

**Leeds  
City  
Gate**





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# Contents

<b>Executive Summary</b>	<b>1</b>
The Results	3
General Considerations	8
<b>1. Introduction</b>	<b>10</b>
1.1. UK Gas Transportation Network Operation	11
1.2. UK Gas Transportation Network Ownership	16
1.3. H2I Leeds City Gate Project Origins	18
1.4. The Original and Amended H2I Leeds City Gate Project Concept	21
1.5. The Area of Conversion	24
<b>2. Demand vs. Supply</b>	<b>28</b>
2.1. Gas Demand in the Area of Conversion	28
2.2. Supply System Characteristics	43
2.3. Hydrogen Generation Method (Production)	47
2.4. Hydrogen Supply for the Leeds Conversion Area	55
2.5. Storage – Balancing Supply and Demand	61
2.6. Location of the Hydrogen Production Facilities (SMRs) and Salt Caverns	76
2.7. Demand vs. Supply Conclusions	83
<b>3. Gas Network Capacity</b>	<b>85</b>
3.1. The Gas Industry Below Seven Bar Planning Software	86
3.2. The Steps for Analysis	88
3.3. Natural Gas to Hydrogen Conversion on the MP (blue) Network	94
3.4. Natural Gas to Hydrogen Conversion on the LP (red) Network	100
3.5. Network Capacity Conclusions	110



<b>4. Gas Network Conversion</b>	<b>113</b>
4.1. The Process	115
4.2. Network Enabling Costs for Conversion	137
<b>5. Appliance Conversion</b>	<b>139</b>
5.1. Domestic	142
5.2. Non-Domestic (Industry, Public and Commercial)	148
5.3. Switchover Cost Estimates – All Sectors	153
5.4. Conclusions	154
5.5. Properties of Hydrogen	155
5.6. Types of Hydrogen Combustion	162
5.7. Current Status of Hydrogen Appliances and Equipment	170
5.8. Conclusions	182
<b>6. The Hydrogen Transmission System</b>	<b>184</b>
6.1. HTS Teesside Connections	188
6.2. B and C – The Hydrogen Transmission Pipelines	193
6.3. Connections to the Leeds Distribution Network	201
6.4. Operating Costs (OPEX)	205
6.5. Hydrogen Transportation System Conclusions	206
<b>7. Carbon Capture and Storage</b>	<b>208</b>
7.1. UK Carbon Capture and Storage position	209
7.2. Teesside Collective Report (Taken from the 2015 Industrial CCS on Teesside Business Case)	212
7.3. Carbon Capture from Steam Methane Reformers Using a Post-combustion Scrub of the Flue Gases	214
7.4. Carbon Footprint of H21 System	219
7.5. Conclusion	227

<b>8. Finance and Regulation</b>	<b>229</b>
8.1. Summary of Costs for the H21 Leeds City Gate project	230
8.2. Hydrogen Conversion – The Regulatory Finance Model	231
8.3. Hydrogen Gas Cost per Kilowatt Hour	257
8.4. Cost per Tonne of Carbon Saved	263
8.5. Financial Conclusions	265
8.6. Regulatory Considerations	266
<b>9. Next Steps – The Programme of Works</b>	<b>269</b>
<b>10. The H21 Roadmap</b>	<b>275</b>
10.1. The Existing System	278
10.2. Work Package Descriptions	280
10.3. Work Package Summary	319
<b>11. The H21 Rollout Vision</b>	<b>321</b>
11.1. Incremental Hydrogen Economy Rollout	321
11.2. The Impact of Other Forms of Decarbonised Gas	347
11.3. Hydrogen Production – Market ‘Push and Pull’	349
11.4. Carbon Capture	353
11.5. H21 Vision Conclusions	361
<b>Schedules</b>	<b>362</b>
Chart Schedule	363
Image Schedule	365
Table Schedule	371



# Executive Summary



# Executive Summary

The UK, as with most other countries around the world, recognises the importance of meeting the challenge of climate change and has resolved, by 2050, to reduce carbon emissions by 80% of the level in 1990 under the terms of the Climate Change Act. This is the biggest energy challenge facing the world today although, to date, there has been little investigation or thought leadership around the opportunity to decarbonise the UK distribution gas network by specifically focusing on large cities.

Even natural gas (predominantly methane), the lowest carbon dioxide emitter per unit of energy of any fossil fuel, produces about 180 gm/kWh CO<sub>2</sub> equivalent whereas hydrogen emits zero (at the point of use). The change over from natural gas to hydrogen has the potential to provide a very deep carbon emission reduction. The true carbon footprint of hydrogen depends on its source. For example, grid power electrolysis has very high emissions whereas hydrogen made from stripping the carbon atom from natural gas has about 50 gm/kWh CO<sub>2</sub> equivalent including indirect emissions, a large reduction over the existing unabated natural gas fuel. Renewable based electrolysis could be used, but for the foreseeable future the required quantities do not look realistic.

This report suggests that we can significantly decarbonise parts of the existing gas network at minimal additional cost to consumers. This would significantly contribute to the UK's 2050 and Paris Agreement commitments, remove the risks of carbon monoxide poisoning, increase energy storage, potentially remove air pollution from vehicles, and enable new product development and innovation for manufacturing and industrial businesses.

The UK gas industry is over 200 years old. For the first 150 years the gas used was locally manufactured town gas which contained circa 50% hydrogen with smaller quantities of carbon monoxide and methane. In the early days this was made by distilling coal and, later, oil. Following the initial discovery of natural gas in the North Sea, made up predominantly of methane, during the 1960/70s the UK undertook a nationwide gas conversion programme converting 40 million appliances, reaching a peak of 2.3 million per year. Over 80% of the UK population now use this gas network for heating and cooking. A hydrogen conversion would follow a similar process to the original town gas to natural gas conversion undertaken so successfully and within living memory. The process will involve minimal disruption for the customer (domestic or commercial) and require no large scale modifications to their property.

Since 2002, the UK has been undertaking the Iron Mains Replacement Programme (IMRP), upgrading the majority of its distribution pipes to polyethylene. This is a risk prioritised, Health and Safety Executive mandated initiative due to complete in 2032. These polyethylene pipes are considered to be suitable for transporting 100% hydrogen.





The H21 Leeds City Gate project is a study with the aim of determining the feasibility, from both a technical and economic viewpoint, of converting the existing natural gas network in Leeds, one of the largest UK cities, to 100% hydrogen.

The project has been designed to minimise disruption for existing customers, and to deliver heat at the same cost as current natural gas to customers.

The project has shown that:

- The gas network has the correct capacity for such a conversion
- It can be converted incrementally with minimal disruption to customers
- Minimal new energy infrastructure will be required compared to alternatives
- The existing heat demand for Leeds can be met via steam methane reforming and salt cavern storage using technology in use around the world today

The project has provided costs for the scheme and has modelled these costs in a regulatory finance model.

In addition, the availability of low-cost bulk hydrogen in a gas network could revolutionise the potential for hydrogen vehicles and, via fuel cells, support a decentralised model of combined heat and power and localised power generation.



## The Results

The results of the Project are as follows:

### Demand vs. Supply (Section 2)

The energy demands calculated for the area of conversion are:

1. Average yearly gas demand = 678 MW (derived from DECC data)
2. Maximum peak yearly demand = 732 MW (temperature corrected DECC data)
3. Maximum peak hour demand = 3,180 MW (NGN 1 in 20 peak hour demand)
4. Peak day average demand = 2,067 MW (derived from NGN 1 in 20 peak hour demand design parameter)
5. Total average yearly demand = 5.9 TWh
6. Total peak year demand = 6.4 TWh

This demand would be serviced by the following hydrogen production and storage facilities: Hydrogen production capacity of 1,025 MW<sub>HHV</sub> (305,000 Sm<sup>3</sup>/h) provided by four Steam Methane Reformers (SMRs) located at Teesside, fitted with 90% carbon dioxide capture. This CO<sub>2</sub> is then compressed to 140 bar and assumed to be exported 'over the fence' to permanent sequestration deep under the North Sea. Such hydrogen production at large scale is fully proven, with worldwide production standing at about 50 million tonnes per annum compared to 0.15 million tonnes per annum for the proposed area of conversion.

Additional intraday storage, which together with the SMRs and inter-seasonal storage, will supply a maximum 1 in 20 peak hour demand of 3,180 MW<sub>HHV</sub>. This will be in the form of salt cavern storage located at Teesside, some which may be repurposed from already existing caverns.

Inter-seasonal storage of 702,720 MWh<sub>HHV</sub> (40 days of maximum average daily demand (coldest year), 209 million Sm<sup>3</sup> hydrogen). This will be in the form of salt cavern storage located on the East Humber coast.

A Hydrogen Transmission System (HTS) will connect the SMRs and salt caverns to the proposed area of conversion (Leeds) and will be capable of transporting at least the peak supply requirement of 3,180 MW.

### Gas Network Capacity (Section 3)

Both the Medium Pressure (MP) and Low Pressure (LP) gas distribution networks within the area of conversion have been modelled for hydrogen conversion using the network analysis software and data currently used by Northern Gas Networks. The conclusion of this modelling is that the gas networks have sufficient capacity to convert to 100% hydrogen with relatively minor upgrades.



### Gas Network Conversion (Section 4)

It is possible for the existing gas network to be segmented and converted from natural gas to hydrogen incrementally through the summer months over a three-year period. This approach would mean minimal disruption for customers during the conversion.

### Appliances Conversion (Section 5)

Hydrogen appliances and equipment for domestic, commercial and industrial sectors can be developed. There are already a few models on the market, although sales are extremely low, due to an absence of piped hydrogen. Just with the knowledge of this study, several manufacturers are showing real enthusiasm for their development. A firm long-term plan and significant stimulus would be needed to provide the motivation to develop and produce the wide range of equipment required. This could potentially be in the form of a national heat policy.

### Hydrogen Transmission System (Section 6)

High pressure hydrogen transmission pipelines are operating around the world today. Similar pipelines have been proposed for carrying hydrogen from the SMR site to the conversion area and hydrogen storage sites. In addition a connection between the natural gas transmission system and the SMR has been proposed along with a pipeline from the SMR to CCS. Costs for these have been estimated at £230 million with ongoing OPEX costs of £0.5 million per annum.



## Carbon Capture and Storage (Section 7)

The H21 Leeds City Gate project would give the following savings in CO<sub>2</sub> emissions:

	gm/kWh NG	gm/kWh H <sub>2</sub>	% Reduction
UK Carbon budget basis (Scope 1)	184.0	27.0	85%
Including electricity for sequestration (Scope 1+2)	184.0	49.5	73%
Including embodied CO <sub>2</sub> from the production and importation of natural gas (Scope 1+2+3)	209.3	85.8	59%

The H21 Leeds City Gate project would sequester 1.5 million tonnes per annum CO<sub>2</sub>.

Scope 1, net CO<sub>2</sub> savings for the area of conversion is 927,000 tonnes per year.

Carbon capture and storage technology is well established alongside SMR operations. An example of which can be seen in the Port Arthur SMR plants operated by Air Products in the USA.



## Financial Model (Section 8)

Total costs associated with the Project are summarised in the table below.

Cost Summary (£m)	Cost incurred (£m)	Ongoing costs each year (£m)
Network Capacity and Conversion Preparatory Work (Section 2.2)	10	
<b>Hydrogen Infrastructure/Conversion Costs</b>		
Steam Methane Reformer (SMR) Costs (Section 2.1)	395	
Intraday Salt Caverns (Section 2.1)	77	
Inter-Seasonal Salt Caverns (Section 2.1)	289	
Appliance Conversion (Domestic, Commercial and Industrial users within area of conversion) (Section 2.3)	1,053	
Hydrogen Transmission System (HTS) (Section 2.4)	230	
<b>Ongoing OPEX Costs</b>		
Carbon Capture and Storage		60
SMR/Salt Cavern/HTS Management		31
SMR Efficiency loss (30%)		48
<b>Total</b>	<b>2,054</b>	<b>139</b>

If the H21 Leeds City Gate project was funded using the current UK regulatory business plan it would have negligible impact on customers total gas bills.

## Next Steps, Programme of Works and H2i Roadmap (Section 9 and 10)

The earliest practical date for the initial hydrogen conversion of a UK city is 2025. In order to achieve this, several preparatory actions need to have taken place these are:

1. **2017 to 2022** – Provision of finance to deliver the 16 work packages identified in this report with an estimated value of between £60m and £80m (See Section 10).
2. **2016/17** – Establishment of the H2i Programme Team to co-ordinate and deliver the 16 identified work packages.
3. **2018** – Provision of funding to begin the FEED/detailed design of the hydrogen production, storage and pipeline systems.
4. **2018** – Clear direction by Ofgem that gas distribution networks need to allow provision within their GD2 business plans (2021–2029) to facilitate the conversion of the first cities.
5. **2021/22** – A policy decision committing to the strategic, incremental material conversion of the UK gas grid over an agreed timescale.

## The H2i Vision (Section 11)

The H2i Leeds City Gate Project has focused on the provision of heat through a 100% hydrogen gas network conversion for Leeds. Additionally by utilising gas industry expertise some thought leadership has been provided around the impact of an incremental rollout of such a system across UK cities and/or regions. This has also considered the potential impact of establishing the first commercial hydrogen economy in the world.

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***Two rollout options have been presented and, alongside efficiency savings, both options could be developed with minimal impact on customers overall bills***



## General Considerations

1. The H21 Leeds City Gate Project has shown that the conversion of the UK gas distribution network to hydrogen would enable a dramatic reduction in UK emissions with circa 73% reduction from heat but also from transport and power generation.
2. Converting the UK gas network avoids the need to persuade householders to raise the funds and give up the space to install other complex low carbon technology. The absence of hassle for the customer is considered to be very important in the likely success of any decarbonisation strategy.
3. Leeds with circa 1% of the UK's population is a sensible starting point because of its size and geographical location, near to both Teesside (with its existing hydrogen infrastructure) and the salt beds north of Hull.
4. The use of hydrogen storage addresses inter-seasonal storage, one of the known problems of trying to use only electricity as the energy vector for heat, This inherently smooths out:
  - The UK's large variation in inter-seasonal energy demand as hydrogen is produced and stored 'downstream' at a relatively constant rate throughout the year.
  - The production of CO<sub>2</sub> thereby simplifying sequestration.
  - The wholesale natural gas purchases as the demand is relatively constant over the year for hydrogen production and storage and therefore this reduces the volume of natural gas required at periods of high demand (and therefore cost).
5. Low cost pipeline quality hydrogen (99.9%) can be purified to the very high quality gas required by fuel cells. Therefore a UK gas grid conversion to hydrogen could provide feedstock for automotive use, and via fuel cell combined heat and power open up the opportunity for an alternative to centralised power generation.
6. All of the individual steps in the hydrogen supply train (except for some appliances) are proven and widely available by competitive tender.
7. The project could stimulate the Northern Powerhouse bringing economic benefits to both the North and the UK economy as a whole.

The H21 Leeds City Gate project provides evidence that converting the UK gas network to hydrogen is technically possible and economically viable. A UK hydrogen conversion strategy could make a significant contribution towards meeting the challenge of the Climate Change Act as well as establishing the world's first hydrogen economy. It could also create a significant impact on UK GVA and establish a real anchor project around the Northern Powerhouse concept.



## SECTION 1

# Introduction





# 1. Introduction

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## *The UK Gas Industry History*

*William Murdoch was the first to exploit the flammability of gas for the practical application of lighting. He worked for Matthew Boulton and James Watt at their Soho Foundry steam engine works in Birmingham, England, in the early 1790s. In 1798 he used gas to light the main building of the Soho Foundry and in 1802 lit the outside in a public display of gas lighting, which astonished the local population.*

*One of the employees at the Soho Foundry, Samuel Clegg, saw the potential of this new form of lighting. Clegg left his job at the Soho Foundry to set up his own gas lighting business, the Gas Lighting and Coke Company. The first public street lighting with gas was demonstrated by Frederick Albert Winsor in Pall Mall, London, on 28<sup>th</sup> January, 1807. In 1812 Parliament granted a charter to the London and Westminster Gas Light and Coke Company, and the first gas company in the world came into being. Less than two years later, on 31<sup>st</sup> December, 1813, Westminster Bridge was lit by gas. (Wikipedia).*

*For the following 150 years 'town gas' companies grew and prospered across the UK manufacturing gas from coal, then in the later years, oil (post World War Two). At its peak, before conversion to natural gas, town gas was manufactured across UK towns and cities using over 26 million tonnes of coal and 0.5 million tonnes of oil per annum (Charles Elliott, *The History of Natural Gas Conversion in Great Britain*).*

*There are two important factors which need to be considered when reviewing this rich history. Firstly, town gas consisted of up to 50% hydrogen (other gases included carbon monoxide, methane and small quantities of various other gases) and was piped throughout the distribution system – the same distribution system we are upgrading today with polyethylene. Secondly, town gas was manufactured and distributed on an individual town by town basis, no Local Transmission System or National Transmission System existed (see explanation later in this section).*

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## 1.1. UK Gas Transportation Network Operation

The UK gas transportation industry has evolved over the last 200 years to be the well-integrated highly robust system that we see today. If we consider the 19<sup>th</sup> century to have been dominated by town gas, the 20<sup>th</sup> century by natural gas, what if the 21<sup>st</sup> century could be dominated by hydrogen? To fully understand the implications of the H21 Leeds City Gate project it is important to understand how the current UK gas transportation network operates.

The UK gas transportation infrastructure is a vast network of pipes (37,000 km in Northern Gas Networks alone) ranging in diameter from 48 inch (1,200 mm) high pressure mains to 2 inch (50 mm) low pressure mains. The gas used in the UK system, since the town gas to natural gas conversion between 1966 and 1977, has predominantly come from the UK's North Sea gas reserves. In more recent years there has been an increasing dependence on gas from Europe, or from around the globe through the process of liquid natural gas transportation.

The current UK gas transportation system has three key component parts:

System	Level of Pressure
The National Transmission System (NTS)	45 – 85 bar
The Local Transmission System (LTS)	> 7 – 70 bar
The Distribution System	7 bar and below which consists of: Intermediate Pressure (IP) (> 2 bar to 7 bar) Medium Pressure (MP) (> 75 mbar to 2 bar) Low Pressure (LP) (not exceeding 75 mbar)

Table 1.1. *The UK gas transportation system*

Note: A 'bar' is approximately the pressure exerted by the atmosphere at sea level. Strictly, the pressures indicated within this document are barg or bar-gauge, i.e. pressures in excess of local atmospheric pressure. For example, 2 barg is approximately 3 bar absolute.

By way of analogy, the UK gas transportation system could be compared to the UK road network, whereby the NTS are major motorways, the LTS minor motorways or 'A' roads and the distribution system is everything else.

The storage of gas, to ensure that supply is able to meet the demands of end users, which includes both intraday and inter-seasonal swings, is managed by using Liquid Natural Gas (LNG), salt caverns/depleted hydrocarbon fields and linepack within the NTS (intraday only) and LTS (intraday only). The distribution system, which mainly consists of medium and low pressure pipe networks, does not provide any significant storage for the system and is designed specifically for an instantaneous reaction to match peaks in demand.

### ***Breakout: Storage Descriptions***

**LNG** – *When natural gas is cooled to  $-162\text{ }^{\circ}\text{C}$  it becomes a liquid. As a liquid it is possible to store 600 times the quantity of natural gas than in a gaseous state of the same volume.*

**Salt Caverns** – *There is a long and successful history of storage cavern utilisation in the UK (over 30 in number) which provide seasonal, diurnal (daily) and rapid response storage. Salt caverns can be manmade in geographical areas which have large salt beds which have been washed out using high pressure water jets. They are typically cathedral size, 80 m in diameter and 80 m high.*

**Linepack** – *Increasing and reducing the pressure in the transmission pipeline to store or release additional gas.*

### **Some technical differences:**

The UK gas industry is one of the safest industries in the world and has continuously evolved driven by high levels of technical expertise and stringent regulation. The NTS and LTS are designed and built to the same technical standards and specifications. They are constructed using a hard steel (X42, C4Gas PIPO etc.), and as such are not suitable for the transportation of hydrogen at high pressure. This is due to the well documented embrittlement problems hydrogen can cause when transported at high pressure through hard steel pipes. These problems are most likely to occur within the original welded joints of the 1960s, but could arise almost anywhere within this high pressure system.

There are two significant differences between the NTS and the LTS. The NTS uses compressors to move gas throughout the country. There are currently no compressors on the LTS. The gas transported in the NTS is unodourised (see **Breakout: Gas Odour** later in this section).

The UK gas distribution system has evolved since the foundation of the gas industry over 200 years ago. The pipes within this system historically were iron (cast, spun, ductile) and steel. Since the 2002 there has been a HSE mandated replacement programme in the UK, referred to as the Iron Mains Replacement Programme (IMRP) with the purpose of upgrading these pipes with Polyethylene (PE) pipes. The IMRP is scheduled over a 30 year period, to be completed by 2032. Historically town gas (circa 50% hydrogen by volume, referred to as v/v) was transported through these iron mains. Due to degradation of these mains over time it is likely a 100% hydrogen gas would need to be transported through a predominantly PE pipe network.

Natural gas leakage from the current system is calculated within the Gas Distribution Networks using a 'leakage model'. Leakage reduces year-on-year in the industry as more old metallic mains are upgraded to PE and the IMRP progresses. If the existing metallic distribution mains were used to transport hydrogen without the upgrade being undertaken by the IMRP it is reasonable to assume that there would be an increase in leakage levels. This is due to hydrogen having a low density at only  $\frac{1}{8}$  the density of methane. This is not necessarily an increased safety issue from today's current position when compared directly to the risk associated with natural gas, but is certainly a commercial problem. It should be noted that hydrogen is not a greenhouse gas, and therefore any associated leakage, unlike methane, does not have a significant negative impact on climate change. Some academics indicate that hydrogen contributes slightly to a second tier of global warming but it is agreed this effect is very small.

### ***Breakout: Gas Odour***

*Natural gas as it is extracted from the ground has no smell. It is odourised here in the UK to ensure that 'gas' has a recognisable smell, even at low concentrations – well below the explosive limit – to make the public aware that there is a gas leak so that the appropriate action can be taken.*

*The odourant added to natural gas is a group of sulphur based compounds chosen because of their distinctive and highly concentrated smell.*

*The odourant is added to the gas at the 'offtakes' which are the point of transition between the NTS and the LTS. This is the most cost effective point to add the odourant to the gas. This also allows gas in the NTS to be transferred via interconnectors to continental Europe where odourising regulations vary considerably.*

Today's gas transportation system is represented simplistically on the map in **Image 1.1**.



**Image 1.1. Existing UK Transportation System**

This transportation system is represented in simple pressure tiers, illustrated in **Image 1.2**. As gas is injected from the NTS, it cascades down the pressure tiers, to be used by the customer at the appropriate point. The majority of gas customers are located off the medium and low pressure systems (domestic heat demand). As pressure drops in a lower pressure tier (for example as demand increases), gas 'cascades' from the pressure tier above to maintain supply. Simplistically if the system is thought of a series of cascading sinks of water, as the sink at the bottom starts to empty (the plug is pulled out – or gas demand increases) the sink above flows into the sink below to maintain volume and thereby ensuring security of supply.

