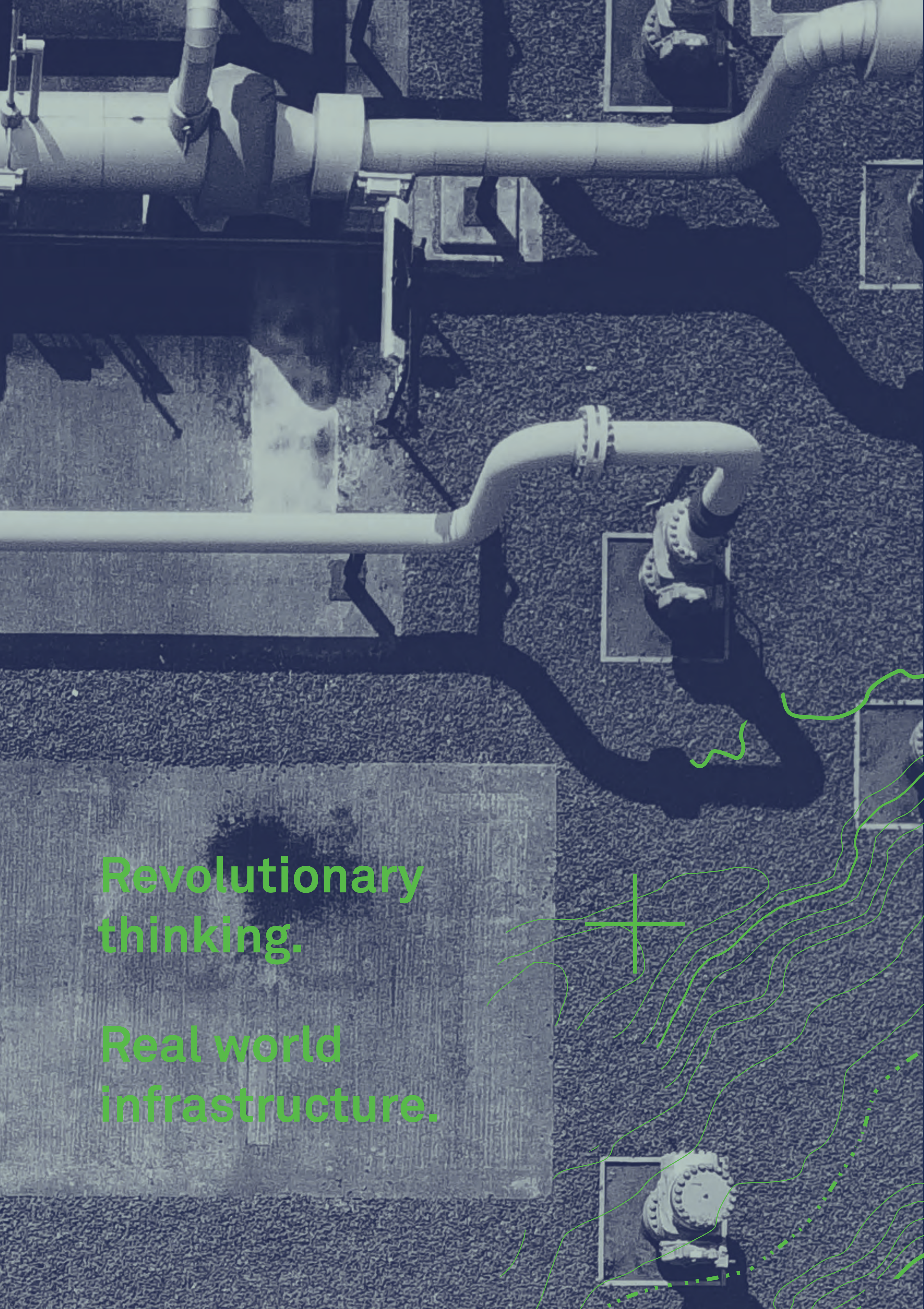


Revolutionary thinking.

Real world infrastructure.

Executive Summary

H21 North of England (H21 NoE) has been developed in partnership between Cadent, Equinor and Northern Gas Networks. Equinor was considered a perfect partner for the onshore UK gas distribution industry to develop the H21 concept.

The UK, like most other countries around the world, recognises the challenge of climate change. The UK has committed to reduce greenhouse gas emissions by 80% of their level in 1990 by 2050; this is a legal obligation defined under the terms of the UK Climate Change Act 2008. In 2018 the UK still need to reduce greenhouse gas emissions by more than 300 million tonnes per year (Mtpa) before 2050. This is a big challenge that requires big and realistic solutions – H21 NoE is such a solution. Climate change is one of the most significant technical, economic, social and business challenges facing the world today.

H21 NoE presents a detailed engineering solution for converting the gas networks across the North of England to hydrogen between 2028 and 2034. This would provide deep decarbonising of 14% of UK heat and become the world's largest CO_2 emissions reduction project achieving 12.5 Mtpa of CO_2 avoided to the atmosphere. The project also sets out how to decarbonise 70% of all UK meter points by 2050 using a six-phase regional hydrogen rollout strategy. Based on credible, proven at scale technology and a strong industry supply chain, H21 has the potential to replace all UK natural gas with hydrogen for deep decarbonisation of residential, commercial and industrial heat, power generation and transport by 2050.

The H21 NoE ambition is to enable the transition to a 100% sustainable and global hydrogen economy by 2100. This would be established through the utilisation of the appropriate technologies and practical delivery timescales to begin this transition focusing firstly up to 2050.

Currently the UK requires 2,200 to 2,500 terawatt hours (TWh) per year of primary energy to support heat (including industry), transport and electricity generation[1]. This is broadly made up of:

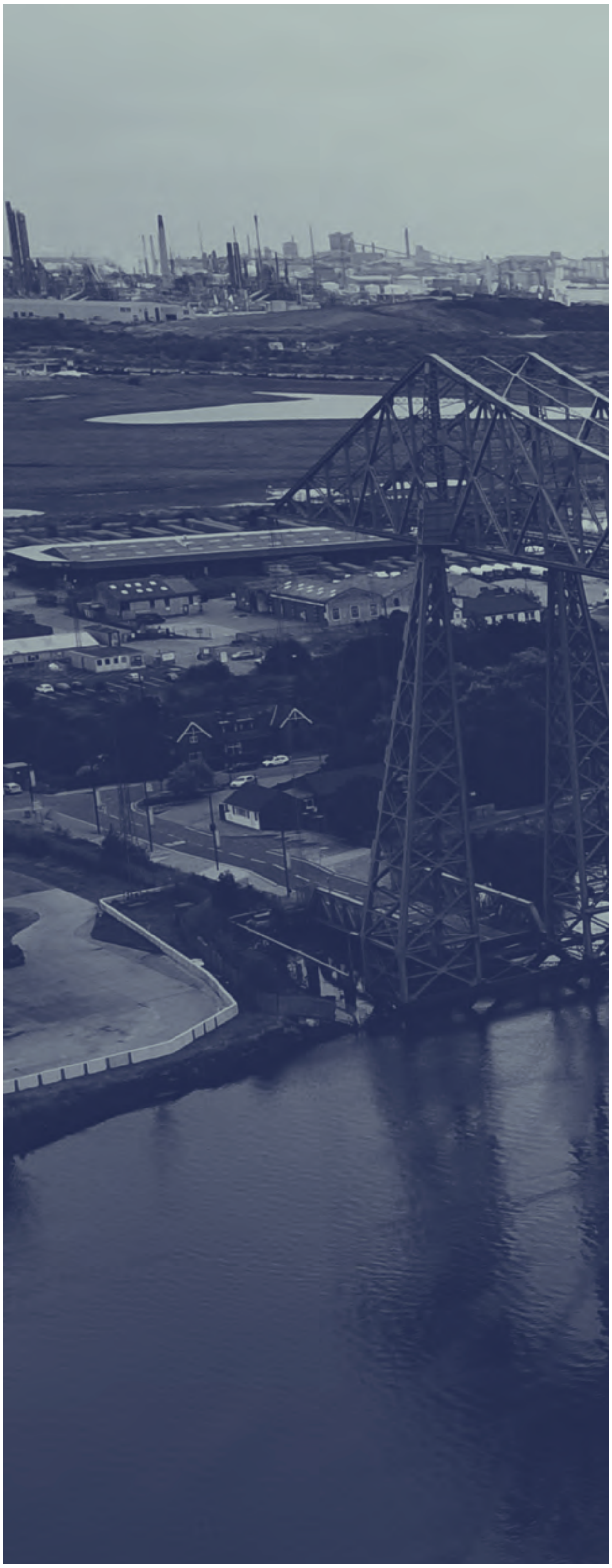
USE	UK TOTAL PRIMARY ENERGY (TWH)
Gas consumption	900
Oil – Road	470
Oil – Aviation and shipping	200
Oil – Energy + non-energy use	250
Coal (75% power)	140
Renewable (all sources)	240
TOTAL	2,200

Table ES.1: UK primary energy

In 2017, the UK's primary energy consumption was between 2,200 and 2,500 TWh. Of this, only 1,734 TWh was utilised by end users, the rest is 'lost', e.g. the consumption is via power generation processes. Of the 1,734 TWh, over 540 TWh was used for heat in domestic, commercial and industrial settings.

