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Study on Bringing TEN-E and The CEF In Line with Our COP-21 Climate Goals

Trinomics

Contract details

TEC1178EU EP SD, Group of the Progressive Alliance of Socialists & Democrats in the European Parliament

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List of Abbreviations

ACER	Agency of the Cooperation of Energy Regulators
BCM	Billion Cubic Meters
BT	ENTSOG Behind Targets Scenario
CEF	Connecting Europe Facility
CO_2	Carbon Dioxide
COP 21	21st Conference of the Parties
DG	Directorate General of the European Commission
DG	ENTSOG Distributed Generation Scenario
DG CLIMA	Directorate General for Climate Action
DG ENER	Directorate General for Energy
DG ENV	Directorate General for Environment
GCA	ENTSOG Global Climate Action Scenario
ERDF	European Regional Development Fund
EFSI	European Fund for Strategic Investments
EIB	European Investment Bank
ENTSO	European Network of Transmission System Operators
ENTSO-E	European Network of Transmission System Operators of Electricity
ENTSOG	European Network of Transmission System Operators of Gas
ETS	European Emissions Trading System
EU	European Union
EU REF	European Reference Scenario
FDI	Foreign Direct Investments
IPCC	Intergovernmental Panel on Climate Change.
LNG	Liquified Natural Gas
MTOE	Million Tonnes of Oil Equivalent
NRA	National Regulatory Authority
PtG	Power-to-Gas
PCI	Projects of Common Interest
RES	Renewable Energy Sources
TEN-E	Trans-European Networks for Energy
TYNDP	Ten-Year National Development Plan
TWh	Terra-Watt Hour
UNFCCC	United Nations Framework Convention on Climate Change
SGE	ENTSOG Subsidized Green Europe Scenario
ST	ENTSOG Sustainable Transition Scenario

Executive Summary

This study assesses the extent to which the ENTSOG's Ten-Year Development Plans and the selection of Gas Projects of Common Interest are in line with the 2030 EU Energy and Climate policies and targets, and in particular with more ambitious targets for energy efficiency (30, 35 and 40% improvement of energy efficiency).

In the context of the COP21 Paris Climate Agreement the European Union has pledged to substantially reduce its Greenhouse Gas Emissions and to massively invest in low carbon energy technologies that contribute to a rapid decarbonisation of its economy. The energy sector, being one of the main contributors of greenhouse gas emissions, will have to play an important role in implementing adequate technologies and measures for energy efficiency and sustainability, whilst maintaining competitive and affordable energy prices and ensuring security of supply for European consumers. The European Union has already taken significant steps in that direction with the adoption of ambitious climate and energy policies and targets for the 2020 and 2030 time-frame. The 2030 targets agreed by the Council in October 2014 date from before the COP21 summit and focus on a global temperature rise of 2°C. Since the parties at COP21 agreed upon a more stringent goal of "holding the increase in the global average temperature to <u>well below</u> 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels", the 2030 targets agreed by the Council should be tightened up to remain in line with the Paris agreement. More ambitious energy efficiency and RES targets for 2030 are already approved with a large majority by the European Parliament in its first reading of the review of the Energy Efficiency and Renewable Energy Directives, also in view of reducing greenhouse gas emissions by mid-century with 85-90% compared to the 1990 levels.

In order to stimulate the development and interoperability of trans-European networks, dedicated measures have been taken at EU level, such as the TEN-E regulation, which provides an enabling regulatory treatment for priority energy infrastructure with cross-border impact. In this context, Projects of Common Interest (PCIs) are identified, which benefit from accelerated permitting and access to mechanisms for cross-border cost allocation (CBCA). Such projects can also be eligible for specific national incentives as well as for EU financial support via the Connecting Europe Facility (CEF), which disposes of EUR 5.3 billion to provide funding for energy infrastructure projects in the 2014-2020 period. These instruments have substantially contributed to the realisation of additional gas infrastructure across the EU, which has significantly enhanced gas systems and markets' integration as well as security of gas supply. These aspects are extensively commented on in this report.

The transition to a low carbon energy supply will have a huge impact on the future role of natural gas in the energy mix. To reduce the risk of overcapacity, investment decisions should be based on updated and accurate demand forecasts. In order to assess possible changes in gas demand and their impact on the need for infrastructure, different scenarios for gas consumption by 2030 and beyond, have been analysed and compared with the estimates put forward by ENTSOG in the context of its 2017 TYNDP. The possible evolution of EU domestic gas production as well as imports of LNG and pipeline gas are also highlighted in this study. This demand/supply analysis, together with the evaluation of investment needs in order to further improve security of supply and markets' integration, provides useful input in evaluating the need for additional gas infrastructure.

As natural gas demand is expected to decrease as of 2025 in most scenarios, there is a risk that gas infrastructure which already exists or is under construction, will in the medium or long term become redundant and could end up as stranded assets in the second half of this century. Therefore, this report also analyses potential technologies and areas in which natural gas transmission and storage networks could be used and contribute to the decarbonisation of the energy sector. One option analysed is the injection of decarbonised fuels (biomethane, synthetic methane or hydrogen from renewable resources) into the gas transport and distribution infrastructure. Another option is the conversion of transport and/or storage facilities such as (decommissioned) pipelines and depleted gas fields (salt caverns) in order to transport and store hydrogen or carbon dioxide (CO_2). Possible measures for improving the flexibility of the gas infrastructure, such as greater integration between the gas and electricity systems, as well as financing R&D and pilot projects like the power-to-gas (P2G) technology and establishing Guarantees of Origin (GOs) for green gas, are also presented.

On the basis of this overview and analysis, the study concludes with the following key findings and recommendations:

- **Most studies expect a substantial decrease of EU overall gas demand by 2030, while ENTSOG's development plans are still based on stable or slightly decreasing demand estimates**
- **Future EU natural gas demand can be covered by (decreasing) domestic gas production and more diversified gas imports without major new investments in infrastructure**
- **TEN-E and Connecting Europe Facility have substantially contributed to the development of a well interconnected and resilient gas system which offers a high security of supply level**
- **Use of fossil fuels including natural gas, will have to be reduced more drastically to meet COP21 Paris Climate Agreement commitments**
- **Gas markets integration and competition have been substantially enhanced by regulatory and market rules aiming at a more efficient use of existing gas infrastructure**
- **Proposals for new gas infrastructure projects in the context of TEN-E/PCI or CEF funding should be carefully scrutinized in order to avoid overinvestments and cost impacts which might harm the affordability of energy for businesses or citizens**
- **Use of natural gas infrastructure to transport and distribute green gas should be facilitated**
- **Adequate policy measures should be taken to stimulate supply of and demand for green gas**
- **Implementation of Power to Gas technologies (hydrogen or synthetic methane) should be supported to facilitate the development of variable renewable energy sources and to decarbonise energy supply**
- **Decommissioned pipelines and depleted natural gas fields could be used for transporting and storing carbon dioxide, but the economic viability of CCU and CCS is currently not ensured. It could be enhanced by a higher CO_2 price and by co-financing of innovative projects by CEF or the ETS Innovation Fund.**

1. Introduction

The Paris Agreement was signed in 2015 at the 21st annual Conference of the Parties (COP21) of the United Nations Framework Convention on Climate Change (UNFCCC). In it 195 countries agreed on the first-ever universal, legally binding global climate deal. This agreement, which sets out a global action plan to put the world on track to avoid dangerous climate change by limiting global warming to well below 2°C, serves as a bridge between today's policies and climate-neutrality before the end of the century. The European Parliament approved the ratification of this agreement in 2016, thus pledging full support of the European Union in tackling climate issues and accelerating the transition towards a decarbonised and sustainable economy. This climate agreement will inevitably have a great impact on the climate and energy policies and on the energy mix in the EU Member States.

In order to combat climate change and ensure an affordable, competitive and secure energy supply, the European Union has adopted ambitious energy and climate targets for 2020 and 2030 and has made commitments to radically reduce its greenhouse gas emissions by 2050. The underlying policies to reach these targets significantly affect the future role of fossil fuels including natural gas, in the energy mix. This report comments on the possible future demand and supply levels for gas in the European Union according to the latest scenarios elaborated by the European association of Gas Transmission System Operators (ENTSOG) in the context of its Ten-Year Network Development Plans (TYNDPs). It also identifies potential discrepancies between the forecast assumptions and outcomes published by ENTSOG and the results of other publications, in particular studies commissioned by the European Commission, as well as research papers published by independent academic and private institutions. These studies, which estimate the possible levels of EU natural gas demand in the medium and long-run under different scenarios, are useful in identifying the need for additional gas infrastructure, also taking into account other policy objectives, in particular security of energy supply and markets' integration, as a means to enhance competitiveness. Finally, more detailed views on the potential flexibility of existing gas infrastructure are presented in order to highlight the extent to which it can be used to facilitate the development of decarbonised fuels, as well as the transport and storage of carbon dioxide.

2. Gas Infrastructure Planning and Financing

2.1 COP21 Paris Agreement

The pledges made by the European Union in the context of the Paris COP21 Agreement will undoubtedly have an impact on natural gas demand in the medium and long-term and hence on the gas infrastructure use and needs for future investments. Art. 4(1) stipulates that parties to the agreement strive to achieve a balance between anthropogenic emissions by sources and removal by sinks of greenhouse gases in the second half of this century.[1] This means that the European Union will have to develop ambitious policies to drastically reduce the greenhouse gas emissions of its economy, and of its energy sector in particular, in order to comply with the COP21 agreement. The agreed 2030 climate and energy targets are an important step towards this objective, but discussions are still ongoing to set more ambitious targets in order to properly address the climate change challenges. In Art. 4(19), parties agree to develop long-term low greenhouse gas emission development strategies by 2020.[2] In this context, the EU's 2050 roadmap to a low carbon economy will to a large extent determine the future role of natural gas. An effective instrument that could be implemented at EU level, is the introduction of an EU wide carbon emission 'price' or 'cost' at an adequate level, for both the ETS and non ETS sectors, as well as the reduction of the current EUR 4 billion of fossil-fuel subsidies.[3] Such a measure would stimulate the use of low carbon energy technologies, in particular renewable energy sources, and would reduce their need for subsidies. The Paris Agreement should also stimulate an accelerated learning curve for the implementation of innovative technologies. This means that the EU's energy infrastructure will have to change substantially in the coming decades; adequate methodologies and tools for energy network management should be implemented to keep pace with these rapid developments, and to avoid some infrastructure investments not being future-proof and ending up as stranded assets.

2.2 EU Climate and Energy Policies

This chapter focuses on the main EU level climate and energy policies and their potential impact on the gas sector. It also presents the methodologies used to identify possible evolutions in the gas market as well as the EU instruments available to co-finance the construction of additional gas infrastructure. Regional specificities as well the question of whether the gas infrastructure is future proof will also be commented on in this chapter.

[1] UNFCC COP21 Paris Agreement, (http://unfccc.int/files/essential_background/convention/application/pdf/english_paris_agreement.pdf)

[2] UNFCC COP21 Paris Agreement, *Ibid*.

[3] Infrastructure for a changing energy system: the next generation of policies for the European Union, E3G, (https://www.e3g.org/docs/E3G_The_next_generation_of_EU_infrastructure_policies_Dec_2017.pdf)

2.2.1 EU Energy and Climate policies and targets will have a major impact on the future gas demand

EU energy and climate policy objectives and policies

The three main energy policy objectives agreed on by the EU and its Member States which, are **security of energy supply** for all EU businesses and citizens, **sustainability** of energy supply by decreasing the related emissions of GHG and pollutants (NOx, SO_2, etc) and last but not least **competitiveness** of European energy prices by providing affordable energy to European businesses and citizens.

These policy objectives must also guide political decisions regarding the role of natural gas in the energy mix of EU Member States. Investments in gas infrastructure have to contribute to these objectives; we notice that most large gas infrastructure projects primarily focus on enhancing security of supply, while, in general, they also facilitate wholesale markets' integration (and hence enhance competition and market liquidity) and allow more sustainable energy use, e.g. by enabling more efficient energy conversion processes and by replacing other more polluting fossil fuels. As a result of growth in renewable energy, the gas sector is on a course of greater integration with the electricity sector (back-up for intermittent RES, power to gas, etc) as well as on a path for delivering a more flexible infrastructure capable of transporting and distributing (and storing) alternative energy vectors such as hydrogen, biomethane, synthetic methane, etc.

Another important factor in determining the gas demand for European residential and tertiary buildings, is the implementation of the European Ecodesign[4], Energy Efficiency (EED)[5] and Performance for Buildings Directives (EPBD)[6]. These directives set the legislative instruments for improving the efficiency of energy appliances and lowering the energy needs of the building stock as well as for establishing a common methodology to evaluate the energy performance of appliances and buildings and a system for energy certification[7]. Since natural gas is one of the main energy sources used for water and space heating, the gains made in energy efficiency in construction, especially the provision that by 31 December 2020, all new buildings should be nearly zero-energy buildings, will have a strong effect on the demand for gas in the coming decades. The agreement reached in the Trilogue negotiations between the European Council, Commission and Parliament on the revised EPBD will even have a stronger impact since according to this new legislation, Member States will also have to develop and implement long term strategies to renovate their existing building stock to nearly-zero energy buildings (NZEB) by 2050.

Energy and climate 2030 targets

The 2030 Climate and Energy Framework[8] was agreed in 2014. It builds on the 2020 package and sets three key targets for 2030:

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[4] DIRECTIVE 2009/125/EC OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 21 October 2009 establishing a framework for the setting of Ecodesign requirements for energy-related products (http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009L0125&from=EN)

[5] DIRECTIVE 2012/27/EU OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 25 October 2012 on energy efficiency, amending Directives 2009/125/EC and 2010/30/EU and repealing Directives 2004/8/EC and 2006/32/EC (http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32012L0027&from=EN)

[6] DIRECTIVE 2010/31/EU OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 19 May 2010 on the energy performance of buildings (http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32010L0031&from=EN)

[7] DIRECTIVE 2010/31/EU OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 19 May 2010 on the energy performance of buildings (http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32010L0031&from=EN)

[8] COM (2014)15, A policy framework for climate and energy in the period from 2020 to 2030 (http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52014DC0015&from=EN)

- a 40% reduction of greenhouse gas emissions compared to the 1990 levels;
- at least a 27% share of renewable energy in the overall energy consumption; and
- at least 27% energy savings compared to baseline projections.

Both the RES and the energy savings targets are currently being discussed in legislative processes between the European Parliament, Commission and Council. This interaction might lead to more ambitious targets. In its first reading, the European Parliament supported with a large majority an increase of the 2030 renewable energy target to a binding 35% share at EU level and an energy efficiency target of at least 35% by 2030 compared to baseline projections.

The 2016 Clean Energy for All Europeans package[9] aims at enabling the EU to prepare its energy system for the future and to become one of the world leaders on the clean energy transition by implementing decarbonising solutions and increasing the share of renewable energy sources in national energy mixes. This package also provides general guidelines for the development of the energy sector, which affects gas markets and also focuses on the need for integrated and interconnected networks, including for gas.

In general, if methane emissions in the upstream exploitation, storage and transport can be avoided, gas is considered as a viable component in the transition towards a low-carbon energy supply, as it is the less polluting and less carbon-intensive fossil fuel. Substantial GHG emission reduction could be obtained by substituting the use of coal for power generation with gas; however, this shift is currently being hindered by the low price level for GHG emission allowances. If a scenario with high EEA prices materialised, the demand for natural gas for power generation (substitution of coal) could remain at a relatively high level in 2020-2030.

In view of the 2030 and 2050 targets, some Member States are considering to reduce the role of fossil fuels, including natural gas, in their energy mix. In the Netherlands for instance, the new coalition agreement approved in October 2017 mentions that, by 2021, the use of natural gas for heating new buildings will be prohibited, and the heating system of existing buildings should gradually be converted to electricity (e.g. via heat pumps) or renewable sources.

The role of gas in the energy mix by and beyond 2050 is highly unsure

In 2011, EU policy makers agreed on an indicative long-term goal to reduce greenhouse gas emissions by 80-95% by 2050, as set out in the Energy Roadmap 2050.[10] For the period 2020-2030, most projections show that the EU's natural gas demand will be relatively stable and decline only modestly. Post-2030 outlooks reveal potentially dramatic changes. This is especially the case when decarbonisation policies become more aggressive. This will initially impact the use of gas for power generation, progressing to its use in the heating sector. These projections suggest that the European gas sector can only continue to play a major role in the future energy mix, if it is able to deliver cost-effective decarbonisation options (power-to-gas, biomethane, CCS, etc.). Without these, the sector will face declining market shares and the risk of stranded infrastructure assets. Decarbonisation poses different long-term challenges and potentially an existential threat for the natural gas sector, as a combination of renewables and energy storage (batteries, pumped hydro, biomethane, power to gas, thermal storage, etc.) might take a large part of its market in both the power generation and heating sectors.

[9] COM (2016)860. Clean Energy For All Europeans
[10] COM(2011)885, Energy Roadmap 2050

Achieving the transition to a near zero-carbon emission energy supply by 2050 will require substantial investments in low-carbon technologies and an economic and institutional framework capable of facilitating this transition.[11] The impact of these policies on the role of natural gas in the energy mix in 2050 is still highly uncertain, as it will mainly depend on future economic, technological, societal and regulatory developments. The technical and economic feasibility (cost development) of “new” low carbon technologies (fuel cells, CCS, energy storage, gas or electricity driven heat pumps, power-to-hydrogen, large-scale and micro CHP, thermal solar, etc.) will be a major determinant of the future role of gas.

The level of ambition for decarbonisation in the year 2050 is an important factor for the future development of the gas sector. GHG reduction ambitions of around 80% might result in reduced incentives for decarbonising gas and developing renewable or low-carbon gas, while high ambitions, beyond 90% would provide for higher incentives and opportunities for “green gas”.

2.3 EU Natural Gas Infrastructure Planning

2.3.1 Planning of and investments in Trans-European gas infrastructure

At the European level the cross-border integration of energy systems and markets is one of the main issues of relevance in the EU’s energy union. European gas systems and markets are generally already well interconnected, but further efforts are necessary, particularly in some European regions, in order to comply with the N-1 infrastructure standard[12] imposed by Regulation 994/2010 concerning measures to safeguard the security of the gas supply. This standard has recently been reviewed (Proposal 2016/0030 (COD)). The new version, which was endorsed by the Parliament in September and by the Council in October 2017, entered into force on 1 November 2017. The planning of new investments is partly based on market and security of supply imperatives, but also on the expected evolution of the (overall and peak) demand at national or regional level. Reliable forecasts for the mid-to-long term of EU gas demand and comprehensive cost-benefit analyses of the different (possibly competing) infrastructure projects, are hence key in determining the most appropriate network and investment planning. This is the reason behind the legal obligation on the European Network of Transmission System Operators (ENTSOG) to produce a Ten-Year Network Development Plan (TYNDP). every two years. The TYNDP aims to develop a European supply adequacy outlook and assessment of the resilience of the gas system, including identification of the investment gaps where missing infrastructure prevents security of supply and market integration objectives from being achieved. Subsequently, the TYNDP also assesses at EU wide level, whether the submitted projects adequately contribute to the improvement of the European gas system and properly address the infrastructure needs.

This plan is produced on the basis of information gathered from the national Transmission System Operators as well as from other stakeholders involved in the gas market. After the preliminary data is gathered by the local TSOs an open stakeholder consultation is organised by ETNSOG in order to provide greater transparency.

[11] EC (2015), Energy Economic Developments - Investment perspectives in electricity markets. Institutional paper 003, July 2015.
[12] The N-1 criterion means that the network must be able to withstand the (temporary) loss of the biggest asset on the network.

NDPs and TYNDPs are used as basis for investment planning in gas infrastructure

The gas network planning exercise is embedded in the framework of the National Development Plans (NDPs) and the Ten-Year Network Development Plans (TYNDPs). TYNDPs have been established since 2009 by ENTSOG based on the NDPs. Regulation 715/2009[13] requires ENTSOG to adopt and publish such a community-wide network development plan every two years. The latest TYNDP available is the 2017 ENTSOG TYNDP. The preliminary draft report for the new plan is also currently available.[14]

The TYNDPs for gas and electricity are currently not based on a single coordinated and validated scenario so the two plans are not fully aligned. In order to improve this process, a closer cooperation between the two ENTSOs has been agreed in order to achieve improved consistency between the plans. In October 2017 as a first step in this process the ENTSOs released a joint set of scenarios for consultation.[15] With this initiative the gas and electricity ENTSOs have combined their efforts and expertise for the first time in order to develop common scenarios to assist with decision making for future infrastructure investment needs. The selection of the most probable scenario, which properly anticipates the impacts of policies and market developments, is a key part of the basis to making appropriate investment choices in infrastructure.

New gas infrastructure is promoted through TEN-E Regulation and Union Lists of Projects of Common Interest (PCIs)

The Trans-European Energy Networks (TEN-E) Regulation[16] identifies priority corridors and thematic areas of trans-European energy infrastructure and provides guidelines for the selection of Projects of Common Interest (PCIs). For gas, 4 priority corridors have been determined in the Regulation: North-South gas interconnections in Western Europe – North-South gas interconnections in Central and South-Eastern Europe – Southern gas Corridor – Baltic Interconnection Plan in gas. The TEN-E Regulation establishes that PCIs can benefit from financial support from the CEF, accelerated permitting, improved regulatory conditions, cross-border cost-allocation procedures and increased transparency. PCIs need to be included in both the NDPs and TYNDPs.

The 2nd Union list of PCIs[17] published in November 2015 (the '2015 PCI list'), consisted of 195 PCIs of which 111 were electricity, 77 were gas and 7 were oil projects. For gas, transmission projects dominated the list with 64 PCIs, while liquefied natural gas (LNG) and underground gas storage (UGS) facilities accounting for 7 and 6 projects respectively. The PCI technology split and geographical distribution are shown in in the graph and the map below.

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[13] Regulation (EC) No 715/2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005.(http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009R0715&from=en)

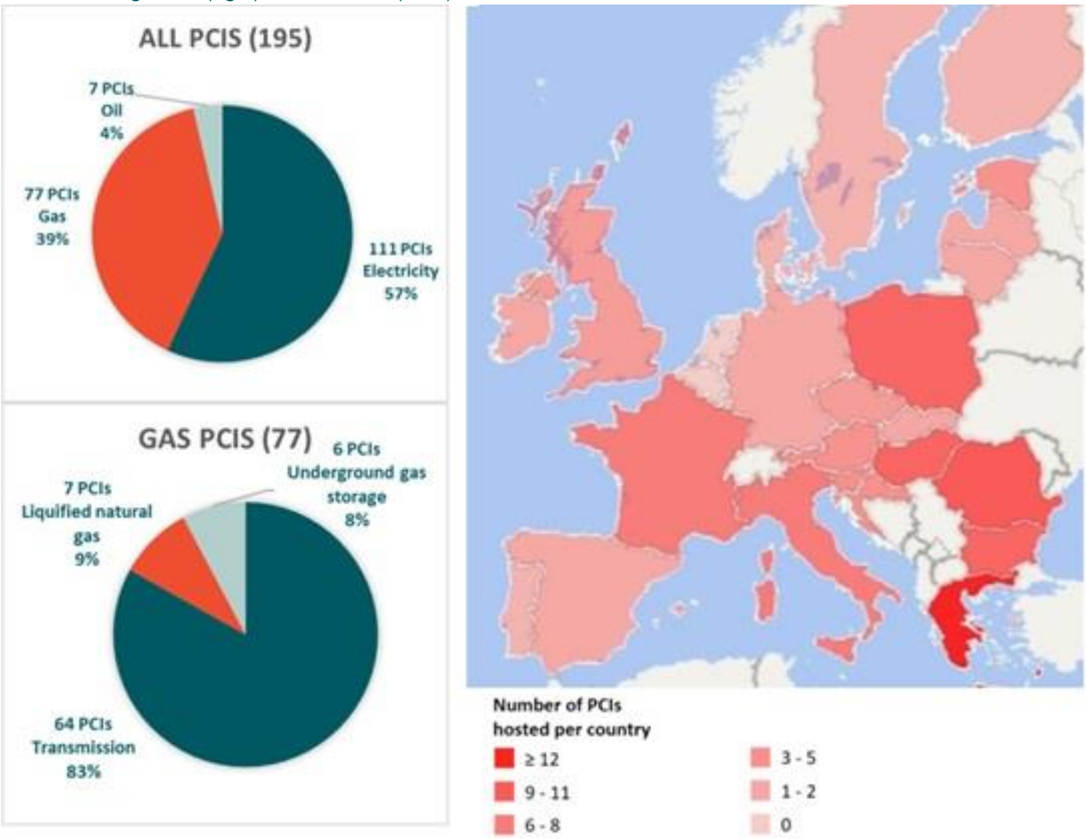
[14] ENTSOG (2017), Ten-Year Network Development Plan 2017. (https://www.entsog.eu/publications/tyndp/2017#ENTSOG-TEN-YEAR-NETWORK-DEVELOPMENT-PLAN-2017)

[15] TYNDP 2018 - ENTSO Gas & Electricity joint scenarios for consultation. http://tyndp.entsoe.eu/tyndp2018/

[16] Regulation 347/2013 on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009 (http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32013R0347&from=EN)

[17] Commission delegated Regulation (EU) No 2016/89 of November 2015

Figure 2-1 Split of all (195) PCIs into electricity, oil and gas (left, top); and split of the 77 gas PCIs (left, bottom). Geographical distribution of gas PCIs (right). Source: ACER (2016)[18]



The 2015 PCI list contained gas projects in all EU Member States with the exception of Belgium, Luxembourg, and the Netherlands. The majority of the gas PCIs were situated in Central and South-East Europe - where adequate infrastructure to access diversified gas supplies was still lacking - with Greece involved in the largest number of PCIs.

The third and latest list of PCI projects was adopted in November 2017 and includes 173 projects, of which 53 concern gas (compared to 77 in the 2015 list). According to the European Commission, this third list provides for fewer but better focused gas projects addressing the critical infrastructure bottlenecks. However, a closer look at the 2nd and 3rd list learns that actually very few projects have been dropped and some new ones have been added. The reduction of the number of gas projects is in fact mostly the result of a regrouping of projects and of counting each of these groups as only one project. The proposed gas PCIs have been assessed by the gas regional groups against the "green revolution" scenario,[19] which is one of the four assessment scenarios presented in the TYNDP 2017, and is the one which assumes the lowest gas demand by 2035. In this respect the "green revolution" scenario is the closest to the EUCO30 scenario (based on an energy savings target of 30% by 2030), which underpins the Clean Energy for All Europeans package. Compared to the 35% energy efficiency target supported by the European Parliament, the “green revolution” scenario that is used to justify the PCIs corresponds with an estimated gas demand in 2030 that is more than 35% higher (4186 TWh in the “green revolution” scenario compared to 3105 TWh in the EUCO+35 scenario; see tables 1, 2 & 3). This means that the prospected benefits might have been overestimated.

[18] ACER (2016), Consolidated report on the progress of electricity and gas projects of common interest for the year 2015. Agency for the Cooperation of Energy Regulators

[19] Pages 64-73 of the ENTSOG 2017 TYNDP. (https://www.entsog.eu/public/uploads/files/publications/TYNDP/2017/entsog_tyndp_2017_main_170428_web_xs.pdf)

On the other hand, the selection process used for the third list of PCIs focuses more on critical infrastructure and bottlenecks, whilst also the methodology used for assessing the benefits of PCI candidates has been improved; PCI candidates were required to demonstrate their contribution to the energy policy objectives of market integration, security of supply, competition and system stability. For coping with bottlenecks at regional level, the most effective path was chosen.

