GAS GOES GREEN

Hydrogen: Cost to customer

May 2020

DELIVERING THE PATHWAY TO NET ZERO

Contents

Executive Summary

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Introduction

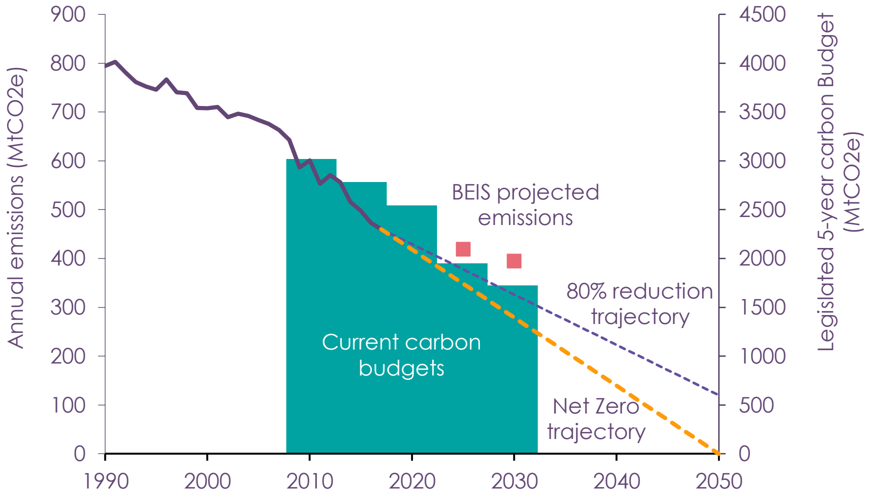
Role for hydrogen

In June 2019 the **UK Government** committed to a Net Zero emissions target, which is accelerating the decarbonisation of the UK economy. Achieving Net Zero will require fundamental changes across all sectors of the economy, with hydrogen increasingly fulfilling energy demand across UK power, heat and transport.

In its recommendations on how to achieve Net Zero, the **Committee on Climate Change** has recognised the significant role hydrogen should play in meeting this target. In their "Hydrogen in a low carbon economy" report, they found that "*hydrogen could replace natural gas in parts of the energy system, where electrification is not feasible or is prohibitively expensive, for example in providing heat on colder winter days, industrial heat processes and back-up power generation*."

In their 2020 Net Zero report, the **National Infrastructure Commission** (NIC) conclude that a highly renewable power system, combined with flexible technologies including hydrogen powered generation, could be substantially cheaper than alternatives.

Carbon emissions for Net Zero in 2050



With stated ambitions for power and transport, the question remains as to how the UK will meet the challenge of decarbonising the heat sector. Hydrogen stands ready as a deployable technology to integrate power and transport decarbonisation with a readily deployable solution for heat.

According to a recent study by the **Leeds Sustainability Institute**, hydrogen receives indicative support from energy customers, who were generally willing to accept a moderate increase (presented as 7%) in their gas bills to support this conversion.

Taken together, these reports demonstrate that the hydrogen debate has now moved on from establishing whether there's a need for hydrogen in a Net Zero economy, with the discussion now focused on how to unlock its potential.

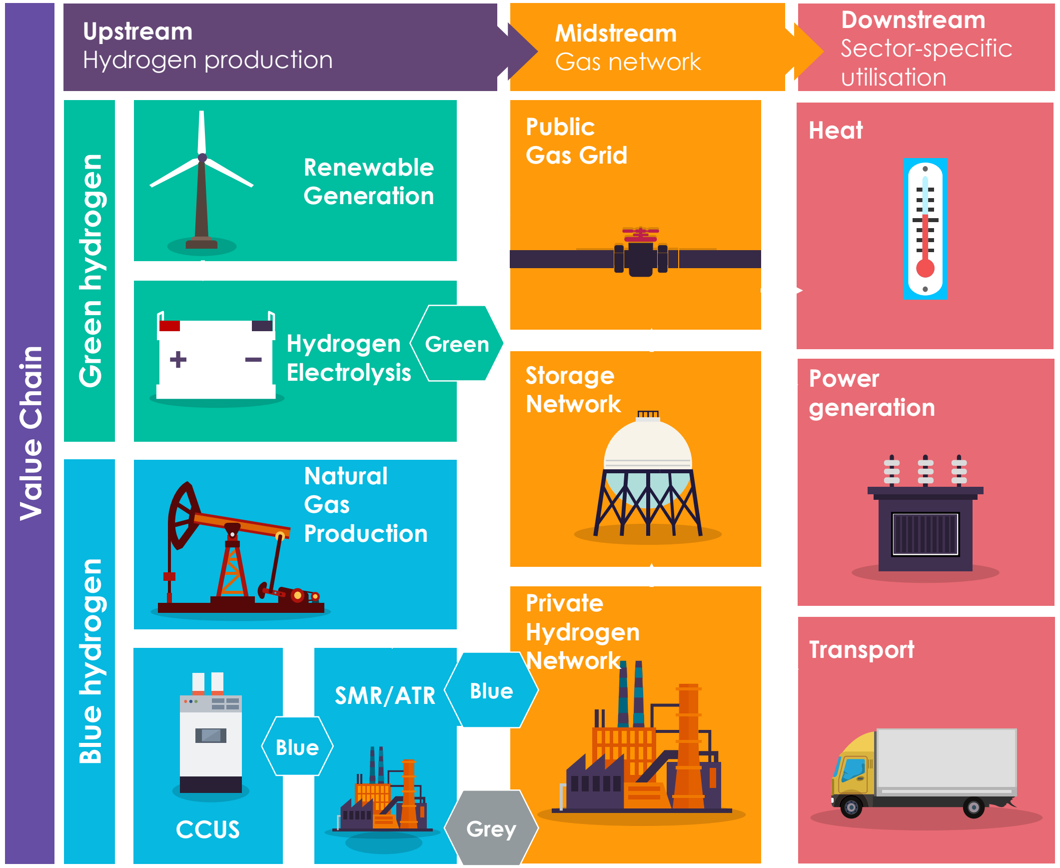
Background

In 2019, the Energy Networks Association (in collaboration with all gas distribution/transmission network operators) engaged Navigant to undertake an independent, academic-reviewed assessment of gas decarbonisation pathways and their cost impacts.

The 'Pathways' report presents a pathway through to Net Zero by 2050 showing that if more low carbon and renewable gases are used along with further electrification, this has the potential to save around £13 billion a year compared to a pathway that relies on electrification alone.

Whilst developed independently of Navigant's work, this report represents the logical next step, which is to determine the level of support required to develop a hydrogen economy.

Specifically, this GGG report sets out analysis relating to upstream (production), midstream (transmission and distribution) and downstream (heat, power and transport) costs of establishing a hydrogen economy, now through to 2050. It focuses heavily on determining production volume and cost forecasts for both blue and green hydrogen, taking account of technology developments, potential uptake rates, supporting markets and emissions trajectories.



Key Takeaways

1 **Hydrogen is an essential component of the UK's future Net Zero economy**

There is no realistic scenario whereby the UK is able to achieve Net Zero carbon emissions by 2050 without Blue and Green hydrogen playing a key role in the decarbonisation of large emitting sectors such as industry, transport, power and heat. Today, the UK is exceeding a Net Zero aligned trajectory for gas emissions by the equivalent of 170TWh of natural gas consumption in CCGTs. The UK's gas emissions could be realigned with a Net Zero trajectory in 2025 if capacity is deployed to provide 110TWh of hydrogen from combined blue and green production in that year.

2 **Blue hydrogen is the gateway for Green hydrogen**

Our analysis shows both Blue and Green hydrogen will be required to meet the UK's energy needs in 2050. Meeting the UK Government's target of having one CCUS project operational by 2025, with further roll out to 2050, is key to the deployment of cost-effective Blue hydrogen. This will allow for rapid decarbonisation which will continue to deliver low carbon heat through to 2050. Meanwhile, Green hydrogen is expected to become cost-competitive with natural gas by 2030 if investment into its uptake is made now.

3 **Prompt investment will unlock £89bn of net savings, in addition to the economic value to UK Plc. of a domestic hydrogen industry.**

By 2050, the £182 billion investment required to convert the UK's hydrogen infrastructure will have delivered a net benefit to customers of £89 billion.

The sooner investment is made into critical hydrogen infrastructure, the greater and more timely the return on investment would be to the UK Government. Our analysis shows that at a system level, with investment beginning today, the UK would start to see returns on its investment before 2045. Stimulating jobs and investment into a domestic hydrogen supply chain now, could crystallise GVA for UK Plc. by promoting the development of a world-leading hydrogen industry within the UK, mirroring or surpassing the success seen in the offshore wind sector.

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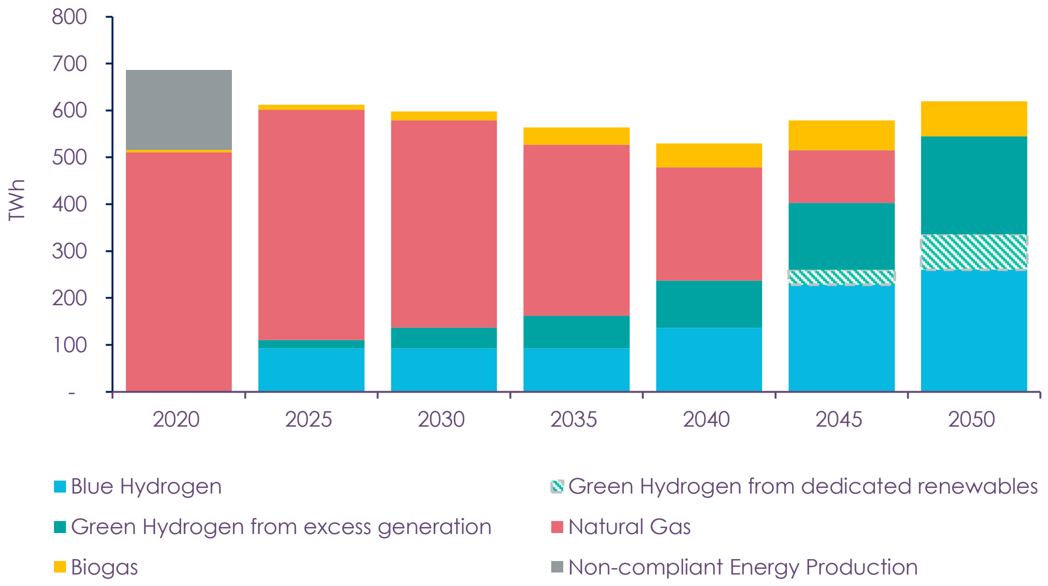
Key takeaways

1 Hydrogen is an essential component of the UK's future Net Zero economy

- Based on the Navigant Pathways report, the UK is currently unable to meet a Net Zero compatible trajectory for gas demand in 2020, falling short by 170TWh per annum.
- 110TWh per annum of hydrogen is required to meet a Net Zero trajectory in 2025 with Blue hydrogen making up the majority of hydrogen production at 92TWh per annum.
- Green hydrogen is projected to play a significant role in achieving Net Zero, starting by 2025 and growing to up to c.280TWh per annum by 2050 through a combination of generation from excess renewable power and dedicated renewables build out.
- Green hydrogen is unable to meet 2050 gas demand in isolation, due to limitations of renewable generation capacity build out, even accounting for dedicated renewables being built out especially for hydrogen production.
- Therefore we anticipate a sustained requirement for blue hydrogen to meet Net Zero requirements throughout the period, which grows to make up 43% of demand from the gas grid in 2050.

Gas Production Profiles



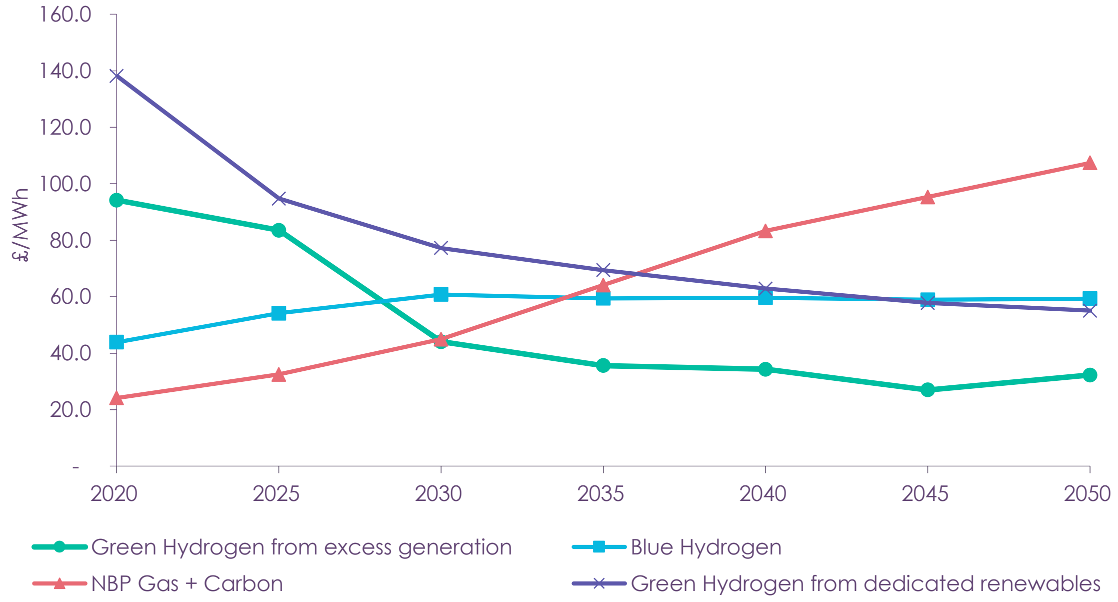
Sources: National Grid FES, Exelon, BEIS, Navigant, CCC

Key takeaways

2 **Blue hydrogen is the gateway for Green hydrogen**

- Blue hydrogen is currently the cheapest form of hydrogen at £43/MWh. However, this is still 79% higher than the NBP gas + carbon price driven primarily by conversion efficiency from gas to hydrogen and CCUS costs.
- Green hydrogen produced from excess renewable power is rapidly becoming cheaper, falling to parity with NBP gas + carbon price in 2030 at £44/MWh as a result of capex reductions and falling electricity wholesale prices due to increased renewables penetration.
- Green hydrogen from dedicated renewables only becomes more cost effective than blue hydrogen in 2045. After this date, construction of green production capacity should always be favoured over blue hydrogen, where the renewable generation supply chain can accommodate this.
- The cost reduction trajectory for Green hydrogen is similar to that experienced with solar and OSW over the past decade.
- **All hydrogen production becomes cost-competitive with natural gas + carbon by 2040.**

Levelised cost of hydrogen



Sources: BEIS, BNEF, Element Energy, IRENA, Hydrogen Council, Navigant, National Grid FES, DNV-GL

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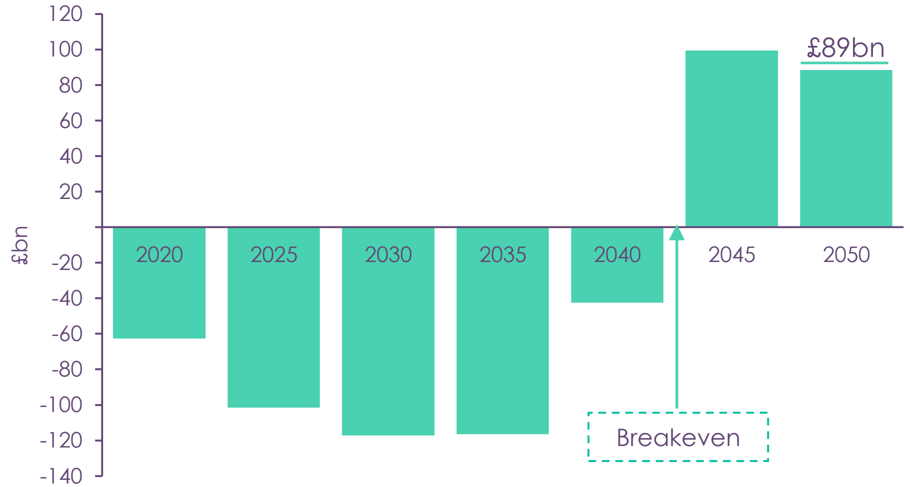
Key takeaways

3 Prompt investment will unlock £89bn of net savings, in addition to the economic value to UK Plc. of a domestic hydrogen industry.

- Converting to a hydrogen economy requires investment of £182 billion. However, our analysis shows that this investment will be paid back through benefits to customers, by 2045.
- By 2050, this investment into the UK's hydrogen infrastructure will have delivered a net benefit to customers of £89 billion.
- The earlier that investment is made into hydrogen infrastructure, the sooner the benefits can be realised economically and environmentally for the UK.
- If investment into hydrogen infrastructure were to begin today, the UK would be able to achieve returns on the investment in 2045.
- Timely and substantial investment into hydrogen infrastructure will unlock savings earlier in the UK's transition to Net Zero and unlock the possibility for greater returns in the latter years.
- The development of the UK's hydrogen supply chain could yield wide ranging economic benefits including job creation and secure a world-leading hydrogen industry for the UK to export globally providing long-term GVA.

Rolling NPV of the UK's hydrogen economy



Frequently Asked Questions (FAQs)

- **Q: Why should the government support the conversion of gas networks to hydrogen?**

  A: Both the Climate Change Committee (CCC) and Energy Systems Catapult (ESC) assert that many technologies will be required to deliver Net Zero by 2050 and that there is no realistic scenario which would allow UK government to reach this target without hydrogen playing a key role. An efficient hydrogen economy is not possible without gas networks providing the ability to distribute large volumes of clean gas from producers to offtakers. The market is not incentivised to foster the transition in absence of government intervention.

- **Q: What can the government do to support increased supply and utilisation of hydrogen?**

  A: Government should provide the market with a clear signal for the future of gas networks, thereby facilitating investor confidence and enabling the deployment of £182 billion of capital necessary to convert to a hydrogen economy. The private sector has already made strides towards developing hydrogen technologies across the value chain. In order to achieve the cost reductions and scale required, the government must provide an investable framework, and soon, to unlock the abundance of private capital waiting to be deployed into these technologies.

- **Q: Can we not just wait for international markets to develop and import clean hydrogen?**

  A: The cost of inaction is high and delaying investment will increase total overall costs and put the UK's ability to hit legally binding targets at risk whilst forgoing GVA associated with developing our own manufacturing capacity and supply chain. Equally, domestic investment now, rather than waiting for international imports to arrive at our shores at an undefined date in the future, improves the UK's resilience through increasing energy independence whilst allowing a continued role for many firms reliant on revenues from the North Sea – e.g. gas for Blue hydrogen and carbon storage.

- **Q: How disruptive will the transition to hydrogen be for customers?**

  A: Minimal disruption for customers will be key in delivering Net Zero. According to a report led by the Institution of Engineering and Technology (IET), the disruption for customer both in their home and in street works is lower through a hydrogen conversion than alternative technologies such as air source heat pumps, hybrid heat pumps and district heating.

- **Q: What impact will hydrogen have on the resilience of our energy networks?**

  A: Diversifying the UK's energy supply through the use of multiple technologies, including the use of hydrogen for heat, reduces the customers exposure to electricity system outages. Ensuring energy system resilience during this transition is critical. Putting the heat supply to vulnerable customer homes at risk would not be in the public's interest.

Next Steps – What is required

- The key conclusion of this analysis is that £182 billion of investment is required across the UK value chain in order to develop a diversified Net Zero economy with hydrogen at the forefront.
- The current fallout from COVID19 offers an opportunity for the UK government to ensure that any fiscal stimulus measures they decide upon align with the ongoing climate emergency.
- Recent analysis undertaken by a team of internationally recognised experts, and led by Oxford University, shows the potential for strong alignment between the economy and the environment. Their evidence suggests that green projects create more jobs, deliver higher short-term returns per dollar spend and lead to increased long-term cost savings, by comparison with traditional fiscal stimulus.
- The delay to COP26 equally provides the opportunity to develop a robust hydrogen proposition which can put the UK at the forefront of this technology and be presented to a global audience through such a prestigious forum.
- The private sector is ready and willing to act, and there are various policies available to the Government to drive this transition, either through mandating change or providing an investable framework in which private capital can be deployed.
  - An example of mandating change could be the requirement for households to install a hydrogen ready boiler in all new and existing homes which require an upgrade to the central heating system by 2025. Manufacturers are already making progress in this area, and with the right incentive, could facilitate a seamless and cost-effective transition for customers.
  - Stimulating investment through a well designed framework which fairly apportions risks and costs between investors and customers may be more appropriate for certain technologies. For example, a subsidy akin to the CfD mechanism successfully deployed for Offshore Wind, would allow low carbon hydrogen production to compete with unabated technologies with the view to increasing utilisation and driving down costs.
  - It is critical that any policy is practical, limits costs, instils confidence among investors and customers, is compatible with the Net Zero agenda and incentivises the private sector to deliver value to the wider economy.

Gas Goes Green will continue to work collaboratively with policy-makers to undertake detailed assessment of policy options available to government.

Introduction

The Government's existing strategy in response to climate change lays the foundation for a robust hydrogen market to develop in the UK

The UK Government's Clean Growth Strategy promises a nurturing approach to low carbon technologies such as hydrogen, which will be all the more necessary in light of its commitment to achieving Net Zero by 2050. The Committee on Climate Change has further promoted the role of hydrogen within a Net Zero economy.

Environmental Policy

1 Government commitment to Net Zero

— In May 2019, the UK become the first major country to legislate for a Net Zero target for carbon emissions by 2050 in line with the recent recommendations from the Committee on Climate Change (CCC), representing a significant tightening of the current 80% target set under the 2008 Climate Change Act.

— Achieving Net Zero will therefore require fundamental changes across all sectors of the economy, with hydrogen increasingly fulfilling energy demand across UK power, industry, heat and transport.

2 Clean Growth Strategy

— The Clean Growth Strategy was published in October 2017 with the aim of setting out a comprehensive set of policies and proposals to deliver economic growth and decreased emissions. This highlights the need for Government to focus its efforts towards the nurturing of low carbon technologies, processes and systems as cheaply as possible in order to decarbonise the UK economy.

— Increased deployment of blue hydrogen and investment in hydrogen infrastructure will be key in achieving the Government's clean growth ambitions.

Current Hydrogen Policy

Currently, the Government has no long-term hydrogen policy. However, some limited funding has been directed towards investments in innovative hydrogen projects and hydrogen feasibility studies.

