HYDROGEN TASKFORCE

Economic Impact Assessment

Methodology

12 August 2020

Overview

This economic impact assessment (EIA) uses a range of modelling techniques to estimate the projected hydrogen demand by 2035, the associated capital and operating expenditure, and the contribution to the UK economy of this investment in terms of gross value added (GVA) and job creation (gross jobs).

Estimating hydrogen demand to 2035

Hydrogen demand in 2035 is estimated for four end-use sectors – transport, heat, industry and power generation. A range of authoritative, credible and influential sources have been used to estimate hydrogen demand in 2035. Valuable input was provided by the Hydrogen Taskforce members to supplement our understanding of the key hydrogen technologies that are likely to be deployed by 2035.

Transport

UK H2 Mobility figures were used to model the uptake of five different types of hydrogen vehicles – cars, LGVs, HGVs, buses and trains. These estimates were developed for the period 2020 to 2030. For the period 2030 to 2035, we utilised National Grid's Future Energy Scenario to forecast a compound annual growth rate (CAGR) and project the uptake of hydrogen vehicles between 2030 and 2035.

In terms of vehicle manufacturing in the UK, we keep the existing import share of vehicle components into the UK constant at ~60 per cent and decrease this assumption to 50 per cent by 2035. While much hydrogen vehicle manufacturing is currently localised overseas, we estimate that the UK's import share starts to decrease as the domestic industry onshores investment.

We utilise the report for the Committee on Climate Change (CCC) (by E4tech and University College London), which provides cost estimates for hydrogen vehicles. We extrapolate the specific cost in 2035 for different vehicle types and multiply this by the annual volume level in 2035 to estimate a market value (£1.7bn annually by 2035). This enables us to estimate the total number of jobs created from vehicle manufacturing.

Heat

Hydrogen demand was estimated for space and water heating in residential and commercial buildings.

Residential

We used National Grid's 2019 Future Energy Scenario projections of the gas boiler stock. Under the Two-Degrees scenario, the stock of gas boilers is expected to decrease from 22.1 million in 2020 to 16.4 million by 2035. To estimate the uptake of hydrogen boilers by 2035, we utilise the Committee on Climate Change (CCC) study – Hydrogen in low-carbon economy. This study presents three scenarios for hydrogen use in buildings – Full Hydrogen, Mix Hydrogen, Hybrid Hydrogen. We model the uptake of hydrogen use in buildings using the Hybrid Hydrogen scenario as this provides a realistic balance of hydrogen use across all sectors. This scenario shows that hydrogen demand in buildings could reach around 19% of overall hydrogen demand by 2035. We then scale the gas boiler stock by this share of hydrogen demand to get an estimate of hydrogen boiler demand by 2035.

The Future Homes Standard consulted on banning connection to a gas network in all new-build residential properties. For these properties, it is assumed that electrical heating will be the preferred low-carbon solution. Therefore, we have assumed that all new-build residential and commercial properties will not use hydrogen boilers.

Commercial

We utilise the Building Energy Efficiency Survey (BEES), which reports that 1.57 million non-domestic premises consume around 161 TWh of energy. Using the BEES, we extrapolate that there could be a little over 500,000 commercial premises, of which 460,234 (92 per cent) use natural gas for space heating and hot water consumption. We assume that the uptake of hydrogen boilers in commercial buildings is the same as in residential buildings – 19 per cent of demand by 2035.

Combined this suggests that the annual hydrogen boiler market could be a little under ~274,000 a year by 2035. In sum, around 98 per cent of annual boiler sales would be attributed to the residential market, with the remaining 2 per cent for the commercial market.

Industry

The two key heating technologies modelled for this sector are hydrogen boilers and hydrogen heaters. The technology readiness level (TRL) of hydrogen kilns is currently conceived to be too low to reach mass commercialisation by 2035 – informed by Element Energy and Jacobs in the Industrial Fuel Switching Market Engagement Study. Hydrogen hybrid heat pumps are out of scope of this study.

A study by Element Energy and Equinor is utilised to understand the split of industrial heating technologies. The report finds that, in 2050, around 49 per cent of industrial heating appliances are boilers and the rest are heaters and kilns. By 2035, we estimate that most industrial heating technologies are boilers (~62 per cent) and the rest are heaters (38 per cent).