The PCI selection takes into account that gas infrastructure is in general already very well developed to face the future challenges, it allows for a wide range of supplies and is resilient to a number of possible disruption cases.[20] The remaining infrastructure needs primarily concern the Eastern Baltic Sea region, Central and South-Eastern Europe and the Iberian Peninsula. The selected gas PCIs will address these remaining infrastructure bottlenecks; they will end the gas isolation of the Baltic States and Finland, they will provide for diversified sources and routes by developing the Southern Gas Corridor and the Norwegian Corridor, and they will develop missing interconnections to increase security of gas supply, cross-border trade and competition particularly in Central and South-Eastern Europe.

The selected gas PCIs mainly focus on the following infrastructure needs:

In **Western Europe** the proposed PCIs will increase the short and medium term security of gas supply. The PCI list includes projects to better integrate the Iberian Peninsula with the internal gas market, as well as a pipeline project between Malta and Italy. Furthermore, PCIs have been identified in France and Belgium in order to facilitate the adaptation from low to high calorific gas which has become an important challenge for this region due to the decreasing production of low calorific gas in the Netherlands.

In **Central Eastern and South Eastern Europe** the PCIs address not only security of supply issues, but also market integration and competition. In order to ensure access to three supply sources for the countries in this region, LNG terminals in Croatia (Krk) and Northern Greece are included in the PCI list, as well as several interconnectors: Poland-Slovakia, Bulgaria-Serbia (IBS) and Greece-Bulgaria (IGB).

In the **Southern Gas Corridor** PCIs will allow the EU to have access to gas sources in the Caspian region, Central Asia and the eastern Mediterranean. In particular the integrated system of gas pipelines including a trans-Caspian pipeline (between the shores of Turkmenistan and Azerbaijan), the expansion of the South-Caucasus Pipeline (linking Azerbaijan, Georgia and Turkey), Trans Anatolia Natural Gas Pipeline (east-west across Turkey) and Trans-Adriatic Pipeline (stretching from the Greek-Turkish border, across Albania to Italy) will give the EU access to natural gas from the Caspian Sea region. The construction works are now advancing and the first gas from Azerbaijan will reach the EU in 2020.

As the Eastern Mediterranean region is now emerging as an important producer of natural gas, the EU could further diversify its supply sources. The primarily offshore pipeline between Cyprus and Greece (EastMed Pipeline) together with an offshore interconnection between Greece and Italy (Poseidon Pipeline) and the corresponding reinforcements of transmission capacities in Italy (Adriatica Line) will now provide an integrated transportation solution which allows the EU to tap into the EastMed gas resources.

Furthermore, together with the development of gas transmission infrastructure in Cyprus, the PCIs will end the isolation of this island from the EU gas market and allow it to reduce its carbon footprint from electricity production.

In the **Baltic Sea Region** (BEMIP) the key objective of PCIs is to end the gas isolation of the three Baltic States and Finland by connecting their networks with the Continental European gas grid. This will be achieved by building two new gas interconnections between Poland and Lithuania (GIPL), and between Estonia and Finland (Balticconnector), as well as by reinforcing existing gas interconnections between

[20] ENTSOG 2017 TYNDP (https://www.entsog.eu/publications/tyndp# ENTSOG-TEN-YEAR-NETWORK-DEVELOPMENT-PLAN-2017)

the three Baltic States. In recognition of their significant regional benefits, GIPL, Balticconnector, and other projects including the LNG terminal in Świnoujście (Poland) have received financial support from EU funds.
In the Western part of the BEMIP region, two important diversification PCIs are proposed. The LNG terminal in Gothenburg aims to improve the security of gas supply of Sweden to reduce its dependence on a single interconnection point with Denmark. The Norwegian Corridor project aims to deliver Norwegian gas to the BEMIP and CESEC regions - via Denmark and Poland - which are still (largely) dependent on one supplier.

2.4 EU Funding of gas infrastructure

The main funding options for EU level gas infrastructure are the Connecting Europe Facility (CEF) and dedicated loans for co-financing of projects granted by the European Investment Bank (EIB) or the European Regional Development Fund (ERDF).

New gas infrastructure is co-financed by the European Investment Bank…

The EIB provides loans to investors under the European Fund for Strategic Investments (EFSI). This Fund represents the main pillar of the so-called Juncker Plan and aims at providing a first loss guarantee to the EIB which should allow it to invest in more risky projects, mostly focused on strategic investments in key areas, including energy infrastructure. Most of the financing provided by the EIB for gas related investments in the EU is focused on projects dedicated to improving security of supply and extending or reinforcing networks. For example, in 2017 the EIB agreed to provide funding for gas network investments in Spain, Ireland and Greece, and is considering funding the Slovakia-Poland gas interconnector and the Italgas network upgrade.[21] In 2017 the EIB also provided a loan of EUR 50 million to the Romanian national transmission company for the construction of the Romanian section of the gas pipeline from Bulgaria to Austria via Romania and Hungary (BRUA).[22] The entire pipeline project is estimated to cost over EUR 500 million. It received EUR 179 million through the CEF as well as an additional EUR 100 million from the EFSI through the EIB.[23]

… by the Connecting Europe Facility…

The Connecting Europe Facility (CEF) is a funding mechanism designed to support the development of cross-border infrastructure. It was introduced by the European Commission's growth package for integrated European infrastructure.[24] EUR 5.35 billion of the CEF funds is allocated to energy projects for 2014-2020 (EUR 4.7 billion to be allocated through grants managed by the INEA). Regulation 1316/2013 establishing the Connecting Europe Facility, states that CEF will support energy PCIs that pursue one or more of the following objectives:

- Increasing competitiveness by promoting further integration of the internal energy market (IEM) and the interoperability of electricity and gas networks across borders;
- Enhancing security of supply; and

[21] Based on information on website EIB
[22] EIB supports gas supply improvements and diversification in Europe with the EFSI guarantee (http://www.eib.org/infocentre/press/releases/all/2017/2017-290-eib-supports-gas-supply-improvements-and-diversification-in-europe-with-the-efsi-guarantee.htm)
[23] COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS Communication on strengthening Europe's energy networks, Brussels, 23.11.2017 COM(2017) 718 final (https://ec.europa.eu/energy/sites/ener/files/documents/communication_on_infrastructure_17.pdf)
[24] COM (2011)676, A growth package for integrated European infrastructures

- Contributing to the integration of energy from renewable sources into the transmission network and developing smart energy networks and carbon dioxide networks.

CEF aims to act as a catalyst and leverage funding from private and public investors by providing PCIs with credibility and lower risk profiles. The CEF is intended to make a difference by targeting a few critical projects and working together with other efforts such as the regulators financing part of the infrastructure via network tariffs (or specific incentives) and the use of European Structural & Investment Funds (ESIF). Under CEF, PCIs can also receive grants for studies and works and/or access to financial instruments (which provide loans at attractive rates and conditions).[25] The TEN-E regulation sets the eligibility criteria for Union financial assistance (Article 14). Grants are used to co-finance preparatory studies and limit the financial impact for the project developer in cases where the concerned PCI is not economically or technically viable. CEF is also used to finance works (up to 50% or 75% in exceptional cases, of the overall PCI related investment costs).[26]

The CEF actions in energy are funded as a result of regular calls for proposals. The CEF Energy – Key Figures brochure[27], published in May 2017, presents an overview of 93 actions contributing to 73 PCIs resulting from the grant agreements. Of the EUR 1.6 billion EU funding allocated, the largest share (64%, i.e. EUR 1.02 billion) has been allocated to gas actions. This is in contradiction with the CEF regulation that stipulates in its recital 57 that "*the Commission should give due consideration to electricity projects, with the aim of making the major part of the financial assistance available to those projects over the period 2014 to 2020 (...)*"[28].

EUR 90.4 million has been allocated to studies (40 actions) and EUR 928.1 million to works (9 actions). The fact that the largest share of CEF Energy funds has been allocated to gas leads to criticism from some stakeholders, who are of the opinion that gas is expected to play a smaller role in the energy mix considering the EU's ambition towards a decarbonised energy system, and that financial support to new gas infrastructure should hence be limited.

… and by the European Regional Development Fund (ERDF)

The European Regional Development Fund (ERDF) aims to reduce the economic and social disparity between the EU's regions. One of the ERDF's four priority areas for 2014-2020 is 'the low carbon economy'. In this context, it also provides financial support for gas infrastructure projects. Poland is one of the countries which has benefited from this financial assistance for the construction of a dedicated liquefied natural gas (LNG) terminal and related uploading, storage and gasification facilities in Świnoujście.[29] A 167.6 km-long natural gas pipeline between the towns of Lwówek and Odolanów in Poland is also being built with EU support.[30] These infrastructure projects, combined with the construction of an interconnector between Poland and Lithuania, will serve the entire Baltic sea region, allowing for greater diversification of gas imports and therefore improved security of supply.

[25] The 2014-2020 CEF budget is EUR 30.44 billion, of which EUR 5.35 billion is allocated to the energy sector. Up to 8.4% of the CEF budget can be used for financial instruments

[26] Regulation (EU) No 1316/2013 establishing the Connecting Europe Facility, amending Regulation (EU) No 913/2010 and repealing Regulations (EC) No 680/2007 and (EC) No 67/2010

[27] INEA (2017), CEF Energy Key figures brochure. May 2017. Available from: https://ec.europa.eu/inea/sites/inea/files/cef_energy_keyfigures_2017_leaflet_final_0.pdf

[28] Regulation (EU) No 1316/2013 of the European Parliament and of the Council of 11 December 2013 establishing the Connecting Europe Facility

[29] Poland's liquefied natural gas terminal increases Europe's energy security (http://ec.europa.eu/regional_policy/en/projects/poland/polands-liquefied-natural-gas-terminal-increases-europes-energy-security)

[30] Construction of natural gas pipeline to bolster Poland's energy security, (http://ec.europa.eu/regional_policy/en/projects/major/poland/construction-of-natural-gas-pipeline-to-bolster-polands-energy-security)

2.5 Regional specificities and current trends in the European gas sector

EU Member States have rather diverse characteristics in terms of gas sourcing, infrastructure and use. While some are producers (UK, the Netherlands, etc.) albeit with a declining trend, others are importers and consumers, others have a strong gas transit component, and in some Member States the gas sector plays a minor role. The diversity of gas sources varies widely with some Member States still largely dependent on a single supplier. The share of gas in the overall national energy consumption is also quite different across the EU. As a consequence, national interests vary considerably with regard to current and possible future roles for gas. The European Union is therefore confronted with a multitude of interests and options on how to decarbonise the EU energy supply by 2050.

Most Western European Member States enjoy highly integrated and liquid gas markets, whereas countries in Eastern Europe still lack interconnectivity

Most Western European countries have been able to establish a highly interconnected gas system and liquid gas market where gas is easily transported across borders through various hubs. This allows for greater market integration and competition, and as a result more competitive prices. However, Eastern and South-Eastern European Member States are still mostly reliant on a single supplier, i.e. Russian pipeline gas. Due to historic and structural issues their grid infrastructure is less interconnected and as a result they are not yet able to achieve the same level of market integration and the prices they pay depend more on political than economic factors.

Several investment projects are currently ongoing to further enhance the interconnectivity of the gas system in the “vulnerable” regions of Europe. e.g. the development of gas interconnections necessary to end the gas isolation of the three Baltic States and Finland, via the Poland–Lithuania interconnection (GIPL), and Estonia–Finland interconnection (Baltic-connector) - the development of an Eastern Gas Axis, from the Iberian Peninsula to France[31] - the Bulgaria-Romania-Hungary-Austria interconnector (BRUA) and investments to allow reverse flows between Croatia and Hungary that will enable the free flow of gas in particular from the Krk LNG terminal which will be constructed in Croatia (Krk LNG) - the Greece-Bulgaria interconnector and the Bulgaria-Serbia interconnector. If all these ongoing projects are implemented, by 2025 Europe should achieve a well interconnected and shock resilient gas grid.

Policies for decarbonising the energy sector lead to ‘new’ technical developments and potential intersectoral synergies

The natural gas sector needs to contribute towards greenhouse gas emission reduction, without sacrificing its reputation and contribution as a relatively clean and affordable primary energy. As a consequence, the focus of policymakers and market players is shifting towards the identification of new roles, technologies, business cases, and structures in the gas industry, knowing that a general trend of decreasing natural gas consumption is restricting the identification of new business cases.

[31] In 2016 and 2017 preparatory work was carried out to prepare a decision on the phased development of the critical Midcat project, including its first phase known as the STEP project.
COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS Communication on strengthening Europe's energy networks, Brussels, 23.11.2017 COM(2017) 718 final (https://ec.europa.eu/energy/sites/ener/files/documents/communication_on_infrastructure_17.pdf)

New technologies such as fuel cells for use in transport or buildings, or innovative concepts such as Power-to-Hydrogen, the thermochemical production of hydrogen by using concentrated solar power or Power-to-Methane are emerging. However, there is a notable lack of alignment of such approaches across Europe and often even within individual Member States, which is a major barrier to establishing new roles for the gas sector. On the one hand, the view that 'new' solutions/concepts are too expensive, are technically too complex, or that approaches represent too far of a diversification are prominent in the current discussions at European level. On the other hand, awareness is increasing that gas infrastructure could have a beneficial role of supporting the electricity sector via the provision of specific services, for which gaseous energy carriers are well known: high transport density and long-term energy storage capabilities. Concepts have been developed for almost all energy uses including mobility, buildings and industry, where gas could utilise its extensive infrastructure to reduce the costs of integrating fluctuating renewable electricity at a large scale and at low costs. Prototype projects have been successfully carried out and have provided valuable insights into new technology and market developments.

Promising new roles for gas are most apparent in the integration of the gas and the electricity sectors, as demonstrated by the recently aligned scenarios from ENTSOG and ENTSO-E. This is a rather new field of development that will also be analysed in this study. It offers the promise of finding synergies between gas and electricity markets and delving deeper into the potential integration of both sectors in fulfilling the EU's energy needs. Sector integration also has an important regulatory element because coordinated and integrated regulation may help reduce the overall transition cost to a low carbon energy supply.

Stable or lower overall gas demand levels might have a huge impact on gas infrastructure and its owners/operators

The expected future decrease in natural gas demand, in particular for heating and power generation, could be partly offset by an increased use of other gas types (biogas/biomethane, synthetic methane, hydrogen...), which can be transported via the same infrastructure and used for the same purposes, including transport and industry. The magnitude of this shift will, inter-alia, depend on economic aspects (cost evolution of energy conversion and storage technologies, price evolution of energy vectors) and technical criteria (e.g. feasibility of injecting biomethane, synthetic methane or hydrogen in natural gas pipelines). In this context an evaluation of the flexibility potential of existing gas infrastructure is useful, also in view of adapting, if appropriate, ongoing or new investment projects, in order to reduce the risk of stranded assets.

An assessment of the impact of the possible changes in the energy sector mentioned above on gas TSOs and other infrastructure owners/operators, would be a useful complementary exercise which would allow the identification of not only the main challenges for TSOs but also opportunities for them to adapt their investment and operational strategies in order to remain active players in the new energy landscape.

Current national regulatory regimes for gas transport and distribution might not be futureproof

In order to anticipate the expected evolutions in the energy sector and to facilitate the transition to a low carbon energy supply where gas will play "another" role, current gas related regulatory principles and policies should be evaluated, and alternative options should be considered. The ongoing study “Quo Vadis” is expected to provide useful input in this respect.[32] The current approaches to network investments and tariff principles are largely based on the assumption that gas demand will not substantially decrease; However, if demand does decrease, (distribution and) transport tariffs per MW or MWh would increase and might hamper the competitiveness of gas and hence the competitiveness of industrial gas users. In order to mitigate the risks of increasing grid tariffs and stranded assets, investments in new gas infrastructure should be thoroughly scrutinised and evaluated. This would also help ensure an optimised overall investment plan for the electricity and gas sectors. Cost allocation and revenue models for TSOs, including tariff principles for grid users, should also be evaluated and adapted if appropriate. Tariff principles and methodologies, such as entry-exit tariffs and tariff bases (consumption, subscribed capacity, off-taken capacity, etc.) have an important impact on the (potential and effective) use of gas in the different market segments, and grid tariff principles and levels will also to a large extent determine the economic feasibility of the use of gas infrastructure for transporting and distributing decarbonised fuels.

[32] https://ec.europa.eu/energy/en/studies/study-quo-vadis-gas-market-regulatory-framework

3. Natural Gas Supply and Demand Evolution and its Impact on Future Infrastructure

This chapter provides an overview of the general trends and the most impactful developments in domestic European gas demand and supply in the last decade. It also describes possible scenarios for the evolution of the gas sector as part of the general energy mix of EU Member States in the near future in order to meet the current and expected climate and energy targets for 2020, 2030 and 2050. Several models are presented in order to provide estimated gas consumption levels post 2020 and highlighting the infrastructure required to support the forecasted demand. This chapter also analyses the potential decline in EU gas domestic production and demand and how this will affect the need for new construction and the utilisation of existing infrastructure.

The need for new gas infrastructure is not only determined by the evolution of the domestic gas production and demand, but also by world-wide supply side developments, as well as EU policies focusing on security of supply, market integration/competition and energy efficiency.

World-wide evolutions on the supply side affect the use of existing gas infrastructure and the potential need for new investments within the EU. Relevant developments include the availability of unconventional gas resources in the EU and other continents as well as the economic, technical, societal, and legal feasibility to exploit them[33]. The IEA forecast an increase in world gas demand driven by (shale) gas production growth in the US[34]. Gas market developments in other continents are also relevant; low gas demand in Asia could for example lead to the availability of high LNG volumes which could be imported into the EU thus reducing the need for additional pipeline construction. Global LNG and Norwegian and Russian pipeline gas are expected to remain the main sources of natural gas for the EU up to 2030, but the ongoing pipeline projects (e.g. TAP pipeline) will offer the potential for broader diversification and will allow gas imports from other eastern European and Asian countries. LNG regasification capacities are already available in most EU regions, but are still limited (although expanding, thanks to EU financial support) in Central and Southern Europe, as well as in the Baltic States.

Security of gas supply is one of the major drivers for investments in gas infrastructure in the European Union. Security of supply issues are addressed by EU Regulation 994/2010[35], which was reviewed in 2016.[36] This Regulation aims, inter-alia to offer an adequate response to concerns about the impact of increasing EU dependence on gas imports. In 2009, the Russia-Ukraine gas dispute revived the need for coping with gas supply risks. The regulation mentioned above focuses on both supply and infrastructure. This is most important for Member States which rely on a single provider (gas-producing country) for their gas supply and/or a single gas route (pipeline). Such dependence increases the risk of price peaks or sudden supply disruptions due to political or technical incidents.[37] For example, Finland and the

[33] see e.g. 2014/70/EU: Commission Recommendation of 22 January 2014 on minimum principles for the exploration and production of hydrocarbons (such as shale gas) using high-volume hydraulic fracturing
[34] IEA Market Report Series: Gas 2017, IEA, July 2017
[35] Regulation (EU) No 994/2010 concerning measures to safeguard security of gas supply and repealing Council Directive 2004/67/EC
[36] Regulation on measures safeguarding the security of the gas supply (2016/0030 (COD)) (http://eur-lex.europa.eu/resource.html?uri=cellar:33516200-d4a2-11e5-a4b5-01aa75ed71a1.0018.02/DOC_1&format=PDF)
[37] SWD (2016)405, Impact Assessment accompanying the document 'Proposal for a Directive of the European Parliament and of the Council amending Directive 2012/27/EU on Energy Efficiency (https://ec.europa.eu/energy/sites/ener/files/documents/1_en_impact_assessment_part1_v4_0.pdf)

Baltic States were before the commissioning in December 2014 of the Klaipeda LNG-terminal in Lithuania, completely dependent on Russian liquified and natural gas. In the medium term, if only infrastructure projects with Final Investment Decision (FID) were implemented, some European countries (in particular Bulgaria, Greece, Croatia, Hungary, Romania, Serbia and Slovenia) would still remain vulnerable as they would not fully respect the N-1 criterion foreseen in the Regulation. [38] If, however, all listed projects (FID and non- FID) were commissioned, the infrastructure resilience would be satisfied.

Investments in gas infrastructure, including reverse flows and quality standardisation, also contribute to enhanced market integration and competition. Lack of sufficient interconnection capacity or its inappropriate use, can lead to congestion and hence diverging wholesale prices. Physical congestion, indicated by actual interruptions of transport capacity, occurred in 2015 and 2016 at respectively 9 and 8 of the contractually congested interconnection points, with varying frequencies but mostly for only a few days.[39] ACER also noted that the physical utilisation of gas interconnectors could be further improved. For the vast majority of Interconnection Points (IPs) – around 60% of IPs – the average physical utilisation was below 50% in 2014 and 2015.[40] EU net welfare gains of up to EUR 400 million could be obtained if all physical unused capacities were used in an optimal way.[41] Contractual congestion (capacity hoarding) also remains an issue of concern. The effective and efficient use of gas interconnection capacity can be enhanced by specific policy measures to prevent contractual congestion (e.g. UIOLI), which should be consistently implemented across the EU.

[38] ENTSOG (2016), Ten-year Network Development Plan 2017, Main report

[39] ACER (2016b), ACER annual report on contractual congestion at interconnection points for 2015 (www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%202017%20Implementation%20Monitoring%20Report%20on%20Contractual%20Congestion%20at%20Interconnection%20Points.pdf)

[40] ACER/CEER Annual Report on the Results of Monitoring the Internal Electricity and Gas Markets in 2016 Gas Wholesale Markets Volume October 2017 (https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202016%20-%20GAS.pdf)

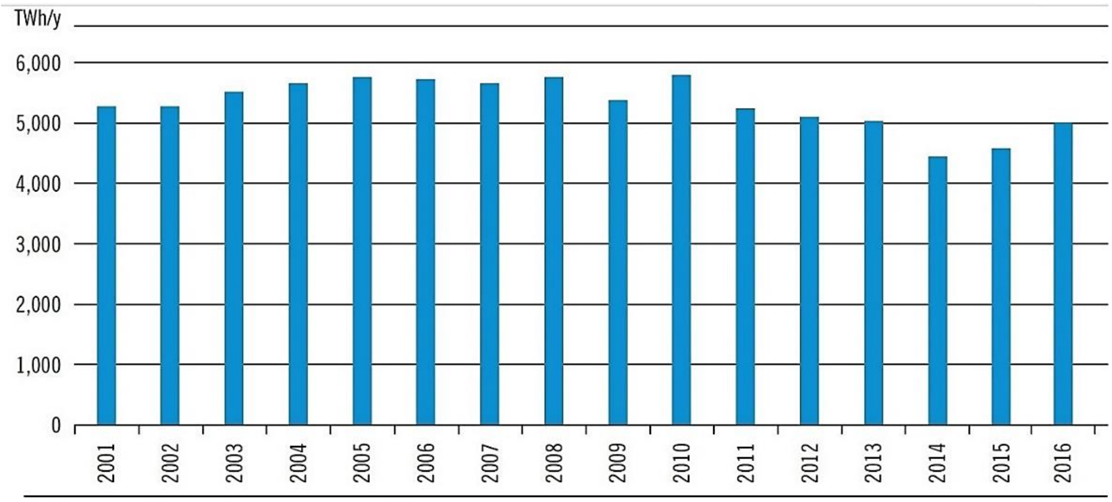
[41] If the analysis was performed instead on the basis of available contractual capacity or on the basis of capacity available over peak monthly utilisation, the net welfare gains would be lower. Source: ACER (2016c), ACER Market Monitoring Report 2015. Key insights and recommendations.

3.1 EU Gas Demand

3.1.1 Current Gas Demand and Trends for 2020

The evolution of gas demand in the EU from 2001 to 2015 is presented in the next graph (based on Eurostat data).

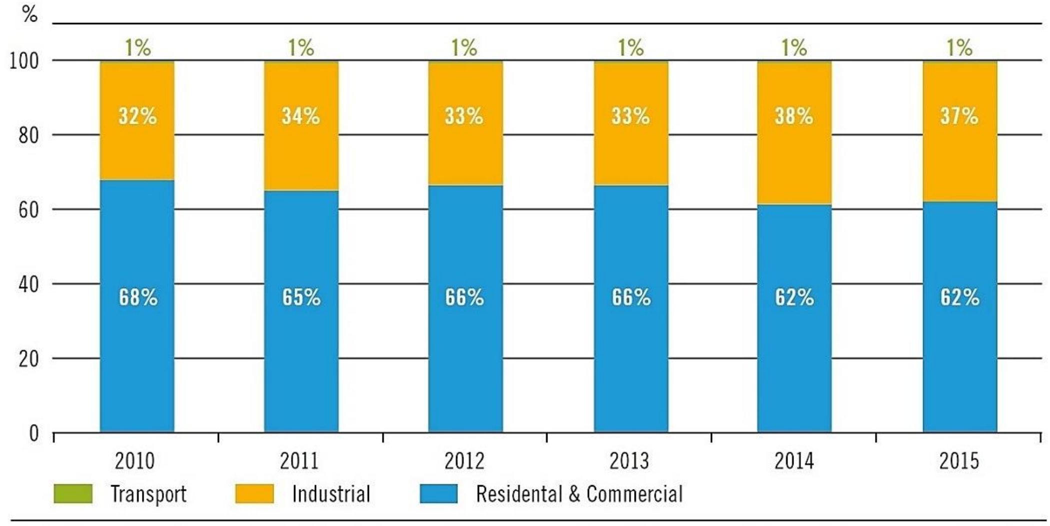
Figure 3-1 Evolution of European Gas Consumption, *(Eurostat)*



The gas demand shows a gradual decline from 2010 to 2014. From 2015 until the second quarter of 2017, there is a moderate increase, however the overall demand is still well below the levels experienced in 2005-2010. Demand in 2016 has risen by 7% compared to 2015, reaching 4,962 TWh, mainly driven by improved gas-to-power economics. This is the second consecutive year of demand growth after 4 years of decline. Because of its flexibility capacities, gas-fired power generation now plays a more crucial role as back-up for variable renewable energy sources.

The decline in gas consumption in the European Union from 2010 to 2015 can be explained by several internal and external factors. On one hand specific climate conditions like warmer winters have contributed to the reduction of the gas demand gas for heating purposes. The economic crisis had a negative impact on certain energy-intensive economic sectors and this played a key role in this evolution and explains the reduction of gas consumption in industry. The evolution of primary energy prices during this period also benefited certain alternative energy sources, such as coal, to increase its share in the power generation mix of certain Member States. On the other hand, internal factors such as the effects of the EU environmental and energy policies to increase efficiency have begun to produce tangible results in reducing gas consumption.