In order for the UK to meet Climate Change Act targets, the net greenhouse gas emissions for all energy needs to be 160 $MtCO_2eq$[2]. This is equal to a 65% reduction in greenhouse gas emissions from the 2017 levels. This requires a substantial change in the way we use energy.

The original H21 Leeds City Gate (LCG) project, published in 2016, proved that the UK gas networks were the correct capacity to convert to 100% hydrogen. The conversion could be undertaken incrementally, and low carbon hydrogen could be sourced at credible scale using technology available today. Since publication of the H21 LCG report there have been numerous reports supporting the proposition of a 100% hydrogen gas grid conversion with the two most notable being the UK Government's October 2017, 'The Clean Growth Strategy' and the The Committee on Climate Change (CCC) October 2016, 'Next Steps for UK heat policy'.



1 Digest of UK Energy Statistics 2016

2 Committee on Climate Change, building a low carbon economy, December 2008

H21 North of England

The H21 NoE project has been designed as a potential foundation upon which the UK Government could set its long-term approach to deep decarbonisation of heat. H21 NoE is over 13 times larger than H21 LCG (by energy).

This allows full advantage to be taken of the economies of scale as well as being large enough to make a tangible impact on UK climate change obligations. Additionally, the project is designed to be of comparable cost with other recent major infrastructure decisions made by UK governments.

H21 NoE will, by default, also decarbonise industrial clusters connected to the distribution gas network, initiate the CO_2 transport and storage infrastructure needed for industry where CCS is the only solution and form the backbone of an energy system needed to provide flexible power to back-up renewables.

The project comes at a critical time with growing global interest in the potential of large scale hydrogen conversion to significantly reduce carbon emissions, create and sustain many high-quality jobs and unlock technological innovation in other industries. H21 NoE places the UK at the forefront of this international debate with a growing consensus that the world would need hydrogen to transition to a low carbon economy.

H21 NoE has been developed in partnership between Cadent, Equinor and Northern Gas Networks. Equinor was considered a perfect partner for the onshore UK gas distribution industry to develop the H21 concept. The scope of the project and areas of responsibility are set out diagrammatically in Figure ES.1.

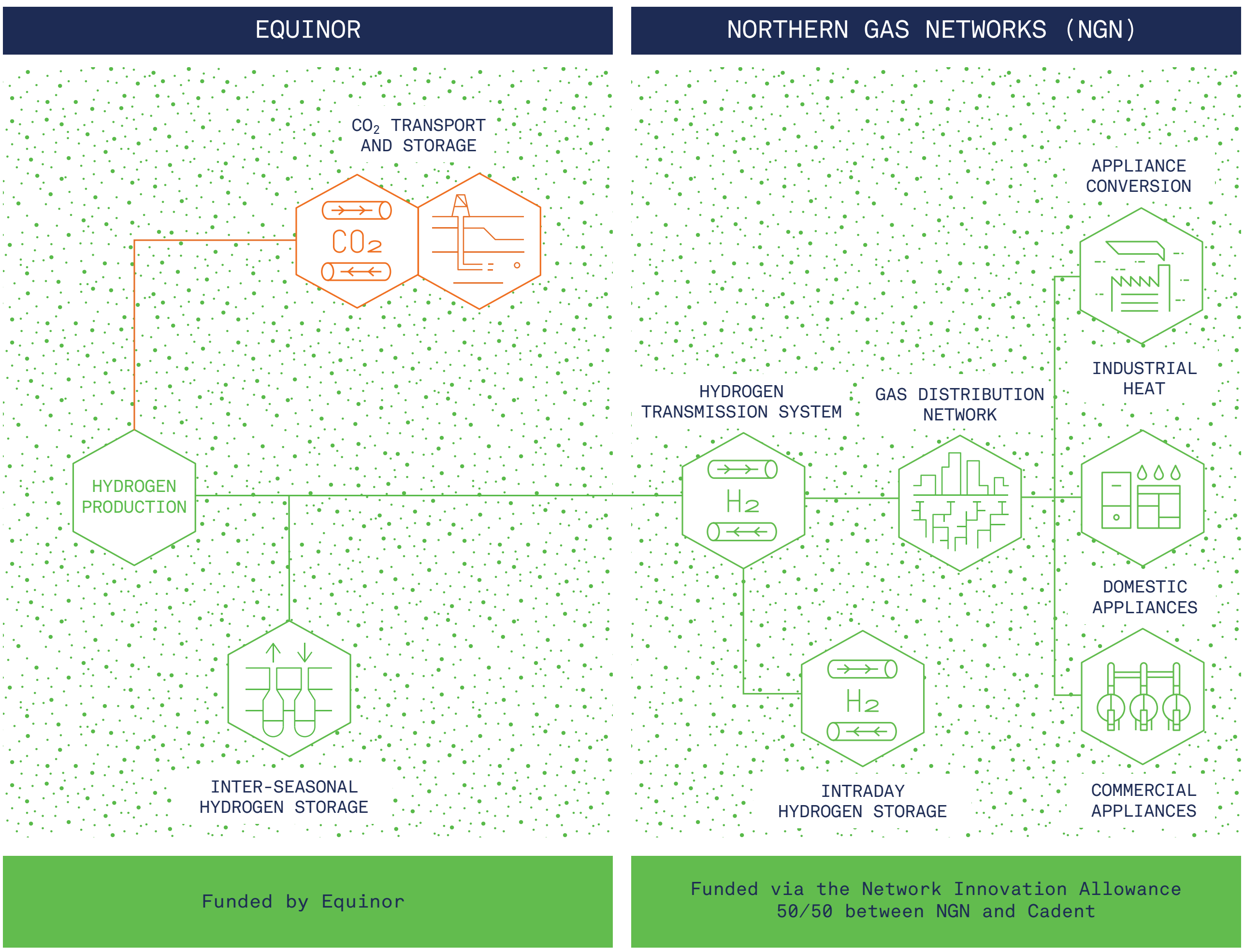


Figure ES.1: H21 NoE scope of work

H21 NoE will be a major investment for UK society and private investors and it has been important for the project to develop a concept based on proven and referenced technologies and design, not to propose a concept based on future expectation of technology breakthroughs, immature supply chains and unrealistic future price scenarios of energy. The basic principles are that both technologies and performance (energy efficiency, lifetime, emissions, etc.) can be found at similar scale and operational conditions as required by H21 NoE.

Key technical aspects of H21 NoE

- Conversion of 3.7 million meter points equivalent to 85 TWh of annual demand (14% of all UK heat) and circa 17% of total UK domestic meter connections
- A 12.15 GW natural gas-based hydrogen production facility (this is 1,215 times larger than 10 MW, i.e. 12,150 MW), delivering low carbon heat for Tyneside (Newcastle, Gateshead), Teesside, York, Hull, West Yorkshire (Leeds, Bradford, Halifax, Huddersfield, Wakefield), Manchester and Liverpool
- 8 TWh of inter-seasonal hydrogen storage, **equivalent to 62,000 Australian mega batteries**
- A 125 GW capacity hydrogen transmission system
- CO_2 transport and storage infrastructure with the capacity to sequester up to 20 Mtpa of CO_2 by 2035

The scheme is summarised in Figure ES.2 which is an isometric map of the North of England.

