April 2024

Hydrogen UK

Economic Impact Assessment for the Hydrogen Sector to 2030

Contents

Executive Summary

This study estimates the economic contribution of the hydrogen sector by 2030, taking into account the increased ambition of the Government's target of up to 10 GW of low carbon hydrogen production by 2030. The demand splits are based on an accelerated version of the hydrogen deployment in the Climate Change Committee's (CCC) Balanced Pathway[i]. Cost estimates are calculated using a range of publicly available sources which can be found in the annex. Multipliers are applied to cost estimates to estimate the employment and gross value added (GVA) of the hydrogen sector by 2030. This scenario and methodology estimates that the hydrogen sector in the UK could support approximately 30,000 direct jobs by 2030, as shown in **Figure 1**. Hydrogen production makes up a significant proportion of employment within the sector, accounting for 8,500 direct jobs by 2030.

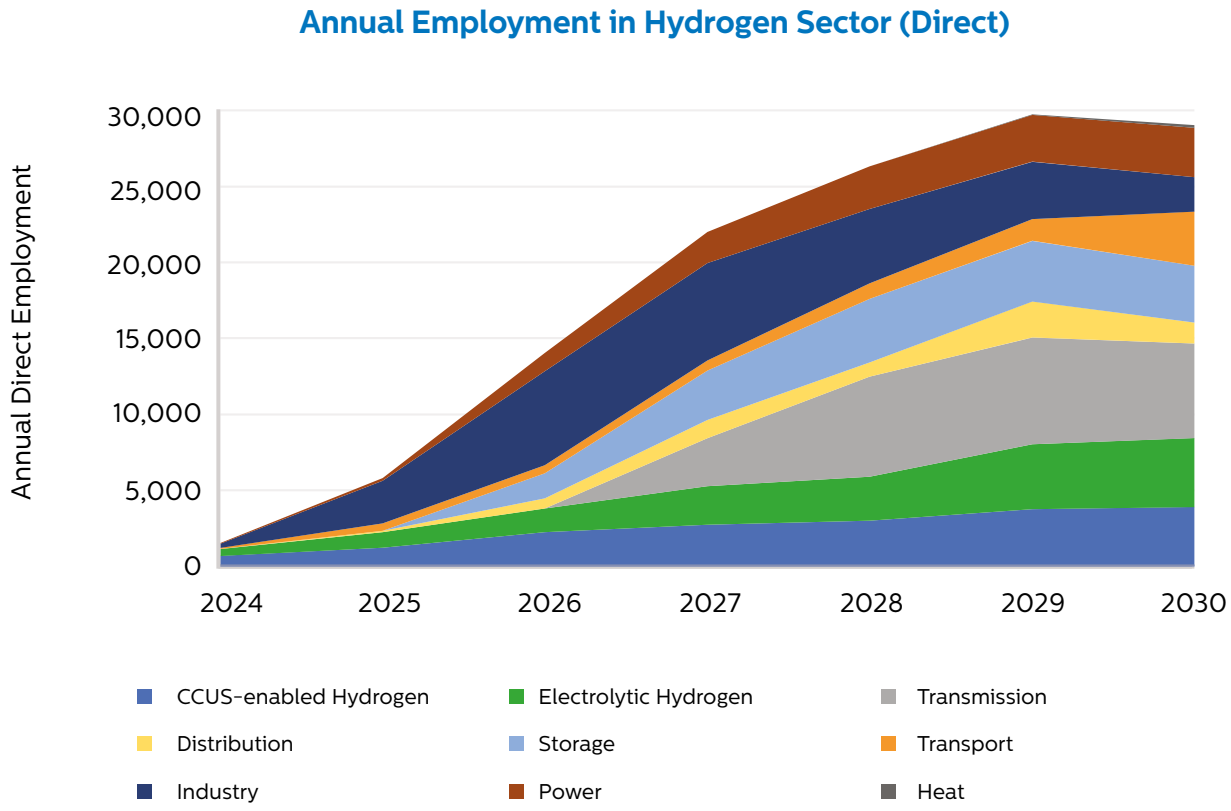

Figure 1: Annual Direct Employment in the Hydrogen Sector from 2024 to 2030 by Value Chain Element

[i] The Balanced Pathway was developed before the Government's production target.

The economic contribution of the hydrogen sector follows a similar pattern to employment with increasing GVA between 2024 and 2030 due to increasing deployment of low carbon hydrogen. This study estimates that the hydrogen sector could contribute more than £7.0bn in annual GVA in 2030 (including both direct and indirect GVA). A significant amount of this economic contribution is provided by low carbon hydrogen production, estimated to be £2.9bn in 2030. The annual GVA split by value chain element is shown in **Figure 2**.

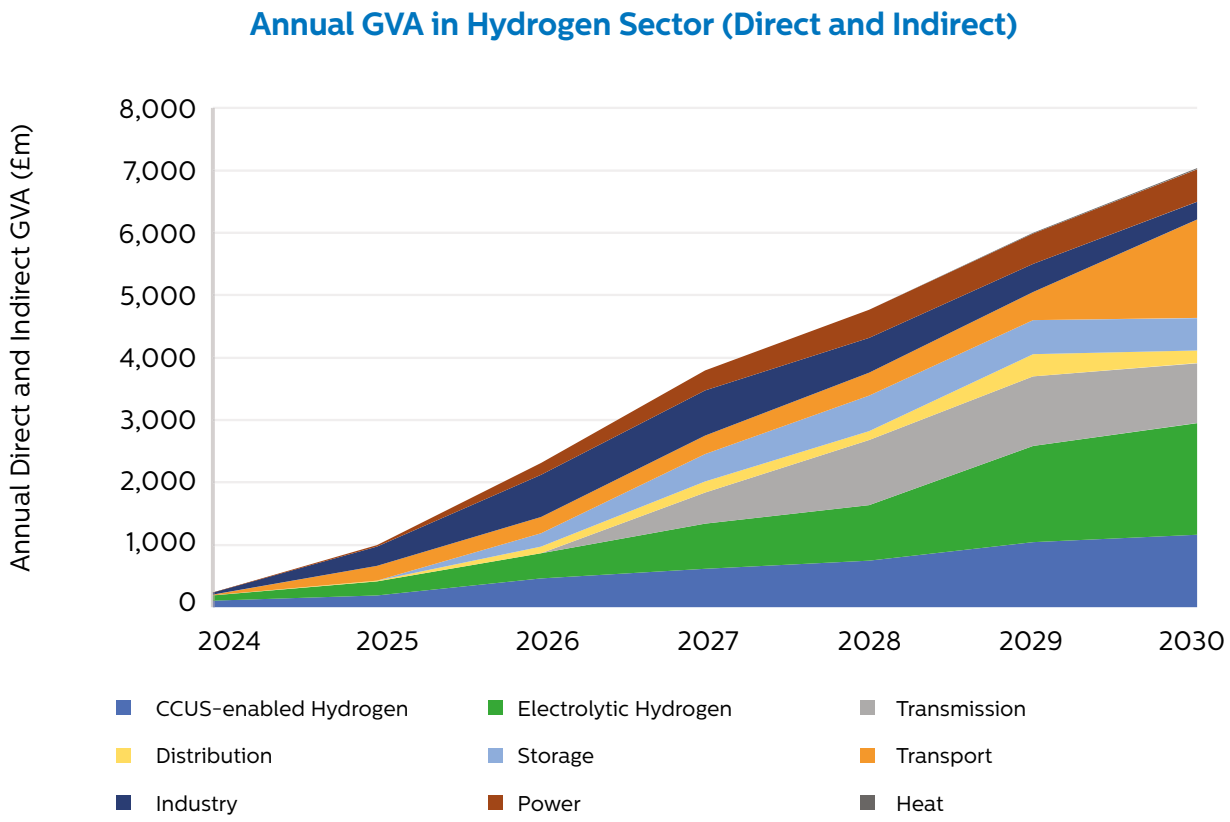

Figure 2: Annual Direct and Indirect GVA in the Hydrogen Sector from 2024 to 2030 by Value Chain Element

Introduction

Hydrogen is one of the key solutions to decarbonising the UK economy along with other carbon abatement solutions such as electrification, CCUS, biofuels and energy efficiency. It provides a low carbon alternative to fossil fuels that has many of the same desirable features, such as burning with a high temperature flame, without producing carbon emissions during combustion. Hydrogen will be particularly valuable in hard-to-decarbonise sectors that have few cost-effective alternatives including elements of industry, heavy transport and dispatchable power generation. However, it's use could be much more widespread depending on how costs, preferences and policy for different low carbon solutions develop. The Government's Hydrogen Strategy estimates that, based on analysis from the Climate Change Committee (CCC), in 2050 between 20% and 35% of the UK's final energy demand could be met with low carbon hydrogen[1].

While hydrogen provides a promising solution to reducing emissions, current deployment of low carbon hydrogen is low with almost all hydrogen in the UK produced from unabated fossil fuels resulting in high emissions. In the UK, hydrogen production must meet the Low Carbon Hydrogen Standard (LCHS) to access government support. This is currently set at 20g $CO_2e/MJ_{(LHV)}$ and will ensure that future deployment will deliver significant emissions reductions when switching from fossil fuels[2].

The period to 2030 will be a critical time for the UK to seize the economic opportunity presented by low carbon hydrogen sector. Internationally, increasing attention has been placed on hydrogen as a solution to global emissions. In the USA, the Inflation Reduction Act (IRA) has provided fixed rate tax credits of up to $3/kg (£2.4/kg[II]) for clean hydrogen production[3]. Closer to home, the EU is targeting 10 million tonnes of domestic electrolytic production and an additional 10 million tonnes of electrolytic hydrogen imports by 2030[4]. This will be achieved through a variety of policy levers including an auction for fixed price subsidy support for electrolytic production with a ceiling of €4.5/kg[5] (£3.84/kg[III]). In the UK, Government have set an ambitious target of up to 10 GW of low carbon hydrogen production by 2030 with at least half of this from electrolytic sources[6]. This will be supported by the Hydrogen Production Business Model (HPBM), a two-way variable CfD which could potentially provide hydrogen for a price as low as the natural gas price[7]. As global supply chains, investment and skills are in international competition, the UK must continue its ambitious hydrogen aspirations to ensure the decarbonisation and economic opportunity presented by low carbon hydrogen is captured.