Figure3-2: Evolution of Sectoral Split of Final Demand, *(ENTSOG 2017 TYNDP)*



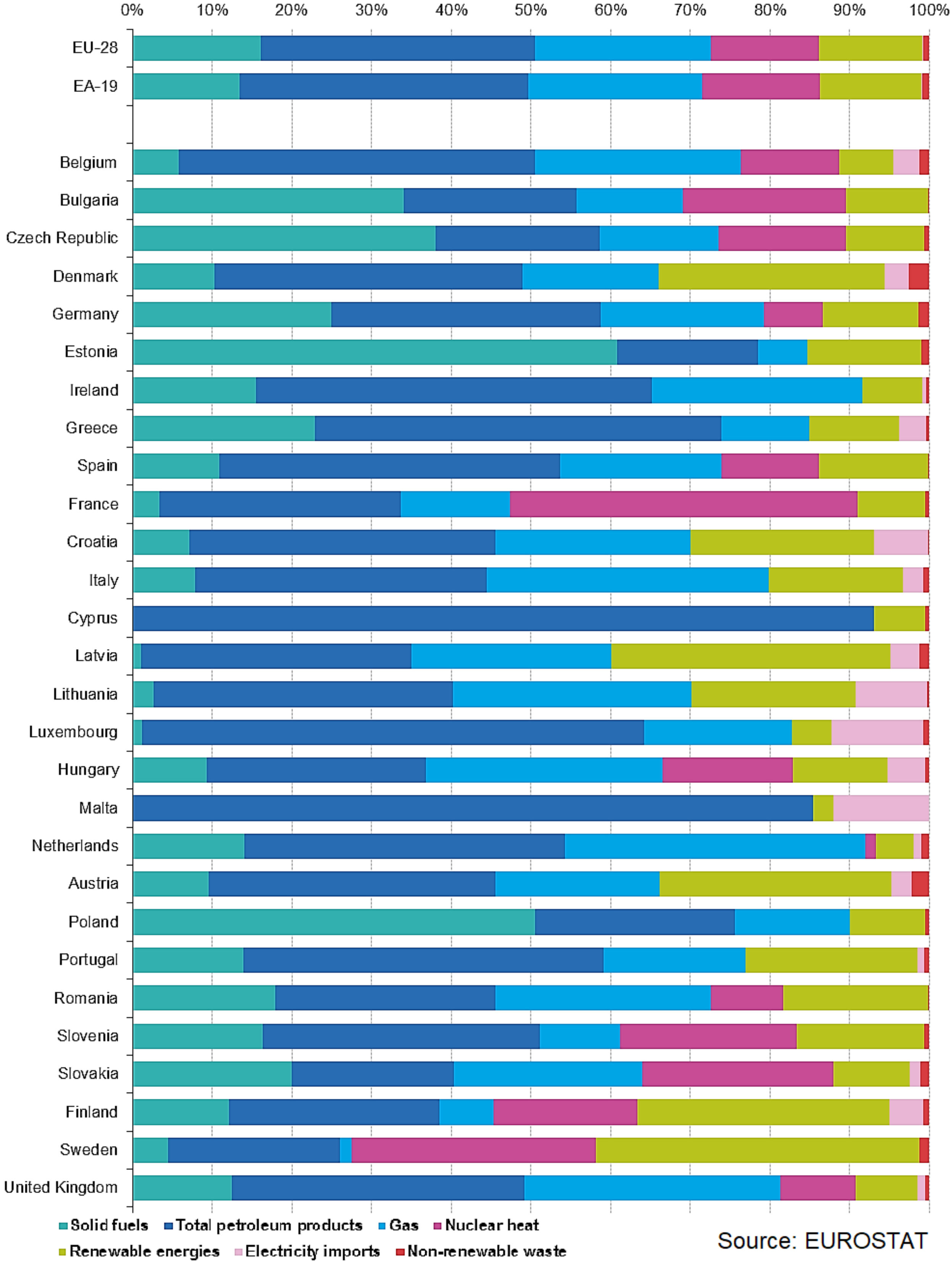
According to the data presented in the graph above,[42] the residential and commercial sectors account for the largest share of the EU's gas demand, ranging from 68% in 2010 to 62% in 2015. [43] Industrial processes relying on gas come second, accounting for between 32% and 37% of demand, while in 2010-2015 transport represented no more than 1% of the aggregated gas demand in the EU Member States. However, with the growth in the use of gas powered ships and vehicles (LNG and CNG), this share is expected to grow slightly in the coming decades.

The EUROSTAT data presented in the graph below, show that in 2015 natural gas accounted for about 20% of the total EU28 gross inland energy consumption.[44] Provisional statistics indicate that in 2016 and 2017 its share will remain at a similar level. Gas is the second largest fuel used in energy consumption in the EU after petroleum products, while renewable energy sources, nuclear energy and solid fuels share roughly the same proportion of the European energy mix[45]. This graph also shows the importance of natural gas in the energy mix of the different EU Member States; in some Member States it represents less than 10 % of energy consumption while in other Member States its share exceeds 30 %.

[42] ENTSOG (2017), Ten-Year Network Development Plan 2017. (https://www.entsog.eu/publications/tyndp/2017#ENTSOG-TEN-YEAR-NETWORK-DEVELOPMENT-PLAN-2017)
[43] ENTSOG (2017), Ten-Year Network Development Plan 2017.*ibid.*
[44] Energy trends: Data from June 2017. Most recent data: Further Eurostat information, Main tables and Database. Planned article update: June 2018. (http://ec.europa.eu/eurostat/statistics-explained/index.php/Energy_trends)

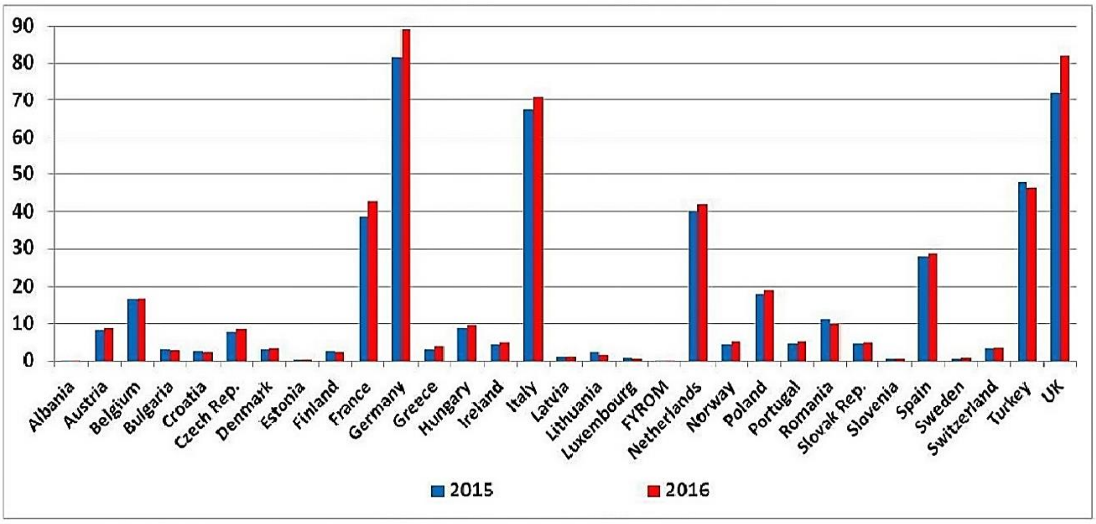
[45] National shares of fuels in gross inland energy consumption, 2015 (http://ec.europa.eu/eurostat/statistics-explained/images/e/e3/National_shares_of_fuels_in_gross_inland_energy_consumption%2C_2015%2C_percentage_F6_update.png)

Figure 3-3: National Share of Fuels in Gross Inland Consumption for 2015 *(Eurostat)*



Due to large differences in national energy markets' size and gas share between the EU Member States, the current EU demand for gas mainly comes from a few member states which have a well-developed gas distribution network and a quite substantial household and industrial demand for gas. [46]

Figure 3-4: Gas Consumption in 2015 Vs 2016, Per Country (bcm)



Source: Oxford Institute for Energy Studies, May 2017

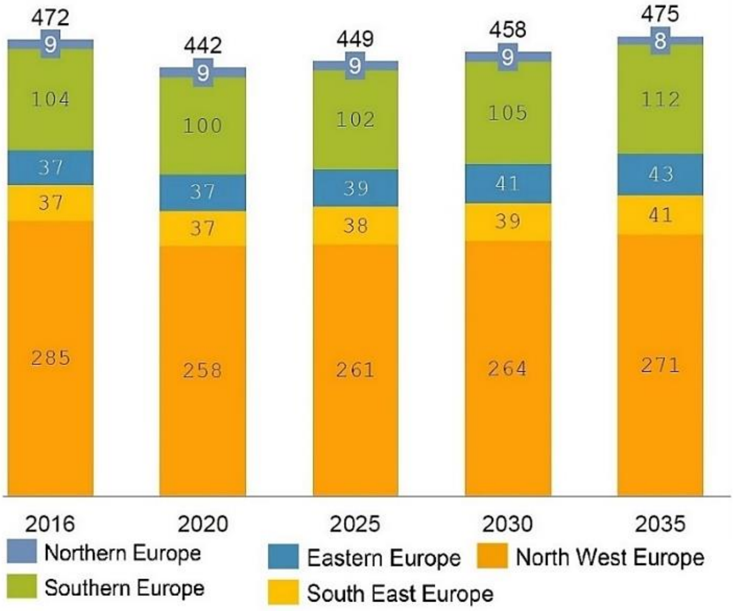
Western European countries like Germany, UK, Italy, the Netherlands, Spain and France represent the vast majority of the gas demand of the EU. Their consumption is also the main driver behind the increase in the aggregated gas demand at European level in the past two years. According to the latest data from the International Energy Agency (IEA) for 2016, gathered by AURORA Energy Research, more than half of European gas demand was situated in North West Europe. According to their analysis and the forecasts presented in the graph below, the total demand for natural gas in the EU would decrease from 508 bcm (4962 TWh) in 2016 to about 442 bcm (4318 TWh) in 2020.[47]

The overall geographic distribution of consumption however, would remain roughly the same, although it is expected that the share of North-Western Europe will decline slightly compared to other EU regions due to tighter and more ambitious energy and environmental policies in this part of Europe.

[46] Oxford Institute for Energy Studies, Natural Gas Research Programme, Dr. Anouk Honoré, 11 May 2017, (https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/05/Natural-gas-demand-in-Europe-in-the-next-5-10-years.pdf)

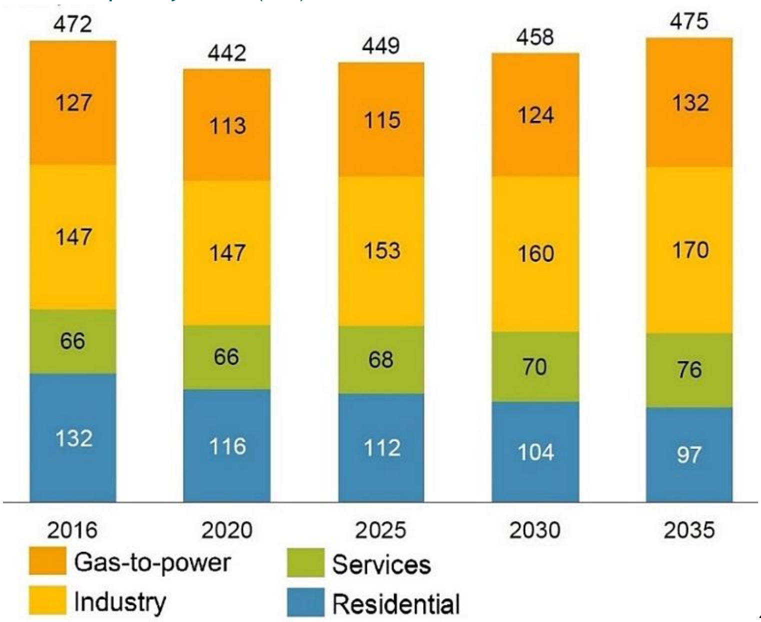
[47] [47] AURORA Energy Research, *Driving Demand & Securing Supply: Outlook on the European gas market*, 11th Gas Forum, Ljubljana, 22 September 2016, (http://www.europeangashub.com/custom/domain_1/extra_files/attach_717.pdf) (1 bcm = 9.77 TWh)

Figure 3-5: European Gas Consumption by Regions (bcm)



Another important element which needs to be taken into account when considering the expected gas demand in the EU by 2020 is the share of the various economic sectors in the overall gas consumption. The graph below, prepared by AURORA Energy Research, shows that natural gas is primarily used in the Residential and Service sectors, which jointly consumed 198 bcm or 1934 TWh in 2016. These sectors would also retain the highest consumption share in the near-to-medium future.[48] According to these forecasts, the industrial sector is expected to consume the same amount of gas in 2020 as in 2016, accounting for 147 bcm or 1436 TWh. The third sector in which gas demand plays an important role is the power generation sector, which consumed 127 bcm or 1241 TWh in 2016. However, it is expected to decline to 113 bcm or 1104 TWh by 2020.

Figure 3-6: European Gas Consumption by Sectors (bcm)



[49]

[48] AURORA Energy Research, *Idem*.
[49] 1 bcm = 9.77 TWh

3.1.2 Evolution of gas demand post 2020 under different scenarios and targets

In this section we compare the medium-to-long-term gas demand levels estimated on the basis of various models and scenarios prepared by ENTSOG, the European Commission and private and public research institutes. We highlight that the demand projections published by ENTSOG in its' TYNDP differ from the outcome of the Impact Assessment study which was carried out in the context of the 2016 review of the EU Directive on Energy Efficiency, which was based on the PRIMES Model.[50] The forecasts of the Oxford Energy Institute based on the TIGER model, as well as forecasts from other specialised consultants also present different values. These discrepancies can be explained by the use of different methodologies and variations in parameters and assumptions used for the forecasting exercises. A comparison of the different outcomes suggests that the gas TYNDP seems to be based on overly optimistic projections by the TSOs of the expected gas demand levels in their Member State. We also notice that some scenarios do not properly take into account the latest 2030 targets adopted or prepared by the EU institutions on energy efficiency, reduction of GHG emissions and share of RES in the energy consumption of Member States. This overview and comparison also helps us to assess whether the ENTSOG's TYNDP, which is used as a basis for investment planning and the selection of Projects of Common Interest (PCI), is based on demand estimates which are in line with the results of other studies.

3.1.2.1 ENTSOG (TYNDP)

Until now the electricity and gas ENTSOs have used separate methodologies and assumptions for forecasting the need for grid investments in their sector without properly considering the potential synergy and interactions between the energy vectors. Recently they have opted for implementing a more integrated approach, which will be used for the elaboration of the upcoming gas TYNDP, scheduled for publishing in 2019. Preliminary reports suggest that the new TYNDP will consider the EU-wide policy trends of decarbonising energy supply and consumption and elaborate on the impact of interdependencies between the electricity and gas systems and markets.

The 2017 TYNDP of ENTSOG was based on gas sector specific scenarios and assumptions. The following 4 scenarios were developed to estimate the possible gas demand evolution: Global Climate Action (GCA), Subsidised Green Europe (SGE), Sustainable Transition (ST), Behind Targets (BT) and Distributed Generation (DG).[51] The results reflect the considered scenarios for several parameters, such as Macroeconomic Trends, Transport, Residential & Commercial, Industry Power and Gas Supply, each further elaborated with expected sectoral evolutions of additional contributing components.[52] The estimates are based on a bottom-up data collection from national TSOs. On one hand, this approach should provide reliable data because national TSOs have a good understanding of the local market and can therefore make accurate gas demand forecasts. On the other hand, national TSOs may have vested interests in suggesting higher levels of expected gas demand in order to strengthen and develop their own activities. Gas demand forecasts from independent actors indeed suggest that the TSOs' demand

[50] SWD (2016)405, Impact Assessment accompanying the 'Proposal for a Directive of the European Parliament and of the Council amending Directive 2012/27/EU on Energy Efficiency (https://ec.europa.eu/energy/sites/ener/files/documents/1_en_impact_assessment_part1_v4_0.pdf)

[51] Annex 1: ENTSO 2040 Scenario Storylines, (https://consultations.entsoe.eu/system-development/joint-electricity-and-gas-consultation-build-the-e/user_uploads/160509_energy-scenarios-2040.pdf)

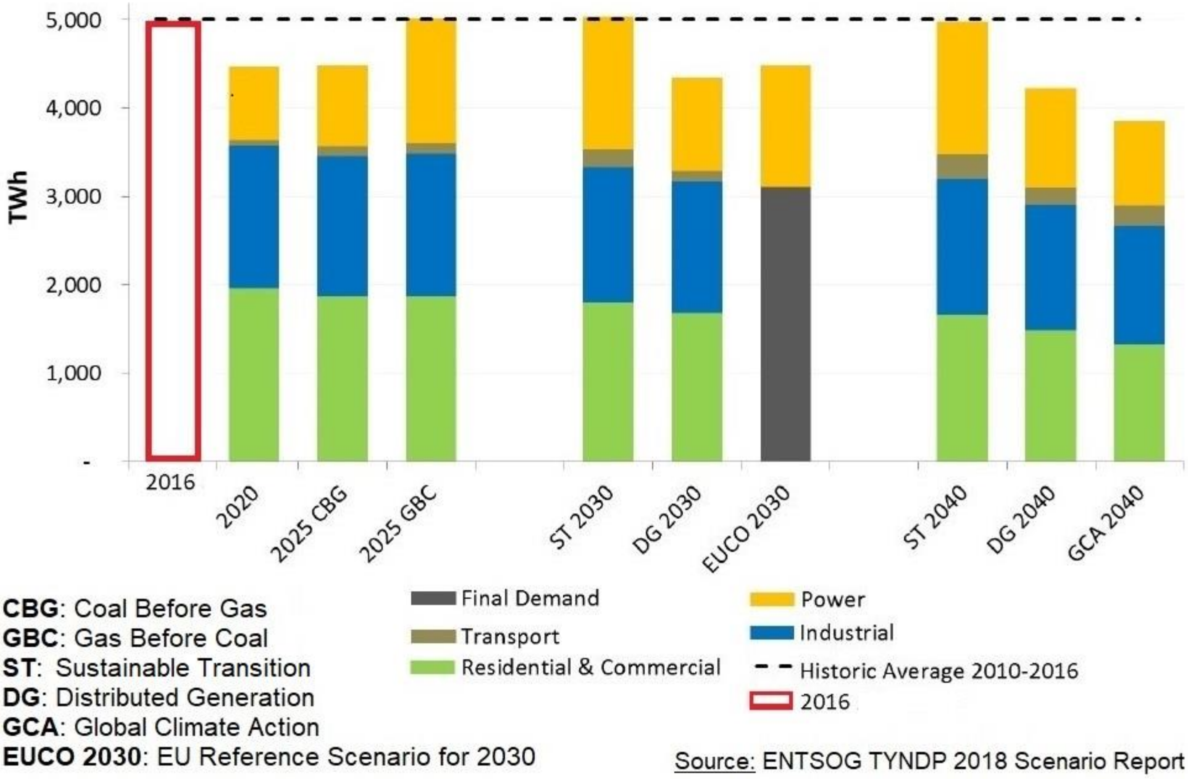
[52] See Annex I: TYNDP 2018 – 2040 Scenario Report Country Level Results

forecasts are rather optimistic, which might provide distorting / misleading signals with regard to the need for additional gas transmission and distribution infrastructure for the post 2020 period.

The TYNDP 2018 scenarios cover the period from 2020 until 2040. The 2020 and 2025 predictions are labelled as 'Best Estimate' scenarios because of the lower uncertainty and the easily predictable outcomes of the already implemented policies and operational investments. These Best Estimate scenarios for 2020 and 2025 are based on data provided by the transmission system operators, reflecting all national and European regulations currently in place, whilst not conflicting with any of the other scenarios. Sensitivity analyses regarding the merit order of coal and gas in the power sector are also included and are based on stakeholder input regarding the uncertainty on coal and gas prices, even in the short term. These analyses are described as 2025 Coal Before Gas (CBG) and 2025 Gas Before Coal (GBC) scenarios.[53]

The data provided by ENTSOG in 2017 (see graph below[54]) shows the expected gas demand up to 2040 of the various sectors, namely Transport, Residential & Commercial, Power and Industry according to different scenarios.

Figure 3-7: EU Gas Demand Scenarios (TWh), *(ENTSOG)*



According to the TSOs' data, the gas demand in the Gas Before Coal (GBC) scenario for 2025 would retain close to present levels. However, in the case where coal is preferred over gas for electricity production (Coal Before Gas scenario) gas demand is expected to decrease by around 15%. As for the 2030 time-frame, two scenarios show a reduction of EU28 overall gas demand. The EUCO30 scenario

[53] ENTOSG TYNDP 2018 Scenario Report, Main Report – Draft Edition, 2017 (https://www.entsog.eu/public/uploads/files/publications/TYNDP/2017/entsos_tyndp_2018_Scenario_Report_draft_edition.pdf)
[54] ENTSOG (2017), Ten-Year Network Development Plan 2017. (https://www.entsog.eu/publications/tyndp/2017#ENTSOG-TEN-YEAR-NETWORK-DEVELOPMENT-PLAN-2017)

models the implementation of the 2030 climate and energy targets agreed by the European Council in 2014 but with a higher energy efficiency target (30%). For the 2040-time horizon, scenarios become much more difficult to forecast because of the high uncertainty regarding potential evolutions of technologies and markets. The Distributed Generation (DG) scenario shows fairly similar levels for the gas demand and the split between the sectors for 2030 and 2040. The highest reduction of gas demand estimated on the basis of data from the national transmission system operators is the Global Climate Action (GCA) scenario, which implies the implementation of ambitious internationally agreed energy and environmental targets and forecasts a decline of almost 25%.

ENTSOG forecasts relatively stable or slightly reduced European gas demand post 2020

ENTSOG identifies three scenarios as the most likely under the expected trends: Sustainable Transition (ST), Global Climate Action (GCA) and Distributed Generation (DG). In the **Sustainable Transition (ST)** scenario the forecasts show similar levels of gas demand for 2030 and 2040 with almost identical shares for the different sectors. In this scenario climate action is achieved with a mixture of national regulation, CO_2 emission trading and subsidies. This scenario is based on moderate economic growth and low gas prices. The **Global Climate Action (GCA)** scenario, is based on the implementation of the most ambitious climate and energy targets and suggests a substantial drop in demand after 2030; the total gas demand would decrease to around 4000 TWh by 2040, which represents a reduction of almost 20% compared to current levels. This scenario is based on globally enforced climate action measures with the EU on-track towards its 2050 decarbonising strategies. Another important factor in this scenario is that CO_2 emission price levels would provide an effective market incentive for investments in low-carbon power generation technologies and flexibility services. This model also assumes high economic growth as well as massive development of renewable energy technologies. The **Distributed Generation (DG)** scenario foresees significant leaps in innovation of small-scale electricity generation and residential/commercial storage technologies would be a key driver in climate action. This scenario assumes an increase in gas demand in the transport sector and a reduction in the residential sector due to rapid implementation of electric heating and cooling technologies.

Based on these scenarios, ENTSOG has also elaborated possible storylines for the development of the European gas market. Taking into consideration the inputs from the models, economic growth and green ambition are used as parameters upon which the scenarios are benchmarked in order to produce two progressive (EU Green Revolution & Evolution) and two less ambitious storylines (Blue Transition and Slow Progression). The table below shows the EU 28 demand levels provided by ENTSOG for the different storylines.[55]

Table 3-1: Expected natural gas demand for 2030 Based on Annex C2 of the 2017 ENTSOG TYNDP

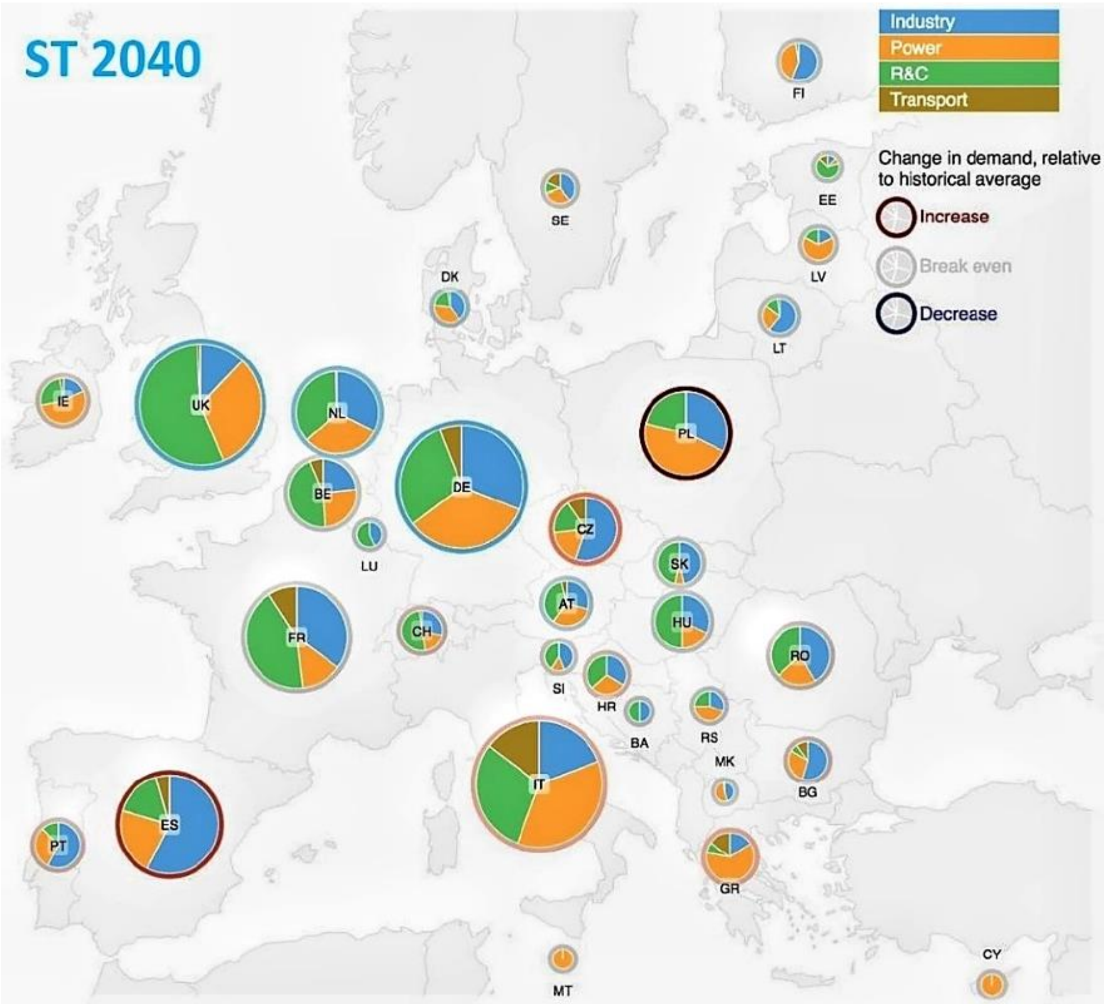
<table>
<tr><th></th><th>EU Green Revolution</th><th>Green Evolution</th><th>Blue Transition</th><th>Slow Progression</th></tr>
<tr><td>EU28 yearly demand (TWh)</td><td>4186</td><td>4582</td><td>5210</td><td>4515</td></tr>
<tr><td>- Residential and commercial demand</td><td rowspan="3">3058</td><td>1279</td><td>1511</td><td>1511</td></tr>
<tr><td>- Industrial demand</td><td>1221</td><td>1314</td><td>1267</td></tr>
<tr><td>- Transport demand</td><td>127</td><td>174</td><td>9104</td></tr>
<tr><td>- Gas for power</td><td>1128</td><td>1325</td><td>1442</td><td>907</td></tr>
</table>

[55] ETSOG 2017 TYNDP Annex C2, (https://www.entsog.eu/publications/tyndp#ENTSOG-TEN-YEAR-NETWORK-DEVELOPMENT-PLAN-2017)

We notice that the different gas demand levels used as input for the elaboration of the TYNDP are, in all scenarios, higher than the levels which would result from the implementation of ambitious EU climate and energy policies for decarbonisation of energy supply and improvements in energy efficiency.

