

Should we inject hydrogen into gas grids? Practicalities and whole-system value chain optimisation

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Abstract

Injection of hydrogen into existing natural gas grids, either partially or as a complete conversion, could decarbonise heat and take advantage of the inherent flexibility that gas grids provide in a low-carbon future. However, hydrogen injection is not straightforward due to the differing properties of the gases and the need for low-cost, low-carbon hydrogen supply chains. In this study, an up-to-date assessment of the opportunities and challenges for hydrogen injection is provided. Through value chain optimisation, the outlook for hydrogen injection is considered in the context of a national energy system with a high reliance on natural gas. The optimisation captures the operational details of hydrogen injection and gas grid flexibility, whilst also modelling the wider context, including interactions with the electricity system and delivery of energy from primary resource to end-use. It is found that energy systems are ready for partial hydrogen injection now, and that relatively low feed-in tariffs (£20-50/MWh) could incentivise it. Partial hydrogen injection could provide a stepping stone for developing a hydrogen infrastructure, but large scale decarbonisation of gas grids requires complete conversion to hydrogen. Whether this solution is preferable to electrification in the long term will depend on the value of the gas grid linepack flexibility, and the costs of expanding electricity infrastructure.

Keywords: Hydrogen; Gas grids; Hydrogen injection; Energy storage; Value Chain Optimisation; Value Web Model.

1. Introduction

Energy use contributes 70% of greenhouse gas (GHG) emissions globally, so strategies are needed to eliminate these emissions in order to meet climate change targets [1]. While technologies are emerging that can enable low-carbon energy production, management and end-use, it is unclear how these technologies will be implemented to deliver low-carbon or even zero-carbon energy systems. Furthermore, whilst technologies such as renewable power and carbon capture and storage (CCS) make electricity decarbonisation increasingly

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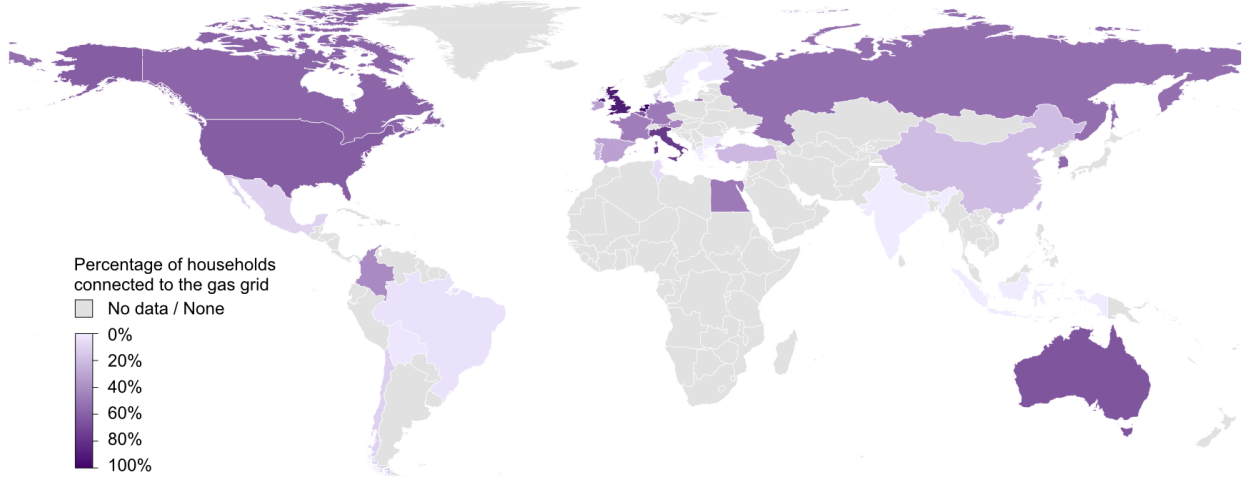


Figure 1: **Percentage of households connected to the gas grid in selected countries.** Data from [5].

achievable, other sectors, such as transport, industry and buildings have less obvious decarbonisation options [2].

The extensive use of natural gas worldwide is an example of this. Globally, over 36,000 TWh of natural gas was consumed in 2017, of which 39% was used for electricity, 32% in industry and 21% in buildings [3]. There are over 2.9 million km of high pressure gas transmission pipelines worldwide [4], and several million km more of pipelines in the low pressure distribution systems used to provide energy to buildings for heating and cooking. Figure 1 shows a map of countries where households are connected to gas distribution grids. In at least seven countries (including the USA, UK, Italy and Australia) more than 50% of households are connected to gas grids [5]. In the UK, for example, 86% of homes are connected to the gas grid [5], and 561 TWh of gas was delivered through the system in 2017, contributing approximately 22% of UK GHG emissions when combusted [6, 7].

Eliminating these emissions is not straightforward, as they are generated at end-use, by each household. The preferred option for reducing GHG emissions may be to abandon gas grids altogether and opt for electrification. However, electrification of heat would require a significant expansion of electricity infrastructure [8], as well as retro-fitting of homes to make them suitable for electric heating technologies such as heat pumps [9]. Meanwhile, gas grids are valuable assets, and maintaining them may be advantageous [10].

For these reasons, injecting hydrogen into gas grids, either through partial mixing with natural gas or as a complete conversion to hydrogen, is appealing. Hydrogen is gaining interest as a low-carbon energy carrier [11], due to its relatively high energy density, multiple production options (including from electricity, fossil fuels and bioenergy), and similarities in behaviour to conventional “fuels” such as methane (which is the principal component of natural gas) [12]. Potential applications for hydrogen include: transport fuel (particularly for long-range and heavy duty use, e.g. freight and shipping) [2]; decarbonising industry (for heating, and in processes such as refining and steel production) [13]; and grid-scale electricity storage [14]. Injecting hydrogen into gas grids can reduce or eliminate emissions from heating and cooking in buildings, whilst maintaining a valuable gas infrastructure (and without requiring significant upgrades to electricity infrastructure). Although end-use appliances such as cookers and boilers would need to be changed for higher

levels of hydrogen injection, the overall impact on gas-heated homes would be smaller than for electrification [9].

Nonetheless, there are practical, technical and economic challenges for hydrogen injection into gas grids. Haeseldonckx & d’Haeseleer [15] and Gondal & Sahir [16] both reviewed these challenges, arguing that whilst there are clear advantages of a hydrogen-based gas system, the transition from the present system to that end-point is not obvious. There is an increasing body of evidence from projects such as NaturalHy [17] and Hy4Heat [18] that is helping to reduce the uncertainties surrounding hydrogen in gas grids. These issues are discussed in section 2 of this article.

Quarton & Samsatli [19] reviewed both real-life projects and modelling studies concerning hydrogen injection into the gas grid and found a growing interest in the process. Over 20 projects have injected hydrogen into gas grids or plan to do so, including several projects in Europe that produce hydrogen from electrolysis (known as power-to-gas) and inject this into the gas grid at low levels (typically up to 5 vol.%). Also of interest are recent projects aimed at understanding the practical issues of partial hydrogen injection in more detail, such as the HyDeploy project in the UK [20] and the GRHYD project in France [21]. Both of these projects are currently injecting hydrogen at up to 20 vol.% into small, private grids that deliver gas to homes and businesses. These projects are intended to validate the safety of this process and pave the way for larger projects. In the past year there has been considerable interest in hydrogen injection into the gas grid, with several new projects announced with scales of up to 100 MW, although these are still mostly at the planning stage [22].

As for modelling studies, Quarton & Samsatli [19] found that many previous studies have focussed on the business case for hydrogen injection for the hydrogen producer, such as Guandalini et al. [23], or else calculated the levelised cost of the hydrogen produced, such as Schiebahn et al. [24] and Parra et al. [25]. Some studies such as Abeysekera et al. [26] and Pellegrino et al. [27] have carried out detailed simulation of gas pipelines with hydrogen injection, providing useful insights into the behaviour of hydrogen in gas grids. However these studies have no representation of the interface with electricity and no consideration of the economics of hydrogen injection. Ogbe et al. [28] optimised natural gas pipelines with injection of hydrogen from power-to-gas, but also focussed on the details of pipeline flow rather than impacts on the wider energy system. Finally, some studies have modelled the effect of hydrogen injection on the wider energy system but these studies tend to over-simplify the process, for example lacking any spatial representation of gas grids (e.g. [29, 30]), or failing to accurately account for the differing properties of hydrogen compared to natural gas (e.g. Qadrdan and co-workers [31, 32], and Clegg and Mancarella [33, 34]).

In this paper, we start (in section 2) by providing an up-to-date review of the opportunities and challenges for partial injection and complete conversion of natural gas grids to hydrogen. Then (in section 3), we present a value chain optimisation model that represents the flows of resources from primary energy to final demand, including comprehensive representation of gas grids and hydrogen injection. We apply this optimisation model to the Great Britain (GB) energy system, as it is representative of a system with stringent decarbonisation targets and significant reliance on the gas grid. The results from this optimisation are presented in section 4, along with some discussion of the outlook for hydrogen injection. Finally, conclusions are provided in section 5.

The value chain optimisation model presented in this paper can represent all of the value chains in an energy system, from primary energy (e.g. natural gas or renewables) to end-use (e.g. electricity or heat). The

costs and efficiencies of all of the processes in these value chains are accounted for, including conversion between energy carriers (e.g. gas turbines or electrolyzers), generation of GHG emissions, and injection into gas grids. The model can find the overall system optimum (e.g. the system with lowest overall cost, lowest GHG emissions or other suitable metric), and can compare alternative value chains (e.g. electrification of heat vs. hydrogen injection) in their optimal configurations. This study is the first to model gas grids and hydrogen injection in energy value chain optimisation and attempts to accurately represent the details of hydrogen injection whilst also modelling the interactions with other aspects of the energy system and finding the overall system optimum.

2. Opportunities and challenges for using hydrogen with existing natural gas infrastructures

2.1. Opportunities for hydrogen injection

2.1.1. Power-to-gas

The term “power-to-gas” has been given various definitions; in this article, it is used to describe the process of converting electricity to hydrogen via electrolysis. Several reviews detailing the technologies and issues surrounding power-to-gas have been written, such as Schiebahn et al. [24] and Buttler & Spliethoff [35]. Arguments for power-to-gas are often based on increasing levels of intermittent renewable electricity (from wind and solar) leading to times where electricity production exceeds electricity demand. This is already happening in many countries including the UK, Germany and France, usually shown by electricity prices falling below zero [36, 37]. If hydrogen is produced from this low-cost, excess electricity, it can be used for a variety of applications, such as in transport, industry, or stored and reconverted to electricity when demands exceed supply.

Another outlet for hydrogen from power-to-gas is injection into the gas grid. Hydrogen can be directly injected into natural gas grids, either to mix with the existing natural gas, or as a complete replacement (100% hydrogen). The practical issues with each of these options are discussed in section 2.2. Hydrogen can also be reacted with carbon dioxide (CO_2) to form “synthetic natural gas” (i.e. methane), which can be directly injected into gas grids without any technical issues [38]. Whilst injection of synthetic natural gas shares some of the advantages of direct hydrogen injection, it does not enable the reduction of end-use GHG emissions so is not the focus of this study.

The economic case for direct hydrogen injection into gas grids is complex. Usually, natural gas is cheaper than electricity, so it is unlikely that hydrogen from power-to-gas would be cost competitive with natural gas [24]. Whether power-to-gas hydrogen can compete with natural gas in gas grids will depend on the value of absorbing excess electricity (e.g. negative electricity prices could lead to lower-cost hydrogen), and any value put on the CO_2 mitigation of hydrogen [23, 39]. Falling electrolyser capital costs will also increase the opportunities for hydrogen to compete economically with natural gas [40].

In general, the capacities of gas systems are large relative to their electricity counterparts, so gas grids could easily absorb hydrogen from excess electricity. Furthermore, gas grids have inherent gas storage capacity, known as linepack, which is described in detail in section 2.1.2. In fact, it is highly unlikely that power-to-gas could supply all of the gas requirements of a gas system, due to the scale of electricity production capacity

that would be required. For example, in 2017, the UK gas distribution system delivered 561 TWh of gas to consumers, compared to a total national electricity production of 336 TWh (of which 62 TWh was from wind, wave or solar) [6, 41]. Consequently, it is more likely that power-to-gas would supplement other gas supplies, either supplementing natural gas in the case of hydrogen-natural gas blending, or supplementing hydrogen produced by other means, for example methane reforming (which could include CCS for a low-carbon solution).

2.1.2. Gas grid linepack flexibility

An aspect of gas grids that makes them particularly useful to energy systems is their inherent storage capacity, known as linepack [42]. The gas grid linepack is the total quantity of gas (usually measured in standard cubic metres, scm) contained within the pipelines on the network. Because the overall pressure level of these pipelines can be varied, the quantity of gas stored is also varied. High pressure gas systems, such as national and regional transmission systems, have greater linepack flexibility due to larger pressure ranges and pipeline volumes [43].

Linepack is varied throughout each day by the gas grid operators in order to balance supplies and demands of gas. As an example, Figure 2 shows data from the UK National Transmission System (NTS). Figure 2(a) shows the linepack over a ten day period in 2018, including an “extreme” demand event due to exceptionally cold weather. Figure 2(b) shows a histogram of linepack swing data over a 5-year period. Linepack swing refers to the difference in linepack between the beginning of the gas day (5 a.m. for the UK NTS) and the minimum level over the subsequent 24 hours [44]. Therefore linepack swing provides a measure of the overall daily flexibility of the gas grid.

On the UK NTS, daily linepack swing is commonly around 100 GWh, and in extreme events it can be more than 400 GWh. A recent study that accessed data from the UK Local Transmission System (LTS) found that the linepack flexibility offered from the LTS is of a similar size, with an average daily linepack swing of around 150 GWh, and more than 300 GWh in extreme events [43]. Linepack data for other countries is less easily available, but several countries have more extensive gas transmission systems than the UK, including the USA, the Netherlands and Japan [5], so are likely to have similar or greater linepack flexibility available.

