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# Power-to-gas for injection into the gas grid: What can we learn from real-life projects, economic assessments and systems modelling?

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ABSTRACT

Power-to-gas is a key area of interest for decarbonisation and increasing flexibility in energy systems, as it has the potential both to absorb renewable electricity at times of excess supply and to provide backup energy at times of excess demand. By integrating power-to-gas with the natural gas grid, it is possible to exploit the inherent linepack flexibility of the grid, and shift some electricity variability onto the gas grid. Furthermore, provided the gas injected into the gas grid is low-carbon, such as hydrogen from renewable power-to-gas, then overall greenhouse gas emissions from the gas grid can be reduced.

This work presents the first review of power-to-gas to consider real-life projects, economic assessments and systems modelling studies, and to compare them based on scope, assumptions and outcomes. The review focuses on power-to-gas for injection into the gas grid, as this application has specific economic, technical and modelling opportunities and challenges.

The review identified significant interest in, and potential for, power-to-gas in combination with the gas grid, however there are still challenges to overcome to find profitable business cases and manage local and system-wide technical issues. Whilst significant modelling of power-to-gas has been undertaken, more is needed to fully understand the impacts of power-to-gas and gas grid injection on the operational behaviour of the gas grid, taking into account dynamic and spatial effects.

## 1. Introduction

Power-to-gas (P2G) is a key area of interest for decarbonisation and increasing flexibility in future energy systems, due to its potential to help integrate high penetrations of renewable energy. Combining P2G with the gas grid, primarily through direct injection of hydrogen, is one of several possible applications of P2G, and it has its own advantages and challenges.

When hydrogen is combusted it releases no carbon dioxide ($CO_2$); consequently any addition of hydrogen to the natural gas grid will result in lower $CO_2$ emissions at end use [1]. Provided the hydrogen is produced in a low carbon manner – either through steam methane reforming (SMR) with carbon capture and storage (CCS) or through electrolysis of "green" electricity – then overall $CO_2$ emissions will also be reduced. Many countries, such as the UK and the Netherlands, have extensive gas grids and there is interest in finding ways to continue to make of use these networks in a low carbon future, to avoid having to abandon these valuable assets altogether [2]. Furthermore, due to the ability of the gas grid to handle a range of gas pressures, it has an inbuilt flexibility which could be exploited by P2G, shifting some variability caused by intermittent renewables on the electricity grid onto the gas grid [3].

Nonetheless hydrogen injection into the gas grid (HIGG) has technical, economical and systems-level challenges [2,4,5]. Considerable work has been undertaken to understand these challenges through research, modelling and real-life demonstrator projects, and some effort has been made to establish a coordinated approach to expanding HIGG, for example through the HYREADY project [6]. However, many academic, industrial and policy studies have called for more to be done, particularly from policymakers [2,7–11].

Several reviews of P2G have previously been performed. Schiebahn et al. [12] performed a technological review of power-to-gas with

*Abbreviations:* $\%_{HHV}$, Efficiency based on higher heating value; CAPEX, Capital expenditure; CCS, Carbon capture and storage; CHP, Combined heat and power; $CO_2$, Carbon dioxide; HIGG, Hydrogen injection into the gas grid; LP, Linear programming; MIGG, Methane injection into the gas grid; MILP, Mixed-integer linear programming; MINLP, Mixed-integer nonlinear programming; NFCRC, National Fuel Cell Research Centre; NLP, Nonlinear programming; OPF, Optimal power flow; P2G, Power-to-gas; PEM, Proton exchange membrane; SMR, Steam methane reforming; vol%, Percentage blend by volume

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respect to the gas grid, including the technologies involved in the production, distribution and end use of the gas. Some reviews, including Haeseldonckx and D'Haeseleer [13], Dodds and Demoulin [14] and Götz et al. [15], have taken a broader assessment of P2G and the gas grid, assessing both the technological and wider system challenges. However, of these only Haeseldonckx and D'Haeseleer [13] considered partial HIGG: Dodds and Demoulin [14] considered a complete conversion of the gas grid to hydrogen, and Götz et al. [15] only considered synthetic methane injection into the gas grid (MIGG). Many similar studies have also been performed by private firms and regulatory and policy-making bodies [1,2,4,16,17]. The NaturalHy project [5] was a major study commissioned by the European Commission which assessed the practicalities of delivering hydrogen in the European natural gas network, considering production, transport and end use.

Reviews of real-life P2G projects have also been performed. Gahleitner [18] performed a wide-ranging study of P2G projects and found that there was a focus of projects in Germany, but that projects had not been running long enough to draw specific conclusions on performance. Garcia et al. [19] conducted an expert opinion analysis of the potential of renewable hydrogen storage systems in Europe, including highlighting significant projects. Bailera et al. [20] reviewed 46 projects, but only considered power-to-methane.

Various approaches have been used to model P2G, but very few reviews of P2G modelling methods and their results have been performed. Typically, reviews that have been performed focus on general energy systems modelling techniques, with no interest in P2G. For example, Connolly et al. [21] reviewed models with a focus on integrating renewables into energy systems; Hall and Buckley [22] reviewed models in the UK context; and Pfenninger et al. [23] reviewed energy system models, questioning what the requirements are for these models in the twenty-first century. Blanco and Faaij [24] and Robinius et al. [25] both reviewed studies which included P2G, but only as one of a number of flexibility options, and were only concerned with the study results, not the modelling techniques.

The aim of this work is to provide a review of P2G and HIGG that for the first time considers both real-life projects and modelling studies and compares them based on scope, assumptions and outcomes. Furthermore, the interaction of P2G with the gas grid, primarily through HIGG, is of specific interest, due to the unique technical, economic and modelling characteristics associated with it. Inevitably, many P2G projects and studies include multiple P2G applications, so these are given consideration where necessary. MIGG is an alternative, or possibly complementary, pathway to HIGG which has its own set of strengths and weaknesses that are also assessed where appropriate.

The methodology comprises three elements:

1. An examination of over 130 reported real-life P2G and HIGG projects worldwide, in order to understand the historical trend in the scale and types of technology employed, as well as the types of application and the global distribution of the projects to identify what the impacts of P2G and HIGG are and where they are taking place;
2. An investigation of economic assessment studies performed for P2G and HIGG, comparing the different assumptions made about the level of hydrogen injection allowed, identifying specific business cases for the technologies and assessing the resulting levelised cost and the wider system cost; and
3. An evaluation of energy systems models that considered P2G and/or HIGG and classifying them based on: the modelling approach employed; how the gas-electricity interface, storage and linepack were represented; how the spatial and temporal dependencies of system properties were captured; and what the objectives and the key design decisions of the models were.

The results from the three steps above were synthesised and categorised based on the scope, assumptions and outcomes of this wide range of studies, in order to obtain insights about the current status of the technologies and make recommendations for future research.

The remainder of this paper is structured as follows. Section 2 discusses the practical issues concerning producing hydrogen, injecting into the transmission and distribution gas grids, and its end use. Section 3 surveys the P2G projects worldwide, with a focus on HIGG projects. Following that is a literature review of modelling studies on P2G with a focus on HIGG: Section 4 reviews economic studies with an interest in the costs and business potential of HIGG, and Section 5 surveys studies that have used optimisation to assess P2G and HIGG from a whole system perspective. Finally, Section 6 summarises and compares the scope, assumptions and outcomes of the real-life projects and modelling studies.

## 2. Practicalities of P2G and HIGG

This section provides a brief summary of the pathways and technologies of power-to-gas. A large number of studies and reviews have been carried out in this area: Schiebahn et al. [12] and Haeseldonckx and D'Haeseleer [13] are particularly recommended for more detail on this subject.

### 2.1. Production

Fig. 1 shows an overview of the gas grid injection pathways, including power-to-gas. Hydrogen can be produced from electrolysis or SMR, and injected directly into the gas grid. Provided that the electricity source used for electrolysis is low-carbon, such as wind or solar energy, electrolysis has very low environmental impact. There are many references available for details of the electrolysis process [12,26,27]. Several different electrolysis technologies exist and are used in P2G applications, as each has its own advantages and disadvantages. The most common technologies are: alkaline; proton exchange membrane (PEM); and solid oxide. Alkaline and PEM electrolysis have been used commercially for several decades in industrial applications. In recent years, manufacturers have also begun to produce commercial alkaline and PEM electrolysers capable of the more flexible operation regimes associated with P2G, although so far at a smaller scale [28]. Although solid oxide technology has been in development since the 1970s, it is less commercially established, mostly at the demonstration or pre-commercial stage [28,29]. The technologies and sizes of P2G projects are discussed further in Section 3.1.

As an alternative to direct injection, hydrogen can be combined with $CO_2$ to produce methane, by methanation (for example using Sabatier synthesis [30]). Methane is a versatile and easy to store substance, and it forms the majority of natural gas [31], however when used as an energy source the $CO_2$ will be re-released. There is considerable interest in power-to-methane as it has fewer barriers to implementation than power-to-hydrogen. However, its potential for significantly reducing $CO_2$ emissions in the long term is limited.

