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Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure

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Executive Summary

The aim of this study is to obtain a better understanding of the potential of biomethane and hydrogen to contribute to the decarbonisation of the EU energy system, the impacts this will have on the gas infrastructure and the extent to which gas network operators and regulators are prepared to cope with these impacts. This study builds on the findings from the previous gas infrastructure 2050 study,[1] while significantly advancing the provision of quantitative data to the analysis. The three explorative scenarios and assumptions regarding the use of electricity, methane and hydrogen serve to analyse this impact on the gas infrastructure, rather than aiming to forecast the most probable deployment pathway of biomethane and hydrogen in the EU or any Member State.

Biomethane and hydrogen will play an important role in the transition to a decarbonised energy system. In 2017, natural gas represented around 22% of the EU final energy consumption,[2] with natural gas infrastructure playing a correspondingly significant role. However, this role is complex and heterogeneous across Member States: the share of gas in the national energy mix is quite diverging, gas transmission networks are managed by 44 system operators (TSOs) that use not fully harmonised gas specifications and technical standards, and the type and extent of infrastructure vary significantly across countries.

According to the different scenarios of the European Commission's 2050 Long-Term Strategic Vision, gas demand in the EU will decrease from the 2015 levels by 20 to 60% in the long term, with the demand for natural gas at least halving.[3] Regardless of the overall gas demand evolution, the role of renewable and low-carbon gases will however in all its scenarios increase in the coming decades. In this context, a number of studies have been conducted on the potential development of low-carbon and carbon-neutral gases in Europe and its impact on the energy infrastructure.[4] Despite methodological differences and diverging study outcomes, a consensus is emerging that low-carbon gases will play a major role in decarbonizing the EU economy, with the support of the European gas infrastructure.

The analysis begins by assessing the technical potentials for renewable hydrogen and biomethane, with a focus on the intra-EU potential. **The EU potential for sustainable biomethane is limited, while the technical potential for hydrogen and synthetic methane production based on renewable electricity is large enough to substitute the (remaining) natural gas demand.**

The technical potential renewable electricity generation in the EU28 is estimated at 14 000 TWh/yr. The annual additional[5] hydrogen production potential from electrolysis of renewable electricity for the EU would amount to 6 500 TWh in 2030, increasing to 7 900 TWh in 2050 due to expected efficiency gains in electrolysis. To exploit this potential, further development and commercialization of electrolysis will be needed, as well as the expansion of renewable electricity production and intermediate hydrogen storage capacity.

For this study, a conservative technical biogas/biomethane EU28 production potential of 1 150 TWh/yr is estimated. Subtracting the current biogas production results in an *additional production* potential of approx. 950 TWh/yr. The potential development of renewable methane is limited by the availability of biomass resources, by the

[1] Trinomics, LBST et al. (2018) The role of Trans-European gas infrastructure in the light of the 2050 decarbonisation targets.
[2] European Commission (2017), Energy balance sheets 2017 Edition.
[3] EC (2018). A Clean Planet for all A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy. COM(2018)773. EC (2018). In-depth analysis accompanying the Communication COM(2018)773.
[4] Trinomics, LBST et al. (2018) The role of Trans-European gas infrastructure in the light of the 2050 decarbonisation targets; Frontier Economics (2019) The Value of Gas Infrastructure in a climate-neutral Europe; Navigant (2019). Gas for Climate - The optimal role gas in a net-zero emissions energy system.; European Climate Foundation (2019). Towards fossil-free energy in 2050; ICCT (2018). The potential for low-carbon renewable methane in heating, power, and transport in the European Union.
[5] Correcting for the electricity that is needed to satisfy the electricity demand as of 2016.

implementation of more strict sustainability criteria, and by competing uses.[6] Major additional potentials for renewable and low-carbon gases exist in neighbouring countries such as Norway, Ukraine, Belarus and Russia; this potential is however not further considered in this study.

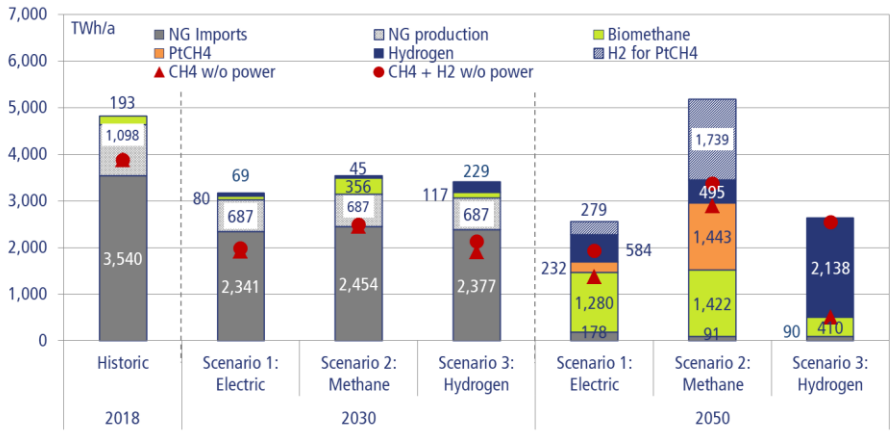
Hence, the EU's technical potential for renewable hydrogen by far exceeds the 2050 gas demand considered in this study: in none of the scenarios for 2030 or 2050 the gas demand exceeds 4 100 TWh/yr. In contrast, the EU biomethane technical potential is not sufficient to meet the current nor future gas consumption. Nonetheless, results for both hydrogen and biomethane vary significantly by Member State based on national determining factors and restrictions.

Physical and trade exchanges of renewable gas (and electricity) between Member States in an integrated market will hence be of great importance to decarbonise energy supply and cover energy demand at least cost, and to ensure efficient energy system and market functioning, given the unequal distribution of renewable energy resources across countries.

Based on the storylines of the gas infrastructure 2050 study[7] **the study develops three explorative scenarios, each focused on strong end-use of one of three considered energy carriers: electricity, methane or hydrogen.** For example, in the "electricity" scenario, electricity end use is dominant while methane and hydrogen play a much smaller role. In all scenarios the overall gas supply until 2030 declines by 20%-30%, to approx. 3 000-3 500 TWh/a mainly due to a switch to other end-user applications using non-gas energy carriers as well as improved end-use efficiencies (Figure 1). The structure of the gas supply in 2030, however, is similar to the present. The gas infrastructure in 2030 is based on natural gas, which is mainly imported from outside the EU, and the share of both biomethane and hydrogen production is still rather limited.

In 2050, the energy system has changed drastically. Due to the strong GHG emission reduction target, almost no fossil fuels can be used, and limited natural gas imports have to be offset by negative emissions. The dominant primary energy sources are biomethane and renewable power, with the latter reaching 5 000-6 800 TWh/a in 2050, thereby becoming the dominant power source for end-use consumption as well as hydrogen and synthetic methane production.

Figure 1 Gas supply in EU28



In the electricity-focused scenario, the system utilises in 2050 the full potential of biomethane of 1 150 TWh/yr. Approx. 230 TWh/a of synthetic methane is produced and used for re-electrification, but it is still cheaper to source fossil gas up to a predetermined

[6] The sustainability criteria of the recast Renewable Energy Directive were taken into account, but may constitute further limitations to the biomethane potentials estimated. The technical potential presented here assumes that all bioenergy not used today is available for biogas / biomethane production; other energetic uses are excluded.
[7] Trinomics, LBST et al. (2018) The role of Trans-European gas infrastructure in the light of the 2050 decarbonisation targets.

GHG cap rather than to further develop methanation. Hydrogen supply amounts to approx. 860 TWh/a, mostly for direct consumption and as feedstock for methanation.

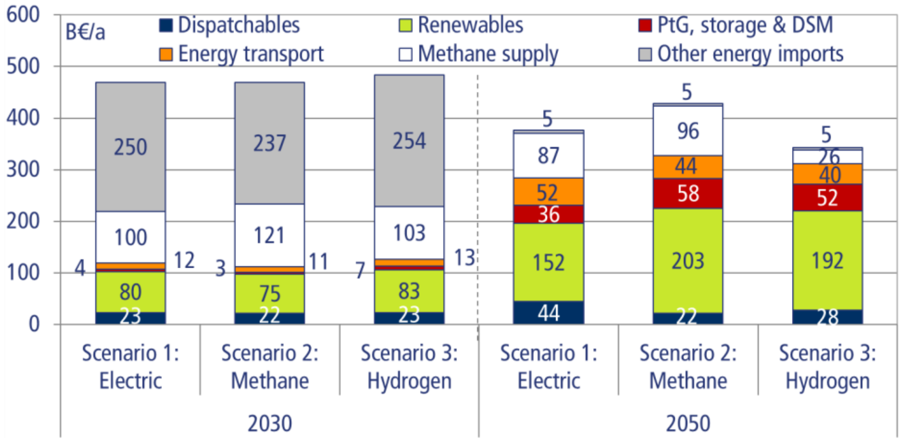
The methane-focused scenario also utilises in 2050 the full biomethane potential. In addition, almost the same amount of synthetic methane is produced via methanation for end-use and re-electrification. Hydrogen production reaches over 2,200 TWh/a, but only limited amounts are employed directly in end-use sectors, as most serves as feedstock for methanation. Hence, the overall gas demand and supply in this scenario is much higher than in the other two scenarios, due to methanation losses.

In the hydrogen-focused scenario, hydrogen is the major gas type with more than 2,100 TWh/a in 2050, due especially to direct end-use. By 2050 electricity is used only for those applications where it is technologically and economically more suitable and more efficient than hydrogen, while methane demand decreases substantially. To avoid parallel gas infrastructures, mainly hydrogen is transported and distributed at all network levels.

The implications for the existing networks vary between scenarios. None or little technical or regulatory barriers exist for the admixture of biomethane. In contrast, current gas networks can only be used to transport admixed hydrogen up to a certain limit, which differs depending on the type and characteristics of the network and end-user appliances. For higher concentration admixtures, technical modifications and/or new infrastructure or equipment are required. While hydrogen admixture is today possible up to different limits depending on national regulations, there is no consistent policy nor regulatory framework in place in Europe to allow small or large-scale injection of hydrogen to the gas network. The pathways for increasing hydrogen admixture are further detailed in this report.

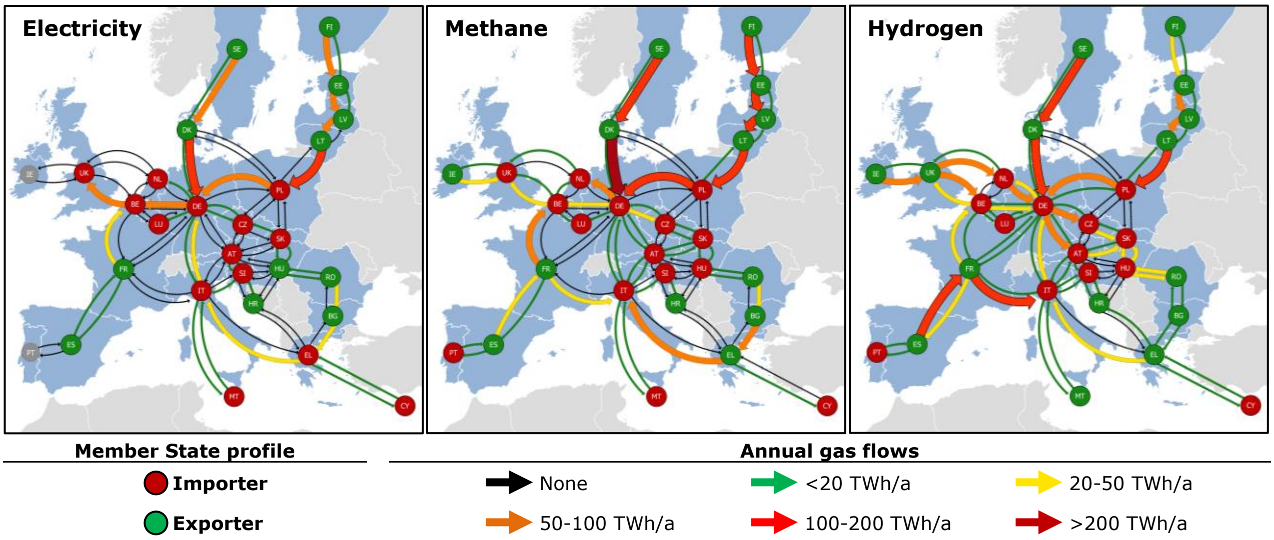
A scenario focused on electricity and gas sector coupling where hydrogen plays a central role would offer the least-cost outcome, while also allowing to value existing gas assets. Until 2030 the three scenarios present similar system cost structures and magnitudes, with major contributions from fossil energy imports. In the long-term to 2050, the overall system costs decrease due to cheap renewable power, increasing sector integration and substitution of energy imports. The lowest system costs are achieved with a hydrogen-focused scenario, followed by the electricity and methane scenarios, and reflect the trade-off between renewable energy production, system flexibility and gas supply. The methane-focused scenario is less attractive due to its lower overall efficiency (related to additional investments, energy losses in the methanation process and lower end-use efficiency for transport). It is important to highlight that the scenario modelling is of explorative character with regard to the demand for the major energy carriers within the end-user sectors, i.e. the three scenarios differ in certain assumptions related to end user choices of applications using either electricity, methane or hydrogen.

Figure 2 Annual energy system costs (excluding national energy transport costs) in EU28



Each scenario leverages and impacts both cross-border and national gas networks differently according to the dominant energy carrier. Countries with large renewable energy potentials in comparison to limited domestic demand become gas exporters, whereas Member States characterised by high gas demand but low domestic production from renewables are net gas importers. Particularly in the electricity and methane-based scenarios, the Scandinavian and Baltic counties supply large amounts of biomethane, while in the hydrogen scenario Scandinavia, the Baltic countries and Southern Europe are important gas exporters (Figure 3).

Figure 3 EU28 cross-border annual gas flows in 2050 for the three scenarios



The decarbonization of gas supply and consequent reconfiguration of gas flows will substantially affect the business case of gas network operators. In the mid- and long-term the risks faced by gas network operators mainly result from changes in underlying technical and regulatory factors affecting the cost of service and the transported gas volumes in the medium and long term. While some grid operators are already acting (in various extents) to address these risks, the confidence of stakeholders that the risks to the business case of grid operators are limited in the mid-term, is related to the belief that these underlying factors such as the need for gas transport services will remain stable until 2030, or at least that measures to contain the cost of service and extreme tariff increases are available.

Based on a simulation of transport tariffs, the most significant long-term risks to TSOs in case of a large change in the cost of service or transported volumes (and thus tariffs) would come from a significant reconfiguration of gas flows in the EU to 2050. Specifically, important cross-border transmission investments could lead to an increase in transmission tariffs, especially in the case that dedicated hydrogen networks would be developed. Related to this, there is still significant uncertainty regarding both the OPEX levels and the necessary regulatory framework for hydrogen networks. Also, if gas transmission investments are made before 2030 while not considering the uncertainty to 2050, this could lead to stranded assets and consequently to substantial re-evaluations of the regulatory asset base. Moreover, the reconfiguration of the network will require the corresponding adaptation of cross-border and national network cost allocation, as different transit and intra-system flows will become the main gas network cost drivers.

DSOs will also have a major role in the gas infrastructure transition, facing some of the same drivers impacting the business case of TSOs. However, the impact magnitude will be different and vary much more across regions. DSOs have a more important asset base and higher cost of service than TSOs. Local developments are expected to be more divergent than at the transmission level, and while the transmission volumes would in general decrease, certain DSOs will see an increase in their transported volumes and a more frequent occurrence of reverse flows from the distribution to the transmission level.

The importance of stable long-term policies is pivotal for the business case of system operators, and impacts many of the other risks discussed, as the period from 2030 to 2050 is where the most important transitions will occur. Clarity on the target decarbonization levels will provide the overarching framework from which the planning scenarios and necessary regulation should be developed, also given the differences in policies aiming at near-complete or full net decarbonization.

Current national policy and regulatory frameworks for renewable gas are largely heterogeneous. There is a variety of incentives in place to stimulate renewable gases, but these vary widely across Member States and few concern grid connection and access. In contrast, the planning and revenue regulatory frameworks for gas networks have many common aspects across Member States. Some countries (especially the few ones with more short-term deployment of renewable gases) are experimenting with measures such as regulatory sandboxes, but still hydrogen and biomethane are addressed sporadically.

Regarding the TEN-E and CEF regulations, they have helped develop well-integrated and secure gas markets. Now a number of changes could be considered to better support the deployment of hydrogen and biomethane in gas networks. Options include the potential update of the TEN-E priority corridors, areas and the eligibility criteria for PCIs and CEF, broadening the scope to distribution projects and those facilitating sector coupling (hydrogen networks, power-to-gas and deblending) and including innovation and robustness to uncertainty in the selection criteria. The cost-benefit analysis methodology and underlying scenarios could also better account for renewable and decarbonised gases, and prioritise making best use of existing infrastructure, including through conversion. Furthermore, there is a lack of coherence across national frameworks for the hydrogen blending which may hinder the development of a consistent European approach and therefore the cross-border transport of hydrogen.

The main high-level recommendations of the study focused on gas infrastructure are:

- Appropriate technical standards and specifications should be elaborated to facilitate biomethane and hydrogen deployment. A supportive regulatory framework for hydrogen blending as a tool for decarbonising the gas supply should be developed. For higher hydrogen volume concentrations, dedicated transmission and distribution infrastructure would be more appropriate than admixture to methane;
- Further analysis of the role of hydrogen and of strategies for a stepwise development of 100% hydrogen network "islands" that subsequently grow into one large hydrogen network is worth exploring;
- Planning of new energy infrastructure should be more integrated and be based on the overall future energy system while optimising the use of existing infrastructure, with clear guidance from policymakers on gas decarbonization pathways;
- TEN-E and CEF regulations should support projects facilitating the integration of renewable gas, shifting the gas sector focus to projects that are future-proof and efficiently contribute to the energy transition;
- An adequate regulatory framework for power-to-gas should be developed, addressing barriers to investment and further considering the role of TSOs;
- An appropriate regulatory framework for dedicated hydrogen networks should be defined in a timely manner, considering the role of the current natural gas network operators in a fully or partially regulated approach;
- Streamlining efforts for incentives to renewable gases are required to improve effectiveness, avoid competition distortion between energy vectors, and value economic benefits of local renewable gas production;
- Measures could be considered to mitigate potential negative impacts on system operators and network users from decreasing gas demand and changes in gas flows. While regulatory principles such as cost-reflectivity should be respected, alternatives to e.g. current unbundling requirements could be considered in order to reduce the system cost.

1 OBJECTIVE, METHODOLOGY AND STRUCTURE OF THE STUDY

1.1 OBJECTIVE

The EU has increased its ambitions to decarbonise its energy system and economy, and has substantially reformed its energy and climate policy framework accordingly. However, these regulatory changes have not specifically addressed the gas market design, for which the European Commission is preparing a regulatory package. In addition, the European Commission will evaluate the Trans-European Energy Network guidelines (TEN-E) while the Connecting Europe Facility (CEF) regulation is being reviewed.

The EU gas infrastructure consists of more than 200,000 km of transmission pipelines, more than 2 million km of distribution networks and over 20,000 compressor and pressure reduction stations.[8] More than 115 million domestic, commercial and industrial end-users are connected to the gas network.[9] Natural gas represented in 2017 around 35% of the households' final energy consumption and 22% of the total final EU energy consumption.[10] The European gas network is highly inhomogeneous and complex. The transmission assets are currently operated by 44 TSOs and gas specifications and technical standards are not harmonised; the type and extent of infrastructure also varies significantly across countries.

In 2017, the EU28 imported about 3,550 TWh and consumed 4,800 TWh of natural gas, which resulted in a dependency level of 74%[11]. As the EU demand for gas is expected to grow by 1% per annum to 2035, which constitutes a total rise of 19.6%, while domestic natural gas production would further decline, the EU would have to increase its imports of pipeline gas and LNG from existing or alternative suppliers. The EU can however reduce its natural gas import dependency by developing and promoting the use of domestic alternatives, in particular renewable gas. In the long term, gas demand would decrease from the 2015 levels by 20 up to 60% according to the different scenarios of the European Commission's Long-Term Strategic Vision, with the demand for natural gas at least halving.[12] The supply of low-carbon gases would rise significantly in all scenarios, and would hence play an increasing role for transforming and decarbonizing the energy system to 2050.

The future gas demand will be heavily influenced by gas prices, economic growth and (geo-)political interests, as well as by climate targets. Therefore, independently of the overall gas demand evolution, the role of biomethane and hydrogen in the European gas system is inevitably going to increase in the coming decades. This is reflected in the scenarios of the 2018 Ten-Year Network Development Plan, which already forecasted a share of biomethane in energy demand by 2040 of up to 13%, and of 3% for power-to-gas. These shares are expected to increase in the scenarios for the 2020 Plan.

In this context, a number of studies have been conducted on the potential development of low-carbon gases in Europe and on sector coupling.[13] There are indeed still many open issues regarding the level of future gas demand, the potential for biomethane and hydrogen, the most appropriate technologies and deployment pathways, the highest value end-uses for low-carbon gas, the impact of these developments on gas infrastructures, the business rationale for gas network operators and the regulatory readiness at the EU

[8] CEER (2018). CEER Benchmarking Report 6.1 on the Continuity of Electricity and Gas Supply, Brussels
[9] Marcogaz (2014). Technical statistics 01-01-2013, Brussels.
[10] European Commission (2017), Energy balance sheets 2017 Edition.
[11] Eurostat (2019) Simplified energy balances
[12] EC (2018). A Clean Planet for all A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy. COM(2018)773.
EC (2018). In-depth analysis accompanying the Communication COM(2018)773.
[13] Trinomics, LBST et al. (2018) The role of Trans-European gas infrastructure in the light of the 2050 decarbonisation targets; Frontier Economics (2019) The Value of Gas Infrastructure in a climate-neutral Europe; Navigant (2019). Gas for Climate - The optimal role gas in a net-zero emissions energy system.; European Climate Foundation (2019). Towards fossil-free energy in 2050; ICCT (2018). The potential for low-carbon renewable methane in heating, power, and transport in the European Union.

and Member State level. Recent studies regarding the potential role of the different low-carbon gases (biomethane, hydrogen and synthetic methane) to achieve the decarbonization of the energy system at least cost, present diverging outcomes. For example, the ICCT study arrives at significantly different potentials for biomethane compared to the Gas for Climate study, while the ECF study reserves a limited role for renewable gases in its least-cost scenario. The assumptions and modelling approaches constrain the comparability of the studies. Nonetheless, despite the remaining uncertainties, a consensus is emerging that low-carbon gases will play a major role in decarbonizing the EU economy and that European gas infrastructure may support this.

The aim of this study is to obtain a better understanding of the potential of biomethane and hydrogen to contribute to the decarbonisation of the EU energy system, the impacts this will have on the gas infrastructure and the extent to which gas network operators and regulators are prepared to cope with these impacts. This study builds on the findings from the previous Gas Infrastructure 2050 study, but it significantly advances in the provision of quantitative data to the analysis.

1.2 Methodology

The methodology used for this study comprised first of all an in-depth review of relevant studies and reports complemented with ad hoc contacts, in view of assessing the potential availability and use of biomethane and hydrogen in the EU28. The potential supply estimates are mainly based on domestic resources, but for biomethane, imports from non-EU countries are also considered. For hydrogen specifically, the potential domestic availability of renewable electricity to operate electrolysis at large scale is screened.

The feasibility and impact from a regulatory and technical perspective, of injecting increasing volumes of biomethane and/or hydrogen into the gas network have been assessed on the basis of an extensive literature overview, including EU and national technical documents, standards and specifications as well as specific studies and projects regarding the suitability of existing gas infrastructure for hydrogen and biomethane.

The economic and environmental costs and benefits of the deployment of the full potential of biomethane and hydrogen have been assessed for three different hypothetical scenarios (environmental costs are calculated as CO_2 emissions avoidance cost). As a first step, the scenarios and general boundary conditions have been defined and agreed upon setting the scene for all data and information compilation feeding the energy model. Following, the major energy framework for the three scenarios was derived from existing studies and policy documents, addressing the energy demand side, the technology evolution, availability and cost, concluding in the quantities of biomethane and hydrogen that potentially could be used in the different end-use sectors. The energy model has been applied in four distinct steps: 1) definition of the energy system and its interlinkages, 2) collection of input data not provided by the preceding steps, 3) model runs, and 4) evaluation of the data from an economic and environmental perspective.

Based on the modelling results for the EU28, the impact of the three scenarios on gas networks and network tariffs has in more detail been evaluated for five selected Member States (Germany, Hungary, the Netherlands, Spain and Sweden), while the readiness of their regulatory regime to facilitate the deployment of renewable gas has also been evaluated. The methodology consisted of an in-depth literature review, using both EU level and Member State specific data sources, complemented by interviews with representatives from the National Regulatory Authorities (NRAs) and network operators from the selected Member States. The regulatory framework for gas infrastructure is presented and analysed, with a focus on the development and operation of the gas network, network operators' revenue regulation and network tariffication. The current state of the development of biomethane and hydrogen in the selected countries is also analysed, covering the entire value chain, from production to transport, storage and finally consumption. Finally, the specific policy and regulatory framework for renewable gas is evaluated for the selected Member States, covering aspects such as targets, economic support and certification. Based on the information gathered and analysed, and on the modelling results, key issues in the regulatory framework hindering the development of hydrogen and biomethane are identified and measures and recommendations are proposed to enhance the regulatory and policy framework.

1.3 STRUCTURE OF THE REPORT

The report is divided into three main parts:

- The **first part** (Chapters 2-4) analyses the potential supply and use of biomethane and hydrogen, evaluates the feasibility and impact of injecting these gases into the natural gas network and assesses the costs and benefits of the deployment of their full potential under three defined scenarios;
- The **second part** (Chapters 5-8) assesses the implications of the three scenarios on gas network operators and network tariffs and evaluates the regulatory readiness of selected Member States;
- The **last part** (Chapter 9) presents recommendations, including on the TEN-E and CEF regulations, to facilitate the deployment of renewable gas.

2 POTENTIAL AVAILABILITY OF BIOMETHANE AND HYDROGEN IN THE EU AND NEIGHBOURING COUNTRIES

In this chapter, the technical potentials of hydrogen and biomethane production in the European Union are assessed; they serve as volume caps for the economic optimization algorithm used in the modelling that is presented in chapter 4.

Based on a definition of the different types of energy resource potentials, the technical potential is assessed for the production of hydrogen from renewable electricity as major source to operate electrolysers. Furthermore, the technical potential for the production of biomethane and the related costs are assessed based on recent studies.

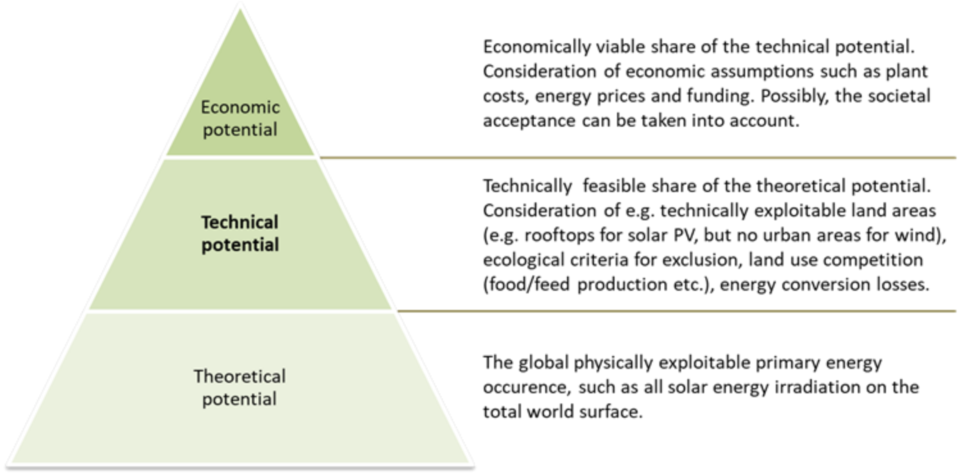
2.1 THEORETICAL, TECHNICAL, ECONOMIC POTENTIAL – DEFINITION OF TERMS

When availability potentials are assessed, a differentiation is made between the theoretical, technical and economic potential. The theoretical potential represents the quantity of energy that can be produced in a given geographical region while only taking into account physical boundary conditions.

The technical potential is derived from the theoretical potential by taking also into account technical, ecological and administrative/legal restrictions including transformation losses, geographical and temporal discrepancies between energy production and energy demand, non-availability of areas, etc. As an example, for onshore wind energy, urban and built-up areas including setback distances as well as protected areas, are excluded, while for solar photovoltaics (PV) urban and built-up areas are perfectly suited and hence taken into account. Competition for land use is also taken into account; for solar PV, roofs and facades are included while in a conservative approach taken here other surface areas are only included along motorways and railway lines.

The economic potential is the part of the technical potential that can be exploited under the prevailing economic circumstances. The definition of the three potential types is illustrated in Figure 2-1.

Figure 2-1 Definitions of energy resource "potentials"



This study mainly focuses on the technical hydrogen and biomethane potentials within the EU. Major additional technical potentials exist in neighbouring countries such as Norway, Ukraine, Belarus and Russia, but it should be further assessed to what extent these sources would comply with the strict sustainability criteria agreed upon in the EU.

2.2 POTENTIAL AVAILABILITY OF RENEWABLE HYDROGEN

Hydrogen (H_2) – the first and lightest element of the periodic table – is not freely available in nature, but is bound to other chemicals. A number of technologies is available to produce hydrogen from different feedstocks and input energies.

In this study, only hydrogen production through electrolysis from renewable electricity is considered, as this production technology has a large potential that could be sufficient to substitute the current natural gas consumption, and as other production technologies, e.g. based on fossil fuels or on bioenergy, would either lead to residual GHG emissions and would hence not allow to reach full decarbonisation or would conflict with other more efficient uses of bioenergy.
The hydrogen production technology considered in this study is hence water electrolysis[14] using renewable electricity. Electrolytic hydrogen can be directly used or synthesized with CO_2 to synthetic methane. However, this latter pathway is not further considered in this study.

The technical potential for renewable hydrogen production is thus based on the renewable electricity generation potential minus the current electricity consumption ('base' electricity consumption), transformed into hydrogen applying the efficiency of electrolysis. For this study, we assume the levels of 'base' electricity consumption to be constant over time.

In order to exploit this technical renewable hydrogen potential commercially, it is necessary to:

a) further improve, develop and commercialise electrolysis technology,
b) strongly expand the production of renewable energy based electricity, and
c) envisage using intermediate hydrogen storage in order to be able to cope with the fluctuating demand of end-users and to supply baseload hydrogen to the industry.

[14] Furthermore, technologies producing hydrogen as a by-product rather than as the main product have been excluded here as the former are typically optimizedoptimised for the main product. Furthermore, supercritical water gasification of biomass, plasma-based carbon black processes using natural gas as feedstock, fermentation and photo-fermentation, photo-catalysis, electro-hydrogenesis and photo-biological water splitting have been excluded. LBST & Hinicio (2015), Study on Hydrogen from Renewable Resources in the EU.

2.2.1 WATER ELECTROLYSIS – STATE OF THE ART AND PERSPECTIVES

Three major electrolysis technologies are considered for large scale industry use today: alkaline electrolysis (AEL), proton exchange membrane-based electrolysis (PEM electrolyser – PEMEL), and electrolysers using an ion-conducting solid oxide (SOEC). AEL and PEM electrolysers are commercially available. Today, the efficiency of larger electrolysis plants (in the order of 5 MW_{el}) is about 68% and 69% based on the higher heating value (HHV) for AEL and PEM electrolysers, respectively.[15] Based on the lower heating value (LHV), the efficiency would be about 57.5% (AEL) and 58.4% (PEM). The efficiency including the use of auxiliary energy does in general not change with the capacity if the same pressure level and hydrogen purity are to be achieved.

In the future, a decrease of electricity consumption can be expected, i.e. an increase in efficiency. According to two detailed studies[16] an efficiency of 67% (based on LHV) can be expected for 2030 in case of alkaline electrolysers, and of 71% (LHV) in case of PEM electrolysers. For the hydrogen production potential, we have not distinguished between alkaline and PEM electrolysis, but have used current values for the short-term ($57\%_{LHV}$, PEMEL and AEL) increasing in the long-term to $71\%_{LHV}$ (PEMEL) until 2040/2050.

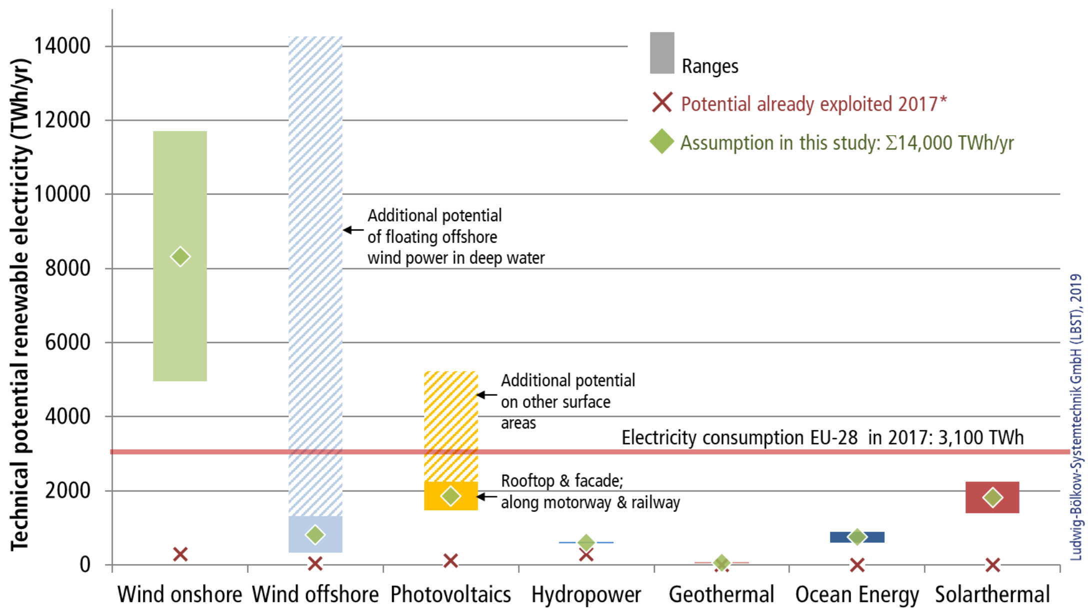
2.2.2 TECHNICAL RENEWABLE ELECTRICITY POTENTIALS IN THE EU

The technical potentials for the production of renewable electricity in the EU are significant. In light of the already low costs and further significant cost reductions to be expected in solar and wind power generation, the realistic level of exploitation of these potentials (economic potential) may not be limited by costs, but possibly rather factors such as public acceptance.[17]

Taking the basic approach for assessing renewable power potentials in EU28 described in DLR (2015)[18] and LBST (2016)[19], recently published studies have been assessed and combined with earlier analyses. The following renewable electricity sources are included: wind power (onshore and offshore), solar PV, hydro power, geothermal power, ocean energy, and solar thermal power. Biomass-based technologies are excluded as we assume all biomass to be available to other uses, including biomethane production. Furthermore, this allows for a clearer picture and avoids potential double counting. The technical electricity production potential from renewable energy sources in EU28 is shown in Figure 2-2. Additional potentials may become available based on societal choices (solar PV on additional surface areas) or technology developments (offshore wind on floating platforms in deeper water).

[15] Deutsches Zentrum für Luft- und Raumfahrt e.V. – DLR (2015), Erneuerbare Energien im Verkehr Potenziale und Entwicklungsperspektiven verschiedener erneuerbarer Energieträger und Energieverbrauch der Verkehrsträger.
[16] E4tech Sàrl with Element Energy Ltd (2014). Study on development of water electrolysis in the EU, 2014. & Deutsches Zentrum für Luft- und Raumfahrt e.V. – DLR (2015), Erneuerbare Energien im Verkehr Potenziale und Entwicklungsperspektiven verschiedener erneuerbarer Energieträger und Energieverbrauch der Verkehrsträger.
[17] LBST (2016). Renewables in Transport 2050, Frankfurt am Main.
[18] Deutsches Zentrum für Luft- und Raumfahrt e.V. – DLR (2015), Erneuerbare Energien im Verkehr Potenziale und Entwicklungsperspektiven verschiedener erneuerbarer Energieträger und Energieverbrauch der Verkehrsträger.
[19] LBST (2016). Renewables in Transport 2050, Frankfurt am Main.

Figure 2-2 Technical renewable electricity generation potential in EU28



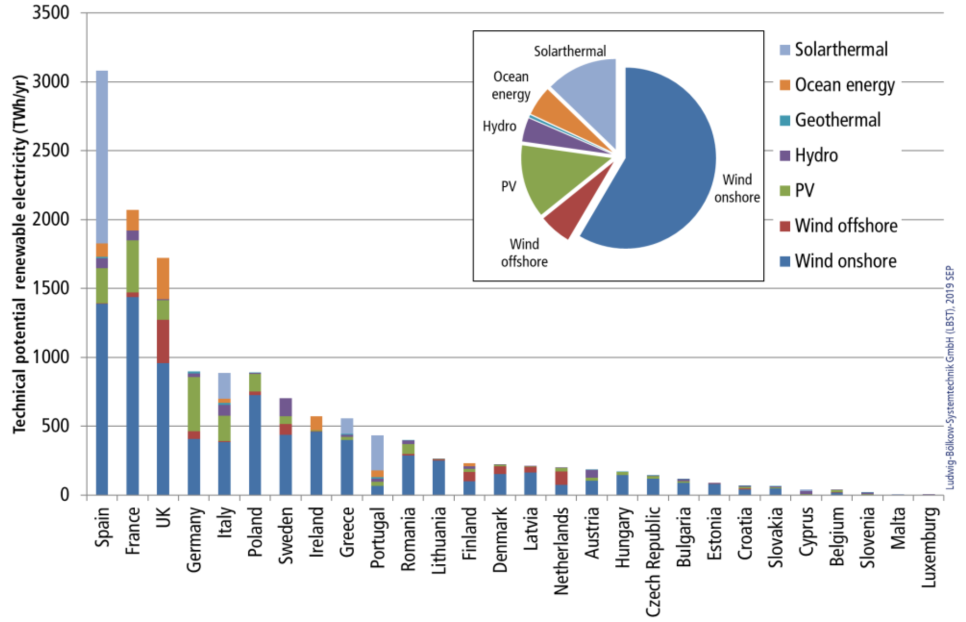
*Source: Diagram from LBST 2016 with data from i.a. JRC 2018, IWES 2012, DLR 1992, DLR 2005, TAB 2003, Stefansson 2005, * Eurostat 2017[20]*

Figure 2-3 shows the EU renewable electricity potentials by Member State. For comparison, in 2017 the net electricity consumption in EU28 was 3 100 TWh[21]. The renewable electricity potentials thus largely exceed the current electricity consumption. The technical potential may be further reduced by factors such as competing land use. In order to take these impacts into account, the ranges of potentials found are averaged to give the final potential, resulting in a long-term technical potential for sustainable renewable power production of some 14 000 TWh per year. More conservative estimates would not be critical to the modelling results presented below as the technical potentials estimated here are by far larger than the demand in the scenarios calculated.

[20] LBST (2016). Renewables in Transport 2050; JRC (2018). Wind potentials for EU and neighbouring countries: Input datasets for the JRC-EU-TIMES Model; IWES (2012). Windenergie Report Deutschland 2011; DLR (1992). Solarthermische Kraftwerke im Mittelmeerraum, Deutsche Forschungsanstalt für Luftund Raumfahrt/Zentrum für Sonnenenergie und Wasserstoffforschung; DLR (2005). Concentrating solar power for the Mediterranean region, Stuttgart, 2005; Büro für Technikfolgen-Abschätzung beim Bundestag (2003), Möglichkeiten geothermischer Stromerzeugung in Deutschland; Stefansson, V. (2005). World Geothermal Assessment. *Proceedings World Geothermal Conference 2005*, Reykjavik; European Commission (2017), Energy balance sheets - 2017 Edition, Luxemburg

[21] Eurostat (2018). Energy statistics - an overview.

Figure 2-3 EU renewable electricity generation potentials, by Member State (average of ranges per Member State)



Source: JRC 2018, LBST 2016, GL et al. 1995, IWES 2012, DLR 1992, DLR 2005, TAB 2003, Stefansson 2005[22]

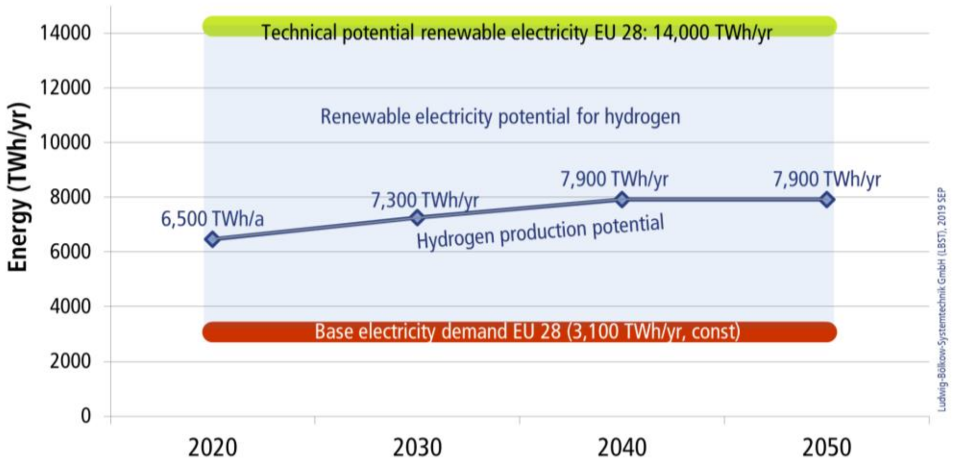
2.2.3 TECHNICAL POTENTIAL FOR HYDROGEN PRODUCTION

Based on the potential renewable electricity generation in EU28 (14 000 TWh/yr), the efficiency of the water electrolysis technology (increasing from 57% to 71% in the long term), and taking today's electricity consumption of 2016 as constant ('base' electricity consumption), the annual hydrogen production potential for EU28 is estimated at 6 500 TWh in 2020, increasing to 7 900 TWh in 2040/2050 due to efficiency gains in electrolysis.

The technical potential for hydrogen largely exceeds the calculated gas demand: none of the scenarios for 2030 or 2050 estimates a gas demand higher than 4 100 TWh/a. Any additional restrictions not taken into account in this analysis would only represent a limitation to European gas production, or more generally energy supply, if they reduce the technical potential significantly.

[22] JRC (2018). Wind potentials for EU and neighbouring countries: Input datasets for the JRC-EU-TIMES Model; LBST (2016). Renewables in Transport 2050; Germanischer Lloyd, Garrad Hassan and Partners, Windtest KWK (1995). Study of Offshore Wind Energy in the EC; IWES (2012). Windenergie Report Deutschland 2011; DLR (1992). Solarthermische Kraftwerke im Mittelmeerraum, Deutsche Forschungsanstalt für Luftund Raumfahrt/Zentrum für Sonnenenergie und Wasserstoffforschung; DLR (2005). Concentrating solar power for the Mediterranean region, Stuttgart, 2005; Büro für Technikfolgen-Abschätzung beim Bundestag (2003), Möglichkeiten geothermischer Stromerzeugung in Deutschland; Stefansson, V. (2005). World Geothermal Assessment. *Proceedings World Geothermal Conference 2005*, Reykjavik.

Figure 2-4 Hydrogen production potential EU 28



2.3 Potential availability of biomethane

The assessment of the biomethane production potential is focusing on the EU28, but the potential in Eastern Europe is also discussed briefly in view of possible imports to the EU. EU natural gas regulations cover biomethane network access, and European standards cover biomethane injection into the gas network (EN 16723-1:2016) and its use in the transport sector (EN 16723-2), both under responsibility of CEN Working group TC408.[23] These regulations and standards form an important basis for the development of the biomethane market in Europe. The potential development of renewable methane is limited by the availability of biomass resources, by the implementation of more strict sustainability criteria under the Renewable Energy Directive (RED II), and by competing uses for food, feed and feedstock production.

Feedstocks for bioenergy production include agricultural and forestry substrates and residues as well as by-products such as straw or manure. Energy crops for bioenergy production can be grown on agricultural land including both farmland and grassland. The availability of the latter for conversion into biomethane is limited due to competitive uses such as for food and feed production, material use of feedstocks, different types of energy production, nature protection, etc.

Competition for surface areas and biomass feedstocks exists on different levels including the selection of crops (e.g. maize for biogas production, grain for bioethanol production, short-rotation forestry for heat production, etc.), competition for electricity, heat or fuel production, competition for food and feed crop production, competition for material use (e.g. in the wood industry or for bio-based insulation materials), temporal or permanent reservation for nature protection purposes, etc.

The recast of the Renewable Energy Directive (RED II)[24] emphasizes the need to ensure that the waste hierarchy[25] and a set of sustainability criteria[26] are taken into account, that indirect land use change is avoided or minimized while promoting the use of wastes and residues, and that no significant distortive effects on markets for (by-)products, wastes or residues are created. RED II defines that only energy from biomass fuels (including gaseous fuels) fulfilling the sustainability criteria is eligible for (a) counting towards the overall Union renewable energy target for 2030 and the renewable energy shares of Member States, (b) measuring compliance with renewable energy obligations to be set on

[23] European Commission (2017). Optimal use of biogas from waste streams.
[24] Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources (recast); OJ L 328/82, 21.12.2018
[25] See Directive 2008/98/EC: a) prevention; (b) preparing for re-use; (c) recycling; (d) other recovery, e.g. energy recovery; and (e) disposal.
[26] As defined in art. 29 of RED II

fuel suppliers by the Member States through national transposition of RED II, and (c) financial support.

Compared to the Renewable Energy Directive of 2009[27] some of the sustainability criteria in RED II are new and have thus not been taken into account by any of the studies used as the basis for the potential estimates.

Greenhouse gas savings are required to be at least 65% for biogas in transport relative to the fossil fuel comparator defined in RED II Annex VI from 2021, and at least 80% for electricity, heating and cooling production from 2026. Standard values included in Annex VI show that these values can be achieved with standard technologies (close digestate, off-gas combustion).

A detailed assessment of all sustainability criteria with respect to the technical biogas potential in the EU is beyond the scope of this study, but would be instrumental in understanding further limitations to the biomethane potentials estimated in the following sections. Although these limitations have been taken into account, the technical potentials may still be more limited than estimated in this study as the understanding of these limitations will improve over time, and the limitations may evolve over time through additional sustainability criteria defined by Member States through the national transposition and potential harmonisation thereof by the end of 2026 (art. 29(14)), as well as through implementing acts to be adopted by the Commission by the end of 2021 establishing the operational guidance on the evidence for demonstrating compliance with the criteria related to forest biomass derived from unsustainable production and LULUCF.

2.3.1 Current biogas / biomethane production in the EU

In 2016, some 193 TWh of biogas were produced in the EU.[28] It was mainly used for electricity generation, followed by heat production and use as a transportation fuel.

Biomethane production for direct use in transport or for injection into the gas network for use in heating or transport represents 11% of biogas production in Europe. Sweden and the Netherlands upgrade significant shares of their biogas to biomethane (status: 2015): Sweden (66%; 61 plants), the Netherlands (19%; 21 plants); Germany upgrades 10% of its biogas to biomethane (185 plants). In 2015, biomethane was produced in 414 plants in the EU (plus 45 in Iceland, Norway and Switzerland) producing an estimated 1.2 billion m^3. Of these, at least 305 plants in the EU (plus 35 in Iceland, Norway and Switzerland) feed into the gas network, with a capacity of at least 1.5 million m^3. About 697 biomethane filling stations provided some 160 million m^3 of biomethane to transport in 2015.

Figure 2-5 shows the biogas production in the EU28 in 2016 by Member State and by feedstock.

