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

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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.

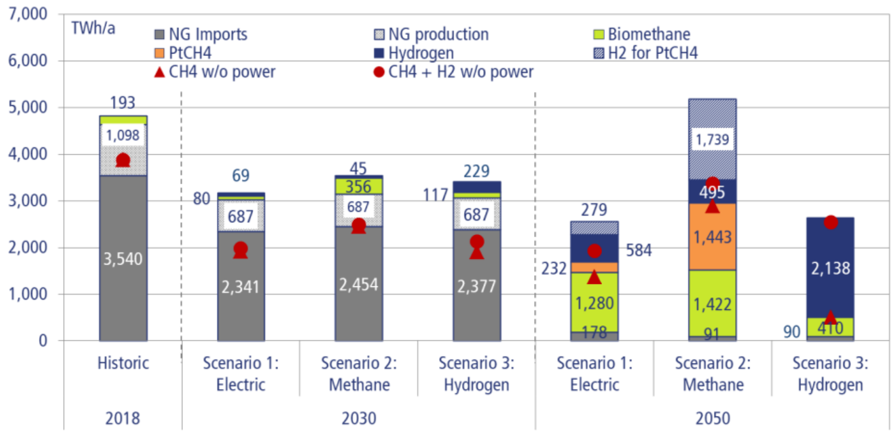
Hence, the EU's technical potential for renewable hydrogen by far exceeds the 2050 gas demand considered in this study: in none of the scenarios for 2030 or 2050 the gas demand exceeds 4 100 TWh/yr. In contrast, the EU biomethane technical potential is not sufficient to meet the current nor future gas 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 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.

[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.

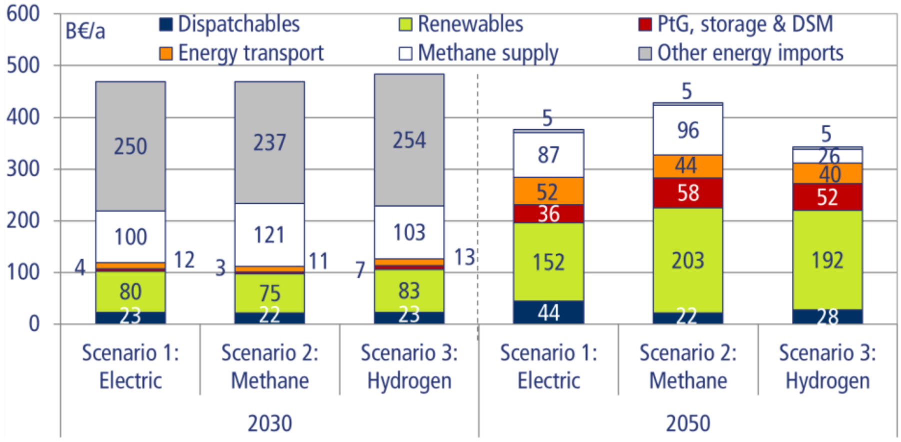
The methane-focused scenario also utilises in 2050 the full biomethane potential. In addition, almost the same amount of synthetic methane is produced via methanation for end-use and re-electrification. Hydrogen production reaches over 2,200 TWh/a, but only limited amounts are employed directly in end-use 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.

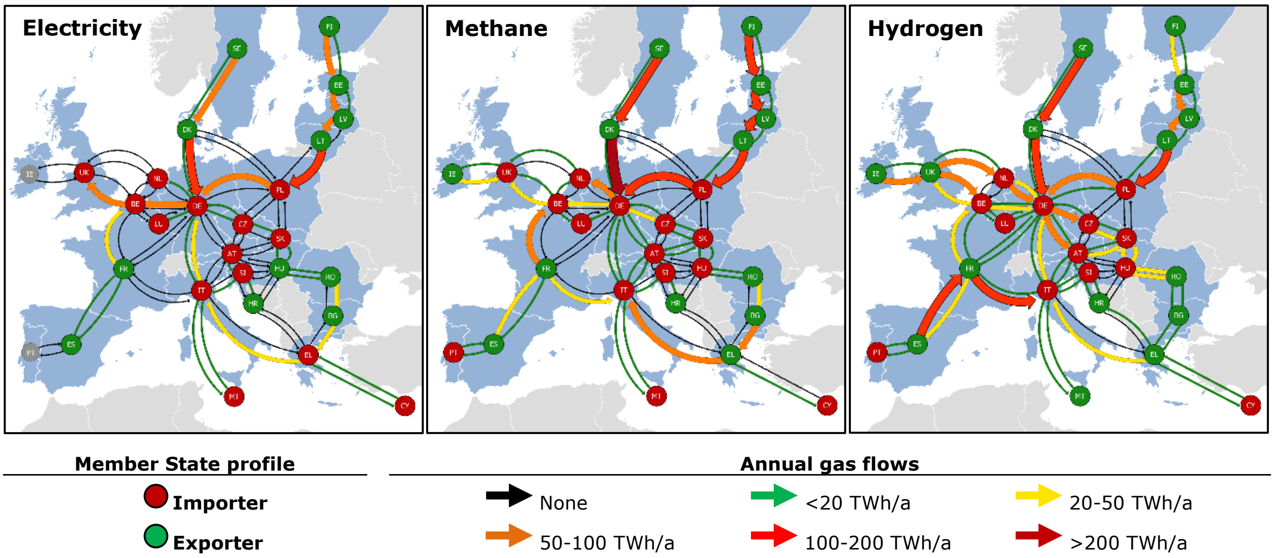
A scenario focused on electricity and gas sector coupling where hydrogen plays a central role would offer the least-cost outcome, while also allowing to value existing gas assets. Until 2030 the three scenarios present similar system cost structures and magnitudes, with major contributions from fossil 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.

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