Linepack flexibility is an essential tool for balancing supplies and demands of gas: typically, NTS linepack is depleted when gas power plants are ramped up to meet electricity peaks, whilst LTS linepack is depleted to meet increases in demand for gas for heating and cooking in homes. Therefore, if gas grid linepack were to be used for absorbing large amounts of energy from the electricity system via power-to-gas, it would be important to ensure that the existing capabilities of the system for balancing of gas supplies and demands were not reduced. This should not be a major challenge, as the scale of linepack flexibility available on the gas system is very large compared to the flexibility needs of the electricity system. For example, pumped hydro storage facilities used for within-day electricity flexibility rarely exceed 10 GWh in size [45], which is only 4% of the typical daily linepack swing on the entire UK gas grid (NTS and LTS). Furthermore, depending on the energy system dynamics, gas grid injection from power-to-gas may in fact complement the operation of the gas system, restoring gas grid linepack following a depletion.

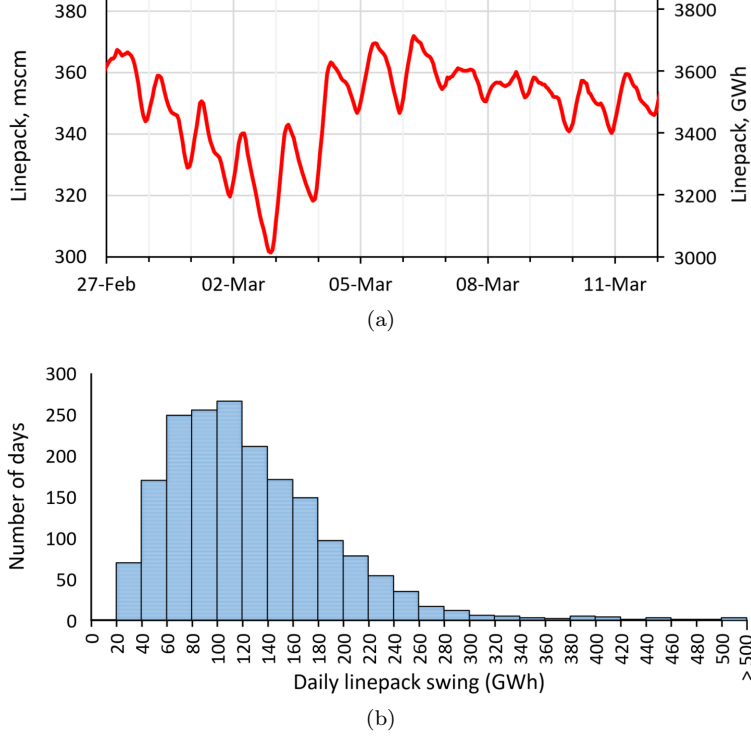


Figure 2: **Linepack data for the UK National Transmission System (NTS).** (a) Hourly linepack over a two-week period in 2018, including an extreme cold weather event; (b) Histogram of the daily linepack swing between 2013 and 2018. Data from [6].

2.1.3. Other opportunities

An advantage of hydrogen injection into gas grids is the reduction in GHG emissions from the gas end-use. Partial injection can achieve small GHG emissions reductions, although due to the lower energy density of hydrogen (see section 2.2.1), emissions reductions are relatively small: for example, hydrogen injection of 20 vol.% reduces the GHG emissions of the final gas blend by only 7%.

Complete conversion of gas grids to hydrogen would eliminate GHG emissions at end-use (and potentially the overall GHG emissions, provided the hydrogen was produced in a low-carbon manner). Therefore this option is appealing for energy systems with a heavy reliance on gas distribution systems for heating in buildings. The H21 project [46] is a proponent of this option, having designed and costed a plan for converting the gas distribution system for the north of England, and subsequently the rest of the UK, to hydrogen.

There may also be wider infrastructure benefits to injecting hydrogen into gas grids. By allowing partial, variable injection of hydrogen into gas grids, a guaranteed outlet for hydrogen is available for hydrogen producers. This can help to overcome the “chicken-and-egg” problem, whereby there is little incentive to develop hydrogen production facilities without any significant, reliable demand for the hydrogen. In this scenario, it may be necessary to provide additional economic incentives for the injected hydrogen, such as a feed-in tariff (FIT), to augment the relatively low price of gas [39]. Similarly, there may be opportunities for hydrogen injection into gas grids in conjunction with wider hydrogen projects. The HyNet project in the north-west of England, for example, proposes producing hydrogen from steam-methane reforming (SMR)

with CCS, primarily for use in industry, but with the option to also feed some hydrogen into the nearby gas grids [47].

2.2. Challenges for hydrogen injection

Despite the opportunities for hydrogen injection, there are several practical challenges that must be overcome for hydrogen to be injected into existing natural gas infrastructures.

2.2.1. Pipeline energy delivery

Due to the differing thermophysical properties of hydrogen and natural gas, the pipeline energy delivery rate of the two gases also differs. This affects both complete conversion of natural gas pipelines to hydrogen and partial injection.

An expression for the energy delivery rate (i.e. the power, in MW) of gas in a pipeline is shown in equation 1:

$$H = u_n Q_n \quad (1)$$

where H is energy delivery rate; u_n is the gas energy density at Standard Temperature and Pressure (STP); and Q_n is the volumetric flow rate at STP. The volumetric flow rate can be calculated using the general flow equation for steady state gas flow (here assuming a horizontal pipe) [26]:

$$Q_n = \sqrt{\frac{\pi^2 \rho_{air}}{64} \frac{T_n}{p_n}} \sqrt{\frac{(p_1^2 - p_2^2) D^5}{f S L T Z}} \quad (2)$$

where ρ_{air} is the density of air at STP; T_n and p_n are the temperature and pressure at STP; p_1 and p_2 are the inlet and outlet pressures; D is the pipe diameter; f is the friction factor; S is the gas specific gravity; L is the pipe length; T is the gas temperature; and Z is the gas compressibility factor (the volume of the real gas divided by the volume of a perfect gas at the same temperature and pressure).

Due to hydrogen's low mass density, it has a low energy density compared to natural gas (3.0 kWh/m³ at STP, compared to around 9.9 kWh/m³ for natural gas [41, 48]). However, as can be seen in equation 2, the low mass density (i.e. low specific gravity S) means that hydrogen will achieve higher volumetric flow rates than natural gas, for the same pressure drop. These factors are captured in the Wobbe number (WN), an index used in the gas industry to indicate interchangeability of gas types [49]:

$$WN = \frac{u_n}{\sqrt{S}} \quad (3)$$

However, there are further factors that cause differences in the flow of natural gas and hydrogen in pipelines; the most significant are the compressibility factor (Z) and kinematic viscosity (which influences friction factor f) [26]. The interaction of these factors is complex and can depend on the absolute pressure level of

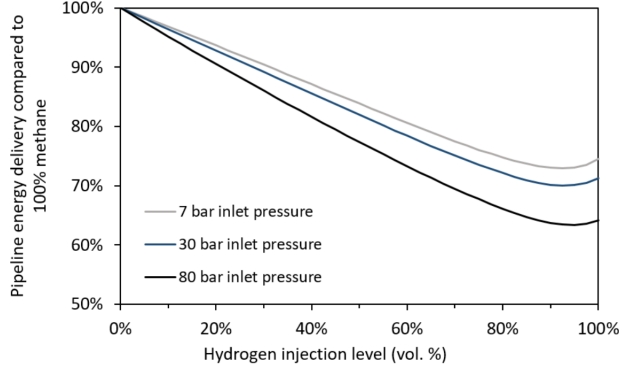


Figure 3: **Effect of hydrogen injection on natural gas pipeline energy delivery at three pressure levels.** Calculated by the authors using the general gas flow equation, assuming smooth pipe flow. See the supplementary material for more details.

the pipeline and the pipe geometry. Equations 1 and 2, in combination with approximations for parameters such as the friction coefficient, can be used to estimate these effects [26, 50]. Calculations were performed to estimate the reduction in pipeline energy delivery for increasing levels of hydrogen injection, assuming a constant pipeline pressure drop. Full details of the calculations are provided in the supplementary material, and the results are shown in Figure 3. The calculations assumed smooth pipe flow, which is reasonable based on the flow regime and relatively low roughness of typical gas pipeline materials. Properties for pure methane were used to represent natural gas; natural gas typically has a methane content in excess of 80 vol.% [51]. At up to around 50 vol.% injection, the behaviour is linear. Higher pressures worsen the reduced energy delivery effect of hydrogen, primarily due to the lower compressibility of hydrogen at higher pressures. For an 80 bar inlet, typical of a high pressure transmission pipeline, only around 64% of the energy can be delivered with 100% hydrogen compared with 100% methane, assuming the same pressure drop.

The lower energy density of hydrogen also means that the linepack flexibility available from a pipeline carrying hydrogen is lower than for natural gas. This effect is worsened at higher pressures by the lower compressibility of hydrogen compared to natural gas. Usable pipeline linepack swing is dependent on pipeline flow rate and the range in pressures over which the pipeline can be “swung”. The effect of hydrogen injection on the available linepack flexibility of a natural gas pipeline was calculated, based on typical flow rates and linepack swing ranges for the pressure levels modelled. These results are shown in Figure 4, and further details can be found in the supplementary material. For a high pressure (80 bar) transmission pipeline, available linepack flexibility with 100% hydrogen is only around 17% of the equivalent value with natural gas. For a lower pressure (30 bar) pipeline, the available linepack flexibility is around 26%.

It may be possible to mitigate the poorer energy delivery and linepack performance of pipelines with hydrogen injection by adjusting the operating conditions (i.e. increasing pressure levels). However, this will depend on the practicality and safety of doing so.

2.2.2. Equipment operability

The differing properties of hydrogen also affect the usability of equipment on the gas grid and at end-use. Compressor stations, for example, are used on high pressure transmission networks to drive the flow of the gas. However, due to the considerably lower energy density of hydrogen, certain types of compressor are

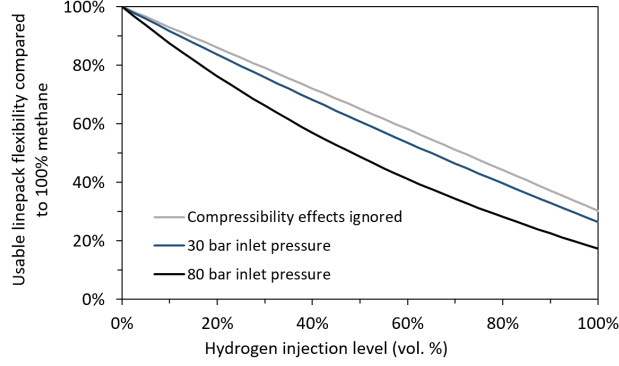


Figure 4: **Effect of hydrogen injection on usable pipeline linepack flexibility.** The energy content of a linepack swing between two fixed pressures was calculated for increasing levels of hydrogen injection. The linepack swing pressures were chosen to be representative of typical linepack swings for each pressure level. See the supplementary material for more details.

unlikely to be able to deliver a sufficiently high energy throughput using hydrogen and would need replacing [15].

At the distribution level, metering the quantity of energy supplied to consumers becomes challenging when hydrogen is injected partially and variably into gas supplies. Gas meters typically measure the volume of gas consumed, with no measure of the calorific value, but with hydrogen-natural gas blends the energy delivered per unit volume drops according to the amount of hydrogen present (cf. Figure 3). Thus, measuring volume consumed alone is not sufficient to determine energy consumption. These problems are already arising with increased levels of biomethane injection into gas grids, which also typically has a lower calorific value than natural gas. Methods are being investigated for tracking the energy delivered to consumers with gas of varying energy content, including through extensive measurement of gas calorific value throughout the gas grid, and modelling-based approaches [52].

End-use appliances would also be affected by hydrogen injection, primarily through reduced heat input, measured by the Wobbe index (equation 3), and flame speed. Various studies and testing programmes have been performed on domestic and industrial equipment for both partial hydrogen injection (e.g. [53, 54]) and complete conversion (e.g. [18]). It is likely that domestic equipment (e.g. natural gas boilers), could perform as normal under partial injection, up to a given limit (e.g. around 20 vol.%), but these appliances would need replacing for complete conversion to hydrogen [55].

Specialist industrial equipment such as gas turbines may be more sensitive to fuel composition, and therefore require more consideration. However, it is technically possible to operate gas turbines with any level of hydrogen-natural gas blend [56], and there are already many bespoke applications of turbines using hydrogen globally [57]. NO_x emissions may be an issue for combustion of 100% hydrogen, but this can be mitigated, for example through water injection or lean pre-mixture combustion [58]. Beyond bespoke applications, turbine manufacturers have indicated that they will be able to supply hydrogen turbines at scale by 2030 [59]. Meanwhile, existing equipment can be retro-fitted for hydrogen or replaced, depending on costs.

2.2.3. Further safety and practical issues

Hydrogen embrittlement is a process where hydrogen diffuses into the existing flaws in steel and iron pipework, reducing the ductility of the material and increasing the likelihood of crack growth [29]. This

is particularly a concern for the high-strength steels that are typically used in gas transmissions systems, and moreover higher pressures are thought to worsen the effects of embrittlement [29]. However, embrittlement is poorly understood, and various testing has found little or no reduction in performance of steel pipelines as a result of hydrogen embrittlement [49]. Furthermore, there are softer steels that are suitable for hydrogen at high pressures [49]. The literature is divided on the level of risk that embrittlement presents [60]; options may exist for mitigating these risks through further investment, such as rigorous pipeline inspection, or even retrofitting pipelines with hydrogen-resistant liners [5, 49]. The lower pressures on distribution systems mean that the risks of hydrogen embrittlement are lower. Furthermore, for lower pressures, more materials exist that are not susceptible to hydrogen embrittlement, such as polyethylene. In the UK, for example, much of the old hard steel and iron pipework on the distribution system is already being replaced as part of the Iron Mains Replacement Program [61].

