ECONOMIC IMPACT ASSESSMENT

2024

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EXECUTIVE SUMMARY

This report has been prepared on behalf of the North West Hydrogen Alliance (NWHA) to understand the potential economic impact of hydrogen deployment in the North West between 2024 and 2030. The analysis estimates and costs hydrogen deployment in the region and applies labour intensities based on Standard Industrial Classification (SIC) codes. It also estimates the gross value added (GVA) of the hydrogen value chain. This analysis is carried out on both a direct and total (direct and indirect) basis.

Figure 1 shows annual employment increasing based on hydrogen deployment in the North West rising to a peak of over 5,000 jobs in 2030 on a direct basis and almost 11,500 jobs on a direct and indirect basis. When considering cumulative employment years, a measure that captures employment impacts over time[1], the estimated direct and total employment impact rises to almost 17,000 and 37,000 employment years respectively by 2030. Job creation in the hydrogen sector will have a weighting towards construction, manufacturing and engineering roles for building infrastructure. However, there will be broader employment impacts such as in professional services and business roles.

ANNUAL EMPLOYMENT RESULTING FROM NORTH WEST HYDROGEN DEPLOYMENT

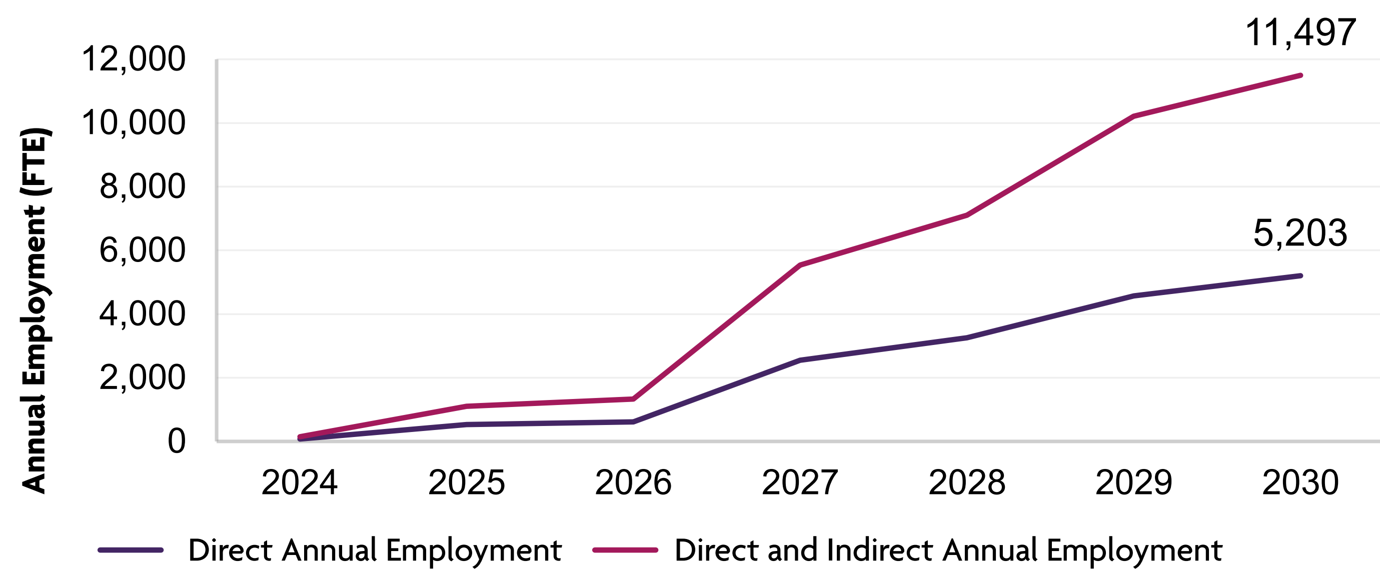

Figure 1 - Annual Direct and Total Employment from Hydrogen Deployment in the North West

The annual GVA from hydrogen deployment in the North West is shown in Figure 2. This shows annual GVA increasing over the 2020s and peaking in 2030 at almost £500m per year on a direct basis and almost £1.1bn per year on a total basis. The cumulative GVA impact of hydrogen deployment in the North West by 2030 is £1.5bn and £3.4bn on direct and total basis respectively by 2030.

ANNUAL GROSS VALUE ADDED RESULTING FROM NORTH WEST HYDROGEN DEPLOYMENT

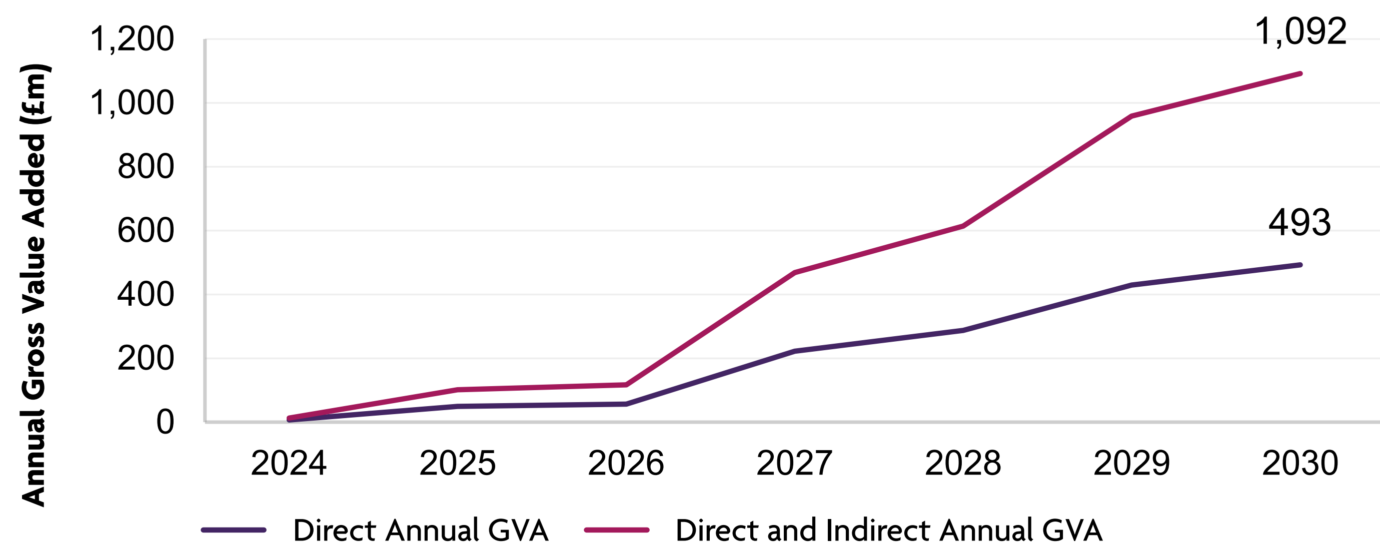

Figure 2 - Annual Direct and Total Gross Value Added from Hydrogen Deployment in the North West

[1] Cumulative employment years is the area under the curve on Figure 1. This captures the time element of employment over a set period. As an example, one job that is retained for five years would be five employment years.

