October 2018

Power-to-Gas: Linking Electricity and Gas in a Decarbonising World?

Introduction

Decarbonisation of energy systems has become a mainstream topic for the global energy industry as countries attempt to achieve the goals to reduce the impact of global climate change as set out at the COP21 meeting in Paris in December 2015. The initial focus of decarbonisation has been in the power generation sector, where, after initial subsidies, the cost of wind and solar generation has now fallen to such a level that, in many cases, it is expected to be able to compete with fossil fuel alternatives without any government support[1].

For several years, incumbent players in the gas industry have advocated that, since natural gas has the lowest carbon dioxide emissions among fossil fuels, the 'obvious' way to reduce carbon emissions was to switch from other fossil fuels to natural gas. In particular, in the power generation sector, switching from coal to gas was seen, with some justification, to yield significant CO_2 savings. More recently, there has been a realisation that with the long term objective that the energy system should be approaching carbon-neutrality by 2050, continuing to burn significant quantities of fossil-derived natural gas will not be sustainable. Against that background, the OIES Natural Gas Programme has been increasing its focus on the 'Future of Gas'[2]. Overall, OIES concludes that in Europe natural gas demand will be relatively flat until around 2030, but will need to decline at an accelerating rate thereafter if carbon reduction targets are to be met. If existing natural gas infrastructure is to avoid becoming stranded assets, plans to decarbonise the gas system need to be developed as a matter of urgency in the next three to five years, given the typical life expectancy of such assets of 20 years or more.

At this stage, different parts of the gas industry are considering various alternative approaches to potential decarbonisation of the gas grid[3]. Alternatives considered include:

- Large scale conversion of the gas network to hydrogen, with hydrogen production by methane reforming with carbon capture utilisation and storage (for example, the UK's Leeds H21 project[4]).

[1] http://www.lse.ac.uk/GranthamInstitute/faqs/do-renewable-energy-technologies-need-government-subsidies/ .
[2] See for example: Stern, J. (Jan 2017). https://www.oxfordenergy.org/publications/future-gas-decarbonising-european-energy-markets-need-new-approach/. Lambert, M. (June 2017). https://www.oxfordenergy.org/publications/biogas-significant-contribution-decarbonising-gas-markets/. Stern, J. (December 2017). https://www.oxfordenergy.org/publications/challenges-future-gas-unburnable-unaffordable/.
[3] SGI. (July 2017). 'A greener gas grid, what are the options?'). http://www.sustainablegasinstitute.org/a-greener-gas-grid/.

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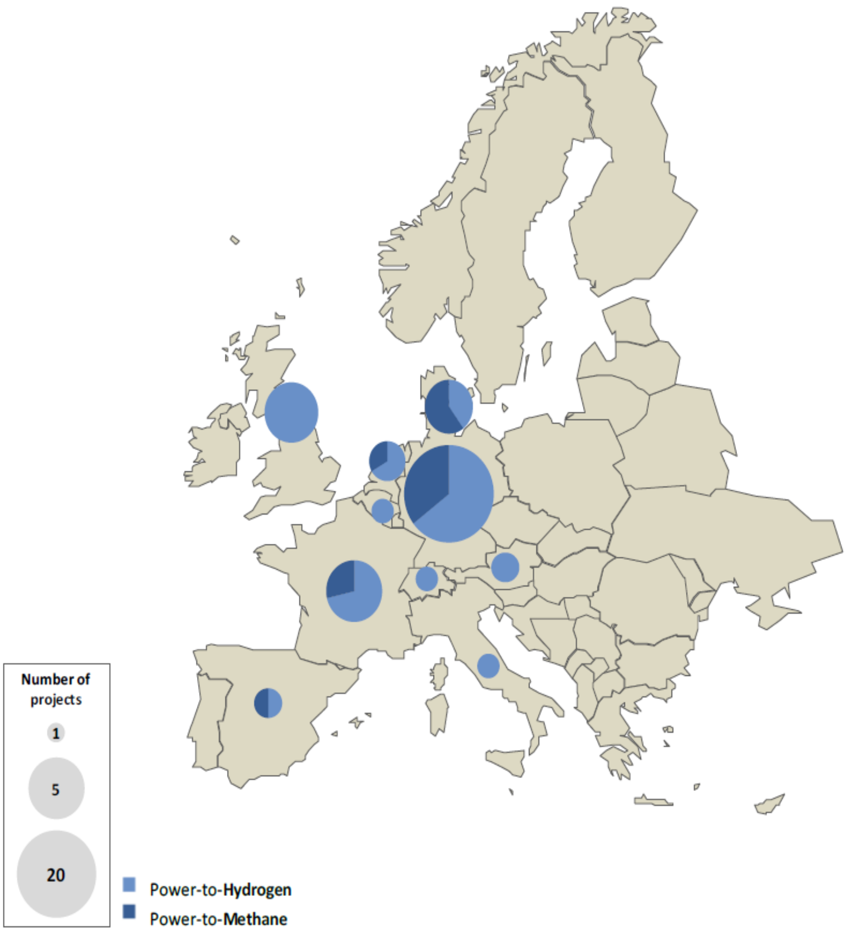
- Greater use of biogas and/or biomethane (see previous OIES report[5]).
- Production of hydrogen or renewable methane via power-to-gas.

This paper reviews the status of power-to-gas and makes an assessment of potential future development pathways and the role which it could play in decarbonising the energy system.

It should be noted that the commercialisation of power-to-gas technology is at a very early stage of development, with a limited number of pilot and demonstration plants in operation or under development. While there are some small scale developments elsewhere (for example in Japan[6] and the US[7]), most of these developments are taking place in Europe, with Germany taking the lead within Europe (see Figure 1), so this paper will focus on Europe.

Figure 1: Map of Pilot and Demonstration P2G projects in Europe[8]