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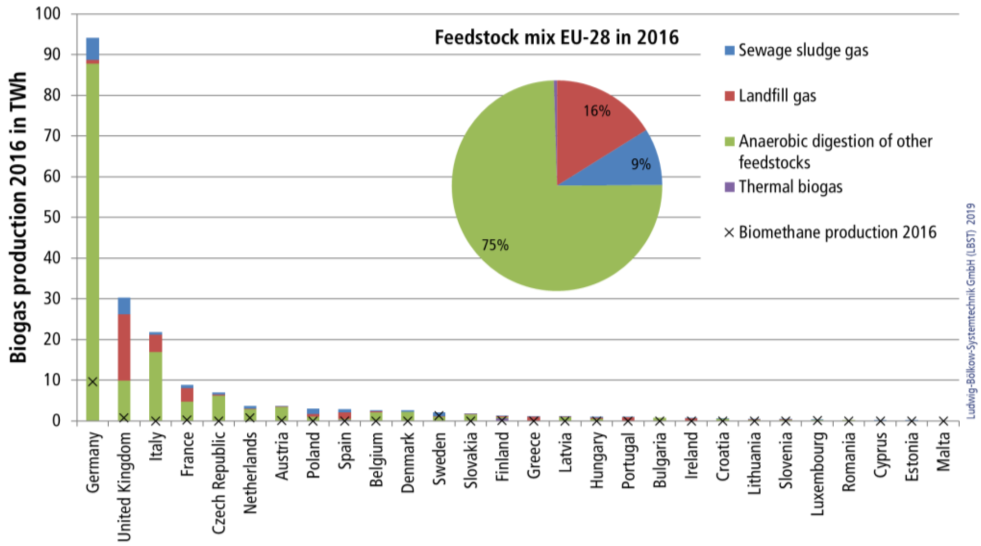
[27] Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC; OJ L 140/16, 5.6.2009

[28] Eurobserv (2019). Online Data-Base.

Switzerland) feed into the gas network, with a capacity of at least 1.5 million m^3.[29] About 697 biomethane filling stations provided some 160 million m^3 of biomethane to transport in 2015. [30]

Figure 2-5 Current biogas production in the EU



Source: Eurobserv (2019). Online Data-Base; Scarlat, N. et al (2018). European Biogas Association (2017) [31]

2.3.2 BIOMETHANE PRODUCTION POTENTIAL

The biomethane potentials considered in this study focus on the technical and so-called mid-term potentials in EU28. Data considered here are notably taken from Kovacs 2015[32], GreenGasGrids 2012, 2013,[33] DBFZ 2016,[34] Deutsche Energie-Agentur GmbH 2017[35], DVGW 2018,[36] and Navigant 2019.[37]

The technical potential, which does not include round wood and limits using energy crops to values compatible with sequential cropping, does not take into account competing uses of the biomass for energy production beyond the current use[38] as biomethane production and consumption is considered as the most efficient bio-energy use.[39] In other words, the technical potential assumes that all bioenergy not used today is available for biogas / biomethane production; other energetic uses are excluded. This assumption of using the full potential of bioenergy for biomethane production does not leave room for applying bio-energy with carbon capture and storage (BECCS) to biomass-fired power plants. The latter is relied upon rather heavily by many climate neutral scenarios compensating unavoidable greenhouse gas emissions through negative emissions from BECCS. However, upgrading

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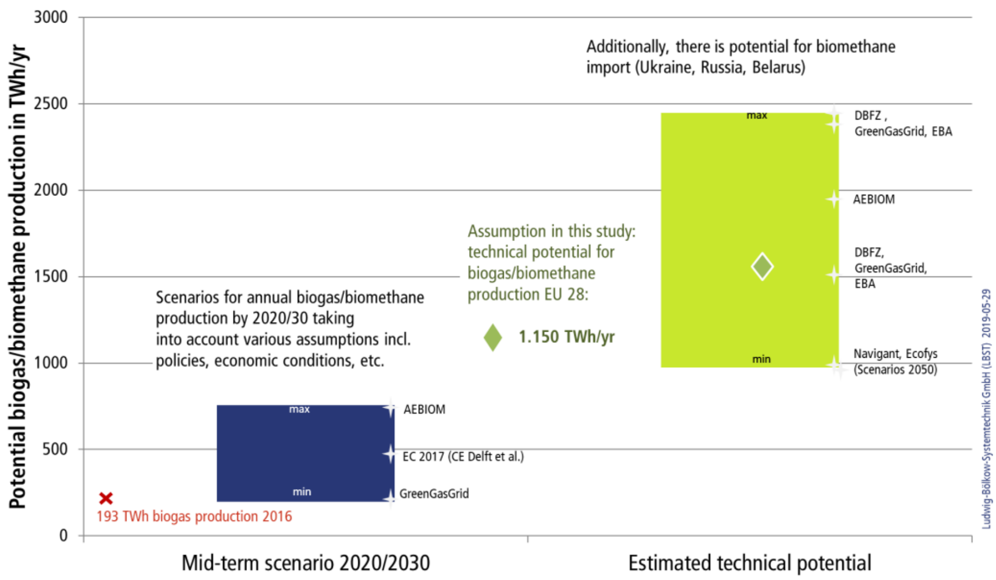
[29] For a number of major biomethane producers including Germany and the UK, the quantities injected into the network are not listed in *Scarlat, N.; Dallemand, J.-F.; Fahl, F. (2018), Biogas. In: Renewable Energy*; therefore, the quantity of biomethane injected into the network is probably much higher.
[30] Scarlat, N., Dallemand, J.-F., Fahl, F., Monforti, F., & Motola, V. (2018). A spatial analysis of biogas potential from manure in Europe. *Renewable and Sustainable Energy Reviews* 94(2018): 915-930.
[31] Scarlat, N.; Dallemand, J.-F.; Fahl, F. (2018). Biogas: Developments and perspectives in Europe. *Renewable energy* 129(2018): 457-472. DOI: https://doi.org/10.1016/j.renene.2018.03.006; European Biogas Association (2017), Statistical Report of the European Biogas Association 2017, Brussels
[32] Kovacs (2015). Biomethan – Beitrag zur zukünftigen Energieversorgung in Europa, European Biogas Association, Berlin, 4/27/2015.
[33] GreenGasGrids (2012). GGG Workshop Biomethane Trade, Brussels & GreenGasGrids (2013). Biomethane Guide for Decision Makers, Oberhausen.
[34] Deutsches Biomasseforschungszentrum - DBFZ (2016). Bewertung technischer und wirtschaftlicher Entwicklungspotenziale künftiger und bestehender Biomasse-zu- Methan-Konversionsprozesse.
[35] Dena (2017), Rolle und Beitrag von Biomethan im Klimaschutz heute und in 2050
[36] DVGW (2018), Die Rolle von Gas im zukünftigen Energiesystem
[37] Navigant (2019). Gas for Climate. The optimal role gas in a net-zero emissions energy system, Utrecht.
[38] Ibid.
[39] Kovacs (2015), Biomethan – Beitrag zur zukünftigen Energieversorgung in Europa, European Biogas Association, Berlin, 4/27/2015.

biogas to biomethane includes capturing the CO_2 contained in the biogas. These carbon streams could be transported and geologically stored resulting in negative emissions. The costs of CO_2 transport and storage, however, are not included in the cost estimates of this study.

The mid-term potential is based on projections for annual biomethane and biogas production by 2020/30 taking into account various assumptions including policies, economic conditions, etc. Data considered here are notably taken from Ecofys 2018,[40] Plank 2009,[41] CE Delft et al. 2017,[42] Bundesministerium für Wirtschaft und Energie 2014.[43] Both the technical potential and the mid-term potential include the current production; in other words, for arriving at the *additionally available* potential, the current production needs to be deducted from the potential.

The EU has significant technical biogas/biomethane production potentials. Conservative assumptions result in a potential of ~1 000 to 1 500 TWh per year[44] while assuming more progressive parameters results in potentials of up to 2 500 TWh per year[45]. For comparison, in 2016 the biogas production in EU28 was 193 TWh (of which 12 TWh biomethane), thus the biogas/biomethane potentials exceed the current production by a factor of 7 to 12.

Figure 2-6 Potential biomethane production EU28 in 2050



Sources: LBST based on data from EurObserv 2019, Online Data-Base. DBFZ 2016, Ecofys 2018, Navigant 2019, Scarlat et al. 2018, Kovac 2015, DENA 2017, CE Delft et al. 2017, GreenGasGrid 2013, Biosurf 2015.[46]

[40] Ecofys (2018). Gas for Climate - The optimal role gas in a net-zero emissions energy system, Utrecht.
[41] Plank (2009). Biogas Road Map for Europe, Austrian Biomass Association, 9/22/2009.
[42] CE Delft, Eclarion & Wageningen Research (2017). Optimal use of biogas from waste streams.
[43] Bundesministerium für Wirtschaft und Energie (2014), Potenziale der Biogasgewinnung und Nutzung
[44] Navigant (2019), Gas for Climate. The optimal role gas in a net-zero emissions energy system, Utrecht & Ecofys (2018), Gas for Climate
[45] Kovacs (2015), Biomethan – Beitrag zur zukünftigen Energieversorgung in Europa, European Biogas Association, Berlin, 4/27/2015 & Deutsches Biomasseforschungszentrum - DBFZ (2016). Bewertung technischer und wirtschaftlicher Entwicklungspotenziale künftiger und bestehender Biomasse-zu- Methan-Konversionsprozesse
[46] Deutsches Biomasseforschungszentrum - DBFZ (2016), Bewertung technischer und wirtschaftlicher Entwicklungspotenziale künftiger und bestehender Biomasse-zu- Methan-Konversionsprozesse; Ecofys (2018). Gas for Climate - The optimal role gas in a net-zero emissions energy system, Utrech; Navigant (2019). Gas for Climate - The optimal role gas in a net-zero emissions energy system, Utrecht; Scarlat, N., Fahl, F., Dallemand, J-F., Monforti, F., & Motola, V. (2018). A spatial analysis of biogas potential from manure in Europe. *Renewable and Sustainable Energy Reviews* 94(2018): 915-930; Kovacs (2015). Biomethan – Beitrag zur zukünftigen Energieversorgung in Europa, European Biogas Association, Berlin, 4/27/2015; DENA, LBST (2017). "E-Fuels" Study, The Potential of electricity-based fuels for low-emission transport in the EU, Berlin; CE Delft, Eclarion & Wageningen Research (2017). Optimal use of biogas from waste streams; GreenGasGrids (2013), Biomethane Guide for Decision Makers, Oberhausen; Biosurf (2015). Report on current and future sustainable biomass supply for biomethane production

For this study, a conservative technical biogas/biomethane production potential of 1 150 TWh/yr has been assumed for EU28 (see Figure 2-6). Competing uses of areas have been taken into account by giving priority to food and feed production as well as to material use, by excluding round wood for bioenergy beyond current use, and by limiting energy crops to a value compatible with sequential cropping[47]; all other feedstocks are residues and wastes. Subtracting the current biogas production, results in an *additionally available* potential of 957 TWh/yr. This additional potential may grow until 2050 if the current use of bioenergy, e.g. for electricity or heat production, would decrease as a consequence of energy efficiency measures and thus would make bioenergy resources available for biomethane production. This impact would not directly change the overall technical potential, but it may affect the scenario calculations.

Detailed, bottom-up technical potential data by Member State and by feedstock are lacking; most studies analyse EU28 as a whole. CE Delft *et al.* have carried out an analysis by Member State[48], however, this has to be considered as a mid-term potential rather than a technical potential. The GreenGasGrids and the BIOSURF projects have published detailed assessments of selected, but not all, Member States.[49] A detailed country analysis has been carried out by Scarlat, N. *et al*. 2018 for manure, which provides for a limited contribution to the technical potential.[50]

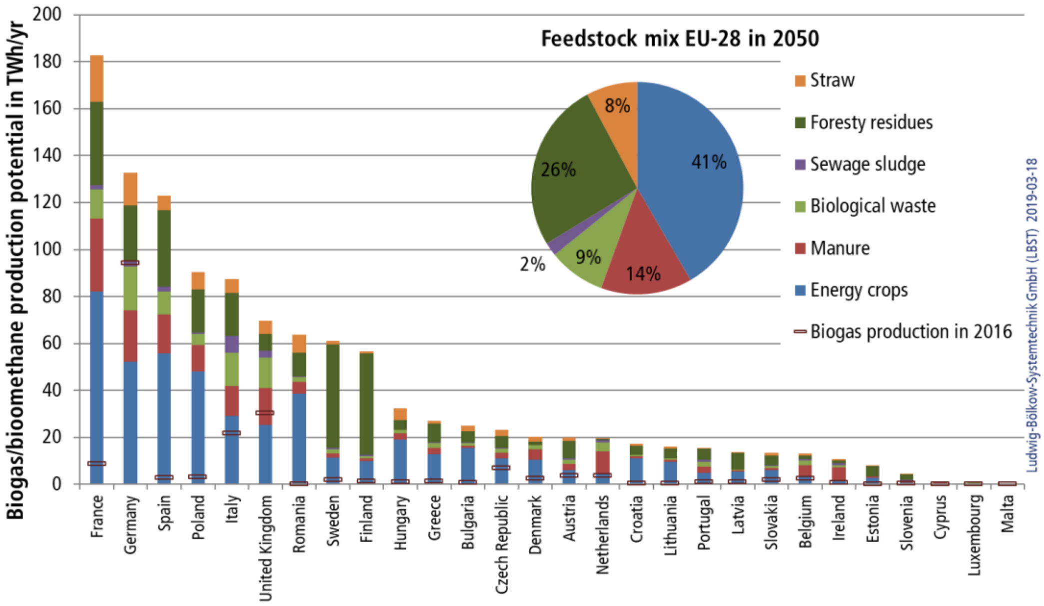
The total technical biomethane production potential of 1 150 TWh/yr assumed for this study is broken down by feedstock as shown in Table 2-1. In order to estimate the biomethane potential for each Member State, the total potentials were broken down by country for each feedstock separately in a simplified approach. Figure 2-7 shows the resulting overall biogas/biomethane production potential by country and by feedstock.

Table 2-1 Estimates of biomethane production potential EU 28 by feedstock

Substrate	Gas production potential in TWh/yr
Agricultural biomass	639
of which manure	160
of which energy crops	479
Biological waste	100
of which household waste	80
of which municipal waste	20
Straw	90
Forestry residues	298
Sewage sludge	24
Total	**1,150**

47 Navigant (2019). Gas for Climate. The optimal role gas in a net-zero emissions energy system, Utrecht.
48 CE Delft, Eclarion & Wageningen Research (2017). Optimal use of biogas from waste streams.
49 GreenGasGrids (2012). GGG Workshop Biomethane Trade, Brussels. & Biosurf (2015). Report on current and future sustainable biomass supply for biomethane production.
50 Scarlat, N., Fahl, F., Dallemand, J.-F., Monforti, F., & Motola, V. (2018). A spatial analysis of biogas potential from manure in Europe. *Renewable and Sustainable Energy Reviews* 94(2018): 915-930.

Figure 2-7 Technical biomethane potential EU28 by Member State and by feedstock



Sources: LBST based on data from DBFZ 2016, Ecofys 2018, Scarlat et al. 2018, DBFZ 2007, Kovac 2015, DENA 2017, CE Delft et al. 2017, GreenGasGrid 2013, Biosurf 2015.[51]

2.3.3 BIOMETHANE PRODUCTION COST

Biomethane production costs have been assessed based on a literature review including the following sources: European Biogas Association 2016,[52] IEA Bioenergy 2014,[53] University of Oxford 2017,[54] Kovacs 2015,[55] Navigant 2019.[56]

Biomethane costs include biogas production costs, costs of upgrading to biomethane, and injection costs into the gas network. Biogas production costs vary significantly by substrate, and also by plant size, by technology applied and further parameters. For each Member State, biomethane production costs by substrate were combined with the country potential for production from these substrates to give a weighted average production cost per country (see Table 2-2).

[51] Deutsches Biomasseforschungszentrum - DBFZ (2016), Bewertung technischer und wirtschaftlicher Entwicklungspotenziale künftiger und bestehender Biomasse-zu- Methan-Konversionsprozesse; Ecofys (2018). Gas for Climate - The optimal role gas in a net-zero emissions energy system, Utrecht; Scarlat, N., Fahl, F., Dallemand, J-F., Monforti, F., & Motola, V. (2018). A spatial analysis of biogas potential from manure in Europe. *Renewable and Sustainable Energy Reviews* 94(2018): 915-930; Kovacs (2015). Biomethan – Beitrag zur zukünftigen Energieversorgung in Europa, European Biogas Association, Berlin, 4/27/2015; DENA, LBST (2017). "E-Fuels" Study, The Potential of electricity-based fuels for low-emission transport in the EU, Berlin; CE Delft, Eclarion & Wageningen Research (2017). Optimal use of biogas from waste streams; GreenGasGrids (2013), Biomethane Guide for Decision Makers, Oberhausen; Biosurf (2015). Report on current and future sustainable biomass supply for biomethane production

[52] European Biogas Association (2016) Biomethane in Transport.

[53] IEA Bionergy (2014). Biomethane - Status and Factors Affecting Market Development and Trade. A Joint Study by IEA Bioenergy Task 40 and Task 37.

[54] University of Oxford (2017) Biogas: A significant contribution to decarbonising gas markets?, Oxford.

[55] Kovacs (2015). Biomethan – Beitrag zur zukünftigen Energieversorgung in Europa, European Biogas Association, Berlin, 4/27/2015.

[56] Navigant (2019). Gas for Climate. The optimal role gas in a net-zero emissions energy system, Utrecht.

Table 2-2 Weighted average biomethane production costs by Member State; production costs by feedstock

Biomethane production, upgrade and injection				Crops	Manure	Biological waste	Sewage sludge	Forestry	Straw
in:	ct/kWh		ct/kWh	ct/kWh	ct/kWh	ct/kWh	ct/kWh	ct/kWh	ct/kWh
Austria	6.56	**Italy**	6.78	8.5	6.3	6.5	4.5	4.9	8.5
Belgium	6.81	**Latvia**	6.51						
Bulgaria	7.59	**Lithuania**	7.34						
Croatia	7.52	**Luxembourg**	6.82						
Cyprus	7.17	**Malta**	6.76						
Czech Republic	7.26	**Netherlands**	6.77						
Denmark	7.57	**Poland**	7.36						
Estonia	6.38	**Portugal**	6.56						
Finland	5.64	**Romania**	7.67						
France	7.25	**Slovakia**	7.02						
Germany	7.14	**Slovenia**	5.87						
Greece	7.03	**Spain**	7.03						
Hungary	7.78	**Sweden**	5.74						
Ireland	6.52	**UK**	7.10						

2.3.4 EASTERN EUROPE – POTENTIAL FOR BIOMETHANE IMPORT AND COSTS

Russia, Ukraine and Belarus have an interesting technical potential for biogas production (see Table 2-3).[57] However, the domestic energy demand and the need to decarbonise the national energy supply in the future may only leave limited room for exports of biomethane to the Europe Union. Future energy policies, production practices and the regulatory environment in these countries together with the policy and market development in the European Union, will decide on whether importing biomethane will become a realistic option. So far, the biogas sector in the three countries is in very early stages; biomethane upgrading is not applied yet.

Table 2-3 Estimates of biomethane production potential in Eastern Europe[58]

	Biomethane production potential	Production costs
Country	**TWh/yr**	**Ct/kWh**
Russia	732	7.5
Ukraine	212	7.5
Belarus	41	7.5

3 TECHNICAL AND ECONOMIC IMPACT OF INCREASING INJECTION OF BIOMETHANE AND HYDROGEN INTO GAS INFRASTRUCTURE

3.1 TODAY'S EUROPEAN GAS INFRASTRUCTURE AND ITS MAJOR COMPONENTS FOR TRANSPORT AND DISTRIBUTION

The European natural gas network across the EU Member States constitutes more than 200,000 km of transmission pipelines, over 2 million km of distribution network and over 20,000 compressor and pressure reduction stations[59]; in 2017 natural gas represented 22% of the EU's total final energy consumption.[60] The share of biomethane and hydrogen

[57] Deutsches Biomasseforschungszentrum - DBFZ (2012)
[58] Deutsches Biomasseforschungszentrum - DBFZ (2012)
[59] Council of European Energy Regulators (2018). CEER Benchmarking Report 6.1 on the Continuity of Electricity and Gas Supply
[60] European Commission (2017). Energy balance sheets2017 Edition, Luxemburg.

in the European gas network is still rather low, but it is expected to substantially increase, mainly as a result of decarbonisation targets and policies.

While the current gas infrastructure (including end-use appliances) can in general be used for a mixture of natural gas and biomethane, or for 100% biomethane, without major technical adaptations as long as the gas quality specifications are met, strict technical limitations apply for the admixture of hydrogen. Since hydrogen differs significantly from natural gas in its chemical properties, any admixture will have a direct effect on the gas-mixtures' chemical and physical behaviours, including density, reactive properties, calorific value, ignition energy, flammability limits and burning velocity. Thus, existing networks that are designed to transport and distribute natural gas can only be used to transport blends of natural gas and hydrogen up to a certain limit, which can be different depending on the type and characteristics of the network one the one hand and the end-user appliances on the other hand. For higher percentages of admixtures, and a fortiori for 100% hydrogen, technical modifications and/or new infrastructure or equipment are required.

3.2 Assessment of the technical and regulatory admixture limits for hydrogen and biomethane

3.2.1 Technical limitations for the admixture of hydrogen

The hydrogen admixture implications are widespread: transport or distribution infrastructure can either be highly sensitive concerning gas quality fluctuations or be specifically suitable to accept large hydrogen admixture rates due to the point to point supply/demand connections being simpler to control. Today, there is no consistent policy and regulatory framework in place to allow small or large-scale injection of hydrogen to the gas network, neither at national nor at European level.

The major concern of Gas System Operators is the potential impact of hydrogen admixture on cross-border gas transmission and underground gas storage (UGS) But even though smaller in number, hydrogen sensitive large volume industry end-users are today also directly served from the transport network, necessitating the TSOs to control the hydrogen admixture rates in their gas network. Moreover, as networks of Distribution System Operator (DSO) are fed by TSO pipelines, end-users' restrictions concerning the hydrogen content valid for the DSO-level directly also affect the gas transporting TSOs.

Consequently, both DSOs and TSOs have to deal with the direct impact on end-use applications, resulting from higher or fluctuating hydrogen concentrations in the gas flow. In addition, the household sector is typically characterised by a seasonally fluctuating gas demand, making constant admixture rates a challenging control task and therefore requiring sufficiently large sized hydrogen storage facilities to level out any hydrogen admixture versus hydrogen demand imbalances. These storage facilities to be located at the interface from TSO and DSO could principally be operated by both TSO and DSO, with TSOs being in charge of large-scale gas storage facilities while both TSOs and DSOs have experience in line-pack, which is used to balance out fluctuations.

According to HyLaw[61], a key concern for both gas network operators (TSOs and DSOs) and appliances' producers is the threshold agreed for which overall appliance design and individual component changes will need to be made in the short- or medium-term. As a first step in tackling the challenge of setting an acceptable hydrogen limit value for end-user equipment, HyLaw recommends an EU wide assessment, covering both the acceptable safety and operational threshold of current generation end-user appliances by main category (domestic, commercial, industrial) for higher levels of hydrogen in the gas stream in conjunction with a status quo supply chain assessment of the economic impact,

[61] HyLAW (2019) Deliverable 4.2- List of Legal Barriers. Available at https://www.hylaw.eu/sites/default/files/2019-01/D4.2%20-%20List%20of%20legal%20barriers.pdf

if modifications are needed in certain categories of end-user equipment. This should be coordinated with the ongoing national initiatives to validate gas network operation with significantly higher hydrogen concentrations that are being trialled (such as in DE, FR, NL & UK) and where the impact on gas appliances is also assessed.

As a consequence, there is a need to take inventory of the various activities at EU level targeting a harmonization and overcoming legal and regulatory barriers with respect to injecting hydrogen into the gas network (which is for instance also the objective of the HyLaw project); in order to avoid addressing this topic in silos, it is further recommended to organize a European round table with all relevant stakeholder groups and industry associations, West and East, for which the drafting of the EU Gas Market Regulation planned for 2019/2020 seems an appropriate opportunity.

Nevertheless, it has to be assumed that the negotiation of an EU wide standard for admixture of hydrogen may take a long time, especially given the regulatory complexity and diversity of stakeholders. For example, negotiating the standard CEN/TC 408 "Natural gas and biomethane for use in transport and biomethane for injection in the natural gas grid",[62] with the aim to harmonise the quality of biomethane across the EU, took six years from 2011 to 2017. With over 470 million gas appliances in the EU that would be affected by a change in gas composition, and given that the sectors Industry and Power generation, which have some of the most sensitive end-users and account for over 50% of total gas use in the EU, finding a common denominator will be a daunting task.[63]

As a consequence, the current practice is that permitting hydrogen admixture to the gas network is considered on a case by case basis, with the outcome that Power-to-Gas (PtG) facilities are run on a demonstration basis or 'by exception'. This provides according to Hylaw (2018) no sound framework to create a business case for the widespread rollout of PtG operations.[64]

Furthermore, adding hydrogen to the gas stream changes the calorific value and the Wobbe-Index[65] of the gas mix and thereby the basis for metering and billing gas supplies under contract to major and multiple users or into distribution networks. Therefore, significant investments will be required in qualified flow monitoring/measurement equipment and/or revisions to regulated national gas metering and billing terms – and may also constrain international gas flow arrangements.

Managing volatility in the gas composition and in particular variations of the calorific valorific of the gas mix will be a crucial success factor to enable higher hydrogen concentrations, beyond technical adjustments to end-user equipment. One way out are constant admixture rates through sufficiently sized hydrogen storages at the TSO/DSO interface, to allow the gas network to offer its dampening service for fluctuations in the electricity network typically understood as a key task of Power-to-Gas concepts. Without sufficiently large scaled storage capacities, the necessity of constant admixture rates seems to be in strong contradiction to the promise of PtG facilities to serve as a flexibility mechanism to support the electricity network in balancing its own fluctuations resulting from an increasing share of intermittent renewables.[66]

Imbalances are expected to be likely among Member States' interests and 'urgency to act' when it comes to adjusting or drafting EU wide regulations to enable higher hydrogen concentrations in the gas network. To illustrate this point:

[62] CEN (2018). New CEN Standards - Biomethane standards to mitigate climate change.
[63] DG ENER (2018). The Role of Trans-European Gas Infrastructure in the Light of the 2050 Decarbonisation Targets, 2018.
[64] HyLAW (2018). Cross-country comparison.
65 Wobbe index or Wobbe number: The WI is an indication of the interchangeability of different energy or fuel gases (e.g. natural gas, liquefied petroleum gas (LPG) as well as town gas containing a hydrogen share). It mainly considers the gases' higher heating (or calorific) value and specific gravity.
[66] Yet, this is only one objective of PtG concepts; others being to provide a CO_2-lean or eventually CO_2-free fuel to industry and mobility.

- Only five countries (Germany, UK, Italy, the Netherlands and France) account for around two-thirds of gas use in Europe.[67]
- More than 50% of all Power-to-Gas demonstration plants in the EU are located in Germany.[68]
- The UK is currently leading efforts in trialling hydrogen to fully replace natural gas by 100% hydrogen in local/residential gas networks (see for example the Leeds CityGate project[69] or HyHouse[70], HyDeploy[71], HyNet[72] and Hy4Heat[73]).
- The Netherlands has very ambitious plans for the introduction of hydrogen, as fossil gas is supposed to be widely phased out by 2030.[74]

As an alternative approach to an EU wide harmonization, it may therefore be easier and quicker to explore options for creating "favourable" regulation at DSO level in individual Member States that allow the creation of locally "ringfenced" sections of the network that run on higher hydrogen concentrations, favourably at 100% hydrogen, as is being suggested for trial in the UK. Promoting such "islands" will provide very valuable learnings and operational experience and enable a scale-up by connecting adjacent "islands" over time. On the other hand, also selected TSOs are keen to initiate hydrogen admixture rates. These approaches have a high risk of failure unless

- an EU wide regulated agreement with one single admixture rate (e.g. 10 or 20 vol%) can be put into place in EU28 as soon as possible[75], or
- technologies to extract the hydrogen from mixed flows can be installed in networks, which are hydrogen sensitive (e.g. CNG fuelling stations). These additional investments could however challenge the economics of these network sections or appliances.

Even if a (constant) 10-20 vol% admixture rate may be technically feasible (both at TSO and DSO level), the cost-benefit of the necessary adjustments seems more questionable and cannot be conclusively answered today; all the more as the volumetric energy content of hydrogen is around one third only of natural gas, unless flow velocities are significantly increased (e.g. doubled to about 20 m/sec).

From this perspective, a direct shift to a dedicated hydrogen (pipeline) infrastructure probably also on TSO level may be a more preferable and cost-effective approach to supply e.g. those industry branches seeking to de-carbonise their operations, such as the steel, chemical or cement industry. Dedicated hydrogen pipelines would avoid the necessary and potentially incremental adjustments of the existing gas infrastructure and end-use applications (this could be the subject of a separate study, which would investigate the (CO_2) cost-effectiveness of incremental adjustments of the existing gas network to higher hydrogen concentrations vs. directly building a dedicated hydrogen pipeline infrastructure). This approach would furthermore be the key to provide fuel cell grade hydrogen for the mobility sector, and hence allow to taking profit from doubling the efficiency of internal combustion by fuel cell electric engines for mobility. Building such a dedicated hydrogen gas infrastructure could be started by converting segments of the existing natural gas network to 100% hydrogen, where early local business cases could emerge, e.g. with an industrial end-user. Over time, these building blocks could be merged to establish a wider pure hydrogen pipeline network in a robust fashion (as illustrated in Figure 2-5). The underlying assumption of this possible full conversion to hydrogen

[67] University of Oxford (2017). Biogas: A significant contribution to decarbonising gas markets? Oxford
[68] LBST, Internal Data, Munich.
[69] https://www.northerngasnetworks.co.uk/2017/04/27/northern-gas-networks-hydrogen-project-takes-step-forward-as-25-million-fund-announced-for-hydrogen-in-homes/
[70] http://www.igem.org.uk/media/361886/final%20report_v13%20for%20publication.pdf
[71] https://hydeploy.co.uk/
[72] https://hynet.co.uk/
[73] https://www.hy4heat.info/
[74] van't Hof (2018). Energy transition in the Netherlands – phasing out of gas, Ministry of Economic Affairs and Climate Policy.
[75] In chapter 3.2.3 detailed considerations are provided on gas grid implications from significant hydrogen admixture rates.

anticipates that the need for natural gas will and has already begun in some Member States to decrease freeing transport and distribution capacity for hydrogen.

3.2.2 TECHNICAL AND REGULATORY ADMIXTURE LIMITS FOR BIOMETHANE

In comparison to an admixture of hydrogen to the gas network, no technical or regulatory barriers exist, which might principally question biomethane admixture rates up to 100 vol% as long as the technical specifications and standards, yet to be transferred to European Regulations or Directives, are fulfilled. Even though limited in occurrence, an issue of practical concern could be that in decentralised biomethane schemes (biomethane plants injecting into the distribution network), reverse flows with decentralised compression from distribution to transport network need to guarantee sufficient feed-in rates allowing for relevant business cases in (seasonal) periods of low gas demand (typically in summer).

Also, and for the latter reason, biomethane admixed to the natural gas network should not be foreseen in distribution networks with hydrogen admixture, as hydrogen could then escape into transport network sections locked for hydrogen admixture, unless:

- A fixed hydrogen admixture rate is enforced for the gas transport network Europe-wide, or
- Hydrogen can be extracted from the bottom-up gas flow once it leaves the distribution network.

3.2.3 POSSIBLE WAY FORWARD FOR HYDROGEN ADMIXTURE

When considering the future admixture of hydrogen and/or biomethane to the gas network, the analysis has shown that transport and distribution networks (TSO/DSO level) have to be distinguished. Figure 3-1 illustrates and summarises the major constraints with respect to the injection of hydrogen and biomethane into the gas network, taking into account the TSO and DSO perspectives.

Admixture of hydrogen to central parts of the gas transmission network, i.e. border-crossing main pipes in one Member State, may carry hydrogen to any location in the EU downstream of the injection point at an uncontrollable admixture level. Unless (locally) removed from the gas mixture – which is neither to be considered cost-effective nor practical today,[76] as there may be no nearby end-user for the hydrogen extracted – this hydrogen could potentially affect any gas consumer across Europe and conflict with the current regulations on gas quality which are different for all Members States. As outlined above, a specific challenge will furthermore be caused by the volatility of admixture over time and by region. Therefore, unless and until a harmonized regulation for Europe is in place (enforcing one harmonised and constant admixture rate of e.g. 10 vol%), hydrogen injection into cross-border transmission pipelines cannot be considered a viable option. A low agreed admixture rate could also result in a lock-in at low energy level (10 vol% is equivalent to only about 3.5 energy%), and continuous rate increases would result in constant refurbishment investments of all end-use applications. In other words, if the introduction of hydrogen into the transport network, i.e. also to import hydrogen from outside of Europe and admixed to the natural gas, then all possible efforts have to be undertaken to adapt the current regulations Europe-wide, East and West.

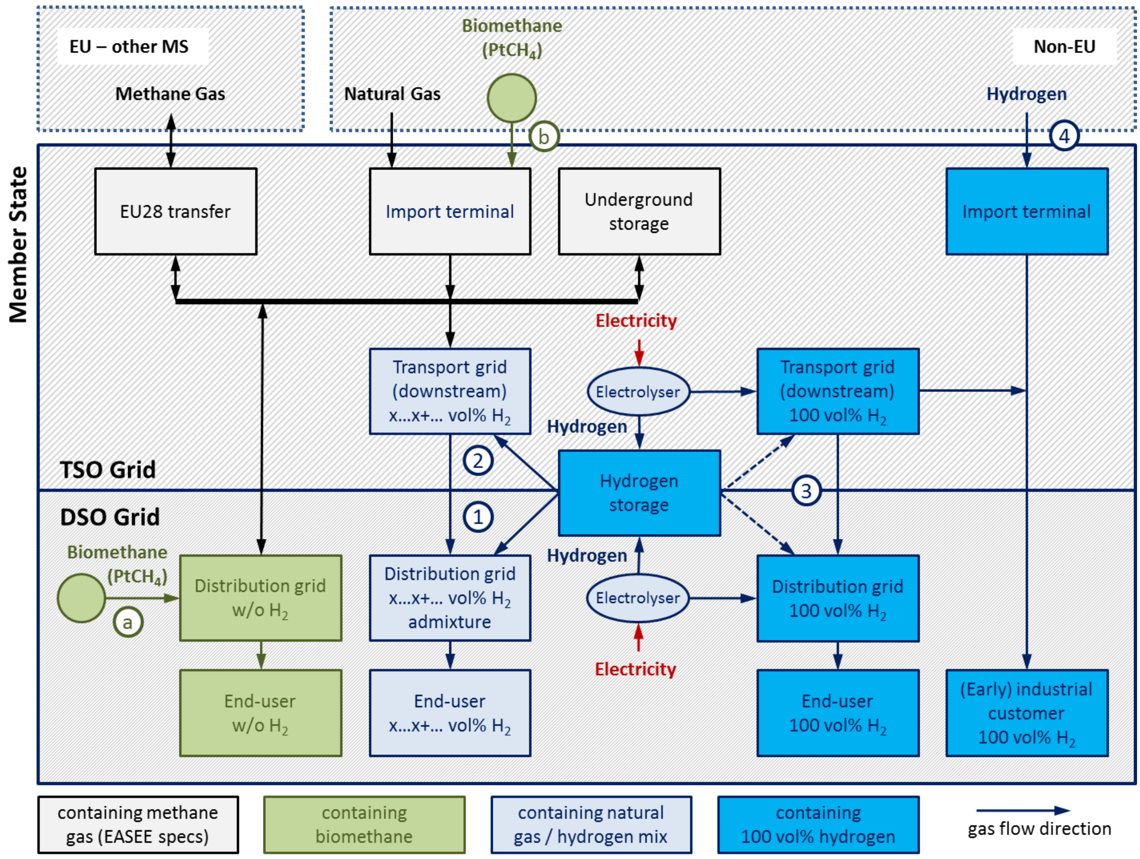
When it comes to the admixture of hydrogen to the distribution network, both a merit order from an economic perspective and the stepwise evolution of gas network sections being converted to a specific (and fixed) hydrogen admixture or 100% refurbishment from a technical and regulatory perspective will need to be considered. Sections of the distribution network which can be ring-fenced from the surrounding gas network could be

[76] Ongoing research activities by the DVGW in Germany currently have been kicked-off to assess whether concepts for hydrogen separation may become economically viable to safeguarding hydrogen sensitive applications.

operated with gas mixtures at any hydrogen share up to 100% (if permitted by national regulation) and theoretically different from sector to sector. Being technically possible, this would however not be in the interest of a common EU future gas infrastructure or equipment and appliances manufacturers. In practice, however, admixture levels will be similar, as gas network components will hardly be developed for a large variety of admixture rates. The full conversion from 0 to 100 vol% hydrogen, probably only with a small investment increment over one single conversion to other admixture rates would have the additional benefit zero GHG emission reductions. However, this would imply a unidirectional flow of gas only from the transport to the distribution network and for that reason exclude decentral biomethane added to the same network segment, which may have to leave the distribution in the direction of the transport network in periods of low gas demand. In principle, the need for re-injection to the TSO network level could also become the case once hydrogen is injected into the distribution network at large scale to provide sufficient capacity for high utilization operation even in periods of low local gas demand.

Also, similar to the transport network, a constant hydrogen admixture rate would need to be guaranteed at all times and in all locations, which in turn would require sufficiently large-scale hydrogen storage for controlled admixture at the point of gas entry from the transport level or decentral injection point. Industry or households could then be adjusted to the hydrogen admixture level, which may theoretically gradually grow over time at incremental steps. However, for the reasons explained above, this seems to be rather unrealistic.

Figure 3-1 Boundary conditions for injection of hydrogen and biomethane into the gas network



4 ASSESSMENT OF THE SOCIO-ECONOMIC AND ENVIRONMENTAL COSTS AND BENEFITS OF INCREASED USE OF BIOMETHANE AND HYDROGEN

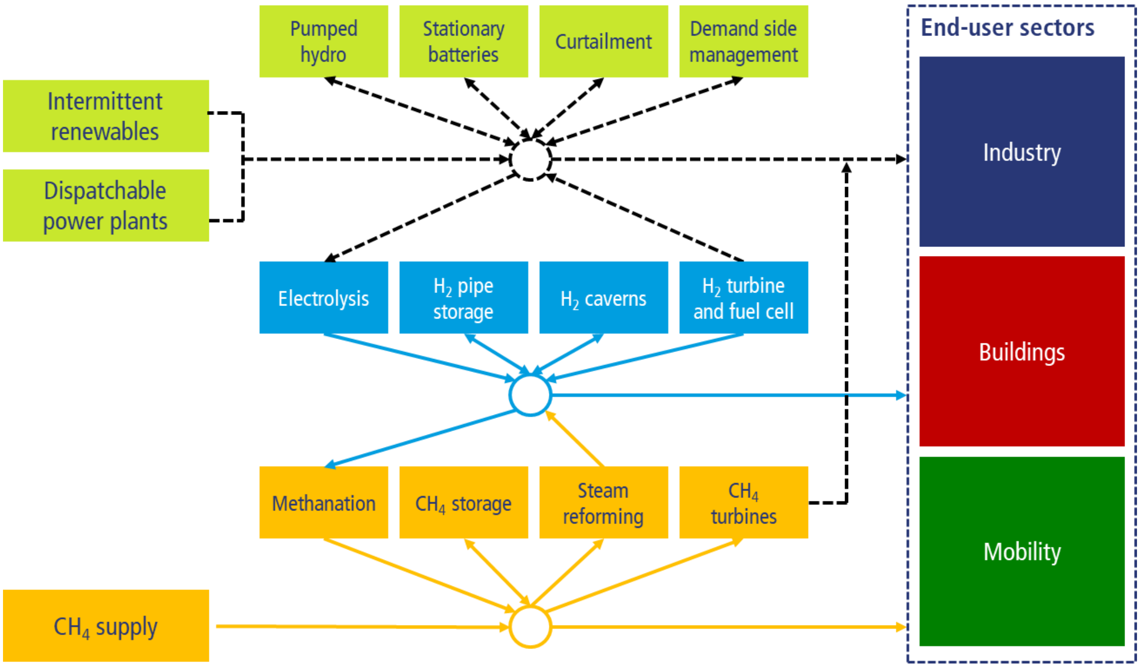
4.1 DESCRIPTION OF THE ENERGY SYSTEM INTERLINKED MODEL

The analysis of the trans-European power and gas infrastructure employs a dedicated modelling tool specifically designed by LBST to simulate and assess integrated electricity and gas energy systems.

As depicted in the figure below, the model simulates the transport of the three major energy carriers electricity, (bio)methane and hydrogen which are needed to satisfy the corresponding end-user demand in the industry (conventional power demand, process heat and H_2 or CH_4 as feedstock), buildings (conventional power, e.g. for appliances as well as energy for heating) and mobility sectors (fuel demand for vehicles in the different sub-sectors). In this study, the scenarios have an explorative character regarding the demand for the three energy carriers. The power sector is intrinsically considered in the model as the end-user demand includes electricity being one of the three energy carries within the simulation, whereas the supply of other energy carries such as coal or oil are out of the modelling scope.

In this context, the energy supply in the model takes into account different power plant types (dispatchable and intermittent power plants) as well as import and production of biomethane and fossil CH_4. The interlinkages between the electricity and both gas infrastructures are represented by electrolysis, methanation facilities, steam reforming producing hydrogen from CH_4 with Carbon Capture and Storage, stationary fuel cells as well as H_2 and CH_4 turbines which allow converting one energy carrier into another. Additional flexibility in the system is provided by energy storage technologies (e.g. pumped hydro, stationary batteries, possibly (bio)methane and hydrogen storage) as well as further measures such as demand-side management and curtailment of renewable power supply.

Figure 4-1 Energy system boundaries included within the quantitative analyses



The fundamental energy system model is formulated as a linear program with production, investment and transportation decision making assuming perfect foresight for hourly renewable generation and fuel demand profiles within a prototypical year. Due to the perfect competition assumption the underlying optimization algorithm corresponds to a minimization of total system costs. For the sake of simplicity, the spatial and the temporal dimension of the optimization algorithm are decoupled into separate model runs. This means that the hourly energy system and the limiting network topology are modelled in two consecutive modelling steps.

In the first modelling step, the short-term unit operation and the long-term investment decisions are optimized simultaneously for a European energy market and addressing all 28 Member States. The target is to match the electricity and gas supply with the pre-defined electricity and demand from all relevant energy consuming sectors for each hour of a prototypical year given the technical constraints of the concerned technologies. An additional important constraint is represented by a GHG cap for energy generation limiting the operation of fossil power plants. Investments in end-user technologies such as vehicles are out of the modelling scope. In this modelling step we also neglect the network constraints and potential investments in network capacities, which are taken up subsequently.

In the second step the model minimizes the transport costs for electricity, hydrogen and (bio)methane between the network nodes based on the results from the first and on the energy demand distributed across the nodes according to a predefined ratio. One major constraint is represented by balancing out the energy input (i.e. energy supply, storage output, energy imports from other nodes) and energy output (demand, storage input, export to other nodes) for each energy carrier, node and hour of the year. Due to a strict separation of the temporal and spatial dimensions all time-depended decision variables from the first step (e.g. storage operation or investments in new capacities) are optimised in the first modelling step and are used as input parameters in the second modelling step. In order to ensure an economic operation of the infrastructure the results from the network simulation are improved in an iterative approach to achieve a minimal utilisation of single lines between the network nodes.

The major limitation of the selected modelling approach is the separation of the temporal and the spatial dimensions into step 1 and 2. In this way, the model tends to underestimate the role of potential bottlenecks of the existing infrastructure when optimizing the investments in and operations of power and gas generation and conversion units. For example, using excess power generation from fluctuating renewable sources in remote areas for hydrogen production via electrolysis might result in large investments either in gas infrastructure capacities to transport renewable hydrogen from the remote areas to demand centres or in power infrastructure to supply renewable power to electrolysis located close to places with substantial hydrogen demand. Hence on the one hand, the model does not provide optimal results on the exact geographical distribution of the abovementioned units in order to minimize the infrastructure needs. A number of iterations between the two steps and sensitivity analyses might improve the reliability of the final outcome in this context. On the other hand, this approach allows for an optimal utilisation of fluctuating power feed-in and required storage capacities in the seasonal context. In this way the model follows an approach associated with a European internal energy market without any discriminatory barriers for all market participants in all Member States.

A further limitation of the model relates to the fact that power and gas generation and conversion are summarized per technology type (e.g. power generation from nuclear fuel, coal, gas, etc.) rather than being modelled as individual units per each technology type. Therefore, the techno-economic assumptions for the technologies such as efficiencies or specific costs represent average values and the corresponding results should also be interpreted as an average. In addition, the gird simulation is typically reduced to a limited number of grid nodes. In this way, the need for network capacities might be underestimated as some bottlenecks are neglected. Also modelling of different prototypical years might be necessary to better understand the role of flexibility measures in system with large amount of renewable energy in particular taking into account the perfect foresight assumptions which allows for a more optimistic operation of the energy system in comparison to real conditions of limited foresight.

In addition, the selected model is a fundamental and deterministic model taking a top-down approach for the representation of the energy system. In fact, it does not take into account the perspective of individual market participants, but rather minimizes the total costs from the perspective of the entire system. This implicitly assumes the existence of a perfect energy market without any information asymmetries and without strategic behaviour of single market participants. In this context, the model provides optimal results from the societal and macroeconomic perspective rather than from the business perspective of individual players. However, in reality potential imperfections in the market might lead to different outcomes in reality. The selected approach is a compromise between mathematical complexity, the required computational resources and the expected development of the future energy market taking into account transport infrastructures within one inter-linked model.

4.2 Scenario description and general boundary conditions for energy system modelling

The scenarios for further analyses are based on the three storylines "Strong electrification", "Strong development of carbon-neutral methane" and "Strong development of hydrogen" from the gas infrastructure study.[77] The major drivers for the scenario definition are the GHG emission reduction targets, end user decisions regarding the final applications[78] as well as the strategy for the gas infrastructure to follow these decisions. In general, however, the scenarios in this study have an explorative character regarding the demand for the major energy carriers.

The three considered scenarios assume ambitious reduction targets for GHG net emissions of 49% by 2030 and 100% by 2050 in comparison to the 1990 levels for the entire energy system. These targets are based on the "1.5TECH" scenario from the European Commission's long term strategic vision (LTS)[79] aiming to achieve the 1.5°C target in 2050 by taking into account all technical options for GHG reduction. According to the LTS this means full decarbonisation and even the use of Carbon Capture and Storage (CCS) and Carbon Capture and Use (CCU) technologies[80] within the energy system as a certain amount of GHG emissions such as from some industrial processes or agriculture can be considered as "unavoidable".

The end user decisions regarding their choice of final applications in the different demand sectors are the major driver for electricity and gas demand in the scenarios of this study. These decisions are based on the expected behaviour and economic considerations from the end user perspective being supported by different regulatory frameworks in particular in regard to the GHG emission reduction targets.[81] These qualitative aspects are in line with the storylines from the previous gas infrastructure study and are used for a bottom-up quantification of the final demand for electricity, (bio)methane and hydrogen within the transport, residential & services as well as industry sectors.

[77] DG ENER (2018). The Role of Trans-European Gas Infrastructure in the Light of the 2050 Decarbonisation Targets.

[78] In the context of this study end user decisions are assumed to take into account different influencing factors such as personal preferences, regulatory aspects, taxation, market decisions, etc.

[79] EC (2018). A Clean Planet for all A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy.

[80] Detailed modelling of the GHG emission in the context of CCS and CCU is out of scope of this study.

