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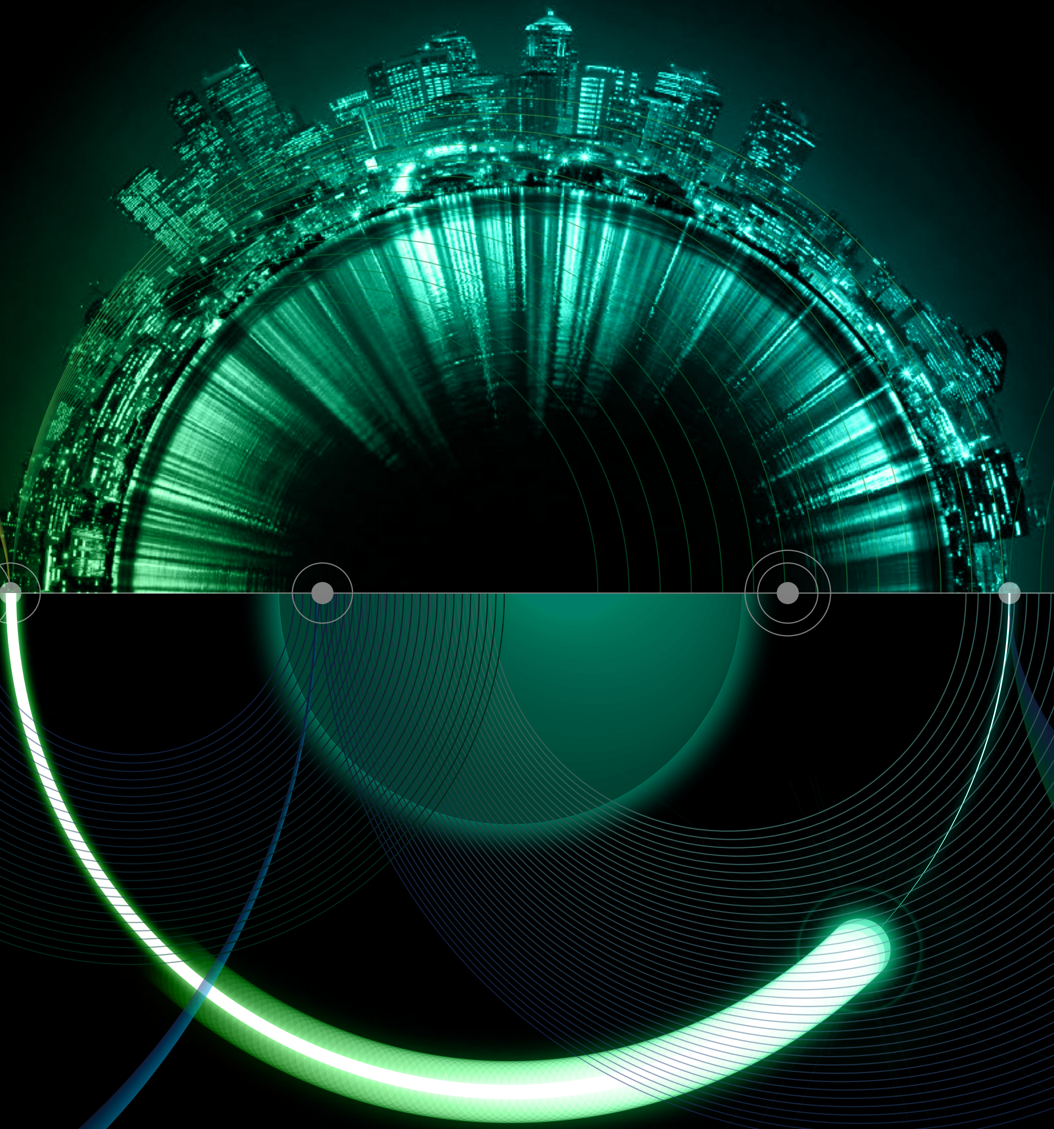


Investing in hydrogen

Ready, set, net zero

November 2020

Home

Executive summary

Hydrogen will play a crucial role in the UK's efforts to reach its net zero target for 2050. It could help decarbonisation efforts in a number of sectors, but needs investment and policy support to establish demand, increase the scale of deployment and reduce costs. This report investigates the costs of hydrogen under different pathways to net zero and factors that could make it more attractive to investors.

With only 30 years to go to 2050, and although good progress has been made, the size of the UK's decarbonisation challenge is huge: how to reduce, eliminate and, if necessary, decarbonise fossil fuels at minimal cost and disruption, while maximising opportunities for all stakeholders.

"Hydrogen could support the UK's decarbonisation efforts in a number of applications."

What roles could hydrogen play in the UK?
Hydrogen could support the UK's decarbonisation efforts in a number of applications. Its contributions could be particularly important in sectors where greenhouse gas emissions are difficult to abate:

- **Heat** – by replacing natural gas and providing low or zero carbon heat for buildings and industrial use
- **Transport** – by replacing fossil fuels in segments where electrification is not possible or practical (heavy goods vehicles, buses, trains, ships and aeroplanes)
- **Industrials** – by possibly replacing fossil fuels as the reducing agent in steelmaking.

In the **power sector**, hydrogen could be used to store low-cost, excess renewable electricity. This in turn would increase short-term and seasonal system flexibility, and support the integration of a higher level of renewable generation in the energy system.

What does our analysis show?

We have created a bespoke cost model to understand the impact of each segment of the hydrogen value chain – from production through to storage and transport – on the final levelised cost of hydrogen.

Hydrogen production is likely to be the largest cost component of most hydrogen projects, according to the model. In production technology alone, somewhere between £3.5 billion to £11.4 billion would need to be invested by 2035. Further investments will be required in carbon capture, hydrogen conversion, storage and transport infrastructure.

Conversion treatments would most likely be the second largest cost component across the hydrogen value chain.

Storing hydrogen in large quantities over longer time periods is most cost effective in salt caverns and compressed gas containers. While salt caverns have geographical constraints, they would ideally serve the heat, industrial and potentially, power sectors, particularly those near industrial clusters where hydrogen demand from several sectors may be concentrated. Compressed gas containers can be placed closer to demand centres and could also serve multiple sectors, including transport and power.

Transporting hydrogen is most cost effective in pipelines in a gaseous state over long distances and in large quantities, according to the model. Trailers – gaseous and liquid hydrogen and ammonia as well as liquid organic hydrogen carriers – are more expensive than pipelines on a levelised cost basis. They are likely to serve sectors and customers where smaller-scale transport is needed on an ad hoc basis or for shorter distances.

Reducing the investment needed in hydrogen production, and conversion treatments in particular, could have a significant impact on the final levelised cost of any hydrogen project. In the transport sector, efforts will need to focus on reducing the costs associated with refuelling stations, which constitute another major component of the final levelised costs. Any reduction in operating costs will further improve the overall competitiveness of hydrogen projects.

> "Hydrogen seems to offer abundant opportunities for future investment."

How can hydrogen be made more attractive to investors?

Hydrogen seems to offer abundant opportunities for future investment, but demand for the commodity is far from certain. While a number of hydrogen pathways are plausible, the volume of demand projected by pathways and applications varies widely, making it challenging for investors to understand the scale of the opportunity.

Time is also of the essence. The majority of financial decisions need to be made in this decade to support the UK's net zero ambitions. In the absence of a nationally coordinated effort at the moment, hydrogen development might be fragmented and limit cost reduction opportunities in future years.

While investors are used to dealing with some uncertainty, given the size of the challenge and the speed with which decisions need to be made, they need to be confident that there will be demand for low carbon or carbon-free hydrogen and that they will see a return on their investments.

Therefore, there is an urgent need for targeted policy interventions in a number of areas, including:

A national strategy and roadmap

A national strategy would show investors a strong UK commitment to hydrogen, while a roadmap would be helpful in developing the regulatory and support mechanisms to deliver the strategy. This should also boost interdependencies between sectors that use hydrogen to achieve the best overall outcomes.

Short- to medium-term funding to reduce risk and stimulate innovation

Producing hydrogen is currently more expensive than other low carbon fuel sources. Investments may also carry higher risk associated with technologies, the deployment of which is limited on a large scale, and technology obsolescence. There is also a lack of clarity on risk allocations between investors and consumers/taxpayers.

At least in the early stages of development, hydrogen will require additional policy support or funding to help cover higher costs, reduce risk and create long-term revenue certainty. Similar support will be needed to encourage innovation to reduce technology costs and to understand hydrogen's role in cross-sector integration better.

Successful support mechanisms already exist in the UK – such as Regulated Asset Base models for economic regulation of monopoly infrastructure assets or Contracts for Difference for stimulating investment in renewable energy generation. Work is already underway to identify the appropriate mechanism. The chosen mechanism will need to ensure compatibility with existing policies through a detailed market design and provide investors with more certainty to enable deployment on a commercial scale.

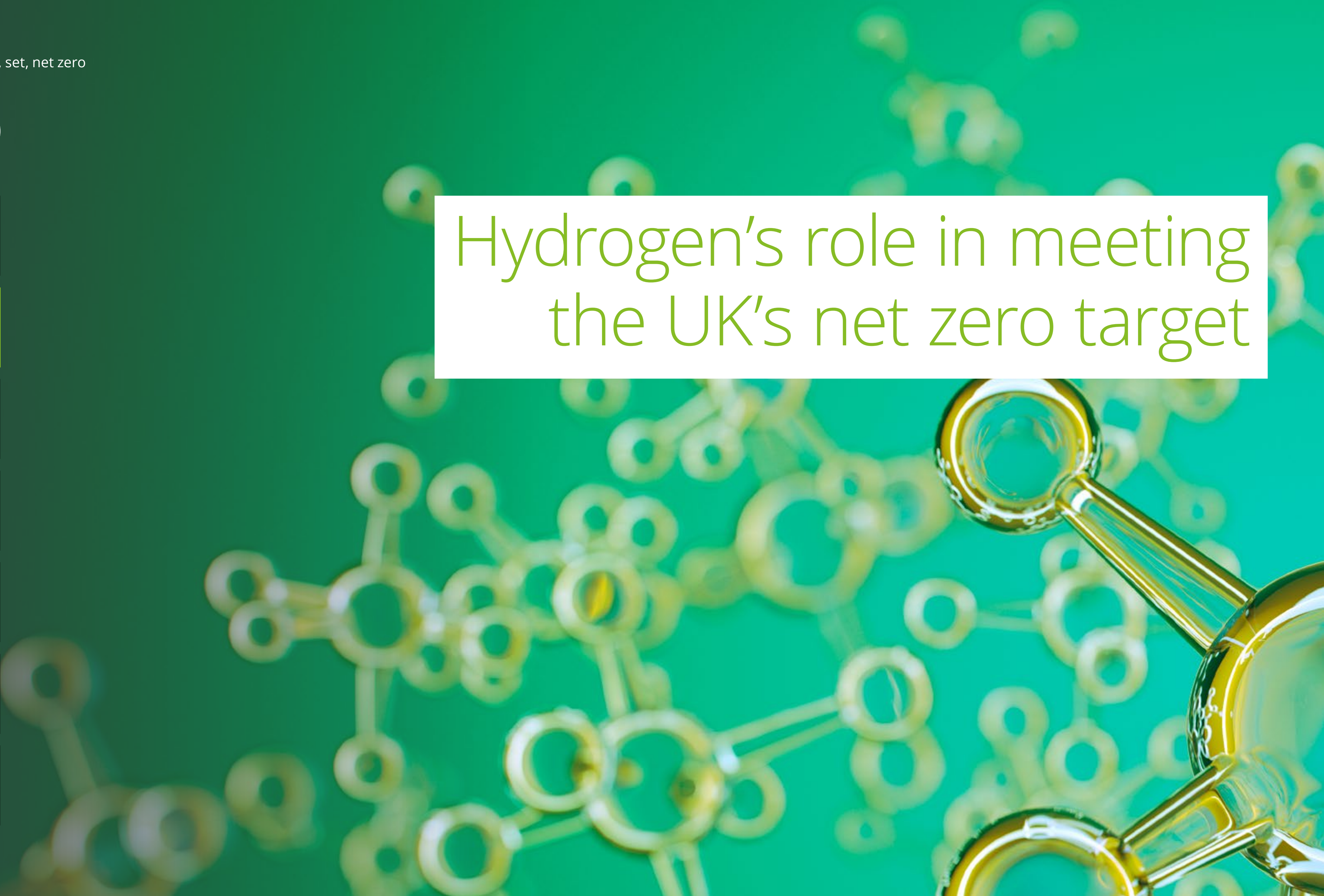
Sectoral coordination

Greater coordination will be needed between the sectors using hydrogen in the future. Such coordination would be easier based around industrial hubs or clusters where opportunities are more immediately visible and stakeholder objectives are more aligned. It will be more challenging on a regional or national level, although the government could play an active role in helping to align the interests of various stakeholders in opening up more opportunities for investment.

