E-fuels case study

Part A: Methane

30/06/2025

1 Introduction

Methane, better known as natural gas in which it is the main component, is ubiquitous in today's economy. In the EU, gross natural gas consumption was 12 PJ in 2022, making it the most important energy source after oil and petroleum products (21 PJ)[1]. Its use is widespread in industry, power production as well as in the buildings sector, and to a lesser extent in transport[2]. It is a low cost and clean burning fuel and has been promoted as an alternative for coal but also nuclear power generation in the EU. Being a gas at atmospheric conditions, transporting and storing of methane is less convenient than is the case for liquids, yet this has been addressed by the major roll-out of pipelines, development of liquefaction equipment and carriers for liquefied natural gas (LNG), and underground storage such as in Loenhout, Belgium[3].

However, the use of natural gas is leading to a large amount of greenhouse gas emissions. First, the combustion of natural gas leads to a CO_2 emission of about 2.7 t/t. Second, in the extraction and transporting of methane leaks can occur, releasing it into the atmosphere. This is particularly harmful since methane is a much more potent greenhouse gas than CO_2, albeit with a shorter lifespan[4]. As a result, methane emissions are estimated to be responsible for 16% of global greenhouse gas emissions[5]. However, it should be noted that a significant share of methane emissions is in fact not linked to the direct use of natural gas as energy source, e.g. there are also emissions from coal mines or livestock farming.

To tackle natural gas related emissions, a multitude of different solutions will need to be implemented, one of them being the substitution of natural gas by renewable methane. This can be either biomethane (produced from anaerobic digestion of biowaste) or e-methane (produced from CO_2 and renewable electricity). The latter has already reached a certain maturity, with several projects being online today. However, biomethane is currently much more developed, with an installed capacity of 5.2 billion cubic meters (bcm)[6]. Since both biomethane and especially e-methane are considerably more expensive than natural gas (see section 4), and the supply side potential for biomethane is limited, it is unlikely that renewable methane will fully replace natural gas supply. Rather, it will be used for applications where direct electrification is not feasible or cost effective, such as the supply of high temperature heat for certain industrial processes[7]. For such applications, renewable methane will be in competition with other e-molecules, e.g. H_2 or ammonia. The outcome of this competition will be determined by cost considerations related both to the production side (where e-methane has a disadvantage because it entails an extra conversion step compared to using H_2 directly as energy carrier) as well as the transport side (where methane has the advantage of the already available infrastructure).

2 Technology description

2.1 Overview

Conceptually, the methanation process resembles well the methanol process (Figure 1). It involves a CO_2 capture step and water electrolysis to obtain the CO_2 and H_2 reactants, respectively. Subsequently, these inputs are fed to a methane synthesis unit, which can be either a thermocatalytic process or a

[1] Energy statistics - an overview - Statistics Explained (europa.eu)
[2] European natural gas demand tracker (bruegel.org)
[3] Home - Gas Infrastructure EuropeGas Infrastructure Europe (gie.eu)
[4] Methane and climate change – Global Methane Tracker 2022 – Analysis - IEA
[5] Importance of Methane | US EPA
[6] New edition of the Biomethane Map shows 37% increase in biomethane capacity in the EU compared to the previous map | European Biogas Association
[7] PATHS2050 | Energy outlook (energyville.be)

biological process where methanogenic micro-organisms are used as catalyst. The reaction is as follows:

$CO_2 + 4H_2 \leftrightarrow CH_4 + 2H_2O$

After methane synthesis a few post processing steps may be required, especially if the e-methane is to be injected in the gas grid, in which case it needs to comply with certain technical specifications.

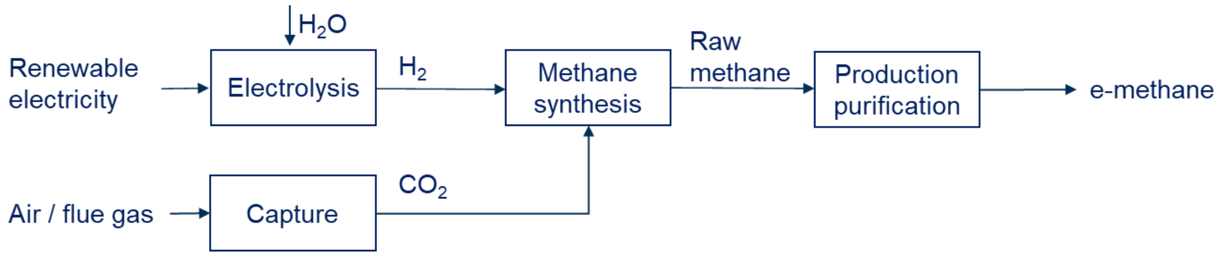

Figure 1 Block flow diagram

The thermocatalytic process usually operates in a temperature range of 200-550°C and pressure range of 1-100 bar[8]. Since the reaction is highly exothermic, it is beneficial to operate at lower temperature as this allows for higher conversion rates. Furthermore, at about 350°C steam methane reforming (i.e. the two methanation production reacting to form syngas) starts occurring[9]. For that reason, the search for catalysts that have good activity and selectivity at lower temperatures is ongoing[10].