— In August 2019, the Government announced a £390 million investment in hydrogen and low carbon technologies. This included:

- a Hydrogen Supply Competition (£20m) to identify and demonstrate bulk low carbon hydrogen supply solutions
- a £100m Hydrogen Production Fund for the deployment of low carbon hydrogen production at scale
- a £250m Clean Steel Fund dedicated to transition to lower carbon iron and steel production through new technologies and processes

— In October 2019, a £170m Industrial Decarbonisation Challenge Fund was announced to accelerate the cost-effective decarbonisation of industrial clusters by developing and deploying low-carbon technologies.

— In the 2020 Budget, the UK Government committed to establishing Carbon Capture and Storage in at least two UK sites, one by the mid-2020s and a second by 2030, supported by the creation of a new CCS Infrastructure Fund of at least £800 million.

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Size of the challenge

The UK is currently set to miss the fourth and fifth carbon budgets which were set prior to the commitment to Net Zero.

In order to achieve Net Zero, decarbonisation across every aspect of the economy will be required.

Current policies will see the UK underperform against the 4th and 5th Carbon Budget targets by a significant margin, relying on large amounts of imported offsets to meet the target.

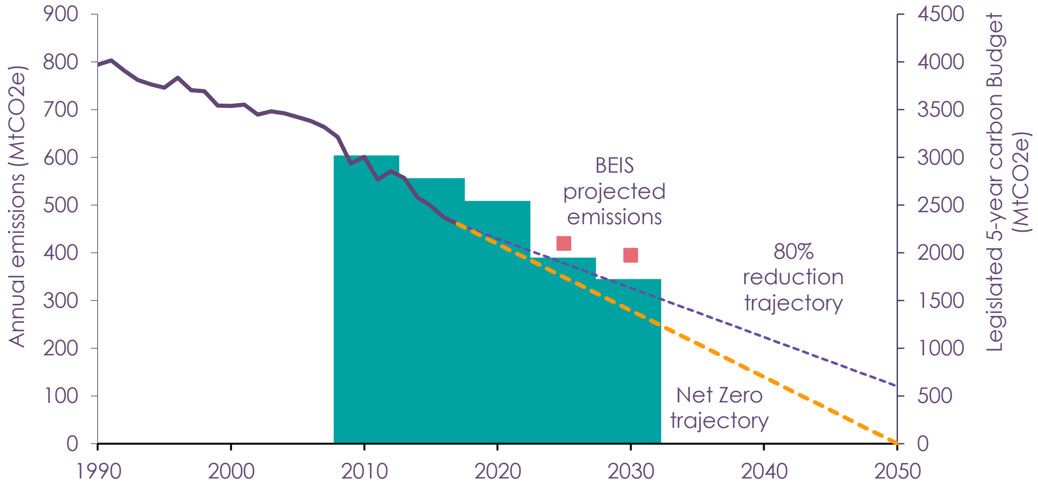
The Committee on Climate Change (CCC) will publish its recommendations on the Sixth Carbon Budget in December 2020. This will contain a recommendation on the volume of greenhouse gases the UK should emit during the period 2033-2037.

The Heat and Transport sectors are major contributors to the UK's carbon emissions. For example, residential and commercial heating represents 30% of UK energy demand and is primarily sourced from unabated natural gas.

Increased activity, in particular around heat, will lead to growing penetration of low carbon technologies as domestic and commercial heat and transport systems are supplanted by green alternatives.

Hydrogen offers the opportunity to utilise existing infrastructure, whilst decarbonising residential and commercial customer demand with minimal disruption.

Carbon emissions for Net Zero in 2050



Sources: BEIS, CCC

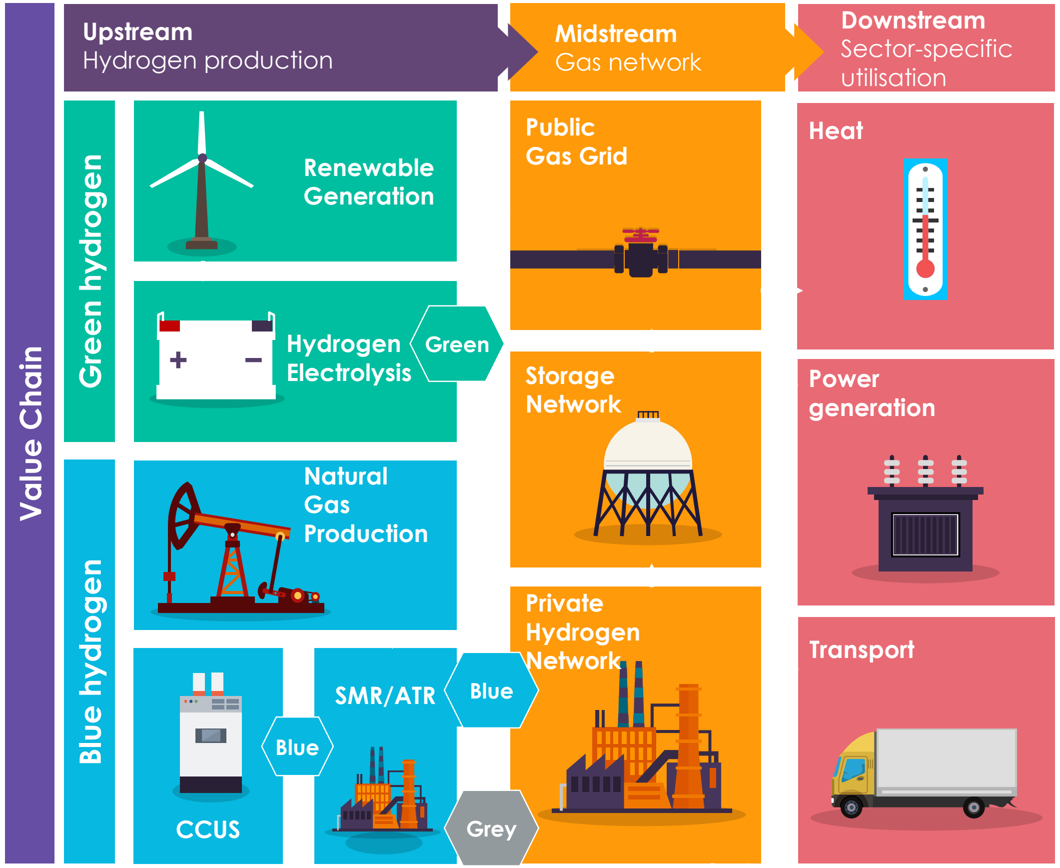
Establishing a Net Zero compliant hydrogen economy will require integration of numerous aspects of the value chain

Upstream – Green hydrogen (produced by electrolysis) and Blue hydrogen (from Steam Methane Reforming (SMR) or Auto Thermal Reforming (ATR)) have distinct upstream value chains, with unique chemical processes. Blue hydrogen production results in direct emissions which are reliant on Carbon Capture, Usage and Storage (CCUS) in order to provide a low carbon solution. However, when coupled with renewable electricity, Green hydrogen production offers truly zero carbon hydrogen production.

Midstream – All technologies rely on the same midstream infrastructure if production is located remotely from the application: injecting hydrogen into the gas grid; or direct delivery to large industrial users (via a private network). Green hydrogen however offers the additional option for energy to be transmitted as electricity via existing infrastructure, then converted to pure hydrogen in distributed electrolysers located at demand hubs.

Downstream – In many cases, Blue and Green hydrogen can be used interchangeably for applications in residential heating and industrial processes. However, fuel cell applications (such as transport) require a higher purity of hydrogen which is most easily achieved by electrolysis (Green hydrogen).

Blue hydrogen is currently the mature technology for hydrogen production at scale, although early investment into the development of electrolysis can improve the future economics of Green hydrogen.



Evolution of hydrogen will see Blue act as the gateway for Green

As hydrogen production is demonstrated at scale in industrial clusters, conversion of residential and commercial heating to hydrogen can begin with a phased blending of hydrogen into the existing natural gas mix, before transitioning to a 100% hydrogen network.

Blue hydrogen production is initially preferred due to the relative cost and proximity of CCUS infrastructure to the industrial demand base. This is consistent with UK Government plans for establishing CCUS in at least two UK sites, one by the mid-2020s and a second by 2030.

Green hydrogen production emerges later as Green hydrogen reliant demand centres such as transport are developed and a growing capacity of intermittent renewables are integrated into the grid.

Illustrative Evolution of the Low-Carbon Hydrogen Economy

2025
Hinkley Point C projected to come online

2030
UK Government commits to 30GW of offshore wind by 2030

2050
CCC recommends 75GW of offshore wind by 2050 in order to reach Net Zero

2020 2025 2030 2035 2040 2045 2050

Midstream

Industrial cluster networks → **Incremental transition of distribution networks to full hydrogen**

As green gas scales and hydrogen demand grows to all sectors, incremental repurposing of portions of the gas grid will be required to service broader demand base.

Refuelling stations

As transport sector demand increases nationwide, refuelling stations will be required to service hydrogen-fuelled vehicles.

Downstream

Industrial demand

Incremental demand for hydrogen among industrials will be required to create demand base for new Blue or Green hydrogen.

Transport demand

Demand from the transport sector emerges initially from industrial clusters before wider adoption as green gas sources grow.

Residential and commercial demand

Residential and commercial heat demand for hydrogen emerges initially through blending of hydrogen into the gas grid followed by a phased transition to a 100% hydrogen network.

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Development of a hydrogen economy will require investment at key nodes in the hydrogen economy

Midstream gas infrastructure is a key enabler for the creation of a hydrogen economy. This requires enabling policy decisions which must first be addressed before incentivising the development of other areas of the value chain. Options are available for supply or demand led subsidies; each of which have merits and drawbacks.

	Upstream Hydrogen production	Midstream Gas network	Downstream Sector-specific utilisation
Enabling		**Network provision:** Establishing a hydrogen economy in which energy is transmitted in gaseous form relies on provision of a supportive framework for hydrogen networks. Without this, hydrogen producers would have limited offtake options for their product and customers would have little access to hydrogen. **Development of storage:** Ever greater amounts of storage will be required as hydrogen utilisation grows and inter-seasonal storage becomes more critical as a result of increased renewable penetration.	
Developing	**Subsidy for Green hydrogen production:** Green hydrogen production is not currently cost-competitive with the alternative (natural gas). Hence, government support is required to create an economic business case. **Development of supporting technologies for Blue hydrogen:** Though already cost-competitive, Blue hydrogen is reliant on CCUS, for which there is not currently an investable business model. This must be resolved in order to produce hydrogen at scale in the short term.		**Proliferation of hydrogen utilisation:** European appliances are already capable of accommodating up to 20% hydrogen. However, in order to develop the hydrogen economy beyond these low concentrations, appliances and industrial processes must be prepared for hydrogen.

Forecasting approach

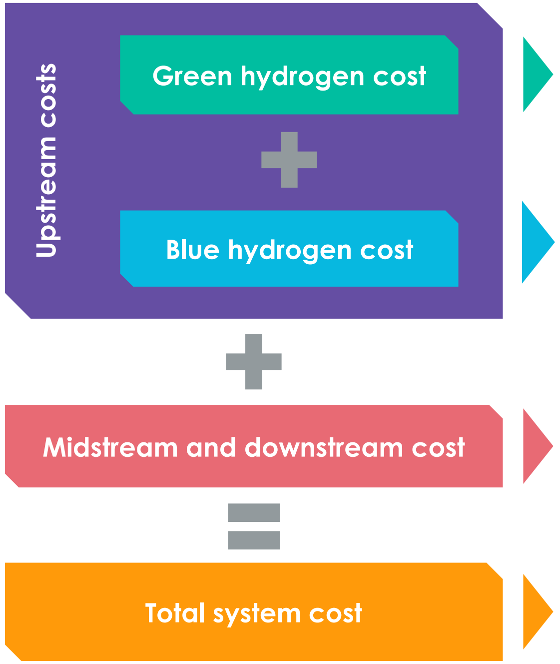
Standing assumptions

Due to the uncertainty associated with long range forecasts, we have made a number of simplifying assumptions regarding the mechanics of the future energy market. The following standing assumptions are applied throughout the analysis.

1. Our analysis is policy and regulation agnostic. We have made no explicit assumptions on potential future subsidy support mechanisms for renewables or hydrogen, but we have assumed long term carbon pricing through to 2050. The cost of decarbonisation is therefore assumed as a straight pass-through to the customer.
2. We have assumed that Net Zero by 2050 continues to be the Government's objective and that incremental progress is made towards achieving this ambition from today.
3. Our methodology includes a preference for Green hydrogen production over Blue. This is due to the natural benefits of Green hydrogen, such as its role in integrating renewable technologies, suitability for fuel cells and the fact that Green production is more appropriate for a Net Zero economy given its low carbon intensity.
4. Our analysis assumes that wherever electrolyser capacity can accommodate, all excess power generation (net of battery and other storage) is converted to hydrogen. Inherently, this assumes that electrolysers are well-distributed and well-sited relative to intermittent generation or are grid connected, enabling offtake of excess power from any point in the electricity grid.
5. The contribution from must-run fossil fired plant (such as CHP plant associated with industrial processes) used in electrolysis process is immaterial. Whilst a residual portion of carbon intensive plant will operate as 'must run', we have assumed that the contribution to Green hydrogen production is immaterial and have not made a corresponding adjustment to Green hydrogen production for this generation source.

Forecasting approach

Our analysis is focussed heavily on hydrogen production methods, with consideration of technology developments, uptake, supporting markets and Net Zero emissions trajectories



The total volume of Green hydrogen production is calculated based on an estimated excess renewable power generation, utilised by grid-connected operational electrolyser capacity in that year. This is multiplied by a levelised cost of Green hydrogen which is driven by an estimated global rollout of Green hydrogen production. We have also presented an upside scenario in which additional renewable capacity is built with the sole purpose of producing hydrogen.

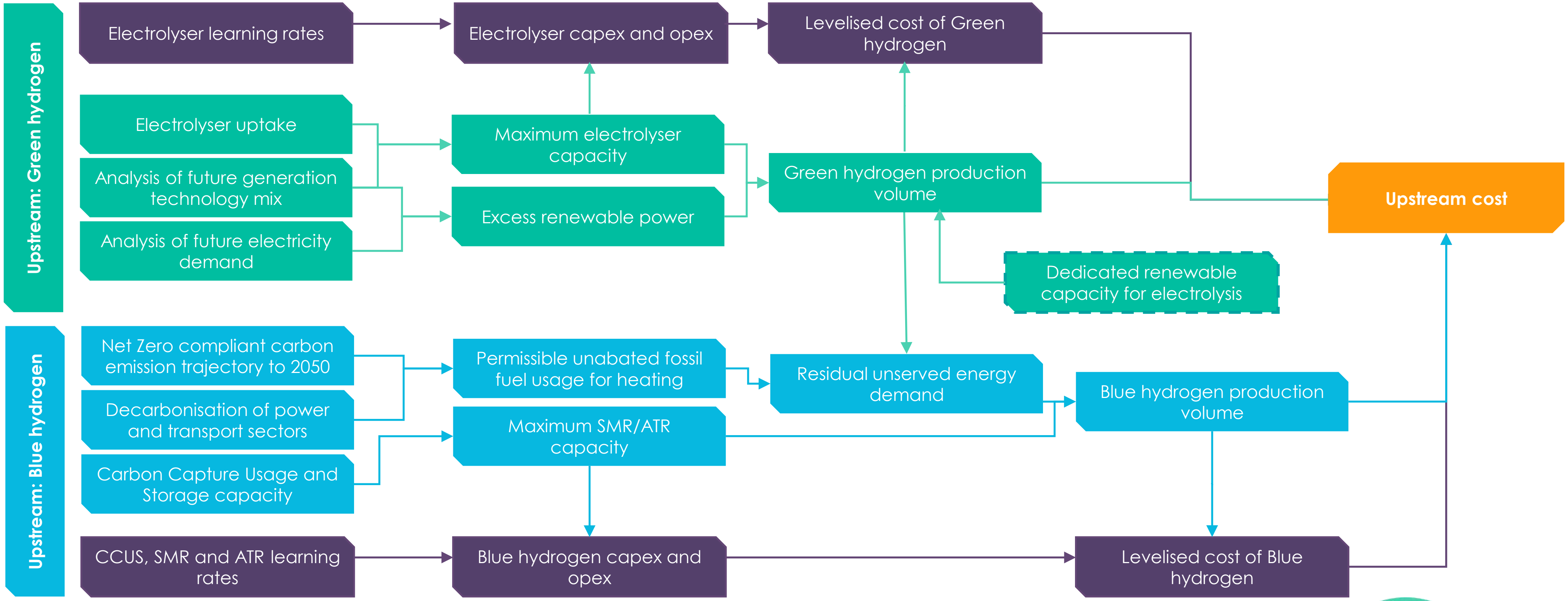
Blue hydrogen production is estimated based on the residual gas demand which cannot be met by the operational renewable power and Green hydrogen in that forecast year. This is multiplied by a levelised cost for Blue hydrogen, based on technology learning rates and global roll out of Carbon Capture, Usage and Storage (CCUS), to provide a total cost of Blue hydrogen over the forecast period.

Midstream and downstream costs have been aggregated from multiple published sources, at a system level.

These three components are summed to provide a total system cost through the period 2020 -2050. This cost is also presented as a cost per unit, by dividing total system cost by the total hydrogen production volume across both technologies.

Calculating upstream cost

Our approach builds on forecasted market composition, to calculate a market share for Green and Blue hydrogen in five-year intervals during the period 2020 - 2050. This is coupled with a calculated levelised cost for each hydrogen production method to provide a total upstream cost.



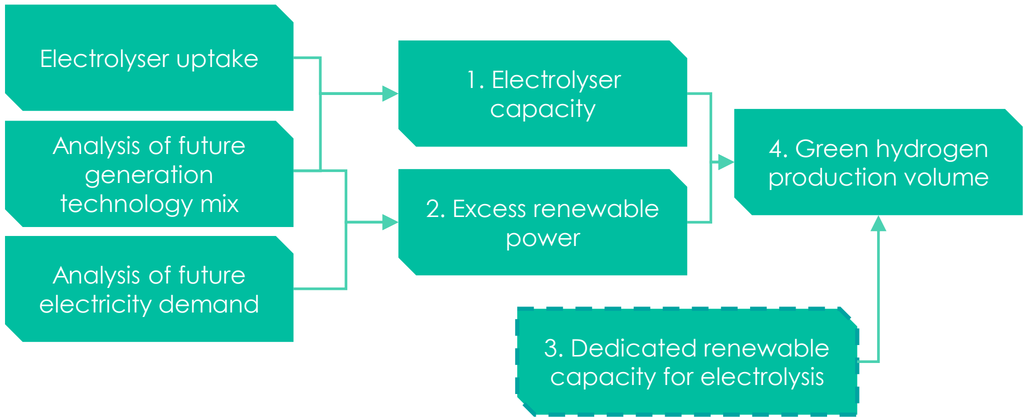
Forecasting Green hydrogen production volumes

Green hydrogen production is forecast based on the feasible capacity which could be accommodated in the UK, and the utilisation of excess power generation volumes from renewable sources. These combine to provide a maximum Green hydrogen production volume in each forecast year.

1. **Electrolyser capacity** is a function of:
    - The **electrolyser uptake** which is economically achievable based on manufacturer estimates of achievable electrolyser size for commercial operation to determine total electrolyser capacity associated with each technology.
    - Our **analysis of future generation technology mix** estimates the total renewable capacity and average renewable project size during the forecast period for offshore wind, onshore wind and solar.

    Combining electrolyser size with renewable capacity provides a ceiling for the maximum electrolyser capacity which the UK could support in any given year based on our central estimates of renewables build to meet electricity demand.
2. **Excess renewable power** has been derived based on scaling current Balancing Market supply and demand data to calculate a supply excess (or deficit) for each forecast year.
    - To calculate future electricity demand, we have scaled current generation for each technology, based on our **analysis of the future generation technology mix** in each forecast year.
    - Our **analysis of future electricity demand** scales in a similar fashion, based on National Grid FES forecasted power demand.

    Our analysis calculates the differential between supply and demand for each settlement period. Excess renewable power is the cumulative excess throughout the forecast year.



3. **Dedicated renewable capacity for electrolysis is incorporated into** a stretch scenario, in which additional offshore wind equivalent capacity accommodates green hydrogen production in addition to that from excess renewable power.
4. **Green hydrogen production volume** is calculated as the lower in each forecast year of:
    - Maximum electrolyser capacity multiplied by a load factor; and,
    - The excess renewable power with which to operate those electrolysers, after an electrolyser efficiency has been applied.

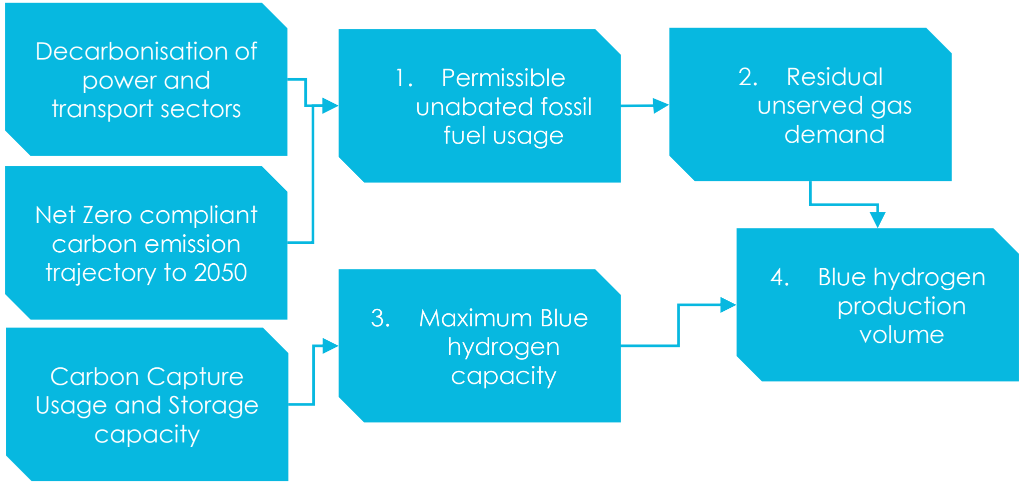
Forecasting Blue hydrogen production volumes

Our methodology uses Blue hydrogen as the bridging technology; to ensure gas demand is met in every year, whilst maintaining a Net Zero compliant emissions reduction profile. This is limited by the capacity which can be accommodated by the UK's Carbon Capture and Storage (CCUS) buildout.