[81] In contrast to the LTS this study assumes for the three scenarios different shares of power, methane and hydrogen for end-use applications under the same set of boundary conditions which come only partially from the LTS. The assumed penetration of different end-user applications in the respective end-use sectors corresponds to different end-user choices based on the outcomes of the gas infrastructure study (DG ENER 2018. The Role of Trans-European Gas Infrastructure in the Light of the 2050 Decarbonisation Targets).

Another driver for the underlying scenarios is represented by the expected strategy to switch from natural gas to biomethane or hydrogen which has to be in line with the abovementioned demand trends and predefined GHG emission reduction targets. In this context, the three scenarios have been defined with corresponding boundary conditions for both time horizons 2030 and 2050 (see also Table 4-1):

- **Scenario 1 – "Strong electricity end-use"** corresponds to the storyline "Strong electrification" with stronger focus on electricity-based applications and thus power as a major energy carrier for renewable energy supply. Hence, lower overall gas demand in comparison to other scenarios is expected although methane and also a small amount of hydrogen can be used for applications which do not lend themselves for direct electrification. The gas infrastructure at TSO level (national and cross-border) is expected to transport mainly natural gas until 2030 which is gradually substituted by biomethane and potentially synthetic methane from Power-to-Methane ($PtCH_4$) in case biomethane is insufficient to satisfy the demand for a given GHG reduction target. The supply of natural gas is expected to follow the established import routes in Europe whereas the biomethane is injected into the gas network according to its potential per Member State giving preference to the most economic biomethane sources. The supply of synthetic methane follows the availability of renewable power generation. In general, dedicated hydrogen infrastructure at TSO level is not foreseen in this scenario except to single and separate national H_2 pipelines in case they are needed to provide larger amounts of hydrogen for big demand hubs in the long-term. The infrastructure at DSO level allows for limited admixture of hydrogen up to a predefined rate until 2030 which then can be converted to limited and separated hydrogen networks until 2050. In addition, the limited hydrogen production is expected in close proximity to the demand and the energy storage in the context of seasonality is provided solely by large-scale CH_4 storage. In this way, parallel gas infrastructures for methane and hydrogen can be avoided.

- **Scenario 2 - "Strong green methane end-use"** corresponds to the storyline "Strong development of carbon-neutral methane" where (bio)methane plays a major role as an energy carrier according to end user decisions and the overall gas demand is higher than in the other scenarios. Electricity-based applications are used where technologically and economically suitable. The development of gas infrastructure follows similar trends as in Scenario 1 in order to avoid parallel pipelines for methane and hydrogen.

- **Scenario 3 - "Strong hydrogen end-use":** corresponds to the storyline "Strong development of hydrogen" with hydrogen as a major energy carrier. Nevertheless, the hydrogen demand is expected to remain rather limited in the mid-term until 2030 due to availability of the hydrogen-based applications. Hence, until 2030 methane is still transported at TSO level and CH_4 storage is used as a seasonal storage. At DSO level hydrogen can be injected into few separate pure H_2 networks. The use of the gas infrastructure is expected to change significantly in the long-term. By then electricity is used only for those applications which are technologically and economically suitable and more efficient than hydrogen applications. Methane demand is expected to decrease substantially according to the end user decisions. In order to avoid parallel gas infrastructures mainly hydrogen is transported and distributed at all levels of the network. Seasonal gas storage is provided by large-scale underground salt caverns. For the remaining methane demand the systems foresees local CH_4 supply within small and isolated distribution networks.

Table 4-1 Scenarios based on the three storylines from the gas infrastructure study[82] for a more detailed quantitative assessment

	Scenario 1		Scenario 2		Scenario 3	
Storyline from the gas infrastructure study	"Strong electricity end-use"		"Strong green methane end-use"		"Strong hydrogen end-use"	
Time horizon	2030	2050	2030	2050	2030	2050
GHG emission reduction target						
Total GHG emission reduction incl. LULUCF* vs. 1990	-49%	-100%	-49%	-100%	-49%	-100%
End user decisions						
End-user decisions regarding the applications in demand sectors	Focus on electricity-based end user applications		Focus on methane-based end user applications		Focus on hydrogen-based end user applications	
Major energy carrier for renewable energy supply	Electricity (followed by methane and hydrogen for application which cannot be electrified)		Biomethane (followed by electricity where technologically and economically suitable; in addition small portion of hydrogen demand)		Hydrogen (followed by electricity where technologically and economically suitable; in addition small portion of biomethane demand)	
Strategy for the gas infrastructure to follow end user decisions						
Gas type expected within international cross-border gas infrastructure	Natural gas followed by biomethane	Biomethane followed by synthetic methane	Natural gas followed by biomethane	Biomethane followed by synthetic methane	Natural gas followed by biomethane	Hydrogen
Utilisation of dedicated hydrogen infrastructure by national TSO and DSO	Mainly hydrogen admixture at distribution level	Limited and separated hydrogen networks possible	Mainly hydrogen admixture at distribution level	Limited and separated hydrogen networks possible	Limited and separated hydrogen networks (only DSO)	Yes, limited and separated methane networks possible
Regional distribution of methane supply	For natural gas according to import routs and production sites For biomethane according to availability and supply costs For $PtCH_4$ according to renewable power supply					Close to methane demand
Regional distribution of hydrogen supply	In close proximity to hydrogen demand					Close to renewable power supply
Gas storage in the context of seasonality	Conventional large-scale CH_4 storage					Underground H_2 storage in salt caverns

** LULUCF : Land use, Land-Use Change and Forestry*

4.3 Major assumptions for the energy system modelling

The focus of this study is on domestic hydrogen production from renewable power via water electrolysis (referred to as Power-to-Hydrogen – PtH_2) and technologies for biomethane production including 1st and 2nd generation technologies.[83] Therefore, other sources for hydrogen supply such as imports, by-product, or its production from biomass are excluded from further analysis. The only exception is conventional hydrogen

[82] DG ENER (2018). The Role of Trans-European Gas Infrastructure in the Light of the 2050 Decarbonisation Targets.

[83] 1st generation biogas: anaerobic decomposition of organic waste or in other words by the natural breakdown of organic matter of different type. 2nd generation biogas is usually produced by gasification of e.g. ligno-cellulosic biomass (wood and straw), dubbed as "thermochemical conversion".

production from steam methane reforming (SMR) with carbon capture and storage (CCS) within a transition phase until 2030. Regarding the production of synthetic methane via Power-to-Methane (PtCH$_4$) CO_2 supply for the methanation process is based on biogenic sources and direct air capture excluding fossil sources. However, the CO_2 supply and CO_2 sources for Power-to-Methane conversion are not considered in this study. For the sake of transparency, the study also excludes imports of synthetic fuels produced via Power-to-Liquids (PtL),[84] liquefied natural gas (LNG) technologies, such as liquefaction plants or trailers, as well as dedicated LNG infrastructure in terms of direct LNG use (e.g. by LNG trucks).

4.3.1 GENERAL BOUNDARY CONDITIONS

The energy prices for further calculations presented in Figure 4-2 are in line with ENTSOG[85] values being mainly based on the "New Policies Scenario" from the IEA.[86] In this context, the major energy price increase is expected for oil (three-fold increase) and natural gas (by more than 60%). All other energy prices remain rather stable.[87] The carbon prices in 2030 correspond to the figure of 84 €/t$_{CO2}$ used by ENTSOG[88] for its "Sustainable Transition" scenario. In 2050 the carbon price is expected to increase substantially up to 350 €/t$_{CO2}$ as predicted by the LTS.[89] The discount rate for valuation of investment outlays is 3% being in line with the average rate for conservative GDP growth of 1% in Europe as presented by Steinbach and Staniaszek (2015).[90] It is considered as a social discount rate without any margins for individual market participants as the modelling of the energy system is conducted from the macroeconomic perspective taking into account societal time preferences.

In order to achieve a good balance between modelling resolution and flexibility each EU28 Member State[91] is represented by one power and gas network node. We assume no further network constraints within the member states/sub-regions. In this way the computational time can be limited while the model still provides a sufficient level of detail for the most important aspects of the power and gas network. For the sake of consistency, a joint network mapping is conducted from the different country-specific nodes representations provided by ENTSOG and ENTSO-E.

In line with the European Commission's long term strategic vision (LTS)[92] the renewable feed-in accounts in 2030 for almost 60% of the total power demand including the anticipated losses from electrolysis, methanation and storage, and for more than 90% in 2050. The split between the feed-in of fluctuating renewable sources is based on the "1.5TECH" scenario of the LTS indicating a comparable share between wind onshore (35%) and offshore (35%) as well as PV (30%) for both time horizons. For hydro power plants we assume constant energy production of ca. 300 TWh/a for both time horizons. Moreover, there are no specific limitations for curtailment of renewable energy within the model. The geographical split of renewable power generation is based on the potential.

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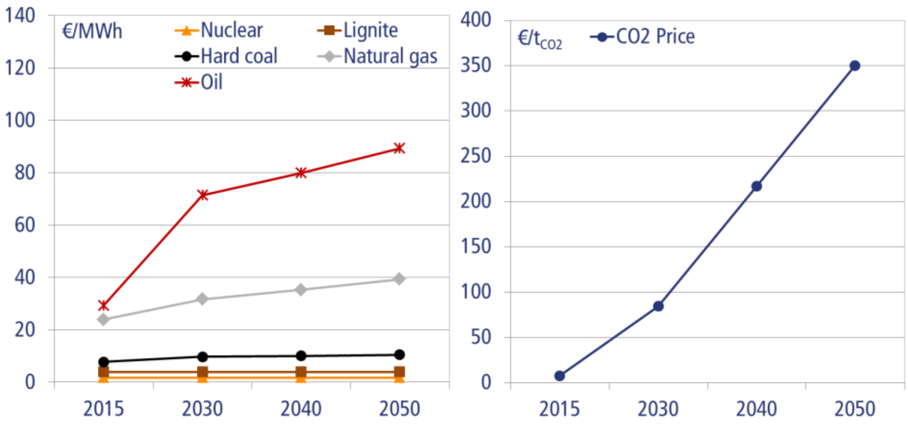
[84] Additional demand for Power-to-Liquids (PtL) fuels from aviation and shipping in the EU from domestic production is addressed in a sensitivity analysis in Chapter 6.3.4.
[85] ENTSOG (2018), TYNDP, Brussels.
[86] IEA (2016). World Energy Outlook.
[87] The actual use of fossil fuels in the energy system is however a model output resulting from the price signals and GHG constraints.
[88] ENTSOG (2018). TYNDP, Brussels.
[89] EC (2018). A Clean Planet for all A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy.
[90] Steinbach, Jan, and D. Staniaszek. (2015). Discount rates in energy system analysis Discussion Paper." BPIE: Berlin, Germany (2015).
[91] The UK is considered in the EU for this study.
[92] European Commission (2018). A Clean Planet for all A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy

Figure 4-2 Assumed energy (left) and CO_2 (right) prices for the analysis



4.3.2 OTHER ASSUMPTIONS

The existing capacities of dispatchable power plants and pumped-hydro storage in 2030 are taken from ENTSO-E TYNDP 2018 [93] and are used for the geographical split of investments in new capacities. In 2050, the model assumes a refurbishment of existing nuclear and biomass capacities being available for comparatively cheap and GHG-free power generation. For all power plants, we assume an availability factor of maximum 80% to take into account planned revisions and outages.

Stationary batteries are generally placed in close proximity to renewable power supply, H_2 pipe storage close to hydrogen demand and H_2 salt caverns are located, according to the HyUnder Project[94] in Member States with suitable geological formations (Germany, France, UK, Poland, the Netherlands and Denmark). Distribution of methane storage is derived from the data provided by GIE.[95] Electrolysers are placed according to hydrogen demand in Scenario 1 and 2 as well as in 2030 in Scenario 3 as these scenarios exclude dedicated hydrogen cross-border transport infrastructure. In 2050 in Scenario 3, the electrolysis capacity is distributed according to renewable power supply. For methanation and biomethane supply, the opposite is true as in Scenario 1 and 2 and in 2030 in Scenario 3 methane sources are distributed according to renewable power supply and biomethane potentials (taking the potential costs into account), respectively. Only in 2050 Scenario 3, methane supply follows the demand as in this case no methane-based cross-border pipelines are expected.

The corresponding existing capacities for power transmission network are derived from ENTSO-E TYNDP 2018.[96] For the sake of simplicity, power imports from outside the EU are excluded from further analysis except for the utilisation of pumped-hydro storage in Norway and Switzerland.

The existing capacities for the gas transmission network are derived from ENTSOG TYNDP 2018[97] and take into account expected network enhancements with final investment decision (i.e. category "low") until 2030. The natural gas supply is based on the import routes via pipelines (from Russia, Norway and North Africa) and LNG terminals in 10 Member States maintaining the historical split between different import routes, while the declining domestic production of natural gas in Europe until 2030 is derived from ENTSOG.[98] In 2030-2050 the limited natural gas demand is supplied by imports to Member

[93] European Network of Transmission System Operators for Electricity – ENTSO-E (2018), TYNDP, Brussels
[94] HyUnder Project (2014). Assessment of the Potential, the Actors and Relevant Business Cases for Large Scale and Long Term Storage of Renewable Electricity by Hydrogen Underground Storage in Europe
[95] Gas Infrastructure Europe (2018), Aggregated Gas Storage Inventory, Online: https://agsi.gie.eu/#/
[96] ENTSO-E (2018). TYNDP, Brussels.
[97] ENTSOG (2018), TYNDP, Brussels.
[98] ENTSOG (2018). TYNDP, Brussels.

States with large gas demand and already existing pipelines (from north, east and south) and LNG terminal infrastructure (the Netherlands, Italy, Spain and UK). Individual agreements on contracted gas infrastructure capacities between single operators are not included in the analysis as the gas flows are a result of the top-down modelling exercise from the EU-wide system perspective. The distances between the single network nodes for the power and gas network are calculated between the geographical centre of each country based on the data provided by the e-Highways 2050 project.[99]

Time-dependent profiles include the hourly profiles for demand for power, hydrogen and methane in each end-user sector and sub-sector as well as country-specific profiles for renewable feed-in. The demand profiles for electricity as well as renewable feed-in are taken from the ENTSO-E Transparency Platform.[100] In the transport sector the hourly power demand profile for BEVs is derived from Malling et al. (2015)[101] based on the charging behaviour of a typical end-user. For FCEVs and methane-fuelled cars a typical demand profile of a conventional refuelling station is assumed as proposed by LBST (2018a)[102] and LBST (2018b).[103] For the gas demand in industry we assume a constant profile. Heat demand profiles are based on historical temperature data from IEM (2019)[104] and translated into actual power and gas demand by taking the (temperature dependent) efficiencies of the corresponding end user heating technologies into account. In particular, the electricity demand profile by heat pumps takes into account variable coefficients of performance based on the outdoor temperature (i.e. lower COPs in the winter and higher in the summer).

4.4 COST STRUCTURE FOR THE NATURAL GAS NETWORK AND FOR THE USE OF BIOMETHANE AND HYDROGEN

4.4.1 GENERAL UNDERSTANDING OF POSSIBLE DEVELOPMENTS OF GAS NETWORKS

If hydrogen is supposed to be part of the European energy landscape, ultimately, a dedicated network separate from the methane network is required to serve specific end user applications. At the beginning, a certain share stems solely from separate networks specifically designed for transporting hydrogen. This is what some Member States have already suggested and it is what we see in places such as the Orkney Islands or in the Hoogeveen HYDROGREENN[105] City Heating project.[106] At this point, however, these are of limited importance in terms of investments and transported gas volumes. Once a sufficient density of such local hydrogen distribution networks will be reached, these can be connected to a larger hydrogen transmission network.

It is widely assumed that the existing pipeline system can safely accommodate either biomethane of up to 100% or (bio)methane with a hydrogen admixture of up to 20 vol%; some gas experts/TSOs consider however that the latter percentage is not feasible without (major) refurbishment. Given the limitations discussed in preceding chapters, we assume that there is zero hydrogen admixture to the transmission network, and 10% in dedicated and closed off parts of the distribution network by 2030. For 2050, the model assumes that a hydrogen admixture into the gas network does not make sense under any scenario, because:

[99] E-Highways 2050 (2015). A modular Development Plan for Pan-European Transmission System 2015
[100] ENTSO-E (2018), Transparency Platform, Online: https://transparency.entsoe.eu/
[101] Mallig, N, Heilig, M, Weiss, C., Chlond, B. & Vortisch, P. (2015). Modelling the Weekly Electricity Demand Caused by Electric Cars. In: Procedia Computer Science (52) 444-451, DOI: 10.1016/j.procs.2015.05.012.
[102] LBST (2018b). Analysis Of The Macro-Economic And Environmental Benefits Of Power-To-Gas, Ottobrunn, 2018.
103 LBST (2018b). Wasserstoffstudie Nordrhein-Westfalen, Düsseldorf, 2018.
[104] Iowa Environmental Mesonet, http://mesonet.agron.iastate.edu/request/download.phtml?network=ES__ASOS, datasets downloaded 2019
[105] HYDROGen Regional Energy Economy Network Northern Netherlands
[106] Willem Hazenberg 2018: HYDROGREENN “Hoogeveen HYDROGEN City Heating project". Groningen & Community Energy Scotland 2019: Surf 'n' Turf. Online: http://www.surfnturf.org.uk/page/introduction.

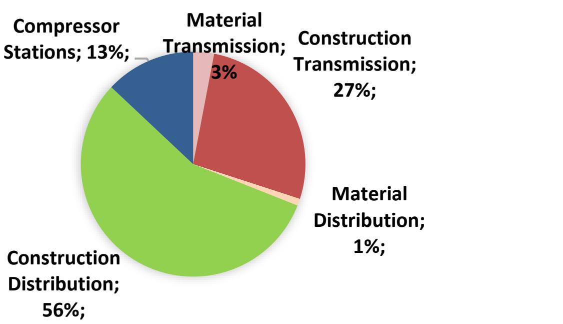
- there will be the necessity to sustain a dedicated methane gas network to collect biomethane and to serve distinguished end-users,
- a low admixture rate of 10 or 20 vol% does not contribute significantly to the required CO_2 emission reduction targets, nor does it reduce the costs associated with novel construction or retrofitting significantly,
- of its miniscule share of the total hydrogen quantities which will need to be distributed, and
- of the fact that the dedicated hydrogen network will have grown to an extent which renders the efforts connected to hydrogen admixture to methane gas unprofitable.

1. For any excess hydrogen that cannot be admixed in 2030, new dedicated networks will have to be constructed or – where capacity permits – old ones have to be retrofitted and closed off.
2. If the share of methane, or more generally, the cumulative gas demand, exceeds the 2015 network capacities, additional infrastructure will have to be built.

4.4.2 COST STRUCTURE FOR METHANE AND HYDROGEN NETWORKS

The cost structure for a hydrogen pipeline network is shown in Figure 5-4.[107] The highest share lies with constructing the distribution network, followed by the transmission network and the compressor stations. Material costs themselves (mainly steel) are of minor nature.

Figure 4-3 Average share of investment costs of a pipeline network based on Krieg (2012)



Investment Costs - Pipeline Infrastructure

The pipeline infrastructure of any gas network represents the highest share of costs. Admixing hydrogen to existing NG-networks impacts the pipelines' "material strength, fracture toughness, enhanced fatigue crack growth rates, low cycle fatigue, subcritical and sustained load cracking, susceptibility to stress corrosion cracking, and hydrogen-induced cracking in welds and joints".[108]

Since about 50% of the European distribution infrastructure is made up of polyethylene pipes,[109] switching local distribution networks for entire cities or neighbourhoods to hydrogen might be generally very feasible. Yet, technical approaches may be applied to adapt the existing steel pipelines to hydrogen operation such as coating with liners or pulling in "inflatable" pipes, further detailed analysis ongoing[110]. The network conditions vary significantly from Member State to Member State. For example, while Ireland relies on polyethylene pipes to almost 100% for its distribution network, only 52% of the distribution network in Romania has polyethylene pipes.

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[107] Krieg, D. (2012), Konzept und Kosten eines Pipelinesystems zur Versorgung des deutschen Straßenverkehrs mit Wasserstoff, 2012, Forschungszentrum Jülich; Institut für Energie- und Klimaforschung,
[108] Argonne National Lab (2008), Argonne National Lab, Overview of interstate hydrogen pipeline systems
[109] Marcogaz (2014). Technical statistics 01-01-2013.
[110] See e.g. http://www.hypos-eastgermany.de/blog/single/forschungsvorhaben-h2-pims.

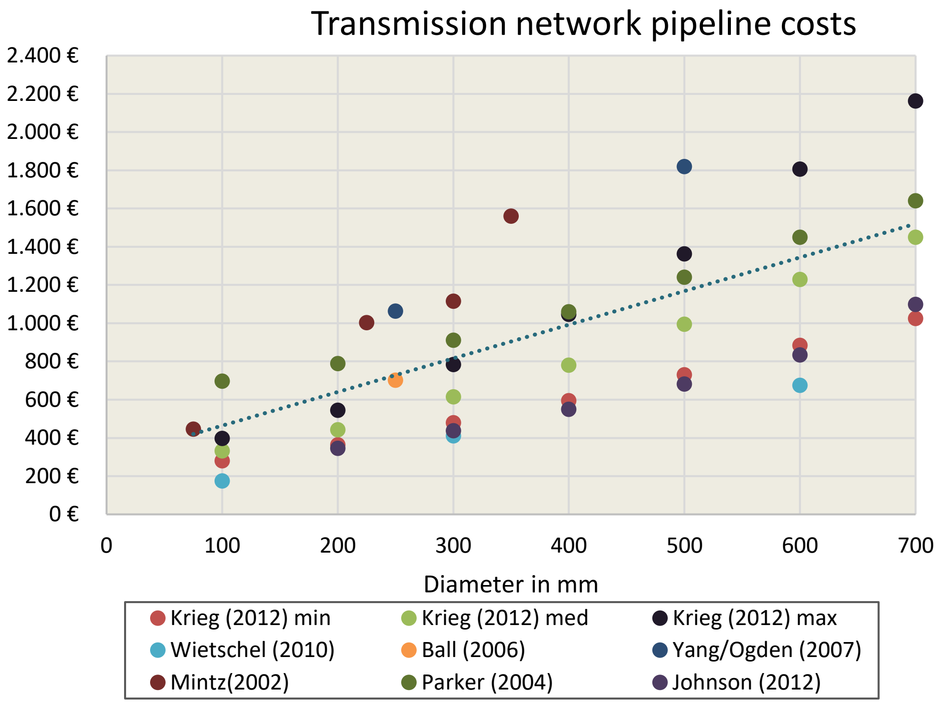
Reduced to the necessary minimum, the pipeline costs are a function of the pressure, diameter and the wall thickness of a pipe, as these three factors determine the material intensity. In alignment with general literature, this report assumes an average pressure level of 100 bar for the transmission network and 30 bar for the distribution network. It relies on synthesizing the findings from existing studies for assessing the costs of pipelines qualifying to transport hydrogen. Figure 4-4 and Figure 4-5 summarize the available data from the available literature and display the costs per meter of building new transmission and distribution pipelines; the dotted line represents an average of the literature sources displayed.

Compressor and Pressure Reduction Stations

Due to pressure losses during transport, compressor stations are indispensable in a pipeline network's transmission system. Radial compressors are the most suitable choice, as their technical specifications (compression ratio, transfer rate) provide optimum efficiency and performance.[111,112] Similar to pipeline costs, data on the costs of compressor stations varies significantly across the available literature. In accordance with industry and synthesizing the data available, a large compressor station's costs are estimated to be about M€ 11.25 (not only including investment but also installation costs).

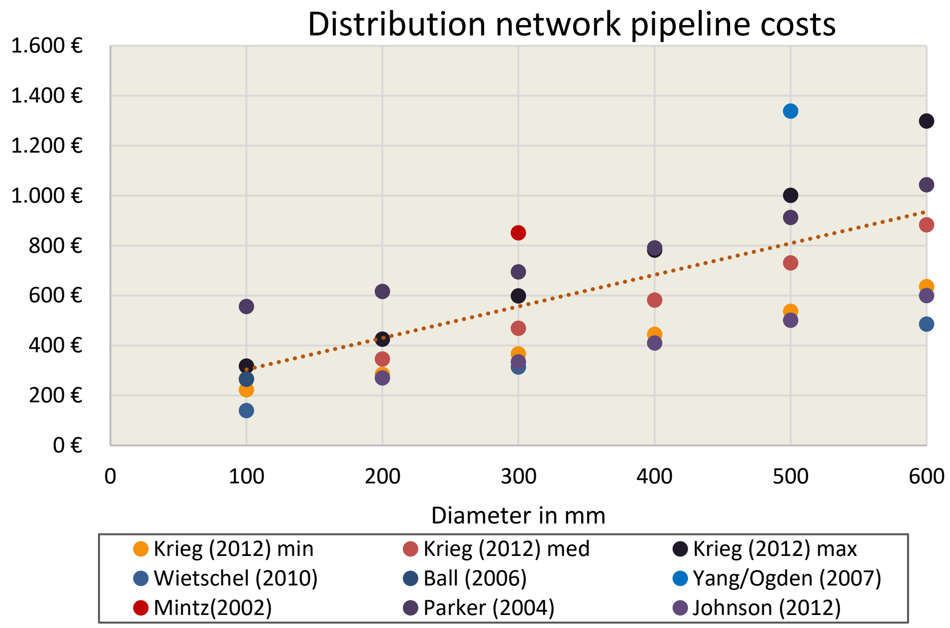
When transporting gas to the end user in the distribution network, the most common approach is to decompress the gas via pressure reduction stations. High gas pressures typically are of little value for the average household and most industrial end-users, instead they rather pose a risk. A distinct difference can be observed for gas refuelling stations, methane or hydrogen, which require high pressure.

Figure 4-4 Literature values for transmission network pipeline costs (inflation adjusted)



[111] Note that this does not apply to high pressure compressors at gas stations.
[112] Krieg, D. (2012). Konzept und Kosten eines Pipelinesystems zur Versorgung des deutschen Straßenverkehrs mit Wasserstoff, Forschungszentrum Jülich; Institut für Energie- und Klimaforschung.

Figure 4-5 Literature values for distribution network pipeline costs (inflation adjusted)



Sources for both figures: Fraunhofer ISI 2010; Yang & Ogden (2007); Mitz et al. (2002); Ball (2006); Parker (2004); Johnson, N.; Ogden, J. (2012).[113]

Operation and Maintenance Costs

Operation & maintenance costs (OPEX) are added as an annual percentage of the investment costs. Krieg (2012) gives an overview of existing literature on hydrogen pipelines, providing for a range of 1-5% per year of the initial investment costs. In general, OPEX are assumed to be at the lower end of the range, higher values are barely substantiated, but are rather assumed to provide for a conservative estimate taking into account technical uncertainties related to the limited experience with hydrogen pipelines. Newly built hydrogen pipelines require higher investment costs than methane pipelines, and the refurbishment of methane pipelines to hydrogen requires investments. Similarly, operation and maintenance costs of hydrogen pipelines are higher in absolute terms than those of methane pipelines.[114] We assume here the same percentage for both methane and hydrogen pipeline OPEX, which leads to higher absolute OPEX for hydrogen pipelines. According to Krieg (2012) this may represent an acceptable level of OPEX for hydrogen pipelines, but more research would be needed to confirm this.

As an example for methane pipeline systems, absolute annual operation and maintenance costs in Germany are published by the Bundesnetzagentur for DSOs and for TSOs separately.[115] These values for the year 2015 are consistent with our cost estimates based on an OPEX percentage of 1% per year for DSOs, which has also been confirmed by the gas industry during stakeholder consultations for this study. It has to be acknowledged, however, that there are national variations. On this basis, an OPEX percentage of 1%/a for DSO networks is used here both for methane and for hydrogen.

[113] Fraunhofer ISI (2010). Vergleich von Strom und Wasserstoff als CO_2-freie Endenergieträger, Karlsruhe; Yang, C.; Ogden, J. (2007). Determining the lowest-cost hydrogen delivery mode. *International Journal of Hydrogen Energy* 32(2): 268-286; Mitz et al. (2002). Cost of Some Hydrogen Fuel Infrastructure Options, 1/16/2002; Ball, M. (2006), Integration einer Wasserstoffwirtschaft in ein nationales Energiesystem am Beispiel Deutschlands. Optionen der Bereitstellung von Wasserstoff als Kraftstoff im Straßenverkehr bis zum Jahr 2030, Deutsch-Französisches Institut für Umweltforschung - Teilinstitut Karlsruhe; Parker, N. (2004). Using Natural Gas Transmission Pipeline Costs to Estimate Hydrogen Pipeline Costs & Johnson, N.; Ogden, J. (2012). A spatially-explicit optimization model for long-term hydrogen pipeline planning. In: International Journal of Hydrogen Energy.

[114] Costs for hydrogen pipeline repairs are higher because the pipes may be coated and welding seams would need special treatment. Furthermore, seals, meters and other components have to be checked and serviced more frequently.

[115] BNetzA (2019) Monitoringbericht 2018.

For TSOs, our calculations are consistent with the BNetzA (2019) absolute values at an OPEX percentage of 2.4%/a for 2015. It has to be noted that the operation and maintenance costs vary from one year to the other providing for an OPEX percentage range of 1.7%/a to 2.4%/a with an average over the years 2013 to 2018 of 2.0%/a. Acknowledging national variations also at TSO level, we assume an OPEX percentage of 2%/a for TSO pipelines, both for methane and for hydrogen.

International gas transport

For international gas transport, pipelines with different transport capacities have been used depending on the required transport capacity. Typically, a compressor station is installed every 100-200 km.[116] The selection of various parameters (diameter for a given throughput, pressure, pipe roughness) of a pipeline system significantly influences the pressure drop and as a result the energy consumption for gas transport. There is a trade-off between investment and low energy consumption.

For hydrogen transport coated steel pipelines are required, leading to higher costs.[117] Compressor investment costs are 22 € per kW of hydrogen, based on the lower heating value.[118] The volumetric gas transport capacity of a hydrogen pipeline is higher than that of a similar methane pipeline as the friction is lower and the gas velocity of hydrogen is higher compared. However, the energy content per volume is much lower for hydrogen (3.00 kWh per Nm³ versus 9.95 kWh per Nm³ based on the lower heating value). Overall, the energy-related transport capacity of hydrogen is somewhat lower than for methane.

4.5 Use of electricity, methane and hydrogen in energy end-use sectors in the EU in 2015, 2030 and 2050

The energy demand from each energy use is developed based on selected literature and to respect the scenario definitions from the previous chapter. The resulting energy demand is derived from assumptions e.g. regarding the share of hydrogen fuel cell vehicles, it is not the result of economic or similar modelling. The main aim is to develop energy demand values for three explorative scenarios with rather ambitious assumptions regarding the use of electricity, methane and hydrogen. To develop the input to the energy system model, the total energy end-use in EU member states is split into the energy use sectors transport, residential and services, and industry comprising multiple subsectors. The power generation sector is not included in this chapter as this sector is inherent calculated by the energy system model.

4.5.1 Transport

The development of the transport activity in Europe is based on the 1.5 °C scenarios in the LTS[119] and on the country specific developments presented in the EU Reference Scenario.[120, 121] Between 2015 and 2050, a EU28 wide sector growth of about 21% for passenger cars and of about 40% for the road freight is assumed. The growth of the rail sector is assumed to be 85%. National and international aviation as well as inland and international shipping is not considered in this study. The future development of specific fuel consumption for various propulsion systems and vehicle types) is based on VDA's E-fuel study.[122] The specific fuel consumption values are used to convert absolute fuel

[116] Cerbe, G.; Lendt, B. (2017). Grundlagen der Gastechnik; 8. vollständig überarbeitete Auflage, Carl Hanser Verlag München, ISBN 978-3-446-44965-7 & Angloher; J.; Dreier, Th. (1999). Techniken und Systeme zur Wasserstoffbereitstellung; Koordinationsstelle der Wasserstoff-Initiative Bayern (WIBA).
[117] Parker, N. (2004). Using Natural Gas Transmission Pipeline Costs to Estimate Hydrogen Pipeline Costs.
[118] Parker, N. (2004). Using Natural Gas Transmission Pipeline Costs to Estimate Hydrogen Pipeline Costs.
[119] EC (2018). A Clean Planet for all A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy.
[120] EC (2016). EU Reference Scenario 2016 - Energy, transport and GHG emissions Trends to 2050, Brussels.
[121] The EU LTS 2018 data was applied to determine the overall change in transport activity, while the EU Reference scenario data was additionally considered to determine member state specific developments.
[122] VDA (2017). E-FUELS STUDY The potential of electricity-based fuels for low-emission transport in the EU.

demand of the transport sector between technologies and years based on national developments of transport activity.

The share of GHG neutral propulsion systems for each member state was mainly determined based on national GHG reduction targets and the technology focus of each scenario. In 2030, BEVs are virtually the only new vehicle technology in the electric and hydrogen scenario. Hydrogen and ICE gas vehicles only play a minor role. In the methane scenario, ICE gas vehicles clearly outnumber battery vehicles. However, battery vehicles still play a relevant role. The fuel demand declines from about 3 500 TWh in 2015 to just above 3 000 TWh. The main reason for this decline is the improved efficiency of conventional ICE vehicles as well as a shift to efficient BEVs. Decline of fuel demand is less pronounced in the methane scenario due to a smaller share of BEVs in the vehicle stock.

In 2050, battery vehicles account for about 75% of all road vehicles in the electric scenario. In the methane and hydrogen scenario, BEVs still account for about 50% of the vehicles. ICE gas and fuel cell vehicles account for about the other half of all vehicles in their respective scenarios. The share of BEVs is higher for passenger cars as for trucks due to weight and range limitations. For 2050, it is assumed that a small share of road freight uses other fuels e.g. bio-based or electricity based liquid fuels (BtL, PtL) in niche applications. Total fuel demand strongly depends on the scenario due to varying efficiencies of the vehicle propulsion technology and their respective relevance in each. In the electric scenario, fuel demand amounts to about 2,000 TWh while in the methane scenario the total is at about 2,500 TWh. Fuel demand in the hydrogen scenario is at about 1,700 TWh. There are no relevant GHG emissions remaining from land transport activity.[123] Emissions from further transport subsectors such as national and international navigation and aviation might exist. However, those subsectors are not considered in this study. From virtually zero today, gas demand the transport sector significantly increases to about 850 TWh in the electric scenario, by 2050. In the methane and hydrogen scenario, demand increases to almost 1,800 and 900 TWh, respectively.

4.5.2 RESIDENTIAL SECTOR AND SERVICES

According to the EU long term strategy (LTS)[124], the demand for space heating in the residential and service sector is expected to decline by about 60% and 50% respectively in average, by 2050. By 2030, the reduction is expected to be already at about 25% compared to 2015 levels. This reduction is assumed to be similar for all Member States. The energy demand for the production of warm water is expected to remain constant at today's level. The future development of electricity consumption for appliances and space cooling is based on the LTS and the EU Heat Roadmap 4.[125] By 2050, electricity consumption for appliances is assumed to increase by 20% compared to 2015 (EU28 average). During that period, demand for space cooling nearly triples, however, starting at a low level. Efficiency data for various heating and CHP technologies are mainly taken from the Asset Technology pathways in decarbonization[126] and the German integrated energy concept 2050.[127]

The technology and fuel split in the heating sector in the three scenarios is based on inputs taken from the LTS,[128] the hydrogen roadmap and the gas network infrastructure study.[129]

[123] There are minor GHG emissions from using natural gas allocated to the residential and service sector. Those emissions could (partly) be allocated to the transport sector instead.
[124] EC (2018). A Clean Planet for all A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy.
[125] Aalborg Universitet (2017). Heat Roadmap Europe 4: Quantifying the Impact of Low-Carbon Heating and Cooling Roadmaps.
[126] Asset (2018). Technology pathways in decarbonisation scenarios.
[127] Bundesministerium für Verkehr und digitale Infrastruktur (2018). Rechtliche Rahmenbedingungen für ein integriertes Energiekonzept 2050 und die Einbindung von EE-Kraftstoffen, Berlin.
[128] EC (2018), A Clean Planet for all A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy.
[129] DG ENER (2018), The Role of Trans-European Gas Infrastructure in the Light of the 2050 Decarbonisation Targets.

In addition, the available infrastructure today (e.g. availability of gas or district heating networks) and the prevailing heating fuels and technologies (incl. district heating, heat plants and CHP) are considered to derive country specific developments.[130]

By 2030, the final energy demand is reduced from today's level of about 4 800 TWh, to 3 900 and 4 000 TWh for the electric and the methane and hydrogen scenario, respectively. The use of fossil energies is significantly reduced. A less pronounced reduction results for district heating, biomass and other renewables due to a strong decline of overall energy consumption in buildings (increased insulation). Depending on the scenario, GHG-neutral gases such as hydrogen and biomethane significantly increase their relevance from almost zero today. Despite an increasing share of heat being produced from electricity, total electricity consumption for heat production stays about at today's level. This is achieved by partly switching from resistance heaters to electric heat pumps with superior efficiency. By 2050, final energy consumption drops further to around 3,000 TWh in all three scenarios. The use of fossil energy carriers is reduced about 6% resulting in about 23 Mt_{CO2}/a emissions. In each scenario, the gas demand significantly declines from above 1,600 TWh in 2015 to 400 TWh in the electric, to about 800 TWh in the methane and to about 900 TWh in the hydrogen scenario, by 2050. This demand also includes gas used for CHP cogeneration in small decentralized units.

4.5.3 INDUSTRY

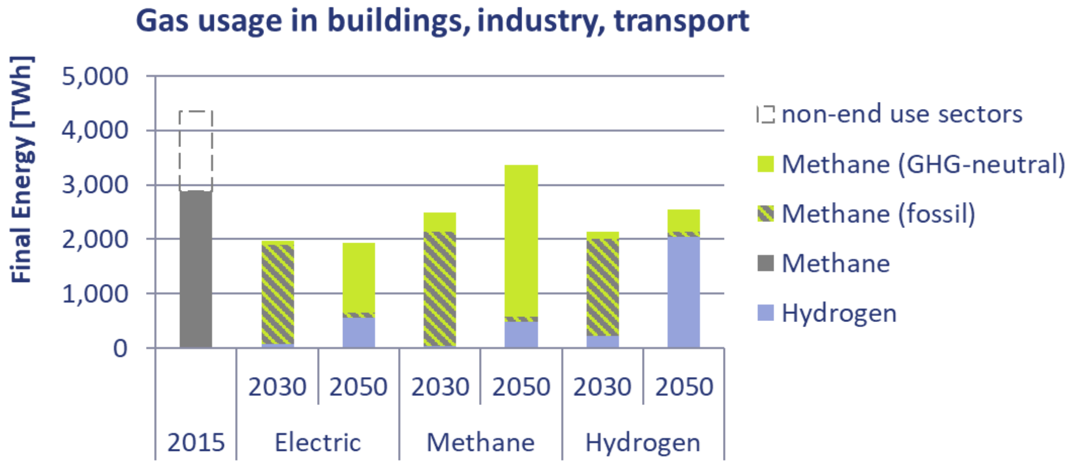
The development of fuel and energy consumption in the industry sector is heavily based on the "1.5 TECH" scenario in the EU's LTS.[131] The development is assumed to be the same in all three scenarios. After 2030, fossil fuels are substituted by biomass, electricity, hydrogen, or methane produced from biomass or electricity. By 2050, the use of fossil energies is close to zero (Figure 3-10). Total use of gaseous energy carriers is reduced from just above 1 000 TWh/a today to about 620 TWh/a by 2050 (Figure 3-11).

4.5.4 OVERALL GAS DEMAND

The overall gas demand in the considered sectors (transport, residential, services, industry) declines from about 2 800 TWh/a in 2015 to between 2 000 and 2 500 TWh/a, in 2030. Due to the developments in the transport sector (replacement of liquid fuels partially by gas consuming technology) gas demand increases between 2030 and 2050 in the Methane (almost 3 500 TWh/a) and Hydrogen (about 2 500 TWh/a) scenario. In the electric scenario, gas demand remains at a low level of just below 2 000 TWh/a (Figure 3-12). The figures do not include gas consumption in the power sector, potential gas demand from aviation or navigation, transport and distribution losses, and energy industry own consumption. The relevance of non-electric and non-gaseous energy carriers is less pronounced in all three scenarios as compared to some other studies. This is an intentional assumption in the scenarios' definition to explore the impact of more gas (H_2, CH_4) loaded scenarios on gas infrastructure.

[130] Aalborg Universitet (2017), Heat Roadmap Europe 4: Quantifying the Impact of Low-Carbon Heating and Cooling Roadmaps & IEA (2017). World Energy Balances, Paris.
[131] European Commission (2018). A Clean Planet for all A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy.

Figure 4-6 Development of gas demand (H_2 & CH_4) in the transport, residential, services and industry sector (gas demand in none-end use sectors indicated for 2015)

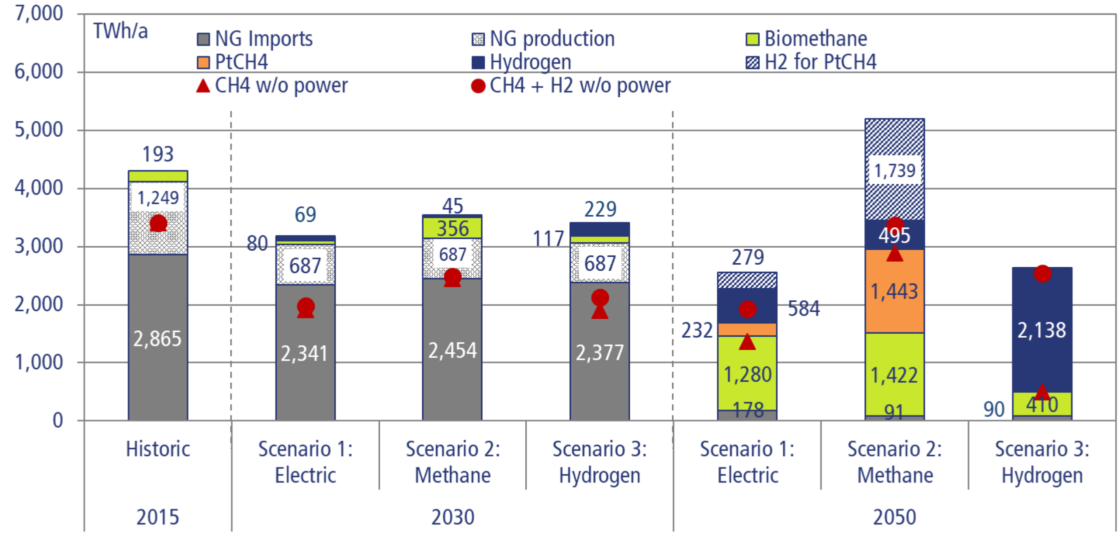


4.5.1 OPTIMAL DESIGN OF THE INTERLINKED ENERGY SYSTEM

According to the GHG emission reduction targets, the structure of entire energy system undergoes substantial changes between the two time-horizons 2030 and 2050 due to the shift from fossil to renewable energy supply.

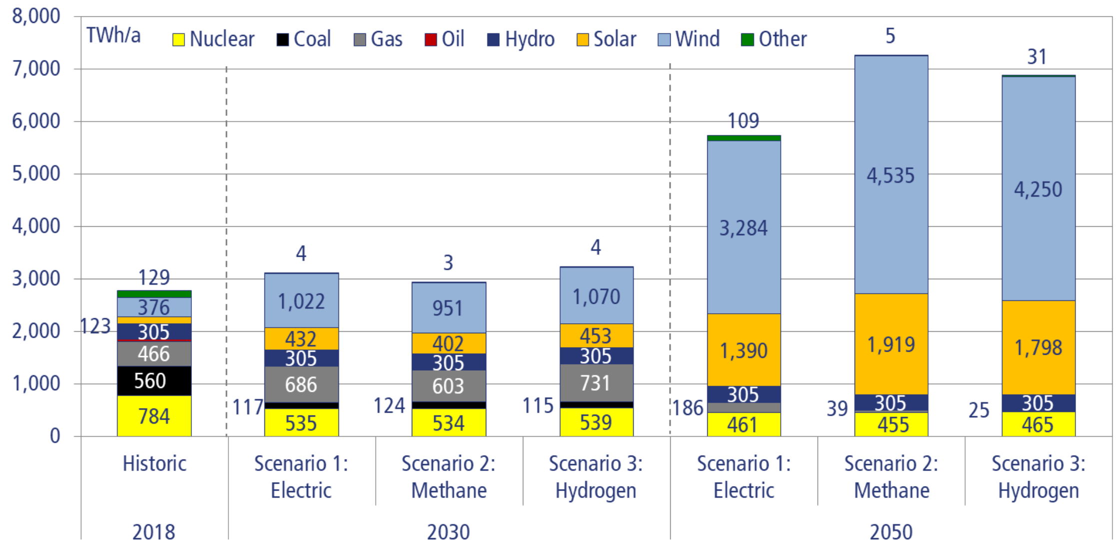
As presented in Figure 4-7, the overall gas supply in the mid-term until 2030 declines substantially in all scenarios by 20%-30% to approx. 3,000-3,500 TWh/a mainly due to energy savings, switch to other non-gas end-user applications as well as improved efficiencies in the end-user sectors. The structure of gas supply in 2030, however, is comparable to 2018. The gas infrastructure in 2030 is based on natural gas mainly imported from outside the EU corresponding to ca. 70% of total gas supply. The domestic production of natural gas within the EU drops to almost 700 TWh/a, but it still accounts for approx. 20% of total gas supply. Both biomethane and hydrogen production are rather limited with approx. 150 and 400 TWh/a in the electricity-focused Scenario 1 and the methane-focused Scenario 2, respectively. In fact, the biomethane production in Scenarios 1 and 3 is even lower than in 2018 as the average biomethane price of 65-73 €/MWh is still higher than natural gas including the corresponding carbon price. Therefore, biomethane use in the power sector is rather limited as other power plants can provide electricity more cost-effectively. Hydrogen is produced exclusively by comparatively cheap water electrolysis. Steam methane reforming combined with CCS is not applied due to high specific costs for rather small units which, lacking dedicated hydrogen distribution infrastructure, have to be located in close proximity to hydrogen demand.

Figure 4-7 Expected gas supply in EU28



The decreasing gas demand in 2030 is partially compensated for by methane use in the power sector going up by 5%-15% from ca. 960 TWh/a in 2018 to well above 1,000 TWh/a in 2030. The increasing electricity generation of gas-fired power plants (from ca. 450 TWh/a in 2018 to 600-730 TWh/a in 2030) is mainly due to favourable development of carbon prices making power generation by coal-fired power plants less competitive in comparison to natural gas (see Figure 4-8). Hence, the carbon price of € 84/t_{CO2} substantially impacts on the merit order of electricity generation. In addition, the phase-out of some nuclear power plants requires additional dispatchable generation capacities, which are provided by comparatively cheap gas power plants. In fact, the combined amount of electricity provided by nuclear and coal power plants drops from 1,300 TWh/a in 2018 to approx. 650 TWh/a in 2030. Moreover, the fluctuating renewable power production from wind and solar PV increases to approx. 1,500 TWh/a accounting for almost half of the overall power generation with a dominant share of wind power among fluctuating power plants. In this context, the flexible gas power plants are used to balance the intermittency of renewable power supply.