Conventional catalyst material includes ruthenium and nickel, whereby the latter is of particular interest due to its lower cost[11]. As the reaction is thermodynamically favorable, high conversion rates can be achieved. For example, with a 3D-printed NiAlOx catalysts, UGent and VITO managed to achieve 98% CO_2 conversion and 99% selectivity to methane in the CATCO2RE project[12]. Similarly, conversion rates >95% have been reported elsewhere with a nickel catalyst[13]. Apart from a high activity and selectivity to methane, a catalyst also needs to possess good cyclical stability[14] (i.e. maintaining performance after repeatedly starting up and shutting down the reactor) as well as resistance to e.g. sulfur or carbon poisoning. Thermocatalytic methanation technology is already offered by several companies today[15,16].

As an alternative to the thermocatalytic route, biological methanation has been developed where microorganisms perform the catalytical work. The main advantages include higher tolerance for impurities, high methane purity in the outlet, and higher flexibility to deal with load fluctuations compared to the thermocatalytic route[17]. Disadvantages include the lower reaction rates and lower

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[8] Götz, Manuel, et al. "Renewable Power-to-Gas: A technological and economic review." Renewable energy 85 (2016): 1371-1390.

[9] Janke, C., et al. "Catalytic and adsorption studies for the hydrogenation of CO2 to methane." *Applied Catalysis B: Environmental* 152 (2014): 184-191.

[10] Development of methanation catalysts and process integration | Laboratory for Chemical Technology (ugent.be)

[11] Frontera, Patrizia, et al. "Supported catalysts for CO2 methanation: a review." *Catalysts* 7.2 (2017): 59.

[12] Unpublished results

[13] Middelkoop, Vesna, et al. "3D printed Ni/Al2O3 based catalysts for CO2 methanation-a comparative and operando XRD-CT study." *Journal of CO2 Utilization* 33 (2019): 478-487.

[14] Janke, C., et al. "Catalytic and adsorption studies for the hydrogenation of CO2 to methane." *Applied Catalysis B: Environmental* 152 (2014): 184-191

[15] Methanation | RNG | Catalytic methanation | Topsoe

[16] Power-to-X (man-es.com)

[17] Aneva, Sara, Dragan Minovski, and Vasilija Sarac. "POWER-TO-X TECHNOLOGIES." *ETIMA* 1.1 (2021): 105-114.

volumetric mass transfer coefficient[18]. Moreover, due to lower operating temperature, the substantial amounts of waste heat generated by the reaction will be more difficult to valorise. Although info on the precise conversion technology that will be used is often missing, from the screening of investments and associated technology suppliers in section 3.2 it appears that the thermocatalytic route is selected most often today.

Process flexibility is important to cope with fluctuations in output from renewable energy sources (solar, wind) which ultimately translate into fluctuating H_2 feed from electrolysis. For the thermocatalytic route, Gorre et al. reported that a maximum load change of 3%/min is achievable and a minimum load of 70% is required[19], although experts contacted for this report indicate that higher flexibility should be possible as well. In the case of methanol, there are already public reports that much higher flexibility is possible (see report on the methanol case study).

Whereas the type of technology used for CO_2 capture and water electrolysis in principle do not affect downstream operations (in so far sufficiently pure CO_2 and H_2 are delivered), there is a potential synergy between electrolysis and thermocatalytic methanation that can be exploited. As methanation is highly exothermic, a significant amount of steam can be generated, which can be used directly by a Solid Oxide Electrolyser (SOEC). Unlike alkaline or PEM electrolyser, a SOEC departs from steam rather than liquid water and is more energy efficient, especially if excess steam from another process is available[20]. Alternatively, the waste heat can be used for CO_2 capture or sold off to nearby industrial processes or district heating, but only if such buyers are available in the neighborhood.

Another potential way of reducing cost is to bypass the CO_2 capture step in case biogas is the CO_2 source. In literature, it has been proposed to perform methanation directly on the raw biogas (containing CO_2 and CH_4) which only has been pre-treated to remove some impurities, instead of using pure CO_2 that was captured from the raw biogas (Figure 2). This approach has also been tested by companies at pilot and demo scale, for both thermocatalytic and biological routes[21]. Economically, the main advantage of this approach is that it avoids the cost of the CO_2 capture step, while the main disadvantages are that more volumes need to be processed by the methanation reaction (increasing capital and energy cost) and that conversion levels are somewhat lower as the presence of much extra CH_4 favors the backward reaction, although the reduction of hot spot formation may mitigate this.

[18] Lecker, Bernhard, et al. "Biological hydrogen methanation–a review." *Bioresource technology* 245 (2017): 1220-1228.

[19] Gorre, Jachin, et al. "Cost benefits of optimizing hydrogen storage and methanation capacities for Power-to-Gas plants in dynamic operation." *Applied Energy* 257 (2020): 113967.

[20] ISPT (2023). Next Level Solid Oxide Electrolysis. Upscaling potential and techno-economical evaluation for 3 industrial use cases

[21] Calbry-Muzyka, Adelaide S., and Tilman J. Schildhauer. "Direct methanation of biogas—technical challenges and recent progress." *Frontiers in Energy Research* 8 (2020): 570887.