Volumetric losses of hydrogen by leakage through pipe walls are larger than for natural gas, however energetic losses are lower, due to the lower energy density of hydrogen. Calculations have shown that volumetric losses through leakage for a hydrogen pipeline should be less than 0.001% of throughput [15]. Although not well understood, hydrogen is thought to behave as an indirect greenhouse gas, and it has been estimated that it has a 100-year global warming potential of around 4.3 [62]. However, for the very low levels of hydrogen leakage that would be expected, this would have a minimal overall global warming impact.

Certain properties of hydrogen raise concerns about the safety of using it as a replacement for natural gas. For example, hydrogen has a wider flammability range than natural gas, and lower limiting oxygen for combustion [49]. Partial mixing of hydrogen with natural gas would result in lower safety risks than use of pure hydrogen. Various testing and studies have been performed to assess the safety of using hydrogen in homes, including through the NaturalHy [17], GRHYD [63] and HyDeploy [54] projects. In the UK, a project is currently underway as part of the Hy4Heat programme to establish a full safety case for the use of 100% hydrogen in homes [18].

Some logistical issues arise when considering hydrogen injection, particularly for the case of partial injection. At the transmission level, transmission networks span different regions, and feed a variety of users including heavy industry, gas-fired power plants, and the local distribution networks. If hydrogen were to be injected into these systems, all users on the system would have to receive the hydrogen-natural gas blend, when in fact some facilities may require a “pure” natural gas feedstock. For example, in a high-hydrogen system, it is possible that some hydrogen will be produced from reforming natural gas; these reformers would benefit from the existing, unmodified natural gas transmission system.

In many countries, legislation would also have to be updated for hydrogen to be injected into gas grids. Much existing legislation is out-dated, with arbitrarily low specifications for the allowable level of hydrogen in the gas grid. In the UK, for example, the allowable limit is only 0.1 vol.%; in France the allowable limit is 6 vol.%; and in the Netherlands it is 12 vol.% [39].

2.2.4. Costs

Upgrade and conversion costs for injecting hydrogen into gas grids are uncertain, as there is limited practical experience of doing so. Nonetheless, some estimates have been made for the costs of injection equipment, gas grid upgrades, and preparation of homes for partial or complete conversion of gas grids to hydrogen.

A key argument for partial hydrogen injection is that limited upgrades would be required, meaning that costs would be low. Therefore the primary costs for partial injection would be safety checks on existing equipment, and installation of injection equipment. The HyDeploy project, demonstrating the feasibility of hydrogen injection at up to 20 vol.% into a private gas network with a peak gas demand of around 25 MW, estimate investment costs for site preparation of £655,000, giving an overall investment cost of around £26 per kW of gas grid capacity [54]. The injection equipment, including 500 kW electrolyser, is estimated at £1,900,000. However, the HyDeploy project is a demonstration project, and it is likely that costs would be lower at a larger scale. The HyNet project, which plans hydrogen production for a range of applications including injecting hydrogen into the gas grid at up to 20 vol.%, plans four injection sites, each supplying a peak gas demand of around 1400 MW [47]. Their estimated cost for each site is £5,000,000, meaning a cost of around £3.60 per kW of gas grid capacity.

For complete conversion of gas distribution grids to hydrogen, network upgrades are more extensive. The pipeline infrastructure would need to be surveyed and potentially upgraded to ensure that it is suitable for carrying 100% hydrogen. Furthermore, it is likely that pipelines may need to be reinforced in order to have sufficient peak energy delivery and linepack. However, arguably the injection and network monitoring requirements may be lower in a system that uses an unvarying gas supply (rather than partial, variable hydrogen injection). In the H21 project, in which the complete conversion of the gas distribution networks of the north of England was planned, the total capital costs for the conversion of the 42 GW peak capacity distribution system was estimated to be £143,000,000 [46]. This equals a conversion cost of £3.40 per kW of gas grid, divided equally between network reinforcement costs and the costs for the sectorisation of the network required to carry out the incremental switchover of the system. However, whilst this study includes thorough analysis of the capacity of the networks, it does not apportion costs for the surveying and safety checks of the pipelines, instead assuming that the ongoing Iron Mains Replacement Programme in the UK will ensure that all pipes on the networks will be converted to polyethylene already.

Meanwhile, consumer equipment that uses natural gas (for heating and cooking in domestic, commercial and industrial applications) would need at least upgrading and more likely replacing. Cost estimates for replacing natural gas heating systems with hydrogen in homes range between £1000 and £4000 per home [46, 55, 64, 65]. For non-domestic applications, costs vary significantly depending on the application, but are estimated to be in the region of £200 to £800 per kW capacity [46, 66].

2.3. Summary

In summary, hydrogen injection into existing gas grids offers an opportunity to create a reliable demand for hydrogen, which can help a larger hydrogen supply chain to develop whilst also reducing GHG emissions. Furthermore, the extent and flexibility of gas grids mean that hydrogen injection can provide benefits to the wider energy system, such as adding flexibility to the electricity system. However, the transport and flexibility capacities of natural gas infrastructures will be reduced when carrying hydrogen.

There are some practical and technical issues for hydrogen injection, but there is growing evidence that these can be overcome. Partial injection of hydrogen into gas distribution networks seems feasible and achievable. In the longer-term, conversion of distribution networks completely to hydrogen is also likely to be feasible, but this will be a much larger undertaking, due to the need to convert the majority of end-use equipment,

including in homes. The feasibility of using existing high pressure transmission networks with hydrogen is less clear, as the same practical issues tend to be more severe when operating at higher pressures. There are also logistical reasons for keeping natural gas transmission networks in operation.

An alternative to using existing natural gas grids with hydrogen could be to build purpose-built hydrogen infrastructures. Purpose-built pipelines for hydrogen transmission could be advantageous, as they would be designed specifically for hydrogen, whilst existing natural gas pipelines would be kept intact. For distribution, brand new networks could be built in certain applications, such as at new-build residential or commercial sites, but it is unlikely to be realistic to build new distribution networks for existing buildings.

Importantly, building new hydrogen pipeline infrastructures will incur higher investment costs than converting existing infrastructures. This is a particular advantage of using existing infrastructures, as they can either be used partially (i.e. through partial injection) or converted gradually, meaning that infrastructure costs will not significantly outweigh hydrogen demand in the early stages of development.

The main alternative to pipeline transportation for hydrogen is transportation on road, typically with trucks carrying liquid or compressed gaseous hydrogen. This option is more straightforward at smaller scales, and is much more logistically flexible, but it becomes more costly for larger hydrogen volumes and transportation distances [67]. Furthermore, this option does not include the benefits of a steady hydrogen supply or gas grid linepack.

A further advantage of purpose-built infrastructures (pipeline or road transport) is that it would be easier to control hydrogen purity. Whilst hydrogen purity is less important for combustion, in fuel cell applications (either stationary or in vehicles) high hydrogen purity is required, and re-purposed natural gas pipelines may be unable to supply this [57].

3. Method

In order to explore the role of gas grids and hydrogen in helping to deliver low carbon energy systems, a value chain optimisation model was developed of a national energy system. The Great Britain (GB) energy system was chosen, as it represents a large sized energy system with heavy reliance on natural gas grids.

3.1. Model

The value chain optimisation was carried out using the Value Web Model (VWM), developed by Samsatli and Samsatli [68]. In this study, the representation of resource transmission and distribution networks in the VWM was extended. This included modelling of linepack storage on both the gas transmission and distribution networks, and the ability to inject hydrogen into existing gas distribution grids. An overview of the VWM is provided in section 3.1.1, and sections 3.1.2 to 3.1.4 describe the additions that were made to the model in this work, including the new mathematical constraints. A reduced nomenclature, covering the equations presented in this work, is provided in appendix B. The full model mathematical formulation and nomenclature can be found in previous studies by Samsatli and co-workers (e.g. [68, 69, 70]).

3.1.1. Overview of the Value Web Model

The VWM is a mixed integer linear programming (MILP) optimisation model that can be used to optimise the value chains in an energy system. The model includes a variety of energy technologies and resources, and has a spatio-temporal representation. Spatially, the model includes discrete zones (16 different zones in the case of GB), each of which has its own resource availabilities and demands. Temporally, the model represents time intervals at four different scales: sub-day intervals can represent the hourly variability in demands and availabilities of resources; day-type intervals can be used, e.g. for different demand profiles on weekdays and weekends; seasonal intervals are used to represent difference in resource demand and availability throughout the year; and finally long-term planning intervals are included for long-term changes in demands as well as long-term technology investment decisions.

An illustration of the structure of the VWM is provided in Figure 5. The model includes availability of primary resources (e.g. natural gas, solar and wind, shown in circles in Figure 5). These resources can be converted to other resources within the energy system via conversion technologies (shown as rectangles). Different types of conversion technologies exist, including those that directly utilise primary resources (e.g. wind turbines and solar PV), general “industrial” conversion technologies (e.g. electrolyzers and gas turbines), distribution technologies (e.g. gas and electricity distribution networks), and domestic and commercial technologies that utilise these distributed resources. All of the resources included in the VWM are shown in Figure 5 (as circles); all of the resource conversions are represented with arrows connecting resources to technologies. Each technology may consume or produce more than one resource; key parameters for each technology are defined, including costs, rates of resource conversion (i.e. efficiency), and maximum operating rates. In addition to the description provided here, more information about the technologies and resources included in the VWM can be found in the associated Data in Brief article [71], which provides an overview of all of the model input data used in this study.

Many resources are included in different forms within the VWM, so that the associated processes can be modelled. For example, CO₂ is represented as “emitted”, “captured” and “stored”, with conversion technologies to convert between each of these states. Similarly, natural gas and hydrogen are both represented at “low pressure” (i.e. transmission-level pressure), “high pressure” (for storage at around 200 bar), and as a “distributed” gas. Distribution technologies are included in the VWM for the first time in this work. Distribution technologies are a subset of conversion technologies, that convert “centralised” resources such as electricity or gas from the transmission system to “distributed” resources to be used in homes and businesses. These technologies have a fixed size, representative of a portion of the distribution network, but multiple instances of the technology can be installed within one zone. In this way, the costs and constraints of distribution infrastructures are included. Representation of gas distribution networks includes the linepack storage capacity of these networks and the ability to inject hydrogen (either partially or as a complete conversion). More details of this modelling are provided in section 3.1.3.

Some resources may have demands associated with them that must be satisfied; in this study, demands for electricity and heat are included. Heat demands are separated into three groups: domestic heat, commercial heat (including low-temperature industrial heat), and high temperature industrial heat. This allows representation of the different types of heating technologies that exist, such as domestic boilers in homes, commercial heating for larger buildings, and specialised equipment for industry (e.g. furnaces). Heat from

commercial heating can also be delivered to homes (i.e. converted to domestic heat) via a heat network (a distribution technology).

Two separate spatial zones are depicted in Figure 5. Conversion and storage technologies can be built in each zone, and transportation technologies exist that can move resources between zones (e.g. electricity transmission and gas pipelines, shown with hexagons in Figure 5). Some transportation technologies include storage capacity, to represent linepack; more details of this are provided in section 3.1.2. Specific storage technologies are also modelled (e.g. pressure vessels and underground storage, shown with pentagons in Figure 5), and resources can be loaded into storage, to be extracted during a later time interval.

All technologies have impacts associated with their installation and operation, such as costs and environmental impacts. The model is able to determine the optimal configuration of technologies (e.g. when and where they should be built), and how these technologies should be operated, in order to satisfy the final energy demands. The objective function to optimise can be cost-based (e.g. minimise overall system cost), or can take into account other objectives. In addition to the numerous constraints in the VWM that ensure that resource flows are in balance and that technologies operate within their feasible limits, further constraints can be included such as limits on GHG emissions.

3.1.2. Gas transmission

“Transmission” is used to refer to the high pressure pipelines that transport gas around the country; in the VWM, this equates to transportation of gas between the discrete spatial zones of the model. To represent the storage and transportation capability of gas transmission systems, a single technology type (“national infrastructure”) is defined for all spatial zones in the model. This is modelled as a single storage technology for the whole of GB (or whichever country or region is being modelled) that allows any zone connected to it (via pipelines) to inject or withdraw resource, as shown in Figure 6. Thus transmission occurs by injecting resource from one zone and withdrawing from another; linepack is increased if the total (over all zones) rate of injection of resource is greater than the total rate of withdrawal. Therefore the constraints required to model gas transmission with linepack storage are the same as those for regular storage technologies, as presented by Samsatli and Samsatli [68, 72, 73], with the following differences: there is a single inventory of stored resource (independent of zone) and a single associated “hold” task; and there is a “put” and “get” task for each zone connected to the transmission network, allowing each zone to inject and withdraw resource from the network. The constraints for the transmission network with linepack storage are described below.