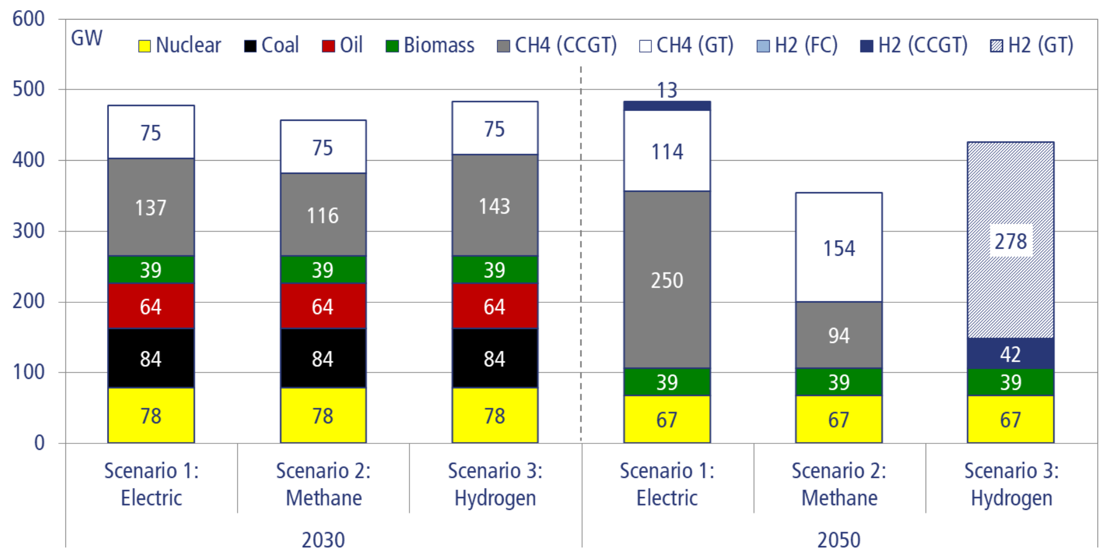
Figure 4-8 Expected power supply in EU28



In fact, the installed capacity of gas power plants goes up from some 170 GW initially to more than 190-220 GW in 2030. In this context, the optimal system design requires additional capacities for combined cycle gas turbines (CCGT), which are capable of comparatively efficient power production. The largest CCGT investments occur in the hydrogen-focused Scenario 3 with the highest overall electricity demand due to the additional power needed for hydrogen production via electrolysis. The total power demand in 2030 in all scenarios is slightly higher than the corresponding figure in 2018 due to sector coupling and advancing electrification of the end-user sectors.

In 2050, the energy system changes drastically. Due to the strong GHG emission reduction target almost no fossil fuels can be used in the system. The limited natural gas imports of approx. 90-180 TWh/a in 2050 are within the predefined GHG emission cap for the energy and end-user sectors, and have to be offset by negative emissions from LULUCF and bioenergy-based CCS. Either biomethane or renewable power are the dominant primary energy source. In the electricity-focused Scenario 1, the system utilises the full potential of biomethane of almost 1,200 TWh/a. This figure takes into account not only the bioenergy potential which is not used today, but also additional bioenergy which is expected to become available from the residential sector due to energy savings in this sector. Moreover, almost 300 TWh/a of bioenergy is directly used by biomass power plants providing more than 100 TWh/a of electricity to the power system. Therefore, the overall biomethane supply in this scenario is slightly lower than in Scenario 2. In addition, approx. 230 TWh/a of synthetic methane are produced and used for re-electrification by gas power plants to balance out the power system. The slightly higher natural gas supply in comparison to the other two scenarios is also consumed by the gas power plants. In this context, it is cheaper to source expensive fossil gas up to a predetermined GHG emission limit rather than to further increase the capacity of the methanation facilities to produce fossil-free gas for re-electrification with a low efficiency. Hydrogen supply in Scenario 1 amounts to approx. 860 TWh/a, out of which 570 TWh/a are foreseen for direct consumption in the end user sectors, 280 TWh/a are feedstock for methanation and 13 TWh/a are used for re-electrification by hydrogen-fuelled CCGT units with a total capacity of 13 GW.

Figure 4-9 Development of dispatchable power generation capacities in EU28

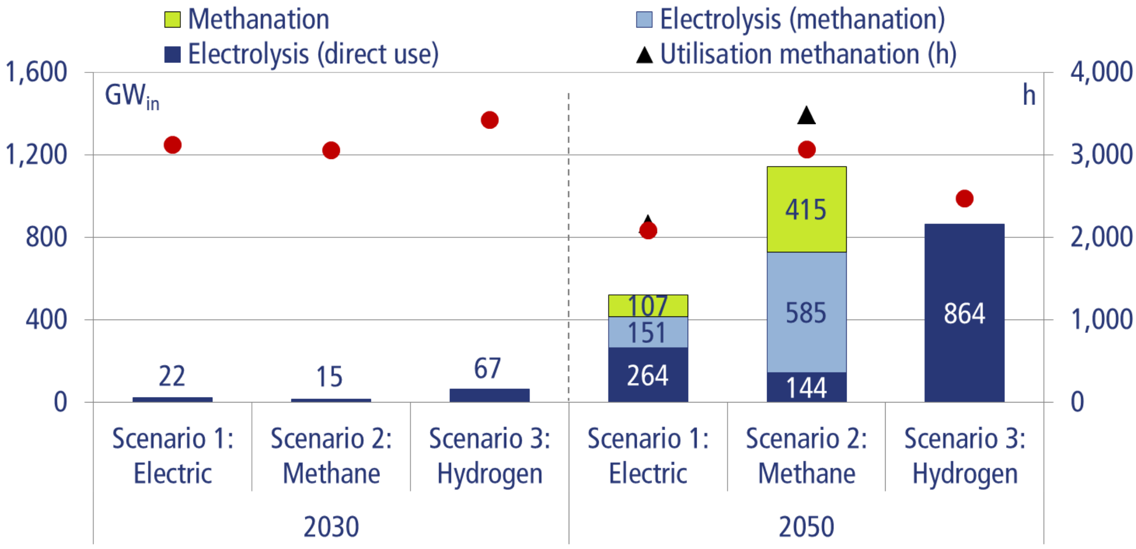


The methane-based Scenario 2 also utilises the full biomethane potential of more than 1,400 TWh/a (including the bioenergy becoming available from the residential sector). In addition, almost the same amount of synthetic methane is produced via the methanation process, and consumed in the end-user sectors as well as for re-electrification in gas power plants. The overall hydrogen production in this scenario accounts for more than 2,200 TWh/a. However, only limited amounts of hydrogen (approx. 500 TWh/a) are used directly by the end user sectors. Most of the hydrogen (some 1,700 TWh/a) is used as feedstock for methanation. Hence, the overall gas demand and supply in this scenario is much higher than in the other two scenarios, but it is at a similar level as in 2030 if the hydrogen for methanation is not taken into account. The hydrogen-based Scenario 3 has a different gas supply structure in comparison to the aforementioned scenarios. Due to demand from the end-user sectors, hydrogen is the major gas type in the system with almost 2,200 TWh/a. Limited amounts of hydrogen (54 TWh/a) are utilised by hydrogen fuelled gas turbines (almost 280 GW installed capacity) and CCGT units (42 GW). Biomethane and natural gas supply of 410 and 90 TWh/a, respectively, are consumed locally in industry as well as in the residential and services sectors. In this way, the overall gas demand in this scenario is at a comparable level as in Scenario 1, but much lower than the corresponding values in 2030.

Until 2050, the overall renewable power supply grows, compared to 2030, by a factor of 3-4 to 5,000-6,800 TWh/a becoming the dominant power source. Nuclear power generation as a cheap low-GHG technology provides some 460 TWh/a in all scenarios and remains at a level comparable to 2030. As in 2030, nuclear power plants are used predominately as base-load technology achieving almost 7,000 annual full load hours. The capacity of gas power plants based both on methane and hydrogen grow substantially to 250-380 GW. The lower value corresponds to Scenario 2 with comparatively low power demand from the end user sectors and large electrolysis capacities as a flexible load, whereas the upper value corresponds to Scenario 1 with the highest direct power demand and thus larger need for flexibility measures in the power sector. In all scenarios, the gas power plants are used to balance out the fluctuating power feed-in and are characterised by low utilisation. Therefore, the comparatively costly generation capacities with CCS are not installed in any scenario.

Figure 4-10 displays optimal electrolysis and methanation capacities together with the corresponding utilisation rates. In 2030 only limited electrolysis of 15-67 GW is needed to satisfy the limited hydrogen demand. The utilisation is between 3,000 and 4,000 annual full load hours indicating that it is used as flexible load in the power system. Until 2050, the required capacities grow substantially to 400-900 GW. The largest electrolysis capacity is installed in Scenario 3 with the greatest direct hydrogen demand from different end user sectors. In scenario 2, most of the installed electrolysis capacity (585 GW or ca. 80%) is needed for methanation. At this point it is important to mention that the electrolysis unit within a $PtCH_4$ facility is directly connected to the methanation process and cannot be used for hydrogen production for consumption by end user sectors. This is mainly due to a different geographical distribution of PtH_2 and $PtCH_4$ units in this scenario (PtH_2 close to hydrogen demand and $PtCH_4$ according to renewable power generation) as otherwise the system would require parallel infrastructures for hydrogen and methane. In this way, the overall electrolysis capacity and the corresponding costs in this scenario tend to be overestimated and could be further optimised through a more synergetic operation of both technologies. The utilisation rates for electrolysis of 2,000-3,000 full load hours are lower than the corresponding values in 2030 mainly due to larger feed-in of renewable power and the increased use of electrolysis as a flexible load. As mentioned above, methanation facilities are built up only in 2050 in Scenarios 1 and 2. The optimal capacity ranges between 100 GW and 400 GW, and the utilisation is between 2,000-3,500 annual full load hours.

Figure 4-10 Electrolysis and methanation capacities and corresponding utilisation in EU28



In all scenarios, seasonal storage of energy is provided by the gas infrastructure. In 2030 approx. 520-590 TWh of CH_4 storage are required to balance out the seasonal fluctuations between power and gas demand and supply (see Figure 4-11). Local hydrogen pipe storage is very limited due to low hydrogen demand and comparatively high specific costs of this technology. In the power system, only existing pumped-hydro storage units are operated in an optimised power system.

Although renewable power supply grows substantially until 2050, the required gas storage capacities decrease to 240-360 TWh. This is mainly due to falling overall gas and power demand on the one hand and enhanced use of other flexibility options such as electrolysis as a flexible load or stationary batteries on the other hand. In this context highest battery capacity occurs in the electricity-based Scenario 1 (180 GW) and the lowest in Scenario 3 (21 GW). Moreover, nuclear power and biomass plants provide back-up power in times when renewable power feed-in is insufficient to meet demand. In Scenarios 1 and 2, some additional hydrogen pipe storage capacities between 2-10 TWh are needed based on local hydrogen demand. In Scenario 3, hydrogen is stored in large-scale underground salt caverns with a total capacity of 280 TWh.

Figure 4-11 Required gas storage capacities in EU28

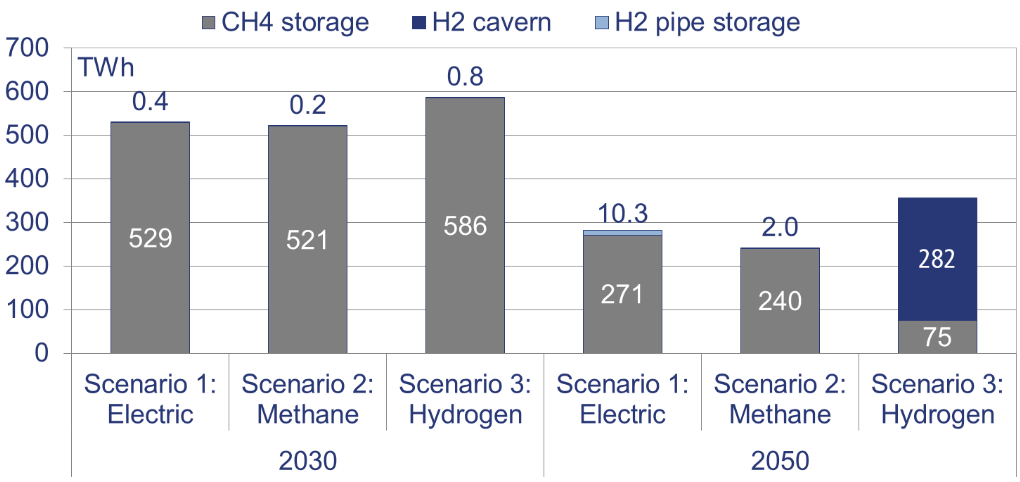
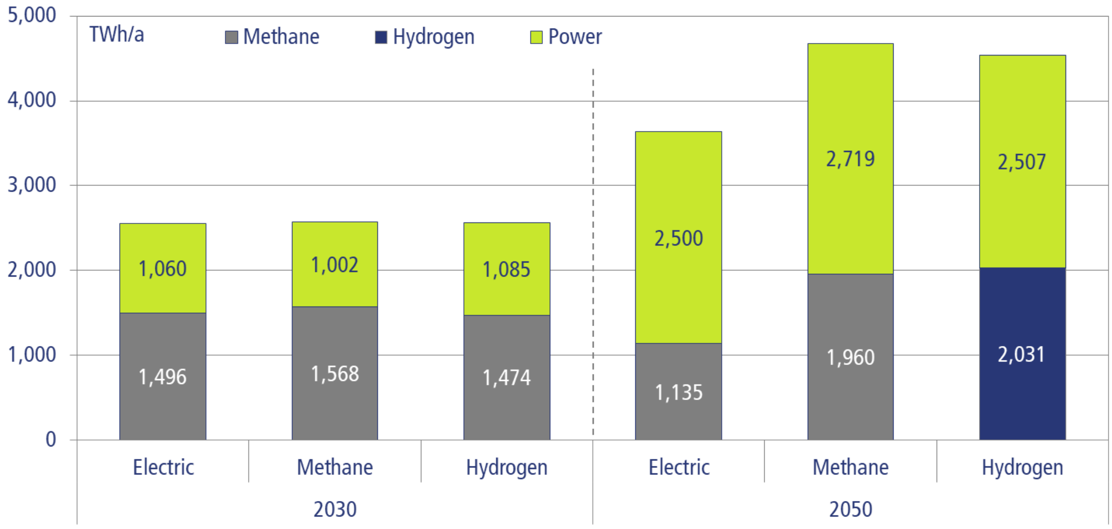


Figure 4-12 displays cross-border energy transport between the different Member States as an indicator of the required gas and power infrastructures. Similar to the previous results, in 2030 the differences between the scenarios are very limited. In all three scenarios total gas transport accounts for approx. 1,500 TWh/a whereas power transport amounts to some 1,000 TWh/a. The difference between the two energy carries is due to varying overall demand for each carrier. This is partially compensated by the wider spatial distribution of power generation and higher hourly fluctuations of electricity demand and supply in contrast to a more centralized distribution of gas along the established import routes and a flatter gas residual load in each node. Until 2050, this relationship is enhanced. Increasing renewable power supply leads to more fluctuations in power generation which is not necessarily in close proximity to power demand. For the gas infrastructure, the cross-border gas transport activities change, too, but not in the same manner. In Scenario 1 the amount of transported gas decreases to 1,100 TWh/a mainly due to lower gas demand. For Scenarios 2 and 3, gas transport increases to 2,000 TWh/a as both the production of synthetic methane and hydrogen are related to the renewable feed-in being differently distributed compared to demand.

Figure 4-13 to Figure 4-15show the corresponding gas flows in EU28 in each scenario and time step whereas Figure 4-16 to Figure 4-18 indicate the required pipeline capacities together with investment needs. Again, for 2030 the gas flows as well as the required pipeline capacities are very similar for all scenarios. Since natural gas imports dominate the gas supply, the infrastructure design follows the established import routes mainly from East to West (from Russia through Poland and Slovakia to Western Europe) and from North to South (from Norway to Germany, France and Italy). Limited changes in comparison to the existing infrastructure are due to decreasing gas demand on the one hand and falling domestic gas production on the other hand. Moreover, since the model assumes an internal energy market without any barriers for all Member States in the first step, the peripheries of the gas infrastructure (e.g. Baltic countries, Iberian Peninsula, Scandinavia, Cyprus and Malta) need some enhancements for a better connection with central Europe.

Figure 4-12 Cross-border energy transport within EU28



Again, in 2050 the switch from natural gas to GHG-free gases has a major impact on the design and requirements of the future gas infrastructure. In fact, countries with large renewable potentials in comparison to limited domestic demand become gas exporters whereas Member States characterised by high gas demand but low domestic production from renewables need additional imports from within the EU. Particularly in Scenarios 1 and 2, the Scandinavian and Baltic counties supply large amounts of biomethane which have to be transported to Central Europe and mainly to Germany. For this reason, the interconnectors between Sweden, Denmark and Germany on the one hand as well as between Lithuania, Poland and Germany on the other hand become important and need corresponding network enhancements, except for the link between Poland and Germany which already has a large capacity. Moreover, the gas supply from Balkan countries (Romania, Bulgaria and Greece) is transported from Greece to Italy with large gas demand. In this way, the gas flows between Germany and Italy as well as from Eastern Europe through Austria to Italy disappear, and the related gas infrastructure is not needed anymore. In contrast, countries with high gas demand but low production such as the Netherlands and the UK import biomethane. These imports, however, can be covered by the existing infrastructure and further investments are not needed. Similar relationships can be observed for biomethane exports from France to the Benelux countries and Italy (however the interconnector between France and Italy is not sufficient for the required gas transport in Scenario 3 and hence needs to be upgraded).

In Scenario 3 in 2050, the required gas infrastructure changes substantially in comparison to today's design and operation. Since hydrogen is produced according to the renewable power potential it has to be transported over long distances from the peripheries to Central Europe. This is true in particular for the Baltic countries including again the route through Lithuania and Poland to Germany as well as for Scandinavia affecting the interconnectors between Sweden, Denmark and Germany. For both routes, substantial investments in new capacities are required. In addition, hydrogen is transported from the solar-rich South (Spain, Greece, Italy) northward (France and Germany) and from the wind-rich West (Ireland, UK, France) eastward (Germany, Benelux, Austria and Czech Republic). Except for individual relations with large existing capacities (e.g. between the UK and Belgium, or Germany and the Czech Republic) new pipeline capacities are needed. In general, hydrogen supply under the assumptions of this study reverses the direction of gas flows having a strong impact on the pipeline capacities.

Figure 4-13 Gas flows under the 2030 and 2050 electricity scenarios

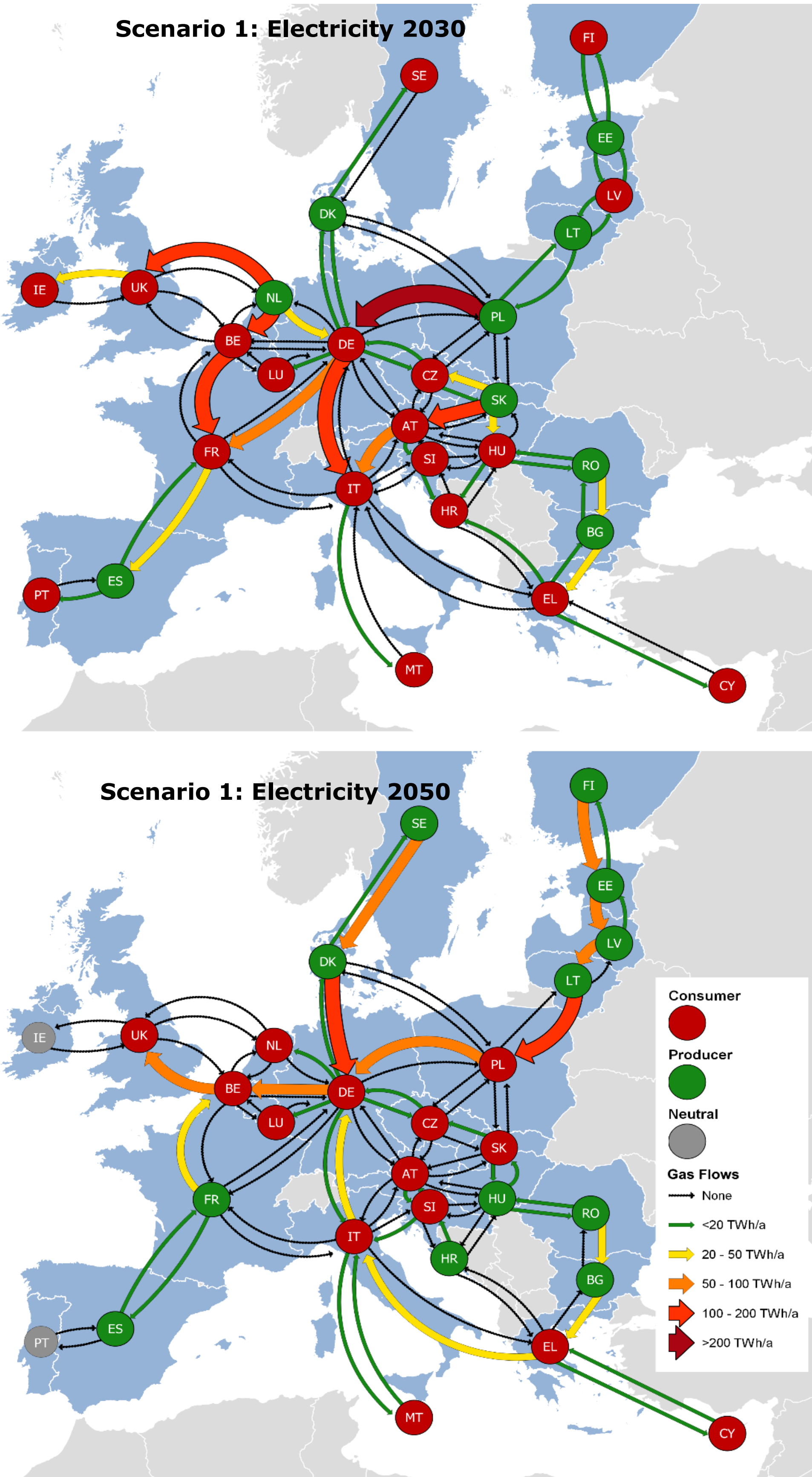


Figure 4-14 Gas flows under the 2030 and 2050 methane scenarios

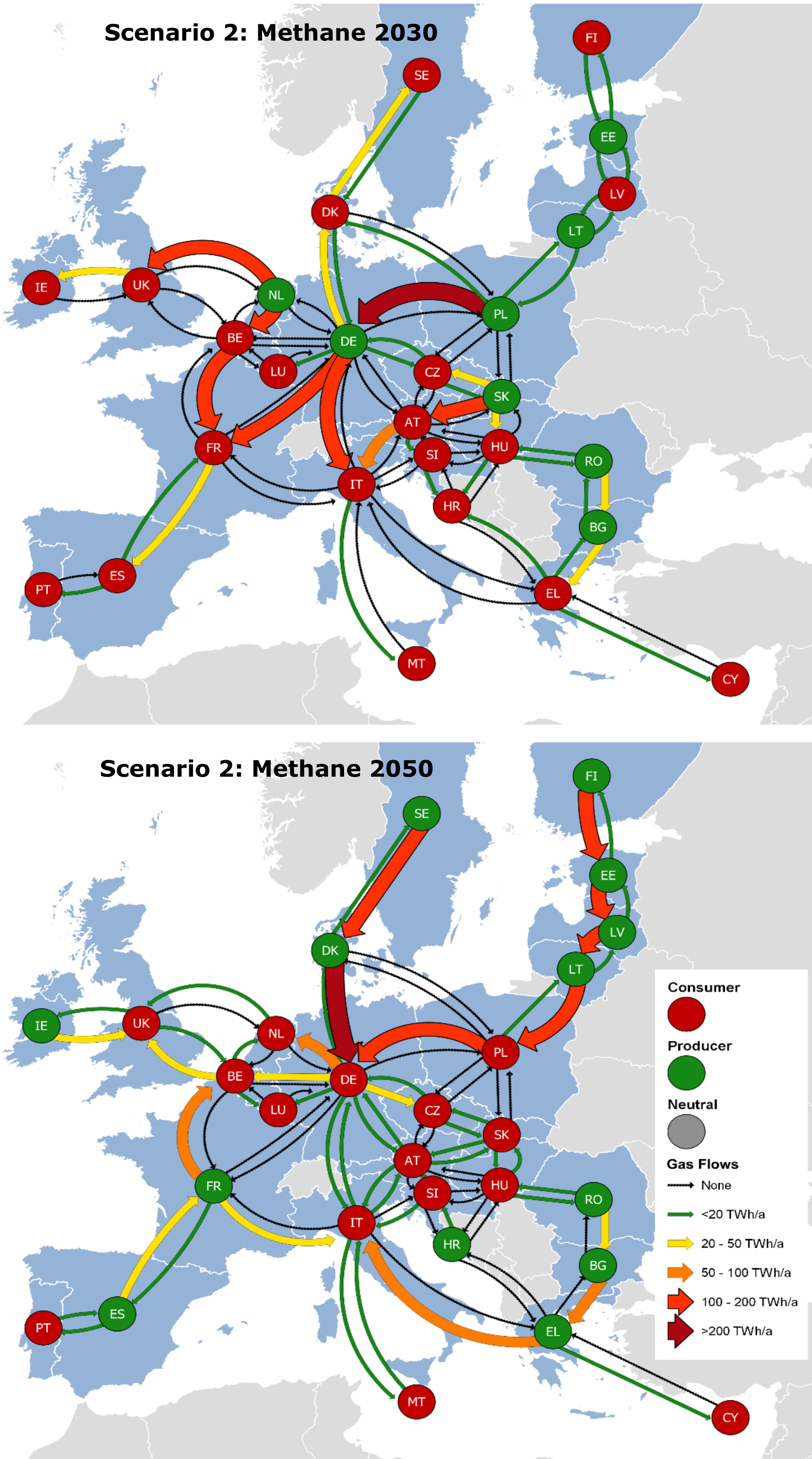
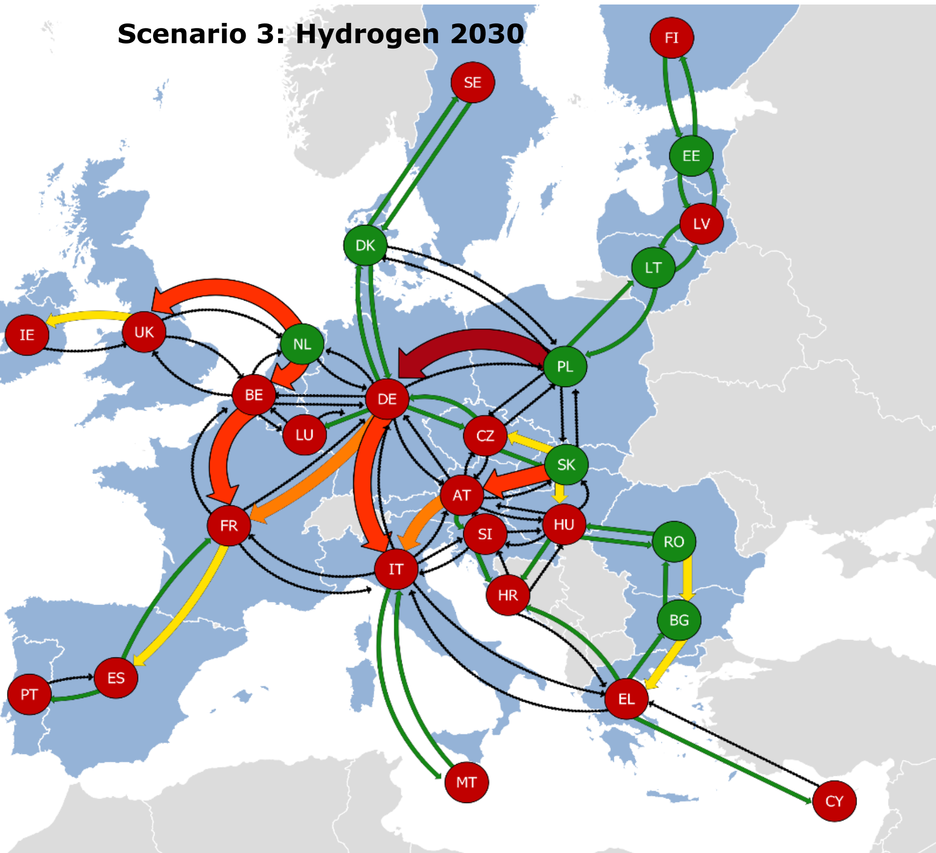


Figure 4-15 Gas flows under the 2030 and 2050 hydrogen scenarios



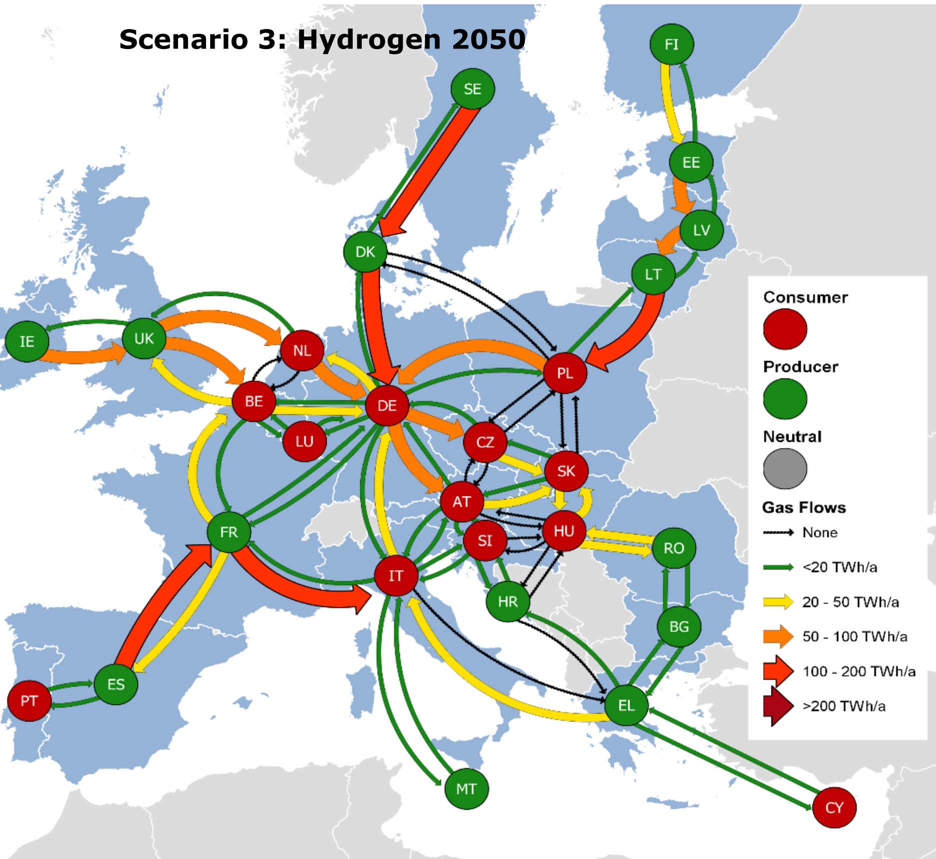


Figure 4-16 Required capacity and related investment under the 2030 and 2050 electricity scenario

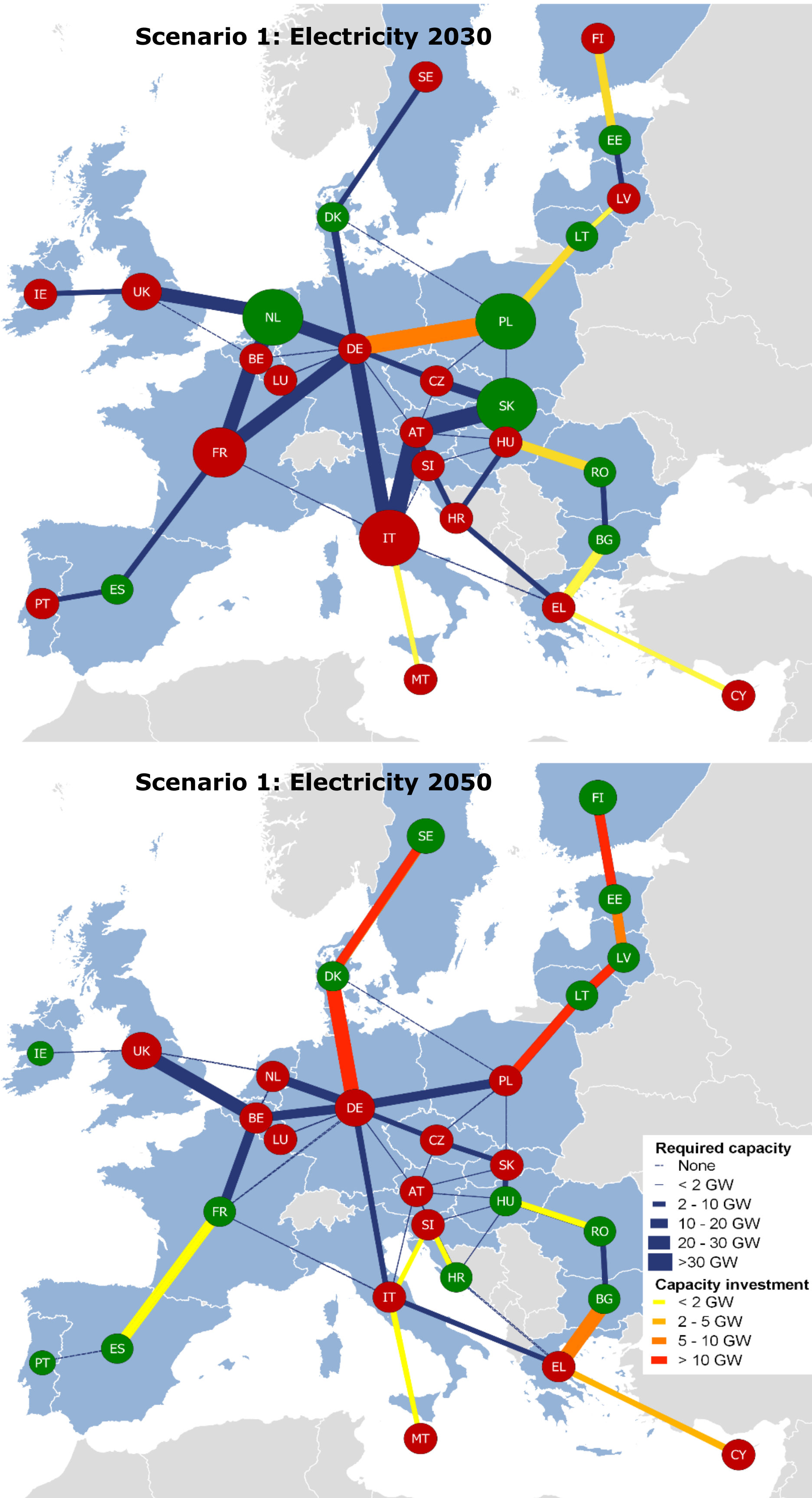
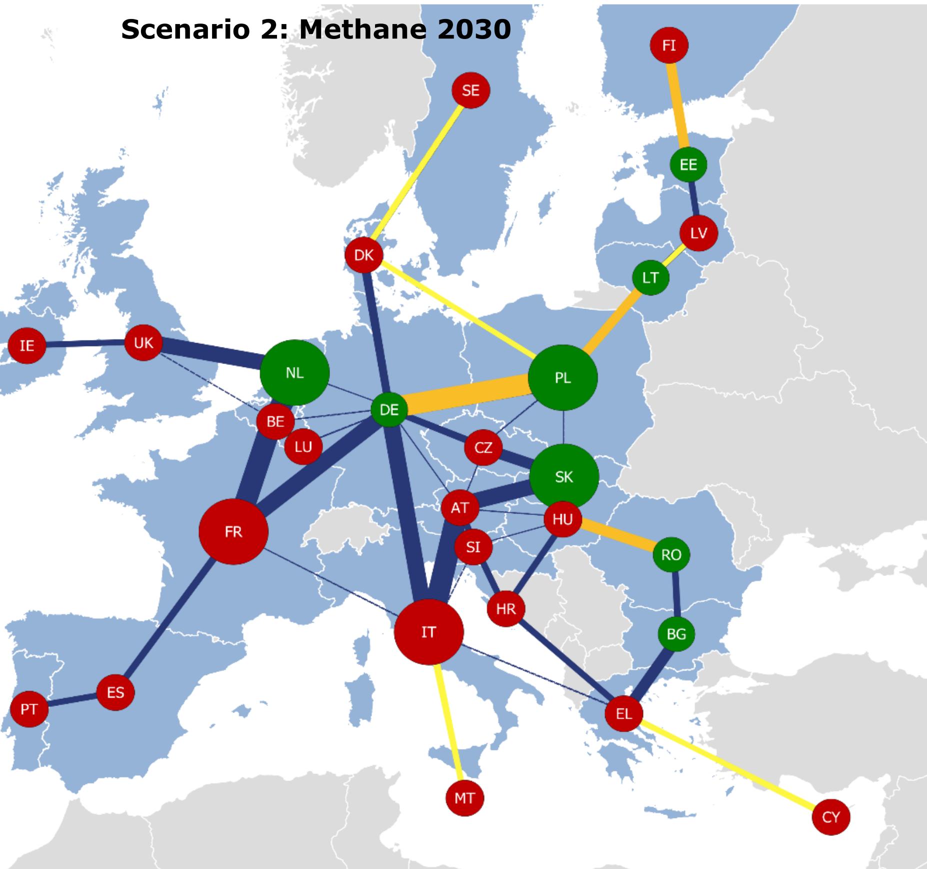


Figure 4-17 Required capacity and related investment under the 2030 and 2050 methane scenario



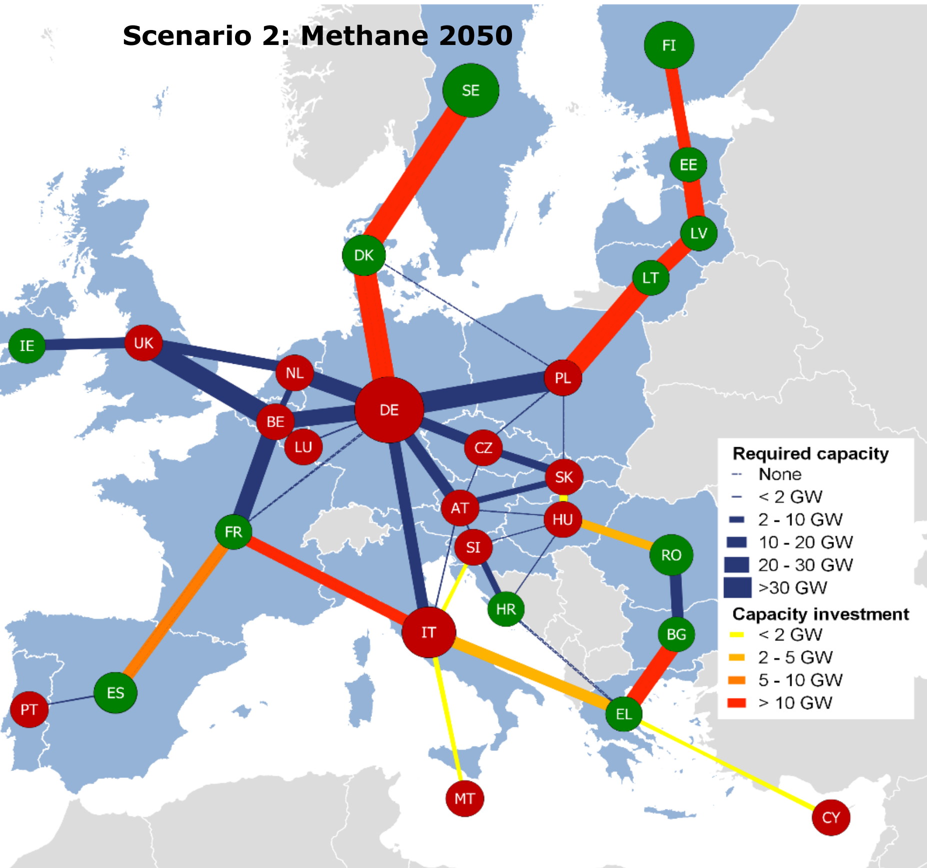
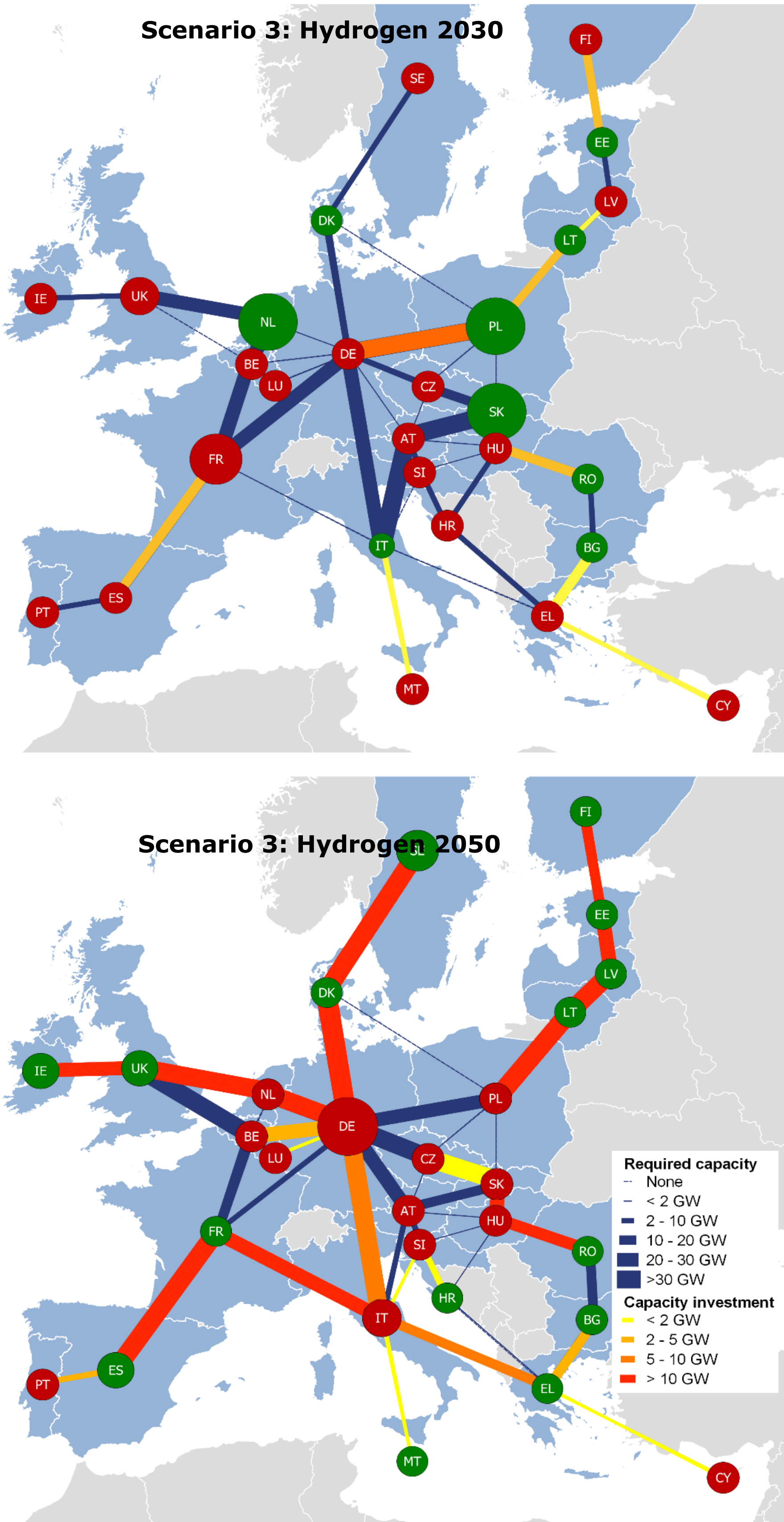


Figure 4-18 Required capacity and related investment under the 2030 and 2050 hydrogen scenario



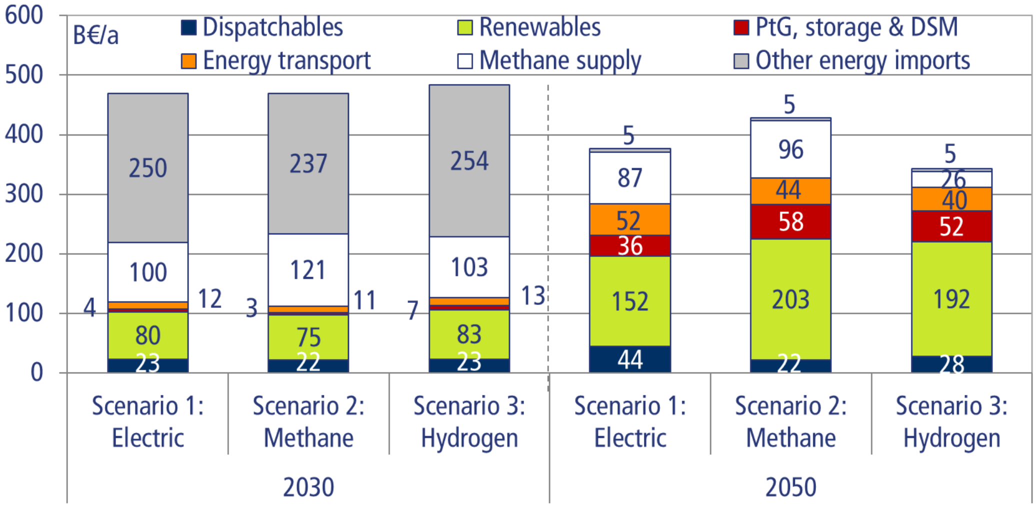
4.6 EVALUATION OF THE ECONOMIC AND ENVIRONMENTAL COSTS AND BENEFITS

4.6.1 COMPARISON OF THE ENERGY SYSTEM COSTS

This chapter provides an economic valuation of the energy system in different scenarios based on the optimal design and operation of the system as described in the previous chapter. The presented figures include the investment costs (expressed as annuity) and fuel costs of the dispatchable power plants, full renewable power generation costs, costs related to power and gas storage (hydrogen and methane), costs due to investments and operation of Power-to-Gas (PtH_2 and $PtCH_4$), DSM costs, investment and operational costs of power and gas infrastructure at international level (i.e. for interconnectors between the Member States) as well as supply costs for biomethane, natural gas and other fossil energy carriers including the direct demand from the end-user sectors. Not included are power and gas infrastructure costs at the national level, in particular for the distribution network (see next chapter for the corresponding cost estimation) as well as end-user appliances.

As indicated in Figure 4-19, in 2030 the cost structure is similar in all scenarios. The major cost contribution of € 240-250bn /a (approx. 50% of total system costs) is represented by coal and oil imports for direct consumption in the end user sectors. Methane supply, i.e. mainly imports and domestic production of natural gas as well as supply of biomethane, account for another €100-120 bn/a or 20%-25% of total costs. Renewable power supply is lower (€ 75-80 bn/a), but still in a similar order of magnitude. Minor costs of approx. €23 bn/a are caused by dispatchable power plants[132] as well as energy transport (more than €10 bn/a) and other system flexibility measures such as electrolysis and electricity storage. In Scenario 3, the higher costs for flexibility are mainly due to larger investments in electrolysis capacities (see Figure 4-20). In general, however, the overall system costs of almost 500 € bn/a are very similar for all scenarios in 2030 with a small advantage for a more electricity-focused system in Scenario 1. Hence in 2030, both methane-focused systems in Scenario 2 and hydrogen-focused system in Scenario 3 have no economic benefit (calculated as the difference in system costs compared to Scenario 1), however, these differences are not significant.