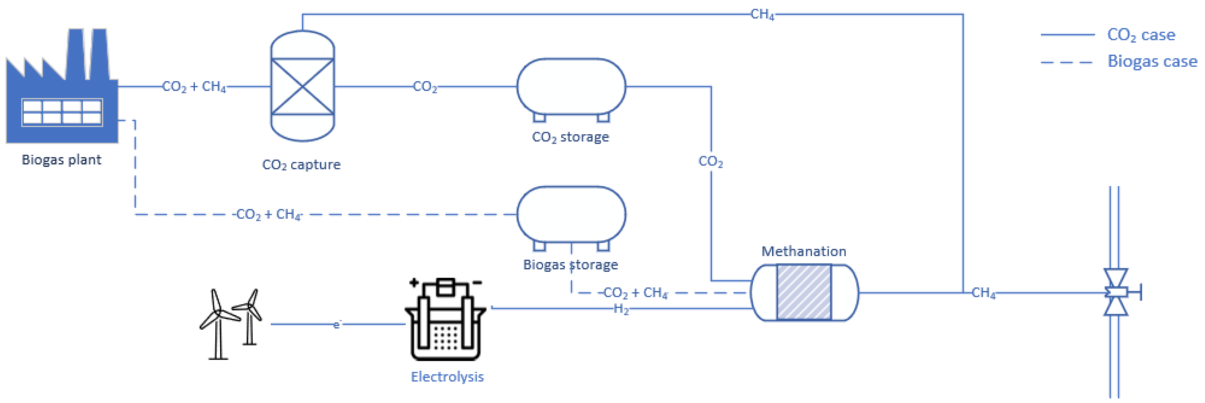

Figure 2 Different approaches to produce e-methane from CO_2 contained in biogas (source: VITO)

When the e-methane is injected in the grid, it needs to meet certain requirements both in terms of energy density as well as tolerance levels for various impurities. A selection of these for the distribution grid are listed in Table 1 (the transport grid has a different set of requirements). There are limits on the shares of CO_2 and in particular H_2, meaning that high conversion rates are necessary in the methanation reactor. Excess reactants can be dealt with by including a second reaction stage (with water removal in between, allowing for higher conversions) or by means of gas separation technologies. Especially if the constraint on hydrogen remains in force, such a second step may be necessary. Interestingly, a number of other countries allow for higher H_2 blends (e.g. 6% in France[22]). The main constraint for increased hydrogen blending lies not on the side of the grid itself, but on the application side (e.g. current CNG cars tolerate no more than 2% H_2). Consequently, Germany allows 10% H_2 injection, but not in locations where there is a CNG refueling station downstream[23]. Naturally, tolerance level for CO is very low, so catalyst selectivity needs to match this requirement. In general, tolerance for impurities is low, so e-methane needs to be brought to high quality standards. It is therefore important that also the CO_2 feed is of sufficient quality (see section 3.2), otherwise further cleaning steps are required before or after methanation.

Table 1 Selection of technical specifications for injections into the Belgian distribution gas grids[24]

Parameter	**Low calorific grid**	**High calorific grid**
Energy density	9.5-10.75 kWh/Nm3 (HHV)	10.8-12.8 kWh/Nm3 (HHV)
C_3H_8	<3%	
H_2O	< 110 mg/Nm³	
CO_2	<6% (mol)	<4% (mol)
$N_2 + CO_2$	<15% (mol)	
H_2	<2 % (mol)	
CO	<0.1% (mol)	
O_2	<1% (mol)	
H_2S	<5 mgS/m³(n)	
Total sulfur	< 20 mgS/m³(n)	

[22] M. Hervy *et al.*, "Power-to-gas: CO2 methanation in a catalytic fluidized bed reactor at demonstration scale, experimental results and simulation,", *J Co2 Util,* vol. 50, Aug 2021, doi: ARTN 101610

[23] Fluxys, "Presentation at Congres WaterstofNet," 2019. [Online]. Available: https://www.waterstofnet.eu/_asset/_public/CongresWR2019/13-Leander-Hanegreefs.pdf.

[24] Synergrid, "G8/01 Voorschrift voor decentrale gasinjectie," 2021.

(before odorization)	
Si	< 1 mg/m³(n)
NH_3	< 10 mg/m³(n)
Amine	< 10 mg/m³(n)

2.2 CO_2 input specifications

The CO_2 feed quality does not only need to be tailored to the requirements of the methanation reactor itself but also to the requirements of any downstream transport and use of the e-methane. For the former, CO_2 feed composition needs to be free of components that may adversely impact the methanation process. A key risk is catalyst poisoning, which in case of the commonly used nickel catalyst may be caused by both sulfur and silicon containing compounds, even in very small concentrations (ppb levels)[25]. To remedy this, several pre-treatment options are available (Figure 3). Another risk is carbon formation, which may impact the catalyst as well. Currently, research efforts are also being dedicated to the development of catalysts that are less sensitive to this problem[26].

In contrast, biological methanation is not sensitive to the presence of siloxans or sulfur. However, if the e-methane is to be injected in the grid, limitations on both sulfur and siloxane need to be respected (see Table 1), and a pre-treatment of the CO_2 feed may be required, nevertheless.