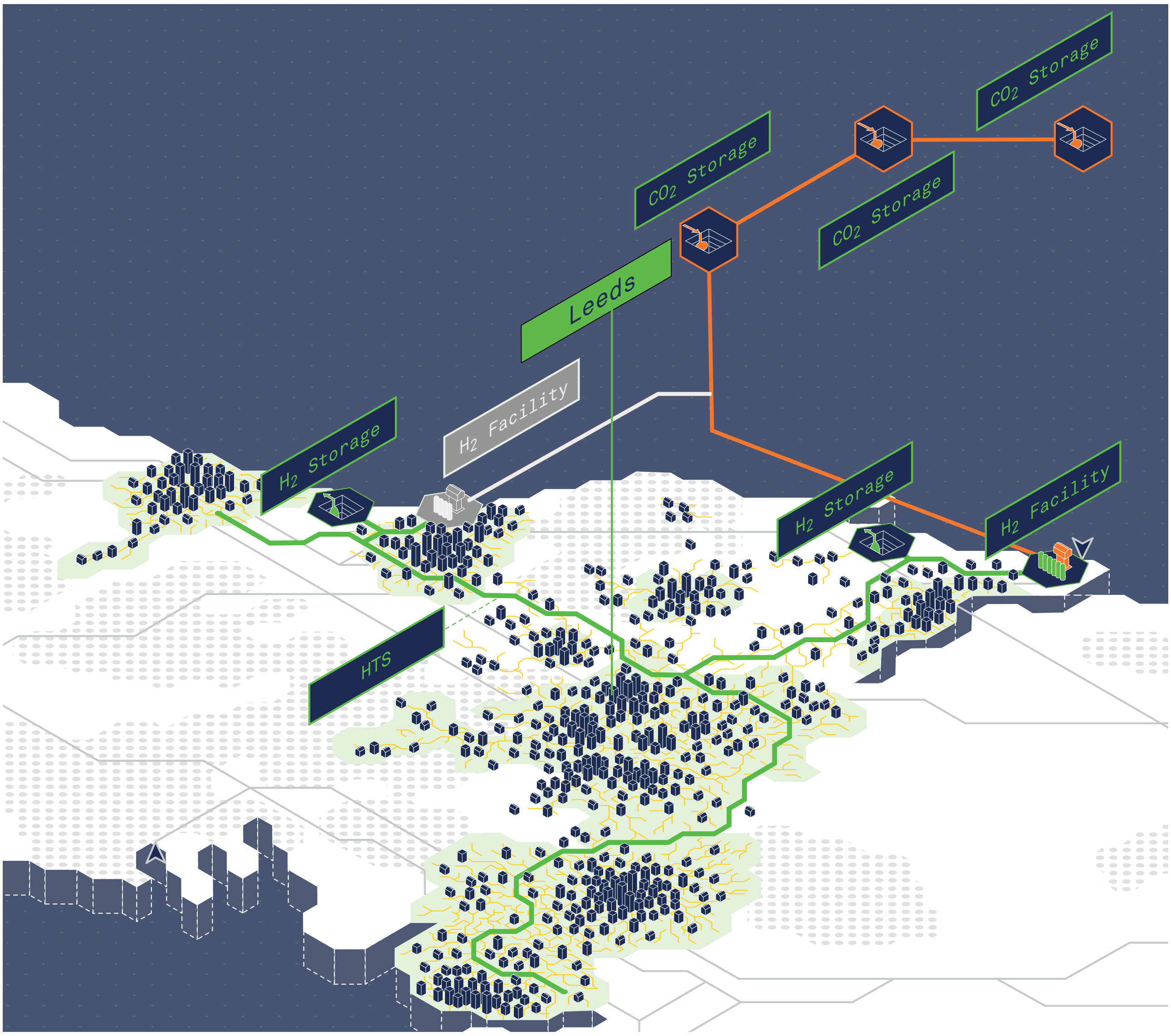


Figure ES.2: H21 NoE

When considering the 2050/2100 targets, all options and technologies need to play a part including energy efficiency improvements, increasing renewables, some nuclear, some district heating, 'bio'-energy, etc. A 100% hydrogen conversion can make a very significant contribution to the overall challenge. There is a common 'no silver bullet' consensus, however, there is a need to be collectively realistic and recognise different 'bullets' having very different contribution capabilities to meet the 2050/2100 targets. Furthermore, 2050 is only 32 years away and large energy infrastructure construction takes time. Deployment timescales of these different 'bullets' are often not realistically considered because economic analysis is preferred over credible deliverable actions.

Converting gas distribution networks to 100% hydrogen has many benefits:

- Re-uses existing assets already paid for by UK customers
- Maintains all the benefits of gas and the gas networks
- Ensures continuation of customer choice (gas or electric)
- Creates thousands of well paid jobs
- Rapidly helps improves air quality, and therefore the nation's health, with hydrogen fuel cell vehicles alongside battery electric vehicles
- Meets 2050 climate change obligations with a deliverable strategy using the most cost-effective solution
- Develops a market for a low carbon energy vector to enable the longer term transition to sustainable hydrogen in line with Paris agreements
- Gives the UK a unique opportunity to lead the world in large-scale decarbonisation strategies

In the journey to zero-carbon energy, hydrogen should be considered the world's destination fuel. The carbon capture and storage part of this journey is the essential transitional step to facilitate a longer term, sustainable, global hydrogen economy.

A brief overview of the key points within the eleven sections of the H21 NoE report is included in the remainder of the executive summary.

Section 2.0 Demand

From detailed analysis, using network modelling and actual gas consumption data, the demand profile for H21 NoE project—Tyneside (Newcastle, Gateshead), Teesside, York, Hull, West Yorkshire (Leeds, Bradford, Halifax, Huddersfield, Wakefield), Manchester and Liverpool—was established.

This is critical to enable the design of a robust energy supply system and is based on a best practice industrial approach with security of supply for the customer as the key driver. From this information the hydrogen production and inter-seasonal hydrogen storage requirements could be determined. The demand parameters are summarised as follows.

DESCRIPTION	H21 NOE DEMAND
Peak year annual demand	85,120 GWh
Peak year average hourly demand	9,736 MW
Peak hour demand (validated across the UK by 'the beast from the East', see Figure ES.3)	42,227 MW
Peak day demand	659 GWh
Peak month demand	14,400 GWh
Peak month average hourly demand	20 GW
Peak day linepack requirement	25 GWh
Average year hourly demand	8,493 MWh
Average year demand	74,450 GWh

Table ES.2: H21 NoE energy demand summary

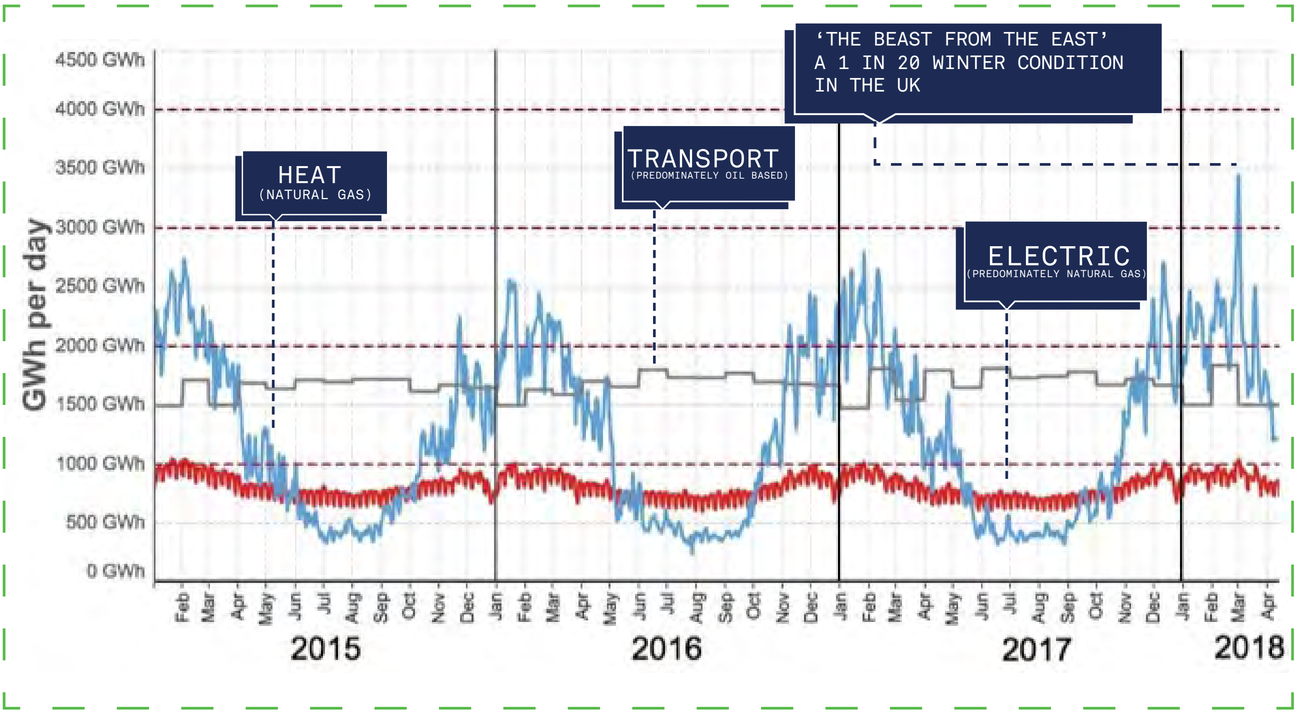


Figure ES.3: UK Energy 2015-18 including the 'Beast From the East' weather period

Section 3.0
Hydrogen production and hydrogen storage

Current global hydrogen production is 6 Mtpa (2,400 TWh), i.e. comparable to total UK energy consumption (see Figure ES.4). The demand per industry segment is shown in Figure ES.5. The biggest proportion (65-70%) of this is used directly for synthesis of new products, e.g. ammonia and methanol (Figure ES.5).

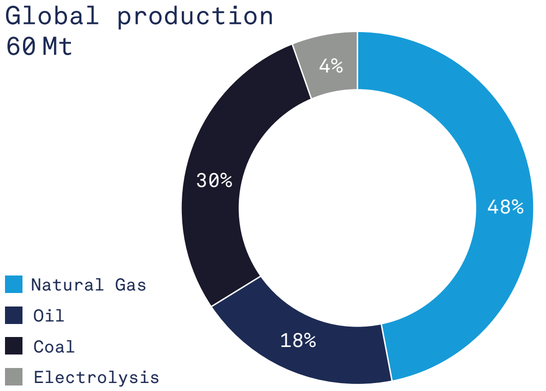


Figure ES.4: Global hydrogen production based on feedstock type

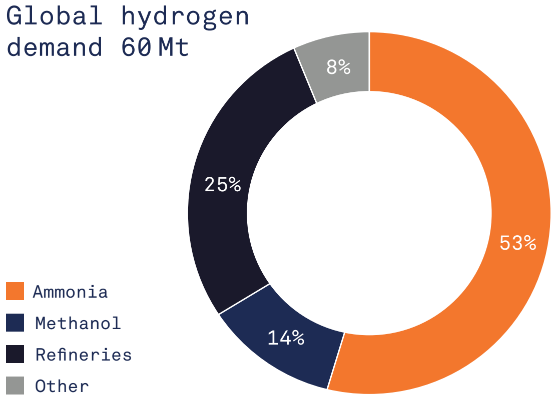


Figure ES.5: Global hydrogen demand

The current hydrogen industry is a part of the oil and gas and power industries. It shares the same supply chains.