The net flow of resource (i.e. gas) out of the transmission infrastructure, into each spatial zone is tracked using “put”, “hold” and “get” tasks:

$$L_{zrhdt y} = \sum_l \left(\mathcal{L}_{lzhdt y}^{\text{put}} \lambda_{lr, \text{src}, y}^{\text{put}} + \mathcal{L}_{lzhdt y}^{\text{get}} \lambda_{lr, \text{dst}, y}^{\text{get}} \right) \quad (4)$$

$$\forall r \in \mathbb{R}, z \in \mathbb{Z}, h \in \mathbb{H}, d \in \mathbb{D}, t \in \mathbb{T}, y \in \mathbb{Y}$$

$L_{zrhdt y}$ is the net flow of resource from the transmission infrastructure l into a zone z . The net flow is negative if resource is being added to the transmission system (linepack increased), or it is positive if the linepack is being depleted. Different zones may be adding or removing resource from the transmission

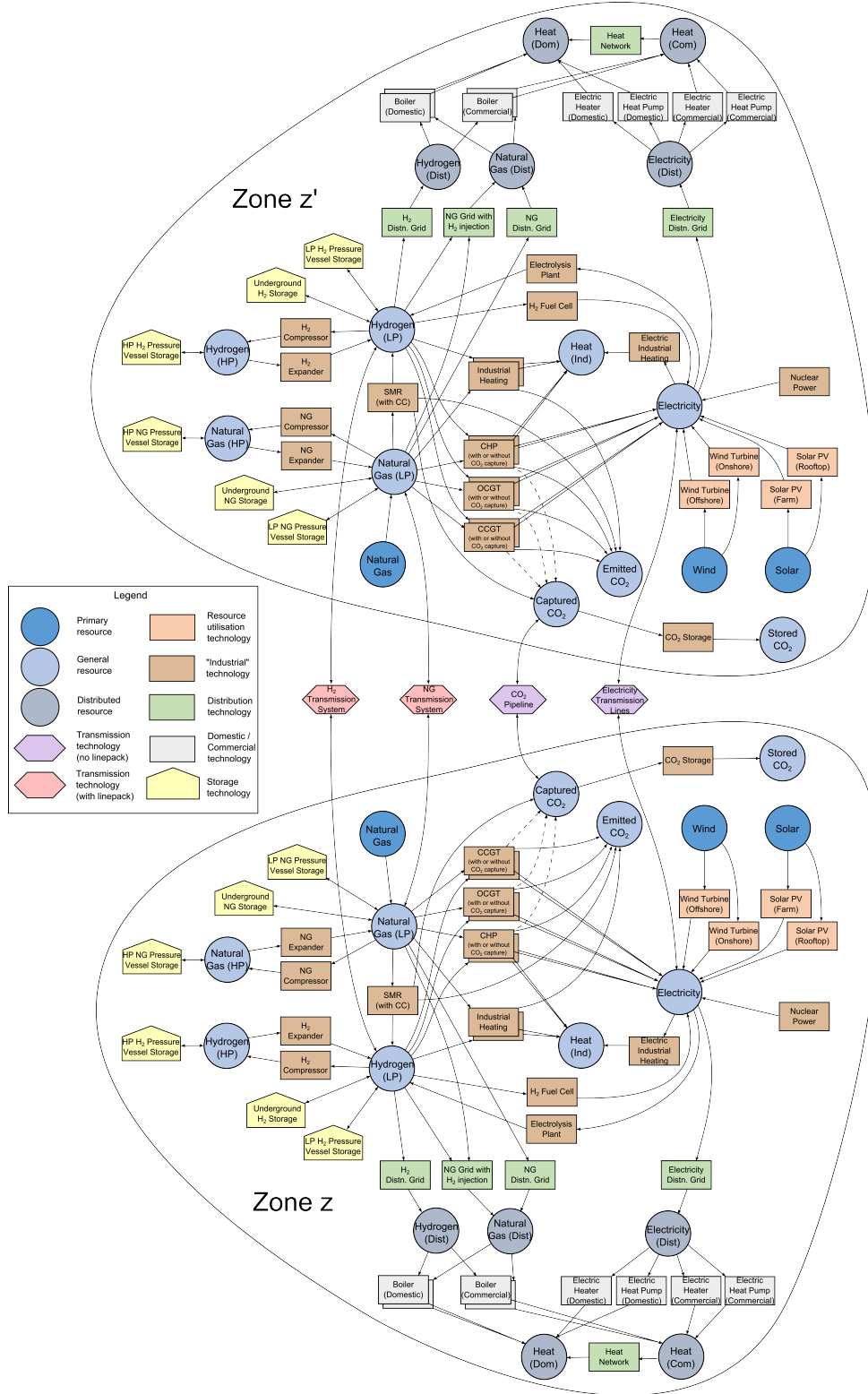


Figure 5: **Representation of resources and technologies in the Value Web Model.** Different resource types include primary resources, general energy system resources, and distributed resources. Demands may be included for any of these resources. Various technology types exist that convert between these resources. Conversion technologies include “industrial” technologies for converting between resources, “distribution” technologies for delivering resources to the consumer, and final consumption technologies such as domestic and commercial heaters. Also represented in the model are transportation technologies (including transmission pipelines with linepack), and storage technologies. Two spatial zones are shown in this diagram.

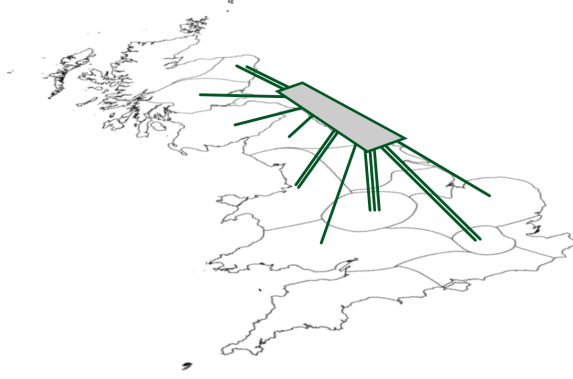


Figure 6: **Representation of gas transmission systems in the Value Web Model.** Pipelines (green lines) can be built in any zone, connecting the zone to the national transmission system. Any zone with a connecting pipeline can inject or withdraw gas from the system. Multiple pipelines can be built for increased injection and withdrawal rates. The overall storage capacity of the system (linepack) is determined by the total number of pipelines built.

infrastructure at one time, allowing for transportation of resource between zones. The “put” and “get” tasks are used to model costs and energy requirements associated with adding resource to the infrastructure and taking from it, respectively. Each of these tasks has a conversion factor, λ_{lrfy}^* ($\star \in \{\text{put, hold, get}\}$), which is multiplied by the operation rate of the respective task ($\mathcal{L}_{lzhdy}^{\text{put}}$, $\mathcal{L}_{lhdty}^{\text{hold}}$ and $\mathcal{L}_{lzhdy}^{\text{get}}$) to give the flow rate of the resource into and out of the transmission infrastructure. The “hold” task represents the maintenance of resource in storage (i.e. the linepack in the whole network), as described later and seen in equations 7 to 9. The set of linepack transmission infrastructures in the model ($l \in \mathbb{L}$) includes natural gas transmission infrastructures and hydrogen transmission infrastructures (other transmission systems, without linepack, are modelled separately). The other sets shown in equation 4 represent the set of resources ($r \in \mathbb{R}$, including all of the resources shown in Figure 5), set of spatial zones ($z \in \mathbb{Z}$), and various time intervals. Definitions of each of these sets are provided in the nomenclature in appendix B.

The operation rates of the “put” and “get” tasks can vary in time (indicated by the h , d , t and y indices representing hourly, day-type, seasonal and annual time intervals, respectively), and are also dependent on the spatial zone, z . Pipelines must be built in a zone for it to be connected to the national infrastructure. Each pipeline has a fixed maximum transportation rate, which determines the rate at which the resource can be injected into or withdrawn from the transmission system (denoted by $l_l^{\text{put},\max}$ and $l_l^{\text{get},\max}$ respectively). Multiple pipelines can be built in a given zone in order to increase the withdrawal/injection rate. Thus, the maximum rate at which resource can be transferred between the transmission infrastructure and a spatial zone is given as follows:

$$\mathcal{L}_{lzhdy}^{\text{put}} \leq N_{lzy}^{\text{L}} l_l^{\text{put},\max} a_{lz} \quad \forall l \in \mathbb{L}, z \in \mathbb{Z}, h \in \mathbb{H}, d \in \mathbb{D}, t \in \mathbb{T}, y \in \mathbb{Y} \quad (5)$$

$$\mathcal{L}_{lzhdy}^{\text{get}} \leq N_{lzy}^{\text{L}} l_l^{\text{get},\max} a_{lz} \quad \forall l \in \mathbb{L}, z \in \mathbb{Z}, h \in \mathbb{H}, d \in \mathbb{D}, t \in \mathbb{T}, y \in \mathbb{Y} \quad (6)$$

Where N_{lzy}^{L} is the number of pipelines built connecting zone z to the transmission system l and a_{lz} is a parameter that can be set to 0 or 1 to specify whether a zone may connect to the transmission system.

The number of pipelines built in all zones also determines the overall storage capacity of the transmission infrastructure (this will be defined and explained later, in equation 18).

In reality, gas transmission systems are complex, spanning a varied landscape with a range of different pipeline lengths, diameters and operating regimes. The approach used here, in which each pipeline has the same diameter, length, maximum flow rate and linepack flexibility, is a simplification. For example, this representation assumes that all zones can connect to the same transmission system for the same cost, regardless of distance from the remainder of the transmission system. However, this approach enables modelling of both the storage and transportation capabilities of a gas transmission system with minimal complexity. Furthermore, with appropriate data assumptions, the overall operating regime of the system (e.g. maximum transportation rates and linepack swing) can be modelled accurately.

A series of equations are used in the VWM to manage the overall linepack inventory of the transmission system. The overall linepack inventory, J_{lhty} , is based on the flows of resource into and out of the system, as follows:

$$J_{lhty} = n_h^{\text{hd}} \sum_r \left(\sum_z \mathcal{L}_{lzhdy}^{\text{put}} \lambda_{lr,\text{dst},y}^{\text{put}} + \mathcal{L}_{lhty}^{\text{hold}} \lambda_{lr,\text{src},y}^{\text{hold}} + \sum_z \mathcal{L}_{lzhdy}^{\text{get}} \lambda_{lr,\text{src},y}^{\text{get}} \right) \quad (7)$$

$$\forall l \in \mathbb{L}, h \in \mathbb{H}, d \in \mathbb{D}, t \in \mathbb{T}, y \in \mathbb{Y}$$

The rate of operation of the “hold” task is defined as the current linepack level divided by the length of the time interval:

$$\mathcal{L}_{l,1,dty}^{\text{hold}} = J_{l,1,dty}^{0,\text{sim}} / n_1^{\text{hd}} \quad \forall l \in \mathbb{L}, d \in \mathbb{D}, t \in \mathbb{T}, y \in \mathbb{Y} \quad (8)$$

$$\mathcal{L}_{lhty}^{\text{hold}} = J_{l,h-1,dty} / n_h^{\text{hd}} \quad \forall l \in \mathbb{L}, h > 1 \in \mathbb{H}, d \in \mathbb{D}, t \in \mathbb{T}, y \in \mathbb{Y} \quad (9)$$

The daily linepack “surplus” is the change in linepack inventory between the first and last hourly intervals of the day type d :

$$\Delta_{lhty}^{\text{d}} = J_{l,|\mathbb{H}|,dty} - J_{lhty}^{0,\text{sim}} \quad \forall l \in \mathbb{L}, d \in \mathbb{D}, t \in \mathbb{T}, y \in \mathbb{Y} \quad (10)$$

The surplus for a week in season t is then calculated from the sum of the daily surpluses of each day type d in the given week, accounting for the number of repetitions of each day type n_d^{dw} :

$$\Delta_{lty}^{\text{t}} = \sum_d \Delta_{lhty}^{\text{d}} n_d^{\text{dw}} \quad \forall l \in \mathbb{L}, t \in \mathbb{T}, y \in \mathbb{Y} \quad (11)$$

Finally, the surplus over year y is the sum of all seasonal surpluses:

$$\Delta_{ly}^y = \sum_t \Delta_{ly}^t n_t^{\text{wt}} \quad \forall l \in \mathbb{L}, y \in \mathbb{Y} \quad (12)$$

A constraint is also included to keep the linepack over one year stationary (i.e. no yearly linepack surplus or deficit; this could also be applied on a shorter timescale if required):

$$\Delta_{ly}^y = 0 \quad \forall l \in \mathbb{L}, y \in \mathbb{Y} \quad (13)$$

The linepack inventory must be tracked to ensure that it does not exceed or fall below its allowable operational levels, and so that the impacts (e.g. costs) and resource requirements of holding linepack inventory are correctly accounted for. However, rather than explicitly calculating the inventory based on resource flows for each hourly interval of the entire time horizon, the total impacts and resource requirements can be calculated from the “average” inventory profile for each day type, season and yearly period. The “average” inventory profile that will give the same overall impacts and resource requirements as the full inventory profile is calculated from the initial linepack inventory at the beginning of each new time interval type, $J_{ldty}^{0,\text{act}}$, and the time interval surpluses defined in equations 10 to 12:

$$J_{ldty}^{0,\text{sim}} = J_{ldty}^{0,\text{act}} + \left[(n_d^{\text{dw}} - 1) \Delta_{ldty}^d + (n_t^{\text{wt}} - 1) \Delta_{ly}^t + (n_y^{\text{yy}} - 1) \Delta_{ly}^y \right] / 2 \quad (14)$$

$$\forall l \in \mathbb{L}, d \in \mathbb{D}, t \in \mathbb{T}, y \in \mathbb{Y}$$

The initial linepack inventory for each new time interval type is calculated from the linepack at the beginning of the previous time interval type, plus the linepack surplus accumulated over the course of the previous time interval type. This approach is used for each new day type, season, and planning period:

$$J_{ldty}^{0,\text{act}} = J_{l,d-1,ty}^{0,\text{act}} + n_{d-1}^{\text{dw}} \Delta_{l,d-1,ty}^d \quad \forall l \in \mathbb{L}, d > 1 \in \mathbb{D}, t \in \mathbb{T}, y \in \mathbb{Y} \quad (15)$$

$$J_{l,1,ty}^{0,\text{act}} = J_{l,1,t-1,y}^{0,\text{act}} + n_{t-1}^{\text{wt}} \Delta_{l,t-1,y}^t \quad \forall l \in \mathbb{L}, t > 1 \in \mathbb{T}, y \in \mathbb{Y} \quad (16)$$

$$J_{l,1,1,y}^{0,\text{act}} = J_{l,1,1,y-1}^{0,\text{act}} + n_{y-1}^{\text{yy}} \Delta_{l,y-1}^y \quad \forall l \in \mathbb{L}, y > 1 \in \mathbb{Y} \quad (17)$$

Finally, constraints are included to ensure that the linepack inventory always remains within its operational limits. The maximum and minimum allowable linepack inventories for the entire transmission system are the upper and lower bounds of the following equation, and are calculated from the maximum and minimum allowable inventories for a single pipeline, and the total number of pipelines installed in all zones. Due to the repeated time intervals within each time interval type (e.g. repeated days within a week), the maximum and minimum linepack inventories will always occur in the first or last interval of an interval type. Therefore

only these intervals need to be constrained. The first and last intervals of each day, season and planning period each must be constrained, resulting in 8 different constraints, which is then doubled to 16 to account for both the lower and upper bounds on the linepack inventory. These 16 constraints are shown in shorthand below, where all 8 combinations of plus and minus should be considered:

$$l_l^{\text{hold,min}} \sum_z N_{lzy}^L a_{lz} \leq J_{lhdty} \pm \frac{(n_d^{\text{dw}} - 1) \Delta_{ldty}^d \pm (n_t^{\text{wt}} - 1) \Delta_{lty}^t \pm (n_y^{\text{yy}} - 1) \Delta_{ly}^y}{2} \leq l_l^{\text{hold,max}} \sum_z N_{lzy}^L a_{lz} \quad (18)$$

$$\forall l \in \mathbb{L}, h \in \mathbb{H}, d \in \mathbb{D}, t \in \mathbb{T}, y \in \mathbb{Y}$$

As with all technologies installed in the model, the total number of pipelines installed in a given zone z in a given planning period y is tracked based on the number of pre-existing pipelines, N_{lz}^{EL} ; number of pipelines installed, NI_{lzy}^L ; and number of pipelines and pre-existing pipelines retired (NR_{lzy}^L and NR_{lzy}^{EL}):

$$N_{lzy}^L = \begin{cases} N_{lz}^{\text{EL}} + NI_{lzy}^L - NR_{lzy}^L & \forall l \in \mathbb{L}, z \in \mathbb{Z}, y = 1 \\ N_{lz,y-1}^{\text{EL}} + NI_{lzy}^L - NR_{lzy}^L - NR_{lzy}^{\text{EL}} & \forall l \in \mathbb{L}, z \in \mathbb{Z}, y > 1 \end{cases} \quad (19)$$

The number of pipelines retired is calculated from the technical lifetime of the pipeline.