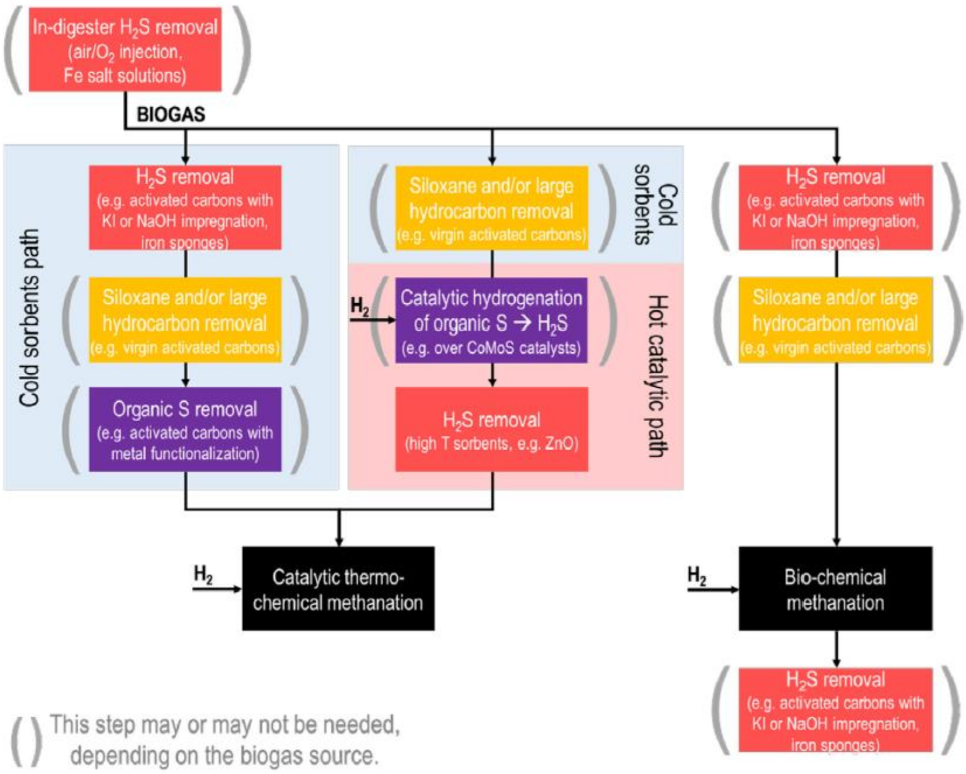

Figure 3 Overview of biogas pre-treatment requirements and suitable technologies for the purpose of e-methane production[27]

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[25] Calbry-Muzyka, Adelaide S., and Tilman J. Schildhauer. "Direct methanation of biogas—technical challenges and recent progress." *Frontiers in Energy Research* 8 (2020): 570887.

[26] Development of methanation catalysts and process integration | Laboratory for Chemical Technology

[27] Calbry-Muzyka, Adelaide S., and Tilman J. Schildhauer. "Direct methanation of biogas—technical challenges and recent progress." *Frontiers in Energy Research* 8 (2020): 570887.

3 Market aspects

3.1 Market volumes & trends

Over the past 3 decades, natural gas consumption in the EU has been surprisingly stable (Figure 4). The trend has been slightly upwards, only to fall back recently somewhat driven by the price shock caused by geopolitical events. In contrast, solid fossil fuels (i.e. coal) use has decreased very significantly. The continued coal to gas switching for power generation in several EU countries has played a role in this. The position of natural gas may be overtaken by renewable energy in the coming years if trends visible in Figure 4 continue.

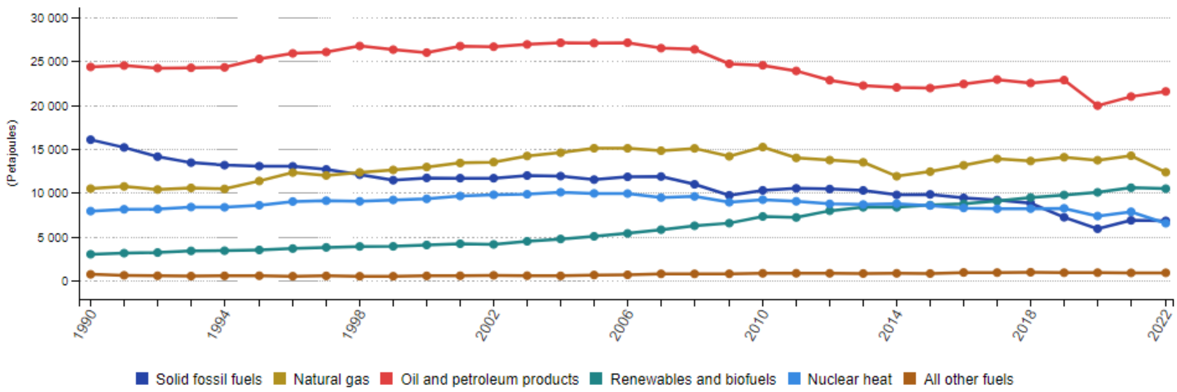

Figure 4 Gross energy consumption in the EU[28]

At the global level, natural gas use has increased strongly over the past decades, only to stabilize recently (Figure 5). The future evolution is highly uncertain and dependent on the speed of the energy transition. In the Accelerated and Net Zero scenarios, global CO_2 emissions drop by -85% and -95%, respectively, in 2050 and require a rapid decline of natural gas use after 2030 to meet these objectives. Such decreases would be driven by climate policies and the strong uptake of renewable energy. On the other hand, BP notes that in many emerging economies in Asia and Africa natural gas use is increasing due to industrialization and coal to gas switching for power production. If this effect would dominate (as captured by the New Momentum scenario), natural gas use may well increase until 2040-2050.