This study estimates the economic impact of the low carbon hydrogen sector in the UK by 2030. The impact is assessed by estimating the costs of hydrogen deployment and applying employment and GVA multipliers to these costs based on historic economic activity. These estimates are broken down by different forms of low carbon hydrogen production and end use as well as the enabling infrastructure required to connect production and demand, namely hydrogen networks and storage. Both the employment and GVA are estimated for each of these value chain elements for every year between 2024 and 2030. Employment and economic growth from the hydrogen sector will be created across the UK with many benefits arising in regions that have faced historic underinvestment such as the industrial clusters and Scotland. Beyond the high-level economic benefits estimated in this study, the hydrogen sector creates an opportunity for the hundreds of thousands oil and gas sector jobs in the UK to transition to a low carbon alternative.

[II]Based on an exchange rate of $1 = £0.78 20/03/2024
[III]Based on an exchange rate of €1 = £0.85 20/03/2024

Alternative Literature on Economic Impact of UK Hydrogen Sector

There are other economic impact assessments (EIAs) of the Hydrogen Sector in the UK. These range in timeframe, sectoral coverage and measure of employment. While these studies have provided a useful basis for showcasing the economic impact of the hydrogen sector, there are some key limitations associated with each source.

Comparable Economic Impact Estimates

The national studies which estimate the potential economic impact of the hydrogen sector are summarised in **Figure 3** below. The most recent public study was produced by Wood and Optimat, this report is focussed on supply chains in the hydrogen sector and included some analysis on the average annual employment and GVA required to deliver the Government's 10 GW production target[8]. This report does not include any estimates of employment or GVA in 2030. It also contains limited coverage of certain end uses so is a conservative estimate of final employment. The other studies shown in **Figure 3** also have limitations in terms of employment measure and were produced prior to the Government's 10 GW production target so are not reflective of the UK's current hydrogen ambition.

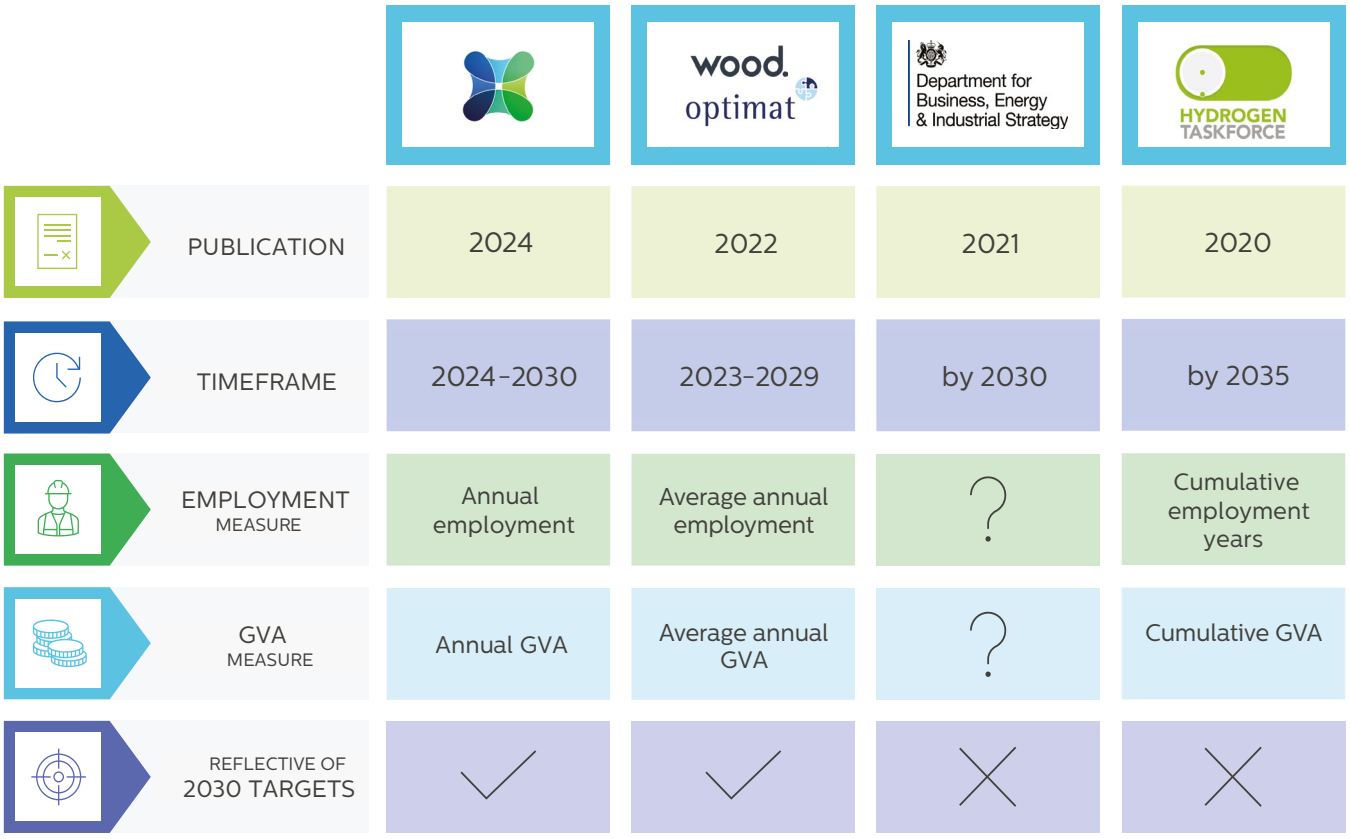

Figure 3: Summary of Key Parameters of UK Hydrogen Economic Impact Studies

As these sources are based on a different timeframes, scope and employment measures, the results are not directly comparable. For this reason, caution should be used in comparing the findings shown in **Table 1**.

	Employment Estimates	Gross Value Added (GVA) Estimates
Hydrogen UK 2030 Economic Impact Assessment	• 29,000 direct jobs in 2030 • 128,500, cumulative direct FTE years by 2030	• £7.0 bn total GVA in 2030 • £25.1bn cumulative total GVA by 2030
Wood & Optimat Supply Chains to Support a Hydrogen Economy[8]	• Average annual employment between 6,100 and 7,100 between 2023 and 2029	• Average annual direct GVA £575-665m between 2023 and 2029
BEIS Hydrogen Strategy[1]	• 9,000 jobs by 2030	• £900m of GVA by 2030
Hydrogen Taskforce Economic Impact Assessment[9]	• 75,000 cumulative FTE years by 2035	• £18bn in cumulative GVA by 2035

Table 1: Key Results of National Hydrogen Sector Economic Impact Studies

Specific Economic Impact Studies

There are a range of other EIAs that have been produced which have a different focus, generally either promoting the benefits of specific end uses or projects. These reports are useful examples, but do not give a complete picture of the economic benefit that could be achieved across the UK from the hydrogen sector. Two of these studies are shown in **Table 2**.

	Employment Estimates	Gross Value Added (GVA) Estimates
Strategy& for Cadent The Economic Value of Hydrogen for Domestic Heat in the UK[10]	• Up to 612,000 cumulative employment years associated with hydrogen heat by 2050	• Up to £47.9bn in cumulative GVA associated with hydrogen heat by 2050
Amion Potential Economic Impacts of the HyNet North West Project[11]	• 290,000 cumulative employment years by 2050 associated with HyNet	• £26.0 bn in cumulative GVA by 2050 associated with HyNet

Table 2: Key Results of Specific Hydrogen Sector Economic Impact Studies

Comparison of Employment Estimates

The number of jobs resulting from economic activity in the literature can be poorly defined with studies simply quoting a certain number of jobs by a specific year. There are several different measures of employment shown below:

- **Annual employment** – provides an estimate of the number of people employed in a given year e.g. 20,000 jobs in 2030.
- **Cumulative employment years** – gives an estimate of the total cumulative number of employment years i.e. one job that is retained for five years would be five employment years.
- **Average annual employment** – is the average number of people in employment over a given time period e.g. average annual employment of 10,000 between 2024 and 2030.

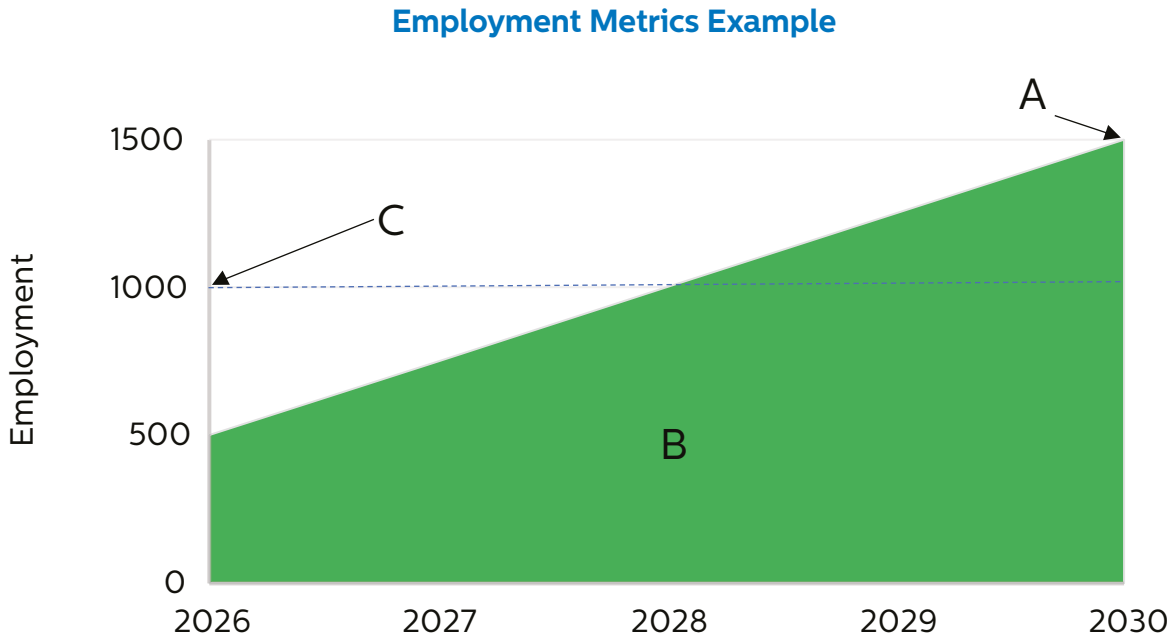

Figure 4: Employment Metrics Example

In the example shown in **Figure 4** employment starts at 500 in 2026 and grows by 250 a year reaching 1,500 in 2030. In this example:

- A) Annual jobs in 2030 is 1,500 – this is shown by the value in 2030.
- B) Cumulative job years is 5,000 employment years – this is the area under the curve i.e. the sum of employment in each year.
- C) Average annual employment for the period is 1,000 – this is found by dividing the cumulative job years by the number of years i.e. 5,000/5.