### 2.2. Distribution and transmission

A concern with direct injection of hydrogen into the natural gas network is hydrogen embrittlement, which can occur in pipes made of iron and steel, and can lead to propagation of cracks in the pipework [32]. It is broadly agreed that hydrogen can be injected into the distribution network at a low concentration with no serious safety issues. Although the exact level is disputed, several studies suggest that up to 15–20% hydrogen blend by volume (vol%) should be allowable [4,5,13]. Meanwhile, many regulators have seemingly arbitrarily low allowances on the amount of hydrogen in the blend. In the UK for instance the allowable limit is 0.1 vol%, whilst in the Netherlands up to 12 vol% is permitted [17]. Nowadays, polyethylene, which is not susceptible to hydrogen embrittlement, is being used more commonly in distribution networks. In the UK, for example, a major scheme is

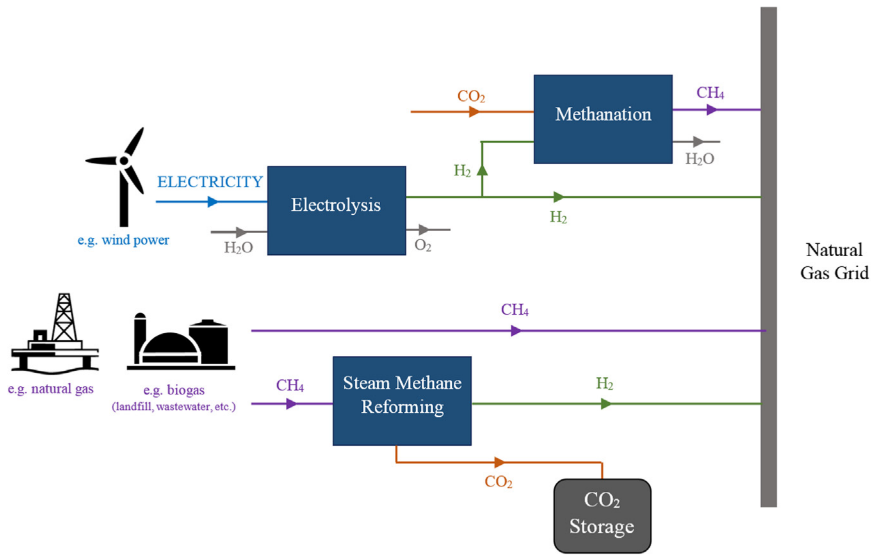


**Fig. 1.** Gas grid injection pathways, including: power-to-gas; hydrogen from steam methane reforming; direct injection of natural gas and biomethane; and synthetic methane from methanation of hydrogen.

underway to replace iron gas pipes in the distribution grid with polyethylene (the Iron Mains Replacement Program), for safety reasons unrelated to hydrogen [33].

High pressures are thought to worsen the effects of hydrogen embrittlement, so it is generally agreed that allowable levels in high pressure transmission grids, which are often made from high strength steel, would be considerably lower than for distribution grids. Should transmission of hydrogen by pipeline over longer distances be required, it is possible that a purpose built pipeline network would need to be built [14]. Another concern which has been raised regarding transporting hydrogen in existing gas grids is the propensity of hydrogen to leak. However, several studies have concluded that leakage rates would not be high enough to be a major concern [5,16].

Adding hydrogen to natural gas pipelines reduces the energy delivery of the pipeline. The effects are nonlinear and depend primarily on the energy density by volume and the flow properties of the hydrogen. As hydrogen is also less compressible than natural gas, the effect becomes more pronounced at higher pressures [1]. Fig. 2 shows the energy delivery of pipelines, at low and intermediate pressure levels, with increasing levels of hydrogen injection as a percentage of the energy delivery of pure methane. In order to manage the reduced energy delivery in gas networks, either peak energy demand would need to be reduced, or higher flowrates (causing larger pressure drops and therefore higher compression requirements) would be needed [3].

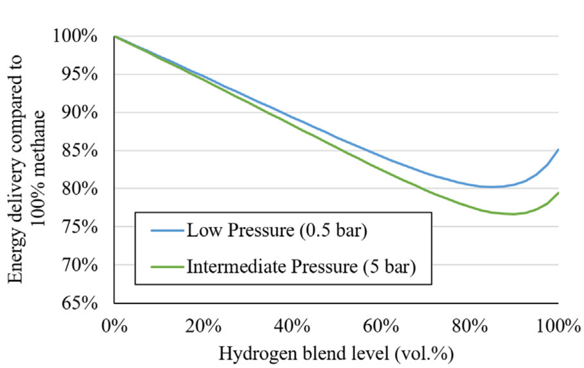


**Fig. 2.** Effect of hydrogen blend level on the energy delivery of gas pipelines (based on the relationships presented in Abeysekera et al. [34]).

### 2.3. End use

Gas from the distribution grid is most commonly used in homes for cooking and/or heating. In the UK for example, 86% of homes are connected to the natural gas grid [2]. Further safety concerns arise when considering hydrogen in the home, particularly regarding leakage and risk of ignition. For example, hydrogen has a higher risk of ignition than natural gas and, as with natural gas, it may be necessary to add an odorant to hydrogen to improve detectability. It may also be necessary to add a colourant as, unlike natural gas, a pure hydrogen flame is almost invisible [4]. Multiple studies have considered the effect hydrogen would have on the performance of household appliances, notably the NaturalHy project [5,35]. Whilst most modern appliances should be capable of burning hydrogen blends of up to 20 vol% [4], above this level it is likely that appliances would need adjusting or replacing, which would be a major undertaking [14,36].

Besides in the home, the other major uses of natural gas are in power generation and industry. These facilities are more likely to be connected to high pressure pipelines or have their own direct supply of natural gas. Introducing hydrogen blends into combustors for equipment such as gas turbines will alter the combustion characteristics. However, a considerable amount of work has been performed in recent years to design burners suited to these characteristics. Although a gas supply with a time-varying hydrogen blend level would present additional challenges, work is ongoing to overcome these challenges [37].

## 3. P2G and HIGG projects worldwide

### 3.1. Overview of P2G projects

A review of P2G projects worldwide was performed based on several references. In addition to Gahleitner et al. [18], Garcia et al. [19] and Bailera et al. [20], screenings performed by both Iskov and Rasmussen [38] and Vartiainen [39] were used. Additionally the European Power-to-Gas Platform [40], containing a database of past, current and planned P2G projects in Europe was used. Only projects which include on-site electrolysis were considered, and projects producing hydrogen solely for transport, such as refuelling stations, were excluded. According to the website H2stations.org [41], at the beginning of 2018 there were 328 hydrogen refuelling stations worldwide but many of these do not produce hydrogen through on-site electrolysis. Nonetheless plants that produce hydrogen for transport in addition to other

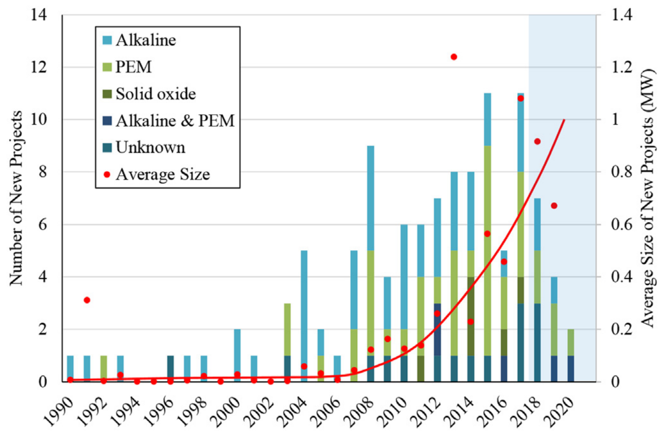


**Fig. 3.** Timeline of power-to-gas projects going into operation (data obtained from [18–20,38–40]). Data for 2018 onwards (shaded) is for known planned projects only; the actual number of new projects is likely to be higher.

applications were included in the review. Electrolysis has been used to produce hydrogen for industrial applications since 1940 [42] – these historic projects were not included due to a lack of literature. Based on these references and criteria, over 130 P2G projects were identified worldwide.

Fig. 3 shows the number of P2G projects that began operation in each year since 1990. After a small number of projects in the 1990s, increasing interest in P2G can be seen throughout the 2000s and 2010s. A breakdown of new electrolyser technology type per year is also shown. As can be seen, alkaline and PEM technologies dominate, with alkaline electrolysis being used in the majority of early projects, and PEM technologies growing in popularity more recently. Today, the two technologies have comparable performance characteristics and specific project requirements tend to determine the technology choice. Six projects have employed solid oxide technology, all intending to demonstrate the functionality of the technology and the wider system. These projects either use the reversibility of the solid oxide technology (operating in both electrolysis and fuel-cell mode) [43]; co-electrolysis (to produce synthetic natural gas or liquid fuels) [44–46]; or both of these functionalities [47,48]. Regarding future projects (from 2018 onwards), it is likely that additional projects are in planning for which no literature was found.

The average size (electrolysis capacity) of new projects each year is also shown in Fig. 3, with a clear upward trend. Fig. 4 also illustrates project sizes by categorising them by size and operational status. Electrolysis capacity is used as the measure of plant size rather than hydrogen output, as the data are more easily available. According to a market survey by Buttler and Spliethoff [28], individual alkaline electrolyser stacks are available up to a capacity of 6 MW, whilst PEM stacks are typically smaller, with capacities of up to 2 MW. However, it is possible to install multiple electrolyser stacks at a single site, achieving overall electrolysis capacities of multiple megawatts using either technology. In addition to offering "nominal" capacities which can be maintained for continuous operation, electrolyser manufacturers commonly offer higher "peak" capacities for short term operation, a useful feature for grid balancing [17].