1. **Permissible unabated fossil fuel usage** is calculated based on:
   - A **Net Zero compliant carbon emissions trajectory to 2050**, acknowledging the Government's commitment to achieve Net Zero in the UK within that period.
   - **Decarbonisation of power and transport sectors** are taken into account to reflect the accelerated emissions reduction trajectories in those sectors.

   This provides a residual, declining carbon budget within which the gas sector must meet demand through to 2050.
2. **Residual unserved gas demand** is calculated by subtracting Green hydrogen and biogas production, and permissible fossil fuel utilisation from total gas demand. This presents a shortfall, which represents the demand for Blue hydrogen in the UK.
3. **Maximum Blue hydrogen capacity** is predominantly driven by the available **Carbon Capture Usage and Storage capacity** within the UK, given the hydrogen production technology is mature and readily scalable. We have therefore mapped CCUS storage within the UK to determine the maximum annual flowrate in each forecast year. This provides a ceiling for Blue hydrogen production.
4. **Blue hydrogen production volume** is calculated as the maximum Blue hydrogen demand which can be accommodated by the CCUS capacity.

   Where CCUS is unable to accommodate the residual demand, natural gas is assumed to fill this shortfall and the emissions target is noted as breached in that forecast year.



Assumptions

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Summary of underlying assumption groups

1	**Total energy demand**	Forecast annual UK energy demand is based on National Grid FES data and is utilised in our analysis to determine both electricity and gas demand through the period, capping the total requirement for both Blue and Green hydrogen annual production.
2	**Allowable emissions**	Allowable natural gas emissions are utilised in our analysis to inform the maximum permissible Blue hydrogen production due to residual carbon emissions associated with its production.
3	**Generation capacity**	Generation capacity of all technologies informs our analysis of the available future intraday generation from intermittent renewable to be utilised for Green hydrogen production.
4	**Renewables capacity**	Intermittent renewables capacity determines the available renewable projects which could accommodate electrolysers. This has been constructed from National Grid FES, combined with CCC recommendations for offshore wind capacity required to achieve Net Zero.
5	**Merit order**	For the purposes of estimating future excess generation availability for Green hydrogen production, we assume a merit order which ranks renewable energy sources first in order of price followed by non-renewable sources in order of short-run marginal cost dictated by fuel cost and carbon intensity.
6	**Green hydrogen production methods**	Green hydrogen production methods inform the technology parameters utilised in our analysis to be paired with intermittent renewables for production of Green hydrogen.
7	**Green hydrogen levelised cost inputs**	Green hydrogen cost assumptions based on a range of market information are utilised in our analysis to establish the total production cost per MWh of Green hydrogen.
8	**Blue hydrogen production methods**	Blue hydrogen production methods inform the technology utilised in our analysis to determine the cost and efficiency of hydrogen production from natural gas.
9	**Blue levelised cost inputs**	Blue hydrogen capex and opex assumptions are utilised in our analysis to establish the levelised cost of production per MWh of Blue hydrogen, based on a range of technical and market data sources.
10	**T&S levelised cost inputs**	Transport and Storage cost is utilised in our analysis to establish the production cost per MWh of Blue hydrogen, on a user pays basis. This in turn is represented as an opex line item in the calculation of Blue production costs.

1 Total energy demand | Forecasting future demand

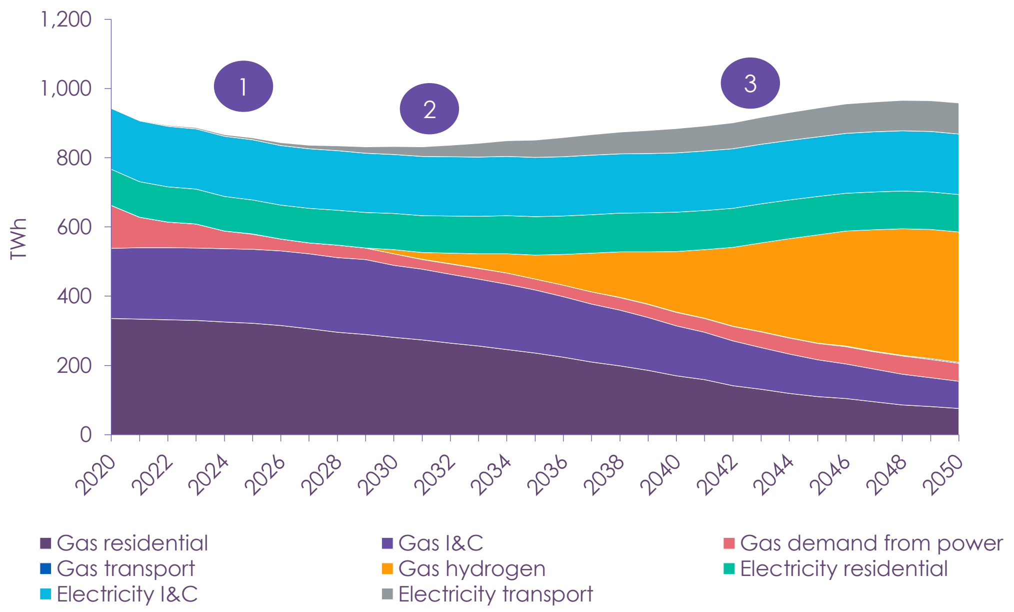
Total energy demand has been adopted directly from the National Grid FES Two Degrees scenario, as this is most closely aligned with achieving Net Zero.

There are three distinct drivers of this trajectory:

1. There is an initial fall in energy demand due to a reduction in gas demand from electricity generation as renewable capacity increases.
2. From the late 2020s, annual demand begins to rise, driven by transport switching from oil-based fuels to electricity, gas or hydrogen which outweighs the effects of increasing energy efficiency in the absence of renewable power generation to meet full demand.
3. A sustained increase in energy demand to 2050 is realised as CCUS enables significant production of Blue hydrogen from natural gas to support residential and I&C heat representing a further system level energy efficiency reduction.

Forecast annual UK electricity demand is utilised in our analysis to scale 2019 Balancing Data intraday demand for each 5 year interval. This is used to calculate available excess generation from intermittent renewables for Green hydrogen production in each settlement period.

Forecast UK Annual Energy Demand



Sources: National Grid FES

2 Allowable emissions | Allowable emissions from natural gas

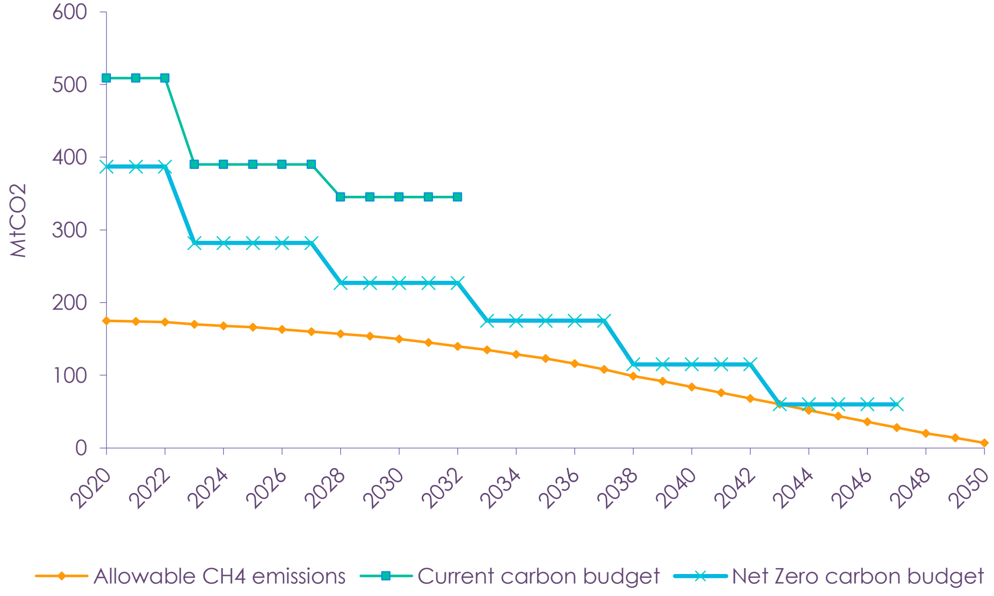
Allowable natural gas emissions are calculated using Navigant data. This is utilised in our analysis to inform the maximum allowable Blue hydrogen production due to residual carbon emissions associated with its production.

Projected allowable natural gas emissions in line with Net Zero fall moderately in the 2020s driven by demand-side measures such as increasing energy efficiency measures and electrification of heat in new builds.

As hydrogen production ramps up in the late 2020s, allowable gas emissions begin to fall at a faster rate as natural gas is displaced by low carbon hydrogen.

In 2050, emissions related to Blue hydrogen production will remain but these can be mitigated through carbon offsetting from new technologies such as bioenergy CCS (BECCS) and direct air capture.

Permissible natural gas emissions



Sources: CCC, Navigant

3 Generation capacity | Evolution of power generation capacity (1/2)

As renewable costs have become cost-competitive with non-renewable sources and political momentum has built towards addressing the climate crisis, unabated conventional capacity will become increasingly uneconomical.

Coal, formerly Britain's main power source, has dropped from supplying 70% of UK's electricity generation in 1990 to 3% in 2019. A government deadline for the phase-out of coal set is for 2025 and may yet be brought forward to 2024.

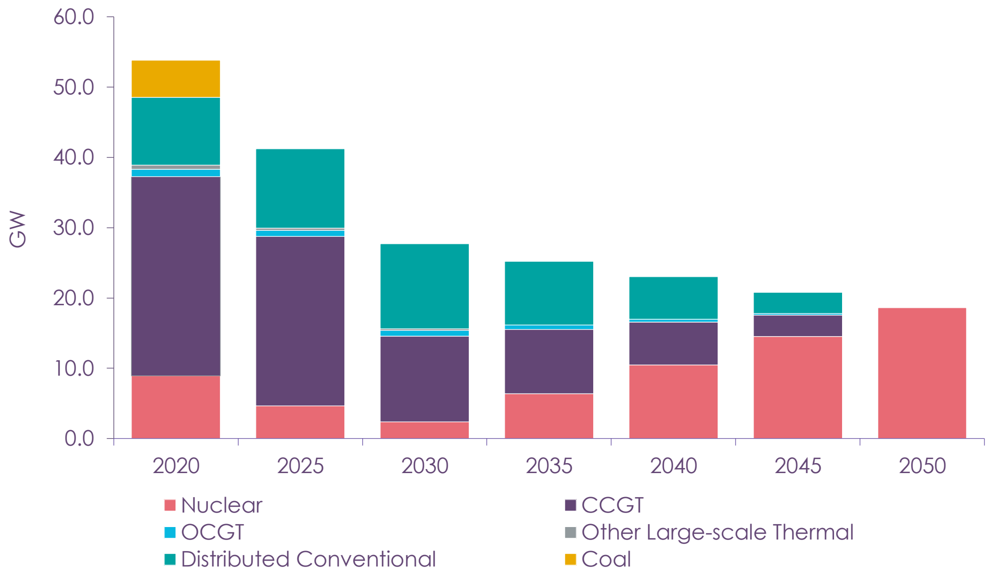
Unabated gas generation capacity (OCGT and CCGT) is expected to decline more slowly with OCGT projected to be phased-out by 2045 and CCGT by 2050. Our analysis assumes this critical flexible generation resource is replaced with low-carbon flexible generation through either pre- or post-combustion CCUS.

Industry snapshot

Siemens has committed to increasing the suitability of their gas turbines to be 'hydrogen-ready' with a goal that all Siemens gas turbines will be able to – or can be retrofitted – to run on 100% hydrogen by 2030.

This offers a pathway for unabated gas generation capacity to be utilised in the long-term as flexible low-carbon generation.

Unabated generation capacity



Sources: National Grid FES, Siemens

3 Generation capacity | Evolution of power generation capacity (2/2)

With the UK's commitment to achieving 'Net Zero' emissions by 2050, in all realistic scenarios renewables will play a dominant role in powering the UK's energy system and are forecast to grow from 43% of total installed capacity in 2020 to 83% in 2050.

We use FES Two Degrees and their updated Net Zero Scenarios capacity projections to 2050 to calculate the capacity of intermittent renewables. This drives demand for electrolysers and the scaling of intraday generation profiles for each technology to calculate available excess generation to be utilised for Green hydrogen production.

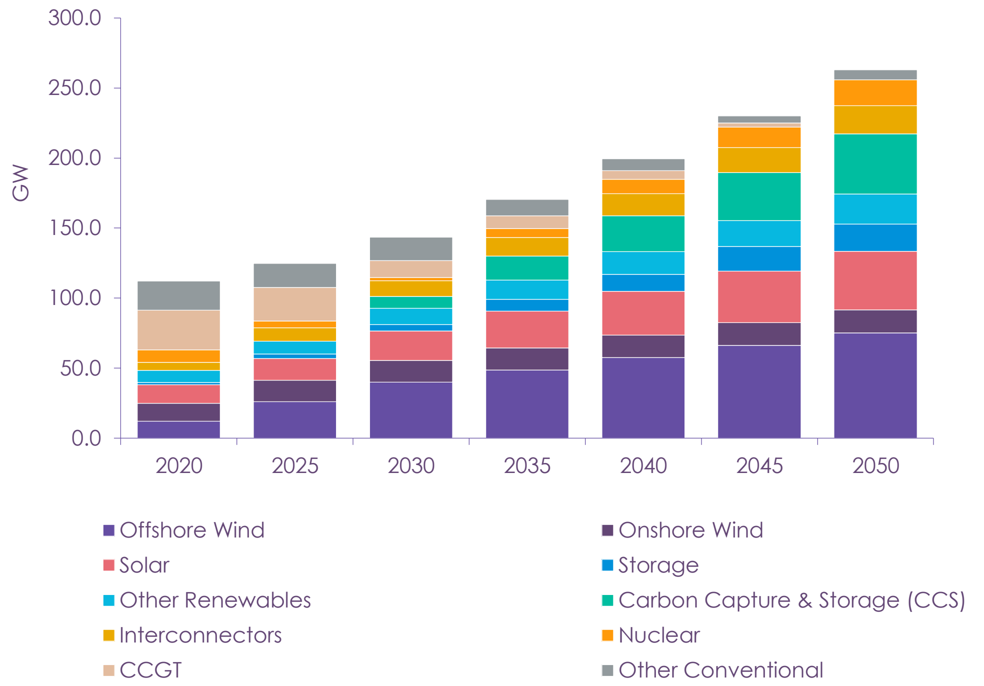
Offshore wind capacity is forecast to grow rapidly from 12GW to 75GW in 2050 due to demonstrated cost reduction and recommendations from the Committee on Climate Change for 40GW of offshore wind capacity in 2030 and 75GW in 2050.

Onshore wind is forecast to double in capacity by 2050 to 24GW driven by capex cost reductions and improvements to the planning process.

Solar is forecast to grow from 13GW in 2020 to 35GW in 2050 as it remains a cost competitive renewable source necessary to meet growing future energy demand.

This translates to an average renewables build-out rate of 4.2GW per year. We have assumed the maximum build-out rate which the UK supply chain could support, would be equivalent to 150% of this value. In our green upside scenario, we use this to provide a ceiling for the maximum capacity of dedicated renewables for Green hydrogen production.

Total Installed Capacity by Technology



Sources: National Grid FES

4 Renewables capacity | Future renewables projects

Projected distribution of new-build intermittent renewable projects by capacity is used in our analysis to calculate electrolyser deployment for Green hydrogen production in each 5 year interval.

Based on the current pipeline to 2025 and historic growth in offshore wind project sizes, only projects with a capacity over 1GW are expected to be commissioned out to 2050 with average project size to cap at 1.5GW in line with the maximum project capacity of 1.5GW eligible to participate in CfD auctions. Given the significant continued development of offshore wind technology, we have assumed growth in offshore wind load factors from 42% to 53% during the period 2020-2035.

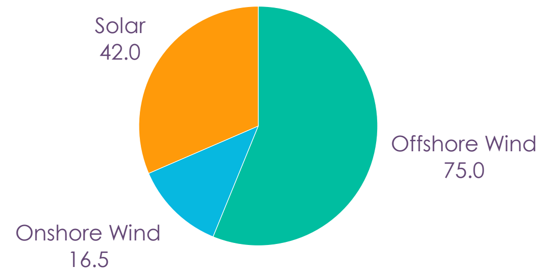
The distribution of new-build onshore wind projects is expected to continue at current rates as evidenced by historical project sizes stabilising due to restrictions around land availability and local restrictions limiting turbine height and consequently turbine and project capacity.

Utility scale solar project capacity is also forecast to remain consistent with current project sizes given the maturity of the technology and scarcity of available site locations for larger solar projects.

Industry snapshot

A consortium of Shell, Gasunie and Groningen Seaports have ambitions to build up to 10GW of offshore wind in the North Sea dedicated to hydrogen production by 2040, showcasing potential for upscaling offshore wind projects in the UK to support green hydrogen production.

2050 Variable Renewables Capacity (GW)



Newly installed project size share per technology

	Size (MW)	2020	2025	2030	2035	2040	2045	2050
Offshore Wind	<100	8%	0%	0%	0%	0%	0%	0%
	100-500	58%	0%	0%	0%	0%	0%	0%
	500+	34%	100%	100%	100%	100%	100%	100%
Onshore Wind	≤ 25	25%	25%	25%	25%	25%	25%	25%
	25-100	48%	48%	48%	48%	48%	48%	48%
	100+	27%	27%	27%	27%	27%	27%	27%
Solar	50 kW to ≤ 5 MW	38%	38%	38%	38%	38%	38%	38%
	5 to ≤ 25 MW	46%	46%	46%	46%	46%	46%	46%
	> 25 MW	16%	16%	16%	16%	16%	16%	16%

Sources: BEIS, RenewablesUK, DNV-GL, Gasunie

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5 Merit order | Generation merit order

The merit order shows, in simplest terms (i.e. absent of actions from the SO), the order by which different generation technologies will dispatch power to the grid. This is done by ranking them in ascending order on a short run marginal cost basis, and level of electricity generated.

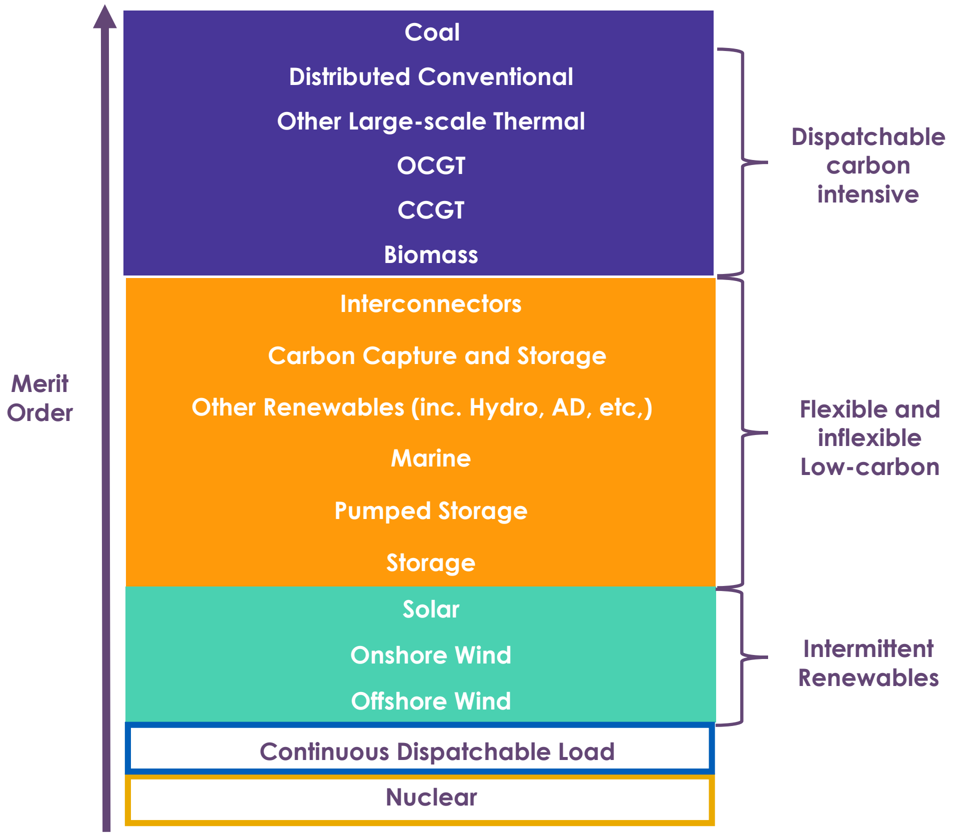
The Carbon Price Support and EU ETS prices paid by carbon emitters in Great Britain increases their short run marginal cost subsequently making them less competitive compared to less cleaner technologies.

For the purposes of estimating future excess generation availability for Green hydrogen production, we assume a merit order which ranks renewable energy sources first in order of price followed by non-renewable sources in order of short-run marginal cost dictated by fuel cost and carbon intensity.

Carbon emitting generators will not be dispatched with the intention of generating hydrogen from electrolysis. Green hydrogen will be produced in scenarios with excess renewables.

3.5GW of dispatchable gas capacity is treated as a grid requirement, based on historic operating conditions during 99% of the year. This is comprised of abated CCGT capacity whenever available and otherwise unabated CCGT capacity.

Nuclear remains at the bottom of the merit order due to its 'must-run' operating profile.