## Distribution Network

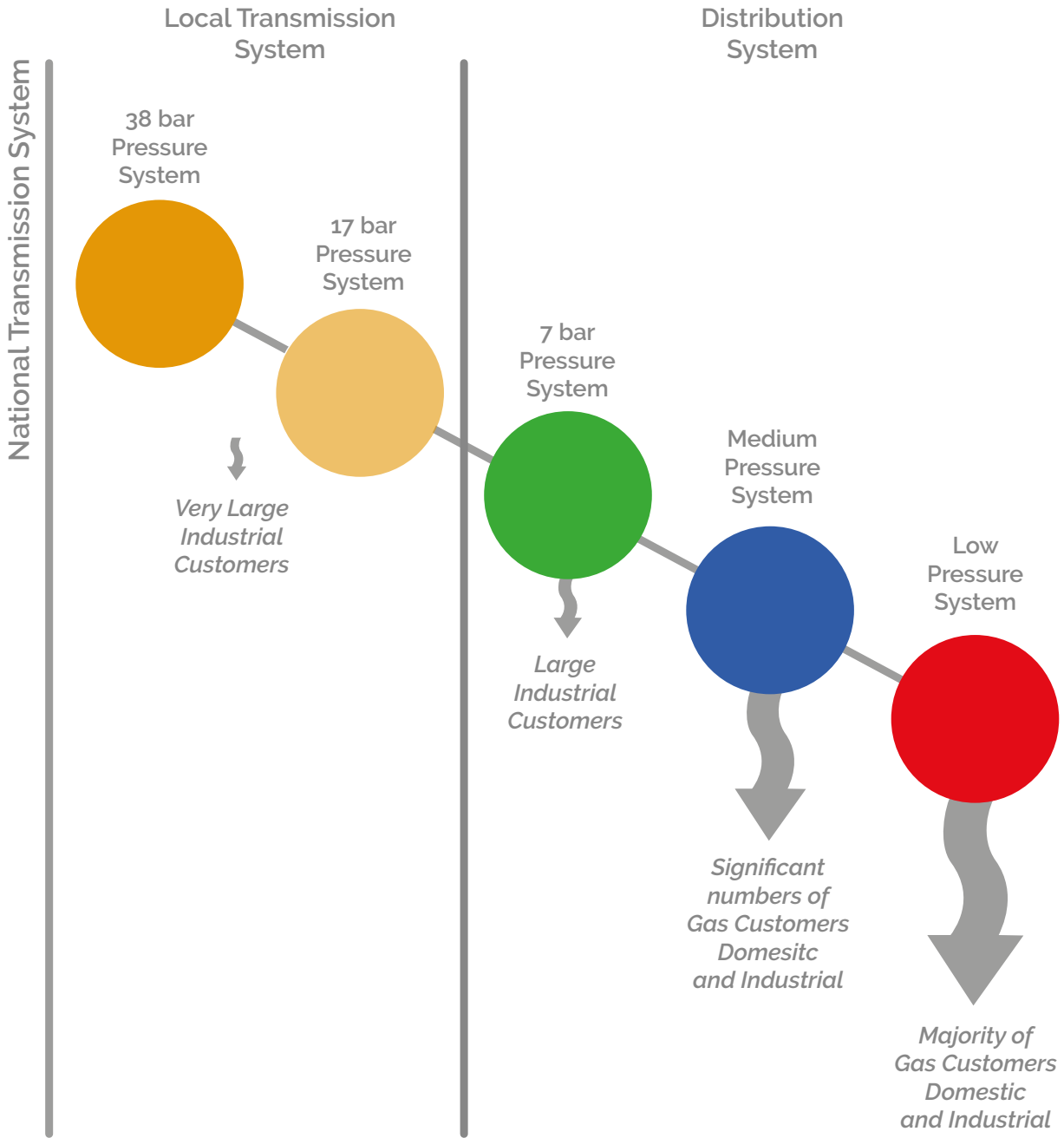


Image 1.2. UK Gas Pressure Tiers

## 1.2. UK Gas Transportation Network Ownership

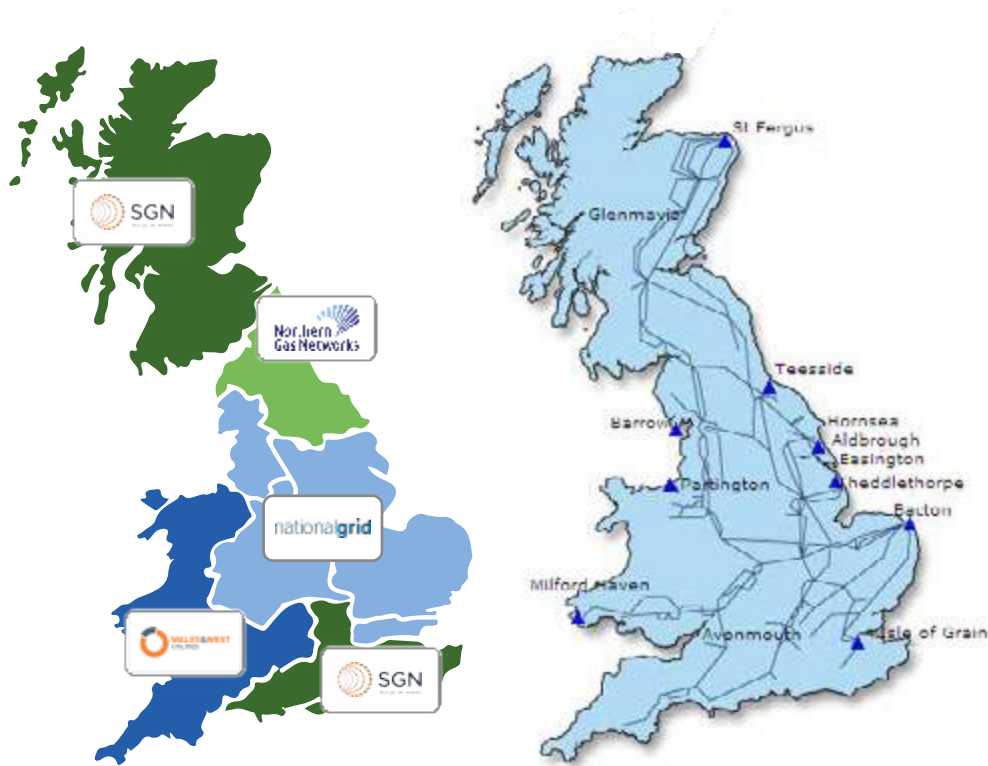
In recent history the ownership of the transportation assets has changed considerably:

- **1800s–1948:** Around 2,000 independent town gas companies were in operation.
- **1948–1973:** These independent companies were nationalised to form 12 autonomous gas boards.
- **1973–2000:** British Gas Corporation was established and privatised 8<sup>th</sup> December 1986. This owned the entire UK gas transportation system.
- **2000–2005:** The UK gas transportation operation became Transco (and then National Grid Transco (NGT)) following the de-merger of the British Gas Corporation.
- **2005–present:** Four of the eight Gas Distribution Networks (GDNs) within the gas transportation system were sold. Today the ownership of this UK gas transportation system is illustrated in the **Image 1.3**. The NTS remains in the ownership of National Grid whilst the relevant LTS are owned by the respective GDN.

Today the industry ownership model is referred to as the National Transmission System and Gas Distribution Networks (GDNs). Rather unhelpfully the later description often leads to the incorrect assumption that the GDNs only operate the distribution system (below 7 bar). However the GDNs own and operate both the LTS, including the major pressure reduction stations where gas is taken from the NTS (offtakes), and the distribution system.



The ownership model is represented in **Image 1.3**:



**Image 1.3. Current Gas Transportation System Ownership**

National Grid own the NTS and there are currently four gas distribution operators who collectively own the eight gas distribution networks (only the operators are shown on the map), National Grid Distribution (who own four GDNs), Northern Gas Networks, Scottish and Southern Gas Networks (who own two GDNs) and Wales and West Utilities.



## 1.3. H21 Leeds City Gate Project Origins

The UK, as with most other countries around the world, recognises the importance of meeting the challenge of climate change. The Climate Change Act seeks to address this, with the opening statement *"It is the duty of the Secretary of State to ensure that the net UK carbon account for the year 2050 is at least 80% lower than the 1990 baseline"*. The UK needs big ideas that work on a practical basis. To quote David MacKay's book *Sustainable Energy – without the hot air, 'What is required are big changes in demand and supply'*. To date there has been little investigation or thought leadership around the opportunity to decarbonise the UK by using hydrogen on a large city scale, a big idea that could work on a practical basis.

The academic concept of 100% hydrogen gas grids and their potential viability relative to the UK gas networks was presented to DECC by Kiwa Gastec in February 2012. DECC subsequently supported a piece of work to compare the relative fire risks from natural gas and hydrogen in a Scottish farmhouse (HyHouse). This had an encouraging outcome, but the idea gained little traction as there was minimal tangible evidence addressing gas network capacity and conversion capability, no industry support, no financial model and no practical 'anchoring' to the concept. Following an information meeting between Kiwa Gastec and NGN at the LCNi conference in Aberdeen in October 2014 the H21 Leeds City Gate project was developed, the first to address the 100% hydrogen concept in the UK in a practical manner.

When formulating the concept of H21 Leeds City Gate project there were multiple considerations that needed to be taken into account.

- Over 80% of customers in the UK use natural gas, rising to 90% in cities.
- Customers have little money to convert to alternative sources of heat. (See Wales and West Bridgend study available via the Network Innovation Allowance portal on the ENA website).
- There are two challenges to decarbonisation that are particular to cities. Firstly, the types of existing buildings (over 80% will still be there in 2050) and secondly the complexities involved with the installation of new network infrastructure. Beneath the roads and pavements of most major UK cities there are high levels of congestion with large quantities of utilities already competing for space. The gas industry has vast experience laying and modifying mains throughout cities and is experienced in the significant challenges and complexities involved. A major advantage to using hydrogen gas for transporting energy in cities is that the gas pipe network is already in place. Other energy options would require extensive new infrastructure causing significant disruption.
- Cities emit the largest quantities of carbon, due to using larger volumes of natural gas. Cities therefore represent the most significant opportunity for the reduction of carbon emissions. Due to the scale of energy demand and age they are also the most difficult to address.

- Large inter-seasonal swings in energy demand, of up to 80% in city centres and 99% in suburbs are managed by the gas network through a system that already exists and operates, largely invisibly, to the general public.
- Hydrogen is not regarded as a conventional greenhouse gas. It is thought to be involved in some second order effects but these are minute compared to the known effects of carbon dioxide or methane.
- There is no shortage of methane due to the long term potential supply of unconventional gas (shale gas, coal bed methane, biomethane) and LNG/interconnector availability.
- If the gas industry is to have a long term future it needs to be able to make significant contributions to decarbonisation.
- If hydrogen could offer the UK a large scale solution to decarbonisation it will provide opportunities for all the energy vectors (electric, heat and gas) to contribute. With more options available there is a greater probability in meeting the challenge of the climate change act.
- There are only three parts to the end-to-end energy system, as shown in **Image 1.4**.

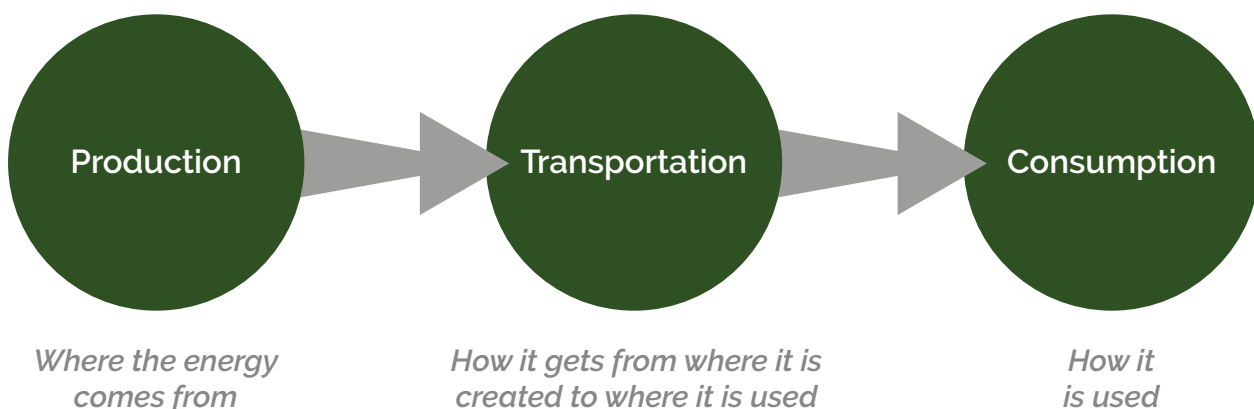


Image 1.4. *End-to-End Energy System*

Considering these factors, the key question for the project team in the formulation of the H21 Leeds City Gate project was:

***'Is it possible to develop and cost a holistic, large scale solution to the decarbonisation of cities with minimal impact on consumers (relative to alternatives) which can consider the end-to-end energy system?'***

Solutions presented to date generally focus on one area of energy, production or consumption, and often do not take transportation into consideration. No large scale practical solution has been presented to date to address decarbonisation of heat, which would involve minimal impact on all three parts of the existing energy system.

The H2i Leeds City Gate project was developed around the following six parameters:

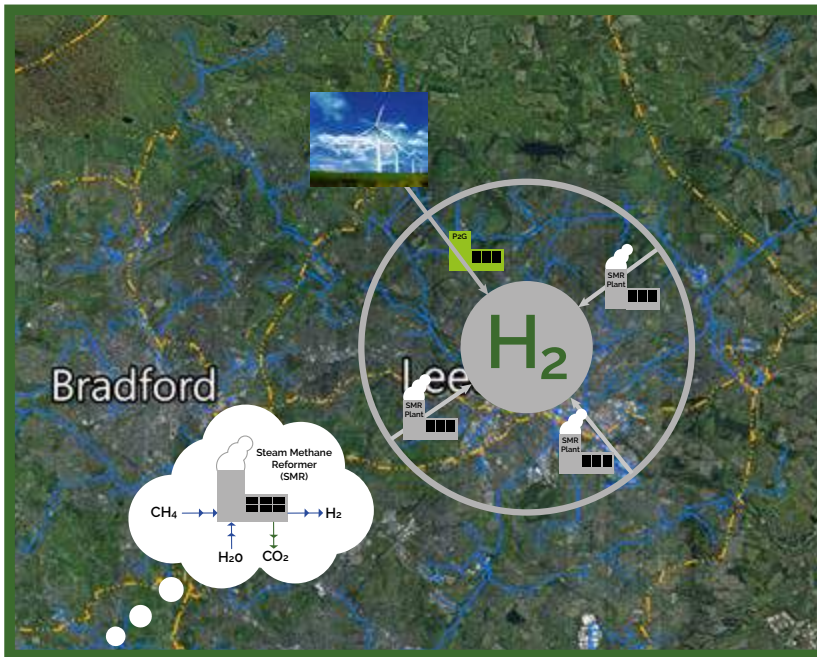
1. A scalable solution to decarbonisation needs to have gas network distributed hydrogen as the gas.
2. Can the current gas network of a large city be converted to 100% hydrogen and supply the existing energy requirements and can it also be converted in a way which is acceptable to customers?
3. Can hydrogen production meet the demand requirements and, as importantly, the profile of those requirements for a large city? Production likely being via Steam Methane Reformers (SMRs) with the methane feedstock supplied by the existing NTS/LTS gas networks.
4. All the technologies in the project have to be demonstrable today.
5. The city selected to convert must be of sufficient scale to enable the project to be used as a reasonable 'blueprint' for all major UK cities.
6. Hydrogen would only be introduced to the below 7 bar network (distribution network) to avoid problems of embrittlement.



## 1.4. The Original and Amended H21 Leeds City Gate Project Concept

Leeds was selected as the city on which to undertake the project. This was because the city's gas grid is large and complex enough to provide a blueprint for all UK cities, and it is located in the north near the east coast, where the geology is suitable for the construction of the salt cavern storage required to manage demand profile variations.

### H21 Leeds City Gate



It is located within reasonable proximity to the White Rose and Teesside Collective carbon capture projects.

The original project vision was to construct a high pressure (17 bar) natural gas ring main around the city of Leeds with strategically located SMRs to provide hydrogen to the distribution network of the city.

Image 1.5. *H21 Leeds City Gate – Original Concept*

During the initial stages of the project, it became clear that building this option was not practical or the most economical solution. As a result three more additional parameters for the project were introduced:

1. The location of the SMRs should be nearer to the potential carbon capture centres of the White Rose line and/or Teesside. This is due to the advantage of linepack and/or storage potential in longer hydrogen transmission pipelines and associated benefits of clustering carbon capture.
2. The SMRs would need to be situated near salt caverns to facilitate hydrogen storage.
3. The SMRs are more likely to be clustered in locations ideally in chemical industry heartlands to maximise economies of scale and efficient system design, as well as utilising local skills and acceptability.

More detail on the location of the SMRs is provided in [Section 2, Demand vs. Supply](#). The original concept was amended, as shown in [Image 1.6](#).

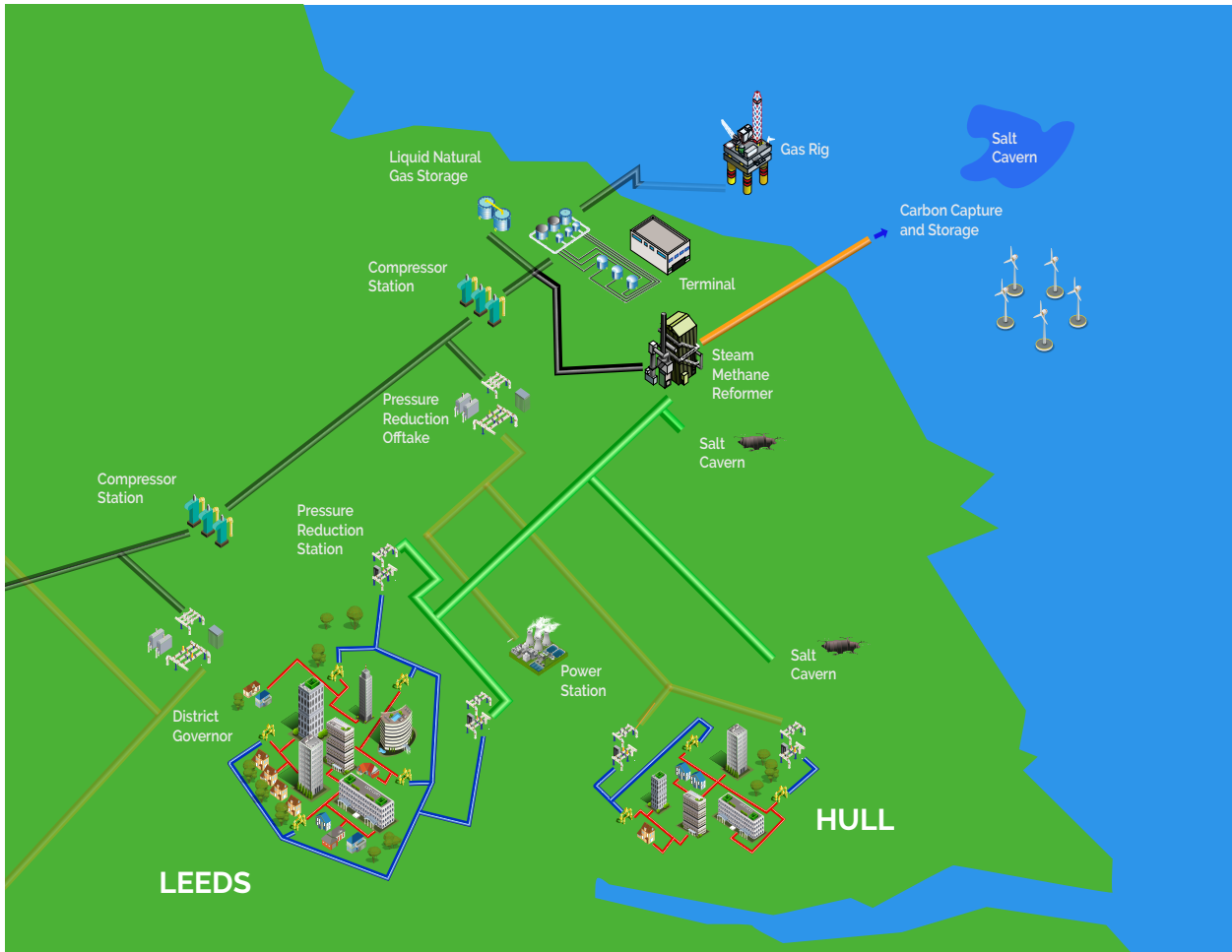


Image 1.6. *H21 Leeds City Gate – Amended Concept*

It is important to note that the scope of the H21 Leeds City Gate project was specifically constrained to converting the city of Leeds. Also importantly, the project scope only covers the implications of the conversion to hydrogen of the demands for heat. No additional potential benefits associated with vehicle transportation and/or electrical decarbonisation have been considered.

Additionally all of the design schemes and costs given in this document are essentially 'well to sofa', i.e. they include.

- Extracting the natural gas from the ground.
- Processing it.
- Transporting it to Teesside.
- Converting it to hydrogen using an SMR plant large enough to meet annual demand.
- Storing the hydrogen in salt caverns for both inter-seasonal and intraday demand.
- Supplying the hydrogen to Leeds.
- Converting/replacing each appliance in Leeds with a new hydrogen burning device, at no cost to the householder/business at point of conversion.
- Converting the Leeds distribution network over three years.

This point is offered in great detail because often other technologies, e.g. wind-farms or nuclear power, only quote costs of energy at the terminals of the generating station. To provide heat in the home, such electricity has then to be transmitted (at high voltage) then through local distribution networks (at lower voltage) to new heat pumps (installed in every home) which frequently require large radiators to operate at their design efficiency. Because of the integrated nature of the gas industry such an isolated cost is of little value, but it does make direct comparison of electric and hydrogen heating more challenging. In essence a cost of 10p/kWh for electricity from a nuclear power station or other renewable energy source makes no allowance for the real cost of winter peaks (requiring inter-seasonal storage and/or peak generation facilities) or getting the energy to a householder's 'sofa'.



## 1.5. The Area of Conversion

In order to undertake the project the team had to define the specific area to be converted from natural gas to hydrogen. This area is referred to throughout the remainder of this report as 'the area of conversion'.

Following detailed appraisal (more detail is provided in [Section 3, Gas Network Capacity](#)) the finalised area for conversion contained 264,000 meter points, covering a population of circa 660,000 people. The area includes the City of Leeds and some of its suburbs, Swillington to Morley to the south of Leeds and Pudsey to Otley/Burley in Wharfedale to the north west of Leeds.

**Image 1.7** shows the area of conversion and the extent of the gas distribution network. This is taken from the Northern Gas Networks record system for gas mains locations.

