The carbon credentials of hydrogen gas networks and supply chains

Paul Balcombe[a,b,*], Jamie Speirs[b,c], Erin Johnson[a], Jeanne Martin[b], Nigel Brandon[b,c], Adam Hawkes[a,b]

[a] Department of Chemical Engineering, Imperial College London, SW7 2AZ, United Kingdom
[b] Sustainable Gas Institute, Imperial College London, 10 Prince's Gardens, SW7 1NA, United Kingdom
[c] Department of Earth and Atmospheric Science, Imperial College London, SW7 2BP, United Kingdom

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ABSTRACT

Projections of decarbonisation pathways have typically involved reducing dependence on natural gas grids via greater electrification of heat using heat pumps or even electric heaters. However, many technical, economic and consumer barriers to electrification of heat persist. The gas network holds value in relation to flexibility of operation, requiring simpler control and enabling less expensive storage. There may be value in retaining and repurposing gas infrastructure where there are feasible routes to decarbonisation. This study quantifies and analyses the decarbonisation potential associated with the conversion of gas grids to deliver hydrogen, focusing on supply chains. Routes to produce hydrogen for gas grids are categorised as: reforming natural gas with (or without) carbon capture and storage (CCS); gasification of coal with (or without) CCS; gasification of biomass with (or without) CCS; electrolysis using low carbon electricity. The overall range of greenhouse gas emissions across routes is extremely large, from -371 to $642\,gCO_2eq/kW\,h_{H_2}$. Therefore, when including supply chain emissions, hydrogen can have a range of carbon intensities and cannot be assumed to be low carbon. Emissions estimates for natural gas reforming with CCS lie in the range of $23–150\,g/kW\,h_{H_2}$, with CCS typically reducing CO_2 emissions by 75%. Hydrogen from electrolysis ranges from 24 to $178\,gCO_2eq/kW\,h_{H_2}$ for renewable electricity sources, where wind electricity results in the lowest CO_2 emissions. Solar PV electricity typically exhibits higher emissions and varies significantly by geographical region. The emissions from upstream supply chains is a major contributor to total emissions and varies considerably across different routes to hydrogen. Biomass gasification is characterised by very large negative emissions in the supply chain and very large positive emissions in the gasification process. Therefore, improvements in total emissions are large if even small improvements to gasification emissions can be made, either through process efficiency or CCS capture rate.

1. Introduction

Natural gas networks have historically been a relatively lower carbon route to heat or electricity generation, because combustion emissions are lower than other fossil fuels: approximately $50\,gCO_2/MJ$ HHV heat, compared to $90\,gCO_2/MJ$ for coal. However, meeting 1.5–2 °C climate targets requires much deeper decarbonisation. Extensive natural gas infrastructure exists in many countries, resulting from many years of investment. If nations are to contribute to climate stabilisation, these gas networks must either be decarbonised or become stranded assets.

Decarbonisation pathways have typically involved reducing dependence on gas grids via greater electrification of heat using heat pumps or even electric heaters. However, there are several technical,

economic and consumer related barriers to electrification of heat e.g. [1–3]. Additionally, the gas network may hold significant value in relation to its flexibility of operation and supply, requiring simpler control and enabling less expensive storage [4]. Therefore, there could be value in retaining and repurposing gas infrastructure if there are feasible routes to decarbonisation. There are several options for decarbonisation, including blending or replacing natural gas with hydrogen [5].

Hydrogen can be used as an alternative to natural gas for heat, electricity or transport and unlike natural gas, hydrogen combustion produces no direct CO_2 emissions. Nevertheless, the supply chain associated with hydrogen production and delivery is likely to be more complicated compared to natural gas, which may result in emissions and/or a loss in efficiency. Additionally, some infrastructure changes

are required to replace hydrogen with natural gas due to the difference in physical properties, which will result in additional costs and system shutdown periods while the transition is made.

This study investigates the greenhouse gas impacts associated with the conversion of gas grids to deliver hydrogen. This review builds upon on an extensive evidence-based assessment produced by the Sustainable Gas Institute [6]. The paper focuses on the options associated with decarbonising the source gas within the network rather than reducing demand or decarbonising at the point of use. Previous studies have estimated GHG emissions associated with hydrogen production via specific feedstocks and production processes, whilst a few have reviewed a selection of processes in aggregate [7–11]. This study goes further by reviewing a large range of production options and supply chains, combining fossil and renewable feedstocks, including renewable electrolysis and biomass gasification, the use of carbon capture and storage, as well as the most important current and prospective production processes. Particular focus is on emissions associated with the upstream supply chain, in order to understand the contribution to the large range of emissions seen in the literature and give insight into how emissions may be reduced in the future.

The following first describes the options, current status and potential for producing hydrogen via various feedstocks and processes. For each option, Section 3 reviews the evidence on associated GHG emissions. Section 4 discusses the importance of supply chain emissions associated with the different routes and the potential to reduce emissions, prior to concluding remarks in Section 5.