INTRODUCTION

The North West is strongly positioned to capitalise on the economic and decarbonisation potential presented by the low carbon hydrogen sector. The region has natural features that lend itself to hydrogen production including offshore geology suitable for storage of carbon dioxide and salt layers onshore that are well suited to hydrogen storage in salt caverns. The North West also contains one of the largest industrial clusters in the UK[i], which provides a source of early demand for low carbon hydrogen. The combination of these features makes the North West an ideal region for early adoption of hydrogen.

The region has some of the most developed projects in the UK, including HyNet, Trafford Green Hydrogen and Barrow Green Hydrogen. All three of these projects have been successful in the first round of government support, through cluster sequencing and the Hydrogen Allocation Round (HAR) process respectively. This study estimates the economic potential of hydrogen deployment in the North West in terms of employment and gross value added (GVA) between 2024 and 2030.

POLICY CONTEXT

In 2020 the Government set an ambition to deliver 5 GW of low carbon hydrogen production by 2030[ii]. This production target was subsequently doubled to up to 10 GW of low carbon hydrogen production by 2030, with at least half coming from electrolytic production[iii]. More recently, in December of 2024, government defined the split between production more clearly and it was announced that up to 6 GW of production would be delivered through the HAR process. This leaves up to 4 GW of production from CCUS-enabled sources and to be delivered through the cluster sequencing process. The expectation is that the majority of production linked to the HAR process will be electrolytic[iv], although there are some alternative technologies that are permitted such as gasification and pyrolysis of biomass or waste without CCS and splitting methane to form solid carbon[v]. For the purposes of this study, it is assumed that the HAR process delivers electrolytic projects exclusively. Since publication of the initial target, there have been numerous policy announcements to support the development of the low carbon hydrogen sector. These policy announcements and updates include the development and publication of:

1. The UK Hydrogen Strategy (2021–2023), which sets the high level, strategic direction of the hydrogen economy[vi].
2. The Hydrogen Production Business Model (HPBM) (2022–2023), which sets out the Government's approach to providing revenue support for hydrogen production[vii].
3. The Low Carbon Hydrogen Agreement (LCHA) (2023), which provides the legal contract that underpins the HPBM[vii].
4. The Net Zero Hydrogen Fund (NZHF) (2022–2023), which is the Government's policy to provide up to 20% capital cost support for projects[viii].
5. The Low Carbon Hydrogen Standard (LCHS) (2022-2023), which creates the maximum emissions threshold for low carbon hydrogen production at 20 $gCO_{2e}/MJ_{(LHV)}$[ix].
6. HAR 1 Successful Projects (2023), which announces the 11 successful projects under the first hydrogen allocation round[x].

These announcements provide the policy framework for low carbon hydrogen deployment. Furthermore, the Government have announced plans to make the Hydrogen Transport and Storage Business Models available to developers in 2025[xi]. These models will stimulate the development of infrastructure necessary to link producers with end users of hydrogen.

NORTH WEST HYDROGEN DEPLOYMENT SCENARIO

The economic impacts of the hydrogen sector in the North West depend on the extent of hydrogen use. This section sets out the expectations for hydrogen production and demand in the North West between 2024 and 2030. The analysis bases production estimates on expectations of future production projects in the region that are likely to receive government support. The demand is then estimated as a function of the production estimate, using the Demand Side Study produced by NWHA as a basis for some sectoral splits.

HYDROGEN PRODUCTION

PRODUCTION CAPACITY

The CCUS-enabled hydrogen production deployment assumptions are based on HyNet delivering its planned capacities through both the track-1 (350 MW) and track-1 expansion (1,000 MW) cluster sequencing process[xii]. This deployment assumption also sits within the wider context the Government's target of up to 4 GW of hydrogen production from CCUS-enabled routes by 2030[iv].

The electrolytic hydrogen production deployment is more challenging to estimate. This is due to smaller scale projects and greater uncertainty about which projects are likely to progress through the HAR process. However, approximately a quarter of successful HAR 1 projects are based in the North West region at 31.5 MW of 125 MW of projects provided an offer for revenue support through the HPBM. These projects are Trafford Green Hydrogen and Barrow Green Hydrogen, both led by Carlton Power[x]. In this study, it is assumed that the proportion of North West based projects that succeed in future HAR rounds remains at 25% and that projects operational date is split equally between the options for delivery year in each HAR round. Finally, it is assumed that the HAR capacities that are not yet determined are appropriate scale to ensure the Government is on track to meet its target of up to 10 GW of low carbon hydrogen production by 2030[ii].