Scenario Development

The first stage in developing an EIA on the hydrogen sector is developing a scenario for hydrogen production, transport, storage and end use. The level of hydrogen penetration and consumption of hydrogen by sector will determine the costs, labour requirements and GVA of the hydrogen sector.

The Government's Production Target

In the British Energy Security Strategy, the UK Government doubled its hydrogen production target to "up to 10GW by 2030, with at least half of this from electrolytic hydrogen"[6]. This target is vague in terms of actual hydrogen volumes produced which will depend on the load factor of individual production sites. In its most recent progress report to parliament, the Climate Change Committee (CCC) stated that government "should provide clarity on its hydrogen production ambition by publishing targets on a TWh/year basis"[12] . In the absence of a government target on a hydrogen volume basis, assumptions have been made about the split between production pathways and load factors. These are shown in **Table 3** below. Since development of this analysis, government have outlined an expectation that up to 6 GW of production will be delivered through the Hydrogen Allocation Rounds (HAR) and up to 4 GW through the cluster sequencing process[13]. The HAR target includes a minority proportion of novel technologies, such as natural gas splitting to produce solid carbon which may have similar cost structures to CCUS-enabled production. As costs of these technologies are largely unknown, the analysis has remained focussed on technologies with more confidence in costs and assumed an even split between electrolytic and CCUS-enabled production.

Production Type	CCUS-enabled	Electrolytic	Basis for Assumption
Capacity ($GW_{H2(HHV)}$)	5 GW	5 GW	**HM Government: BESS**
Load factor (%)	95%	51%	**BEIS: H2 Production Costs 2021**
Annual production ($TWh_{(HHV)}$)	41.6 TWh	22.3 TWh	Calculation
Total annual production ($TWh_{(HHV)}$)	64.0 TWh		Calculation

Table 3 : Estimated hydrogen volumes from government production target

Load factors are uncertain, and the values used in **Table 3** represent optimistic but credible values for expected load factors of CCUS-enabled and electrolytic production.

CCUS-enabled facilities will generally aim to maximise load factors due to lower levelised cost of hydrogen and lower greenhouse gas emission intensity. Costs are lower with higher load factors as the capital costs can be spread over a larger hydrogen volume reducing costs on a per unit basis, while energy input costs are generally fixed on a per unit basis. The carbon intensity of CCUS-enabled hydrogen is greatest during start up, further incentivising CCUS-enabled producers to operate at steady state where possible.

Electrolytic facilities have several operational models that could make commercial sense. In order to meet the Low Carbon Hydrogen Standard (LCHS)[2], electrolytic production will require low carbon electricity input. This may lead to hydrogen production matching low carbon electricity generation which may be intermittent if renewable or relatively fixed if using nuclear energy. Electrolytic producers could increase load factors by supplementing their electricity supply with a battery or multiple sources of low carbon electricity. An alternative option is using electrolysers to reduce curtailment of renewable electricity generation assets. In this case, load factors will depend on the location of the electrolyser and how often curtailment occurs in that location either due to electricity supply exceeding demand or a lack of grid capacity.

Independent Scenarios

The Government's production target does not provide any indication of end use demands. In the absence of government estimates, an assumption must be made on the level of low carbon hydrogen demand in different sectors. The two main sets of scenarios on future energy demands in the UK are produced by the CCC and National Grid ESO, titled the Sixth Carbon Budget[14] and Future Energy Scenarios 2023[15], respectively.

The Sixth Carbon Budget

The Sixth Carbon Budget does not set out the levels of hydrogen production in its scenarios. It does, however, include a range of low carbon hydrogen demands. These are shown in **Figure 5** and range between 12 and 33 TWh of low carbon hydrogen demand per year by 2030. These values are inconsistent with the low carbon hydrogen production target set by government and assumed load factors in **Table 3**. This may be due to the Sixth Carbon Budget being produced in 2020, over a year before the update to the 10 GW target and increased international activity on hydrogen. While these scenarios are not directly compatible with the volumes shown in **Table 3**, they do provide a good basis for sector level hydrogen demands.

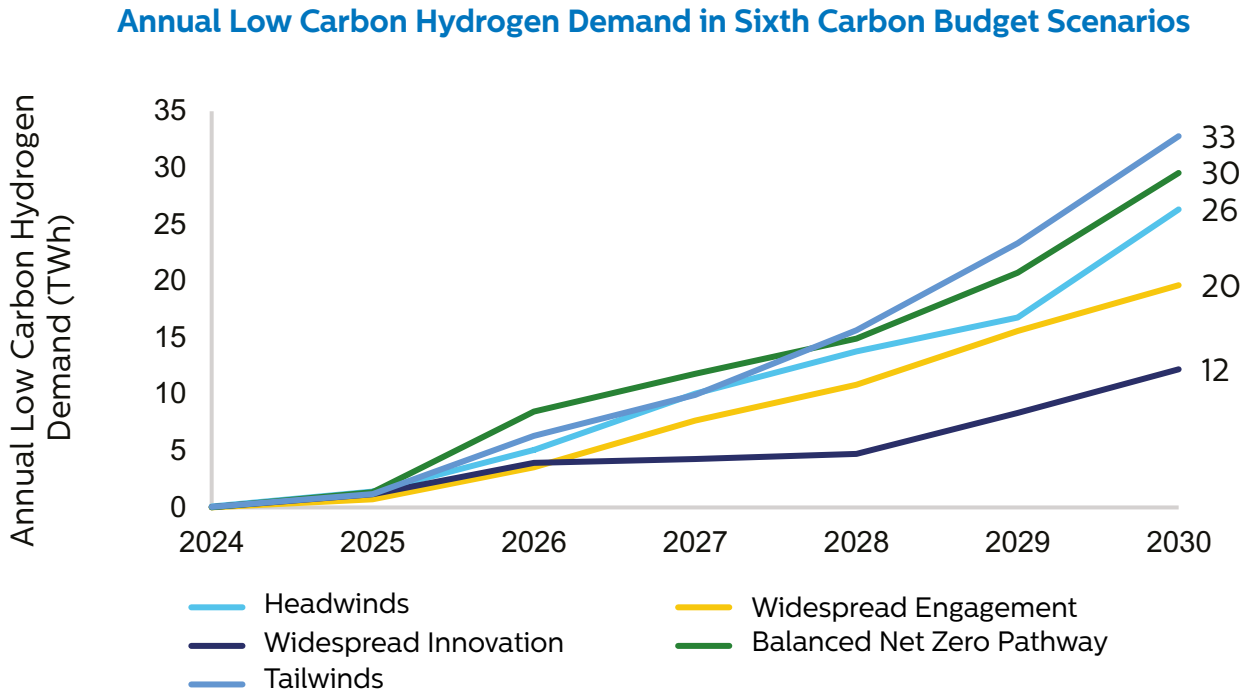

Figure 5: Annual Low Carbon Hydrogen Demand in Sixth Carbon Budget Scenarios Between 2024 and 2030

Future Energy Scenarios 2023

National Grid ESO produce similar scenarios and include information on the low carbon hydrogen production capacity for each of these. These capacities are shown in **Figure 6**. Purely on the basis of production capacity, the Leading the Way scenario appears consistent with the Government's overall production capacity target. However, in this scenario, only 9% of production capacity comes from CCUS-enabled hydrogen. This is inconsistent with government's plan for a twin-track approach to production[1] and the cluster sequencing process which has shortlisted four CCUS-enabled hydrogen production projects in the first round[16].

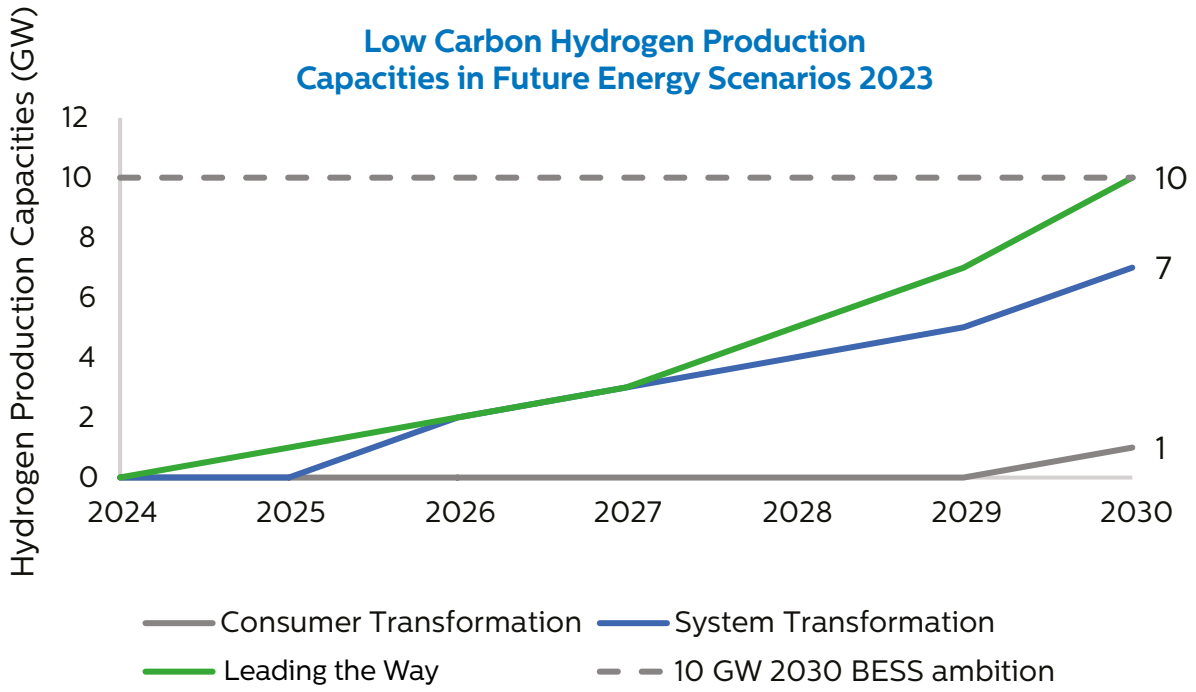

Figure 6: Low Carbon Hydrogen Production Capacity Between 2024 and 2030 in Future Energy Scenarios 2023

The electrolytic hydrogen capacity in Leading the Way would represent a significant increase on the current allocation rounds, with 1 GW expected to be in construction by 2025[17]. However, at 9.1 GW this electrolytic capacity is marginally less than Labour's electrolytic production target of 10 GW by 2030[18]. This breakdown of production capacity in the Leading the Way scenario is shown in more detail in **Figure 7**.