A full analysis of current H_2 production and hydrogen storage technologies, which are commonly referred to as 'large' scale, was undertaken. Production technologies assessed included water electrolysis, natural gas reforming, coal gasification, ammonia production and cracking. Storage technologies considered included salt caverns, depleted hydrocarbon fields, ammonia and liquid hydrogen.

Most hydrogen production capacity has been installed over the last 40-50 years and equates to 5.5–7 GW installed capacity per year well within the suggested 2 GW per year needed for H21 NoE.

Based on the energy requirements, need for guaranteed deep decarbonisation, CAPEX and OPEX cost, status of supply chains, evidence of proven (and referenced) technology, ability to construct within the required timescales and security of supply to customers, natural gas reforming via Autothermal Reforming (ATR) technology coupled with carbon capture and storage was proved to be the most attractive option. From an inter-seasonal hydrogen storage perspective, salt caverns were selected. This was based on technical grounds and the location of salt strata in the Yorkshire area (Aldbrough) and wider North East of England.

Section 4.0
H21 design concept

To design the hydrogen production and storage system, optioneering was undertaking to determine the balance between Hydrogen Production Facility capacity and inter-seasonal hydrogen storage. Less capacity means more storage and vice versa. A hydrogen production capacity at 125% the peak year average hourly demand was selected. This results in the following hydrogen production and storage design parameters:

Hydrogen Production Facility: 12.15GW (1,215 x 10MW, i.e. 12,150MW

Inter-seasonal hydrogen storage requirement: 8,052GWh (equivalent to 62,000 Australian 'mega' batteries)

The Hydrogen Production Facility for H21 NoE is set out schematically below. It is based on nine Auto Thermal Reformer (ATR) units operating in parallel each with a production design capacity of 1.35GW (9 x 1.35GW = 12.15GW). All necessary utilities and power are produced within the facility. The production facility layout is planned to allow a phased construction to align with the conversion strategy presented in Section 6.0. Further the multi-unit facility gives high operational flexibility and security of supply which is the most critical factors in domestic energy supply.

The UK gas system is based on a high degree of flexibility which is the key premise to design a flexible ATR multi-unit Hydrogen Production Facility. This reduces investment cost, operational expenses and allows significant gas trading

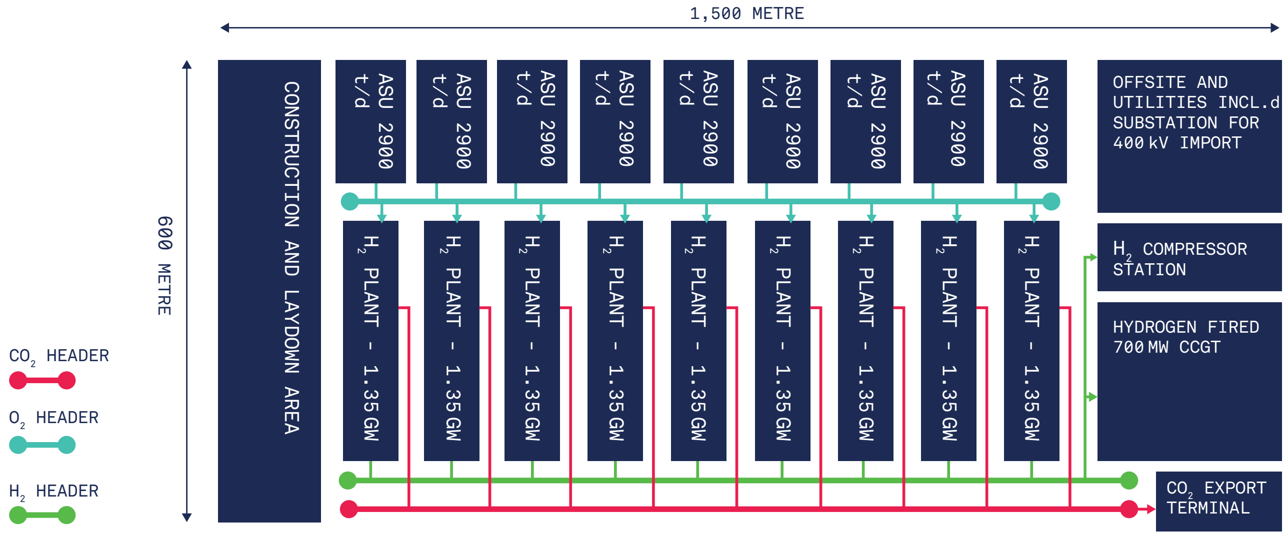


Figure ES.6: H21 NoE Hydrogen Production Facility layout (total design capacity 12.15GW)

Key performance parameters are:

- Plant efficiency: 74.4%(HHV)
- CO_2 capture: 94.2%
- CO_2 footprint: 14.14g/kWh
- Hydrogen purity: 98.3%
- Location: Easington with a split location option provided at Teesside

Inter-seasonal hydrogen storage will be established using the deep salt strata in the Yorkshire area at Aldbrough. This avoids the requirement for re-compression when exiting the caverns whilst meeting the 8,052GWh storage requirement. The storage system would be based on 56 caverns operating between 275 and 85 bar and 8 surface facilities. The salt caverns would require 54.4GWh of power for operation per annum which is approximately 0.073% of total hydrogen supplied.

Section 5.0
Hydrogen Transportation System (HTrS)

The HTrS required to connect the Hydrogen Production Facility and inter-seasonal hydrogen storage to the existing below 7 bar gas distribution networks across the North of England has been conceptually designed.

The HTrS comprises three elements. Firstly, and most significantly, a Hydrogen Transmission System (HTS) of 125 GW capacity (3 times more than the capacity to provide heat for the H21 NoE concept) with a capability to provide a minimum of 25 GWh of intraday hydrogen storage. Secondly, a Local Hydrogen Transmission System (LHTS) to distribute hydrogen to strategic points across individual urban centres. Thirdly, a Hydrogen Intermediate Pressure System (HIPS) required to allow strategic connections to the existing below 7 bar gas distribution networks to facilitate conversion.

There are:

- → The HTS 80 bar pipeline is 520 km long including 23 offtakes, 13 block valves and 50 connection tees. The HTS requires no additional compression
- → The LHTS operates at 40 bar maximum pressure. In total, the pipelines are 334 km long (specifically 61 km and 130 km required for Yorkshire and Manchester respectively) with 46 injections points into the HIPS/existing gas networks.
- → The HIPS comprises 605 km of below 7 bar network mains

This new pipeline infrastructure requirement is very small when put into a UK existing gas infrastructure context. In terms of high pressure pipelines, (i.e. below 7 bar), it represents 4% of the existing NTS and LTS system whilst the below 7 bar gas mains required (605 km) is 0.2% of the existing low pressure network.

Section 6.0
Commissioning and Conversion

To undertake a conversion at the scale of H21 NoE detailed consideration needs to be given to how increasing hydrogen supply and hydrogen storage coincides with increasing demand which is dictated by the number of gas customers converted per annum. This section presents this analysis showing how annual demand increases compared directly to scaling hydrogen production and hydrogen storage.

Demand: Within the NoE area there over 3.7 million meter points. To covert these gas customers within a 7 year timescale (2028-35) three district workforces based in Yorkshire, the North East and the North West would be required. These workforces would be working in parallel over a 7-year conversion period. On average 3,000 plumbers are required per summer conversion period and 1,500 per winter period. An average of 240 management/administrative staff are required throughout. To put the size of this workforce into context, the UK currently has 128,000 gas safe registered engineers and over 250,000 plumbers.

Additionally, the towns gas to natural gas conversion between 1966 and 1977 at peak (1971/72) was converting 2.3 million customers (meter points) per year, effectively four times the North of England peak. Achieving this conversion strategy is well within the UK's capabilities.

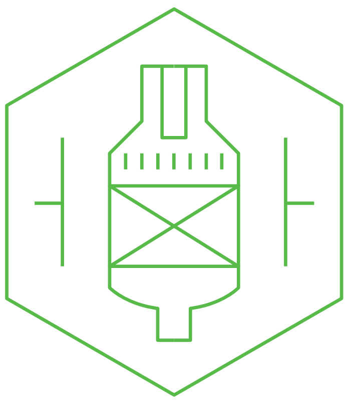
Supply: The Hydrogen Production Facility has been designed to be modular build adding one ATR of 1.35 GW module unit per annum from 2026 up to 2035. This ensures there is always enough hydrogen supply to match the increasing annual demand profile whilst ensuring constructability and efficient operation of the facility. Using this strategy, excess hydrogen production in the early years can be managed via inter-seasonal hydrogen storage, turn-down of individual units, or the preferred solution of exporting as power to the UK electric grid.