We utilise European Commission analysis of the stock of UK industrial gas, oil and coal boilers by size. The boiler size in scope range from 100kW to more than 25MW. We use typical industrial boiler replacement rates to estimate the stock of these boilers by 2035.

The Industrial Fuel Switching study by Jacobs and Element Energy enables us to project the rate of fuel switching to hydrogen and other fuels. The results suggest that hydrogen has the highest potential overall (at 96 TWh by 2040, 78 per cent of the total fuel consumption in scope), although around half of this only becomes available after 2030. Under a hydrogen and electricity (H&E) scenario, the total switching potential is 48.7 TWh in 2030 and 90 TWh by 2040. We assume the latter scenario (H&E) and extrapolate the switching potential in 2035 and use this to inform the replacement of industrial gas boilers by industrial hydrogen boilers.

We also model the switching of oil and coal boilers to hydrogen. Based on the Industrial Fuel Switching study and the three fuel switching options – hydrogen, biomass and electricity – we estimate a switching rate of 33 per cent per year to 2035.

Costing hydrogen supply and infrastructure

Estimating hydrogen demand by 2035 enables us to estimate the required installed capacity of hydrogen production technologies. We assume that both blue and green hydrogen, in varying proportions, will be required to meet projected hydrogen demand in 2035.

The total capital cost of deploying the necessary hydrogen supply and infrastructure is estimated at ~£53bn by 2035. The ongoing operation and maintenance of the supply and infrastructure is estimated to cost £3.4bn by 2035.

Upstream production – blue and green hydrogen

A BEIS workshop on Energy Innovation Needs Assessment for Hydrogen recommended that autothermal reforming (ATR) of hydrogen is the most suitable reforming technology to be integrated with carbon sequestration at a reasonable cost – ahead of steam-methane reforming and coal gasification.

In addition, the UK's global leading role in material science and advancements in cell components materials mean that the UK can be ambitious in deploying centralised green hydrogen from electrolysis (PEM).

The modelling suggests annual hydrogen demand in 2035 could be around 125.3 TWh. Blue hydrogen is forecast to meet most of this annual demand at around 100.3 TWh (80 per cent). Green hydrogen is projected to meet the remaining 25.1 TWh (20 per cent) of annual demand.

Several ATR (with CCS) installations would be required to meet blue hydrogen demand. A blue hydrogen production installed capacity of 12.0 GW would be required to meet 100.1 TWh of cumulative demand by 2035.

The capital cost of deploying the necessary blue hydrogen infrastructure is estimated at £8.4bn by 2035. The ongoing operation and maintenance of this infrastructure is estimated at £384m by 2035.

The assumptions regarding the deployment of green hydrogen are built on the work done by the CCC in their Net Zero Technical report. They estimate that green hydrogen could account for 16 per cent of total hydrogen demand by 2050. Building on this report, recent technological advances from the industry, and driven by views from Taskforce members, we believe that this share could be increased by ~20 per cent by 2035, largely as a result of increased policy momentum and the upcoming support for green hydrogen projects at both a UK and European level.

Around 3.2 GW of PEM electrolysis would be required to meet a demand of 25 TWh by 2035.

We use BEIS's Hydrogen Supply Chain Evidence report to estimate the capital and operating cost of deploying blue and green hydrogen technologies. Cost-down is built into the model, which sees the capital cost of ATR fall from £651/kW to £538/kW by 2035. The cost of transporting and storing CO_2 is calculated independently from the cost of the ATR technology (which only includes carbon capture). We use data from the study by Element Energy, which shows the capital cost of transporting and storing CO_2 is just over £12m/TWh.

Hydrogen electrolysis with PEM (proton exchange membrane) offers rapid dispatchability and turn down to follow the energy output from renewables and is therefore ideal for pairing with wind farms for low-carbon hydrogen production. A twinned offshore wind farm and electrolyser plant is modelled up to ensure dispatchability is comparable with other hydrogen production technologies (i.e. steam-methane reforming).

We model a load factor (wind to H2 HHV) of 72 per cent initially, increasing to 96 per cent by 2035.

By 2035, we estimate that the cost of deploying the necessary infrastructure (including the electrolyser plants and wind farms) is estimated to reach £3.2bn by 2035. The ongoing operation and maintenance for this infrastructure is estimated at £330m by 2035.