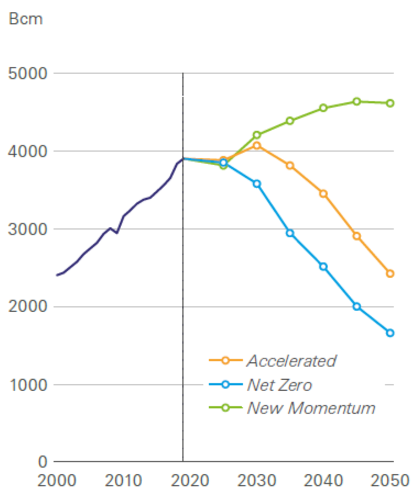

Figure 5 Global natural gas consumption: past and future projections[29]

[28] Energy statistics - an overview - Statistics Explained (europa.eu)
[29] BP Energy Outlook 2023

Due to higher cost levels, the role of renewable methane in the future energy system will be very different than the role of natural gas today. The applications will be more limited and oriented towards cases where direct electrification is not feasible or desirable. According to a recent study by the European Commission[30], the use of natural gas is expected to decline strongly by 2050 and will only partially be compensated by the deployment of renewable gases (H_2 and carbon free gases, meaning here biomethane or e-methane).

However, great variations can be observed between different scenarios (Figure 6). In the baseline scenario (continuation of agreed and expected EU policies, leading to a -65% reduction of GHG by 2050 compared to 1990 levels), the reduction of natural gas use is rather limited and there is barely any H_2 uptake expected. In the other scenarios, which achieve between 80 and 95% CO_2 reduction in 2050, the role of natural gas and renewable gases varies strongly depending on the route taken. In pathways that invest highly in energy efficiency (EE) or electrification (ELEC), natural gas use decreases strongly but the deployment of renewable gases remains moderate. In the P2X and H_2 scenarios, which foresee favorable development for renewable gases (e.g. use for heating of buildings instead of heat pumps), uptake is much larger and close to current natural gas levels. In the two scenarios' achieving -95% GHG (1.5TECH and 1.5LIFE), the uptake of both hydrogen and carbon free gases is also strong.

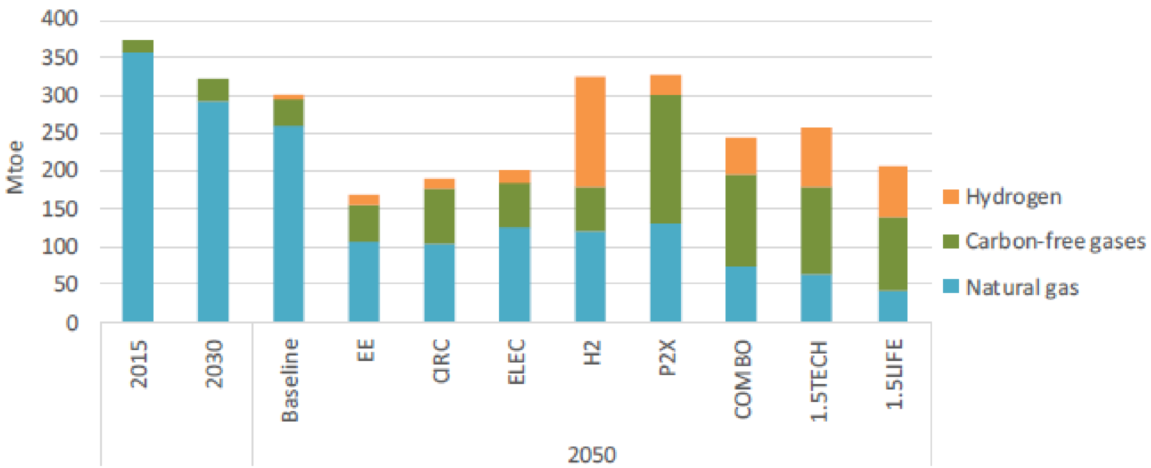

Figure 6 Use of natural and renewable gases in various scenarios.

Figure 7 provides a split of the importance of biomethane and e-methane ('e-gas'). The use of the former in future scenarios is relatively stable in different scenarios, as it is a relatively low cost energy vector that is restricted on the supply side. The use of e-methane, on the other hand, appears only in scenarios with the highest GHG ambitions (1.5TECH, 1.5LIFE, COMBO) and the one which assumes an explicit role for e-methane in buildings and transport (P2X). In other words, the large-scale deployment of e-methane is far from certain and will be dependent on both the speed of energy transition and the road taken to achieve those objectives. It should be noted that according to this study, the H_2 and P2X scenarios have the highest system cost relative to the GHG reduction they achieve.

[30] European Commission (2018). IN-DEPTH ANALYSIS IN SUPPORT OF THE COMMISSION COMMUNICATION COM(2018) 773