Inter-seasonal hydrogen storage can be built incrementally in line with the conversion and commissioning strategy. However, the first set of salt caverns (four surface facilities) would be in place by 2026 with the remainder phased in through the early years of conversion.

H21 NoE XL – a wider energy strategy

There is a very significant opportunity to use the surplus hydrogen in summer (when heat demand is low) to generate 30-50% of the NoE electrical requirements via hydrogen fired CCGT power stations. This strategy could be adopted in conjunction with scaling renewables in the form of off-shore wind. This would require a larger Hydrogen Production Facility (16.99 GW as opposed to 12.15 GW) but also significantly smaller inter-seasonal storage (2,164 GWh versus 8,052 GWh).

This would reduce CAPEX and OPEX by approximately 20% and 15% respectively and improve constructability. The H21 XL strategy would also provide an overall reduction of circa 10% in the wholesale hydrogen unit cost.



Section 7.0
CO_2 transport and storage

Storing carbon dioxide (CO_2) emissions produced by human activity underground helps address climate change by keeping this greenhouse gas out of the atmosphere. This is not a new or emerging technology, it is happening now. **In fact, the current CO_2 capture capacity is nearly 40 million tonnes per year (Mtpa).** There are many geological systems throughout the world that are capable of injecting centuries' worth of CO_2 captured from industrial processes and retaining it for millennia. **The United Nations Intergovernmental Panel on Climate Change (IPCC) estimates the world's potential capacity at two trillion tonnes, although it may possess 'much larger potential[3]'.**

CCS technology involves three major steps illustrated below.

The UK Continental Shelf (UKCS) has one of the largest potentials for CO_2 storage in Europe. The majority of the storage units are in three major regions; the Central and Northern North Sea (C-NNS), the Southern North Sea (SNS) and in the East Irish Sea (EIS). The UK has a total theoretical storage capacity of 78 Gt (78 thousand million tonnes). The SNS is a natural place to start the first UK CCS infrastructure project due to the potential storage structures' proximity to the shore and large emission sources in the UK.

The SNS also has large potential to serve as a storage hub for other European projects, with a strategic position close to countries like the Netherlands and Germany.

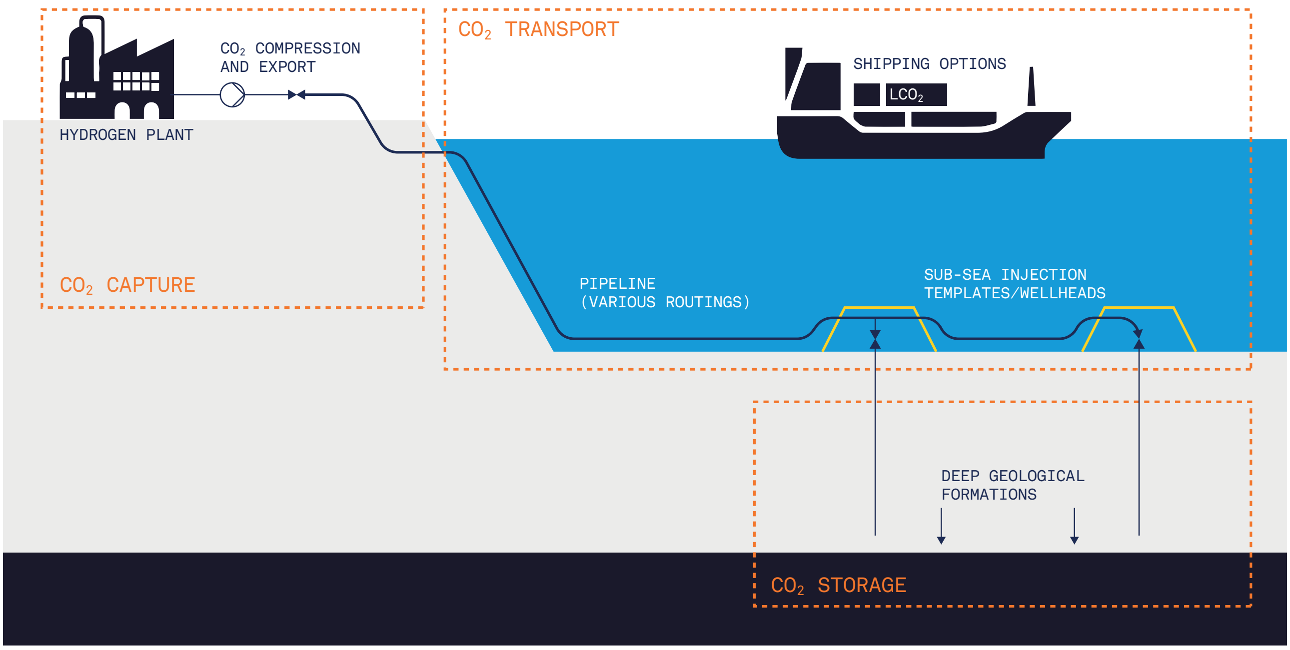
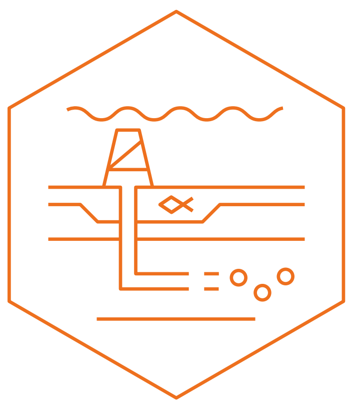


Figure ES.7: CCS technology steps



3 IPCC, 2005, Special Report on Carbon Dioxide Capture and Storage: Summary for Policymakers

A detailed assessment has been undertaken by Equinor's experts into the viability of CCS associated with the H21 NoE CCS requirements in the SNS. This would require scaling up of CO_2 transport and storage facilities to 2,827 t/h CO_2 (up to 20 Mtpa) by 2035 with a total CO_2 storage capacity of 516 Mt.

Whilst H21 NoE would represent the world's largest CCS scheme, it is only a factor of 10 larger than existing schemes which is within the realms of technical confidence. This is possible on both UK and Norwegian continental shelf.

In the Clean Growth Strategy, the Government has stated its ambition is to have "the option to deploy CCUS at scale during the 2030s". The Committee on Climate Change (CCC) state in their 2018 Progress Report to Parliament[4] that the UK will need to store at least 60, and potentially well over 100 Mt CO_2 each year by 2050, if it is to meet the 2050 Climate Change Act target. The CCC recommends at least 20 Mt CO_2 should be stored per year by 2035.

The H21 NoE project has the potential to single handedly deliver a CCUS solution in line with the recommendations from the CCC.

CO_2 transport and storage, economies of scale

As with all large projects there are significant financial benefits which can be realised with scale.

For CO_2 transport and storage, the most significant savings are achieved between the original H21 LCG (one Leeds) volumes of circa 1.5 Mtpa to the H21 NoE (13 Leeds) volumes of up to 20 Mtpa with an average of circa 17 Mtpa. This suggests that:

A CO_2 transport and storage scheme for the UK should be based around a project the scale of H21 NoE. This takes maximum advantage of economies of scale to ensure the unit costs are as low as possible.