Transmission and distribution

We utilise the BEIS methodology on estimating the amount of transmission and distribution network repurposed, based on the underlying level of hydrogen demand in any year. Our modelling suggests that around 2,629 km (cumulatively) of the UK transmission system would have to be rebuilt to be hydrogen-ready by 2035. This estimate is based on the cumulative level of hydrogen demand five years on top of the baseline year and dividing this by the level of natural gas demand in that year. This is multiplied by the length of the existing UK transmission network (~7,600 km) to estimate the length of transmission network that is forecast to be repurposed by 2035.

We estimate that the cost of repurposing 2,629 km of transmission network is expected to cost ~£3.6 billion by 2035. The ongoing operation and maintenance for this infrastructure is estimated at £203m by 2035.

A similar methodology is used to estimate the cost of repurposing the distribution network. BEIS reports that the estimated cost of repurposing the entire distribution network is around £22 billion. We adjust this by final natural gas demand in 2035 to estimate a repurposing cost of £41.3 million / TWh. This is then multiplied by the level of cumulative hydrogen demand by 2040 (a future hydrogen demand is used because infrastructure is likely to lead demand), which is estimated to be 110 TWh.

The conversion of the distribution network is in line with projected hydrogen demand by 2035. The cost of repurposing the distribution network is £4.6bn by 2035. The ongoing operation and maintenance for this infrastructure is estimated at £364m by 2035.

Energy storage

Centralised salt cavern storage can be used to store excess hydrogen, which can be dispatched when required i.e. during periods of high demand. The economic assumptions for centralised salt cavern storage were provided by Storengy, a Taskforce member. The need for storage also depends on optimising the whole system and assessing the demand profile (load duration curve) and production capability (redundancy).

We assume that around 10% of hydrogen produced in 2035 will need to be stored in centralised salt caverns. Salt cavern uptake is modelled from 2025 onwards and the capital cost of installing this begins to decrease as more salt caverns are used in this way – economies of scale and learning by doing. We estimate capital costs reduce by a CAGR of 5.4 per cent between 2020 and 2035 (based on projected cost data input by Storengy).

The cost of deploying the required energy storage capacity, based on projected hydrogen demand, is estimated at ~£5.0bn by 2035. The ongoing operation and maintenance for this infrastructure is estimated at £203m by 2035.

Power generation

Between 2020 and 2035, ageing and fossil fuel-based generation plants are likely to be phased out in order for the UK to hit its climate targets. We utilise cost data and assumptions from the study by Element Energy where certain generation technologies are replaced with a series of First-of-a-Kind (FOAK), Second-of-a-Kind (SOAK) and Nth-of-a-kind (NOAK) hydrogen plants.

Our assumption is that gas power-generating technologies are best suited to being replaced with hydrogen/CCS. Renewables are not considered because they provide most of the low-carbon generation at close to zero marginal cost. Oil is not considered because it only operates as back-up generation. Coal plants are going to be phased out from the mid-2020s and therefore are out of scope.

Due to the uncertainty of nuclear deployment, we have not modelled the potential of hydrogen replacing baseload nuclear power generation.

The main data source on the cumulative new installed capacity by generation type is from BEIS - Energy & Emissions Projections (2018). We use the Reference Scenario to assess the cumulative installed capacity by 2035.

We utilise the assumption by Element Energy that, between 2020 and 2025, new capacity additions will be retrofit changes only. Between 2026 and 2029, there could be deployment of FOAK hydrogen plants, between 2030 and 2034 the deployment of SOAK will occur and from 2035 onwards NOAK hydrogen plants will be deployed. It is assumed that 100 per cent of gas installed capacity is replaced with hydrogen-generating power plants. It is also assumed that the new hydrogen plants operate at the same load factor (35 per cent to 15 per cent) as the natural gas plants they are replacing.

We estimate the capital cost of replacing gas plants with hydrogen to be around £2.0bn by 2035. The ongoing operation and maintenance for this infrastructure is estimated at £979m by 2035.

Transport

Cars, LGVs, HGVs, buses and trains are within scope of the analysis to estimate the number of hydrogen refuelling stations (HRS) required by 2035.

HRS capacity is assumed to increase as time increases (a three-phased approach every five years). This is supported by research by UK H2Mobility ('A hydrogen mobility strategy for the early 2020s').