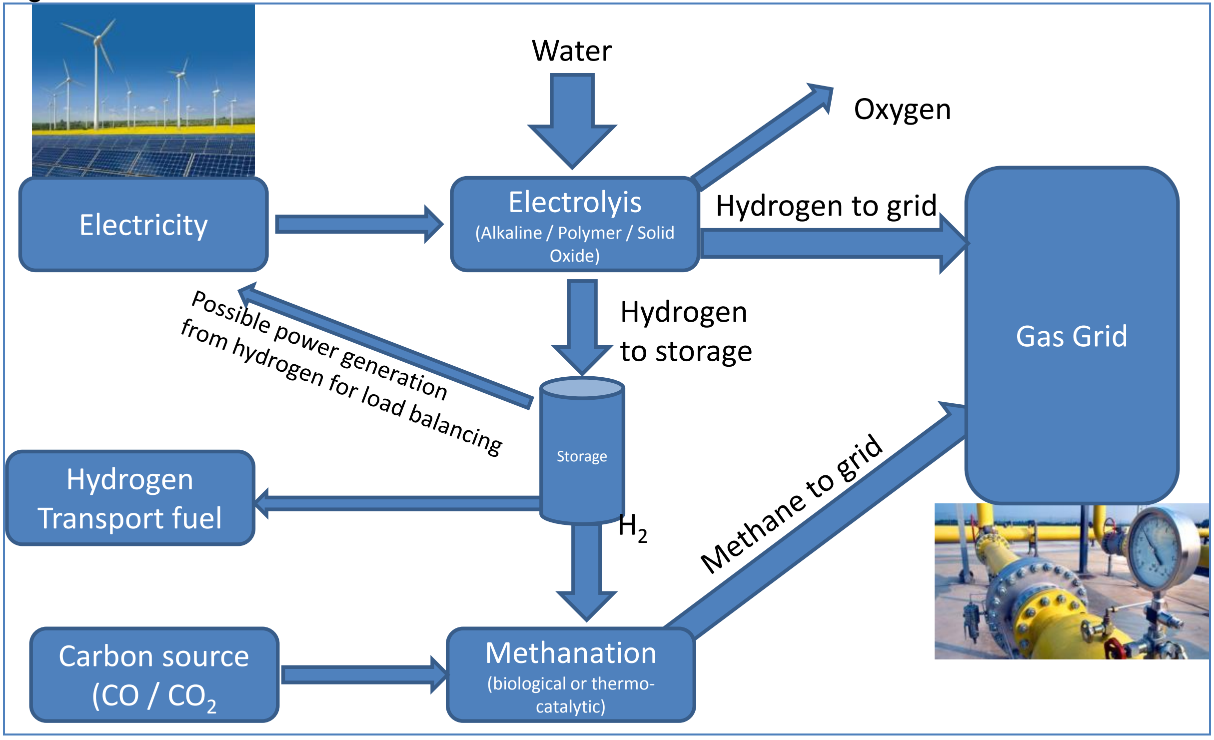


[4] Leeds City Gate H21 (July 2016): https://www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Report-Interactive-PDF-July-2016.compressed.pdf.
[5] Lambert, M. (June 2017). https://www.oxfordenergy.org/publications/biogas-significant-contribution-decarbonising-gas-markets/.
[6] https://www.pv-magazine.com/2018/05/30/toshiba-to-start-power-to-gas-supply-chain-demonstration-in-japan/.
[7] https://www.greentechmedia.com/articles/read/power-to-gas-tech-tested-hydrogen#gs.DWe1IdQ.
[8] ENEA (Jan 2016). 'The Potential of Power-to-Gas' http://www.enea-consulting.com/wp-content/uploads/2016/01/ENEA-Consulting-The-potential-of-power-to-gas.pdf.

Technical Overview

Power-to-gas (P2G) relies on the principle of electrolysis: using electricity to separate water into its component parts of hydrogen and oxygen. While the principle has been known since the middle of the nineteenth century[9], and experimental P2G pilot plants were developed in the late 1990s and early 2000s, the potential for widespread commercial deployment has come to the fore in, approximately, the last five years. This development is particularly due to the availability of renewable power generation in excess of immediate electricity demand[10] and an expectation that as the share of intermittent renewable power generation increases, such excess supply of renewable electricity will increase.

Figure 2: Power to Gas Schematic Overview



Source: Author's analysis

Figure 2 shows a schematic overview of the various ways in which P2G can be deployed into the overall energy system. Detailed technical information on the electrolysis process is beyond the scope of this paper, and has been well documented elsewhere.[11] This section outlines the process to provide sufficient background to support the commercial and economic review later in the paper.

The starting point for P2G is to use excess electrical energy to produce hydrogen (with oxygen as a by-product). As will be discussed later, a key factor is the cost of that electrical energy: the business case for power-to-gas relies on sufficient low cost, low carbon electricity being available.

The electrolysis process is applied to water (after some initial purification process) and is broadly the reverse of the process to produce electricity in a fuel cell, and a similar range of technologies is available:

[9] https://electronicspani.com/electrolysis-principle-faradays-laws-and-applications-of-electrolysis/.
[10] Götz, M, et al. (2015). 'Renewable Power to Gas: A technological and economic review'. https://www.sciencedirect.com/science/article/pii/S0960148115301610.
[11] For example, Götz et al (2015), as above, or Lehner, M, et al. (2014). 'Power-to-Gas: Technology and Business Models'. https://gpreview.kingborn.net/1291000/323d925b625f43a1bf7d19f6b95159bf.pdf.

- Alkaline Electrolysis (AEL). This is the most well-established technology, using an aqueous alkaline solution as the electrolyte. It is available commercially at a price of about €1000/kW[12], but it can take 30 to 60 minutes to restart the system following a shutdown, making it less suitable for handling intermittent power supply with frequent starts and stops: a considerable drawback for the envisaged use of balancing supply from intermittent renewables;
- Polymer Electrolyte Membrane (PEM) Electrolysis. This technology is newer than AEL, and is also available commercially[13]. It has better start-stop characteristics than AEL membranes, but currently costs around €2000/kW and is predicted to have a shorter equipment lifetime than AEL[14].
- Solid Oxide Electrolysis (SOEC) has been developed more recently and is still at the laboratory stage. While these are still to be commercialised, they are expected to have a higher electrical efficiency, lower material cost, and the ability to operate in reverse as a fuel cell[15].

A life cycle analysis of water consumption required for hydrogen production[16] shows that around 10 US gallons (38 kgs) water is required per kilogram hydrogen production from electrolysis. This is comparable to the water requirement for hydrogen production from Steam Methane Reforming (SMR). The hydrogen produced from electrolysis can be used directly in a variety of applications (see below). Alternatively, in an additional processing step, the hydrogen can be reacted with a carbon source (either CO or CO_2) to produce methane ('methanation'). Methanation is a mature technology which is already widely applied in industrial processes such as ammonia synthesis[17]. Such industrial processes are typically continuous operations, whereas to be suitable for P2G applications, methanation needs to be adapted for intermittent operation. Two types of methanation are being tested in P2G demonstration plants:

- Catalytic methanation. This is a thermo-chemical process, taking place in the range 200 to 750°C, typically using a nickel catalyst[18]. While this has been the main method used in industrial processes to date, it is less well suited to intermittent operation and for handling impurities which may be present in the CO_2 stream, for example when derived from anaerobic digestion.
- Biological methanation. This converts H_2 and CO_2 to methane using methanogenic microorganisms. These are typically those from the Archaea family, single cell microorganisms as also found, for example, in the digestive systems of humans or cattle[19]. These microorganisms operate under anaerobic conditions in an aqueous solution at a temperature in the range 20-70°C. Biological methanation is better suited than thermo-catalytic methanation to handling intermittent operation and impurities in the gas stream. In some cases, for example at the Audi demonstration plant in Allendorf, Germany[20], or the BioCat plant near Copenhagen[21], Denmark, the methanation process uses raw biogas as a feedstock to produce synthetic methane suitable for injection into the gas grid.

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[12] Götz et al (2015). https://www.sciencedirect.com/science/article/pii/S0960148115301610 and Schmidt, O, et al (2017). https://www.sciencedirect.com/science/article/pii/S0360319917339435

[13] For example, 3 MW capacity PEM electrolyser from Hydrogenics, http://www.hydrogenics.com/2017/04/25/hydrogenics-unveils-3-megawatt-pem-electrolyzer-stack/.

[14] Götz et al (2015) and Schmidt et al (2017).

[15] Schmidt et al (2017).

[16] https://www.hydrogen.energy.gov/pdfs/review16/sa039_elgowainy_2016_o.pdf.

[17] European Power to Gas White Paper. (Sept 2017). http://www.europeanpowertogas.com/media/files/European%20Power%20to%20Gas_White%20Paper.pdf.

[18] European Power to Gas White Paper. (Sept 2017).

[19] https://www.sciencedirect.com/science/article/pii/S2452231716300148.

[20] https://www.audi-mediacenter.com/en/press-releases/new-method-for-producing-the-synthetic-fuel-audi-e-gas-5722.

[21] http://biocat-project.com/.

Power-to-hydrogen or power-to-methane?

With the technology still at an early stage of development and commercialisation, there is a wide range of alternatives and not yet any consensus regarding how the hydrogen produced from P2G can best be deployed in a decarbonising energy system.