6 Green hydrogen production methods | Production methods

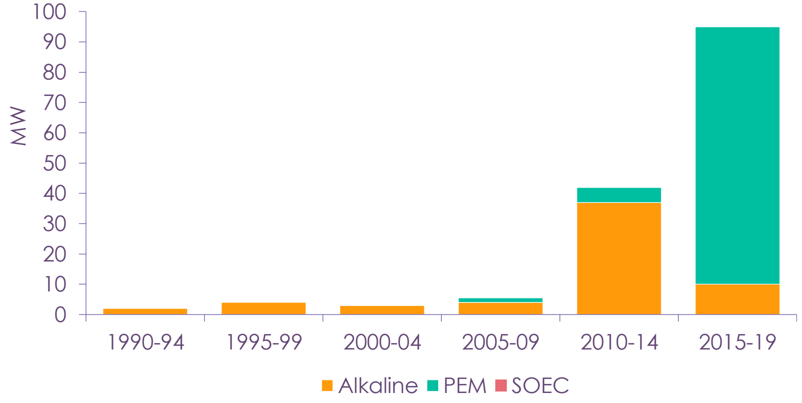
Green hydrogen production is possible through electrolysis which involves passing electric current through two charged electrodes, an anode and a cathode, resulting in the breakdown of water to extract hydrogen and oxygen. There are three electrolyser technologies currently in the market:

- **Alkaline electrolysis (ALK)** is a proven technology with over 90 years of commercial experience in the chemical industry. However, these units are larger than the same capacity of the alternatives and are designed for baseload operation.
- **Proton Exchange Membrane (PEM)** technology is better suited to be paired with renewable sources due to its ability to offer rapid dispatch and to follow variable loads from non-dispatchable renewables such as wind and solar. However, there are significant optimisations available through improved manufacturing methods and economised design to reduce the quantity of precious metals used.
- **Solid-oxide electrolysis (SOEC)** is an early-stage technology which has potential for improved energy efficiency but is still in the development phase and, unlike ALK and PEM, works at much higher temperatures. The main barriers to overcome are associated with degradation of components at these high temperatures.

Due to their more compact design and improved flexibility, PEM electrolysers are best suited for operation alongside intermittent power generation assets from which they are expected to derive input power. We have therefore adopted this assumption for the purposes of this analysis. This is further supported by data gathered from the IEA which shows a strong preference for PEM electrolysers in the last four years and Navigant, who assume all future UK capacity will be PEM.

Electrolyser type	Alkaline	PEM	SOEC
Temperature (°C)	60 - 80	50 - 80	650 - 1000
Production rate (kgH2/h)	1 - 68	1 - 21	3.6
Efficiency (%)	63 - 70	56 - 60	74-81
Purity (%)	99.5 - 99.9998	99.5 - 99.9998	99.9998
Capex (£/kW)	370 - 1040	815 - 1300	2075 - 4150
Life span ('000 hours)	60 - 90	30 - 90	10 - 30

Global electrolyser capacity additions



Sources: IEA

6 Green hydrogen production methods | Electrolyser capacity

Historically electrolyser project sizes have tended to be below 1MW due to high capex costs and lack of cheap input electricity.

As intermittent renewable capacity continues to grow globally, the level of potential excess generation to be captured by electrolysers increases, driving growth in electrolyser capacities.

The upper limit of electrolyser sizing per project in our analysis is based on the largest demonstrated electrolyser size from company data with Siemens planning to scale up PEM electrolyser system capacity to >100MW systems by 2023 and 1,000MW by 2030.

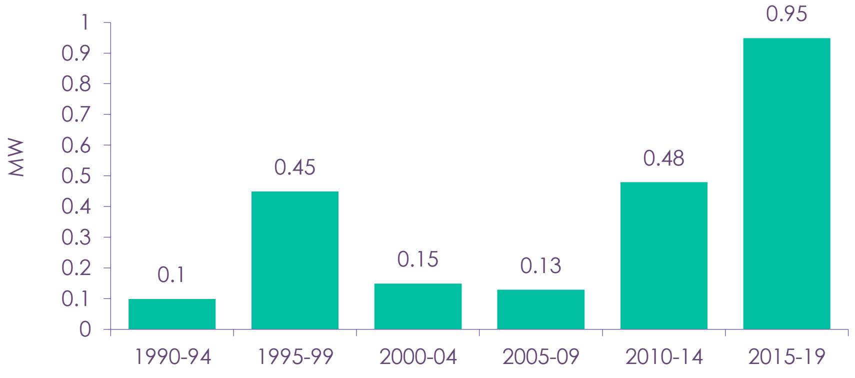
Maximum electrolyser capacity per renewables project has been assumed as 80% - based on equivalent storage technologies paired with intermittent renewables and diminishing utilisation of electrolyser capacity at upper end of capacity.

No minimum capacity for renewable projects eligible to be paired with an electrolyser has been assumed for our analysis due to rationale that any project where economically feasible will generate Green hydrogen rather than curtail their generation.

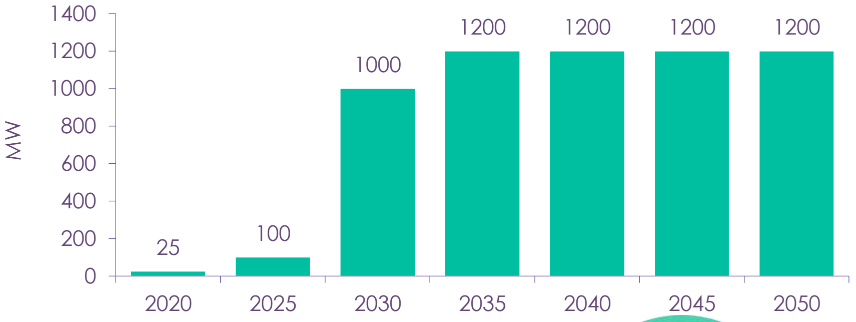
Industry snapshot

The Gigastack project led by ITM Power and Ørsted has recently been awarded £7.5 million under the BEIS Hydrogen Supply Competition for a FEED study for a green hydrogen project using a 100MW electrolyser system and utilising energy taken from Ørsted's Hornsea 2 offshore wind farm

Average Electrolyser Project Size



Largest Demonstrated Electrolyser Size



Sources: IEA, ITM Power, Siemens

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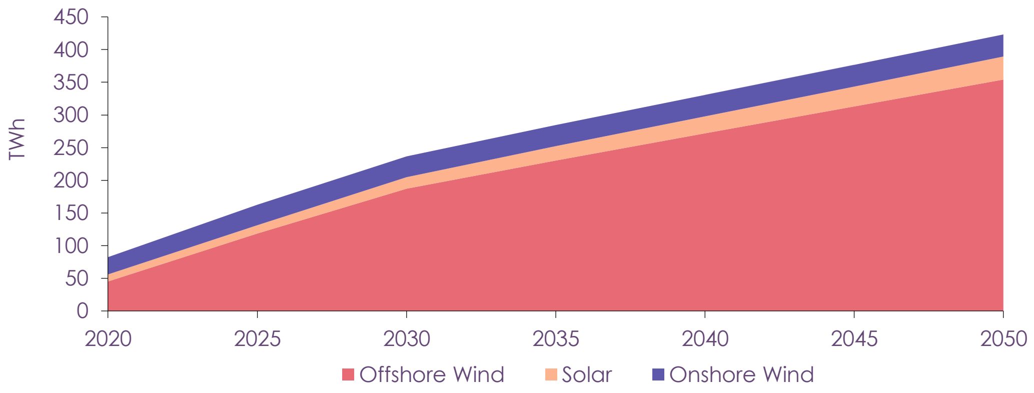
Green hydrogen production methods | Excess power for Green hydrogen production

Annual renewable generation and excess renewable generation to 2050 have been calculated by scaling intraday generation and demand data from Elexon with National Grid FES Two Degrees and their updated Net Zero Scenario generation capacity and demand projections.

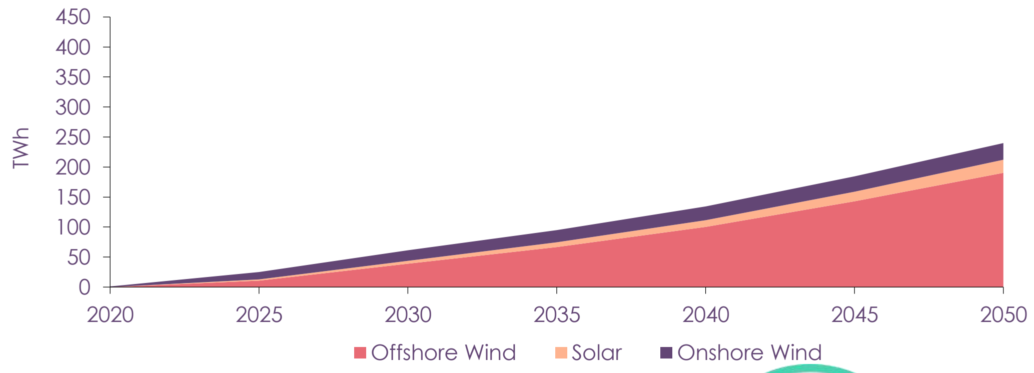
Annual renewable generation is calculated to grow steadily from 82 TWh in 2020 to 423 TWh in 2050 as unabated conventional capacity begins to retire and is replaced by offshore wind which sees a rise from 45 TWh in 2020 to 354 TWh in 2050.

As increasing levels of intermittent renewable generation comes online, the level of potential excess renewable generation to be utilised for Green hydrogen production grows rapidly with annual excess renewable generation forecast to reach 250 TWh in 2050.

Annual Renewable Generation



Annual Excess Renewable Generation



7 Green hydrogen levelised cost inputs | Electrolyser build out

Electrolysers are currently rare consisting mostly of demonstration projects and hydrogen production for transport and industry.

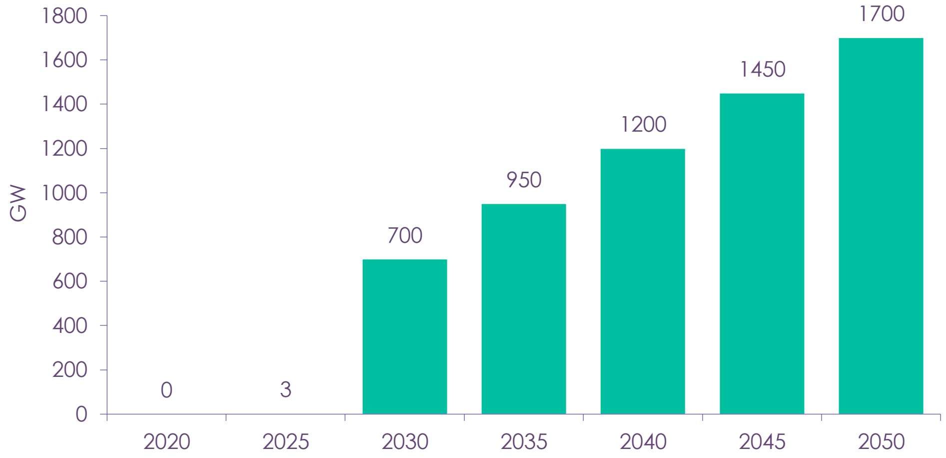
Capex reductions, driven by learnings from demonstration projects and increased available excess generation from renewable penetration, leads IRENA to forecast total global electrolyser capacity of 700GW in 2030 and 1700GW in 2050.

Global electrolyser capacity growth drives capex and opex cost reductions in our analysis with a 13% reduction in both capex and opex per doubling of global electrolyser capacity according to Hydrogen Council assumptions.

UK electrolyser capacity growth is forecast to accelerate into 2030 driven by renewable penetration in line with National Grid FES Two Degrees and Net Zero scenarios, in turn increasing the availability of excess generation to be utilised for Green hydrogen production in our analysis.

UK electrolyser capacity will be calculated based on a maximum utilisation of 57% as assumed by Navigant in their Pathways to Net Zero report.

Global Electrolyser Capacity Build-out



Sources: IRENA

7 Green hydrogen levelised cost inputs | Levelised cost of hydrogen

Capex	2020 Capex is calculated as £0.75m per MW capacity using assumptions from Element Energy and IEA. For each further 5 year interval, a reduction of capex by 13% per doubling of global electrolyser capacity has been assumed as per Hydrogen Council assumptions. Global electrolyser build-out has been forecast based on existing electrolyser project pipeline to 2025 and IRENA capacity forecasts out to 2050.
Opex	2020 Opex has been calculated as £11,000/MW per year based on assumptions of opex as 1.5% of capex for the whole period from 2020 to 2050 per IEA and Element Energy assumptions. As such, opex reductions also scales with global electrolyser build out using a 13% reduction in opex per doubling of global electrolyser capacity as per Hydrogen Council and IRENA assumptions.
Electrical efficiency	2020 Electrolyser electrical efficiency (MWh power per MWh Hydrogen) has been calculated as 65% and for each further 5 year period drawing upon the assumptions from IEA, Hydrogen Council, Navigant with sensitivities according to KPMG internal analysis.
Utilisation	Utilisation has been back solved by dividing the available electrolyser production capacity according to the build-out schedule by the maximum available excess generation from renewable sources according to KPMG forecasts with an upper limit of annual utilisation of the available electrolyser capacity at 57% as per Navigant assumptions.
Asset life	Electrolyser asset life has been fixed at 25 years for electrolysers built in any period from 2020 to 2050 based on assumptions by Element Energy, Navigant and IEA.
WACC	2020 WACC for electrolyser units has been calculated as 12% using WACC assumptions for other renewable sources at early stages of adoption and following the trajectory of WACC reduction as the technology matures based on Lazard & NERA: Hurdle Rates for Electricity Generation assumptions.
Power price	Power price has been calculated using capture price forecasts for intermittent renewables from Bloomberg blended by forecast production volumes for each technology calculated in our analysis.

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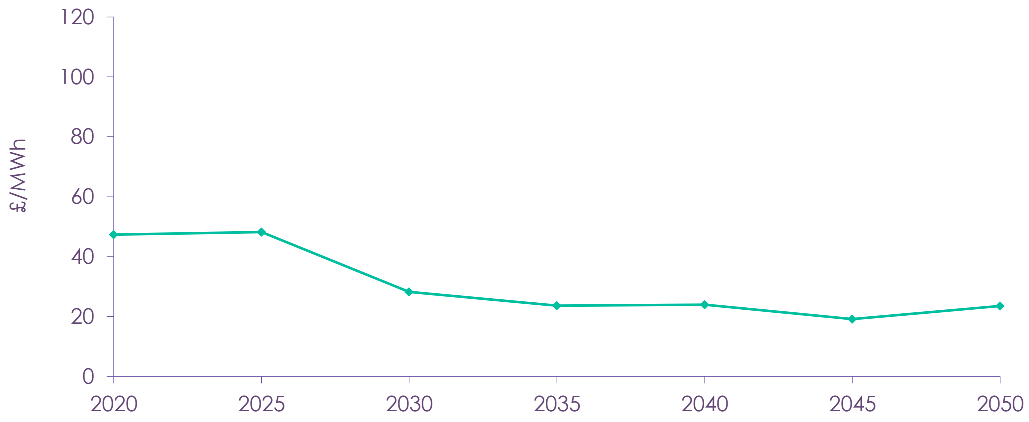
7 Green hydrogen levelised cost inputs | Power Price

Electrolyser input power price has been calculated using capture price forecasts for intermittent renewables by Bloomberg blended by forecast production volumes for each technology calculated in our analysis.

Capture price has been chosen as it reflects the market value that intermittent renewable generators could expect to receive in that period for each unit of power generated.

Blended Capture Price



Sources: BNEF

8 Blue hydrogen production methods | Production methods

Blue hydrogen is produced by converting natural gas and other hydrocarbons into hydrogen and a synthetic gas which is captured with carbon dioxide recovered and sequestered typically in depleted oil fields.

The two main technologies relevant for usage with UK's natural gas resource are steam methane reforming (SMR) and auto-thermal reforming (ATR).

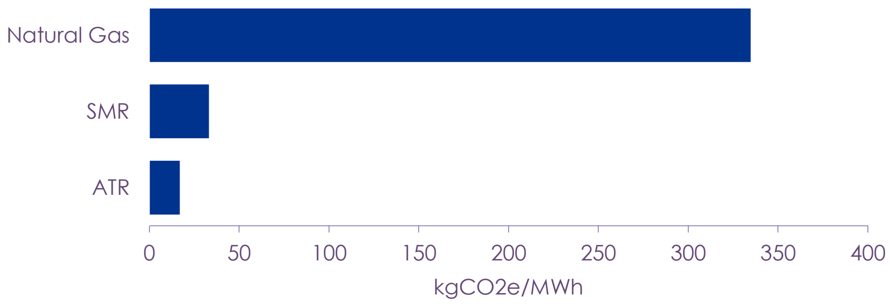
Steam methane reforming is a mature technology which is widely used across the refining and petrochemical industries using high temperature steam to split natural gas into hydrogen, carbon monoxide and carbon dioxide with the latter two, after processing, being transported to storage.

Auto-thermal reforming offers improved gas process efficiency by oxidising natural gas which provides heat for the subsequent reforming reaction and a higher potential carbon capture rate of 95% compared to 90% from SMR.

Both technologies are being evaluated for usage in the UK by 2 major hydrogen network projects with HyNet North West proposing to use 2 ATRs to produce hydrogen and H21 proposing to use SMR technology across the country for its proposed nationwide roll-out.

Roll-out of SMR/ATR capacity out to 2050 for Blue hydrogen production in our analysis is assumed to be 55% ATR and 45% SMR based on existing project pipeline in the UK and Navigant assumptions in 'Pathways to Net Zero'.

Carbon Intensity of Blue Hydrogen



Comparison of SMR/ATR Costs for unit producing 500 tonnes H2 per day

	SMR	ATR
Plant Energy Efficiency	0.78	0.82
Natural Gas Consumption (kwh/kwh H2)	1.355	1.197
CO2 Captured (tonnes/day)	4014	3927.3
CO2 Emitted (tonnes/day)	446	206.7
Total CO2 generated (tonnes/day)	4460	4134
Total Capex H2 production (£/kW H2 HHV)	529	554
Total Fixed Opex (£/kW/y)	25.38	24.41
Variable Opex (£/kWh/ H2)	0.00013	0.00013

Sources: Concepts for Large Scale Hydrogen Production: Jakobsen & Åtland, 2018, Hydrogen Supply Chain Evidence Base, Element Energy, IEA

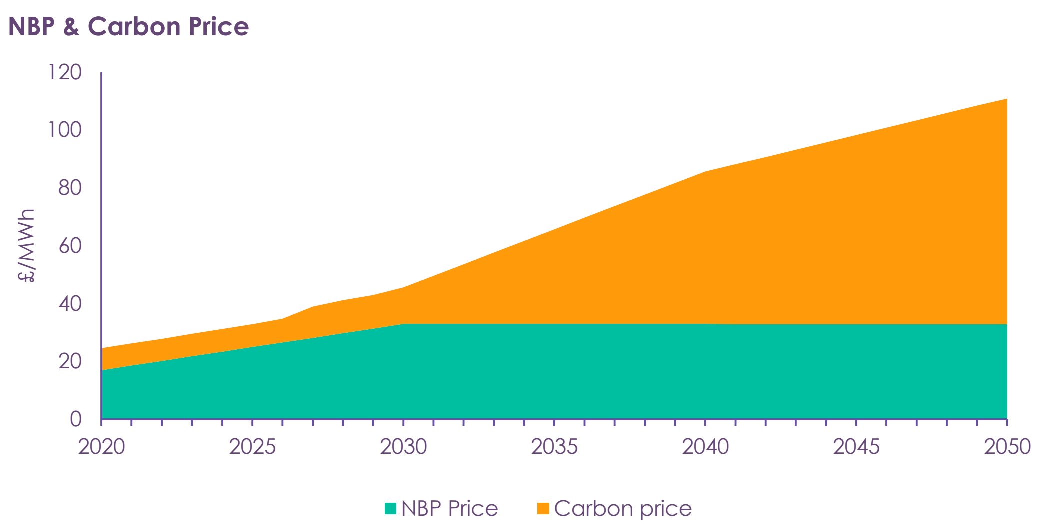
9 Blue hydrogen levelised cost inputs | Levelised cost of hydrogen

Blue capex	**Production:** 2020 capex is calculated as £529/kW per SMR Unit and £554/kW per ATR Unit based on assumptions from Concepts for Large Scale Hydrogen Production: Jakobsen & Åtland, Element Energy and Wood. Capex for each subsequent 5 year segment is calculated using Element Energy and Wood assumptions **Carbon Capture:** 2020 capex for capture technology is calculated as £342/kW per SMR Unit and £336/kW per ATR Unit as per BEIS and Concepts for Large Scale Hydrogen Production: Jakobsen & Åtland assumptions . An annual capex learning rate of 1.26% is assumed for a 10 year period with no capex reductions beyond 2030, based on BEIS and Wood assumptions.
Blue opex	**Production:** 2020 opex is calculated as £25.38/kW per year for each SMR Unit and £24.41/kW per year for each ATR unit based on assumptions from Concepts for Large Scale Hydrogen Production: Jakobsen & Åtland, Element Energy and BEIS. Opex for each subsequent 5 year segment is calculated using Element Energy and Wood assumptions **Carbon Capture:** 2020 opex for capture technology is calculated as £11.32/kW per year for SMR units and £11.11/kW per year for ATR Units as per BEIS and Concepts for Large Scale Hydrogen Production: Jakobsen & Åtland assumptions . An annual learning rate of 1.26% is assumed for a 10 year period with no further opex reductions beyond 2030, based on BEIS and Wood assumptions. CO_2 capture rate is calculated as 90% for SMR units and 95% of ATR units as per HyNet & Teesside Collective technical documents and Concepts for Large Scale Hydrogen Production: Jakobsen & Åtland for the whole period to 2050.
Blue asset life	Asset life is calculated to be 25 years for both ATR and SMR units built at any time from 2020 to 2050 based on assumptions in Concepts for Large Scale Hydrogen Production: Jakobsen & Åtland and Navigant: Gas for Climate.
Blue WACC	2020 WACC for SMR/ATR units and Capture Technology has been calculated as 10% using WACC assumptions for other renewable sources at early stages of adoption and following the trajectory of WACC reduction as the technology matures based on Lazard & NERA: Hurdle Rates for Electricity Generation assumptions.

9 Blue hydrogen levelised cost inputs | Gas + Carbon Price

We have adopted BEIS' forecasting for NBP gas and Carbon pricing within the UK market. Forecast resolution beyond 2020 is challenging, though the combined effect is a steadily increasing trajectory for unabated carbon costs.

The underlying NBP gas + carbon price shown here will contribute to the operational costs of Blue hydrogen.



