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A mountain to climb?

Tracking progress in scaling up renewable gas production in Europe

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Preface

Over the past three years the Natural Gas Programme at OIES has published a number of papers on the future of gas, highlighting the need for the industry to demonstrate its ability to operate within a decarbonising energy system. This is particularly true in Europe, where policy makers have effectively signalled that gas may have a declining future beyond 2030 if it cannot play a role in meeting the EU's "net zero emissions by 2050" target. We have discussed how the gas industry might develop a narrative to meet this goal, and have described how bio-gas, bio-methane, hydrogen and synthetic gas can be part of the solution.

Having laid the conceptual and theoretical context, though, which essentially urged the industry to take active steps to show its "renewable gas" credentials, we have now decided to actively monitor what is actually happening in terms of practical activity. This report, which we have developed in co-operation with the Sustainable Gas Institute at Imperial College, shows our initial results in the form of a database of projects across the "low-carbon gas" space, and we intend to keep this updated over the coming months and years as a record of the progress that the industry is making. The report also reviews the range of targets that have been set for the potential share for renewable gas in the European energy mix by 2050, and we will continue to assess the extent of industry activity relative to these goals. We would encourage any actors with information on additional projects to make contact with us, as we believe that the database could be a useful tool in discussions between industry players and policy makers. We will also be extending the database to cover projects across the globe, as we believe that the current initiatives in Europe could well provide a catalyst for action elsewhere.

Finally, we would like to thank the Sustainable Gas Institute, and especially Gbemi Oluleye and Adam Hawkes, for their input to this report, and we look forward to continuing our cooperation with them.

James Henderson

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1. Introduction

In recent years, and particularly following agreement of specific goals at the COP21 meeting in Paris in December 2015, the global energy industry has increased its focus on decarbonisation. Against this background, both the Natural Gas Programme at OIES and the Sustainable Gas Institute at Imperial College have been conducting research relating to the future of the gas industry in a decarbonising energy system.[1]

Prior to 2015, many incumbent players in the gas industry had advocated that, since natural gas has the lowest carbon dioxide emissions among fossil fuels, it would have a role to play in a low carbon energy system, and reassurance was given that there were enough natural gas reserves to last for over 200 years.[2] As the implications of the Paris Agreement became clearer, it was realised that to be consistent with the objective of keeping global temperature rise 'well below' 2˚C, the energy system should be approaching carbon neutrality by 2050. Continuing to burn significant quantities of fossil-derived natural gas would not be consistent with the Paris Agreement.

The power generation sector has made the greatest progress in decarbonisation up to now. While actual implementation varies by country, there is a clear path forward to reduce carbon emissions from generation of electricity. After several years of subsidies, the cost of wind and photovoltaic generation has now fallen to a level where, in many situations, it is able to compete with natural gas and other fossil fuel alternatives without any government support.[3] Renewables (wind, solar, biomass) achieved a one per cent share of global primary energy supply in 2006, and by 2018 this had risen to around five per cent.[4] This rapid growth has led to some suggestions that the decarbonised energy system would be dominated by electricity, across all sectors, including transport, industry and buildings/heat. Several studies, however, have considered the feasibility and cost of various 'all electric' decarbonisation solutions in comparison with alternative 'hybrid' solutions where gaseous fuel continues to play a significant role in the energy system.[5] The consistent message from such studies has been that continuing to use existing gas infrastructure for energy storage and transmission provides a much lower cost pathway to decarbonisation than the 'all electric' alternative. However, it is also understood that gas used in such a hybrid solution will need to be decarbonised.

A number of studies have developed detailed scenarios for production of various types of renewable or low carbon gas (biomethane from anaerobic digestion, synthetic gas from gasification of biomass, power to hydrogen, power to methane or hydrogen from methane reforming with carbon captura and storage (CCS)). Specifically:

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[1] See for example: Spiers, J. et al, (July 2017). SGI. http://www.sustainablegasinstitute.org/a-greener-gas-grid/
Stern, J. (December 2017). OIES. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/12/Challenges-to-the-Future-of-Gas-unburnable-or-unaffordable-NG-125.pdf
Lambert, M. (October 2018). OIES. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2018/10/Power-to-Gas-Linking-Electricity-and-Gas-in-a-Decarbonising-World-Insight-39.pdf
Stern, J. (February 2019). OIES. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2019/02/Narratives-for-Natural-Gas-in-a-Decarbonisinf-European-Energy-Market-NG141.pdf
[2] See, for example, Shell Sustainability Report 2013: https://reports.shell.com/sustainability-report/2013/our-activities/natural-gas.html
[3] www.lse.ac.uk/GranthamInstitute/faqs/do-renewable-energy-technologies-need-government-subsidies/
[4] BP Energy Outlook 2019 edition.
[5] See, for example, Poyry, (May 2018).
https://www.poyry.com/sites/default/files/media/related_material/poyrypointofview_fullydecarbonisingeuropesenergysystemby2050.pdf
DENA, (October 2018).
https://www.dena.de/fileadmin/dena/Dokumente/Pdf/9283_dena_Study_Integrated_Energy_Transition.PDF

- in November 2018, the European Commission published 'A Clean Planet for All – A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy'.[6] This report contained multiple scenarios for consumption of renewable gaseous fuels in 2050.
- in December 2018, the European Network of Transmission System Operators for Gas and Electricity (Entsog and Entoe) published their final scenario report for the 10 year network development plan,[7] which included forecasts for renewable gas production in 2030 and 2040.
- in March 2019, the 'Gas for Climate' group of leading European Transmission System operators published a report developed by Navigant on 'The optimal role for gas in a net-zero emissions energy system'.[8] This report also contained scenarios for renewable gas production in 2050.

More details on the ambitious targets set by these studies are given in Section 2, together with our analysis of the scale up pathways which would be implied by such target scenarios.

Note that throughout this report, in the absence of agreed industry definitions, we refer to 'renewable gas' and 'low-carbon gas' to cover the various alternatives for gaseous fuels (either hydrogen or methane) which may be used in future as significantly lower carbon alternatives to fossil-derived natural gas. Many of these are not zero-carbon, particularly where the electricity used is not 100 per cent renewable, or carbon is not fully captured and stored, but they are relevant as they are steps on the pathway to eventual decarbonisation of the energy system.

SGI and OIES have been working together, with input from a range of sources and stakeholders, to build a database of current production of renewable gas, and the status of projects under development. Our objective has been to assess the extent to which specific actions being taken, principally by governments, regulators and industry investors, are consistent with being on a pathway which could reasonably be expected to reach the ambitious targets being contemplated by reports such as those listed above. We have focussed on Europe initially, which has been taking the lead on renewable gas developments, but we intend future updates to expand the scope beyond Europe.

Our concern is that while it is relatively easy to write a report with bold projections 30 years ahead, there are significant barriers to overcome if those bold projections are to be realised:

- the scale of the energy system is so large in relation to the small scale of current pilot and demonstration projects for production of renewable gas;
- there is an expectation that as levels of production increase, there will be a significant reduction in costs, but there is not yet sufficient evidence that such cost reductions are achievable;
- development of new infrastructure projects has a long lead time: a project at the feasibility study stage in 2019 is likely to be onstream around 2023 at the earliest, and more likely somewhat later;
- in the absence of greater government and regulatory certainty, it will be difficult for potential project developers to justify investing shareholder capital or raise third party finance to build the large scale plants which will be required to meet the projected production levels.

This report examines these issues in more detail.

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[6] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52018DC0773&from=EN
[7] https://www.entsog.eu/sites/default/files/entsog-migration/publications/TYNDP/2018/entsos_tyndp_2018_Final_Scenario_Report.pdf
[8] https://www.gasforclimate2050.eu/files/files/Navigant_Gas_for_Climate_The_optimal_role_for_gas_in_a_net_zero_emissions_energy_system_March_2019.pdf

2. Long term targets and implied development pathways

In recent months, several reports have been published making bold projections on the level of renewable gas production which could be achieved in Europe by 2040 or 2050. For this report, we have selected three of these reports for further analysis. These have been chosen as they have been produced with backing of key players in the European gas industry.

2.1 European Commission: A Clean Planet for all (Nov 2018)

This report,[9] subtitled 'A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy' was published in November 2018, together with a more detailed document 'In-Depth Analysis in support of the Commission Communication COM(2018) 773'.[10] The latter document contains details of eight scenarios for 2050, all of which would achieve a more than 80 per cent reduction in greenhouse gas (GHG) emissions compared to the 1990 baseline. The key features of each scenario are given in Table 1 (taken from the EU report).[11]

Table 1: EU Clean Planet for all scenarios

Long Term Strategy Options

	Electrification (ELEC)	Hydrogen (H2)	Power-to-X (P2X)	Energy Efficiency (EE)	Circular Economy (CIRC)	Combination (COMBO)	1.5°C Technical (1.5TECH)	1.5°C Sustainable Lifestyles (1.5LIFE)
Main Drivers	Electrification in all sectors	Hydrogen in industry, transport and buildings	E-fuels in industry, transport and buildings	Pursuing deep energy efficiency in all sectors	Increased resource and material efficiency	Cost-efficient combination of options from 2°C scenarios	Based on COMBO with more BECCS, CCS	Based on COMBO and CIRC with lifestyle changes
GHG target in 2050	-80% GHG (excluding sinks) ["well below 2°C" ambition]					-90% GHG (incl. sinks)	-100% GHG (incl. sinks) ["1.5°C" ambition]	
Major Common Assumptions	• Higher energy efficiency post 2030 • Deployment of sustainable, advanced biofuels • Moderate circular economy measures • Digitilisation • Market coordination for infrastructure deployment • BECCS present only post-2050 in 2°C scenarios • Significant learning by doing for low carbon technologies • Significant improvements in the efficiency of the transport system.							
Power sector	Power is nearly decarbonised by 2050. Strong penetration of RES facilitated by system optimization (demand-side response, storage, interconnections, role of prosumers). Nuclear still plays a role in the power sector and CCS deployment faces limitations.							
Industry	Electrification of processes	Use of H2 in targeted applications	Use of e-gas in targeted applications	Reducing energy demand via Energy Efficiency	Higher recycling rates, material substitution, circular measures	Combination of most Cost-efficient options from "well below 2°C" scenarios with targeted application (excluding CIRC)	COMBO but stronger	CIRC+COMBO but stronger
Buildings	Increased deployment of heat pumps	Deployment of H2 for heating	Deployment of e-gas for heating	Increased renovation rates and depth	Sustainable buildings			CIRC+COMBO but stronger
Transport sector	Faster electrification for all transport modes	H2 deployment for HDVs and some for LDVs	E-fuels deployment for all modes	Increased modal shift	Mobility as a service			• CIRC+COMBO but stronger • Alternatives to air travel
Other Drivers		H2 in gas distribution grid	E-gas in gas distribution grid				Limited enhancement natural sink	• Dietary changes • Enhancement natural sink

Source: EU Clean Planet for All, supporting analysis

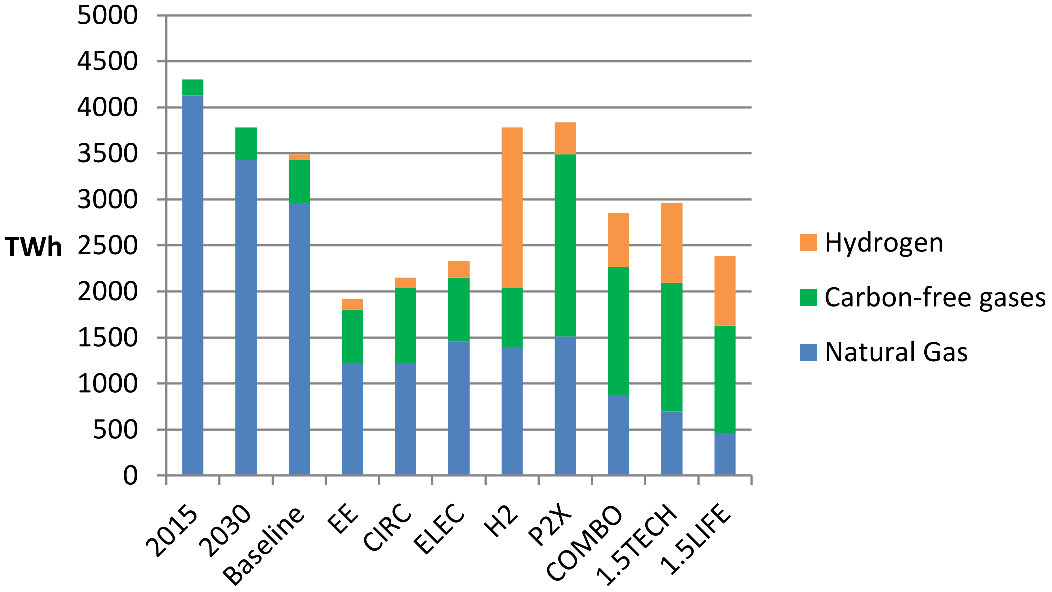
[9] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52018DC0773&from=EN
[10] https://ec.europa.eu/clima/sites/clima/files/docs/pages/com_2018_733_analysis_in_support_en_0.pdf
[11] Table 1, Page 56 in EU Clean Planet for All, supporting analysis (link at Footnote 10).

All scenarios are intended to achieve the EU target of 80 per cent reduction in GHG emissions by 2050, while the last three aim for a more ambitious 90 per cent and 100 per cent reduction of emissions. All the scenarios have the power sector being nearly fully decarbonised by 2050, so the main differences between scenarios relate to the assumptions regarding energy use in the industry, buildings and transport sectors. In particular, the ‘Hydrogen (H2)’ scenario assumes a large penetration of hydrogen in those three sectors, while ‘Power-to-X (P2X)’ assumes use of ‘e-gas’ (renewable methane) in industry and buildings and ‘e-fuels’ (liquid and gaseous fuels derived from renewable power).

The report then goes on to give detailed data for the consumption of natural gas, biogas (both biogas and biomethane), gas from waste, e-gas and hydrogen in the various scenarios.

The total consumption of gaseous fuels in the report is summarised in Figure 1. For ease of reference and consistency with other data in this paper, we have converted the data to TWh. (Note that Bcm of natural gas equivalent can be obtained by dividing TWh by a factor of approximately 10.4).