- The hydrogen can be used directly as a transport fuel. This is potentially one of the highest value applications[22], particularly by displacing oil products for long distance heavy duty transportation, including railways and perhaps marine transport. For short-range and light vehicles it will be in competition with electric vehicles, so less likely to have a significant role. The European Union is supporting the use of hydrogen for transportation through the Fuel Cells and Hydrogen Joint Undertaking[23].
- The hydrogen could be used directly to produce heat, particularly suitable for those industrial applications where higher temperatures are required than can easily be achieved with electricity. Industrial users are the primary focus of the proposed Cadent Hynet NW project in the Liverpool/Manchester area of the UK[24], aiming to deliver hydrogen produced through methane reforming with CCS (see further details below).
- The hydrogen could be stored, and used later to generate electricity (either through combustion or a fuel cell) thereby helping to balance the electricity grid. In this application, the power-to-gas/gas-to-power combination is playing a similar role to batteries, but with the potential for storage of larger quantities of electricity over a longer time period than currently possible for batteries[25].
- The hydrogen, within certain limits, can be injected into the natural gas grid. Current regulatory standards generally impose very low limits on the amount of hydrogen in the gas grid (for example the UK limit is 0.1 per cent by volume[26], and Netherlands between 0.02 and 0.5 per cent[27]). There is a growing consensus that a higher hydrogen content, certainly up to one per cent and in some cases as high as five per cent, could be accommodated without impact on the gas grid or end user equipment. (*Note: these blend percentages are on a volumetric basis: hydrogen has an energy density about 1/3 of natural gas, so the energy blend percentage is correspondingly lower*). Too high a hydrogen content raises technical and safety concerns, and requires very detailed consideration of the specific characteristics of the natural gas network and end-use applications. For example, gas with higher hydrogen compositions may not be compatible with some forms of gas storage and may cause embrittlement of steel components of the natural gas network or in natural gas vehicles[28]. Some tests are being planned to evaluate the impact of higher concentrations of hydrogen (for example, the HyDeploy project at Keele University in the UK, contemplating up to around 20 per cent hydrogen[29]).
- Finally, and most directly relevant to decarbonisation of the natural gas network, the hydrogen can be used in a methanation process in which it is reacted with carbon (usually carbon dioxide) to produce biomethane of a quality suitable for injection into the natural gas grid. There are various catalytic and biological methods for methanation which have been developed at a demonstration scale (in the range 1 to 10MW of electricity consumption) in recent years, as discussed further in the section on Case Studies below.

[22] ENEA. (Jan 2016). 'The Potential of Power to Gas', p. 27.
[23] https://www.fch.europa.eu/.
[24] https://hynet.co.uk/.
[25] https://www.bloomberg.com/news/articles/2017-09-05/better-than-a-battery-big-energy-backs-hydrogen-power-storage.
[26] Institution of Gas Engineers and Managers. (Dec 2017). 'Gas Quality Standards'. https://www.gasgovernance.co.uk/sites/default/files/ggf/page/2017-12/UNC%20Transmission%20Working%20Group.pdf
[27] Gasunie Transport Services data. http://wetten.overheid.nl/BWBR0035367/2016-04-01#Bijlage1.
[28] http://gerg.eu/public/uploads/files/publications/GERGpapers/HIPS_-_the_paper_-_FINAL.pdf.
[29] https://hydeploy.co.uk/.

P2G or Hydrogen production via methane reforming?

While it is not, strictly speaking a P2G technology, it is appropriate to make a brief mention of an alternative low-carbon route to hydrogen, namely reforming of methane. Over 95 per cent of all hydrogen produced today is by steam reforming of natural gas, and a modern steam methane reforming plant emits around 25 tons of CO_2 per 1MMscf of hydrogen produced[30]. To make low-carbon hydrogen, some projects are considering combining reforming of natural gas (either Steam Methane Reforming or Autothermal Reforming) with Carbon Capture Usage and Storage (CCUS). This technology has already been demonstrated at scale at Port Arthur Refinery in Texas, with the captured CO_2 being used for enhanced oil recovery[31]. In a future low-carbon energy system, hydrogen could be produced both from power-to-gas and from methane reforming with CCUS. Two projects being contemplated in the UK illustrate the potential to combine methane reforming with CCUS with supply of hydrogen to end users as a low-carbon substitute for natural gas:

- The Hynet North West project in the Liverpool-Manchester region plans to reform methane, store the resulting CO_2 in depleted gas fields close offshore, supply pure hydrogen to a small number of industrial customers and blend some hydrogen into the natural gas grid at levels which would not impact end-consumers[32].
- The Leeds H21 project is similar, but more ambitious, in that it proposes to convert equipment of all end-users (households, commercial and industrial) in the city of Leeds (around 265,000 consumers) to burn hydrogen rather than natural gas[33]. The hydrogen would also be produced by methane reforming, in this case on the east coast of the UK, with the resulting CO_2 assumed to be stored in depleted gas fields or aquifers in the North Sea. The scale of such a conversion is significant: if the same process were extended to all current UK gas consumers, it would require conversion of 20,000 consumers per week for 25 years[34].

It is important to note that such projects are dependent on suitable, and publicly acceptable, CO_2 storage being available nearby. This is not universally the case. For example, in Germany CCUS opportunities appear limited and public acceptability is very low[35].

Case Studies

Since P2G technology is at an early stage of development, it is instructive to consider some specific case studies of demonstration plants which are currently in operation or under development, and which illustrate alternative possible approaches to the deployment of P2G. It must be stressed that these are all at demonstration scale in the context of the scale of the European natural gas industry. To produce 1Bcm of substitute natural gas would require an electrolyser capacity of around 5000 MW operating for around half of the time, whereas the largest demonstration plant is less than 10MW capacity. The first three examples (Audi, BioCat and Store&Go) are all various approaches to power-to-methane and the last one (ITM Power) is power-to-hydrogen.

Audi e-gas

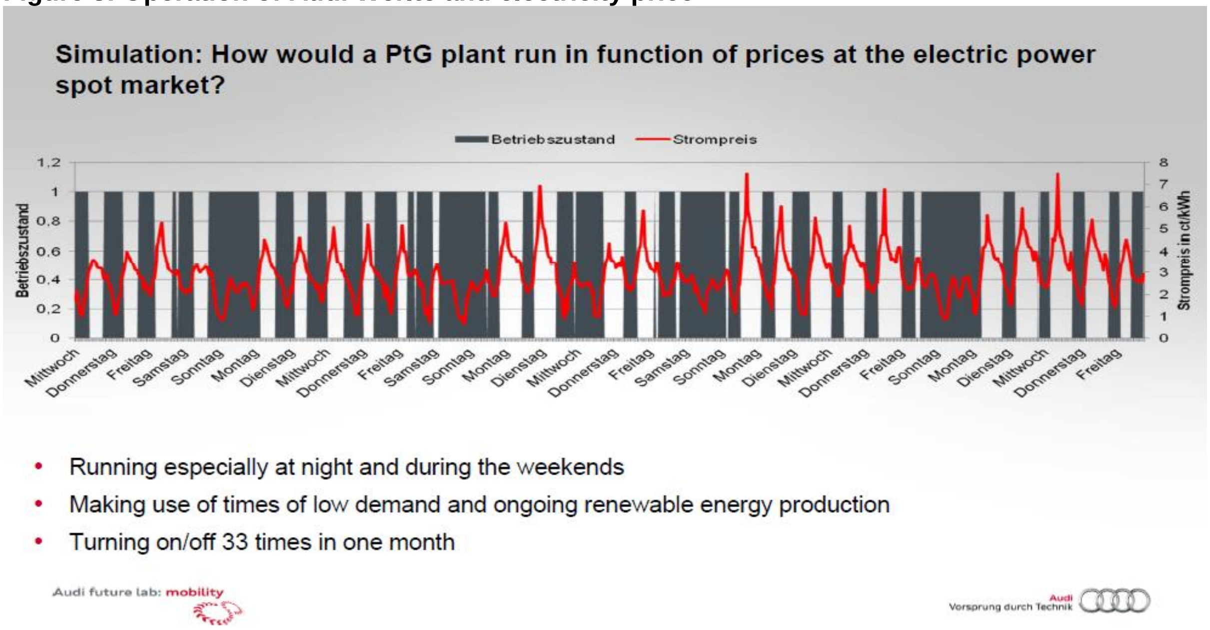
The automaker Audi, anxious to offer its customers a climate friendly fuel option to promote sales of its cars, and particularly the ‘g-tron’ range of natural gas vehicle models, has been developing an ‘e-gas’ offering. To promote the product, it is being offered to customers initially at the regular (fossil-