Regulation

Work is already underway to establish the changes necessary in regulatory regimes and standards for the safe use of hydrogen across the national infrastructure and in people's homes and businesses. This work needs to continue and be adopted as soon as possible to 'future-proof' the energy system.

Hydrogen's role in meeting the UK's net zero target



The net zero target means that all forms of fossil fuel energy sources – natural gas as well as petrol and diesel – will have to be replaced by 2050. Low carbon hydrogen can be the solution to help reduce carbon emissions across a number of sectors.

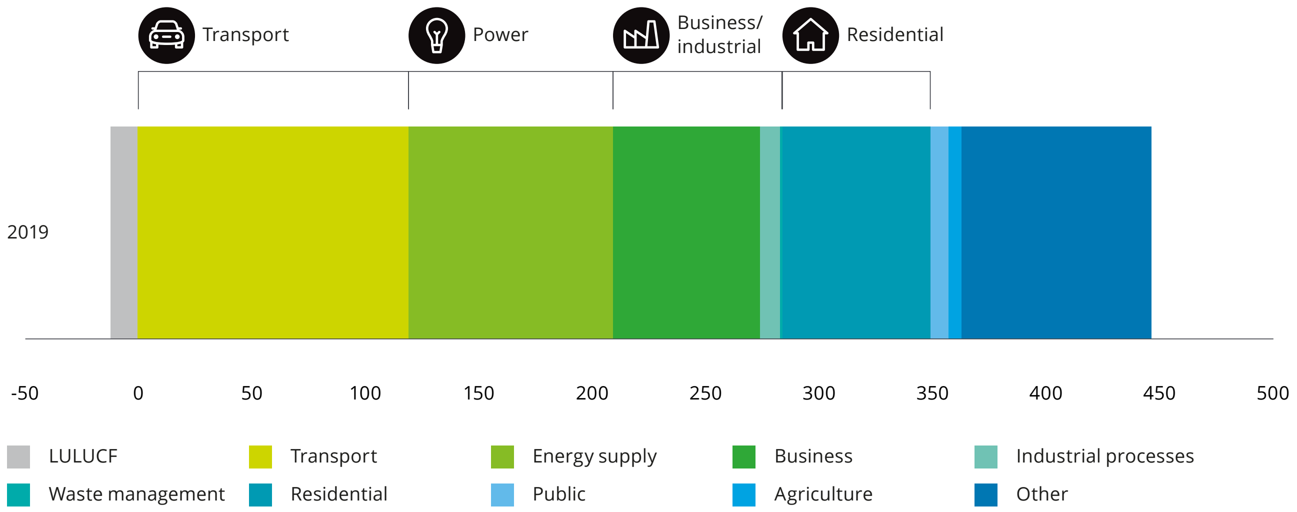
Hydrogen will be crucial in meeting the UK's net zero target

In June 2019, the UK government made achieving net zero emissions a statutory target for 2050. This means that by 2050 all forms of fossil fuel energy sources will need to be reduced or phased out and any carbon emissions generated will need to be captured and sequestered. Some energy production will need to be carbon negative to offset industrial sectors that cannot decarbonise.

Figure 1 shows the size of the challenge: in 2019 the UK's territorial greenhouse gas emissions were 435.2 million tonnes of CO_2 equivalent ($MtCO_2e$).

Encouraging progress has already been made in electricity generation by decreasing coal fired power generation and increasing the proportion of renewable energy technologies in the generation mix. Coal will be phased out by 2025 at the latest and replaced by low carbon generation capacity.

Figure 1. UK greenhouse gas emissions 2019 ($MtCO_2e$)



Note: LULUCF stands for land use, land use change and forestry
Source: Provisional UK greenhouse gas emissions national statistics 2019, Department for Business, Energy & Industrial Strategy (BEIS)

"In June 2019, the UK government made achieving net zero emissions a statutory target for 2050."

Now the focus must shift to other energy-intensive sectors where emissions are hard to abate, such as heat and transport. Interest in hydrogen in the UK has increased for a number of reasons, including:

- **Its carbon reduction potential** – Hydrogen produces no carbon emissions at end use, but only low-carbon or carbon-free hydrogen can support the UK's net zero target
- **Its versatility** – Hydrogen can be made from a range of sources and stored in large quantities for long periods of time and transported to the point of use without any major losses
- **Its role in sector coupling** – It can be used in a variety of applications such as industry, transport, power and heat and can help absorb some of the growing pressure that electrification of transport and heat would put on electricity infrastructure and the total electricity investment requirement. Hydrogen can additionally help to reduce some of the investment needed in electricity generation and complex infrastructure upgrades

"UK government support for hydrogen has been increasing in recent years."

- **Its ability to increase system flexibility and integrate higher levels of renewable power into the energy system** – Renewable generation is projected to rise to 81 per cent in the electricity generation mix even under the most conservative scenario by 2050.[1] However, increased levels of intermittent renewable generation leads to more complex requirements to balance electricity supply and demand in real time, potentially adding costs to manage the electricity grid. Hydrogen generated from renewable electricity can serve as a storage medium, to support system stability and provide much needed flexibility.

UK government support for hydrogen has been increasing in recent years. Hydrogen was named as one of the illustrative pathways to 2050 in the Clean Growth Strategy published in 2017. The Strategy's Hydrogen Pathway sees a key role for low carbon hydrogen and carbon capture, utilisation and storage (CCUS) to decarbonise transport and heating, and forecasts that in such pathways up to 700 terawatt-hours (TWh) of hydrogen would be produced to meet demand across multiple sectors.

A number of hydrogen pilot projects and feasibility studies have also received public funding over the last five years, including H21, HyDeploy and Hy4Heat. More recently, in February 2020, five projects – Gigastack, Hynet, HyPER, Dolphyn and Acorn – received government support totalling £28 million.[2] BEIS has also announced a Carbon Capture and Storage Infrastructure (CCS) Fund in the Spring Budget 2020, committing at least £800 million to support the deployment of CCS in at least two UK sites, and has run a consultation on CCUS business models.

In addition, BEIS has also commissioned a report to identify the appropriate business model to support hydrogen production in the UK.[3] The project has identified four economic models: contractual payments to producers; regulated returns; obligations; and end-user subsidies. The next phase of this project will be selecting the appropriate business model and developing it further.

While government support is growing, there is a need to accelerate the speed with which government policy on hydrogen is determined, and what support mechanisms are developed and implemented to provide timely signals to investors.

Hydrogen pathways

A number of pathways exist to meet the net zero target and hydrogen plays a prominent role in each, thus confirming its huge potential for the UK. However, there is uncertainty around the volumes of hydrogen required and the sectors in which it will be deployed.

Pathways to net zero and the Deloitte cost model

How will the UK move from pilot projects and feasibility studies to larger scale operational projects within the next decade? Not only does progress need to be made from a policy and regulatory perspective, more clarity is also needed to understand cost competitiveness of different hydrogen production, transportation and storage technologies, opportunities for cost reduction and the scale of investment needed. These factors will be necessary to consider when making policy decisions on support mechanisms aimed at attracting timely investment into hydrogen infrastructure, as well as establishing and developing efficient supply chains to meet the net zero target.

To this end, we developed a bespoke cost model to understand the impact of each segment of the hydrogen value chain – production, conversion, storage and transport – on the final levelised cost of hydrogen (LCOH). The Deloitte LCOH model ('the model') is based on hydrogen demand figures projected in three Future of Energy Scenarios 2020 (FES 2020): Steady Progression, Consumer Transformation and System Transformation.[4]

Large projected growth in hydrogen demand, but uncertainty on volumes and applications

Currently, 27 terawatt-hours (TWh) of hydrogen, all from fossil fuels, are used as industrial feedstock in the UK.[5]

In the future, hydrogen consumption – which must be low carbon or carbon free – is projected to expand to a number of other applications ranging from transport to power generation and heat.

Depending on the scenario, the volume of hydrogen demand can differ substantially between applications, as shown in Figure 2.

Figure 2. UK hydrogen demand in 2050 by sector

Sector	Hydrogen use	UK hydrogen demand in 2050 (TWh)		
		Steady Progression	Consumer Transformation	System Transformation
Industrial	Refining/Steel production/Chemicals feedstock	27	27	27
Transport	Road transport	2	32	54
	Rail	0	0	2
	Shipping	0	70	70
Power	Electricity generation, storing low-cost electricity, supporting the integration of a higher level of renewable generation and providing short-term and seasonal system flexibility	0	20	28
Heat	Residential heat	6	17	224
	Industrial and commercial	0	13	213
	Gas blending	8	0	0
	Total	**43**	**179**	**618**

Source: FES 2019 (Industrial feedstock, Deloitte addition) and FES 2020

In scenarios where the UK meets the net zero target – Consumer Transformation and System Transformation – demand is projected to increase somewhere between 179 TWh and 618 TWh by 2050. This large growth will require substantial increases in production capacity, supported by adequate development of CCS/CCUS, storage, conversion, transmission and distribution infrastructure, as well as substantial changes in customer appliances.

While all these infrastructure developments provide opportunities to invest, the lack of clarity on future demand levels and hydrogen's applications pose a high level of uncertainty for investors. In addition, each segment of the hydrogen value chain provides investors with further options to choose from. All of these options have different cost and risk profiles, infrastructure and regulatory challenges and investors need to be satisfied that any potential issues have been resolved.

Both blue and green production technology will be needed

Hydrogen can be produced in a number of ways. The dominant methods that this report refers to are summarised in Figure 3.