HRS demand is based on UK H2Mobility research which provides estimates for average H2 demand/vehicle type in phase 3 (end of support phase). HRS utilisation rates are based on UK H2Mobility research, which shows an increasing utilisation rate (46% to 77%). We assume cars, LGVs and HGVs reach a utilisation rate of 80 per cent, and that trains and buses reach a utilisation rate of 90 per cent.

The cumulative uptake of hydrogen vehicles is estimated to 2035. This enables estimation of the total level of hydrogen consumption in each year for each vehicle type.

The number of HRS required for any year is estimated by dividing the level of hydrogen demand/day by the HRS capacity in that year or time period. Based on the total level of hydrogen demand from transport, we estimate there will need to be around 1,159 HRS across the UK (by 2035) of varying sizes – 300kg/day to 6,000 kg/day – to support the estimated level of transport demand by 2035.

We assume that most HRS will have (blue) hydrogen delivered via tube trailers from a centralised production plant, but that some stations will generate hydrogen for refuelling on-site using electrolysis. We estimate that there could be around 490 HRS (42 per cent of total HRS) by 2035 that supply on-site green hydrogen via electrolysis.

The deployment of electrolysis for use in transport has been estimated as 'captive' demand from centralised green hydrogen production. By 2035, we assume that of total green hydrogen demand, 50 per cent is for the transport sector (decentralised) and 50 per cent is deployed to other sectors via pipelines.

We use Hydrogen Council assumptions for the cost-down of HRS stations. This applies for larger capacity HRS (>1000 kg/d); where they say costs falling by 60% to 2030, we assume a 60 per cent cost reduction by 2035. For capacity <1,000kg/d, we assume no cost-down improvement.

Constructing these HRS could cost up to £3.6bn by 2035. The ongoing operation and maintenance for this infrastructure is estimated at £195m by 2035.

Heat in buildings

Residential sector

Total energy consumption for the residential sector is estimated based on assuming an average boiler size of 24kW and an average heating consumption of 17,000 kWh. Multiplying the average heating consumption by the number of residential hydrogen boilers by 2035 gives total hydrogen heating consumption.

We assume a 2.05% CAGR reduction in energy consumption owing to energy efficiency improvements. This is calculated from an extrapolation of current trends displayed in the UK's Energy Consumption tables (ECUK 2019).

We use the Sustainable Gas Institute study, which estimates the cost of converting homes to use a hydrogen boiler at £3,300 per household. A review of the literature shows a conversion cost range of between £3,000-£4,000 per household.

We multiply this conversion cost (£3,300) by the number of cumulative residential boilers by 2035 to estimate the total capital cost required to convert all households to hydrogen boilers.

The cost of converting the entire modelled stock of 3.1 million hydrogen boilers by 2035 is £10.3bn. The ongoing operation and maintenance for this infrastructure is estimated at £548m by 2035.

Commercial sector:

Commercial premises are split as SME and large organisations, and the energy consumption per SME and per large organisation is estimated. This is calculated by dividing total energy consumption of SMEs by the number of SMEs – similarly for large organisations. This translates to a specific energy consumption of ~34MWh for an SME and 79MWh for a large organisation, with an average boiler size of 250kW and 500kW for an SME and large organisation, respectively.

The cost of converting these commercial premises is found by utilising the Hydrogen Supply Chain Evidence report. This gives the boiler cost, installation cost and cost of repurposing the pipework.

Ensuring commercial premises are hydrogen ready is estimated to cost around £2.0bn by 2035. The ongoing operation and maintenance for this infrastructure is estimated at £93m by 2035.

Industry

For hydrogen boilers we assume full load heating hours of 1,250, based on research from the European Commission. For hydrogen heaters we assume the technology operates at a heat load around 50 per cent of the boiler (625 hours). The boiler sizes are already estimated based on the European Commission breakdown of industrial boiler stock in the UK. We assume a typical size for the hydrogen heater is 10MWth based on research by Jacobs and Element Energy (Industrial Fuel Switching Market Engagement study).

Capital costs for the boilers are sourced from the European Commission (WP2) study and are scaled to reflect small and large boiler sizes. Capital costs for the heater are sourced from the Element Energy and Jacobs report on Industrial Fuel Switching. Relevant conversion costs are sourced from EE/Jacobs study for both technologies, as are the opex costs (fixed and variable).