Sources: BEIS, BNEF

10 T&S levelised cost inputs | Levelised cost of Transport and Storage

Transport and Storage capex	Transport and Storage capex is calculated as £94m per project based on HyNet & Teesside Collective technical documents for First of a Kind projects built between 2020 and 2030 and a 30% reduction is assumed for projects built from 2030 onwards based on BEIS CCS Cost Reduction Taskforce Assumptions
Transport and Storage opex	Transport and Storage opex is calculated as £11.9m a year per project based on HyNet & Teesside Collective technical documents for First of a Kind projects built between 2020 and 2030 and a 30% reduction is assumed for projects built from 2030 onwards based on BEIS CCS Cost Reduction Taskforce Assumptions
Annual pipeline capacity	Annual pipeline capacity is calculated as 10MtCO2 per year for each Transport and Storage facility based on HyNet, Teesside Collective and Caledonia Clean Energy technical documents.
Storage capacity	Total storage capacity for each storage site is calculated as 130MtCO2 based on HyNet, Teesside Collective and Caledonia Clean Energy technical documents.
Transport and Storage Asset Lifetime	Transport and Storage facility asset lifetime is fixed at 40 years for transport and storage projects built in any period from 2020 to 2050 based on Teesside Collective assumptions.
Transport and Storage WACC	2020 WACC has been calculated as 10% based on assumptions by Teesside Collective and forecast WACC reductions following the trajectory of WACC reduction of other early stage renewable technologies as they mature using Lazard & NERA: Hurdle Rates for Electricity Generation assumptions.

Production forecast

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Future hydrogen production

Gas production profiles have been calculated to meet the forecast gas demand through to 2050. Our analysis shows an inability to meet a Net Zero compliant emissions target in 2020 and action needs to be taken now to put us on the right path to achieving our Net Zero targets by 2050.

However, this can be addressed in 2025 by the addition of Blue hydrogen capacity enabled by the first CCUS projects becoming operational in that year. Blue hydrogen production remains constant through to 2030 as a result of gas demand falling at a steeper gradient than the allowable carbon emissions.

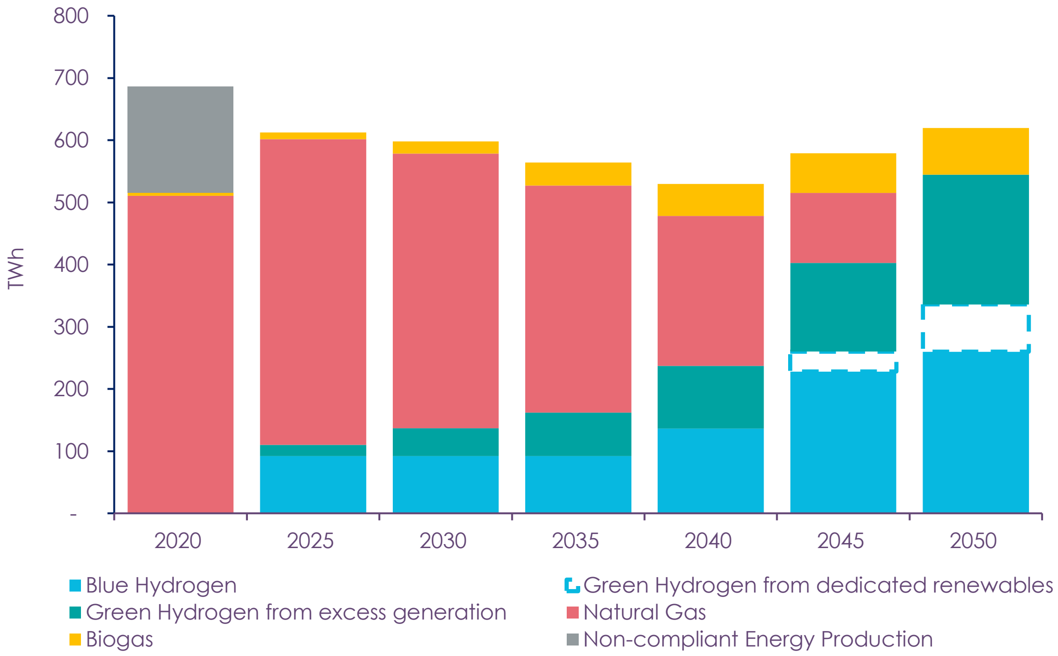
Beyond 2030, Blue hydrogen production continues to grow once more, driven as the volume of permissible natural gas emissions continues to fall.

Green hydrogen produced from this excess energy reaches a maximum of 209 TWh in 2050, consuming all annual renewable excess power generation available in that year.

Our analysis shows potential for an further 76 TWh of Green hydrogen from dedicated renewables by 2050. This is based on an assumed maximum build out of 22GW of dedicated offshore wind equivalent renewables in that period. We have assumed the maximum build-out rate which the UK supply chain could support would be equivalent to 150% of average renewables build-out rate over the 30 year period of 4.2GW per year, due to supply chain constraints.

In the absence of additional renewables build-out, this is fulfilled by Blue hydrogen.

Gas Production Profiles



Sources: National Grid FES, Exelon, BEIS, Navigant, CCC

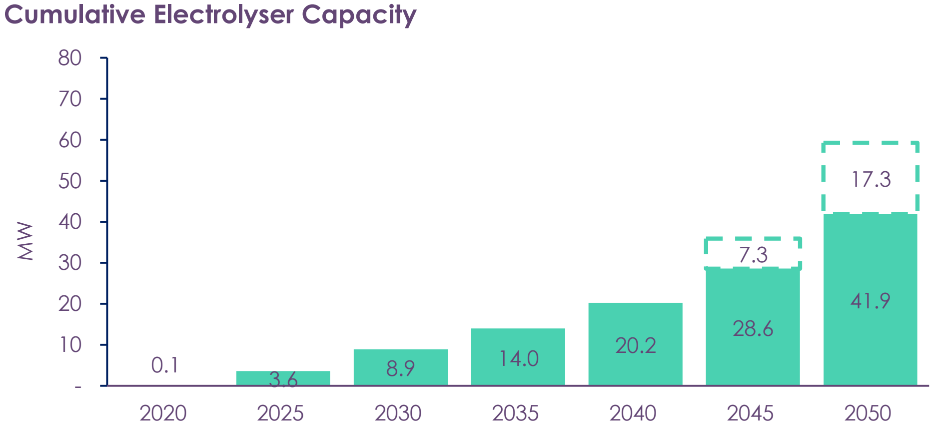
Green hydrogen; capacity and production

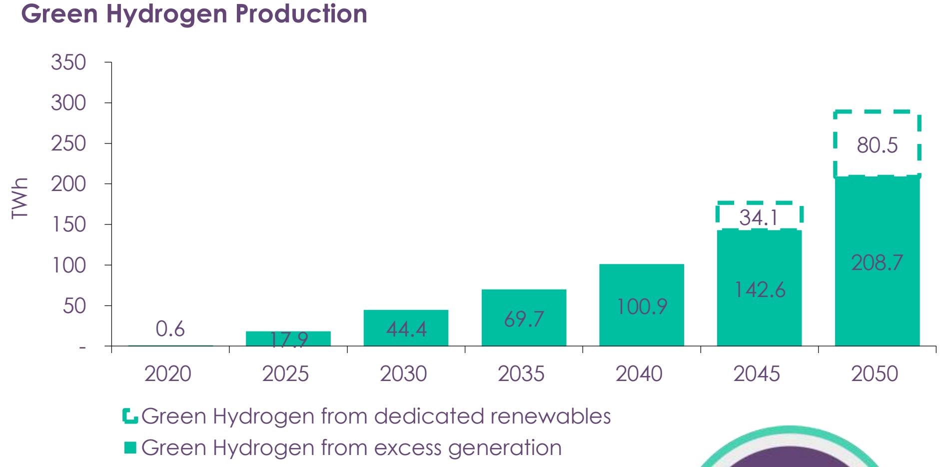
Due to limited excess renewable generation and high capex costs, initial growth in electrolyser capacity is slow, reaching 14 GW of cumulative electrolyser capacity in 2035. As the level of excess renewable generation grows and assumed global electrolyser capacity growth drives down capex costs, electrolyser capacity could increase up to 41.9 GW in 2050.

Over time, growth in production begins to outstrip growth in renewable capacity driven by technical advances leading to greater electrolyser efficiency.

A more aggressive buildout of renewable power capacity can emerge, specifically for the purpose of generating Green hydrogen once costs decline to the extent that this becomes more cost effective than Blue hydrogen. This is estimated to take place by 2045 in our analysis.

The addition of dedicated renewables for hydrogen production could offer supply of up to 80.5 TWh of Green hydrogen, based on an additional 17.3 GW of dedicated offshore wind equivalent renewable capacity.





Blue hydrogen; capacity and production

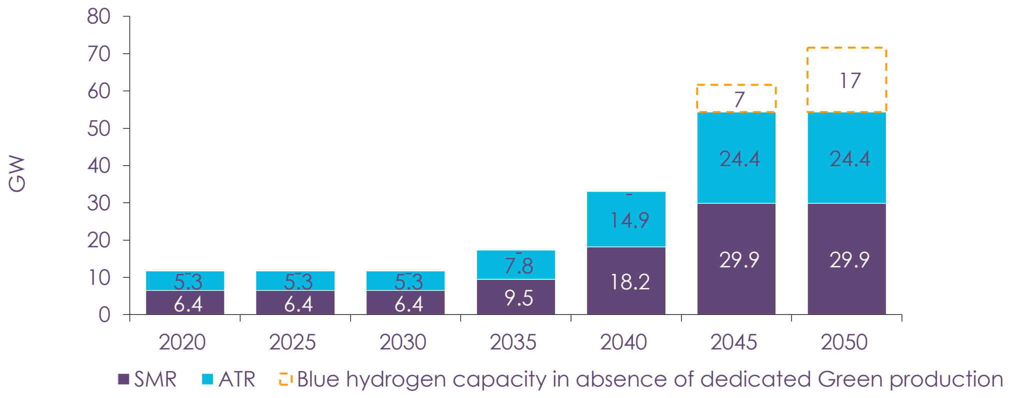
Blue hydrogen capacity build-out begins during the period 2020-2025, in anticipation of the first CCUS project being commissioned in 2025 as per BEIS objectives.

This capacity could reach up to11.7 GW in 2025 if timely deployment of CCUS infrastructure is enabled, giving investors the necessary visibility on future transport and storage connectivity.

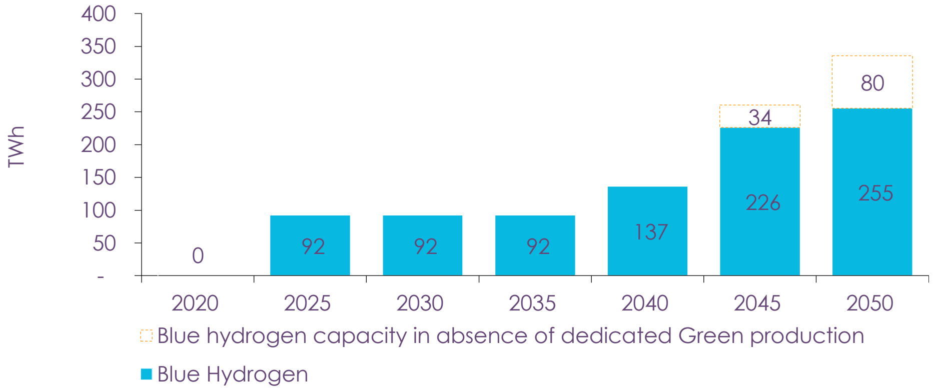
As unabated gas generation begins to fall away from 2035, in order to maintain Net Zero compliant emissions, Blue hydrogen capacity expands reaching a cumulative capacity of 54.3 GW by 2045, with no new-build capacity additions forecast thereafter.

Blue hydrogen production is forecast to commence in line with CCUS enablement in 2025, with production volumes of 92 TWh per annum. Production remains stable until 2040 due to the cost-competitiveness of unabated gas within allowable natural emissions before growing to 335 TWh in 2050 as emissions limits enhance and as Blue hydrogen falls below gas plus carbon in the merit order.

Blue Hydrogen Capacity Build-out



Blue Hydrogen Production



Cost trajectories

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Levelised cost of hydrogen production

Comparing levelised cost forecasts for hydrogen shows Green hydrogen production as the least cost technology from 2030 onward.

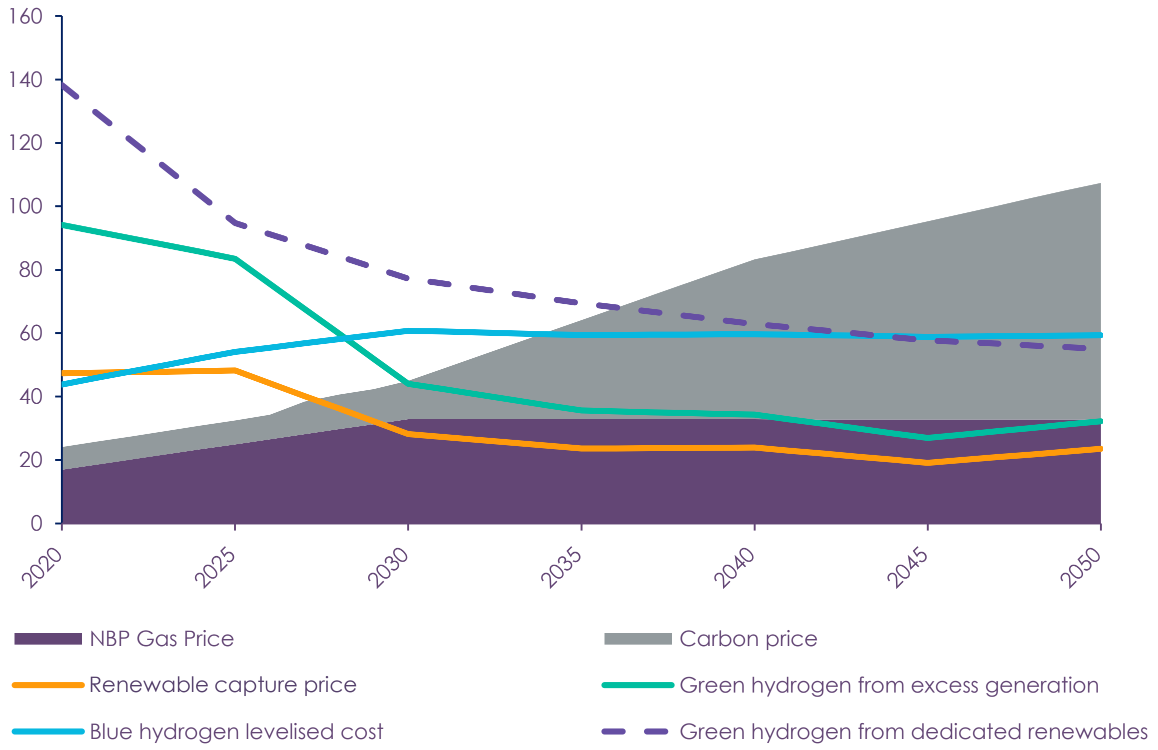
Blue hydrogen remains the most cost effective low-carbon hydrogen technology through to 2030, becoming cost competitive with unabated gas by 2040, driven predominantly by the carbon price. Blue hydrogen cannot be cost competitive with natural gas in the absence of a carbon price, due to the efficiency loss in converting natural gas to hydrogen.

Potential capex cost reductions realised through a strong global electrolyser rollout to 2030 rapidly drives down the cost of Green production from excess generation. In combination with lower input power prices, this makes green hydrogen from excess generation cost competitive with Blue hydrogen and other unabated technologies by 2030 under a Net Zero compliant scenario.

Green hydrogen production from dedicated renewables is more expensive than utilising excess power in a dual power/gas market, due to the requirement to support the full cost of the renewable asset. However, this still has the potential to become cost-competitive with Blue hydrogen by 2045.

These cost profiles demonstrate that investment into Green hydrogen production should be prioritised within build out constraints, as this technology has the potential to provide the least-cost Net Zero consistent energy supply.

Hydrogen cost comparison



Levelised cost of Green hydrogen

Early cost reductions in Green hydrogen are driven by capex savings resultant from global uptake of hydrogen. These are expected to be realised across design and manufacturing optimisations as global installed capacity increases from 0.1GW today, to an estimated 1700 GW by 2050.

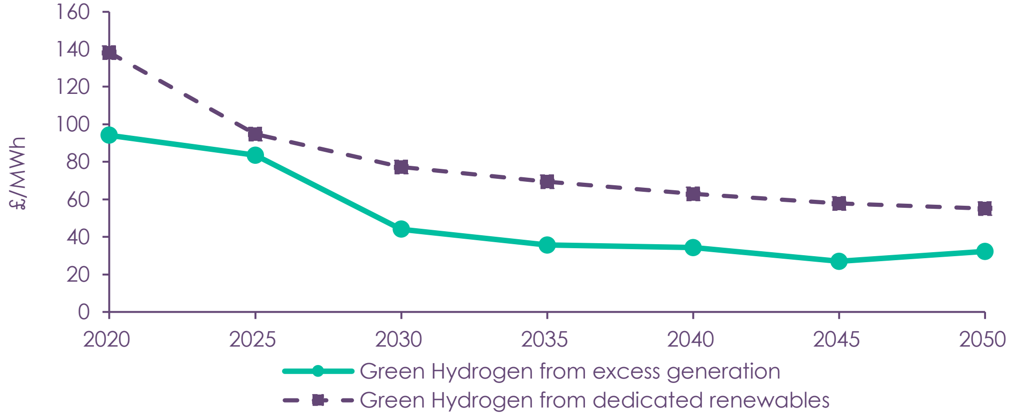
Supportive government policy into Green hydrogen production methods could drive earlier realisation of capex reductions.

This is compounded in 2030 as the removal of conventional generation leads to lower electricity wholesale prices in the market, driven by the penetration of zero marginal cost power generation.

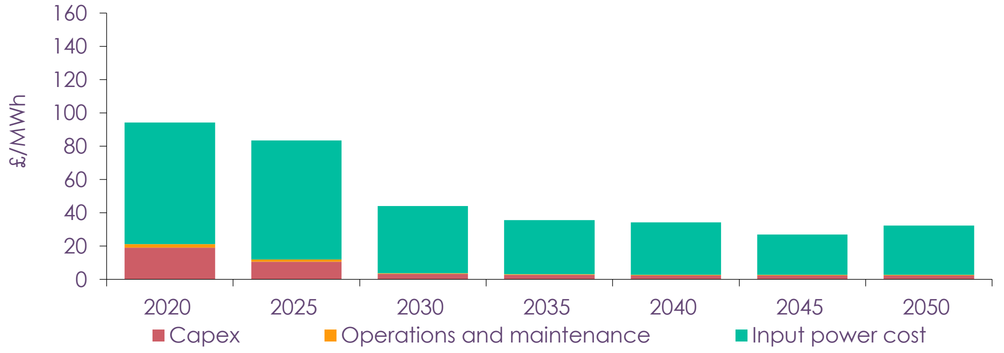
By 2035, the majority of capex cost reductions are realised, with the levelised cost of production continuing to be exposed to the prevailing power pricing onwards.

Green hydrogen production from dedicated renewables (offshore wind equivalent) follows a steeper initial cost reduction driven by a fall in the levelised cost of dedicated renewables. However, this fails to reach parity with hydrogen from excess renewables due to the requirement to support the full cost of the renewable asset.

Green Hydrogen LCOE



Green hydrogen from excess generation cost breakdown



Levelised cost of Blue hydrogen

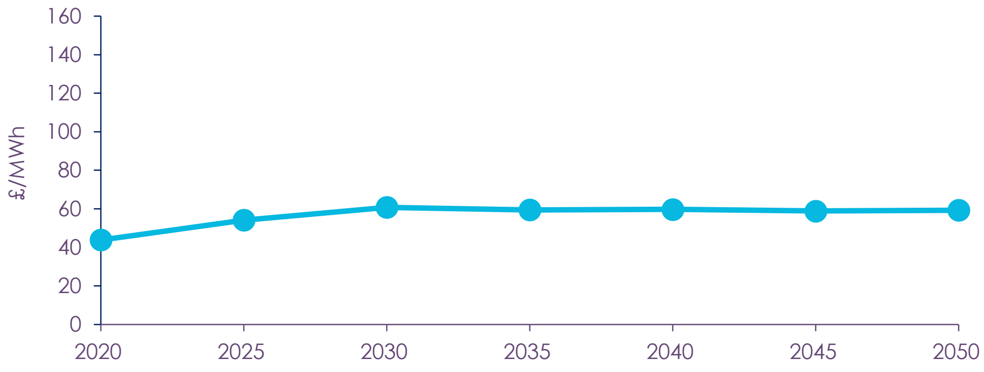
A consistent increase in input fuel costs drive growth in the levelised cost of blue hydrogen, despite early capex cost reductions of both SMR/ATR and carbon capture technology.

Some cost reductions are seen across the Carbon Capture and Storage components, though in the case of Transport and Storage, this has been levelised across the T&S asset, on the assumption of a 'user pays' model for carbon sequestration.

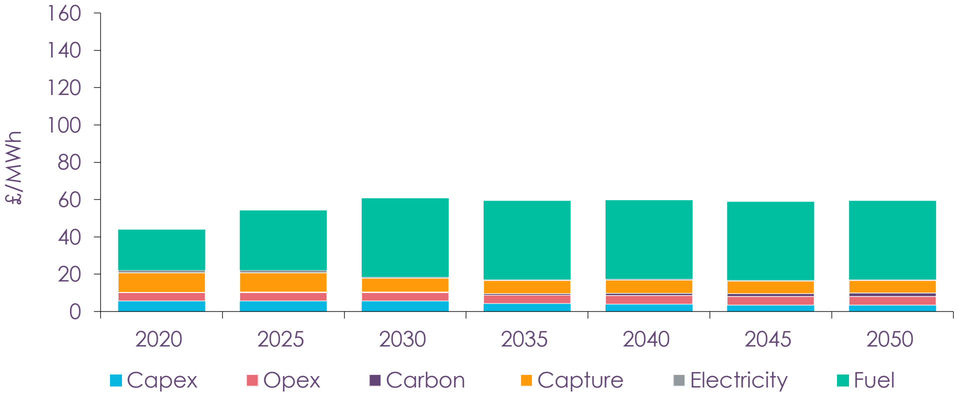
A supportive policy and regulatory framework is required to promote the long-term development of Transport and Storage facilities to realise cost reductions in this cost segment of Blue hydrogen.

The levelised cost of Blue hydrogen remains heavily exposed to gas and carbon pricing through to 2050. Reductions in gas pricing during this period could see levelised costs falling. However, market fundamentals do not support a price reduction, given the sustained demand for gas which is itself driven by the uptake of Blue hydrogen.