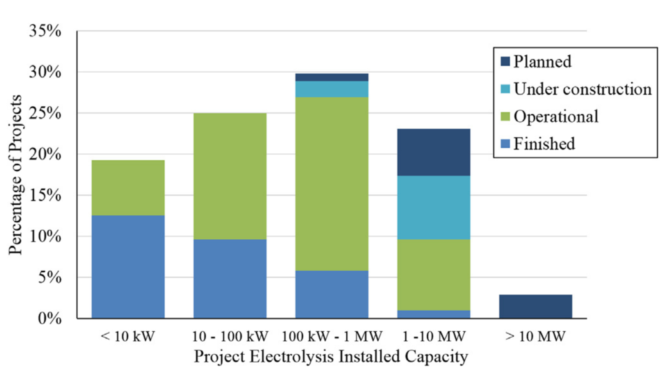


**Fig. 4.** Nominal electrolyser capacities of the projects examined in this paper (data obtained from [18–20,38–40]).

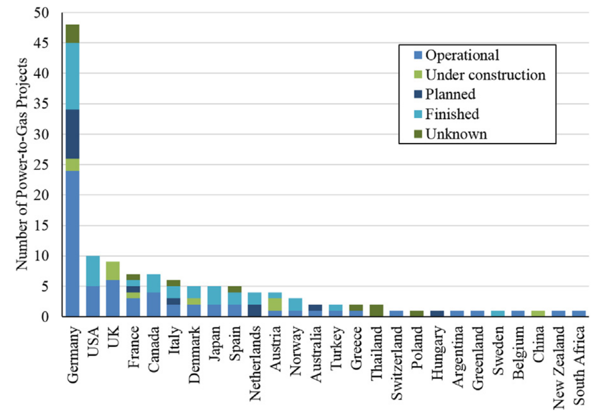


**Fig. 5.** Locations of power-to-gas projects (data obtained from [18–20,38–40]).

Almost half (43%) of all projects reviewed had an electrolysis capacity of less than 100 kW, however all planned projects are at least 0.5 MW in size. The largest plant in operation is the Audi e-gas plant in Werlte, Germany [18,20,49]. The plant has three electrolysers with a total capacity of 6.3 MW. The electrolysers are operated variably, powered by wind, and the hydrogen is used to produce methane which is injected into the gas grid (MIGG). The planned H2V Product project in France is far bigger, with 100 MW of electrolysis planned for HIGG [50,51]. This project is discussed in more detail in Section 3.2.

Fig. 5 shows the countries in which all completed, operational and planned projects are located. Germany leads in all of these categories, hosting over a third of all of the P2G projects that were identified. The USA has hosted a significant number of finished or currently operational projects, but all of these are quite small in size, and no planned projects in the USA were identified at all. Many countries, predominantly located in Europe and including the UK, have between four and nine projects either completed, operational or planned. Fifteen other countries (including Greenland) were identified which host three projects or fewer, meaning that twenty-six countries were covered in total.

Fig. 6 shows the functions of all of the P2G projects identified. As can be seen, many projects have multiple functions (such as power and heat). Despite the low round-trip efficiency, over half of all projects include power-to-power functionality. The majority of these projects use hydrogen as a storage medium to provide a more stable power supply from renewable energy – either in a micro-grid setup where a small community relies on a local renewable electricity supply, or for wind farms connected to the grid aiming to provide a more stable electricity output. Despite transport-only plants being excluded from the review, still 18% of projects include delivery of hydrogen as a transport fuel as an additional functionality. Injection into the gas grid is another common function of the projects: 19% inject hydrogen directly whereas 8% inject methane. Other common uses for the hydrogen are for heating and as an industrial feedstock.

### *3.2. HIGG projects*

Twenty-five projects were found that include HIGG, which represent 18% of the P2G projects that were reviewed. The details of these projects are summarised in Table 1.

There have been a few projects investigating the effects of HIGG on the pipelines and end use appliances. The first was the Lolland

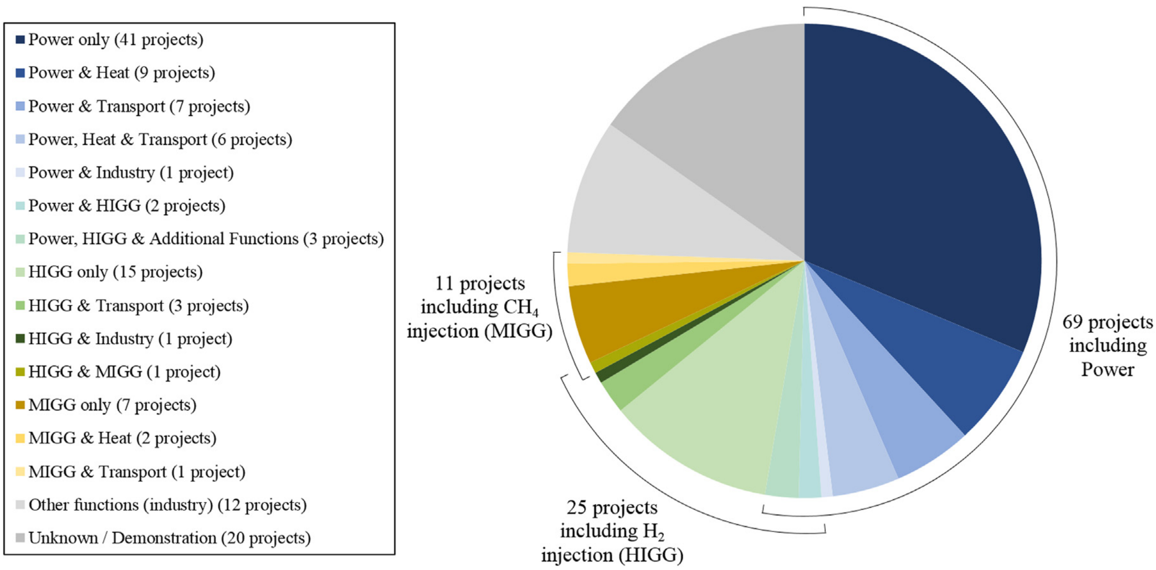


**Fig. 6.** Breakdown of the functions of power-to-gas projects (data obtained from [18–20,38–40]). Note that due to the very large numbers of transport-only projects that have been carried out, they were not included in the diagram. "Demonstration" refers to projects whose sole purpose was the demonstration of the technology, with no specified outlet for the hydrogen.

Hydrogen Community project [52], although rather than using an existing gas grid, a purpose-built pipeline network was constructed to supply pure hydrogen to 40 homes. Each home was fitted with a micro-combined heat and power (CHP) unit which used the supplied hydrogen for heating and electricity. Up to 20 $Nm^3/h$ of hydrogen could be supplied by the PEM electrolyser. A project with a similar scope began in 2008 in Ameland in the Netherlands [53]. Fourteen homes in an apartment block were supplied with gas for heating and cooking. A PEM electrolyser was installed which could produce up to 1.05 $Nm^3/h$ of hydrogen, and at its maximum, up to 20 vol% hydrogen was injected. No effects from the hydrogen were detected in any of the pipework, the standard boilers and cookers that were used in the homes passed all of the safety tests and no issues were identified during operation. The National Fuel Cell Research Centre (NFCRC) in California, USA, are carrying out a small HIGG research project [56,57]. A 7 kW PEM electrolyser is connected to a solar PV supply, in order to assess the operational performance of the system under variable electricity supply. A 60 kW electrolyser was also installed which supplies hydrogen to be injected into a small "off-system" natural gas grid. This setup is used to assess the physical impacts of HIGG on a pipeline network.

The GRHYD project in Dunkirk, France, which began operating in 2017, has similar objectives but is of a larger scale, injecting hydrogen produced by electrolysis into a gas grid supplying around 200 new homes [66]. The injection blend level will be stepped up to levels of 6 vol%, 13 vol% and finally 20 vol%. The electricity supply rate from the electricity grid will be varied to simulate the effects of a variable renewable supply. Finally, of a similar scope is the planned HyDeploy