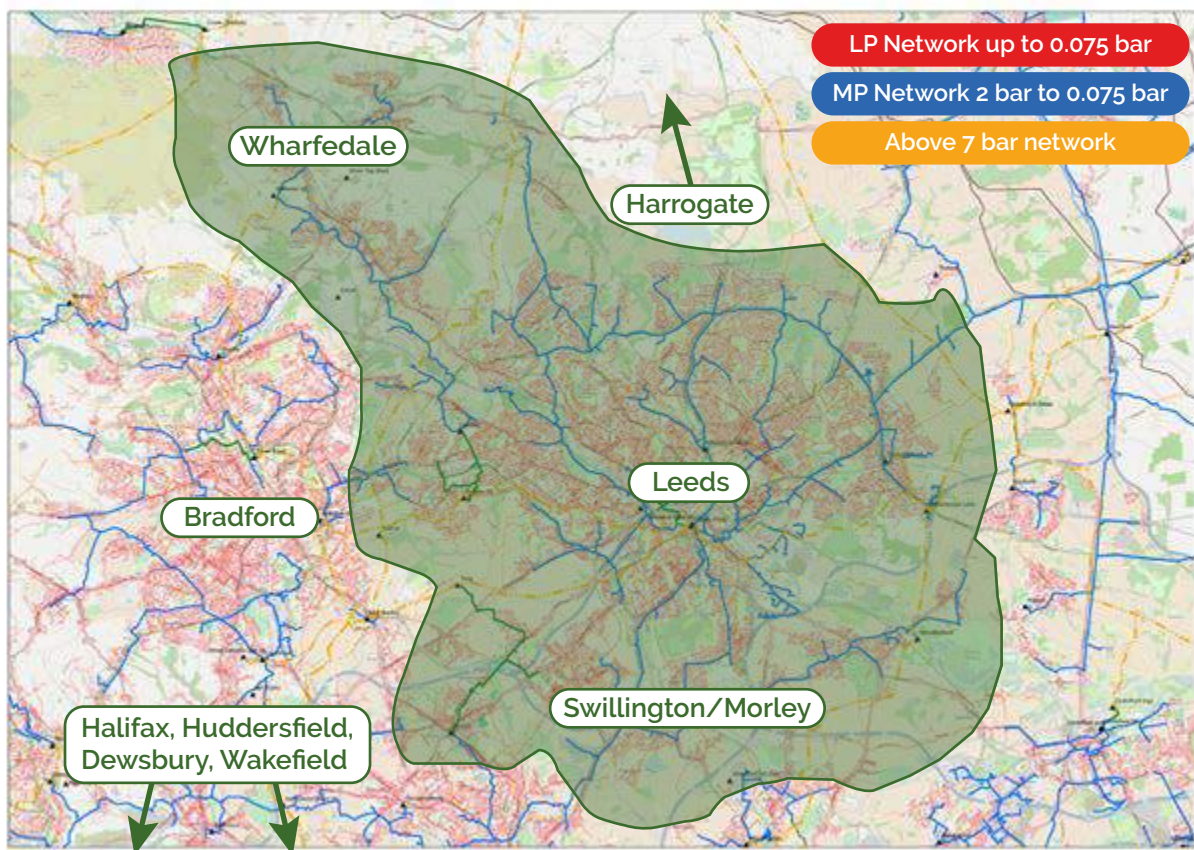


Image 1.7. *Area of Conversion*

# The Results

This section details the results of the H21 project. It provides a clear description of how the work was undertaken, what assumptions were made, what data was used and the conclusions.

For ease, the results have been split into the following sub-categories:

**Section 2: Demand vs. Supply**

**Section 3: Gas Network Capacity**

**Section 4: Gas Network Conversion**

**Section 5: Appliance Conversion**

**Section 6: The Hydrogen Transmission System**

**Section 7: Carbon Capture and Storage**

**Section 8: Financial Model**

**Section 9: The Next Steps – Programme of Works**

These are illustrated on the next page.

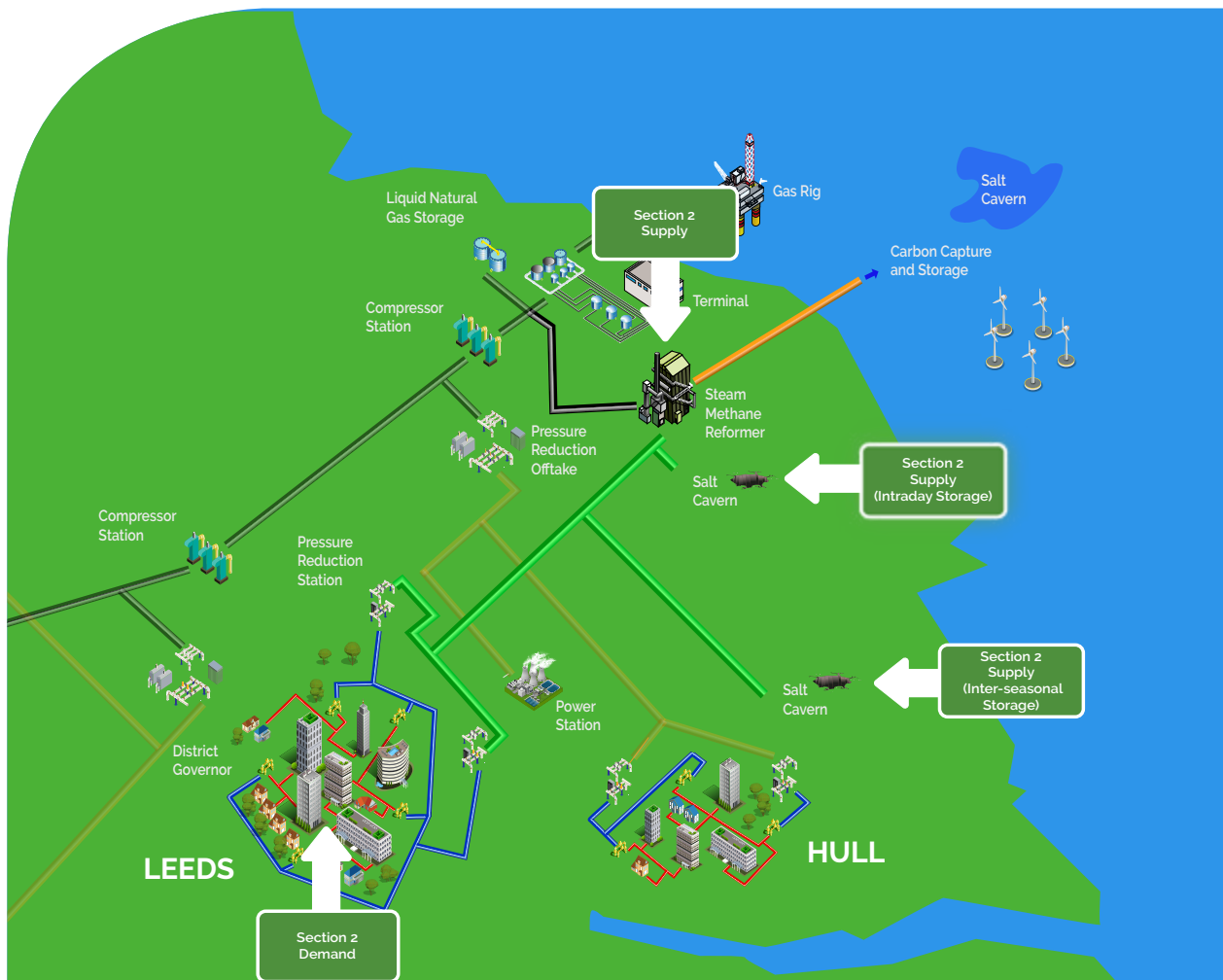






## SECTION 2

# Demand vs. Supply



## 2. Demand vs. Supply

This section explains how total energy demand for the area of conversion has been determined and the profile for that demand both intraday and inter-seasonal. It then explains how this was matched to hydrogen supply to meet these demand characteristics including the associated energy storage requirements.

### 2.1. Gas Demand in the Area of Conversion

There are multiple factors which need to be taken into account when designing a new hydrogen supply to a city.

#### Daily and Peak Demand

The UK gas industry design, build and maintain the distribution network to supply a theoretical maximum 1 in 20 year peak 6 minute (Low Pressure (LP) network) and peak hour (Medium Pressure (MP) network) demands (see [Section 3, Gas Network Capacity](#) and [Section 4, Gas Network Conversion](#)). This means a peak in demand that lasts for 6 minutes/1 hour and theoretically occurring once in 20 years. For the remainder of this project the 1 in 20 peak hour demand will be used as the peak demand design criteria. This is because the MP is the direct feed from the proposed hydrogen transmission system, see [Section 6, The Hydrogen Transmission System](#). This peak is most likely to occur at around 18:00 between December and February. This requirement has been carried over into the modelling of the network supplying hydrogen, to assess likely reinforcement and operational upgrades which may be required. As the Network Analysis (NA) models are built around this 1 in 20 peak hour demand, this is the most accurate source for peak demands (see [Section 3, Gas Network Capacity](#)).

#### Intraday Demand Profile

This is the amount of gas used hour-by-hour within any given day. This can be low, for example at 02:00, or high, typically around 18:00 in the evening. Understanding this profile helps determine what level of intraday gas storage is required to manage these fluctuations.

#### Inter-seasonal Demand Profile

This is the amount of gas used month-to-month in an area as we move through the year. In the gas industry, the difference in demand between summer and winter can be up to six-fold. Understanding this profile allows us to appropriately size the inter-seasonal storage requirements. Simplistically these storage facilities allow the hydrogen production facility to store gas in periods of low demand (summer) and use that stored gas to supplement production of hydrogen in periods of high demand (winter).



## Total Annual Gas Demand

This is the total volume of gas required by the area of conversion over the entire year. This value is important to enable us to set the annual capacity of the hydrogen production facility, i.e. the supply.

Understanding the demand for the area of conversion is critical to understanding how to size the associated supply system (primary hydrogen production facilities and storage). The figures for inter-seasonal, intraday and 1 in 20 peak hour demand have been determined by Northern Gas Networks (NGN) based on their historical data and NA modelling. Figures for annual demand have been obtained using the Office for National Statistics Middle Layer Super Output Areas (MSOAs) which have then been cross-checked with NGN figures to ensure a high level of confidence. Each of these demand requirements are explained below.

### 2.1.1. 1 in 20 Peak Hour Demand

NGN manages the existing below 7 bar natural gas network using an NA software package called Synergi. The software is configured to model demand and flow data for natural gas, predominantly methane, as this is the current gas flowing in the networks pipes. It is also used for five-year forecasting projection simulations by utilising demand and planning forecast data. All data used by the Synergi software model is validated as part of a regular cycle by cross-referencing the information used by Synergi (pressures/flows) with data obtained from network loggers, source pressures and demand data from the field and consumer data from Xoserve.

Peak energy demand does not correlate accurately with the average annual demand requirement in that the off-peak demand, e.g. middle of the night and during summer, is not typically modelled within the gas industry. The assumptions required to model off-peak energy demand, particularly with regard to the profiles of commercial and industrial loads, can produce significant margins of error when scaled over the full year. This variation will also depend on upon the area being modelled. Areas with large domestic load tend to have less than predicted load in summer while areas with a large commercial load, e.g. laundries or hospitals, tend to use gas more uniformly over the year. Within the gas industry, it is possible to determine individual date/time of day demand forecasts throughout the year, this will be discussed in [Section 2.1.2](#).

For the area of conversion the 1 in 20 peak hour demand has been determined to be:

---

***1 in 20 peak hour demand:  
955,660 Scmh (hydrogen), 3,180 MWh***

## 2.1.2. Intraday and Inter-seasonal Demand Profile

Forecast network gas demand levels are based on a proportionate decrease in the 1 in 20 peak demand level determined by scaling factors. These factors are based on empirical data and were derived by British Gas Research. Two sets of values are used to predict demand levels within the network. These sets of values allow the forecast of demand levels at a specific date or time of day (Table 2.1) and in combination can be used to provide a forecast for a specific time and date. For example, the forecast peak demand in April at 14.00 can be calculated as follows:

**1 in 20 peak hour demand = 955,660 Scmh (3,180 MW)**

**April demand = Peak 955,660 Scmh x 0.70 = 669,000 Scmh (2,230 MW)**

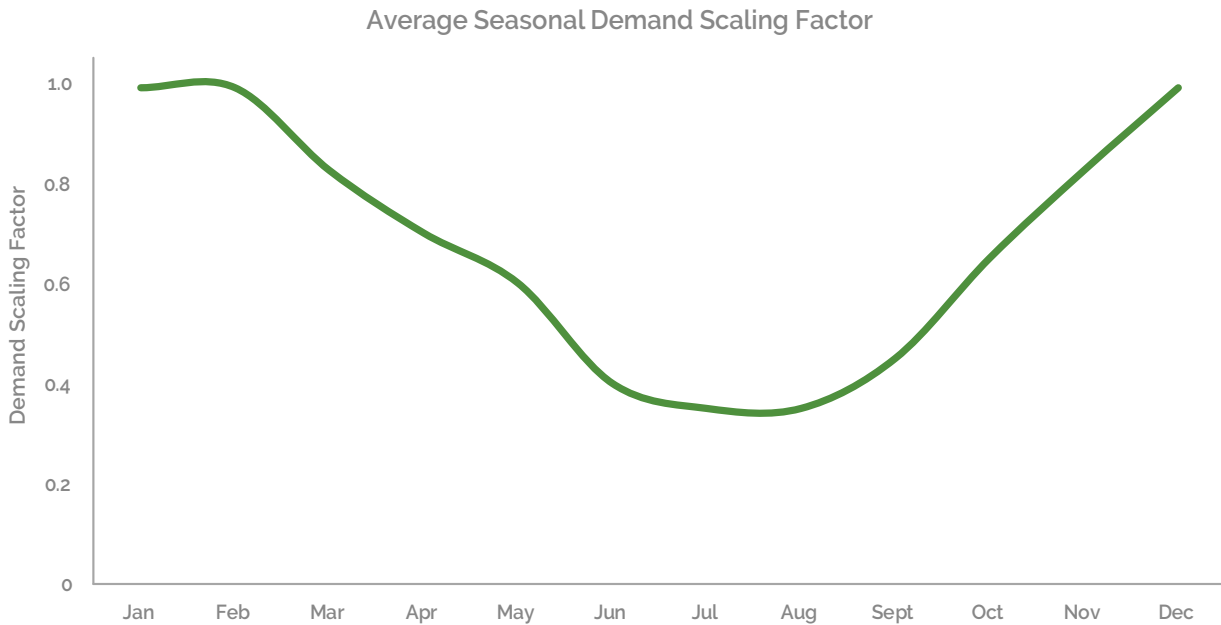
**Demand at 14:00 = 669,000 Scmh x 0.73 = 488,000 Scmh (1,630 MW)**

MONTHLY RATIOS		DAILY RATIOS			
Month	Average Turndown	Time	Turndown	Time	Turndown
January	1.00	00:00	0.46	12:00	0.75
February	1.00	01:00	0.36	13:00	0.76
March	0.83	02:00	0.25	14:00	0.73
April	0.70	03:00	0.25	15:00	0.73
May	0.60	04:00	0.25	16:00	0.78
June	0.40	05:00	0.28	17:00	0.93
July	0.35	06:00	0.35	18:00	1.00
August	0.35	07:00	0.55	19:00	0.97
September	0.45	08:00	0.76	20:00	0.92
October	0.65	09:00	0.82	21:00	0.84
November	0.83	10:00	0.78	22:00	0.76
December	1.00	11:00	0.76	23:00	0.64

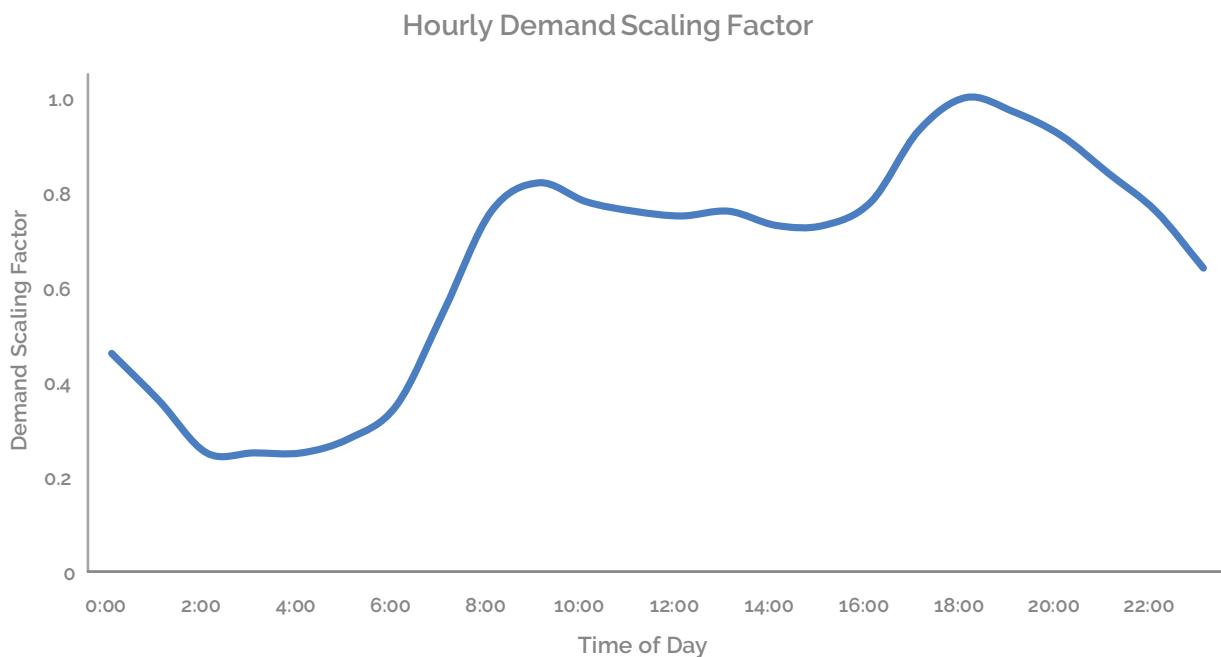
Table 2.1. Monthly and Daily Turndown Ratios

These factors are used throughout the UK distribution gas industry to forecast appropriate operational windows for work on the network ensuring security of supply for customers. For example, they are used to predict operational windows for mains laying or repair which can have a significant impact on gas supplies in a certain area of the network.

They are also used to assess response requirements under emergency conditions on the network, e.g. a major mains break or loss of a district governor. The values are essentially the highest potential demand levels, which enable long range forecasting – actual demand levels may be lower as the likely forecasted weather will not be the cold extreme predicted by the scaling factors possible for the time of year. **Charts 2.1 and 2.2** show how these demand ratios are interpreted in graphical format.



**Chart 2.1. Scaling of Demand When Considering the Monthly Factors**



**Chart 2.2. Scaling of Demand When Considering the Within Day Ratios**



## Breakout: Gas Industry Operation Windows

*Demand profiles are used in the gas industry to derive appropriate timeslots for undertaking intrusive works on the network. For example, the analysis giving a 0.2 maximum demand level leads to the recommendations shown in the table below.*

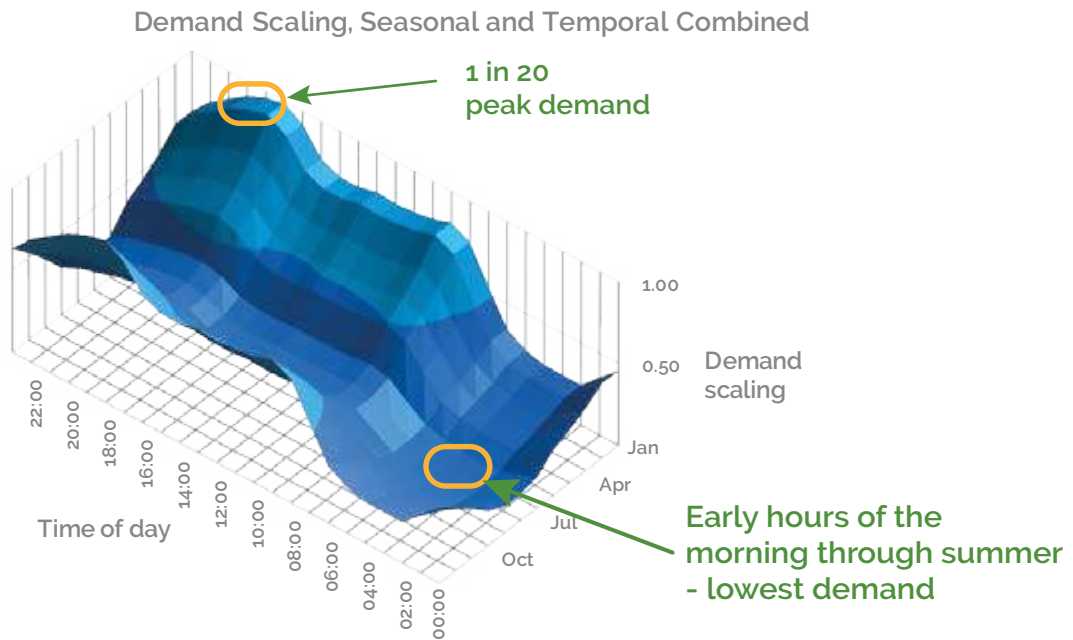
Month	Recommended Time of Day
November to March	None
April, May	02:00 to 05:00
June	00:00 to 06:00
July and August	00:00 to 07:00
September	01:00 to 06:00
October	02:00 to 05:00

*These recommended operational windows are used by the industry when works can be planned well in advance, such as maintenance and new connections. However, urgent maintenance and emergency work may require decisions and actions to be made in a much shorter time frame. This allows the use of the prevailing demand forecast that is issued by NGNs system control, which is usually for five days ahead, and utilises the weather forecast for the period. Therefore, rather than applying the average turndown factor from Table 2.1 the forecast demand level for the work can be used, e.g. a gas escape occurs on a warm March day and the forecast demand level is 0.65 – this would then provide an operational window between 02:00 and 05:00 for the repair to be carried out, assuming the same NA recommendation of 0.2 and below demand level.*

*Emergency work can, of course, be carried out as soon as practicable where the risk level requires this, and this would override any of the above recommendations. NA would then be carried out to provide the best option to reduce the impact of the work on the network (e.g. raising neighbouring district governors or connection of a bypass main).*

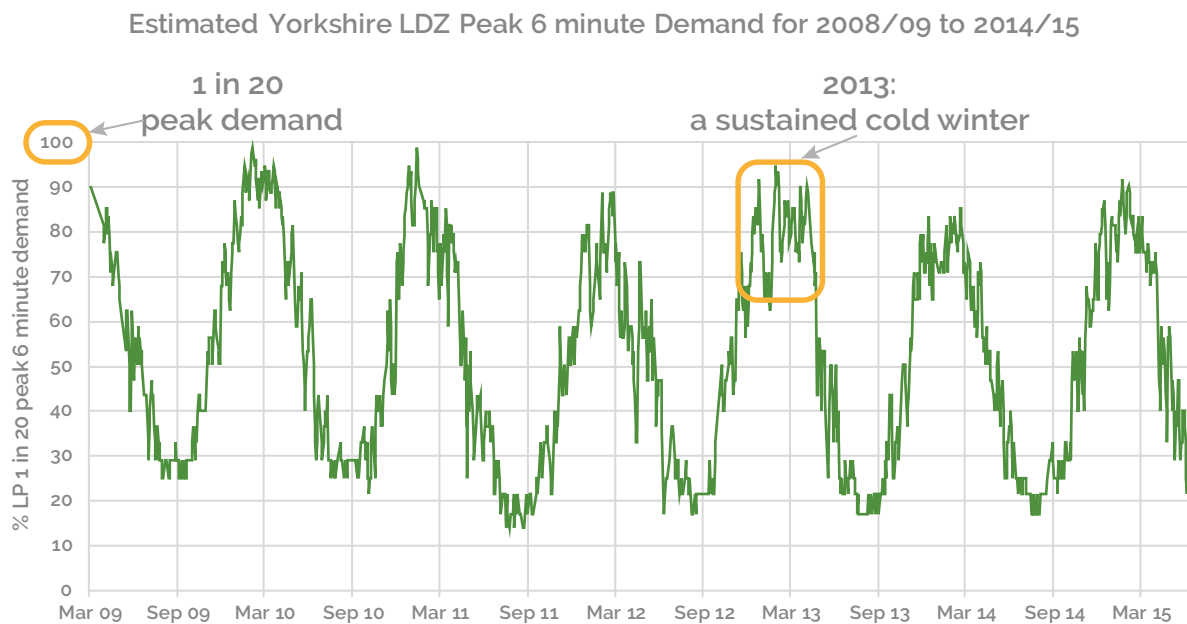


Finally, **Chart 2.3** gives a view of combining the inter-seasonal and intraday factors for the forecasted demand over the year.