According to the Sustainable Transition (ST) scenario for 2040, represented in the graph below, the most significant consumption sector driving national gas demand in Germany and Italy would be power generation. In France and the United Kingdom, the heating sector would be the most important consumption sector, whereas in Spain industry would represent the highest share in national gas demand.[56]

Figure 3-8: EU Member States Gas Consumption according to ENTSOG Sustainable Transition Scenario

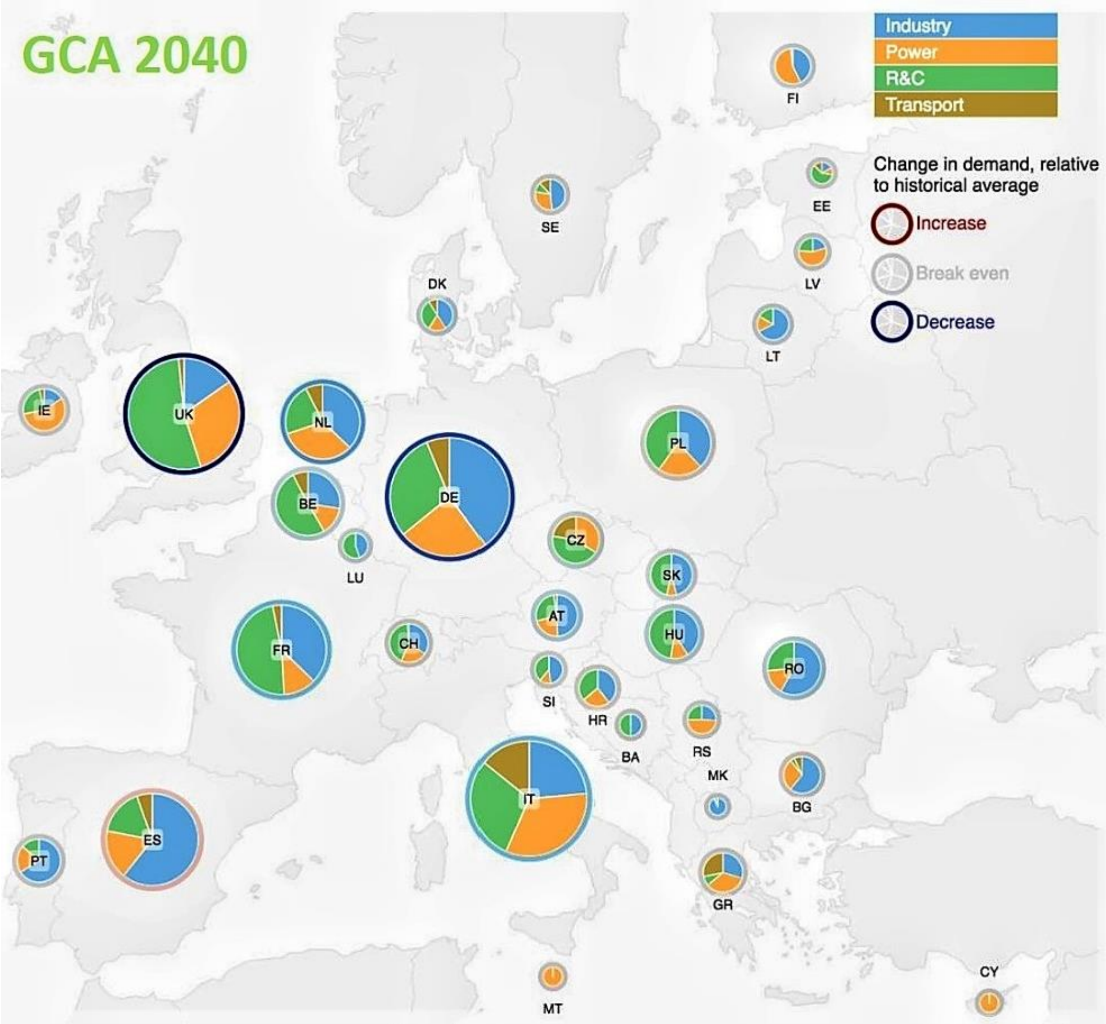


However, according to the Global Climate Action (GCA) scenario the overall gas demand of EU Member States would decrease in the 2040 time-frame.[57] The largest national markets remain Germany, Italy, the United Kingdom, France and Spain, however there are slight changes in the sectors driving the

[56] TYNDP 2018 – Scenario Report Annex I: Country Level Results - Draft edition (https://www.entsoe.eu/Documents/TYNDP%20documents/entsos_tyndp_2018_Scenario_Report_ANNEX_I_Country_Level_Results.pdf
[57] See Annex I: TYNDP 2018 – 2040 Scenario Report Country Level Results - Draft edition, *Idem*.

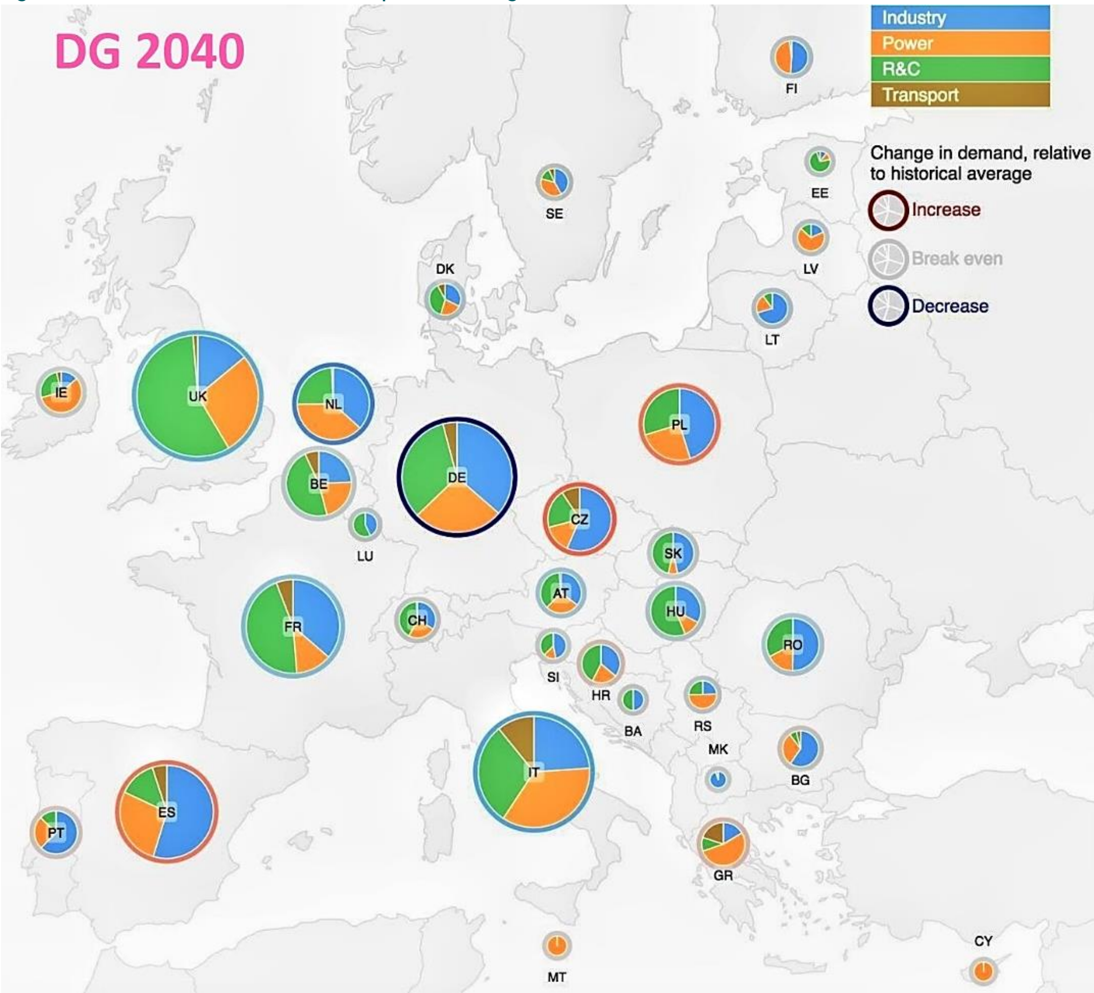
demand. The most important difference is experienced in Germany where the Industrial sector would become the largest gas consumer.

Figure 3-9: EU Member States Gas Consumption according to ENTSOG Global Climate Action Scenario



According to the Distributed Generation (DG) scenario for 2040, small scale power-generation technologies would become economically viable without subsidies. This would lead to greater use of solar technologies as well as domestic battery storage facilities which would allow prosumers to balance their energy needs throughout the day and mitigate seasonal demand fluctuations. Thanks to lower battery costs the process of electrification of the transport sector would substantially accelerate in this scenario and gas would be used for mobility purposes only as a transition fuel. Electric and hybrid heat pumps would make it easier for consumers to reduce their consumption of fossil fuels, including gas. These changes would go hand in hand with improvements in the building sector, especially in the energy efficiency of buildings and appliances. In this scenario, the UK would become the biggest single gas consumer by 2040, closely followed by Italy and Germany.

Figure 3-10: EU Member States Gas Consumption according to ENTSOG Distributed Generation Scenario



Although the TYNDP process allows stakeholders to actively engage in the scenario building, its seems that the scenarios are not optimally determined, as none of the scenarios used in the TYNDP 2017 would allow reaching the 2030 European energy and climate targets agreed upon in 2014, in particular the 27% target for energy efficiency. Moreover, two of the scenarios considered seem to substantially overestimate future gas demand, as they ignore the trend of gas demand reduction during the last five years and assume unrealistically high coal and CO_2 prices. They also seem to not take into account the substitution of natural gas with biomethane or hydrogen. These scenarios are a fortiori not in line with more ambitious 2030 targets for energy efficiency and renewable energy which will most probably result from the ongoing negotiations on the “Clean energy for all Europeans” package. While according to the impact assessment study on the EED review an energy efficiency target of 27% would in 2020-2030 lead to an annual decrease of the EU natural gas consumption of 0.9%, more ambitious targets of 30 or 35% would result in a decrease of respectively 1.9 and 3.5% annually. The energy and climate target setting will hence substantially affect the future gas demand and utilisation level of gas infrastructure.

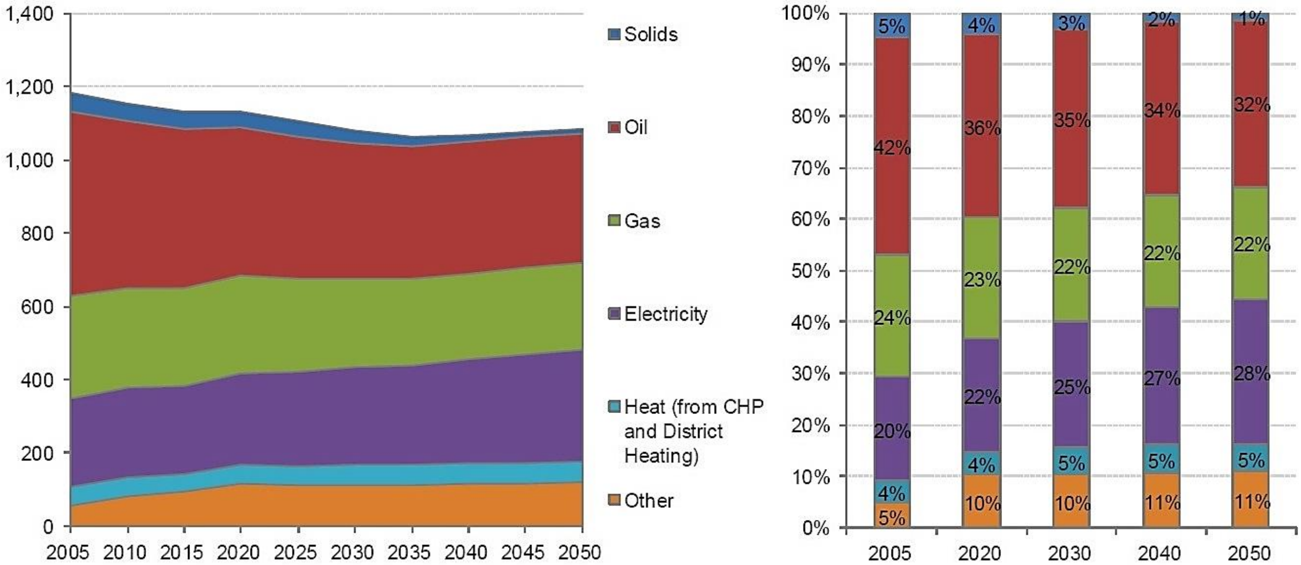
The next sub-chapter focuses on some relevant forecasting scenarios which are elaborated by the European Commission on the basis of the PRIMES model and by the Oxford Institute for Energy Studies, using its TIGER model. We then present the scenarios and outcome of a recent assessment from the German consultancy firm Prognos of low carbon options for gas infrastructure.

3.1.2.2 Gas demand forecasts resulting from analyses with PRIMES

The PRIMES model, developed by the National Technical University of Athens is used to simulate the possible evolution of the European energy system and markets on a country-by-country basis and across Europe. This model is also often used to estimate the potential effect of implementing new or revised EU legislation on the energy sector and is for instance applied in 2016 for the Impact Assessment on the review of the Energy Efficiency Directive. The model evaluates market behaviour but also presents in an explicit and detailed way the available energy demand and supply technologies and pollution abatement technologies. The methodology reflects considerations about market economics, industry structure, energy and environmental policies and regulation. Primes based modelling studies for gas assess the relationships between gas resources, gas infrastructure and the degree of competition in gas markets over the Eurasian and MENA area and evaluate their impacts on gas prices paid by gas consumers in the EU Member States. The Primes model also presents the detailed present and future gas infrastructure of each EU Member State, other European countries and the gas producing and consuming countries of the Eurasian and MENA region.

The outcomes of the Primes based modelling exercise suggest that given the current state of EU energy and environmental policies, final global energy demand would decrease after 2020. However, as can be seen in the graphs below of the **EU Reference Scenario 2016***, after 2035 the model foresees a slight increase and a return by 2050 to the levels experienced in 2020. According to this source, the demand for gas would slightly decrease as of 2025, but its relative share would from 2030 to 2050 continue to represent 22% of the total final energy demand in the EU.[58] In absolute figures the gas demand, which was 403 Mtoe (4687 TWh) in 2015 is expected to amount to 398 Mtoe (4629 TWh) in 2020, 380 Mtoe (4419 TWh) in 2030 and 2040 and 382 Mtoe (4443 TWh) in 2050.

Figure 3-11: Evolution of Final Energy Demand by Fuel (Mtoe-left, Shares-right)

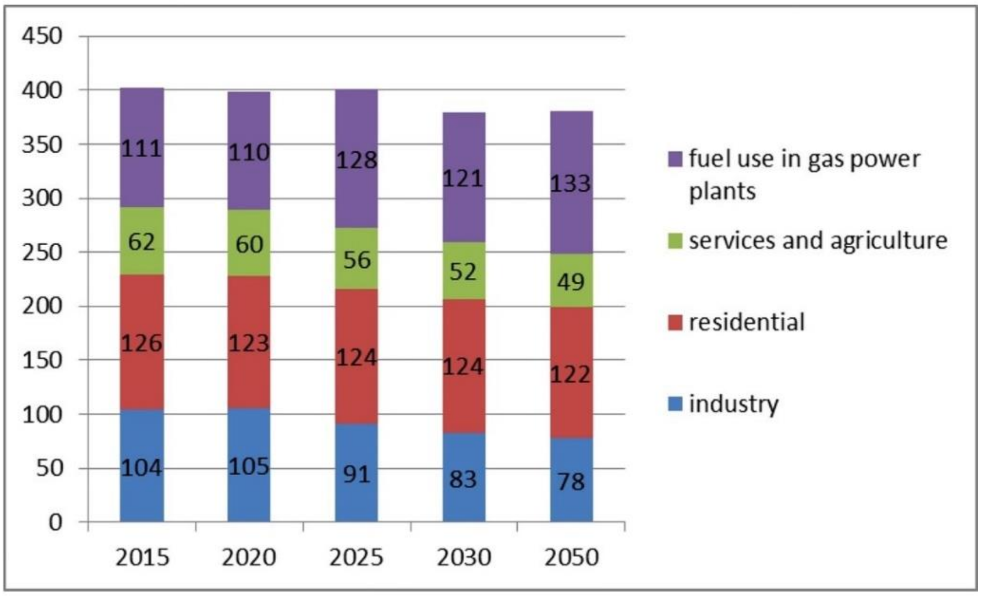


Source: PRIMES

[58] EU Reference Scenario 2016 Energy, transport and GHG emissions Trends to 2050 Main results (https://ec.europa.eu/energy/sites/ener/files/documents/20160712_Summary_Ref_scenario_MAIN_RESULTS%20%282%29-web.pdf)
* 1 Mtoe = 1.163 TWh

The graph below also shows that, according to the EU Reference Scenario elaborated in 2016 with the Primes model, the demand for gas used for power generation would increase, while the demand in the other sectors is expected to decline.

Figure 3-12: Evolution of Gas Demand by Sector (Mtoe)



Source: PRIMES

The PRIMES model was also used in 2016 to assess the impact of the proposed amendments of Directive 2012/27/EU on Energy Efficiency. This review mainly addressed the concern that insufficient progress in energy efficiency was holding back the potential benefits of energy price reduction and increased security of supply for European customers. The Impact Assessment clearly showed that ambitious energy efficiency targets for 2030 would have a higher impact on gas demand, than was estimated by ENTSOG in its scenarios for the 2017 TYNDP; as a result, infrastructure investment decisions solely based on demand estimates elaborated in the context of the TYNDP could lead to overcapacity.

According to the forecasts made using the PRIMES model, ambitious targets on reducing energy consumption by 2030 would lead to a substantial decline in EU gas consumption. The table below presents the results for different targets: 27%, 30%, +33%, +35% and +40% reduction of primary energy consumption for the EU by 2030.

Table 3-2: Gross inland natural gas consumption in 2030 (TWh). Based on SWD (2016) 405, table 6 & 9

	REF2016	EUCO27	EUCO30	EUCO+33	EUCO+35	EUCO+40
Gross inland natural gas consumption (TWh)	4314	4082	3663	3302	3105	2698
% change from EUCO27	-		-10%	-19%	-24%	-34%
Net gas imports volume (2005=100)	116	110	97	84	78	64

Depending on the ambition level of the energy efficiency target, the reduction of the gas demand in 2030 compared to the level determined in REF2016 varies between 9.5% and 38%. As the Commission's proposal for the revised EED already comprised an increased energy efficiency target of 30% and the

European Parliament voted for a 35% target, the above results indicate that ENTSOG's 2017 TYNDP as well as the PCI list are based on expected gas demand levels for 2030 (between 4186 and 5210 TWh depending on the scenarios) that are between 12.2 and 40.5% too high.

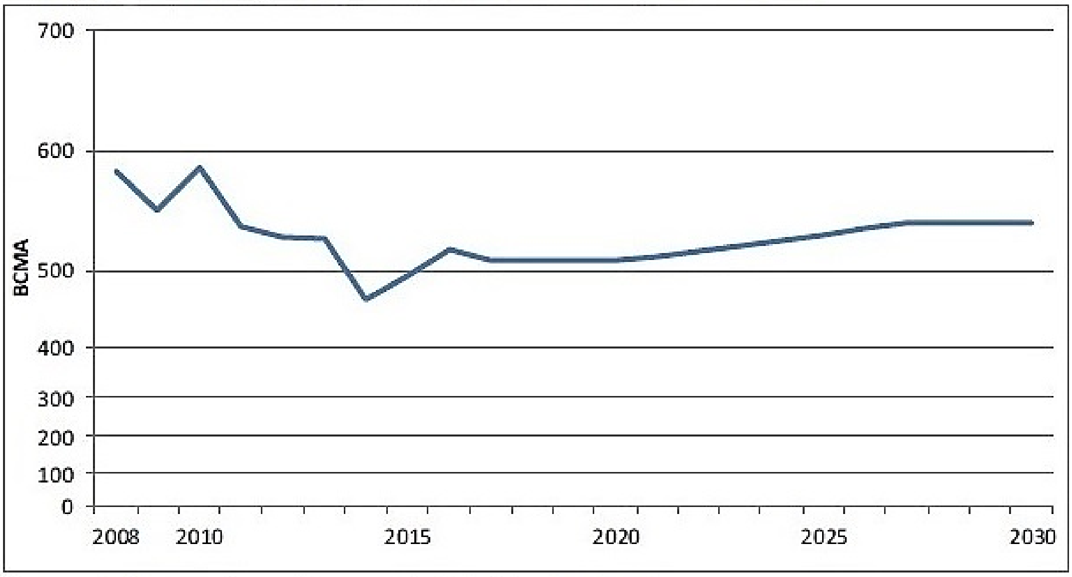
3.1.2.3 Oxford Institute for Energy Studies (TIGER)

The TIGER model is developed by EWI and the Institute for Energy Economics at the University Cologne. It uses European supply-demand transmission inputs as well as production capacities of major gas suppliers, European domestic production, information on long term contracts and transmission tariffs data to forecast the expected physical gas flows within the EU. Being a cost minimising model, TIGER allows the optimisation of the whole system in order to minimise the overall cost of gas supply. It also takes into account major infrastructure constraints, namely capacity limits of pipelines or injection/withdrawal storage curves.

The study, undertaken by the Oxford Institute for Energy Studies in 2017, uses several scenarios to forecast the possible demand levels for gas in the EU for 2030. It considers the expected evolution of imports from both Russian and other pipeline gas. The scenarios also depend on the level of connectedness of the global LNG system as a mean of providing more liquid gas markets to meet demand. In this model the South and Eastern Asian region plays the most important factor in global gas demand. Countries like China, India, Japan, South Korea and Taiwan account for the biggest rise in global gas demand in the medium and long term. Given that estimated rise, the model suggests that a potential fluctuation in that trend might result in large quantities of LNG, initially intended for the Asian market to be left unused. The model then analyses the extent to which European gas demand can tap into these unused LNG quantities in order to satisfy its needs. As illustrated in the chart below, the model forecasts stable gas demand in the European region through 2020 with a slight increase from 2025 until 2030. This increase would result from the expected phasing out of coal and nuclear technologies for power generation, as well as a slowing down of the development of Renewable Energy Sources. It is important to note that this model does not take into account any targets for decarbonising EU energy supply for 2030. As a result, the forecast for 2030 is only based on the 2020 levels and targets.[59] This is the reason why the gas demand estimates in this study are much higher than the outcomes of the other studies.

[59] Oxford Institute for Energy Studies, *Future European Gas Transmission Bottlenecks in Differing Supply and Demand Scenarios*, (https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/06/Future-European-Gas-Transmission-Bottlenecks-in-Differing-Supply-and-Demand-Scenarios-NG-119.pdf)

Figure 3-13: European Region Gas Demand 2008-2030



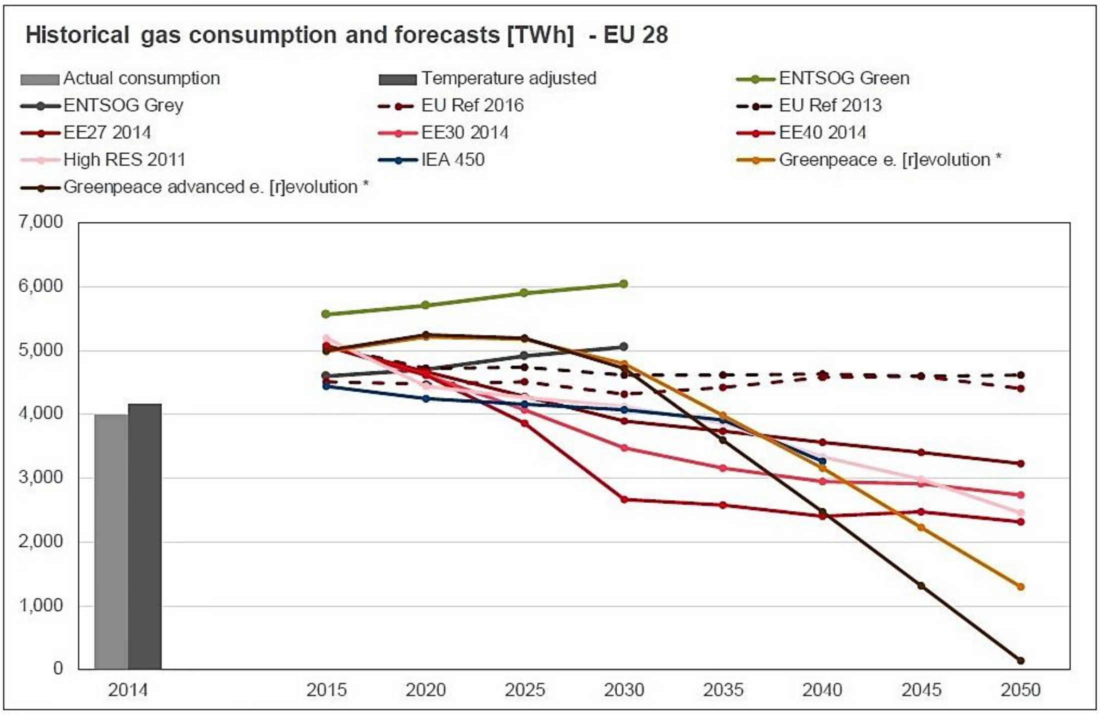
Source: Based on Honoré, OIES , Oxford

3.1.2.4 Other relevant studies

Another relevant study on the potential of low carbon options for gas infrastructure in Europe is being produced by the Ecologic Institute and a German consultancy company Prognos. It shows a comparison of the outcomes of several forecast studies about the possible evolution of the gas demand under various scenarios.

The graph below shows an overview of the collected data starting from 2015 up to 2050.[60]

Figure 3-14: Primary Gas Demand in the Analysed Scenarios in Europe (TWh)



* *Gas demand for OECD Europe*
Note: 2014 was an exceptional warm year
Source: Prognos based on [EC 2016], [EC 2013], [E3M 2014], [EC 2011], [IEA 2015], [Greenpeace 2015]

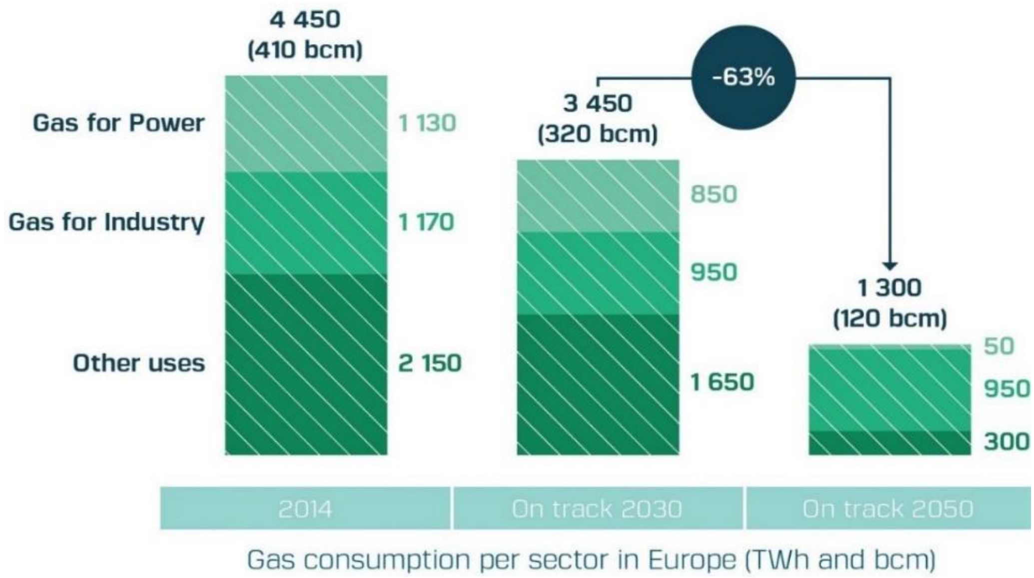
The two bars on the left hand-side show the gas demand for 2014 both in absolute figures as well as the temperature adjusted figures. The lines show the various forecasts under the analysed scenarios. The graph includes the most optimistic (Green) and lowest (Grey) forecasts of ENTSOG, as well as the outcome of the Impact Assessment study commissioned by the European Commission in 2016 in the context of the review of the Energy Efficiency Directive and assessing the impact of reducing energy consumption by 2030 with 27%, 30% and 40% respectively compared to BAU. It also presents the Commission's Reference Scenarios (EU Ref) produced in 2013 and 2016 which forecast the expected demand evolution if no additional targets and policies are adopted and the energy sector continues to develop on a business as usual scenario. Another scenario developed by the Commission in 2011 for the high deployment of renewables (High RES 2011) is also presented in the graph. Data from the International Energy Agency is also included showing the expected gas demand until 2040. Last but not least, two Greenpeace scenarios are shown, based on the Simple or Advanced (r)evolution of the energy sector. However, these scenarios only use data for EU Member States which are members of the OECD[61]. As a result, this shows a limited scope for the expected EU demand. However, given the fact that these countries represent the biggest gas consumers in the EU it is worth taking into account and analysing the data.