Blue Hydrogen LCOE



Blue hydrogen LCOE breakdown



Mid and downstream cost review

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Summary of mid and downstream review

Midstream costs

1	**Distribution costs**	The cost of repurposing the distribution network including the replacement of gas network components has been estimated for our central case at **£22.2 billion** using the base case of Element Energy & Jacobs that 100% of the of the distribution network components have to be replaced on a like for like basis. Due to uncertainties over the percentage of network components that require replacement, we have taken **£7.7 billion** as our low case and **£26.7 billion** as our high case.
2	**Transmission costs**	We have therefore treated the establishment of an entirely new high pressure transmission pipeline network to transport hydrogen to local distribution networks as a high-cost scenario with no entirely new transmission pipeline being built in our central case. The cost of set up of a national hydrogen transmission network for our high case has been calculated using an average of aggregated sources using an assumed network length of **7,000km** and **£1.2m per km** of pipeline, giving a total cost of **£8.4 billion.**
3	**Residential Costs**	We have calculated an average cost of conversion as **£3,300 per property** as our central assumption giving a total cost for converting residential properties for our central case as **£80.9 billion.** Sensitivities have been shown using the upper and lower bounds of total costs per property from our aggregated sources from **£3,000 per property** to **£4,000 per property** giving a cost for residential conversion in our low case as **£71.7 billion** and **£95.6 billion** in our high case.
4	**Commercial Costs**	The cost of converting commercial premises to hydrogen has been calculated in our central case as **£5.9 billion** by drawing upon Element Energy assumptions for cost of pipework and boiler replacement for commercial usage and using BEIS data on commercial premise sizing and number of non-domestic gas meter points. Using sensitivities around the average boiler and installation costs, the total cost of commercial premise conversion has been calculated as **£4.7 billion** in our low case and **£7.0 billion** in our high case.
5	**Industrial Costs**	The total capex cost to convert UK industrial equipment used primarily for production of heat uses Hy4Heat analysis by Element Energy and Advisian which calculated **£2.7 billion** as the base case which we have carried forward as our central case. We have carried the lower and upper bounds as calculated in the report with £1.0 billion as our low case and **£3.9 billion** as our high case.

Midstream transmission and distribution costs

Our midstream cost review is split into two aspects: 1) conversion of transmission networks; and 2) conversion of distribution networks. The analysis assumes conversion of the distribution networks is critical for widespread hydrogen uptake due to the intention of decarbonising decentralised emissions such as residential and commercial heating. However, the conversion of the transmission network remains subject to requirement. Where hydrogen supply and demand is managed on a localised basis, within the distribution network, transmission infrastructure of equivalent scale to the existing Natural Gas pipelines may be unnecessary. We have therefore treated the establishment of an entirely new high pressure transmission pipeline network to transport hydrogen to local distribution networks as a high-cost scenario.

1

Distribution

The cost of repurposing the distribution network including the replacement of gas network not covered under the Iron Mains Replacement Program and replacement of network components has been estimated at **£22.2 billion** using the central case of Element Energy & Jacobs that 100% of the of the distribution network components have to be replaced on a like for like basis.

Due to uncertainties over the percentage of network components that require replacement, a range of **£7.7 to £26.7 billion** has been calculated. The low sensitivity assumes only 50% of iron/steel pipeline and 20% of gas meters and detectors need replacing whilst the high case assumes 150% of all network components must be replaced.

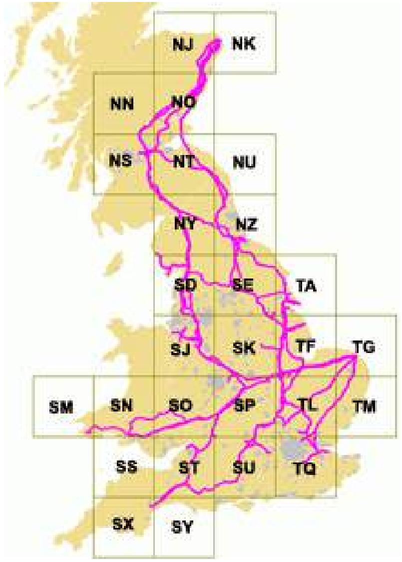
2

Transmission

We have aggregated data from a number of sources on the length and cost of establishing a national hydrogen transmission based on an assumed network length of **7,000km.** The outturn cost estimate is equivalent to **£1.2m per km** of pipeline, giving a total cost for the hydrogen transmission network at **£8.4 billion.** This assumes a graduated establishment of a national transmission network from 2025 to 2052 as per the national roadmap supported by the H21 Leeds City Gate report.

Sensitivities for the national transmission network have been incorporated based on the range of pipeline costs seen across our literature review. This provides a range of **£1.0 - £1.46m per km** giving a sensitivity range for the total cost of the hydrogen transmission network of **£7.0 to £10.2 billion.** The data supporting this is shown overleaf.

Current GB Gas Transmission Network



Sources: National Grid

2

Midstream transmission costs

A range of public sources have been aggregated and used in our calculations to come up with a total cost for a new-build hydrogen transmission network.

Source	Description	Unit cost	Total Stated Cost
Element Energy & E4Tech, Cost analysis of future heat infrastructure, 2018	Models a national hydrogen transmission pipeline connecting SMR generation plants to all of its downstream connected authorities. Local transmission network of around 6300km in length and average pipeline diameter of 400mm	£1.46m per km	£9.2bn
Element Energy, Hydrogen supply chain evidence base, 2018	A national hydrogen transmission network of 7,623km of an inlet pressure of 10MPa is required produces the lowest lifetime cost at £25.9bn with a pipeline cost of £1.4m per km for a pipeline with diameter of 650mm and £0.9m per km for a pipeline with a diameter of 400mm	£1.4m per km	£25.9bn
Frontier Economics, Future Regulation of the Gas Grid, 2016	A hydrogen transmission network of 10km per Local Authority corresponding to a total national transmission network of 2,530km is required at a cost of approximately £1.2m per km	£1.2m per km	£3.0bn
NGN H21 Leeds City Gate Report, 2017	For the Leeds City Gate project, the Hydrogen transmission pipeline from SMR facilities in Teesside to the distribution network in Leeds and to deep salt cavity storage would total £196m for a 114km pipeline with a diameter of 650mm and a 76km pipeline with a diameter of 450mm	£1.03m per km	n/a
Imperial College London and Sustainable Gas Institute, A Greener Gas Grid: What are the options?, 2017	Average cost of new hydrogen ready high pressure transmission infrastructure is approximately £1.15m per km	£1.15m per km	n/a
Cadent, Liverpool-Manchester Hydrogen Cluster Report, 2017	Transport of 936MW of hydrogen at 17 bar in new 90km onshore hydrogen transmission pipeline from SMR complex to industrial cluster would cost £1m per km	£1m per km	n/a

Downstream costs

Our downstream cost review is split into three categories: 1) conversion of residential heating; 2) conversion of commercial heating; and 3) industrial heating to be hydrogen-ready. In order to align with Net Zero emission targets, it is assumed that 100% of the existing gas-grid connected sites in the residential and commercial categories will be required to convert to hydrogen by 2050.

The Future Homes Standard to be brought in in 2025 will require all new-build residential properties to use low-carbon heating systems, sighting electrification as the preferred option due to it's compatibility with well-insulated new build housing. Therefore we have assumed that all new-build residential and commercial property beyond 2025 will not require conversion to hydrogen. However, electric technologies such as heat pumps are unlikely to be able to meet the elevated heat demand requirements of the existing housing stock. We have therefore assumed hydrogen will be used to decarbonise this existing housing stock.

3

Residential
Conversion of residential heat to hydrogen comprises the replacement of boilers, pipework and other gas appliances (hobs, ovens, heaters etc.) with hydrogen-ready equivalents. We have calculated the cost of conversion as **£3,300 per property** as our central assumption by taking an average of each cost component from aggregated data giving a total cost for converting residential properties of **£80.9 billion.** Sensitivities have been evaluated using the upper and lower bounds of total costs per property from our sources with a range of **£73.5 to £98 billion.**

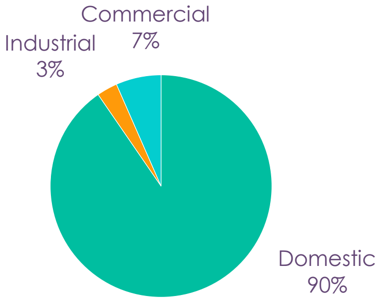
4

Commercial
We have calculated the cost of converting commercial premises to hydrogen as **£5.9 billion** by drawing upon Element Energy assumptions for cost of pipework and boiler replacement for commercial usage and using BEIS data on commercial premise sizing and number of non-domestic gas meter points. Using sensitivities around the average boiler and installation costs, we have calculated a range for commercial premise conversion of **£4.7 to £7.0 billion.**

5

Industrial
Hy4Heat analysis by Element Energy and Advisian calculated the total capex cost to convert UK industrial equipment used primarily for production of heat at **£2.7 billion** which we have carried forward in this analysis with sensitivities giving a **range of £1.0 to £3.9 billion**.

Breakdown of downstream costs by segment



Downstream segment	Total Cost (£bn)
Domestic	80.9
Industrial	2.7
Commercial	5.9
Total	**89.5**

3 Downstream residential costs

Decarbonising residential heating requires significant intervention at a individual household level and utilising hydrogen offers a pathway of minimal disruption for the existing household stock connected to the gas grid.

Conversion of residential heat to hydrogen comprises the replacement of boilers, pipework and other gas appliances (hobs, ovens, heaters etc.) with hydrogen-ready equivalents and the cost of labour/overheads of each task. We have aggregated data from a number of sources on the individual cost components of conversion of residential premises and we have calculated the total cost per property by taking an average of aggregated data on each cost component based on the following data points. It is assumed all gas-grid connected properties have an associated boiler and one gas appliance that require replacement.

To calculate the total cost of conversion of residential properties, we are drawing upon data from ONS and OFGEM to calculate the number of residential households that are connected to the gas grid at 2025 and using an assumption that every residential household already connected to the gas grid will be converted to hydrogen. This sets aside new build housing, which is likely to be constructed with electric heat pumps (Future Homes Standard). However, we have assumed electrification is not suitable for older housing stock based on Element Energy and E4Tech's Cost Analysis of Future Heat Infrastructure report which states:
"Heat pumps operate more efficiently at lower output temperatures, and are therefore less suitable in thermally-inefficient buildings where high temperature heating may be required during cold periods".

Based on the above, we have calculated an average cost of conversion as **£3,300 per property** as our central assumption giving a total cost for converting residential properties of **£80.9 billion.** Sensitivities have been analysed using the upper and lower bounds of total costs per property from our sources ranging from **£3,000 per property** to **£4,000 per property** giving a range for total residential conversion costs of **£71.7 to £95.6 billion.**

Total domestic costs per property

Cost segment	Cost (£)
Appliance	1,700
Labour	1,000
Overheads	500
Pipework	100
Total	3,300

Industry snapshot

UK based boiler manufacturers Worcester Bosch and Baxi have both unveiled 100% hydrogen boilers, in anticipation of a ban on oil and natural gas boilers from 2025. Both manufacturers are also developing units which can operate at varying concentrations of hydrogen in the natural gas stream.

3

Downstream residential costs

A range of public sources have been aggregated and used in our calculations to come up with a total cost of conversion of each gas-grid connected household built before 2025.

Source	Description	Stated cost
Imperial College London and Sustainable Gas Institute, A Greener Gas Grid: What are the options?, 2017	Cost of conversion per household, including pipework, boiler modification and meter replacement is estimated between £3000 – £3600 with cost of individual hydrogen boilers estimated at £1100 - £2200	£3,000 - £3,600 per household
NGN H21 Leeds City Gate Report, 2017	Cost of conversion per property in representative Leeds local authority was £3,078 per household comprising £842 for manpower, £1,723 for hydrogen ready appliances (£850 for hydrogen boilers and £300 for other appliances) and £513 overhead for GDNs for managerial and regulatory costs.	£3,078 per household
Imperial College London, Analysis of Alternative UK Heat Decarbonisation Pathways, 2018	Cost of conversion per household is estimated at £4,000 per household with hydrogen boiler costs of £3000 and each gas appliance replacement cost as £500 per unit	£4,000 per household
Frazer-Nash Consultancy, Logistics of Domestic Hydrogen Conversion, 2018	Labour costs per household conversion total £1,110 comprising £100 for initial surveying, £150 - £300 for pipework upgrades and £500 - £600 for appliance conversion/installation	£750 - £1150 labour costs per household
KIWA & E4Tech, DECC Desk Study on the development of a hydrogen fired appliance supply chain, 2016	Hydrogen boilers can be manufactured at volume (10,000 to 100,000 units per year at ~1.5 times current ex-works cost at £700 – £1,100	£700 - £1,100 per domestic hydrogen boiler

Downstream commercial & industrial costs

Emissions from downstream industrial and commercial heating together comprise 24% of the UK's annual carbon emissions, according to BEIS data, the second largest segment after surface transport, showcasing the importance of decarbonising this challenging sector.

4

Commercial

We have calculated the cost of conversion of commercial premises by using non-domestic gas meter points as a measure of gas-grid connected commercial premises and assuming each meter point will have an associated boiler that requires conversion.

We are using the assumption that no new meter points are connected by 2025 based on historical data and beyond 2025, new-builds will have low-carbon heating that doesn't require conversion.

Drawing upon Element Energy assumptions for costs of boiler replacement for commercial premises and BEIS data on commercial premise sizing, the total cost of conversion of commercial premises has been calculated as **£6.2 billion.** Using sensitivities around the average boiler and installation costs, we have calculated a range for the conversion of commercial premises at **£4.7 to £7.0 billion.**

5

Industrial

Hy4Heat analysis by Element Energy and Advisian calculated the total capex cost to convert industrial equipment used primarily for production of heat (sites with usage of >1GWh/year of gas). The total capex cost including the conversion of industrial heating equipment and site-wide gas distribution pipelines is calculated as **£2.7 billion** which we have carried forward in this analysis with sensitivities giving a **range of £1.0 to £3.9 billion**.

Commercial heat conversion costs

Commercial premise distribution by floor area	No of boilers	Total Installation Cost per premise (£)	Total Cost per Group (£bn)
'Small' Commercial Premises	98,000	13,000	1.27
'Medium' Commercial Premises	95,200	20,250	1.93
'Large' Commercial Premises	86,800	35,000	3.04
Totals	**280,000**		**6.24**

Industrial heat conversion costs

Industry	Conversion capex (£m)
Elec and mech engineering	660
Food and drink	460
Vehicle manufacturing	410
Chemicals	340
Other industry	310
Basic metals	160
Ceramics	110
Paper	100
Glass	65
Other NM minerals	60
Lime	10
Total Cost	**2685**

Total System Costs

Cost of hydrogen conversion

Analysis of the total system cost shows a net saving, resultant from carbon savings as hydrogen becomes a cheaper source of energy than natural gas.

In the absence of a clear plan from government detailing how the UK will meet Net Zero, the market will continue to use natural gas. We have therefore adopted this scenario as our 'business as usual' scenario.

Based on the BEIS gas and carbon price forecasts, the total cost of meeting the UK's gas demand requirements using unabated technology is equivalent to £1.4 tn over the forecast period. This is largely driven by the carbon price in the latter years.

Applying the combined costs we have identified through this study, the costs of converting to and operating a hydrogen based economy in the period to 2050 is equal to £1.3 tn.

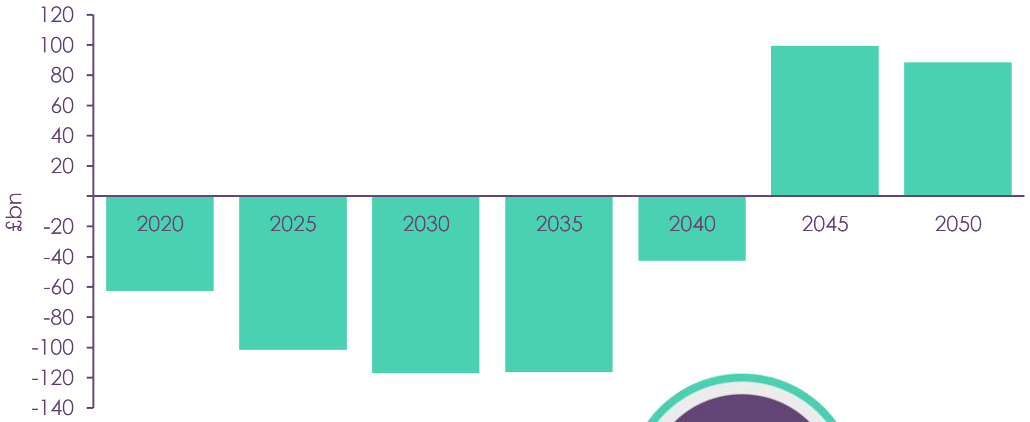
Analysis of the system cost profile shows an initial cost of developing the hydrogen network through the period to 2035. This cost represents investment into new infrastructure, technological advancement, supply chain development and conversion of point of use technology which enables a Net Zero economy.

This investment is paid back over the long term, as hydrogen insulates the economy from the cost of carbon emissions. The result is a net saving, whilst delivering the Government's Net Zero ambitions for the gas sector.

Total system cost (£bn)

Supply chain segment	Unabated	Net Zero
Upstream		
Green Hydrogen	-	99
Blue Hydrogen	-	579
Nat Gas	1,390	512
Midstream		22
Downstream		90
Total System Cost	**1,390**	**1,301**

Rolling NPV of the UK's hydrogen economy



Cost to customer

On a pence per kWh basis, conversion to hydrogen offers a net saving to customers versus the costs of sustained natural gas utilisation.

The total system cost is divided by total production volumes of hydrogen to arrive at a unit cost for each kilowatt-hour of hydrogen power.

Baseline cost to customer assumes natural gas represents all gas consumption throughout the forecast period to 2050.

Baseline cost to customer (natural gas) — **5.97p per kWh**

Net Zero cost is calculated as the difference between the levelised cost of hydrogen and natural gas + carbon price in each 5 year interval divided by total gas demand to arrive at a net unit cost for each kilowatt-hour of hydrogen.

Net Zero cost to customer — **5.59p per kWh**

Net cost to customer for a Net Zero compliant hydrogen economy is calculated by subtracting the baseline cost from the calculated Net Zero cost.

Net cost to customer — **-0.38p per kWh**

Sensitivities

Sensitivities – Carbon Price

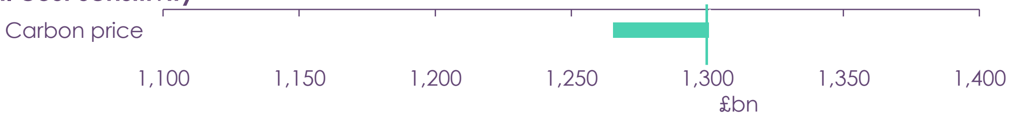
In our carbon price sensitivity case, we have adopted a lower carbon price forecast, as per the National Grid FES central case. FES forecast the GB carbon price as a combination of an EU Emissions Trading Scheme (EU ETS) linked programme and the GB carbon price support (CPS).

Total hydrogen production volumes remain broadly unchanged, as they continue to be driven by allowable carbon emissions. In the green upside case, the intersect between the cost of Green hydrogen from dedicated renewables and Blue hydrogen remains close through to 2040, leading to little change in the potential for this technology.

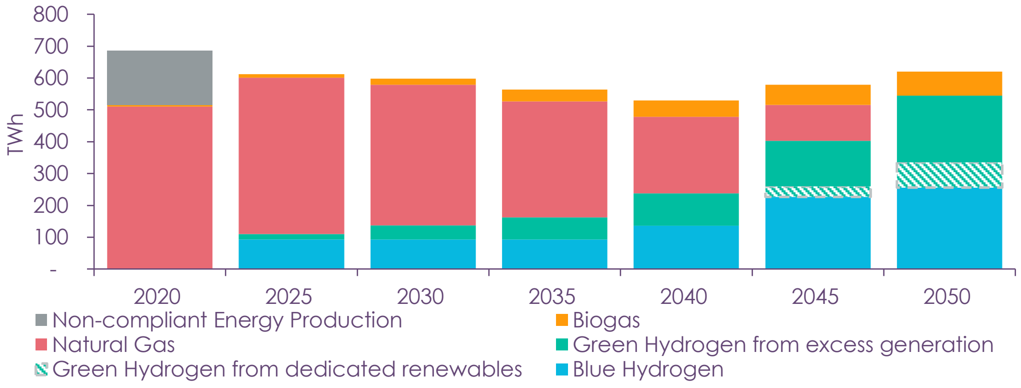
The effect of this is to significantly reduce the differential between hydrogen and the gas plus carbon price. In this case, Green hydrogen remains the least cost technology from 2030, with Blue hydrogen following a similar profile to that of gas plus carbon.

Little change in the volume of production coupled with a significant reduction in the saving per megawatt hour in comparison to natural gas utilisation sees a significant increase in the net cost of hydrogen conversion. In this case, the UK is denied the opportunity to recover costs in later years. This illustrates the requirement for investment in the short term to maximise roll-out of low cost Green hydrogen, as the least cost Net Zero compliant gas source.

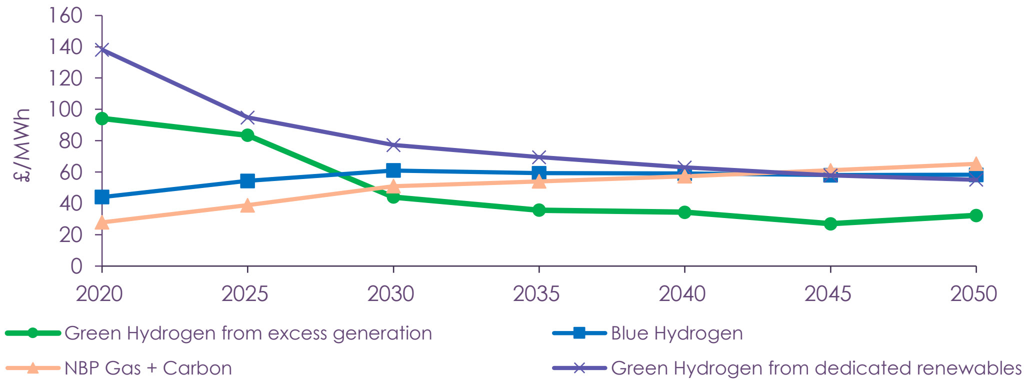
Total cost sensitivity



Gas Production Profiles



Levelised cost of hydrogen



Sensitivities – Allowable emissions

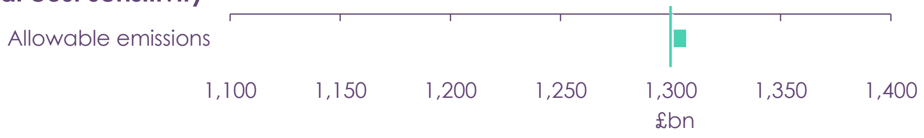
Adjustment of the carbon budget forecast driving alignment with existing budgets rather than a smoother Net Zero trajectory increases the volume of natural gas which can be utilised in any given year.