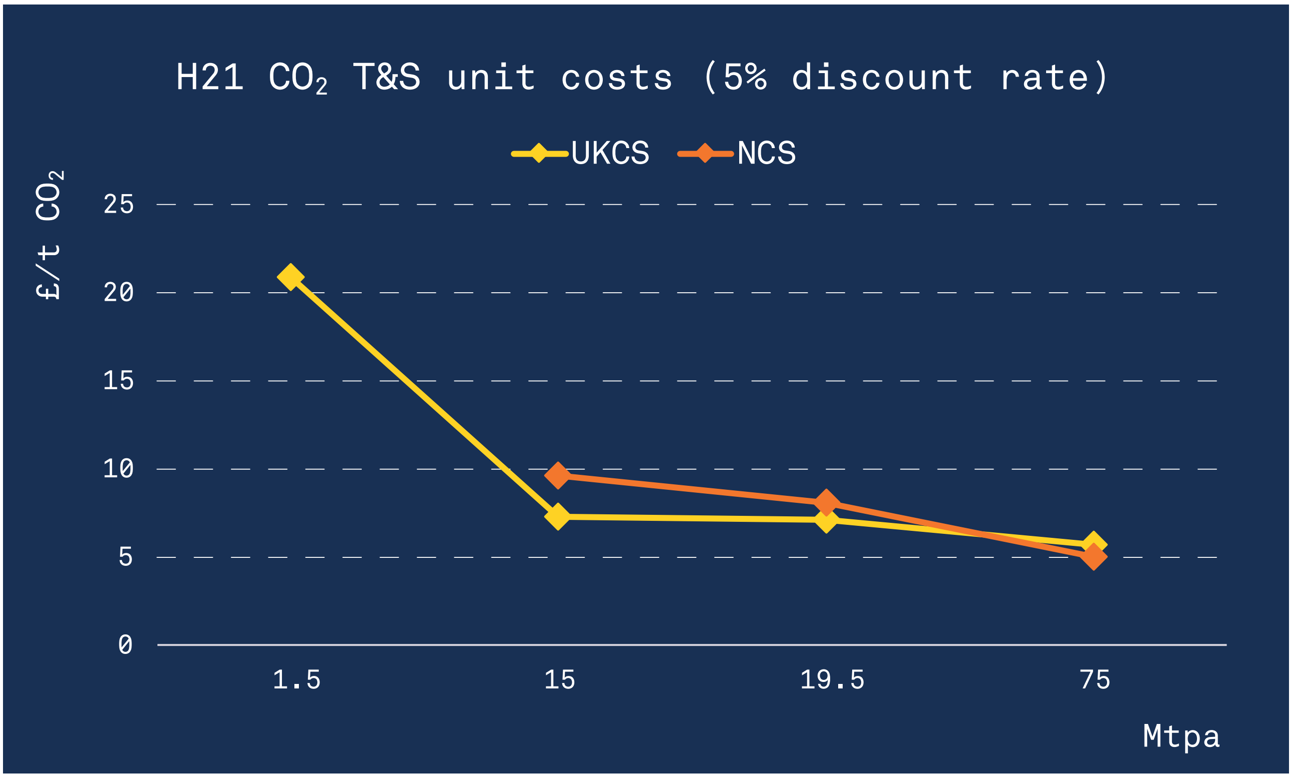


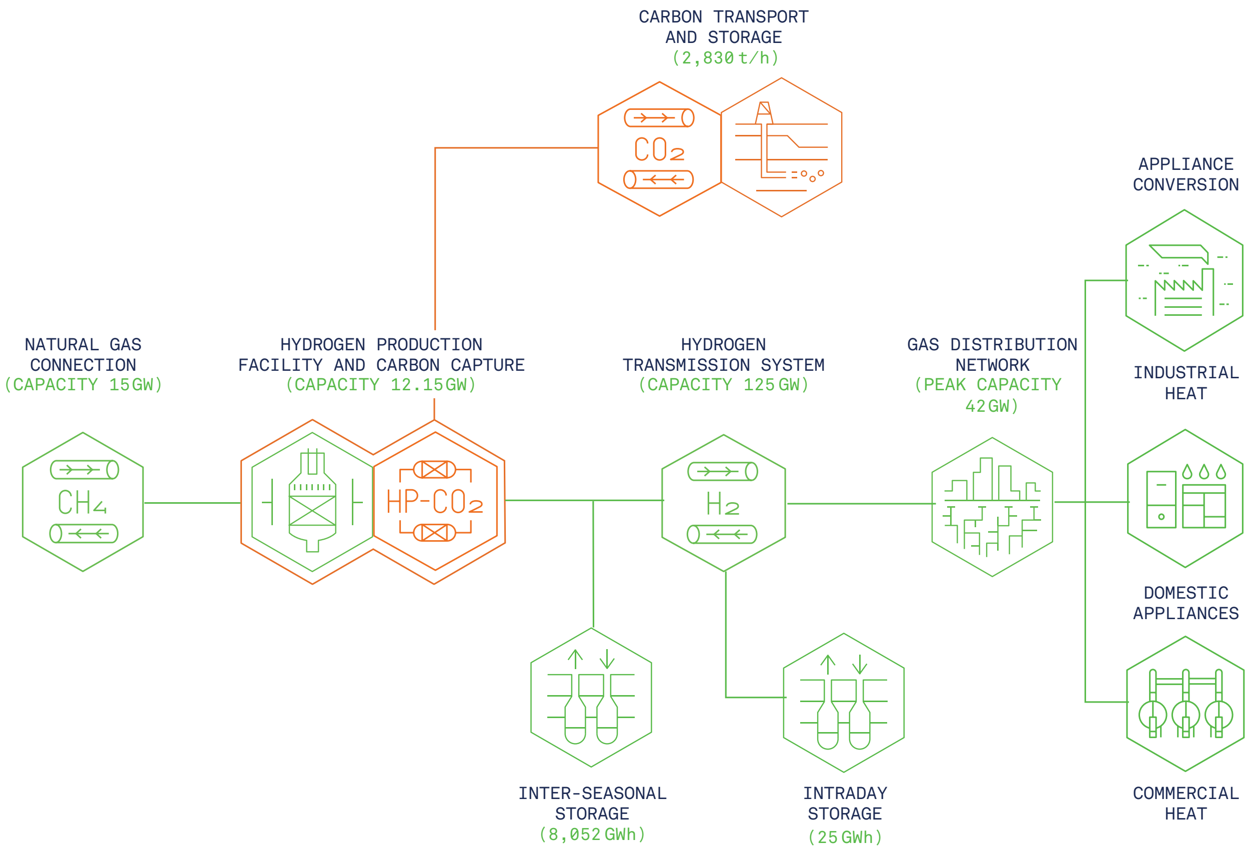
Figure ES.8: Summary unit cost estimates per tonne CO_2 – all UKCS and NCS cases

4 Committee on Climate Change, 2018. Reducing UK emissions – 2018 Progress Report to Parliament

Section 8.0
Project costs

For all aspects of the project a detailed and transparent assessment of costs has been given which draws on the expertise of the supply chain. It is recommended that comparisons with H21 NoE should be undertaken on a similar scale, timeline for constructability and **guaranteed** carbon savings basis.

CAPEX	£1,340 M
OPEX	£24 M



CAPEX	£0	£8,520 M	£1,991 M	£3,427 M	£0	£143 M	£7,500 M
OPEX	£0	£285 M	£63 M	£3.0 M	£0	£0	£0

£580 M ADDITIONAL ENERGY COST FOR HYDROGEN PRODUCTION FACILITY

Figure ES.9: H21 NoE project costs (CAPEX and OPEX)

ITEM	CAPEX (£M)	OPEX (£MPA) POST 2035 (ONCE CONVERSION AND COMMISSIONING IS COMPLETE)
Natural gas connection	0 (included in HPF)	0
Hydrogen Production Facility (HPF)	8,520	285
Inter-seasonal hydrogen storage	1,991	63
CO_2 transport and storage	1,340	24
Hydrogen transportation system	3,427	3
Appliance conversion	7,500	0
SUB TOTAL	22,778	373
Additional energy cost for Hydrogen Production Facility	N/A	580 (total annual gas cost is £2,292m based on gas price of £23/MWh)
TOTAL	22,778	955

Table ES.3: H21 NoE project costs table

The H21 NoE project is 13.3 and 14.2 times larger than the original H21 LCG project on an energy and meter point basis respectively. The H21 NoE project provides a CAPEX and OPEX saving of 25% and circa 50% respectively when compared on an energy basis against the original H21 LCG project costs.

Section 9.0
Finance and carbon footprint

H21 NoE is a fully aligned major infrastructure development with a long asset life time and a potential monopoly position. Therefore, a finance model for the H21 NoE project has been established based on the principles of regulatory financing.

A finance model has been developed and benchmarked against NGNs fully detailed regulatory finance model to confirm it is directionally accurate. This finance model assumes all the new hydrogen infrastructure including the Hydrogen Production Facility, inter-seasonal hydrogen storage, hydrogen transportation system, carbon transport and storage and appliances are part of a new national 'hydrogen regulated asset'. This is based on the factual and ethical assumptions established in Section 9.0 with the key statement being:

It is important not to think in terms of different types of gas having different costs. The individual customers' gas bills are not based on gas type, they are based on energy. As such, it is the mechanisms to distribute the cost that are important not the type of gas the customer is using.

The model uses Net Present Value (NPV) where the NPV is set to zero, depreciation is set to 45 years (appliances 10 years) and the WACC is seen as the internal rate of return of the project. The output from this model is used to calculate the new unit price and new annual gas bill for UK gas customers.

For the hydrogen regulated asset the additional unit cost for UK gas customers is £3.8/MWh

Based on a standard gas bill with current consumption at 14,200 kWh per year this translates to an additional £53 pa and total overall gas bill increase in 2035 (peak) from £780 pa (using 2035 gas prices £23/MWh) to £837 pa, i.e. a circa 7% increase.

Other scenarios, presented in Section 11.0, have the potential to significantly reduce this impact further still.