**Table 1**
Power-to-gas projects that include hydrogen injection to the gas grid.

| Project | Start Date | Status | Electrolyser Type | Size (kW, nominal) | References |
|---|---|---|---|---|---|
| Lolland Hydrogen Community, Denmark | 2007 | Operational | PEM | 104 | [18,38–40,52] |
| P2G Ameland, Netherlands | 2008 | Finished | PEM | 8.3 | [38–40,53] |
| P2G Frankfurt, Germany | 2013 | Finished | PEM | 315 | [39,40,54] |
| WindGas Falkenhagen, Germany | 2013 | Operational | Alkaline | 2000 | [18,38–40,55] |
| P2G NFCRC, USA | 2014 | Finished | PEM | 67 | [56,57] |
| Hybrid Power Plant Enertrag, Germany | 2014 | Operational | Alkaline | 500 | [18,19,38–40,58] |
| Energiepark Mainz, Germany | 2015 | Operational | PEM | 3750 | [39,40,59] |
| WindGas Hamburg, Germany | 2015 | Operational | PEM | 1000 | [19,38–40,60] |
| Hybridwerk Solothurn, Switzerland | 2015 | Operational | PEM | 350 | [20,40,61] |
| RWE Ibbenbüren, Germany | 2015 | Operational | PEM | 150 | [38–40,62] |
| Wind2Hydrogen, Austria | 2015 | Operational | PEM | 100 | [19,40,63] |
| H2BER,Germany | 2015 | Operational | Alkaline | 500 | [39,40,64] |
| P2G Hassfurt, Germany | 2016 | Operational | PEM | 1250 | [39,40,65] |
| GRHYD, France | 2017 | Operational | Alkaline | Unknown | [19,38–40,66,67] |
| Wind to Gas Südermarsch, Germany | 2018 | Operational | PEM | 2400 | [40,68] |
| Kidman Park, Australia | 2018 | Planned | Unknown | Unknown | [69] |
| Jupiter 1000, France | 2018 | Under construction | Alkaline & PEM | 1000 | [39,40,67,70] |
| HPEM2GAS, Germany | 2019 | Planned | PEM | 180 | [71] |
| HyDeploy, UK | 2019 | Under construction | PEM | 500 | [40,72] |
| H2V Product, France | 2021 | Planned | Alkaline | 100,000 | [50,51] |
| P2G Ontario, Canada | Unknown | Under construction | PEM | 2000 | [73] |
| P2G Hanau, Germany | Unknown | Operational | PEM | 30 | [40,74] |
| RH2-PTG, Germany | Unknown | Planned | Unknown | Unknown | [39,75] |
| Storag Etzel, Germany | Unknown | Planned | Unknown | 6000 | [40,76] |
| P2G Wyhlen, Germany | Unknown | Planned | Alkaline | 1000 | [40,76] |

project at Keele University in the UK. This project will see hydrogen blends of up to 20 vol% injected into the university's private gas network in order to assess the performance of the network and all of the associated appliances. The university campus contains a variety of gas users including homes and more heavy duty use, so is representative of a town of 12,000 residents. After planning and checks on the network, hydrogen injection is due to take place for one year from April 2019 [72].

HIGG has seen the most development in continental Europe, predominantly Germany. Here, several projects are using electrolysis for electric load balancing, and have shown that electrolysers are capable of rapidly following variable loads, and that low levels of hydrogen (typically not more than 5 vol%) can be injected with no technical issues. However, these projects are still in the exploratory stages, and many are still attempting to find sustainable business models, with or without government support. The economics of HIGG projects is explored further in Section 4.

One of the first projects of this kind was by energy company Thüga in Frankfurt, Germany [54], where grid electricity was used to power a 315 kW PEM electrolyser, and the produced hydrogen was injected into the local 3.5 bar gas distribution grid at a controlled blend level of 2 vol %. Results from the project showed that the system was quick enough to be able to access the electricity balancing market.

Several projects are still in operation, including two plants from German energy company Uniper: WindGas Falkenhagen [55] and WindGas Hamburg [60]. In Falkenhagen, 2 MW of alkaline electrolysis capacity is connected to a wind farm and the produced hydrogen is injected into the 55 bar gas transmission grid at a blend level of 2 vol%, showing that hydrogen injection into high pressure pipelines can be achieved, at low levels at least. In the first year of operation, Uniper claim that they injected 2 GWh of hydrogen into the grid. In Hamburg, 1 MW of PEM electrolysis capacity is connected to a wind farm, trialling the newer technology at a larger scale.

Further German projects include one in Hassfurt [65], which includes 1.25 MW of PEM electrolysis capacity and can inject up to 5 vol% into the gas grid when excess renewable electricity is available, and one in Brunsbüttel [68], with a single 2.4 MW PEM electrolyser connected to a nearby 15 MW wind park. One of the few grid balancing HIGG projects being carried out outside of Germany is the Wind2Hydrogen project in Austria [63] but this is quite small in size with only 100 kW of PEM electrolysis capacity.

Three projects in this category enhance the load balancing offering with CHP in addition to HIGG. The first is the Hybrid Power Plant Enertrag [58], based in Prenzlau, Germany, which can store the hydrogen produced by a 500 kW alkaline electrolyser and use it at a later time in combination with biogas in a CHP unit [39], or alternatively inject the hydrogen directly into the gas grid. In the first three months, 100 MWh of hydrogen was injected. In Solothurn, Switzerland, grid electricity is used in a 350 kW PEM electrolyser, and the resulting hydrogen is stored and injected into the gas grid [61]. Meanwhile, an on-site CHP unit is operated using gas from the grid. Finally, a similar setup exists at the RWE P2G plant in Ibbenbüren, Germany [62]. At times of high renewable generation, a 150 kW PEM electrolyser produces hydrogen for injection into the natural gas grid. At times of low electricity supply, a CHP unit supplied from the gas grid produces electricity and heat.

The Energiepark project in Mainz, Germany is the largest HIGG project in operation, with electrolysis capacity of 3.75 MW. Electricity input is available from both the grid and a nearby wind farm, and hydrogen is injected into the 6–8 bar gas grid, at blend levels of up to 15 vol% [59].

There are also several electric load balancing projects that are yet to begin operation. Several of these are based in Germany and are of a similar scale to existing projects, such as the RH2-PTG project [75], the HPEM2GAS project [71], and a project run by EnergieDienst in Wyhlen [77]. Further planned projects of this scale, but outside Germany include the Jupiter 1000 demonstration project [67,70] in Foss-sur-Mer, France, which will demonstrate P2G, HIGG and MIGG using both PEM and alkaline electrolysers; a project in Ontario, Canada [73], and the first HIGG project in Australia [69].

A larger project, with 6 MW of electrolysis capacity, is planned in Etzel, Germany [76], with the primary focus of investigating salt caverns for hydrogen storage but also including HIGG. Of a completely different scale is the planned H2V Product project in Northern France, which will see the installation of 40 alkaline electrolysers, for a total electrolysis capacity of 100 MW. This plant is still in the early planning stages and is the first part of the ambitious H2V Product project which aims to install several large HIGG plants across France [50,51].

Finally, two of the identified projects have HIGG capability, but not as the main activity of the plant. Rather, hydrogen is only injected into the gas grid when either the capacity of the usual outlet or storage of the plant is exceeded. These are also both located in Germany, at the Berlin Brandenburg Airport [39,64] and at the Wolfgang Industrial Park in Hanau [74].

## 4. Economic assessment studies on P2G

Significant interest in P2G has led to many assessments of the economics of P2G being performed. These assessments are concerned with the costs and potential usefulness of P2G in the wider energy system. Table 2 summarises the studies, with a focus on gas grid injection, that have been reviewed.

Various approaches were taken to assessing the economic potential of P2G and HIGG, including "case study" assessments, looking at specific business cases, such as a particular plant setup; "levelised cost" assessments of the final product gas (usually hydrogen); and wider

**Table 2**
Summary of power-to-gas economic assessments.

| Study Type | Author(s) | Year | Geographical scope | Timeframe | HIGG | Ref. |
|---|---|---|---|---|---|---|
| Case study | Dickinson et al. | 2010 | South Australia | 2010 | Not modelled | [78] |
| | Scamman et al. | 2013 | UK | 2015 – 2050 | ≤ 21 vol% | [17] |
| | de Joode et al. | 2014 | Regions within the Netherlands | 2014 – 2030 | 0.02 vol%; 0.5 vol%; 100 vol% | [79] |
| | Bertuccioli et al. | 2014 | Europe | 2012 & 2030 | Unspecified low level | [27] |
| | Guandalini et al. | 2015 | Generic European country | 2015 | Unspecified low level | [80] |
| | Budny et al. | 2015 | Plant in Germany | 2015 | On-site pipe storage | [81] |
| | FCHJU | 2015 | Europe | 2015 – 2050 | Not modelled | [82] |
| | Thomas et al. | 2016 | Flanders, Belgium | 2015 – 2050 | Unspecified low level | [10] |
| | Sadler et al. | 2016 | Leeds, UK | 2013 – 2029 | None | [42] |
| Levelised cost | Schiebahn et al. | 2015 | Germany | 2015 | 5 vol% | [12] |
| | de Bucy | 2016 | Generic European country | 2016 – 2050 | Unspecified low level | [83] |
| | Parra et al. | 2017 | Plant in Switzerland | 2017 | 10 vol% | [84] |
| System cost | Polman et al. | 2003 | UK / France / Netherlands | 2025 | ≤ 25 vol% | [1] |
| | Ma & Spataru | 2015 | UK | 2015 | ≤ 50 vol% | [85] |

system cost assessments.

The studies indicate that it is difficult to find profitable business cases for HIGG. Thomas et al. [10], for example, studied eight different renewable hydrogen case studies for the region of Flanders in Belgium and failed to find any competitive scenarios in 2015; the only competitive scenarios were found for industry and transport (not HIGG) in 2050. This is largely due to the low value of natural gas in the gas grid compared to the higher price of electricity used to produce the hydrogen. Schiebahn et al. [12], for example, found the levelised cost of hydrogen in the gas grid to be almost four times larger than the current gas price. De Bucy [83] and Parra et al. [84] both calculated similar results for 2015, and predicted that although by 2050 the levelised hydrogen cost would fall, it would still be higher than the gas price.