**Chart 2.3. Combined Inter-Seasonal and Intraday Factors for the Forecasted Demand Over the Year**

For comparison with the theoretical values in **Charts 2.1, 2.2 and 2.4**, show the daily demand levels for the Yorkshire area between March 2009 and June 2015 baselined against the 1 in 20 peak hour demand.



**Chart 2.4. Yorkshire Actual Daily and Seasonal Demand Levels 2009 to 2015**



Having understood the 1 in 20 peak hour demand and the daily turn down profiles, it is important to translate the peak hour demand into a peak day demand profile. This can be established using a very simple calculation (for clarity, these are design parameters).

Peak hour demand = 3,180 MW

Average hourly turn down factor (average of all the ratios in Table 2.1) = 0.65

Peak day average demand = 3,180 MW x 0.65 = 2,067 MW

Therefore total peak day daily demand (1 in 20 years) = 2,067 x 24 = 49,608 MWh

---

***Peak day average demand for the area of conversion: 2,067 MW***

### 2.1.3. Total Annual Demand

Obtaining annual demand figures for the area of conversion via NA proved more challenging, and it became clear that reliance on the NGN network analysis for this value was not appropriate. Two methods for calculating annual demand for the area for conversion were considered:

#### **Annual Demand Calculated Using NGN Peak Demand Figures**

Using NGN peak demand data and the appropriate turndown ratios it is possible to derive a peak annual network demand for the conversion area. The annual demand using this methodology would be 9,904 GWh (9.9 TWh or 2,976 million Scmh).

If this hypothetical peak year is plotted against actuals for the last five years (see [Chart 2.5](#)) it becomes clear that using this figure would provide an annual demand significantly in excess of that required. This is because using the peak demand and turn down ratios assumes every day in a year is a peak for that specific day – clearly this is not reality. [Chart 2.5](#) shows how using the peak demand and turn down ratios would contrast to the actual demand used in the network for the period 2009-2015.

Estimated Yorkshire LDZ peak 6 minute demand for March 2009 to May 2015 vs. theoretical average

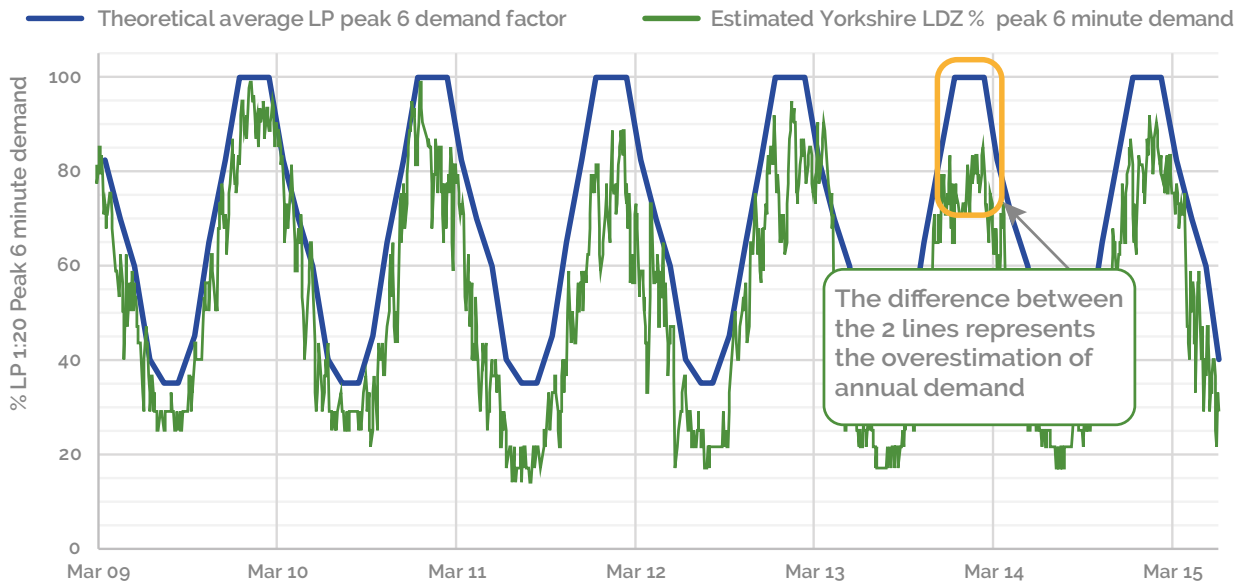


Chart 2.5. *Estimated Yorkshire LDZ peak 6 minute demand for March 2009 to May 2015*

The NA models used to produce this value were designed primarily to provide accurate results under conditions of 1 in 20 peak demand. As the bulk of the year has a demand level significantly less than this, the model will diverge from the actual as assumptions regarding off-peak industrial and commercial loads become less valid.

As a result, it was considered that utilising the NGN model to derive overall annual demand was not an appropriate method. Therefore, for the area of conversion a robust way to determine the annual demand was required. This is necessary to size the inter-seasonal storage, the SMRs (for hydrogen production) and understanding the volume of carbon dioxide likely to be produced and sent to long-term storage under the north sea.



## Annual Demand Derived From Middle Layer Super Output Areas (MSOA) Data

In order to do this two data sets were acquired:

- Postcodes for all properties which are located within, or partly within, the area of conversion. These were acquired through a rigorous process of visual comparison with NGN network maps.
- Annual gas demand against MSOA was acquired from the Office for National Statistics. DECC collect and publish annual GB gas use on the basis of such MSOA data. This data is primarily based upon 'cleaned' Xoserve billing data. This is the large database that ties 23 million GB consumers with individual gas suppliers. This MSOA information is accepted by DECC to have an uncertainty of better than +/-5%. DECC provided the demand data for these MSOA areas for the year 2013. An example of an MSOA area is given in **Image 2.1**.



Image 2.1. MSOA Area Example

Having obtained this data the postcodes were then meticulously cross-correlated with the 118 MSOA areas that include Leeds and the surrounding area. The percentage of each MSOA that fell within the conversion zone was then estimated. This was often 100%, (i.e. the whole MSOA fell within the conversion area), sometimes 0%, (i.e. the whole MSOA fell outside the conversion zone), or sometimes a % had to be judged. In practice, both postcodes and MSOA maps were used to assist with this process, as the percentage was based upon property numbers rather than simple land area. This was carried out separately, for both domestic and non-domestic demand to reflect the DECC data.

**Table 2.2** lists example MSOA districts and shows how this was adjusted against postcodes in the area of conversion.

Location	MSOA Code	Domestic Consumption (kWh)	% of Area Within Conversion Area	Adjusted Domestic kWh
Bradford 001	E02002183	42,677,527	1	426,775
Bradford 003	E02002185	41,325,136	100	41,325,136
Bradford 005	E02002187	48,800,644	85	41,480,547
Bradford 010	E02002192	67,792,479	1	677,925
Bradford 013	E02002195	48,855,082	1	488,551
Bradford 017	E02002199	39,920,814	40	15,968,326
Harrogate 018	E02005778	19,328,832	10	1,932,883
Harrogate 021	E02005781	37,555,864	2	751,117
Leeds 001	E02002330	51,748,947	0	0
Leeds 002	E02002331	37,702,778	0	0
Leeds 003	E02002332	33,766,456	100	33,766,456
Leeds 004	E02002333	50,165,174	100	50,165,174

Table 2.2. MSOA Examples

DECC collates industrial and large commercial meter readings (> 70 kW) and the subset for the area of conversion was extracted and added to the MSOA domestic consumption to give a total annual demand for the area of conversion in 2013. At the end of this evaluation process, the annual demand was determined by dividing the total kWh for the year by the number of hours in the year, as shown below.

**Total demand in the area of conversion in 2013 = 5,940,000,000 kWh (6 TWh)**

**Number of hours in a year = 8,760**

**Average demand (2013) = 678,000 kW**

**Average demand (2013) = 678 MW (c.204,000 Sm<sup>3</sup> hydrogen)**

***Average annual demand for the area of conversion: 6 TWh/year (678 MW)***

We need to be aware that the figure of 678 MW is the average demand for Leeds, specifically for 2013. 2013 had an average temperature of 9.4 °C against an annual average, since 1977, of 9.7 °C. This annual average temperature has been calculated using data from the 'Sheffield weather page' which has published an average yearly temperature for Sheffield since 1977. Leeds does not have an equivalent data set for annual average temperature. However, noting the close proximity of the two cities (35 miles centre-to-centre), Sheffield's data set has been considered adequate for the analysis.

Visual inspection of the Sheffield average annual temperature data since 1977 shows annual temperatures drop below 8.9 °C very rarely (twice in 30 years to 8.7 °C), i.e. 0.5 °C below average for 2013. Analysis of temperature variances for the domestic heating season in the last 30 years, (i.e. just considering average annual temperature for Autumn, Winter and Spring) returns an average temperature of 9.2 °C, less than 0.2 °C below 2013. A design condition of 8.9 °C, as the average annual temperature was therefore chosen to calculate 'worst case conditions annual demand' over the past 30 years (for Leeds and Sheffield). This is equivalent to 0.5 °C below 2013 or 0.8 °C against the long-term annual average temperature of 9.7 °C.

This is summarised in [Table 2.3](#).

2013 Annual Average Temperature (Sheffield)	Annual Average Temperature for the Last 30 Years (Sheffield)	Coldest Annual Average Years (Sheffield)
9.4 °C	9.7 °C	8.9 °C

**Table 2.3. Sheffield Average Annual Temperatures**

Having a design condition average annual temperature of 8.9 °C, it is necessary to consider the appropriate scaling factor to adjust the Leeds total average demand of 678 MW for 2013, to produce a 'worst case condition average demand' figure for future demand. In order to effectively make this predication, degree days methodology was used, (for full details of degree days methodology see [Breakout: Degree Days](#) later in this Section).

Degree days is a recognised method of analysis used to compensate for heat energy generation in a property from the boiler, in addition to 'other forms of heat' (people, animals, lights etc.). It is accepted that for most properties, 3 °C of heat is provided by 'other forms of heat'. By way of example:

- The outside temperature is 8 °C.
- The average internal temperature of the house is 18.5 °C.
- The heat required is, therefore, 10.5 °C (to go from 8 °C to 18.5 °C).
- The reference heating temperature (the temperature the boiler needs to heat the property to) is, therefore, 15.5 °C (the additional 3 °C is provided by 'other forms of heat').



Understanding the concept of degree days it is now possible to calculate the required adjustment for the average hourly demand figure of 678 MW for Leeds in 2013 as follows:

---

***The Leeds annual average temperature design criteria is 8.9 °C***

Data was obtained from the [www.enmanreg.org](http://www.enmanreg.org) website, the official website for UK degree day data. The data used was for West Pennines, as this was identified as being the closest in proximity to the area of conversion. The specific degree day data set used for West Pennines provided a 20 year average degree days figure of 2,231.

Therefore, to calculate the percentage difference adjustment between our 2013 average demand figures of 678 MW the following calculations were made:

- Total degree days: 2,231.
- Difference in design temperature of 8.9 °C vs. 2013 average temperature of 9.4 °C is 0.5 °C.
- 2013 adjustment in average temperature =  $365 \text{ (days in the year)} \times 0.5 \text{ °C} = 182.5 \text{ °C}$ .
- $182.5 / 2,231 = 0.082 = 8\%$ .

This is equivalent to an 8% increase in demand over the year 2013. Therefore the amended 'worst case average hourly year demand' is  $678 \text{ MW} \times 1.08 = 732 \text{ MW}$ .

---

***Maximum (peak) annual demand for the area of conversion:  
6.4 TWh/year (732 MW)***

## Breakout: Degree Days

*Degree Days is the UK recognised method for determining heat requirements over a year. Simplistically it works as follows:*

- *Properties in the UK are on average heated to 18.5 °C (over the entire property).*
- *3 °C is provided by 'other forms of heat' (people, animals, lights, cooking etc.).*
- *A boiler will be required to heat the house to 15.5 °C from the outside temperature. As an example to calculate the 'Degree Days' for a given week:*

Day	Mon	Tue	Wed	Thu	Fri	Sat	Sun
Average Outside Temperature (°C)	16	10	12	11	10	15	17
Degree Day, (i.e. Boiler Required Heat to 15.5 °C)	0	5.5	3.5	4.5	5.5	0.5	0

*In this example the total degree days for the week = (0+5.5+3.5+4.5+5.5+0.5+0) = 19.5. If the calculation for the same week every year for 20 years is made and divided by 20 it is possible to derive the average degree days for that week, i.e. the average amount of °C that a boiler would need to provide in heat for that particular week. For the area of conversion, the annual degree days average (taken over 20 years) for West Pennines was used.*

*The degree days calculated for the one-week scenario above is 19.5. If we assume, for this example, that this is the average for this week over a 20 year period then in order to calculate the 'worst case average boiler heat requirement' for the same week, it could be arrived at by using the below method. Consider the coldest average week in the last 20 years for that week, and assume it to be an average of 12 °C. This would give a degree days total for this coldest week of 24.5 degree days.*

Day	Mon	Tue	Wed	Thu	Fri	Sat	Sun
Average Outside Temperature (°C – Average 9 °C)	12	13	11	10	11	14	13
Degree Day, (i.e. Boiler Required Heat to 15.5 °C)	3.5	2.5	4.5	5.5	4.5	1.5	2.5

*To then calculate the percentage difference from the 20 year average to the coldest week =  $24.5/19.5 = 24\%$  difference. This difference can then be used to adjust the average energy demand.*

*It is fully appreciated that the above explanation is much simplified for the general reader, even degree day websites recommend caution regarding the complexity of the degree day concept. More comprehensive understanding of the topic can be derived from the website quoted earlier. The method adopted however is cautious i.e. will give a higher increase in load than is likely to occur in reality.*

*Whilst there may be variances in this worst case annual average figure this would be consolidated as part of the detailed design but is considered in the right order of magnitude for the stage in this project. Noting production capacity of the proposed SMR's significantly exceeds annual demand.*

### 2.1.4. Summary of Demands

Demands have been calculated for the area of conversion and can be summarised as follows:

- Average 2013 yearly demand = 678 MW (derived from DECC data).
- Maximum peak yearly demand = 732 MW (temperature corrected DECC data).
- Maximum peak hour (18:00) demand = 3,180 MW (NGNs 1 in 20 peak hour demand for the area of conversion).
- Maximum peak day demand = 2,067 MW (derived from NGNs 1 in 20 peak hour demand design parameter).
- Total average yearly demand = 5.9 TWh.
- Total peak year demand = 6.4 TWh.

As expected, if the NGN values (used to design the network) are used to calculate the annual demand, the value is circa 50% larger than that from the DECC data but it is important, going forward, that major items of capital equipment (e.g. SMR plant) are not oversized. As such annual demand has been determined using MSOA data, whereas peak demands have been established using the networks 1 in 20 peak hour modelling results.





## Breakout: Units of Energy Measurement

For those used to dealing with different units, the maximum peak day demand of 2,067 MW equivalent units are:

- 2,067 MJ/s or 1.7 million Therms/d.
- Hydrogen is 52.5 tonnes H<sub>2</sub>/h.
- 521 MMSCFD of H<sub>2</sub>.

The yearly design demand equivalents of 732 MW are:

- 6.4 TWh/y, 23 PJ/y, 551 thousand tonnes oil.
- Hydrogen is 163,000 tonnes/y, 217,900 Sm<sup>3</sup>/h, 206,500 Nm<sup>3</sup>/h.
- 185 MMSCFD of H<sub>2</sub>.

The gas industry works in standard cubic meters rather than kilowatts.

A referenced standard cubic metre or Sm<sup>3</sup>, is a cubic metre of natural gas at 15 °C, 1 atmosphere pressure (101.325 kpa).

International reference normal cubic metre, Nm<sup>3</sup>, which is gas at 0 °C and 101.3 kpa (1.01325 bar). The difference is 5.5% less energy per cubic metre at standard temperature.

In this study, the High Heat Value (HHV or GHV) used for natural gas used is 39.5 MJ/Sm<sup>3</sup> and for hydrogen is 12.10 MJ/Sm<sup>3</sup>. The hydrogen mass-energy content is 141.87 MJ/kg<sub>HHV</sub> or 39.4 kWh/kg. The report default reference is to HHV rather than Low Heat Value (LHV or NHV) figures. Some process designs typically use LHV values with hydrogen 120 MJ/kg LHV. A watt is a joule/second. (W = J/s)

- To convert kWh to Sm<sup>3</sup> of natural gas:  $Y \text{ kWh} \times 3.6/39.5 = X \text{ Sm}^3$ .
- To convert kWh to Sm<sup>3</sup> of hydrogen gas:  $Y \text{ kWh} \times 3.6/12.10 = X \text{ Sm}^3$ .



## 2.2. Supply System Characteristics

### 2.2.1. Energy Demand for the Area of Conversion

The demand requirements for hydrogen for the area of conversion are to match the demand parameters established in [Section 2.1](#), these were:

- Average 2013 yearly demand = 678 MW (derived from DECC data).
- Maximum peak yearly demand = 732 MW (temperature corrected DECC data).
- Maximum peak hour demand = 3,180 MW (NGNs 1 in 20 peak hour demand for the conversion area).
- Maximum peak day demand = 2,067 MW (derived from NGNs 1 in 20 peak hour demand design parameter).
- Total average yearly demand = 5.9 TWh.
- Total peak year demand = 6.4 TWh.



### 2.2.2. Choosing the Production and Storage Mix

Having determined the energy demand requirements for the area of conversion both in terms of overall demand but also inter-seasonal and intraday variations the project team needed to establish what the appropriate mix of hydrogen production capability and storage should be to meet these energy requirements. To do this a combination of hydrogen production through Steam Methane Reformation (SMR) and salt cavern storage was selected (see **Section 2.3 to 2.6** for details and justification).

Intraday storage is required to compensate for the slow turndown rates of the primary hydrogen production facility (SMRs) which are unable to match the intraday swings in demand, e.g. low demand at 02:00 high demand at 18:00. Inter-seasonal demand is required to match the significant swings in demand that occur between winter and summer as domestic heating is turned off.

Average demand is met by the primary hydrogen production process. Choosing the minimum production capacity cannot be less than the design average for the year of 732 MW. A production capacity to match the peak day (2,067 MW) or the peak hour (3,180 MW) requires significantly more investment and is unpractical. To do this would require a production facility which is sized at over four times the average demand requirements (3,180 MW vs. 732 MW).

The storage capacity is more complicated as storage is characterised by:

1. Flow, i.e. fill and empty fast enough to meet the variation in demand not met by changing the primary production of hydrogen. Flows are a function of the chosen storage technology and sizing.
2. The amount of energy stored, Typically the amount of storage is expressed as a percentage of the whole energy demand over the year or the number of days of average demand.

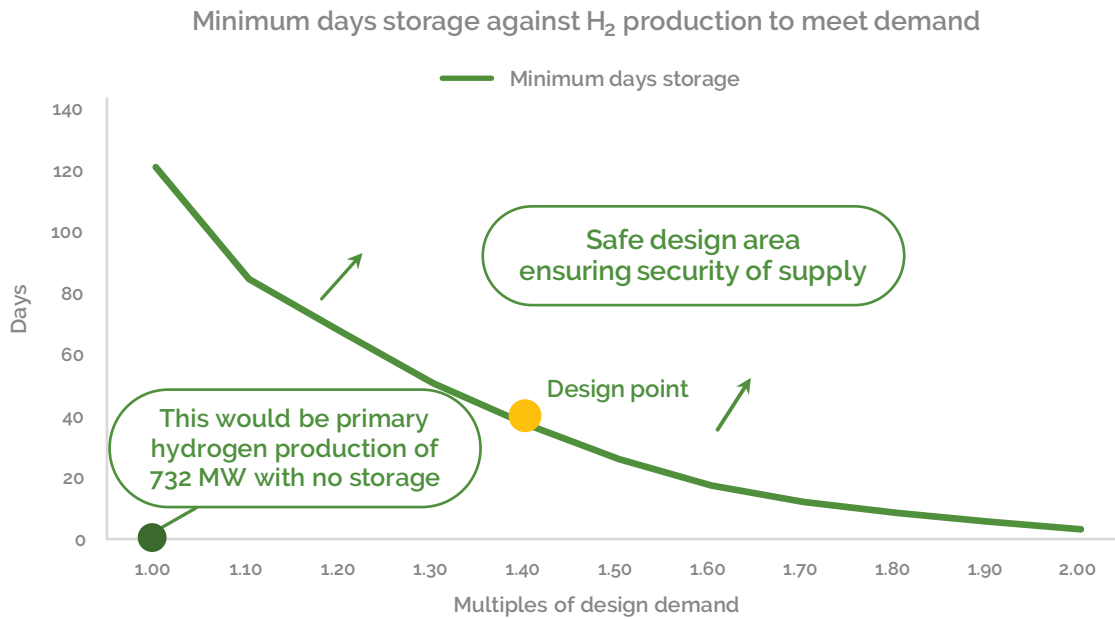
For example in our case the design average demand is 732 MW.

**So say 40 days of that demand is  $40 \times 24 \times 732 = 702,720$  MWh.**

**Also, as average yearly demand is 5.9 TWh.**

**The storage is 12% of demand.**

The trade-off between primary production and storage is best depicted in **Chart 2.6**. This shows required storage capacity in days of average primary hydrogen production versus the percentage of overcapacity (amount of production above 732 MW) for the five winters 2009/10 to 2014/15. Any supply combination of primary hydrogen production and storage above the line will satisfy the demand requirement. Closer to the line is cheaper, but needs more provision for high availability, further away from the line is more expensive but more secure to unforeseen events.



**Chart 2.6. Minimum Days Storage Against H<sub>2</sub> Production to Meet Demand**

The choice of design point is also affected by the relative cost of production, storage characteristics and infrastructure capital cost. It is further discussed in the SMR and storage **Sections 2.3 to 2.6** and would be revisited as part of a detailed design process. Initially, the design point shown above is selected for a basic overcapacity for the hydrogen production factor of 1.4 (that is 732 MW x 1.4 = 1,025 MW, further discussed in **Section 2.4**) and a storage capacity of 40 days.



### 2.2.3. Summary of Supply Requirements

- Hydrogen production capacity of  $1,025 \text{ MW}_{\text{HHV}}$  (305,000 Scmh) provided by SMRs.
- Hydrogen inter-seasonal storage of  $702,720 \text{ MWh}_{\text{HHV}}$  (40 days of maximum average daily demand, 209 million  $\text{Sm}^3 \text{H}_2$ ).
- Additional intraday storage, which together with the SMRs and inter-seasonal storage shall supply a maximum 1 in 20 peak hour demand of  $3,180 \text{ MW}_{\text{HHV}}$ .
- The hydrogen production facility shall be capable of capturing  $\text{CO}_2$  emissions and exporting at 120 bar to a suitable  $\text{CO}_2$  transport and storage system provided by others.
- Hydrogen transmission pipelines to connect the SMRs and stores to the area of conversion area shall transport at least the peak supply requirement of  $3,180 \text{ MW}$  to regulators that limit the distribution network pressure to not more than 7 bar.

Besides meeting the demand requirements detailed in [Section 2.2.1](#) the above facilities are estimated to have the following features:

- Average energy into the distribution system of  $678 \text{ MW}_{\text{HHV}} \times 24\text{hrs} \times 365 \text{ days} = 6 \text{ TWh/year}$  as pure hydrogen.
- Gas storage of 12% of average gas energy use.
- Capture of 1.49 million tonnes of  $\text{CO}_2$  per year (see [Section 7, Carbon Capture and Storage](#)).