Figure 1: EU projections of 2050 consumption of gaseous fuels converted to TWh



Source: EU Clean Planet for all, supporting analysis, Figure 33, and authors’ calculations

For the analysis of required rates of scale up in the remainder of this paper, we have selected the H2, P2X and Combo scenarios, since these call for the largest quantities of carbon-free gases by 2050. Note that all scenarios show natural gas (the fossil fuel) consumption at one third or less of its 2015 level. The H2 and P2X scenarios envisage total demand for gaseous fuels in 2050 being of a similar order of magnitude to current levels (in the range 3500 to 4500 TWh per year), but requiring over 2000 TWh of renewable gas, compared with less than 50 TWh of renewable gas production today.

2.2 Entsog/Enstoe: Ten Year Network Development Plan (2018)

Every two years the European Network of Transmission System Operators for Gas (ENTSOG), and its sister organisation for electricity, ENTSOE, are required by the European regulator to issue a Ten Year Network Development Plan (TYNDP). The latest TYNDP was produced in 2018, with the Final Scenario report containing details of possible European energy futures up to 2040 being released in December 2018.[12] This report covers three scenarios: Sustainable Transition, Global Climate Action

[12] https://www.entsog.eu/sites/default/files/entsog-migration/publications/TYNDP/2018/entsos_tyndp_2018_Final_Scenario_Report.pdf

(GCA) and Distributed Generation (DG). Of the three, the first is not assessed to be on track to meet the EU 2050 decarbonisation target, but the last two are. For that reason, this paper focuses on the GCA and DG scenarios. As supporting documentation, the TYNDP also contains detailed spreadsheets with volumes of biomethane on an annual basis up to 2040 and snapshots for Power-to Gas (P2G) in 2030 and 2040.

The levels of biomethane production under each scenario are shown in Figure 2, and the levels of total European P2G production (either hydrogen or synthetic methane, blended into the gas grid) under the GCA and DG scenarios are given in Table 2.

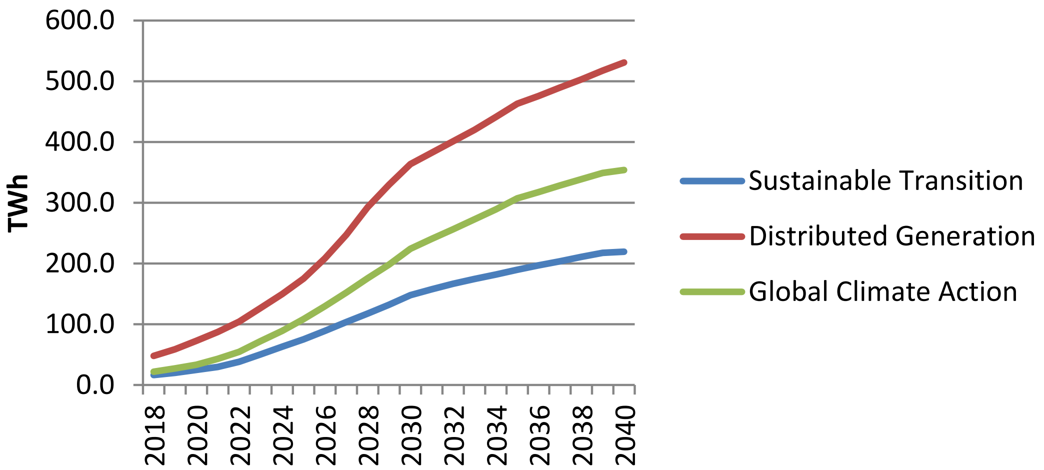
Source: ENTSOG TYNDP 2018

Table 2: Total Europe Power to Gas production under ENTSOG scenarios

TWh	2030	2040
Global Climate Action	13.91	95.06
Distributed Generation	5.92	47.79

Source: ENTSOG TYNDP 2018

Figure 2: Total Europe biomethane production under ENTSOG scenarios



Source: ENTSOG TYNDP 2018

Table 2: Total Europe Power to Gas production under ENTSOG scenarios

TWh	2030	2040
Global Climate Action	13.91	95.06
Distributed Generation	5.92	47.79

Source: ENTSOG TYNDP 2018

2.3 Navigant: Gas for Climate. The optimal role for gas in a net-zero emissions energy system

A group of seven European gas transport companies (Enagás, Fluxys, Gasunie, GRTgaz, Open Grid Europe, Snam and Teréga), plus the European and Italian biogas associations, have together formed the ‘Gas for Climate: a path to 2050’ group.[13] The group contracted the consultants, Ecofys, to produce an initial report published in March 2018.[14] The same consultants, rebranded as Navigant, produced a more comprehensive updated report which was published in March 2019.[15]

[13] https://www.gasforclimate2050.eu/who-we-are

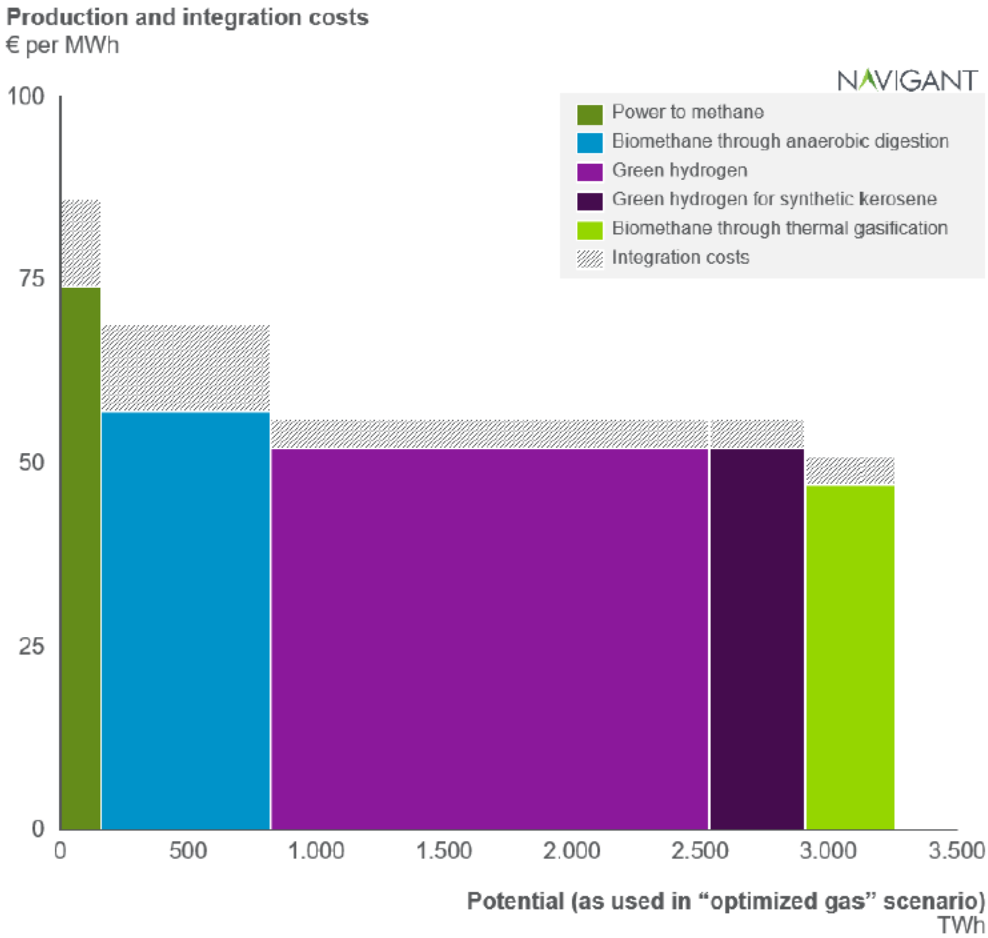
[14] https://gasforclimate2050.eu/files/files/Ecofys_Gas_for_Climate_Report_Study_March18.pdf

[15] https://www.gasforclimate2050.eu/files/files/Navigant_Gas_for_Climate_The_optimal_role_for_gas_in_a_net_zero_emissions_energy_system_March_2019.pdf

The report compared two pathways, 'minimal gas' (where electricity dominated the path to decarbonisation) and 'optimised gas' (which envisaged continued use of gas infrastructure) both of which would arrive at a net-zero emissions EU energy system by 2050. It concluded that the 'optimised gas' scenario would save society €217 billion annually by 2050 compared with the 'minimal gas scenario'. The levels of renewable gas production required by the optimal gas scenario by 2050 total 1170 TWh of renewable methane and 1710 TWh of renewable hydrogen. The split of that volume across different pathways and the projected unit production costs are shown in Source:.

It should be noted that for 'green' hydrogen production (manufactured via electrolysis using renewable electricity), the study assessed that, in 2050, only about 200 TWh would be produced using surplus electricity production resulting from fluctuations in grid demand, with over 1,500 TWh being produced using dedicated renewable electricity generation (offshore wind farms or solar farms specifically built to provide electricity for electrolysis).

Figure 3: Navigant report: 2050 production volumes and cost projections



Source: Navigant, Gas for Climate March 2019

2.4 Comparison of renewable gas production levels envisaged in these studies

The current (2019) level of renewable gas production is small. While consistent, reliable and up to date data is not readily available, total EU biomethane production for grid injection is estimated to be around 20 TWh[16] and current power to methane and green hydrogen production is negligible.

[16] According to EBA Statistical review 2018, total biomethane production in 2017 was 19.4 TWh.

Table 3: Total Europe production in 2030 and 2050 under selected scenarios (TWh)

TWh	2030	2050
Navigant Opt Gas Power to Methane		160
EUCP4A Combo Power to Methane		581
EUCP4A P2X Power to Methane		1047
ENTSOG GCA Power to Methane	14	
Navigant Opt Gas Biomethane		660
EUCP4A Combo Biomethane	349	814
EUCP4A Combo Biomethane	349	930
ENTSOG GCA Biomethane	224	

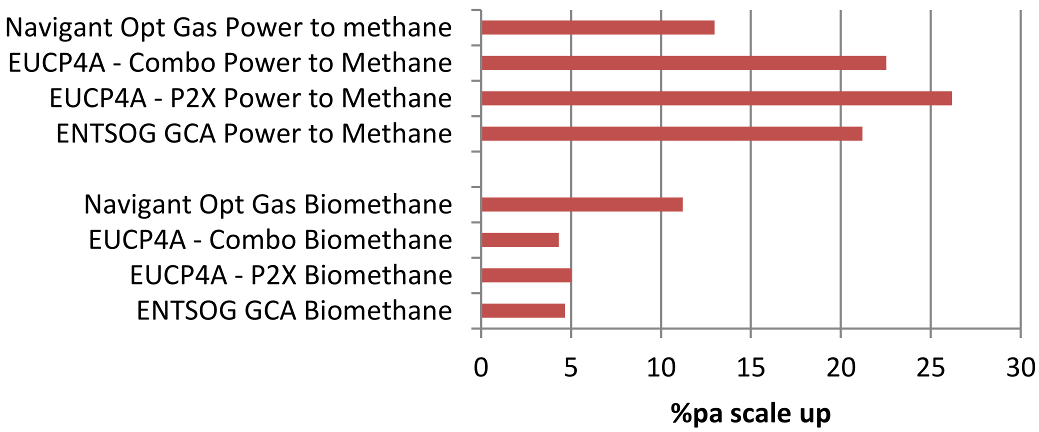
Source: Authors' analysis of stated sources

Table 3 summarises the 2030 and 2050 targets under selected scenarios, and Figure 4 shows the calculated annual average percentage increase in renewable gas production which is contemplated by the various scenarios described above. It can be seen that the required level of scale up, in some cases requires well over 20 per cent per annum increases sustained over many years. This is likely to be challenging to achieve.

Some comfort can perhaps be drawn from looking at the rate of increase of solar and wind power generation over the 10 year period from 2007 to 2017.[17] Over that period, total EU solar power generation increased from 3.8 TWh to 119.7 TWh, an average annual increase of 41 per cent. At the same time, total EU wind power generation increased from 104.4 TWh to 362.2 TWh, an average annual increase of 13.2 per cent.

These historic increases in renewable power generation are clearly significant, but were achieved with the help of strongly supportive government policy, for example feed-in tariffs and other subsidies for renewable power generation. The following sections consider whether the level of activity of project development, and the actions being taken by governments and industry players, in both the public and private sectors, appear to be consistent with renewable gas production being able to achieve a similar trajectory of scale-up.

Figure 4: Per cent per annum average annual scale up by scenario



Source: Authors' analysis of stated sources

[17] Data taken from BP Statistical Review of World Energy 2018 (June 2018).

3. Renewable gas (biomethane, renewable methane and hydrogen) database

With input from a range of sources, OIES and SGI has built a database of over 550 actual European projects for biomethane, hydrogen and renewable methane injection into the gas grid. The database includes projects which are operational, under construction and at various phases of development. The review was performed based on several references.[18,19,20,21,22,23,24]. The Appendix gives the list of names and locations of projects in the current database. Our intention is to update the database as more information becomes available.

3.1 Biomethane

The split of biomethane for grid injection projects by country in the EU is shown in Figure 5. Overall the database contains 497 operational biomethane projects (Figure 6b). Most of the projects are located in Germany (46 per cent), 20 per cent in the UK and 7 per cent in France and Switzerland. The total feed-in capacity of biomethane from these plants is approximately 240,400 m^3/h (Figure 6a) – by comparison, 236,000 m^3/h is reported in literature.[25] The biogas plant availability (in terms of operational hours per year (h/yr) is a key parameter in calculating the annual production potential. It has been proven that upgrading plants achieve technical availability up to the 96 per cent[26] equivalent to 8,410 h/yr. The resulting annual nominal potential for biomethane can be estimated as 2.02 billion m^3/yr (Bcm), equivalent to 21 TWh or 73.2 PJ (calculated based on higher heating value (HHV)). According to the European Biogas Association Statistical report 2018,[27] total biomethane production in Europe grew from 0.08 Bcm in 2011 to 0.93 Bcm in 2013 and to 1.94 Bcm in 2017. The 1.94 Bcm (20 TWh) is remarkably close to the 2.02 Bcm (21 TWh) calculated above, indicating that biomethane plants are operating at high capacity factors in excess of 90 per cent.