[30] http://www.praxair.com/-/media/corporate/praxairus/documents/reports-papers-case-studies-and-presentations/our-company/sustainability/praxair-co2-emissions-reduction-capture-white-paper.pdf?la=en Table 2, page 6.
[31] https://www.globalccsinstitute.com/projects/air-products-steam-methane-reformer-eor-project.
[32] https://hynet.co.uk/.
[33] https://www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Report-Interactive-PDF-July-2016.compressed.pdf.
[34] National Grid (March 2018). ‘The Future of Gas’..futureofgas.uk/wp-content/uploads/2018/03/The-Future-of-Gas_Conclusion_web.pdf. p13.
[35] https://setis.ec.europa.eu/setis-reports/setis-magazine/carbon-capture-utilisation-and-storage.

derived) CNG price[36]. ‘e-gas’ can be biomethane, but Audi has also developed two of its own P2G facilities.

- The Audi e-gas project at Werlte in Lower Saxony, Germany, has been in operation since 2013. It comprises three 2MW alkaline electrolysers, which use surplus renewable power to produce up to 1300Nm^3/hour hydrogen[37]. It is located alongside a biogas plant which produces separate streams of biomethane and CO_2. The separated CO_2 is then combined with the produced hydrogen in the methanation process to produce up to 325 Nm^3/hour of synthetic natural gas. This would be sufficient to fuel 10 vehicles per hour with synthetic CNG, enabling each vehicle to travel about 500km. The methanation process in Werlte uses a chemical-catalytic process under high temperature (300-400°C) and pressure.[38] As shown in Figure 3, the plant runs to take advantage of times of low spot electricity prices (typically around €4/kWh or less). With a growing share of renewable power in Germany, the economic running hours would be expected to increase.

Figure 3: Operation of Audi Werlte and electricity price[39]



- A second Audi e-gas project at Allendorf in Hesse, Germany, started operation in 2016 using an alternative biological methanation process developed by MicrobEnergy, a subsidiary of the Viessmann group. The plant is smaller than the thermo-catalytic plant in Werlte with an electrolyser capacity of just 300kW, but also is co-located with a biogas plant. Compared with the thermo-catalytic method at Werlte, it has the advantage that the hydrogen produced from electrolysis is reacted with the raw biogas (methane/CO2 mixture) directly, without the need to separate the CO2 before methanation. The biological process results in a gas stream of around 98 per cent methane, and is claimed to have a high tolerance to impurities and capable of adjusting to fast and flexible load cycles. This process takes place at a pressure of around 5 bar and at relatively low temperatures (45-70°C)[40].

[36] https://www.audi-mediacenter.com/en/press-releases/new-audi-e-gas-offer-as-standard-80-percent-lower-co2-emissions-7353.
[37] http://www.cedec.com/files/default/8-2014-05-27-cedec-gas-day-reinhard-otten-audi-ag.pdf.
[38] https://www.audi-mediacenter.com/en/press-releases/new-method-for-producing-the-synthetic-fuel-audi-e-gas-5722.
[39] www.cedec.com/files/default/8-2014-05-27-cedec-gas-day-reinhard-otten-audi-ag.pdf.
[40] http://www.greencarcongress.com/2016/02/20160229-audi.html.

BioCat Project, Avedøre (near Copenhagen) Denmark

The BioCat Project near Copenhagen in Denmark, like the Audi Allendorf plant, uses a biological methanation process but at the next stage of scale up. In this case, the biological methanation technology was developed by Electrochaea, a German start-up company[41]. The BioCat project, completed in 2016, comprises a 1MW electrolyser and upgrades biogas from an adjacent water treatment plant. The 1MW electrolyser yields 200 Nm3/hr hydrogen. This is combined with 50 Nm3/hr CO2 to produce 50 Nm3/hr of synthetic methane. The primary output of this project is to produce synthetic natural gas of grid quality to be injected into the Danish distribution grid. It also provides ancillary services to the power grid to help with load balancing. One of the key objectives of the project was to demonstrate the ability to store 'low cost or stranded electricity as methane in … the nearly 45TWh or energy storage capacity in Denmark's gas grid.'[42] The project has also demonstrated the ability of the system to handle repeated on/off cycles and to achieve output with around 97 per cent methane within minutes of start-up. Based on the experience from the plant in Denmark, Electrochaea is now aiming to scale up to a larger reactor size and develop a 10MW capacity plant in Hungary and/or California, and the company believes that, in future, a single reactor would be capable of scaling up to 50MW capacity[43].

EU Horizon 2020, 'Store&Go' project

The 'Store&Go' project, sponsored under the EU Horizon 2020 programme and involving collaboration between 27 partner organisations across Europe, is testing the integration of power-to-methane into the daily operation of European energy grids. It has three demonstration sites at Falkenhagen in Germany, Solothurn in Switzerland and Troia in Italy[44]. The three sites are using different methanation technologies and connect to the natural gas network in different ways.

- The site at Falkenhagen in Germany has added a methanation process to an existing power-to-hydrogen plant 'WindGas Falkenhagen' (so called because it was designed to store surplus power from nearby wind turbines in an area with low overall electricity consumption) which had been in operation, using alkaline electrolysis, since 2013. Work on adding the methanation plant, taking a CO_2 stream from a nearby bio-ethanol plant started in July 2017 and was completed in May 2018[45]. The plant uses 1MW of electrical input, and the methanation plant, using a novel honeycomb catalytic reactor, produces up to 57 Nm3/h of synthetic natural gas, equivalent to around 600kWh per hour.

- The site at Solothurn in Switzerland uses 700kW of electrical input (in two 350kW PEM electrolysers). Taking CO_2 from a nearby waste water treatment plant, methanation will be carried out using the Elecrochaea technology as at the BioCat site in Denmark[46]. Ground breaking took place in July 2017 and the plant is due to start up during 2018.

- The site at Troia in Italy, uses 200kW of electrolyser capacity, and is adding a thermo-catalytic methanation process to an existing power-to-hydrogen facility. The existing (1.2MW) power-to-hydrogen facility consists of an electrolyser, a hydrogen solid storage system, a fuel cell and an electric vehicle recharging station, designed to test the ability to balance variable electrical supply and demand from intermittent renewable energy (both wind and solar)[47]. In this case, CO_2 for the methanation process is taken from the atmosphere, and since the location is remote from the pipeline gas grid, the resulting methane is converted to LNG to be

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[41] Biocat final report at https://energiforskning.dk/sites/energiteknologi.dk/files/slutrapporter/12164_final_report_p2g_biocat.pdf.

[42] Biocat final report. https://energiforskning.dk/sites/energiteknologi.dk/files/slutrapporter/12164_final_report_p2g_biocat.pdf. p3.

[43] Author's conversation with Electrochaea, August 2018.

[44] https://www.storeandgo.info/demonstration-sites/.

[45] http://www.greencarcongress.com/2018/05/20180513-falkenhagen.html.

[46] https://www.messe-dus.co.jp/fileadmin/essj/uploads/essj_presentations_2016/ESSJ2016_Session2_5_Hein.pdf.

[47] http://93.62.162.196:8080/opencms/export/sites/Anigas/Galleria_Documenti/RelazioniInterventi/28052018-Bertoncini-PtG-INGRID-StoreGo.pdf.

transported to end-users. The methanation plant is under construction and scheduled to start operation towards the end of 2018.

Once all three plants are in operation, the ‘Store&Go’ project will provide very valuable experience of the range of power-to-gas technologies available, and the comparison of power-to-hydrogen with power-to-methane.