To find more favourable business cases, studies were required to consider the additional benefits that P2G plants could provide, such as grid balancing services. Scamman et al. [17] found that a 1 MW P2G plant could be profitable in the UK in 2030 if it had access to free excess electricity and demand-side management markets. However, these cases are still challenging due to the limited hours where balancing markets or surplus renewable energy are available. As a result, any cases that do find HIGG to be profitable rely on policy support. For example for the same case, Scamman et al. found that a hydrogen feed-in tariff of £ 170/MWh would be required for the plant to be profitable in 2015. Similarly, Guandalini et al. [80] found profitable cases when hydrogen feed-in tariffs of €20/MWh and a carbon tax of at least €40/t$CO_2$ were included.

A further challenge is the technical limitations of hydrogen in the gas grid, for example the low allowable concentration of hydrogen in the blend. The assumptions made regarding this constraint vary widely across the literature, which reflects the uncertainty and variability in regulation around the world. In those studies that used very low restrictions, the capacity or demand available for HIGG was found to be too low to offer a worthwhile market. For example de Joode et al. [79] studied three case studies in the Dutch energy system but only allowed a maximum HIGG level of 0.5 vol%. Consequently, where there was an alternative to P2G available, such as electricity transmission lines, this was economically preferable. Polman et al. [1] performed an investigation of the technical challenges of hydrogen in the gas grids in the UK, Netherlands and France. It was found that small amounts (up to 3 vol%) of hydrogen could be injected into the gas grid with little cost or impact, which could provide a small but useful outlet for hydrogen produced from renewable energy. However, the cost effectiveness of higher levels of injection was found to be very poor, with a maximum of a 4% reduction in $CO_2$ emissions being achieved with a 25 vol% hydrogen injection level. This poor $CO_2$ mitigation was due to the overall (average) hydrogen blend level being much lower than the peak, the lower volumetric energy density of hydrogen, and the non-zero $CO_2$ impact of the hydrogen (in this study, the hydrogen was produced from SMR with CCS).

Those studies that considered alternative P2G applications found transport to be a more profitable option than HIGG, such as Schiebahn et al. [12], de Joode et al. [79] and Thomas et al. [10]. This is predominantly due to the considerably higher value of energy in the transport market compared to the gas or electricity markets.

The H21 Leeds City Gate project [42] is not a P2G project, as it considers hydrogen production from SMR in its economic assessment of a switch for the city of Leeds, UK, from natural gas entirely to hydrogen. SMR was chosen due to the very large supply of hydrogen required (6 TWh per year). Nonetheless, the potential of electrolysis for supplementing hydrogen supply was identified in the report. Furthermore, the study is of interest due to its ambitious scope and detailed review of the requirements for the production, distribution and end use of hydrogen. For example, the linepack storage capacity of the gas grid was considered, accounting for the reduced calorific value of hydrogen compared to natural gas. As a result, additional intra-day salt cavern storage was included in the design. Further salt cavern storage was also specified to cover inter-seasonal differences in demand, allowing the SMRs to operate more consistently throughout the year. Overall, the study found that the switchover would cost around £ 2 billion and would reduce the carbon emissions associated with heating in the city by 73%.

Although these studies evaluate possible business cases and identify challenges that need to be addressed if P2G and HIGG are to be profitable, they are limited in a number of ways. Many of the studies focus on the cost or profitability of a few pre-defined cases without considering the wider system benefits. For example, these studies have limited ability to model the intermittency of renewable energy and the need for storage. Furthermore, as they do not model the physical aspects of P2G and HIGG, these studies assumed that these strategies would be technically feasible. Even those studies that do consider the wider system do not take into account system dynamics, instead performing the evaluation based on a few operating points at most.

## 5. Simulation and optimisation of gas and electricity networks with P2G

In this section, studies using more in-depth mathematical modelling of gas and electricity systems and P2G are reviewed. Various categorisations have been used for these techniques: here, a commonly used distinction (e.g. used by [21–23]) between *optimisation* and *simulation* models is used.

Optimisation modelling involves defining an "objective function", which quantifies the performance of the system as a function of design and operating variables of the system (which are decision variables). This could be any suitable performance metric, such as cost, efficiency or environmental impact. The solver determines the values of the decision variables that maximise or minimise the objective function, subject to a number of constraints. The constraints can be physical limitations of the technologies, such as the maximum amount of energy that can be stored or the maximum rate of operation of a technology, and also policy constraints such as siting of technologies, emissions targets, investment budgets etc.

Optimisation modelling has been used for many applications, and various techniques have been developed [86]. In linear programming (LP), optimisation variables are continuous, and the model constraints and objective function involve only linear functions of these variables. As a result, LP problems are relatively straightforward to solve. However many real life systems exhibit nonlinear behaviour. If these nonlinearities cannot be approximated linearly it can be necessary to include nonlinear functions in either the objective function or the constraints, resulting in a nonlinear programming (NLP) problem. These problems might have improved representation of the physical system, but are considerably more difficult to solve. Additionally, in some cases, variables may be required to take integer values only (for example an on/off binary decision). The resulting problem will be a Mixed-integer linear programming (MILP) or Mixed-integer nonlinear programming (MINLP) problem, which are also more difficult to solve, as continuous optimisation techniques cannot be used.

There can be a trade-off between realistic representation of the problem and solvability. Many energy systems problems are not suited to linear modelling. For example classical gas network modelling involves nonlinear functions of the pipeline pressures. Meanwhile many energy system decisions are binary, e.g. should a plant be built in a certain location, or not? In this section, several methods for overcoming these challenges will be explored.

Unlike optimisation, simulation involves modelling a single scenario based on a fixed set of inputs. Alternative scenarios can be modelled and compared but no decisions are made by the model. In the context of energy systems, simulation models are often thought of as models which generate "forecasts" of the future evolution of systems [23]. However, simulation can also be used at a greater level of detail, for example to model operation of a gas network [87] or individual power

**Table 3**
Details of power-to-gas optimisation models.

| Study author(s) | Model name & reference | Modelling approach | Spatial representation | Temporal representation | Objective function(s) | Key design decisions | Key operation decisions | Gas grid | Elec. grid | HIGG | MIGG |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Dodds et al. [14,89] | UK MARKAL [90] | LP optimisation | UK represented as 1 region | Yearly/decadal time steps, with (unlinked) time-slicing for shorter variability | Min cost | Penetration of each tech. in each year/decade | Average operation of each tech. type in each year/decade | ✓ | ✓ | ✓ | ✓ |
| IEA [91] | TIMES [92] | LP optimisation | Global represented as 1 region | Yearly/decadal time steps, with (unlinked) time-slicing for shorter variability | Min cost | Penetration of each tech. in each year/decade | Average operation of each tech. type in each year/decade | ✓ | ✓ | ✓ | ✓ |
| de Joode et al. [79] | OPERA [79] | Optimisation (formulation unknown) | Netherlands represented as 1 region (multiple regions can be modelled) | 1 year represented, with (unlinked) time-slicing for hourly variability | Min cost | Penetration of each tech. in each year/decade | Operation of each tech. type in representative time slice | ✓ | ✓ | ✓ | ✓ |
| Vandewalle et al. [93] | Unnamed [94] | MILP optimisation | Belgium represented as 1 region | 1 year represented with a 15 min time interval & 3 day rolling horizon | Min operational cost | Number of each generation or P2G tech. to be used in the given year | Operation of each tech. in each time interval | ✓ | ✓ | | ✓ |
| Sveinbjörnsson et al. [95] | SIFRE [96] | MILP optimisation | Danish town represented as 1 region | 1 year represented with a 1 h time interval & 1 week rolling horizon | Min operational cost | Penetration of each tech. type for the given year | Operation of each tech. in each time interval | ✓ | ✓ | | ✓ |
| Jentsch et al. [97] | Unnamed [97] | MILP optimisation | Germany represented as 18 zones | Unknown time horizon, with a 1 h time interval | Min operational cost; Min excess energy | Penetration and spatial distribution of P2G techs. | Operation of each tech. in each time interval | | ✓ | | ✓ |
| Abeysekera et al. [34] | Unnamed [34] | Newton-node simulation | Generic 12 node gas network | Steady state | n/a | n/a | n/a | ✓ | | ✓ | ✓ |
| Hafsi et al. [98] | Unnamed [98] | Newton-loop simulation | Generic 9 node gas network | Steady state | n/a | n/a | n/a | ✓ | | ✓ | |
| Pellgrino et al. [87] | Unnamed [87] | Non-isothermal nodal simulation | Italian region represented with 80 nodes (gas) | Steady state | n/a | n/a | n/a | ✓ | | ✓ | ✓ |
| Tabkhi et al. [99] | Unnamed [99] | NLP optimisation | Generic 3 pipeline network with compressor stations | Steady state | Min fuel consumption; Max transmitted power; Max $H_2$ injection | None | Network pressures and flow rates | ✓ | | ✓ | |
| Devlin et al. [100] | Unnamed [100] | MILP optimisation | GB & Ireland represented with 19 buses (elec.) & ~ 40 nodes (gas) | 1 year represented with a 1 h time interval & 1 day rolling horizon | Min operational cost | None | Operation of each tech. in each time interval | ✓ | ✓ | | |
| Deane et al. [101] | Unnamed [101] | MILP optimisation | EU represented with 1 bus (elec.) & 1 node (gas) per country | 1 year represented with a 1 h time interval & 1 day rolling horizon | Min operational cost | None | Operation of each tech. in each time interval | ✓ | ✓ | | |
| Zhang et al. [102] | Unnamed [102] | MILP optimisation (elec.) + Newton-node simulation (gas) | Generic network with 6 buses (elec.) & 76 nodes (gas) | 1 month represented with a 1 h time interval | Min operational cost | None | Operation of each tech. in each time interval | ✓ | ✓ | | |
| Zhang et al. [103] | Unnamed [103] | MILP optimisation (elec.) + Newton-node simulation (gas) | Generic network with 118 buses (elec.) & 4 nodes (gas) | 20 years represented with a 1 month time interval & 3 load blocks per month | Min net present cost | Whether to build candidate generation or transmission techs. | Operation of each tech. in each time interval | ✓ | ✓ | | |
| Zeng et al. [104] | Unnamed [104] | Newton-node simulation | Generic network with 9 buses (elec.) & 7 nodes (gas) | Steady state | n/a | – | – | ✓ | ✓ | | |
| Qadrdan et al. [105,106] | CGEN [107] | MINLP optimisation | GB represented with 16 buses (elec.) & 47 nodes (gas) | Up to 1 week represented with a 1 h time interval & 1 day rolling horizon | Min operational cost; Min total costs | Installed capacity of P2G facilities at different locations | Operation of each tech. in each time interval; transport flows; storage | ✓ | ✓ | | ✓ |
| Clegg & Mancarella [3,108] | Unnamed [108] | | | 1 year represented with a 30 min time interval | | | Operation of each tech. in each time interval | ✓ | ✓ | ✓ | |