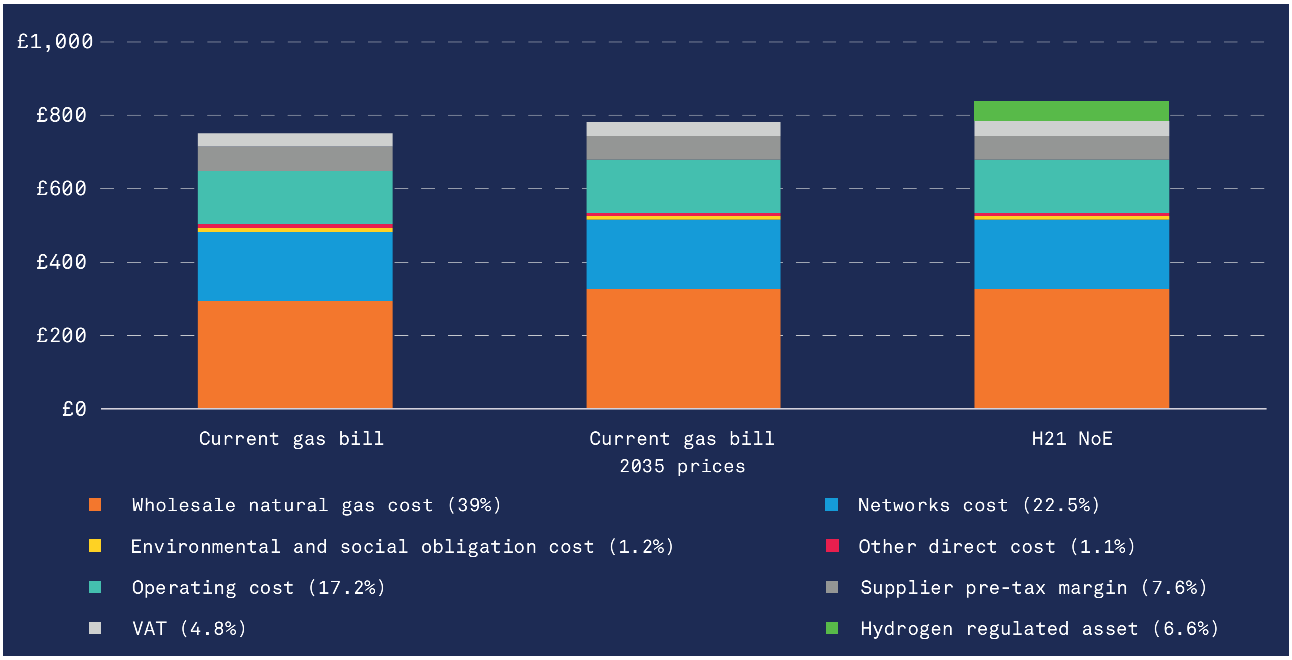


Figure ES.10: Impact of H21 on total annual gas bills (peak in 2035)

Section 9.8.4 Carbon footprint

The overriding imperative for any natural gas to hydrogen conversion programme must be a net reduction in emissions of CO_2 and other greenhouse gases. This must be expressed as their CO_2 equivalent in line with Kyoto Protocol. Carbon emissions associated with H21 NoE have been analysed against Scope 1; direct emissions at the system boundary, Scope 2; emissions associated with additional energy inputs and Scope 3; emissions outside the system boundary.

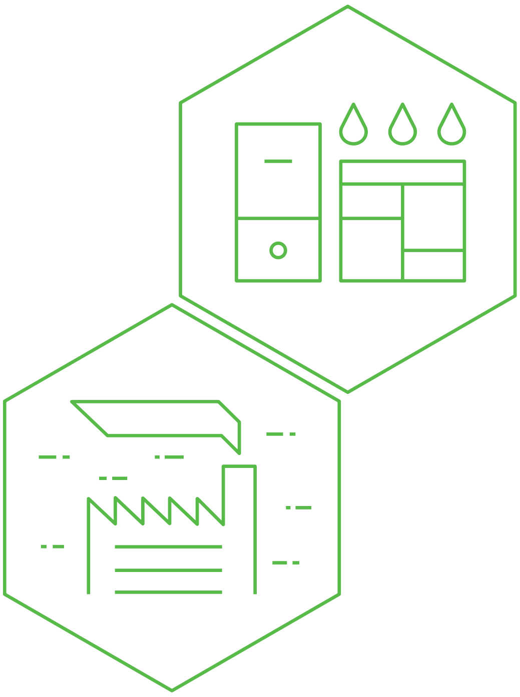
Scope 1: Emissions associated with the production of hydrogen and burning of the hydrogen fuel will be **14.4 g/kWh$_{H2HHV}$** at the ATR.

Scope 2: These emissions include the electrical consumption for inter-seasonal hydrogen storage with all power for the ATR generated internally. In the analysis of Scope 2 emissions it is assumed that the UK will meet the target set by BEIS of 100 g/kWh in 2030 and 50 g/kWh in 2050. This results in a Scope 2 emission of **0.073 g/kWh** in 2030 dropping to **0.036 g/kWh** in 2050.

The Scope 1+2 emissions directly impact the UK carbon budget and these are summarised in Table ES.4. Scope 3 emission are outside the UK carbon budget and are subject to more debate and conjecture than Scope 1+2 emissions but considerations for these emissions are provided below.

SCOPE OF EMISSIONS	H21 NoE SYSTEM BASED ON 2018 UK MIX (G/KWH)	NATURAL GAS (G/KWH)	% REDUCTION IN EMISSIONS
Scope 1	14.40	183.6	92.2%
Scope 1+2	14.47 (14.4 + 0.073)	183.6	92.1%

Table ES.4: Summary of H21 NoE emissions levels, Scope 1+2



Future UK gas supply will include continental European gas and LNG imports. Therefore, it is important to understand the supply chain emissions and potential for reduction. As the world continues to decarbonise it seems reasonable to assume that the upstream gas industry will also look to decarbonise. This will be partly by default as electrical power across the world becomes decarbonised and partly by deliberate actions (similar to those being adopted in Norway) to lower carbon footprints in response to domestic and international market demands. As with future electrical emission projections, the UK should look to target and promote upstream gas emissions comparable with those of the Norwegian Troll field in 2026, i.e. **2.4 g/kWh$_{H2HHV}$**. This is well within the gas industry's technical ability.

The H21 NoE project will provide an estimated 374 Mt of CO_2 avoided by 2060. This is a significant contribution to the carbon budget.

The H21 NoE project provides carbon capture and storage at a price of £5.54 per tonne based on a regulated asset finance model.

Section 10.0
Next Steps and FEED

To deliver the H21 NoE project within the 2028–34 timelines the FEED study should commence without delay. Any delay will have a direct impact on H21 NoE delivery timescales which will therefore have a subsequent impact on the UK government's ability to meet its climate change obligations.

The H21 NoE project can be executed within the timescales recommended by the Committee on Climate Change subject to development of the FEED. The programme below gives an overview of FEED activities:

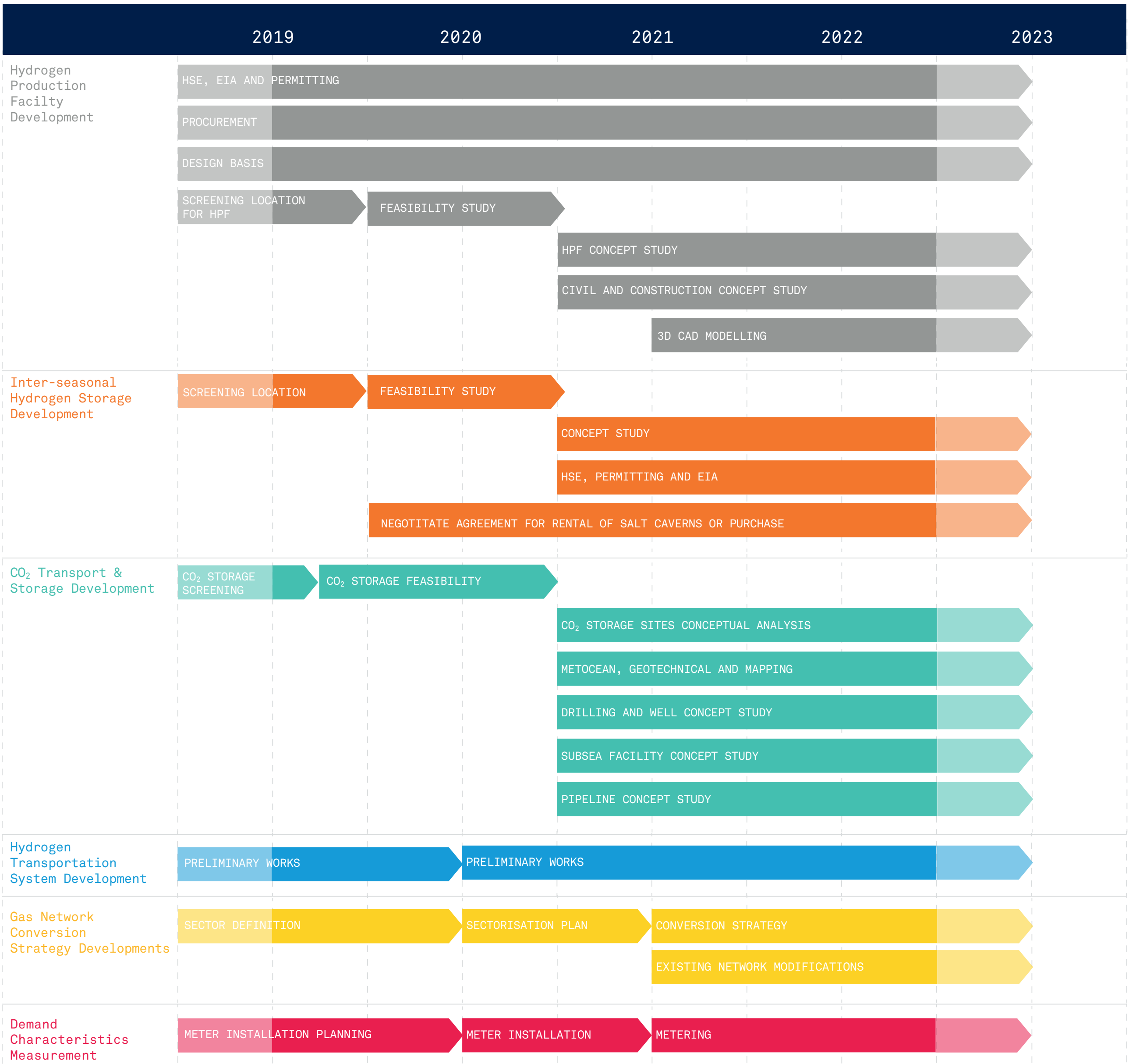


Figure ES.11: FEED delivery programme

The FEED will deliver the critical next step in delivery of a UK hydrogen conversion strategy. At a total cost of £250m this is only 1% of the total project value. Progression to FEED is a no regrets position for the UK as it allows a large scale (GW) hydrogen and CCS system to be developed which can still support decarbonisation of industrial clusters, centralised power generation (hydrogen CCGTs) and transport, irrespective of a final policy decision on heat.