Figure 3. Hydrogen production methods

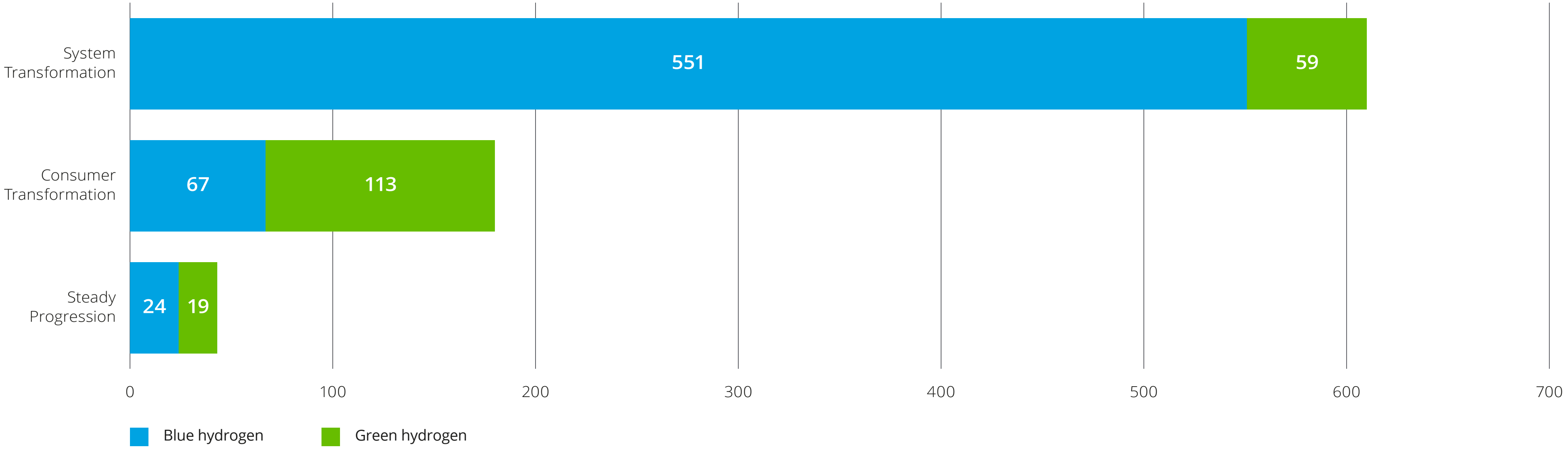
Method	Description
Grey	• Produced from fossil fuels typically with natural gas reforming (for example, Steam Methane Reforming – SMR) or coal gasification.
Blue	• Produced from fossil fuels typically with natural gas reforming or coal gasification. • Carbon emissions during the reforming process are captured by a CCS plant and stored in underground sites. • Hydrogen produced from fossil fuels with CCS, where CO_2 is used for enhancing oil recovery, does not qualify as blue hydrogen. • Blue hydrogen may need additional steps to remove small levels of contaminants before it can be used in applications that require high purity hydrogen.
Green	• Produced from renewable power by electrolysis or from biomass with emissions of less than 8 kg CO_2e/kgH_2. • Electrolysis is the process of splitting water molecules into their constituents, hydrogen and oxygen. Hydrogen can be stored and used as feedstock for other applications or reversed to produce electricity again – with some loss of the initial energy used in the electrolysis. • This category refers to methods that result in low levels of greenhouse gas emissions. • This report refers to two main electrolyser technologies, Alkaline Electrolysis Cells (AEC) and Proton Exchange Membrane (PEM) Electrolysis Cells. While electrolysis is a well-established technology, its commercial use is currently limited, due to its high costs compared with other methods.

"This large growth will require substantial increases in production capacity, supported by adequate development of CCS/CCUS, storage, conversion, transmission and distribution infrastructure."

A combination of blue and green hydrogen will be needed to meet the net zero target, but the volumes will depend on a variety of factors, such as the end-use applications, government policy and the available mechanisms supporting the different types of hydrogen production technologies.

Figure 4 shows the projected balance of blue and green hydrogen demand in the three scenarios based on FES 2020 figures. Blue hydrogen demand in the System Transformation scenario is driven by extensive hydrogen use in heat applications.

Figure 4. The balance of blue and green hydrogen in the Deloitte LCOH scenarios (TWh)



Source: Deloitte analysis

The cost of hydrogen

Building a hydrogen economy will require substantial investment. Production technologies alone will need to attract between £3.5 billion and £11.4 billion by 2035. Minimising the hydrogen conversion, storage and transport costs by using localised applications could significantly improve hydrogen's commercial competitiveness.

This section sets out the findings of the Deloitte LCOH model. The aim of the model is to show the impact of each segment of the hydrogen value chain – production, conversion, storage and transport – on the final levelised cost.

LCOH figures help to understand the cost of hydrogen per unit – in our model it is £ per kg. The LCOH can be one of the metrics to assess the economics and commercial viability of a project or to understand its cost competitiveness compared with other energy sources or projects located elsewhere.

LCOH is calculated as the discounted total costs incurred during the lifetime of an asset or project over the total discounted hydrogen volumes generated. Total costs in our model include capital costs (total upfront costs to bring the asset to commission) and operating costs (fixed and variable – these vary depending on the segment and hydrogen production technology, but typically include stack replacement, CO_2 levy, electricity and natural gas costs, water for electrolysis, grid, maintenance and other costs). Assumptions about a number of factors (including useful life of plants, stack lifetimes and replacements, load factors and conversion energy losses) have been made based on publicly available sources or Deloitte expert views on the topic.

As explained earlier, the model uses hydrogen demand and new production capacity projections from the following three FES 2020 scenarios:

01. Steady Progression – low hydrogen demand case

02. Consumer Transformation – central hydrogen demand case

03. System Transformation – high hydrogen demand case.

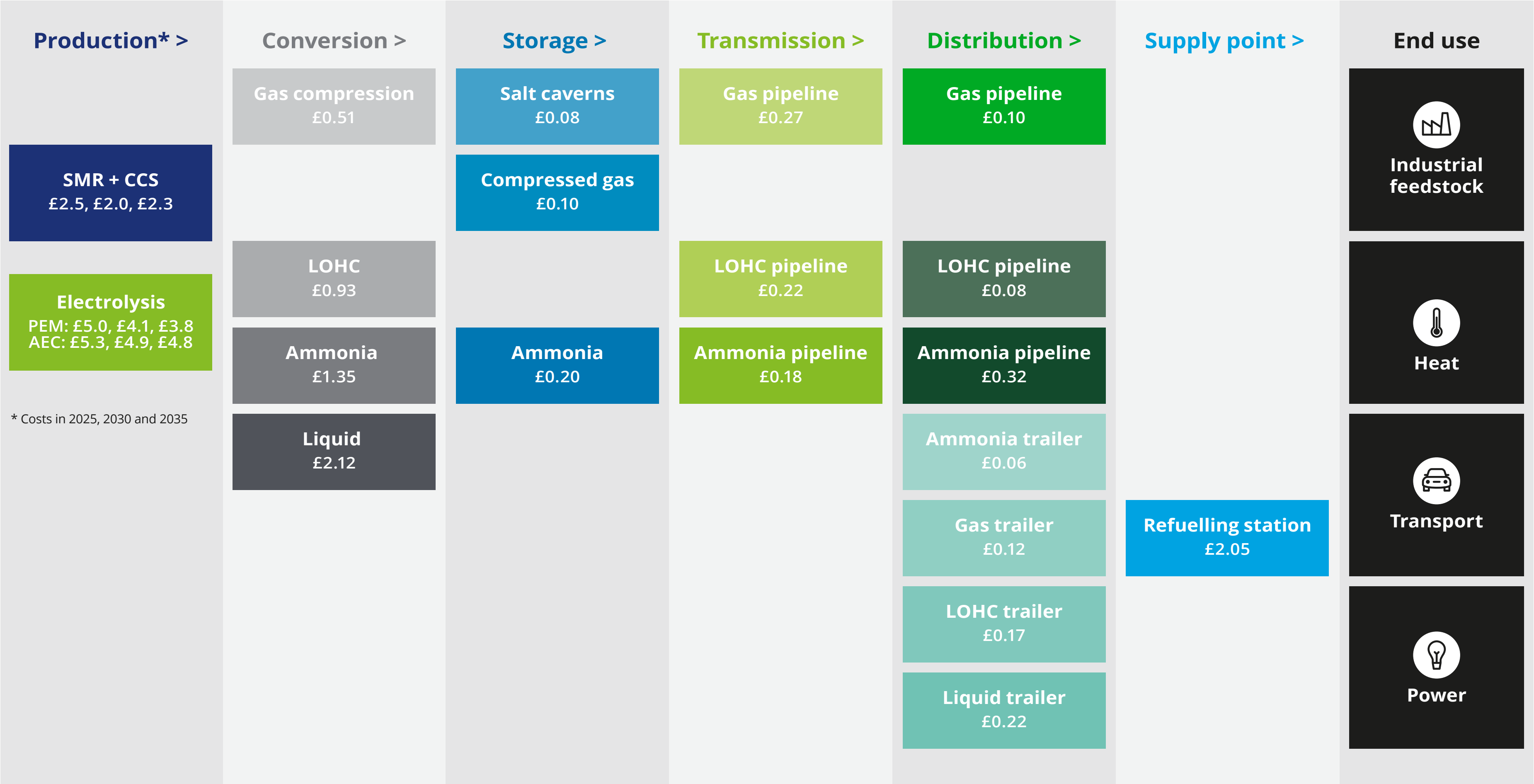
UK input data – either from actual or pilot projects – has been used for the model. Where UK data was not available, respected international sources were used.

Figure 5 provides a summary of the model's output in the Consumer Transformation – central hydrogen demand – scenario in each value chain segment. For production, forecast figures for 2025, 2030 and 2035 have been provided in the chart.

LCOH costs in the Steady Progression and System Transformation scenarios are covered in the following sub-sections along with implications for each value chain segment.

"The LCOH can be one of the metrics to assess the economics and commercial viability of a project or to understand its cost competitiveness compared with other energy sources or projects located elsewhere."

Figure 5. Summary of the Deloitte LCOH model's results in the Consumer Transformation scenario, £/kg



Source: Deloitte analysis

Our analysis does not offer a whole system analysis where cost reduction opportunities could be realised from integration of different energy systems. It also does not define what 'good' cost levels are as different stakeholders may have different criteria for success when evaluating investment opportunities in hydrogen. For example, some investors may solely focus on return on investment, while the national government may be considering other factors, including innovation, delivering energy system stability and flexibility, and supporting long-term strategic goals.