[60] Prognos, *Low carbon options and gas infrastructure*, Interim report, Berlin, 19 January 2017 (https://www.prognos.com/uploads/tx_atwpubdb/20170407_Prognos_Report_Low_Carbon_options_2016_19.1.17.pdf)
[61] Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovak Republic, Slovenia, Spain, Sweden and United Kingdom.

This graph shows that the ENTSOG's 2017 TYNDP forecasts for gas demand for 2030 are higher than all the other projections produced by the presented studies. ENTSOG used scenarios envisioning an increase in the demand for natural gas, while most other studies expect a stable or decreasing demand. Even the two EC Reference Scenarios which are based on the current decarbonising strategies, show almost stable levels of gas demand throughout the examined period. All projections made by the Commission implementing more ambitious energy efficiency targets show a decrease in the EU gas demand. The IEA 450 Scenario, which sets out an energy pathway consistent with the goal of limiting the global increase in temperature to 2°C by reducing the concentration of greenhouse gases in the atmosphere to around 450 parts per million of CO_2, also shows a decline in EU gas demand with a steeper reduction after 2035.

The future EU gas demand has also been assessed by a consortium of consultants, think-tanks and non-governmental organisations, namely the European Climate Foundation, E3G, Cambridge Institute for Sustainable Leadership, Regulatory Assistance Project, Agora Energiewende, WWF, under the umbrella of *Energy Union Choices*.[62] This consortium has examined the gas demand which would result from a strategy driven only by the use of natural gas compared to a strategy driven by an integrated and regional perspective of gas and electricity systems in the context of scenarios of High Demand, continuation of the Current Trends and On Track implementation of decarbonising policies. [63]

Figure 3-15: Gas Consumption per Sector in Europe (TWh and bcm), *(Energy Union Choices)*



If the European Union would continue to stay On Track with the energy and environmental targets, the study forecasts that by 2050 there would be a 63% decline in EU gas demand compared to 2030 levels and a 70% decline compared to 2014 levels.

3.1.2.5 Overall Comparison between the different Scenarios

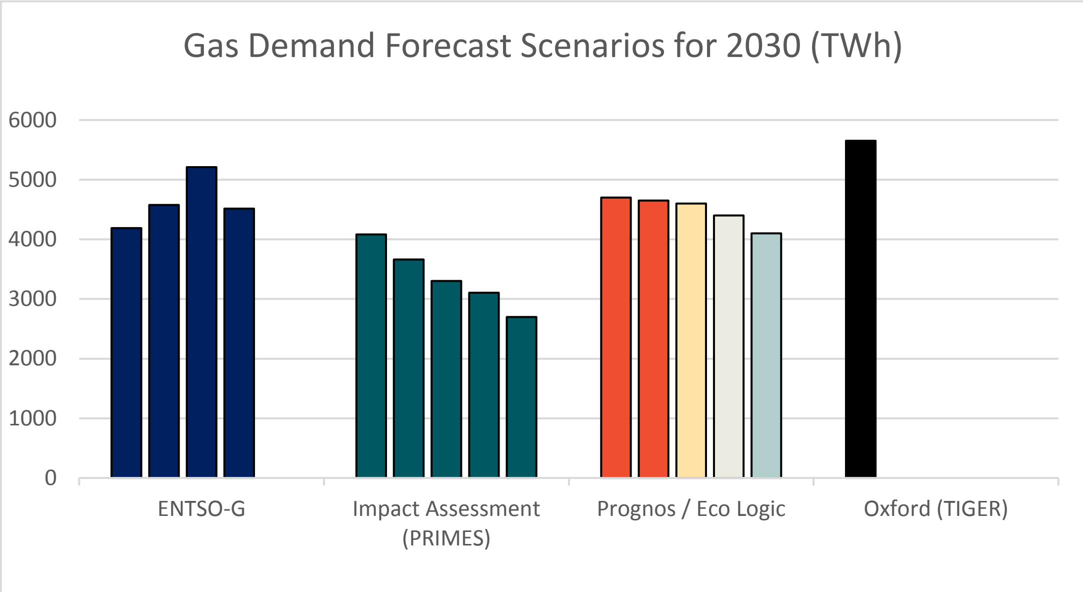
The following table and graph present an overview of the main results for 2030 of the analysed models and studies.

[62] http://www.energyunionchoices.eu/
[63] Energy Union Choices, *A Perspective on Infrastructure and Energy Security In the Transition*, 3 March 2017, (http://www.energyunionchoices.eu/wp-content/uploads/2017/08/EUC_Report_Web.pdf)

Table 3-3: Comparison Between Different Scenarios for EU Gas Demand for 2030, (TWh)

Source	Scenario	Features							Demand 2030 TWh	Scope
		ENERGY POLICIES / REGULATION	ECONOMIC CONDITION	GREEN AMBITIONS	CO^2 PRICE	FUEL PRICES	INTERNAL ENERGY MARKET	RENEWABLES DEVELOPMENT		
ENTSOG TYNDP 2017	Green Revolution	On track with 2030 / 2050 targets	Strong growth	Highest	Highest CO^2 price	Lowest expected gas and coal prices	Well-functioning, strongest MS cooperation	Highest	4188	EU28
ENTSOG TYNDP 2017	Green Evolution	On track with 2030 / 2050 targets	Strong growth	High	Highest CO^2 price	Lowest expected gas and coal prices	Well-functioning, strong MS cooperation	High	4576	EU28
ENTSOG TYNDP 2017	Blue Transition	On track with 2030 / 2050 targets	Moderate growth	Moderate	Moderate CO^2 price	Moderate expected gas and coal prices	Well-functioning, moderate MS cooperation	Moderate	5210	EU28
ENTSOG TYNDP 2017	Slow Progression	2030 / 2050 targets not realistically reachable	Limited growth	Lowest	Lowest CO^2 price	Highest expected gas and coal prices	Well-functioning, low MS cooperation	Lowest	4515	EU28
European Commission Impact Assessment (PRIMES Model)	EUCO27	27%	Target for reduction of primary Energy Consumption by 2030 compared to 2007 baseline scenario						4082	EU28
European Commission Impact Assessment (PRIMES Model)	EUCO30	30%	Target for reduction of primary Energy Consumption by 2030 compared to 2007 baseline scenario						3663	EU28
European Commission Impact Assessment (PRIMES Model)	EUCO33	33%	Target for reduction of primary Energy Consumption by 2030 compared to 2007 baseline scenario						3302	EU28
European Commission Impact Assessment (PRIMES Model)	EUCO35	35%	Target for reduction of primary Energy Consumption by 2030 compared to 2007 baseline scenario						3105	EU28
European Commission Impact Assessment (PRIMES Model)	EUCO40	40%	Target for reduction of primary Energy Consumption by 2030 compared to 2007 baseline scenario						2698	EU28
Prognos	Greenpeace (R)evolution	Practical blueprint for cutting carbon emissions while achieving economic growth by replacing fossil fuels with renewable energy and energy efficiency. Global target of reducing 50% of energy related GHG globally by 2050 (basis 1990 level)							4700	OECD EU MS
Prognos	Greenpeace Advanced (r)evolution	*Ibid.* Global target of reducing 80% of energy related GHG globally by 2050 (basis 1990 level)							4650	OECD EU MS
Prognos	EU Ref 2013	Projects energy, transport and greenhouse gas emissions trends in the EU up until 2050. The Reference Scenario is a projection of where current set of policies coupled with market trends are likely to lead.							4600	EU28
Prognos	EU Ref 2016	Projects energy, transport and greenhouse gas emissions trends in the EU up until 2050. The Reference Scenario is a projection of where current set of policies coupled with market trends are likely to lead.							4400	EU28
Prognos	IEA 450	Sets out energy pathway consistent with goal of limiting global increase in temperature to 2°C by limiting concentration of GHG in the atmosphere to 450 ppm							4100	EU28
Oxford	TIGER Model	Supply-Demand transition cost-minimising model. It works using as inputs demand, production capacities of major gas suppliers, European domestic production, information on long term contracts, transmission tariffs data and gives as an output a pattern of physical gas flows within Europe.							5652	EU28

This table presents the levels of gas demand forecast for 2030 under the scenarios produced by ENTSOG, the Primes Model used in the Impact Assessment, the TIGER model used in the Oxford study as well as the data collected in the Prognos study. The Greenpeace forecasts concern OECD Europe, while all other scenarios cover the 28 EU countries.



The chart above shows the differences between the ENTSOG forecasts elaborated in the 2017 TYNDP and other forecasts, with the data resulting from the Impact Assessment of the Energy Efficiency Directive showing the largest divergence. This chart illustrates that even the lowest ENTSOG forecast based on the *Green Revolution scenario*, which envisions a demand of 4186 TWh in 2030, is still higher than the lowest outcome of the Impact Assessment based on a target of 27% reduction in energy consumption, which foresees 4082 TWh of gas demand in 2030. With higher Energy Efficiency targets of 30 to 40 %, the PRIMES model used in the Impact Assessment indicates a progressive reduction of EU gas demand by 2030. The most ambitious target of 40% reduction of energy consumption by 2030, would lead to a reduction in gas demand of almost 40% compared to the outcome of the most ambitious ENTSOG Storyline (*Green Revolution)*. The expected demand in 2030 according to ENTSOG's Green Revolution scenario (4186 TWh), lays 35% above the demand in the 35% energy efficiency scenario (3102 TWh) endorsed by the European Parliament.

The differences between the overestimated gas demand in the ENTSOG forecasts and the gas demand forecasted in scenarios that are in line with EU's 2030 climate and energy goals, will further exacerbate after 2030, when a deeper decarbonisation of the European economy will take place. As the cost-benefit analyses of new gas infrastructure investments are in general based on an economic lifetime of 25 years for networks (including pipelines and compressor stations) and 20 years for LNG/UGS facilities, substantially lower effective demand levels than anticipated in the investment evaluations might involve reduced revenues for project developers, and/or increased grid tariffs for end-users. This evolution might also lead to an increased risk of stranded assets.

The Prognos report also provides expected demand figures which are higher than the forecasts resulting from the Impact Assessment, but the Prognos demand expectations do not take into consideration any EU target on energy savings. The difference of around 200 TWh between the EU Reference Scenarios (EU Ref) for 2016 and 2013 shows that the effects of the policies already implemented produce a tangible result for the 2030 time-period. This comparison also highlights the potential reduction of gas demand in the future if more ambitious energy efficiency targets were implemented.

The Oxford study shows an EU gas demand in 2030 above 5500 TWh. However, it is important to note that these results are based on a scenario which assumes an increase of global LNG trading, a reduction of gas prices and no additional policies or targets implemented at the European level.

3.2 EU Gas Supply

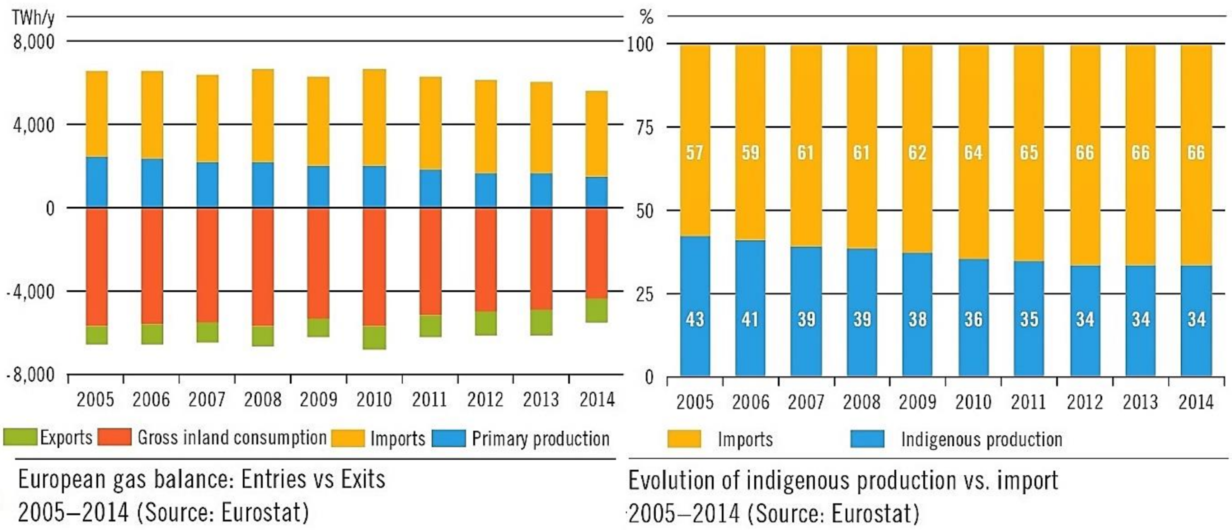
Defining the expected gas supply in the European Union is an important input to adequately forecast the expected needs for infrastructure investments in the near future. This exercise must not only take into account the anticipated evolution of domestic production within the EU but also the expected imports from third countries, be it through existing pipelines and LNG terminals or the ones which are currently under construction.

The analysis in this section is based primarily on data published by Eurostat and DG Energy as well as input gathered by ENTSOG in its TYNDP. We also present the potential evolution of the EU's gas supply as forecast in the Oxford study on the *Future European Gas Transmission Bottlenecks* in the context of fluctuations in the Asian LNG market as well as Russian pipeline supplies.

3.2.1 Historic and current EU gas supply

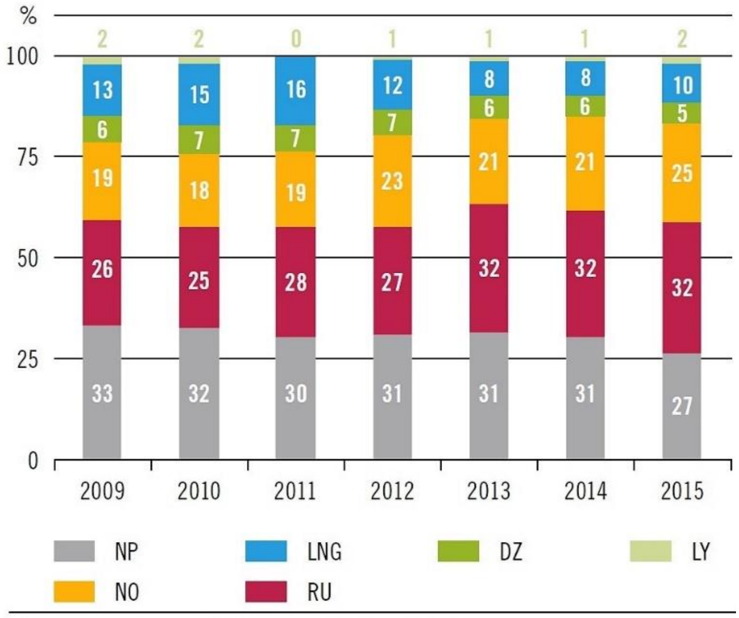
The graphs below present the gas balance from 2005 to 2014 in TWh/year and the ratio between imports and indigenous production; we notice that both EU gas production and demand slightly decrease during the period.

Figure 3-16: Evolution of European Gas Balance (TWh), *(Aurora Energy Research)*



The share of indigenous national production (NP) in the total gas supply entering the EU gas market has decreased from 33% in 2002 to 27% in 2015. LNG imports 'share peaked in 2011 at around 16% of the total EU gas supply and slightly declined in the consecutive years. The gap in supply has been met mostly by increased imports of pipeline gas from third countries like Russia (**RU**) and Norway (**NO**) which delivered 32% and 25% respectively of the total gas supply in 2015. The 2015 supply figures show that 73% of the total gas supply in the EU came from direct imports from external sources, namely Russia, Norway and LNG.

Figure 3-17: Evolution of Supply Shares 2009-2015, *(Aurora Energy Research)*[64]



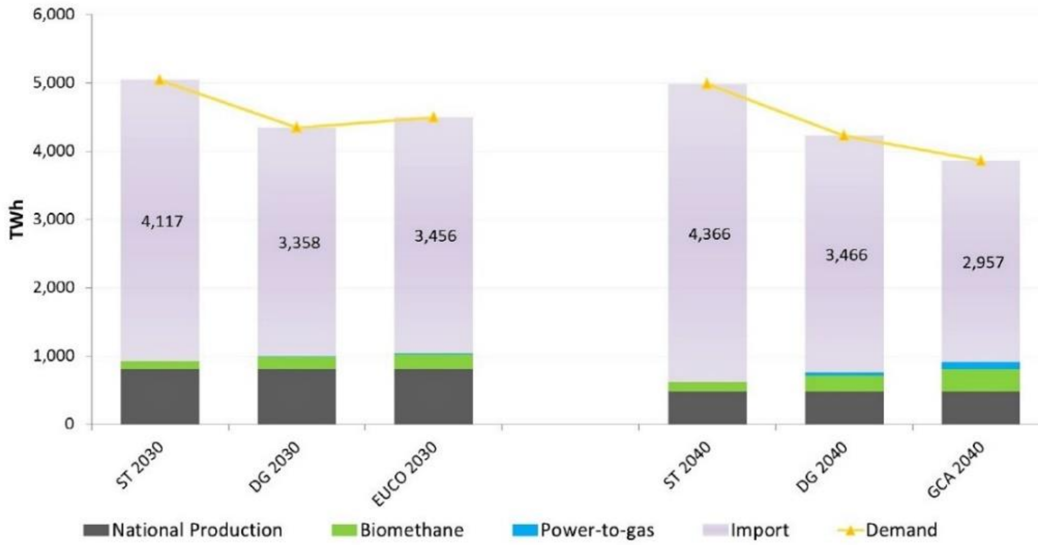
3.2.2 *Forecasts for Future EU Gas Supply*

According to the latest forecasting scenarios elaborated by ENTSOG for the 2030 time-frame, between 3358 and 4117 TWh will come from imports in 2030. The forecasts for 2040 show greater fluctuation amongst the scenarios depending on the level of implementation of EU energy efficiency policies as well as the expected share of renewables and range from 2957 to 4366TWh.

The graph below shows that in all of the scenarios the indigenous EU production as well as the biomethane injection would represent only a minor part of the total gas volumes needed to satisfy the overall demand in 2030 and 2040. The majority of EU gas supply will hence continue to be provided by imports.

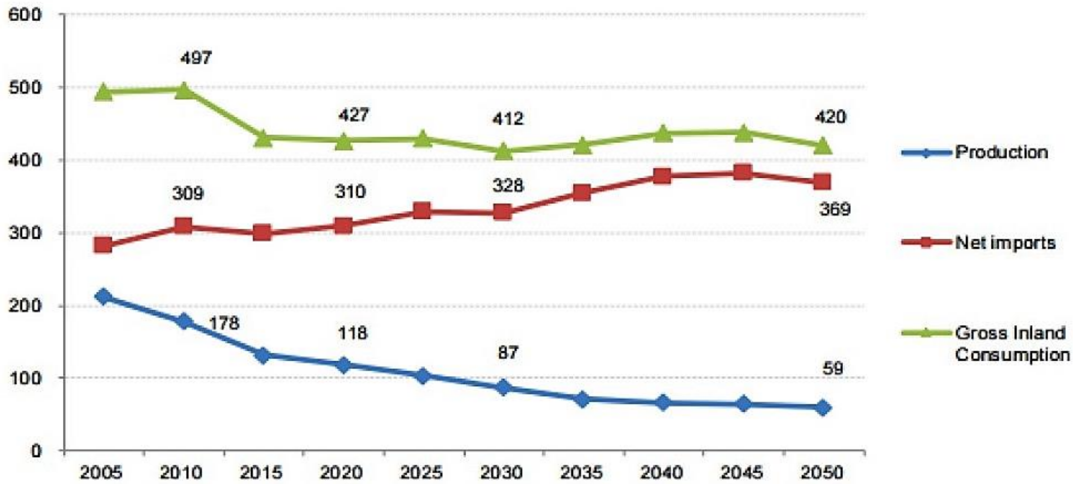
[64] AURORA Energy Research, *Driving Demand & Securing Supply: Outlook on the European gas market*, 11th Gas Forum, Ljubljana, 22 September 2016, (http://www.europeangashub.com/custom/domain_1/extra_files/attach_717.pdf)

Figure 3-18: ENTSOG Scenario Forecasts for Gas Demand



The forecasts below, produced by the PRIMES model are used by the Commission in its projections for the evolution of EU energy markets, also confirm the declining trend of domestic EU gas production. Since this model also forecasts a relatively stable level of demand for the 2050 time-horizon, the gap in gas consumption has to be filled by a growing share of imports from third countries.

Figure 3-19: Gas Production: Net Imports and Demand (bcm)



Source: PRIMES, EU Reference Scenario 2016

The EU gas supply forecast scenarios presented in the Prognos report, also confirm the declining trend of domestic gas production. However, as these studies also forecast a declining gas demand, the import dependency is not expected to increase. The table below shows that, even with the adoption of the 27% energy efficiency target, the overall demand for gas is expected to decline more than the domestic production, and the total net imports would hence also decrease in this scenario. The two EU reference scenarios result in increasing gas imports, which is not surprising as they are both based on the assumption that no further energy efficiency or RES target would be adopted for 2030 or 2050.

Figure 3-20: Net Gas Import Under Various EU Scenarios

Gas imports EU	2015	2020	2030	2050
Gas production in the EU according to EU Reference 2016 [TWh]	1377	1239	913	620
Resulting gas imports [TWh]				
EU Reference 2016	3132	3237	3405	3784
EU Reference 2013	3684	3486	3707	3993
EU EE27 2014	3683	3433	2981	2607
EU EE30 2014	3683	3380	2566	2119
EU EE40 2014	3683	3378	1755	1692
EU High RES 2011	3821	3206	3200	1828
IEA 450	3050	3006	3146	
Greenpeace e. [r]evolution	3605	3964	3873	675
Greenpeace advanced e. [r]evolution	3621	4006	3801	-476

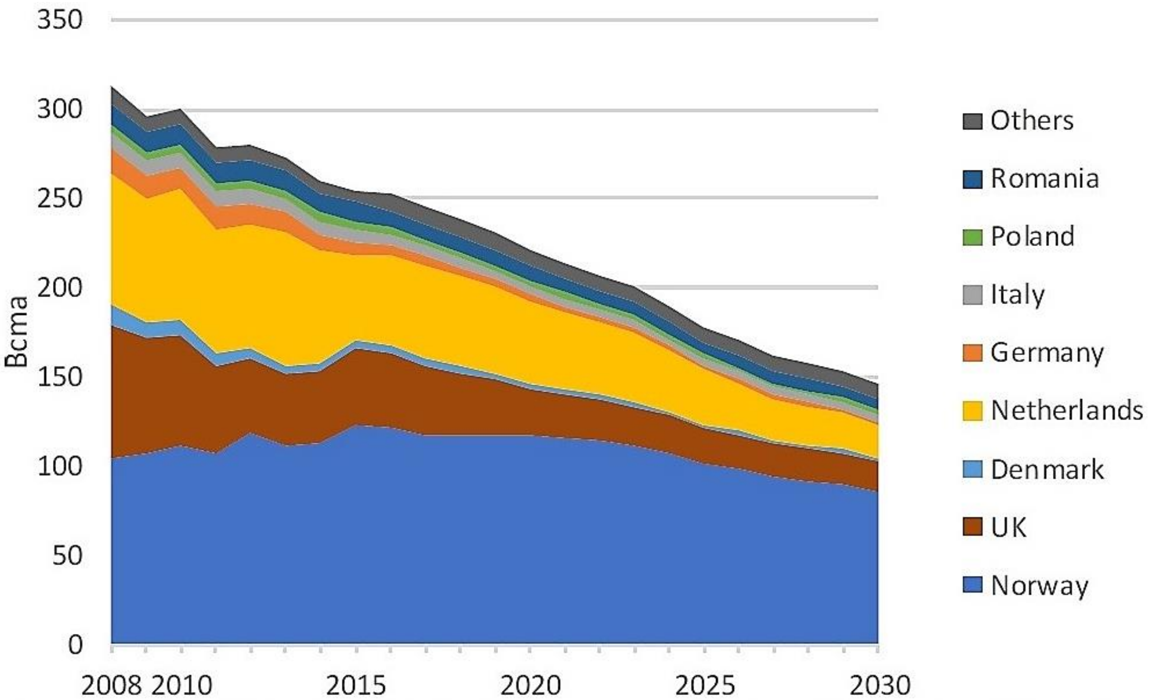
Note: Uses domestic gas production from EU Reference Scenario 2016 as a baseline

Source: Prognos based on [EC 2016A], [EC 2013], [E3M 2014], [EC 2011], [IEA 2015B], [Greenpeace 2015]

3.2.2.1 Expected evolution of domestic EU Gas Production

The Oxford study on the *Future European Gas Transmission Bottlenecks* clearly shows the expected decline in European gas production in the different EU Member States as well as in Norway. The Netherlands and the UK are expected to experience the most drastic decline in their gas production.