LOW CARBON HYDROGEN PRODUCTION CAPACITY IN THE NORTH WEST

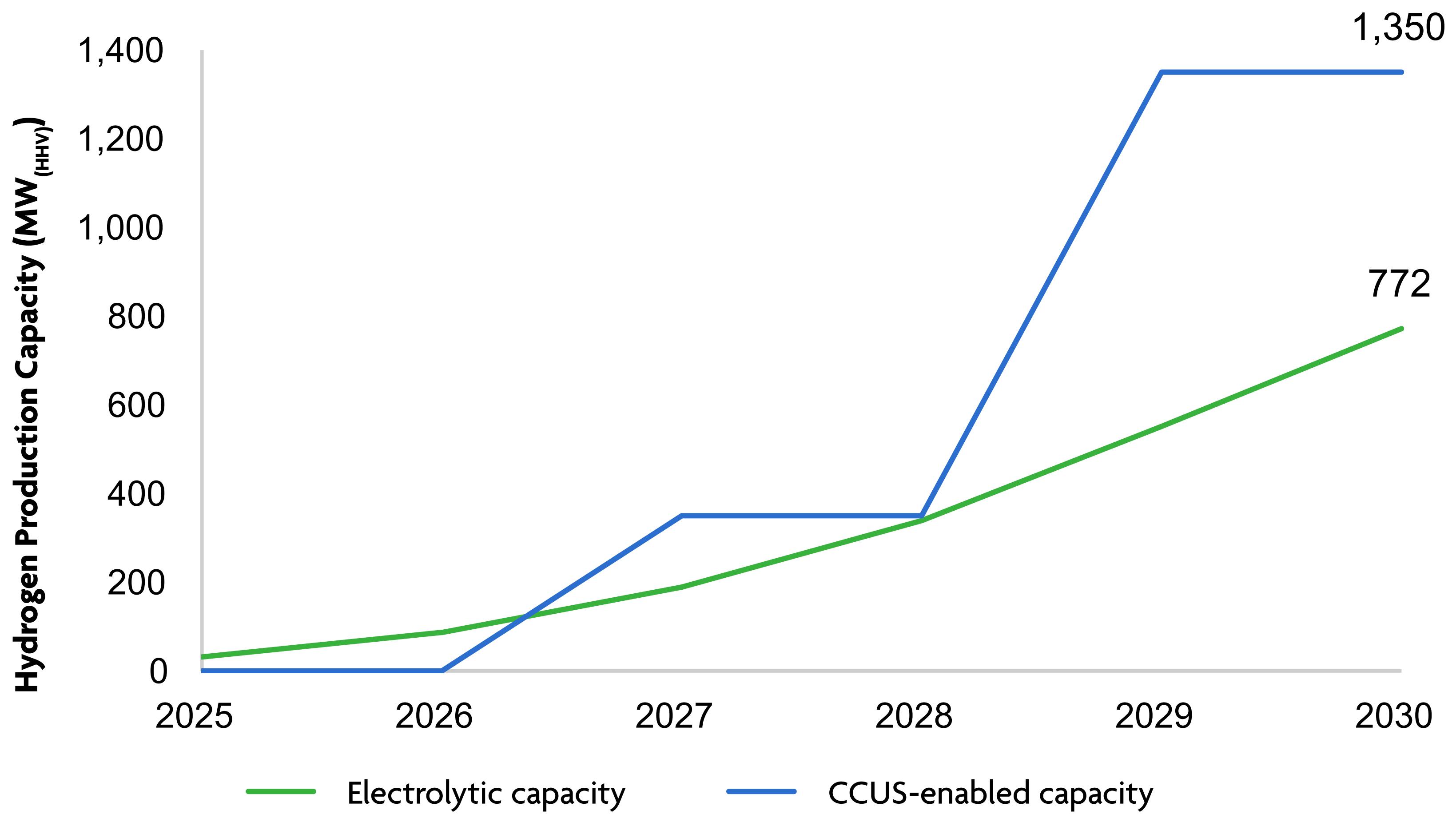

Figure 3 - Estimated Hydrogen Production Capacity in the North West from 2024 - 2030

PRODUCTION VOLUMES

A load factor of 50% for electrolytic and 95% for CCUS-enabled is assumed to estimate the annual volumes of hydrogen that will be produced at these production sites. CCUS-enabled production will typically run as much as possible to reduce the cost of production. While electrolytic hydrogen load factors are more uncertain and may depend on the source of electricity or operating model of the electrolyser. A load factor of 50% for electrolytic production reflects this uncertainty and is a value used by government . The resulting annual production volumes are shown in Figure 4