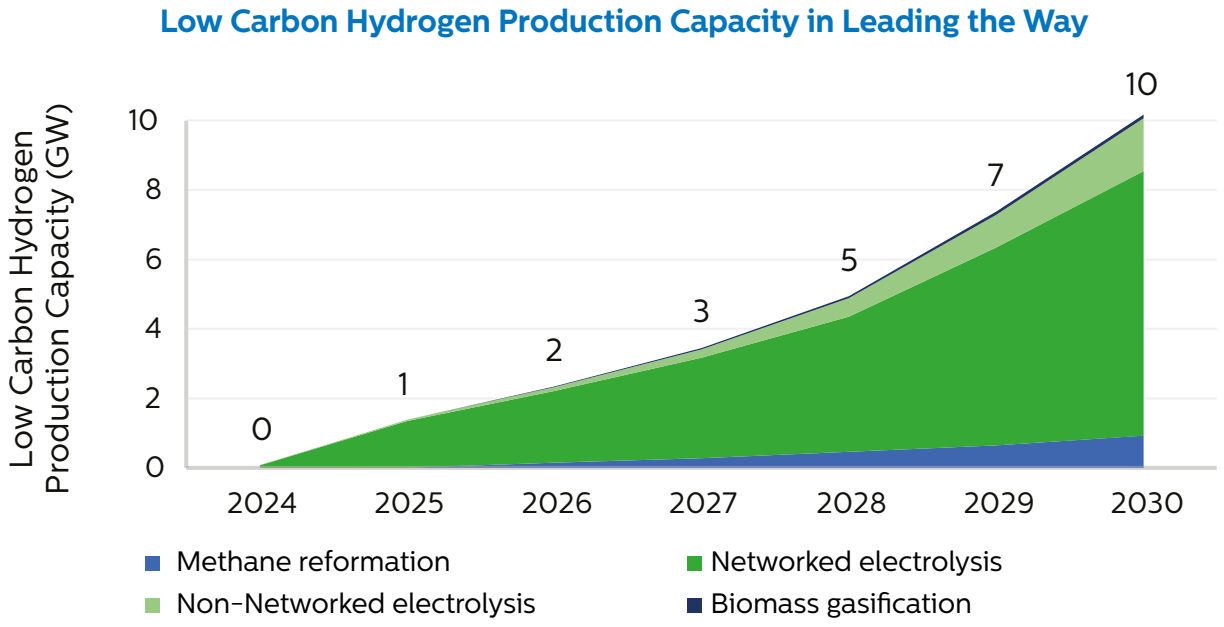

Figure 7: Low Carbon Hydrogen Production Capacity in Leading the Way (Future Energy Scenarios 2023) from 2024 to 2030

The two other Net Zero compliant FES scenarios, System Transformation and Consumer Transformation, are inconsistent with government's 10 GW target with low hydrogen production capacities of 6.7 GW and 0.7 GW respectively.

2030 Hydrogen Deployment Scenario: Accelerated Balanced Pathway

There are several options for developing a hydrogen deployment scenario based on both the government's target and publicly available sector demand scenarios from the CCC and FES 23. The main options are summarised below.

Option 1: Reducing assumed load factors of production in government's 10 GW target.

The load factors shown in **Table 3** are based on optimistic but realistic projections. These would have to be decreased excessively for 10 GW of production capacity to align with CCC and FES 23 demand scenarios. An average load factor of less than 46% across the 10 GW of production capacity would be necessary to supply the required hydrogen for the highest external demand scenario.

Option 2: Increasing the proportion of electrolytic hydrogen in the government's 10 GW target.

The government is currently proceeding with a twin-track approach, with 'at least half' of the 10 GW production capacity by 2030 to come from electrolytic sources. However, the proportion of electrolytic production would have to be very high (over 90% depending on assumed load factor) for the government target to be compatible with CCC or FES 23 demand scenarios.

Option 3: Applying the sectoral percentage splits in CCC or FES 23 demand scenarios to the estimated production capacities and volumes in Table 3.

However, this can create problematic and unrealistic demand estimates. Applying this approach to the CCC's Balanced Pathway would estimate almost 50 TWh of industrial hydrogen demand by 2030, a challenging level of fuel switching for the sector.

Option 4: Bringing forward CCC or FES 2023 demand scenarios. (Selected Option)

This allows for flexibility in production assumptions while providing realistic end use splits, albeit on an accelerated timeline.

The CCC's Balanced Pathway has 64 TWh of hydrogen demand in 2032, the same volume of production estimated in this study in 2030 shown in **Table 3**. The analysis in this study assumes that the level of demand in Balanced Pathway in 2032 is accelerated and brought forward to 2030. The hydrogen demand trajectories for both scenarios are shown in **Figure 8**.

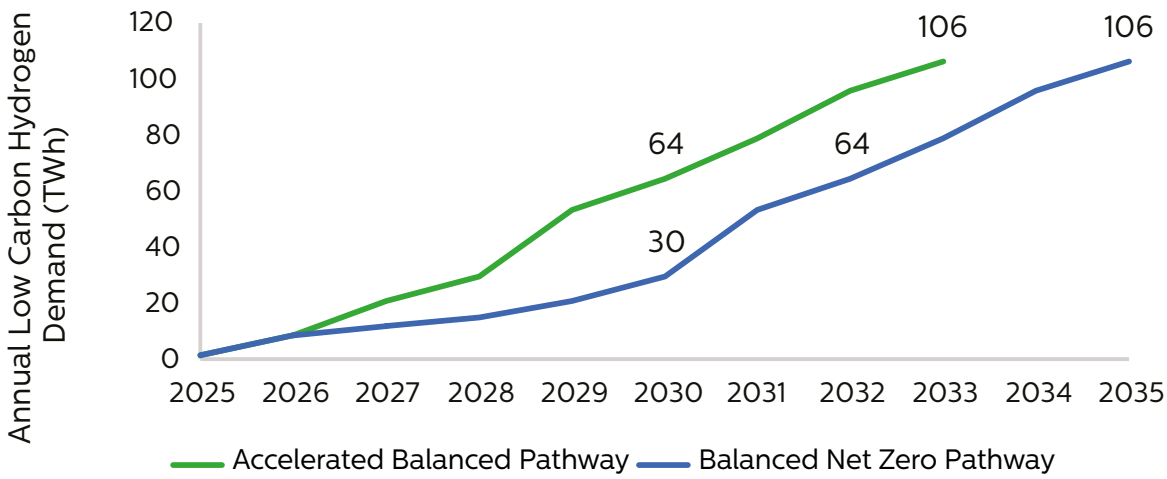

Figure 8: Low Carbon Hydrogen Demand in CCC's Balanced Pathway from 2025 – 2035

This is achieved by removing demand estimates for 2027 and 2028 as this provides the most realistic hydrogen deployment to 2030, shown in **Figure 9**. The power sector demand has a significant increase between 2028 and 2029. This is consistent with work commissioned by the CCC which states that between 2028 and 2030, low carbon dispatchable power generation capacity should increase from 3-6 GW to 9-13 GW to be on track for a decarbonised power system by 2035[19]. The only way in which demand in this analysis differs from accelerating the Balanced Pathway is hydrogen demand for public transport which has been smoothed to 2030 to represent a more realistic deployment of hydrogen vehicles.

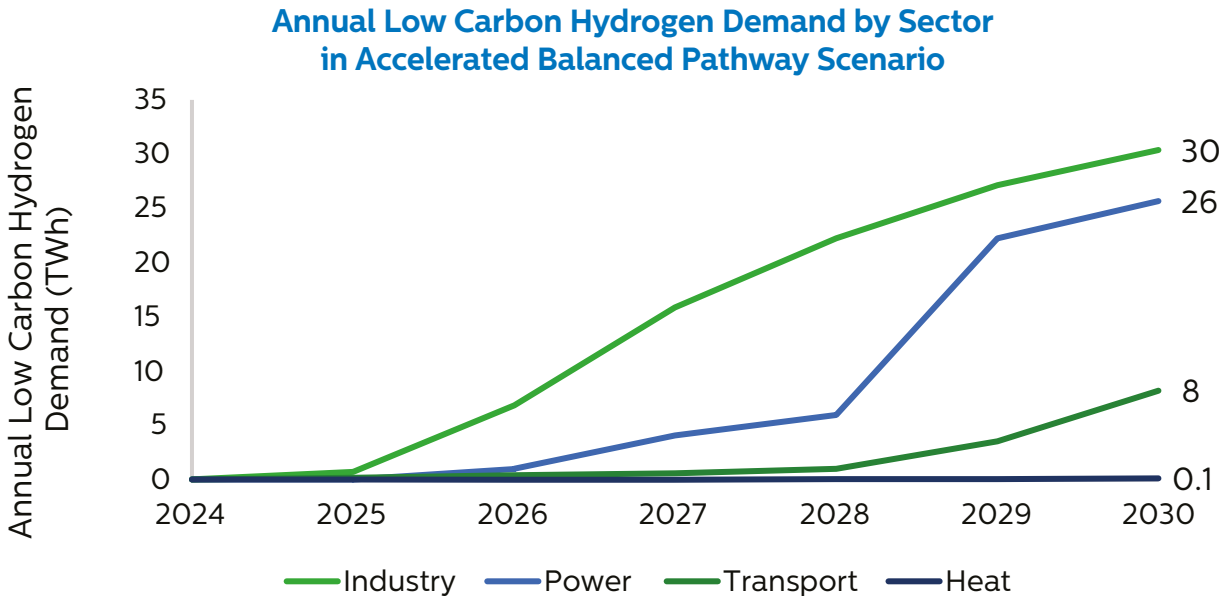

Figure 9: Annual Low Carbon Hydrogen Demand in Accelerated Balanced Pathway

The low carbon hydrogen production capacities in the Accelerated Balanced Pathway scenario are based on current expected allocation rounds of production capacities, while meeting annual demand shown in **Figure 10**. To allow both criteria to be met, the load factors of production are flexed, with load factors increasing up to 2030. The load factors for electrolytic production increase from 38% in 2025 to 51% by 2030, while load factors in CCUS-enabled production increase from 90% in 2025 to 95% in 2030.