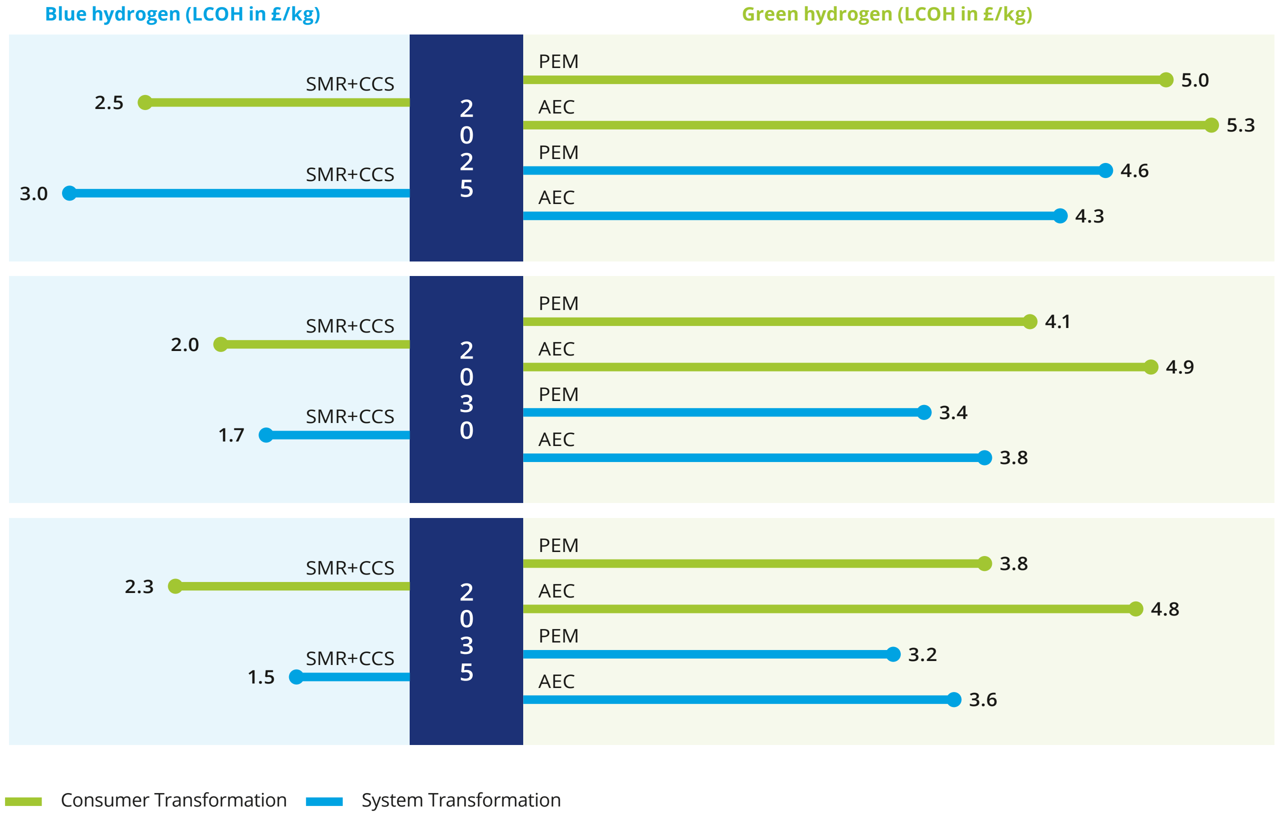
Hydrogen production: a major cost element

The costs of different hydrogen production methods vary widely due to factors such as technology and fuel costs, carbon tax and load factors and the volume of deployment. In the scenarios designed to meet net zero, hydrogen production costs are projected to range between £1.5/kg (SMR and CCS technology, System Transformation) and £4.8/kg (AEC technology, Consumer Transformation) in 2035 – see Figure 6.

Blue hydrogen is likely to be cheaper than green to 2035

Our model shows that blue hydrogen production is more cost-effective than green production in 2025. While the costs of SMR technology are well known, there are no CCS plants currently operating in the UK. Therefore, assumptions for the CCS element of our blue hydrogen levelised cost calculations have been based on the 'cost of CO_2 avoided' figures provided by the Global CCS Institute. SMR and CCS costs combined are still less than half the cost of green hydrogen production in 2025 – see Figure 6.

Figure 6. Levelised costs of hydrogen production technologies in the Consumer Transformation and System Transformation scenarios (£/kg)



Note 1: SMR – Steam Methane Reforming; PEM – Proton Exchange Membrane Electrolysis Cells; AEC – Alkaline Electrolysis Cells.
Note 2: Blue hydrogen production costs in the Consumer Transformation scenario appear to increase between 2030 and 2035. This is because the cost model is based on FES 2020's required new production capacity figures, which fluctuate between 2025 and 2050.
Source: Deloitte analysis

The UK has more than half a century of experience in using natural gas for heat and power generation. It relies on domestic resources from the UK Continental Shelf and imports both via pipelines and in form of liquefied natural gas from abroad. The country has developed a vast network of natural gas transport infrastructure and world-class supply chain to support the industry. Blue hydrogen would allow the continued use of most of this extensive infrastructure and the associated supply chain.

Depending on the scenario, blue hydrogen may make up a large proportion of hydrogen demand in the UK, which would help increase efficiencies in constructing and operating blue hydrogen production facilities. These factors, even with the addition of CCS/CCUS, keep blue hydrogen production in our model consistently cheaper than green to 2035 and beyond.

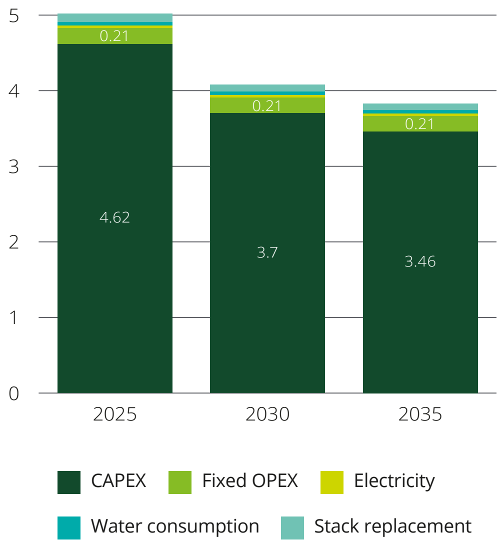
While the costs of all hydrogen production technologies are expected to decline over time, blue hydrogen production costs may reduce more rapidly in the System Transformation scenario, primarily due to its large deployment. Green hydrogen remains more expensive than blue to 2035 and beyond. See Figure 6, System Transformation scenario, £1.5/kg (SMR +CCS) vs £3.2/kg (PEM).

Blue hydrogen may not only appear cheaper on a unit-per-unit basis, but could also help the UK establish its hydrogen economy faster. It could help the country progress towards net zero while the costs of green technologies decline and provide an invaluable learning experience. On the other hand, green hydrogen can offer independence from natural gas, enable the storage of renewable electricity and help manage supply and demand in the power system, thus providing opportunities for cost savings elsewhere.

Reducing electrolyser costs and improving utilisation rates can lead to lower green hydrogen production costs

Green hydrogen production costs in Figure 7 are driven by capital expenditure (CAPEX), which is the cost of the electrolyser.

Figure 7. Breakdown of green hydrogen production costs (Consumer Transformation scenario, PEM, £/kg)



Source: Deloitte analysis

Electrolysers are expensive to manufacture. PEM technology, which is currently not deployed on a large scale, costs between £700/KWel and £1,050/KWel.[6] However, optimised, automated production and increased deployment could reduce costs to between £265/KWel and £620/KWel by 2050.[7] AEC technology is currently deployed on a larger scale and has significantly lower costs, between £530/KWel and £700/KWel.[8] This is expected to reduce to around £325-£590/KWel by 2050.[9]

Another factor that increases the electrolyser costs in the model is the utilisation rate: 50 per cent has been assumed as electrolysers in the model run on curtailed or low cost renewable energy. Improving the load factor would substantially reduce electrolyser operating unit costs. Electrolysers could run fully on dedicated electricity – for example from renewable electricity from offshore wind farms or nuclear power stations – if the hydrogen price was high enough to cover both the electricity generation and hydrogen technology costs.

The load factor also impacts electrolyser cost in another way: The higher the electrolyser utilisation, the larger the impact electricity price has on the total cost of production. As electricity costs vary depending on the market, so too will green hydrogen production costs. Markets with high levels of renewable penetration have favourable conditions for deployment of electrolysers, as the level of renewable output continues to increase and power prices are expected to decline.[10]

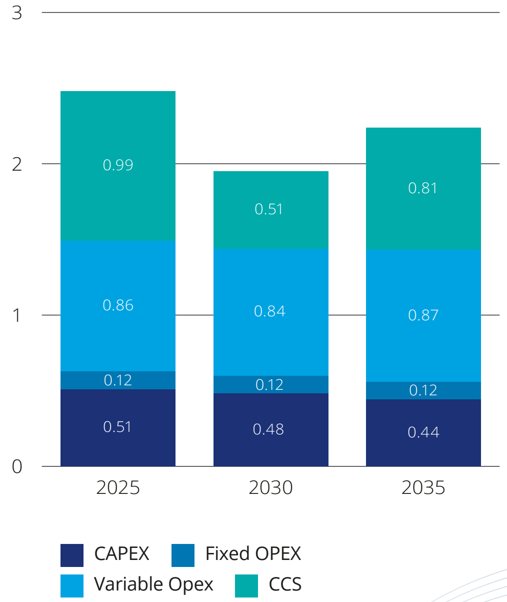
In terms of blue hydrogen production costs, the CAPEX in Figure 8 covers the cost of the facility that uses SMR technology, while variable OPEX costs are driven by the future price of natural gas. With large-scale deployment, innovation and more efficient supply chains, there is an opportunity to reduce CAPEX and CCS costs.

PEM electrolysers could achieve cost parity with blue hydrogen in the LCOH model in the Consumer Transformation scenario by 2035 if:

- Load factors rose to 98 per cent from the current 50 per cent assumption
- Electrolysers run on free curtailed renewable electricity constantly, compared to the currently assumed 35 per cent of the time [11]
- CAPEX reduced to approximately £340/KWel from the current cost of £700-£1,050/KWel by 2035.

While the combination of the above factors is unlikely to materialise in the near future, they can still be helpful in understanding the level of improvement needed in green hydrogen economics. On the other hand, green hydrogen may not need to achieve full cost parity with blue hydrogen for higher uptake, if there is sufficient market demand.

Figure 8. Breakdown of blue hydrogen production costs (Consumer Transformation scenario, £/kg)



Source: Deloitte analysis

"With large-scale deployment, innovation and more efficient supply chains, there is an opportunity to reduce CAPEX and CCS costs."

Investment between £3.5 billion to £11.4 billion may be required in production capacity alone by 2035 under net zero scenarios

Establishing a hydrogen economy will require substantial amounts of investment. According to our LCOH model, an investment of between £3.5 billion and £11.4 billion will be needed in SMR and electrolysis alone to support hydrogen demand by 2050.

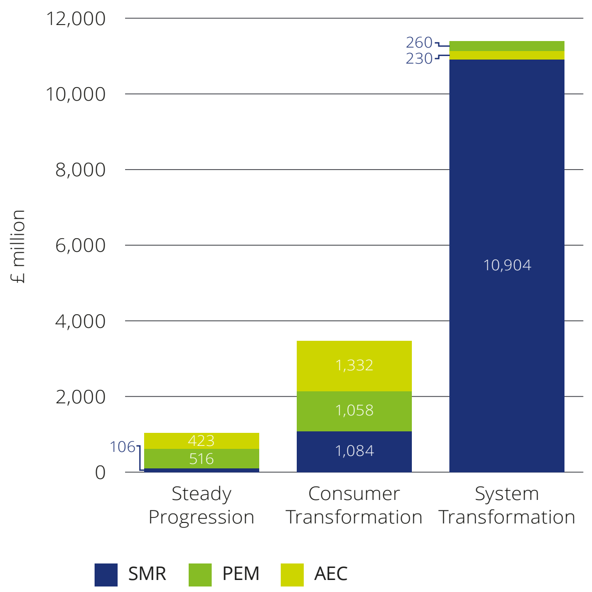
Although blue hydrogen is more cost effective on a levelised unit cost basis to 2035 in our model, investment in SMR technology is estimated to be approximately £10.9 billion in the System Transformation scenario where the projected hydrogen demand is much higher (see Figure 9). In addition to the SMR technology, further detailed modelling would be required to estimate the CCS investment costs, which are not included in the above £10.9 billion figure. While a full systems cost analysis was not conducted, it is likely that CCS and blue hydrogen would displace other technologies for decarbonisation.