## 2.3. Hydrogen Generation Method (Production)

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### *History: Steam Methane Reformation (SMR)*

*Since the 1960s, the global technology of choice for producing large quantities of hydrogen is the Steam Methane Reformer or SMR. Common hydrocarbon feedstocks, i.e. the fuel for the SMR, include natural gas (methane), LPG (propane/butane) or naphtha and this is usually dictated by neighbouring processes in refinery operations where large volumes are needed to upgrade and de-sulphurise heavy oils. Roughly 500 large SMRs are operational around the globe including a single train SMR operated on Teesside. There is a limit to the size of a single twin cell reformer which approximates to an overall plant capacity of around 110,000 Nm<sup>3</sup>/h (116,000 Sm<sup>3</sup>/h) of hydrogen.*

*There are a number of technology providers for SMRs and the variation between these technologies focuses on heater design to maximise energy efficiency (operating costs) and maximise run length of the fired heater catalyst tubes (circa 100,000 hours operation). They are often designed and operational in 2-3 years and are quite standard designs.*

---



### 2.3.1. Hydrogen Generation Method for the Area of Conversion

There are around 20 general H<sub>2</sub> production methods, but the choice of source for hydrogen is dependent on the natural resources and competitive advantage of the country, the specific geographic location, and the government policy. For example, different scales and approaches may apply. If you consider Iceland, it has no hydrocarbons, but substantial geothermal and hydropower. Indeed, they could develop exports of 1 GWe of power to the UK from their resources. Germany is driven by its 'Energiewende' policy favouring renewable energy industrial development, and the UK by its robust transmission grids and geological resources particularly offshore. The end use for hydrogen can often dictate the production method, i.e. volume required, quality, demand profile (quantity), distribution method and unit cost.

Generally industrial scale hydrogen production methods fall into one of three categories:

1. Electrolysis, ideally from renewable resources. This is one of the older methods of making hydrogen and, when made from low carbon electricity, is both green and pure.
2. By-product hydrogen from chlor alkali plants or refineries. The carbon footprint of this can be contentious. Whilst this may be a convenient additional resource it is not considered as a generic based production source which could act as the anchor for substantial hydrogen supplies. The above options from 'green and/or available sources' may be advantageous, but would be unable to provide the volume and security of supply required for the decarbonisation of heat for the demand in the area of conversion.
3. Steam methane reforming and the shift reaction from either natural gas or a gasifier. If the latter uses renewable biomass the hydrogen has a small carbon footprint, if coal a large footprint (without CCS).

After considering the demand profile for the area of conversion the method selected for hydrogen generation becomes relatively straight forward. The demand quantities are substantial (732 MW average for design capacity, that is 6.4 TWh/y, with 5.9 TWh/typical year for average costings). Alongside this there is the extreme inter-seasonal variation, with approximately a factor of 8 between a winter day maximum demand and a summer day minimum demand, and a factor of 30 between a winter 1 in 20 peak hour demand, (e.g. 18:00 very cold day high demand) to a summer minimum hour demand, (e.g. 02:00 very warm day). There are only two established ways to generate such significant volumes of hydrogen; electrolysis and SMR.



### 2.3.2. Electrolysers

Historically large (typically 1 to 2.5 MW scale) alkaline electrolysers were used with local hydroelectric power for chemicals such as ammonia production; Norsk Hydro installed units in Norway producing 30,000 Nm<sup>3</sup>/h by 1940. They can be understood as the reverse of fuel cells that use hydrogen to make electricity, and advances in fuel cell technology open up new electrolyser options. The efficiency of energy conversion is similar to SMRs, circa 70% (HHV), although values up to 80% have been achieved.

The increase in non-fossil fuel generation is renewing interest in the conversion of low-value electricity to hydrogen, especially for transport use. Further research and development are needed to decrease capital cost and increase efficiencies, but generally, the high value of export to the UK grid makes this the preferred option. Curtailed electricity (when wind farms are paid not to generate) offers a theoretical route to low-cost hydrogen but, in practice, the hours per year during which this is available are currently very limited.



28 alkaline electrolysers, type S-556 for a production of 21,000 Nm<sup>3</sup>/h H<sub>2</sub> and 10,500 Nm<sup>3</sup>/h O<sub>2</sub> in Zimbabwe. [www.iht.ch](http://www.iht.ch) In use for over 35 years since built in 1973. (1.9 t/h, 74 MW, 2.6 MW each H<sub>2</sub> HHV basis)

**Image 2.2. 21,000 Mc<sup>3</sup>/h H<sub>2</sub> Electrolysis Plant**





Given that a typical large alkaline electrolyser has a cost of circa £0.7m per MWe or an efficient Polymer Electrolyte Membrane (PEM) electrolyser has a cost of circa £1.1m per 1 MWe, excluding installation and civils costs, bulk hydrogen production via electrolysis for the area of conversion, it was not considered practical for the following reasons:

- Bulk grid electricity at 6 p/kWh results in about 10 p/kWh for hydrogen at the electrolyser, without storage and transmission costs. This is expensive hydrogen.
- To produce 6 TWh of decarbonised electricity to subsequently turn into hydrogen would require the generation of decarbonised electricity on a huge scale. As an example, the 630 MWe London Array wind farm covering a 100 km<sup>2</sup> area, currently one of the largest offshore in the world, has a yearly output of over 2 TWh. Taking account of the 20-30% efficiency loss across the electrolyser as well as the design point hydrogen production demand of 1,025 MW, if hydrogen for decarbonising the area of conversion was produced via electrolysis it would require four to five London Arrays. To match wind production that is about 1,000 x 2.6 MW electrolysers.
- Assuming electricity was available as required 400 x 2.6 MW electrolysers would be needed to meet the design point hydrogen supply of 1,025 MW.
- Land footprint considerations for both the decarbonised electrical generation and associated electrolysers would be significant.
- Due to the variability and intermittency of wind power significantly more storage (possibly by a factor of three) would be required vs. the SMR solution.
- Significant amounts of new electrical transmission and distribution infrastructure would be required if the grid was required to meet the heat load as well as power demand.

Whilst not economic or low carbon when supported by the current deep pool of the UK electricity grid, electrolysers can remain an option in a portfolio of hydrogen supply in a hydrogen distribution system (see [Section 4, Gas Network Conversion](#)). They may be used for electrical system balancing converting constrained electrical energy to hydrogen for use in a future hydrogen grid and might also provide a load balancing function for nuclear power stations.

As a result, the use of electrolysers as the anchor load for the area of conversion was not considered a practical option.



### 2.3.3. The Steam Methane Reformer

Since the 1960s, the technology of choice for producing large quantities of hydrogen is the Steam Methane Reformer or SMR. Steam methane reforming can utilise a wide range of feedstocks, including refinery offgases, LPG and light distillates (naphthas). Fuel for the SMR would ideally be a low-value waste offgas, but if this is not available natural gas is commonly used.

Natural gas is widely used as both feedstock and fuel and requires significantly less pretreatment than alternatives and is typically available at high pressure such that no feed gas compression is required. The overwhelming commercially preferred reforming option is to use natural gas in an SMR to produce large volumes of hydrogen at low cost.



Image 2.3. A Typical SMR Plant – Picture Courtesy of BOC



Image 2.4. Existing BOC 36.4 MMSCFD (c. 150 MW) SMR at Teesside

The existing SMR plant at Teesside consists of two twin cell reformers but has a common feed gas pre-treatment and syngas cooling train. There is a limit to the size of a single twin cell reformer which approximates to an overall plant capacity of around 110,000 Nm<sup>3</sup>/h of hydrogen. More typically, though, the size of SMRs for refinery operations are in the range 150-250 MW. The largest SMR designed to date by Amec Foster Wheeler has a capacity of 110,000 Nm<sup>3</sup>/h (equivalent to 338 MW) and this is limited by the physical size of equipment.

Without space optimisation the overall footprint of the multiple required SMRs is about 445 m x 665 m including access and utilities, similar to a large power station, with vents about 50 m tall. The Terrace Wall reformers are taller in structure (typically 27 m high) but occupy a small footprint. Routine operations are likely to be remote, with a shift maintenance team on site plus service providers for major maintenance.

The SMR hydrogen generation option was selected for the project for the following reasons:

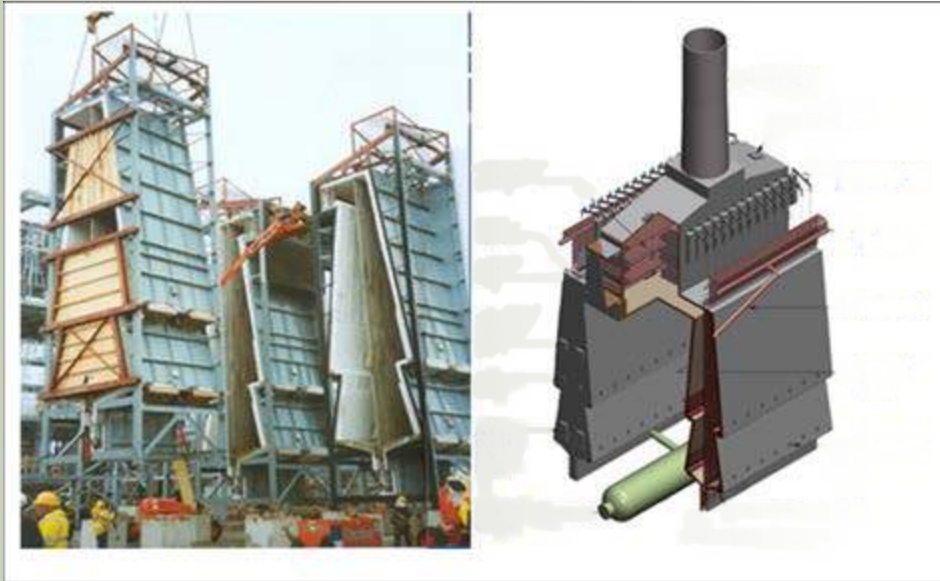
- The high energy output (typical 250 MW per unit) versus the demand 732 MW criteria.
- A proven commercial technology.
- A small footprint (versus other options).
- Availability of feedstock.
- Ability to add carbon capture using by-product steam from the SMR to export to carbon capture and storage in the region (see [Section 7, Carbon Capture and Storage](#)).

The SMR, therefore, represents local and established technology at the right scale for the initial design study for Leeds.



## Breakout: Energy balancing in the UK

Natural gas is a high purity feedstock with low sulphur content and therefore pre-treatment of the feedstock is simple. The gas is preheated using waste heat from the outlet of the SMR to circa 350-370 °C and passed to a desulphurisation reactor. This traps all sulphur present in the feedstock which would otherwise poison the main reformer catalyst. The gas is combined with an excess of steam in a ratio of 3:1 and enters the reformer catalyst tubes at the top of the firebox. The firebox is fired by purge gas (offgas/tailgas) recovered from Pressure Swing Adsorption (PSA) technology, supplemented with make up fuel gases. This heats the reformer catalyst tubes, rapidly reforming the natural gas in the presence of a nickel-based catalyst which facilitates the main reactions.



### Radiant Section of an Amec Foster Wheeler Terrace Wall Reformer

The gas leaving the bottom of the reformer fired heater is in excess of 800 °C and must be cooled to prevent loss of hydrogen yield. This is achieved by introducing steam at high-pressure circa 40-45 bar. The synthesis gas (or syngas) as it is now, contains H<sub>2</sub>, CO and excess water. The synthesis gas passes through a second catalyst bed (shift reactor) which targets the conversion of CO to CO<sub>2</sub> and in doing so yields additional hydrogen from the excess water.

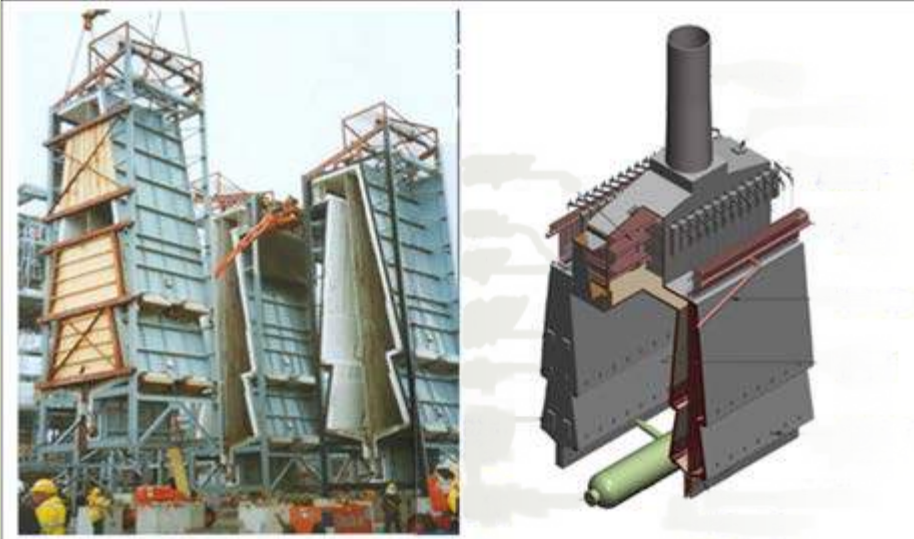
After cooling to recover heat the synthesis gas is cooled in an air fin exchanger and the excess water is condensed and removed.

The synthesis gas contains CO<sub>2</sub> and methane which are removed in a PSA unit to yield pure hydrogen (> 99.9% vol). The very low pressure PSA offgas which contains unconverted methane, CO<sub>2</sub> and some hydrogen is recycled to the reformer firebox as fuel. The PSA offgas has a low calorific value and is fired through dedicated burner ports. The majority of the fired heat duty is obtained by burning the PSA offgas (up to 75% thermal basis) and the balance of fuel which is used for control is natural gas. The natural gas is burned in low NO<sub>x</sub> burners at the bottom of the radiant section.

The flue gases from the firebox pass through the convection section of the reformer fired heater which recovers as much of the waste heat as possible.

## Breakout: SMR Operation

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The flue gases from the firebox pass through the convection section of the reformer fired heater which recovers as much of the waste heat as possible.

## 2.4. Hydrogen Supply for the Leeds Conversion Area

### Design Parameters

The area of conversion requires hydrogen production capacity of 1,025 MW<sub>HHV</sub> (305,000 Sm<sup>3</sup>/h) provided by SMRs. The supply basis of using natural gas from the NTS is a simple application of the SMR operation described in the above box.

The design accounts for variation in natural gas quality over the year, and a typical composition is used for this initial concept. The process yields pure hydrogen (> 99.9% volume) and flue gases of inert gases including CO<sub>2</sub>. The hydrogen from the PSA is compressed for export to either storage or immediate use via the transmission pipelines at 40 bar. The quality of the hydrogen is suitable for heat applications as discussed in [Section 5, Appliance Conversion](#).

**Image 2.5** is a block diagram of an SMR with an associated Carbon Capture Plant (CCP) to capture that CO<sub>2</sub>. The CCP uses heat (steam) from the SMR to capture (typically) 90% of the CO<sub>2</sub> by scrubbing the flue gas in an absorber tower by contact with MEA (monoethanolamine), a liquid which preferentially binds with CO<sub>2</sub>. The MEA is regenerated and re-used by heating, enabling the CO<sub>2</sub> to be separated, dehydrated, and compressed for export. The process is described in more detail in [Section 7, Carbon Capture and Storage](#).

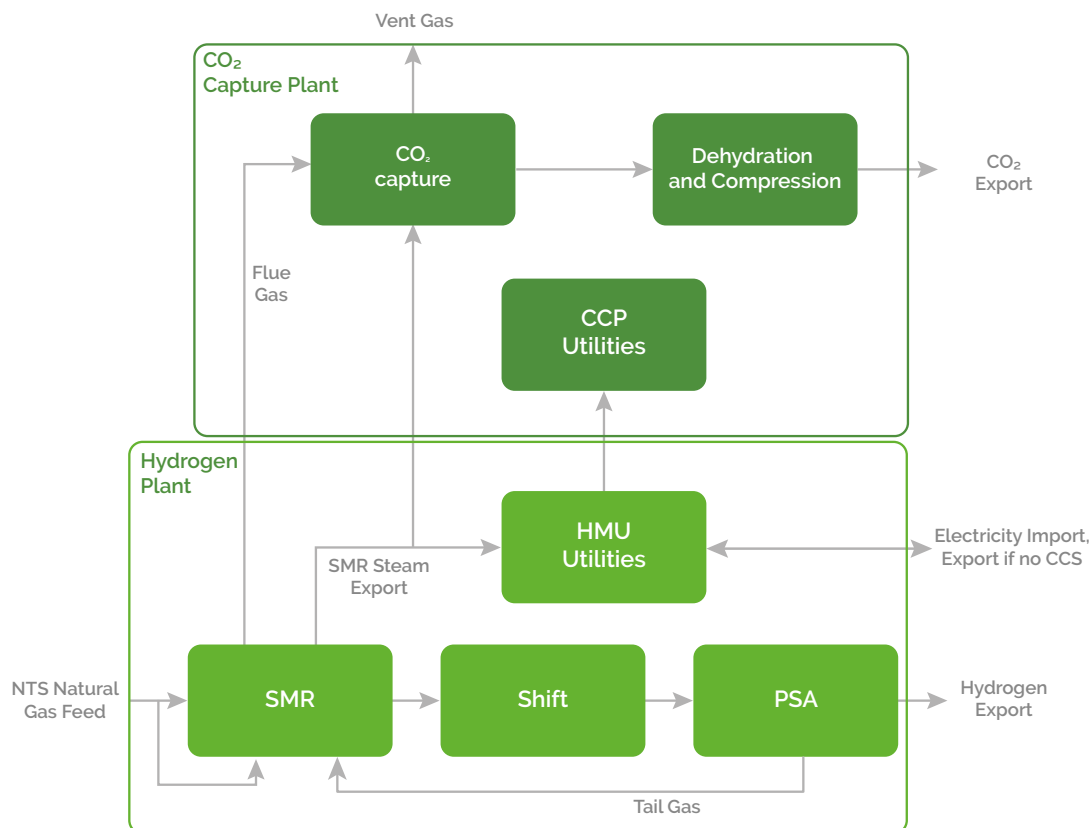


Image 2.5. Simple Block Flow of an SMR and CO<sub>2</sub> Capture Plant

### 2.4.1. Number and Configuration of SMRs

After several iterations in SMR train configuration, the optimum number for the H21 Leeds City Project was determined to be four parallel SMR trains of 256 MW each. When considering the configuration of the SMRs, production reliability is of high importance. Planned maintenance must be carried out typically every four years to replace catalysts and inspect equipment for regulatory reasons. The catalysts do not contain rare earth metals and therefore spent catalysts are replaced and not regenerated. This replacement and inspection work takes three weeks and would be planned during the summer months when the work can be undertaken without adversely affecting the reliability of hydrogen supply.

In a four train SMR configuration, the design can be optimised to provide two PSA units for the four SMRs.

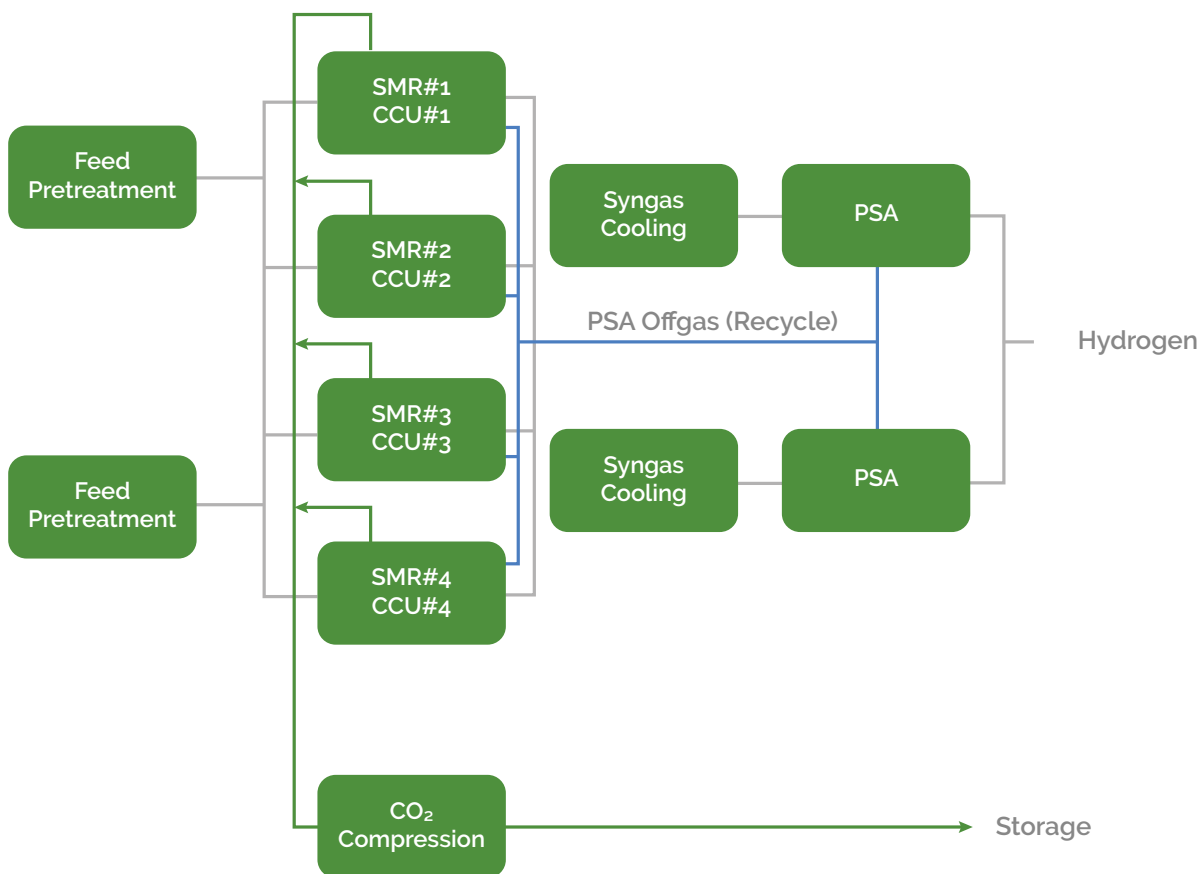


Image 2.6. H21 Leeds City Gate SMR Train Configuration

Indicatively future design development may indicate an overall site footprint of circa 10-20 hectares for this production facility.

### 2.4.2. Production Output Flexibility

One of the most important drivers for this study is to propose a design that achieves as close to 100% overall availability as reasonably practicable. In order to do this without relying on storage of hydrogen would require over-capacity to be installed in the SMRs. Moreover, the daily demand profile is such that having no hydrogen storage isn't technically viable because the SMR output cannot be changed rapidly for mechanical and safety reasons.

SMRs have a good turndown capability and can be designed so they are able to operate down to 30% design output. The total natural gas flow varies non-linearly with hydrogen production rate. Most of the natural gas is consumed to produce hydrogen and this is a linear relationship. However in order to maintain reaction temperatures, the burner fuel consumption flat lines below 70% turndown and therefore impacts overall efficiency.

SMRs are able to increase and decrease output at a maximum of 5% of design capacity per hour. In addition, restarting an idled SMR from cold is a relatively slow process and takes around 24 hours. This is because the refractory lined firebox within the SMR cannot be heated up rapidly without risk of mechanical damage. During this 24 hour period, fuel is consumed but no hydrogen is produced and this has significant operating cost if performed on a frequent basis. For mechanical reliability purposes, the SMRs should not be started and stopped more than a few times per year.