ITM Power to Hydrogen

The UK company, ITM Power, has been involved in several power-to-gas demonstration projects. The focus has been on power-to-hydrogen, without the additional methanation step included in the case studies above. Initially, the company constructed some small scale electrolysers as hydrogen fuel stations at various sites around the UK. For example, on the M1 motorway it constructed the ‘Wind Hydrogen Station’ with a 220kW wind turbine linked to an electrolyser. The hydrogen produced was then available for vehicle refuelling or for supply to a 30kW fuel cell to supply power to the grid.

In September 2017, Shell and ITM Power announced a project to construct a 10MW electrolyser, claimed to be the largest in the world, at the Shell Rhineland refinery in Germany. The hydrogen will be used within the refinery for oil product upgrading, and will provide valuable experience of operating an electrolyser at the next stage of scale up[48]. Total cost of the project, including integration into the refinery is stated as €20m, of which €10m is funded by the EU Fuel Cells and Hydrogen Joint Undertaking.

Perhaps even more significantly in the context of decarbonising the gas network, in early 2018 ITM Power and the gas distributor Northern Gas Networks completed a Large-Scale Power-to-Gas Energy Storage Deployment Study[49]. This study considered several locations in the UK for potential deployment of a 50-100MW electrolyser, and selected a site near Newcastle in NE England for the next stage of engineering design. This project is significant in that it is at a substantially larger scale than other P2G facilities which have been constructed or under development elsewhere in the world. This project also does not include a methanation step, but contemplates injection of hydrogen into the gas grid up to a share of 20 per cent hydrogen by volume.

The above case studies illustrate the considerable variety of potential approaches already operational or at an advanced stage of development for P2G. This paper now moves on to consider potential roles for the technology in a decarbonising energy system.

P2G requires closer linkage of gas and electricity systems

In today’s energy system, the natural gas system and the electricity systems have been largely considered independently, with the main significant interconnection being the potential use of gas as a feedstock for power generation. In that system, natural gas has been broadly considered upstream of electricity, with gas competing with other sources of power generation like coal, hydro, nuclear and oil.

The potential introduction of P2G at a significant scale changes that dynamic, and requires a more holistic view of the gas and electricity systems on an integrated basis, particularly given the wide range of potential uses of the hydrogen produced from the initial electrolysis step.

- P2G, with standalone storage of hydrogen and subsequent generation of power from the stored hydrogen, could be considered merely as an additional tool to balance the electricity system, with no impact on the gas system. In this role, it performs a similar role to other forms of electricity storage like pumped hydro, compressed air and batteries.

[48] http://www.itm-power.com/news-item/worlds-largest-hydrogen-electrolysis-in-shells-rhineland-refinery.

[49] http://www.itm-power.com/news-item/northern-gas-networks-deployment-study-findings.

— Alternatively, P2G could be viewed as an additional source of supply (of either hydrogen or methane or both) to the gas grid, competing with (or supplementing) traditional natural gas, biomethane from anaerobic digestion or synthetic natural gas from gasification of waste.

— As another alternative, P2G could be viewed as a source of hydrogen for a variety of applications, for example in transport or for industrial heat.

The most economic use of P2G is likely to vary by location and over time, depending on market conditions. Closer integration between electricity and gas systems is likely to require a reconsideration of the market mechanisms and regulatory frameworks in both markets.

A recent report from the UK's Institution of Mechanical Engineers summarised the situation well: 'Power to gas provides a conduit for connecting the energy system together, providing fuel from excess power and reducing air pollution and CO_2 emissions.'[50]

Efficiency and Greenhouse Gas impact of P2G

The key driver for development of P2G is the desire to decarbonise the energy system and, ultimately, to achieve carbon-neutrality. At this early stage of development, there is a wide range of system losses and overall conversion efficiencies (that is: energy output as a percentage of energy input) from the P2G chain, and expectation of future increases in efficiency, as shown in Table 1. Broadly, conversion efficiency of production of hydrogen from P2G ranges from 50 to 75 per cent, with the addition of a methanation step reducing this by around 10 percentage points to the range 40 to 65 per cent[51].

Table 1: Energy efficiency comparison of different P2G pathways

P2G Pathways	Technologies	Current	Long Term
Power to Natural Gas End-users	Electrolyser, Low pressure hydrogen storage/compression, Injection to pipeline	59–83%	64–86%
	to heat for residential	52–76%	56–79%
	to micro-CHP	40–72%	55–74%
	to large scale gas turbines	18–26%	23–31%
Power to Renewable Content in Petroleum Fuel	Electrolyser, Low pressure hydrogen storage/compression	55–83%	59–86%
Power to Power	Electrolyser, Low pressure hydrogen storage/compression, fuel cell	17–40%	27–43%
Power to Seasonal Energy Storage to Electricity	Electrolyser, low-pressure compression, underground storage, Transmission pipelines, Natural gas-based power plants	16–24%	22–29%
Power to Hydrogen for zero—emission transportation	Electrolyser, low-pressure compression and storage, high-pressure compression for refueling station.	50–79%	54–82%
Power to Seasonal storage for Transportation	Electrolyser, low-pressure compression, underground storage, hydrogen separation technologies, high-pressure compression	36–68%	43–66%
Power to Renewable Natural Gas (RNG) to Pipeline ("Methanation")	Electrolyser, Low-pressure energy storage and compression, Methanation reactor, Gas Clean-up, Injection of Renewable Natural Gas to the Natural Gas Pipeline	40–63%	45–65%
Power to Renewable Natural Gas (RNG) to Seasonal Storage	Electrolyser, low-pressure compression, Methanation reactor, Gas Clean-up, Underground storage, Injection of RNG to the Natural Gas Pipeline	34–60%	43–58%

Source: Transition of Future Energy System Infrastructure; through Power-to-Gas Pathways. *Energies*. (2017)

The overall greenhouse gas (GHG) impact is also highly dependent on the carbon intensity of the electricity supply and the individual components of the supply chain. Audi, for its 'e-gas' product (see Case Studies above) estimates that the resulting fuel used in its vehicles gives 80 per cent CO_2

[50] Institution of Mechanical Engineers. (May 2018). 'Energy from Gas: Taking a whole system approach.' https://www.imeche.org/docs/default-source/1-oscar/reports-policy-statements-and-documents/imeche-energy-from-gas-report-final-may-2018.pdf?sfvrsn=2.