Figure 4-19 Annual energy system costs (excluding national energy transport costs) in EU28

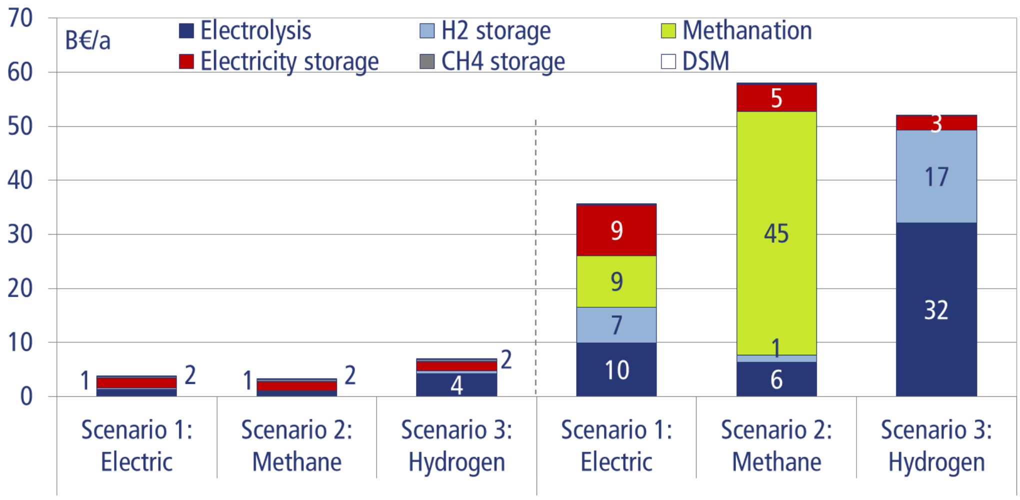


Increasing system coupling and decarbonisation of the energy system until 2050 have a positive effect on the overall system costs in all scenarios. The total system costs decrease by € 40-140 bn/a, leading to total system costs of € 340 bn/a in the hydrogen-focused

[132] Note that the fuel costs of gas power plants are not included in the category "Dispatchables" but are rather summarized in the category "methane supply" as the model jointly optimizes the gas supply for both energy and end user sectors.

Scenario 3, and € 430 bn/a in the methane-focused Scenario 2. In all scenarios, major costs are caused by very substantial investments in new renewable capacities contributing €150-200 bn/a, or 40%-55%, to total costs. However, these investments are more than compensated by the decrease of payments for fossil fuels related to the end user sectors (€5 bna) and lower methane supply costs (€26-100 bn/a). The difference between the scenarios for the latter cost driver is based on the varying demand for biomethane (low in Scenario 3 and high in Scenario 2) and corresponding average biomethane prices which typically rise with increasing demand (€56 /MWh in Scenario 3 and 65 €/MWh in Scenario 2). Due to investments in new dispatchable capacities needed to balance out the fluctuating power feed-in, the corresponding costs increase slightly to €22-44 bn/a. Moreover, renewable electricity supply also causes additional costs for flexibility measures (€36-58 bn/a) and energy transport (€43-53 bn/a). In Scenario 1, the costs for flexibility measures are equally distributed (€ 7-10 bn/a) between electrolysis, local H_2 pipe storage, methanation[133] and power storage (pumped hydro and stationary batteries). In Scenario 2, major cost driver are the methanation facilities with € 45 bn/a or almost 80% of the costs for flexibility. Electrolysis needed to satisfy direct demand from the end user sectors and electricity storage have minor influences. In contrast in Scenario 3, electrolysis and the large underground salt caverns are major cost components with € 32 bn and €17 bn/a, respectively. The costs for demand-side management and CH_4 storage are negligible in both time steps and all scenarios.

Figure 4-20 Annual costs for flexibility measures in EU28



The major cost contribution related to energy transport is made by electricity transport. The operation of existing power infrastructure and investments in new power lines in a system mainly based on renewable power supply cause annual costs of €10-12 bn/a (or 90% of total energy transport costs) in 2030 and €33-52 bn/a (or 75%-95% of total energy transport costs) in 2050. The highest costs for power transport occur in the electricity-focused Scenario 1 with the largest direct power demand form end user sectors.

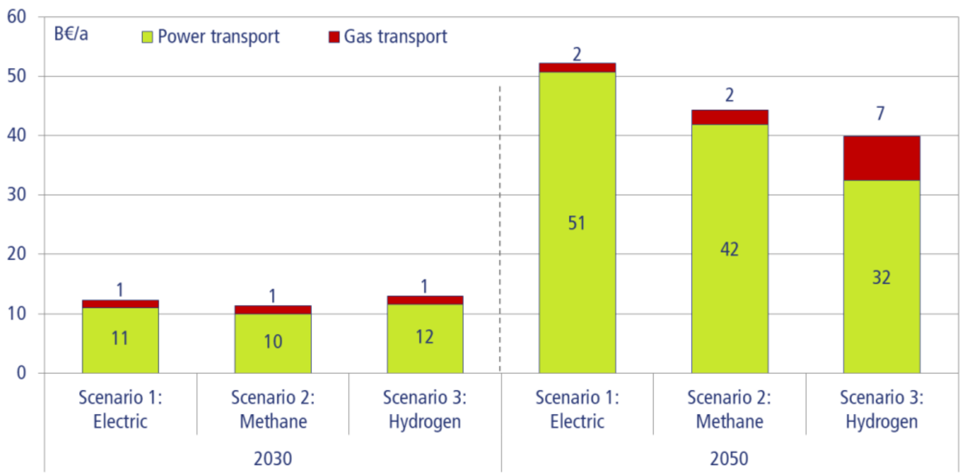
In contrast, the costs of the gas infrastructure in all scenarios are much lower (see Figure 4-22). In 2030 they account for approx. €1.3 bn/a as the existing infrastructure is mainly capable of balancing out methane supply and demand across the Member States. Although the gas demand decreases in comparison to 2018, some pipeline investments with annualized costs of €0.4 bn/a are required as the geographical distribution of gas supply changes due to decreasing domestic natural gas production compensated by the increase of biomethane supply. The remaining costs of €0.9 bn/a are operational costs of the gas infrastructure. In 2050, the corresponding costs in Scenarios 1 and 2 are only slightly higher with €1.5-2.4 bn/a, respectively. The cost structure is also comparable to

[133] Note that the costs for methanation also include the electrolysis costs within the PtCH4 facility.

2030. The additional cost related to the gas infrastructure such as specific metering and refurbishment/replacement of end-user appliances is addressed qualitatively in the previous chapters but is not included in the above-mentioned estimates.

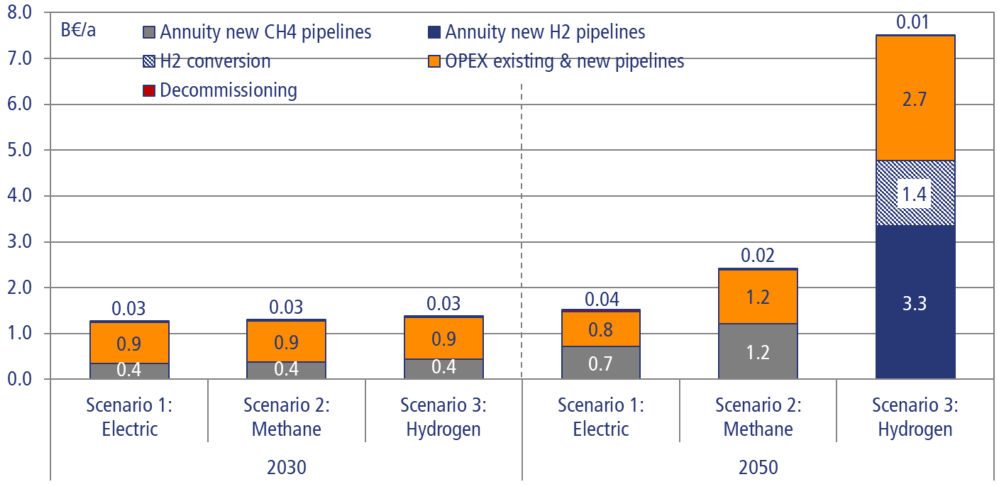
For the hydrogen-focused Scenario 3, however, the overall costs are much higher and the cost structure differs substantially. The overall costs account for approx. €7 bn/a almost equally distributed between costs for new pipelines or conversion of existing CH_4 pipelines (together almost €5 bn/a), and operational costs (€2.7 bn/a). For the former cost component, the major driver are the comparatively costly investments in new compressor capacities due to different physical flow characteristics of hydrogen. Nevertheless, the overall transport costs in Scenario 3 are lower than in the other two scenarios as power transport in this scenario requires lower investments in new power lines. The costs for decommission of unneeded infrastructure are negligible in all scenarios.

Figure 4-21 Annual costs for power and gas infrastructure for international energy transport in EU28



In general, the lowest system costs in 2050 are achieved in the hydrogen-focused Scenario 2, and the highest in the methane-based Scenario 3. This result shows that the overall system costs can be summarized as trade-off between system efficiency (high for Scenario 1 and low for Scenario 3) and system flexibility (low in Scenario 1 due to the direct power demand with limited possibilities for direct power storage and higher in Scenarios 2 and 3). The system design with a strong focus on hydrogen technology appears to be a robust compromise for both factors. Hence, in comparison to the electricity-based system and under the assumptions of this study, a hydrogen-focused system has a positive economic benefit of €30 bn/a in 2050 whereas a methane-focused system is characterised by an economic disadvantage of €53 bn/a. In 2030, the differences are negligible. In this context in Scenario 1 in the long-term the advantages of the higher energy efficiency are offset by the disadvantages of lower system flexibility (due to direct electricity use and low roundtrip efficiency of re-electrification of synthetic methane) in comparison to Scenario 3.

Figure 4-22 Annual costs for gas infrastructure for international gas transport in EU28



4.6.2 Incremental gas infrastructure costs for national transport and distribution networks

As blending hydrogen into the existing NG network is a frequently discussed topic, it is worth exploring its feasibility and reviewing the assumptions made regarding admixture. Assuming a safe admixture rate of 10 vol% hydrogen to methane for 2030 and 20 vol% for 2050, the energy contents required and the resulting hydrogen demand to be supplied under a given scenario have been calculated and presented in Table 4-2. Note that the model does assume 0% admixture by 2050 and that this serves to illustrate that the potential to admix hydrogen is insignificant under any scenario. As we can observe from Table 4-2, the potential to admix hydrogen ranks in the lower one-digit percentage range when comparing its contribution to the entire gas market. It may indeed make sense to admix hydrogen in the early years of hydrogen market introduction, as dedicated infrastructure will not have been retrofitted or constructed to accommodate 100% hydrogen for some time, but once this has occurred there is no case to be made for admixing large quantities of hydrogen.

The model therefore assumes that there will be no admixture in 2050, neither in the TSO nor in the DSO network. However, in 2050 there will be a minor share of dedicated hydrogen networks in the electricity and methane scenarios and some dedicated methane networks under the hydrogen scenario. For the electricity and methane scenario in 2030, up to 10% of hydrogen are admixed in the DSO network. Should there be more hydrogen gas left to be distributed, additional dedicated H_2 networks would have to be converted from freed-up NG-networks, or newly constructed.

Table 4-2 Energy equivalent hydrogen quantity in TWh/a to be safely admixed to the NG-network and its percentage of total hydrogen and of the entire gas market under the respective scenario (maximum admixture share of 20 vol%)

	Electric	Methane	H2	Electric	Methane	H2
	2030			2050		
Potential H_2 admixture in TWh/a	103	115	105	112	195	33
Potential H_2 admixture as share of total H_2	151%	263%	46%	20%	40%	2%
Potential H_2 admixture as share of entire gas market	3%	3%	3%	5%	6%	1%
Total H_2 as share of entire gas market	2%	1%	7%	24%	14%	71%

Under the 2030 hydrogen scenario, the available hydrogen is distributed through dedicated hydrogen networks. After initially establishing a decentralized system of hydrogen distribution networks – both retrofitted and newly constructed - these should gradually be linked through a dedicated separate hydrogen transmission network.[134] While certain areas will have transitioned to be served through dedicated hydrogen distribution networks until 2030, dedicated hydrogen transmission pipelines will only be built on a large scale once sufficient density of local distribution has been achieved. Retrofitting and conversion are most easily done with existing polymer pipes that are least prone to material exhaustion and degradation from hydrogen.[135]

Figure 4-23 and Figure 4-24 display the annual costs for the national transmission and distribution gas networks under the three different scenarios for 2030 and 2050. Figure 4-23 shows the general depreciation costs and OPEX for the transmission and distribution network. These costs add to the cross-border infrastructure costs as presented in the previous chapter. One can observe that until 2030 the bulk of investment and operational costs lies with the operation of the distribution network followed by the operation of the transmission network. In 2050, the scenarios differ strongly, with increasing importance of investment depreciation, notably in the distribution network. Figure 4-24 further splits the costs into OPEX of existing pipelines, refurbishment, decommissioning, conversion as well as costs for new CH_4 and H_2 pipelines.[136]

Compared to the 2015 baseline, depreciation and OPEX show constant or slightly decreasing costs until 2030 under all scenarios, with the methane scenario showing constant costs, the hydrogen scenario slight cost reductions and the electricity scenario stronger cost reductions. This is sensible as the gas capacity is also highest under the methane scenario for 2030. Similarly, for 2050, the electricity scenario comes out as the cheapest option from a gas infrastructure perspective as it involves the lowest quantity of gas. This may come at higher costs for the electric network, which is not estimated here.

Depending on the scenario and the quantities of different kinds of gases, significant investments will be required under certain scenarios. The most expensive one, both in terms of depreciation and OPEX, is the 2050 methane-scenario, with the highest gas capacity and the need for significant additional construction of DSO pipelines. Instead, overall costs under the 2050 hydrogen-scenario are lower than under the 2050 methane-scenario due to substantial free and readily available NG network capacity that can be converted to 100% hydrogen operation. Initial investment into a dedicated hydrogen network is moderately low. Instead, a significant share can be covered through retrofitting parts of the existing NG system to transport hydrogen. Costs for the conversion of existing NG pipelines make up about half of the total annual costs under this scenario (compare Figure 4-24).

[134] In the NaturalHy project it has e.g. been concluded that for high concentrations of hydrogen (≥ 50 vol%) in natural gas pipelines, small effects on the inspection and repair frequency and therefore incremental total costs (inspection & repair for corrosion and cracks) were assumed in the order of ≤10%.

[135] International Gas Union (2017). Using the natural gas network for transporting hydrogen – ten years of experience.

[136] At this point, the cost estimate assumes that (i) costs for refurbishment for admixture are negligible (compare town gas), (ii) decommissioning does not take place and (iii) converting existing NG-pipelines to 100% hydrogen makes up 10% of the costs of new H_2 pipelines.

Figure 4-23 Annual costs of national gas networks (EU28) by scenario, split into depreciation and OPEX for TSO and DSO

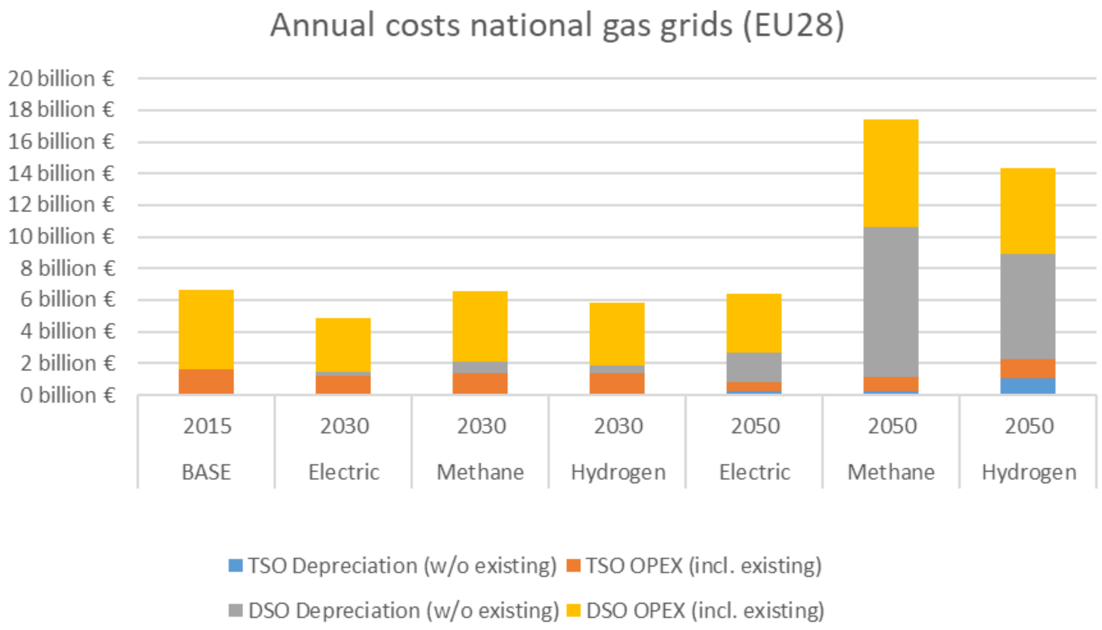
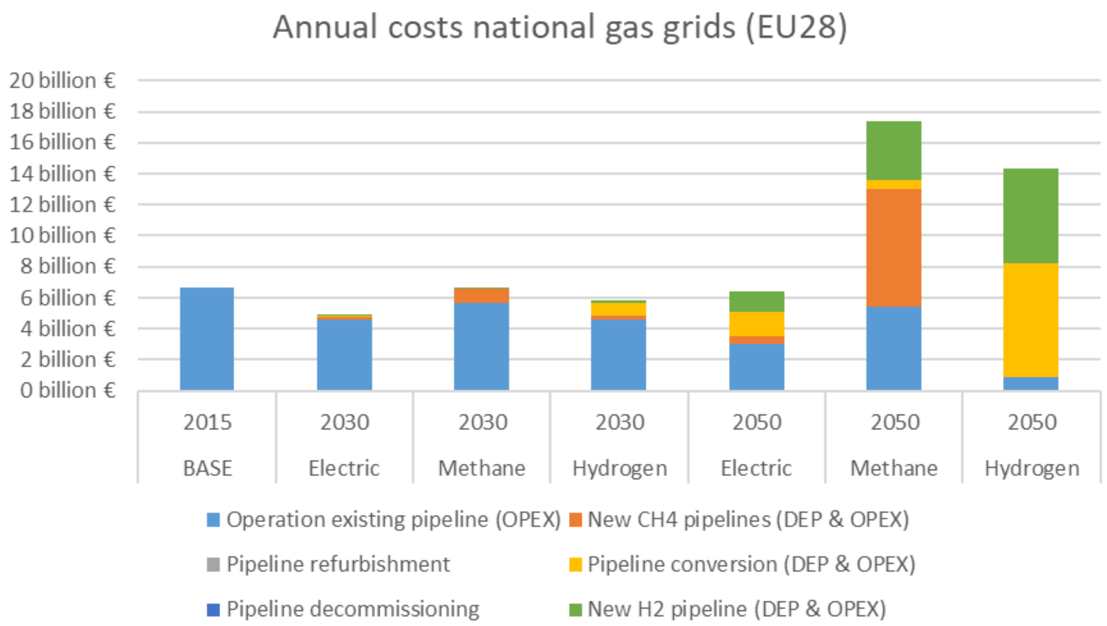


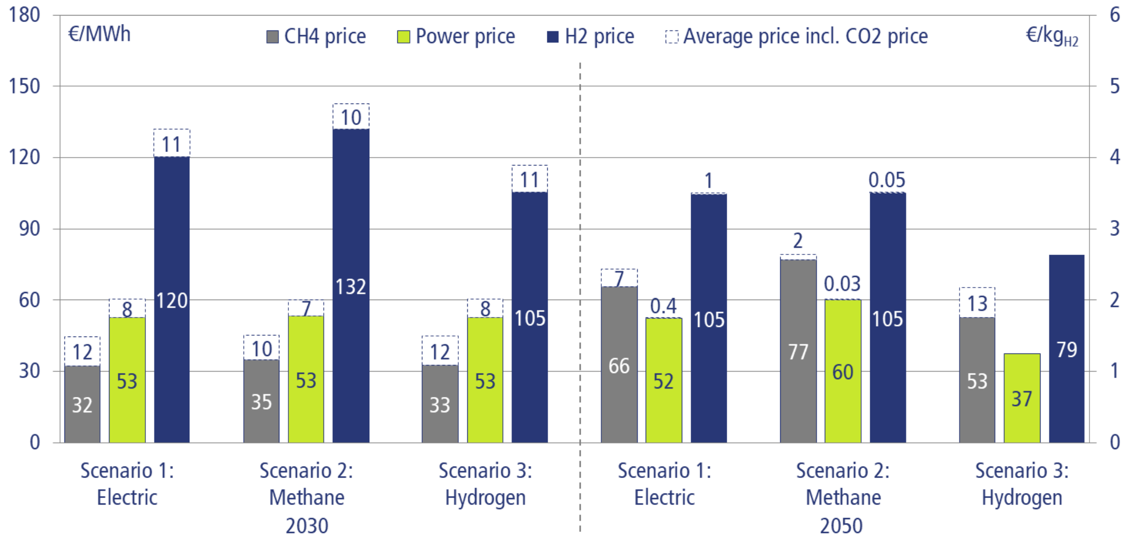
Figure 4-24 Costs for pipeline infrastructure by scenario, split into different aspects of depreciation and OPEX



4.6.3 Economic valuation of hydrogen and biomethane in gas infrastructures

Based on the results of the previous analysis, this chapter provides an additional valuation of the three scenarios based on average methane, power and hydrogen prices. Figure 4-25 shows the corresponding prices under the assumption that synthetic methane is produced from renewable power as a starting point. The corresponding CH_4 prices together with other cost components are then used to calculate the power price which in turn is a starting point for the estimation of the hydrogen price by taking into account also the costs of the entire hydrogen-related infrastructure.

Figure 4-25 Average methane, power and hydrogen prices in EU28



In 2030, the average methane price is comparatively low at 32-35 €/MWh, increasing to approx. 45 €/MWh if payments for CO_2 certificates are equally distributed among all consumers. The power price is higher at 53 €/MWh (or up to 61 €/MWh if the CO_2 payments are taken into account), but comparable among the three scenarios. Both results indicate that in 2030, the energy system design has no influence on the consumer-related energy prices. The highest energy prices of 105-132 €/MWh occur for hydrogen produced via electrolysis based on the aforementioned electricity prices. The higher the overall hydrogen demand the better the utilisation of the required units and infrastructure, and hence the lower the average hydrogen price. This can be observed in Scenario 3 with lower hydrogen prices.

In 2050, the average methane price increases substantially to 53-66 €/MWh. This is mainly due to the switch from comparatively cheap fossil natural gas to more expensive biomethane and synthetic methane. Power prices remain rather stable at 37-60 €/MWh. The highest value is observed in the methane-focused Scenario 2, and the lowest in the hydrogen-focused Scenario 3 where the overall system costs are low but the overall power demand both from end user sectors and electrolysis are moderate. A similar behaviour can be observed for hydrogen prices which, however, are much lower in comparison to 2030. This is due to decreasing specific investment costs for electrolysis as well as lower electricity prices. In general, hydrogen-focused systems as designed in Scenario 3 can be seen as a robust compromise providing lower average end user prices.

4.6.1 ENVIRONMENTAL VALUATION OF HYDROGEN AND BIOMETHANE

In line with the objective of this study, environmental costs focus on CO_2 emission avoidance costs.

The overall GHG emission reduction targets are met in each scenario both in 2030 and 2050. CO_2 reduction in 2030 is approximately 53% compared to 1990, and 100% in 2050. For the sake of comparability, all scenarios are characterized by similar CO_2 emissions per sector for the respective time horizon. Negative emissions stem from LULUCF and BECCS in industry as estimated by the LTS in its "1.5TECH" scenario (300-400 Mt_{CO2}) as well as from BECCS in energy supply of 51-68 Mt_{CO2}/a (district heating as well as biomass and biomethane power plants). Emissions from aviation and navigation (35 Mt_{CO2}/a in 2015) are not taken into account and will require either additional decarbonisation efforts in both sub-sectors or additional negative emissions from BECSS in the power and industry sectors or from biomethane production (see chapter 2.3.2).

The overall system costs are calculated in the energy system modelling as described above, excluding the CO_2 costs incurred in the model as the product of CO_2 emissions and the CO_2 price (84 €/t_{CO2} in 2030, 350 €/t_{CO2} in 2050). Total system costs in 2030 are in the range of B€ 470-480 in the three scenarios, and B€ 376 (electric scenario), B€ 428 (methane) and B€ 343(hydrogen), respectively.

A comparison between net emissions and total system costs reveals that increased use of biomethane and hydrogen in combination with sector coupling and decreasing costs of renewable energy supply lower both overall emissions and system costs between 2030 and 2050. On this basis, the CO_2 avoidance costs are calculated as system cost difference divided by emission difference between 2030 and 2050 resulting in negative values ranging between -20 €/t_{CO2} in the methane focused Scenario 2 and -68 €/t_{CO2} in the hydrogen focused Scenario 3.

4.6.2 SENSITIVITY ANALYSES

Additional sensitivity analyses allow for testing the robustness of the modelling results in respect to predefined input parameters. Therefore, based on the findings from the first modelling runs following three input parameters are defined for variations in the selected scenarios:

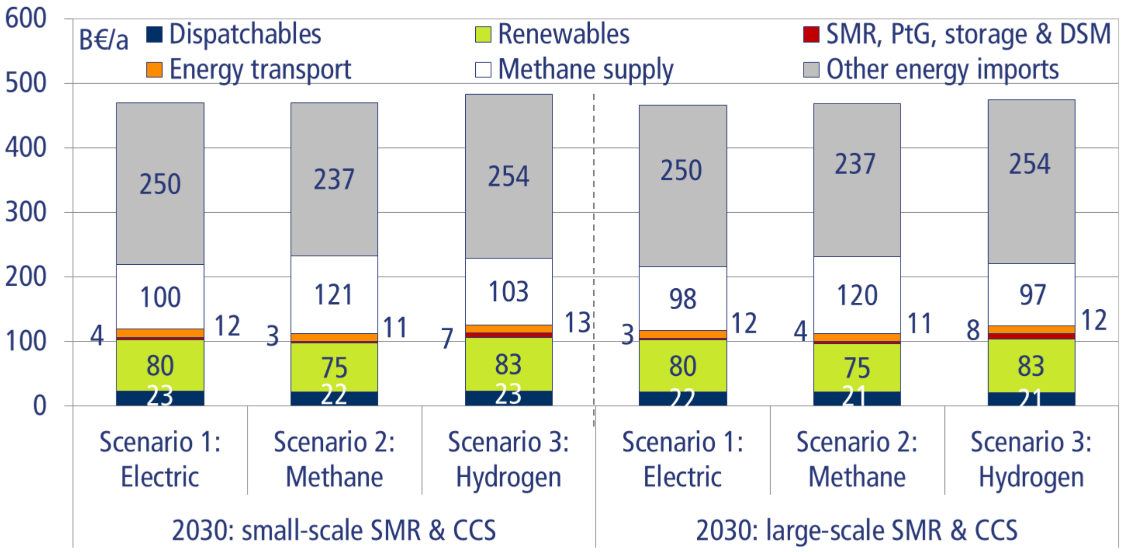
- Sensitivity analysis 1 for the 3 scenarios in 2030: consideration of large-scale instead of small-scale SMR with CCS for hydrogen production with lower specific facility costs (see Appendix for details) and neglecting delivery costs for hydrogen from the large-scale SMR to the end-user;
- Sensitivity analysis 2 for the 3 scenarios in 2030: carbon price 28 €/t_{CO2} as defined in LTS instead of 84 €/t_{CO2} as defined by WEO 2016;
- Sensitivity analysis 3 for the 3 scenarios in 2030: natural gas price of 38 €/MWh i.e. 20% increase in comparison to the original value of 31 €/MWh according to WEO 2016;
- Sensitivity analysis 4 for the 3 scenarios in 2050: increasing biomethane costs by 20% for biomethane from digestion processes and 30% from gasification i.e. 5.4 ct/kWh from sewage sludge; 6.4 ct/kWh from forestry; 7.6 ct/kWh from manure; 7.8 ct/kWh from biological waste and 10.2 ct/kWh from crops and straw.

Sensitivity analysis 1: Large-scale SMR with CCS and lower costs in 2030

Hydrogen production changes significantly when large-scale SMR with CCS is taken into account. Due to much lower technology costs almost the entire hydrogen demand is covered by SMR with a high utilisation rate of approx. 5,000 full load hours. Nevertheless, small electrolysis capacity of 2 GW (Scenario 2) to 10 GW (Scenario 3) with an utilisation rate of less than 1,000 full load hours is still needed to provide additional flexibility in the energy system. Given the unchanged intermittent feed-in, the power generation from dispatchable power plants drops by 5%-23% from 1,250-1,400 TWh/a to 1,000-1,250 TWh/a as less electricity is needed to satisfy the end user hydrogen demand. Consequently, also the investment in new power generation capacities is smaller. Due to a more constant hydrogen production via SMR the system requires lower hydrogen but higher methane storage capacities. Interestingly, methane supply decreases from 3,100-3,500 TWh/a to 3,000-3,400 TWh/a as converting methane directly to hydrogen is more efficient than hydrogen production from electricity provided by gas-fired plants. In addition, investment needs in new gas pipelines are lower by 4%-25% (calculated as a sum of capacity additions between network nodes) due to lower overall gas demand as well as more constant methane consumption and a better geographical distribution of large-scale SMR in comparison to gas power plants.

Although large-scale SMR has a significant impact on the optimal sizing and operation of the energy system the overall costs remain rather unchanged being responsible for limited decrease in total costs by 1%-2% or 1-8 B€/a. This is due to the fact that hydrogen demand and production in 2030 are limited and the abovementioned effects balance out each other. On the one hand the SMR and CCS technology costs account for additional 1 B€/a (Scenario 2) to 5 B€/a (Scenario 3). On the other hand, electrolysis costs decrease by 0.8 B€/a (Scenario 2) to 3.6 B€/a (Scenario 3) whereas methane supply costs drop by 1 B€/a (Scenario 2) to 6 B€/a (Scenario 3). Additional costs savings from storage, gas transmission network and dispatchable power plants are less significant.

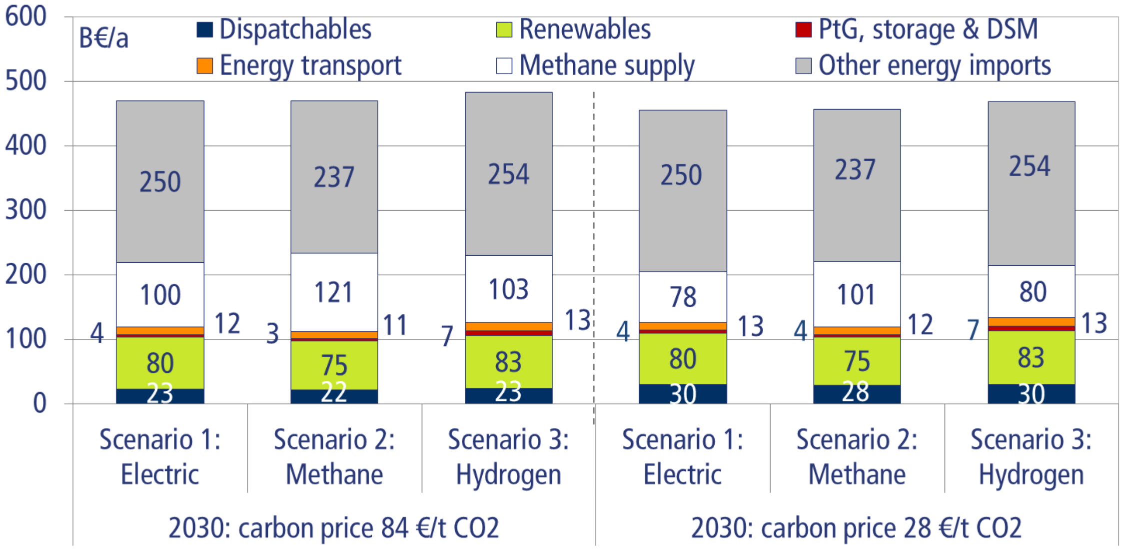
Figure 4-26 Annual energy system costs in EU28 including large-scale SMR with CCS



Sensitivity analysis 2: Lower carbon price in 2030

Changing the carbon price in 2030 has a significant impact on the operation of the power sector and the entire energy system. In fact, lower carbon price in combination with a low coal price changes the merit order of power supply making power generation by coal-fired plants more cost-competitive in comparison to the gas-fired plants. As a consequence, power supply from coal rises from 115-124 TWh/a up to 517-541 TWh/a, whereas the power generation from gas drops by 60% from 600-739 TWh/a down to 220-231 TWh/a. In this context, the investments in new capacities for gas-fired power plants are also lower. On the one hand the build-up of new gas transport infrastructure is smaller by 25%-30% due to lower peak-demand from gas-fired plants. On the other hand, however, additional power lines are needed to manage increased power transport from the coal-fired plants with a less favourable geographical distribution across Europe. Therefore, the costs for energy transport increase slightly due to the changing carbon price. Moreover, the costs of dispatchable power generation (including fuel costs from power generation other than natural gas) are higher by almost 30% rising to 41-44 B€/a due to additional coal consumption. In contrast, the methane supply costs drop by approx. 10% due to lower gas demand from the power sector. All in all, the above-mentioned effects balance out each other and the overall energy system costs remain almost unchanged.

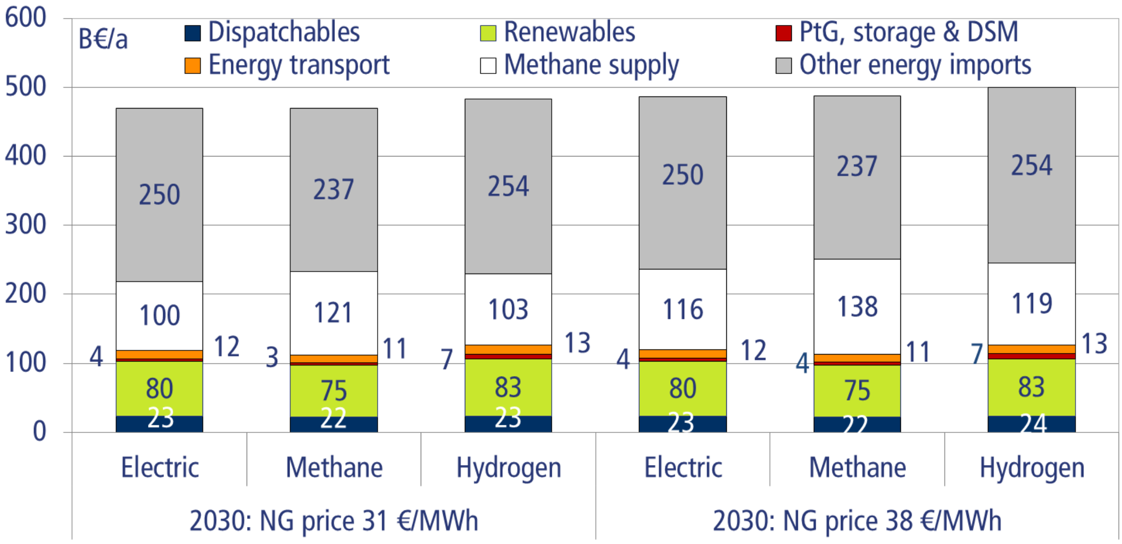
Figure 4-27 Annual energy system costs in EU28 for different carbon prices



Sensitivity analysis 3: Higher natural gas prices in 2030

Similar to the previous sensitivity analysis also increasing natural gas prices lead to a shift in power generation from gas-fired to coal-fired generation. The capacity of gas power plants is slightly lower whereas the utilisation of the coal power plants increases. Nevertheless, the dispatchable costs (excluding methane supply for gas-fired power plants) are almost unchanged as the merit order effect of increasing gas prices is rather limited. The capacity requirement for new gas pipelines is lower by 20% in all scenarios as the gas infrastructure is exposed to lower gas demand peaks from the power sector. The sizing and operation of all other system components remains almost unchanged. Given the decreasing natural gas demand from the power sector the overall costs of methane supply to all sectors go up only by approx. 15% up to 116-138 B€/a. The overall impact of the natural gas price on the entire system costs is limited: increase by approx. 3%-4% while preserving the cost order between the three scenarios.

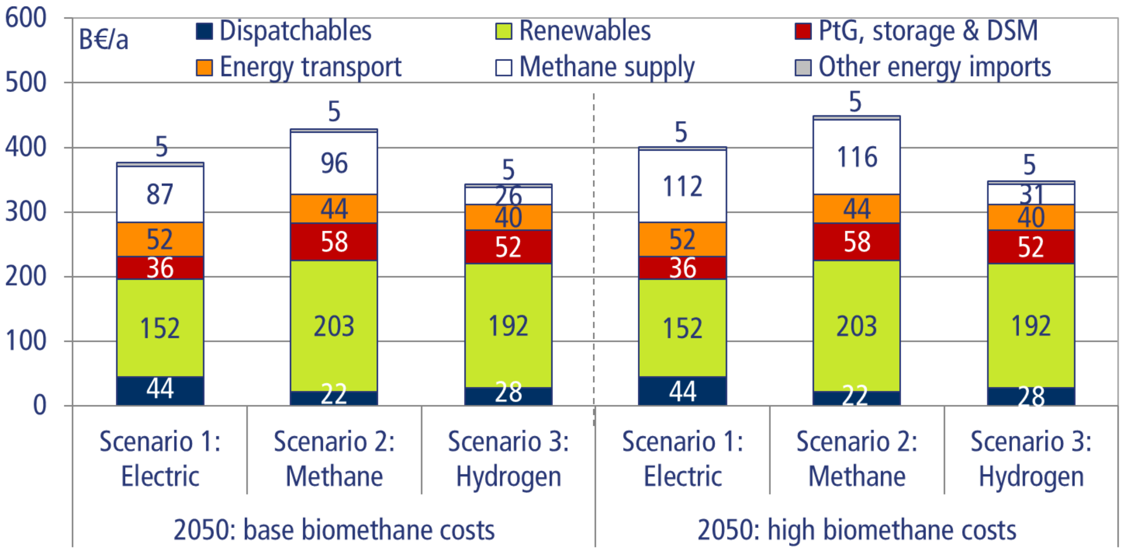
Figure 4-28 Annual energy system costs in EU28 for different natural gas prices



Sensitivity analysis 4: Higher biomethane costs in 2050

Increasing biomethane costs in 2050 have only a limited impact on the design and operation of the overall energy system. In fact, biomethane is used mainly in the end-user sectors either up to potential limits (Scenario 1 and 2) or up to a predefined level (Scenario 3) as described in previous chapters. Power generation by gas-fired plants for balancing intermittent electricity supply are based either on the unchanged production of synthetic methane from $PtCH_4$ (Scenario 1 and 2) or hydrogen from PtH_2 (Scenario 3). Therefore, the dimensioning and optimal operation of all system components inducing the gas infrastructure remain unchanged. Nevertheless the overall costs for biomethane supply increase according to the assumptions by 20%-30% up to 30-120 B€/a, however, having only a limited impact on the overall system costs (increase by 2% up350 B€/a in Scenario 3 with lowest biomethane usage and 7% up to 450 B€/a in Scenario 2 with highest biomethane demand). In this way the cost differences between the three scenarios are more pronounced in comparison to the base case.

Figure 4-29 Annual energy system costs in EU28 for different biomethane costs



5 Current status of the gas sector in selected Member States

The following chapters focus on a selection of countries (and their respective regulatory regimes), TSOs and DSOs.[137] Each of the selected Member States has archetypical characteristics which are briefly summarised below and further detailed in the following sections. This chapter addresses the gas network planning, revenue regulation and tariffication in these countries.

Table 5-1 Overview of the characteristics of the selected countries

Member State	Description
Germany	**Leading in both biomethane and hydrogen**, virtually all biomethane injected Medium share of gas in energy consumption (23%) & net importer of natural gas Very extensive transmission (38 800km) and distribution (497 400km) networks Large salt cavern storage capacity (152 TWh) & other gas storage capacity (118 TWh)
Hungary	**Limited regulatory or project developments for biomethane and hydrogen** High share of gas in energy consumption (32%) & net importer of natural gas Considerable transmission (5 900km) and distribution (86 500km) networks No salt cavern storage capacity; 68 TWh of other gas storage capacity
Netherlands	**Mature biogas development (virtually all injected to the network)** Incipient but ambitious role for power-to-gas High share of gas in energy consumption (40%) & net exporter of natural gas Very long transmission (12 600km) and distribution (125 200km) networks

[137] The NRAs from Germany, Hungary and Spain, as well as gas TSOs from the five selected countries and one German DSO have been interviewed in the context of this study. However, all views expressed in this report are the authors' and do not necessarily represent the opinions of the interviewed stakeholders.

Member State	Description
	Limited salt cavern storage capacity (4TWh), studies for hydrogen storage, and 127 TWh of other storage capacity
Sweden	**Limited network but central biomethane role** (especially in transport, also off-grid) Low share of gas in energy consumption (2%) & net importer of natural gas Only one of the countries with no cross-border interconnection capacity (extra-EU) Very limited network (600km transmission and 3 000 km distribution), marginal storage capacity (0.1 TWh)
Spain	**Initial developments in biomethane and hydrogen** Medium share of gas in energy consumption (21%) & net importer of natural gas Considerable transmission (13 800km) and distribution (71 400km) networks No salt cavern storage capacity; 32 TWh of other gas storage capacity

Source: Network lengths from CEER (2018) & CEER (2019) Report on Regulatory Frameworks for European Energy Networks for Spain; Storage capacity (operation + under construction) from GIE (2018) Storage map

5.1 Gas network planning

The most important European regulations for the planning of gas infrastructure are the internal natural gas market directive,[138] the regulation for access to natural gas transmission networks,[139] the Trans-European Networks for Energy regulation[140] (TEN-E) and the Connecting Europe Facility (CEF) regulation.[141] TEN-E and CEF are further discussed in chapter 8.

According to the current EU gas network planning framework, the European Network of Transmission System Operators for Gas (ENTSOG)[142] must develop a ten-year network development plan (TYNDP)[143] at the European Union level every two years, building on the National Development Plans (NDPs, submitted by TSOs to their NRAs and cross-border projects being planned or identified (including Projects of Common Interest - PCIs). These plans include relevant information regarding the transmission system interconnections and operation, as well as infrastructure development needs.

Textbox 5-1 TYNDP and PCI projects in selected countries

All selected countries have at least one planned gas project listed in the ENTSOG TYNDP 2018 and included in the third PCI list. While Germany has the most gas infrastructure projects planned (20 projects) in the ENTSOG TYNDP 2018 from the selected countries, Hungary has the most PCIs (8 PCIs).[144] Besides the PCIs and other projects included in the ENTSOG TYNDP, the five countries have their own NDPs. However, these are not always publicly available. Germany[145], Hungary[146] and the Netherlands[147] have publicly available NDPs, while Spain's latest infrastructure planning document[148] was for 2012-2020 (and covered both gas and electricity). Given the limited extent of Sweden's gas infrastructure, Swedegas' project portfolio includes only one LNG terminal and one extension of the current gas network.[149]

Regarding gas network planning, increasing coordination is required both between gas and electricity, as well as between transmission and distribution levels. These aspects have yet to find their way into European legislation. They are further explained in chapter 8.

[138] Directive 2009/73/EC concerning common rules for the internal market in natural gas
[139] Regulation (EC) No 715/2009 on conditions for access to the natural gas transmission networks
[140] Regulation (EU) No 347/2013 on guidelines for trans-European energy infrastructure
[141] Regulation (EU) No 1316/2013 establishing the Connecting Europe Facility
[142] Established by the Regulation (EC) No 715/2009 on conditions for access to the natural gas transmission networks
[143] Regulation 715/2009 require ENTSOG to adopt and publish a Community-wide network development plan (TYNDP) every two years.
[144] TYNDP 2018 – Annex A: Project table
[145] FNB Gas (2019) Netzentwicklungsplan Gas 2018-2028
[146] FGSZ (2018), 10 Year Development Proposal Consultation.
[147] GTS (2017) Network development plan 2017 – consultation document.
[148] Ministerio de industria, turismo y comercio (2011), planificación de los sectores de electricidad y gas 2012-2020. Desarrollo de las redes de transporte.
[149] Swedish Energy Markets Inspectorate (2018), The Swedish electricity and natural gas market 2017

Textbox 5-2 Increased coordination for network planning

Increasingly coordinated approach for gas and electricity infrastructure development planning

There is an increasing need for improved coordination for electricity and gas infrastructure development and operations, among others to cover more efficiently the flexibility needs of the energy system. ACER proposes an obligation for gas and electricity TSOs to cooperate and the European Commission is studying the potential of sector coupling for the EU natural gas sector.[150]

Following the TEN-E requirement to develop a common interlinked electricity and gas market and network model, the ENTSOs published common scenarios for the 2018 TYNDP and have released common storylines for the 2020 TYNDP, which will allow for comparable assessments of future investment decisions between the sectors.[151] The ENTSOs are currently improving the interlinked model, due to be operational in 2019.[152] Also, the ENTSOs cooperate with ACER and the European Commission in the PCI process.

TenneT and Gasunie are an example of enhanced cooperation of electricity and gas TSOs; they have published a joint infrastructure outlook to 2050 for Germany and the Netherlands, which also analyses the impact of power-to-gas developments.

Increasing importance of the distribution level

European regulation on the development of gas infrastructures used to focus on projects at the transmission level, in particular with cross-border impact. However, the development of decentralized renewable and decarbonised energy sources, of demand-side management initiatives and of 'new' conversion technologies such as power-to-gas is shifting the attention to the distribution level to which many of these applications will be connected, and to the interaction of the transmission and distribution levels. Several studies[153] acknowledge the relevance of transmission and distribution level coordination. In Germany, for example, DSOs have to elaborate ten-year forecasts of capacity needs, which are provided to their respective TSOs, which take them into account for the development of their network development plan.

Despite the regulatory developments at the European level, stakeholders generally agree that the regulation of distribution activities is best left at the national level. European legislation should provide the general framework and guarantee the cooperation of the actors.

5.2 REVENUE REGULATION AND NETWORK TARIFFICATION

5.2.1 REVENUE REGULATION FOR GAS NETWORK OPERATORS

National regulatory frameworks for determining the revenue of regulated gas transmission and distribution operators have some common structural elements. The regulated revenue of system operators can be separated in three revenue streams: to cover operational expenses, depreciation costs and capital remuneration of the regulatory asset base.[154] To determine these, regulators make use of key revenue-setting elements: the operational and capital expenditures, the regulatory asset base, depreciation rules and the cost of capital. These elements are indicated in Table 5-2 for the selected Member States.