For the practical reasons described in section 2.2, injection of hydrogen (either partial or complete conversion) into existing natural gas transmission pipelines was not modelled as an option. Instead, separate hydrogen transmission pipelines must be built. These have the same linepack capabilities as the equivalent natural gas system (although with lower energy throughput and storage).

3.1.3. Gas distribution

“Distribution” is used to refer to the delivery of gas from centralised locations such as storage facilities or the transmission system to the homes and businesses that use it for heating. Hydrogen distribution networks have previously been modelled in the VWM (e.g. [69, 74]) but this work is the first time that electricity and natural gas distribution networks have also been modelled. More importantly, the linepack capability of the natural gas and hydrogen distribution networks has now been modelled, as well as hydrogen injection into the natural gas distribution network and the option to convert to pure hydrogen networks. In order to represent both the delivery of gas to consumers and the storage capability (linepack) of distribution systems, they are represented in the model by a conversion technology coupled to a storage technology. An illustration of how these networks are represented is shown in Figure 7. Figure 7(a) shows the modelling of a conventional gas distribution grid (with linepack), whilst Figures 7(b) and 7(c) show operation with partial hydrogen injection and complete conversion to hydrogen, respectively.

All conversion technologies in the model, including for distribution technologies and other conversion technologies such as gas turbines or electrolyzers are governed by the following constraint, defining the net rate of production (or consumption) of resource r :

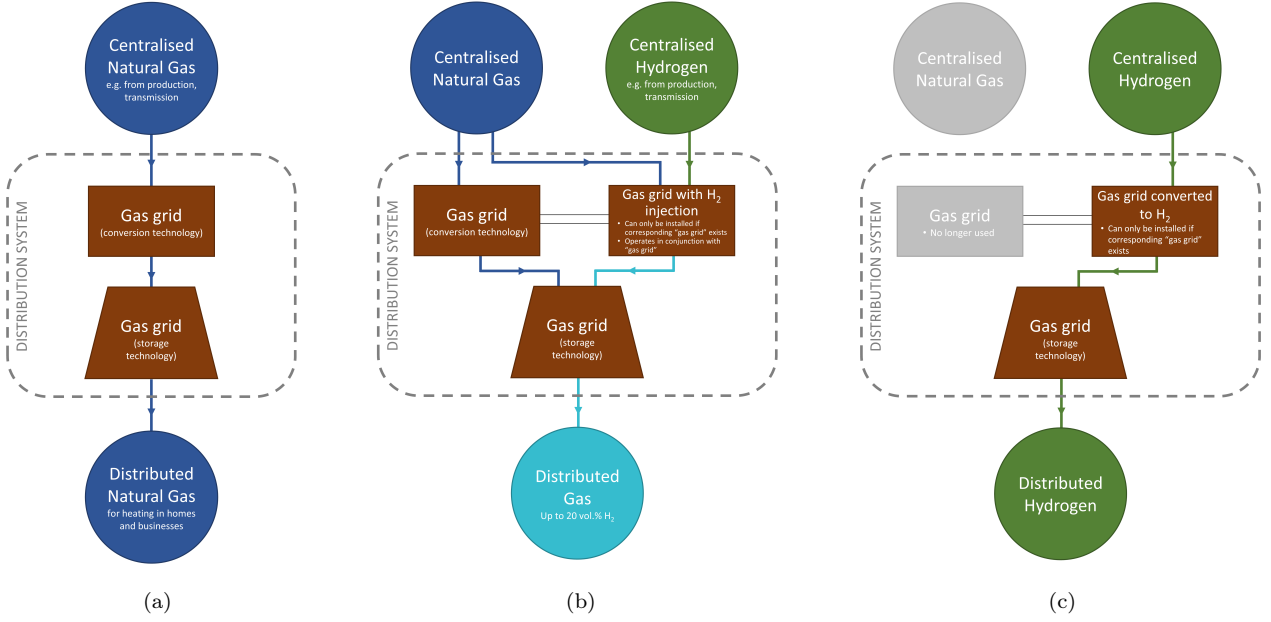


Figure 7: **Representation of gas distribution networks in the model.** (a) Standard natural gas distribution grid, including conversion of “centralised” gas to “distributed” gas, and storage (linepack) capacity of the grid; (b) Partial hydrogen injection into an existing natural gas grid; (c) Complete conversion of an existing natural gas grid to hydrogen.

$$P_{rzhdy} = \sum_{p \in \mathbb{P}} \mathcal{P}_{pzhdy} \alpha_{rpy} \quad \forall r \in \mathbb{R}, z \in \mathbb{Z}, h \in \mathbb{H}, d \in \mathbb{D}, t \in \mathbb{T}, y \in \mathbb{Y} \quad (20)$$

where P_{rzhdy} is the net resource production rate, $\mathcal{P}_{pzhdy}$ is the operating rate of the technology and α_{rpy} is a conversion factor that defines the rate of conversion between resources. For gas distribution networks this represents a conversion of 1 MWh of “centralised” gas to 1 MWh of “distributed” gas and can also include other resource requirements, such as electricity requirements for the process.

All conversion technologies, including distribution networks, come in pre-defined sizes in the model, but several of these technologies can be installed in one zone in order to increase the maximum overall operating rate. Hence, the overall operating rate of a technology type p in a zone z is constrained by upper and lower bounds based on the allowable operating rates of a single technology ($p_p^{\max}$ and $p_p^{\min}$) and the number of technologies installed (N_{pzy}^{PC}):

$$N_{pzy}^{\text{PC}} p_p^{\min} \leq \mathcal{P}_{pzhdy} \leq N_{pzy}^{\text{PC}} p_p^{\max} \quad \forall p \in \mathbb{P}, z \in \mathbb{Z}, h \in \mathbb{H}, d \in \mathbb{D}, t \in \mathbb{T}, y \in \mathbb{Y} \quad (21)$$

The total number of conversion technologies installed in a zone is tracked in the same manner as for the linepack technologies, as shown in equation 19. With this representation, all of the costs, efficiencies and operating rates of the gas distribution grid are represented in the model. As shown in Figure 7(a), in order to represent the gas distribution grid linepack, a storage technology is coupled to the conversion technology. In general, storage technologies are modelled in a similar manner to the linepack technology constraints shown in equations 4 to 19, except that separate storage technologies can be built in each zone, rather than only

one national infrastructure, and the zones can only have access to their own storage technologies (rather than any zone that is connected to the national infrastructure). For the full mathematical formulation for storage technologies, refer to [68, 69].

The storage technology representing distribution grid linepack has zero cost (this is included in the conversion technology), but represents the storage capacity of the distribution grid. The storage capacity of each portion of distribution grid was determined based on UK data for the overall linepack capacity of the gas distribution system [43], and estimates of the peak delivery rate of the distribution system from National Grid data [6]. Distribution grid conversion and storage technologies must always be installed together, therefore a constraint is included that the number of each is equal:

$$N_{szy}^S = N_{pzy}^{PC} \quad \forall s \in \mathbb{S}^{\text{Dist}}, z \in \mathbb{Z}, y \in \mathbb{Y}, p \in \mathbb{P}^{\text{Dist}}, SP_{sp} = 1 \quad (22)$$

where SP_{sp} is an association parameter that is equal to 1 where a storage technology is associated with a conversion technology (i.e. the corresponding storage and conversion technologies for the distribution network in question), and equal to 0 otherwise.

This representation is available for both natural gas distribution networks and for hydrogen distribution networks (if the model chooses to build these). Additionally, hydrogen injection into existing natural gas networks is modelled. Two options for injection of hydrogen into gas grids are modelled: partial, variable injection up to a level of 20 vol.%, or complete conversion of networks to hydrogen.

Figure 7(b) illustrates how partial hydrogen injection is represented in the VWM, using a conversion technology that converts natural gas and hydrogen in a fixed ratio (80:20 by volume / 93:7 by energy) into the same “distributed” gas that a typical natural gas distribution grid converts natural gas into. This technology can operate at a variable rate, alongside existing gas distribution grid technologies, so that the average hydrogen injection rate in the zone is determined by the relative operating rates of the technologies.

Figure 7(c) illustrates how complete conversion of a portion of gas distribution grid to hydrogen is represented in the VWM, using a new conversion technology that, similar to a new hydrogen distribution grid, converts “centralised” hydrogen to “distributed” hydrogen. However in this case, a “complete conversion” technology replaces an existing conventional gas distribution technology, (i.e. the section of gas distribution grid has been switched from natural gas to hydrogen and cannot be switched back). A constraint is included to ensure that the number of “complete conversion” technologies installed cannot exceed the number of conventional gas grid technologies already installed:

$$N_{HIGG-Complete\ Conversion,zy}^{PC} \leq N_{NG\ Distribution\ Grid,zy}^{PC} \quad \forall z \in \mathbb{Z} y \in \mathbb{Y} \quad (23)$$

Finally, a constraint is required to ensure that the overall peak capacity of the gas distribution grid in a given zone is modified based on the number of partial hydrogen injection and complete conversions carried out. Converting a portion of the distribution grid to hydrogen reduces the total capacity for delivering natural gas. Meanwhile installation of a “partial injection” technology does not increase the peak capacity of gas delivery. Therefore, a constraint specifies that the overall operating rate of all conventional gas distribution

and partial hydrogen injection technologies in a zone does not exceed the maximum allowable operating rate of the remaining gas grid (that has not undergone complete conversion to hydrogen).

$$\sum_{p \in \mathbb{PHGG}} \mathcal{P}_{pzhdty}^h \leq (N_{NG \text{ Distribution Grid},zy}^{PC} - N_{HIGG-Complete \text{ Conversion},zy}^{PC}) p_{NG \text{ Distribution Grid}}^{\max} \quad (24)$$

$$\forall z \in \mathbb{Z}, h \in \mathbb{H}, d \in \mathbb{D}, t \in \mathbb{T}, y \in \mathbb{Y}$$

Representing partial injection into the distribution grid and conversion of the distribution grid to 100% hydrogen as “partial injection” and “complete conversion” conversion technologies enables the optimisation to choose where and when these decisions may take place, taking into account the costs and other impacts of doing so.

3.1.4. Further additions

Electricity distribution networks were also included in the VWM. They are modelled by only a conversion technology as the electricity network has no linepack storage equivalent. Solar power was also included in the VWM for the first time in this work. Solar irradiance is included as a time-varying natural resource and solar PV technologies can be built to utilise this resource. Both rooftop and solar farm PV units can be installed, and have costs, efficiencies, and land footprint constraints associated with them.

3.2. Scenarios

In this study the VWM was applied to the GB energy system, as this represents a medium-sized energy system with an extensive gas grid, multiple energy resources (including wind, solar, nuclear, and natural gas), and stringent decarbonisation targets. The resources and technologies included in the optimisation are shown in Figure 5. The complete set of model input data used in this study, including resource availabilities and demands, and technology costs and operating data, can be found in the associated data article [71]. The optimisation objective was to satisfy overall demands for heat and electricity, including domestic, commercial and industrial demands, to maximise overall system net present value (NPV).

Table 1 provides a summary of the scenarios that were studied. Scenarios in both 2020 and 2050 were considered. In the 2020 scenarios, the present-day potential for partial hydrogen injection into the gas grid was investigated, including the effect of FITs incentivising the injection of hydrogen into the gas grid. For the 2050 scenarios, first the effects of different decarbonisation targets on the optimal energy system were assessed. Following this, the role of hydrogen in the optimal 2050 energy system was considered, focussing on the conversion of gas grids to hydrogen. The results and further details of these scenarios are provided in sections 4.1, 4.2.1 and 4.2.2.

Each of the 53 scenarios in Table 1 includes around 133,000 constraints and 77,000 variables, of which over 900 are integer variables. The optimisation was performed on a workstation with 10 cores and 128 GB RAM. Each scenario took up to three hours to solve with an optimality tolerance of 2%. Choices in scenario design will always be subject to some trade-offs with computational capability. For example, the size of

Table 1: Details of the scenarios modelled.

Time horizon	Issues explored	Number of scenarios modelled
2020	Partial hydrogen injection	33
2050	Effect of CO ₂ emissions targets	6
2050	Conversion of gas grids to hydrogen	14

the problem, hence the computational effort required, quickly scales up with the number of spatial zones or time intervals. The spatio-temporal resolutions used in the scenarios in this paper represent a good balance between achieving sufficient detail to answer the research questions posed without becoming computationally intractable.