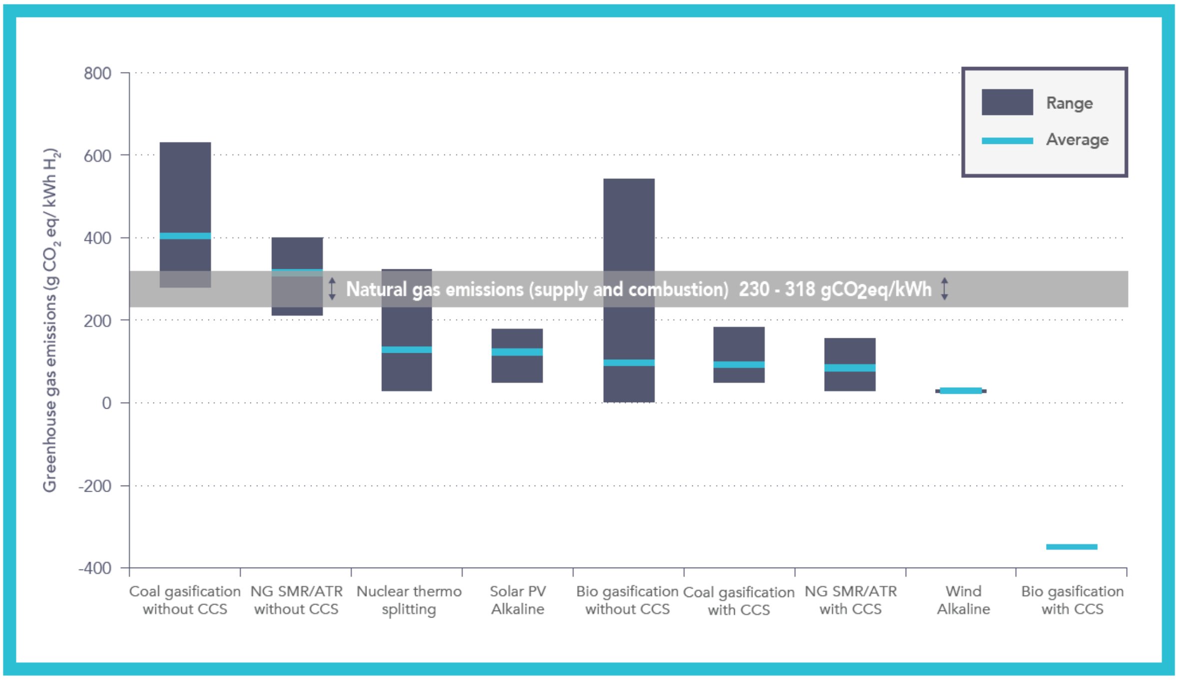
[51] Transition of Future Energy System Infrastructure; through Power-to-Gas Pathways. *Energies*. (2017) www.mdpi.com/1996-1073/10/8/1089/pdf.

emission savings when compared with the traditional gasoline alternative[52]. This assumes that the electricity used as the input to the P2G process is derived from renewable generation. This level of savings is also comparable with biomethane from upgrading of biogas[53].

The Sustainable Gas Institute at Imperial College in London, UK, has produced a comprehensive analysis of the range of GHG emissions associated with hydrogen production via different technologies and from different feedstocks, as shown in Figure 4. GHG emissions associated with electrolysis are primarily determined by the source of electricity and the efficiency of electrolysis. Use of wind generation and electrolysis produces significantly lower supply chain GHG emissions at around 25g CO_2eq/kWh H_2, whereas use of solar photovoltaics (PV) instead of wind generation produces a wider range of emissions from 51 to 178g CO_2eq/kWh H_2[54]. This range for PV is largely due to the different efficiency of PV conversion in different regions.

In the context of the eventual target to achieve carbon-neutrality of the overall energy system, it should also be noted that hydrogen derived from P2G based on wind power has significantly lower carbon emissions than hydrogen from reforming of natural gas, even with the addition of CCUS. In order to achieve complete carbon-neutrality, it would be necessary to include some negative emission technologies in the overall mix, notably from biogas/biomethane combined with CCUS.

Figure 4: Range of GHG emissions from various routes to hydrogen[55]



Economics and potential economies of scale

Since the number and scale of pilot and demonstration projects is currently small, it is not surprising that there remains considerable uncertainty regarding future costs. While not directly comparable technology, it is interesting to consider the significant cost savings achieved in solar power as the scale of implementation has grown. A recent study by the International Renewable Energy Agency

52 https://www.audi-mediacenter.com/en/press-releases/new-audi-e-gas-offer-as-standard-80-percent-lower-co2-emissions-7353.

53 Lambert, M. (June 2017). https://www.oxfordenergy.org/publications/biogas-significant-contribution-decarbonising-gas-markets/.

54 SGI: A Greener Gas Grid: what are the options? p.68.

55 SGI: A Greener Gas Grid: what are the options? Table 40, p.66.

(IRENA)[56] illustrates how the total installation cost of solar power fell from around $5000/kW in 2009 to $2000/kW by 2015 and is projected to approach $1000/kW by 2020. It is particularly noteworthy that cost reductions come not only from the modules themselves, but also from installation and EPC costs. Fairly consistently, each doubling of cumulative volume led to a 22 per cent cost reduction. The same study indicates a 12 per cent cost reduction for each doubling of cumulative volume for wind power. It remains to be seen whether similar economies of scale are achievable for P2G technology.

The cost of AEL electrolysers is currently around €1000/kW (of electrical input). As noted earlier, this technology is already relatively mature and available commercially. A survey of industry experts[57] suggests that this could fall to between 500 and 700 €/kW by 2030. In the same study, costs of the alternative, and less mature, PEM electrolyser are envisaged to fall from around 2000 €/kW currently to between 500 and 1000 €/kW by 2030, albeit with a wider range of uncertainty. Similar cost ranges were envisaged in a separate study conducted for the EU Fuel Cells and Hydrogen Joint Undertaking[58]. A comparison with the experience of solar cost reduction, suggests that these modest levels of reduction may be conservative.

In addition to the capital costs, the cost of gas from P2G is highly dependent on the assumed price for electricity and the load factor (number of hours of operation per year). A comprehensive study by ENEA in 2016[59] evaluated the potential costs of power-to-hydrogen and power-to-methane under a range of electricity price and load factor assumptions. It also drew on an earlier study[60] which postulated that by 2050, with the increasing use of renewable power, the marginal electricity price could be at or below €15/MWh for up to 6,100 hours per year (equivalent to around 70 per cent of the year). The extent to which a P2G facility would actually be able to purchase electricity at that price will be dependent on the regulatory regime and the commercial arrangements which can be negotiated.

Figure 5 shows the range of levelised costs of hydrogen or methane under the various scenarios modelled in the 2016 ENEA study. Some key observations can be made:

- In the lowest cost case, where low cost (<€15/MWh) electricity would be available for around 75 per cent of the time, power-to-hydrogen is calculated with a levelised cost around €50/MWh.
- In other scenarios, where low cost electricity would be only available for around 10 per cent of the year or electricity costs averaged around €40/MWh, the cost of power-to-methane could be as high as €150-200/MWh.
- In all cases, the methanation step adds an additional €40-50/MWh to the cost. The lowest resulting cost of power-to-methane of around €100/MWh is at the upper end of the range of costs for biomethane production.
- The cost of all power-to-gas alternatives remains higher than the cost of fossil-derived natural gas (with current price levels on the Netherlands TTF hub in the range €25-30/MWh), even with the addition of an assumed €100/t CO_2 carbon price. This underlines the assumption that decarbonisation of the energy system has to be the primary driver to pursue P2G (or indeed biomethane) and will need to be driven by government policy rather than commercial economics.

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56 IRENA. (2016). "The power to change: Solar and Wind cost reduction potential to 2025'. http://www.irena.org/publications/2016/Jun/The-Power-to-Change-Solar-and-Wind-Cost-Reduction-Potential-to-2025.