Between 2013 and 2017 biomethane production grew at an average annual rate of 20 per cent, so if growth were to continue at this rate the scenarios considered in Section 2 could be achieved. However, as shown in Figure 6(a), the increase in capacity was on a downward trend in 2016 and 2017 on account of changes in regulatory incentives. We await with interest the growth rates for 2018 and 2019 when these become available.

[18] European Power to Gas Platform, Online. Available at 〈http://europeanpowertogas.com

[19] HyDeploy at Keele University Online, available at https://hydeploy.co.uk/〉

[20] Engie, Website: The GRHYD demonstration project - ENGIE, Online, available at https://www.engie.com/en/innovation-energy-transition/digital-control-energy-efficiency/power-to-gas/the-grhyd-demonstration-project/

[21] Quarton, C. and Samsatli, S. (2018). Power-to-gas for injection into the gas grid: What can we learn from real-life projects, economic assessments and systems modelling? *Science Direct,* Renewable and Sustainable Energy Reviews, 98, 302-316.

[22] Sadler, D., Cargill, A., Crowther, M., Rennie, A., Watt, J., Burton, S. and Haines, M. H21 Leeds City Gate. (2016). URL: http://www.northerngasnetworks. co.uk/document/h21-leedscity-gate/

[23] International Energy Agency (IEA), Hydrogen Production & Distribution. (2007). IEA.

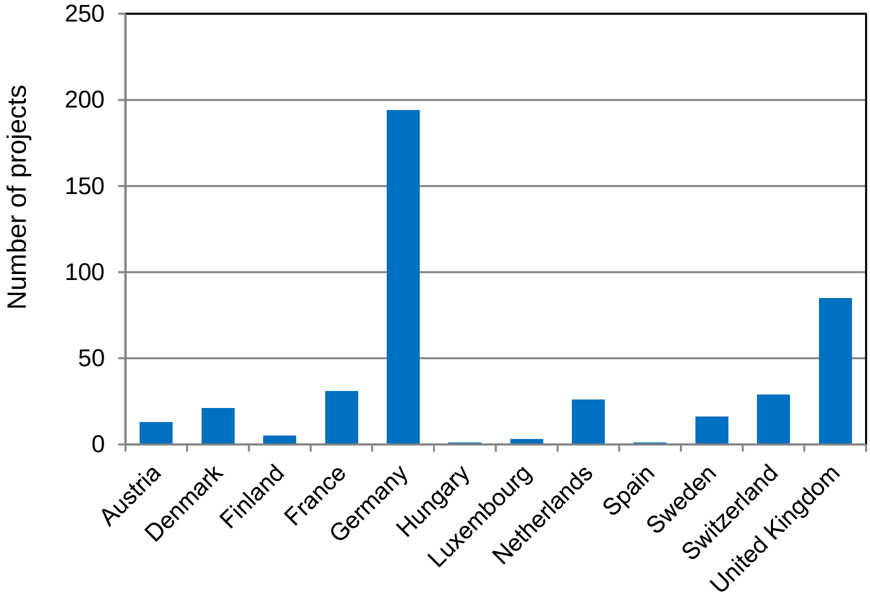
[24] H21 NOE (2018): H21 North of England, November 2018. https://www.northerngasnetworks.co.uk/event/h21-launches-national/

[25] Prussi, M., Padella, M., Conton, M., Postma, E. and Lonza, L. (2019). Review of technologies for biomethane production and assessment of EU transport share in 2030. ScienceDirect, *Journal of Cleaner Production*, 222, 565-572.

[26] Bauer F., Hulteberg C., Persson T., Tamm D. (2013). Biogas Upgrading-Review of Commercial Technologies. SGC Rapport 270. Svenskt Gastekniskt Center AB.

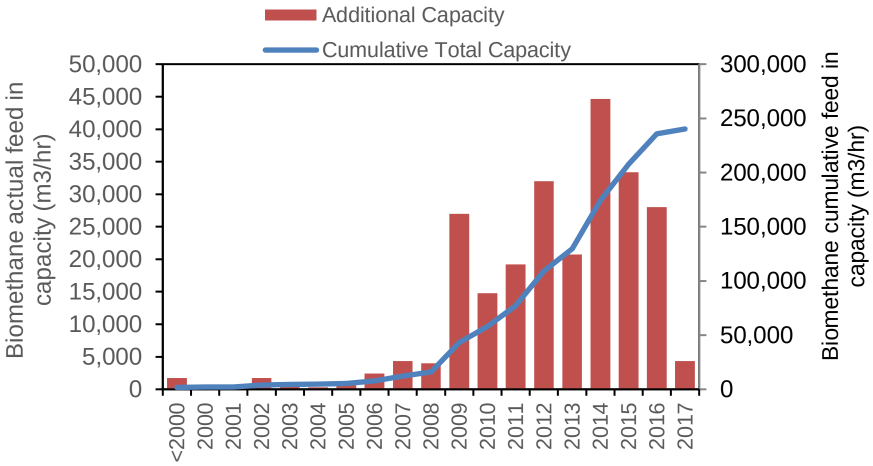
[27] http://european-biogas.eu/wp-content/uploads/2019/05/EBA_report2018_abriged_A4_vers12_220519_RZweb.pdf

Figure 5: Biomethane for grid injection projects in Europe



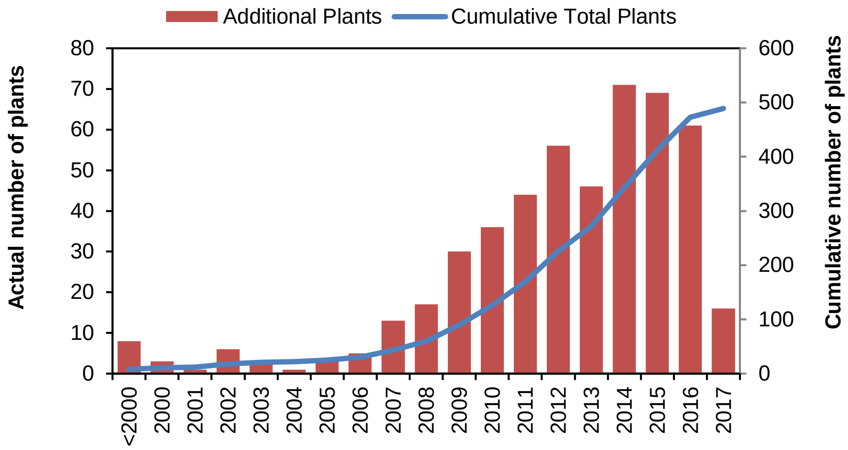
Source: Authors' analysis

Figure 6: (a) Biomethane feed in capacity



Source: Authors' analysis

Figure 6: (b) Associated number of plants (the average capacity growth is 6.88 %, the max is 21% and minimum 1.2%)



Source: Authors' analysis

Various techniques are available to upgrade biogas to biomethane. These techniques include physical and chemical absorption, adsorption, membrane and cryogenic separation.[28] The most common technology applied in the EU in terms of number of plants is chemical scrubbing (Table 4); however, 22 per cent of biogas produced is from water scrubbing (Figure 7). Cryogenic separation only occurs in one plant located in the Netherlands (Table 4).

Biomass gasification is another technology for efficient utilization of biomass. Compared to anaerobic digestion, the claimed advantage of biomass gasification is its ability to produce biomethane on a large scale.[27] However, as shown in Table 4, very few plants have successfully demonstrated biomethane production via gasification.

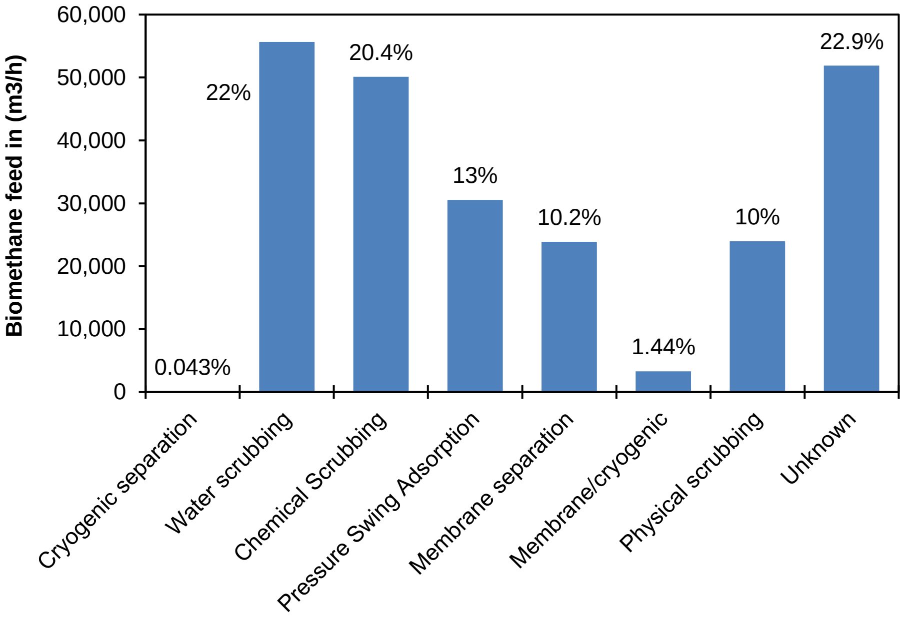
[28] Li, H., Mehmood, D., Thorin, E. and Yu, Z. (2017). Biomethane Production Via Anaerobic Digestion and Biomass Gasification. ScienceDirect, *Energy Procedia*, 105, 1172-1177.

Table 4: Breakdown of biomethane production routes (2017)

Technology type	Number of Plants	Location
Cryogenic separation	1	Netherlands
Water scrubbing	124	Germany, Denmark, Finland, France, Sweden, UK
Chemical Scrubbing	102	Austria, Denmark, Germany, Luxembourg, Netherlands, Norway, Sweden, Switzerland, UK
Pressure Swing Adsorption	68	Germany, Netherlands, Spain, Sweden, Switzerland, France, Finland and Austria
Membrane separation	82	Switzerland, United Kingdom
Membrane/cryogenic	7	UK
Physical scrubbing	37	Austria, Denmark, Germany, Luxembourg, Netherlands, Norway and Sweden
Biomass gasification	3	France, Sweden and Netherlands

Source: Authors' analysis

Figure 7: Contribution from each upgrading technology, and relative share of the total current EU feed in capacity (2017)



Source: Authors' analysis

Biomethane can be produced from various substrates (ie. feedstocks):

- 7 PJ (1.9 TWh) is from 56 plants using agricultural residues, manure and plant residues;
- 28.1 PJ (7.8 TWh) is from 168 plants using energy crops;
- 4 PJ (1.1 TWh) is from 14 plants using industrial organic waste from food and beverage industries;
- 0.5 PJ (0.1 TWh) is from 4 plants using biogas from landfill;

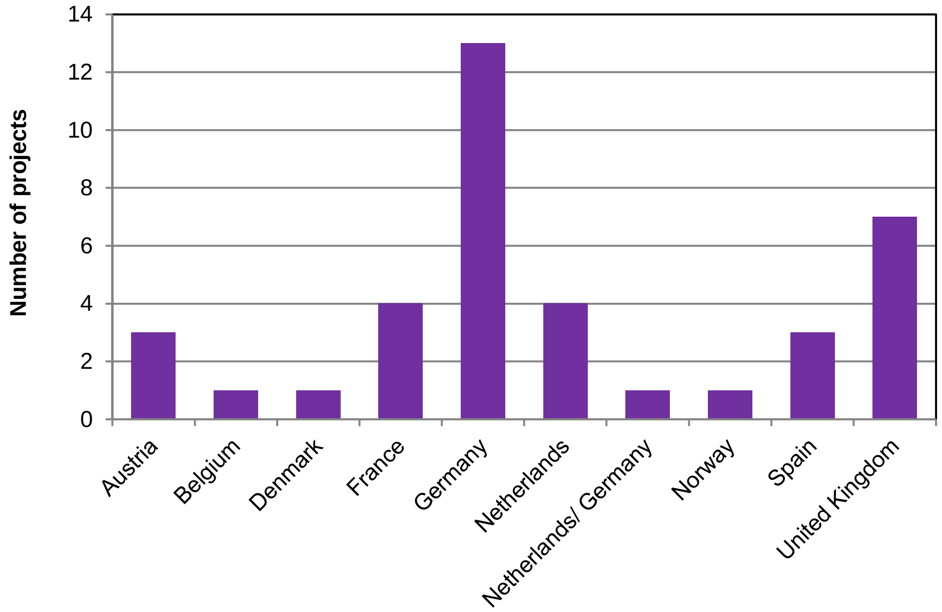
- 5.5 PJ (1.5 TWh) is from 38 plants using Municipal Solid Waste (both bio and municipal waste);
- 2 PJ (0.6 TWh) is from 31 plants using sewage sludge.

The large number of production facilities using energy crops is largely as a result of government policy support in Germany. This policy was changed in 2014 after the adverse effects of large scale production of energy crops had been realised.[29] For future growth in biomethane to be sustainable, it will need to be predominantly using waste feedstocks.

3.2 Renewable hydrogen and renewable methane (other than biomethane)

The database also contains 43 renewable hydrogen projects: 34 per cent are located in Germany, 18 per cent in the UK, 11 per cent in France and Netherlands, and 8 per cent in Austria (Figure 8). Also, 15 power to methane projects were identified in the EU – 31 per cent in Germany, and 13 per cent in both Norway and Netherlands (Figure 9).