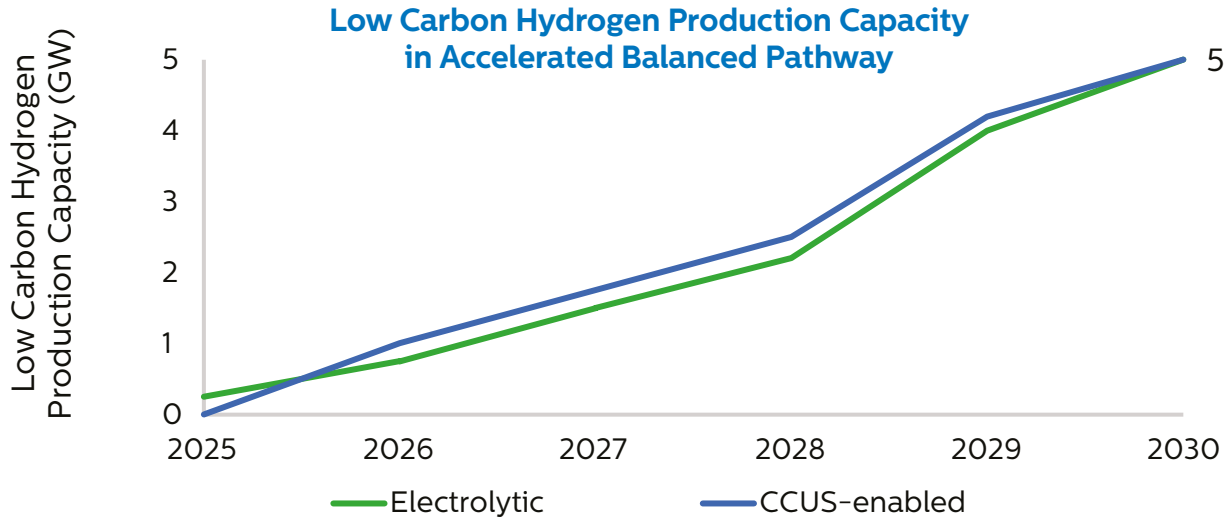

Figure 10: Low Carbon Hydrogen Production Capacity in Accelerated Balanced Pathway Between 2025 and 2030

Analysis Results

The results of the analysis are based on the Accelerated Balanced Pathway scenario set out in this report. The full methodology used to develop these estimates can be seen in the Annex of this report, including scenario costing and the macroeconomic modelling.

Annual Employment and GVA Results

This study estimates that the hydrogen sector could support more than 21,000 direct jobs by 2027 and 29,000 direct jobs by 2030, as shown in **Figure 11**. When including indirect jobs this study estimates that the hydrogen sector could support 64,000 jobs in 2030. These jobs are a result of investment in hydrogen production, midstream and end use.

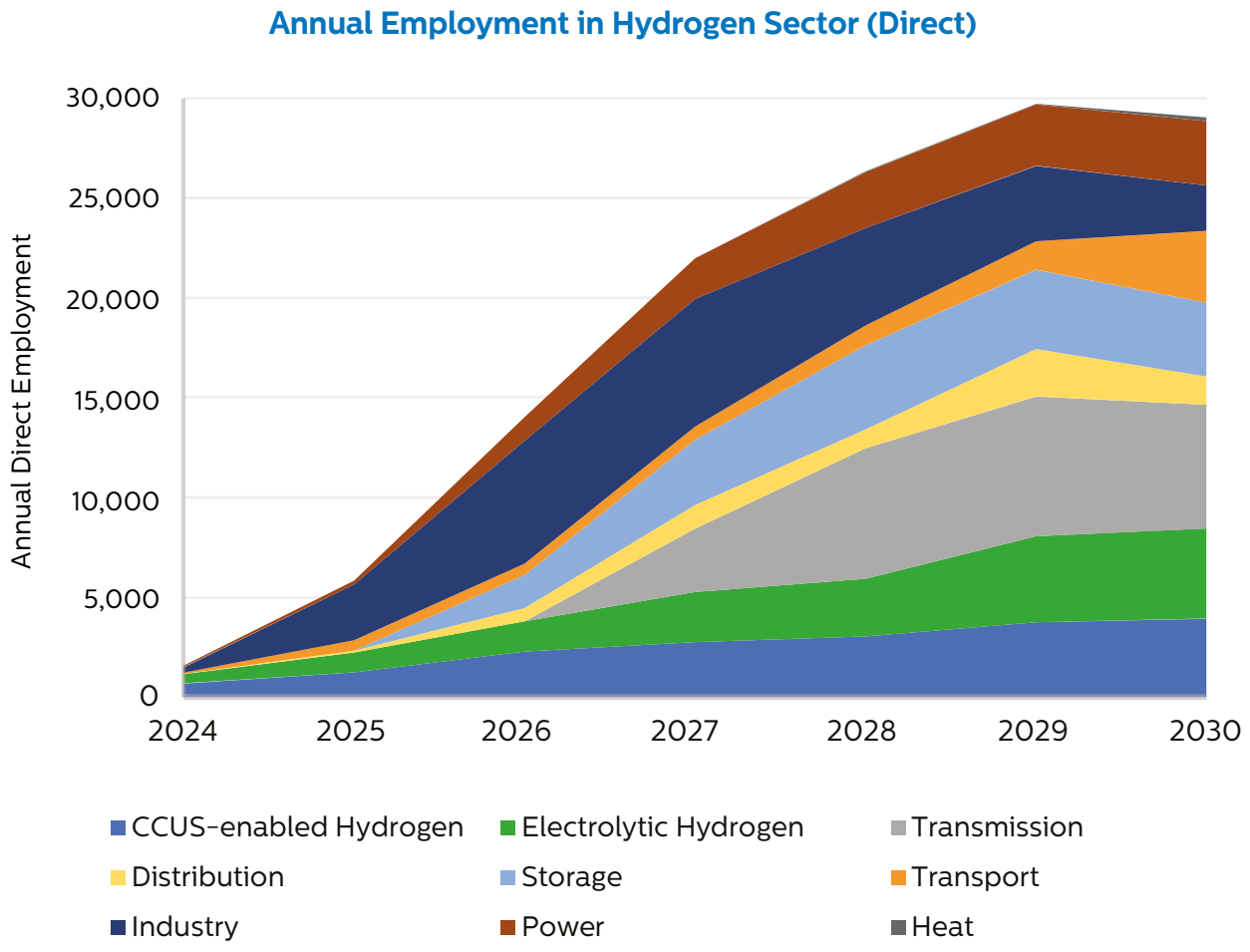

Figure 11: Annual Direct Employment in the Hydrogen Sector Between 2024 and 2030

The smallest sub-sector for job creation by 2030 is hydrogen heat. This is driven by the modest deployment of hydrogen heating in this timeframe, reflecting the fact that if hydrogen heating receives a positive policy decision in 2026, large scale switching is unlikely to occur before the 2030s.

Annual GVA resulting from the hydrogen sector follows a similar pattern to employment, with subsectors with greater activity generally driving higher GVA. The annual total GVA (direct and indirect) broken down by value chain element for the period 2024 – 2030 is shown in **Figure 12**. The annual total (direct and indirect) GVA in 2030 is more than £7.0bn with almost £3.2bn of this being direct GVA.