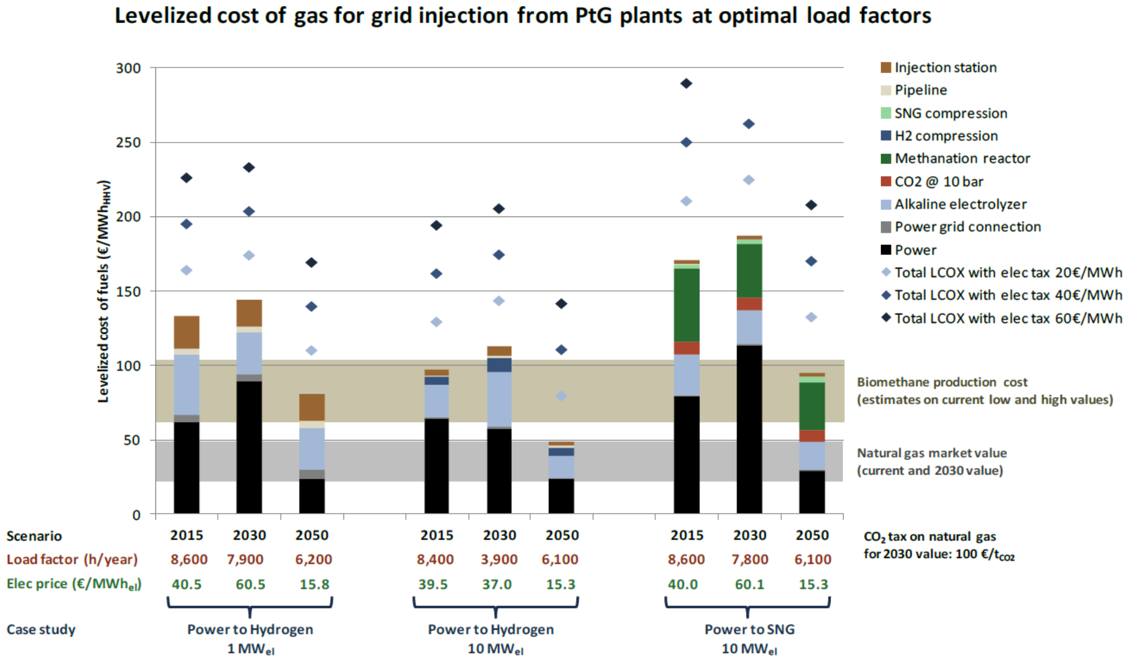
57 Schmidt et al (2017). 'Future Cost and performance of water electrolysis'. https://www.sciencedirect.com/science/article/pii/S0360319917339435?via%3Dihub.

58 http://www.fch.europa.eu/sites/default/files/study%20electrolyser_0-Logos_0_0.pdf.

59 http://www.enea-consulting.com/en/the-potential-of-power-to-gas/.

60 Voss, A. (12 March 2013). 'The system effects and electricity market impacts of the energiewende policy in Germany'. IER, University of Stuttgart.

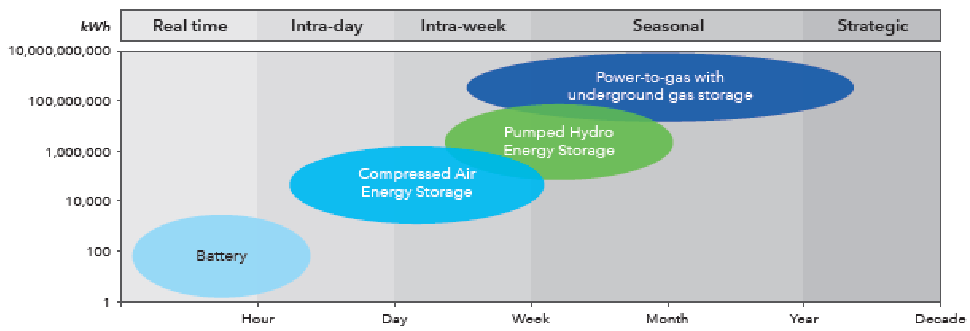
Figure 5: Levelised cost of hydrogen and methane under various scenarios[61]



Costs of P2G compared with battery storage

As noted previously, P2G can be viewed through various lenses, either as a source of renewable gas, which is the main focus of this paper, or as a form of energy storage, in addition to batteries. Several studies have considered the role of P2G and whether it is in competition with batteries, or whether batteries and P2G have complementary roles[62]. It is concluded that, on account of the different characteristics, the roles are complementary, and that a variety of electricity storage technologies will be required, as illustrated in Figure 6.

Figure 6: Typical storage capacities and time scales of different network scale technologies[63]



For short-duration storage, in the range one to 10 hours, pumped hydro and batteries, with much higher round-trip efficiency and lower levelised cost of energy (LCoE) are a better solution than P2G.

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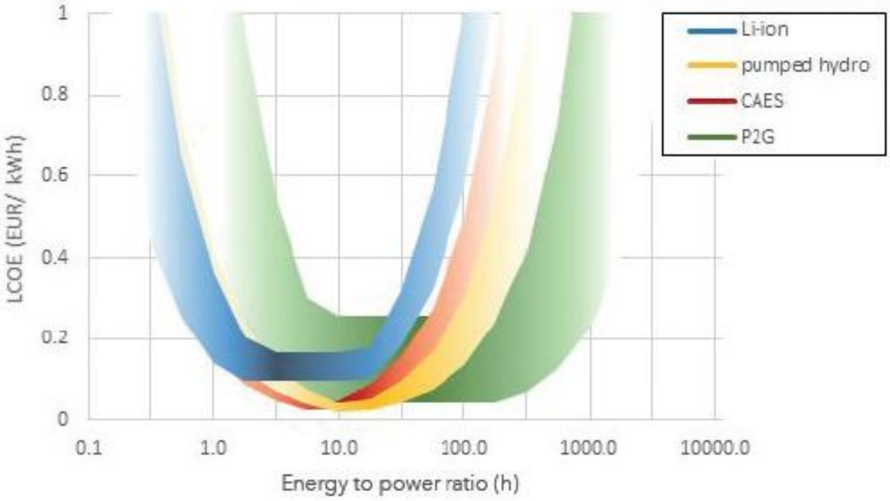
[61] ENEA (2016). The potential of Power-to-Gas.

[62] See for example: Blanco, H and Faaij, A. (2017). 'A review of the role of storage in energy systems with a focus on power to gas'. https://www.sciencedirect.com/science/article/pii/S1364032117311310?via%3Dihub or Ameli, H, Qadrdan, M and Strbac, G. (2017). 'Techno-economic assessment of battery storage and Power-to-Gas: A whole-system approach'. https://www.sciencedirect.com/science/article/pii/S1876610217358630.

[63] European Power to Gas platform White Paper, September 2017. http://europeanpowertogas.com/news/

As illustrated in Figure 7, however, P2G with hydrogen storage in a salt cavern provides the lowest cost for seasonal storage with a cycle time in the order of 1000 hours.

Figure 7: Comparison of storage LCoE for Li-ion batteries, compressed air (CAES), pumped hydro and P2G[64]



Potential path forward for P2G in decarbonising the energy system

In the latest network development plan published by the European Network of Transmission System Operators for Gas (ENTSOG)[65], all scenarios contemplate around 50 per cent of electricity demand will be covered by renewable generation by 2030, with this share rising to between 65 per cent and 80 per cent (depending on the scenario) by 2040. Given the drive for decarbonisation of the electricity sector and the declining cost of wind and solar, there seems little doubt that such scenarios are achievable. Against that background, there is likely to be increasing frequency of occasions when available renewable electricity supply exceeds the immediate demand from consumers, increasing the opportunities for various storage technologies. This presents a considerable opportunity for the growth of P2G.

There are, however, significant challenges. From the evaluation of the costs and economics of all renewable gases above, it is clear that switching from use of fossil-derived natural gas to low carbon alternatives will need some form of government support. The nature of that government support will be crucial in determining the path forward.

In a recent OIES paper, Malcolm Keay highlights some of the challenges of introducing renewable hydrogen into the UK[66]. 'It involves the wrong sort of technology and the wrong sort of economics', highlighting, in particular, that it would need a very strong government role to drive the major investment in the alternative technology, and it would cause considerable disruption to consumers who would need to change their boilers and other end-use equipment. In the absence of such direct government intervention, it is hard to see how the large number of individual stakeholders would take the steps required to achieve the transition to hydrogen. Keay contrasts this with the introduction of renewable electricity which was possible in small increments (individual solar panels and wind turbines) with each change being largely invisible to individual consumers, and with the significant overall cost hidden in gradual increases in electricity bills.

[64] European Power to Gas platform White Paper, September 2017. http://europeanpowertogas.com/news/
[65] https://www.entsog.eu/publications/tyndp/2018.
[66] Keay, M. (2018). Decarbonisation of heat and the role of 'green gas' in the UK. https://www.oxfordenergy.org/publications/decarbonisation-heat-role-green-gas-united-kingdom/.