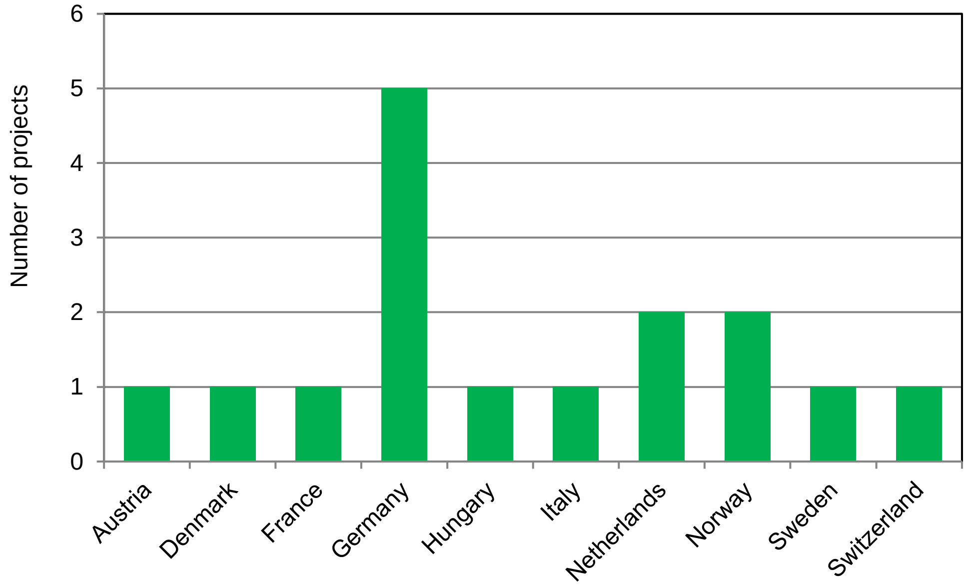
Figure 8: Hydrogen for grid injection projects in Europe



Source: Authors' analysis

[29] e.g. growth of energy crops tends to increase pressure on food production: see Appel, F. et al. (2016). 'Effects of the German Renewable Energy Act on structural change in agriculture – The case of biogas'. ScienceDirect, *Utilities Policy*, 41, 172-182. https://doi.org/10.1016/j.jup.2016.02.013

Figure 9: Renewable methane for grid injection projects in Europe



Source: Authors' analysis

Hydrogen and renewable methane (other than biomethane) can be produced using various technologies. Projects in Europe are largely dominated by power to hydrogen and power to methane (Table 4). Other hydrogen production technologies include Steam Methane Reforming (SMR) with Carbon Capture and Storage (CCS), Autothermal Reforming (ATR) with CCS, and thermal solar hydrogen plant, but there are very few projects planning to use these technologies. Note that in most cases where these projects do not use 100 per cent renewable power or they do not capture and store 100 per cent of carbon produced they are not strictly 'renewable'. However, they are relevant as demonstrations of technologies which could, in future, produce low-carbon or renewable carbon gaseous fuels.

Table 5: Hydrogen and renewable methane production pathways

Technology type	Number of Projects	Location
SMR with CCS	4	UK, France and Netherlands
ATR with CCS	1	UK
Thermal Solar Hydrogen	1	Spain
Power to hydrogen	29	Germany, UK, France, Spain, Netherlands, Austria, Norway
Power to methane	11	Germany, Switzerland, Italy, Denmark, Netherlands, Austria, Hungary

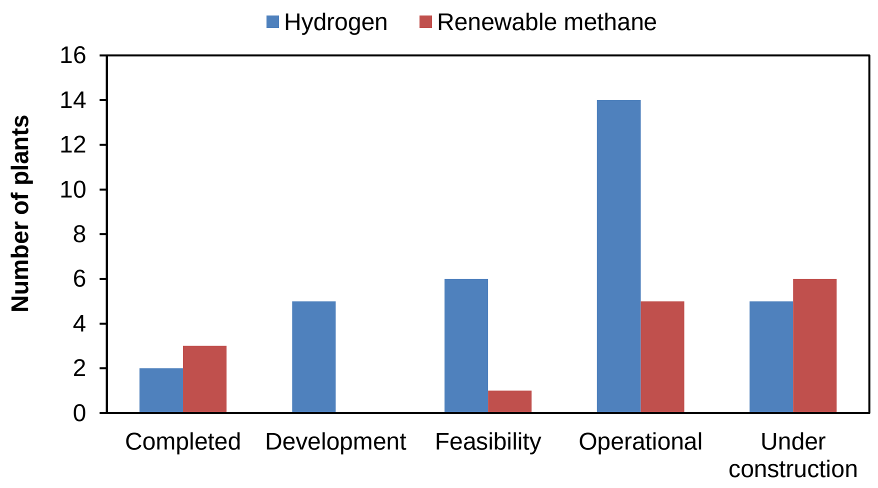
Source: Authors' analysis

Figure 10 shows the status of hydrogen and renewable methane projects at all stages of development. To explain the category descriptions used, some examples are given below:

- Completed (once operational, but now shut down or dismantled) projects: e.g. a small 7 GWh/year power to hydrogen in Germany which stopped operation in January 2013;
- Development (before final investment decision and generally more advanced than 'feasibility'): Some projects in this category include the 'Element One' 0.5 TWh/year power to hydrogen (100MW electrolyser) project in Germany, and the 'Hynet' seven TWh/year ATR with CCS project in the UK;
- Feasibility: (at an early stage of consideration, requiring considerably more work before approaching final investment decision). For example, the 'H21' approximately 100 TWh/year SMR with CCS project in the UK, and another 0.5 TWh/year power to hydrogen project in Germany.
- Operational: The database contains four operational power to methane plants, and seven operational power to hydrogen plants. (We have not included some very small power to gas plants – that is, less than one megawatt (MW) electrolyser capacity - as they are not relevant to our interest in scaling up the technology). Two of the power to methane plants are located Germany (started in 2013 and 2018 respectively). Five of the power to hydrogen plants are also located in Germany.
- Under construction: Nine plants are under construction, five of these are power to methane plants.

As discussed further below, the relatively small number of projects in the feasibility and development phase does not provide confidence that the industry is on track to meet the large scale up ambitions of the reports in Section 2.

Figure 10: Status of Hydrogen and renewable methane for grid injection projects in Europe (2019)



Source: Authors' analysis

Table 6: Associated hydrogen output capacity for projects (status in 2019)

Project Status	P2G Hydrogen output capacity (GWh/year)	SMR/ATR with CCS hydrogen output capacity (GWh/year)
Completed	8	
Development	985	
Feasibility	2,000	130,000
Operational	36	590
Under construction	28	0
Unknown	4,205	

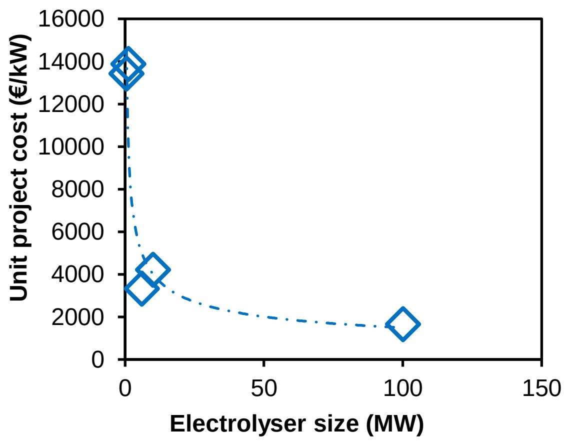
Source: Authors' analysis

Table 5 shows the intended hydrogen output quantity from the projects in the database. It can be seen that the scale of production from projects using SMR/ATR with CCS technology ('blue hydrogen') is an order of magnitude larger than P2G projects. Thus, the scale up challenge for methane reforming with CCS is less than for P2G, but it is also notable that there is only one such operational project in Europe, at Port Jerome in France (with carbon capture but not storage), supplying hydrogen to ExxonMobil's adjacent refinery, and using the captured CO2 in various food industry and industrial applications. CCS remains very controversial technology in many European countries (notably Germany, Austria and Italy).

Where available, data on total project budget was also collected. The total budget per unit of electrolyser capacity is shown in Figure 11 for power to hydrogen. Figure 11 is based on the following limited number of projects for which data is available:

- 0.5 MW electrolyser in the UK
- 1.2 MW Polymer Electrolyte Membrane (PEM) electrolyser in Denmark
- 6 MW PEM electrolyser in Austria
- 10 MW electrolyser in Germany
- 100 MW electrolyser in Germany

Figure 11: Unit project cost. The unit project cost is the ratio of the total project budget and the electrolyser capacity



Source: Authors' analysis

Figure 11 shows that cost advantages are already obtainable from increased scale. For example, the budgeted project cost associated with a 1.2 MW electrolyser is €16.6 million, 10MW electrolyser is €42.1 million and 100 MW is €66.5 million. More details on comparative costs are given in the next section.

4. Current costs and potential cost-reduction pathway if scale up progresses in line with target scenarios

A systematic review of literature considered a number of cost estimates across a range of EU countries, years and plant scales.[22,30,31,32,33] Figure 12 shows the unit cost estimates (in €/MWh)[34] for 2018 and projections for 2030 and 2050. As can be seen, the cost estimates for different techniques producing hydrogen, biomethane and renewable methane vary significantly. The unit production cost is made up of annualized investment costs, annual operation and maintenance costs (including feedstock costs) but excludes profit margin. The significant range of cost estimates is driven by the different processes and technologies used to generate these gases.

The production cost for green hydrogen depends on CAPEX for electrolyser and balance of plant, feedstock electricity costs, capacity factor expressed in full-load hours (FLH) and electrolyser system energy efficiency. Feedstock electricity costs and capacity factor are driven by the production route for electricity. For blue hydrogen, the CAPEX of both production processes consists of the H2 production plant (reactor), carbon capture installation, carbon transport infrastructure, and CO_2 storage facilities.[33,34]

Biomethane costs depends heavily on feedstocks, the lower end is when manure and agricultural residues are used and the higher end is associated with energy crops. Overall unit biomethane costs are currently estimated in the range €60-80/MWh and little further unit cost reduction is assumed, with unit costs around €50/MWh in 2050.

The average capital costs associated with hydrogen production technologies range from around €300 per kW using SMR to over €2,000 per kW using small scale electrolysis. SMR is one of the cheapest production technologies in capital cost terms, with the additional cost of CCS adding less than €100 per kW (~30 per cent) to the average capital cost. Unit costs of SMR with CCS are expected to be in the range €40-60/MWh by 2050.

[30] IEA Greenhouse gas R&D Programme Technical report. (2017). Techno-Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS. https://ieaghg.org/exco_docs/2017-02.pdf

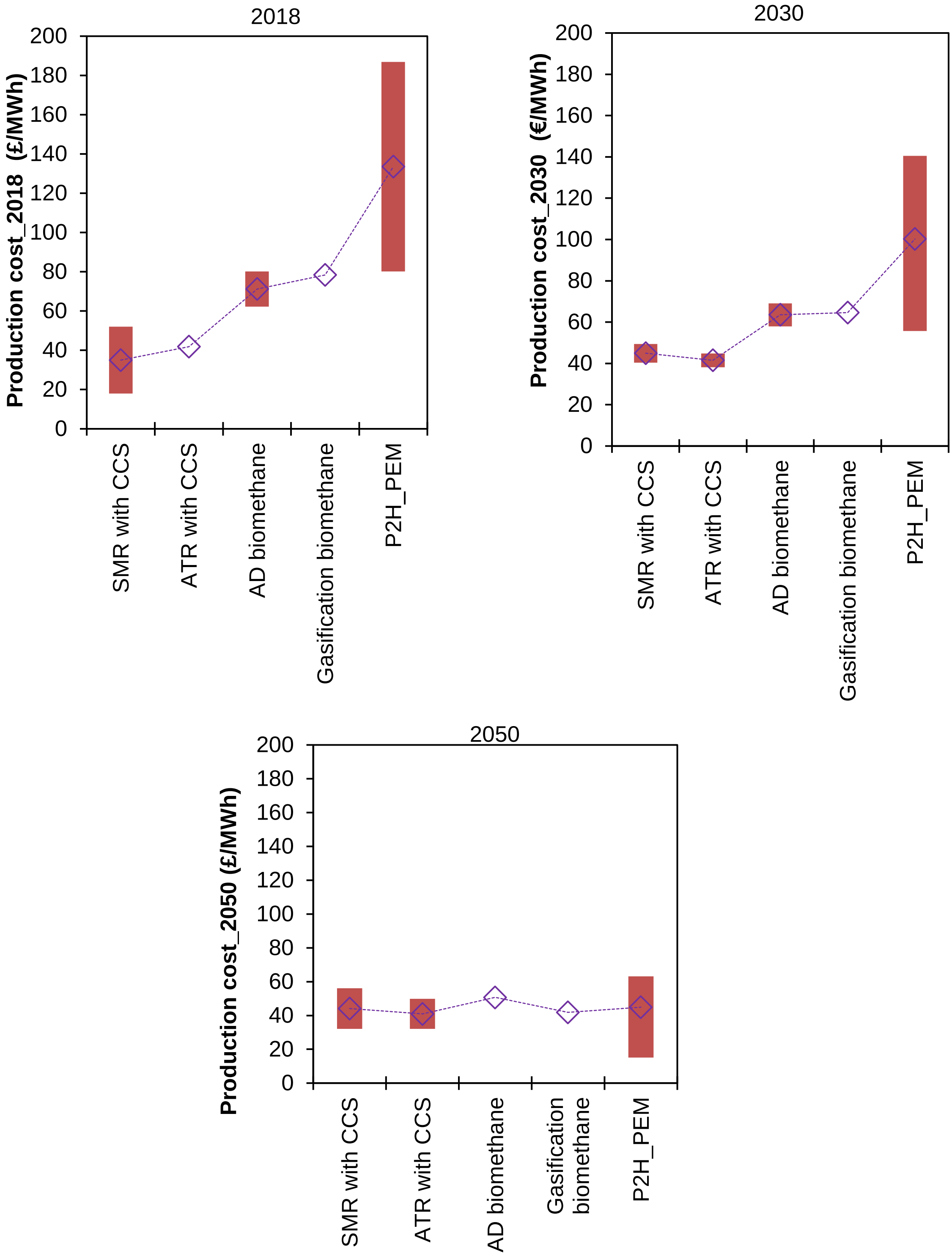
[31] Speirs, J., Balcombe, P., Johnson, E., Martin, J., Brandon, N. and Hawkes, A. (2018). ‘A greener gas grid: What are the options’. SGI, Energy Policy, 118, 291-297.

[32] NREL. (2009)., ‘Current (2009) State-of-the-Art Hydrogen Production Cost Estimate Using Water Electrolysis’.

[33] Navigant report. (2019). ‘Gas for Climate. The optimal role for gas in a net-zero emissions energy system’. https://www.gasforclimate2050.eu/files/files/Navigant_Gas_for_Climate_The_optimal_role_for_gas_in_a_net_zero_emissions_energy_system_March_2019.pdf

[34] All costs in this paper are on the basis of €/2018.