As for green hydrogen, investment requirements under net zero scenarios range from approximately £0.5 billion to £2.4 billion by 2035. AEC technology costs appear to be higher because PEM technology has better potential for cost reduction over the next three decades.

The bottom line: achieving net zero will require a significant amount of investment, the majority of which will need to be made over the next decade. Not only are low carbon or carbon free hydrogen production costs currently higher than other low carbon energy production costs, there is also less certainty around future demand levels and applications of hydrogen that would give more clarity on investment needs for specific technologies.

However, there is an opportunity to reduce production technology costs over the next decade. This requires stimulating innovation and research, and establishing efficient manufacturing processes and supply chains to help

Figure 9. Investment requirements into new blue and green production capacity by 2035



Source: Deloitte analysis

reduce the costs of both electrolysers and blue production technologies. The renewables sector provides examples for significant cost reduction through improvements in technology and supply chains as well as successful policy support. According to the International Renewable Energy Agency, the cost of electricity from utility-scale solar photovoltaics declined by 82 per cent between 2010 and 2019, while onshore and offshore wind costs fell by 39 per cent and 29 per cent respectively in the same period.[12] However, as production technology CAPEX is expected to continue falling significantly, there is a need for targeted policy interventions, at least in the early stages of hydrogen development, to protect first mover investors from the risk of their projects becoming obsolete as technology costs fall.

Building CCS/CCUS facilities cost-effectively provides substantial opportunities for learning, while using existing oil and gas, as well as manufacturing supply chains, in the UK.

There is also considerable potential for the offshore oil and gas sector to repurpose some of its assets. Rather than being decommissioned, some platforms could be reutilised to support green hydrogen production using electricity from offshore wind farms, while some of the pipeline infrastructure could transport hydrogen onshore.

As mentioned earlier, policy work is already underway on assessing which business models should be used to support hydrogen production in the UK. The next steps include evaluating the shortlist of potential business models and choosing the right path to stimulate investment into hydrogen production.

The cost of converting, storing and transporting hydrogen

End-user costs for hydrogen rise rapidly if it cannot be used in a gaseous state close to where it is produced, but needs to be converted into another medium, stored or transported.

Currently, most hydrogen is used directly worldwide. A smaller proportion is compressed and stored as a gas in underground geological storage facilities, or pressurised gas tanks before being transported via pipelines or trailers to the end-users.

Hydrogen can also be liquefied and transported in cryogenic trailers to customers. Due to the high costs of the cryogenic containers and the energy needed to keep the hydrogen at low temperatures, hydrogen is usually not stored as a liquid in large quantities.

Hydrogen can also be converted into other chemical compounds. Of the options available, ammonia and liquid organic hydrogen carriers (LOHCs) are the most commonly considered. These can then be stored or transported as either compound via dedicated pipelines or trailers.

We assume that gaseous hydrogen pipelines, liquefied hydrogen, ammonia and LOHC trailers are the most likely to be used in the UK, and these are therefore examined in more in detail below.

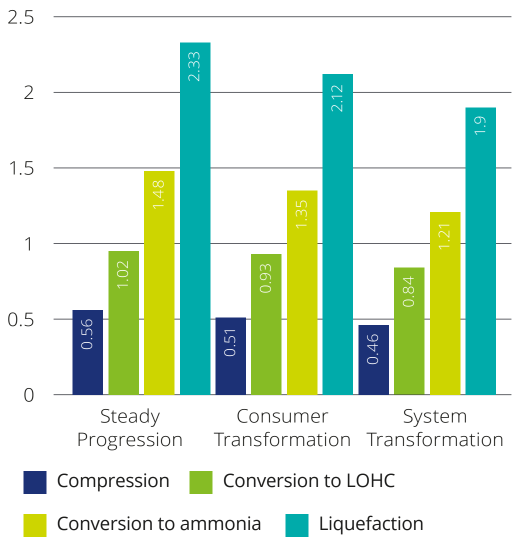
Conversion is potentially the second largest cost component in a hydrogen project

Any conversion treatment could considerably add to the cost of hydrogen. Increasing hydrogen's volumetric density is one of the main reasons for hydrogen conversion: the higher the volumetric density, the less space it will require for storage and transport.

Hydrogen is compressed before being pumped into underground facilities or transmission pipelines. Compression is the cheapest conversion treatment, adding an average of £0.5/kg to the cost across the three scenarios, according to the model (see Figure 10). However, at 40 kg/m^3 (at 700 bar pressure), compressed gas is the least dense by volume of the conversion options.[13]

Conversion to LOHC and ammonia are the second and third most expensive conversion treatments respectively, but both chemicals have higher volumetric density than

Figure 10. Compression, conversion and liquefaction costs (£/kg)



Source: Deloitte analysis

compressed gas.[14] Converting to LOHC adds an average of £0.9/kg to the levelised cost of hydrogen, while converting to ammonia adds an average of £1.4/kg.

Perhydro-dibenzyltoluene (PDBT) is one of the most well investigated LOHCs. PDBT has a volumetric hydrogen storage density of 64 kg/m^3.[15] LOHCs have several advantages, including reversible hydrogenation and dehydrogenation, the relative purity of hydrogen after dehydrogenation and non-toxicity. Their properties are similar to crude oil-based liquids (for example diesel or gasoline), therefore a mature supply chain already exists for their handling, storage and transport.

Ammonia has the highest volumetric density, at 123 kg/m^3 (at 10 bar pressure) of all forms of hydrogen carriers examined in this report.[16] As ammonia is a commonly used bulk chemical, it already has a mature and efficient supply chain. However, because of its toxicity, it requires handling by certified personnel. To save on reconversion (otherwise known as cracking), ammonia is also being proposed as an alternative fuel to hydrogen in high temperature fuel cells, internal combustion engines and gas turbines.

Liquefaction is the most expensive method because hydrogen has a low boiling point. The liquefaction process requires the use of liquid nitrogen to pre-cool hydrogen before it can be cooled further to -253°C. Liquefaction can add an average of £2.2/kg to the levelised cost of hydrogen.

Liquefaction and conversion/reconversion also result in energy losses, which are captured in the cost of conversion treatment.

The bottom line: conversion treatments are costly. Liquefaction, for example, can be more expensive per kilogram of hydrogen than production costs: in the System Transformation scenario the cost of blue hydrogen production in 2035 is £1.5/kg compared to £1.9/kg for liquefaction. Liquid hydrogen today is primarily used in specialist applications that need high purity hydrogen (for example as rocket fuel or in the chip making industry). However, demand for it may grow in the future as it is the proposed fuel in some fuel cell vehicle models.

There is an opportunity to reduce compression, conversion and liquefaction costs; indeed, innovation and research could result in substantial savings for the overall levelised cost of hydrogen.

The cost of storage

At present, there are no large-scale hydrogen storage facilities in the UK because demand and supply are closely aligned. However, as both the volume and the number of applications of hydrogen are projected to rise in the future, the volume and number of storage options will need to increase.

The appropriate storage option will depend on a number of factors, including the volume of storage needed, available geological options, duration of storage, required speed of discharge, purity of the hydrogen that the end-user needs and their location. The volumetric and gravimetric density of the various technologies can also be a factor in choosing one storage technology over another.

Considering the maturity and economic viability of the various storage technologies, our analysis has focused on storing and transporting hydrogen in pure and chemical forms. For a broad overview of the storage options see Figure 11.

Figure 11. Storage options and a selection of benefits and challenges

Storage form	Storage medium	Duration and size of storage	Benefits	Challenges
Gas	Salt caverns (up to 120 bar pressure)	Long-term/seasonal storage; large-scale storage solution	Large-scale storage option, low cost, high efficiency, lower CAPEX and OPEX costs than alternatives; low risk of contamination; usually operated as series of adjacent caverns, natural gas facilities can be converted gradually to hydrogen as demand increases	Limited by geographical availability; discharge rates may be reduced to avoid stress to cavity walls
	Compressed in large-scale storage tanks (350 to 700 bar)	Short-to long-term storage; small-to large-scale storage solution	High discharge rates make it suitable for applications where fuel needs to be readily available; better ability to control and maintain the stability of stored hydrogen and ensure its purity than geological storage	Higher costs than salt caverns due to the costs of container and compression
Liquid	Cryogenic tanks (cooled to -253 °C)	Medium-to short-term storage; small-scale storage solution	Higher volumetric density than gaseous compression, which makes it a suitable medium for transport and storage in limited space	Higher costs due to liquefaction costs, constant cooling and efficiency losses
Chemical	Ammonia tanks	Short-to long-term storage; small-to large-scale solution	Mature supply chain, regulated production, handling and transportation; higher gravimetric and volumetric hydrogen density than compressed gas or liquid hydrogen; it can be used directly in some applications	Higher costs due to conversion costs and efficiency losses, if reconversion is needed; toxic chemical, requires handling, transport and storage by certified personnel
	LOHC tanks	Medium-to short-term storage; small-to medium-scale solution	Liquid, therefore no cooling needed	Higher costs due to chemical conversion/reconversion costs; carrier molecules can be expensive, some options are toxic and can be flammable; after extraction carrier needs to be returned to chemical plant

Source: Deloitte analysis

Long-term, large-scale storage: salt caverns and compressed gas tanks are the most cost-effective options

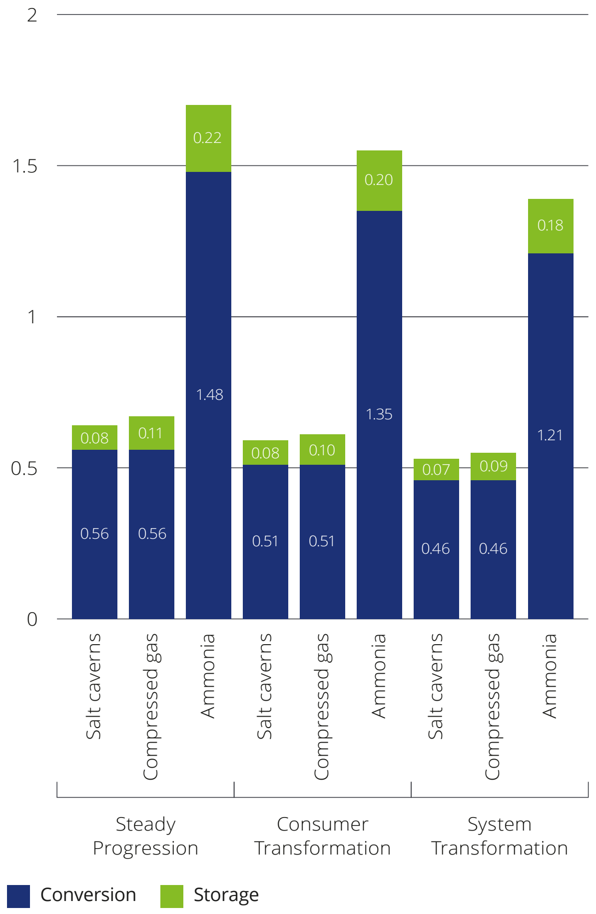
In a fully developed hydrogen economy, the UK is likely to need a substantial amount of hydrogen storage capacity. If hydrogen is used as the main source of heat – for example in the System Transformation scenario – then potentially large volumes of it will need to be stored cost-effectively seasonally or for strategic reasons. If hydrogen is used to store renewable electricity for the short, medium or long term, then again potentially large, relatively cheap storage facilities will be needed.