2. The routes to hydrogen production

Broadly, hydrogen may be used similarly to that of natural gas in that it may be combusted in gas boilers to provide thermal energy. Additionally, it may be used as a feed for fuel cells. But whilst hydrogen may meet the demand previously associated with natural gas, there are several key differences between the fuels which results in some required changes on an infrastructural and consumer appliance level. Table 1 gives a summary of the properties of hydrogen and methane for comparison. Key differences between the physical properties of hydrogen and methane are their energy density, flame speed and molecular size. Hydrogen has an energy density approximately a third of that of natural gas on a volume basis [12]. Consequently, greater volumetric throughput is required to deliver the same heat duty. The flame speed of hydrogen is higher than methane, meaning that the flow rate of hydrogen to a burner must be higher to prevent upstream flame propagation (applicable where air is mixed upstream). The molecular size of hydrogen is smaller than methane, resulting in greater propensity for leaks through equipment seals and connections.

There are several options to produce hydrogen from different feedstocks, such as:

Table 1
Physical and chemical properties of methane and hydrogen. Relevant conditions are measured at normal temperature and pressure: 20 °C and 1 bar absolute pressure.
Source: [13].

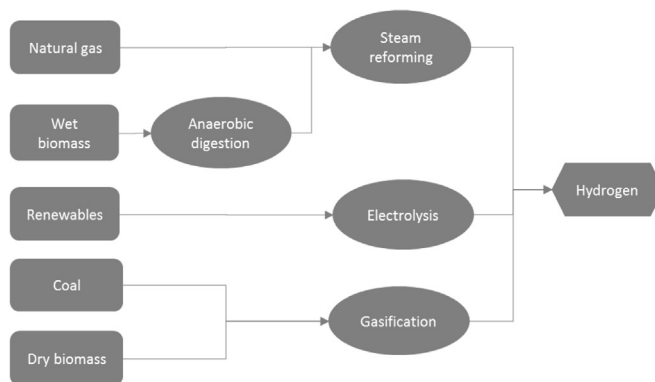| Property	Methane	Hydrogen
Chemical formula	CH_4	H_2
Molecular weight (g/mol)	16	2
Density (kg/m³)	0.668	0.084
Energy density (Higher heating value, MJ/kg)	55.5	142
Energy density (Higher heating value, MJ/m³)	37.3	12.0
Maximum flame speed (m/s)	0.39	3.06
Low flammability limit (vol%)	5.3%	4%
High flammability limit (vol%)	15%	75%
Flame temperature (adiabatic) (°C)	1953	2107
Flame colour	Blue	None

Fig. 1. Routes to hydrogen production.

1. Reforming natural gas to hydrogen with (or without) carbon capture and storage (CCS).
2. Gasification of coal to hydrogen with (or without) CCS.
3. Gasification of biomass to hydrogen with (or without) CCS.
4. Electrolysis to hydrogen using low carbon electricity.

These options are depicted in Fig. 1 and described in the following section, in terms of their technical and process characteristics, as well as resource potential.

2.1. Reforming natural gas with CCS

Hydrogen production from the reforming of natural gas is the most common form of bulk hydrogen production, representing approximately 48% of global production (with 30% from oil reforming, 18% from coal gasification and 4% from electrolysis) [14–17]. The steam methane reforming (SMR) process initially involves a reaction between methane, the main constituent of natural gas, and steam at 800 C and 30 bar [18,19]. Hydrogen and carbon monoxide, known as synthesis gas (syngas), is formed by the following reaction:

$$H_2O + CH_4 \rightarrow CO + 3H_2 \quad \Delta H_{298\,K} = +206\frac{kJ}{mol}$$
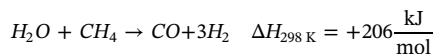
A water-gas-shift reaction then reacts the carbon monoxide with steam to produce more hydrogen as well as carbon dioxide by the following reactions:

$$H_2O + CO \rightarrow CO_2 + H_2 \quad \Delta H_{298\,K} = -41\frac{kJ}{mol}$$
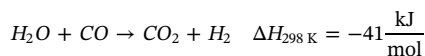
Production capacities are in the order of 150–250 MW (as embodied heat energy in hydrogen product). Total process efficiencies are typically estimated to be 70%, although a range between 60% and 90% has been cited [5,18,20–26]. This range is likely to be due to different estimation methods and scope boundaries rather than real efficiency differences. Only marginal improvements in system efficiencies are expected with this mature process, for instance with improved waste heat recovery [27].

A number of alternative processes to convert methane to hydrogen have been developed to varying degrees of maturity, including partial oxidation, autothermal reforming, dry reforming, autocatalytic decomposition or methane pyrolysis [28,29]. In particular methane pyrolysis presents a promising prospect as instead of generating CO_2, solid carbon is produced. This results in less gaseous separation and no CO_2 transport or storage requirements albeit at the expense of potentially lower hydrogen yield [29]. However, several technical, economic, catalytic and efficiency related barriers prevail with these alternative methods and thus far they have not been shown to be commercially viable.

Low carbon hydrogen is only produced from SMR processes if CO_2 is separated via carbon capture and storage (CCS) or utilisation (CCU).