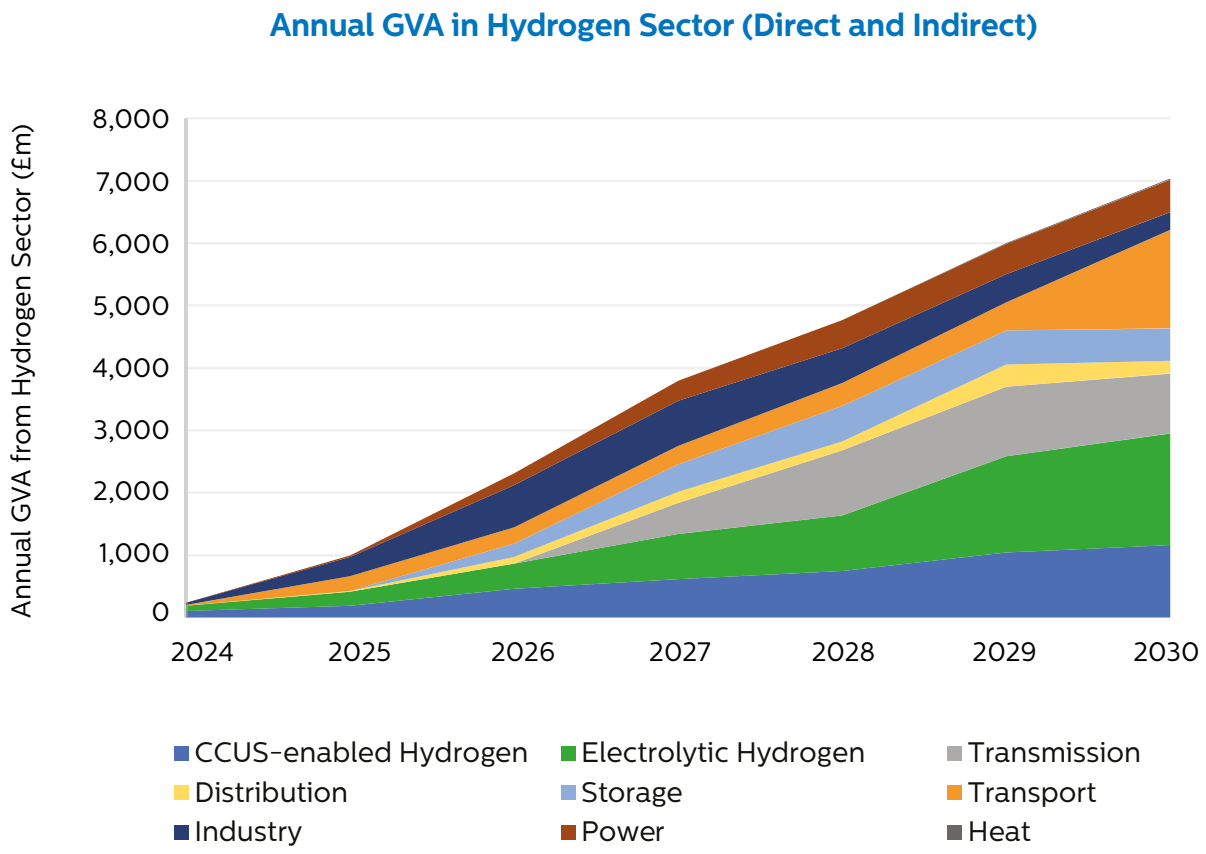

Figure 12: Annual Direct and Indirect GVA from the Hydrogen Sector Between 2024 and 2030

Cumulative Employment and GVA Results

Cumulative employment is based on FTE job years. This means that one job that is retained for five years would result in five FTE years. While this metric does not give any annual figures, it is useful to measure the employment impact over time. **Table 4** shows the direct and indirect FTE job years broken down by hydrogen value chain element, along with capital and operational expenditure. As with the annual estimates, hydrogen production is a large source of employment in the hydrogen value chain, with over 91,000 FTE years by 2030 on a direct and indirect basis. When using this metric, there is a relatively even split between production pathways.

	Cumulative Jobs by 2030: FTE Years				
	Capex		Opex		Total
	Direct	Indirect	Direct	Indirect	
Production	20,888	24,448	14,002	32,003	91,342
CCUS-enabled Hydrogen	*11,449*	*14,095*	*6,200*	*13,492*	*45,236*
Electrolytic Hydrogen	*9,439*	*10,353*	*7,802*	*18,512*	*46,106*
Transmission	21,410	29,379	1,542	907	53,238
Distribution	5,417	7,999	1,253	737	15,406
Storage	15,470	12,736	1,310	771	30,287
Transport	6,643	7,668	1,200	731	16,242
Industry	23,279	12,084	3,229	1,899	40,490
Power	11,318	10,321	1,338	787	23,764
Heat[IV]	156	110	73	43	382
Total	**104,582**	**104,745**	**23,947**	**37,877**	**271,151**

Table 4: Cumulative Employment Years in the Hydrogen Sector by 2030

[IV]The heat estimates produced by this approach are likely to be an underestimate if hydrogen heating is pursued as estimates are based on deployment and not supporting expenditure, this limitation is explored in more detail in the Annex.

GVA follows a similar albeit different pattern to employment. Hydrogen production remains dominant by this metric with electrolytic production the largest sub-sector for cumulative total GVA by 2030 at over £5.6bn (£2.3bn direct GVA). CCUS-enabled production has the second largest GVA with over £4.3bn in cumulative total GVA (£1.7bn direct GVA). Seven of the nine sub-sectors have cumulative total GVA of £2bn or more by 2030, with hydrogen heating the only sub-sector with a cumulative GVA significantly less than £1bn. The total GVA by sub-sector is shown in **Figure 13**.

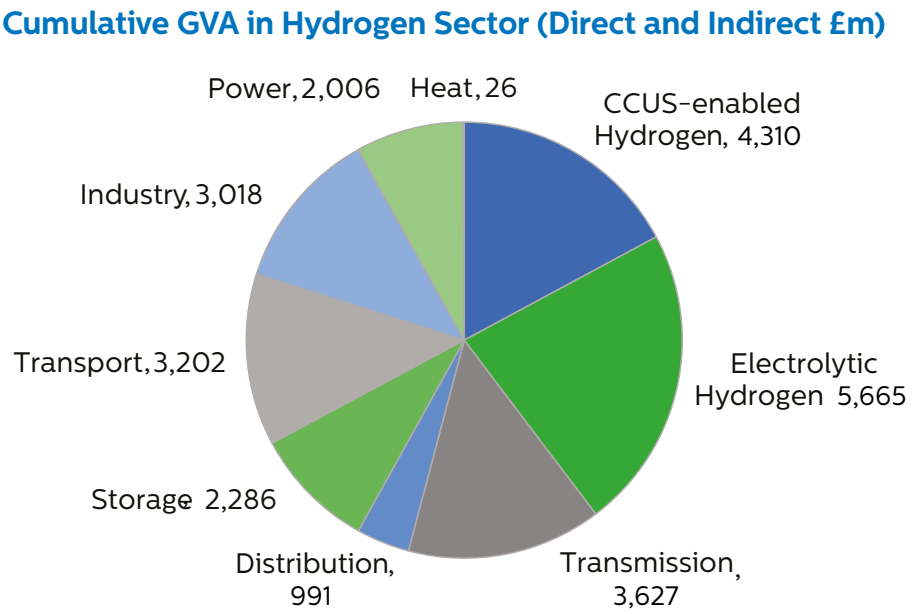

Figure 13: Cumulative Direct and Indirect GVA in Hydrogen Sector Broken Down by Value Chain Element by 2030

Sector Based Employment and GVA

Production

Figure 14 shows the annual direct employment specifically in hydrogen production between 2024 and 2030. In 2030, hydrogen production is associated with more than 8,000 jobs. When including indirect jobs, this estimate rises to 24,000 in 2030. Production is also a large source of GVA with CCUS-enabled and Electrolytic production providing £1.2bn and £1.8bn in direct and indirect GVA annually in 2030 (£0.4bn and £0.7bn on a direct basis), respectively.

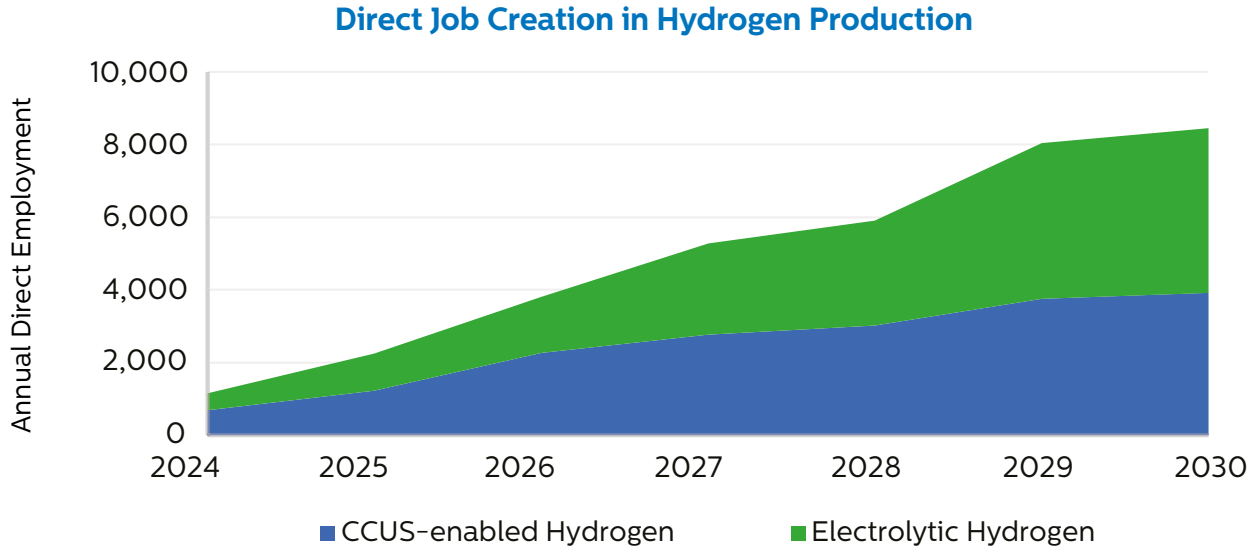

Figure 14: Annual Direct Employment in Hydrogen Production between 2024 and 2030

Midstream

Transmission pipelines are the largest driver of employment in hydrogen midstream in the period to 2030. Direct employment in transmission networks in 2030 is more than that in hydrogen distribution and storage combined, shown in **Figure 15**. This decreases in 2030 due to large proportions of the network being built by 2029. In direct terms, investment in hydrogen networks and storage could support more than 13,000 direct jobs. This rises to 29,000 jobs when including indirect employment in the estimate. Annual direct and indirect GVA in 2030 in hydrogen transmission, distribution and storage is estimated at £960m, £210m and £520m respectively. On a direct basis the GVA in these sectors in 2030 is £480m, £100m and £280m.