Based on these two design parameters it is clear that the daily demand profile cannot be met by the SMRs on their own and some reliance on storage will be required to smooth the peaks and troughs in demand. The aim of hydrogen storage should be a rapid response (minutes) to provide the time needed to ramp up/down reformer production capacity. Reformer production capacity should, therefore, be considered as a function of seasonal demand, keeping stopping and starting of SMRs to a minimum.

In winter all four SMR trains would need to be online and operate near maximum output. In summer a minimum of two SMR trains would be online and operate at around 70% of their individual output capacity. The spare capacity in summer is useful because this can be utilised to top up storage prior to a maintenance event. Also the two idled trains will be offline for a longer period and there is less likelihood of frequent stop/starting which is undesirable. The annual average operating mode for the facility is three trains working at 90% output. This configuration of SMRs allows reformer outputs between 70-100% to meet the seasonal demand requirements. These parameters ensure the SMRs maintain operation in their most efficient output window.



Chart 2.7 shows the SMR supply profile against the demand profile (as defined in Section 2.1) with the maximum output from four, three, and two SMRs operating between 70-100% of each unit's 256 MW capacity.

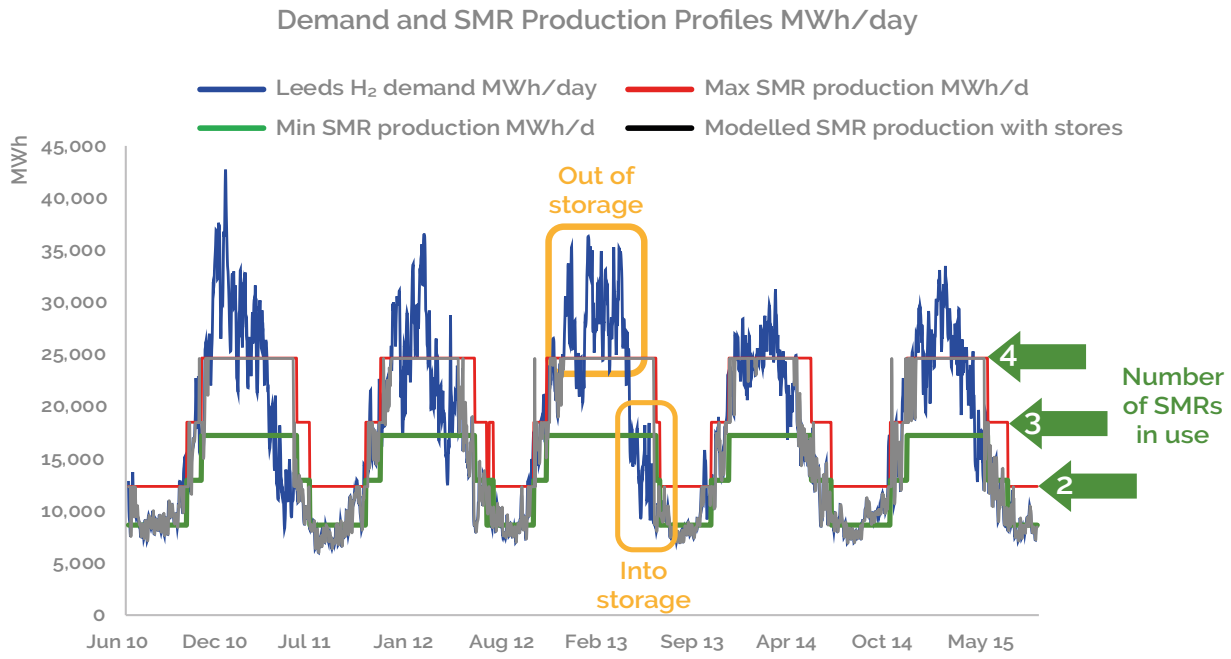


Chart 2.7. SMR Supply vs. Demand

Chart 2.7 shows that four SMRs provide a sensible capacity to match the foreseen supply requirements, minimising the number of shutdowns and enabling operation in their most efficient range. The period where all SMRs are online is only about 50% of the year.

A detail of the 2013 winter, the largest demand for winter storage, is shown below.

Demand and SMR Production Profiles MWh/day

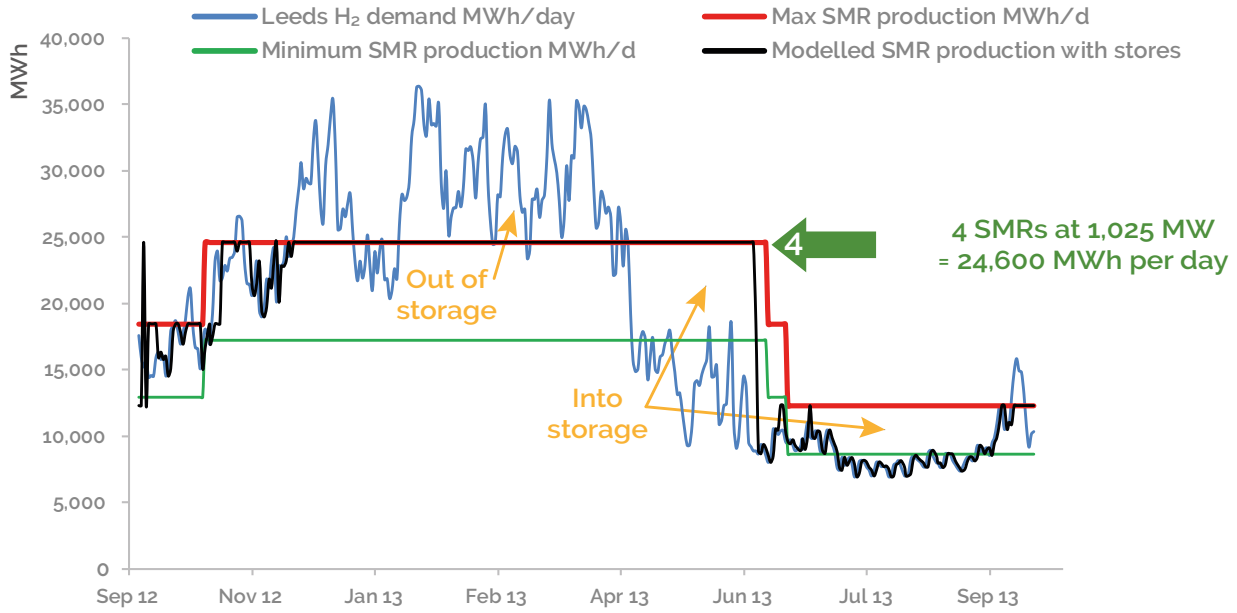


Chart 2.8. 2013 Winter Storage Demand



### 2.4.3. SMR Conclusions

The SMR configuration chosen for baselines cost comprises:

- Four SMRs each of 256 MW capacity.
- Associated utilities and compression to deliver 99.9% pure hydrogen at 40 bar.
- Integrated carbon capture to capture 90% of produced CO<sub>2</sub> for export at 120 bar. The plant can operate without CO<sub>2</sub> capture.
- An overall site footprint of circa 10-20 hectares per GW.
- Whilst can provide a flexible output production level through both 'turndown and off-line capability there is still need to provide storage for inter-seasonal and intraday demand profile management.
- An average year would see production of:
  - 5.94 TWh (5.9 million MWh, 151,000 tonnes, 1,770 million Sm<sup>3</sup>) of hydrogen.
  - 1.5 million tonnes of CO<sub>2</sub>.



## 2.5. Storage – Balancing Supply and Demand

### History: Salt Caverns

Salt caverns are washed voids in deep geological strata of salt, typical of those seen in the Cheshire salt mines. They are used for storage of many sorts of gases as the salt is an excellent seal and is resilient to fractures. Underground storage of natural gas in deep saline formations is already undertaken in the region at Attwick/Hornsea and Aldborough, and the storage of hydrogen is proven at scale in the UK. Three caverns are licensed for operation on Teesside. Each cavern is 70,000 m<sup>3</sup>. Operated by SABIC, the facilities support hydrogen distribution to chemical plants in the Teesside chemical complexes and have done so for over 30 years. The caverns operate at 45 bar at a depth of 400 m with a total storage tonnage of 700-1000 tonnes and are adjacent to the BOC SMR. The quantity of hydrogen stored in any one cavern is dependent its pressure (which is, in turn, a function of depth) and size of the washed cavern on the strata which determines the design pressures used in the store.

Salt caverns are secure stores given the high tightness of the salt rock mass, relatively low unit construction costs and the small footprint required above ground. A typical store is above 100,000 m<sup>3</sup> in geometrical volume and up to 200 bar maximum operating pressure.



The technology is directly comparable to the storage of natural gas for seasonal load balancing, shut-down reserve, reserved for extreme weather conditions, and as a trading reserve.

Image 2.7. Salt Dome Salt Cavern    Image 2.8. Salt Caverns At Teesside

The Praxair hydrogen storage cavern facility at the Moss Bluff salt dome in Texas is integrated into Praxair's 310 mile hydrogen pipeline, serving more than 50 refineries and chemical plants from Texas City, Texas, to Lake Charles, Louisiana. This facility has a storage capacity of 70 million Nm<sup>3</sup> and a working capacity of 40 million Nm<sup>3</sup>. It is a cushion gas system with a working pressure of 55 to 150 bar. The maximum fill rate is 2 million Nm<sup>3</sup>/day, with the withdrawal rate being storage pressure dependent. To put the scale of these types of caverns into context, the Eiffel Tower could fit inside a single cavern.

### 2.5.1. Design Parameters for Hydrogen Storage

The hydrogen supply analysis in [Section 2.1](#) determined a design point for the area of conversion that requires a hydrogen inter-seasonal storage of 702,720 MWh<sub>HHV</sub> (40 days of average daily demand, 209 million Sm<sup>3</sup> H<sub>2</sub>) and additional intraday storage. These two forms of storage (inter-seasonal and intraday) together with the SMRs and toned to supply a maximum day demand of 2,067 MW and a 1 in 20 peak hour demand of 3,180 MW.

Natural gas storage is an established method to assist in matching supply to demand. The same issues of managing variations in demand to basic gas production apply to hydrogen for Leeds.

With the selected SMRs and given the need to be very secure about the supply to Leeds, the design of the system looks to closely tie the primary production assets with the storage assets to ensure security of supply of gas to match demand. Having established the SMR train configuration and hydrogen production facility capacity it is important to now understand the associated storage requirements to allow the overall system to match the intraday and inter-seasonal demands. A by-product of this is that:

- The hydrogen stores will effectively add to the UKs overall gas storage.
- The SMR operator can source some lower cost natural gas in the summer.
- The profile of the export CO<sub>2</sub> remains relatively constant throughout the year, certainly more constant than would be the case for some power stations.

The north east of England is an area with good and proven storage assets. In particular, proven types of geological storage used for natural gas can be considered for hydrogen storage. The potential is also present to repurpose natural gas storage for hydrogen. Gases, including hydrogen, are also stored in vessels, either in compressed and or liquefied states, and new technologies are being developed for hydrogen bound into matrices. However, this applies to smaller volumes and not even the most cutting edge university research large scale solid state storage competing at the inter-seasonal scale.

When considering the requirement for intraday versus inter-seasonal storage we must consider the overall energy use of the system to store and then extract the gas. In a sub optimised design, the inter-seasonal store may be able to also act as an intraday store. This would require significant amounts of additional compression into inter-seasonal caverns operating at circa 200 bar vs. smaller intraday caverns operating at between 20 and 60 bar. It may be the case that on the detailed design a more optimised intraday option than the one presented in this report could be available utilising pressurised containers around converted cities. For example line pressure containers may be able to meet the ideal intraday storage requirements, but location and safety considerations could prove prohibitive for this option. To put this option into context, to store the volume required for the intraday profile in the area of conversion at transmission pressure would require approximately 31 km of 56 inch pipe.



## 2.5.2. Methods of Storage

There are in effect three deployed storage technologies applicable to hydrogen.

### Storage of Gaseous Hydrogen in Pressurised Containers

Scaled up from gas cylinders at 125 bar to 800 bar high pressure storage, down to 12 bar for scales of up to around 150,000 Nm<sup>3</sup> of H<sub>2</sub>. Such storage would only be relevant for intraday storage. Location and safety considerations could prove prohibitive to this option. This technology is inappropriate for bulk hydrogen.

### Storage of Liquid Hydrogen in Refrigerated Containers

Typically used for rockets, it is relatively expensive to liquefy but is an option for shipping, similar to shipping LNG, although the liquefaction of hydrogen is considerably more complex.

### Storage of Gaseous Hydrogen in Underground Formations

With ambient temperature and pressure related to geological conditions. Storage in depleted hydrocarbon fields would require other process treatment, not just water dew point control. The hydrogen product must be free of contamination from water and hydrocarbon fluids.

Whilst geological storage is the usual high volume option it requires the right geology. There are a number of techniques including depleted hydrocarbon fields, aquifer formations and solution mined halite/salt caverns. In the north of England, it is salt caverns that offer the best solution as they are extremely gas tight and the salt is inert in contact with the hydrogen. In operating a salt cavern the stored gas can be maintained at a lower pressure range by varying liquid (brine) volumes in the cavern, or by a cushion gas limiting the minimum storage pressure.

As part of a detailed design for the project, the choice of brine or cushion gas should be further examined. If the storage facility were to be supported with brine as the cushioning fluid (a fluid which is used to drive the gas out of the cavern) then associated brine ponds, pumps and conditioning equipment would be required, although this equipment could be the same solution as that used to mine new caverns in the first place. However, the choice at this stage is a cushion gas design because it is less influenced by scale, brine storage details and planning consent. The costs are based on total costs for similar sized cushion gas stores so is a reasonable approach to take at this stage of facilities definition.



Conveniently the region has excellent opportunities for salt cavern gas storage.

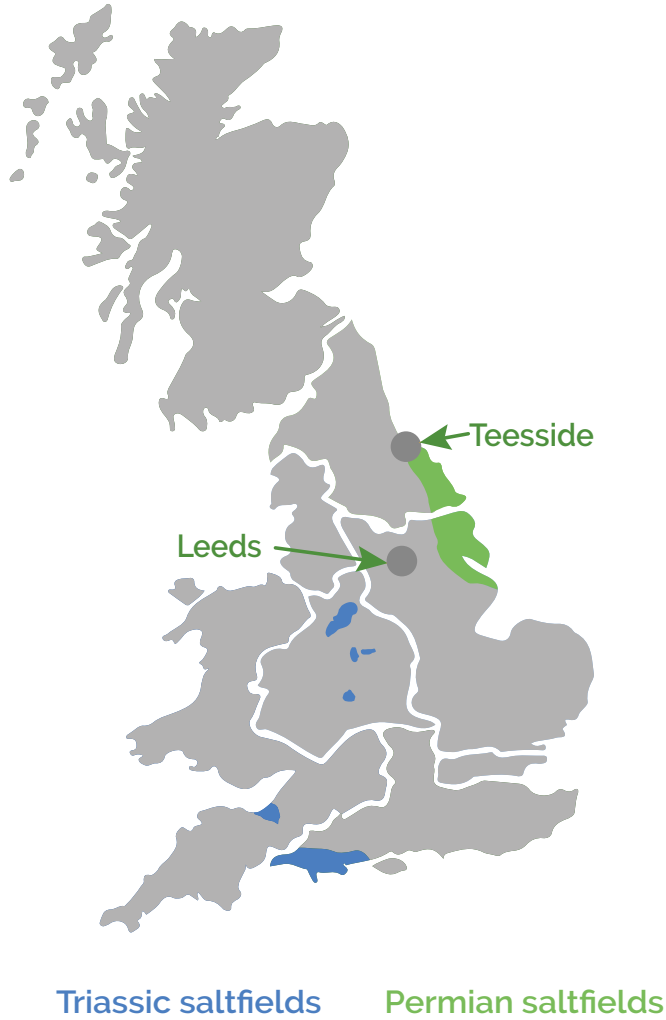


Image 2.9. Local Salt Deposits and Salt Cavern Storage (Extract from ETI Report)

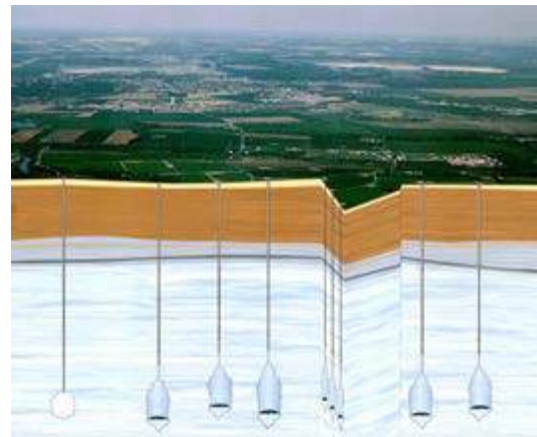


Image 2.10. Local Large Natural Gas Salt Cavern Storage (Courtesy of SSE)



### 2.5.3. Size of Storage

For the inter-seasonal storage (totalling 702,720 MWh) the flow rates in and out of the store, and the rate of change of flow rates are important design parameters. **Chart 2.9** shows the flow in MWh/day in and out of the store contrasted with the design supply to Leeds and the production from the SMRs.

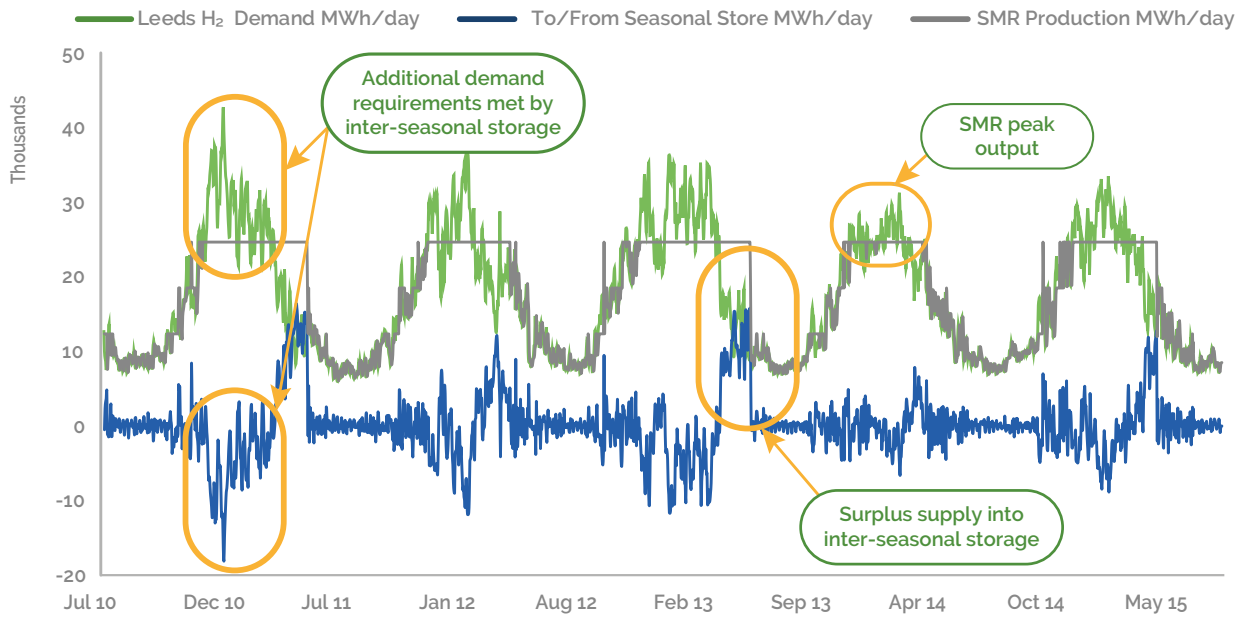


Chart 2.9. Demand and Seasonal Storage Changes MWh/day



This illustrates how the inter-seasonal store works with the SMRs to deliver the daily demand.

- The modelled maximum energy into the store is 16,343 MWh over a day, seen in July 2011 in **Chart 2.10**.
- The maximum withdrawal is 25,013 MWh modelled from the 1 in 20 year peak demand, reference earlier **Section 2.1**. That defined peak day demand of 49,608 MWh for that day is an average of  $49,608 / 24 = 2,067$  MW, met by 1,025 MW of SMR production, and 1,042 MW from the inter-seasonal store over 24 hours, a total of  $1,042 \times 24 = 25,013$  MWh from the store.

The inter-seasonal storage fills up during spring and summer, and discharges over winter, as detailed in the following profile for 2013.

2013 Demand and Seasonal Storage Changes MWh/day

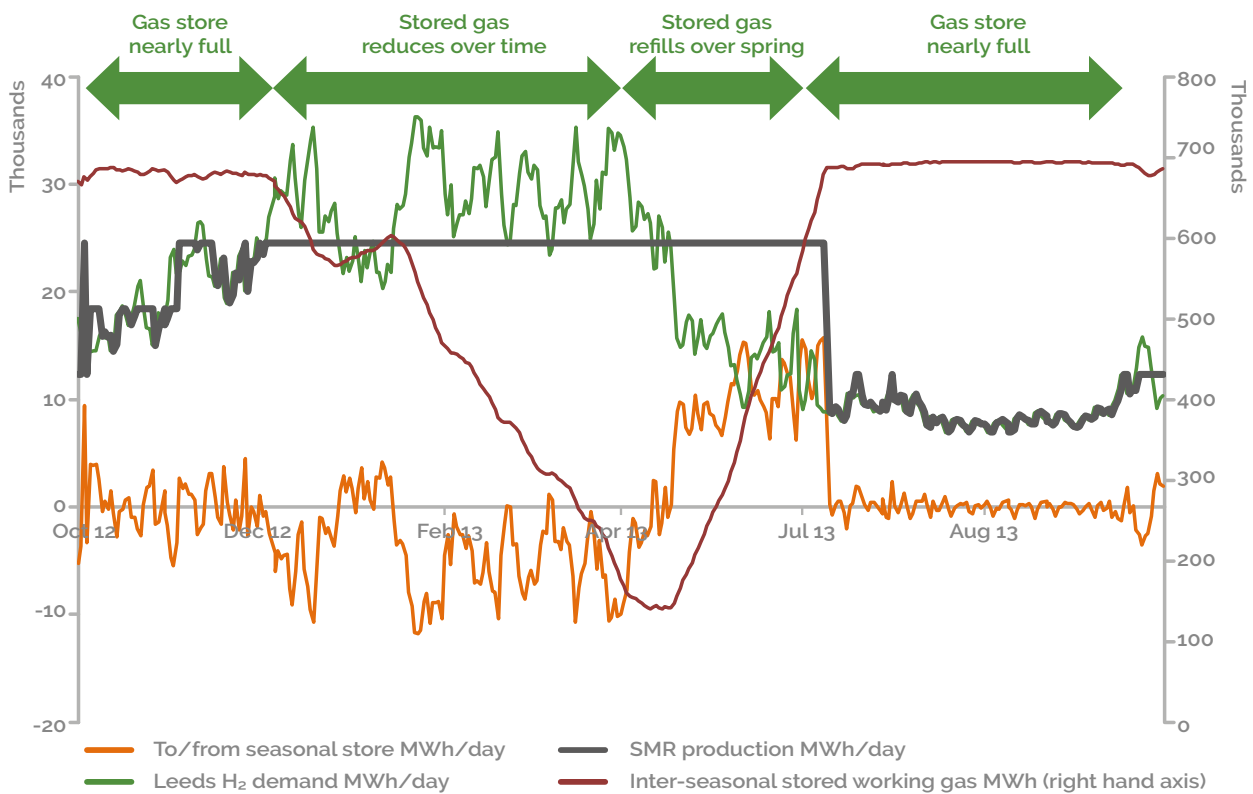


Chart 2.10. *Seasonal Storage*

The characteristics of the inter-seasonal storage are therefore as follows.

