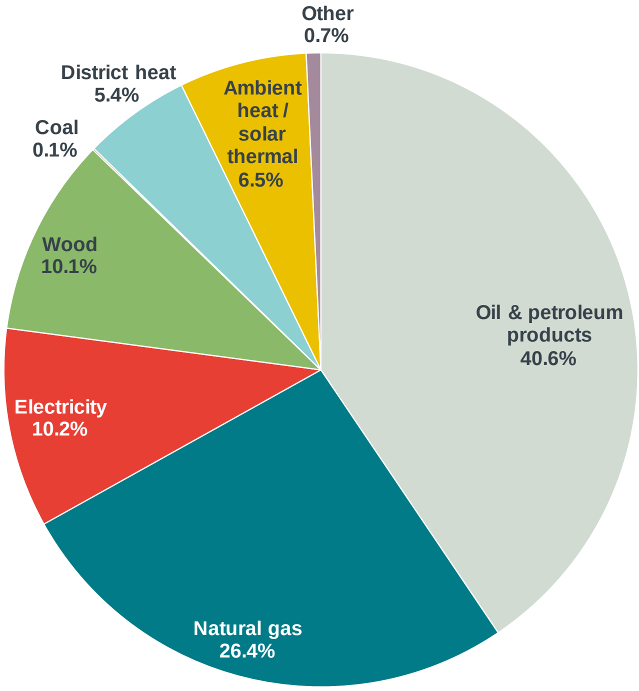
Thus, there are good arguments to keep existing gas connections active and let households continue to heat with (in the future renewable) gas.

In addition, where oil-dependent households are located close to existing gas networks, it may be cost effective to let them switch to gas by densifying the existing network, which would help reduce the peakiness of electricity demand and avoid capital-intensive investments. Another alternative is the development of micro CHP solutions, either as pure solutions – such as internal combustion engines for old buildings or solid oxyd fuel cells for new or renovated buildings – or as combinations of micro CHP and electric heat pumps.[260]

Where oil-dependent households are located in remote areas and in the case of new buildings, solutions based on the supply with CNG or LNG via virtual networks will be an option. Even more so because a Swiss virtual network is already in place and because the alternative, electric heating, is forbidden in some cantons.

[260] See EPFL (2018) for current research on the perspectives of micro CHP in Switzerland.

Figure 128 Final energy demand for space and water heating in buildings by fuel (2017)

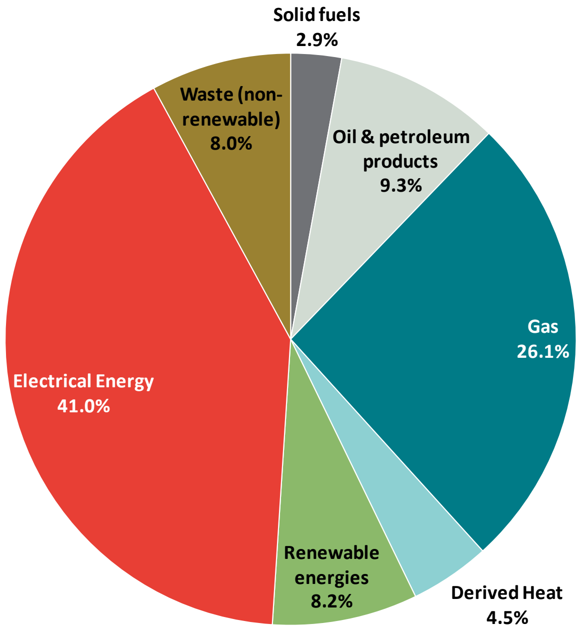


Source: Frontier Economics based on SFOE (2018b)

- **Industry** – Today, more than 18% of final energy demand in Switzerland is consumed in the industry. Of this, around 55% is used to generate process heat. While low-temperature process heat can be electrified relatively easily, this is much more difficult and inefficient for high-temperature process heat and feedstock. Instead of substituting the entire current share of gas (26%), oil (11%)[261] and other fossil fuels used in industry, it may therefore be sensible to leave an opportunity for the continued use of the gas infrastructure for transporting renewable gas. There may even be a role for the direct use of LNG or hydrogen, yet machines and processes would have to be adjusted appropriately.

[261] See SFOE (2018b).

Figure 129 Final energy consumption in industry by fuel (2017)



Source: Frontier Economics based on SFOE (2018c)

- **Transport** – Today Switzerland's transport sector is, similar to that of most other European countries, dominated by oil products. Gas does play a limited role, supplying 0.3% of final energy demand in transport.[262] Analogously to other countries, though, gas or hydrogen-fuelled transport is likely to be one essential pillar of future transport, in particular in transport modes that are difficult to electrify, such as heavy-duty road transport. LNG and CNG could also play a role in light vehicle transport.

[262] See SFOE (2018c).

VI. Gas networks reduce system costs of energy supply and increase public acceptance

In the previous section we found that renewable gas is not only important for seasonal storage, where it is practically indispensable, but also potentially a valuable energy carrier to supply various sectors directly. This is reflected by our calculations of system costs for two different decarbonisation paths.