Figure 12: Renewable gas production costs in 2018, and projections for 2030 and 2050

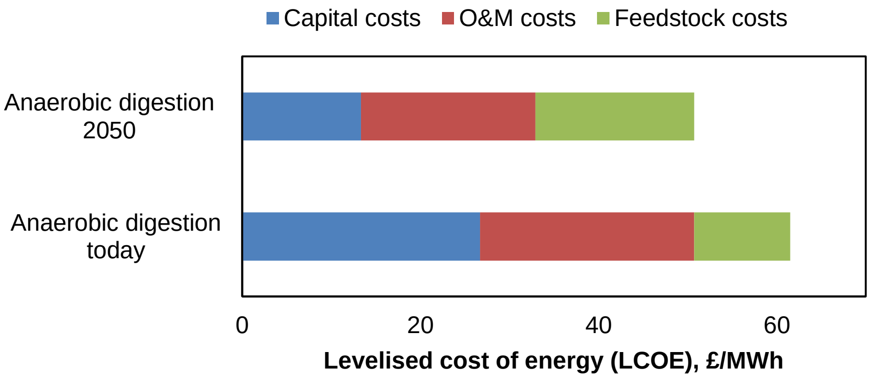


Source: Authors' analysis

According to the Navigant report, continuous deployment and technology scale up are the key factors contributing to the projected 2050 cost reduction of new technologies.[34]

- For biomethane production via gasification, plants are expected to scale up from around 3MW capacity today to around 200MW capacity (each producing 240 TWh of biomethane annually) by 2050. This scale up is predicted to reduce CAPEX by around 50 per cent and OPEX by around 40 per cent.[32] This, combined with increasing efficiency (from 65 – 75 per cent), is predicted to reduce unit costs from around €88/MWh today to around €47/MWh by 2050. The costs for 2018 are from the Gothenburg Biomass Gasification project.[35] The cost breakdown for biomethane from anaerobic digestion is provided in Figure 13.
- Cost reduction for green hydrogen is from expected technology maturity leading to reduced electrolyser system costs mainly from economies of scale, cheaper electricity, and improvements in system energy efficiency.[31-34] The Navigant report focuses on PEM electrolyser technology and assumes that system costs will reduce from €800-1000/kW today to €420/kW by 2050. Depending on the cost of electricity, this is predicted to lead to unit hydrogen production costs in the range €44-61/MWh. The cost of electricity depends on the source. The Navigant report considers four sources: curtailed electricity, dedicated production from North Sea offshore wind power, dedicated production from Southern European photovoltaic (PV) and dedicated production from Southern European hybrid sources (PV plus onshore wind power). The different sources demonstrate the impact of different capacity factors and electricity feedstock costs.
- For power-to-methane, currently investment costs for the methanation reactor are very high and there is a large uncertainty on the investment cost, mainly due to the lack of commercially deployed units. The Navigant report predicts an incremental cost of €20/MWh for conversion of green hydrogen to methane, resulting in a methane cost in the range €65-80/MWh in 2050. The Navigant report assumes 147 TWh of renewable methane produced in 2050 with 80 per cent methanation reaction efficiency. The report also assumes a specific methanation reactor CAPEX of €400/kW with a lifetime of 20 years.

Figure 13: Production costs for biomethane based on anaerobic digestion



Source: Navigant, Gas for Climate March 2019

These numbers demonstrate that there are very significant aspirations for achievable cost reductions as a result of production scale up. In reality, it is clearly very difficult to make accurate predictions of what can be achieved, underlining the importance of making significant progress on building larger capacity facilities as soon as possible. Only such real world experience can give confidence regarding achievable cost reductions.

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[35] GoBiGas 2018. Demonstration of the Production of Biomethane from Biomass via Gasification. https://www.chalmers.se/SiteCollectionDocuments/SEE/News/Popularreport_GoBiGas_results_highres.pdf

5. Benchmarking cost reduction estimates for intended development pathways

In general, increase in experience gained from manufacture and use of a technology causes specific costs to fall. It is interesting to compare the projected fall in costs for the various renewable gas technologies with the actual fall in costs for renewable power generation in recent years, as a benchmark for what might be achievable. It should, however, be recognised that the rate of decrease in renewable power generation costs (particularly solar PV) has been very rapid and faster than many had predicted.[36] There is no guarantee that renewable gas technology will be able to replicate this reduction in costs.

The fall in costs has been studied for the Solar PV module as shown in Figure 14.[37] The Learning Curve (LC) of the module was determined by the evolution of spot prices (average selling price). The LC predicts how the costs of a technology evolves based on historical trends. The LC is also referred to as the learning rate. Most of the LC from literature is close to 80 per cent, or a 20 per cent progress ratio (PR = 1–LC).[35,38] A Learning Curve of 80 per cent means the new cost of production is 80 per cent of the previous level each time the cumulative manufactured quantity doubles. Figure 14 shows learning occurs at a faster rate during the early years of deploying the module. A certain level of manufacturing maturity is reached after which doubling production quantity requires more time. Empirical evidence demonstrates that a strong correlation exists between experience and falling costs for various electricity generation technologies, with costs declining at a certain rate (called the learning rate) for each doubling of the technology's capacity.[39,40] Assuming that the learning rates observed in the past will remain stable in the future, changes in the cost of electricity generation technologies can be anticipated.

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[36] https://cleantechnica.com/2018/02/11/solar-panel-prices-continue-falling-quicker-expected-cleantechnica-exclusive/

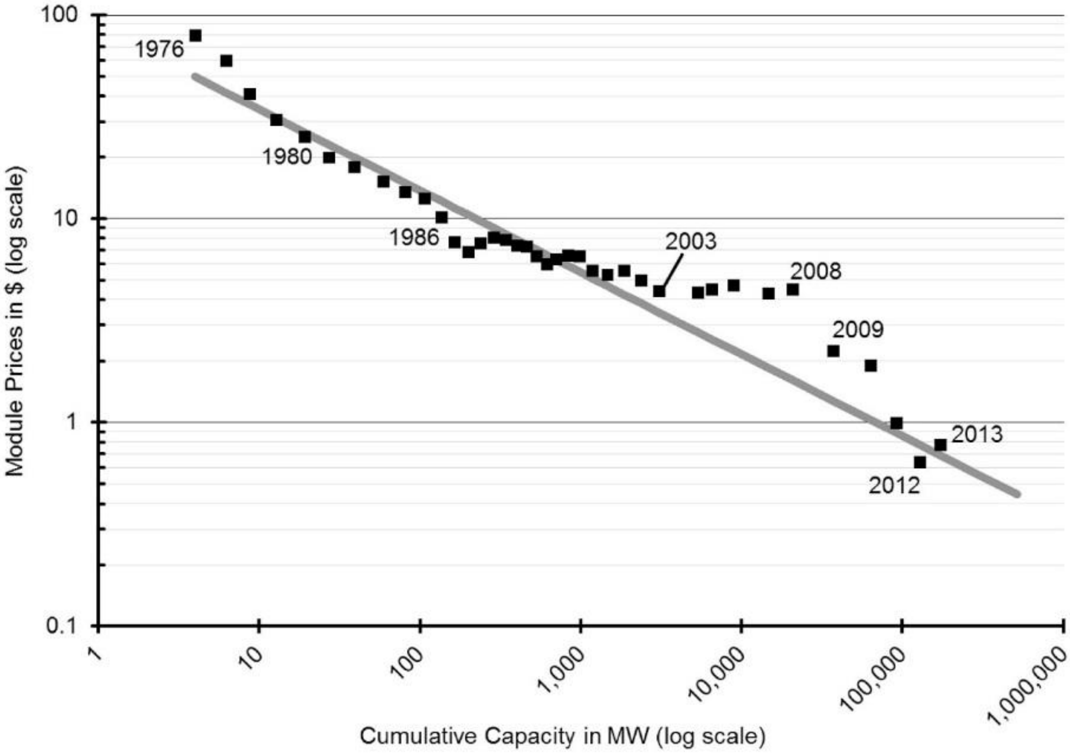
[37] Elshurafa, A., Albardi, S., Bigerna, S. and Bollino, C. (2018). 'Estimating the learning curve of solar PV balance–of–system for over 20 countries: Implications and policy recommendations'. ScienceDirect, *Journal of Cleaner Production*, 196, 122-134.

[38] Mauleón I. (2016). 'Photovoltaic learning rate estimation: issues and implications'. ScienceDirect, *Renewable and Sustainable Energy Reviews*, 65, 507-524.

[39] McDonald, A., Schrattenholzer L. (2001). 'Learning rates for energy technologies'. ScienceDirect, *Energy Policy* 29, 255-261. https://www.sciencedirect.com/science/article/pii/S0301421500001221

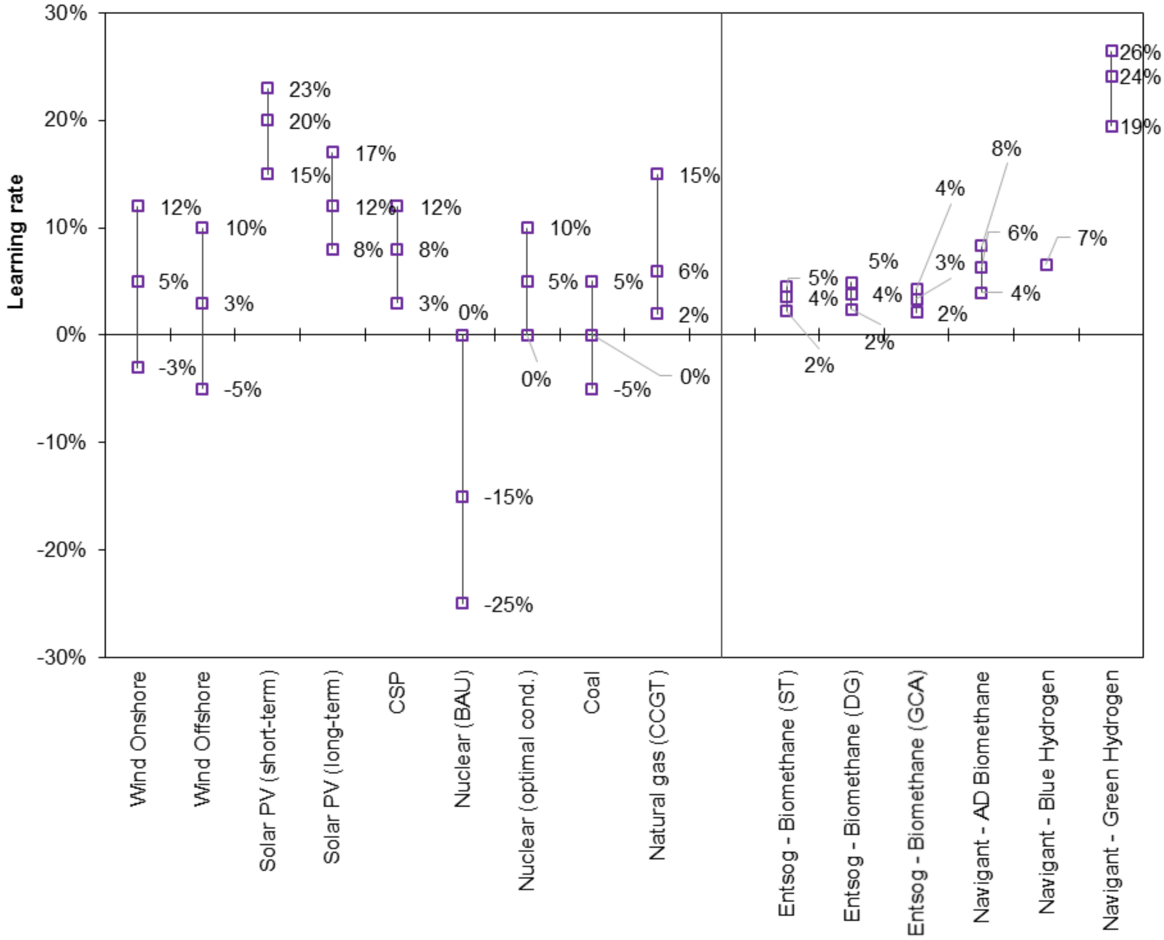
[40] Rubin, E.S., Azevedo, I.M.L., Jaramillo P., Yeh S. (2015). 'A review of learning rates for electricity supply technologies'. ScienceDirect, *Energy Policy* 86, 198-218.

Figure 14: Learning curve of the solar PV module.



Source: Data from IRENA. Showing how the solar PV cost has evolved based on historical trends. Prices are plotted against global cumulative production. Since the axes are in log-scale, the exponential decay is transformed into a linear decrease. The years are included for completeness.

Figure 15: Estimates of plausible future learning rate ranges for several important electricity generation technologies[41]



Source: Authors' own calculations for renewable gas production based on cost projections in Figure 12, and productions forecasts in Figure 1 and 2. ST – sustainable transition, DG – distributed generation, GCA – global climate action.

The learning rate for biomethane production based on three scenarios is low (4-5 per cent) as most of the components for biogas upgrade have reached commercial application. By contrast, the learning rate for green hydrogen based on the Navigant projects, in the range 19-26 per cent, is very high and even slightly higher than the historical learning rate for solar PV. Further empirical evidence from additional and larger green hydrogen projects will be required to provide confidence that such an ambitious learning rate can really be achieved. The uncertainties associated with using observed learning rates to anticipate future cost developments are one of the limitations of the experience curve concept. A comparison of the learning curve estimate and actual electricity costs for wind power showed that the learning curve estimate was outside the range of the actual cost in 2004.[42] Therefore, even though valuable insights are provided from extrapolating cost reductions over long-time frames, caution is required.

[41] Samadi, S. (2018). 'The experience curve theory and its application in the field of electricity generation technologies – A literature review'. ScienceDirect, *Renewable and Sustainable Energy Reviews*, 82, pp.2346-2364.

[42] Ferioli, F., Schoots, K. and van der Zwaan, B. (2009). 'Use and limitations of learning curves for energy technology policy: A component-learning hypothesis'. ScienceDirect, *Energy Policy*, 37(7) 2525-2535.

6. Conclusion: what more is required to be on track for each scenario?

The objective of this paper has been to analyse the growth rates and cost reductions suggested by various projections of renewable/low-carbon gas production in Europe between 2030 and 2050, and to assess the extent to which actual projects in operation or under development give confidence that such projections may be achievable.

From our analysis, we believe it is important to consider two categories of renewable/low-carbon gas separately: (a) biomethane and (b) renewable gases other than biomethane (notably hydrogen or methane from P2G and hydrogen from methane reforming with CCS[43]).