<b>702,720 MWh</b>	Total capacity as design point		
<b>25,013 MWh</b>	From store on peak day	<b>16,343 MWh</b>	Into store max day during year
<b>1,042 MW</b>	From store peak day average	<b>674 MW</b>	Into store max flow
<b>1,607 MW</b>	From store max flow		

Table 2.4. *Inter-seasonal Storage*

There are other store characteristics used in design such as the rate of change of flow rates, which influence the detailed design of both each inter-seasonal store and the intraday stores.



### 2.5.4. Managing the 1 in 20 Peak Day

The above flow rates are the average supply over a day from inter-seasonal storage. Intraday storage is at this stage modelled as starting with zero stored, filling up overnight, and discharging during the day to meet the load variation within a single day. The main inter-seasonal store also has the ability to vary the amount supplied to the area of conversion during the day, which is to discharge less than the average rate between 00:00 and 08:00, and discharge more than average between 08:00 and 00:00, still keeping to the required average for the day whilst minimising compression costs and reacting to demand variations.

This varying of the discharge during the day can reduce the need for the intraday storage to meet the peak hourly flows which are typically at their greatest around 18:00. This opportunity is used in the analysis of the intraday storage. For the peak day, all four SMRs are operational, having a constant output of 1,025 MW. The supply required for a peak day hourly flows over the maximum day average flow of 2,067 MW and a maximum peak demand (circa 18:00) of 3,180 MW. **Chart 2.11** show the supply profile for the peak design day.

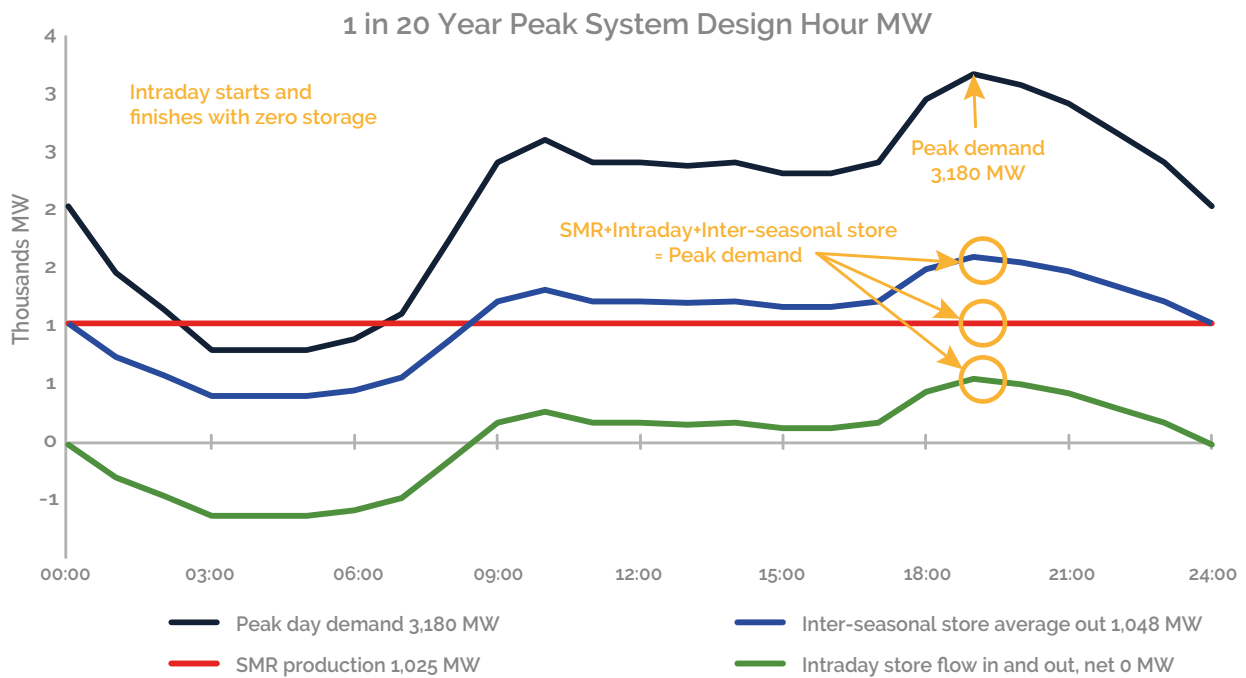


Chart 2.11. Supply Profile For Peak Day Design

The inter-seasonal store contributes an output at an average of 1,042 MW, but varying between 402 MW and 1,607 MW, to give a total for the day of 25,013 MWh. Its maximum hourly delivery rate is around 18:00 as shown in **Chart 2.11**. This leaves the intraday store with the residual tasks within a day of:

- Energy amounts into storage vary from 0 MW to 632 MW (02:00 in the morning on a peak day) over the period from about 00:00 to about 08:00. The total energy into storage is 3,892 MWh.
- Delivering from storage 0 MW to 548 MW over the period from about 08:00 to about 00:00. The total from storage peaks at 3,892 MWh. The peak flow rate around 18:00 is about 548 MW.

Therefore, the intraday store ends the day with the same storage as it started with. For the peak flow, it can contribute 548 MW.

The total at 18:00 is 3,180 MW, made up by SMRs = 1025 MW, inter-seasonal store = 1,607 MW, intraday store = 548 MW.

The intraday store is able to support meeting the peak as it has been filled up during the early hours of the day from the excess of production over demand, the production being the steady production of the SMRs and the decanting of gas from the high pressure inter-seasonal store.

Using the above information the storage parameters for intraday storage are as follows:

Minimum Storage	3,892 MWh
Net Daily Flow	0 MWh
Peak Inflow Rate	632 MW
Peak Extraction Rate	548 MW

**Table 2.5. Intraday Storage Meeting Peak Day Demand**

Note that these reflect the peak day issues and other factors may influence some design details, including the relative pressure difference between the storage pressures and the delivery pipeline pressure.



### 2.5.5. Specific Storage Configuration

With geologically proven salt beds caverns in and around Teesside and to the east of Leeds it is suggested storage should take the form of:

- Inter-seasonal 702,720 MWh (209,150,000 Sm<sup>3</sup>) plus.
- Intraday 3,892 MWh (1,158,000 Sm<sup>3</sup>).

The intraday store is effectively providing the linepack that is missing when compared to conventional natural gas designs due to the low calorific value of hydrogen. As noted elsewhere, this linepack could be provided by running much of the hydrogen through the high pressure inter-seasonal store, but this would be wasteful of compression energy. Other options as noted above would be checked again when the project moves to the next stage.

The actual size and number of caverns have been chosen based on the following factors:

- Available depth of the salt strata, determining the viable pressure range for the store.
- The supply pressure of the supply to and from the store.
- The need for cushion gas (in this case rather than brine support) to achieve the minimum storage pressure.
- Minimisation of the compression required to inject gas to storage.
- Flow rates in and out of storage.
- Minimisation of the mining work; because a higher pressure store holds more energy per actual cubic metre than a low pressure stores.
- Maintainability and reliability of the cavern and associated well and surface facilities.

As can be observed these objectives are sometimes in conflict, and at this stage engineering judgement is used to determine a reasonable combination of actual size, operating pressure range and a number of caverns for both types of stores.

- A choice was made to have the intraday storage in Teesside where the shallower salt and relevant operating experience is best known at that scale, and the pressure difference with the transmission pipeline is least. As only one store is essential a second store is used to ensure availability.
- For the inter-seasonal storage to be in East Riding, east of Hull, where the same but deeper salt is associated with existing similarly sized natural gas stores. For the long term storage, the compression costs are less critical and minimising the actual salt cavern size is more important. The security of the stores is allowed for with an additional cavern to ensure availability and peak use maintenance of the facilities.

It is also worth noting that on typical days the operators have flexibility to match supply to demand by varying the amount of production from the SMRs, the amount to or from both intraday stores, and the amount to and from any of the inter-seasonal stores over any hour of the day.

The direct staff on site maintain the compressors and gas clean up equipment including the disposal of removed material from the recovered gas. Power is the main consumable. The operating cost is dependent on the actual store designs and operational choices. At this stage, a typical total operating cost is assumed.

The safe operation of both of these sorts of gas stores is well established. The area presently used for gas storage in Teesside and East Riding show their relative isolation.



Image 2.11. *Teesside and East Riding Underground Gas Storage*

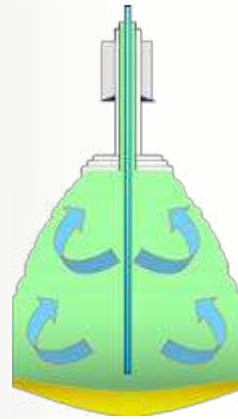
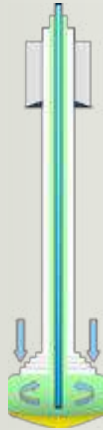
The chosen scale of salt caverns to support the required supply for the initial concept costs is as the outlined in **Table 2.6**.

Store type	Inter-seasonal	Intraday	Total
No	7	2	9
Cavern Capacity actual size (m <sup>3</sup> )	400,000	240,000	
Working capacity each	122,100 MWh 36,334,000 Sm <sup>3</sup>	5,552 MWh 1,652,000 Sm <sup>3</sup>	
Cushion gas allowance total (Sm <sup>3</sup> )	203,500,000	1,850,000	
Total working capacity (MWh)	854,000	11,100	865,000
Online caverns	6	1	7
Online working storage (MWh)	732,000	5,552	737,000
Location	Hull area	Teesside	

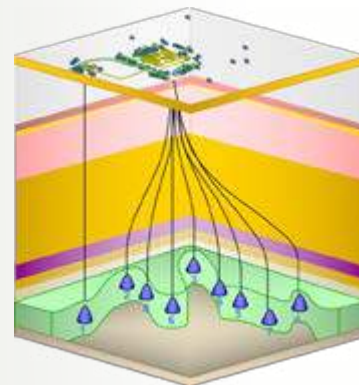
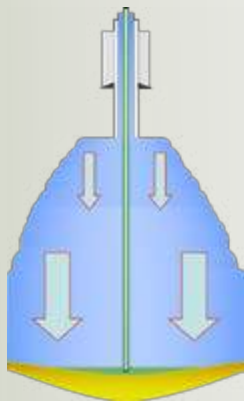
Table 2.6. *H2i Leeds City Gate Storage Requirements*

## 2.5.6. Salt Cavern Operational Requirements

### *Breakout: Construction of salt caverns (courtesy of SSE)*



- Seawater is pumped into the 9 $\frac{5}{8}$  inch diameter well
- The seawater dissolves the salt at depth and creates brine solution
- A blanket of nitrogen being progressively raised helps to create the cavern shape
- The brine solution is pumped from the well
- The leaching process continues for approximately 2 years
- When the cavern is the correct shape and size, leaching is stopped
- The cavern is ready to be filled with gas



- Gas is injected into the cavern, pushing the brine out, a process is known as dewatering
- The cavern is now storing gas, ready for commercial use
- Multiple completed caverns (Aldbrough at Hull)



There are minor differences between hydrogen and natural gas caverns, primarily concerning the selection of materials in the access well and the cavern head at the surface. High pressure gas caverns function by compression and decompression between a minimum and a maximum pressure. The maximum pressure approximately corresponds to 80% of the initial formation pressure at the depth of the cavern roof, whilst the minimum pressure is around 30% of the maximum pressure. For example, a design pressure of 250 bar would allow a maximum cavern pressure of 200 bar and a minimum pressure of 75 bar. The cavern always retains a volume of gas at a set pressure to maintain cavern integrity and this 'cushion gas' remains unrecoverable unless removed by a fluid. This removal method is also deployed on natural gas and hydrogen stores. Gas fill rate is limited by compressor size and emptying rate by the need to avoid spalling of the inside walls.

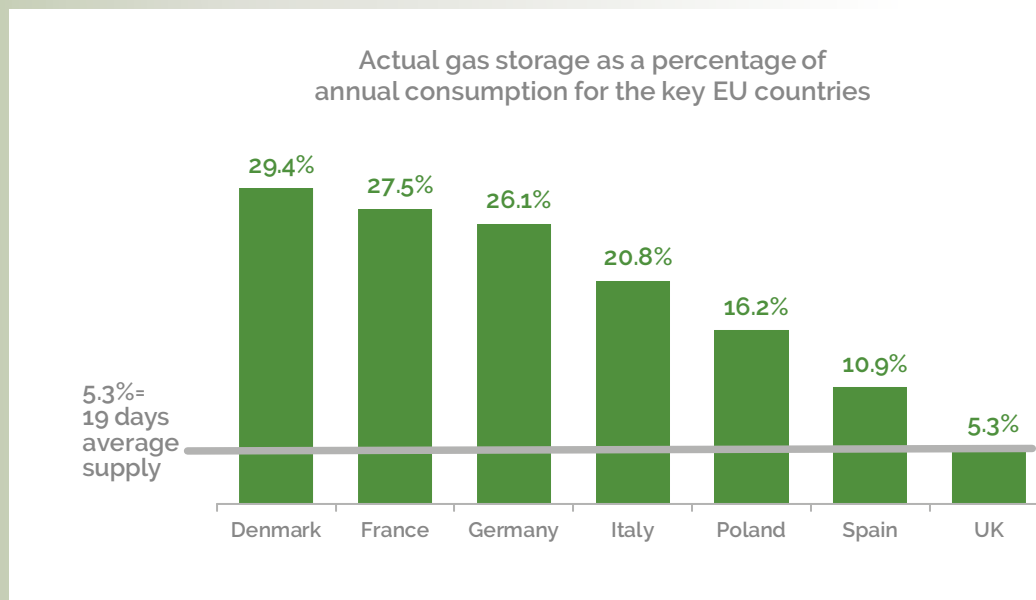
In addition filling the cavern will require compression, particularly for deeper storage. A halite (rock salt) formation will inevitably be wet, and if solution mined the residual brine in the cavern takes a number of operations to evaporate and the ingress of moisture is also possible. Therefore, dehydration equipment will be required, in addition to pressure raising/control and subsequent temperature control.



## Breakout: Energy balancing in the UK

Managing supply and demand swings in the UK has been undertaken by the gas industry at a significant scale since the town gas to natural gas conversion. Prior to this, most winter heating was made with coal (in rural areas) or coke (in urban areas). In the UK we have been in the privileged position of being able to manage significant variations in gas demand requirements, (energy buffers) by using our natural gas reserves as our demand vs. supply swing 'buffer'. However, as these reserves are depleting, the UK has a growing need to develop additional storage capability. Today this is being managed by a growing reliance on gas in the form of Liquid Natural Gas (LNG) or gas via the interconnectors to and from mainland Europe.

The chart below shows the actual gas storage as a percentage of annual consumption for the key EU countries.



Historically, the gas industry could manage intraday (within same day demand variations) capacity with the use of gas holders to 'peak shave' demand by acting as a localised supply. The gas holders were filled during off peak hours, (usually through the middle of the night) and then utilised during peak hours.

Natural gas has a calorific value approximately twice that of town gas and in conjunction with additional storage capacity coming from transmission networks, which have evolved over the last 50 years, the need for gas holder storage has reduced to the point of where they are gradually being decommissioned and demolished.

## 2.6. Location of the Hydrogen Production Facilities (SMRs) and Salt Caverns

Having understood the method of hydrogen production, the demand vs. supply characteristics and optimised salt cavern configuration it is now possible to determine the optimal geographical arrangement. In order to do this, the first things to identify are the constraints, e.g. location of infrastructure. For the project there are three fixed points:

1. The areas of conversion – Leeds;
2. The area where salt exists for salt cavern development; and
3. The area where CCS is available, i.e. at the coast (see [Section 7, Carbon Capture and Storage](#)).

The elements which are less fixed are:

- The locations of the hydrogen production facilities (SMRs);
- The connecting pipelines; and
- The potential location of new salt caverns within the confines of the areas with geological salt availability.

The context of a specific set of elements also influences the further design of the new hydrogen facilities.

- Check on security of supply of the whole system.
- Issues of implementation.
- The value added as a consequence of the concept for Leeds.

In order to provide a price for the overall system design the project team needed to establish a geographically realistic 'conceptual design'. The final recommendation in this report would clearly be subject to a detailed design but the project team believe the locations are the most practically viable outcome considering all the known parameters which will be discussed in this section of the report.

The detailed study went through a five-level mapping process:

1. Defined connection points to Leeds, salt storage and CCS systems. Note that it was found that the NTS and utilities connections were not top level drivers as the region is well served with respect to these inputs to SMRs.
2. Local area searches covering planning and environmental sensitivities.
3. Existing pipelines and area classifications.
4. Site nominations, size and pipe access.
5. Outline options. About 23 were considered for screening.



The SMR site was the most complicated facility to locate. The main features to consider in the plant design and location is feedstock supply, power connection and site access, the impact on the local area, control of Greenhouse Gas (GHG) emissions, including NO<sub>x</sub>s and the other quality parameters for the hydrogen. The most important is the ability to export captured CO<sub>2</sub> for sequestration. This combination aims for the lowest unit cost of hydrogen to consumers.

Despite the current issues with the funding of CO<sub>2</sub> disposal under the North Sea, two layouts were considered worthy of investigation:

- The SMR+CCS and all storage near Hull with CO<sub>2</sub> disposal along the National Grid White Rose line.
- Location of the SMR+CCS at Teesside together with intraday storage, with inter-seasonal storage near Aldeburgh. CO<sub>2</sub> disposal through the Teesside Collective line.

Consideration of other factors made the second arrangement more favourable:

- All new facilities have been proposed, however Teesside offers more re-use (but unconfirmed) options for intraday storage.
- The existing SMR at Teesside offers (unconfirmed) options to assist in additional security of supply and commissioning.
- The existing H<sub>2</sub> network at Teesside offers options to test, trial and demonstrate low pressure conversions from natural gas to hydrogen distribution, house conversions, and appliance demonstrations.
- The existence of new hydrogen production on Teesside may assist industrial CCS concepts which are ongoing in the area.
- The cost difference in pipe sizing is not a major consideration given the cost benefits of having intraday stores near the SMRs and inter-seasonal (high pressure) stores down the coast. Such a layout also enables multiple options for smaller parts of the local distribution system more or less near the pipelines to be served with hydrogen if that was desired in the future.

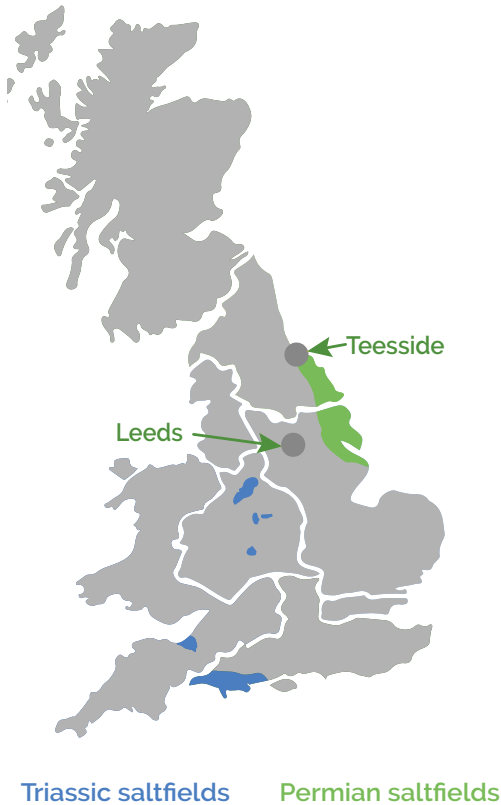
Both the Humber and Teesside areas have experienced workforces and public understanding of power, industrial and chemical plants. The project's discussions with key stakeholders showed considerable enthusiasm for a Teesside location, with support from Tees Valley Unlimited and linkage to the work of the Teesside Collective.

An interface with the existing hydrogen network is not confirmed but is highly desirable. The final recommendation in this report would clearly be subject to a detailed design but the project team believe the locations are the most practically viable outcome considering all the known parameters further to the broad acceptance of this report.



## Strategic Locational Analysis

Before trying to establish the specific locations of the salt caverns and hydrogen production facility (SMRs) it is important to firstly understand the UKs available resources.



**Image 2.12. UK Salt Deposits and Salt Cavern Storage**  
(From ETI Report on Hydrogen)



**Image 2.13. UK Carbon Capture Availability**  
(From 'Strategic UK CCS Storage Appraisal Project')

It is clear from **Image 2.12 and 2.13** that the east coast offers significant advantages for the following reasons:

- The nearest coast to Leeds.
- The largest UK salt area.
- Significant industrial heartlands exist within this region of salt at Hull and Teesside.
- The UKs current hydrogen caverns are located at Teesside.
- The UKs existing SMR plant is located at Teesside.
- There is significant carbon capture and storage availability (see [Section 7, Carbon Capture and Storage](#) for more details).

As a result, the study was constrained to locational analysis of the hydrogen production facility and associated storage to near the east coast, rather than in the proximity of Leeds.

### 2.6.1. The Location of the Hydrogen Production Facility (SMRs)

The main factors to consider in the plant design and location are feedstock supply, the impact on the local area, control of the embodied greenhouse gases (GHGs) and the other quality parameters, which include the ability to export captured CO<sub>2</sub> for sequestration, all at the lowest unit cost of hydrogen to consumers.

The consideration of location options is critical to the overall cost and reliability of any project. For the location of infrastructure such as in this report, there are multiple elements to consider. Here we are considering a production unit that feeds hydrogen to a network, but also to storage and rejects carbon dioxide to a CCS infrastructure. In addition it requires a fuel route and utility connections.

Whilst several areas were considered for the location of the SMRs Teesside was selected. As part of a detailed design, this could be revisited as Hull also offers good potential for hydrogen production facilities. The main reasons for the selection of Teesside are described in the following pages.

#### Fuel Supply: Natural Gas

Hydrogen production via reforming requires significant volumes of natural gas typically 1:4 by mass. Therefore, the reformer site needs to connect to a suitable natural gas source at a suitable pressure. Typically as reforming takes place at 20-30 bar this means that any reformer must be supplied by a natural gas pipeline in the National Transmission System (NTS) operated by National Grid or by the Local Transmission System (LTS) operated by the Local Distribution Zone (LDZ) – in this case Northern Gas Networks.

Both the Teesside and Hull areas have easy access to a range of both NTS and LTS pipelines reducing connection costs and expensive pipeline infrastructure. In Teesside pipeline access for natural gas is already established and chemical pipelines (ethylene) already leave the area to feed chemical sites in Hull.

#### Potential for Carbon Capture

Delivery points for carbon dioxide have to be assumed as no infrastructure currently exists. Instead, we consider existing plans such as those in the Humber and Teesside regions ([Section 7, Carbon Capture and Storage](#)). The Humber CO<sub>2</sub> transport and storage infrastructure is proposed by National Grid Carbon in support of the White Rose CCS project. The Teesside project, led by Tees Valley Unlimited, is considering the development of a CCS network to support industry in the region under the Teesside Collective project.

In both cases, the proposed projects aim to provide infrastructure to accommodate regional activity, not just a single emitter. Therefore, this project considers either location to be a viable target for consideration.

Additionally, it was considered potentially more contentious and costly to build a large CO<sub>2</sub> capture pipeline to these hydrogen production facilities. It is more practical to locate the hydrogen production facility in close proximity to CCS cutting cost for the transportation of carbon and also planning considerations.