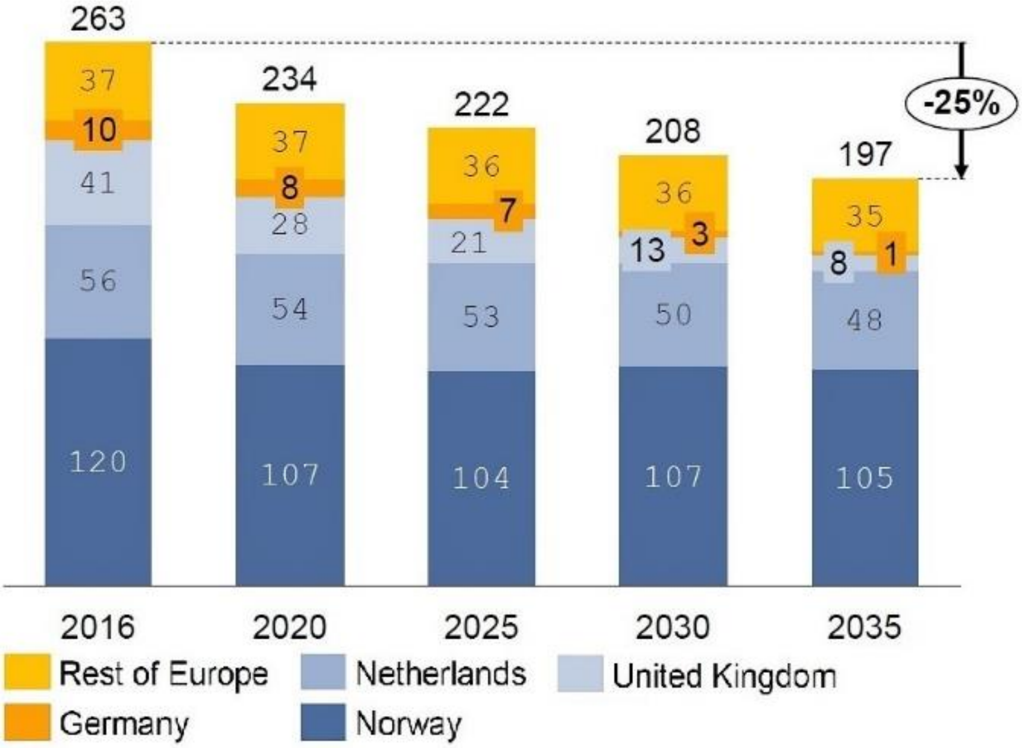
Figure 3-21: European Region Domestic Production 2008-2030



Sources: IEA. National Grid. Dutch Ministrv of Foreign Affairs, Energi Styrelsen, Norwegian Ministry of Petroleum and Energy, Authors' Analysis

The latest forecasts produced by ENTSOG in 2017 and spanning until 2035 suggest a decrease of 25% in the total EU gas production (including Norway). This forecast also highlights that the biggest decline in production would occur in the UK, the Netherlands and Germany where national regulations expect a decline of local gas production. [65]

Figure 3-22: Indigenous EU and Norwegian Gas Production (incl. shale) *(ENTSOG)*



The only segment of indigenous EU production which is expected to slightly increase in the short-to-medium term, if environmental concerns are properly addressed, is shale gas. As seen on the graph below, according to ENTSOG, shale gas is expected to reach a production of 14 bcm in 2035, which would represent about 7% of the overall domestic production.[66]

Figure 3-23: Indigenous Shale Gas Production in Europe (bcm), *(ENTSOG)*

3.2.3 Expected evolution of EU Gas Pipeline and LNG Imports

The Oxford study, which is based on the TIGER model, shows a rather detailed forecast until 2030 of the expected breakdown of EU gas imports between pipeline gas and LNG. The study assumes a growing supply of LNG in 2020-2030 with greater price convergence and increased European infrastructure development. The main factor influencing the outcomes of this model is the expected fluctuation of LNG demand from the Asian market. A lower demand will lead to greater quantities of 'unused' LNG,

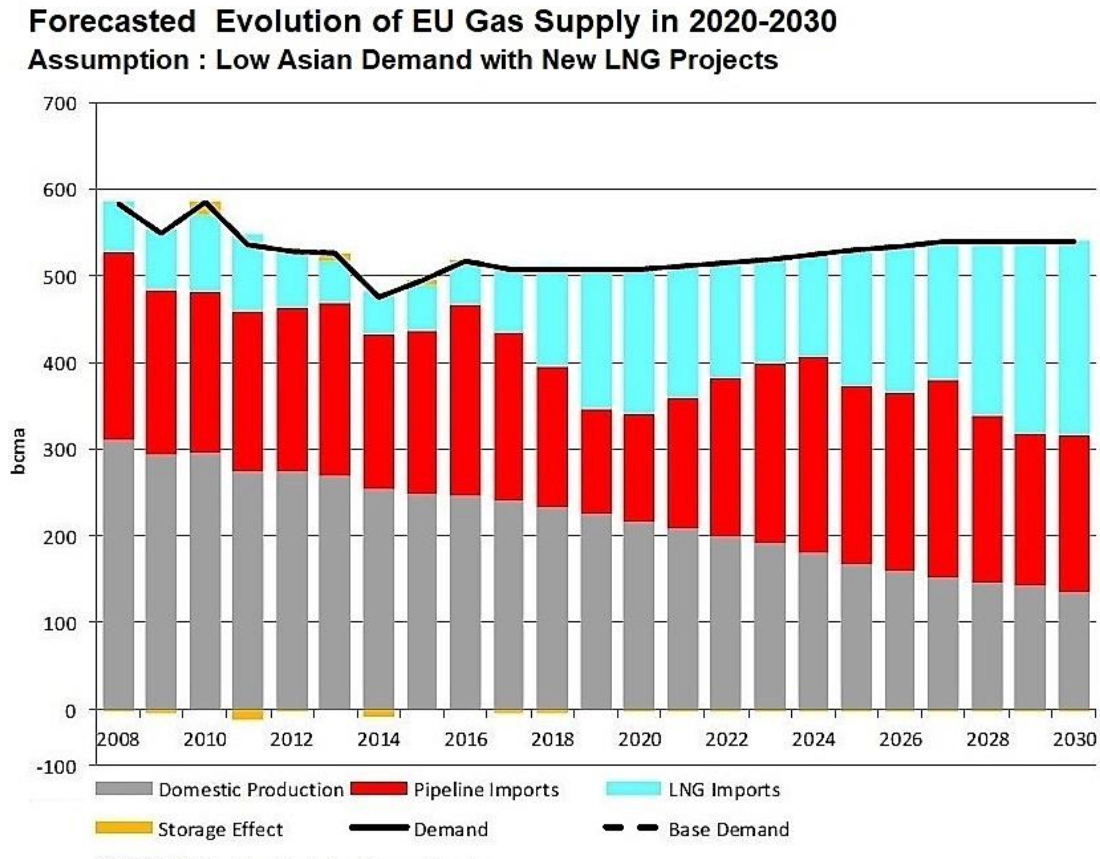
[65] AURORA Energy Research, *Idem*.
[66] AURORA Energy Research, *Idem*.

which will contribute to greater global gas market liquidity. The table and charts below show the expected shares of both LNG as well as pipeline gas imports until 2030. We notice that the demand level of the Asian market has a strong effect the outcomes of the model, especially the Russian pipeline imports. Depending on the availability of LNG on the international market and its price, the EU could reduce its gas imports from Russia and diversify the gas supply of its Member States, thus enhancing their security of supply.

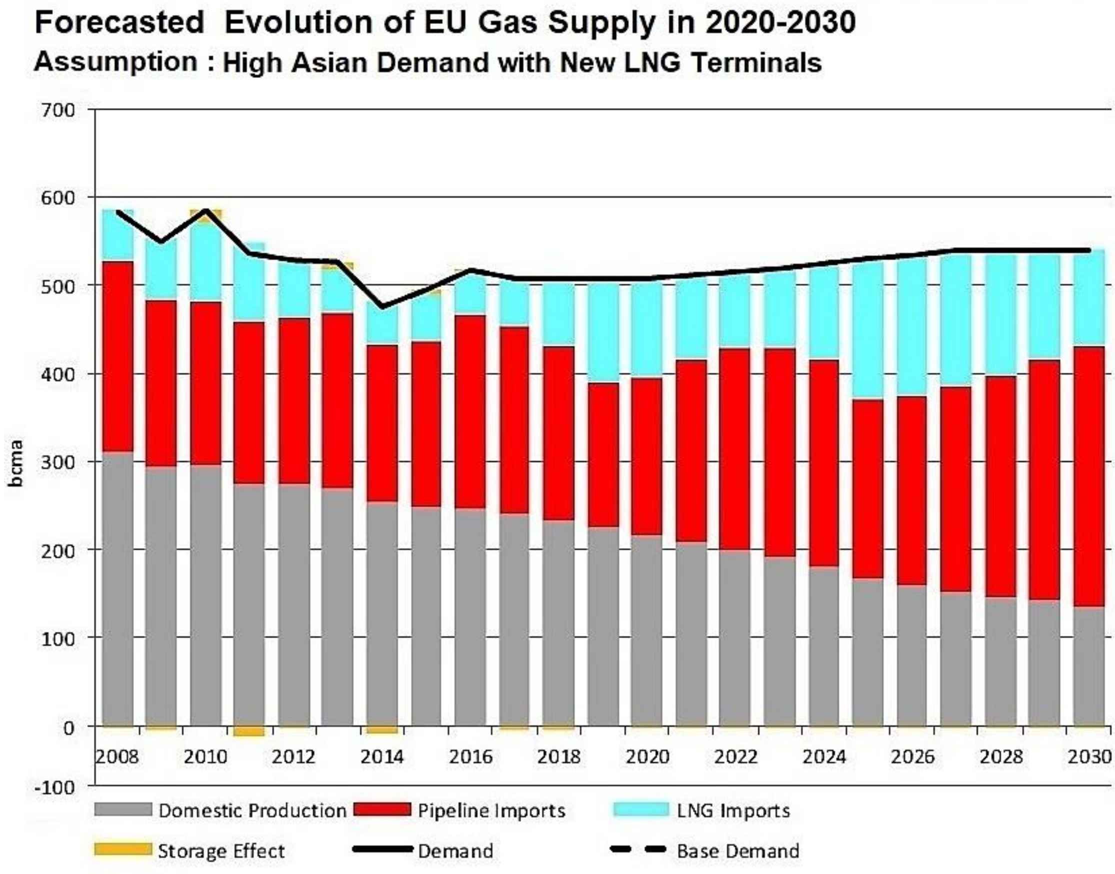
Table 3-4: Forecast Evolution of EU Gas Supply until 2030 (bcm) *(Oxford)*

Parameter		2016	2020	2025	2030
Demand		517.4	508.0	530.0	540.0
Domestic Production		252.4	221.4	172.8	140.9
LNG Exports		6.2	4.7	4.6	4.6
LNG Imports	Low Asian Demand	49.7	169.1	159.0	224.7
	High Asian Demand		112.9	160.3	109.7
Russian Pipeline Imports	Low Asian Demand	171.7	92.0	171.5	149.8
	High Asian Demand		140.2	170.3	254.7
Other Pipeline Imports	Low Asian Demand	49.2	31.7	32.9	30.8
	High Asian Demand		39.7	32.7	40.8
Storage Inventory Change		0.6	-1.5	-1.5	-1.5

Figure 3-24: Forecasted Evolution of EU Gas Supply 2020-2030, *(Oxford Institute for Energy Studies)*



Source: Oxford Institute for Energy Studies



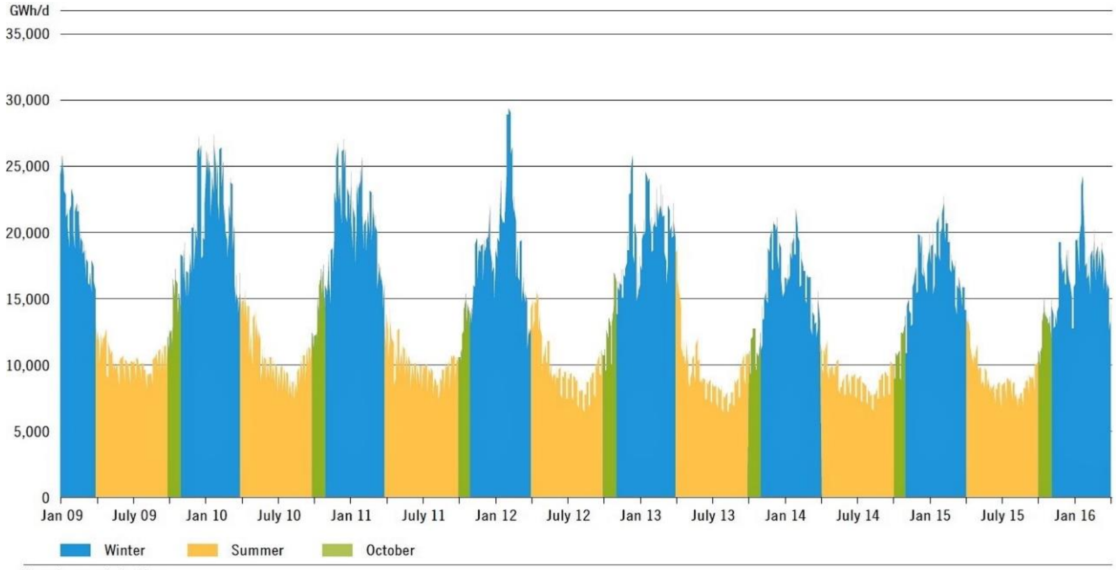
Source: Oxford Institute for Energy Studies

3.3 Impact on gas infrastructure needs

3.3.1 Impact of gas (peak) demand on gas infrastructure needs

In addition to the evolution of the overall gas demand, which is extensively commented on in section 3.1, an important parameter which is considered by ENTSOG in order to forecast the need for infrastructure investments is the expected **Peak Demand**. The graph below, published by ENTSOG in 2017, illustrates the aggregated seasonal fluctuations in gas demand for EU28.[67]

Figure 3-25: EU Peak Demand Modulations, *(ENTSOG 2017 TYNDP)*



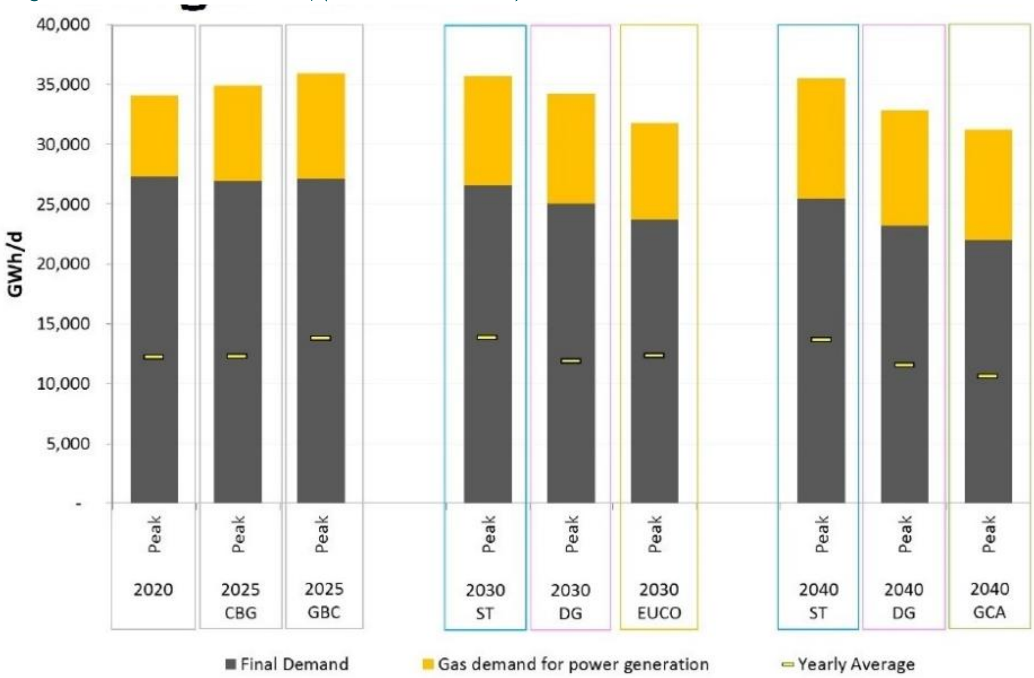
Yearly modulation

There is a huge variation in gas demand depending on the season. During the summer the average gas consumption in the EU is around 10 000 GWh per day. However, during winter months when gas is primarily used for heating purposes, the demand reaches peaks of over 25 000 GWh per day. The daily peak demand is an important factor for gas network planning because it indicates the minimum capacity levels which have to be assured by the transport and distribution infrastructure. Even if overall demand declines, peak demand could increase or remain at the same level due to changing use patterns (e.g. increased use of gas as back-up for power generation and for heating).

As the possible evolution of peak demand is not explicitly assessed in most studies, we can only refer to ENTSOG, which has published forecasts of the peak demand levels in different scenarios in 2017. The graph below shows that, depending on the scenario, in 2030 and 2040 the peak demand would remain at the same level or slightly decrease compared to 2020. We can therefore conclude that the currently expected evolution of the (peak) demand levels for the time horizon 2020-2040 would not lead to specific needs for additional gas infrastructure.

[67] ENTSOG (2017), Ten-Year Network Development Plan 2017. (https://www.entsog.eu/publications/tyndp/2017#ENTSOG-TEN-YEAR-NETWORK-DEVELOPMENT-PLAN-2017)

Figure 3-26: EU Peak Gas Demand, *(ENTSOG 2017 TYNDP)*



3.3.2 *Impact of security of gas supply and markets' integration imperatives and demand/supply evolution on gas infrastructure needs*

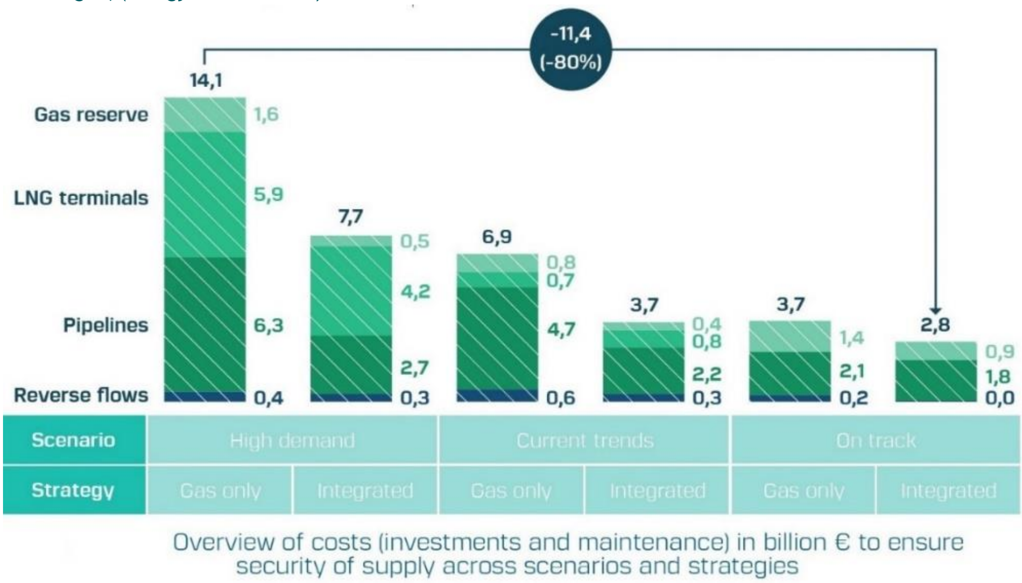
The large investments in gas infrastructure have allowed most EU Member States to have access to diversified supply gas sources via different routes and have resulted in highly interconnected markets and converging wholesale prices, especially in Western Europe. Physical congestion, indicated by actual interruptions of interruptible capacity, occurred in 2016 at only 8 contractually congested IP sites with varying frequencies.[68] If wholesale prices are still not fully converging across the EU, this is due to contractual congestion and lack of liquid market places, rather than to insufficient physical transport or interconnection capacity.

The existing infrastructure already offers resilience to extreme temperatures and to disruptions of Algerian, Libyan and Norwegian supply sources. However, further investments are required to mitigate the impact of disruptions in the Belarus and Ukrainian routes on gas supply to the EU and to mitigate the N-1 infrastructure risks in specific countries. Some EU Member States do not yet fully meet the criteria defined in the Regulation on Security of Supply and may face demand curtailment in the event of unavailability of their largest national infrastructure, and/or disruptions on the supply side. To mitigate these risks, several investment projects have been launched in the framework of the TYNDPs and PCI lists. According to ENTSOG the current gas infrastructure is in general already today well equiped to face the challenges of the future, as it allows for a wide range of supplies and is resilient to a number of disruption cases.[69] Some remaining infrastructure needs have been identified by the

[68] ACER 2017 Implementation Monitoring Report on Contractual Congestion at Interconnection Points, 31/05/2017, (https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%202017%20Implementation%20Monitoring%20Report%20on%20Contractual%20Congestion%20at%20Interconnection%20Points.pdf)
[69] https://www.entsog.eu/publications/tyndp#ENTSOG-TEN-YEAR-NETWORK-DEVELOPMENT-PLAN-2017.

regional groups in the context of the elaboration of the 3rd PCI list; these needs are mainly situated in the Eastern Baltic Sea region, the Central and South-Eastern part of Europe and the Iberian Peninsula.[70]
The investment needs, taking into account the evolving EU gas demand, have also been assessed in a study published by a consortium consisting of the European Climate Foundation, E3G, Cambridge Institute for Sustainable Leadership, Regulatory Assistance Project, Agora Energiewende, WWF, under the umbrella of *Energy Union Choices.*[71]
The study shows that if the European Union stays 'On-Track' with its decarbonising policies and implements the integrated power generation approach there will be a gradual decline in the investments and operational costs needed in order to ensure the security of supply of European demand. As is shown in the graph below the total cost difference between the High demand and the On track scenario would amount to 11.4 billion euros.[72] This study further highlights that future construction of gas transmission infrastructure could become redundant and end up as stranded investments.[73]

Figure 3-27: Overview of Costs (Investments and Maintenance) in Billion EUR to Security of Supply Across Scenarios and Strategies, *(Energy Union Choices)*

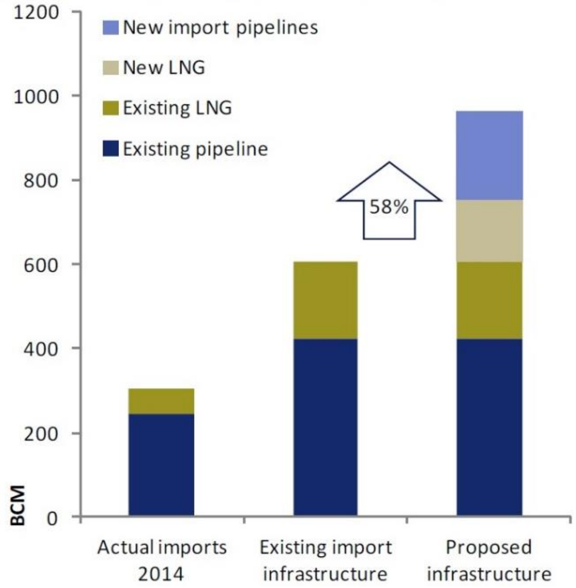


According to data gathered by the climate and energy think tank E3G, shown in the graph below, the currently ongoing and planned construction of gas infrastructure in the European Union, as announced by ENTSOG, would increase the gas import capacity by 58%.[74]
The very low load factor of existing infrastructure[75], together with the potentially decreasing gas demand, and the long lifetime of gas assets require a cautious approach to new investments in order to avoid overcapacity and additional costs for consumers, which might hamper the affordability and competitiveness of natural gas. Priority should be given to a more efficient use of existing infrastructure at regional level and to better enforcement of the market and regulatory measures, including measures to avoid contractual congestion (UIOLI) and to enhance market liquidity and

[70] COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS Communication on strengthening Europe's energy networks, Brussels, 23.11.2017, COM(2017) 718 final, (https://ec.europa.eu/energy/sites/ener/files/documents/communication_on_infrastructure_17.pdf)
[71] http://www.energyunionchoices.eu/
[72] Energy Union Choices, *Ibid.*
[73] Energy Union Choices, *Ibid.*
[74] Jonathan Gaventa, Manon Dufour, Luca Bergamaschi, *More Security, Lower Cost A Smarter Approach To Gas Infrastructure In Europe*, March 2016, (https://www.e3g.org/docs/E3G_More_security%2C_lower_cost_-_Gas_infrastructure_in_Europe.pdf)
[75] According to GIE data the average utilisation rate of LNG terminals in Europe has decreased significantly since 2010 to below 20 % of the total send-out capacity in 2016

competition. New PCI projects should be more adequately scrutinised and evaluated based on updated demand forecats and their actual contribution to security of supply and market development. According to ACER[76], this is a major deficiency in the current selection process for gas PCIs. The CBA methodology does indeed not allow to properly determine whether a project's benefits outweigh its costs due to the limited availabilty of actual benefit and cost data and their assessment in monetary terms in the ENTSOG TYNDP. This process should be improved, also in order to limit the risk of stranded assets.

Figure 3-28: Projects Representing a 58% Increase in EU Gas Import Capacity are Under Development, ***(E3G, Bruegel, ENTSOG, European Commission)***



[76] http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2013-2017.pdf

4. Flexibility of Gas Infrastructure

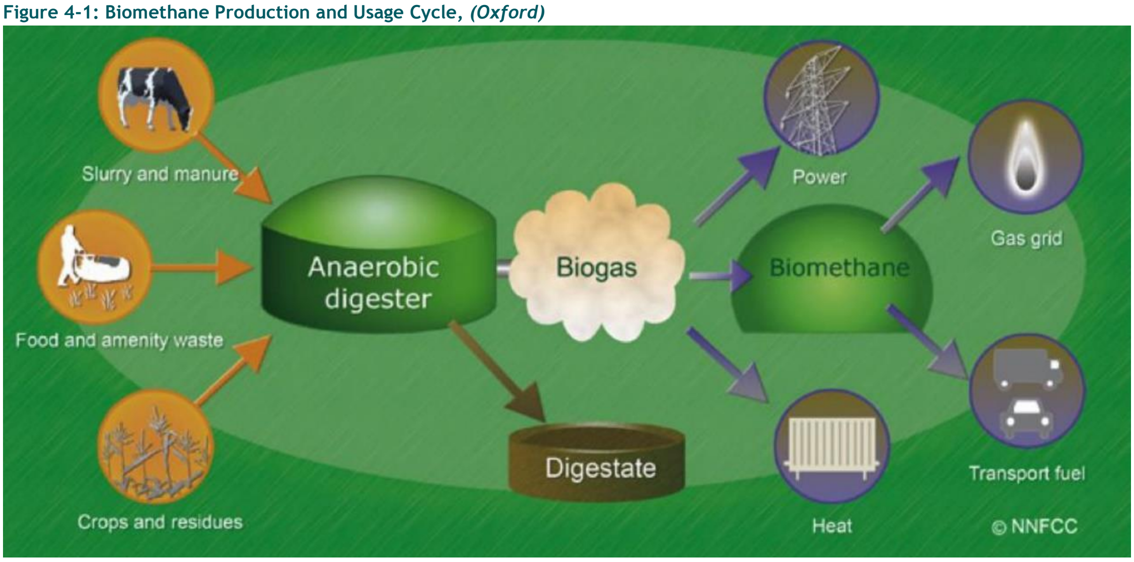
As the EU natural gas consumption is in most scenarios expected to decline as of 2030, and as most gas assets have a lifetime of 30 to 60 years, an assessment of the feasibility of using (part of) this infrastructure to accommodate other types of energy sources or gaseous products is highly relevant. Energy vectors like hydrogen, synthetic methane or biomethane can already, up to a certain limit depending on the energy vector and the network characteristics, be injected into the natural gas network and storage infrastructure with minimal costs. In the context of CCS or CCU, carbon dioxide could be transported via (decommissioned) gas pipelines and stored in depleted gas fields.
This chapter presents an overview of the potential and ongoing/possible developments in this domain, including some key European pilot projects, for using the natural gas network infrastructure to deliver a carbon neutral energy future. We also look at the options of using depleted gas storage facilities in the CCS process as well as potential measures to enhance gas infrastructure flexibility across the European Union.