[150] European Commission (ongoing) Potentials of sector coupling for the EU natural gas sector - Assessing regulatory barriers
[151] ENTSOG & ENTSO-E (2018), TYNDP 2018 – Scenario report & ENTSOG & ENTSO-E (2018) Overview of the proposed Gas and Electricity TYNDP 2020 Scenario Building Storylines
[152] Artelys (2018) Investigation on the interlinkage between gas and electricity scenarios and infrastructure projects assessment & ENTSOG and ENTSO-E (2018) Focus Study Interlinked Model Joint ENTSOs Workshop
[153] CEER (2015) The Future Role of DSOs - A CEER Conclusions Paper & CEER (2016) Position Paper on the Future DSO and TSO Relationship - C16-DS-26-04 & CEER (2019) Conclusion paper - new services and DSO involvement - C18-DS-46-08 & CEDEC et al. (2018) Joint Statement from the DSO Associations on the proposal to revise the TEN-E Guidelines & CEDEC, Eurogas, GEODE (2018), Flexibility in the energy transition. A toolbox for gas DSOs.
[154] ACER (2018) Report on the methodologies and parameters used to determine the allowed or target revenue of gas transmission system operators

Regarding assessment methods employed by regulators for the **operational expenses** of TSOs, bottom-up and top-down assessments are the most common methods in Europe. The methods are usually combined and applied for different operational cost items, with each regulator applying nonetheless usually one main method. Germany and Hungary apply hybrid approaches with several methods: Germany combines multiple methods (bottom-up, top-down, TOTEX[155], benchmarking and trends analysis), while Hungary combines mostly a bottom-up assessment with additional benchmarking and trends analysis. The Netherlands uses mostly TOTEX and benchmarking, while Sweden and Spain apply a top-down assessment.[156]

In Europe, national regulators most commonly apply bottom-up assessments for **capital expenditures**, but this is not reflected in the Member States under study. While Hungary does use bottom-up assessments and Spain combines them with benchmarking, Germany applies multiple approaches, the Netherlands combines TOTEX with benchmarking and the Swedish NRA verifies ex-post the CAPEX proposal of the TSO.[157]

Germany, the Netherlands and Spain have measures in place for increased efficiency related to CAPEX (such as an X-factor or an efficiency requirement), while all considered countries except Spain have such measures related to OPEX.[158] Ex-post assessments of capital expenditures (i.e. to verify the relevance of the investment and its cost) at EU level are more common, with around half of the national regulators conducting such reviews. Furthermore, while traditional fixed network assets are in general included in the regulatory asset base, the inclusion of linepack, customer connection assets and working capital varies in the countries under analysis.[159]

Table 5-2 Summary of revenue regulation aspects related to gas network operators

Aspects	Germany	Hungary	Netherlands	Spain	Sweden
TSO & DSO regulatory system in place	Revenue Cap – incentive based	Incentive-based (mixture of price cap, revenue cap and quality regulation)	Revenue Cap – incentive based	Revenue Cap & quality regulation	Revenue Cap – incentive based
Composition of the regulatory asset base[160]	Mix of historical and re-evaluated fixed assets plus working capital	Re-evaluated fixed assets	Historical cost-based fixed assets	Historical cost-based fixed assets	Re-evaluated fixed assets
NRA-approved depreciation ratio for transmission network assets	Pipelines 45-65 years Compressors 25 years	Pipelines 50 years Compressor stations 50 years	Mostly 30 – 55 years	40 years	Pipelines 90 years
Depreciation calculation	Linear	Linear	Linear, indexed to inflation	Linear	Linear
Difference between RAB defined on net book value and RAB based on re-evaluated value	140%	121.50%	NA	NA	NA
Gas PCI project-specific incentive	Methodology with applicable risks, project pre-requisites	Methodology with applicable risks, project pre-requisites and	Methodology with application information	No specific methodology defined*	No specific methodology defined*

[155] Totex: 'Allowed revenues do not differentiate between CAPEX and OPEX, but considers the whole costs instead. Therefore, it ensures that the incentive is technologically neutral'. CEER (2017) Incentives Schemes for regulating DSOs, including for Innovation.
[156] ECA (2018) Methodologies and parameters used to determine the allowed or target revenue of gas transmission system operators (TSOs)
[157] ECA (2018) Methodologies and parameters used to determine the allowed or target revenue of gas transmission system operators (TSOs)
[158] CEER (2019) Report on Regulatory Frameworks for European Energy Networks
[159] ECA (2018) Methodologies and parameters used to determine the allowed or target revenue of gas transmission system operators (TSOs)
[160] ECA indicates a different classification, with Germany, Hungary, Spain and Sweden using historical costs while the Netherlands re-evaluates costs. It can be explained by the fact that while Germany does apply historical costs at the beginning of the period, the RAB may change due to efficiency targets and investments not foreseen.

Aspects	Germany	Hungary	Netherlands	Spain	Sweden
methodology defined by NRA[161]	and required information	required information	requirements from promoters		

**Spain and Sweden argue that the regulatory framework already provides sufficient incentives.[162]*

Source: CEER (2019) Report on Regulatory Frameworks for European Energy Networks & ECA (2018) Methodologies and parameters used to determine the allowed or target revenue of gas transmission system operators (TSOs)

Pre-tax nominal **weighted average cost of capital** (WACC) is the most common methodology to determine the cost of capital in Europe, being applied by 12 national regulators, followed by pre-tax real WACC in use in 6 Member States. For the countries covered in this study, Hungary, the Netherlands and Sweden use the pre-tax real WACC while Spain is using the pre-tax nominal WACC. Germany does not use the WACC approach but determines the cost of equity and debt separately, with the cost of equity set by law.[163,164] The cost of capital of the Spanish gas TSO is indexed to the returns on government bonds, accrued by a premium.[165]

5.2.2 GAS NETWORK ACCESS AND USE TARIFFICATION

Tariff setting for gas transmission in Europe is currently undergoing significant changes, with the 'network code on harmonized transmission tariffs structures for gas'[166], which provides much more detailed guidelines on tariff setting (compared to the 2009 gas regulation[167]) and is due to be fully implemented by all Member States by 2021.

Table 5-3 presents key parameters of the tariff methodologies published by TSOs for consultation.[168] The parameters govern how TSO costs are allocated to different network uses, considering the split between transit vs domestic uses, gas system entries vs exits, capacity- vs commodity-based tariffs and transmission vs non-transmission services, and any discounts to storage. Thus, the tariff structure as shaped by the TAR network code will have a direct and distinct economic impact on network users, it being paramount that the tariff structure be transparent, non-discriminatory and cost reflective.

Table 5-3 Gas transmission structure tariff parameters

Parameter	Germany	Hungary	Netherlands	Spain	Sweden
Choice of reference TSO tariff methodology	Postage stamp	Postage stamp	Postage stamp	Capacity Weighted Distance	Postage stamp
Revenue from transmission services	NCG:83.4% GASPOOL:82.6%	98.8%	100%	100%	98%
New entry-exit splits	NCG:32/68% GASPOOL:38/62 %	40/60%	50/50%	50/50%	0/100%
Previous entry-exit splits (2017)	Determined per TSO[169]	50/50%	35/75%	25/75%	0/100%

[161] For PCIs the TEN-E guidelines require that Member States and national regulators 'ensure that appropriate incentives are granted' in case of higher risks. However, by October 2018 only 4 requests were submitted for gas projects, none in the countries selected for this study.
[162] ACER (2018) Summary report on project-specific risk-based incentives
[163] ECA (2018) Methodologies and parameters used to determine the allowed or target revenue of gas transmission system operators (TSOs)
[164] 'Equity is valuated at an interest of 6.91% (nominal interest) and 5.12% (real interest rate) depending on the share of new and old assets in the RAB'. CEER (2018) Report on Regulatory Frameworks for European Energy Networks
[165] CEER (2019) Report on Regulatory Frameworks for European Energy Networks
[166] Regulation (EU) 2017/460 establishing a network code on harmonised transmission tariff structures for gas
[167] Regulation (EC) No 715/009 on conditions for access to the natural gas transmission networks provides few guidelines on tariff-setting (i.e. tariffs should be transparent, non-discriminatory, account for system integrity, facilitate gas trade and competition, reflect efficiently incurred costs and include an appropriate return on investment). According to this regulation cross-subsidization among different network users is explicitly forbidden.
[168] ENTSOG (2018) Implementation Document for the Network Code on Harmonised Transmission Tariff Structures for Gas – Second Edition (revised)
[169] 50/50% according to ENTSOG (2017) Implementation Document for the Network Code on Harmonised Transmission Tariff Structures for Gas. However, the split is actually determined per TSO, e.g. was 4/96% for Ontras in 2019, following the publication according to Art. 29 and 30 Regulation (EU) 2017/460 (NC Tariffs).

Parameter	Germany	Hungary	Netherlands	Spain	Sweden
Storage entry/exit discount	75/75%	90/100%	50/50%	100/100%	100/100%
Discount to LNG	No	No	No	0%	No
Capacity cost allocation comparison index[170]	NCG:2.6% GASPOOL:1%	8.7%	6.3%	0.6%	N/A
Transmission services revenue from capacity-based tariffs	100%	85.1%	100%	96.7%	100%
Domestic/cross-border split	NCG:75/25% GASPOOL:68.4/31.6%	71.75/28.25%	57/43%	90.1/9.9%	100/0%
Non-transmission services	Biogas Market area conversion Metering	Odorization Title transfer Data provision Balancing services	N/A	N/A	Pressure reduction service Administrative charge

Sources: Previous entry-exit splits: ENTSOG - TAR NC Implementation Document - Second Edition September 2017. All other parameters: TAR NC national tariff consultations.

The TAR NC provides guidelines on how regulators should set up the revenue recovery methodologies for gas TSOs. The TAR NC separates regulatory frameworks for tariff setting in two categories: price cap and non-price cap (which includes revenue cap, cost plus and rate of return).[171] As seen, the Member States under study apply generally non-price cap regulation. Revenue is recovered through two main streams: transmission services revenue (separated into capacity and commodity-based charges) and non-transmission services revenue.[172] By default, transmission service costs should be recovered through capacity-based tariffs, although a limited part of the costs may be recovered through commodity-based tariffs upon regulatory approval. The three possible revenue streams are shown in the figure (transmission service revenues from capacity- and commodity-based charges and non-transmission service revenues).

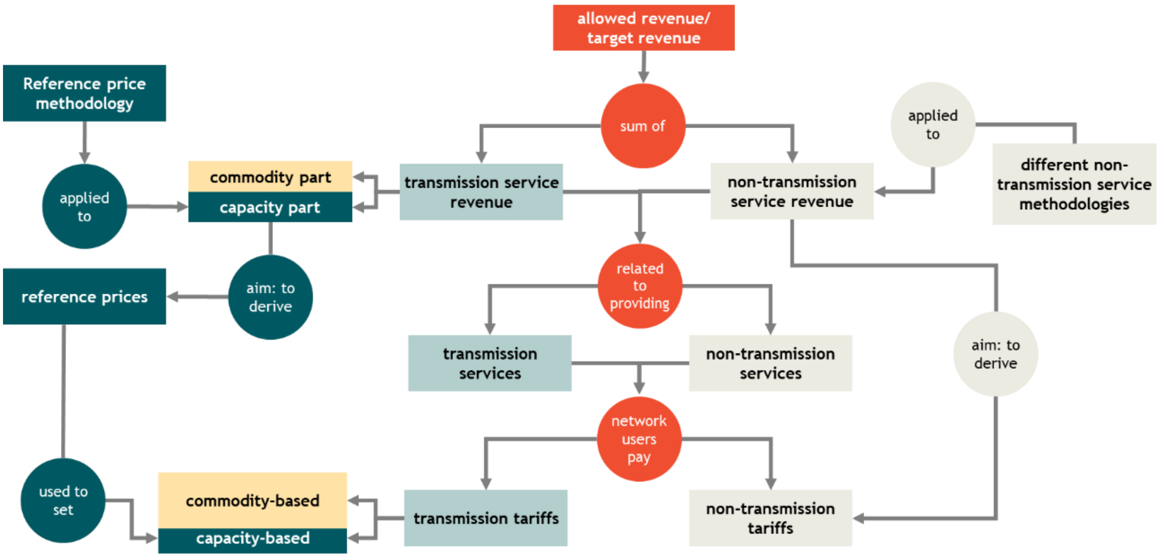
Discounts are allowed for LNG and isolated system points, and required for gas storage (minimum 50% unless it competes with an interconnection point). Of the Member States covered in this study, the Netherlands applies the minimum 50% storage discount, Germany 75%, while Hungary and Sweden apply 100% discounts (only for exit in the case of Hungary).

[170] Following the TAR NC, the capacity cost allocation comparison index provides a simplified indicator to identify the allocation of costs according to cost drivers for intra- and cross-system flows, for capacity- and commodity-based tariff. The NRA is required to provide a justification if the index is above 10%.'

[171] ENTSOG (2018) Implementation Document for the Network Code on Harmonised Transmission Tariff Structures for Gas – Second Edition (revised)

[172] Ibid

Figure 5-1 Revenues and revenue recovery through tariffs in the TAR network code



The TAR NC requires the national regulator or TSO to conduct cost allocation assessments on capacity-based charges (and commodity-based charges if applicable) to avoid cross-subsidization between intra- and cross-system use. A cost allocation assessment must be conducted, with the regulator justifying any cost allocation which exceeds the threshold of 10%. Of the concerned countries, none indicated a capacity cost allocation comparison index above the threshold of 10%, but ACER indicates that if the storage discounts in Hungary were considered in the index calculation, the actual value would be 17%.[173] Member States are also obliged to publish the intra-system/cross-system split of revenues. This split ranges from 100/0% for Sweden (which has no cross-system flows) to 57/43% for the Netherlands.

According to the TAR network code, flow-based tariffs can differ for entry and exit points, but have to be uniform within each point group. Of the concerned Member States with available data, only Hungary makes use of commodity-based tariffs.[174] Tariffs for non-transmission services must respect cost-reflectivity, non-discrimination, objectivity, transparency requirements and must minimise cross-subsidisation, trying to allocate costs as much as possible to the service beneficiaries.[175] The ENTSOG provides examples of services which will need to be classified as either transmission or non-transmission services, including blending and/or ballasting; odorization and biogas services. In the countries of interest, only Germany proposed non-residual non-transmission services tariffs (around 17% of revenues), mainly split between a biogas charge (for recovering costs due to subsidization to renewable gas injections) and market area conversion services (related to the conversion of L-gas to H-gas).

6 DEVELOPMENT OF BIOMETHANE AND HYDROGEN IN SELECTED MEMBER STATES

6.1 CURRENT STATE OF BIOMETHANE AND HYDROGEN IN THE SELECTED EU MEMBER STATES

This chapter briefly investigates the current status of biomethane and hydrogen gases in the selected countries. Table 6-1 provides an overview of the development of biomethane

[173] ACER (2019) Analysis of the consultation document for Hungary
[174] Hungarian Energy and Public Utility Regulatory Authority (2018) Response to ACER Consultation Template
[175] ENTSOG (2018) Implementation Document for the Network Code on Harmonised Transmission Tariff Structures for Gas – Second Edition (revised)

and hydrogen in the selected countries. There is a large difference across countries, with Germany leading in both gases while Spain and Hungary have only incipient development.

Overview of biomethane and hydrogen with a focus on the selected countries

Production of biogas is more established in Europe than hydrogen, with a trend to shift from local electricity and/or heat production from biogas towards upgrading it to **biomethane** due to its higher added value[176] and end of public support to biogas. Upgrading biogas has expanded especially in countries where its production was already consolidated.[177] **Hydrogen** and **power-to-gas** (hydrogen or synthetic methane) development is still relatively limited, but is growing due to its potential for supporting the decarbonization of the economy. However, its economic feasibility is still quite poor due to high costs of renewable electricity, high investment costs for electrolysers and low efficiency in intermittent operation.[178]

Table 6-1 Overview of the development of biomethane and hydrogen in the selected countries

		Biomethane			Power-to-gas	
Country	Overview	Use	Plants injecting	Feed-in capacity (TWh/y)	Projects	Gas use
Germany	Leading in both gases[179]	Injection	194	14.41	26 (9 of which can inject H_2 or CH_4[180])	Injection Mobility CHP
Hungary	Little regulatory or project developments for either gas	Export	1	0.07	Lab prototype[181]	
Netherlands	Mature biogas development, incipient but ambitious role for PtG	Injection[182]	28	1.84	1 (and past demonstration projects)[183]	Space heating
Sweden	Limited network but central role for biomethane	Mobility[184]	15	0.57	Planning pilots[185]	
Spain	Initial developments in both gases	Injection	1	0.58	1 pilot[186]	Injection

Source: Number of plants and feed-in from GIE (2018) European Biomethane Map 2018.[187]

Almost all EU Member States[188] have natural gas transport and distribution infrastructure which can easily be used for **biomethane** as well as for **synthetic methane**.[189] Currently, the injection capacity is limited in some distribution networks, especially in summertime. In some areas this has become a barrier for biomethane plants to access distribution

176 EBA (2019). http://european-biogas.eu/2019/02/06/biogas-trends-for-this-year/
177 ISAAC (2016) Deliverable D5.2: Report on the biomethane injection into national gas grid
178 Glenk and Reichelstein (2019) Economics of converting renewable power to hydrogen. Nature Energy 4
DNV GL (2019) Hydrogen in the electricity value chain & http://europeanpowertogas.com/projects-in-europe/
179 Germany is one of the largest producers of biomethane in Europe, accounting for roughly 35% of the number of plants installed in Europe and 46% of the injected biomethane volume. Source: Bundesnetzagentur (2019) Monitoringbericht 2018; EBA (2018), Annual report 2018.
180 4 plants inject synthetic methane into the grid and 5 inject hydrogen. Stakeholders are effectively exploring the potential role of synthetic methane with several demonstration projects experimenting with methanation.
181 Power-to-gas Hungary company was established in 2016, a protoype is in operation since 2018, and projects are being developed, in Central and Eastern Europe countries, with first injection expected in 2021. Source: Communication with developers (2019).
182 In the Netherlands, the Dutch gas TSO GTS is assisting two new projects that will feed in biomethane into the transmission grid. Sources: https://www.gasunienewenergy.nl/projecten/ambigo & https://www.gasunienewenergy.nl/projecten/scw
183 https://energiekaart.net/initiatieven/duurzaam-ameland-power2gas/
184 Transported by road instead of injected to the grid. Source: Energigas Sverige (2018), National biogas strategy 2.0.
185 https://www.swedegas.se & Energigas Sverige (2018), National biogas strategy 2.0.
186 https://prensa.naturgy.com/en/gas-natural-fenosa-launches-pilot-project-to-produce-renewable-gas-in-catalonia/
187 EBA & GIE (2018), European Biomethane Map.
188 Except Cyprus and Malta. Cyprus, however, has projects to exploit its own natural gas reserves by 2022, and has initiated constructing a natural gas network and storage.
189 European Commission (2016) Optimal use of biogas from waste streams - An assessment of the potential of biogas from digestion in the EU beyond 2020

networks, as production levels are relatively stable throughout the year. Solutions for the Netherlands[190] include the connection of biomethane plant to the transmission network and better balancing of local supply and demand. In Germany, there are more than 10 gas boosting installations for allowing reverse flows. [191]

Discussions are currently ongoing on how much **hydrogen** can be blended into natural gas without the need to adapt networks and end-use equipment (see chapter 4.4). Also, adding hydrogen to natural gas pipelines reduces their energy capacity although this can be partially offset by higher flow rates.[192] Some studies assessed the requirements and impacts for converting the natural gas infrastructure to hydrogen. A recent Dutch study found converting the Dutch gas distribution grid into a 100% hydrogen grid is technically feasible but would require adaptation of the gas metering equipment and the boilers and cooking equipment on the users' side. Another study found that the continued use of the gas infrastructure for transport of renewable gas is the least-cost scenario for Germany.[193]

Storing large volumes of renewable energy will be one of the main challenges in the transition to a low carbon energy system.[194] Using existing gas storage (e.g. to cover seasonal energy peak needs related to heating) could be more economic than expanding the electricity storage capacity, which is still limited (600 GWh at EU level). While almost all gas storage capacity (1 100 TWh at EU level) could be used to store biogas/biomethane/synthetic gas, part of it, in particular salt caverns, is also technically suitable to store hydrogen.[195] Storage of hydrogen in depleted gas fields might also be feasible under certain circumstances, but has not yet been tested in practice.[196] From the selected Member States, only Germany (152 TWh of working gas) and the Netherlands (4 TWh) have salt-cavern storage capacity, which might offer them a competitive advantage for hydrogen storage and thus the development of power-to-gas. The Netherlands already has plans to test a salt cavern for hydrogen storage.

Concerning uses, in the EU, **biomethane** produced is mostly used for transport and space heating.[197] In 2018, biomethane was injected into the gas network in 18 European countries.[198] The reason that most biogas production is not converted into biomethane is that the direct local use of biogas is currently more cost-effective. In Germany, biomethane use for heating especially of the old building stock has been growing, with a willingness of consumers to pay a premium.[199] Also in the other selected countries at least some biomethane is injected into the network. In 2016 approximately 80% of Sweden's biomethane was used in the transport sector.[200]

The **hydrogen** and **synthetic methane** produced in PtG projects are consumed in a variety of ways. Around 40% of the power-to-gas plants operational in the selected countries are injecting gas into the network, 7 of which inject hydrogen and 7 synthetic methane, with experimentation by network operators especially in Germany and the

[190] Netbeheer Nederland (2018) Advies: 'creëren voldoende invoedruimte voor groen gas'.
[191] CEDEC, Eurogas, GEODE (2018), Flexibility in the energy transition. A toolbox for gas DSOs.
[192] Effects are nonlinear and depend on energy density and H_2 flow properties. As hydrogen is also less compressible, the effect becomes more pronounced at higher pressures. Source: Quarton et al. (2018) Power-to-gas for injection into the gas grid: What can we learn from real-life projects, economic assessments and systems modelling?
[193] Netbeheer Nederland (2018), Toekomstbestendige gasdistributienetten; Frontier Economics et al. (2018) The importance of the gas infrastructure for Germany's energy transition.
[194] Ecofys (2018) Gas for Climate - How gas can help to achieve the Paris Agreement target in an affordable way.
[195] FCH JU Hydrogen Roadmap Europe 2019 p.22
[196] HYUNDER (2013)Assessment of the potential, the actors and relevant business cases for large scale and seasonal storage of renewable electricity by hydrogen underground storage in Europe.
[197] EBA(2018), Annual report 2018; Eurostat (2018) Complete energy balances Nrg_110a. & Biosurf (2015) Market survey on determining the market accepted threshold for the value of tradable biomethane certificates.
[198] EBA (2018), Annual report 2018.
[199] DENA (2019) Biogaspartner – gemeinsam einspeisen - Biogaseinspeisung und -nutzung in Deutschland und Europa - Markt, Technik und Akteure
[200] ACEA (2018) Vehicles in use Europe 2018 & https://www.swedegas.se/gas/biogas/nyttan-med-biogas

Netherlands.[201] Next to injection, fuel production for transport and use of the gases for combined heat and power (CHP) are the most common uses.

6.2 Policy and regulatory framework for biomethane and hydrogen

6.2.1 Targets and regulatory framework at the EU level

Several EU policies and regulations shown in Table 6-2 address biomethane and hydrogen as part of the European decarbonization options, though from a technology-neutral approach. However, in general, EU regulation does not extensively address the treatment of these gases in infrastructure and for the injection of hydrogen into gas networks there is not yet a comprehensive regulatory framework at EU level.[202] The hydrogen value chain is complex,[203] and some of the concerned activities do not entirely match current classifications or are not addressed by current legislation. There is thus still the need for clarifications on which European and national regulations apply to power-to-gas, either at the transmission or the distribution level, despite economic considerations still being the main barrier to large scale development of the technology.[204]

Table 6-2 Overview of key EU policies and strategies for biomethane and hydrogen

Policy	Overview
Recast Renewable Energy Directive[205]	• EU-wide 2030 target of 32% for renewable energy plus a 2023 upward review clause; • EU-wide target of 1.3% average annual renewable energy increase in the heating and cooling sector from 2020 to 2030; • EU-wide target of 14% for renewable energy in the transport sector by 2030, including 'gaseous transport fuels of non-biological origin' and recycled carbon fuels; • Provisions for the access to and operation of gas networks with gases from renewable sources; • Extension of guarantees of origin to all renewable gases, including hydrogen • Sub-target for transport of 3.5% in 2030 from advanced biofuels and biogas[206] • Sustainability and greenhouse gas emissions savings criteria[207] • Biomethane is included in the definition of biogas as 'gaseous fuels produced from biomass'
Gas directive	• Regulators to ensure the definition of technical design and operation rules for the network and connection, including safety • Promoting, in line with energy policy, the integration of large- and small-scale production of renewable gas both in transmission and distribution networks, including through the removal of barriers for new capacity • Regional cooperation between regulators for operation, network codes and congestion • Unbundling rules to DSOs and exemption possibility to those serving less than 100 000 customers • Regulatory exemption to closed distribution systems • Duties of regulators, including setting the rules and conditions for connection and access to networks and ensuring there are no cross-subsidies
Recast regulation establishing ACER	• Participation in the development of and opinion on the network codes and guidelines • Recourse decision-maker on cross-border issues • Monitoring of infrastructure investments including TYNDP and TEN-E guidelines
TEN-E regulation	• Scope of pipelines includes biogas transport • Eligibility criteria for gas projects include support to biogas and power-to-gas under the sustainability category
CEF 2021-2027 proposal	• Financial support to PCIs • Financial support for studies and construction of cross-border renewable energy projects (if part of joint cooperation mechanisms of the Renewable Energy Directive)

[201] Sources: for German projects: powertogas.info as well as personal communication with individual projects, for NL: Stedin (2018), Fact Sheet Power-to-gas Rozenburg 2018-2023; and for Spain: SEDIGAS (2018), Plan de Desarrollo de Gas Renovable – Hoja de ruta al 2030.
[202] HyLAW (2019) Horizontal Position Paper - Gas Grid Issues
[203] The hydrogen value chain is highly complex, involving the conversion from electricity into hydrogen, possible methanation and then injection into the gas network.
[204] HyLAW (2018) D4.1 Cross-country comparison
[205] Directive (EU) 2018/2001 on the promotion of the use of energy from renewable sources (recast)
[206] As carbon neutral methane is one of the possible solutions for decarbonizing transport, renewable methane is eligible for the advanced biofuel consumption target of 3.5% by 2030 of the directive
[207] Increasing from 60% in 2020 to 80% in 2030, with typical and default emission values for biomethane

Policy	Overview
Clean mobility package	• CO_2 emissions standards for heavy-duty vehicles, with at least a 30% reduction in 2030 compared to 2019 • European Commission role regarding CNG standards (and hence H_2 $\%_{vol}$) • Consideration of hydrogen and natural gas including biomethane as alternative fuels for heavy-duty vehicles

6.2.2 EXISTING PLANS AND TARGETS FOR BIOMETHANE AND HYDROGEN

In some Member States, the draft National Energy and Climate Plans to 2030 also provide specific measures for the deployment of biomethane and hydrogen. Table 6-3 provides an overview of the relevant plans, targets and other policy measures related to biomethane and hydrogen included in the draft NECPs.[208] Only a few of the selected EU Member States have set explicit targets for biomethane.

In April 2019, 17 EU energy ministers (including Hungary[209]) signed a declaration[210] supporting the role of hydrogen and renewable gases in the decarbonization of the EU economy and stating that gas infrastructure needs to be prepared to support the integration of biomethane, synthetic methane and hydrogen, while addressing methane venting and fugitive emissions. However, this declaration was not signed by 4 of the 5 selected Member States due to a perceived lack of ambition: Germany, the Netherlands, Spain and Sweden.[211]

Table 6-3 Overview of overarching RES target as well as plans, targets and other policy measures related to biomethane and hydrogen in the draft NECPs

Country	Biomethane and hydrogen in draft NECPs
Hungary[212]	• Share of RES in final energy use 2030: 20% (14.65% by 2020) • **Target 2030**: 93 GWh of renewable hydrogen for transport • **Target 2030**: 93 GWh of biogas for transport • No significant increase in electricity generation from biogas
Germany	• Share of RES in final energy use 2030: 30% (18% by 2020) • No specific measures for the stimulation of biomethane mentioned • Reference to a National Innovation Program for hydrogen and fuel cell technology. • 0.1% share of hydrogen in the final energy demand for transport in 2030
Netherlands	• Share of RES in final energy use 2030: NA (12.4% by 2020) • No specific targets for biomethane nor hydrogen mentioned • The Netherlands intends to set up a program for hydrogen innovation and deployment
Sweden[213]	• Share of RES in final energy use 2030: 65%[214] (50% by 2020) • **Rural development programme 2014-2020**: Including measures for production of biogas • **Support for biogas production** through anaerobic digestion of manure • **Fossil-free transport solutions**: SEK 1 billion 2018–2023 allocated to fossil-free transport (including biogas) • No explicit mention of hydrogen in the context of future policies
Spain[215]	• Share of RES in final energy use 2030: 42% (20% by 2020) • R&I for introducing renewable gas (biomethane and syngas) into the gas infrastructure • R&I for hydrogen (including hydrogen for transport) • **Advanced biofuels in transport**: Adapt certification system to gather advanced biofuels, especially biomethane injected into the network. Support programme for advanced biofuels production facilities.

[208] https://ec.europa.eu/energy/en/topics/energy-strategy-and-energy-union/governance-energy-union/national-energy-climate-plans
[209] However, 4 (Germany, the Netherlands, Spain and Sweden) of the 5 selected Member States did not sign due to a perceived lack of ambition. Source: Euractiv (2019) https://www.euractiv.com/section/energy/news/11-eu-countries-snub-romanian-presidencys-gas-declaration/
[210] Sustainable and Smart Gas Infrastructure for Europe (2019)
[211] Euractiv (2019) https://www.euractiv.com/section/energy/news/11-eu-countries-snub-romanian-presidencys-gas-declaration/
[212] Hungary (2018) National Energy and Climate Plan of Hungary (Draft). Courtesy Translation in English provided by the Translation Services of the European Commission.
[213] Government offices of Sweden (2018), Sweden's draft integrated national energy and climate plan According to Regulation (EU) 2018/1999 of the European Parliament and of the Council on the Governance of the Energy Union and Climate Action.
[214] Not an explicit national target; results from 2016 reference scenario.
[215] Spain (2019), Borrador Plan Nacional Integrado de energía y clima 2021-2030.

Country	Biomethane and hydrogen in draft NECPs
	• **Promotion of renewable gases** including biomethane and hydrogen. An assessment will be undertaken to determine their potential, in view of defining a strategy for its effective use, and the design of the necessary support mechanisms • **Integration of gas market**: become a hub for natural gas, renewable gas / hydrogen

In **Germany** the German Renewable Energy Heat Act of 2008 (EEWärmeG) aims for 14% share of renewables in final energy consumption for heating and cooling by 2020. Biomethane withdrawn from the gas network may count towards that target when a mass balance system is used.[216] Germany had an ambitious target for biomethane of 6% of total gas consumption by 2020, reaching 10% by 2030, but these targets are now outdated.[217] The draft NECP indicates that biogas domestic production would decrease from 79.93 TWh in 2015 to 62.5 TWh in 2040.[218]

While biomass-based energy is sporadically addressed in the **Hungarian** strategies and programmes, a clear, comprehensive and integrated approach is lacking, particularly for the injection of biomethane and hydrogen in the network. The support for renewable energy in the country has furthermore been characterized by changes in the measures implemented, such as in the revised KÁT program.[219] However, the Hungarian draft NECP indicates two specific relevant targets: 93 GWh of renewable hydrogen for transport and 93 GWh of biogas for transport by 2030.[220] In 2017 the 2nd Second Climate Change Strategy[221] was adopted. While the Strategy also included funding for biomass-based energy, it does not cover specifically biomethane, hydrogen or its injection in the gas network, although specific projects may be supported.

In the **Netherlands**, there are no national targets for biogas or biomethane production, but the new draft climate agreement sets some national targets for hydrogen production for 2030. The Dutch government is currently negotiating a Climate Agreement which foresees that biomethane will play a role in the Dutch energy transition and is expected to publish a biomethane roadmap in 2019. The Climate Agreement also includes concrete plans with regard to hydrogen, aiming to realise 3-4 GW of electrolyser capacity by 2030 for which a hydrogen program will be set up,[222] a follow-up to the Hydrogen Roadmap of 2018.[223] Also multiple regional initiatives exist in the country.[224]

Spain does not have specific targets for renewable gases in its draft NECP, but proposes measures to adapt the certification system, assess the potential, determine a strategy, and design support mechanisms. While initiatives have been set up, the dedicated roadmaps and plans are mostly from the private sector.[225] Spanish authorities have developed a national framework for alternative energy in transport[226] which includes biomethane and hydrogen.

[216] Erneuerbare-Energien-Wärmegesetz - EEWärmeG
[217] GreenGasGrids (2013) Proposal for a European Biomethane Roadmap. NB the biomethane target of 6 bcm was converted into TWh, using the biomethane energy contents from: Ministry of food and Agriculture (2014) Bioenergy in Germany: Facts and figures.
[218] DG Energy (2019) National Energy and Climate Plans (NECPs). Available at https://ec.europa.eu/energy/en/topics/energy-strategy-and-energy-union/governance-energy-union/national-energy-climate-plans.
[219] Biosurf. Hunga ry's country network. Available at http://www.biosurf.eu/en_GB/networking/hungarys-country-network/ & Kovács (2017) Roadmap for Hungary. Biosurf 2017 Project Meeting & Inter-Association Workshop.
[220] Hungary (2018) National Energy and Climate Plan of Hungary (Draft). Courtesy Translation in English Provided by the Translation Services of the European Commission
[221] Innovációs és Technológiai Minisztérium (2018) Második Nemzeti Éghajlatváltozási Stratégia
[222] Ontwerp Klimaatakkoord (2018) & CBS Statline (2019) 1. Elektriciteitsbalans; aanbod en verbruik; Hernieuwbare elektriciteit; productie en vermogen.
[223] Topsector Energie TKI Nieuw Gas (2018) Outlines of a hydrogen roadmap.
[224] Noordelijke Innovation Board (2017) The green hydrogen economy in the northern Netherlands & De Volkskrant (2019) Onderzoek naar mogelijkheid grootste groene waterstoffabriek in Rotterdamse haven.
[225] SEDIGAS (2018). Plan de Desarrollo de Gas Renovable – Hoja de ruta al 2030; http://prensa.naturgy.com/el-gas-renovable-es-una-de-las-soluciones-para-cumplir-los-objetivos-de-descarbonizacion-e-impulsar-la-economia-circular/; http://www.ptehpc.org/
[226] https://industria.gob.es/es-ES/Servicios/Documents/marco-energias-alternativas.pdf

Sweden set out a new climate policy framework in 2018[227] and reiterated the goals in its NCEP. The Swedish government put in place the Fossil Free Sweden Initiative[228] and has, since 2009 articulated its political ambition to have a fossil-independent vehicle fleet by 2030.[229] The Swedish Gas Industry aims to have 100% biomethane in the gas network by 2050 and prepared a proposal for a national biogas strategy 2.0.[230] The Sweden Energy Agency has commissioned Sweco to develop a strategic innovation agenda for vehicles powered by hydrogen.[231]

6.2.3 National legal framework for the injection of biomethane and hydrogen

In the following sections we discuss the diverse regulatory frameworks for injection of hydrogen and biomethane across the selected Member States. The main issues identified are summarized in the table below. Injection of biomethane is authorized in an increasing number of European countries, including Germany and Sweden, as long as the gas conforms to national technical specifications.[232] Nonetheless, some national frameworks lack or have limited provisions specific to renewable gases in general or biomethane, hydrogen or synthetic methane in particular. Furthermore, the acceptable hydrogen blending levels vary significantly, from trace levels to $10\%_{vol}$ or more.[233]

The legal status and classification of power-to-gas in the gas and electricity market designs is still unclear. The lack of a clear regulatory framework for power-to-gas in most Member States and at the EU level means that even if hydrogen injection is allowed, every project needs to be addressed individually, resulting in a complex process. In addition, there is a lack of coherence in initiatives on higher hydrogen blending levels, hampering the development of EU-wide solutions and cross-border transport of hydrogen.[234]

The injection of biomethane and hydrogen may have consequences on the gas calorific value, with possible fluctuations across the network and in time. These fluctuations will require monitoring of the flows and measuring of the gas properties as well as the revision of national gas metering and billing regulation at the domestic level and of cross-border trade aspects at the European level.[235]

Table 6-4 National regulatory framework aspects for the injection of biomethane and hydrogen

Aspects	Germany	Hungary	Netherlands	Spain*	Sweden
Connection and access rules (except technical specifications)	Specific	Same as natural gas	Same as natural gas	Same as natural gas, hydrogen not allowed	Same as natural gas
Connection regulation	Obligation to connect	Same as natural gas	Same as natural gas	Same as natural gas	Same as natural gas
Classification of power-to-gas	Not specified[236]	Not specified	Not specified	Not specified	Not specified
Maximum allowed hydrogen	10 vol%	Not specified	0.5 mol% for the distribution and mid-pressure TSO networks, <0.02% for high-pressure TSO networks	Not specified (5 mol% for non-conventional gas)	0.1-0.5 vol%

[227] Swedish government bill 2016/17:146. A climate policy framework for Sweden.
[228] http://fossilfritt-sverige.se/in-english/
[229] Regeringens proposition 2008/09:162.
[230] Sia Partners (2018) Observatoire du biométhane - Benchmark des filières européennes; Svensson (2015) Natural gas and biomethane are complementary fuels – developments in Sweden; Energigas Sverige (2018), National biogas strategy 2.0.
[231] https://www.sweco.se/en/our-offer/project/hydrogen/
[232] CEDEC, Eurogas, GEODE (2018), Flexibility in the energy transition. A toolbox for gas DSOs. & HyLAW (2018) D4.1 Cross-country comparison
[233] HyLAW (2018) D4.1 Cross-country comparison
[234] HyLAW (2018) D4.1 Cross-country comparison
[235] HyLAW (2018) D4.1 Cross-country comparison
[236] Except for methanation for the production of synthetic methane

Aspects	Germany	Hungary	Netherlands	Spain*	Sweden
Exception to inject pure hydrogen?	Yes	No	No	Non-conventional gas (strict)	Clarification needed

** A new version of Spanish regulation is in approval phase to allow the injection of pure hydrogen into the Spanish gas network. The limit will depend on the connection point.*

The legal framework for renewable gases in **Germany** is not addressed by a single piece of legislation but determined by a number of laws and regulations, due to the variety of uses (especially heat, CHP and transport).[237] Network operators are obliged to connect biogas facilities on condition that the connection is economically feasible, and they cannot refuse it due to capacity bottlenecks. They must design transparent, non-discriminatory and efficient standard contracts for biomethane access to the network.[238] Exemptions on network access tariffs apply also to renewable hydrogen and synthetic methane[239]. On the other hand, the 2017 Renewable Energy Sources Act excludes hydrogen and synthetic methane from receiving EEG support. In Germany PtG is not considered as a storage activity, while electricity consumption by PtG facilities is classified as final consumption. Nonetheless, PtG is considered a competitive activity and as such BNetzA has indicated that gas and electricity network operators cannot be allowed to own and operate such facilities.

In **Hungary**, biogas producers in Hungary are treated as natural gas producers and are entitled to non-discriminatory access to the gas networks as long as the gas quality provisions are respected.[240] The gas quality requirements of standard MSZ1648:2000 could constitute a barrier to further biomethane development.

In the **Netherlands**, injection of biomethane and hydrogen is allowed, as long as the gas complies with the quality standards. The maximum allowed hydrogen content is a molar fraction up to 0.02% in the transmission network and 0.5% in the distribution network.[241]

In **Spain**, the regulation for natural gas also applies to unconventional gas types[242] as long as it is technically feasible and safe to inject and transport them. The PD-01 protocol defines specific requirements for unconventional gas (including biomethane) to be injected into the transmission and distribution networks (with a maximum of 5% hydrogen concentration). However, the quality specifications are very strict[243] and alignment to the European standard is currently being discussed.[244] In Spain, power-to-gas has not been recognised as energy storage and electrolysers cannot yet participate in the provision of flexibility in the electricity sector as there are no demand-side flexibility incentive mechanisms beyond the interruption services (for which a threshold of 5MW applies).[245]

[237] DENA (2019). Biogaspartner – gemeinsam einspeisen - Biogaseinspeisung und -nutzung in Deutschland und Europa - Markt, Technik und Akteure
[238] Regulation on access to gas supply networks (Gas Network Access Ordinance - GasNZV)
[239] This refers to hydrogen and synthetic methane produced with electricity and CO2 from predominantly renewable energy sources; meaning that 80% of the electricity used in the electrolyser in the yearly average must come from renewable sources, as must all the carbon used for methanation (i.e. biogenic sources or direct air capture). Available at https://www.gesetze-im-internet.de/enwg_2005/BJNR197010005.html
[240] GreenGasGrids. Available at http://www.greengasgrids.eu/market-platform/hungary/grid-connection.html
Decree at https://net.jogtar.hu/jogszabaly?docid=A0900019.KOR
[241] Regeling gaskwaliteit - https://wetten.overheid.nl/BWBR0035367/2016-04-01#Bijlage8
[242] Ley 34/1998, de 7 de octubre, del sector de hidrocarburos
[243] BOE 6 (7 January 2013). 185 Resolución de 21 de diciembre de 2012, de la Dirección General de Política Energética y Minas, por la que se modifica el protocolo de detalle PD-01 «medición, calidad y odorizacion de gas» de las normas de gestión técnica del sistema gasista.
[244] Gas Natural Fenosa (2018), I Fórum Tecnológico: Impulsar el desarrollo del gas renovable en España. Documento base para el debate & SEDIGAS (2018), Plan de Desarrollo de Gas Renovable – Hoja de ruta al 2030
[245] HyLAW (2018), Draft report with legal recommendations for the hydrogen sector in Spain.

Sweden's Natural Gas Act[246] explicitly considers biogas as natural gas, as long as it respects the technical specifications. In 2011, new tax rules were introduced to facilitate joint distribution of natural gas and biogas in a single network.[247] Further, given that biogas' injection leads to a difference in the energy content, new rules and methods apply since 2016 for the settlement and debiting according to a varying heating value of gas.[248]

6.2.4 Support for biomethane and hydrogen

Overall, there is a complex patchwork of support mechanisms for biomethane and hydrogen. As the gap between the green hydrogen production costs and the fossil fuel market price is still very large, there are no large-scale production support schemes yet except in Germany, while for biomethane (and biogas), support schemes have been widely implemented. Table 6-5 provides an overview of regulatory incentives for biomethane and hydrogen in the selected countries.

The internalisation of the external costs related to climate change and other environmental impacts (such as those due to extraction or combustion) into the fossil fuel prices would substantially improve the competitiveness of biogas/biomethane and hydrogen from renewable energy-based electricity. Partial exemptions from network fees, electricity taxes or levies for electrolyser operators, provided these offer benefits to the electricity system, also help improve the economic feasibility of power-to-hydrogen, which is the main barrier to its large-scale deployment. Such partial exemptions are already in place today in some countries (e.g. France, Germany, Great Britain, Denmark). [249]

Moreover, power-to-gas technologies are modular, allowing the stacking of multiple electrolysis units to increase the overall capacity to several megawatts. The nominal capacity which is used for continuous hydrogen production can be flexibly increased to achieve higher peak capacities, which can be used for electricity system balancing purposes.[250] If electrolysers were able to participate in balancing markets and network congestion management services, this would provide additional revenue streams improving their economic feasibility,[251] but this is not yet the case in all national electricity markets, due to for instance thresholds for participation (e.g. 5 MW in Spain).

Guarantees of origin support biomethane and hydrogen by recognising their economic value compared to natural gas when injected in the gas network. The recast Renewable Energy Directive[252] extends the guarantees of origin requirements to renewable gases. The European Renewable Gas Registry (ERGaR) aims to enable cross-border trade and mass balancing of renewable gases, building on (voluntary) national registries. In December 2018 ERGaR re-applied to be recognized by the European Commission as a voluntary international scheme for transport fuels in the calculation of their contribution to the renewable energy share in the transport sector, following the Renewable Energy Directive.[253] Germany, the Netherlands and Sweden (the latter in a limited form) have certification registries, of which the first two are currently members of ERGaR.

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[246] Natural-gas Act (2005:403) https://www.riksdagen.se/sv/dokument-lagar/dokument/svensk-forfattningssamling/naturgaslag-2005403_sfs-2005-403
[247] Swedish Energy Markets Inspectorate (2018), The Swedish electricity and natural gas market 2017
[248] https://www.energimarknadsbyran.se/gas/dina-avtal-och-kostnader/varmevarden-och-gaskostnader/
[249] Tractebel (2017) Study on early business cases for H_2 in energy storage and more broadly power to H_2 applications & Tractebel et al. (2018) Power-to-Hydrogen: Early business cases in Europe.
[250] Quarton et al. (2018) Power-to-gas for injection into the gas grid: What can we learn from real-life projects, economic assessments and systems modelling?
[251] Roland Berger (2018) Fuel Cells and Hydrogen for Green Energy in European Cities and Regions.
[252] Directive (EU) 2018/2011 on the promotion of the use of energy from renewable sources
[253] ERGaR (2019) Presentation - European Renewable Gas Registry

6.2.5 Network connection and access tariffs

Network connection and access tariffs can influence significantly the business case of biomethane and hydrogen. At present, there is in general an absence of a coherent regulation, both at the transmission and distribution levels (with the exception of Germany).[254] Contrary to electricity there is no EU network code governing the connection of producers to gas networks, whether natural gas or other gas types.

It is relevant to consider the tariff levels but also their structure, taking into account design parameters such as discounts for storage and entry-exit/commodity-capacity splits. For example, the shift to capacity-based transmission service tariffs will favour gas producers which have a more constant injection profile; the consequences of capacity-based tariffs, also for intermittent end-users such as gas fired power plants, need hence to be further understood. An open issue is the ownership and operation of facilities for compression, treatment and metering of biomethane or hydrogen before its injection. Possible arrangements include ownership and/or control by the producer or by the network operator, and the extent the costs are borne by the concerned producers or socialised via the network fees.

Germany has a number of incentives related to network connection and access for biomethane and hydrogen including exemption of transmission tariffs, feed in tariffs and priority access.[255] Network operators pay a flat-rate tariff to shippers feeding biogas into the gas network, for ten years after the commissioning. The recovery of this cost is to be charged in the non-transmission services component of the tariff, which is questioned by ACER.[256] Also, the network operator is responsible for 75% of the connection costs, as well as for the maintenance and operation of the network connection and the input facility, and has to ensure a minimum availability. Finally, designated market area managers in Germany are obliged to provide a special framework for biomethane balancing.[257]

Biomethane plants in the **Netherlands** have to pay the same connection and access costs as other gas operators.[258] In **Spain**, there is no clear framework defining the ownership of the connection. In **Sweden** there are no network access restrictions as long as the gas quality specification is upheld.[259]

Table 6-5 Regulatory incentives for biomethane and hydrogen

Production incentives (FiT/FiP)	**Germany**: 2017 EEG pay-as-bid tenders for biomethane and hydrogen & **statutory support[260]+ injection premium** **Netherlands**: Feed in premium for injected biomethane & biogas with guarantees of origin via SDE+[261] **Sweden:** Applicable for biomethane
Investment incentives	**Germany:** Connection for biomethane and hydrogen **Netherlands:** Energy Investment Deduction (EIA), allows companies to deduct investments (including e.g. biodigesters, electrolysers and injection systems) from corporate profit tax. Plans to set up a financial support scheme for hydrogen demonstration projects.

254 HyLAW (2018) D4.1 Cross-country comparison
255 Also, they must take measures (when economically reasonable) to ensure the capacity necessary for biomethane transport at all times, including regarding reverse flows into the transmission network, being also required to assess the adequacy of transportation capacities considering future needs. Source: Regulation on access to gas supply networks (Gas Network Access Ordinance - GasNZV)
256 BNetzA (2018) Decision BK9-18/610-NCG and BK9-18/611-GP
ACER (2019) Analysis of the Consultation Document on the Gas Transmission Tariff Structure for Germany
257 Regulation on access to gas supply networks (Gas Network Access Ordinance - GasNZV).
258 http://www.greengasgrids.eu/market-platform/netherlands/grid-connection.html
259 http://www.greengasgrids.eu/market-platform/sweden/technical-standards.html; Swedish Energy Markets Inspectorate (2018), The Swedish electricity and natural gas market 2017
260 BMWi. Renewable Energy Sources Act (EEG 2017).
261 Sia Partners (2018) Observatoire du biométhane - Benchmark des filières européennes; RVO (2019) Stimulering Duurzame Energieproductie.

Priority connection and access	**Germany**: Applicable for biomethane and hydrogen
Minimum renewable gas share	**Germany:** Building heat (30% for biogas)
Consumption incentives	**Germany:** Electricity consumption for power-to-gas in Germany is currently exempt from the EEG surcharge for financing the support schemes for renewable electricity[262] **Sweden:** Fiscal exemptions & subsidies for biogas and biomethane (mostly transport)[263]
Other	**Germany:** Long history of support for biogas **Hungary:** Low level and uncertainty concerning feed-in electricity tariffs (METAR & brown premium for biogas and biomass-fuelled power plants) & absence of support for biomethane injection[264] **Netherlands:** No financial support mechanism yet for hydrogen (wo be included in SDE+ once it is competitive). The costs for the SDE+ are recovered through a charge on the energy bill of consumers.[265] **Sweden:** Long history of support for biogas though various schemes and policies[266] **Spain:** Focus on renewable electricity generation

Source: Country analyses

7 Impact of considered scenarios on selected TSOs and DSO

The objective of this chapter is to assess the impact of the three scenarios focusing on the use of the full EU potential of biomethane and hydrogen, on the business of selected network operators in five Member States (Germany, Hungary, the Netherlands, Spain and Sweden), both in the short- and the long-term.