(continued on next page)

**Table 3** (*continued*)

| Study author(s) | Model name & reference | Modelling approach | Spatial representation | Temporal representation | Objective function(s) | Key design decisions | Key operation decisions | Gas grid | Elec. grid | HIGG | MIGG |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | NLP optimisation (elec.) + Nodal simulation (gas) | GB represented with 29 buses (elec.) & 79 nodes (gas) | | Min operational cost + Max P2G integration (2-stage optimisation) | Installed capacity of P2G facilities at different locations | | | | | |
| Pudjianto et al. [109] | Unnamed [109] | MILP optimisation | GB represented as 5 zones (each with 10 subregions) | 1 year represented with a 1 h time interval | Min net present cost | Whether to reinforce existing infrastructure & invest in candidate infrastructures | Operation of each tech. in each time interval | ✓ | ✓ | ✓ | ✓ |
| Geidl et al. [110,111] | Energy Hub Model [110] | MINLP optimisation | Single plant ("Energy hub") | 1 or more steady state time intervals | Min cost | Configuration of conversion & storage technologies for a given plant | Operation of techs. within plant | | ✓ | | |
| Almansoori & Shah [112–114] | Unnamed [112] | MILP optimisation | GB represented as 34 zones | 6 year time steps, cannot capture shorter dynamics | Min net present cost | Number, size & location of production, transport & storage techs. | Operation of each tech. in each time interval | ✓ | ✓ | | |
| Mesfun et al. [115] | BeWhere [115] | MILP optimisation | Alpine Europe represented with 3000 grid cells | 1 year represented, with (unlinked) time-slicing for hourly variability | Min total cost; Min $CO_2$ emissions | Number, size & location of conversion techs. | Operation of each tech. in each time interval | | ✓ | | ✓ |
| Kötter et al. [116] | Unnamed [116] | Optimisation (formulation unknown) | Small region in Germany represented with 17 subregions | Unknown time horizon, with 15 min time interval | Min total cost | Penetration of each tech. type | Operation of each tech. in each time interval | ✓ | ✓ | | ✓ |
| Samsatli et al. [117–120] | Value Web Model [119] | MILP optimisation | GB represented as 16 zones | Decadal timesteps for planning and (linked) time-slicing for hourly variability | Min net present cost (or max NPV); Min $CO_2$ emissions; Max energy production | Number, size & location of conversion, transport & storage techs. | Operation of each tech. in each time interval | ✓ | ✓ | | ✓ |

plant [88].

Given that a variety of approaches exist for modelling energy systems, particularly when modelling the interactions between gas and electricity networks, a range of models have been reviewed which include simulation, dispatch optimisation, equilibrium optimisation, and supply chain optimisation. Table 3 provides details of the models that were reviewed.

### 5.1. Modelling objectives and approach

Simulation models can be used to assess the behaviour of gas in pipeline networks by calculating pressures, flow rates and temperatures under different operating conditions. Several studies have used these techniques to assess the effects of HIGG on pipeline networks, with varying assumptions concerning steady state or transient conditions, compressibility, and isothermal behaviour [34,87,98]. These studies use nonlinear gas flow equations to express the pressure drop along a pipeline in terms of the gas properties and the pipe's physical characteristics. Kirchoff's laws are then used to assess gas flow around the network, by ensuring that either nodal gas flows or pressure drops around a loop sum to zero. Zeng et al. [104] used a similar approach, also including an electricity network in the problem: all gas and electricity flows were converted to a per-unit system and were summed to zero at each node.

Whilst simulation models are able to assess the effects of P2G and compare scenarios, they are not able to make decisions. Tabkhi et al. [99] integrated optimisation into a gas network simulation problem by including compressor stations with variable operating regimes. An NLP optimisation was used to optimise compressor performance or energy throughput subject to constraints on the required level of HIGG.

In electrical power engineering, optimisation is widely used to solve the Optimal Power Flow (OPF) problem. In its classic form, the OPF is a combination of the economic dispatch problem with electricity network power flow equations [121]. The cost of generation is minimised for a point in time, based on the generators available on the network (each of which has its own operation cost curve), subject to network power flow constraints. The cost curves are often nonlinear, leading to the additional challenges of solving an NLP problem. Various versions of the OPF problem exist, such as scheduling and planning problems which have longer time frames and often include binary on/off decisions – resulting in a MINLP (or sometimes MILP) problem. Jentsch et al. [97] and Kötter et al. [116] both used OPF models to assess the potential for P2G in high renewable energy scenarios, but each used simplifications to maintain linear problems.

Clegg and Mancarella [3,108] combined a gas network simulation with an OPF model. A two-stage optimisation was used: first, the OPF problem was solved for an electricity network. Then, an optimisation was performed to install P2G facilities in the locations which would provide the maximum benefit, in terms of the unused renewable power generation available from the first dispatch. Finally, a gas network simulation was performed to balance gas supplies (including from P2G) with demands (including from electricity generators). A transient gas flow analysis was performed in [108], whilst a steady state analysis was performed in [3]. In both cases, a nodal balance was performed to ensure that the optimal electricity dispatch could be supported by the gas network. If a solution could not be found, the two-stage optimisation could be re-run with additional constraints at the gas nodes which could not be solved. A similar approach was used by Zhang et al. [102]. Whilst this approach is able to find a cost optimal electricity dispatch which maximises the benefit of P2G and is feasible for the gas network, the solution might not be optimal for the overall system as dispatch and P2G are optimised separately, and gas network operating costs are not taken into account.

OPF was also combined with gas network modelling in the CGEN model, developed by Chaudry and co-workers [107]. In this case the gas network nodal balance constraints were included in the optimisation at every timestep, which helps to ensure that the solution is optimal for the whole system. Devlin et al. [100] and Deane et al. [101] also developed models which perform OPF and gas flow balancing at every timestep. In order to retain a linear (MILP) problem, linear generator cost curves were used and the gas flow was modelled as "energy flow", rather than modelling pressures around the network.

"Equilibrium" models assess the wider energy system by taking into account economics and resource supplies and demands. Objective functions can include operational and investment costs in order to seek an overall optimum system design. Whilst they are often able to consider a large number of different technologies, these models can lack the resolution to model finer details. For example, they might only consider overall penetration of a given technology type, rather than installation of specific facilities. As a result, many equilibrium models exclude integer decisions altogether.

Most well known and widely used in this category is the MARKAL/TIMES family of models [92,122]. Dodds and McDowall [89] used the UK MARKAL model to assess the potential for HIGG in the UK, whilst the IEA used TIMES to assess P2G in their Hydrogen and Fuel Cells Technology Roadmap [91]. Other equilibrium models that have been used to assess P2G include the OPERA model [79], SIFRE [96], and the model used by Vandewalle et al. [93,94].

A final category is supply chain models. Traditionally, supply chain models were developed to optimise the operations (and sometimes the design) of manufacturing supply chains, which may include demand forecasting, logistics and inventory management, taking account of production and delivery lead times. Supply chain models have been applied to energy systems, and can be used to optimise system design, such as types, sizes and locations of energy conversion, transport and storage technologies, whilst accounting for the operation of these technologies in different timesteps. Typically these models involve discrete decisions regarding whether technologies are installed, and form MILP problems as a result.

Almansoori and Shah [112–114] developed a hydrogen supply chain model concerning the production and distribution of hydrogen for mobility, however the gas and electricity grids were not included. Other notable supply chain models that have included the gas and electricity grids are the BeWhere model, developed by Mesfun et al. [115], and the Value Web Model, developed by Samsatli and co-workers [119].