4.1 Use of natural gas infrastructure for transport/distribution of decarbonised fuels

4.1.1 *Biomethane*

Biogas is a naturally occurring gas which is created as by-product of anaerobic digestion of biodegradable material or waste. Its chemical properties and characteristics are, after its upgrading to biomethane, identical to those of natural gas used today. However, unlike natural gas it is not considered a fossil fuel, because it is produced from organic material. This inherent ability to reproduce the primary source for producing biomethane makes it qualify as a renewable form of energy. This is recognised in Directive 2009/28/EC on the promotion of the use of renewable energy sources. The chart below visualises the production process for biomethane, as well as its potential use in the power, heat and transport sectors.[77]

Figure 4-1: Biomethane Production and Usage Cycle, *(Oxford)*

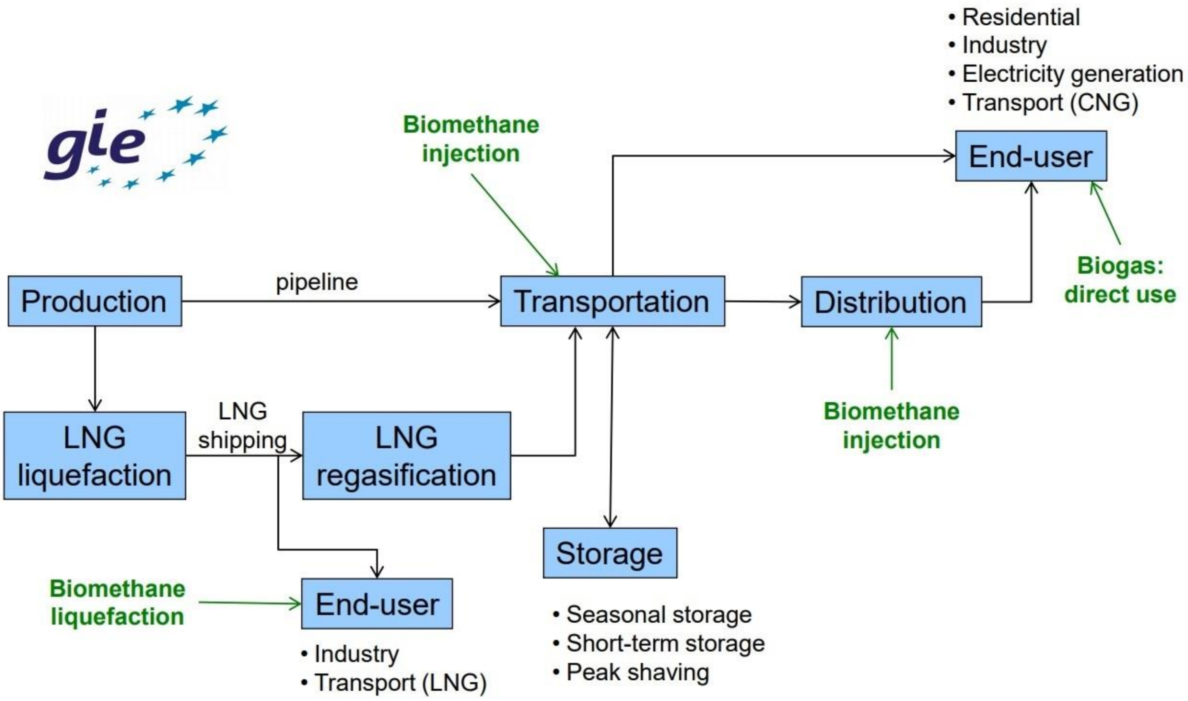


[77]The Oxford Institute for Energy Studies, *Biogas: A significant contribution to decarbonising gas markets?*, June 2017, Oxford, UK, (https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/06/Biogas-A-significant-contribution-to-decarbonising-gas-markets.pdf)

Biomethane has characteristics which make it particularly suitable for replacing fossil fuel in the energy mix of EU Member States. Methane has, based on a 100-year horizon, a global warming potential which is 34 times higher than carbon dioxide, while, considering a more realistic time horizon of 20 years, its warming potential is 86 times higher. If left untapped, organic biodegradable material would emit large quantities of methane in the atmosphere. By extracting and using biomethane, a direct reduction of emissions of greenhouse gases in the atmosphere can be realised. Combined with the fact that raw materials used in the production cycle are grown and collected locally means that there is reduced risk of delocalisation.[78] The local production and use of biomethane has also a positive impact on the import dependency of energy, as well as on security of supply.

Even though biogas is an advanced biofuel, due to the fact that hemicelluloses and celluloses are naturally degraded; it can be used for power and/or heat generation, but it needs to be upgraded to biomethane before being injected in the natural gas grid. This means that for biogas to become a suitable biofuel for vehicles or be fed in into the gas grid, carbon dioxide has to be removed and the concentration of methane has to be increased to around 96% in order to meet the quality standards for natural gas.

Figure 4-2: Gas Value Chain and Biogas/Biomethane, (*Gas Infrastructure Europe*)



At the present, 13 EU Member States have developed production facilities for biogas[79] but only 8 of them have an enabling regulation which allows injection of biomethane into the gas grid[80]. Out of the countries with biogas production facilities, Germany has been the leading proponent of biogas in

[78] European Biomethane Fact Sheet, (http://european-biogas.eu/wp-content/uploads/files/2013/10/eba_biomethane_factsheet.pdf)
[79] AT, DE, DK, ES, FI, FR, HU, IS, IT, LU, NL, SE, UK
[80] AT, DE, ES, FI, FR, LU, NL, UK

Europe: its development of biogas plants started in the 1990s and grew rapidly between 2006 and 2013.[81]

Raw biogas (typically with CO_2 content > 40 %) is mostly burned near the point of production for a combination of electricity and heat production. The electricity produced is either consumed locally or, depending on the regulatory regime, injected into the grid. It is expected that, even in an optimistic forecast of biomethane upgrading, by 2030 60 % of the biogas production will still be consumed locally.[82]

While the majority of the biogas produced is still used for heat and power generation, it is also frequently upgraded to biomethane for use in the transport sector. Biomethane can be used locally, but it can also be injected in the transmission or distribution grid in order to be transported to end-consumers.[83]

There is not yet a clear pathway to significant cost reduction in biogas or biomethane production; however, the choice of the most adequate scale and technology is a determining factor which can provide further cost reduction.[84]

Studies show that there is significant potential to increase the production of biogas and biomethane. This increase would help to reach the RES and GHG targets and improve the EU's energy security by reducing its reliance on imports of natural gas. Research shows that by 2020 biomethane could reduce the EU's imports of natural gas by 30.5 Mtoe, which would represent approximately 19% of projected 2020 natural gas imports from Russia into the EU.[85] .[86] Another study[87] shows that biogas production in the EU could increase from the current level of 14.9 Mtoe towards 28.8 to 40.2 Mtoe in 2030, depending on the amount of feedstock deployed and the learning effects attained. The largest growth potentials are found to be in liquid and solid manure, and in organic wastes. The biogas and biomethane production would in 2030 represent between 2.7 and 3.7% of the EU energy consumption, depending on the scenarios. Due to the additional cost for upgrading biogas to biomethane and for respecting the technical requirements for grid injection, it is expected that only part of the biogas production will be converted to biomethane and injected into the gas grid, and that biogas will continue to be used locally for power and/or heat production.

The total cost of biomethane production is still much higher than the market price of natural gas. The results of a recent study[88] show that under the most favourable scenario injected biomethane is approximately 19% more expensive than natural gas. The total cost of biomethane produced and delivered to the natural gas grid is about 46 EUR/MWh, based on the most favourable upgrading method and a 20-year economic lifetime. Therefore, under current conditions, biomethane production needs financial support to make its costs compatible with the price of natural gas; the required support would be about 22 EUR/MWh for an existing biogas plant equipped with a joint biogas upgrading facility. The support level for larger joint biogas production and upgrading facilities could be reduced to about 7 EUR/MWh. 'The results of this study also show that if biogas producers co-operated in constructing

[81] The Oxford Institute for Energy Studies, *Biogas: A significant contribution to decarbonising gas markets?,* June 2017, Oxford, UK, (https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/06/Biogas-A-significant-contribution-to-decarbonising-gas-markets.pdf)

[82] Oxford, Biogas, *Ibid*

[83] Biomethane and the European gas infrastructure, (http://european-biogas.eu/wp-content/uploads/2015/09/6_Thierry-20150903-EBA-Workshop-GIE-presentation.pdf)

[84] Oxford, Biogas, *Ibid*

[85] The role of natural gas and biomethane in the transport sector, Ricardo Energy & Environment, (https://www.transportenvironment.org/sites/te/files/publications/2016_02_TE_Natural_Gas_Biomethane_Study_FINAL.pdf)

[86] The role of natural gas and biomethane in the transport sector, Ricardo Energy & Environment, (https://www.transportenvironment.org/sites/te/files/publications/2016_02_TE_Natural_Gas_Biomethane_Study_FINAL.pdf)

[87] CE Delft for EC (2016), Optimal use of biogas from waste streams

[88] Anna Paturska, Mara Repele, Gatis Bazbauers (2015), Economic Assessment of Biomethane Supply System based on Natural Gas Infrastructure

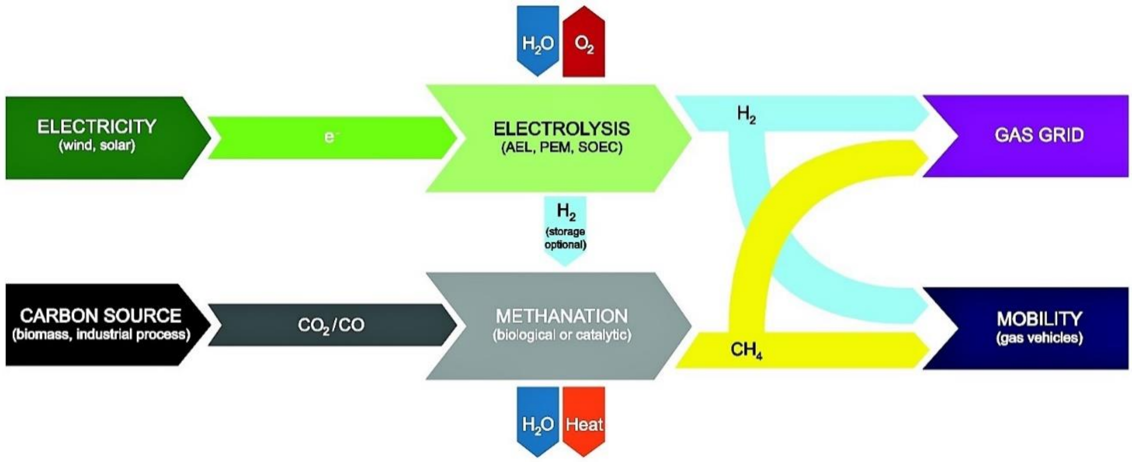
larger joint biogas production and upgrading facilities, this would be the most efficient solution. This option could be feasible for new plants in the future. For existing biogas plants, the option to consider would be to construct joint biogas upgrading facilities. According to the CE Delft study (2016), the calculated EU-wide biogas production costs range between 12 and 14€/GJ. If the biogas is upgraded to biomethane at natural gas quality or all production is converted to electricity in a cogeneration unit, the resulting cost levels are 1.3 to 2.0 times the current EU prices for natural gas and electricity. Accelerating learning curves resulting from market and innovation stimulation could reduce the cost, but the cost reduction would be insufficient to become competitive with natural gas at the current price level.

4.1.2 *Hydrogen and synthetic methane*

Hydrogen and synthetic methane, which can be produced via different processes, can also be injected into the natural gas grid. A promising innovative process which would also facilitate the integration of renewable energy into the system is the so-called Power-to-Gas (PtG) method. This technique allows the conversion of electricity into a gaseous product; this option is most economically interesting during periods of low (or negative) electricity prices (due to high supply of variable renewable energy sources and/or low demand) and to balance the electricity system. This gas product can be used locally (e.g. for vehicles or heating appliances) or stored and used later (e.g. for power generation to balance the system) or can be injected – either as hydrogen or as synthetic methane - into the gas network and sold to end-users as “renewable” gas.

The electrolysis process [89] consists of using an electrical current to split the molecules of water (H_2O) into its main building blocks, i.e. hydrogen (H_2) and oxygen (O). This gas can be used as an energy source on its own or combined with other elements in order to produce alternative energy sources. This latter method is used in the PtG process where the hydrogen produced (H_2) is combined with carbon dioxide (CO_2) in order to form synthetic methane (CH_4). This process is called methanation and as a result the only by-product of this reaction is pure oxygen (O_2). The figure below highlights the stages of this process as well as the potential use of the generated substances.

Figure 4-3: Power to Gas Process Chain, *(Renewable Energy 85 (2016) 1371e1390[90]*

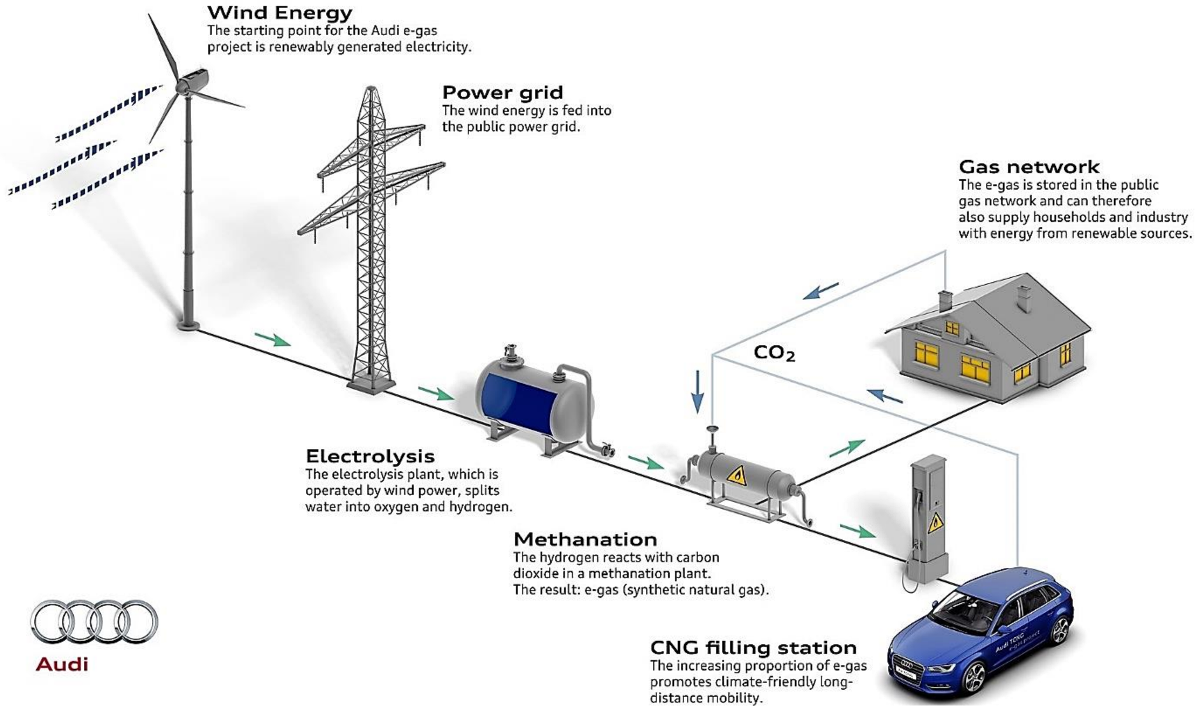


[89] H2O + 2e- = H2 + O2-
[90] *Renewable Power-to-Gas: A technological and economic review*, Manuel Gotz, Jonathan Lefebvre , Friedemann Mors, Amy McDaniel Koch, Frank Graf, Siegfried Bajohr, Rainer Reimert, Thomas Kolb, 9 https://ac.els-cdn.com/S0960148115301610/1-s2.0-S0960148115301610-main.pdf?_tid=9c606866-e583-11e7-8ae9-00000aab0f02&acdnat=1513774088_c20930f7b3ff2bec6533d1f015aec392)

Carbon free hydrogen can also be produced on the basis of solar thermal energy (concentrated solar power). Instead of using the heat of the solar reactor to produce electricity (e.g. via a steam turbine), the heat can be used to activate a thermochemical reaction splitting water into hydrogen and oxygen. This technology is still in the development/demonstration phase, but it might become an attractive option to decarbonise the energy supply, as it would allow to convert renewable energy into hydrogen with a much higher efficiency than via electrolysis

The characteristics of synthetic methane are identical to those of natural gas in the gas transmission and distribution infrastructure which is used today for power generation and domestic or commercial heating purposes. It can also, as the Audi driven process shows, be used for powering road vehicles in which the conventional gasoline internal combustion engine has been converted. Audi is going a step further in its pilot project by taking the synthetic methane to compressed natural gas (CNG) filling stations and producing vehicles which run on CNG.

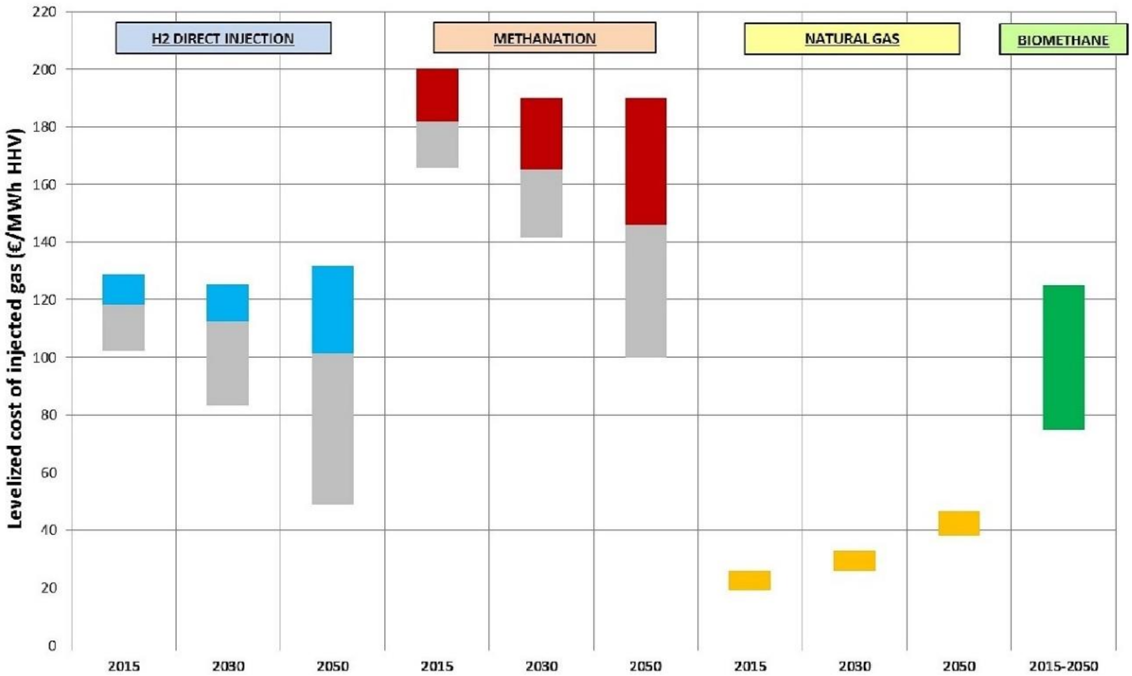
Figure 4-4: Audi Power to Gas Process *(Audi)*



Hydrogen can be injected into the gas grid up to a relative hydrogen share of maximum 10%, while synthetic gas can be fed in into the grid without an upper limit. Power to hydrogen in combination with methanation hence allows high shares of hydrogen to be fed into the gas grid, without a technical impact for the end-user. The large coverage of the natural gas transport and distribution grid in most EU member states enables potential hydrogen production facilities to get connected to the gas grid at a reasonable cost. The gas grid and connected storage sites also offer seasonal storage opportunities for flexible use of hydrogen in gas fired power plants. However, the power-to-gas-to-power process is expensive and has a low efficiency and is hence in the short and medium term not expected to become competitive with conventional flexibility technologies, such as pumped hydro storage.

According to the Power to Gas Roadmap for Flanders (October 2016), power to gas via a 15 MW electrolyser would lead to cost levels ranging from 85 to 125 €/MWh hydrogen in 2030, which is similar to the cost of biomethane. The conversion of hydrogen to synthetic methane by using carbon dioxide would lead to much higher cost levels ranging between 150 and 190 €/MWh, by 2030 compared to about 30 €/MWh for natural gas.

Figure 4-5: Power to gas - Injection in Natural Gas Grid[91]



Another recent study[92] shows that the generation costs for hydrogen and synthetic methane are much higher than the natural gas price and strongly depend on the annual operational time and electricity price. For economic feasibility, a high number of annual operational hours and low electricity costs are required. However, these aspects are contradictory. For low full load hours, the CAPEX for the electrolysis is dominant, for larger full load hours, the electricity price is the most important parameter influencing the economics. According to IEA[93], a combination of low electricity costs and high load factors would allow renewables-based hydrogen generation to compete with the conventional way of producing hydrogen from natural gas through steam methane reforming. In Europe, authorities and market parties opt at present in general for other solutions to balance electricity supply and demand, such as demand response, stationary batteries, dynamic charging of electric vehicles, pumped hydro, etc., but conversion of excess renewable energy-based electricity to hydrogen or synthetic methane could in the future become a competitive option, in particular in countries with favourable conditions for deployment of wind and/or solar energy. Remote areas with excellent solar and wind resources or with abundant hydropower and/or geothermal resources, such as Iceland and Norway, are possible choices for siting electrolysers. The produced hydrogen can be injected into the gas grid and transported to consumption centres.

[91] Power to Gas: A roadmap for Flanders, (http://www.power-to-gas.be/sites/default/files/P2G%20Roadmap%20for%20Flanders%20-%20Executive%20summary%20-%20EN.pdf)

[92] Manuel Götz et all, (2016), Renewable Power-to-Gas: A technological and economic review

[93] OECD/IEA (2017), Renewable Energy for Industry: From green energy to green materials and fuels

Enea Consulting confirms in its 2016 study[94] that power-to-gas for grid injection is not likely to be viable without substantial financial support, due to its high CAPEX and the low market value of the gas produced. Based on current costs and advantageous electricity prices (average purchase price of 40 €/MWh), the levelised cost of gas-from-power injected into the grid is 100 and 170 €/MWh for hydrogen and synthetic methane respectively. This study concludes that power-to-gas for grid injection is thus far from competitive with natural gas (about 20 €/MWh) and remains costlier than biomethane (60 to 100 €/MWh), in particular for synthetic methane. At the 2030 or 2050 horizons, it is likely that hydrogen produced from power can reach costs comparable to current biomethane production costs; it however appears unlikely for synthetic methane.

The technical potential for power-to-gas (direct injection of hydrogen or injection of synthetic methane) is significant. In the short term, direct injection of hydrogen in natural gas grids seems the most promising option, which is more or less competitive to biomethane. Methanation technologies combining hydrogen from electrolysis with CO_2 show much higher cost levels but have the advantage of better exploiting the natural gas transport and distribution grids without a limitation on the maximum allowed concentration. Transport of either hydrogen or synthetic methane over the natural gas grid could also be considered as an alternative to electricity transport over long distances.

In addition to the option of feeding-in hydrogen or synthetic methane into the gas grid, an alternative is adapting (part of) the gas infrastructure to accommodate 100% hydrogen. This option is currently being assessed in a pilot project in the UK, the so-called H21 Leeds City Gate venture. The pilot is run by the North British gas distributer Northern Gas Networks (NGN), this project foresees the transformation of the whole gas infrastructure grid of Leeds to 100% hydrogen.[95] The main objective of this project is to demonstrate that such a conversion is both economically and technically feasible with minimal disruptions while maintaining the current price for domestic heating usage. Unique characteristics of the existing gas transmission and distribution network, storage facilities and other supporting industrial infrastructure make the City of Leeds a good starting point for implementing such a project.

This project has been launched to demonstrate that existing technology and gas infrastructure can be adapted with minimal investments and costs to serve a carbon-neutral fuel, like hydrogen, which also allows the storage of energy in sufficient quantities to cover seasonal peaks in the same manner as natural gas does today.

If the H21 Leeds City Gate project succeeds in proving that this transition model is technically and economically viable, similar initiatives at the same or larger scale could be considered across the EU. This would mean that with limited investments and without industry disruptions, the gas sector could continue to use its infrastructure and deliver on the goals of decarbonising energy supply and ensuring security of supply at a competitive price for end customers.

Several other hydrogen related research and pilot projects are being undertaken in the EU. For example, Statoil, Vattenfall and Gasunie have signed a Memorandum of Understanding to evaluate the possibility of converting Vattenfall's gas power plant Magnum in the Netherlands into a hydrogen-powered plant. Gasunie examines in this context what transport and storage infrastructure is needed.

[94] http://www.enea-consulting.com/wp-content/uploads/2016/01/ENEA-Consulting-The-potential-of-power-to-gas.pdf
[95] H21 Leeds City Gate, Progress Report, (https://www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Report-Interactive-PDF-July-2016.compressed.pdf)

The scope of this project also includes exploring how to design a large-scale value chain where production of hydrogen is combined with CO_2 capture, transport and permanent storage as well as considering potential business models.

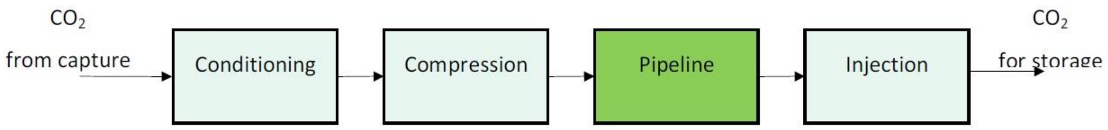
4.2 Feasibility of using gas infrastructure for CO_2 transport and storage

Reducing carbon dioxide emissions through dedicated decarbonisation policies and measures focusing on energy conversion processes is one of the main drivers of the EU's energy and climate strategy for 2030 and the roadmap for 2050. In this context Carbon Capture and Storage (CCS) or Utilisation (CCU) technologies can offer an important contribution. CO_2 can be used in different industrial processes as well as in methanation processes in order to produce synthetic methane. Capturing CO_2 in energy conversion processes (e.g. ammonia or cement production processes) in view of reusing it at other locations or storing it underground, could become economically feasible if the EU Emission Trading Scheme offered a higher price signal. This would create an opportunity to transport CO_2 through refurbished gas pipelines and/or to store it in depleted natural gas storage facilities.

4.2.1 Using Existing Transit Pipeline Infrastructure

From the technical perspective, CO_2 can be transported both in liquid and gaseous form. In some limited cases CO_2 can even be transported in solid form for industrial purposes. However, pipelines are the most common and economically viable method for transporting CO_2 over long-distances. The chart below shows the technical stages involved in the CCS process using pipelines.[96]

Figure 4-6: Climate Capture and Storage Process[97]



At present, there are very few CO_2 pipelines in Europe. The largest project to date is the 160 km long Snøhv LNG pipeline used for transporting CO_2 in Norway since 2008. Another existing project is the 80 km CO_2 pipeline between Rotterdam and Amsterdam. Existing gas pipelines can in principle be converted in order to transport CO_2, but, as the operating pressures are different (CO_2 pipelines operate at 85 to 150 bar, whereas gas pipelines operate at around 85 bar), additional investments are needed to make gas pipelines able to resist to the higher pressures required. Pipelines would also have to operate with low levels of impurities, including water, which can react with CO_2 to create carbonic acid that is corrosive to commonly-used pipeline materials. There is however no cost indication available to assess the two options, i.e. construction of new dedicated CO_2 pipelines versus the conversion of existing gas pipelines.

4.2.2 Depleted Gas Fields for Storage

Given the similar physical characteristics of CO_2 and natural gas, storage facilities like depleted salt caverns could be used to store carbon dioxide. Storing CO_2 in depleted or depleting gas fields has been

[96] *Ibid*
[97] *Ibid*

proven at a number of sites worldwide. Key risks have been overcome, for example, relating to site design for dealing with reduced reservoir pressure, re-using infrastructure and managing wellbore integrity risks. Despite this, large-scale “pure” CO2 storage in depleted fields remains to be tested and closure of a large-scale CO_2-Enhanced Oil Recovery site has not yet occurred.[98] According to a study by the Global CCS Institute[99], the CO_2 storage capacity in depleted gas fields in Europe is estimated at 37 Gt (practical), 62 Gt (effective) and 83 Gt (theoretical capacity) respectively. This storage capacity is primarily located in the North Sea, and while it could accept a significant volume of CO_2, it would not be possible to store the bulk of CO_2 emissions from large stationary sources in depleted gas fields. The CO_2 storage option is at present not considered, as CCS is not economically viable, and it is not expected that this situation will substantially change in the near future.

4.3 Measures to enhance and optimally use gas infrastructure flexibility

4.3.1 Integrated electricity and gas network Operating and Planning

The gas system is highly flexible to rapidly react to intra-day fluctuations in gas demand. This flexibility is an important value for the electricity system whose balancing is becoming increasingly challenging due to the massive development of renewable energy sources. In this context, the dependency of the electricity system on back-up gas supply is not expected to decrease in the short and medium term, as flexible gas generators will continue to be needed to support the electricity system balancing, along with other flexibility sources such as storage and demand response. As potential solutions to improve security of gas and electricity supply, several options can be considered, such as the use of flexible multi-directional gas compressor stations as well as adopting a fully integrated approach to operating gas and electricity networks, in order to better anticipate the impact of dispatching decisions (CHP or other gas-fired power generators) or of the uncertainty of wind forecasts on the performance of gas infrastructure. Case studies have been realised to quantify the value of an integrated operation paradigm versus sequential operation of gas and electricity networks.[100] The results indicate there are significant overall system benefits (up to 65% in extreme cases) to be gained from integrated optimisation of gas and electricity systems, emphasising the important role of gas network infrastructure flexibility in efficiently accommodating the expansion of intermittent RES in power systems. Electricity and gas network planning should also be more coordinated and integrated to increase the overall efficiency and minimise cost. The ENTSOs are aware of the potential benefits of closer cooperation in view of agreeing on common assumptions and scenarios and better capturing the interdependencies and potential synergies between the two sectors.