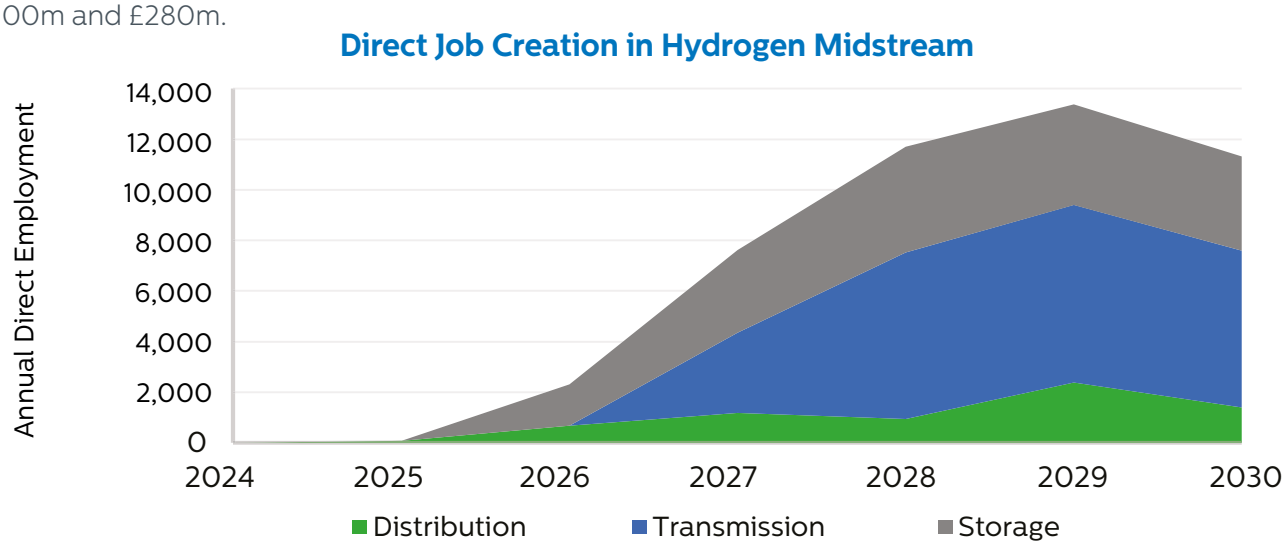

Figure 15: Annual Direct Employment Related to Hydrogen Midstream Between 2024 and 2030

End Use

Employment across the end use sectors varies significantly depending on deployment and therefore economic activity. Transport has a significant increase in employment in 2030 associated with significant deployment of HGVs as well a large increase in maritime demand. Employment associated with industry is dominated by capital costs of switching industrial process to hydrogen equipment. Alternatively, employment in power generation is smoother due to the longer development times for large scale hydrogen power plants. There are very low levels of employment associated with hydrogen heat by 2030. In direct terms peak employment in hydrogen end use is over 9,000, rising to 17,000 when including indirect employment. The direct employment estimates are shown in **Figure 16**. Annual direct and indirect GVA in 2030 for transport, industry, power and heat are £1,580m, £280m, £520m and £20m, respectively. When considering direct GVA alone, these estimates fall to £750m, £180m, £290m and £10m respectively.

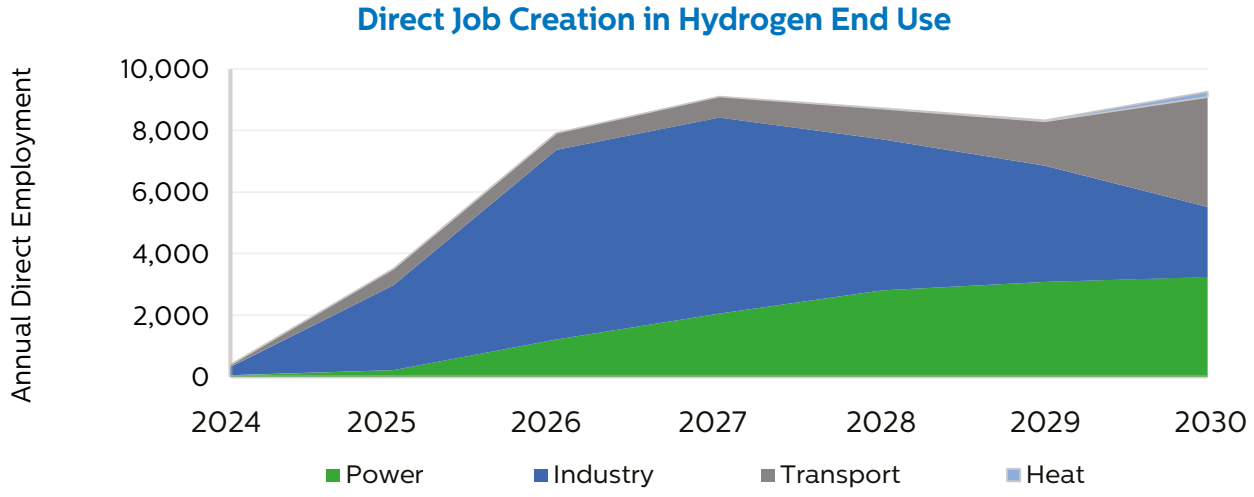

Figure 16: Annual Direct Employment Related to Hydrogen End Use Between 2024 and 2030

Conclusions and Recommendations

This study showcases the significant economic opportunity presented by the hydrogen sector in the UK by 2030. It estimates that in 2030, the low carbon hydrogen sector could result in over 29,000 direct jobs and £7.0bn in annual direct and indirect GVA. While the economic benefits of the hydrogen sector will be dispersed throughout the UK, there will be a higher concentration of benefit in regions that have historically received lower levels of investment. This occurs due to the concentration of hydrogen related activity in industrial clusters and Scotland, resulting in greater employment and economic growth in these regions.

For the benefits outlined in this study to be realised, government and industry must continue to collaborate and make progress in the deployment of novel low carbon hydrogen projects. Activity to date has largely been focussed on target setting and policy development. This is a time consuming and necessary stage in the development of any novel low carbon technology, which is especially relevant for hydrogen due to the breadth of different potential production technologies and end uses. Significant milestones have been passed in 2023 including the publication of the:

1. **Low Carbon Hydrogen Agreement** - the contract which underpins the Hydrogen Production Business Model[20].
2. **Third version of the Low Carbon Hydrogen Standard** - the rules which ensure hydrogen production in the UK will be low carbon[2].
3. **The Energy Act 2023** – the legislation that allows both the Hydrogen Production and Transport and Storage Business Models[21].

The UK must now move from initial policy design to delivery for momentum to be maintained. Government is expected to imminently sign contracts on the first set of projects under the Hydrogen Allocation Round 1, which will be the first key delivery milestone in the low carbon hydrogen sector[22]. To realise the economic benefits of hydrogen success, government should:

Deliver on timelines and targets

The results in this study are based on Government achieving its low carbon hydrogen production target of 10 GW by 2030[6]. To provide investor confidence and ensure that the UK maintains pace in the global race for hydrogen deployment, Government must meet announced targets and policy milestones.

Strategic Decisions and Support for Hydrogen Transport and Storage Infrastructure

Hydrogen transport (e.g. pipeline networks) and storage infrastructure is vital to ensure security of supply and lower cost hydrogen for end users. Some of these large infrastructure projects will take many years to deliver and work must begin now for infrastructure to be in place by 2030. The CCC's most recent report to Parliament also recommends speeding up delivery of this policy[12], and the NIC's Second National Infrastructure Assessment report recommended that a core network of pipelines should connect the industrial clusters to a minimum of 8TWh of hydrogen storage by 2035[23]. And while government's revised timeline for opening the first allocations of both business models by end of 2024 is a welcome acceleration, the lack of a clear target with a pathway and development expenditure support risks infrastructure not being in place in time.

Develop closer alignment between government departments

There are several government departments which have a responsibility for the hydrogen sector. These include: the Department for Energy Security and Net Zero, the Department for Transport, the Department for Business and Trade and the Department for Science, Innovation and Technology. All these departments are committed to the deployment and commercialisation of hydrogen technologies, but nuances exist between how they support the sector. For example, the Hydrogen Production Business Model and Renewable Transport Fuel Obligation are both policies which provide incentives to producers to low carbon hydrogen. However, these have different standards for what counts as low carbon hydrogen[2,25]. This has led to uncertainty around selling hydrogen to multiple off takers ultimately leading to reduced investment confidence in the UK.

It's also recognised that many funding pots for hydrogen exist, but these are disjointed and tend to focus on one element of the value chain. For example, established DBT funding organisations like the Aerospace Technology Institute or Advanced Propulsion Centre are actively funding hydrogen projects but just in a narrow area of transport. Moreover, DESNZ and UKRI fund sections of the hydrogen economy but there's a perception within industry there's no apparent long-term strategic vision or co-ordination. Therefore, investigating the viability of a central hydrogen funding organisation that complements and co-ordinates the capital and R&D investment of existing funding organisations is needed.

Refine the Low Carbon Hydrogen Agreement

There are elements of the Low Carbon Hydrogen Agreement which should be reviewed to ensure that risks within the Hydrogen Production Business Model can be adequately managed between government and industry. Lowering the risk of projects would reduce financing costs and therefore total subsidy cost for government. This could be achieved in part by unlocking blending, as a reserve offtaker, subject to safety assessments. The Government should also continue to assess the need for greater sharing of CO_2 cross-chain risks between industry and government. As the hydrogen sector develops, government should reconsider its position on risk taking intermediaries (RTIs) to allow the development of a liquid market and the Price Discovery Incentive (PDI) which is currently low and may not deliver true price discovery. Increasing the PDI could also reduce subsidy costs for government if it results in higher sales prices for hydrogen.

Ensure adequate demand side policy and trials across end uses

There are a range of supporting government policies that would incentivise demand for low carbon hydrogen and increase understanding of different use cases.

In industry, the UK ETS places a carbon price on greenhouse gas emissions and is the main policy lever which incentives switching to low carbon fuels. Government should develop a Carbon Border Adjustment Mechanism (CBAM) which will allow government to phase out free allocation and place an effective carbon price on UK industry while preventing carbon leakage[26].

The role of hydrogen in heat is uncertain, with government currently committing to a strategic decision in 2026[1]. The hydrogen neighbourhood trials and other evidence building measures are critical to making the correct policy decision.

In power generation, government should continue to explore a Hydrogen to Power Business Model to ensure the optimal forms of hydrogen power generation are incentivised[27].

Finally, a range of measures should be explored across hydrogen transport including the development of the announced Sustainable Aviation Fuel (SAF) Mandate[28] and SAF Revenue Certainty Mechanism[29]. In addition to this government should explore the need for support for hydrogen refuelling stations (HRS) and low carbon maritime fuels.