### 5.2. Modelling of gas-electricity interface

In practice, there are different ways in which energy can be transferred between the gas and electricity networks. Gas-to-power conversions (such as combined cycle gas turbines) are the conventional interface, and many studies, such as Devlin et al. [100], Deane et al. [101], Zhang et al. [102,103], and Chaudry and co-workers [107,123–126], only included these.

Power-to-gas conversions include HIGG and MIGG. Several studies included MIGG, such as Vandewalle et al. [93], Sveinbjörnsson et al. [95], Zeng et al. [104], Mesfun et al. [115] and Kötter et al. [116]. The MIGG interaction is fairly simple to model. Assuming that the impacts of MIGG on the behaviour of the gas grid are minimal, it can be represented by a conversion efficiency between a quantity of electricity and a quantity of gas. As Jentsch et al. [97] did not model gas flows, MIGG was only modelled as a revenue from selling the produced methane at the gas price.

Due to the differing physical properties of hydrogen compared to natural gas, the behaviour of hydrogen in the gas grid is more complex. Those studies that have modelled HIGG have taken a range of approaches to modelling these effects.

Dodds et al. [89], IEA [91] and de Joode et al. [79] only considered overall demands and supplies of energy, so only the efficiency with which hydrogen can be produced (e.g. from electricity) was considered. Qadrdan et al. [105,106] converted injected hydrogen into the equivalent volume of natural gas which would carry the same quantity of energy, effectively modelling HIGG in the same way as MIGG. In this way, energy flows are represented but the volume of gas in the network is underestimated and pressure effects are not accounted for.

An alternative method assumes that the blend level of hydrogen is uniform throughout the grid. Hence, the average calorific value of the gas in the grid is reduced according to the overall proportion of hydrogen injected compared to natural gas. In this way, energy and volumetric flows, and hence also pressure effects, are appropriately modelled. This approach was adopted by Hafsi et al. [98], Tabkhi et al. [99], and Clegg and Mancarella [3,108].

Finally, Pellegrino et al. [87] and Abeysekera et al. [34] tracked varying gas compositions due to hydrogen injection throughout the network by ensuring that both volumetric and mass flows were balanced at each node. This is particularly relevant where hydrogen injection occurs at distributed locations, as is the case in these studies, and is likely to be the case in real-life HIGG scenarios.

### 5.3. Storage and linepack

Gas grids have an inherent flexibility, known as linepack, because the volume of the pipework itself is treated as a storage vessel. Assuming that the network may be operated within a defined range of pressures, the quantity of gas stored within the pipework can be varied. Gas network operators exploit this behaviour to allow for some flexibility between gas supply and demand. Typically, it is ensured that enough gas is supplied to the network to meet demand on a daily basis, but during the day the linepack can vary [127]. When modelling P2G and gas grid injection, it is important that this flexibility is represented appropriately.

Several models included representation of the gas grid for transport, but did not include any grid flexibility, so gas grid supplies and demands needed to be balanced at each timestep (e.g. hourly). Nonetheless many of these models did include gas or hydrogen storage as either pressurised vessels or underground storage, enabling some overall flexibility. Examples of these models include the model used by Deane et al. [101], SIFRE [96], the Value Web Model [119] and OPERA [79]. Meanwhile Mesfun et al. [115] and Kötter et al. [116] both represented the gas grid as an infinite storage resource: methane could be injected into or withdrawn from the grid without any consideration of the overall supply of gas.

Several studies which modelled gas network pressures were able to model linepack. In Devlin et al. [100], Zhang et al. [102] and Zeng et al. [104], linepack was modelled by using constraints to define allowable network pressure ranges. In Qadrdan et al. [106] the linepack was directly calculated based on pressures and pipe volumes, tracked between timesteps, and constrained. Clegg and Mancarella [3,108] used a similar approach, but the gas flows were only solved on a daily basis, which added some additional intra-day flexibility and is representative of the way in which systems operators manage linepack.

In order to fully capture the flexibility of the gas network it is important that linepack is modelled. However, modelling all of the gas network pressures is computationally demanding and nonlinear. Vandewalle et al. [93] is the only study that has been identified that modelled linepack flexibility without modelling gas network pressures. Instead, for each timestep a gas flexibility variable was included so that supplies and demands do not have to match exactly. The flexibility variable was unconstrained in each timestep, but was made to sum to zero in each twenty-four hour period (so that any deficits and surpluses balance over one day). Additionally there was a cost which scaled linearly with the range of flexibility demanded within one day, representative of any costs which may be incurred by the system operator in managing this flexibility.

### 5.4. Spatio-temporal representation

Details of the spatio-temporal representations in the models that have been reviewed are given in Table 3.

The majority of the models include a spatial resolution, either representing a geographic region as a series of interconnected zones (e.g. in the Value Web Model [119]), or as a series of nodes which represent important locations in the gas or electricity infrastructure (e.g. in the CGEN model [107]). However, the more high level equilibrium optimisation models, such as MARKAL/TIMES [92,122], OPERA [79] and SIFRE [96], lump the region they are representing as one, with no spatial representation. Consequently these models cannot accurately model the costs or practicalities of the transportation of energy. In Dodds and McDowall [89], for example, the value of the UK gas grid was assessed despite having no representation of spatial transmission and distribution requirements.

When modelling P2G and the influence of intermittent renewable energy, high temporal resolution is required to capture the short term balancing needs between supply and demand. Meanwhile, it can be important to optimise over long enough time horizons to ensure that, for example, network operation is optimised for interseasonal variabilities, and even investments in network design are optimised at decadal timescales.

Some models are able represent high temporal resolution with contiguous timesteps of around one hour. This captures the short term dynamics accurately, however due to computational demands, only short time horizons (typically a number of days) can be optimised. A commonly adopted solution for modelling longer time periods is a rolling time horizon, where a relatively short horizon of between one day and one week is optimised at a time. The final conditions of one time horizon can be used as the starting conditions of the next horizon. This approach was used by several studies including Vandewalle et al. [93], Sveinbjörnsson et al. [95] and Qadrdan et al. [105,106]. In this manner, longer periods of time are modelled without requiring an optimisation of a very large number of timesteps at once. It can also be argued that a rolling horizon is representative of the lack of reliable longer term forecasts of supplies and demands. However an overall optimum for the entire time horizon is not found: for example, interseasonal storage would not be optimised. Furthermore, despite its simplifications the rolling horizon approach is still relatively computationally demanding.

An alternative approach is to use time-slicing, where a small number of time intervals are selected to represent typical system behaviour. For example, a day could be split into periods of low, medium and high demand, or one representative day could be chosen for each season. When these time-slices are optimised they can be repeated and combined in order to develop a complete representation of a year or more of operation. In MARKAL/TIMES [92,122], OPERA [79] and in Mesfun et al. [115] time-slicing is used, however each time slice is optimised in “steady state”, with no linking between intervals. As a result, although the computational demand is low, system dynamics, for example for storage, are not modelled. The Value Web Model [119] overcomes this by allowing changes (such as storage inventories) to occur over the course of the time interval, using constraints to manage the conditions at the start and end of a series of repeated intervals. This approach is more computationally demanding than unlinked time-slicing, but allows for a considerably better representation of system dynamics on both a short term (such as hourly) and medium term (such as interseasonal) scale.

Finally, it is desirable to be able to model longer time periods, such as years or decades, in order to carry out system planning and investments. For example, the MARKAL/TIMES models [92,122] have yearly or decadal timesteps for investment decisions. In their supply chain planning model, Almansoori and Shah used 6-year time periods over a time horizon of up to 30 years [113]. Zhang et al. adjusted their short-term operation optimisation model so that it could be used for infrastructure planning, by increasing the timestep from hourly to monthly [103]. Using the linked time-slicing technique, the Value Web Model [119] is capable of capturing both short term variability and long term planning. Yearly or decadal time intervals can be used in order to make planning decisions. However, computational tractability becomes a significant challenge for any model that simultaneously considers such a range of time intervals.

## 6. Comparison of scope, assumptions and outcomes of models and real-life projects

All of the real life projects, economic studies and optimisation studies that have been reviewed are concerned with using P2G and HIGG for either grid balancing or decarbonisation of heat. Many real-life projects and economic studies assessed the potential of HIGG for grid balancing from the plant operator perspective, for example investigating whether it is feasible to use HIGG in conjunction with a wind farm. Typically, these economic studies represent scenarios realistic to the real-life projects: Thomas et al. [10], for instance, used information directly from the Uniper HIGG project in Falkenhagen [55] in their economic study. Alternatively, the potential for HIGG from a system wide perspective was assessed. Several real-life projects are investigating the practicalities of HIGG for higher injection levels. Some economic studies have also attempted to take a whole-system perspective; however, optimisation studies are best suited to this as they can model the operation of the system and make operational and investment decisions. However, to date, relatively few optimisation studies have included HIGG.

Regarding input data assumptions, two key parameters are electrolyser efficiency and electrolyser cost. Fig. 7(a) shows the electrolyser efficiencies that were assumed across all the modelling based assessments, based on the higher heating value of the hydrogen produced divided by the electricity input ($\%_{HHV}$). Although the range over all electrolyser types is large, agreement for a given technology type is fairly good, and all studies predict improvements in efficiencies by 2030.