LOW CARBON HYDROGEN PRODUCTION VOLUMES IN THE NORTH WEST

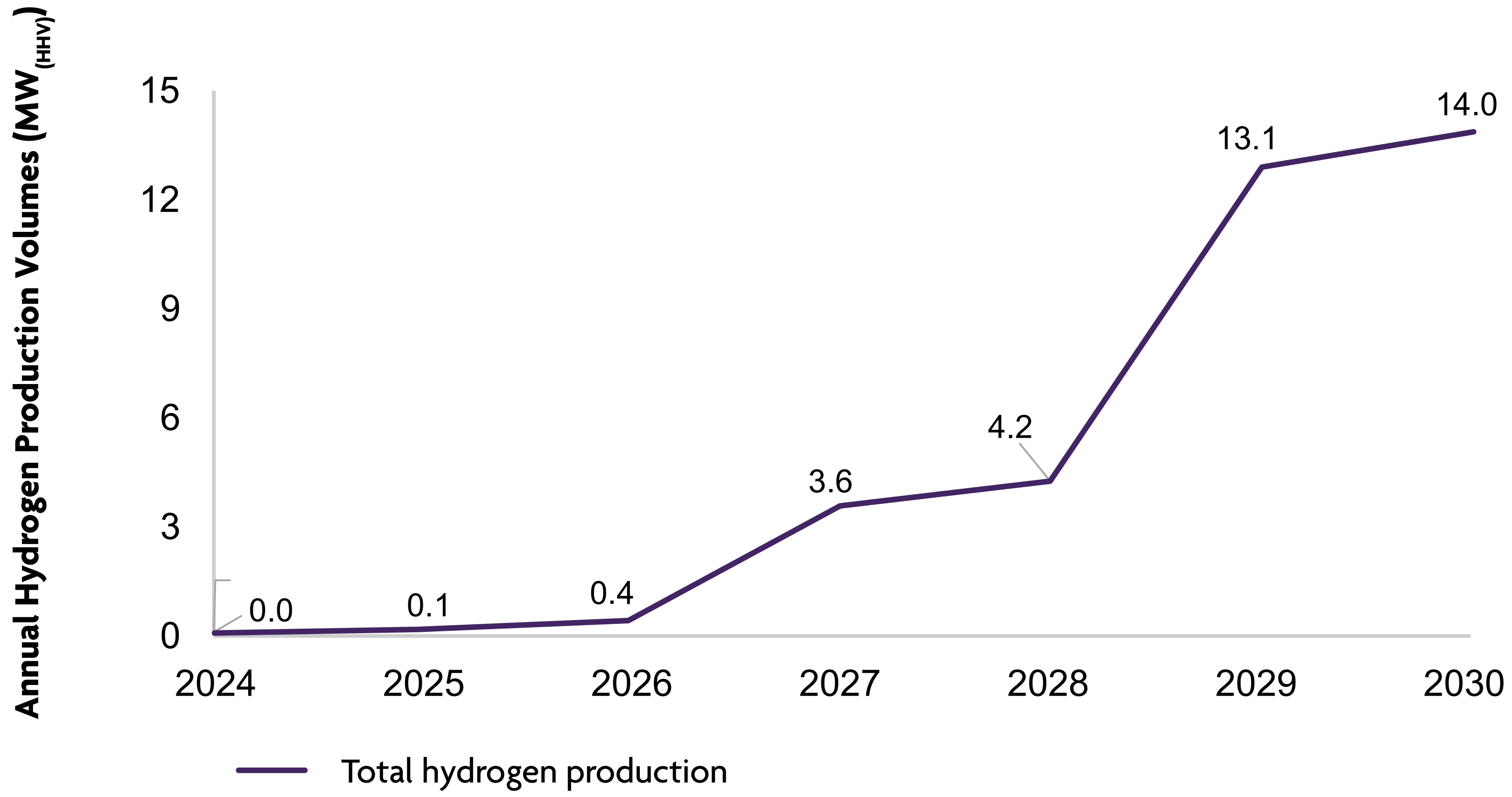

Figure 4 - Estimated Annual Hydrogen Production Volumes in the North West from 2024 - 2030

HYDROGEN DEMAND

Hydrogen demand is likely to follow supply with production projects potentially able to sell hydrogen at the price of natural gas and make a return. Furthermore, the fact that the HPBM provides limited volume support (i.e. projects have limited access to subsidy if they can't sell hydrogen) means that production project developers will need to be confident in demand before investing in production[xiii].

The EET press release published at the start of 2024 highlights industry such as low carbon refining operations, glass and chemicals manufacturing as key demand sectors for HyNet[xii].

As HyNet is expected to form the majority of hydrogen production in the region this has a significant impact on the demand assumptions in this study. The hydrogen demand for heat, power[2] and transport are based on the central scenario of the NWHA demand side study produced in 2023. Industrial demand is assumed to be a demand sink and is estimated as the difference between production volumes shown in Figure 4 and the demand from other sectors. The sectoral demand splits developed based on these assumptions are shown in Figure 5. These are used in combination with the production deployment estimates to estimate the economic impact of the hydrogen sector.

ANNUAL LOW CARBON HYDROGEN DEMAND IN NORTH WEST

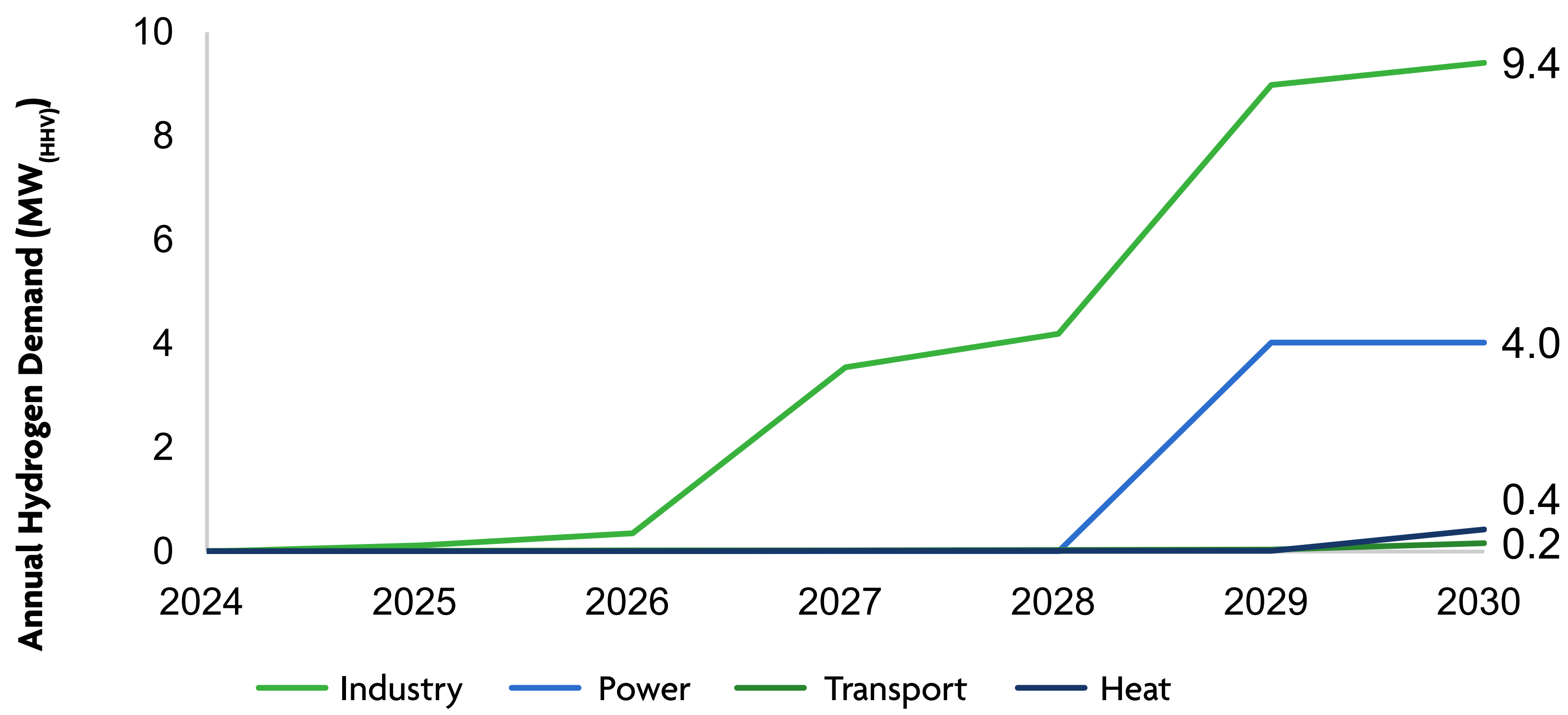

Figure 5 - Estimated Annual Hydrogen Demand in the North West from 2024 – 2030

[2] Power demand is adjusted from the demand side study to produce consistent results in this study. In this study power demand is assumed to begin a year later, in 2029 and remain constant between 2029 and 2030.