This conclusion regarding the importance of consumer behaviour and consumer acceptability may be significant to the path forward for P2G. A key decision will be whether P2G primarily focuses on power-to-hydrogen, or whether it adds (at additional cost and complexity) the further processing step to produce methane. It could be argued that conversion of the entire natural gas system to hydrogen is ultimately the 'better' solution, as it provides more flexibility of supply and, at the point of final consumption, use of hydrogen does not release any carbon dioxide to the atmosphere. However, the issues around persuading consumers to change their gas-consuming equipment to hydrogen, and ensuring that the entire natural gas network can handle hydrogen safely remain significant.

One of the key arguments for decarbonising the gas network is to take advantage of the considerable investment in existing network infrastructure. An alternative route to decarbonise the energy system could be to convert nearly all applications (including the majority of the heat sector) to (low carbon) electricity. As well as requiring large scale change to end-user equipment, this would also require significant incremental investment in upgrading the electricity system, and it would leave the gas network largely idle. In a 2016 report focused on the UK heat sector, KPMG[67] concluded that, whichever route is chosen, a large investment (>£100bn) would be required to achieve 2050 decarbonisation targets, but an all electric alternative would cost more than double other alternatives which continued to use the gas network. Broadly similar conclusions were also reached by a 2018 DENA (Deutsche Energie-Agentur) study for Germany comparing all electric and technology mix scenarios[68].

If a country or region did not have an existing natural gas network (for example, a developing country outside Europe), and wished to develop a low carbon energy system, it could consider a system based entirely on renewable electricity, perhaps combined with a new gas network designed specifically to distribute hydrogen. That hydrogen may be useful for industrial applications requiring high temperatures and for long-distance transport applications where electricity did not provide a suitable alternative.

However, where the key driver is to utilise investment in an existing gas network, it is likely to prove easier to continue to use methane in the system, and gradually to transition to lower carbon sources of methane, from biomethane or from P2G. This gradual transition could be achieved through government imposed carbon pricing, feed-in tariffs or similar mechanisms to promote investment in renewable gas production facilities – both from biomethane and power-to-methane. This type of pathway is already contemplated by the latest ENTSOG ten year network development plan[69]. That plan, in its scenarios with a high share of renewables, contemplates a renewable gas share of total supply of between 10 and 15 per cent by 2040, of which around 80 to 90 per cent is from biomethane, and the balance is from P2G. The level of biomethane at around 10 per cent of current total natural gas demand is consistent with other forecasts, and is largely constrained by availability of suitable feedstocks[70]. The total contribution of P2G in the 'Global Climate Action' scenario is around 100 TWh, plus 350 MWh of Biomethane (out of a total gas demand of 3900 TWh), so the ENTSOG scenarios still envisage a very high share of fossil-derived natural gas at that time. It remains to be seen whether that level of natural gas consumption remains acceptable and compatible with COP21 commitments by 2040.

A recent study in France by ADEME (the environment and energy management agency) and GRDF (the gas distribution network company)[71] was more ambitious and aimed to show the technical and economic feasibility of a gas system based entirely on renewable gases by 2050. The study concludes that there is a theoretical potential within France for generation of 460TWh/yr of injectable

[67] http://www.energynetworks.org/assets/files/gas/futures/KPMG%20Future%20of%20Gas%20Main%20report%20plus%20appendices%20FINAL.pdf.
[68] https://www.dena.de/en/integrated-energy-transition/.
[69] https://www.entsog.eu/publications/tyndp/2018.
[70] Lambert, M. (June 2017). https://www.oxfordenergy.org/publications/biogas-significant-contribution-decarbonising-gas-markets/.
[71] https://www.grdf.fr/espace-presse/**communiques**-de-presse/renewable-gas-mix-2050-study.

renewable methane, derived roughly one third each from (i) anaerobic digestion, (ii) gasification of waste and (iii) P2G. The overall system costs per MWh of gas consumed were in the range €100-150/MWh, with P2G being the most expensive of the three sources of renewable gas, with power-to-methane in the range €105-185/MWh. The study does include the important caveat that both gasification of waste and P2G are not yet commercial technologies, and the study does not identify the roadmap to achieve that supply mix by 2050. If P2G were to provide 150TWh of injectable gas, assuming 4000 operating hours per year and 50 per cent conversion efficiency, this would require 75GW of electrolyser capacity. Even if electrolyser costs fall by a third from current levels, this would require investment in the order of €25bn, reconfirming the need for strong government support.

Thus, P2G could play a role in both (a) a predominantly hydrogen future for the gas industry and (b) a phased transition from fossil-derived methane to renewable methane. In alternative (a), power-to-hydrogen could operate alongside hydrogen production from other routes, most likely natural gas reforming with CCUS. In alternative (b), power-to-methane could operate alongside renewable gas production from anaerobic digestion and (assuming the technology can be commercialised successfully) gasification of waste, as well as fossil-derived natural gas for as long as that remains compatible with decarbonisation objectives.

For the reasons outlined in this paper, the gradual transition in alternative (b) appears more likely to be successful than an attempt to pursue alternative (a) by repurposing the existing gas infrastructure to carry pure hydrogen. The first challenge for the industry is to start a process to scale up the technology to demonstrate further the potential for cost reductions and how P2G could play an expanded role in the decarbonising energy system. Whichever route is followed, P2G can also play the additional role of providing seasonal storage to help balance an electricity system increasingly reliant on intermittent renewables.

Summary and Conclusions

- Power-to-Gas technology is currently in its infancy with about 50 pilot/demonstration plants currently in operation, mainly in Europe.
- The technology provides a promising approach as a low-carbon source of renewable gas: either hydrogen or, with a further processing step, methane.
- The extent to which different countries will implement different solutions is likely to vary, depending on individual circumstances.
- All developments constructed to date have been of pilot and demonstration plants, with the largest electrolyser capacity less than 10MW. To produce 1Bcm of substitute natural gas would require an electrolyser capacity of around 2500MW, operating continuously.
- P2G can introduce considerable flexibility into the energy system, resulting in 'system coupling', namely much closer integration between the gas and electricity system than has previously been the case.
- Costs of production, assuming some future economies of scale, are likely to be in the range €50-100/MWh for hydrogen and €100-150/MWh for methane. These ranges are broad because of the early stage of development and uncertainty regarding the extent to which economies of scale may be achievable. A further uncertainty is the extent to which low cost renewable power will be available as input to the P2G process. The price of power-to-methane is higher than the price of biomethane derived from anaerobic digestion.
- While biomethane production is constrained by availability of suitable feedstocks, P2G does not have the same constraint, with the main constraint being suitable justification for the required investments.
- Thus while P2G could play a potentially significant role in decarbonising the existing gas network, it would require significant investment, and this is unlikely to be made without a clear strategic direction, supportive regulatory frameworks and financial incentives from the relevant governments.

Key issues to be addressed

Throughout this paper, it has been emphasised that this technology and plans for its commercial deployment are in their infancy. There are a number of outstanding key issues, and the approach taken to addressing them may make the difference between this technology remaining on the drawing board or becoming a key part of a future decarbonised energy system.

A key first question is whether the future of the gas grid will be through transformation to carry renewable hydrogen or a gradual supply transition from fossil-derived methane to various sources of renewable methane, including from P2G. This is largely a matter of government policy (to be determined through dialogue with industry players), and different solutions may be appropriate in different locations.

Governments will also need to consider the most appropriate mechanisms, be it carbon pricing, support for specific technologies or changes to regulatory frameworks, in order to motivate investors to take the actions required in order to make the changes required to achieve COP21 targets. This support will be essential to move P2G from its current status of interesting, but tiny, pilot and demonstration projects to a scale where it can demonstrate a pathway to playing a significant role in the future energy system.

OIES will continue to follow and develop updated research in these areas as the pathway to a decarbonised energy system evolves.