4. Results: the role of hydrogen and gas grids in Great Britain

4.1. Opportunities for partial hydrogen injection today

A number of scenarios were modelled, exploring the role that hydrogen injection could have in the present day energy system, based on a hydrogen FIT incentivising injection into the gas grid. This tariff acts as a financial reward for every MWh of hydrogen that is injected partially into the natural gas distribution grid. Scenarios with FITs in the range of £0/MWh to £100/MWh were modelled. In order to carry out hydrogen injection, the injection equipment must be installed and relevant safety checks carried out; the costs of carrying out these upgrades were included in the capital cost of the “partial injection” technology. In the central case, these costs were assumed to be £3.60 per kW of gas distribution grid capacity, based on estimates from the HyNet project [47]. Sensitivity scenarios for these costs were also modelled, with upper and lower cost estimates of £7.20 and £1.80 per kW of grid capacity, respectively.

4.1.1. Effect of feed-in tariff on hydrogen uptake

Figure 8 shows the average level of partial hydrogen injection across the whole gas grid distribution network in each of the optimisation scenarios described above. As expected, higher FITs incentivise increased hydrogen injection. The upper limit for injection in these scenarios is 20 vol.%, which is a technical constraint based on the issues discussed in section 2. For higher levels of injection, the grid must be converted to 100% hydrogen, which would incur further costs and is not supported by a FIT in these scenarios.

In scenarios with FITs of up to £20/MWh, very low levels of hydrogen are injected (less than 1 vol.% on average across the whole system). With no FIT in place, annual injection is 0.1 TWh/yr, rising to 1.0 TWh/yr in the case with a FIT of £20/MWh. In these scenarios, hydrogen is only a small part of the wider energy system, and all hydrogen is produced from power-to-gas.

Figure 9 (left) shows a map of the hydrogen-related technologies installed in the scenario with a FIT of £20/MWh. Electrolysers are installed in only four zones and are accompanied by some pressure vessel hydrogen storage. Hydrogen is mostly produced overnight, when excess electricity is available. Although the gas grid linepack allows for some flexibility, the storage vessels are installed so that hydrogen injection

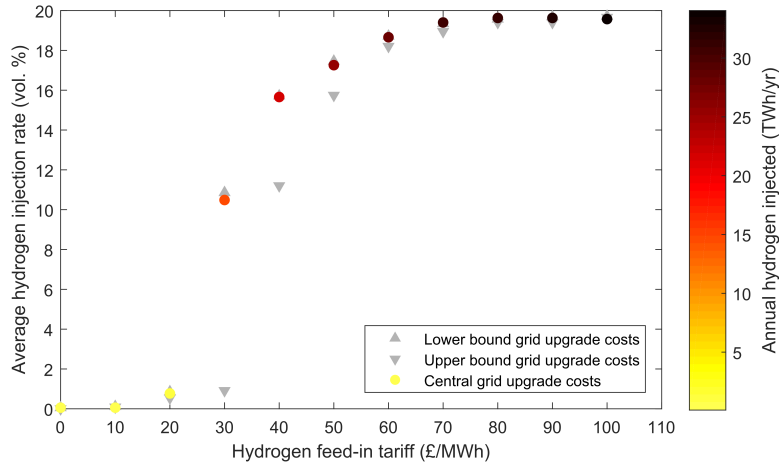


Figure 8: **Rate of partial hydrogen injection into the gas distribution grid in scenarios with a range of hydrogen feed-in tariffs and upgrade cost assumptions.** The average level of injection is the average across the entire gas distribution system. 20% injection in volume terms is equal to 7% in energy terms.

can be maximised throughout the day. Almost all hydrogen (96%) is injected into the gas distribution grid and the remainder is used directly for heating, for example in industrial plants that are connected directly to the hydrogen production or storage facilities.

With FITs of £30/MWh and above, there is sufficient incentive to build SMR plants, leading to a much larger scale of hydrogen production and higher levels of injection into the gas grid. However, the cost of injection also depends on the variability of gas demand and the flexibility of hydrogen supply. In the case with a FIT of £30/MWh, SMR plants are operated consistently throughout the year, producing a steady supply of hydrogen. This means that hydrogen injection is maximised (20 vol.%) at times of low gas demand, but much lower at times of high gas demand, resulting in an average injection rate of around 10 vol.%. To achieve higher average levels of injection than 10 vol.%, additional infrastructure (in particular hydrogen storage) must be installed to provide more hydrogen supply flexibility. This increases costs, so that higher levels of FIT are required to make it worthwhile. With a FIT of £50/MWh, average hydrogen injection across the whole system exceeds 17 vol.%, and the majority of the network has been upgraded for hydrogen injection.

Details of the hydrogen system design in the case with a FIT of £50/MWh case are shown on the right of Figure 9. In this case, hydrogen is produced entirely by SMR with CCS. SMR plants are built in two locations, each with offshore CO₂ storage. A national hydrogen transmission system is established, connecting most of the country, and hydrogen is injected into the existing gas distribution system in all zones that are connected to this transmission system. With an established hydrogen infrastructure, hydrogen is also used to provide some flexibility to the electricity sector: hydrogen is extracted from storage at times of low electricity supply, and converted to electricity in fuel cell plants. Overall, 80% of hydrogen is injected into the gas distribution grid, 15% is used in fuel cells for power, and the remainder is used for other heating applications such as industrial use.

Finally, the effect of the grid upgrade cost assumptions for hydrogen injection can be seen in Figure 8. With upper bound cost estimates, a greater incentive for hydrogen injection is required (a FIT of approximately

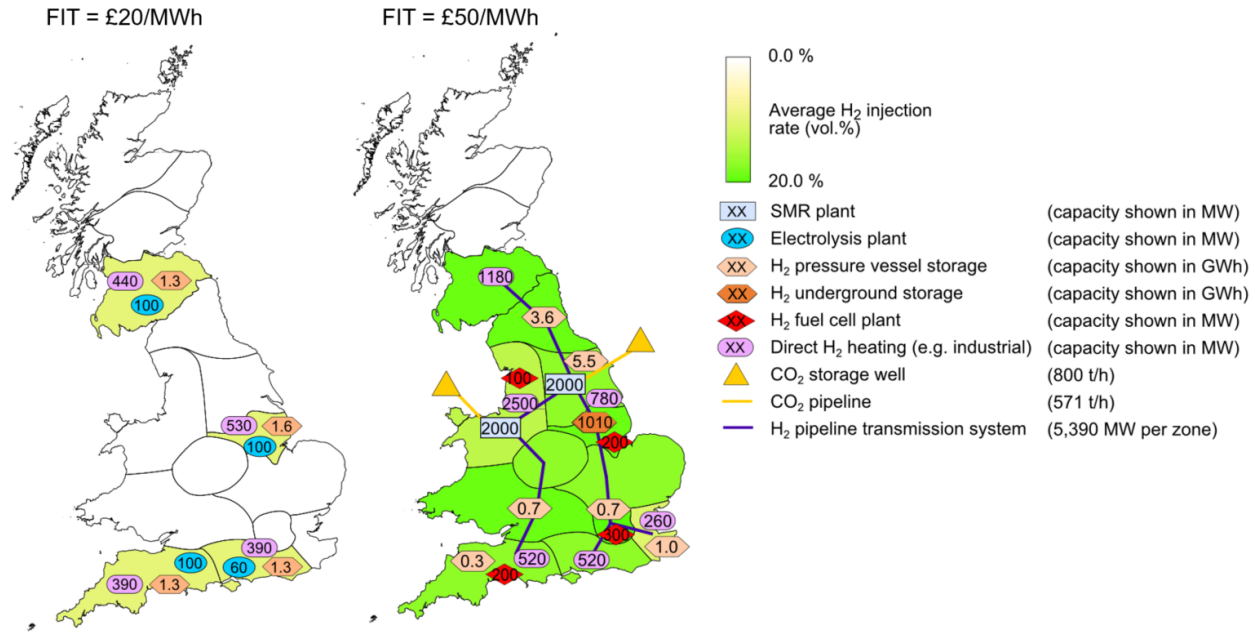


Figure 9: **Maps of the hydrogen-related technologies installed in two present-day scenarios with partial hydrogen injection.** The map on the left shows details of the power-to-gas based system arising in the case with a feed-in tariff of £20/MWh; the map on the right shows details of the SMR based system arising in the case with a feed-in tariff of £50/MWh. Only hydrogen-related technologies are shown: further technologies that are not shown in the figure include the existing natural gas transmission system and electricity generation technologies such as wind turbines and natural gas power plants. The numbers shown represent the total installed capacity of the technology in each zone.

£10/MWh more is needed to achieve a similar level of hydrogen injection). However, lower bound upgrade cost assumptions have little influence on the overall level of hydrogen injection.

4.1.2. Cost of hydrogen and impact on consumer bills

Figure 10 shows the levelised cost of hydrogen in the gas grid for the scenario with a FIT of £20/MWh and the scenario with a FIT of £50/MWh. These costs represent the average cost of all hydrogen injected into the gas grid. This cost is not equal to the FIT, primarily because the “optimal” level of injection for a given FIT will be driven by the marginal cost of injection (rather than the average cost), but also because of other factors such as the profitability of alternatives, such as injection of natural gas.

The costs of grid upgrades contribute a relatively small amount to the overall cost of hydrogen in the gas grid. In both cases, less than 3% of the cost of hydrogen in the gas grid is attributed to gas grid upgrades (based on the central cost estimates). In the £50/MWh case, in which hydrogen is produced from SMR, over half of the hydrogen cost is the cost of the natural gas feedstock. In the £20/MWh case, in which the hydrogen is produced from power-to-gas, electricity cost is not included in the levelised hydrogen cost. Most of the hydrogen in this scenario is produced overnight, from “excess” electricity which can be assumed to have a low or even zero cost. Although Figure 10 shows that the hydrogen from power-to-gas has a lower cost than hydrogen from SMR in these scenarios, only a limited amount of excess electricity is available for this power-to-gas. Larger scale power-to-gas would have to compete with other demands for electricity, therefore increasing the levelised hydrogen cost. Consequently SMR becomes the preferred (lowest cost) hydrogen production option as the scale of production increases.

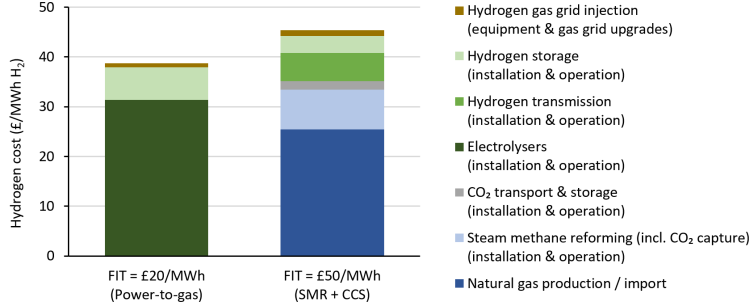


Figure 10: **Levelised cost of hydrogen injected into the gas distribution grid for hydrogen produced from power-to-gas and hydrogen produced from SMR (with CCS).** Costs shown are with baseline injection cost assumptions. The power-to-gas case is taken from the scenario with a feed-in tariff of £20/MWh, and the electricity price is not included. The SMR case is taken from the scenario with a feed-in tariff of £50/MWh.

These results suggest that partial hydrogen injection into gas grids is possible in present day energy systems and that hydrogen FITs in the range of £20-£50/MWh would help to establish hydrogen production and transmission infrastructures. Whilst no hydrogen FITs currently exist in the UK, FITs for biomethane injection are available in the range of £22-49/MWh [75]; Figure 8 suggests that a similar level of incentive for hydrogen injection would be sufficient.

The total annual costs of the FIT payments are £21m in the £20/MWh scenario and £1233m in the £50/MWh scenario. If these costs were to be funded by consumer gas bills, the average consumer's annual bill would increase by around £1 in the £20/MWh scenario and by £46 in the £50/MWh scenario¹. Once these infrastructures are established, opportunities arise for hydrogen in other sectors, such as direct heating in specialist applications and providing flexibility to the electricity system by converting stored hydrogen to electricity at times of peak demand.

4.1.3. CO₂ impacts of partial hydrogen injection

The CO₂ emissions reductions resulting from partial hydrogen injection are small compared to the CO₂ emitted elsewhere in the system (predominantly in the combustion of natural gas for heating and electricity production). In the £20/MWh case presented above, hydrogen injection reduces gas distribution grid emissions by 0.1%, but this is offset by increased natural gas usage elsewhere. In the £50/MWh case, the overall reduction in emissions across the whole system compared to the case with no hydrogen injection is 2.3%. In the modelled scenarios, power-to-gas hydrogen should in theory offer greater emissions reductions because it is powered mostly by excess wind and therefore has a near-zero CO₂ footprint. Meanwhile SMR hydrogen has a footprint of around 50 kgCO₂/MWh, due to the uncaptured emissions and upstream natural gas production emissions. However, the availability of excess renewables for power-to-gas is small, so this hydrogen production route does not offer emissions reductions at any significant scale.

4.2. Outlook for hydrogen and gas grids in 2050

In order to assess the long-term potential for hydrogen in gas grids, the GB energy system in 2050 was considered, taking into account GHG emission reduction targets. Emissions reduction targets can be imposed

¹Based on an average consumer using 15,000 kWh of gas per year [76].

in the VWM using a constraint on total allowable emissions. The effect of different emissions constraints on the scenario results is determined in section 4.2.1. Subsequently, in section 4.2.2, the role of hydrogen in these scenarios is considered in detail.

4.2.1. Long term decarbonisation and the effects of emissions reduction targets

The UK has recently committed to achieving net-zero GHG emissions by 2050 [77]. However, a major challenge for achieving a net-zero target is the “unavoidable” emissions associated with fossil fuels. For example, even for processes with CO₂ capture, the rate of CO₂ capture rarely exceeds 90% [78, 79]. In some cases, higher rates of capture can be achieved, but this comes with a significant energy penalty [46, 80]. Furthermore, there are emissions associated with the upstream production of fossil fuels that are hard to avoid: for example, natural gas production can have GHG emissions of around 0.013 tCO₂ (equivalent) per MWh of natural gas produced [81]. These emissions could be avoided if fossil fuels were removed from the energy system altogether, however this would be a major challenge for the present day fossil-based system, especially by 2050.