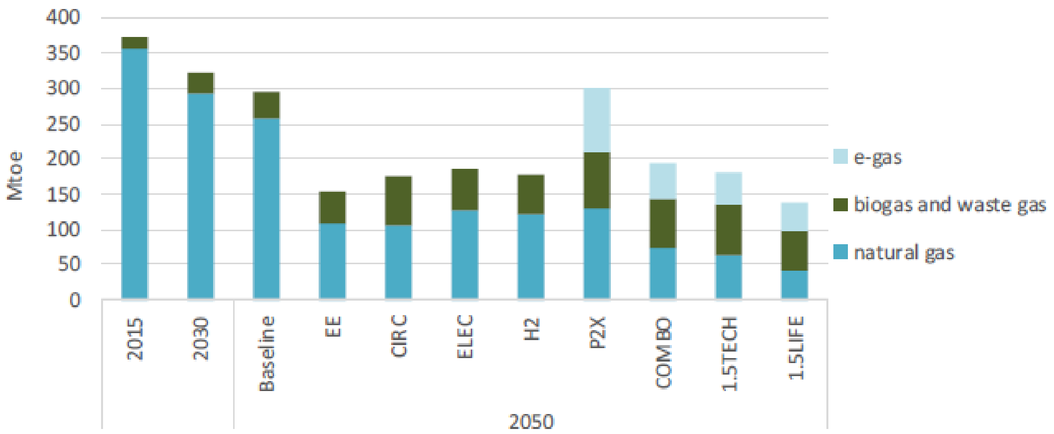

Figure 7 Use of natural and renewable gases in various scenario's, with focus on e-methane and biomethane

With a focus on Belgium, the PATHS 2050 has sought to investigate how a climate neutral country in 2050 can be achieved[31]. Here, 3 scenarios are defined: central (baseline), electrification (with a larger share of offshore wind available and an assumed breakthrough of small modular reactors (SMR)) and clean molecules (lower costs for clean molecule production and restrictions on CO_2 storage capacity). In this work, the role for H_2 in the economy grows from 2040 onwards (Figure 8). In 2050 in the central scenario, H_2 is used in industry (for high temperature heating, a role similar to biogas, as well as for ammonia and steel production) and for power generation. In buildings and transport sector, its use is very limited. Naturally in the electrification scenario (which assumes better access to local, clean power sources) the use of imported H_2 for power generation disappears. However, in the clean molecule's scenario where access to cheaper H_2 is assumed, its use increases strongly and extends towards domestic methanol production. In all cases, the use of hydrogen remains significantly below the current levels of about 170 TWh for natural gas in Belgium[32].

It is important to outline that the European Commission and Paths 2050 study differ significantly in terms of assumptions on the import of H_2. In the former, all H_2 is assumed to be produced in the EU, while in the latter import via pipeline from regions with large renewable energy availabilities is allowed. Consequently, no e-methane is produced or imported since H_2 import via pipeline is always more competitive. Only in specific cases where H_2 imports via pipeline as well as ammonia imports would be limited, e-methane imports may pick up in the TIMES model[33]. The reason is that e-methane has a cost disadvantage compared to these other energy carriers[34].

[31] Correa Laguna et al. (2023). PATHS 2050 - Scenarios towards a carbon-neutral Belgium by 2050

[32] [België bereikt zijn doelstelling om het aardgasverbruik te verminderen | FOD Economie (fgov.be)]

[33] Bilateral communication with PATHS 2050 authors

[34] Hydrogen import coalition (2021). Shipping sun and wind to Belgium is key in climate neutral economy. Final report

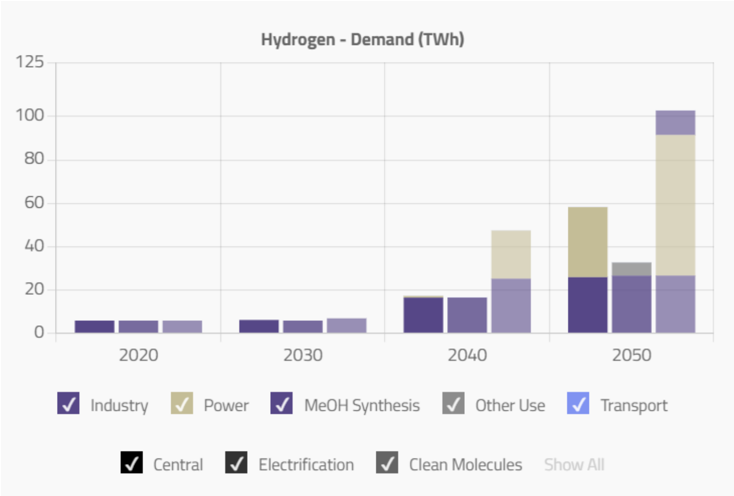

Figure 8 Hydrogen demand by application for various scenarios[35]

The company Navigant, on behalf of the Gas for Climate consortium, has developed a detailed study on the role of renewable gases in the future energy system[36]. They consider e-methane production in the EU starting from the CO_2 contained in biogas combined with flexible, local H_2 production at the biogas site. The resulting e-methane can be injected in the grid together with the biomethane that is now obtained after converting (i.e. removing) the CO_2 from biogas. In the optimized gas scenario, which has a considerably lower total system cost than the minimal gas scenario used as benchmark, about 3,300 TWh of renewable gas is deployed (Figure 9). This is very similar to the amount of natural gas used in the EU in 2022 (see Figure 4; 1 TWh= 3.6 PJ) and higher than the figures of the European Commission study. The largest part of this is supplied by green hydrogen, followed by biomethane and e-methane (referred to as power-to-methane in Figure 9). While the amount of e-methane could in theory be quite similar to the amount of biomethane (biogas typically contains 34-38% CO_2[37]), it is much lower in this simulation, mainly because demand is limited as e-methane comes at a price premium compared to other renewable gases.

The study foresees substantial use of renewable methane in all sectors, particularly in transport where liquefied methane offers a cost-effective alternative for electrification of long-distance trucking. It also maintains a gas connection for all buildings that have one today, allowing them to consume a combination of biomethane and hydrogen from the grid. As such, older houses can avoid a costly retrofit to meet insulation requirements for heat pumps. This is a key difference with e.g. the PATHS 2050 study, which does not anticipate a large role for renewable gases in those two sectors.