ECONOMIC IMPACT ASSESSMENT

The economic impact assessment in this study estimates the employment and GVA impact of the hydrogen deployment set out in the North West Hydrogen Deployment Scenario section. These metrics are presented separately on a direct and total (direct and indirect) basis.

EMPLOYMENT IMPACT

DIRECT EMPLOYMENT

The estimated direct employment impact of the North West Hydrogen Deployment Scenario (above) is shown in Figure 6. By 2030, there could be over 5,000 direct jobs related to spending in the hydrogen sector. This includes 1,800 direct jobs associated with hydrogen production, 2,100 direct jobs associated with networks and storage and 1,300 associated with hydrogen end use sectors. When considering cumulative employment years, a measure that capture employment impact over time, the estimated direct employment impact rises to almost 17,000 FTE (full time equivalent) years by 2030. Job creation in the hydrogen sector will have a weighting towards construction, manufacturing and engineering roles for building infrastructure. However, there will be broader employment impacts such as in professional services and business roles.

ANNUAL DIRECT EMPLOYMENT IN HYDROGEN SECTOR

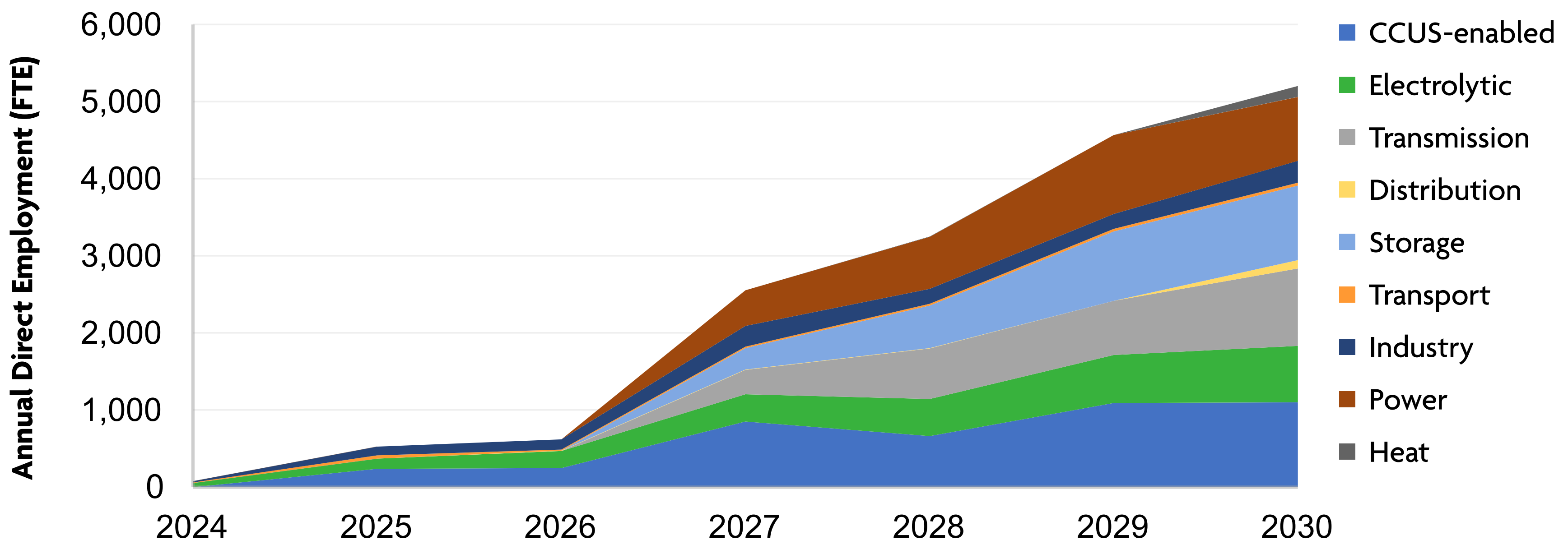

Figure 6 - Estimated Direct Employment Impact of North West Hydrogen Deployment Scenario

DIRECT AND INDIRECT EMPLOYMENT

The combination of direct and indirect employment, which includes employment impacts in the broader supply chain (e.g. steel manufacture), is shown in Figure 7. A greater proportion of this employment impact is expected to be based outside of the North West due to the broader definition of this metric when compared to direct employment. On a direct and indirect basis, the North West Hydrogen Deployment Scenario could result in employment of almost 11,500 by 2030. Similarly to direct employment, there is a greater expenditure and economic activity associated with production and midstream than end uses. When considering cumulative employment years, a measure that captures employment impacts over time, the estimated total employment impact rises to almost 37,000 FTE years by 2030.