This drives a much later uptake of blue hydrogen, as there is no requirement to decarbonise gas until emissions limitations bite in 2045. Green hydrogen from excess renewables continues to develop from 2030, driven by the opportunity to improve integration of renewable power generation. This scenario assumes renewables buildout is unaffected by this adjustment, given the UK Government has committed to existing carbon budgets and renewables targets.

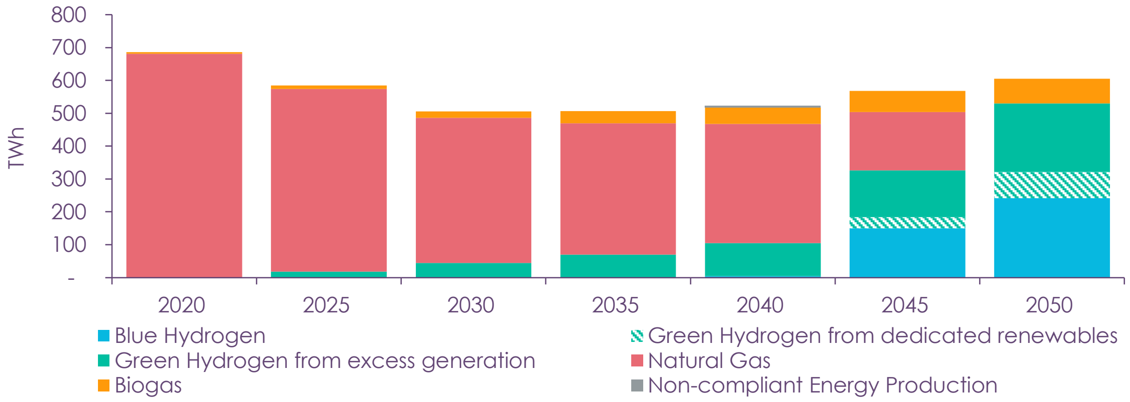
Levelised costs remain unchanged as capex reductions continue to be driven by global uptake.

The net result of this delayed uptake is an increase in net costs, as late adoption of hydrogen sacrifices the opportunity to recover this investment in later years. The UK will also fail to capture the GVA potential associated with establishing a hydrogen economy.

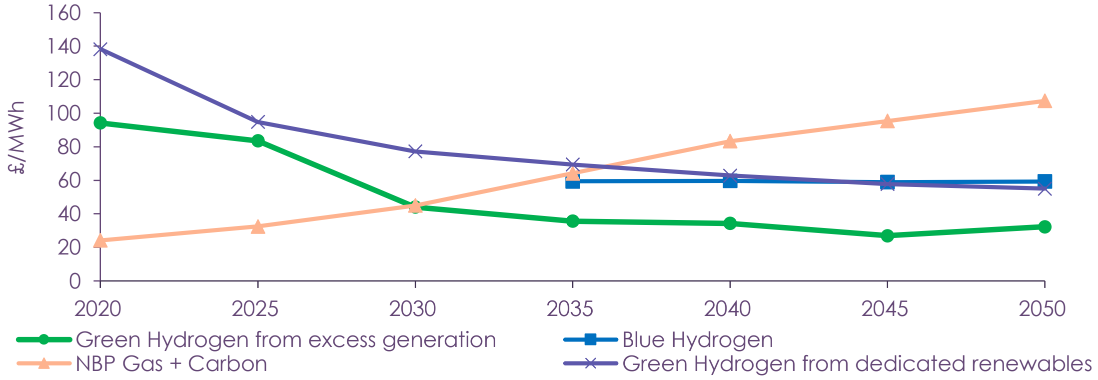
Total cost sensitivity



Gas Production Profiles



Levelised cost of hydrogen



Sensitivities – Electrolyser efficiency (low)

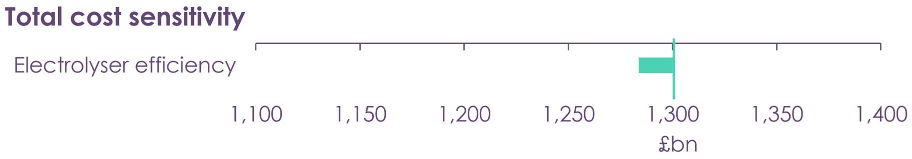
In our low electrolyser efficiency sensitivity case, we have assumed electrolyser efficiency remains at 65% throughout the forecast period.

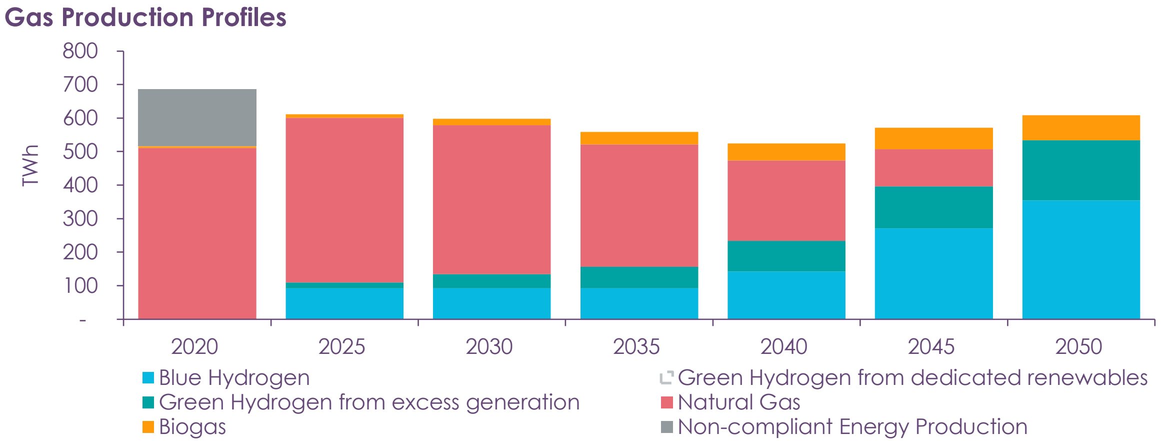
The effect is to limit the output volume of Green hydrogen resultant from excess renewables proportionately. This low efficiency also denies the UK the opportunity for dedicated renewables build out as the levelised cost of Green hydrogen from dedicated renewables is unable to out perform that of Blue hydrogen.

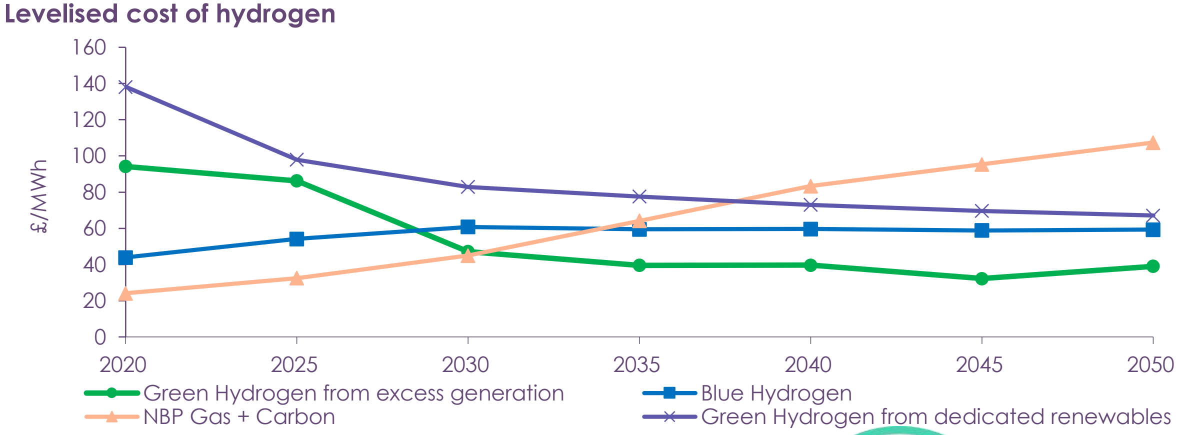
This results in much heavier reliance on Blue hydrogen through the forecast period.

The total cost of operating the system in this way also increases, as access to savings from the utilisation of low-cost Green hydrogen are unavailable.

This highlights the need for early investment into Green hydrogen and suggests the case for dedicated renewables for Green hydrogen is predicated on material improvement to electrolyser efficiency.







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Sensitivities – Input power price for electrolysis (low)

Due to the uncertainty around electrolyser input power pricing, we have presented a broad range of prices. In the low case, we have adopted a £0 /MWh price for electrolyser input power for Green hydrogen produced from excess generation as it relates to period of oversupply.

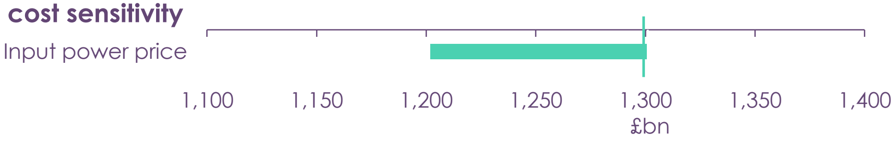
This has a limited effect on production as Green hydrogen remains limited by the volume of excess power available and the assumed limit to additional renewables build out.

On a levelised cost basis, Green hydrogen from excess renewables is now markedly cheaper than other forms of gas. It is possible in this scenario that arbitrage with other energy vectors could see wider uptake of hydrogen over electrification, thereby resulting in greater volumes of excess power generation. The impact of hydrogen on the electricity market exceeds the scope of this report.

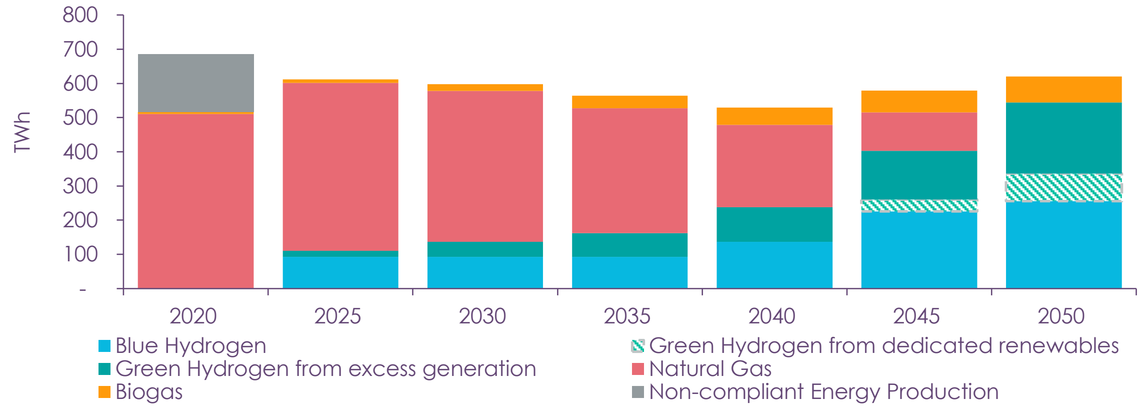
Hydrogen production from dedicated renewables remains unchanged, as this is reliant on the LCOE for renewable asset.

This inherently results in a net saving, driven by the cost of green hydrogen.

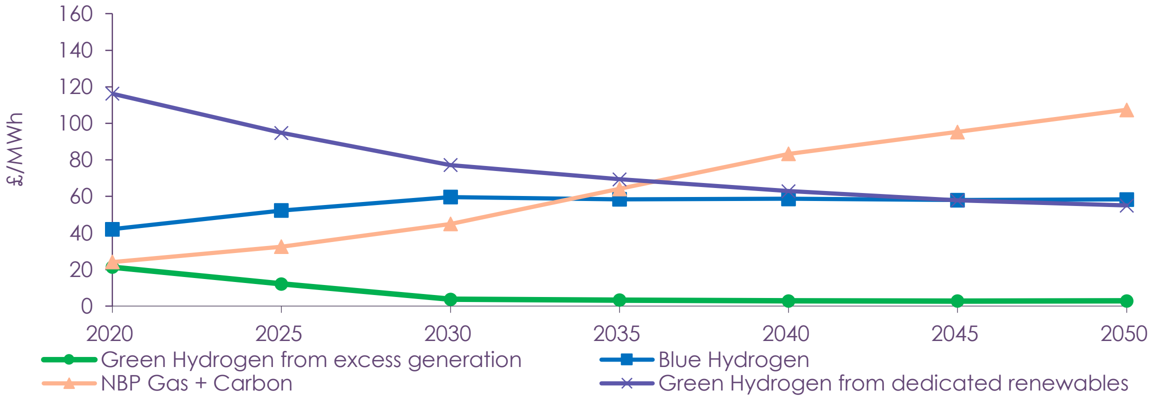
Total cost sensitivity



Gas Production Profiles



Levelised cost of hydrogen



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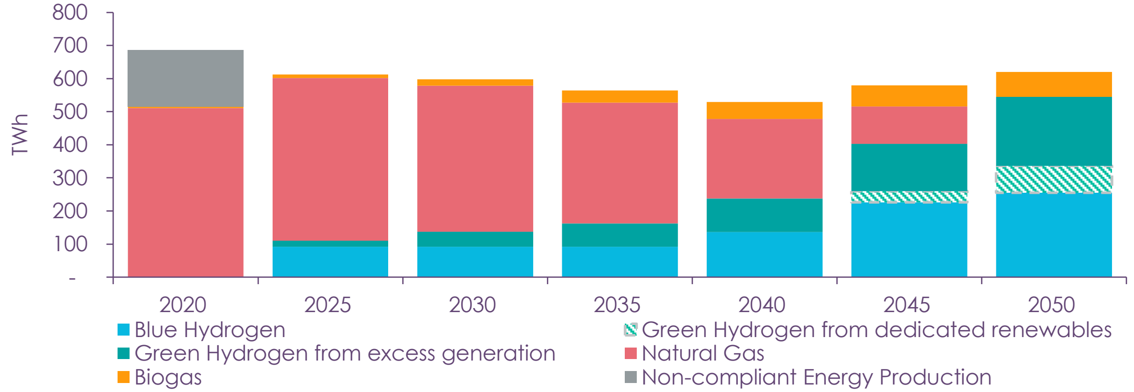
Sensitivities – Input power price (high)

We have also measured the inverse effect of a high power price. In this case, we have adopted the levelised cost of renewable power as the input power price.

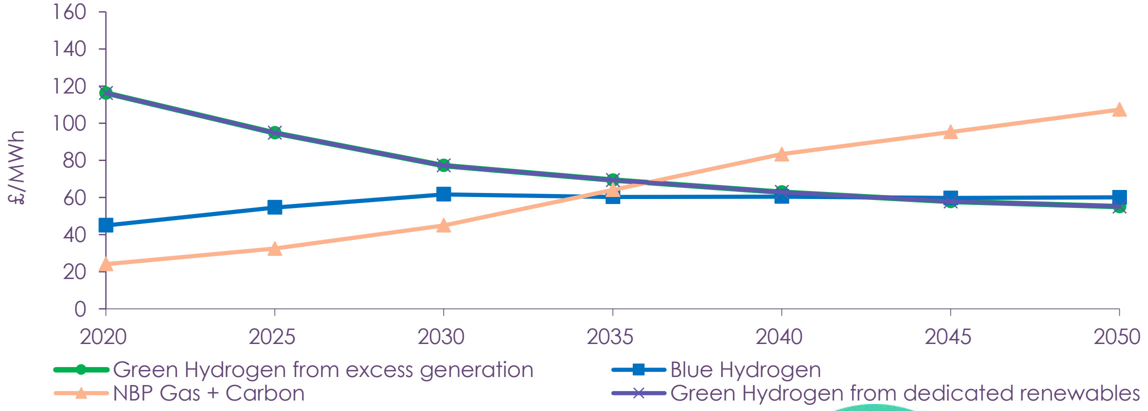
Production profiles remain largely unchanged, though the cost of green hydrogen from excess power is now equivalent with that coming from dedicated renewables.

Here the effect is to increase the total cost, proportionate to the uplift in green hydrogen pricing.

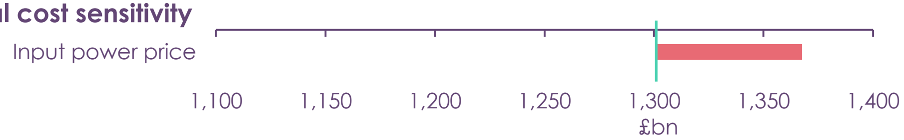
Gas Production Profiles



Levelised cost of hydrogen



Total cost sensitivity

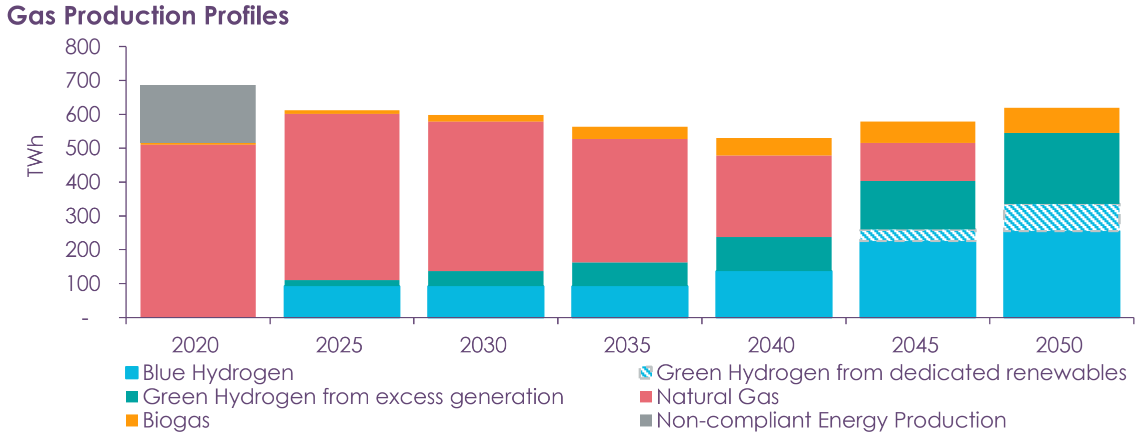


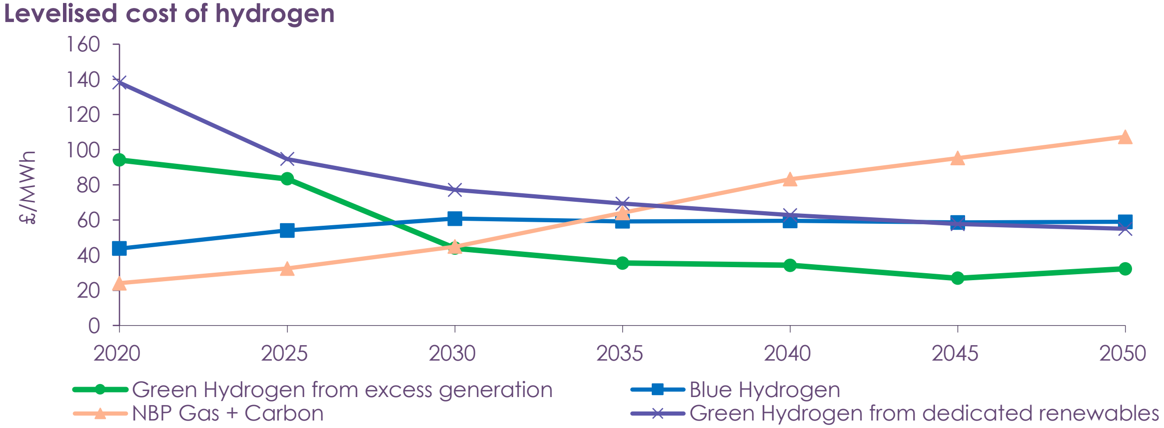
Sensitivities – Transport and Storage cost

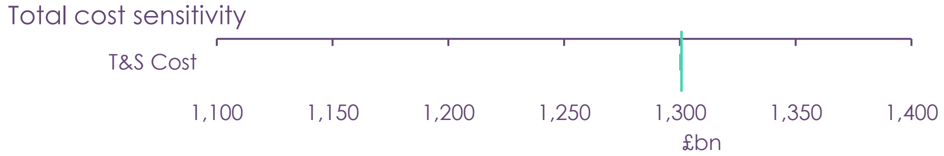
In our Transport and Storage (T&S) cost sensitivity, we have tested the effect of a doubling the associated capex.

This has a direct impact on Blue hydrogen costs, though the effect is limited, due to the assumption that T&S costs are levelised across the life of the storage asset.

The effect is therefore a negligible increase in the total system cost.







Conclusions

Conclusion

- This analysis highlights the potential cost savings which could be recognised through immediate investment into a UK hydrogen economy to support the delivery of Net Zero carbon emissions by 2050. Whilst not in scope for this report, such a move would also likely be able to capture significant Gross Value Add (GVA) for UK PLC.
- Green hydrogen production is heavily linked to the volume of renewable power which can be made available. This is therefore critically linked to renewables buildout; highlighting the role which renewables could play in the decarbonisation of the heat sector.
- In addition to renewable power buildout and capital cost reductions, the economic case for dedicated renewables to produce Green hydrogen relies upon improvements in the efficiency of the electrolysis process.
- In all scenarios, Blue hydrogen is expected to play a significant role in the UK's hydrogen economy through to 2050. Development of capacity to serve that requirement is dependent on urgent deployment of CCUS.
- In all cases, early deployment of both Green and Blue hydrogen provide a lower total system cost, due to the opportunity for long term cost savings.
- Over the forecast period, our central case shows a saving of £89bn where hydrogen is deployed at the earliest opportunity. Any delays could see this saving reduced and ultimately end up representing a cost to customers.
- This translates to 0.38p per kWh when this is evenly apportioned across all gas consumption, representing a modest unit cost.