The cost of converting the total modelled stock of industrial hydrogen boilers and hydrogen heaters by 2035 is £10.7 billion. Around 80 per cent (or £8.5bn) of this investment is associated with the cost of the new technologies. The remaining 20 per cent (or £2.2bn) is the cost associated with converting industrial sites to operate hydrogen for process heating and other applications.

The ongoing operation and maintenance for this infrastructure is estimated at £90m by 2035.

Macroeconomic modelling

A bespoke macroeconomic model was created to estimate the economic contribution from investing (and maintaining) the necessary hydrogen infrastructure. Capital spending generates turnover, creates job and adds economic value to the economy. The positive economic impact is captured both directly (in the producing industry) and indirectly (engaging the wider supply chain).

We used the Standard Industrial Classification (SIC) system to classify industries by a two- and four-digit code. There are thousands of SIC codes and many correspond to similar industries. The Office for National Statistics (ONS) produces datasets (e.g. input-output tables) showing the performance of industries, classified by their SIC, in the UK, their contribution to GVA and job creation.

Estimating these key outputs requires a mapping of the demand to each SIC, of which around 83 individual cost components were identified for the purpose of this study. Capital and operating costs generated were split into subcomponents and mapped onto different industrial classifications. This was based on a wide review of the available literature sources. An example of mapping is shown below for energy storage.

Table 1: Example of the capital cost breakdown for energy storage

CAPEX ITEM	COST - £M	CAPEX SHARE, %	SIC ACTIVITY	SIC CODE (2-DIGIT)
Engineering and permitting	507	10%	Architectural and engineering activities	71
Leaching	614	12%	Architectural and engineering activities	71
Drill and casing	854	17%	Architectural and engineering activities	71
Geological survey	694	14%	Architectural and engineering activities	71
Cushion gas	193	4%	Gas distribution	35.2-3
Piping and drying	262	5%	Basic iron and steel	24
Compressor	925	19%	Machinery & equipment n.e.c	28
Disposal	421	9%	Basic iron and steel	24
Transportation	421	9%	Land transport services and transport services via pipelines	49.5
Storage	35	1%	Construction	41-43
Total	**4,926**	**100%**	-	-

This process was undertaken for the entire hydrogen value chain (in scope of this study) and then fed into the macroeconomic model to generate estimates of UK gross output, GVA, imports, intermediate consumption, investment and jobs. We used two key datasets from the ONS: Input-Output tables and Supply & Use tables.

Below we outline calculation of the key outputs.

Imports: defined as the market value * import intensity.

UK gross output: defined as the market value + exports – imports.

Intermediate consumption: Gross output * intermediate consumption coefficient

Direct GVA: defined as Gross output – Intermediate consumption

Indirect GVA: defined as Direct GVA * ($GVA_{\text{Type 1 multiplier}}$-1). Type 1 multipliers for GVA were sourced from the ONS's Input–Output tables.

Direct jobs: defined as Gross output * labour intensity (adjusted by productivity improvement). Labour intensity was calculated by dividing total jobs in an industry by the turnover of that industry, yielding a labour intensity figure of number of jobs required to generate £1m turnover. This labour intensity was forecasted for 2035 by adjusting for productivity improvements. Historical labour productivity rates were used.

Indirect jobs: Direct jobs * ($Employment_{\text{Type 1 multiplier}}$-1)

Additional notes

Gross vs net impact

This study does not estimate the impact of a counterfactual scenario i.e. 100 per cent electrification. As a result, final estimates of jobs and GVA should be considered as 'gross' estimates and represent the "hydrogen-related" jobs and GVA.

Economic impact – induced multiplier

The total economic assessment of capital investment includes the direct, indirect and induced effect. This analysis only considered direct and indirect impacts. Since the Office for National Statistics (ONS) does not, currently, produce official estimates of induced (or Type 2 multipliers), we have decided not to estimate the induced impact, even though including this impact could further support the case for hydrogen.

Macroeconomic modelling – input / output analysis

I/O modelling captures a 'snapshot' in time, following the immediate impacts of money spent in specific parts of the economy on the activity in all other parts. As such it does not capture dynamics over time. While this 'snapshot' is still an informative tool, other approaches, such as econometrics or CGE modelling, could provide those dynamic aspects.

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