ANNUAL DIRECT AND INDIRECT EMPLOYMENT FROM HYDROGEN DEPLOYMENT IN THE NORTH WEST

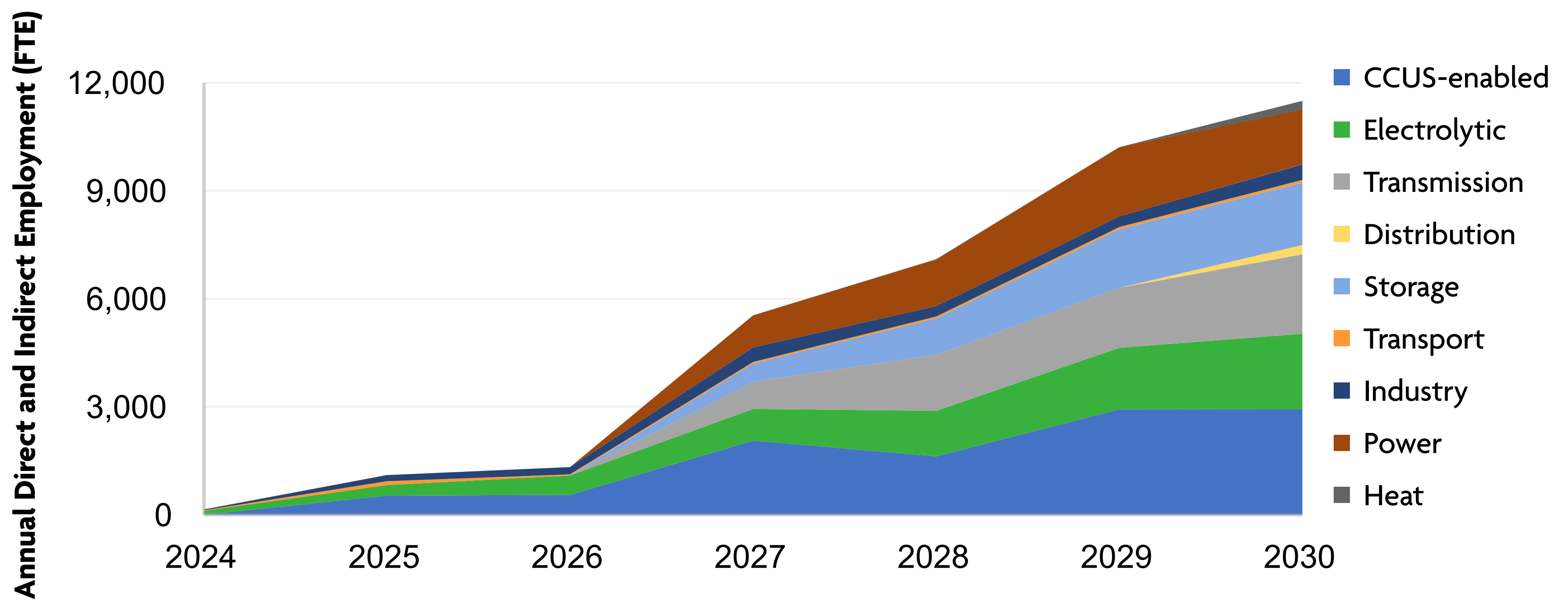

Figure 7 - Estimated Direct and Indirect Employment Impact of North West Hydrogen Deployment Scenario

GROSS VALUE ADDED IMPACT

DIRECT GROSS VALUE ADDED

Gross value added (GVA) is a measure of the economic contribution from an individual producer, industry or sector to the economy as a whole. The estimated direct GVA resulting from the North West Hydrogen Deployment Scenario (developed for this study) is shown in Figure 8. This follows a similar pattern to employment with direct GVA increasing towards 2030 and reaching an annual peak of almost £500m. On a cumulative basis this estimates that there could be £1.5bn of GVA between 2024 and 2030.

ANNUAL DIRECT GVA IN FROM HYDROGEN DEPLOYMENT IN THE NORTH WEST

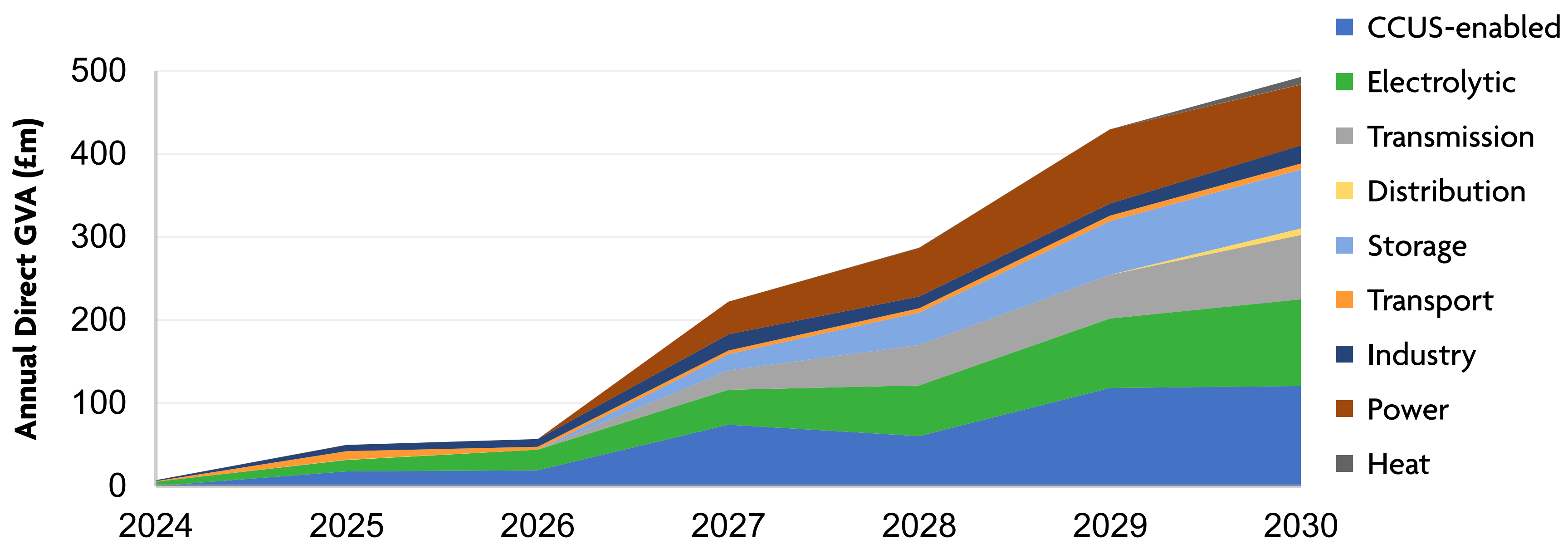

Figure 8 - Estimated Direct Gross Value Added Impact of North West Hydrogen Deployment Scenario

DIRECT AND INDIRECT GROSS VALUE ADDED

The total (direct and indirect) GVA from the North West Hydrogen Deployment Scenario is shown in Figure 9. This takes into account broader supply chain benefits and shows total annual GVA increasing to almost £1,100m by 2030. On a cumulative basis this estimates that there could be £3.4bn of cumulative GVA between 2024 and 2030.