Annex: Methodology and Limitations

Scenario Costing

In developing the economic impact of hydrogen activity, costs estimates are produced based on the Accelerated Balanced Pathway developed above. The cost estimates are based on the best available evidence on costs. This approach is explored for each of the sectors included in scope of this project. It is important to note that some capital costs and therefore economic activity which are related to hydrogen deployment in the 2030s, occur before or during 2030. As an example, hydrogen production facilities may take several years from taking final investment decisions (FID) to producing hydrogen due to the construction time. For this reason, a small proportion of the capital costs included in the analysis correspond to hydrogen deployment between 2030 and 2033.

Production

The capital and maintenance costs of both electrolytic and CCUS-enabled production are based on government's Hydrogen Production Costs 2021 report[30]. This analysis assumes splits between different forms of production. In the case of electrolytic hydrogen, both alkaline and proton exchange membrane (PEM) electrolysers are considered, with alkaline the dominant technology in the short term and relatively even split between the technologies by 2030. For CCUS-enabled production, capacity is made up of both 300 MW units and 1000 MW, with the first 1000 MW units assumed to come online in 2029. The construction period for all technologies is assumed to be 3 years.

As we have seen in recent times, energy input costs, which form a large basis of hydrogen production costs, can be extremely variable. As discussed in the Annex, the methodology used to estimate economic impact is based on historic economic activity that arises due to capital and operational expenditure. As a result, this analysis will be based on approximate energy input costs at the time period of macroeconomic multipliers and employment intensities. If analysis used current prices, which could be over double those several years ago[31], the estimated economic activity associated with this expenditure would be overestimated as higher prices do not equate to greater employment or GVA.

Midstream

Networks

This section covers the costs of hydrogen networks and storage. Both transmission network and distribution network are within scope of this project. Transmission network requirements are taken from a report by Afry for the CCC[30] which is based on 9-14 GW of low carbon hydrogen production by 2030, this is broadly consistent with the production scenario in this analysis. This report estimates 2,800 km of hydrogen transmission pipeline in 2030 and 3,800 km in 2035. The costs of this transmission network are estimated based on the hydrogen transmission network cost equation in the Hydrogen Supply Chain Evidence report[33] and pipeline diameter in the Afry report[32]. The number of compressors on the transmission network is estimated by applying the proportion of hydrogen transmission pipeline length to current natural gas transmission pipeline length and multiplying this proportion by the number of compressors on the natural gas transmission system today[34]. These compressors are then costed based on Hydrogen Supply Chain Evidence Base[31], assuming 30 MW compressors based on compression requirements assessed for the Irish Government[35]. The capital cost of hydrogen distribution network by 2030 are estimated by calculating the proportion of estimated hydrogen demand to natural gas use in 2018[36] and applying this proportion to costs of complete network conversion[31]. The operational costs of both transmission and distribution networks are taken as a percentage of cumulative capital costs with operational costs estimated at 5% of pipeline capital costs in addition to 15% of compressor capital costs[31]. Development times are assumed to be three years for transmission networks and one year for repurposing distribution networks.

Storage

The storage requirements in this analysis are based on an Afry report for the CCC[32] as this broadly aligns with the government production target and demand in this analysis. The analysis focusses on large scale storage as pressurised tank storage is likely to form a very small percentage of storage capacity in 2030. The Afry report is based on salt cavern storage, and while depleted gas fields such as Rough offer an alternative option for large scale hydrogen storage, public cost data on these is less available than for salt caverns. The Afry report estimates 2 TWh of salt cavern storage is needed by 2030 with this requirement rising to 5 TWh by 2035. The capital and operational costs of this storage are estimated based on the Hydrogen Supply Chain Evidence report[33] and a development time for capital expenditure of three years is assumed.

End Use

Power

Hydrogen power generation assumptions are developed based on the hydrogen demand for the power sector in the Accelerated Balanced Pathway. It is assumed that average load factors in the hydrogen power sector decrease over time. Small facilities are likely to operate at high load factors in applications such as combined heat and power (CHP) plants. Whereas large hydrogen to power facilities are likely to operate far more flexibly to provide electricity supply in times of low renewable energy generation. Hydrogen power is expected to be the lowest cost form of low carbon dispatchable power generation at lower load factors (up to the around 25%)[32]. However, in the early stages of hydrogen power, load factors may be higher than the long term optimal due to lower storage capacities. As the hydrogen power facilities grow in size out to 2030, the average load factors in this analysis reduce, falling from 83% in 2026 to 34% in 2030. The capital and operational costs of hydrogen to power facilities are estimated using Element Energy's Hydrogen for Power Generation study[37]. Development timelines are assumed to be two years for small scale power generation and three years for large scale generation.

Industry

Industry is expected to be a large early consumer of hydrogen due to the extensive options for fuel switching and lack of alternative low carbon options for some parts of the industrial sector. As this analysis is based on an accelerated version of the CCC's Balanced Pathway, the capital and operational cost estimates have already been produced[38]. These are then adjusted to match the demand in the Accelerated Balanced Pathway.

Transport

In the CCC's Balanced Pathway, hydrogen transport demand is split between public transport, HGVs and maritime in the period up to 2033. This analysis assumes that public transport demand is in the form of hydrogen buses and consumption is smoothed between 2025 and 2030 to represent a realistic deployment of hydrogen buses. Annual surface vehicle deployment is estimated using FES 23[15] which has both annual demand and number of vehicles for each vehicle mode. In this analysis hydrogen buses and HGVs are assumed to cost £400,000 and £225,000 respectively, with annual operational costs estimated to be 2% of capital costs. Hydrogen refuelling stations (HRS) are necessary to support the roll out of hydrogen vehicles. In this analysis refuelling stations are assumed to have a capacity of 1t/day and a utilisation rate of 80%. Capital costs of refuelling stations are estimated at £2.7m/HRS with costs being incurred a year before hydrogen demand. Annual operational costs are estimated at 3% of capital costs.

Shipping demand in the Accelerated Balanced Pathway increases significantly in 2030. It is assumed that this demand is in the form of cargo ships as larger vessels are less suited to electrification. The hydrogen demand and costs of cargo ships is taken from an Argonne report on Hydrogen for Maritime Applications[39].

Heat

Hydrogen heat demand in the Accelerated Balanced Pathway is based on the roll out of hybrid heat pumps with a hydrogen boiler. Assuming that the boiler component of this heating system meets 25% of demand and an annual total heat demand of 11,500 kWh[40], results in approximately 20,000 domestic hybrids in 2030. Capital costs for residential boilers are assumed to be £2,000[41]. Non-domestic hydrogen boiler demands are based on average non-domestic gas demand[42], assuming a load factor of 25% gives an average non-domestic hydrogen boiler size of 1.2 MW. The costs of non-domestic boilers are assumed to be £199/kW[43]. The annual operational costs of all boilers is assumed to be 10% of capital costs.

Direct and Indirect Impacts

Direct impacts are the immediate result of spending in a sector in the economy. For example, when considering hydrogen production, direct employment and GVA would capture the economic impacts of expenditure on developing a production site, energy inputs and maintenance. Indirect impacts are the broader supply chain effect. For example, the economic impact from the manufacture of steel used in a hydrogen production site would be categorised as an indirect impact. This study focuses on direct impacts for employment to estimate the immediate effect of spending in the hydrogen sector on employment. However, the GVA analysis considers both direct and indirect GVA impacts as this is the broader economic benefit of this spending.

Macroeconomic Modelling Approach

A similar process to the EIA produced by the Hydrogen Taskforce was utilised to estimate the economic impact of the hydrogen sector by 2030. This modelling builds on the model developed previously by updating the deployment scenario, economic multipliers and cost data. It also includes new sector demands such as shipping.

Once estimated costs of investing in and maintaining the infrastructure associated with the hydrogen sector by 2030 are established, a macroeconomic model was developed to estimate the gross impact on jobs and gross value added (GVA) of this investment. The impact of this capital and operational expenditure was captured directly in the specified industry and also indirectly through the wider supply chain impact.

Costs for sectors were broken down into subcomponents using a range of literature sources and Standard Industrial Classification (SIC) codes were used to classify costs by the relevant two and four-digit code. This analysis relied on datasets from The Office for National Statistics (ONS) including input-output tables[44] and supply and use tables. This process was undertaken for the hydrogen value chain including electrolytic and CCUS-enabled production, transmission, distribution, storage, industry, power generation, transport and heat. The key outputs were estimated using the equations shown below:

Imports: Market value * import intensity.

UK gross output: Market value + exports – imports.

Intermediate consumption: Gross output * intermediate consumption coefficient.

Direct GVA: Gross output – Intermediate consumption

Indirect GVA: Direct GVA * ($GVA_{\text{Type 1 multiplier}}$ – 1).

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 an estimate for employment per £1m in turnover. This labour intensity was forecasted for 2030 by adjusting for productivity improvements using historical labour productivity growth rates.

Indirect jobs: Direct jobs * (Employment $_{\text{Type 1 multiplier}}$ – 1)

Macroeconomic Modelling Limitations

There are several limitations to this approach in estimating economic impact, some of these are shown below:

Induced Multiplier

A full analysis would take into account the direct, indirect and induced impact of capital expenditure. However, this analysis only considered the direct and indirect impact due to The ONS not estimating type 2 (or induced) multipliers.

Gross Impact

The impact of counterfactual scenarios such as expenditure on alternative sources of low carbon energy were not estimated. These could have been used to estimate the net effect of the hydrogen sector by 2030. In lieu of counterfactuals, any estimates shown should be seen as gross impacts.

Dynamic Effects

Studies that use input-output tables rely on snapshot data and therefore do not capture dynamic impacts over time. This study takes annual snapshots, however does not capture dynamic impacts.

Narrow Definition of Hydrogen Related Expenditure

The hydrogen related expenditure was based on deployment estimates and does not take into account hydrogen related expenditure in research, supporting activities or building capacity in the system. While costs of deployment will form the basis of most economic impacts, there may be some sectors in which this other supporting expenditure is significant. For example, the modelled deployment of hydrogen heat to 2030 is low due to uncertainty and expectations that if hydrogen heating is pursued, most activity would occur in the 2030s and 2040s. This approach to only estimating costs related to deployment could result in underestimates in cases like this.

Reliance on Historic Data

In estimating the future economic impacts, historic data, adjusted for expected productivity growth, has been used. While this approach is widely accepted and the best option available, there may be significant changes in the economy which result in inaccurate predictions when basing future estimates on historic data.

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