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[35] Hydrogen | Energy outlook (energyville.be)

[36] Terlouw, Wouter, et al. "Gas for Climate. The optimal role for gas in a net-zero emissions energy system." *Navigant Netherlands BV, März* (2019).

[37] Biogas composition (biogas-renewable-energy.info)

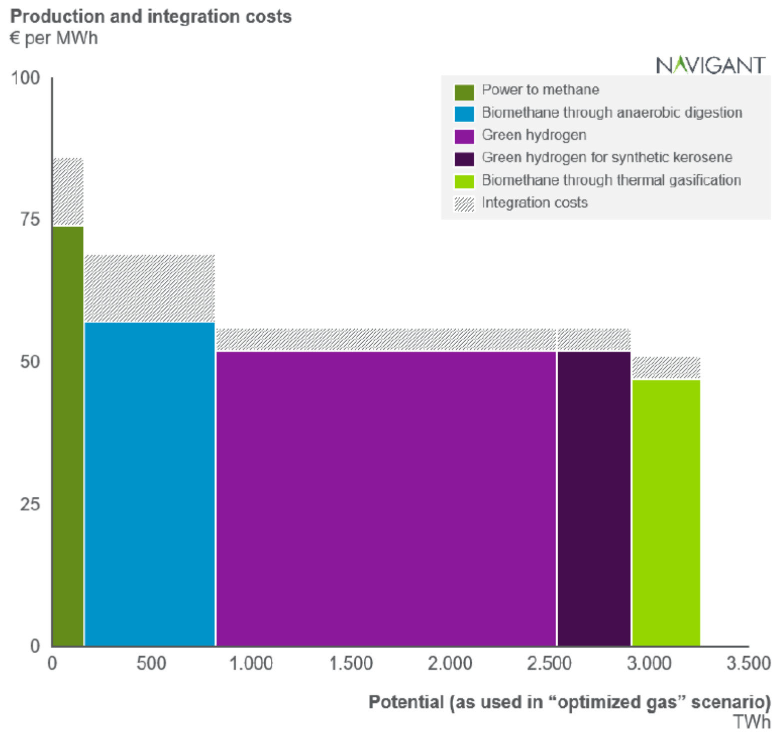

Figure 9 Simulation of the use of renewable gases in the 'optimised gas' scenario[38]. 'Power to methane' is equivalent to 'e-methane'. Green hydrogen refers to hydrogen produced via electrolysis coupled to renewable electricity.

3.2 Commercial projects and pioneers

A leading investor in e-methane projects is the Finnish company Ren-Gas, which recently was awarded support from the European Investment Bank[39]. It is developing a 550 MW portfolio of projects in Finland. The general model it pursues is to couple the methanation plant to a biomass heat and power plant (which provides a biogenic source of carbon) coupled to H_2 production driven by wind power, and to sell the excess heat generated by the process via a district heating network. This is an important point since the amount of waste heat is significant (see section 3). In terms of applications, it targets primarily heavy road and maritime transport. Similarly, a 200 MW project by Koppö Energia in Finland also targets the use of e-methane in heave transport[40]. An investment announced in France targets the conversion of biogenic CO_2 produced during sludge processing via anaerobic digestion into e-methane, using electricity from a waste-to-energy plant. This will result in the production of about 4,400 MWh per year of e-methane[41]. Partners here involve Suez, Storengy and MAN Energy Solutions.

The US company TES energy has several projects across the globe for e-methane in the pipeline, bringing renewable energy from areas with large endowments in renewable energy to areas with high energy consumption[42]. It intends to use the newly established LNG terminal in Wilhelmshaven to

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[38] Terlouw, Wouter, et al. "Gas for Climate. The optimal role for gas in a net-zero emissions energy system." *Navigant Netherlands BV, März* (2019).
[39] EIB approves Ren-Gas 230 MEUR financing framework to back its renewable e-methane projects in Finland - Ren-Gas Oy
[40] MAN Energy Solutions Wins Pre-Engineering Contract for Methanation Reactor in Power-to-X Plant (man-es.com)
[41] Storengy Chooses MAN Energy Solutions for Methanation Reactor to Produce Syngas at a French Wastewater Treatment Plant (man-es.com)
[42] Global Impact | TES H2 (tes-h2.com)

import the product to Germany. According to German law, this terminal should transition entirely to e-methane by 2044[43].

However, many e-fuel projects have difficulties to reach final investment decision. This is illustrated by the Columbus project in Belgium, which intended to convert CO_2 from lime production (which is a difficult to abate point source) into e-methane[44]. It was a relatively large project (100 MW electrolysis unit) that could avoid 187 kton/year of CO_2 emissions. To improve the business case, it would tap into several other revenue streams in addition to the sales of e-methane, namely sales of O_2 produced during electrolysis, sales of waste heat, and participation in grid balancing services market. Despite the subsidies available, the project was not deemed viable. The fact that policy targets for e-fuels in the short term are very moderate undoubtedly has played a role in this.