This chapter first presents the impact of the scenarios on the gas demand in the considered countries as well as on the investments and operational expenses of the selected system operators. Second, a simulation of these impacts on the volumetric network tariffs in 2030 and 2050 is developed, where the two main elements determining tariffs are analysed: the cost of service (composed of investment depreciation, capital remuneration and operation and maintenance expenditures) and the transported gas volumes. Finally, a summary is provided of the assessed impacts of the three scenarios on the system operators' business cases.

Some preliminary considerations are important in order to correctly understand the aim and scope of this analysis:

- In line with the study objectives, this section does not aim to provide a forecast of probable future developments of biomethane and hydrogen, and their impact on the gas infrastructure and network operators, but rather forms the basis for the impact analysis of a strong development of these gases, based on the use of their full EU potential;
- The focus of the modelling exercise on the EU28 as a whole (as opposed to particular Member States) and the focus on the impact of the use of the full biomethane and hydrogen potential may lead to differences in the data resulting

[262] Kreeft (2018) STORE&GO D7.3 'Legislative and Regulatory Framework for Power-to-Gas in Germany, Italy and Switzerland'
[263] Board of Agriculture. http://www.jordbruksverket.se/amnesomraden/stod/andrastod/biogasstod2018.4.3ed012e7163ab843f5e5557.html; https://www.iea.org/policiesandmeasures/pams/sweden/name-47928-en.php; https://www.iea.org/policiesandmeasures/pams/sweden/name-167633-en.php; https://www.iea.org/policiesandmeasures/pams/sweden/name-21456-en.php; ISAAC (2016) Deliverable D5.2: Report on the biomethane injection into national gas grid
[264] RES Legal. Government Decree No. 299/2017; GreenGasGrids (2013) Hungarian roadmap for the development of the biomethane sector; MEKH (2017) Information on the Renewable Energy Support System (METÁR).
[265] Law opslag duurzame energie. Available at https://wetten.overheid.nl/BWBR0032660/2019-01-01
[266] Rural Development Programme 2014-2020; Klimatklivet 2015-2018 (Climate Leap – Swedish EPA); 2015 support scheme for anaerobic digestion of manure; 100% deduction of the energy and CO2 tax granted for biogas consumed or sold as motor fuel. Sources: Government offices of Sweden (2018), Sweden's draft integrated national energy and climate plan; https://www.naturvardsverket.se/klimatklivet; State aid decision SA.51967; Swedish Tax Authority.

from the modelling for individual Member States compared to targets and expectations of national stakeholders;
- The modelling to 2030 and 2050 are independent, so pathways are also independent, and represent the gas system evolution from the present to the target years separately;
- The present chapter focuses only on gas network infrastructure and does not address electricity infrastructure; the cost impacts of the scenarios on other actors such as end-users are also not included. Nonetheless, the gas network costs discussed here result in avoided costs for electricity networks and end-users, which differ per scenario, as presented in Chapter 6. Thus, no conclusions should be drawn from this chapter on which is the socially optimal scenario.

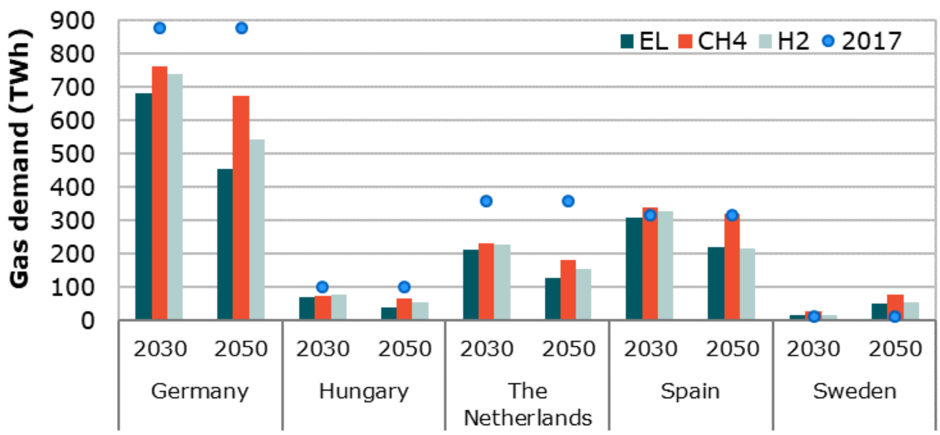
7.1 IMPACT OF BIOMETHANE AND HYDROGEN IN THE NETWORKS OF SELECTED SYSTEM OPERATORS

Whereas chapter 4 shows the impacts of the three scenarios for the EU28 as a whole, this chapter focuses on the impacts in the five selected TSO's Member States.

Developments in gas demand

Most of the five selected countries follow the European trend of declining gas demand, especially in the 2030-2050 period, a decline which would be highest in the electricity scenario and lowest in the methane scenario. Sweden is an exception, where the modelling results show an overall increase, in the 2030 scenarios as well as in the 2050 scenarios (Figure 7-1). For Spain, gas demand would remain relatively stable in the 2030 scenarios, but would decrease in some of the 2050 scenarios. The modelling results show that the distribution-connected demand would be significantly higher than the transmission-connected one by 2050 for all scenarios.

Figure 7-1 Total gas demand for the selected countries, compared to the gas demand in 2017.



Note: The gas demand for 2017 is the total primary energy demand for gas, including off-grid use. The scenarios only include grid-connected demand.

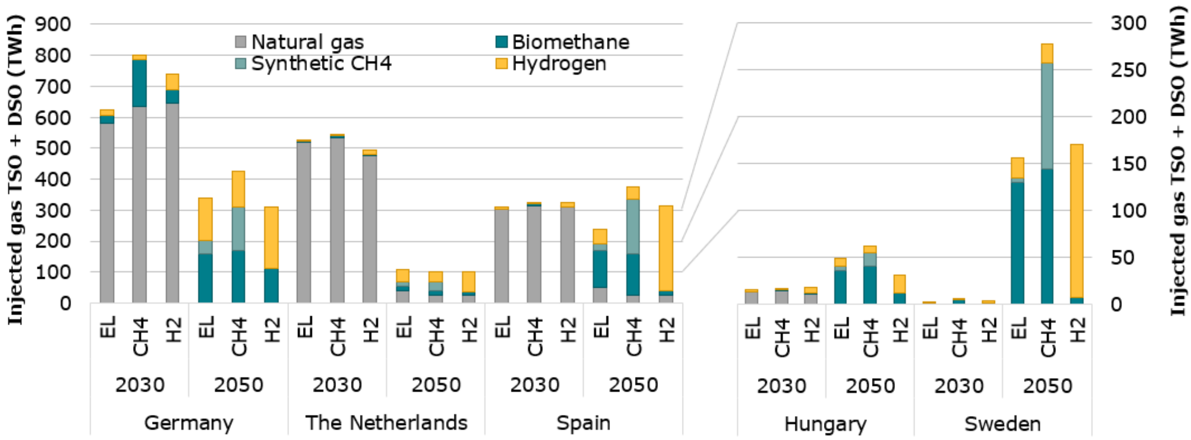
The evolution of the gas mix

An important difference in the gas mix between the 2030 and 2050 scenarios can be seen in Figure 7-2. The key results on the gas supply structure in the six scenarios for the five case study countries are as follows:

- Natural gas dominates the supply structure in the 2030 scenarios. Only the methane scenario for Germany shows significant amounts of biomethane in 2030;
- Synthetic methane only enters the mix in the 2050 scenarios and only plays a significant role in the methane scenario;

- At the EU-level the electricity scenario has the lowest gas injection levels in 2050, but for three of the five case study countries this is the hydrogen scenario. In the hydrogen 2050 scenario, hydrogen dominates the gas mix accounting for 62-96% of all national gas injection;[267]
- In Sweden and Hungary biomethane not only plays an important role in the methane scenario but is also the major gas type in the electricity scenario.

Figure 7-2 Gas injection by type for the selected Member States



Decarbonisation scenarios in perspective

As stated earlier, the goal of the modelling exercise in this study is not to give a plausible forecast of the changes in gas demand and gas mix for each Member State, but rather to assess the impacts in a uniform manner of particular policy choices based on using the full potential of biomethane and hydrogen, on the gas infrastructure in the EU28. Still, as the previous sections described the modelling results in rather high detail for the case study countries, it is useful to put these results in the context of national policies, plans and strategies. In general, the total gas demand resulting from our study tends to be lower than in several other studies. Compared to the forecasts for 2030 in ENTSOG's TYNDP 2020 the results of this study are mostly lower, although for Germany the ranges for 2030 are rather similar. The demand forecasts used by the Dutch TSO are consistently higher than in our study, around 50% higher in 2030 and 19-70% higher in 2050. In Germany, the technology mix scenario is mostly used as a guidance for future gas demand. In the technology mix scenario that assumes a 95% GHG emission reduction by 2050, gas demand is 30-92% higher than in our study, which is based on 100% GHG emission reduction while using the full hydrogen and biomethane potential.

Table 7-1 Comparison of gas demand estimates of our study with other commonly used studies

TWh/a	ENTSOG TYNDP	National studies		This study	
	2030	2030	2050	2030	2050
DE	642-812	812[268]	785-877	682-740	456-673
HU	88-100			69-76	39-65
NL	277-348	330[269]	216[270]	211-231	127-182
ES	299-400			308-327	215-319
SE	14-21			17-28	52-78

[267] Injection = domestic production + imports
[268] DENA (2018) Leitstudie integrierte Energiewende.
[269] Gasunie Transport Services (2017) KCD investment plan 2017.
[270] Gasunie & Tennet (2019) Infrastructure Outlook 2050.

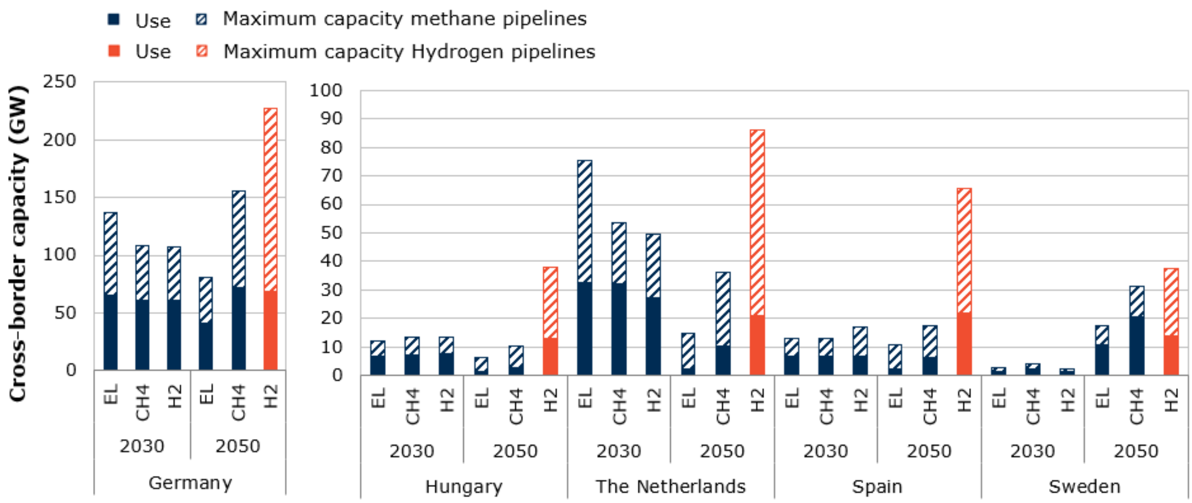
7.1.1 NETWORK INVESTMENTS

Investments in cross-border gas transmission capacity

The added value of gas infrastructure for the future energy system is in particular that it can be used to transport large energy quantities over long distances at a relatively low cost. The for 2030 required cross-border transmission capacities in the selected Member States

Figure 7-3) are comparable across scenarios, although for Germany and the Netherlands the electricity scenario requires significantly higher cross-border gas transmission capacities. In contrast, for 2050 the scenarios show diverging results, with the hydrogen scenario requiring the largest cross-border gas transmission capacity in all selected countries while the electricity scenario shows the lowest required gas transmission capacity in 2050.

Figure 7-3 Required cross-border gas transmission capacity and average use



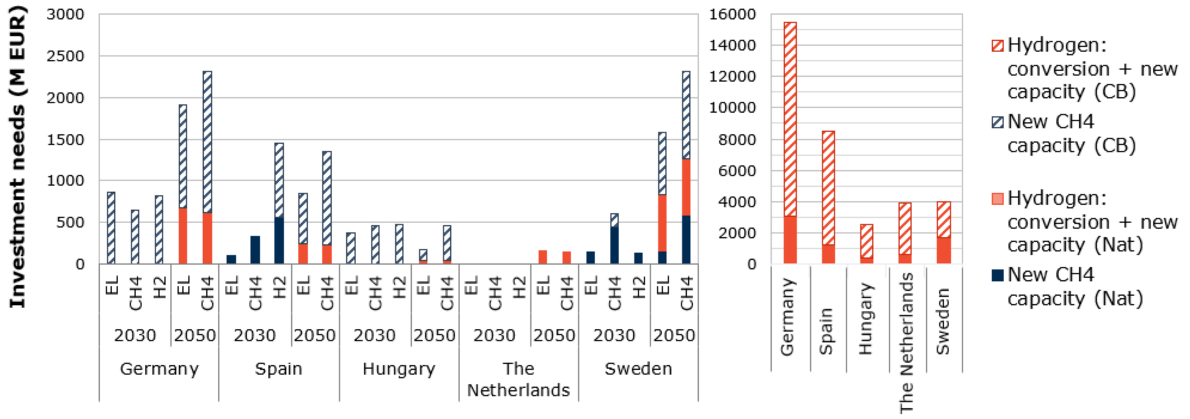
Investment in the gas transmission network

The transition towards a decarbonised gas supply in Europe will require investments in the gas transmission network, for domestic as well as for cross-border gas transport. Figure 7-4 provides an overview of the investment needs at the TSO level, and the following findings stand out:

- For 2030 the investment requirements are limited across scenarios and investments are only related to methane networks;
- Towards 2050 the investment needs increase, especially in the hydrogen scenario, which requires the largest investments;
- Across all scenarios, investment in cross-border transmission capacity dominate, except for Sweden;
- In the three considered scenarios, the overall investment needs for Sweden would be very high compared to the current size of the gas sector, due to a strong increase in gas supply, demand and exports in this country.

The hydrogen scenario has the highest investment requirements for new or converted gas infrastructure at the TSO level, whereas the electricity scenario has the lowest gas investment requirements. At the EU28 level, there is a factor 4.4 difference in required gas transmission investments between the hydrogen scenario (€245 bn) and the electricity scenario (€56 bn) to 2050. However, required investments in the electricity network will be higher in the electricity scenario, balancing the investment needs across scenarios.

Figure 7-4 Total investment requirements at the TSO level (national + cross-border)



Note: 2030 investments represent cumulative investments for the period 2020-2030, while 2050 investments are cumulative over the period 2020-2050, so costs for 2030 and 2050 are not additional.
Costs for decommissioning are not included due to its negligible impact on total investment requirements.

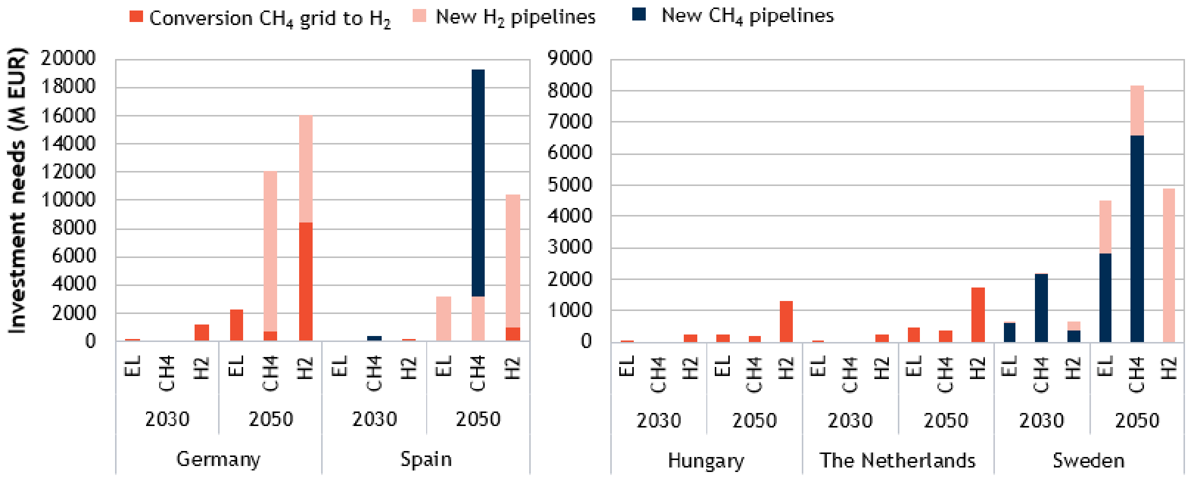
When looking at the five selected countries, we see the same trend as for the EU28 (Figure 7-4). Up to 2030 the investment requirements at gas TSO level are still rather limited, with the exception of the hydrogen scenario for Spain. For the Netherlands, the 2030 scenarios do not require any investments in the gas transmission network. In the period 2030-2050 the investment requirements increase in all countries, with the exception of Hungary, which is related to the sharp fall in gas demand towards 2050. Costs related to decommissioning of pipelines (not shown in the figure) are very limited in all scenarios, accounting for a maximum of 13% of all investment needs, but an average (unweighted) of 3%. The model results only show decommissioning in cross-border transmission capacity.

The hydrogen scenario is the costliest scenario, with total gas investment requirements in the case study countries being 2-25 times higher than in the electricity scenario. The methane scenario requires much lower investments in gas transmission infrastructure, but it is still significantly more expensive than the electricity scenario in most cases. In all five countries except Sweden, investments in cross-border transmission capacity dominate the overall costs, although this is most pronounced in Hungary. Also, in the hydrogen scenario for 2050, the investment requirements relate primarily to cross-border gas transmission capacity (around 57-85% of the total investments in the 5 countries). In the electricity and methane scenario, all investments in hydrogen networks relate to conversion of existing methane networks to hydrogen networks. In the hydrogen scenario, new pipelines dominate the investments in all case study countries, except Germany.

Investments in the gas distribution network

Apart from the investments in the transmission network, the considered scenarios aiming at full decarbonisation also require significant investments in gas distribution networks. Overall, these costs represent for the five countries on average 37-85% of the total investments needed in gas infrastructure. At the distribution level, the hydrogen scenario is not always the one that needs the highest investments. In Spain and Sweden, the investment needs for the methane scenario exceed those of the hydrogen scenario. Similar to transmission networks, the 2050 scenarios require much higher distribution network investments than the 2030 scenarios.

Figure 7-5 Total investment requirements at the gas distribution level for the three scenarios



Network investments in perspective

To date, gas network operators are in many countries are already actively investigating how they can anticipate and facilitate a stronger uptake of renewable and decarbonised gases. It should be noted that the technical feasibility and investment costs for conversion of existing transmission and distribution networks into hydrogen networks are still uncertain. The cost levels will also quite differ amongst Member State, depending on the characteristics (e.g. PE vs other material) of their network; therefore, some system operators have indicated that the cost levels assumed in this study for the refurbishment of the distribution networks might be too high for their grid.

Also, some short-term investments might not be reflected in the 2030 scenarios. The modelling exercise does not take all actual investments into account, as it is based on a theoretical optimisation of investments based on minimisation of overall energy system costs. As an example, the modelling results foresee no investments in the gas distribution networks for the Netherlands in any of the 2030 scenarios, while the Dutch system operators are currently investing in compressor stations to enable the feed-in of biomethane from the distribution networks into the transmission network.

7.2 IMPACT ON THE BUSINESS CASE OF SELECTED SYSTEM OPERATORS

In this section the results are presented of tariff simulations that estimate the impact of the use of the full biomethane and hydrogen potential on the system operators' costs of service and their tariffs, with a focus on the distribution level. Very few studies have been dedicated to analysing the impact of infrastructure costs from this perspective. One notable exception is the study on the future regulation of the UK gas network[271].
The scope and limitations of the analysis comprise:

- The tariff simulation considers the necessary investments to start in 2020, so tariff estimates are additional to the tariff components that cover the depreciation of pre-2020 investments. However, especially by 2050 most of the pre-2020 investments will have been depreciated;
- Tariffs indicated are volumetric tariffs, calculated according to the transported gas volumes, while the actual gas tariffs are split between gas entries and exits and are mainly capacity-based;

[271] Frontier Economics et al. (2016) Future regulation of the UK gas grid - Impacts and institutional implications of UK gas grid future scenarios – a report for the CCC

- Common parameters are used across countries such as the cost of capital, while the parameters are in practice set by national regulators and can differ per MS;
- These considerations combined with the uncertainties to 2050 mean that the tariff levels resulting from this study are not forecasts, but rather serve to evaluate the possible impact of the three considered scenarios on the TSOs/DSOs and their tariffs.

The tariff simulation methodology first calculates the cost of service for gas transport from the network costs. The cost of service is composed of four components: depreciation, capital remuneration, decommissioning and operation and maintenance expenses (OPEX). The cost of service for gas transport is separated as transmission (subdivided in intra-EU cross-border and national transmission) and distribution. The regulatory asset base (RAB) is composed of the accumulated (adjusted) investments minus the accumulated depreciation. Then, the transported gas volumes are calculated (for distribution only distribution-connected demand). Volumetric tariffs can be derived for each network by dividing the total cost of service by the transported gas volumes (for transmission equal to exports + storage injection + transmission-connected demand).

As indicated, the main tariff simulation parameters are the cost of capital and the depreciation period. In order to enhance the comparability of the simulated cost of service and tariffs, the same values for the cost of capital and depreciation period are used across countries and years in the analysis, with a sensitivity analysis being also conducted.
Following an analysis of ACER and CEER[272] data, a cost of capital of 5% is used for both transmission and distribution system operators, with a sensitivity analysis based on a level of 9%. A depreciation period of 45 years is used, with a sensitivity analysis based on an economic lifetime of 25 years. In order to assess the impact of different OPEX levels, the cost of service and tariffs have been calculated for high (2% of CAPEX) and low (1% of CAPEX) OPEX levels.

Cost of service

Figure 7-7 presents the cost of service for the gas transmission level (related to cross-border and national transmission assets). For the EU28 and all selected Member States, the hydrogen scenario in 2050 has the highest gas transmission cost of service, amounting to 8.1 billion EUR/year for lower OPEX levels (1% of CAPEX). The cost of service is driven by investments in cross-border hydrogen transmission networks to accommodate increased cross-border gas trade, especially in hydrogen corridors to Central Europe. In the other scenarios, cross-border and national transmission play a more balanced role, with a transmission cost of service in 2050 of 2.6 billion EUR/y for the methane scenario and 1.7 billion EUR/y for the electricity scenario, with main new export corridors leading from Scandinavian and Baltic countries to central Europe.

Of the selected countries, Germany and Spain present the highest cost for gas transmission services, also due specially to cross-border investments in the hydrogen scenario. Cross-border investment costs for Germany are driven by gas transmission capacity expansions to Denmark and the Netherlands and to a lesser extent to Belgium and Italy. For Spain, the major driver is the expansion of transmission capacity primarily with France, and secondly with Portugal.

For the 2030 horizon, OPEX form the most important component of the cost of service for the EU28 and the selected Member States at the transmission level. For the EU28 average, OPEX account for 60-70% of the cost of service in 2030 in all scenarios, rising to around 80% in the case of high OPEX assumptions (2% of CAPEX). Looking to 2050, the importance decreases, but still OPEX remains significant under high OPEX assumptions, accountable for 40-60% of the cost of service across the EU28.

[272] CEER (2019) Report on Regulatory Frameworks for European Energy Networks & ECA (2018) Methodologies and parameters used to determine the allowed or target revenue of gas transmission system operators (TSOs)

Capital remuneration accounts for 25-36% of the cost of service across the EU28 in 2050 for a higher OPEX assumption. Logically, selected Member States with higher investment levels compared to the existing asset base exhibit higher shares of capital remuneration. By 2050, depreciation amounts to 4% of the regulatory asset base, so capital remuneration is 1.2 times the depreciation in 2050, for the parameters chosen.

While decommissioning costs are assumed to be passed through to network users via the tariffs and to occur before the 2030 and 2050 horizons, thus not affecting tariffs in those years, they may lead to modest tariff increases in the years before. Decommissioning costs in years before the end of the horizon occur only for cross-border transmission assets, where, if spread over the 2020-2029 horizon, they could represent up to 2.0% of the transmission cost of service in 2030 for the EU28. For 2050, only the electricity scenario would lead to a relevant decommissioning level, amounting to around 1.2%.

Dedicated hydrogen networks have in 2030 a very limited impact on the cost of service. At the transmission level, cost of service is due exclusively to methane networks, with no share for hydrogen networks. For 2050, the impact of hydrogen networks remains limited in the electricity and methane scenarios for transmission (20% and 12% of the transmission cost of service, respectively). In contrast, the deployment in the hydrogen scenario makes H_2 drive the total cost of service at the transmission level for that year.

The regulatory asset base of system operators

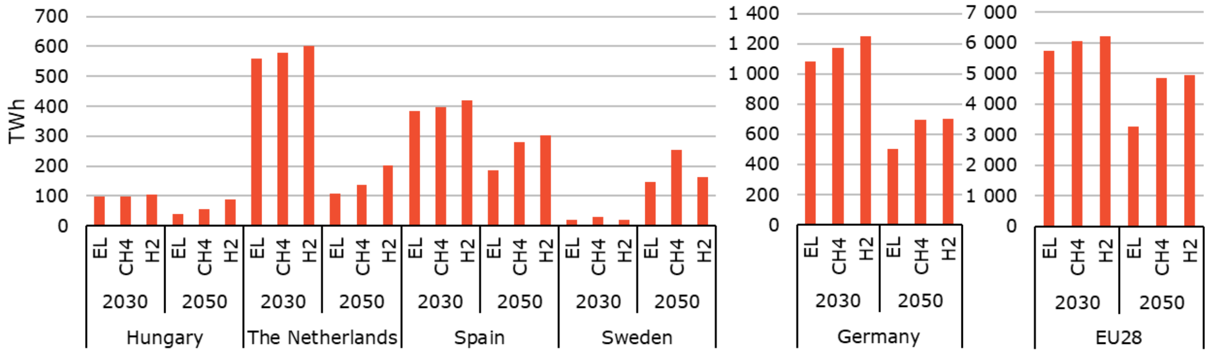
The transmission RAB per unit of transported gas for the EU28 ranges from 3.6 million EUR/TWh in 2050 in the electricity, 3.8 million EUR/TWh in the methane and 14.6 million EUR/TWh in the hydrogen scenario. Hence, a hydrogen-focused scenario could lead to a transmission RAB per unit of transported gas in the EU (due to investments from 2020 on) which would be substantially higher than for the electricity or methane scenarios.

The unit transmission RAB varies significantly between selected Member States and levels of renewable and decarbonised gases, ranging from very low RABs to up to 18.3 million EUR/TWh in 2050. Nonetheless, for any given country and scenario, the RAB in the 2050 horizon would be higher than the 2030 one (not considering the depreciation of pre-2020 investments). The fact some transmission and distribution networks were developed earlier than others (e.g. Germany compared to Spain) means the actual RABs may not be proportional to the size of the network, as smaller but newer networks may have a larger RAB than older networks which are depreciated to a greater extent.

Transported gas

Transported gas volumes in the transmission level are stable across scenarios for the EU28 and selected Member States in 2030, with by 2050 the hydrogen scenario exhibiting the largest transported volumes and the electricity scenario the smallest. Regardless of the scenario, transmission gas volumes decrease from 2030 to 2050, ranging from -43% in the electricity scenario to -20% in the other two. Exports and storage injection help contain the fall in transmission volumes. Cross-border gas flows will remain fairly constant across scenarios in 2030, and both for the EU28 and the selected Member States the transported gas volumes at the transmission level are higher than at the distribution level, for all scenarios in 2030 and 2050.

Figure 7-6 Transported gas volumes at the transmission level



Tariff impact

The accumulated depreciation and regulatory asset base arising from the investments in the 2020-2030 and 2030-2050 periods lead to higher tariffs in 2050, which should however be offset by the depreciation of the current system operators' RAB, partially or entirely. Likewise, gas network costs in the methane and hydrogen scenarios are offset by avoided electricity system and end-users' costs, which are not analysed here.

The EU28 average transmission volumetric tariffs to 2030 are modest, amounting to less than 0.5 EUR per MWh transported in the different scenarios (with a low OPEX assumption). In 2050, tariffs remain in the order of 0.5 EUR/MWh, except for the hydrogen scenario which shows the highest volumetric tariffs, reaching 1.6 EUR/MWh, driven by cross-border investments, while an increase in transported gas volumes for the EU28 partially offsets this. The conversion of cross-border methane networks for hydrogen transport forms about one third of the cross-border investment costs for the 2020-2050 period. At a country level, a similar pattern is observable, but the importance of conversion of cross-border infrastructure to hydrogen varies significantly.

The results of the sensitivity analyses show that a shortened linear depreciation of 25 instead of 45 years would increase tariffs in the short-term while leading to lower tariffs in the long-term. A depreciation period of 25 years would lead to a +3.4 to 4.0% increase in the 2030 EU28 transmission cost of service, while causing a 2.8 to 4.1% decrease for the 2050 horizon. For the selected Member States the range is larger, but still the impact of accelerated depreciation never surpasses +10 to -5% of the transmission cost of service.

A higher 9% cost of capital compared to the standard level of 5% leads to a 10-12% increase in the transmission cost of service for 2030 across the scenarios, while the impact for 2050 is in the range 20-29%. The impact of a natural gas price increase from 31 to 38 EUR/MWh is limited, resulting in a 1.1-1.7% increase in volumetric transmission tariffs to 2030 for the three scenarios, while an increase in biomethane costs has no noticeable impact to 2050 on the service cost, transported gas volumes or tariffs, for all scenarios.

Figure 7-7 Gas transmission cost of service

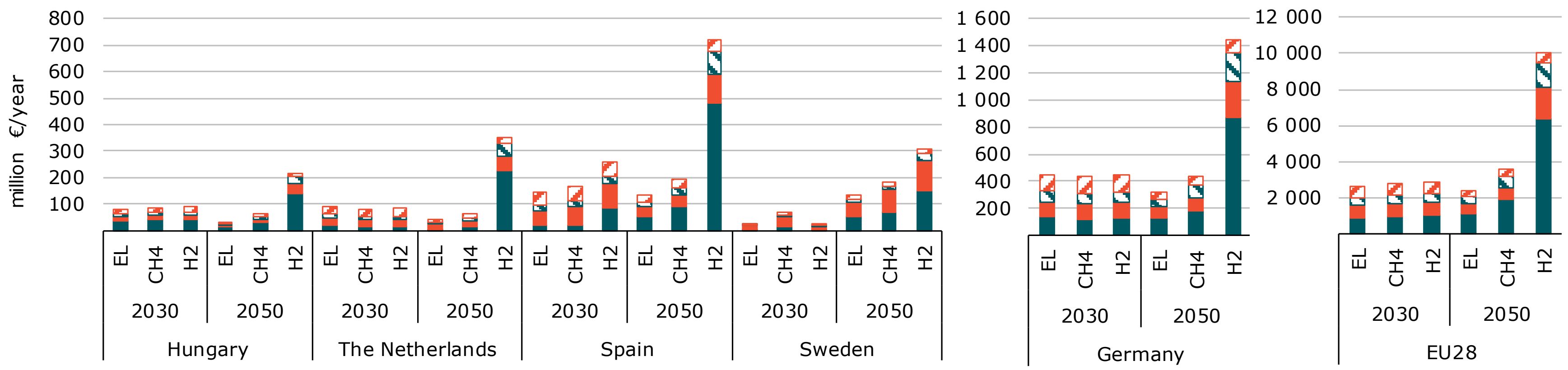
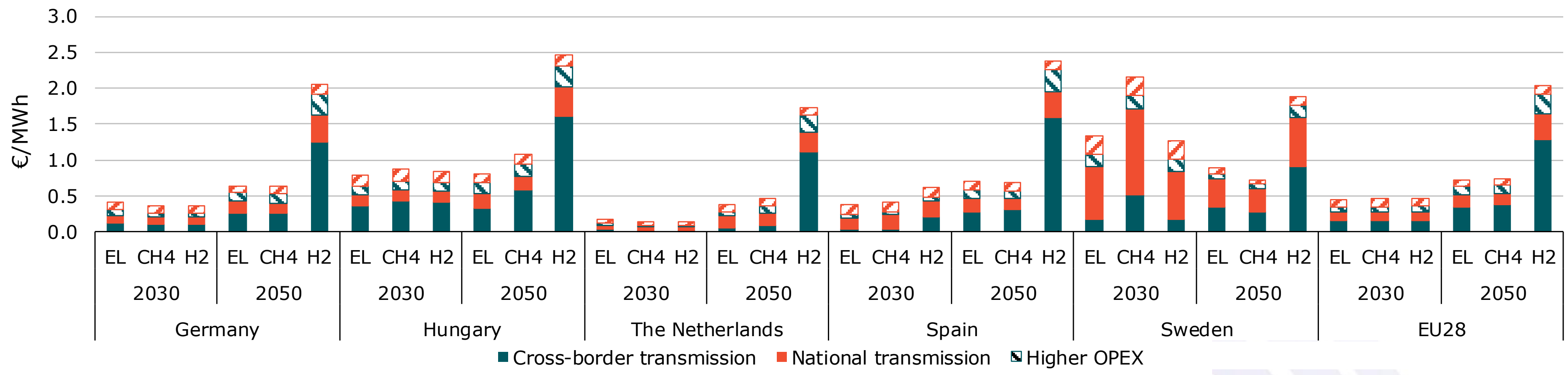


Figure 7-8 Gas transmission volumetric tariffs



Note: Higher gas network cost of service in the gas scenarios are partly or entirely offset by avoided electricity system costs, not shown here. The tariff graph does not include tariffs related to depreciation of the current RAB.

7.3 MAPPING OF THE SYSTEM OPERATORS BUSINESS CASES

TSOs face low risk in the short-term, especially within the current regulatory period, and foreseeable at least in the next ones. Presently, the regulatory period in the selected Member States varies from 4 to 7 years.[273] In the long-term, the risk to TSOs results from changes in the allowed revenues based on the cost of service and from tariff increases which may cause the loss of network users, threatening cost recovery in the long-run due to a vicious circle of tariff increases and reduction of transported volumes.

The main cost of service components influencing risk comprise the investment depreciation, the capital remuneration and operation & maintenance costs (in their turn influenced by regulatory parameters such as the return on capital, the depreciation period, pass-through of O&M expenditures and efficiency requirements). Tariffs are also influenced by the transported gas volumes, a function of transmission services demand by both domestic and foreign users.

Therefore, in the mid- and long-term the risks faced by TSOs result not from the end of the present regulatory period, but rather from changes in underlying technical and regulatory factors affecting the cost of service and transported gas volumes. While some TSOs are acting (in various extents) to address these risks in the long-run, ultimately the confidence of stakeholders that in the mid-term the risks to the business case of TSOs is limited is related to the belief that these underlying factors such as the need for gas transport services will remain stable to 2030, or at least that measures to contain the cost of service and extreme tariff increases are available.

The tariff simulation indicates that the most important risks to TSOs in case of an important change in the cost of service or transported volumes (and thus tariffs) arise from:

- Cross-border transmission investments leading to an increase in transmission tariffs in case of a significant reconfiguration of gas flows in the EU to 2050, especially if dedicated cross-border hydrogen networks are developed. This is enhanced by the fact that currently hydrogen networks are an unregulated activity and thus not a TSO responsibility, with the conversion of methane networks forming only part of the necessary investments in hydrogen networks;
- Uncertainty on the regulatory framework for hydrogen networks (related to the point above). While the CEER Future Role of Gas and consultation indicates hydrogen networks have similar economic characteristics to methane networks and thus would warrant regulation, national regulators do not see the immediate need to act. This is confirmed by the modelling results to 2030, but in the case of a strong development of hydrogen to 2050 it will be necessary to determine the role of existing and future TSOs for both new hydrogen networks and converted methane ones. Furthermore, the regulatory cycle length and proactive planning will require the definition of the approach for hydrogen networks much before 2050;
- Re-evaluation of the regulatory asset base in case some assets become stranded to the 2050 horizon, especially if gas transmission investments are made before 2030 while not considering the uncertainty to 2050 regarding investment levels, cross-border corridors and hydrogen/methane content in transmission networks. While the components of investment depreciation and OPEX may not represent a risk, capital remuneration based on the RAB remains a major component of the revenues and would be affected in case of important re-evaluations;
- Short-term rises in tariffs due to the implementation of shorter depreciation periods to reduce the exposure of network users and thus TSOs to long-term tariff increases and the grid defection spiral (vicious circle). The use of shorter depreciation periods should consider the short- and long-term impact on tariffs and the capacity of network users to absorb any tariff increases in either horizon resulting from the application or absence of such measure;

[273] CEER (2019) Report on Regulatory Frameworks for European Energy Networks

- Misallocation of the cost of service between network users, as long-term investments in hydrogen and/or methane transmission networks coupled with an important reconfiguration of the EU gas production, demand and cross-border trade, will requiring a timely adaptation of cost allocation between users. The reconfiguration to 2050 with cross-border flows occurring from peripheral regions (Scandinavia, Southern Europe and British Isles in varying degrees per scenario) to Western and Central Europe will require the restructuring of entry-exit tariffs and other parameters to allocate the cost of service to domestic or foreign users as adequate. This may be aggravated by significant changes from 2030 to 2050 in the contribution to total transported gas volumes of cross-border flows, storage and exchanges with transmission-connected end-users and DSOs;
- Higher OPEX levels due to hydrogen transport admixed in methane networks or through dedicated hydrogen networks, as OPEX is an important component of the total cost of service and given the uncertainty on O&M costs, both due to hydrogen development and any future variations across EU Member States in H_2 content and O&M requirements. This will impact particularly those national networks which have lower investment requirements by 2050, as then OPEX will constitute a higher share of the total transmission cost of service;
- Uncertainty and inflections in national policy regarding renewable and decarbonised gases (either increasing or decreasing support) as well as related aspects such as decarbonisation targets and nuclear and coal phase out plans. TSOs (and NRAs) must evaluate investment plans based on supply and demand scenarios, which are highly affected by policies which are not the competence of NRAs. Hence, TSOs require stable or at least predictable long-term policies which reduce the uncertainty to 2050 while at the same time providing correct and consistent signals for the development of biomethane and hydrogen. This is compounded by the varying positions of stakeholders including TSOs on the potential development of specific technology routes, concerning e.g. hydrogen from hydrolysis, steam methane reforming with CCS or synthetic methane.

The latter point on the importance of stable long-term policies is pivotal for the business case of TSOs and impacts many of the other risks discussed, as the period from 2030 to 2050 is where the most important transitions will occur (although this will vary per Member State, and may be accelerated by national policy). Moreover, the stability of the regulatory framework as set by national regulators is also important. Finally, as the required actions to achieving full net decarbonization by 2050 differs significantly to a policy aiming for near-complete decarbonization (80 to 95% decarbonization) given hard-to-decarbonise end-users such as some industries and the old buildings stock, clarity on the target decarbonization levels will provide the overarching framework from which the planning scenarios should be developed.

Impact of the tariff simulation on DSOs

Given the extensive discussion on the impact of the scenarios on the TSOs which forms the central focus of the assignment, Table 7-3 highlights only the main impacts on DSOs which are additional to those discussed above. DSOs will also have a major role in the gas infrastructure transition, having an important asset base and usually representing a higher cost of service than TSOs, with a high impact of OPEX levels.

Eventually, DSOs will be faced with some of the same drivers impacting the business case of TSOs, but the impact magnitude will be different and much more variate across regions. Local developments are expected to be more divergent than at the transmission level, and while the transmission volumes would in general decrease, certain DSOs will see an increase in their transported volumes (which remains dependent however mainly on local injection and demand).

Table 7-2 Mapping of the TSO business cases

Aspect	Impact
Gas sector decarbonization pathways	• **Importance of policy making to provide guidance and reduce uncertainty to 2050** • **Policy support central to PtG pathway, impacting importing and exporting MSs**
Cost of service	• **Balanced impact of cross-border and national transmission assets for EU28, variable per MS** • **Cross-border hydrogen network investments: role of regulated TSOs or left to market (new TSOs/merchant operators)** • **Strong investments increase share of depreciation and capital remuneration, dampened by effect on OPEX through increase of asset base** • **Strong influence of OPEX, with additional uncertainty especially for hydrogen networks** • **Marginal impact of decommissioning, country-specific, higher for electricity scenario**
RAB and depreciation	• **Accelerated depreciation would increase cost to 2030 and lower increase of tariffs post 2030** • **Countries with developed gas infrastructure may see RAB decrease** • **Important differences in RAB between scenarios to 2050 -> risk of stranded assets**
Transported gas volumes	• **Transported gas volumes less dependent on main driver than distribution** • **Despite increases in injection at distribution level, reverse flow needs to 2030 would remain limited** • **Transmission transported volumes decrease to 2050, especially in electricity scenario (with MS exceptions)**
Gas tariffs	• **Tariff increases due to new investments to be (partially) offset by decreasing depreciation of current RAB** • **Short-term cost recovery of TSOs is assured** • **Gas network users may absorb tariff increases, similar to the electricity system transition** • **Changing environments will require flexible tariff structures that adequately allocate cost of service among network users** • **Volumetric tariffs may be commensurate with current tariffs and other studies, despite uncertainty and comparability challenges** • **Some concern in regions with already high network tariffs or vulnerable consumers**
Potential TSO roles	• **Some few TSOs are taking anticipatory measures** • **Potential provision of PtG conversion services (as service provider, without buying/selling energy)** • **Other potential services (treatment of biomethane before injection, deodorization, deblending)** • **Experience with H_2 networks and power-to-gas varies strongly across the EU TSOs** • **Exclusion from new and converted hydrogen networks would lead to loss of potential business activities** • **Possible risk in cost recovery when stepping out of PtG activity once market maturity is reached**
Non-demand drivers	• **Differences in renewable gas supply potential among countries may increase the need for cross border capacity** • **Increasing deployment of intermittent renewable electricity will incentivize PtG for flexibility, requiring gas transport services** • **Investment needs to facilitate further market integration, but this is expected to become less important on the medium-term** • **Increased use of gas storage for flexibility and security of supply might lead to increasing (bi-directional) cross-border flows within the EU -> complementarity of transmission and storage flexibility**

Legend: potential impact of indicated factors

Positive impact **Mixed impact** **Negative impact**

In several Member States biomethane is increasingly being injected into the distribution network, and some DSOs are already planning or exploring dedicated hydrogen networks. While reverse flows should remain limited to the 2030 horizon, nonetheless there should be increasing interaction between TSOs and DSOs, especially regarding the coordination for the connection of renewable and decarbonised gas projects in order to optimize the utilization of existing gas infrastructures.

Table 7-3 Summary of the impacts on DSOs of the use of biomethane and hydrogen

Impact	Summary
Cost of service	• Important cost of service variation across scenarios with methane scenario having the highest cost • Reverse flows are mature technology but may still require important investments, would however be limited to the 2030 horizon • OPEX is major cost of service component across scenarios, especially in 2030
Depreciation period & RAB	• There is less visibility on the current RAB and forecast of its depreciation cost at the national level for DSOs
Distributed gas volumes	• Stable or increasing distributed gas volumes • Near total dependence of distributed gas volumes on local end-user gas demand, in contrast to transmission level • Increasing share of gas remaining in distribution networks and not flowing from or to transmission networks
Volumetric tariffs	• Volumetric tariff increases from 2030 to 2050 due to required additional gas transition costs (CAPEX and OPEX)
Hydrogen networks and power-to-gas	• Hydrogen distribution networks are implemented by 2030 (earlier than dedicated transmission pipelines) and represent both in 2030 and 2050 a higher proportion of gas network costs than for transmission • Certain Member States have integrated DSOs owning and operating both electricity and gas networks, enabling sharing of services (lowering fixed costs) and reducing exposure to scenario uncertainty

8 Readiness of the regulatory regimes to support decarbonised gases & proposed policy and regulatory measures

This section assesses the readiness of the European and national regulatory regimes to support the development of infrastructure needed to accommodate renewable and decarbonised gases. Further, it proposes policy and regulatory measures to address identified gaps or potential issues, in view of improving the regulatory frameworks such that they more adequately support the deployment of decarbonised gases.

8.1 Readiness of the TEN-E and CEF regulations

There have been a number of assessments of the Trans-European Networks for Energy (TEN-E) and Connecting Europe Facility (CEF) regulations which propose recommendations for their improvement.[274] This section aims to provide a focused analysis with regards to their readiness to support the deployment of (gas infrastructure for) decarbonised gases in particular.

TEN-E lays down the procedure to identify Projects of Common Interest (PCIs), which can benefit of enabling permitting procedures, possible additional economic incentives addressing project-specific risks and access to CEF funding. Gas infrastructure[275] is one of the four main energy infrastructure categories in the TEN-E guidelines, including underground storage facilities and pipelines for natural gas, but excluding pipelines at the distribution level and not explicitly including hydrogen transport infrastructure nor conversion projects such as power-to-gas. Nonetheless, the sustainability criteria for the evaluation of gas infrastructure do include the contribution of a project to support not only

[274] Trinomics (2018), Evaluation of the TEN-E Regulation; and SWD(2018) 44 on the mid-term evaluation of the Connecting Europe Facility (CEF); and CEDEC, E.DSO, Eurelectric and GEODE (2018) Joint Statement from the DSO Associations on the proposal to revise the TEN-E Guidelines

[275] Covering transmission pipelines, underground storage, LNG and CNG facilities and other required equipment such as compressors

biomethane (referred to as biogas) but also power-to-gas. This has been included in the 2nd ENTSOG methodology for cost-benefit analyses[276], where the project benefits must consider the sustainability criteria of integration of 'biomethane and other synthetic gases'.[277] Hence, the evaluation of the TEN-E guidelines does note that gas PCIs have the potential to support the development of renewable energy sources.[278] However, none of the gas PCIs in the 3rd or 4th PCI list (published for consultation in 2019) make reference to the integration of biomethane or hydrogen.

All gas PCIs are eligible for grants for studies under CEF and some are eligible for grants for works. Gas PCIs are also eligible to receive funds from the European Fund for Strategic Investments (EFSI). The proposed CEF renewal[279] still covers the energy PCIs but also includes funding for the study and deployment of cross-border renewable energy projects, a new project category which is not included in the TEN-E regulation. Eligible renewable energy sources are those indicated in the Renewable Energy Directive, which does include landfill gas, sewage treatment plant gas and biogas. While not explicitly mentioned, power-to-gas projects from renewable energy resources should qualify as long as they can participate in one of the cross-border cooperation mechanisms referred to in the Renewable Energy Directive (joint projects, joint support schemes and statistical transfers).

Another relevant aspect that may need to be addressed at EU level are the technical and regulatory requirements to facilitate cross-border transmission of hydrogen, including the definition of quality conversion to handle for example varying hydrogen admixture rates. While authorities and network operators are assessing the potential of different (higher) hydrogen blending levels, there is a lack of coherence which may hinder the development of a consistent European approach and therefore of cross-border transport of hydrogen.[280] The HYREADY project, for example, aims to deliver engineering guidelines for gas TSOs and DSOs to support them with preparing their networks for the accommodation of hydrogen-natural gas mixtures with acceptable consequences and risks.[281] International standard developments are also key in this regard with CEN/CLC/JTC 6[282] leading the work regarding standardization in the context of hydrogen in the energy system.