The FEED study, requires government leadership to provide capital stimulus, confidence across the supply chain and galvanise industry. There is confidence that a firm commitment from UK government based around a 50/50 split with the private sector could provide the funding required to progress the FEED. Without significant government support a FEED study will not be developed. There is a high level of confidence that £100 m of private sector funding would be available should the UK government match funding and ensure critical enabling policies are in place or progressing.

Budget costs for the FEED study can be summarised as follows:

ITEM	COST (£M)
Hydrogen Production Facility (including CO_2 capture)	95
Inter-seasonal hydrogen storage	43
CO_2 transport and storage	78
Hydrogen transmission system	29
Gas network conversion strategy (fuel switching)	4
Demand characteristics measurement validation 2019/20	1
TOTAL COST FEED H21 NoE	250

Table ES.5: FEED cost breakdown

Section 11.0 Vision

The Vision section has been provided to show how hydrogen conversion could be rolled out across the UK. The rollout is based on hydrogen conversion of below 7 bar gas networks utilising the appropriate technology in the required timescales. The UK 2050 rollout position based on these six phases is shown in Figure ES.12.

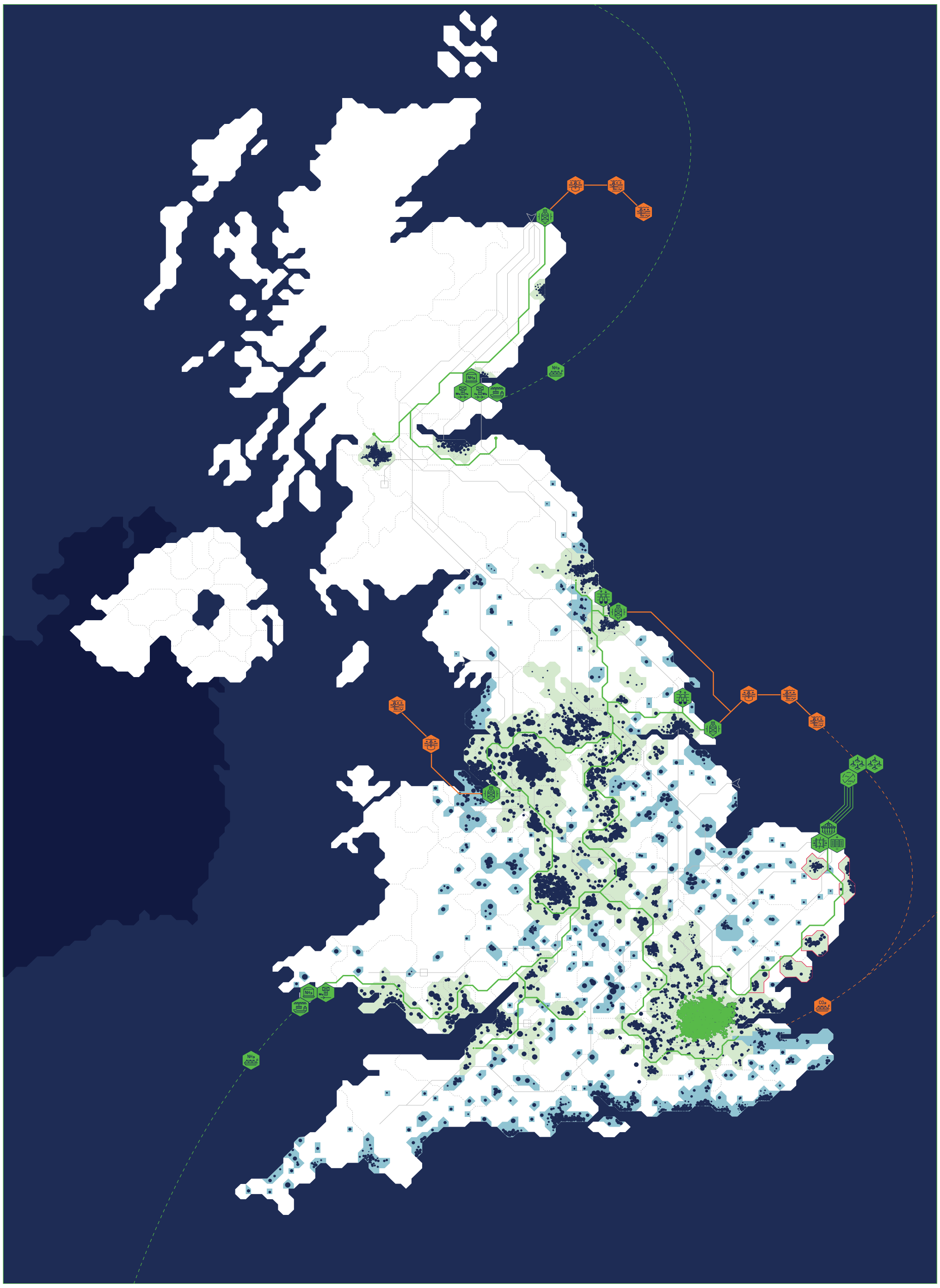


Figure ES.12: H21 2050

The six phases are:

- Phase 1: H21 NoE (conversion 2028-34)
- Phase 2: H21 South Yorkshire and East/West Midlands (conversion 2033-38)
- Phase 3: H21 Scotland (conversion 2030-32)
- Phase 4: H21 South Wales and South West (conversion 2036-37)
- Phase 5: H21 East Anglia and Home Counties (conversion 2040-45)
- Phase 6: H21 London (conversion 2045-50)

By 2050 the recommended rollout of H21 can provide deep decarbonisation (14.47 gms/kWh) of UK heat. Key points are summarised below:

- 62% by energy and 70% by meter points of domestic heat. (194,000 GWh of hydrogen per annum)
- 48% of non-domestic heat across the below 7 bar gas distribution networks including all industrial clusters and commercial users. (109,000 GWh of hydrogen per annum)
- 56% of all UK heat (109,000 + 194,000) ÷ 540,000)
- A total CO_2 reduction by 2050 of 50 Mtpa or 17% of the required reduction needed to meet the target of the Climate Change Act 2008

In addition to decarbonisation of UK heat (the H21's primary strategy), two other scenarios were also modelled based on the same regional rollout.

H21 XL (decarbonising heat and power); a summary is provided below:

- As H21 for heat plus
- 31% of UK power
- 61% of UK heat and power including 'high pressure industrial clusters'
- A total CO_2 reduction by 2050 of 88 Mtpa or 28.5% of the required reduction needed to meet the target of Climate Change Act 2008

H21 Max (decarbonising all energy); a summary is provided below:

In the H21 Max scenario 1,087,063 GWh of hydrogen is available. It is assumed this will replace all current (2016) natural gas, i.e. 850,000 GWh leaving 237,063 GWh for transport. In 2016 consumption of diesel and petrol in UK road transport amounted to 36.7 Mt or 466 TWh (12.7 $kWh_{HHV/kg}$) and a total CO_2 emission of 117.4 Mt (3.2 kg CO_2/kg).

Assuming a hydrogen fuel cell vehicle is twice as efficient compared to a diesel/petrol vehicle about 233 TWh of hydrogen will be needed for the entire UK road transport. Therefore, H21 Max would also enable a complete decarbonisation of UK road transport.

Total UK CO_2 reduction would be 258 Mt or 83.5% of the requirement to meet the Climate Change Act 2008.

These two rollout scenarios add an average of 2.3 GW and 5.4 GW hydrogen capacity per annum for the H21 XL and H21 Max scenarios respectively. Both these figures are less than the average annual global added hydrogen capacity over the last 40 years which is 5.5 to 7 GW. Therefore, it is well within technical capability of the existing supply chain.

Scaling CO_2 transport and storage

CO_2 transport and storage for a 50 times H21 LCG scenario, i.e. 50-75 Mtpa has been considered in both the UK and Norwegian continental shelves. This has shown that the capacity for such a scheme exists. Importantly, a carbon transport and storage scheme for the UK should be based around a project the scale of H21 NoE. This takes maximum advantage of economies of scale to ensure the unit costs are as low as possible.

By combining the UK and Norwegian storage described in this section shows that it is technically possible to meet the CO_2 storage requirement for H21 Max of 147 Mtpa.