4.3.1 Financing of research and demonstration and pilot projects

Feeding-in biomethane, hydrogen or synthetic methane into the gas grid are promising developments to support the transition to a low-carbon energy supply, while continuing the use of natural gas infrastructure. However, in order to improve the economic feasibility of these options, further research and pilot projects are necessary, also in view of upscaling the technology and enhancing the energy efficiency of the conversion processes. In this context, for Power-to-Gas, the realisation of further Power-to-Hydrogen (direct injection) demonstration projects to be launched by consortia comprising

[98] Sarah Hannis et all (2017), CO2 storage in depleted or depleting oil and gas fields: What can we learn from existing projects?
[99] https://hub.globalccsinstitute.com/publications/co2-storage-depleted-gas-fields/6-summary-co2-storage-capacity-depleted-gas-fields
[100] Hossein Ameli et all (2017), Value of gas network infrastructure flexibility in supporting cost effective operation of power systems

relevant network and industrial companies is key. These consortia could lead the efforts to create the necessary regularly framework applicable for such projects, in particular the possibility of injecting up to 10%vol of hydrogen in gas grids and the possibility of benefiting from RES support schemes similar to biomethane projects. As methanation is much more expensive and considered as a medium to long-term solution, demonstration projects including the production of synthetic methane could be initiated afterwards.

At EU level, these projects could be financially supported by several instruments, in particular innovating technologies can apply for funding via the ETS Innovation Fund or Horizon 2020[101] or can be co-financed through the European Fund for Strategic Investments (EFSI)[102] utilising the resources and delivering the objectives set out by the Juncker Plan. Projects providing higher efficiency by greater integration between gas and electricity systems could also be eligible for Energy Efficiency financing[103].

In parallel, a clear political and strategic vision on decarbonisation and specifically on the injection and transport of green gases (biomethane, synthetic methane and hydrogen) in existing gas grids should be defined in collaboration with the competent authorities, industry partners and gas network operators.

4.3.1 Policy measures to stimulate supply of and demand for green gas

Energy suppliers are in most EU Member States at present not specifically stimulated to offer green gas to their customers connected to the natural gas grid, and end-users are not incentivized to opt for green gas.

The commercialisation of green gas could be enhanced by properly implementing Article 3(9) of Directive 2009/28/EC on the promotion of the use of renewable energy sources, which states that all EU Member States are required to establish and maintain a Renewable Energy Guarantees of Origin certification scheme. The purpose of Guarantees of Origin (GO) is to provide evidence of the origin of the generated energy, showing clearly the renewable source used in the generation process. GOs should in all EU member states also be granted for green gas injected into the gas grid. This measure would enhance the market value of renewable gas and hence improve the economic feasibility of such projects. It could also serve as a tool to measure the contribution of these technologies to reaching the RES targets.

Projects already exist where a dedicated guarantee of origin scheme is developed for green hydrogen.[104] The objectives of this initiative are to define a widely acceptable definition of green hydrogen, design a robust GO scheme and propose a roadmap to implement the EU-wide GO scheme for green hydrogen. The implementation of an EU-wide system of Guarantees of Origin for the different types of renewable gas would facilitate the (physical and/or administrative) trade of the concerned products and improve disclosure and transparency.

A second option that could be considered to stimulate the demand for and/or supply of green gas, is the implementation of a legal obligation on gas retailers to supply a gas mix with a minimum share (to be determined on the basis of the technical and economic potential) of decarbonised gas. Such a supplier's obligation scheme could be implemented via tradable guarantees of origin to be submitted to

[101] Horizon 2020 Funding available for projects focusing on smart cities, smart energy systems or renewable fuels (https://ec.europa.eu/inea/en/news-events/newsroom/over-%E2%82%AC138-million-available-to-energy-projects)
[102] European Fund for Strategic Investments (EFSI), (http://www.eib.org/efsi/)

[103] Financing energy efficiency (**https://ec.europa.eu/energy/en/topics/energy-efficiency/financing-energy-efficiency**)

[104] Roadmap for the first EU-wide Guarantee of Origin Scheme for Green Hydrogen 17 June 2016, Brussels, (http://ec.europa.eu/research/index.cfm?pg=events&eventcode=6C885754-CC3F-ED0D-45249815790ABEC0)

national regulators and could be set up at national level or (preferably) at EU level with guarantees of origin which are mutually recognised and tradable across Europe.

Finally, the demand for decarbonised gas could be stimulated by the implementation of a specific carbon tax or ETS for fossil fuels for transport and heating purposes. The introduction of such a carbon tax was considered at EU level in the context of the proposed review of the energy taxation Directive, but it was at that moment impossible to reach a political consensus on this proposal. Several EU Member States have meanwhile introduced such a tax at national level, and it is in general considered as an effective instrument to accelerate the transition to a low carbon energy supply.

4.3.2 Enabling technical specifications for injection of renewable gas into natural gas grid

At present, injection of biomethane into the grid is only allowed in 8 EU member states, on the basis of national specifications. Initiatives could be taken at EU level (e.g. Marcogas) to develop best practices and to elaborate enabling common requirements for injection of biomethane, hydrogen and synthetic methane into the gas grid. EU-wide technical standards and sustainability criteria, as well as harmonisation of (administrative) data transfer could also be beneficial to support this development.

5. Key Findings and Recommendations

Most studies expect a substantial decrease of EU overall gas demand by 2030, while ENTSOG's development plans are still based on stable or slightly decreasing demand estimates.

The massive development of renewable energy, and the policies and measures aiming at reducing the energy needs in buildings, have a major impact on the future role of natural gas in the EU energy mix. Recent studies suggest that EU gas demand will decrease from 4962 TWh in 2016 to between 2700 and 4100 TWh in 2030, depending on the ambition level of the energy efficiency policies. However, the latest TYNDP refers to much higher estimates, ranging from 4200 to 5200 TWh in 2030. Recent investment decisions in the gas sector therefore appear to be based on demand estimates which are much too high and might imply a risk of overinvestment and eventually stranded assets.

Another important parameter to assess the need for infrastructure investments is the expected evolution of the daily peak demand. But even according to the overestimated ENTSOG forecasts, peak demand would in 2030 and 2040 remain at the same level or slightly decrease compared to 2020 levels. This implies that there would be no requirement for additional trans-European gas transport infrastructure because of peak demand growth.
Decreasing gas demand levels would lead to lower utilisation levels of gas infrastructure, and possibly to higher grid tariffs for end-users. For this reason, it would be appropriate to thoroughly reassess - on the basis of updated demand forecasts that are in line with the newly proposed energy efficiency target - the net benefits of the large PCIs which have not yet reached the Final Investment Decision phase, in order to limit the risk for overcapacity and stranded assets and to avoid tariff increases that might undermine the competitiveness of industrial gas users and the affordability of gas for households.

Future EU natural gas demand can be covered by (decreasing) domestic gas production and more diversified gas imports without major new investments in trans-European gas transport infrastructure

Domestic natural gas production in the EU in 2016 (including Norway) accounted for 27% of the EU supply. The latest forecasts suggest a decrease in domestic production of 25% by 2035, and of about 50% by 2050. The largest decline is expected to occur in the UK, the Netherlands and Germany. This evolution will however have a limited impact on the use of existing and need for new gas infrastructure.

The remaining demand can - with the existing infrastructure and the projects under construction - be covered by imports from multiple sources and via different routes. Studies assume a growing overall supply of LNG in 2020-2030 with greater global price convergence. The main factor influencing the effective share of LNG in the EU gas supply is the expected fluctuation of LNG demand in Asia. A lower LNG demand in Asia would lead to greater global gas market liquidity. Depending on the availability of LNG on the international market and its price, the EU could reduce its gas imports from Russia and further diversify its gas supply, thus enhancing its security of supply.

TEN-E and Connecting Europe Facility have substantially contributed to the development of a well interconnected and resilient gas system which offers a high level of security of supply

The European framework has substantially contributed to enhancing the security of EU gas supply and diversification. Gas infrastructure projects have constituted a significant share of the projects on the first and second PCI lists as well as of awarded CEF funding. Gas PCIs have substantially enhanced the interconnectivity of the gas system, and have particularly improved the supply security of the most vulnerable Member States and regions. Today, the EU is in a better position thanks to completed gas PCIs, for instance in the Baltic States where security of gas supply, as well as competition in gas market have substantially improved thanks to the realisation of PCIs with CEF funding. The EU gas grid has in general become more resilient and nearly all Member States[105] comply with the N-1 infrastructure criterion and have access to two sources of gas. If the ongoing PCIs with Final Investment Decision are implemented on schedule, all Member States, except Malta and Cyprus, should in principle by 2022 have access to three gas sources. Most remaining bottlenecks will be addressed between 2020 and 2025 through the finalisation of the ongoing PCIs. Once these projects are commissioned, Europe should achieve by 2025 a well interconnected and shock resilient gas grid, with limited need for additional investments in trans-European gas infrastructure.

The use of fossil fuels - including natural gas - will have to be reduced more drastically to meet COP21 Paris Climate Agreement commitments

According to the scenarios used for preparing the latest gas network development plan, the EU is not on track to comply with the climate commitments of the Paris Agreement in terms of CO_2 emissions generated by the energy sector. According to the ENTSOG TYNDP-scenarios CO_2 emissions would in 2040 range between 600 and 800 Mt-equiv., which represents between 55% and 70% reduction in GHG emissions compared to the 1990 baseline. If the energy sector is supposed to meet the Paris COP21 commitments, it needs to decarbonise more rapidly.

Further policies and measures will hence be necessary, which will to a large extent determine the future role of natural gas. Effective measures which could be considered in this context, are the introduction of an EU wide carbon emission 'cost' or 'price' at an adequate level, and the reduction of the current EUR 4 billion of fossil-fuel subsidies, including the funding of natural gas infrastructure by the CEF, that should be re-oriented to support low carbon technologies (see further). Both measures would stimulate the use of low carbon energy technologies and reduce the need for support for renewable energy sources. The introduction of an EU wide carbon price at an adequate level, might be obtained by introducing a price floor in the ETS and by implementing a similar measure (carbon tax or ETS) for transport and heating fuels that are not in the scope of the current ETS.

Gas market integration and competition have been substantially enhanced by regulatory and market rules aiming at a more efficient use of existing gas infrastructure

European regulatory and market measures, including intensified regional cooperation amongst authorities and TSOs and the setting up of regional gas hubs, have substantially contributed to enhancing gas market integration and competition. Wholesale prices within the EU are converging to a

[105] Excluding the Member States, i.e. Cyprus, Luxemburg, Malta, Slovenia and Sweden that have an exemption.

large extent, especially in Western Europe, and the price differentials which remain do not justify investments in additional interconnection capacity, as they are generally not due to physical congestion. Physical congestion, indicated by actual interruptions at interconnection points (IP), only occurred in 2016 at 8 contractually congested IP sites with varying frequencies. If wholesale prices are still not fully converging across the EU, this is mainly due to contractual congestion and lack of liquid market places, rather than to insufficient physical transport or interconnection capacity.

Proposals for new gas infrastructure projects in the context of TEN-E/PCI or CEF funding should be carefully scrutinised in order to avoid overinvestments and cost impacts which might harm the affordability of energy for businesses and citizens

The current low load factors of existing infrastructure, together with the potentially decreasing gas demand, and the long lifetime of gas assets require a cautious approach to new investments in order to avoid overcapacity and additional costs for consumers, which might hamper the affordability and competitiveness of natural gas. Priority should be given to a more efficient use of existing infrastructure at regional level and to better enforcement of the market and regulatory measures, including measures to avoid contractual congestion and to enhance market liquidity and competition. Moreover, in order to efficiently take into account the increasing interdependencies between the electricity and gas systems, network development planning for both vectors should be more coordinated and based on common scenarios and methodologies.

In this context, it would also be appropriate to review the TEN-E regulation. At present, 4 gas priority corridors have been determined in its annex 1. Because, on the basis of security of supply and markets' functioning imperatives, the need for new gas projects with cross-border impact has become very limited, an update of this list of priority corridors and related eligibility criteria would be appropriate, in order to have a more future-proof approach. Flexible guidelines, which are not a formal part of the regulation, could be a suitable instrument for consideration.

CEF funding has substantially contributed to the realisation of gas PCIs. Of the EUR 1.6 billion CEF funding allocated, the largest share (64% or EUR 1.02 billion) has been allocated to gas studies or works. Taking into account the limited need for new trans-European gas infrastructure and in view of stimulating the decarbonisation process, it would be appropriate to review the eligibility criteria for CEF funding, in order to only support investments that effectively contribute to both the energy and decarbonisation objectives. Investments in gas infrastructure would hence only be eligible for CEG funding if they also contribute to decarbonising the energy supply.

Use of natural gas infrastructure to transport and distribute green gas should be facilitated

Biomethane has characteristics which make it particularly suitable for replacing natural gas. At present, eight Member States allow injection of biomethane into their natural gas grid. Research shows that by 2020 biomethane could reduce the EU's imports of natural gas by 30.5 Mtoe, which would represent approximately 19% of the 2020 gas imports from Russia. As biogas/biomethane is in most cases locally produced from organic material or waste, it has a positive impact on environment and local economy; it also reduces import dependency and security of supply. Measures could be taken at EU level to more efficiently address the main barriers for conversion of biogas to biomethane and its injection into the grid; enabling technical and economic grid connection conditions, EU-wide technical standards and sustainability criteria, as well as harmonisation of (administrative) data transfer would be beneficial to support this development.

Local use of hydrogen or synthetic methane is also in some cases, dependent on the location of the production site and its characteristics, more efficient than injecting it into the gas grid. However, in order not to hinder the optimal development of this energy vector, grid operators should be obliged to reduce the barriers for injection of hydrogen and synthetic methane into their grid by developing enabling conditions for grid connection and access.

Adequate policy measures should be taken to stimulate supply of and demand for green gas

In view of facilitating the development of green gas, several policy measures can be considered to stimulate energy retailers to offer green gas to their customers connected to the natural gas grid, and to incentivize end-users to opt for green gas to cover their energy needs.

First, EU member states should be encouraged to extend the scope of their Guarantees of Origin scheme to all types of green gas. The economic viability of green gas projects could further be enhanced by introducing a legal obligation on gas retailers to supply a gas mix with a minimum share of decarbonised gas. Such a supplier's obligation scheme could be implemented via tradable guarantees of origin to be submitted to national regulators and could be set up at national level or (preferably) at EU level with guarantees of origin which are mutually recognised and tradable across Europe.

Finally, the demand for green gas, and hence the shift from fossil fuels to decarbonised energy, could be stimulated by the implementation of an EU wide specific carbon tax or ETS for fossil fuels used for transport and heating purposes

Implementation of Power to Gas technologies (hydrogen or synthetic methane) should be supported to facilitate the development of variable renewable energy sources and to decarbonise energy supply

The massive development of variable renewable energy sources for electricity generation is increasingly leading to situations where power production exceeds demand, which results in imbalances leading to a need for congestion management, including possible curtailment of feed-in of renewable energy-based electricity. In order to efficiently balance the electricity system, conversion of power to hydrogen or synthetic methane could be an appropriate solution. The gas produced can be stored or used locally or be injected into the gas grid. Hydrogen can be injected into the grid at concentrations of up to 10%, though after its conversion to synthetic methane, it can be injected without any concentration limit. In the medium or long term, (part of) the natural gas infrastructure could be refurbished to accommodate 100% hydrogen. Pilot projects show that 'power to gas' technologies are technically feasible, but their economic viability is not yet ensured. Further research and pilot/demonstration projects are necessary to improve and scale up the technology; co-financing of these projects at EU level – via CEF, Horizon 2020 or the ETS Innovation Fund - would be appropriate.

Decommissioned pipelines and depleted natural gas fields could be used for transporting and storing carbon dioxide, but the economic viability of CCU and CCS is currently not ensured. It could be enhanced by a higher CO_2 price and by co-financing of innovative projects by CEF or the ETS Innovation Fund

Carbon dioxide can be used in industrial processes (e.g. in manufacturing certain building materials) or in energy conversion processes (e.g. to produce ethanol or synthetic methane). The re-use of CO_2 for these purposes (CCU) might create opportunities for using decommissioned gas infrastructure to transport CO_2 between the concerned industrial sites. The potential of this technology is however limited to a few percent of CO_2 emissions.

CO_2 capture in industrial processes in order to enable its final storage (CCS) could be another relevant and economically feasible option, if the economic incentives for avoiding CO_2 emissions were substantially higher. This technology could also be used in fossil fuel fired power plants, but as these plants should in the future have limited load factors and due to high energy losses caused by the CO_2 capturing process, large scale implementation of this technology is neither expected nor desirable. The potential of using decommissioned pipelines or depleted natural gas fields for transporting and storing carbon dioxide is hence limited.

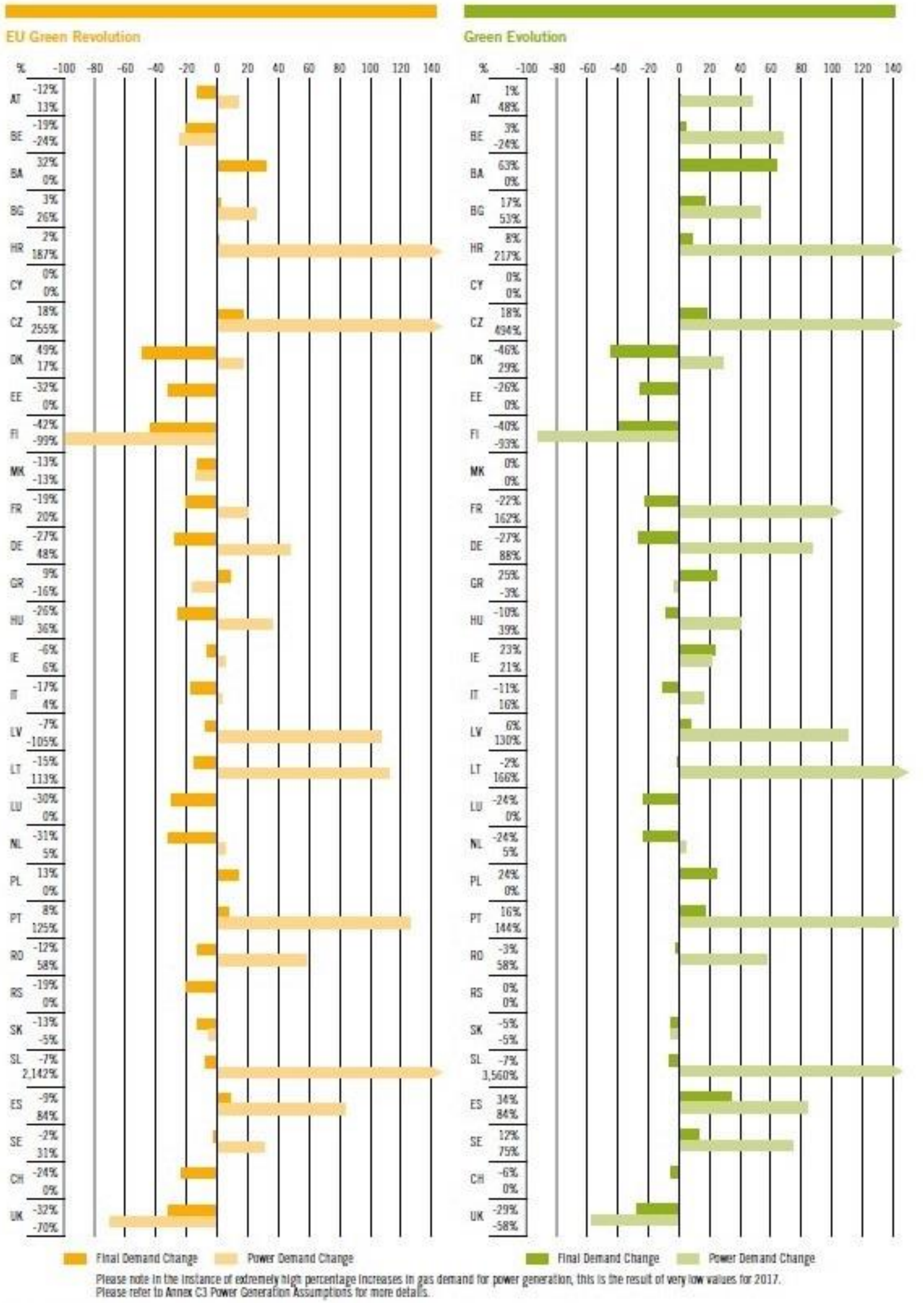
The economic viability of both CCU and CCS options could be improved by a stronger CO_2 price signal; the proposed reinforcement of EU-ETS will have a positive impact but it is likely to be insufficient to trigger CCU or CCS projects. The implementation of an annual increasing floor price for GHG emissions under ETS would be a more effective measure. Co-financing of innovative projects by CEF or the ETS Innovation Fund could also be considered.

6. Annexes

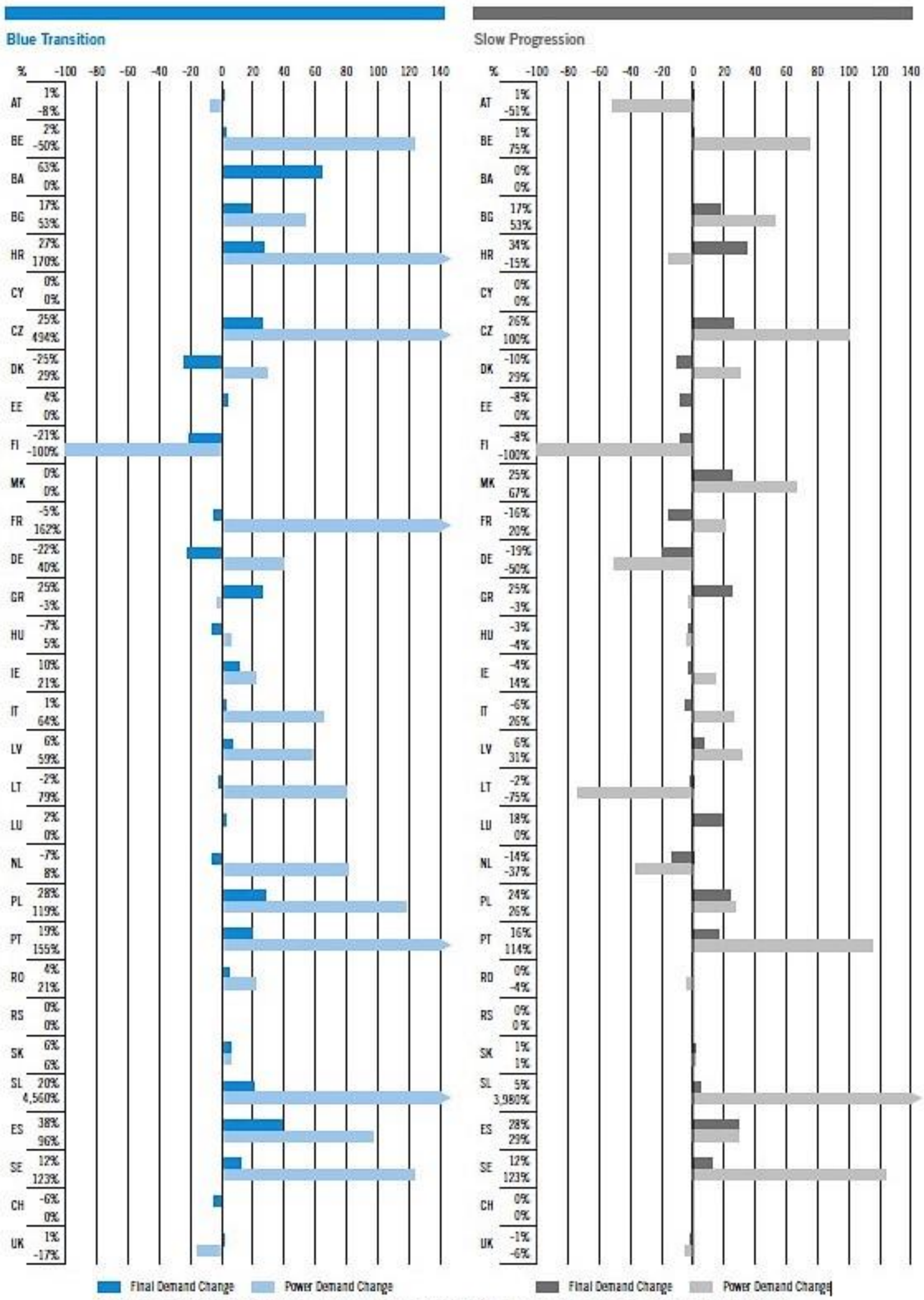
Annex I: TYNDP 2018 – 2040 Scenario Report Country Level Results

Scenario		Global climate action	Subsidized Green Europe	Sustainable Transition	Behind Targets	Distributed Generation
Category	**Criteria**	**Parameter**				
Macroeconomic Trends	Climate action driven by	Global ETS	Global ETS & direct RES subsidies	EU ETS & direct RES subsidies	Climate action low	EU ETS
	EU on track to 2050 target?	Yes	Yes	Slightly behind	Behind	Yes
	Economic conditions	High growth	High growth	Moderate growth	Low growth	High growth
Transport	Electric and hybrid vehicles	High growth	High growth	Moderate growth	Low growth	Very high growth
	Gas vehicles and shipping	High growth	High growth	Moderate growth	Low growth	Very high growth
Residential / Commercial	Demand flexibility	High growth	High growth	Moderate growth	Low growth	Very high growth
	Electric heat pump	Moderate growth	Very high growth	Low growth	Low growth	Moderate growth
	Energy efficiency	Moderate growth	Very high growth	Moderate growth	Low growth	High growth
	Hybrid heat pump	Very high growth	Moderate growth	Moderate growth	Low growth	Very high growth
Industry	electricity demand	Stable	Favourable development	Stable	Stable	Favourable development
	gas demand	Stable	Reduction	Stable	Stable	Reduction
	demand flexibility	Moderate growth	Low growth	Low growth	Low growth	Very high growth
Power	Merit order	Gas before coal	In par	Gas before coal	Coal before gas	Gas before coal
	Nuclear	Potential for growth	Stable	Minimum new units	Reduction	Reduction
	Storage	Moderate growth	High growth	Low growth	Low growth	Very high growth
	Wind	High growth	Very high growth	Moderate growth	Low growth	High growth
	Solar	High growth	Very high growth	Moderate growth	Low growth	Very high growth
	CCS	Not significant	Not significant	Not significant	Not significant	Not significant
	Adequacy	Some surplus capacity	High surplus capacity	Some surplus capacity	Low surplus capacity	High surplus capacity
Gas Supply	Power-to-gas	High growth	High growth	Not significant	Not significant	High growth
	Shale Gas	Not significant	Not significant	High growth	Low growth	Not significant
	Bio Methan	High growth	High growth	High growth	Not significant	High growth

Annex II: Evolution of total gas demand 2017-2030 per country under different ENTSOG Scenarios



Evolution of total gas demand in the period 2017–2035 per sector and country.



Please note in the instance of extremely high percentage increases in gas demand for power generation, this is the result of very low values for 2017. Please refer to Annex C3 Power Generation Assumptions for more details.

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