Considering this, the following aspects would need to be addressed to enhance regulatory readiness:

Table 8-1 Overview of proposed policy and regulatory measures regarding TEN-E, CEF and other aspects to facilitate the deployment of renewable and decarbonised gases

Aspects	Proposed measures
Scope and eligibility (PCI/CEF)	• Assess potential update of the priority corridors and areas and the eligibility criteria of the TEN-E regulation, using flexible guidelines which can be adapted to a changing context. • Assess broadening the TEN-E scope to projects at the distribution level • Broadening the scope to projects facilitating sector coupling and/or the integration of decarbonised and renewable gases, including dedicated hydrogen networks, PtG and cross-border quality conversion (i.e. H_2 deblending) • Include robustness to uncertainty in mid- and long-term scenarios and innovation in the PCI selection criteria • Ensure that PCI cost-benefit analysis methodology and underlying scenarios account for renewable and decarbonised gases and prioritise making best use of existing infrastructure, including through conversion

Cross-border hydrogen transmission	• Clear EU wide specifications for the injection of hydrogen
	  ○ Revise CEN provisions on gas quality
	  ○ Revise interoperability network code

[276] TEN-E specifies that the PCI cost-benefit analysis methodology must consider the evolution of the gas network taking into account projects with a final investment decision which are due to be commissioned in the next 5 years.
[277] ENTSOG (2019) 2nd ENTSOG Methodology for Cost-Benefit Analysis of Gas Infrastructure Projects
[278] Trinomics (2018) Evaluation of the TEN-E Regulation and Assessing the Impacts of Alternative Policy Scenarios.
[279] European Parliament (2018) Briefing: Connecting Europe Facility 2021-2027 - Financing key EU infrastructure networks & European Council (2019) ST 9951/18 + ADD 3 - Proposal for a Regulation establishing the Connecting Europe Facility - Progress report
[280] HyLAW (2018) D4.1 Cross-country comparison
[281] http://www.gerg.eu/projects/gerg-projects"
[282] https://standards.cen.eu/dyn/www/f?p=204:7:0::::FSP_ORG_ID:2121095&cs=1D3657688753497E82D704DC9DE846D33

8.2 PERFORMANCE OF THE SELECTED NATIONAL REGULATORY REGIMES UNDER THE THREE SCENARIOS

This section aims to assess the performance of the selected national regulatory regimes to support the development of the infrastructure needed under the different scenarios, by focusing on planning of gas infrastructure; revenue regulation; network tariffication; role of system operators in the development of new technologies; and network connection and access for renewable and decarbonised gases. These are discussed in further detail in the sections below.

8.2.1 PLANNING OF GAS INFRASTRUCTURE

Article 20 of the recast Renewable Energy Directive requires, where relevant, Member States to assess the need to expand gas infrastructure to integrate renewable gas. As such, long and mid-term gas infrastructure planning should take into account the future role of renewable and decarbonised gases, as well as the integration of the electricity and gas sectors and the transmission and distribution levels. Currently, several member states do take into account renewable and decarbonised gases in their planning, though to different extents.

The **need for interaction and coordination between transmission and distribution system operators** is increasing due to the development of decentralised renewable and low carbon energy sources, demand-side management initiatives and 'new' conversion technologies such as power-to-gas. CEER recognizes the need for this interaction.[283] The current level of cooperation between TSO and DSO across the selected countries varies, with most having only limited operational cooperation and others already cooperating with regards to investment planning.

Similarly, there is also an increased **need for interaction and coordination between electricity and gas (and heating) system operators**, in view of valuing the synergy (coupling) potential between the sectors. The electricity and gas TSOs are, for example, already required to jointly develop the scenarios for the sectoral ten-year network development plans and the common interlinked electricity and gas market and network model. Some stakeholders already notice closer cooperation between electricity and gas TSOs given the increasing links between the sectors, but do not expect joint investment planning; while others noted that the current regulation does not incentivize integrated sectoral planning, even though it would offer a number of benefits. TenneT and Gasunie, for example, have published a joint infrastructure outlook to 2050 for Germany and the Netherlands, analysing the impact especially of power-to-gas developments.

Key aspects regarding future-proof planning of gas infrastructure are listed below along with proposed measures.

Table 8-2 Assessment of the performance of the regulatory regimes regarding planning of gas infrastructure and proposed policy and regulatory measures

Aspect	Description	Proposed measures
National infrastructure planning	Article 20 of the REDII requires, where relevant, Member States to assess the need to expand gas infrastructure to integrate renewable gas. According to the transmission planning framework, TSOs shall submit to their national regulator a ten-year network development plan (NDP) containing information on planned infrastructure from the short- to the long-term.	✓ NDPs regulation to consider flexibility options such as power-to-gas, injection at distribution level, storage and demand response, and H_2 deblending, based for example in the Energy Transition Projects process of the gas TYNDP 2020. ✓ NDPs regulation to require the inclusion of hydrogen network roll-outs when these are planned by policy makers ✓ TSOs to establish a project collection system for 3rd parties to indicate projects for inclusion.

[283] CEER (2015) The Future Role of DSOs - A CEER Conclusions Paper & CEER (2016) Position Paper on the Future DSO and TSO Relationship - C16-DS-26-04

Aspect	Description	Proposed measures
		✓ Authorities should improve the transparency and the vision on the future infrastructure constraints and costs that will weigh on the energy system.
Guidance	Guidance provision from regulators/ policy makers, with long-term visions for TSOs	✓ Provision of guidance from policy makers and/or regulators to TSOs regarding the NDP scenarios and the consideration of flexibility options such as power-to-gas, injection at distribution level, storage and demand response. ✓ Provision of guidance from policy makers regarding development of hydrogen networks and cooperation with system operators for staged roll-out, with adequate risk-revenue balance
Cooperation between DSO & TSO	Interaction between TSOs & DSOs is key due to the development of decentralised renewable and low carbon energy sources, demand-side management initiatives and 'new' conversion technologies such as PtG. DSOs and TSOs should coordinate in the assessment and/or planning of infrastructure needs and in the decision for connection of biomethane/PtG at transmission or distribution level.	✓ Effective coordination between DSOs and TSOs for the assessment and/or planning of infrastructure needs and, especially in the decision for connection/injection of biomethane and/or power-to-gas at transmission or distribution level. ✓ DSOs could base their investment plans on the same scenarios as those developed by the TSO for the NDPs ✓ Clarify the role of the EU DSO association for the gas sector, to ensure cooperation with ENTSOG on the operation and planning of the gas networks
Coupling of electricity & gas infrastructure planning and operation	Stronger coordination and interaction between electricity, gas and heat infrastructure will contribute to more efficiently cover the higher flexibility needs of the energy system resulting from the increasing penetration of intermittent RES.	✓ Regulated initiative for systematic coordination of electricity-gas to ensure effective cooperation between electricity and gas TSOs for the assessment and/or planning of infrastructure needs, including through common scenarios and joint project impact assessment when significant intersectoral interactions are identified. The interlinked ENTSOs model could provide inspiration for cooperation at national level.

8.2.2 Revenue regulation

The **revenue regulatory framework** is of key importance for the timely expansion, renewal or conversion of the gas infrastructure needed in the different scenarios. Generally the current regulatory framework assures the recovery of the 'reasonable' cost of service for the regulatory period (which typically ranges between 3 and 5 years).[284] While the framework allows, in general, for certainty in the short term (during the current regulatory period), there is some uncertainty regarding guaranteed revenues for system operators in the medium and long term. However, even beyond the present regulatory period, risks to system operators should be limited in the absence of important developments such as the need for large investments in new or refurbished infrastructure, or a significant fall in transported gas volumes. At present, there are no indications that NRAs are considering to substantially change the revenue regulation principles; this means that a (significant) fall in transported volumes would not necessarily lead to lower remuneration levels for network owners and operators in the short-term, as cost recovery is guaranteed. Increasing network tariffs might, however, put pressure on NRAs and network operators to reduce costs.

In most EU member states, the capital remuneration of gas network operators[285] depends, among others, on the Regulatory Asset Base. This approach might stimulate network operators to favour long depreciation periods, even if from a macro-economic perspective and taking into account the upcoming energy transition, shorter depreciation periods could

[284] CEER (2019), Incentive regulation and benchmarking work stream: Report on regulatory frameworks for European energy networks.
[285] In the current regulatory framework, gas network operators are remunerated either on the basis of their actual or approved cost of service, which may result from a benchmarking exercise and/or imposed efficiency improvements. This cost of service includes a return on their investment, allowing them to remunerate their capital providers. This rate of return is in general based on the level a company would get in a competitive market environment. In some national regulatory regimes, network operators can get a bonus or malus on top of this remuneration level, depending on their efficiency level and/or their achievements of imposed or agreed objectives.

be more appropriate in order to reduce the exposure to stranded asset risks. However, shifting to shorter depreciation periods would have disadvantages, especially the resulting short-term increases in tariffs, and are hence in general not favoured by NRAs or operators.[286]

A supporting regulatory framework is needed to **incentivise innovation by transmission and distribution system operators**. Some countries, where power-to-gas is most developed, are planning to launch sandboxes within the regulatory framework to provide specific incentives and a tailored regulatory regime to experiment with innovative technologies, such as power-to-gas. This type of scale-up programme can provide the space and regulatory flexibility necessary for experimentation in certain projects.

Table 8-3 Assessment of the performance of the regulatory regimes regarding revenue regulation & proposed policy and regulatory measures

Aspect	Description	Proposed Measures
Revenue levels	Revenues are guaranteed in the short term (within current regulatory period). After this regulatory period, risks should be limited in the absence of important developments (i.e. cross-border hydrogen infrastructure or significant fall in transported gas volumes)	✓ As revenue levels are regulated based on actual (or allowed) costs, measures should be considered to reduce costs and hence tariff increases due to falling transport volumes, e.g. by exploring and valuing synergy potentials between regulated operators via vertical (TSO/DSO) and/or horizontal (storage & network, electricity & gas) cooperation/integration in order to reduce fixed costs, pending an analysis and potential changes to unbundling requirements ✓ NRAs should recognise within the RAB investments which contribute to decarbonisation of gas networks (such as hydrogen-tolerant pipeline materials and devices or investment in technologies or measures to limit methane emissions)
Incentives for TSO/DSO innovation	A supporting regulatory framework is needed to incentivise TSO/DSO innovation.	✓ In countries where innovation is expected/needed, development of a supporting regulatory framework (e.g. 'sandboxes') providing incentives and tailored regulatory regime to experiment with innovative technologies, such as power-to-gas. ✓ Project-specific risk incentives (i.e. premium) for innovative projects with higher risks, similar to the PCI project-specific incentive methodology defined by NRA under the TEN-E regulation ✓ Incentive regulation for gas networks should support and facilitate the conversion of gas infrastructure to accommodate higher proportions of hydrogen[287] and even allow system operators to proactively explore hydrogen network rollouts
Incentives for sustainability	Regulatory frameworks need to reward system operator actions internalizing environmental externalities	✓ Revision of revenue-setting criteria for allowing investments addressing sustainability issues such as methane leakages
Depreciation	The linear depreciation method applied in all selected member states, and related depreciation periods (which differ per Member State and asset type) may be misaligned with the best depreciation approaches for the transition.	✓ Review regulation rules so that they better anticipate expected evolutions of gas system and properly reflect the economic lifetime of assets, considering current tariff levels and the ability of network users to absorb short-term hikes, especially vulnerable consumers and industrial users exposed to international competition.

[286] See among others CEER (2019), Regulatory challenges for a sustainable gas sector: Public consultation paper. Ref: C18-RGS-03-03; Eurogas (2018) Eurogas discussion paper for the gas package (2020)
[287] DENA (2018) Integrated Energy Transition - Impulses to shape the energy system up to 2050

8.2.3 NETWORK TARIFFICATION

Gas network tariffs in the current regulatory framework are determined and approved ex-ante for a period of several years. The shift from commodity to capacity tariffs has an impact on the competitiveness of both natural and renewable gas. This shift will negatively affect consumers with a low load factor (e.g. hybrid installations where gas is used as back-up) and favour base-load consumers (e.g. use of gas as feedstock).

Several measures could be considered to reduce the impact of a fall in gas demand which can either allow to recover costs via additional services (e.g. offering flexibility services, such as balancing, to the energy system), or to reduce the overall cost level (e.g. by structural measures, as mentioned supra). One of the most straightforward solutions to anticipate the tariff impact of a potential future fall in transported gas volumes is to shorten the depreciation periods, though this would lead in the short term to an increase in tariffs (as discussed supra). Moreover, short-term tariff increases from accelerated depreciation may have a disproportionate effect on vulnerable consumers or in Member States where tariffs are already comparatively high. Although this can be addressed with targeted policies, the broader distributional impacts may hinder the implementation of accelerated depreciation.

Table 8-4 Assessment of the performance of the regulatory regimes regarding tariffication & proposed policy and regulatory measures

Aspect	Description	Proposed measures
Cross-subsidization & allocation of tariffs among users	There are several new cost allocation issues within the gas sector concerning hydrogen networks, domestic/foreign split, changing flows between T&D, intertemporal cost allocation and connection of new methane users	✓ Joint tariffication of methane and hydrogen networks ✓ Allow in TAR NC tariff discounts for renewable and/or decarbonised gases ✓ Apply super-shallow connection charges and tariff discounts for renewable and/or decarbonised gases when justified by system benefits or policy objectives ✓ Apply shallow/deep connection charges for the connection of new gas users when there is absence of system benefits ✓ Share reverse flow costs between transmission entry and distribution exit tariffs
Impact of tariffs on network users		✓ Non-tariff support measures defined by policy makers ✓ Menu of options for users to pay for connection costs ✓ Joint tariffication of methane and hydrogen networks ✓ Targeted policies for vulnerable consumers
Grid defection spiral	A fall in transported gas volumes would lead to higher gas network tariffs, which would in turn make defection more attractive, thus undermining the TSO/DSO's traditional business model.	✓ Joint tariffication of methane and hydrogen networks, or even electricity ✓ Policy measures above targeted at addressing the impact of tariffs on network users.

Specific case: A fall in gas demand

According to our scenario analysis, a reduction in transported gas volumes via transmission networks would occur in all scenarios by 2050, though varying per scenario and Member State. The fall in gas demand and consequently transported volumes at the transmission level[288] could lead to tariff increases, though this would be offset entirely or partially by depreciation of the current RAB (and would also differ as investment levels and transported volumes will vary strongly per Member State). This is attenuated also by storage injections and cross-border exchanges which provide more stability to transmission transported volumes. Coupled with the cost of service arising from investments in the renewal, expansion and conversion of methane and/or hydrogen networks, the potential for the

[288] Except for Sweden, from selected Member States

largest tariff increases are in the hydrogen scenario to 2050, due to cross-border investments in hydrogen networks. However, as discussed in Chapter 7 the tariffs arising from the post-2019 investments and operation of the gas transmission network in 2050 are not significantly higher than current tariff levels as indicated by Eurostat data (but the remaining depreciation cost by 2050 of pre-2020 investments needs still to be factored in).

While the scenarios focus on the deployment of renewable and decarbonised gases, a significant fall in overall gas demand was not indicated as likely by some stakeholders, since they expect that a mixed technology scenario leveraging biomethane, hydrogen and/or synthetic methane will be implemented rather than an all-electricity scenario. Stakeholders also mentioned their concern regarding signals of a fall in demand to the market, as these could discourage network investments. Therefore, policy makers should take care to provide clear and stable signals reducing uncertainty to the 2050 horizon, allowing system operators and network users to take actions accordingly based on expected demand levels (and consequently transported gas volumes).

The current regulatory frameworks guarantee in principle the cost recovery of efficient investments and operational expenses made by TSOs; hence, regardless of the uncertainty on the probability of a fall in demand, it does not provide any measures to deal with a potential increase in tariffs due to a fall in transported volumes coupled with transmission network investments. As cost recovery is guaranteed in the regulatory frameworks and taking into account that the transmission tariff simulation indicates only modest tariff additions due to investments to the 2050 horizon (except in the hydrogen scenario), the business case for investments in Trans-European gas infrastructure is not substantially threatened. However, this applies in principle only for methane infrastructure, as at present there is no regulatory framework for hydrogen networks at the EU or Member State level, and hydrogen infrastructure is also not included in the TEN-E regulation.

Rationale for changes in cost allocation

Transmission tariffs account generally for between 5 to 10% of the overall gas bill, but their actual share largely varies depending on the demand level and characteristics as well as on the gas price level and other cost components, such as the distribution costs and taxes and fees. This section addresses the issue of cost allocation among gas network users and of partial recovery of costs by other mechanisms than tariffs, such as direct or indirect subsidies which would not pose all costs on gas network users.

While the TAR NC regulates a number of tariffication aspects, there are still important differences between the selected Member States in how national tariff structures are set. Chapter 7.3 indicates for example that the TAR network code still allows a non-marginal share of costs to be recovered through non-transmission services or commodity-based tariffs. Also, the entry-exit and domestic-transit tariff splits and the discount to storage all vary between the Member States. Moreover, chapter 6.2 shows that the connection and access rules for the injection of biomethane and hydrogen in gas networks also vary significantly across countries. Hence, while hydrogen injection is not allowed in Hungary, the Netherlands and Sweden provide equal treatment to biomethane and hydrogen as long as they respect the technical specifications. On the other hand, Germany explicitly addresses the issue, imposing the obligation for system operators to connect renewable gas producers and establishing incentives for both connection and access costs.

The different tariff structures, specific connection and access costs, and incentives to renewable gas lead in practice to different cost allocations between network users. Moreover, positive externalities arising from gas infrastructure and the development of renewable gas, may justify alternative cost allocation approaches which do not pose all costs on some or all gas customers. This might be especially relevant in the case of a rise in transmission and/or distribution tariffs due to investments in the renewal, expansion or conversion of methane or hydrogen networks or due to a fall in demand (or a combination of both, and possibly only at a local level). The beneficiary-pays principle would entail that not all costs should be allocated to gas network users if these are not the only to benefit from renewable or decarbonised gas injection in gas networks.

Also, unaddressed negative externalities such as inadequate carbon pricing in non-ETS sectors could result in unfair competition of natural gas with renewable and decarbonised gases. This could argue for (cross-)subsidization measures in order to promote the deployment of the latter and compensate for the non-internalization of climate externalities in the price of natural gas. However, as this approach would not allow to properly internalize external costs, it would only adjust relative costs but not in the most appropriate way, as network costs would not be related to the inadequate carbon pricing. Thus, in this case, (cross-)subsidization of network costs would also not be an appropriate option.

The gas regulation of 2009[289] provides few guidelines on tariff-setting and explicitly forbids cross-subsidization among different network users. These legal provisions have been translated in Article 7 of the TAR network code. To avoid cross-subsidization between intra- and cross-system uses, the TAR network code requires NRAs or TSOs to conduct cost allocation assessments on capacity-based charges (and commodity-based charges if applicable).[290] As presented in chapter 7.3, no selected Member State presented a capacity cost allocation comparison index above the indicative threshold of 10%[291] (although Hungary's case is particular). However, the Agency's analysis of the national tariff consultation documents highlights some relevant aspects regarding cost allocation:[292]

Table 8-5 Agency analysis of the national tariff consultation documents on cost allocation

Country	Description
Germany	Proposed methodology will result in a significant increase of tariffs to cross-system users.[293] The Agency cannot rule on cross-subsidization in the absence of information relating the reference price methodology to network characteristics. The Agency praises the German sensitivity analysis of cost allocation given different levels of storage use by cross-system users.
Hungary	Proposed rescaling adjustment leads to cost under-recovery, which constitutes intertemporal subsidization. NRA should provide additional information on the choice of tariff structure, and adjust aspects such as tariff scaling. Moreover, if storage discounts were considered in the cost allocation assessment calculation, the actual value would be 17%, thus above the 10% threshold
Netherlands	Allocation of quality conversion services (related to H/L gas) impacts cost-reflectivity, cross-subsidizing l-gas users, although it does create a positive externality by facilitating trade
Sweden	Under-recovery of costs will persist in the following regulatory period according to the TSO tariff proposal. Hence, the Agency considers the tariffs are not cost-reflective and that there is cross-subsidization. In response, the Swedish Energy Markets Inspectorate calculates tariffs to ensure full cost recovery for the 2015-2018 period

Note: For ***Spain*** *no consultation document was available by April 2019*

Source: ACER (2019) Analysis of the national consultation documents.

Previous studies[294] indicated that (cross-)subsidization measures are not fully compatible with all the tariffication principles simultaneously, especially cost-reflectivity and non-discrimination. However, the studies and the 2050 Long-Term Strategic Vision concur that the reduction of gas demand is a possible scenario, which could lead to significant tariff increases to 2050. The tariff simulation of the present study indicates that estimated volumetric tariff additions due to investments necessary to address the gas transition to 2050, will to a certain extent be compensated by the decreasing depreciation cost of the current regulatory asset base.

Based on the adopted assumptions[295], power plants would be affected mostly by transmission tariffs, and industries will be affected by both transmission and distribution

[289] Regulation (EC) No 715/009 on conditions for access to the natural gas transmission networks
[290] Following the TAR NC, the capacity cost allocation comparison index provides a simplified indicator to identify the allocation of costs according to cost drivers for intra- and cross-system flows, for capacity- and commodity-based tariff. The NRA is required to provide a justification if the index is above 10%.
[291] Following the TAR NC, the capacity cost allocation comparison index provides a simplified indicator to identify the allocation of costs according to cost drivers for intra- and cross-system flows, for capacity- and commodity-based tariff. The NRA is required to provide a justification if the index is above 10%.
[292] ACER (2019) Analysis of the national consultation documents. Available at https://www.acer.europa.eu/en/Gas/Framework%20guidelines_and_network%20codes/Pages/Harmonised-transmission-tariff-structures.aspx
[293] https://www.euractiv.com/section/energy/news/italy-squeals-on-german-gas-tariff-reform-eu-ready-to-step-in/
[294] Trinomics, LBST et al. (2018) The role of Trans-European gas infrastructure in the light of the 2050 decarbonisation targets & Frontier Economics et al. (2016) Future regulation of the UK gas grid – Impacts and institutional implications of UK gas grid future scenarios
[295] The most important assumptions for the analysis of the cost allocation per main type of user concerning the use of transmission and distribution infrastructure are:

tariffs to varying extents. Distribution tariffs will directly impact buildings and transport gas demand, while methane transmission tariffs will affect those users less in the future, with the opposite happening for hydrogen transmission tariffs if a hydrogen scenario materializes. Storage needs at the transmission levels will also change per scenario, generally decreasing in the hydrogen scenario to 2050 in certain Member States, especially hydrogen exporters such as in Scandinavia and Southern Europe.

The subsidization of the network cost of service is generally not favoured by policy makers, regulators and stakeholders and would be against the cost-reflectivity tariff principle. However, there is a number of new cost allocation dimensions within the gas sector which need to be considered in the revenue regulation and the tariff structure, comprising:

- **Costs for hydrogen networks**, which may be allocated to the users of this network or be recovered from the larger base of methane and hydrogen network users;
- The **split between domestic and foreign users** (due to gas transit or exports) in a context of changing cross-border gas flows where regions such as Scandinavia, Southern Europe and the British Isles may become significant renewable and decarbonised gas exporters, and where traditional EU natural gas suppliers will either disappear or switch to supplying renewable or decarbonised gases;
- The potential **system benefits of renewable or decarbonised gas injection**, alleviating congestion and reducing network investment needs;
- **Changing flow patterns between transmission and distribution**, with potentially a reduction in transmission volumes, an increase in distribution ones and a more frequent occurrence of reverse flows;
- **The intertemporal arbitrage** in the recovery of the cost of service from gas users either in the present or in the future reflecting choices in the rate of investment depreciation, stability of the user base and capacity of present and future users in absorbing tariff changes;
- **The connection of new methane network users** as a consequence of e.g. continued network expansion in specific areas or changes in policy (e.g. substitution of coal and oil or end of economic support to CHP production from biogas);
- **Trans-European Networks for Energy,** and aspects such as the cost allocation between developing and affected Member States, financial support from the CEF and potential inclusion of hydrogen networks, power-to-gas and distribution-level projects in a revision of the TEN-E regulation.

Regulation at the EU and MS level should aim for cost-efficient, non-discriminatory and reproducible tariffs which do not distort cross-border trade and manage volume risks for domestic users following TAR network code guidelines. Although subsidization of gas network costs is in general not favoured by stakeholders nor allowed by the current regulation, several cost of service allocation issues remain.

8.2.4 Role of system operators in the development of new technologies

System operators may have additional tasks and roles to facilitate the energy transition. The regulatory framework might need to be adjusted to include new technologies such as power-to-gas and dedicated networks for hydrogen, and thus allow for an increasing share of renewable or decarbonised gases in the gas network.

Currently, the **legal status for power-to-gas remains unclear,** and therefore also the role of system operators in this regard. On the one hand, the gas directive seems to

Methane and hydrogen **power plants** will remain connected for the most part in the transmission level
The large majority of gas demand for **buildings** would still be at the distribution level (though with the opposite trend for hydrogen demand in buildings, which may increasingly be transported through the transmission network);
Industry methane demand separation of flows between the transmission and distribution levels may remain stable, while increasingly hydrogen flows due to industry demand may flow through the transmission network
Transport gas demand will remain connected at the distribution level with the impact on methane transmission flows decreasing, while the share of hydrogens demand which also flows through the transmission level will increase.

determine the unbundling of gas TSOs for storage facilities but power to gas is excluded from its classification of the storage function[296]. On the other hand, the ACER gas target model and the recast electricity directive classify power-to-gas as storage.[297] At national level, there should be a clear legal status and classification which do not hinder power-to-gas from providing balancing and ancillary services. If power-to-gas facilities were treated as electricity consumers and needed to pay the corresponding connection and access fees as well as related taxes, their business case would be undermined. Currently, the regulatory framework in most countries assessed does not specify the legal status of power-to-gas.

Concerning the **ownership and operation of power-to-gas facilities**, the gas directive requires storage to be unbundled from the activities of transmission and distribution system operators, but the applicability of the unbundling requirements is unclear due to the above-mentioned uncertainty on the facilities' legal status. In the electricity sector, the recast electricity directive provides the possibility for national regulators to grant exemptions to the unbundling requirements for transmission and distribution system operators.[298] In Germany, power-to-gas is considered a competitive activity and, as such, network operators cannot own and operate such facilities under the current legal framework. TSOs favour the classification of power-to-gas as a conversion service rather than storage, in order to avoid unbundling rules and be allowed to provide conversion services to market parties.

The role of system operators (if any) would also need to be determined with regard to the potential **construction and operation of dedicated hydrogen networks**, which are relevant mostly in the hydrogen scenario. For this scenario, it would be important, first, to define whether these dedicated networks should be regulated or not, and secondly, to clarify the role of incumbent and new system operators in this regard. Currently, these aspects are not addressed by the regulatory framework in the assessed countries.

Table 8-6 Assessment of the performance of the regulatory regimes regarding the role of system operators in the development of new technologies and proposed policy and regulatory measures

Aspect	Description	Proposed measures
PtG legal status	There are inconsistencies at EU level in the legal status of PTG, and whether it should be considered as storage or not (and, therefore, unbundled or not from SO activities). At national level, there should be a clear legal status and classification which do not hinder PTG from providing balancing and ancillary services.	✓ Clarification at EU level on the role of power-to-gas (legal certainty), and definition of a clear legal status and classification at national level which do not hinder power-to-gas from providing balancing and ancillary services. ✓ Implement a market test framework to allow system operators, if there is no market interest, to develop, own and operate power-to-gas as conversion services with separation from network activities, and to step out when there is market interest, while guaranteeing the cost recovery ✓ Role of TSOs in deblending should be defined in regulation
Hydrogen networks	In the future, dedicated hydrogen distribution or transmission networks may be put in place (e.g. as show in the hydrogen scenario). However, they do not fit within the current regulatory framework.	✓ Clarification at EU level on whether dedicated hydrogen networks should be regulated or not. If need be, tailor the gas framework or develop a dedicated hydrogen framework defining what the role of incumbent and new system operators will be in this regard, as well as of merchant cross-border interconnectors

[296] Directive 2009/73/EC: "'storage facility' means a facility used for the stocking of natural gas and owned and/or operated by a natural gas undertaking, including the part of LNG facilities used for storage but excluding the portion used for production operations, and excluding facilities reserved exclusively for transmission system operators in carrying out their functions"
[297] ACER (2015). European Gas Target Model Review and Update
[298] The recast electricity directive allows for exemptions to the unbundling requirement, e.g. if storage facilities are necessary for the fulfilment of their obligations and if tendering procedures were not able to award these facilities to market actors.

8.2.5 NETWORK CONNECTION AND ACCESS FOR RENEWABLE AND/OR DECARBONISED GASES

Having the right regulatory framework for the network connection and access of renewable and decarbonised gases is a first step to ensure they can cover a substantial part of the future energy mix. Article 20 of the recast Renewable Energy Directive requires network operators to publish **technical rules for the integration of renewable gases** (i.e. network connection rules including gas quality, odorization and pressure requirements). These rules should, ideally, also provide clarification regarding possible ownership and operation of facilities for network injection providing compression, mixing (if necessary) and metering functions (e.g. ownership and/or control by producer or network operator).

Most countries assessed apply the same connection and access rules for injection of biomethane and hydrogen as for natural gas, while only Germany has specific rules for renewable gases, including priority access (obligation to connect). Currently, there is a broad range regarding the maximum amount of hydrogen allowed in the network, ranging from 0.1% to 10% volume (or not specified at all) in the countries assessed. Regulatory regimes in some countries limit the injection of renewable or decarbonised gases (e.g. do not allow the injection of hydrogen or do not recognise hydrogen as gas for transport); while others, such as Germany, incentivise hydrogen production by allowing a relatively high (10% H_2) admixture. However, there are at present in several countries ongoing discussions or planned changes regarding injection of hydrogen in the network.

Article 20 of the recast RED also requires network operators to publish **connection tariffs for renewable gases.** These network connection and access tariffs may influence significantly the business case of renewable gas injection in the transmission and distribution levels. Exemptions from access tariffs for renewable gas injection and even injection support measures (as done in Germany) positively impact the business case for injection of decarbonised gases, while applying the same connection and access costs as for natural gas operators as done in most other countries can hinder the business case and not reflect system benefits of local gas injection.

Table 8-7 Assessment of the performance of the regulatory regimes regarding network connection and access for hydrogen and biomethane and proposed policy and regulatory measures

Aspect	Description	Proposed measures
Injection of hydrogen/ biomethane	Article 20 of the REDII requires network operators to publish technical rules for the integration of renewable gases (i.e. network connection rules including gas quality, odorization and pressure requirements).	✓ Publication of technical rules for the integration of renewable gases by TSOs and DSOs ***(transposition of REDII),*** allowing higher hydrogen admixtures to the extent that it has no impact on pipelines and end-use equipment and ensuring that no renewable/decarbonised gases are excluded. ✓ Clarification regarding ownership and operation of facilities for network injection.
Tariff for injection of hydrogen/ biomethane	Article 20 of the REDII requires network operators to publish connection tariffs for renewable gases. These tariffs have an impact on the business case of renewable gases.	✓ Publication of connection tariffs for renewable gases by TSOs and DSOs based on objective, transparent and non-discriminatory criteria ***(transposition of REDII).*** ✓ Provide incentives to the injection of hydrogen/biomethane (e.g. obligation to connect, priority access) following policy priorities and/or according to added system benefits

9 CONCLUSIONS AND RECOMMENDATIONS

The EU potential for sustainable biomethane is limited, while the technical potential for hydrogen and synthetic methane production based on renewable electricity is large enough to also substitute the natural gas demand. Policies should ensure that the potential of renewable energy, including gas, is valued in the best possible way.

In this study, a conservative domestic technical biomethane production potential of 1,150 TWh/a is considered for the EU28, which corresponds to 24% of the current natural gas demand. As the biogas/biomethane production is at present about 200 TWh/a, the additionally available potential is estimated at 950 TWh/a. Fully utilizing this potential would leave little room for bio-energy with carbon capture and storage (BECCS) based on bioenergy firing, an important element in climate neutral scenarios of the European Commission's Long-Term Strategic Vision. However, in any case CO_2 captured in the process of upgrading biogas to biomethane could be geologically stored resulting in negative emissions. As the biomethane potential is not equally spread across the EU, it can in some Member States play a significant role to substitute natural gas, while other Member States would rather have to import biomethane or rely on other options to decarbonise their natural gas consumption. Further consideration of sustainability requirements and interactions with other biomass uses could be explored to refine this potential.

The technical domestic long-term potential considered for hydrogen production based on renewable electricity is much higher; the renewable electricity potential is estimated at some 14 000 TWh/a and would be sufficient to cover both the final electricity demand (currently approx. 3,100 TWh/a) and the electricity volumes needed for the production of hydrogen to cover the entire gas demand in 2030-2050 (estimated at maximum 4,100 TWh/a, depending on the scenario). However, the renewable electricity potential is, similarly to biomethane, not equally spread across the EU; some Member States would have a (large) export potential while others would have to import renewable electricity and/or gas to decarbonise their energy supply. In addition, the technical potential estimate does not take into account critical factors like public acceptance of energy infrastructure. However, such restrictions would only represent a limitation to European hydrogen production, or more generally energy supply, if they reduce the potential significantly. Hence, particular Member States with more limited renewable electricity potential (such as in Central Eastern Europe) could be impacted by these potential limiting factors, but they would not affect the overall conclusions for the European Union.

Physical and trade exchanges of renewable gas (and electricity) between Member States in an integrated market will hence be of great importance to decarbonise energy supply and cover energy demand at least cost and to ensure efficient energy system and market functioning. In this context, the interoperability of gas networks facilitating domestic and cross-border transport of renewable gas as well as an EU wide system for guarantees of origin for renewable gas are important prerequisites. Imports of renewable gas from outside the EU may also be of relevance, given the high production potentials of neighbouring regions and countries. As this study focuses on domestic renewable gas production and excludes imports, further analyses could be useful to assess the impact of imports of different renewable and decarbonised energy carriers along various decarbonisation pathways on the overall energy system in the EU. In this context, the role of power-to-gas as a flexible load could also be further examined.

Biomethane and small admixtures of hydrogen can be safely transported in existing natural gas networks. Appropriate technical standards and specifications should be elaborated to facilitate this development. A supportive regulatory framework for hydrogen blending as a tool for decarbonising the gas supply should be developed. For higher hydrogen volume concentrations, dedicated transport/distribution infrastructure would be more appropriate than admixture to methane.

Biomethane may replace fossil methane with very limited or no technical requirements for changes in the gas network, mainly related to adjustments to the network structure (reverse flows) linked to the decentralized nature of biomethane production. Hydrogen may be admixed to methane in limited quantities (a hydrogen admixture rate of 10 vol% to methane can be safely assumed), which do not require investments in adjustments to the gas networks and thus allow for using renewable hydrogen without additional costs to the gas infrastructure. Moreover, even if a (constant) 10-20 vol% admixture rate may be technically feasible (both at TSO and DSO level), the cost-benefit of the necessary adjustments seems questionable and cannot be conclusively answered today. Alternatively, a dedicated hydrogen network may be established retrofitting the existing network and building new network elements where necessary, if transport of higher hydrogen concentrations is desired. In this scenario, parallel methane and hydrogen networks may develop.

Injecting hydrogen into existing natural gas transmission and distribution networks requires a preliminary assessment and review of the gas specifications. Standards defining maximum hydrogen admixture levels should be addressed at European cross-border points, with coordination between interconnected countries. A regulatory challenge is to identify hydrogen thresholds which provide equal and adequate opportunities to develop hydrogen injection into the network in each market (without penalizing "downstream" countries compared to "upstream" countries). Specifically, the framework should define thresholds of hydrogen content applicable for the upstream gas networks that will be compatible with the downstream cross-border network; alternatively, the framework could require an additional treatment of the gas, e.g. methanation, decreasing the hydrogen share.

Hence, a supportive regulatory framework for hydrogen blending as a tool for decarbonising the gas supply should be developed. TSO/DSO cooperation in this domain (focusing on research and demonstration projects, elaboration of technical standards and specifications) should be encouraged in order to contribute to the development of an adequate European and national framework for the blending of hydrogen in gas networks. In parallel, it would be appropriate that TSOs/DSOs further assess the technical and economic feasibility of refurbishing (specific sections of) the gas infrastructure in view of their use for 100% hydrogen in the medium and long term.

A thorough assessment of three scenarios (focusing respectively on strong electricity, green methane or hydrogen end-use) shows that a scenario based on electricity and gas sector coupling where hydrogen plays a central role would offer the least-cost outcome, while also allowing to value existing gas assets. Further analysis of the role of hydrogen and of strategies for a stepwise development of 100% hydrogen network "islands" is worth exploring.

The comparison of the system costs for the three scenarios reveals until 2030 similar cost structures and magnitudes with major contributions from fossil energy imports. In this time period, biomethane and hydrogen supply would still have a limited impact on the energy system costs. In the long-term, until 2050, the overall system costs decrease due to cheap renewable power production and increasing sector integration between power and gas. The lowest system costs are achieved in the hydrogen-focused scenario followed by the electricity and methane-focused scenarios and can be viewed as a trade-off between renewable energy production, system flexibility and gas supply. The system design with a focus on hydrogen technology appears to be a robust compromise where the advantages of a higher system flexibility overcompensate the disadvantages of lower energy efficiency in comparison to the electricity-focused scenario. The methane-focused scenario is less attractive due to its lower overall energy efficiency (related to additional investments and energy losses in the methanation process and lower end-use efficiency for transport applications) in comparison with the other two scenarios.

It is important to highlight that the scenario modelling is of explorative character with regard to the demand for the major energy carriers within the end-user sectors. Moreover, different assumptions are made regarding the supply of biomethane and hydrogen (focusing on the domestic EU supply), the availability and location of flexibility resources to 2050 such as batteries and H_2, as well as the hourly profile for renewables supply and demand for electricity and gas. The optimal mix in this respect is an interesting area for further research.

From a system perspective, the optimal design strongly depends on the anticipated GHG emission reduction targets. Therefore, binding targets in particular in the long-term (until 2050) are needed for a cost-effective transition of energy supply and transport infrastructures both for gas and power. In this way, suboptimal investment decisions and unfavourable lock-in effects can be avoided. A more coordinated development of power and gas infrastructures, and between the transmission and distribution level, in line with the build-up of renewable energy and seasonal storage capacities, is also needed to minimize the system costs.

Moreover, further analyses from the end-user and business perspectives would be useful to complement the current modelling exercises from a pure system perspective. Especially for gas infrastructure, the ongoing or planned re-investments in ageing assets should be assessed in more detail both from an operator perspective and from an overall energy system perspective, taking into account sustainability criteria and alternative solutions, in order to ensure that new investments are future-proof and take into account expected developments in the energy market.

In order to facilitate the modelling of the overall energy system, the availability and quality of data should be improved aiming towards a European set of harmonised national gas network data covering structural, technical and economic data. Cost elements of hydrogen networks including pipelines, compressor stations, pressure reduction stations, metering, etc. for the full range of relevant technical parameters should be further analysed and refined allowing for improved cost modelling and more robust economic results.

Based on this study's results, strategies for fully decarbonised gas systems by 2050 should be developed describing stepwise and cost-effective transition pathways in the medium-term (2030). Notably for hydrogen, further analysis of possible development strategies and pathways for a stepwise development of 100% hydrogen network "islands" that subsequently grow into one large hydrogen network in the future are worth carrying out. For this purpose, a European roadmap for the transition from a fully methane-based gas system to a gas system with separate hydrogen and methane network systems in 2050 would be useful.

Planning of new energy infrastructure should be more integrated and be based on the overall future energy system while optimising the use of existing infrastructure.

Policy makers should provide clear guidance on gas decarbonization pathways to reduce uncertainty for investments and base system operators' planning scenarios for efficient investments. As such, authorities should improve the transparency and the vision on the future infrastructure constraints and costs of the energy system, which would be key to prepare the adaptation of gas infrastructures to the energy transition.

Planning of new energy infrastructure should be based on a "future" energy system concept, anticipating the increasing development of renewable gas (and electricity) and accounting for the necessary changes required. Network planning should, therefore, take a holistic view, guaranteeing cost-efficiency across all available options[299] and optimal use of existing infrastructure, while accounting for national differences and ensuring new investments are future-proof. Moreover, planning should be more integrated, both between distribution and transmission levels (including with storage and LNG terminal operators), as well as between the electricity and gas (and heating) sectors. As such, mid-term and long-term developments and planning should be coherent, to avoid investments in potentially stranded assets given uncertainties in national pathways towards a fully decarbonised energy system. Furthermore, regulation should ensure appropriate coordination between DSOs and TSOs especially for defining the most efficient way to connect renewable gas production. As such, the future regulatory framework should foresee that national and European network development plans (NDPs and TYNDPs) are developed in a coordinated way between electricity and gas, ensuring cross-sectoral optimisation of investments and overall cost-efficiency. This also entails further harmonised scenarios and methodologies for both electricity and gas infrastructure planning.

[299] As such, planning should consider the roll-out of hydrogen networks and alternative flexibility solutions such as demand response, reverse flow projects, and power-to-gas. Further, CCU and CCS (and the related networks) should also be considered when planning for a carbon neutral energy system.

TEN-E and CEF regulations should support projects facilitating the integration of renewable gas

As renewable gas and gas infrastructure are expected to play an important role in the transition to a decarbonised energy system, and as the European gas markets are already well-integrated and security of supply is properly ensured in most EU Member States, the focus of the TEN-E and CEF regulations should for the gas sector shift to projects that are future-proof and efficiently contribute to the energy transition, thereby limiting the risk of stranded assets. To this end, infrastructure projects supporting the integration of renewable gas (including power-to-gas projects, connections of renewable gas production to the grid, cross-border hydrogen transmission projects or facilities allowing renewable gas reverse flows from DSO to TSO grids) should be eligible to apply for PCI status and consequently CEF support. Although such investments may seem rather local in nature, they can have important cross-border impacts and benefits as collectively such investments can facilitate the trade of renewable gas between countries with high and low production potentials. The eligibility criteria should also include adequate sustainability criteria to ensure that candidate projects are future-proof and sustainable (in terms of decarbonisation as well as other environmental impacts) and should value sector coupling projects, for which adequate principles on allocation of costs between electricity and gas network tariffs should be defined.

An adequate regulatory framework for power-to-gas should be developed

Although power-to-gas is considered as a promising technology to facilitate the deployment of renewable energy and to provide system flexibility, the carbon price is still too low to trigger large scale commercial investments in power-to-gas installations. In order to help kick-off this technology, there could be a role for TSOs to build, under well-defined conditions, power-to-gas facilities as demonstrator or as industrial unit, and operate them as service provider for market parties, e.g. via a tolling agreement. To enable this option, regulatory changes would be needed to integrate the facility in the TSO regulated asset base and to implement regulated open and non-discriminatory third-party access to the power-to-gas conversion services.

Moreover, barriers for investments in power-to-gas facilities should be removed, e.g. by classifying them as energy conversion facilities rather than as electricity end-users, and as such they could be exempted from taxes and levies on end-use of electricity. Given their role for seasonal flexibility and to optimize the electricity system, power-to-gas could also be entitled to a discount on the exit capacity tariff from the electricity network on the same basis as underground gas storage. Since power-to-gas facilities also contribute to the long-term use of gas infrastructure, gas network charges could be reduced or eliminated to the extent that they provide system benefits (as is the case for biogas plants in certain Member States).

An appropriate regulatory framework for dedicated hydrogen networks should be defined in a timely manner

In view of facilitating the development of dedicated hydrogen networks, likely using existing natural gas infrastructure, the regulatory framework of how these pipelines are developed and operated will have to be determined in a timely manner. Hydrogen networks can be considered as natural monopolies with similar characteristics as methane networks: essential facilities, with considerable fixed costs that only can be recovered over a long time period. In the current context, it is unlikely that private parties will invest in new hydrogen transport infrastructure. Taking into account that (sections of) the existing natural gas network could serve as a basis for developing dedicated hydrogen transport and distribution infrastructure, it might be appropriate to extend the role of TSOs/DSOs and to allow them to develop and operate hydrogen networks under the same regulatory framework as natural gas networks. This would include regulated non-discriminatory third-party access to support and further develop the internal European energy market, including for hydrogen.

Independent of being fully or partially regulated or not, there are several benefits of TSOs/DSOs building and operating hydrogen pipelines including, for example, infrastructure optimisation and cost savings as a result of coordinated planning, as well as integration of hydrogen and (bio)methane markets to deliver one price signal for gaseous energy, preventing market fragmentation. This would, however, require a redefinition of the TSOs/DSOs' role and mandate as they are currently only entitled to act as the monopoly operator for methane networks.

National policy and regulatory frameworks for renewable gas are current largely diverging. Streamlining efforts are required to improve effectiveness, avoid competition distortion between energy vectors, and value economic benefits of local renewable gas production.

Currently, there is a variety of incentives and support schemes in place to stimulate the deployment of renewable gases, though these vary widely across Member States, ranging from specific targets, support schemes for production or consumption to tax exemptions. However, investments in renewable and decarbonised gas production are still limited and substantial increases are not expected in the short-term, except in some Member States in Western-Europe. In order to stimulate the deployment of renewable gas, stakeholders argue for more and specific policy support, ranging from R&D incentives, to binding national targets for renewable and decarbonised gases, to feed-in-tariffs. Renewable gas injection into the grid could also be supported by priority access rules and discounts on connection and/or injection costs, justified by the positive impact of local injection on the gas system costs.

Internalising the external cost of climate change into the price of all fossil fuel end-uses, would be the most efficient and least distortive measure to support renewable and decarbonised gases. Such as measure should preferably be implemented at EU level. Renewable energy targets can also be a cost-efficient and non-distortive measure. However, specific sub-targets per market segment or per energy vector, as specifically proposed by some stakeholders for renewable gas, might be useful to stimulate investments in innovative gas technologies, but could lead to higher overall energy system costs.

As such, national incentives and support schemes for renewable and decarbonised gases should be streamlined from an overall energy system perspective to ensure that decarbonisation is reached at least cost, while also taking national differences into account, including the direct and indirect economic benefits of valuing local renewable gas potentials.

Decarbonising gas supply will substantially affect the business case of gas network operators and could lead to higher grid tariffs. Options to mitigate this impact should be further considered.

At the EU level, a decrease in the overall transported/distributed gas volumes is expected, with the most important changes in the 2030-2050 period. The impact per Member State will be different, depending on national differences at the supply and demand side. Given the current regulatory framework, the direct impact on the revenue levels of network owners/operators would be limited, in the absence of important evolutions, such as the development of cross-border hydrogen infrastructure by third parties or substantial changes in the regulation principles. As the revenue levels are at present regulated based on actual (or allowed) costs, decreasing transported gas volumes would mainly translate into increasing grid tariffs, which would put pressure on authorities and network operators to mitigate this impact, in particular for vulnerable consumers and industrial gas users exposed to international competition. As (cross-)subsidisation of network costs is not considered as an appropriate option, and lowering the remuneration level of grid owners might jeopardise their willingness to invest, measures should be explored to reduce network costs, e.g. by valuing synergy potentials between regulated operators via vertical (TSO/DSO) and/or horizontal (storage & network, electricity & gas) structural cooperation, allowing to reduce the overall fixed costs and to enhance the energy system efficiency by an improved coordination. Valuing these synergy potentials might require changes to the unbundling requirements.[300]

[300] As defined by the Gas Directive 2009/73/EC and the recast Electricity Directive 2019/944, which establish unbundling requirements for gas and electricity TSOs and, to a lesser extent, DSOs. For an overview of the requirements and the changes brought by the Clean Energy Package, see CEER (2019) Implementation of TSO and DSO Unbundling Provisions - Update and Clean Energy Package Outlook. C18-LAC-02-08

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