Figure 12 shows that salt caverns and compressed gas tanks are the most cost-effective ways to store hydrogen.

A number of salt caverns around the world have been storing hydrogen in large quantities for long periods without any major losses. Similar facilities could also be used in the UK to store hydrogen in large volumes, potentially for the heat and power generation sectors. However, their availability is limited by geography and they will need dedicated transport infrastructure to carry large volumes of hydrogen from the production to the storage facility and then on to end-users.

In the UK, four large salt deposits are currently being explored for their potential to store hydrogen in Teesside, East Yorkshire, Cheshire and under the East Irish Sea, with a total estimated storage capacity of 322 TWh.[17] While these four sites offer more than enough potential to accommodate all of the UK's hydrogen supply by 2050, there is significant uncertainty about their actual capacity until they are built.

Figure 12. Levelised cost of conversion and storage options in the UK (£/kg)



Source: Deloitte analysis

Compressed gas tanks have a number of advantages over salt caverns. They can be set up at a required location, independently from geological constraints. For example, they could be located near congested electricity grids where electrolysers generate hydrogen from curtailed electricity. They also have a better ability to control and maintain the stability of stored hydrogen and ensure its purity. Therefore, they could offer a cost-effective storage solution for the transport sector and be set up near locations of high demand such as hydrogen refuelling stations.

> "In a fully developed hydrogen economy, the UK Is likely to need a substantial amount hydrogen storage capacity."

The levelised cost of storing hydrogen in ammonia is more than twice that of storing it as compressed gas in the model, while liquid hydrogen and LOHCs appear to be prohibitively expensive. Therefore, we do not consider these latter two as economically viable larger-scale storage options. However, their cost may be justified for smaller-scale usage or where storage space is limited as their volumetric density is higher than that of compressed gas. It may also make more economic sense, for example, to store imported – low-cost, green – ammonia if it can be used in applications directly.

Bottom line: demand for both large-scale and smaller-scale hydrogen storage is expected to grow both in the UK and internationally. There are also substantial innovation and research opportunities to improve the costs of existing storage technologies and find new materials and methods for storing hydrogen.

Establishing large-scale underground storage facilities can take years. While technical studies are looking at the feasibility of identified sites, construction can only commence if the regulatory and legal elements are also put in place.

There are already a number of international companies providing chemical storage, however strengthening the UK supply chain will offer opportunities for other sectors – oil and gas or industrials – to participate.

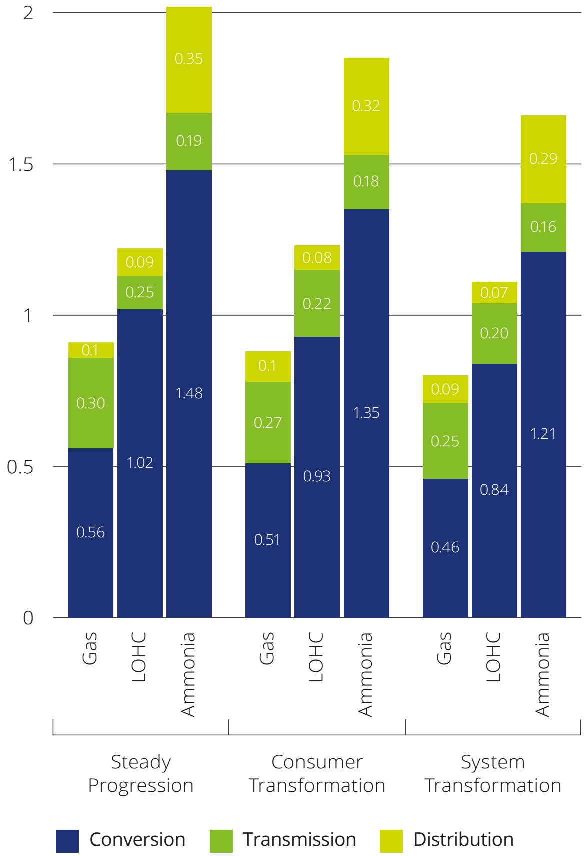
The cost of transporting hydrogen

Future demand in some sectors may require large quantities of hydrogen to be transported over long distances. The heat sector, for example, may need considerable volumes of hydrogen to be transported from production facilities to storage or directly to customers – both industrial and domestic – who may be dispersed over long distances. In other cases, for example in transport, hydrogen may be moved in smaller quantities over shorter distances. The methods and subsequently the costs of hydrogen transport will vary considerably according to the end use.

Large volumes and long distances: gas pipelines are the most cost effective option

Figure 13 shows that the most cost-effective way to transport hydrogen in large quantities over long distances is via gas pipelines.[18] The figure also shows that although LOHC pipelines would be cost competitive with gas on a levelised cost level, their advantage is lost due to the high conversion costs. In addition, the 'spent' LOHC material would need to re-transported to the production facility to be rehydrogenated, probably via parallel pipelines, further increasing the transport costs.

Figure 13. Levelised cost of conversion and storage options in the UK (£/kg)



Source: Deloitte analysis

If pipelines are used, hydrogen would be transmitted in a gaseous state in high pressure (40-80 bar) pipelines from production and potentially storage facilities to the low pressure (2-7 bar) distribution system that would deliver hydrogen to end-users.

The existing UK natural gas infrastructure includes 7,600 km of high pressure national and 12,000 km of local transmission systems.[19] While low percentage hydrogen can be injected into this network, tests are currently being carried out to assess the tolerance of the UK transmission system to pure hydrogen. Nevertheless, new dedicated high pressure transmission pipelines will also be needed to connect new production and storage facilities to the distribution system. The UK currently has 40 km of dedicated hydrogen pipeline networks that are operated by two chemical companies.

In addition to the transmission systems, the UK has 35,000 km of intermediate and medium pressure and 233,000 km of low pressure distribution systems.[20] In light of recent tests, the distribution systems can take on a higher concentration of natural gas/hydrogen blend.

Injecting hydrogen into the gas grid or fully replacing natural gas with hydrogen has multiple benefits:

- the majority of the existing gas distribution networks could continue to be used, subject to completion of the ongoing iron mains replacement programme
- the gas distribution network could serve as a storage medium for renewable electricity during times of low demand, thereby linking the electricity and gas grids and increasing the flexibility for both
- it is cheaper to transport hydrogen in large quantities via pipes than transporting the energy equivalent in electricity.

Figure 14. Hydrogen use in the distribution network

	Blending of hydrogen up to 20%	100% hydrogen in the network
Distribution networks	May not require major upgrades, but some modifications as well as increased maintenance and monitoring may be necessary	May require major upgrades, including the replacement of iron mains with non-corrosive materials (e.g. polyethylene). Increased maintenance and monitoring of leakage will be necessary
End-user appliances (heating and cooking)	No modifications needed to end-user appliances	Replacement or conversion of end-user appliances required

In the UK, hydrogen is already blended in the gas network up to the legal blending limit of 0.1 per cent. This limit will need to be raised to allow higher volumes of hydrogen to be blended into the network, as is the case in other European countries.

Injecting hydrogen at low concentrations (up to 20 per cent – equivalent to six to seven per cent on an energy basis) into the gas grid may not require major modifications to the infrastructure and would cause no disruption to customers.[21] Research is underway to understand the impact of injecting hydrogen into the grid at various concentrations (up to 100 per cent) on safety and operations of many parts of the hydrogen lifecycle, especially on gas turbines, compressor stations and most of the end-user applications. Blending at concentrations above 20 per cent will likely require substantial changes to existing infrastructure and end-user applications, such as boilers and cookers. In the UK, this can mean the upgrade or replacement of tens of millions of appliances in people's homes and businesses. Figure 14 summarises potential grid decarbonisation routes with hydrogen.

In both FES 2020 scenarios designed to meet net zero which we adopted for cost modelling purposes, the distribution network would be fully converted to hydrogen by 2050 where hydrogen is used for heat.

Multiple pilot programmes in the UK are looking at establishing the distribution network and end-user equipment tolerances to higher blending fractions. These include HyDeploy, HyNET, H100 and H21. In addition, the UK Health and Safety Executive runs the long-term Iron Mains Risk Reduction Programme to address the risk of failure of iron gas mains in the gas grid. The Programme, which is expected to be completed by 2032, replaces the iron mains with polyethylene pipes that are capable of accepting 100 per cent hydrogen.

Hydrogen demand in residential buildings will depend on a number of factors, such as the existing natural gas infrastructure, the building's overall energy needs, as well as safety considerations, costs and customer acceptance.

The bottom line: A number of regulatory issues will need to be addressed before hydrogen can play a larger role in the UK industry and energy sectors. Initially, these should focus on making blending safe, but with the ultimate goal of fully converting the transmission and distribution grids from natural gas to hydrogen over time.

In addition to assessing the transmission and distribution systems' tolerance to higher levels of blending or full conversion to hydrogen, some new hydrogen transmission and distribution infrastructure might need to be built to connect new production and storage facilities with end-users.

The distribution grid's ability to accommodate hydrogen also needs to be proven definitively to ensure that hydrogen can be used as safely, if not more safely, than natural gas. Standards and procedures for operations and maintenance for blending or full hydrogen conversions need to be updated and potentially new odorants, leak detection and emergency response methods need to be developed.

In people's homes and businesses, safe limits need to be established for hydrogen in existing gas appliances. New, hydrogen-compatible appliances will need to be developed, approved and fitted, or existing ones retro-fitted. Appropriate metering and billing methodologies will also need to be developed.

The construction of transmission infrastructure and potential upgrades to the distribution grid can provide excellent opportunities for oil and gas and manufacturing supply chains in the construction of pipelines, compressor stations and end-user appliance upgrades.

"A number of regulatory issues will need to be addressed before hydrogen can play a larger role in the UK industry and energy sectors."