In summary, the continued use of gas networks to transport energy to final customers in Switzerland in 2050 yields cost benefits of **EUR 1.3 to 1.9 bn per year**. Further, it contributes to the public acceptance of decarbonisation through avoided electricity network expansion.

EUR 1.3 - 1.9 bn / year

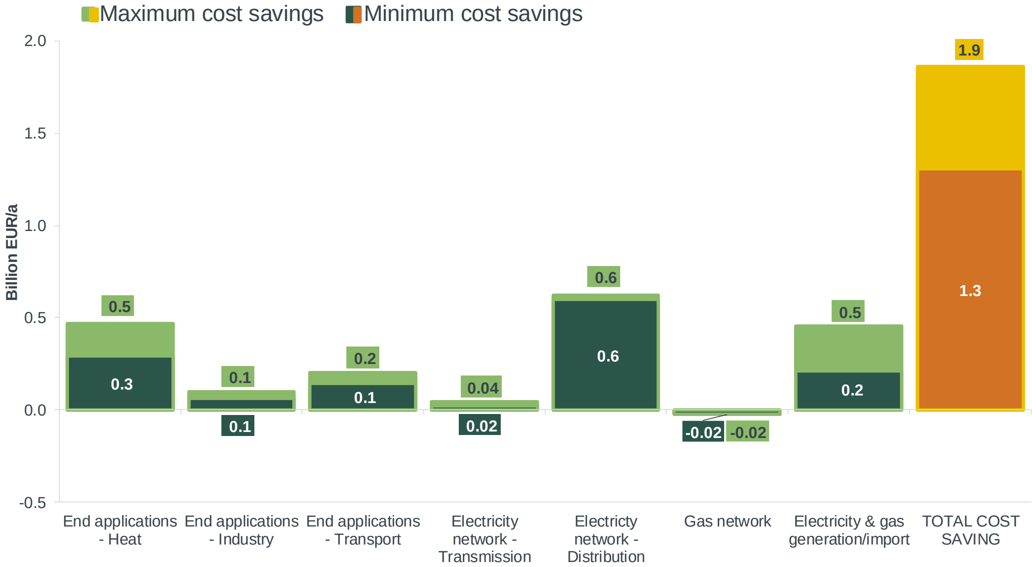
can be saved through the continued use of gas networks in 2050.

The gas network helps save costs across the whole value chain

We have derived these estimates by comparing a scenario in which gas networks are still used to deliver (renewable) gas to end users ("Electricity and Gas Infrastructure" scenario) to a scenario where most end appliances are electrified and gas is only used for seasonal storage with (re-)electrification ("All-Electric plus Gas Storage" scenario) in 2050 (see Section 4.2 for more details).

To compare energy system costs between the two scenarios, our analysis has taken into account costs along the entire energy supply chain. To capture uncertainty about the future development of key parameters such as gas and electricity demand or renewable gas generation costs in 2050, we have executed the calculations for a number of different parameter sets, resulting in the cost saving intervals presented below.

Figure 130 Min and max cost savings of a continued use of gas networks per year in 2050 along the supply chain in Switzerland



Source: Frontier Economics/IAEW

Note: The values illustrate the difference in annual costs between the "All-Electric plus Gas Storage" scenario and the "Electricity and Gas Infrastructure" scenario. A positive value reflects cost savings in the "Electricity and Gas Infrastructure" scenario, where parts of end energy are supplied by renewable and low-carbon gas via gas networks, compared to the "All-Electric plus Gas Storage" scenario, where end energy is primarily supplied by electricity and gas networks are no longer needed. Minimum and maximum savings refer to varied assumptions on key parameters that are uncertain from today's perspective, such as production prices of different renewable gases or the development of final energy demand until 2050.

As a country with difficult geographical conditions and limited RES potentials, except hydro power, Switzerland can benefit considerably from the continued use of gas networks. In 2050 it can save **EUR 1.3 to 1.9 billion per year** in an "Electricity and Gas Infrastructure" scenario compared to an "All-Electric plus Gas Storage" scenario where most end appliances have been electrified and gas is only used for temporal storage. This corresponds to annual cost savings of **EUR 155 to 221 per capita.**

The bulk of these total savings results from lower costs for end appliances in residential heating, cost savings through avoided investments in electricity distribution networks, and savings from substituting expensive additional electricity generation capacity and electricity imports through (mostly imported) lower cost renewable gas.

Use of gas networks benefits public acceptance of decarbonisation

As explained above, in the "All-Electric plus Gas Storage" scenario the Swiss electricity grid would have to be expanded substantially. The gas network, on the other hand, is already fit for purpose. Its continued usage would therefore render significant parts of the electricity grid extension obsolete: Based on an extensive network modelling exercise, we previously identified that for the German transmission network this effect is as large as 40% by 2050.[263] Transferring this

[263] See Frontier Economics et al. (2017).

result to Switzerland by taking into account the less significant penetration of gas and the lower extent of RES expansion until 2050, it is likely that Switzerland could avoid electric transmission grid extensions of approximately 5-8 % through the continued use of gas networks (without extensions) by 2050, compared to the "All-Electric plus Gas Storage" scenario. In light of the public resistance against the new construction of overhead power lines, gas networks therefore benefit public acceptance of decarbonisation.