ANNUAL DIRECT AND INDIRECT GVA FROM HYDROGEN DEPLOYMENT IN THE NORTH WEST

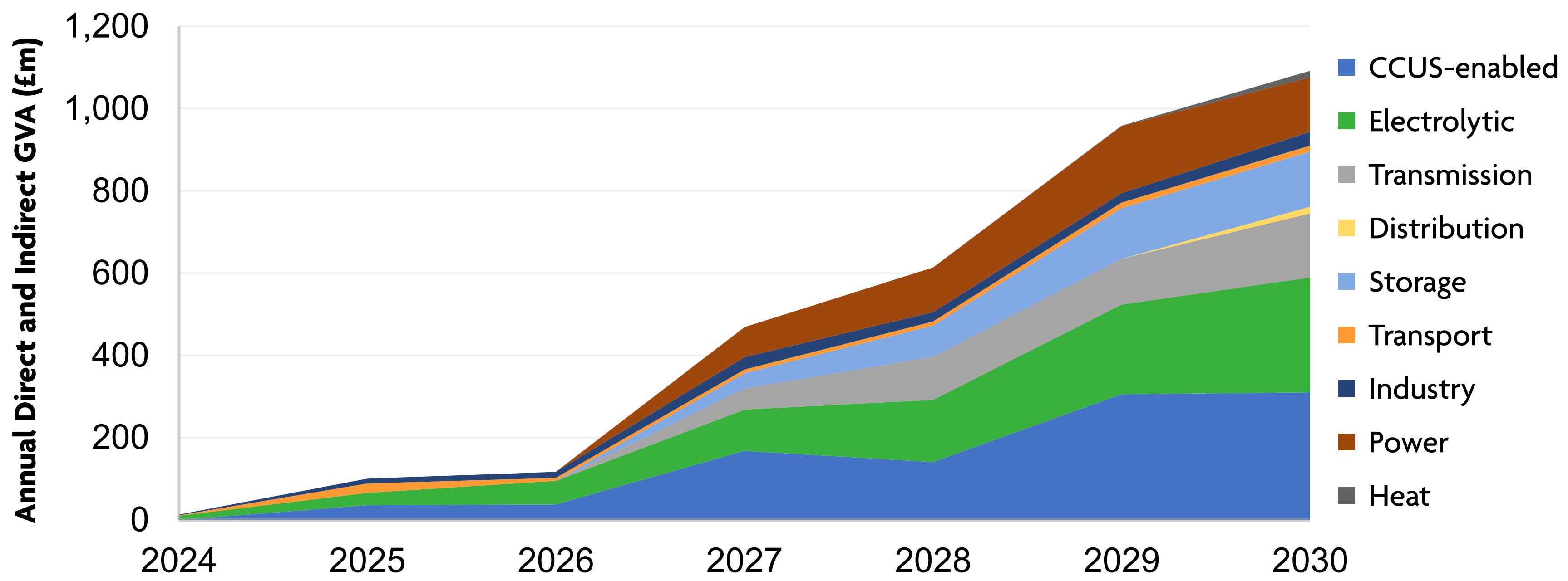

Figure 9 - Estimated Direct and Indirect Gross Value Added Impact of North West Hydrogen Deployment Scenario

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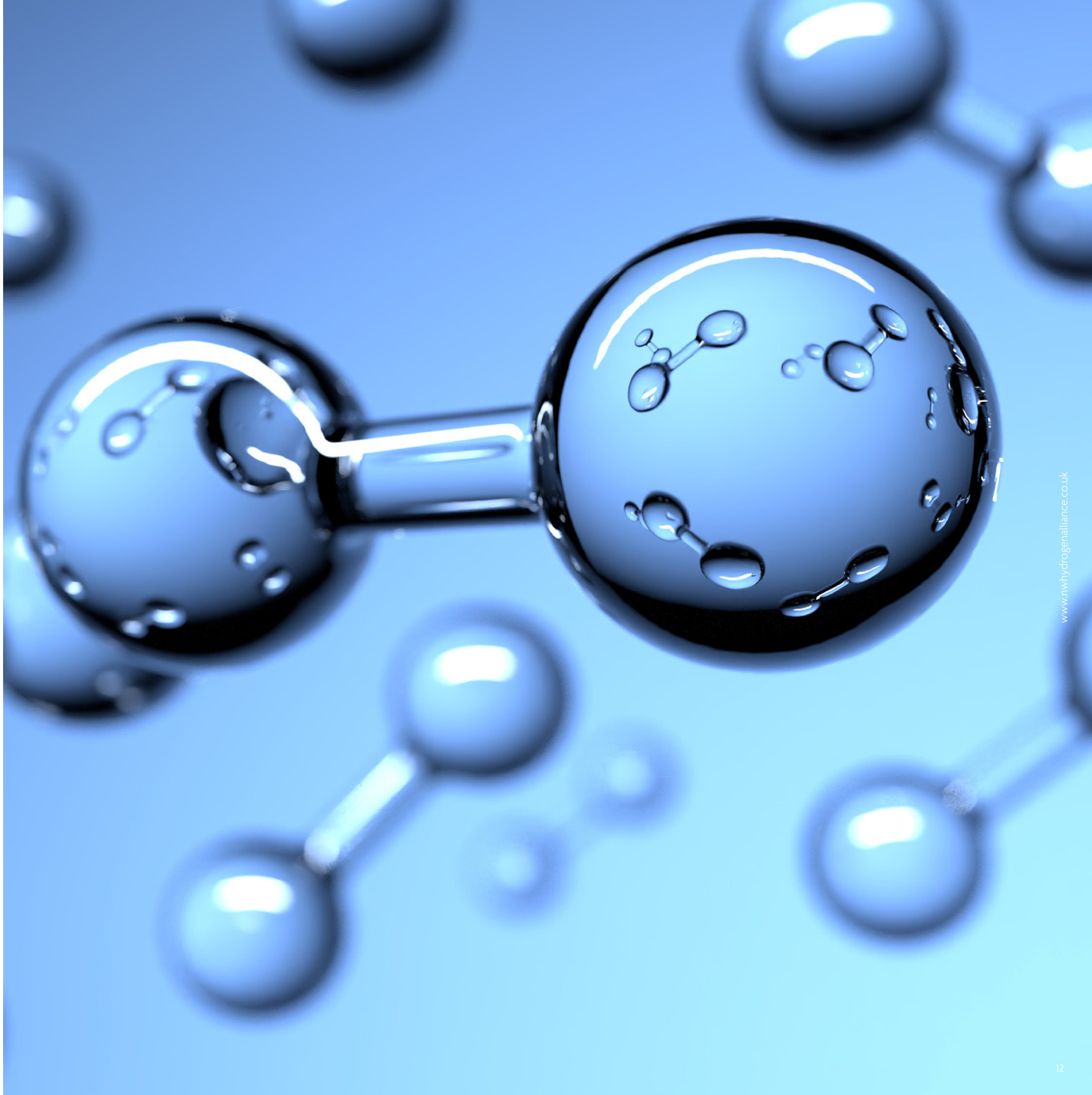
CONCLUSIONS

The North West is well positioned to capitalise on the economic opportunity presented by hydrogen. The region has some of the most well-developed projects including HyNet and a quarter of the electrolytic capacity made an offer under the HAR 1 process. The region also has features that make it an ideal candidate for early hydrogen adoption including salt layers for hydrogen storage, offshore geology suitable for storage of carbon dioxide and a large industrial cluster.