Smaller volumes and shorter distances: trailers may be more suitable, albeit at a higher cost

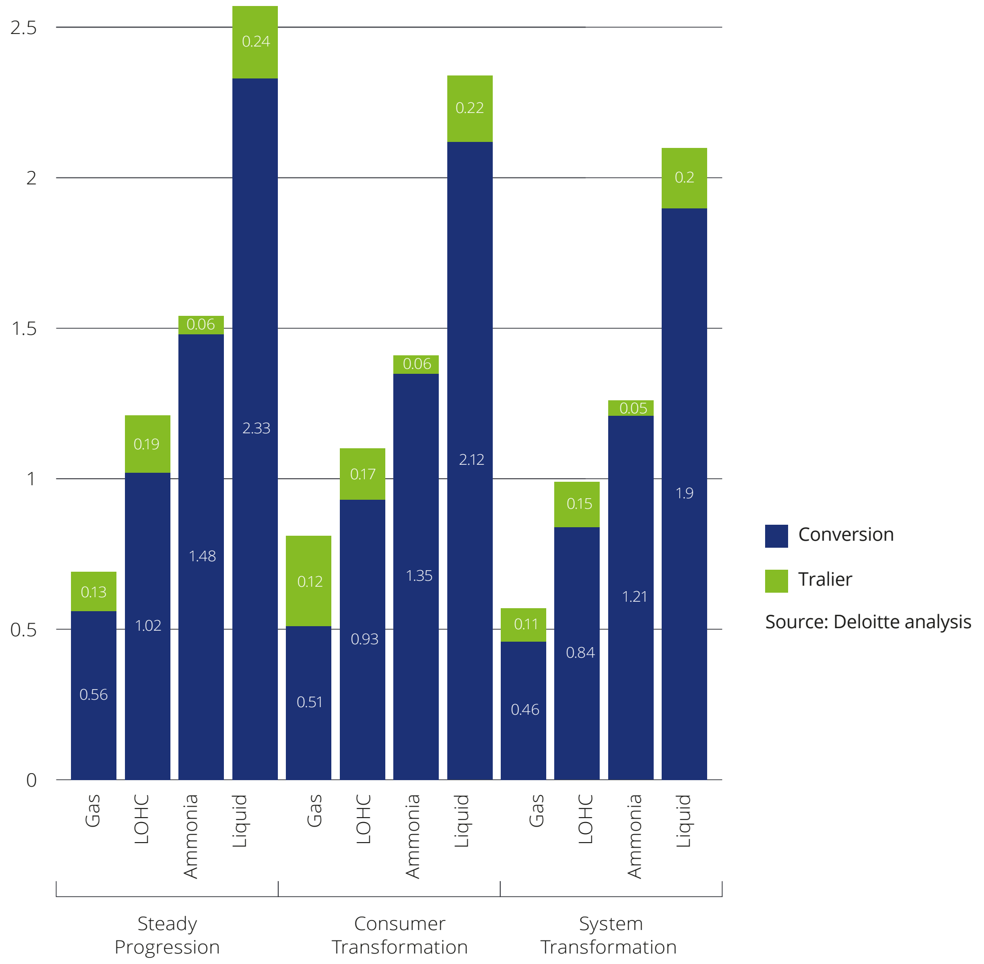
Trailers are likely to distribute hydrogen to customers in smaller quantities and over shorter distances than via pipelines. Such customers may also have limited storage space or need high purity hydrogen that is easier to control in trailers than in pipelines. The transport sector, some industrial customers, or parts of the power sector are likely candidates to use trailers for hydrogen deliveries.

Figure 15 shows that ammonia trailers are the least expensive, with liquid trailers the most expensive trailer transport methods.

A number of criteria will determine in what state hydrogen is going to be delivered, including its end use, the volumetric density of the carrier, the costs of conversion and transport or a combination of these factors. If ammonia can be used directly in some applications, it might be the preferred transport method given its high volumetric density and low transport costs. But, if hydrogen needs to be extracted from it, ammonia is likely to be transported to a central location to be cracked. Similarly, hydrogen will need to be extracted from LOHC – probably in a central facility – before it can be used and the spent material sent back for rehydrogenation. Hydrogen would then be transported to the final customer in a gas or liquid format.

As previously discussed, volumetric density can be another factor in making a selection among the available transport methods: the higher the volumetric density of the transport medium, the smaller the trailer needed to carry the same quantity (kilogram) of hydrogen (see Figure 16).

Figure 15. Levelised cost of hydrogen trailer distribution (£/kg)



Source: Deloitte analysis

On a volumetric basis, one kilogram of ammonia can carry three times the weight of hydrogen per volume as compressed gas (at 700 bar pressure), but the choice will depend on a number of parameters. For example, can ammonia be used directly or does it need to be transported elsewhere to be cracked? While liquid hydrogen is nearly twice as dense as gaseous hydrogen, liquid trailers are at least three times more expensive than compressed gas trailers on a levelised cost basis and liquefaction is also the most costly of the conversion methods.

Figure 16. Volumetric density of select transport methods

	Volumetric density
Compressed gas	40 kg/m³ (at 700 bar pressure)
LOHC (PDBT)	64 kg/m³
Liquid hydrogen	70 kg/m³ (at 1 bar pressure)
Ammonia	123 kg/m³ (at 10 bar pressure)

Source: Large-scale storage of hydrogen, J. Andersson, S. Grönkvist, 2019.

Refuelling stations – Refuelling station costs can add considerably to the final levelised cost of hydrogen – somewhere between £1.85/kg and £2.26/kg (see Figure 17). For example, in 2035 in the Consumer Transformation scenario, refuelling station costs can reach as much as £2.05/kg, which is nearly half the cost of producing green hydrogen with PEM electrolysers (£5/kg).

Figure 17. Levelised cost of refuelling stations (£/kg)

	Steady Progression	Consumer Transformation	System Transformation
Refuelling stations	£2.26/kg	£2.05/kg	£1.85/kg

Source: Deloitte analysis

Refuelling station costs are highly dependent on utilisation rates. Therefore, initially, it will be easier to make the business case for back-to-base refuelling stations with concentrated demand or for locations close to interchange hubs, depots or ports, rather than building refuelling stations for the general public.

The bottom line: government support will be crucial for hydrogen deployment in the transport sector. This would include a number of well-timed measures to ensure investment:

- engagement with and brokering support from a wide range of industry stakeholders to facilitate business plans
- public funding of refuelling stations – initially for captive fleets to reduce underutilisation
- supporting research and development of fuel cell research
- fast-tracking approval and construction of infrastructure.

Future development of the hydrogen refuelling station network in the UK could differ substantially from the development of the electric vehicle charging infrastructure. Hydrogen refuelling stations typically require a high pressure storage system and one or more dispensers as a minimum. If hydrogen is delivered to the station in a liquid state, it will also need a precooling and a compression system to bring the hydrogen to the desired gas pressure level. With the market for these components currently limited, refuelling station set up costs are typically considered higher than those of electric charging stations.

How does it all fit together?

The first part of this section explained the individual cost elements of the hydrogen value chain. But what impact does the final use of hydrogen have on production, transport and storage? We will look at these now before creating sets of illustrative cost pathways for hydrogen by end-user.

What hydrogen is used for and how much of it is consumed will determine how hydrogen is produced, how much needs to be stored and transported, and what method of transport will be used.

Figure 19 brings together the cost elements with the implications described in Figure 18 for the hydrogen value chain and demonstrates how the different cost components could contribute to the final levelised cost of hydrogen. The various cost pathways have been based on the needs and characteristics of each user group and illustrate the potential end-user cost.

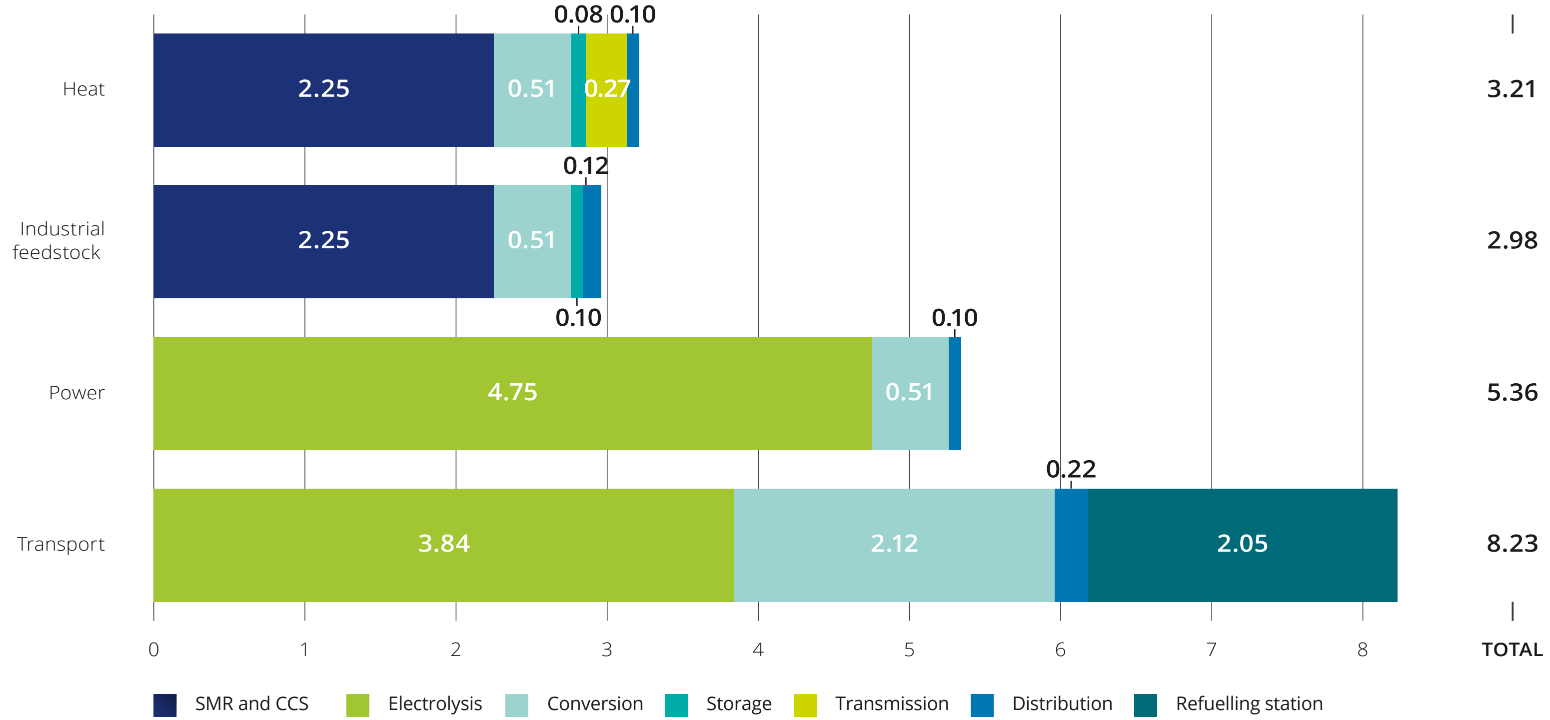
The figure shows that three cost elements can have a major impact on the levelised cost of hydrogen: production technology and conversion for all industries, and refuelling stations for transport in particular. Cost reduction in any and all of these components therefore will have a vastly beneficial effect on overall levelised costs.

Figure 18. Implications of end-use for production, transport and storage

Applications	Implications for production	Implications for hydrogen transport and storage
Industrial feedstock and beyond	Blue hydrogen will most likely be required	• In the UK currently the vast majority of hydrogen is used by refineries and is grey, which is most likely to be substituted with blue hydrogen. This is because the projected demand is large. In addition to demand from refineries, any production plant will aim to provide hydrogen to nearby industrial and domestic customers in heat and potentially power applications. • The Deloitte LCOH model also suggests that blue hydrogen will be more cost effective through to 2035, which will position it strongly to displace grey hydrogen. • Therefore, a number of SMR facilities may be established with CCS at centralised positions near refineries to capture demand from a wider region. • Given the large volumes, it is likely that dedicated, large-scale storage and transportation infrastructure will be required.
Transport	Green hydrogen will most likely be used as fuel cells require high purity hydrogen. SMR with CCS is also possible, but hydrogen may require further purification, adding to costs	• There is a potential to build decentralised green production facilities. Wind/solar farms and electrolysers may be located relatively close to demand centres to minimise transport and storage costs. • Given that demand centres will be located in densely populated areas, the use of small-scale transport and storage of hydrogen is likely to be needed. • To increase the volumetric density of the transported hydrogen, conversion/liquefaction is likely to be needed. • The number of refuelling stations will also need to increase.
Power	Blue or green hydrogen	• Electrolysers located near offshore or onshore renewable power generation facilities or congested grid can generate hydrogen from curtailed or low cost electricity. • Application of hydrogen could be twofold – as a medium to store surplus renewables using electrolysis, or as a fuel for gas turbines. • Power plants fully running on hydrogen could purchase either blue or green hydrogen from third parties – either from UK producers or from future international markets. For imports, an international market will need to developed, based on certificates of origin. • These plants will require dedicated large-scale transport and storage facilities.
Heat	Mostly blue hydrogen will likely to be used for full hydrogen conversion or blending	• If hydrogen replaces natural gas for heat, demand will be large. The UK is likely to continue using natural gas from the UKCS along with the existing natural gas import infrastructure as long as possible. These factors suggest that blue hydrogen may be used as far ahead in the future as economically possible. • Large swings in seasonal demand will require large-scale storage – although the pipelines themselves also provide a level of storage. • Extensive use of hydrogen in heat will aim to rely on existing transmission and distribution systems, but some new pipelines will inevitably need to be constructed to connect new production and storage facilities.