An equivalent plot for electrolyser capital expenditure (CAPEX) is shown in Fig. 7(b). There is a wide range in assumed CAPEX in 2015, but this can again be explained by differing technology types: PEM electrolysers are agreed to be more expensive in 2015. Costs are expected to fall by 2030 for both of the main technologies, more so for PEM. Nonetheless, in 2030 there is a range of £646/kW in the assumed electrolyser CAPEX. The effect of electrolyser CAPEX on project profitability is unclear: Kötter et al. [128] found the impact of electrolyser CAPEX to be small, however the falling cost of electrolysers between now and 2030 was enough for Scamman et al. [17] to conclude that projects that are not profitable today will be profitable by 2030.

The assumed electrolyser plant size varied from less than a megawatt to hundreds of megawatts, so assumptions regarding economies of scale are also important. Meanwhile a variety of measures have been modelled, such as negative electricity prices, carbon prices and “green” hydrogen tariffs. Determining realistic and probable future business models will be important for any future modelling.

Fig. 8 shows the maximum levels of hydrogen injection allowed in the real-life projects, in addition to the assumed maximum injection level in the modelling studies. The assumed level in the modelling studies varies widely. Many studies considered multiple discrete maximum injection levels, up to 20 vol% or even higher, which seems appropriate based on the real-life projects such as the Ameland project [39] that have shown that blends at around this level can be achieved. Those studies, such as Schiebahn et al. [12] and de Joode et al. [79], and indeed the real-life grid balancing projects, that allow much lower levels of hydrogen injection are arguably overly pessimistic. Many of the studies that are shown in Fig. 8 to have investigated 100 vol% injection levels modelled this as an independent “pure hydrogen” case, rather than modelling an unconstrained level of injection up to a maximum of 100 vol%.

Whilst local, practical issues with higher levels of HIGG have been shown to be minimal, wider effects such as energy delivery and management of linepack are currently less certain. Modelling can be used to understand these uncertainties, and operational studies that have been performed conclude that issues with pressures and throughput should be manageable.

Regarding further results and conclusions of the real life projects and modelling, it is clear that in the current economic and policy landscape it is challenging to find profitable business cases for HIGG. Economic studies used a variety of policy support measures to find profitable business cases, whilst real life projects are yet to reach commercial scale. A variety of scenarios were considered in the modelling scenarios, but all identified the potential for P2G to help increase penetration of renewable energy into the energy system. Many of the modelling studies predict more profitable pathways for hydrogen as a transport fuel, due to the higher value of energy when used in transport. This result is supported by the large number of P2G projects which deliver hydrogen for transport.

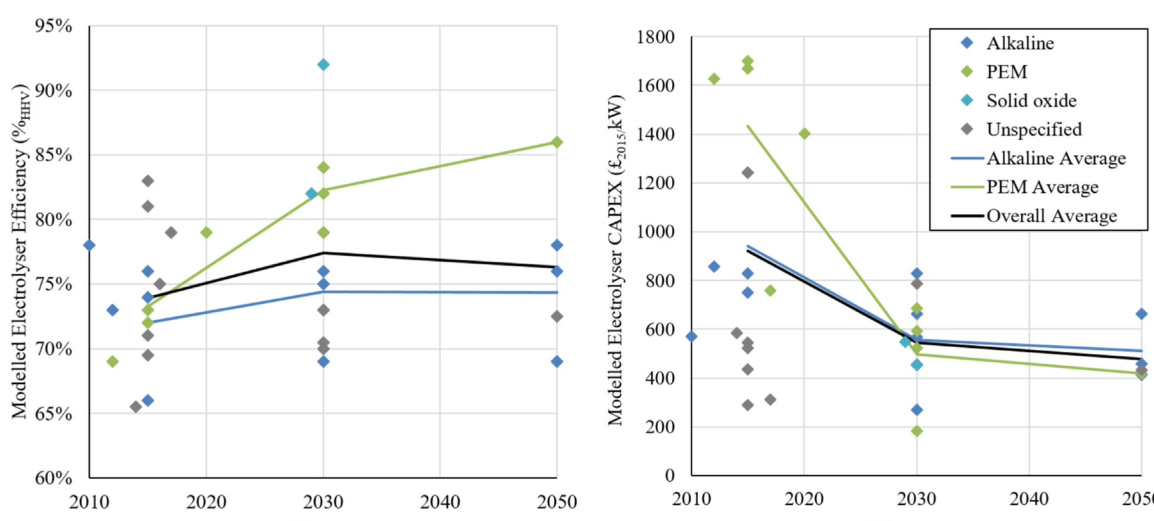


**Fig. 7.** Input data assumptions in all economic and optimisation studies: (a) electrolyser efficiencies ($\%_{HHV}$); and (b) electrolyser CAPEX (£$_{2015}$/kW). References for the studies are provided in Tables 2 and 3.

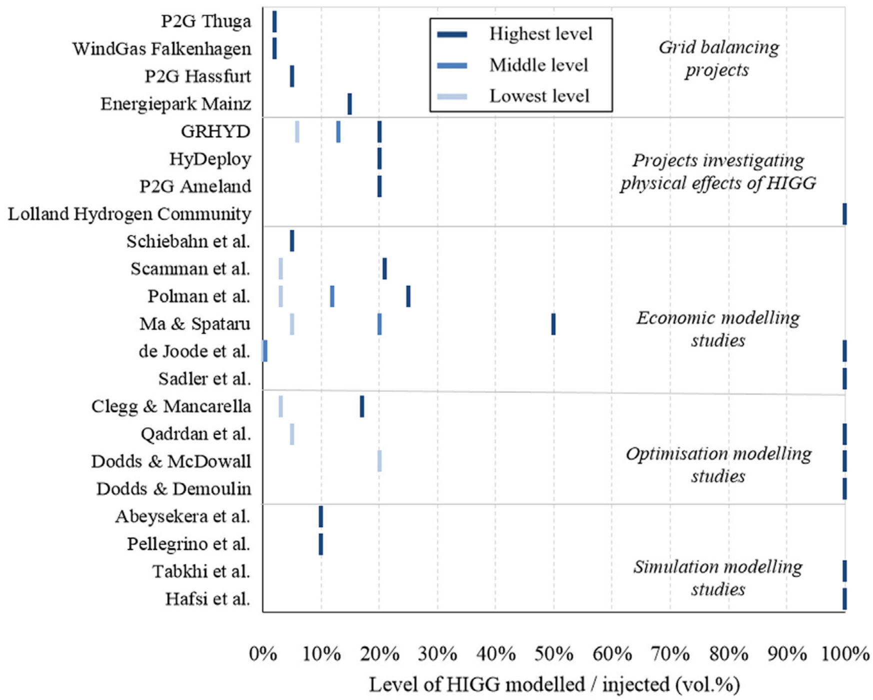


**Fig. 8.** Maximum levels of hydrogen injection used in real-life projects and assumed in modelling studies. Where a project/study investigated more than one discrete injection level, this is shown using the "lowest", "middle" and "highest" level markers. References for the projects and studies are provided in Tables 1–3.

## 7. Conclusions

From the number of real life P2G projects and economic and optimisation studies including gas grid injection it is clear that there is considerable interest in this area. However, there are challenges: HIGG projects that have been carried out are yet to reach commercial scale, and economic studies have indicated that, whilst profitable business cases may be possible, they will require complex scenarios such as electricity balancing markets or government support through taxes or subsidies. Additionally, there are technical challenges such as the physical issues with mixing hydrogen with natural gas and maintaining a stable overall system. Further real life testing will help to identify and understand the physical challenges of individual technologies, whilst modelling will play an important role in evaluating the system effects. Despite the challenges for P2G, the overall outlook from the literature is positive, although some contributors such as electrolyser manufacturers may arguably have an interest in magnifying the potential of P2G.

Whilst the field of optimisation modelling for energy systems is vast, P2G has only just begun to be considered. P2G is incorporated into some high-level system models such as MARKAL/TIMES, but these lack the spatial and temporal resolution to model appropriately the business cases that are being identified for P2G. Various studies have investigated the physical impact of HIGG on the gas and electricity grids, and this work is highly useful for establishing what the challenges will be for systems operation and how to overcome them. However, with such a close focus on the operational details of the networks, these models lack a view of the wider picture, and so are unable to represent system issues such as interseasonal variability and $CO_2$ emissions.

There exists a class of optimisation models that are capable of capturing these wider system issues, as well as the fine spatio-temporal resolution needed to represent variability and operational issues. However, although some of these models have included hydrogen as an energy vector, perhaps for transport, none have modelled the intricacies of P2G and HIGG, such as linepack storage, grid upgrades and the effect of hydrogen blends on end-use. These models should be developed in order to incorporate P2G and HIGG, using results from the real-life projects, economic studies and operational network models to guide the scenarios that are modelled.

Small advances in the technologies involved in P2G are taking place, and efficiencies and costs are expected to improve by 2030. However, these improvements are unlikely to be dramatic enough to make significant differences to business cases, unless a currently little-known technology makes strong progress and becomes a game-changer, such as reversible solid oxide technology. However, with further operating experience, and increased understanding from modelling, real-life projects will be able to discover the most viable business models. The economic landscape is likely to become more appealing, as systems operators value flexibility more highly, and will be more likely to reward flexibility providers such as P2G plants.

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