This study estimates that hydrogen deployment in the North West could result in employment of over 5,000 jobs in 2030 on a direct basis and almost 11,500 jobs on a direct and indirect basis. On a cumulative employment years basis, the potential impact of hydrogen deployment is 17,000 FTE years by 2030 on a direct basis and 37,000 FTE years by 2030 on a total (direct and indirect) basis.

The hydrogen sector also has significant potential to contribute to economic growth with the potential for almost £500m per year of GVA on a direct basis in 2030 and almost £1,100m per year on a total (direct and indirect) basis. Cumulative GVA is estimated at £1.5bn and £3.4bn on a direct and total basis respectively between 2024 and 2030.

The employment and gross value added impacts are split between different elements of the hydrogen value chain with hydrogen production, infrastructure and end use all having significant contributions to the economic impact. Of the three, hydrogen production is estimated to have the greatest impact on both employment and GVA. This is driven by the higher modelled expenditure in production than infrastructure or end use.



ANNEX 1: COSTING METHODOLOGY

In developing the economic impact of hydrogen activity, costs estimates are produced based on the North West Hydrogen Deployment Scenario developed for this study. 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[xiv]. 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, the costs related to the first phase of HyNet are based on the cost of 300 MW projects and the second phase is based on cost assumptions for projects of 1,000 MW. The construction period for all technologies is assumed to be 3 years.

Energy input costs form a large basis of hydrogen production costs and have been extremely variable in recent years. As discussed in the Annex 2, 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[xv], the estimated economic activity associated with this expenditure would be overestimated as higher prices do not equate to greater employment or GVA.

MIDSTREAM

NETWORKS

For the purposes of this study, transmission networks are defined as new, large hydrogen pipelines used to transport hydrogen to large users or storage. Distribution networks refers to the conversion of existing gas distribution networks for smaller users such as domestic properties. This approach is justified given the new networks proposed for HyNet will have a maximum diameter of 42 inches[xvi].

This study assumes that 280 km of large pipelines are required in the North West by 2030, reflecting both the initial 125 km planned by HyNet[xvii] and some network to connect the east and west coast as is planned by Project Union[xviii]. The costs of the transmission network are estimated based on the hydrogen transmission network cost equation in the Hydrogen Supply Chain Evidence report[xix] and pipeline diameter assumptions from Afry[xx]. 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[xxi]. These compressors are then costed based on Hydrogen Supply Chain Evidence Basexix, assuming 30 MW compressors based on compression requirements assessed for the Irish Government[xxii].

The capital cost of hydrogen distribution network by 2030 are estimated by calculating the proportion of estimated hydrogen heat demand to natural gas use in 2018[xxiii] and applying this proportion to costs of complete network conversion[xix].

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[xix]. 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 proposals for storage at Keuper, which would theoretically be able to storage up to 1.3 TWh[xxiv]. It is assumed that this capacity is reached in 2035 with linear growth from 2029 – 2035. 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 capital and operational costs of this storage are estimated based on the Hydrogen Supply Chain Evidence report[xix] 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 NWHA Demand Side Study in 2029. 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.

This analysis focusses on large scale power generation due to the high probability that this forms the majority of power sector hydrogen demand. 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%)[xx]. The capital and operational costs of hydrogen to power facilities are estimated using Element Energy's Hydrogen for Power Generation study[xxv]. Development timelines are assumed to be 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 part of the industrial sector. As set out in the North West Deployment Scenario, the industrial demand estimate is based industry being a large user of hydrogen in the short term, particularly from HyNet. The cost analysis is based on the costings produced for CCC's Balanced Pathway, where the capital and operational cost estimates of using hydrogen in industry have already been developed[xxvi]. These are then adjusted to match the demand in the North West Deployment Scenario.

TRANSPORT

This analysis assumes that transport demand follows the central scenario in the NWHA Demand Side Study. Annual surface vehicle deployment is estimated using FES 23 which includes both annual demand and number of vehicles for each vehicle mode[xxvii]. In this analysis hydrogen buses, HGVs and cars are assumed to cost £400,000, £225,000 and £40,000 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 features a small proportion of hydrogen demand for transport. The hydrogen demand and costs of ships is taken from an Argonne report on Hydrogen for Maritime Applications[xxviii]. The hydrogen demand for aviation is assumed to be based on utilising hydrogen for creation of synthetic fuels. The costs of this process are not included in the analysis due to the low volumes of hydrogen and challenges accessing reliable cost data.

HEAT

Hydrogen heat demand in this study is based on the central scenario in the NWHA demand side study. Assuming a fuel demand of 11,500 kWh[xxix] per boiler, results in approximately 35,000 domestic properties using hydrogen heat in 2030. This is the size of a medium sized town and aligns with the Government's plan for a hydrogen town by 2030[ii]. Capital costs for residential boilers are assumed to be £2,000[xxx]. Non-domestic hydrogen boiler demands are based on average non-domestic gas demand[xxxi], 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[xxxii]. The annual operational costs of all boilers is assumed to be 10% of capital costs.

CONCLUSION

ANNEX 2: ECONOMIC IMPACT ASSESSMENT METHODOLOGY

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 considers both direct and indirect impacts for employment and GVA to estimate the immediate effect of spending in the hydrogen sector but also the broader impact on the economy.

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.

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 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[xxxiii] and supply and use tables[xxxiv].

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 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 each year to 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.

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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