Source: Deloitte analysis

Figure 19. An illustrative view showing the cost elements of the four hydrogen end-user groups (Consumer Transformation scenario, 2035, £/kg)



Heat: SMR and CCS, gas compression, storage in gas salt caverns, pipeline transmission and distribution
Industrial feedstock: SMR and CCS, gas compression, compressed gas tank, compressed gas trailer
Power: AEC, gas compression, compressed gas tank
Transport: PEM, liquefaction, liquid trailer, refuelling station

Source: Deloitte analysis

Finally, Figure 20 provides broader consideration as well as policy implications for each application.

Figure 20. Implications for end-user applications

Source: Deloitte analysis

Applications	Wider considerations	Policy implications
Industrial feedstock and beyond	• UK refineries are the obvious places to start establishing demand for blue hydrogen as they already use large volumes of hydrogen. They also play an important role in regional economies and exist in geographical proximity to other energy intensive industries. • The CCS infrastructure, which supplies industrial customers with blue hydrogen would also be able to capture emissions from other nearby industrial customers, providing opportunities to spread some of the investment costs and risks. • Accelerating the deployment of hydrogen and CCUS through industrial hubs would build on existing skills, support regional economies and help develop new products using hydrogen and carbon dioxide.	• There is a need for policy interventions – the most obvious would be further increasing the price of CO_2 to facilitate a switch over to blue hydrogen. • To meet its net zero target, the government has decided to take a cluster approach to decarbonising industry. As cluster approaches will rely on managing and coordinating multiple organisations and rollout of infrastructure, swift progress will need to be made to provide clear financial incentives and regulatory guidance. • To this end, the government announced £170 million in funding for deploying both hydrogen and CCS in industrial clusters in July 2019. Later in the year a CCS Infrastructure Fund (confirmed in the March 2020 Budget) was announced to help develop at least two CCS industrial clusters. The government has also consulted industry on potential business models for CCUS.
Transport	• Battery electric vehicles (BEVs) are expected to be more popular for passenger vehicles. Initially the uptake of fuel cell electric vehicles (FCEVs) is likely to be higher in the medium and heavy duty vehicle transport segments. Trams, railways, buses and coaches may also opt for FCEVs because of their reduced refuelling times and long ranges. • High upfront costs of FCEVs and limited refuelling infrastructure in the UK hinder the more rapid adoption of hydrogen in the transport sector. • As the transport sector is likely to use green hydrogen, transported in trailers compressed or liquefied to a refuelling station, cost reduction in any of these value chain components will have a substantial impact on the final levelised cost of hydrogen at the pump.	• Initially, public funding may be required to support business models for adopting FCEVs in the heavy duty and public transport segments. • There will also be a need for public funding to support the building of refuelling stations. • There is also a need to consider the wider impact on consumer acceptance of fuel cell mobility in the UK.
Power	• While hydrogen is unlikely to play a dominant role as a fuel source in power generation, it can contribute substantially by providing stability and flexibility to the energy system and can result in revenue streams associated with price arbitrage, ancillary services and well as selling hydrogen to an off-taker. • To capture power sector revenue streams, electrolyser capital costs need to reduce, electricity price volatility needs to increase and gas turbine technology for burning hydrogen also needs to improve to help improve power sector revenue streams from hydrogen. • These possible revenue streams may open up new business lines for existing utilities or potential new players and investors.	• Long-term incentives will need to be developed to scale up blue and green hydrogen production and increase its competitiveness within the power sector so that potential revenue streams can be unlocked. • Such long-term incentives may require government support in the form of investment or a regulatory framework (for example a CfD-based model or other schemes to ensure price and revenue certainty).
Heat	• Hydrogen blending or full hydrogen use in the gas grid will require substantial capital investments, which could lead to higher consumer prices and result in disruption for customers while infrastructure and end-use appliance upgrades take place.	• The UK will need to take clear national strategic decisions to help deliver economies of scale in decarbonising residential heat. • There is also a clear need for government to coordinate heat strategy on a regional and national level to facilitate closer collaboration between investors and industry, and ensure close engagement with consumers. • Technical standards for hydrogen blending will need to be updated allowing higher levels of hydrogen in the gas system.

Making hydrogen more attractive to investors

Investors are used to dealing with some degree of uncertainty. However, the challenges relating to climate change and how to reach net zero require a more coordinated approach across government and businesses to provide greater certainty that there will be demand for hydrogen and investments will earn a return. This report has highlighted a number of factors that make this need for clarity even more important given:

- the scale of investment needed over the next 20-30 years
- the need to stimulate innovation and research, with the aim of reducing costs for hydrogen production, in particular for green and blue hydrogen
- the integrated nature of hydrogen, which can bring together previously distinct energy demands in the economy (electricity, heat, industry and transport), meaning a greater need for integration and coordination
- the potential to repurpose existing assets and the transition process required to move away from fossil fuels to zero carbon energy sources, which will affect everyone.

Government to date has developed decarbonisation policies and support frameworks that are largely technology neutral, and allow the market to decide which technology is best to meet specific objectives. However, given the scale of the challenge to meet net zero, a more targeted and focused set of interventions are likely needed to make hydrogen more attractive to investors.

National hydrogen strategy

Scenarios developed since the UK's commitment to net zero highlight that there are various pathways to reach net zero by 2050. These scenarios recognise that hydrogen will play an important part in the future energy mix to meet that target. Where scenarios differ is in the scale and applications for the use of hydrogen in the economy. Therefore, there is uncertainty around the speed and overall volume or demand required.

The development of a UK hydrogen strategy could be a useful way of providing greater certainty to investors around the commitment to use hydrogen in the future. It could be linked to a roadmap for the applications, regulations and support mechanisms necessary to develop options for the UK's energy transition. The strategy should be co-developed with industry and reviewed periodically to ensure that it remains relevant and takes into account progress over time. It will also need to recognise the interdependencies with other policies, in particular around the growth of renewable electricity generation and the development of carbon capture, usage and storage.

Short- to medium-term funding support to reduce risk and stimulate innovation

The costs associated with producing green and blue hydrogen are high relative to other sources of low carbon energy. There are also a number of risk factors, including the risk of technology failures and cost overruns as there is limited experience in the large-scale deployment of some of the technologies; there is also a high risk of technology obsolescence for first mover investors as technology costs decline; in addition, there is a lack of clarity on risk allocation between investors and consumers/taxpayers.

As with renewable sources for electricity, investors will require additional funding to cover these higher costs and risks in the initial stages of development of hydrogen solutions until they reach scale, efficiency and maturity to compete against other technologies. Policy schemes, such as CfDs or regulated asset based models can be used to provide greater certainty to investors across various parts of the hydrogen supply chain and to stimulate innovation and research to help integrate different energy systems and to provide a system-wide view of hydrogen's role.

By providing revenue certainty, the government could help attract significantly lower cost of capital for hydrogen and reduce its overall levelised costs, similar to what has been achieved in the offshore wind and wider renewable power sectors. In addition, revenue certainty will be critical for green hydrogen production for attracting investors and managing risk of obsolescence faced by first mover investors as electrolysis technology costs are rapidly improving. The potential options for additional financial support could be developed as part of the roadmap and hydrogen strategy.

A commitment to support these innovation and research will give investors confidence on the future role of hydrogen and support the UK in developing its own capability.

Coordination role

Hydrogen is expected to play a part in a number of areas of the economy. Historically, such areas (upstream oil and gas, electricity generation, natural gas for heating, fossil fuels for transport) have developed largely independent of each other. In the future, greater coordination and collaboration across different companies and stakeholders will be needed to achieve the best outcome. While this can often be achieved in relatively small geographical locations or clusters, where the objectives of different parties are aligned, it is more challenging at a regional and national level. Therefore, the government should consider the need for some form of coordination role, possibly linked to the national strategy, that could facilitate greater cooperation between different parties, in particular where interests may not be fully aligned. This coordination should also extend to areas such as regulations and standards given the interlinkages with transport, gas networks and CCS.

Regulation and standards

Work has already begun around technical standards and regulation required for the development of hydrogen. In particular, safety aspects need to be covered to assure end users that it can be used in an equal or safer way than existing fossil fuels. Hydrogen is already used in a number of industrial processes, but additional regulations and standards are needed for it to be used in the future in other applications, such as space heating. An initial step could be around allowing for blending of hydrogen and natural gas. This could be complemented with the introduction of minimum standards for new equipment (such as boilers) to make them 'hydrogen-ready', allowing for minimal conversion costs in the event that 100 per cent hydrogen is to be used for space heating.

Considering the size of the challenge and the urgency to make decisions, investors need to be confident that there will be sufficient demand for low carbon or carbon-free hydrogen – and that they will see a good return on their investments.

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9. Ibid.
10. When renewable energy output is greater that demand, the wholesale price will decline or even fall to zero. This phenomenon is also known as price cannibalisation.
11. Based on 50 per cent load factor, we assumed that electrolysers run on curtailed – that is, free – electricity 70 per cent of the time. This would mean that the proportion of free electricity goes up from 70 per cent to 100 per cent.
12. Renewable power generation costs in 2019. International Renewable Energy Agency 2020. See also: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Jun/IRENA_Power_Generation_Costs_2019.pdf
13. Large-scale storage of hydrogen, J. Andersson, S. Grönkvist, 2019.
14. Ammonia and LOHC conversion costs also include reconversion to hydrogen, but LOHC costs do not include disposal or return trip to chemical facility for rehydrogenation.
15. Large-scale storage of hydrogen, J. Andersson, S. Grönkvist, 2019.
16. Ibid.
17. Element Energy, 2018, and Deloitte analysis. See also: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/760479/H2_supply_chain_evidence_-_publication_version.pdf
18. The levelised transmission and distribution pipeline costs include building, maintaining and operating the pipelines over a period of 40 years.
19. H21 North of England, 2018. See also: https://www.h21.green/wp-content/uploads/2019/01/H21-NoE-PRINT-PDF-FINAL-1.pdf
20. Ibid.
21. Hydrogen from renewable power: Technology outlook for the energy transition, International Renewable Energy Agency, 2018.

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Please request a briefing session if you would like to discuss this analysis – or the broader topic of energy transition – in more detail with our team.

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