4 Economics

To shed light on the economics of e-methane production, a basic techno-economic assessment was conducted. A typical value chain where CO_2 is captured from a point source, hydrogen is produced via electrolysis, and these two reactants are subsequently converted into methane in a thermocatalytic unit, is considered. More concretely, CO_2 is assumed to be captured with amine technology from a dilute point source[45]. The hydrogen is produced via alkaline water electrolysis, and economic parameters are taken from the Hydrogen Observatory[46]. For methanation[47], a product yield of 95% is assumed, since high conversion and selectivity are typically feasible in the state of the art. Electricity cost is 75€/MWh and cost for general maintenance and operational cost are added as a fixed 6% of CAPEX per year.

Altogether this leads to production of around ~4000 €/t – equivalent to 260 €/MWh (*Figure 10*). This is nearly an order of magnitude higher than the prices of natural gas in the EU in 2025 (30-50 €/MWh[48], which is by itself already much higher than historical prices due to the supply interruptions following the Russo-Ukrainian conflict). Several other scholars have found a similar result [49,50]. This should come as no surprise as natural gas is a cheap commodity which is a precursor for many other chemicals, while the e-methane value chain requires more process steps and starts with a more expensive energy source. Here, the electricity cost assumed reflects an average of typical prices for large industrial consumers in the EU. These prices can also be lower when the plant is coupled to renewable energy in favorable locations in Europe (e.g. South of Spain), but then a lower utilization factor for the plant CAPEX needs to be considered. Evidently, e-methane scores better than natural gas in terms of climate footprint, and hence both products are not entirely comparable in that sense, but the cost difference indicates that spontaneous uptake of e-methane in the market is going to be low without policy support. Biomethane is another clean alternative for natural gas and generally has a lower cost than e-methane (50-90 €/MWh[51]). However, biomethane production is restricted by the amount of suitable biomass waste available.

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[43] Wilhelmshaven Green Energy Hub receives exemption from regulation | TES H2 (tes-h2.com)
[44] Columbus - Pioneer of the energy transition | Columbus (columbus-project.com)
[45] Energy consumption of 1 MWh/t, see MEA chemical absorption info sheet
[46] Levelised Cost of Hydrogen Calculator | European Hydrogen Observatory
CAPEX: 2310 €/kW_{AC}; Energy use: 52.4 kWh/kg H2; stack lifetime: 80,000 hr; stack replacement costs: 15% of CAPEX
[47] CAPEX of 1,500 €/kW_{CH4} from an industry source
[48] Dutch TTF Natural Gas Futures Pricing
[49] TREGAMBI, C. et al. *International Journal of Hydrogen Energy*, 2023, 48.96: 37594-37606.
[50] Nelissen, D. (2020). Availability and costs of liquefied bio-and synthetic methane.
[51] Terlouw, Wouter, et al. "Gas for Climate. The optimal role for gas in a net-zero emissions energy system." *Navigant Netherlands BV, März* (2019).

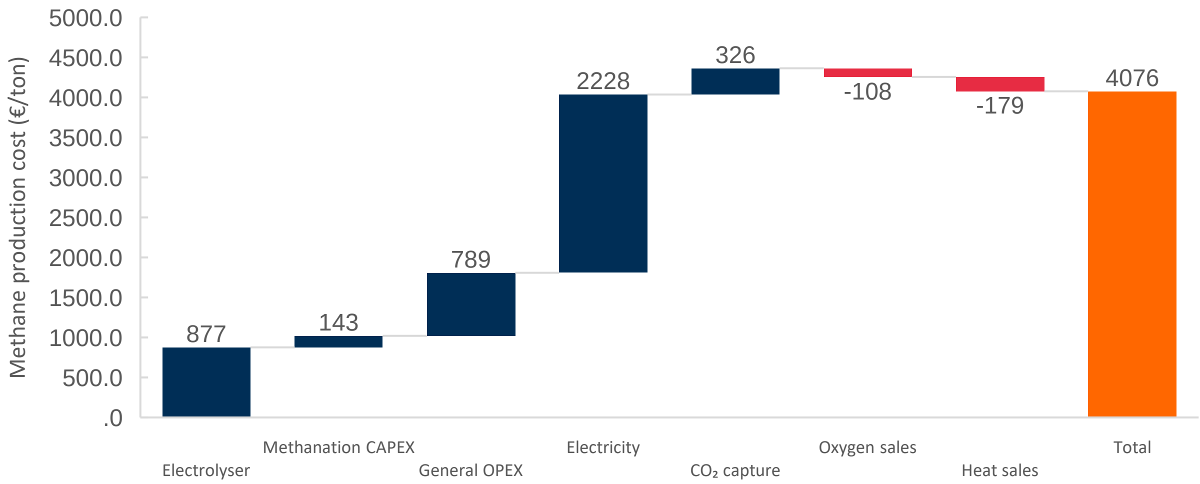

Figure 10 Cost estimate for e-methane production

The cost structure shown in *Figure 10* shows that electricity cost is the dominant cost factor, followed by the CAPEX of the water electrolysis unit. A key avenue for the future to lower this energy cost is to explore better valorisation options for the considerable amount of excess heat coming from the methanation step. In the economic model, this heat is assumed to be sold at 40 €/MWh, which provides a significant revenue stream, however the heat could also be re-used internally via for example an SOEC or the CO_2 capture step which both can take steam as input. The advantage of SOEC, apart from giving a good valorisation for the steam, is that it is also very energy efficient way of producing H_2 and may therefore be a good match for methanation processes, provided commercial roll-out proceeds and CAPEX of such systems remains acceptable.

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