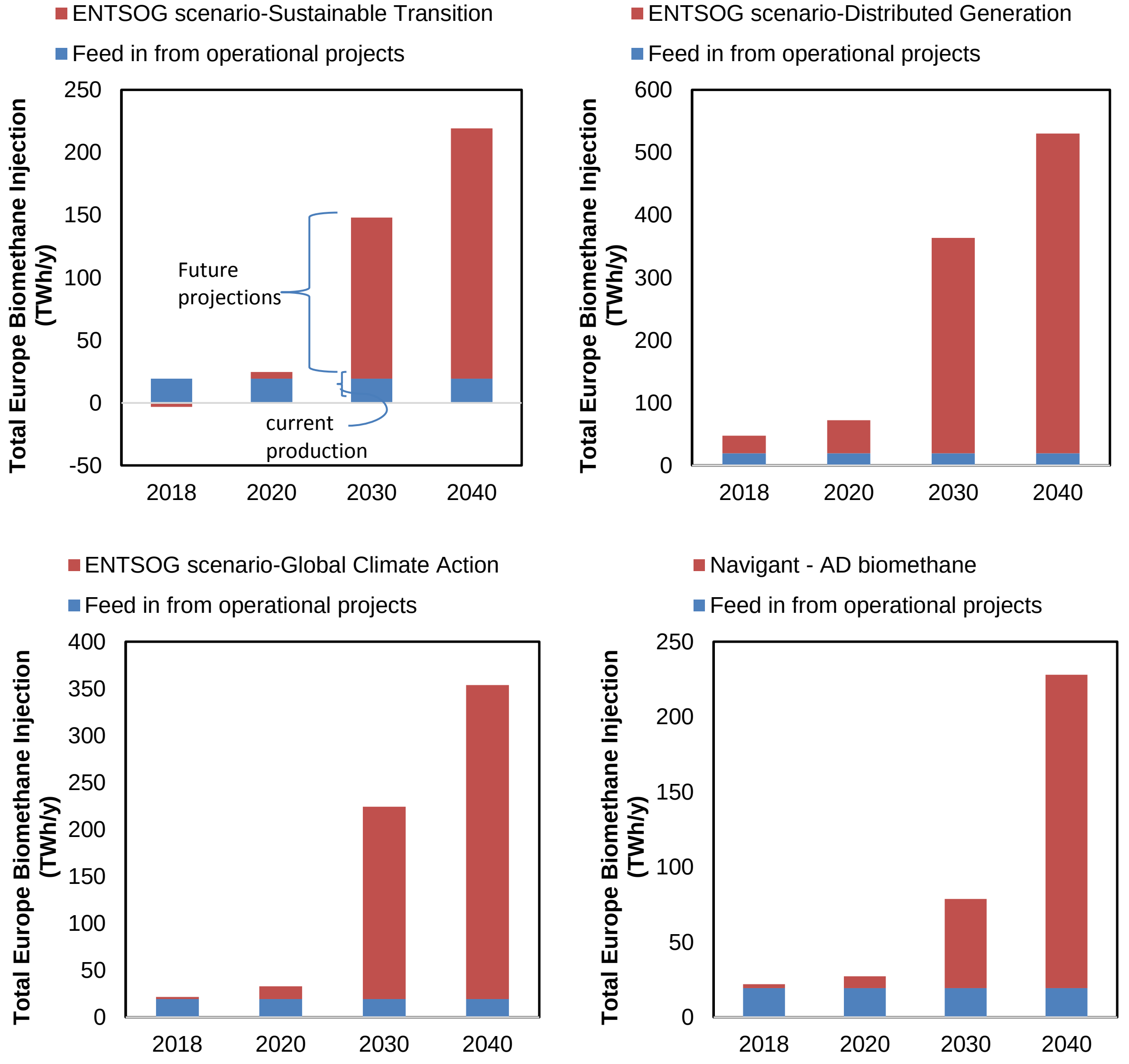
6.1 Biomethane

As noted in Section 2, the projections of biomethane production envisage growth from around 20 TWh/year currently to between 200 and 500 TWh in 2040 (as shown in Figure 19). This is very significant growth, but could be achieved with average annual growth rates in the range 5 to 15 per cent per annum. With nearly 500 biomethane plants in operation across Europe, this can be considered mature technology, although some further modest cost savings may be achievable.

Actual future growth will depend on individual investment decisions by project developers which, in turn, is dependent on government policy. However, we noted in Section 3 that average annual growth in biomethane production averaged around 20 per cent per annum between 2013 and 2017. Furthermore we noted that EU growth in solar power generation averaged 41 per cent per annum between 2007 and 2017. We have not been able to identify reliable data for all biomethane plants currently under construction or under development but, provided government policy continues to provide incentives to biomethane producers, it seems reasonable to assume that average annual growth rates in the range 5 to 15 per cent per annum are achievable. The caveat regarding government policy is important, as there is limited scope for further cost reduction of the mature production technology, so costs of biomethane production in the range €40-60/MWh are likely to remain higher than those of fossil derived natural gas (in the range €10-20/MWh). It is assumed that European government policy will continue to strive to achieve an 80 per cent or greater reduction in CO_2 emissions from 1990 levels, and thus policies will continue to support production of renewable gases.

[43] It could be argued that methane reforming with CCS is not 'renewable', but only 'low carbon' but for convenience we include methane reforming with CCS here.

Figure 16: Projections of future biomethane production under various scenarios compared with current production



Source: Authors' analysis

6.2 Renewable gases other than biomethane

While biomethane technology is relatively mature, technology for production of other renewable gas is in its infancy. Our database contains just 43 renewable hydrogen projects and 15 power to methane projects. Of those, just 10 hydrogen projects and 4 methane projects are currently operational. Total low-carbon hydrogen production capacity is just 0.6 TWh/year, of which more than 90 per cent is represented by the single SMR with carbon capture facility at Port Jerome in France (which some would argue should not be counted as renewable gas production, since the carbon dioxide is still ultimately emitted to the atmosphere). Power to Gas production capacity is less than 50 GWh (0.05 TWh). With Entsog targets envisaging between 6 and 14 TWh of P2G production by 2030, there is clearly a very significant scale up challenge. Three P2G projects under development (Hybridge and Element Eins in Germany, and Centurion in the UK) each envisage electrolyser capacity of 100MW, equivalent to potential renewable hydrogen capacity of 500 GWh/yr. These three projects are currently targeting start up around 2022 or 2023, which, if all were completed as planned would see production capacity of 1.5 TWh/yr in 2023. Achieving the Entsog target would require between about 10 and 25 similar projects to be on stream by 2030.

Drawing parallels from the experience with biomethane, with appropriate policy and regulatory support, it should be possible to achieve, or even exceed, this number of projects in a 10 year time scale. We have noted that there are relatively few P2G projects in the feasibility stage. Normal project development experience shows that only a relatively small proportion of projects at the feasibility stage eventually come on stream, so to be on track to achieve the Entsog target we would expect to see at least 20 – 30 projects of at least 100MW electrolyser capacity being actively developed in the next two to three years and additional, larger projects continually entering the ‘project funnel’.

Unit cost projections are similarly ambitious. The learning rate for green hydrogen based on the Navigant projects, in the range 19-26 per cent, is very high and even slightly higher than the historical learning rate for solar PV. Further empirical evidence from additional and larger green hydrogen projects will be required to provide confidence that such an ambitious learning rate can really be achieved.

6.3 Follow up work

Overall it is clear that collectively the gas industry (across private and public sector companies, regulators and governments) needs to accelerate the level of project activity if there is to be a reasonable chance of meeting stated production targets and unit cost reductions by 2030 and 2050.

SGI and OIES will both continue their research programmes related to the Future of Gas. For the database in particular, we intend to keep it up to date over the next few years to be able to track the extent to which actual developments are in line with stated aspirations and hence with meeting the ambitions set in Paris in 2015. We envisage that significant renewable gas developments are likely to expand beyond Europe and so will expand the scope of the database accordingly.

We encourage project developers to keep us apprised of new projects and the status of existing ones so that we can ensure that the data is as up to date and comprehensive as possible.

Appendix. List of names and locations of plants/projects included in SGI/OIES database

Project Name	Output Type	Location	Country
	Biomethane	Asten/Linz	Austria
	Biomethane	Bruck an der Leitha	Austria
	Biomethane	Engerwitzdorf	Austria
	Biomethane	Eugendorf	Austria
	Biomethane	Leoben	Austria
	Biomethane	Lustenau	Austria
	Biomethane	Margarethen am Moos	Austria
	Biomethane	Rechnitz	Austria
	Biomethane	Schlitters	Austria
	Biomethane	Steindorf/Salzburg	Austria
	Biomethane	Straß - Leibinitzerfeld	Austria
	Biomethane	Vienna Pfaffenau	Austria
	Biomethane	Wiener Neustadt	Austria
	Biomethane	Zell am See	Austria
	Biomethane	Fastranz	Austria
NGF Nature Energy Nordfyn A/S	Biomethane	Bogense	Denmark
GFE Krogenskær P/S	Biomethane	Brønderslev	Denmark
	Biomethane	Copenhagen Lynetten	Denmark
Fredericia Spildevand og Energi A/S	Biomethane	Fredericia	Denmark
Vicus B ApS - Frijsenborg Biogas	Biomethane	Hammel	Denmark
	Biomethane	Hashoj / Dalmose	Denmark
Hemmet Bioenergi ApS	Biomethane	Hemmet	Denmark
AU-vindmøller I/S	Biomethane	Hjerm	Denmark
LBT Agro K/S	Biomethane	Hjørring	Denmark
BB Biogas ApS	Biomethane	Hjørring	Denmark
Rønnovsholm v/N. K. Kirketerp	Biomethane	Hjørring	Denmark
NGF Nature Energy Holsted A/S	Biomethane	Holsted	Denmark
Horsens Bioenergi ApS	Biomethane	Horsens	Denmark
Linkogas A.M.B.A.	Biomethane	Lintrup	Denmark
	Biomethane	Midtfyn	Denmark
Rybjerg Biogas I/S	Biomethane	Roslev	Denmark
Sindal Biogas v/propr. Per Kirketerp	Biomethane	Sindal	Denmark
Madsen Bioenergi I/S	Biomethane	Skive	Denmark
Zastrow Bioenergi ApS	Biomethane	Søndersø	Denmark
NGF Nature Energy Vaarst A/S	Biomethane	Vaarst	Denmark
Sønderjysk Biogas Bevtoft A/S	Biomethane	Vojens	Denmark
Grøngas, Vraa A/S	Biomethane	Vrå 2	Denmark
	Biomethane	Espoo	Finland
	Biomethane	Forssa	Finland
	Biomethane	Haukivuori	Finland
	Biomethane	Joutsa	Finland
	Biomethane	Kouvola	Finland
	Biomethane	Lahti	Finland
	Biomethane	Laukaa	Finland
	Biomethane	Laukaa 2	Finland
	Biomethane	Mustasaari	Finland
	Biomethane	Nykarleby/Jeppo	Finland
	Biomethane	Riihimaki	Finland
	Biomethane	Virolahti	Finland
Les Longchamps	Biomethane	Andelnans	France
Ecocéa	Biomethane	Chagny	France
Gâtinais Biogaz	Biomethane	Château-Renard	France

Project Name	Output Type	Location	Country
Biogaz Meaux	Biomethane	Chauconin	France
Bioénergie de la Brie	Biomethane	Chaumes-en-Brie	France
Agrifyl	Biomethane	Chaumont	France
STEP SILA	Biomethane	Cran-Gevrier	France
Ferme de Chantemerle	Biomethane	Epaux-Bezu	France
Centrale Biogaz du Vermandois	Biomethane	Eppeville	France
Aquapole	Biomethane	Fontanil-Cornillon (Grenoble)	France
STEP Tour	Biomethane	La Riche	France
Champ Fleury	Biomethane	Liffré	France
CVO	Biomethane	Lille-Séquedin	France
Bio'Seine	Biomethane	Méry-sur-Seine	France
	Biomethane	Morsbach/Forbach	France
Agribiométhane	Biomethane	Mortagne-sur-Sèvre	France
Quimper-Vol-V	Biomethane	Quimper	France
ISDND St Florentin	Biomethane	Saint-Florentin	France
	Biomethane	Saint-Pourçain-sur-Sioule	France
Méthavos	Biomethane	Sarreguemines	France
Létang Biogaz	Biomethane	Sourdun	France
Pré du loup énergie	Biomethane	St Josse-sur-mer	France
Sioule Biogaz	Biomethane	St Pourçain-sur-Sioule	France
Biogénère	Biomethane	Strasbourg	France
TVME	Biomethane	Symevad Hénin-Beaumont	France
Panais Energie	Biomethane	Ténnelières	France
O' Terres Energie	Biomethane	Ussy-sur-Marne	France
Biovilleneuvois	Biomethane	Villeneuve-sur-Lot	France
Biogaz Pévèle	Biomethane	Wannehain	France
Méthachrist	Biomethane	Woellenheim	France
	Biomethane	Aicha (Osterhofen)	Germany
	Biomethane	Aiterhofen / Niederbayern	Germany
	Biomethane	Allendorf-Eder	Germany
	Biomethane	Altena	Germany
	Biomethane	Altenhof	Germany
	Biomethane	Alteno	Germany
	Biomethane	Altenstadt Schongau	Germany
	Biomethane	Altenstadt/Hessen	Germany
	Biomethane	Angermünde	Germany
	Biomethane	Anklam	Germany
	Biomethane	Apensen/Grundoldendorf	Germany
	Biomethane	Arnschwang	Germany
	Biomethane	Augsburg	Germany
	Biomethane	Badeleben	Germany
	Biomethane	Barby	Germany
	Biomethane	Barleben	Germany
	Biomethane	Barsikow	Germany
	Biomethane	Beerfelde	Germany
	Biomethane	Beetzendorf	Germany
	Biomethane	Bergheim/Paffendorf	Germany
	Biomethane	Berlin-Ruhleben	Germany
	Biomethane	Blankenhain	Germany
	Biomethane	Blaufelden - Emmertsbühl	Germany
	Biomethane	Brandis Waldpolenz	Germany
	Biomethane	Broistedt	Germany