These “unavoidable” GHG emissions are likely to mean that a “net-zero” emissions target will require negative emissions technologies (NETs), environmental restoration such as afforestation, and/or international CO₂ trading. The contribution that these options could make in the future is uncertain: the Royal Society and Royal Academy of Engineering estimated a maximum technical potential in the UK in 2050 of 130 MtCO₂/yr, including 50 MtCO₂/yr from biomass energy CCS (BECCS) and 25 MtCO₂/yr from direct air CCS (DACCS) [82]. In the Net Zero scenario in the National Grid Future Energy Scenarios, BECCS contributes 37 MtCO₂/yr in 2050 [83], whilst Daggash et al. model contributions from BECCS of up to 51 MtCO₂/yr and DACCS of up to 19 MtCO₂/yr [84].

As the focus of this study is on whether and how to utilise hydrogen in natural gas networks and not on which particular NETs could or should be employed, the scenarios considered in the section do not include any negative emissions technologies. However, to evaluate when the use of NETs becomes beneficial, the CO₂ emissions targets are progressively made more stringent in each scenario until a final target of zero emissions is reached. The marginal costs of meeting each additional target are calculated and thus it can be seen at which point further investment in and modification of the natural gas/hydrogen networks is less economical than employing NETs, based on their typical costs per tonne of CO₂ abated.

Figure 11 shows results from these scenarios, including the overall system cost and technologies used for electricity, heat and hydrogen production in each scenario. The electricity mix remains similar in all low-carbon scenarios, relying mainly on nuclear and wind power, although total electricity production grows from 460 TWh/yr in the 40 MtCO₂/yr scenario (representative of an 80% reduction in emissions from 1990 for the sectors modelled) to 662 TWh/yr in the zero-carbon scenario.

The increase in electricity production shown in Figure 11(a) is to provide heating, which is increasingly switched from natural gas to electricity. Whereas natural gas is used for 82% of domestic heating in the scenario with unlimited emissions (cf. section 4.1), this is reduced in each of the lower carbon scenarios and by the 10 MtCO₂/yr scenario natural gas is no longer used for domestic heating. In this scenario, almost all domestic heating is provided by electric heat pumps, except for 1% of heating that is provided by hydrogen by converting a portion of the natural gas grid.

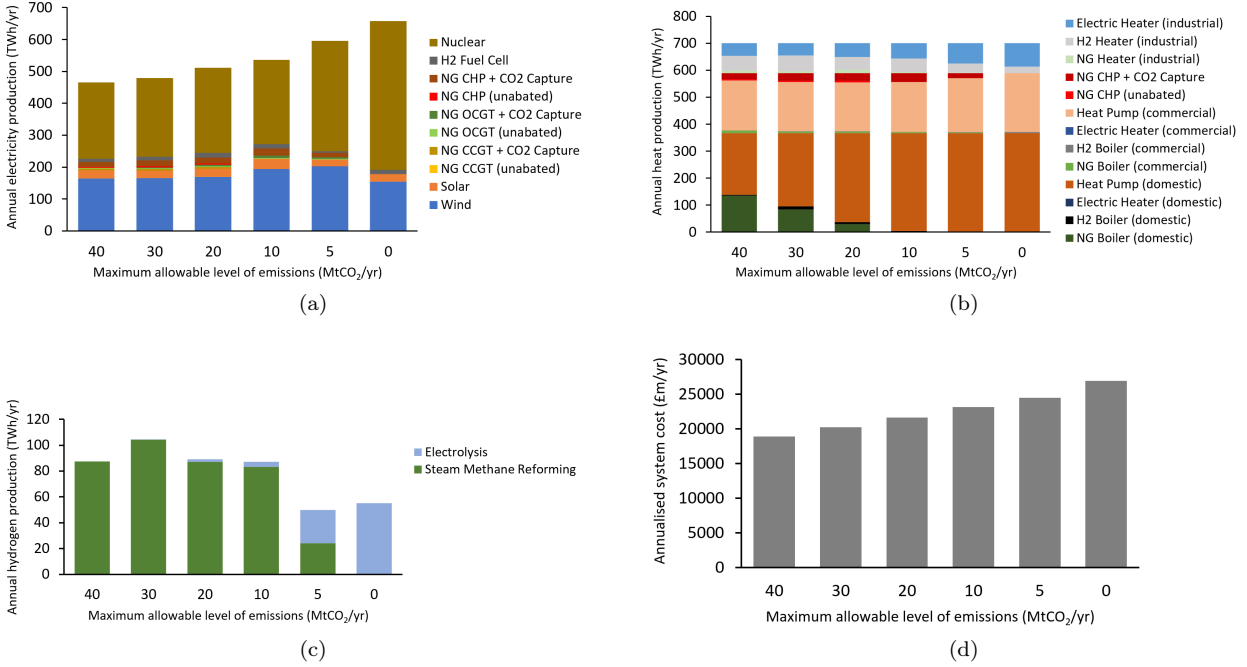


Figure 11: **Results from optimisation scenarios for 2050, with a range of allowable CO₂ emissions limits.** (a) Electricity production; (b) Heat production; (c) Hydrogen production; (d) Annualised overall system cost.

Hydrogen has a role in these scenarios, without any specific incentives such as feed-in tariffs. The main use for hydrogen in these scenarios is in industrial heating, although hydrogen usage reduces with increasing CO₂ stringency. This is due to the unavoidable emissions associated with SMR, which is the cheaper hydrogen production option. Although increased production of hydrogen from electrolysis counteracts this to some extent, overall hydrogen production still reduces. The reasons for the preference to electrify heat rather than use hydrogen are discussed in section 4.2.2.

The system becomes increasingly more expensive with lower CO₂ emissions limits and the marginal cost of emissions reductions increases as the “easiest” emissions are eliminated first. Whilst reducing the overall system emissions from 40 MtCO₂/yr to 20 MtCO₂/yr costs on average £138 /tCO₂, reducing emissions from 20 MtCO₂/yr to 10 MtCO₂/yr costs £158 /tCO₂, and from 10 MtCO₂/yr to 5 MtCO₂/yr costs £259 /tCO₂.

From the increasing costs of the scenarios with more stringent emissions reduction targets, there is likely to be an optimal level of emissions that would be mitigated at a lower cost through negative emissions options. Estimates for the costs of negative emissions options such as NETs exceed £100 /tCO₂, and often more than £200 /tCO₂ [82]. Therefore, from the above scenarios, applying an emissions limit between 5 MtCO₂/yr and 20 MtCO₂/yr would provide the most pragmatic energy system design, with the remaining emissions reductions being achieved more cost effectively through negative emissions options. A detailed assessment of the actual NETs required is beyond the scope of this paper, as the focus is on the usefulness of HIGG.

4.2.2. Hydrogen injection into the gas grid in 2050

As the scenarios in section 4.2.1 show, the main alternative to converting gas grids to hydrogen is electrification of heating. There are many advantages and disadvantages of each of these options; in this optimisation

Table 2: Cost assumptions for investment in electrification of heating and conversion of gas grids to hydrogen. The central assumptions for 2050 are shown.

Electrification			Conversion of gas grids to hydrogen		
Investment	Cost	Ref.	Investment	Cost	Ref.
Expansion of electricity distribution infrastructure (cost per kW of new grid capacity)	£650	[64]	Conversion of existing gas distribution grids to hydrogen (cost per kW of grid converted)	£3.40	[46]
Installation of domestic heat pump and new heating system	£3,600	[65]	Installation of hydrogen boiler and heating system	£2,400	[55, 65]

study, the choice is driven primarily by cost and emissions. In this section, these issues are discussed and optimisation scenarios are presented that explore them in detail.

The assumptions used in this study for the investment costs of either converting gas grids to hydrogen or electrification of heating are shown in Table 2. For electrification, it is likely that electricity distribution infrastructure would need expanding and that this would be more expensive than converting existing gas distribution grids to hydrogen. Meanwhile, given that the majority of homes currently have natural gas based heating systems, it is also likely to be more expensive to install electric heating systems (e.g. electric heat pumps, which typically also require new radiators [85]) than hydrogen systems (which would only require that the boiler be replaced).

However, although the investment costs for conversion of gas grids to hydrogen may be lower than electrification of heating, the hydrogen supply chain is more complex, relying on conversion of either natural gas or electricity to hydrogen. Electricity supply chains, however, are more direct between production of electricity and heating. Therefore the “fuel” costs are likely to be lower for electrification. Furthermore, the lower-cost hydrogen production route, via SMR, has unavoidable emissions associated with it, from the upstream natural gas production and the fraction of emissions that cannot be captured at the SMR plant.

The results in section 4.2.1 suggest that the lower supply chain costs of electrification outweigh the higher investment costs of upgrading/replacing the end-use technologies, when compared to conversion of gas grids to hydrogen. To explore this further, the significance of the cost assumptions in Table 2 were examined by modelling a series of scenarios with increasing electricity infrastructure costs. Scenarios in 2050 with investment costs between £650 per kW and £1250 per kW of new electricity distribution capacity were modelled, with emissions constraints of both 10 MtCO₂/yr and 20 MtCO₂/yr. No feed-in tariffs or other technology incentives were included in these scenarios.

The results from these scenarios are shown in Figure 12. Whilst with new electricity infrastructure costs at £650 per kW capacity there is almost no use of hydrogen in gas grids for heating, increasing electricity distribution costs make hydrogen more appealing and with costs of £1050 per kW capacity, with a CO₂ constraint of 20 MtCO₂/yr, around one third of domestic and commercial heating is delivered as hydrogen through converted natural gas pipelines. A more stringent CO₂ constraint of 10 MtCO₂/yr results in less hydrogen being used due to the emissions associated with the hydrogen supply chain.

Figure 13 shows details of the system design and operation for the 20 MtCO₂/yr scenario with electricity distribution infrastructure costs of £1050 per kW capacity. An extensive hydrogen infrastructure is constructed, including hydrogen production from SMR, CCS, hydrogen and CO₂ transmission pipelines

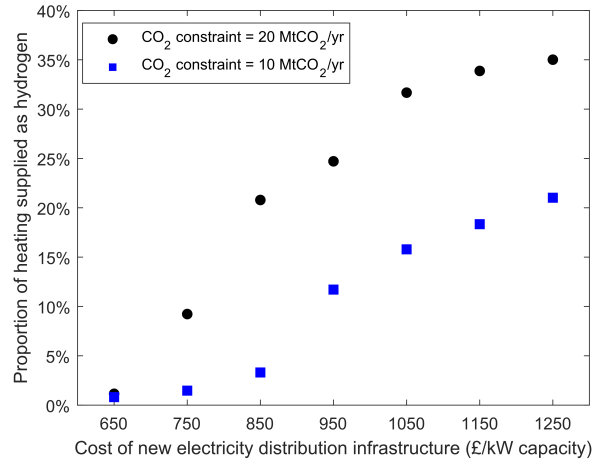


Figure 12: **Proportion of domestic and commercial heating supplied as hydrogen (through the gas grid) in scenarios with increasing costs of electricity distribution infrastructure.**

spanning the country, and a significant amount of hydrogen storage. The total annual hydrogen production is 291 TWh/yr, of which less than 1 TWh is from power-to-gas. A small amount (5%) of hydrogen is converted to electricity via fuel cells and the remainder is used for heating. As Figure 13(a) shows, different choices regarding conversion of natural gas distribution systems to hydrogen are made around the country. Overall, 57% of existing distribution grid capacity is converted to pure hydrogen, 26% is retained for delivering natural gas (including some partial hydrogen injection), and 17% is unused. Where gas grids are not used, electrification of heating is preferred.

Various hydrogen storage options are included to provide system flexibility. Underground storage facilities provide interseasonal storage for balancing variations in demand across the year, as shown in Figure 13(b). Linepack from the distribution and transmission systems provides some within-day flexibility but, importantly this is not sufficient for the whole system, so almost 300 GWh of pressure vessel hydrogen storage is also required. Typically the linepack and pressure vessel storage is accumulated overnight and depleted over the course of the day.

5. Conclusions

Hydrogen injection into gas grids, both through partial mixing with natural gas and complete conversion to hydrogen, is a feasible strategy for maintaining and decarbonising the extensive natural gas grids that serve many countries in the world. The advantages of hydrogen injection include reduced greenhouse gas emissions from the gas grid end users, making use of valuable transmission and distribution infrastructures (and avoiding expansion of electricity infrastructure), and exploiting the inherent flexibility that gas grids have, known as linepack flexibility.

Although there are practical and safety challenges to utilising hydrogen in existing natural gas pipelines, most of these issues can be overcome or managed. Several testing and demonstration projects have been completed or are in progress globally that are expanding the knowledge base in this area and providing confidence on the feasibility of hydrogen injection.