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Appendix A: Base Case Assumptions

Generation assumptions

Projected Generation Capacity		Unit	2020	2025	2030	2035	2040	2045	2050
Generation Capacity									
	Offshore Wind	GW	12.0	26.0	40.0	48.7	57.5	66.2	75.0
	Onshore Wind	GW	12.8	15.2	15.4	15.7	16.0	16.2	16.5
	Solar	GW	13.3	15.7	20.9	26.2	31.5	36.7	42.0
	Storage	GW	1.6	3.1	4.7	8.4	12.1	17.5	19.4
	Pumped Storage	GW	2.7	2.7	2.7	2.7	2.7	3.0	3.6
	Other Renewables	GW	5.8	6.5	8.8	11.1	13.4	15.6	17.9
	Carbon Capture & Storage (CCS)	GW	0.0	0.0	8.6	17.2	25.8	34.4	42.9
	Interconnectors	GW	5.8	9.7	11.1	13.3	15.6	17.8	20.1
	Nuclear	GW	8.9	4.7	2.4	6.4	10.5	14.5	18.6
	Biomass	GW	4.2	4.7	3.4	1.8	2.0	1.8	7.0
	CCGT	GW	28.3	24.1	12.2	9.1	6.1	3.0	0.0
	OCGT	GW	1.1	0.8	0.8	0.6	0.4	0.2	0.0
	Other Large-scale Thermal	GW	0.6	0.3	0.2	0.0	0.0	0.0	0.0
	Distributed Conventional	GW	9.6	11.3	12.1	9.1	6.0	3.0	0.0
	Coal	GW	5.3	0.0	0.0	0.0	0.0	0.0	0.0
New Intermittent Renewable Capacity									
	Offshore Wind	GW	12.0	14.0	14.0	8.8	8.8	8.8	8.8
	Onshore Wind	GW	12.8	2.4	0.3	0.3	0.3	0.3	0.3
	Solar	GW	13.3	2.4	5.3	5.3	5.3	5.3	5.3
Sources: FES, CCC									

Generation assumptions (cont.)

Historic Intermittent Renewable Installations			2015	2016	2017	2018	2019
Offshore Wind Installed Capacity By Project Size							
	Total Capacity (MW)	MW	5005	5005	5695	7814	8402
	Capacity ≤ 100MW	MW	532	532	562	696	696
	Capacity 100-500MW	MW	2763	2763	3423	4835	4835
	Capacity 500MW+	MW	1710	1710	1710	2283	2871
	Proportion ≤ 25MW	%	11%	11%	10%	9%	8%
	Proportion 50-100MW	%	55%	55%	60%	62%	58%
	Proportion 100MW+	%	34%	34%	30%	29%	34%
Onshore Wind Installed Capacity By Project Size							
	Total Capacity (MW)	MW	6662	7156	9372	9847	10436
	Capacity ≤ 25MW	MW	1996	2203	2502	2560	2570
	Capacity 25-100MW	MW	2984	3271	4439	4627	5029
	Capacity 100MW+	MW	1682	1682	2432	2660	2837
	Proportion ≤ 25MW	%	30%	31%	27%	26%	25%
	Proportion 50-100MW	%	45%	46%	47%	47%	48%
	Proportion 100MW+	%	25%	24%	26%	27%	27%
Solar Installed Capacity By Project Size							
	Total Capacity (MW)	MW	6523	8469	9162	9192	9234
	Capacity ≤ 5MW	MW	1814	2897	3478	3500	3500
	Capacity 5-25MW	MW	3762	4164	4275	4283	4290
	Capacity 25MW+	MW	947	1409	1409	1409	1444
	Proportion ≤ 5MW	%	28%	34%	38%	38%	38%
	Proportion 5-25MW	%	58%	49%	47%	47%	46%
	Proportion 25MW+	%	15%	17%	15%	15%	16%
Sources: RenewableUK, BEIS							

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Generation assumptions (cont.)

Projected Intermittent Renewable Installations		Unit	2020	2025	2030	2035	2040	2045	2050
Project Size Share									
Offshore Wind									
	<100	%	8%	0%	0%	0%	0%	0%	0%
	100-500	%	58%	0%	0%	0%	0%	0%	0%
	500+	%	34%	100%	100%	100%	100%	100%	100%
Onshore Wind									
	≤ 25	%	25%	25%	25%	25%	25%	25%	25%
	25-100	%	48%	48%	48%	48%	48%	48%	48%
	100+	%	27%	27%	27%	27%	27%	27%	27%
Solar									
	50 kW to ≤ 5 MW	%	38%	38%	38%	38%	38%	38%	38%
	5 to ≤ 25 MW	%	46%	46%	46%	46%	46%	46%	46%
	> 25 MW	%	16%	16%	16%	16%	16%	16%	16%
Average Project Size									
Offshore Wind									
	<100	MW	70	70	70	70	70	70	70
	100-500	MW	350	350	350	350	350	350	350
	500+	MW	966	1000	1500	1500	1500	1500	1500
Onshore Wind									
	≤ 25	MW	15	15	15	15	15	15	15
	25-100	MW	43	43	43	43	43	43	43
	100+	MW	170	170	170	170	170	170	170
Solar									
	50 kW to ≤ 5 MW	MW	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	5 to ≤ 25 MW	MW	7.5	7.5	7.5	7.5	7.5	7.5	7.5
	> 25 MW	MW	35	35	35	35	35	35	35

Sources: BEIS, RenewableUK, KPMG Analysis. Assumed all offshore built from 2025 is large, and projects size distribution is constant from today for onshore and wind

Generation assumptions (cont.)

Renewables Penetration	Unit	2020	2025	2030	2035	2040	2045	2050
Renewable capacity	GW	48.3	69.2	92.6	112.9	133.1	155.3	174.3
Annual build out rate	GW/year	0.0	4.2	4.7	4.0	4.0	4.4	3.8
Average annual build out rate	GW/year	4.2						
Potential additional renewable build-out								
Max renewables build out multiplier	-	1.50						
Max potential renewables build-out rate	GW/Year	6.30						
Additional build out per year	GW	0.00	2.11	1.62	2.26	2.26	1.86	2.50
Cumulative additional capacity	GW	0.00	10.57	18.67	29.96	41.24	50.53	63.03

Renewables assumptions	Unit	2020	2025	2030	2035	2040	2045	2050
Offshore Wind LCOE	£/MWh	85.0	53.0	48.0	45.0	43.0	42.0	41.0
Onshore Wind LCOE	£/MWh	65.0	52.5	49.0	46.2	43.0	39.8	37.5
Solar LCOE	£/MWh	86.0	73.3	69.0	63.7	58.5	52.9	48.6
Offshore wind load factor	%	42%	50%	51%	53%	53%	53%	53%
Sources: BNEF, DNV-GL								

Generation assumptions (cont.)

Projected Generation Capacity		Unit	2020	2025	2030	2035	2040	2045	2050
Generation Capacity									
	Offshore Wind	GW	12.0	26.0	40.0	48.7	57.5	66.2	75.0
	Onshore Wind	GW	12.8	15.2	15.4	15.7	16.0	16.2	16.5
	Solar	GW	13.3	15.7	20.9	26.2	31.5	36.7	42.0
	Storage	GW	1.6	3.1	4.7	8.4	12.1	17.5	19.4
	Pumped Storage	GW	2.7	2.7	2.7	2.7	2.7	3.0	3.6
	Other Renewables	GW	5.8	6.5	8.8	11.1	13.4	15.6	17.9
	Carbon Capture & Storage (CCS)	GW	0.0	0.0	8.6	17.2	25.8	34.4	42.9
	Interconnectors	GW	5.8	9.7	11.1	13.3	15.6	17.8	20.1
	Nuclear	GW	8.9	4.7	2.4	6.4	10.5	14.5	18.6
	Biomass	GW	4.2	4.7	3.4	1.8	2.0	1.8	7.0
	CCGT	GW	28.3	24.1	12.2	9.1	6.1	3.0	0.0
	OCGT	GW	1.1	0.8	0.8	0.6	0.4	0.2	0.0
	Other Large-scale Thermal	GW	0.6	0.3	0.2	0.0	0.0	0.0	0.0
	Distributed Conventional	GW	9.6	11.3	12.1	9.1	6.0	3.0	0.0
	Coal	GW	5.3	0.0	0.0	0.0	0.0	0.0	0.0
New Intermittent Renewable Capacity									
	Offshore Wind	GW	12.0	14.0	14.0	8.8	8.8	8.8	8.8
	Onshore Wind	GW	12.8	2.4	0.3	0.3	0.3	0.3	0.3
	Solar	GW	13.3	2.4	5.3	5.3	5.3	5.3	5.3

Sources: FES, CCC

Electrolyser assumptions

Electrolyser assumptions		Unit	2020	2025	2030	2035	2040	2045	2050
Electrolyser lifetime		Years	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Proportion of New Renewable Capacity with Electrolysers Developed		%	100%	100%	100%	100%	100%	100%	100%
Maximum Electrolyser Build Per Unit Renewables		%	80%	80%	80%	80%	80%	80%	80%
Minumum Renewable Size Feasible for Electrolysis		MW	0	0	0	0	0	0	0
Largest Demonstrated Electrolyser Size		MW	25	100	1000	1000	1000	1000	1000
Maximum Electrolyser Utilisation at Full Build Out		%	57%	57%	57%	57%	57%	57%	57%
Electrolyser Size Per Project (WM)									
Offshore Wind									
	<100	MW	25	56	56	56	56	56	56
	100-500	MW	25	100	280	280	280	280	280
	500+	MW	25	100	1000	1000	1000	1000	1000
Onshore Wind									
	≤ 25	MW	12	12	12	12	12	12	12
	25-100	MW	25	34.4	34.4	34.4	34.4	34.4	34.4
	100+	MW	25	100	136	136	136	136	136
Solar									
	50 kW to ≤ 5 MW	MW	0.24	0.24	0.24	0.24	0.24	0.24	0.24
	5 to ≤ 25 MW	MW	6	6	6	6	6	6	6
	> 25 MW	MW	25	28	28	28	28	28	28
Electrolyser efficiency (MWh power to MWh Hydrogen)									
	Base	%	65%	68%	70%	73%	76%	79%	80%
	High	%	70%	73%	75%	78%	81%	84%	85%
	Low	%	60%	63%	65%	68%	71%	74%	75%

Sources: DNV-GL, ITM Power, Siemens, Navigant, IEA, Hydrogen Council, Standing Assumptions

Green hydrogen production assumptions

Green Hydrogen Production projections		Unit	2020	2025	2030	2035	2040	2045	2050
WACC		%	12%	11%	10%	9%	8%	8%	8%
Curtailed Power Cost									
	Base	£	47.38	48.22	28.23	23.64	23.92	19.15	23.55
	High	£	75.98	55.84	51.43	48.3	45.62	43.49	41.76
	Low	£	0	0	0	0	0	0	0
Current Capex Cost									
	Base	£	750						
	High	£	1050						
	Low	£	700						
Cost Reduction per Doubling of Global Electrolyser Capacity									
	Learning Factor		2						
	Learning Rate	%	0.13						
Global Electrolyser Build Out & Associated Cost Reduction									
	Global Electrolyser Capacity	MW	0.253	2.98	700	950	1200	1450	1700
	Number of Capacity Doubles	Number	-	4	8	0	0	0	0
	Cost Reduction	%	-	61%	33%	94%	95%	96%	97%
Capital Expenditure									
	Base	£1000s Per MW	750	457	153	144	137	132	128
	High	£1000s Per MW	1050	640	214	201	192	185	179
	Low	£1000s Per MW	700	426	142	134	128	123	119
O&M Share of Capex		%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%
Operations & Maintenance									
	Base	£1000s Per MW	11.25	6.85	2.29	2.15	2.05	1.98	1.92
	High	£1000s Per MW	15.75	9.60	3.20	3.01	2.88	2.77	2.68
	Low	£1000s Per MW	10.5	6.40	2.14	2.01	1.92	1.85	1.79

Sources: Lazard, NERA, Element Energy, Hydrogen Council, IRENA, IEA

Gas demand and cost assumptions

Estimated 2050 heat demand by sector	Residential	Service	Industrial	Total
2017 Demand	33559	11802	14135	59496
Split	56%	20%	24%	100%
2050 Demand	319	112	134	566
Sector Decarbonisation Required.	90%	100%	85%	91%
Demand Reduction Required	287	112	114	514

Sources: BEIS, FES, CCC

Gas demand and cost assumptions		2020	2025	2030	2035	2040	2045	2050
Total Gas Demand	TWh	686.15	584.58	505.58	506.45	522.92	565.20	565.50
Green Gas Supply (BCM)	BCM	0.48	0.95	1.72	3.29	4.54	5.65	6.67
NBP price	£/therm	0.32	0.46	0.61	0.61	0.61	0.61	0.61
	£/MWh	16.96	24.92	32.89	32.89	32.89	32.78	32.78
	£/Mmbtu	3.15	4.63	6.11	6.11	6.11	6.09	6.09
	£/Nm3	0.11	0.17	0.22	0.22	0.22	0.22	0.22
	£/kg	0.14	0.20	0.27	0.27	0.27	0.27	0.27
Carbon price	£/tonne	21.50	22.60	36.10	93.40	150.70	187.00	223.00
	£/MWh	7.19	7.56	12.08	31.25	50.42	62.56	74.60

Sources: BEIS Energy and Emissions

Blue hydrogen assumptions

Project assumptions	Unit	Values			
SMR & ATR lifetime	Years	25			
Project Life	Years	29			
SMR & ATR Construction Period	Years	4.00			
SMR & ATR Capital Expenditure by Construction Year	Year	0 1		2	3
	%	0.15	0.35	0.40	0.10
SMR as % of Blue Hydrogen projects					
ATR as % of Blue Hydrogen projects					
Blended capture rate					
2020 Capture Capex as % of 2020 unit capex	%				
2020 Capture Opex as % of 2020 unit opex	%				
Sources: BEIS & Wood, Concepts for Large Scale Hydrogen Production					

Capture learning rate	Unit	2020	2025	2030	2035	2040	2045	2050
Capex and Opex Costs from First to Next of a Kind Systems								
Capex		1.00	1.00	0.70	0.70	0.70	0.70	0.70
Opex		1.00	1.00	0.70	0.70	0.70	0.70	0.70

Blue hydrogen assumptions

Cost assumptions		2020	2025	2030	2035	2040	2045	2050
WACC	%	10.0%	10.0%	10.0%	9.0%	9.0%	8.0%	8.0%
Capacity factor	%	90%	90%	90%	90%	90%	90%	90%

SMR Cost assumptions	Unit	2020	2025	2030	2035	2040	2045	2050
Capital expenditure	£/kW H2	529	495	466	437	410	385	361
Fixed Opex	£/kW/annum	25.38	25.38	25.38	25.38	25.38	25.38	25.38
Other variable opex	£/kWh H2	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas consumption	kWh/kWh H2	1.36	1.36	1.36	1.36	1.36	1.36	1.36
Electricity consumption	kWh/kWh H2	-	-	-	-	-	-	-
CO2 capture rate	%	90%	90%	90%	90%	90%	90%	90%
Fuel cost	£/MWh H2	22.97	33.77	44.56	44.56	44.56	44.42	44.42
Electricity cost	£/MWh H2	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Carbon cost	£/MWh H2	0.72	0.76	1.21	3.12	5.04	6.26	7.46
Other variable opex	£/MWh H2	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total variable opex	£/MWh H2	23.69	34.53	45.77	47.68	49.60	50.68	51.88

Blue hydrogen assumptions (cont.)

ATR Cost assumptions	Unit	2020	2025	2030	2035	2040	2045	2050
Capital expenditure	£/kW H2	554	527	499	458	430	403	378
Fixed Opex	£/kW/annum	24.41	24.41	24.41	24.41	24.41	24.41	24.41
Other variable opex	£/kWh H2	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas consumption	kWh/kWh H2	1.20	1.20	1.20	1.20	1.20	1.20	1.20
Electricity consumption	kWh/kWh H2	-	-	-	-	-	-	-
CO2 capture rate	%	95%	95%	95%	95%	95%	95%	95%
Fuel cost	£/MWh H2	20.30	29.83	39.37	39.37	39.37	39.24	39.24
Electricity cost	£/MWh H2	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Carbon cost	£/MWh H2	0.36	0.38	0.60	1.56	2.52	3.13	3.73
Other variable opex	£/MWh H2	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total variable opex	£/MWh H2	20.66	30.21	39.97	40.93	41.89	42.37	42.97

Transport and Storage assumptions

Transport and Storage Cost Projections		Unit	2020	2025	2030	2035	2040	2045	2050
WACC Assumptions		%	10.0%	10.0%	10.0%	9.0%	9.0%	8.0%	8.0%
Capex and Opex Learning Rate from First to Next of a Kind Systems									
	Capex		1.00	1.00	0.70	0.70	0.70	0.70	0.70
	Opex		1.00	1.00	0.70	0.70	0.70	0.70	0.70
	Transport O&M as % of Capex	%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%
	Storage O&M as % of Capex	%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%
Capex Assumptions									
	Transport Capex	£Millions	63.00	63.00	44.10	44.10	44.10	44.10	44.10
	Storage Capex	£Millions	31.00	31.00	21.70	21.70	21.70	21.70	21.70
Opex Assumptions									
	Transport Opex	£millions p.a.	2.89	2.89	2.02	2.02	2.02	2.02	2.02
	Storage Opex	£millions p.a.	9.00	9.00	6.30	6.30	6.30	6.30	6.30
T&S Cost information (per Unit)									
	Asset lifetime	years	40						
	Total T&S Lifetime	years	44						
	Total storage capacity	MtCO2	130						
	Pipeline capacity	MtCO2 per year	10						
	Projected annual sequestration	MtCO2 per year	1.14						
	Capex across Build Years	Years	4						
	Build Years		0	1	2	3			
	Proportion of total capex spent per year		0.143	0.286	0.286	0.286			

Sources: HyNet, Teesside Collective technical documents, BEIS: CCUS Technical Advisory Report 2018, Northern Lights

WACC Comparisons

Renewable Technology WACCs	Year	Unit	Value	Source
Offshore Wind	2001	%	12	IRENA, 2019
Offshore Wind	2011	%	10.0 - 14.0	Oxera, Report on Low Carbon Discount Rates
Offshore Wind	2015	%	9.7-10.1	NERA, Hurdle Rates for Electricity Generation
Offshore Wind	2018	%	8.75	Grant Thornton: Renewable Energy Discount Rate Survey
Onshore Wind	2011	%	7 - 10	Oxera, Report on Low Carbon Discount Rates
Onshore Wind	2015	%	5.2 - 6.4	NERA, Hurdle Rates for Electricity Generation
Onshore Wind	2018	%	8	Grant Thornton: Renewable Energy Discount Rate Survey
Solar	2011	%	6 - 9	Oxera, Report on Low Carbon Discount Rates
Solar	2015	%	5.4 - 5.5	NERA, Hurdle Rates for Electricity Generation
Utility Scale PV OR Wind + Storage	2016	%	8	World Energy Council E-Storage: Shifting from cost to value
Utility Scale PV + Storage	2016	%	10	Apricum: Navigating the maze of energy storage costs
Storage in Grids with 'High' Renewable Penetration	2017	%	8	Asian Development Bank: Energy Storage with high penetration of variable generation
Utility Scale PV + Storage	2018	%	11	Lazard: Levelised Cost of Storage
Electrolyser	2019	%	8	IEA. 2019
ITM Power Company WACC (analyst report)	2019	%	10.8	First Berlin, Feb 2019

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Appendix C: Glossary

Glossary

Allowable emissions	Allowable emissions are the carbon dioxide equivalent emissions allocated to emissions from gas consumption in order to maintain a trajectory to hitting Net Zero by 2050 as per legislated Carbon Budgets
ALK	ALK or alkaline electrolysis is a technology that is utilised to produce Green hydrogen which is currently widely used in the chemical industry
ATR	ATR or auto-thermal reforming is an emerging technology utilised to produce Blue hydrogen which has a higher efficiency and carbon capture rate than SMR
Blue hydrogen	Blue hydrogen refers to hydrogen produced through means of splitting natural gas into hydrogen and carbon dioxide with the latter captured and stored with only a residual amount of carbon emissions going into the Earth's atmosphere
Capture price	Capture price is the price that an electricity generating asset or technology is able to achieve in the wholesale market
Carbon sequestration	Sequestration refers to the long-term storage of carbon dioxide and other firms of carbon to slow or reverse atmospheric CO2 pollution
Carbon Budget	Carbon budgets are legislated targets which restrict the amount of greenhouse gas that the UK can legally emit in a five year period
CCGT	CCGT or combined cycle gas turbine plant is a highly efficient energy generation technology that combines a gas-fired turbine with a steam turbine which produces additional power from heat associated with the gas turbine
CCUS	CCUS or Carbon capture, utilisation and storage is the process of capturing waste carbon dioxide and either utilising it for an industrial purpose or depositing it permanently in a storage facility such as a depleted oil well so it doesn't re-enter the atmosphere
CFD	CfD or contracts for difference refers to a government mechanism for supporting the deployment of new low carbon electricity generation projects by providing stability and predictability to future revenue streams
Dedicated Renewables	Dedicated renewables refers to low carbon electricity generation projects that are deployed primarily for the purpose of producing Green Hydrogen rather than supplying power to the GB electricity grid

Glossary

Green hydrogen	Green hydrogen refers to hydrogen produced by splitting water into hydrogen and oxygen through the usage of renewable energy resulting in no carbon emissions
GVA	GVA or Gross value added is the contribution made to an economy by an individual producer, industry, sector or region
I&C	I&C refers to the Industrial and Commercial sector of the UK economy
LCOE/LCOH	LCOE/LCOH or levelised cost of electricity (hydrogen) is a measure of the average net present cost of electricity generation (hydrogen production) for a generating plant over its lifetime
NBP	NBP or National Balancing Point is the wholesale gas market price for natural gas in the UK
OCGT	OCGT or Open Cycle Gas Turbine is an energy generation technology that utilises a single gas-powered turbine
PEM	PEM or Proton Exchange Membrane is a technology that is utilised to produce Green hydrogen which is less widespread than ALK but is more suited to pairing with renewable generation for hydrogen production
SMR	SMR or steam methane reforming is a mature technology which is widely used across the refining and petrochemical industries to produce hydrogen
SOEC	SOEC or solid oxide electrolysis is an early stage Green hydrogen production technology which has potential for improved energy efficiency over ALK and PEM but is still currently in the development stage
T&S	T&S or Transport and Storage is the transportation and long-term storage of the carbon dioxide captured from power generation plants and carbon intensive industry

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