Project Name	Output Type	Location	Country
	Biomethane	Bruchhausen-Vilsen	Germany
	Biomethane	Brumby	Germany
	Biomethane	Coesfeld / Höven	Germany
	Biomethane	Dannenberg	Germany
	Biomethane	Dannheim/Arnstadt/Ilmenau	Germany
	Biomethane	Dargun	Germany
	Biomethane	Darmstadt-Wixhausen	Germany
	Biomethane	Darmstadt-Wixhausen II	Germany
	Biomethane	Dessau-Roßlau (Zschornewitz?)	Germany
	Biomethane	Dorsten	Germany
	Biomethane	Drögennindorf	Germany
	Biomethane	Ebsdorfergrund	Germany
	Biomethane	Eggertshofen bei Freising	Germany
	Biomethane	Eggolsheim (Kreis Forchheim)	Germany
	Biomethane	Eich in Kallmünz	Germany
	Biomethane	Einbeck	Germany
	Biomethane	Elsteraue	Germany
	Biomethane	Eschbach/Breisgau (Heitersheim)	Germany
	Biomethane	Feldberg	Germany
	Biomethane	Forchheim im Breisgau	Germany
	Biomethane	Forst	Germany
	Biomethane	Friesoythe (Heinfelde)	Germany
	Biomethane	Fürth/Seckendorf	Germany
	Biomethane	Gardelegen	Germany
	Biomethane	Geislingen	Germany
	Biomethane	Gellersen (Kirchgellersen)	Germany
	Biomethane	Genthin	Germany
	Biomethane	Giesen	Germany
	Biomethane	Glentorf	Germany
	Biomethane	Godenstedt	Germany
	Biomethane	Gollhofen-Ippesheim	Germany
	Biomethane	Graben/Lechfeld	Germany
	Biomethane	Grabsleben	Germany
	Biomethane	Gröbern	Germany
	Biomethane	Gröden	Germany
	Biomethane	Groß Kelle / Malchow	Germany
	Biomethane	Güstrow	Germany
	Biomethane	Güterglück	Germany
	Biomethane	Hadmersleben	Germany
	Biomethane	Hage	Germany
	Biomethane	Hahnennest	Germany
	Biomethane	Haldensleben / Ohretal / Satuell	Germany
	Biomethane	Haldensleben / Ohretal / Satuelle II	Germany
	Biomethane	Halle/Westfalen	Germany
	Biomethane	Hamburg	Germany
	Biomethane	Hankensbüttel / Emmen	Germany
	Biomethane	Hardegsen	Germany
	Biomethane	Heidenau (Heidkoppel)	Germany
	Biomethane	Hellerwald / Boppard	Germany
	Biomethane	Heygendorf	Germany
	Biomethane	Hohenhameln-Mehrum	Germany
	Biomethane	Holleben	Germany

Project Name	Output Type	Location	Country
	Biomethane	Homberg/Efze	Germany
	Biomethane	Horn - Bad Meinberg	Germany
	Biomethane	Industriepark Höchst	Germany
	Biomethane	Jabel / Waren	Germany
	Biomethane	Jürgenshagen (bei Rostock)	Germany
	Biomethane	Kannawurf	Germany
	Biomethane	Karben	Germany
	Biomethane	Karft	Germany
	Biomethane	Kerpen	Germany
	Biomethane	Ketzin	Germany
	Biomethane	Kirchhain-Stausebach	Germany
	Biomethane	Kißlegg-Rahmhaus	Germany
	Biomethane	Klein Schulzendorf / Trebbin	Germany
	Biomethane	Klein Wanzleben	Germany
	Biomethane	Kleinlüder bei Fulda	Germany
	Biomethane	Koblenz	Germany
	Biomethane	Köckte	Germany
	Biomethane	Kodersdorf	Germany
	Biomethane	Könnern 1	Germany
	Biomethane	Könnern 2	Germany
	Biomethane	Kroppenstedt	Germany
	Biomethane	Lambsborn	Germany
	Biomethane	Laupheim I	Germany
	Biomethane	Laupheim II	Germany
	Biomethane	Lehma	Germany
	Biomethane	Leizen	Germany
	Biomethane	Lenzen	Germany
	Biomethane	Leuben	Germany
	Biomethane	Lichtensee	Germany
	Biomethane	Lüchow	Germany
	Biomethane	Lüdershagen / Stralsund	Germany
	Biomethane	Maihingen	Germany
	Biomethane	Malstedt	Germany
	Biomethane	Marienthal	Germany
	Biomethane	Marktoffingen	Germany
	Biomethane	Menteroda	Germany
	Biomethane	Merzig	Germany
	Biomethane	Müden (Aller)	Germany
	Biomethane	Mühlacker	Germany
	Biomethane	Neubrandenburg / Neuhardenberg	Germany
	Biomethane	Neuburg-Steinhausen	Germany
	Biomethane	Neukammer 2 (Nauen)	Germany
	Biomethane	Neuss am Niederrhein	Germany
	Biomethane	Niederndodeleben I	Germany
	Biomethane	Niederndodeleben II	Germany
	Biomethane	Niederröblingen	Germany
	Biomethane	Nonnendorf	Germany
	Biomethane	Nordhausen (Bielen)	Germany
	Biomethane	Oberriexingen	Germany
	Biomethane	Oebisfelde-Weferlingen	Germany
	Biomethane	Oebisfelde II	Germany
	Biomethane	Oschatz (Leuben)	Germany

Project Name	Output Type	Location	Country
	Biomethane	Osterby	Germany
	Biomethane	Ottersberg	Germany
	Biomethane	Palmersheim-Euskirchen	Germany
	Biomethane	Penkun	Germany
	Biomethane	Pessin	Germany
	Biomethane	Pirmasens	Germany
	Biomethane	Platten	Germany
	Biomethane	Pliening	Germany
	Biomethane	Pohlsche Heide	Germany
	Biomethane	itzwalk-Neudorf (Wolfshagen) (Neudorf-Hel	Germany
	Biomethane	Quesitz / Markransträdt	Germany
	Biomethane	Rackwitz	Germany
	Biomethane	Raitzen	Germany
	Biomethane	Ramstein	Germany
	Biomethane	Rathenow	Germany
	Biomethane	Rätzlingen	Germany
	Biomethane	Reimlingen	Germany
	Biomethane	Rhede	Germany
	Biomethane	Riedlingen-Daugendorf	Germany
	Biomethane	Röblingen am See / Stedten	Germany
	Biomethane	Ronnenberg	Germany
	Biomethane	Rosche	Germany
	Biomethane	Roßwein/Haßlau	Germany
	Biomethane	Rostock, OT Peez	Germany
	Biomethane	Sachsendorf	Germany
	Biomethane	Sagard (Rügen)	Germany
	Biomethane	Schöllnitz	Germany
	Biomethane	Schöpstal	Germany
	Biomethane	Schwandorf	Germany
	Biomethane	Schwarme	Germany
	Biomethane	Schwedt	Germany
	Biomethane	Schwedt II	Germany
	Biomethane	Schwedt (Neuer Hafen)	Germany
	Biomethane	Seelow	Germany
	Biomethane	Semd (Groß Umstadt)	Germany
	Biomethane	Sinsheim	Germany
	Biomethane	Staßfurt	Germany
	Biomethane	Straelen	Germany
	Biomethane	Stresow	Germany
	Biomethane	Tangstedt/Bützberg	Germany
	Biomethane	Thierbach	Germany
	Biomethane	Tuningen	Germany
	Biomethane	Uchte	Germany
	Biomethane	Unsleben	Germany
	Biomethane	Vehlefanz	Germany
	Biomethane	Vettin	Germany
	Biomethane	Vettweiß	Germany
	Biomethane	Weikersheim	Germany
	Biomethane	Weißenborn-Lüderode	Germany
	Biomethane	Werlte	Germany
	Biomethane	Werlte II	Germany
	Biomethane	Wetschen	Germany

Project Name	Output Type	Location	Country
	Biomethane	Willingshausen/Ransbach	Germany
	Biomethane	Wittenburg	Germany
	Biomethane	Wölfersheim	Germany
	Biomethane	Wolfshagen	Germany
	Biomethane	Wolnzach (Hallertau)	Germany
	Biomethane	Wriezen	Germany
	Biomethane	Wüsting / Hude	Germany
	Biomethane	Zerbst	Germany
	Biomethane	Zeven	Germany
	Biomethane	Zeven II	Germany
	Biomethane	Zittau	Germany
	Biomethane	Zörbig	Germany
	Biomethane	Zülpich	Germany
Sugar factory Kaposvar	Biomethane	Kaposvar	Hungary
Sewage plant Zalaegerszeg	Biomethane	Zalaegerszeg	Hungary
Súluvegur	Biomethane	Akureyri	Iceland
Alfsnes	Biomethane	Reykjavik	Iceland
	Biomethane	Este	Italy
	Biomethane	Mantova	Italy
	Biomethane	Montello	Italy
	Biomethane	Ozegna	Italy
	Biomethane	Pinerolo	Italy
	Biomethane	Roma	Italy
	Biomethane	San Giovanni Persiceto	Italy
BAKONA Sàrl	Biomethane	Itzig	Luxembourg
Naturgas Kielen	Biomethane	Kielen	Luxembourg
Minett-Kompost	Biomethane	Mondercange	Luxembourg
	Biomethane	Alphen	Netherlands
	Biomethane	Beverwijk	Netherlands
	Biomethane	Biddinghuizen	Netherlands
	Biomethane	Bunschoten-Spakenburg	Netherlands
	Biomethane	Collendoorn	Netherlands
	Biomethane	Den Bommel	Netherlands
	Biomethane	Dinteloord	Netherlands
	Biomethane	Eindhoven	Netherlands
	Biomethane	Groningen	Netherlands
	Biomethane	Hardenberg	Netherlands
	Biomethane	Middenmeer	Netherlands
	Biomethane	Mijdrecht	Netherlands
	Biomethane	Nuenen	Netherlands
	Biomethane	Port of Amsterdam	Netherlands
	Biomethane	Rijsenhout	Netherlands
	Biomethane	Spaarenwoude	Netherlands
	Biomethane	Tilburg	Netherlands
	Biomethane	Tirns	Netherlands
	Biomethane	Vierverlaten	Netherlands
	Biomethane	Waalwijk	Netherlands
	Biomethane	Well	Netherlands
	Biomethane	Weurt	Netherlands
	Biomethane	Wijster	Netherlands
	Biomethane	Wijster 2	Netherlands
	Biomethane	Witteveen (Bouwhuis)	Netherlands

Project Name	Output Type	Location	Country
	Biomethane	Zwolle	Netherlands
	Biomethane	Lillehammer	Norway
	Biomethane	Oslo	Norway
	Biomethane	Oslo/Esval	Norway
	Biomethane	Stavanger	Norway
VALDEMINGOMEZ	Biomethane	MADRID	SPAIN
Bjuv	Biomethane	Bjuv	Sweden
Svedjan	Biomethane	Boden	Sweden
Borås 1	Biomethane	Borås	Sweden
Borås 2	Biomethane	Borås 2	Sweden
Himmerfjärdsverket	Biomethane	Botkyrka	Sweden
Ekeby reningsverk	Biomethane	Eskilstuna	Sweden
Ellinge avloppsreningverk	Biomethane	Eslöv	Sweden
Falkenbergs biogas AB	Biomethane	Falkenberg	Sweden
Hulesjöns biogasanläggning	Biomethane	Falköping	Sweden
Ekogas	Biomethane	Gävle	Sweden
Göteborg/Arendal	Biomethane	Göteborg	Sweden
Gotland	Biomethane	Gotland	Sweden
Helsingborg 1 (NSR)	Biomethane	Helsingborg	Sweden
Helsingborg 2 (NSR)	Biomethane	Helsingborg	Sweden
Helsingborg 3 (NSR)	Biomethane	Helsingborg	Sweden
Helsingborg Öresundsverket	Biomethane	Helsingborg	Sweden
gr1	Biomethane	Jönköping	Sweden
gr2	Biomethane	Jönköping2	Sweden
LP-COOAB	Biomethane	Kalmar	Sweden
More Biogas	Biomethane	Kalmar	Sweden
VMAB 1	Biomethane	Karlshamn	Sweden
VMAB 2	Biomethane	Karlshamn	Sweden
Mosserud biogasanläggning	Biomethane	Karlskoga	Sweden
Karlstad	Biomethane	Karlstad	Sweden
Katrineholm	Biomethane	Katrineholm	Sweden
SBI Katrineholm AB	Biomethane	Katrineholm	Sweden
Kristianstad 1	Biomethane	Kristianstad	Sweden
Kristianstad 2	Biomethane	Kristianstad 2	Sweden
Laholm	Biomethane	Laholm	Sweden
Käppalaverket	Biomethane	Lidingö	Sweden
Lidköping	Biomethane	Lidköping	Sweden
	Biomethane	Linköping	Sweden
Linköping 2	Biomethane	Linköping	Sweden
Luleå Uddebo	Biomethane	Luleå	Sweden
Lunds Energi Biogas Källby	Biomethane	Lund	Sweden
Sjölunda	Biomethane	Malmö	Sweden
Vadsbo Biogas	Biomethane	Mariestad	Sweden
Motala	Biomethane	Motala	Sweden
Norrköping	Biomethane	Norrköping	Sweden
Örebro	Biomethane	Örebro	Sweden
Örebro	Biomethane	Örebro 2	Sweden
Gövikens reningsverk	Biomethane	Östersund	Sweden
Sävsjö biogas	Biomethane	Sävsjö	Sweden
Skellefteå	Biomethane	Skellefteå	Sweden
Skövde biogas	Biomethane	Skövde	Sweden
Södertörn	Biomethane	Södertörn	Sweden