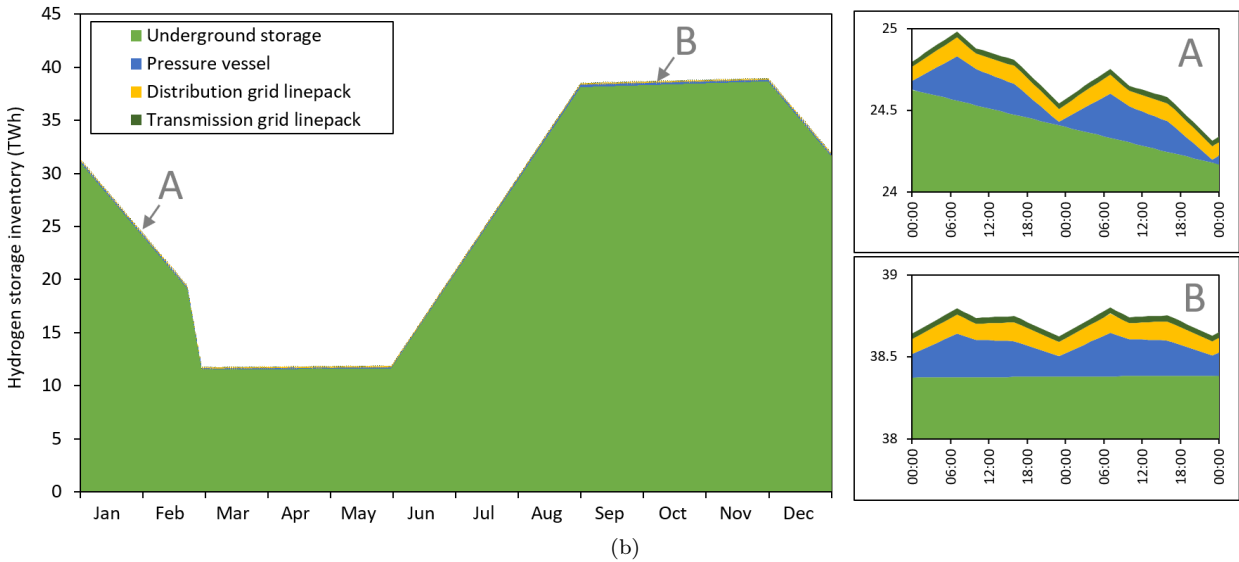
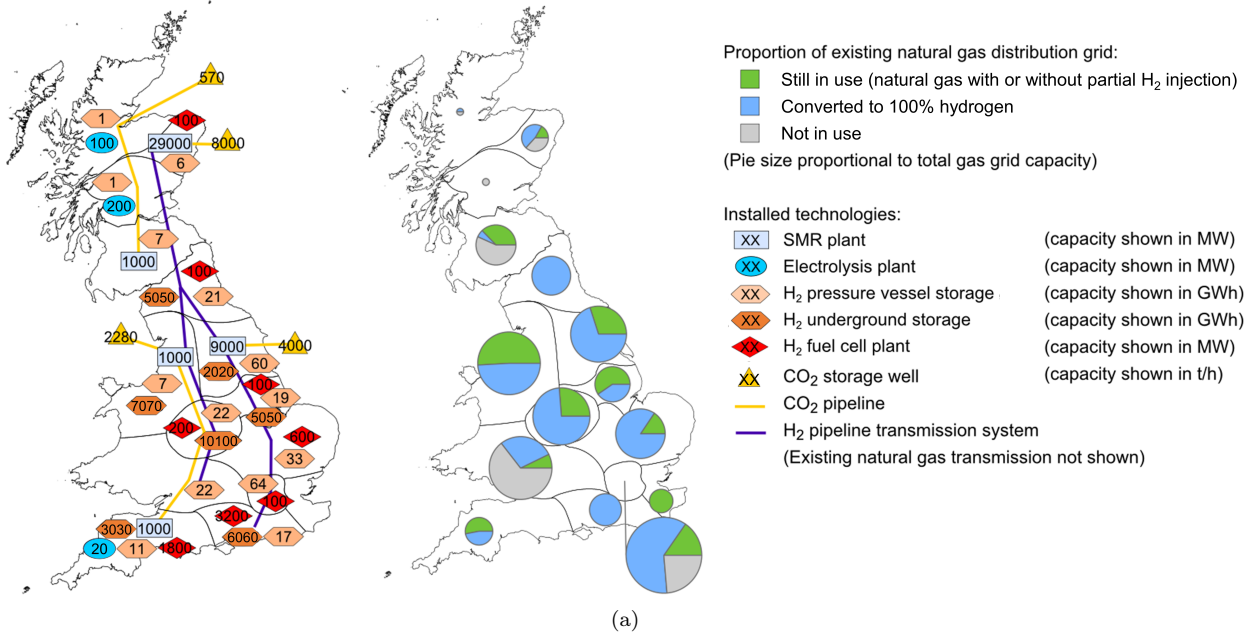


Figure 13: **Energy system design and operation for a 2050 case that includes conversion of gas grids to hydrogen.** The case shown is the case with a CO₂ constraint of 20 MtCO₂/yr and new electricity distribution grid installation costs of £1050/kW. (a) Maps of the energy system, including (left) installed hydrogen-related technologies (numbers show total installed capacity in the zone) and (right) proportion of the existing natural gas distribution grid that is retained, converted to hydrogen or unused in each zone; (b) Total storage inventory for all hydrogen storage options, including gas grid linepack, over the course of one year, with insets showing within-day variation in January and October.

Energy systems are ready for partial hydrogen injection into gas grids now. Using an integrated value chain optimisation model (the Value Web Model, which was further developed here to include hydrogen injection into the gas grid, conversion of gas grids to hydrogen, and linepack storage), this study has shown that feed-in tariffs of £20/MWh for hydrogen injected into gas grids would be sufficient to incentivise injection in certain applications. This would also provide some stability to the electricity system, by absorbing electricity at times of excess supply and converting to hydrogen using electrolysis. Higher feed-in tariffs, of around £50/MWh, would incentivise a wider roll-out of partial hydrogen injection, with average injection levels across the whole gas distribution grid in excess of 17 vol.%. In this scenario, an extensive national hydrogen infrastructure is developed, including hydrogen production from steam methane reforming and a national hydrogen transmission system. Partial hydrogen injection reduces gas grid emissions by up to 4 MtCO₂/yr, which is a reduction in overall system emissions of around 2.5%.

In the long term, complete conversion of gas grids to hydrogen is an option for decarbonising heat and exploiting the flexibility of gas grids. However, this option must compete with electrification of heat, which may have higher infrastructure costs but a more efficient energy supply chain. A particular challenge for conversion of gas grids to hydrogen in very low-carbon scenarios is the unavoidable CO₂ emissions from hydrogen production from fossil fuels. In this study, electrification of heating was found to be the optimal solution with median electricity infrastructure costs of £650 per kW capacity. However, conversion of gas grids could have a significant contribution if electricity infrastructure costs are found to exceed £1000 per kW capacity. Alternatively, other challenges for the electric heating supply chain, such as inadequate performance of electric heat pumps, would improve the case for conversion of gas grids to hydrogen.

Scenarios with significant proportions of the gas grid converted to hydrogen would involve an extensive roll-out of hydrogen-related infrastructure, including production plants, and transportation and storage infrastructure for both hydrogen and CO₂. Gas grid linepack would provide some flexibility to the system but this study found that the reduced linepack of gas networks when converted to hydrogen would mean that additional intra-day flexibility, such as above-ground hydrogen pressure vessels, may be required.

Provided that negative emissions options will be able to provide a small level of negative emissions (5-20 MtCO₂/yr for heating and electricity sectors considered in this study) a net zero emissions target is achievable and does not significantly affect the optimal 2050 energy system. However, achieving net zero emissions without negative emissions options would be significantly more expensive and would affect the final system design, primarily because this would preclude the use of any fossil fuels at all.

This study is the first to have applied value chain optimisation methods to hydrogen injection into gas grids, and the approach has provided valuable insights into the role of hydrogen and gas grids in the wider energy system. The model and insights presented here will be valuable to modellers and researchers looking to understand aspects of current and future energy systems, in particular the practicalities and the role of hydrogen injection into gas grids from a whole-system value chain optimisation perspective. The modelling scenarios in this paper have focussed on the energy system of Great Britain, as an example of a medium-sized energy system with an extensive natural gas grid. However, many other countries have a similar reliance on their gas grids, and the key insights from this study are applicable to these countries and the presented MILP formulation of the Value Web Model can be used together with country-specific data to obtain more direct results and insights. Finally, the results from this study will be valuable to policymakers, exploring the justification for incentives for hydrogen both now and into the future.

Acknowledgements

The authors would like to thank Dr Ian Llewelyn from the UK Government Department of Business, Energy and Industrial Strategy (BEIS) and Dr Jose M. Bermudez from the International Energy Agency for their valuable comments on this work and wider support of the project.

Thanks also to Dr Ting Guo Ho for sharing modelling data from the BEIS Heat Strategic Options project, and Ana Martinez Diaz for sharing the land availability data from the solar site suitability analysis from her MSc project.

The funding and support of BEIS and the Engineering and Physical Sciences Research Council (EPSRC), through C.J. Quarton's PhD studentship, are gratefully acknowledged.

Dr S Samsatli would like to thank the EPSRC for partial funding of her research through the BEFEW project (Grant No. EP/P018165/1).

Appendix A. Abbreviations

BECCS	Biomass Energy Carbon Capture and Storage
CCS	Carbon Capture and Storage
CO ₂	Carbon dioxide
DACCS	Direct Air Carbon Capture and Storage
FIT	Feed in Tariff
GB	Great Britain
GHG	Greenhouse Gas
H ₂	Hydrogen
LTS	Local Transmission System
MILP	Mixed Integer Linear Programming
NETs	Negative Emissions Technologies
NTS	National Transmission System
SMR	Steam Methane Reforming
STP	Standard Temperature and Pressure
tCO ₂	Tonnes of Carbon dioxide
VWM	Value Web Model

Appendix B. Model nomenclature

A reduced nomenclature for the mathematical formulation presented in section 3 is provided here. The full model mathematical formulation and nomenclature can be found in previous studies by Samsatli and co-workers (e.g. [68, 69, 70]).

Indices and sets

$d \in \mathbb{D}$	Daily interval types (e.g. weekday, weekend)
$h \in \mathbb{H}$	Hourly (sub-day) intervals
$l \in \mathbb{L}$	“Linepack” technologies (transmission infrastructures with linepack storage)
$p \in \mathbb{P}$	Conversion technologies
$\mathbb{P}^C \subseteq \mathbb{P}$	Commercial conversion technologies
$\mathbb{P}^{Dist} \subseteq \mathbb{P}$	Conversion technologies that represent distribution networks
$\mathbb{P}^{HIGG} \subseteq \mathbb{P}$	Conversion technologies for hydrogen injection into the gas grid
$r \in \mathbb{R}$	Resources
$s \in \mathbb{S}$	Storage facilities
$\mathbb{S}^{Dist} \subseteq \mathbb{S}$	Storage facilities that represent the linepack storage of distribution networks
$t \in \mathbb{T}$	Seasonal time intervals
$y \in \mathbb{Y}$	Long term planning time intervals (e.g. decadal)
$z \in \mathbb{Z}$	Spatial zones

Parameters

a_{lz}	Binary value determining whether it is possible to connect to the national transmission infrastructure l in zone z ($a_{lz} = 1$ if a facility may be built, 0 otherwise)
$l_l^{\text{put},\text{max}}$	Maximum injection rate per connection into linepack transmission system l
$l_l^{\text{hold},\text{min}}$	Minimum linepack storage capacity per connection for linepack transmission system l
$l_l^{\text{hold},\text{max}}$	Maximum linepack storage capacity per connection for linepack transmission system l
$l_l^{\text{get},\text{max}}$	Maximum withdrawal rate per connection from linepack transmission system l
n_h^{hd}	Duration of hourly interval h [h]
n_d^{dw}	Number of occurrences of day type d in a week (e.g. 5 for a weekday, 2 for a weekend)
n_t^{wt}	Number of repeated weeks in season t
N_{lz}^{EL}	Number of pre-existing connections for linepack transmission system l in zone z
NR_{lzy}^{EL}	Number of pre-existing connections for linepack transmission system l in zone z that retire at the beginning of planning period y
p_p^{max}	Maximum operating rate of technology p
p_p^{min}	Minimum operating rate of technology p
SP_{sp}	Association parameter that links the conversion technologies that represent distribution networks $p \in \mathbb{P}^{Dist}$ to the storage technologies associated with the same network $s \in \mathbb{S}^{Dist}$
α_{rpy}	Conversion factor of resource r in technology p in planning period y
$\lambda_{lrfy}^{\text{put}}$	Conversion factor for performing “put” task with linepack transmission system l on resource r in planning period y
$\lambda_{lrfy}^{\text{hold}}$	Conversion factor for performing “hold” task with linepack transmission system l on resource r in planning period y
$\lambda_{lrfy}^{\text{get}}$	Conversion factor for performing “get” task with linepack transmission system l on resource r in planning period y

Positive variables

J_{lhdt_y}	Linepack inventory in transmission system l during hour h of day type d in season t of planning period y
$J_{ldty}^{0,act}$	Linepack inventory in transmission system l at the start of day type d in season t of planning period y
$J_{ldty}^{0,sim}$	Linepack inventory in transmission system l at the start of the simulated cycle for day type d in season t of planning period y
$\mathcal{P}_{pzhdty}$	Total rate of operation of conversion technology p in zone z during hour h of day type d in season t of planning period y
$\mathcal{L}_{lzhdt_y}^{put}$	Operation rate of “put” task by linepack transmission system l in zone z during hour h of day type d in season t of planning period y
$\mathcal{L}_{lhdt_y}^{hold}$	Operation rate of “hold” task by linepack transmission system l in all zones during hour h of day type d in season t of planning period y
$\mathcal{L}_{lzhdt_y}^{get}$	Operation rate of “get” task by linepack transmission system l in zone z during hour h of day type d in season t of planning period y

Free variables

L_{zrhdt_y}	Net flow rate of resource r from all linepack transmission systems in zone z during hour h of day type d in season t of planning period y
P_{rzhdt_y}	Net rate of production by conversion technologies of resource r in zone z during hour h of day type d in season t of planning period y
Δ_{ldty}^d	Net surplus put into linepack transmission system l over one day in day type d in season t of planning period y
Δ_{lty}^t	Net surplus put into linepack transmission system l over one week in season t of planning period y
Δ_{ly}^y	Net surplus put into linepack transmission system l over one year in planning period y

Integer variables

N_{lzy}^L	Total number of connections to linepack transmission system l in zone z during planning period y
N_{pzy}^{PC}	Total number of commercial conversion technology $p \in \mathbb{P}^C$ in zone z during planning period y
N_{szy}^S	Total number of storage technology s in zone z during planning period y
NI_{lzy}^L	Total number of connections to linepack transmission system l installed in zone z at the beginning of planning period y
NR_{lzy}^L	Total number of connections to linepack transmission system l retired from zone z at the beginning of planning period y

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