Project Name	Output Type	Location	Country
Henriksdal 3	Biomethane	Stockholm	Sweden
Bromma 1	Biomethane	Stockholm	Sweden
Bromma 2	Biomethane	Stockholm	Sweden
Henriksdal 1	Biomethane	Stockholm	Sweden
Henriksdal 2	Biomethane	Stockholm	Sweden
Jordberga	Biomethane	Trelleborg	Sweden
Trollhättan 1	Biomethane	Trollhättan	Sweden
Trollhättan 2	Biomethane	Trollhättan 2	Sweden
Ulricehamn	Biomethane	Ulricehamn	Sweden
Uppsala vatten	Biomethane	Uppsala	Sweden
Uppsala vatten	Biomethane	Uppsala 2	Sweden
Biogas Brålanda	Biomethane	Vänersborg	Sweden
VH Biogas	Biomethane	Vårgårda	Sweden
Västerås	Biomethane	Västerås	Sweden
SBI Västerås	Biomethane	Västerås 2	Sweden
Lucerna	Biomethane	Västervik	Sweden
Reningsverket Sundet Växjö	Biomethane	Växjö	Sweden
Zuckerfabrik Aarberg	Biomethane	Aarberg	Switzerland
axpo Kompogas	Biomethane	Bachenbülach	Switzerland
ARA Bern	Biomethane	Bern	Switzerland
ARA Buchs	Biomethane	Buchs	Switzerland
STEP Penthaz	Biomethane	Cossonay	Switzerland
Emmenbrücke	Biomethane	Emmenbrücke	Switzerland
ARA	Biomethane	Frauenfeld	Switzerland
STEP Fribourg	Biomethane	Freiburg im Üechtland	Switzerland
STEP Genève	Biomethane	Genève	Switzerland
Swiss Farmer Power	Biomethane	Inwil	Switzerland
Ecorecyclage	Biomethane	Lavigny	Switzerland
STEP Martigny	Biomethane	Martigny	Switzerland
ARA Meilen	Biomethane	Meilen	Switzerland
Biorender	Biomethane	Münchwilen	Switzerland
Biopower Pratteln	Biomethane	Pratteln	Switzerland
Grossenbacher	Biomethane	Reiden	Switzerland
ARA Reinach	Biomethane	Reinach	Switzerland
Roche	Biomethane	Roche	Switzerland
ARA Romanshorn	Biomethane	Romanshorn 2	Switzerland
axpo Kompogas	Biomethane	Rümlang	Switzerland
axpo Kompogas	Biomethane	Samstagern	Switzerland
Association	Biomethane	Schönenwerd	Switzerland
Axpo-Kompogas Utzenstorf	Biomethane	Utzenstorf	Switzerland
Vétroz	Biomethane	Vétroz	Switzerland
Axpo-Kompogas Volketswil	Biomethane	Volketswil	Switzerland
ARA Wetzikon	Biomethane	Wetzikon	Switzerland
Rhy Biogas	Biomethane	Widnau	Switzerland
ARA Windisch	Biomethane	Windisch	Switzerland
Axpo-Kompogas Winterthur	Biomethane	Winterthur	Switzerland
ARA Zuchwil	Biomethane	Zuchwil	Switzerland
Biogas Zürich	Biomethane	Zürich	Switzerland
Five Fords WWTW	Biomethane	Abenbury, Marchwiel, Wrexham	United Kingdom
Ridge Road Farm, Garforth	Biomethane	Aberford - Leeds	United Kingdom
Faulkners Down Farm	Biomethane	Andover - Southampton	United Kingdom
Aspatria Creamery	Biomethane	Aspatria / Wigton - Cumbria	United Kingdom

Project Name	Output Type	Location	Country
Arla Foods Aylesbury Dairy	Biomethane	Aston Clinton -Aylesbury	United Kingdom
Strongford Sewage Treatment Works	Biomethane	Barlaston - Staffordshire	United Kingdom
North Moor Farm	Biomethane	Belton - East Yorkshire	United Kingdom
St Nicholas Court Farm, SNCF	Biomethane	Birchington - Kent	United Kingdom
Wingmoor Farm	Biomethane	Bishops Cleeve - Gloucestershire	United Kingdom
Downiehills Farm	Biomethane	Blackhills / Peterhead - Aberdeenshire	United Kingdom
Manor Farm	Biomethane	Blisworth - Northamptonshire	United Kingdom
Manor Farm	Biomethane	Bridgham - Norfolk	United Kingdom
Highwood Farm, Brinklow	Biomethane	Brinklow - Warwickshire	United Kingdom
Harpham Grange Biogas Plant	Biomethane	Buckton / Bempton - North Yorkshire	United Kingdom
East Helscott Farm	Biomethane	Bude - Cornwall	United Kingdom
Hollow Road	Biomethane	Bury Saint Edmunds - Suffolk	United Kingdom
Cannington Cold Stores Ltd	Biomethane	Cannington - Bridgwater	United Kingdom
Mepal/ Chatteris	Biomethane	Chatteris / Ely - Cambridgeshire	United Kingdom
Chittering Hollyhouse Farm	Biomethane	Chittering - Cambridge	United Kingdom
Enfield Farm	Biomethane	Clyst St Mary - Exester	United Kingdom
Former Welbeck Colliery	Biomethane	Cuckney - Nottinghamshire	United Kingdom
Energen Biogas Cumbernauld	Biomethane	Cumbernauld - Glasgow	United Kingdom
Tornagrain	Biomethane	Dalcross - Morayshire	United Kingdom
Derby Island STW Generating Station	Biomethane	Derby - Derbyshire	United Kingdom
Glenfiddich Distillery	Biomethane	Dufftown - Keith	United Kingdom
Holkham	Biomethane	Egmere - Norfolk	United Kingdom
Savock Farm	Biomethane	Ellon - Aberdeenshire	United Kingdom
Euston Estates	Biomethane	Euston / Thetford - Suffolk	United Kingdom
Raynham Farm	Biomethane	Fakenham - Norfolk	United Kingdom
Hill Farm	Biomethane	Farley Hill / Reading - Berkshire	United Kingdom
Girvan Distillery	Biomethane	Girvan -Ayrshire	United Kingdom
Glenrothes	Biomethane	Glentrothes - Fife	United Kingdom
Grindley House Farm	Biomethane	Grindley - Staffordshire	United Kingdom
Avonmouth	Biomethane	Hallen / Bristol - Somerset	United Kingdom
Court Farm	Biomethane	Hampton Bishop - Hereford	United Kingdom
Vulcan Renewables	Biomethane	Hatfield - Doncaster	United Kingdom
Hatton Farm	Biomethane	Hatton / Carnoustie - Angus	United Kingdom
Blackpits Barn, Helmdon	Biomethane	Helmdon / Brackley - Northamptonshire	United Kingdom
Icknield Farm	Biomethane	Ipsden - Oxfordshire	United Kingdom
Keithick Farm	Biomethane	Kettins - Blairgowrie	United Kingdom
Clapham Lodge/ Leeming Bar	Biomethane	Leeming - North Yorkshire	United Kingdom
Springhill Nurseries Ltd - Vale Green Energy	Biomethane	Lower Moor - Pershore	United Kingdom
Davyhulme	Biomethane	Manchester - Lancashire	United Kingdom
Rainbarrow Farm AD Plant, Poundbury	Biomethane	Martinstown - Dorset	United Kingdom
Heath Farm, Sleaford	Biomethane	Metheringham - Lincoln	United Kingdom
Methwold	Biomethane	Methwold - Norfolk	United Kingdom
Greenlight AD Plant, Teeside	Biomethane	Middlesbrough	United Kingdom
Tambowie Farm	Biomethane	Milngavie - Glasgow	United Kingdom
Mitcham	Biomethane	Mitcham - Greater London	United Kingdom
Howdon STW	Biomethane	Newcastle - Tyne and Wear	United Kingdom
Gore Cross	Biomethane	Newport - Isle of Wight	United Kingdom
Preston Road AD Plant (Waste AD)	Biomethane	Newton Aycliffe - Durham	United Kingdom
Heath Farm	Biomethane	Nocton - Lincoln	United Kingdom
Brae of Pert Farm	Biomethane	Northwaterbridge / Laurencekirk - Angus	United Kingdom
Crouchland Farm	Biomethane	Plaistow - Billingshurst	United Kingdom
Portsdown Hill 2	Biomethane	Portsdown Hill 2 - Porthsmouth	United Kingdom

Project Name	Output Type	Location	Country
Portsdown Hill 3	Biomethane	Portsdown Hill 3 - Porthsmouth	United Kingdom
Portsdown Hill 4	Biomethane	Portsdown Hill 4 - Porthsmouth	United Kingdom
Portsdown Hill 5	Biomethane	Portsmouth - Southampton	United Kingdom
Ebbsfleet Farm	Biomethane	Ramsgate - Kent	United Kingdom
Hibaldstow	Biomethane	Redbourne - Lincolnshire	United Kingdom
Adnams Brewery	Biomethane	Reydon - Suffolk	United Kingdom
Gravel Pit Farm	Biomethane	Sand Hutton - York	United Kingdom
The Maltings	Biomethane	South Milford - North Yorkshire	United Kingdom
Great Hele Farm AD farm waste	Biomethane	South Molton - Devon	United Kingdom
Frogmary Green Farm	Biomethane	South Petherton - Somerset	United Kingdom
Scampton/Spridlington	Biomethane	Spridlington / Market Rasen - Lincolnshire	United Kingdom
Charlesfield Industrial Estate	Biomethane	St. Boswells - Scottish Borders	United Kingdom
Penare Farm	Biomethane	St. Columb - Cornwall	United Kingdom
Peacehill Farm	Biomethane	St. Fort Estate - Fife	United Kingdom
Bredbury	Biomethane	Stockport -Greater Manchester	United Kingdom
Stoke Bardolph energy crop	Biomethane	Stoke Bardolph - Nottinghamshire	United Kingdom
Stoke Bardolph STW Generating Station	Biomethane	Stoke Bardolph - Nottinghamshire	United Kingdom
Roundhill STW Generating Station	Biomethane	Stourbridge - Worcestershire	United Kingdom
Minworth Generating Station	Biomethane	Sutton, Coldfield - Warwickshire	United Kingdom
Throckmorton - Vale Green 2, Rotherdale	Biomethane	Tilesford - Pershore	United Kingdom
Bearley Farm	Biomethane	Tintinhull / Yeovil - Somerset	United Kingdom
Penans Farm	Biomethane	Truro - Cornwall	United Kingdom
Widnes / Granox Biogas Plant	Biomethane	Widnes / Liverpool	United Kingdom
Willand, Cullompton	Biomethane	Willand - Cullompton	United Kingdom
Sotterly & Ellough AD plant	Biomethane	Worlingham - Suffolk	United Kingdom
Bay Farm	Biomethane	Worlington - Suffolk	United Kingdom
Fairfield Farm Energy Limited	Biomethane	Wormingford - Essex	United Kingdom
Wyke Farms Biogas	Biomethane	Wyke Champflower - Bruton	United Kingdom
YO1 4RN	Biomethane	York - Norfolk	United Kingdom
GRHYD	Hydrogen	Dunkirk	France
Gaya	Methane	st Fons, Lyon	France
Audi Werlte	Methane	Werlte	Germany
Gobigas	Methane	Gotheborg	Sweden
GrInHy	Hydrogen	Salzgitter	Germany
Helmeth	Methane		Germany
Windgas Falkenhagen	Hydrogen	Falkenhagen	Germany
Windgas Falkenhagen Phase 2	Methane	Falkenhagen	Germany
Solothurn Store&Go	Methane	Solothurn	Switzerland
Troia Store&Go	Methane	Troia	Italy
Exytron Bernsteinsee	Methane	Bernsteinsee	Germany
Exytron Augsburg	Methane	Augsburg	Germany
EnergiePark Mainz	Hydrogen	Mainz	Germany
BioCat	Methane	Avedore	Denmark
Refhyne	Hydrogen	Wesseling	Germany
Ambigo	Biomethane	Alkmaar	Netherlands
Don Quichote	Hydrogen	Halle	Belgium

Project Name	Output Type	Location	Country
Rozenburg	Methane	Rozenburg	Netherlands
RWE Power to Gas	Hydrogen	Ibbenburen	Germany
MefCO2	Hydrogen	Luenen	Germany
Hybridge (OGE / Amprion)	Hydrogen	Emsland	Germany
Element One (Tennet / Gasunie / Thyssengas	Hydrogen	Lower Saxony	Germany
H2Future	Hydrogen	Linz	Austria
Underground Sun	Methane	Pilsbach	Austria
Wind2hydrogen	Hydrogen	Auersthal	Austria
PtG Hungary	Methane		Hungary
Enertrag Windgas	Hydrogen	Prenzlau	Germany
RH2 PTG	Hydrogen	Grapsow	Germany
Wind to Gas Südermarsch	Hydrogen	Brunsbütel	Germany
Hybalance	Hydrogen	Hobro	Denmark
Windgas Reitbrook	Hydrogen	Hamburg	Germany
HyNet	Hydrogen		United Kingdom
InTEGRel	Hydrogen	Low Thornley	United Kingdom
Project Centurion	Hydrogen	Runcorn	United Kingdom
H21 North of England	Hydrogen		United Kingdom
BigHit	Hydrogen	Orkney	United Kingdom
THÜGA POWER-TO-GAS PLANT	Hydrogen	Frankfurt	Germany
Abalone Energie Nantes (F)	Hydrogen	Nantes	France
Fos-sur-Mer (F) - Jupiter 1000	Hydrogen	Fos-sur-Mer	France
Aragon (E) – ITHER	Hydrogen		Spain
Xermade (E) - Sotavento Project	Hydrogen	Xermade	Spain
Gasunie/AkzoNobel	Hydrogen	Delfzijl	Netherlands
Hystock	Hydrogen	Zuidwending	Netherlands
Demo4Grid	Hydrogen	Vols	Austria
Port Jerome SMR CCU	Hydrogen	Port Jerome	France
HyDeploy	Hydrogen		United Kingdom
H2V product for NEL hydrogen	Hydrogen	Notodden	Norway
Hydrosol	Hydrogen	Almeria	Spain
Surf n Turf	Hydrogen	Orkney	United Kingdom
Nouryon (ex AkzoNobel)	Hydrogen		Netherlands/Germany
H Vision	Hydrogen	Rotterdam	Netherlands
Magnum	Hydrogen	Eemshaven	Netherlands
SwissPower Hybridkraftwerk	Methane	Dietikon	Switzerland
Energy Park Pirmasens	Methane	Pirmasens	Germany
Windgas Hassfurt	Hydrogen	Hassfurt	Germany
Haeolus	Hydrogen	Varanger	Norway
H2 Aberdeen Hydrogen bus	Hydrogen	Aberdeen	United Kingdom
H&R Oelwerke Schindler	Hydrogen	Hamburg	Germany

Project Name	Output Type	Location	Country
Westküste 100	Hydrogen	Schleswig-Holstein	Germany