### Regional Acceptability

When considering the construction of four SMR plants regional (and public) acceptability have to be taken into consideration. Both Teesside and Hull have vast industrial areas and, as such, high levels of infrastructure and experience. In addition, Teesside already has an SMR production facility and associated salt cavern storage. Extensive stakeholder engagement has been undertaken with Tees Valley Unlimited and there is a real appetite for the project.

Public acceptance of the project may be aided by it's impact on regional employment. The Tees Valley area recently lost its steel industry and therefore has a skilled workforce ready and available should this area become a centre for hydrogen production.

### SMR Plant Footprint

Whilst relatively speaking SMRs are 'small' industrial plant they are still not likely to be positively welcomed in people's back yards. Industrial heartlands such as those at Hull and Teesside offer the best opportunity for location when considering all the other factors above. To put this into context **Image 2.14** show the Seal Sands industrial area at Teesside, the existing SMR and the additional SMRs required for the Leeds conversion area hydrogen demand.



Image 2.14. Seal Sands Industrial Area

## Safety

Safety constraints apply to SMRs as for all chemical plants. The location has to consider the impact of the development on the surroundings and the environmental factors that may impact on the development. In the case of SMRs, they generally do not fall under the COMAH regulations in the UK (Seveso directive in EU) given that the volumes of single units are low in terms of tonnage of hydrogen contained in the equipment. But a multiple SMR site will have a larger inherent volume. The COMAH designations for hydrogen are 10 tonnes for lower tier and 50 tonnes for the upper tier. This ranking applies for hydrogen storage as well, but not the pipelines which are viewed under a different regulation. The addition of a carbon capture plant has to also be considered. Depending on the process this may also fall under COMAH.

Therefore, the site selection must consider at this stage the impact of being classed as a COMAH site. COMAH applies a safety case, including how to interface with neighbouring facilities and the risk outside the boundary is considered. Without a specific process in hand at a high level, a recommended separation distance is applied. Industry guidelines would suggest a distance from the processing unit to property outside of the boundary as 61 m, with further consideration given for toxic and flammable effects. This stand-off distance is applied here to enable initial siting.

## Location of the Salt Caverns

The locational selection for the salt caverns becomes relatively straight forward based on the geology of the east coast. The geological storage of hydrogen in the region is feasible as discussed previously. Hydrogen storage already occurs in Teesside at the Seal Sands salt field that is an extension of a wider salt layer that reaches far to the south and eventually is utilised by the Hornsea/Attwick and Aldborough gas storage facilities.

In addition hydrocarbon exploration is common south of the Humber with a depleted field at Saltfleeby and Hatfield Moor already proposed or in use for natural gas storage. Offshore the Rough hydrocarbon field is also converted to natural gas storage and is the UK's largest. Whilst the hydrocarbon facilities are still producing they are mature and can be expected to cease production in the near future. As discussed earlier, there are additional considerations when utilising former hydrocarbon stores for hydrogen so they have not been used in this initial study but could be considered as part of a detailed design or even as part of an expanding hydrogen network over time.

The chemical complex on North Tees already hosts hydrogen storage in brine supported salt caverns at around 400 m depth up to a mass stored of 1,000 tonnes. Assuming the implementation of the CCS network, and the ability to supply natural gas through the NTS feeder the area would be ideal, with only a single hydrogen pipeline leaving the area.

High pressure storage for large volumes, however, would still need to be supplied in East Riding. The available caverns on Teesside are not high pressure and so capacity limited to meet the inter-seasonal requirements.



As a result, the two intraday caverns have been located at Teesside providing the ability to take advantage of part of the existing caverns. The inter-seasonal storage could be based at Aldborough near Hull as this already has a planned 'phase two' in place and represents the most viable option for the purposes of this study.

### 2.6.2. Summary of Locational Analysis

The facilities configuration taken forward for costing was therefore as listed below:

- SMRs at a site in the Seal Sands and surrounding area at Teesside.
- Intraday storage in the Seal Sands area.
- Inter-seasonal storage in the East Riding near the coast.
- Interconnecting pipelines (see [Section 6, The Hydrogen Transmission System](#)) between Leeds, Teesside and Hull.



## 2.7. Demand vs. Supply Conclusions

The demand profile for the conversion area has been robustly calculated using a combination of NGN and MSOA data from the Office of National Statistics. This results in an average hourly demand requirement of 732 MW. (6.4 TWh for the year).

The supply to meet these requirements has been designed based on a train of four steam methane reformers with a combined output of 1,025 MW meeting a design of 140% capacity allowing for optimised storage size, operational flexibility, security of supply and maintenance requirements.

The intraday and inter-seasonal variations in demand will be managed through two 240,000 m<sup>3</sup> storage caverns and seven 400,000 m<sup>3</sup> storage caverns.

The hydrogen production facility will be located at Teesside along with the intraday storage cavern. The inter-seasonal caverns will be located at Hull.

Whilst all these assumptions would be subject to a detailed design the project team feel they are all realistic and more important technically and politically viable. In addition, they also represent a 'worst case' option for pricing as they are geographically at the extremities of the required hydrogen pipeline network (see [Section 6, The Hydrogen Transmission System](#)).

### 2.7.1. Costs

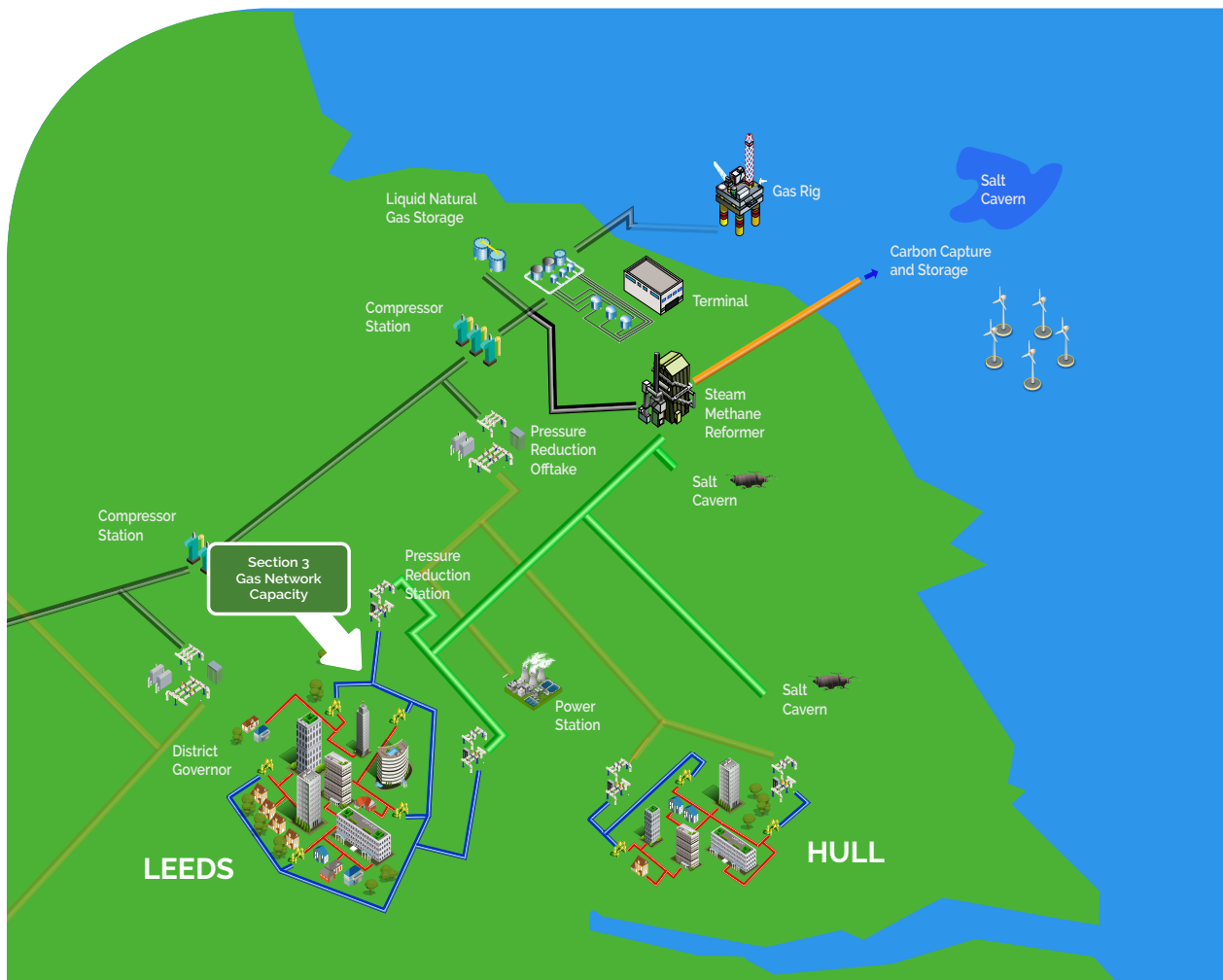
The following costs for SMR+CCS reflect the full cost of the system described above, based on existing facilities costs and high level operating costs, including energy used to run the hydrogen production system. These require further development of the designs to reduce the normal uncertainty of costs at this stage.

Cost Summary	CAPEX Cost Incurred (£m)	OPEX Cost Year One (£m)
Steam Methane Reformer Costs	395	
Inter-seasonal Salt Caverns	289	
Intra-day Storage	77	
Carbon Capture and Storage		60
SMR/Salt Cavern Management		31
Additional Energy Used for Hydrogen Production and Carbon Capture		48
<b>Total</b>	<b>761</b>	<b>139</b>

Table 2.7. *Hydrogen Production System Cost Summary*

## SECTION 3

# Gas Network Capacity



## 3. Gas Network Capacity

### The History

As explained in **Section 2, Demand vs. Supply**, the gas industry manages its MP networks such that they can maintain supply to customers during 1 in 20 peak hour demand conditions ensuring the security of supply during extreme weather. This is done using computer modelling software which is validated against data obtained by physical apparatus in the field. For clarity a 'one in twenty years, peak hour' event indicates the maximum hourly demand that occurs (theoretically) on the network once every 20 years. A general misconception is that this event occurs during the coldest period in a twenty year time frame. However, it is a point in time where not only is it cold but events also conspire to produce the biggest draw on the network. For example, if the coldest day in 20 years was on Christmas Day this might not generate a peak hour demand. This is because large numbers of consumers, such as industrial and commercial customers, have a low demand as a result of Christmas shut down periods.

The modelling used by NGN for analysing the below seven bar network, which is where the vast majority of customers are located, has evolved over the years and NGN now uses the Synergi modelling software for managing and forecasting gas distribution network demands. All UK gas networks use modelling to design and carry out reinforcements, replacements and maintenance to ensure they meet their licence obligation for the security of supply to gas customers. The H21 Project has used Synergi for the analysis of the hydrogen gas network and as such there is a high level of confidence in the results.

This section will explain how Northern Gas Networks (NGN) has assessed its existing gas network capacity in the area of conversion – specifically, analysing if this network, once converted to hydrogen, can still meet the existing 1 in 20 peak hour demand design requirement. Simplistically are the pipes that are currently in the ground in the area of conversion large enough to transfer the same energy demand when using hydrogen as they currently do for natural gas?

## 3.1. The Gas Industry Below Seven Bar Planning Software

A key element to understanding the feasibility of converting the existing gas network to 100% hydrogen was determining if the existing gas distribution network has adequate capacity, when transporting hydrogen, to meet the same design parameters, i.e. 1 in 20 hour peak demand.

NGN manages the below 7 bar natural gas network using a network modelling software package called Synergi. This is used to model demand and flow data for natural gas (predominantly methane) as this is the current gas flowing in the networks pipes.

This software package is used to design reinforcement and replacement projects. Reinforcement involves increasing network capacity to an area which is forecasted to have pressure constraints due to, for example, demand growth and is usually achieved by laying additional mains or connecting additional sources of gas. Replacement modelling is used, for example, to design the projects for the large package of work currently in progress to replace 8 inch and below iron mains. It is also used for quotations for new load requests on a five-year forecasting horizon. Synergi models are validated as part of a regular cycle by cross-referencing the information in Synergi (modelled pressures/flows) with data obtained from loggers at both sources and extremity points on the network and demand data obtained from metering/billing via Xoserve.

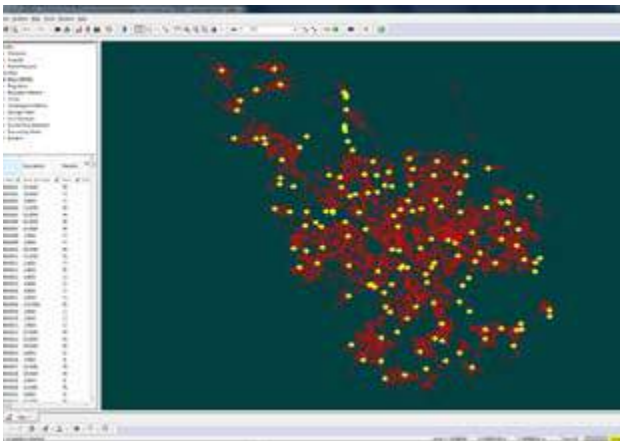


Image 3.1. Screenshot Synergi



Image 3.2. Network Data Logger

To put the information held by of this design software into context, Synergi models are populated with every below 7 bar gas main including diameter and material as well as associated pressure reduction equipment in the network. This amounts to circa 37,000 km of gas mains and 2,355 district governors for NGN alone.

For the H21 Leeds City Gas project **Image 3.3** shows the area considered and the extent of the gas distribution network. This is from the NGN record system for gas mains.

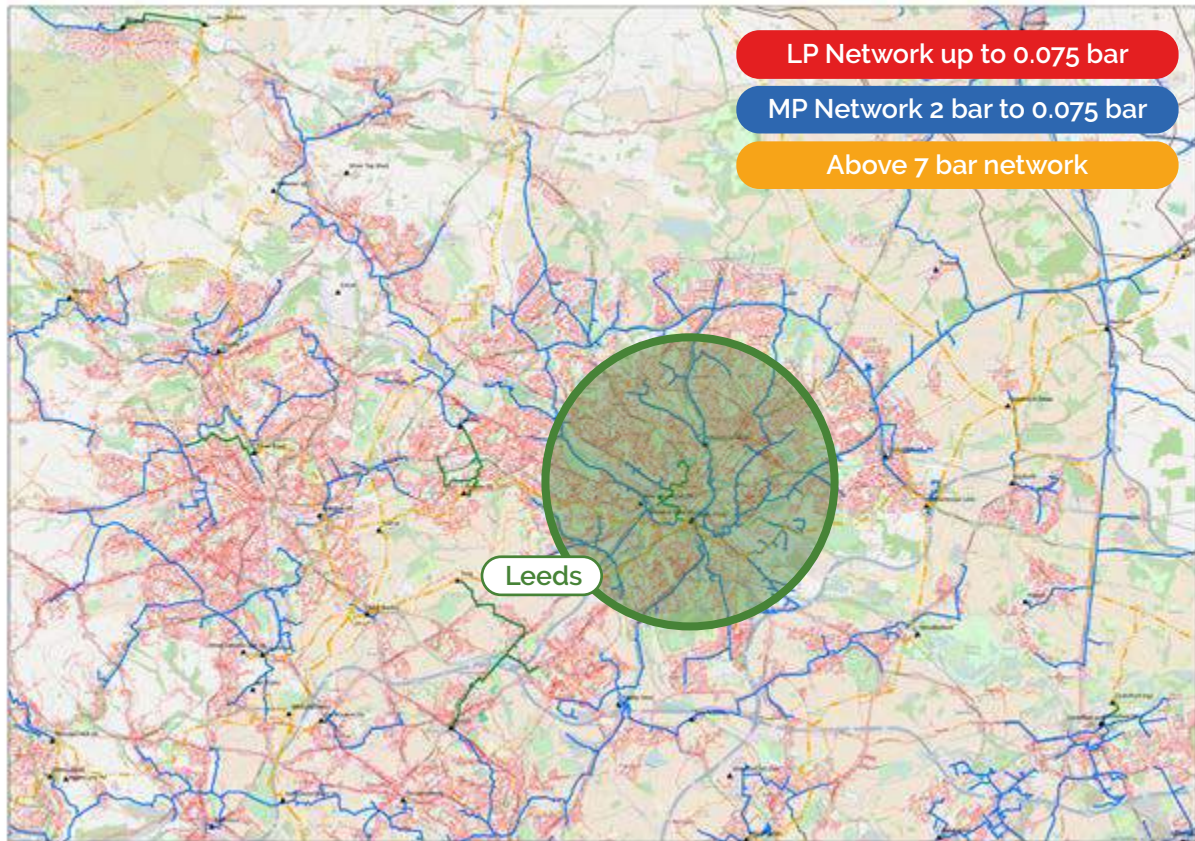


Image 3.3. *Map of Leeds*

## 3.2. The Steps for Analysis

### Step One: Defining the Isolation Area

To undertake the Synergi modelling the first task was to determine the area which could practically be isolated from the existing natural gas network for conversion to hydrogen. This is particularly challenging as adjacent areas often have inter-dependencies for gas supply between them, i.e. one area 'feeds' another area gas. The area of isolation needed to be defined such that any 'disconnected' mains, i.e. gas mains that flow between areas, do not create a problem for natural gas supplies in the area not converted to hydrogen.

As a result of this complexity a larger isolation area than that defined in the original concept for H21 Leeds City Gate was selected. This allowed a much more efficient and practical design. The finalised area for analysis and isolation rose from the original area of approximately 190,000 meter points to 264,000 meter points covering a population of approximately 660,000 people. The area now included the City of Leeds and some of its suburbs, Swillington to Morley to the south of Leeds and Pudsey to Otley/Burley in Wharfedale to the north-west of Leeds.

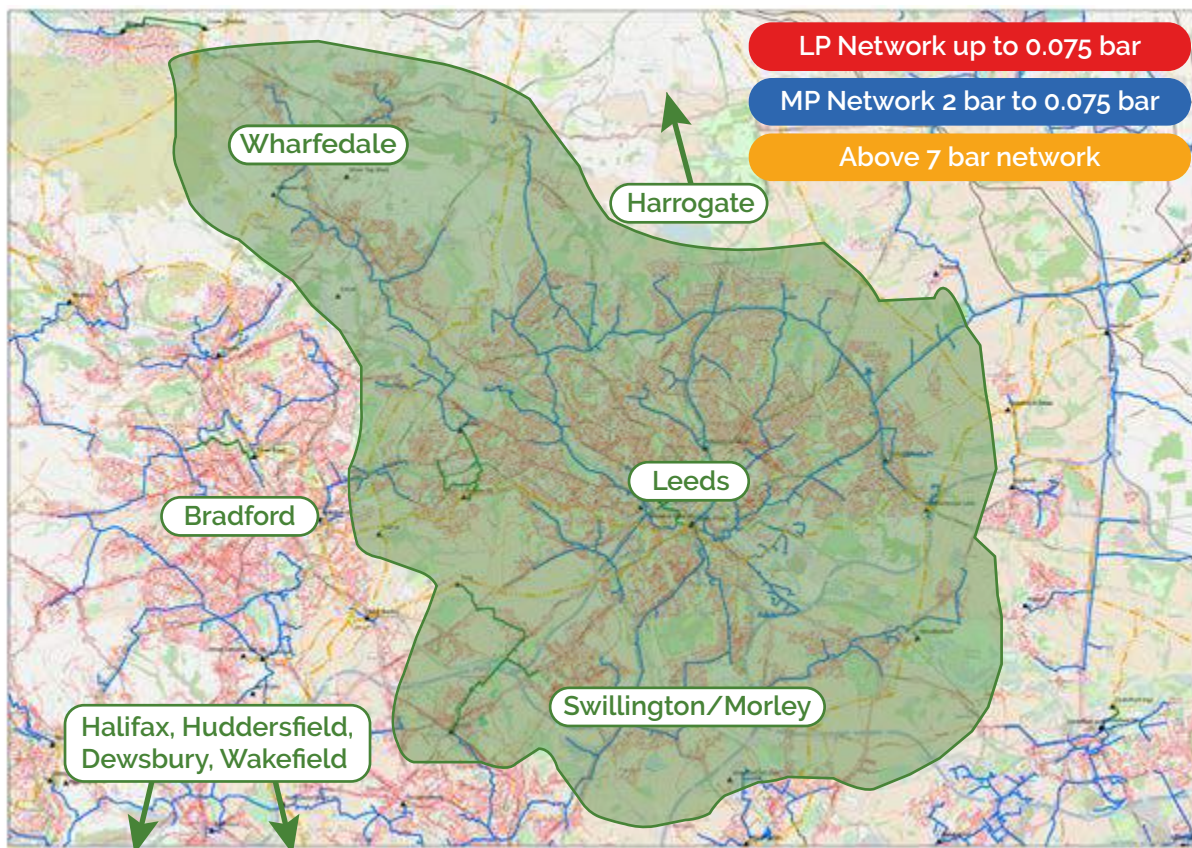


Image 3.4. *Map of Area of Conversion*

## Step Two: Changing the Synergi Model Parameters

Once the isolation area had been identified the Synergi model, currently configured to model based on natural gas parameters, needed to be amended to hydrogen. This is necessary as the physical properties relevant to modelling a gas network utilising hydrogen differ significantly from those used to model natural gas. The following parameters were changed in the Synergi model summarised in **Table 3.1** and evidenced in the model screen shots below.

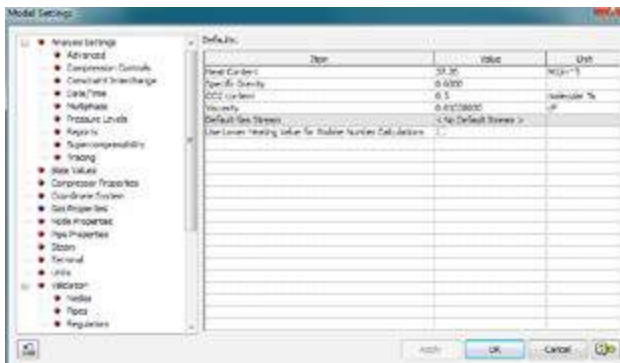


Image 3.5. Synergi Model Natural Gas Parameters

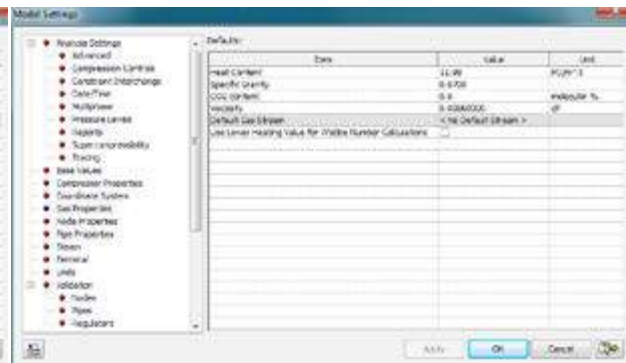


Image 3.6. Synergi Model Hydrogen Parameters

	Natural Gas	Hydrogen
Heat content (MJ/m <sup>3</sup> )	37.26	11.98
Specific gravity	0.60	0.07
Viscosity (cP)	0.01038	0.0086

Table 3.1. Properties of Natural Gas and Hydrogen

A key consideration for the H21 Project team was the accuracy of the Synergi model when modelling for hydrogen. To validate the accuracy and ensure NGN retained a high level of confidence in the results two checks were undertaken:

1. A test model was configured in Synergi using the above process and the results were then compared and validated by tests results produced by the Synergi software owners DNVGL.
2. Sample pipe/load combinations were set up and run using Synergi configured to hydrogen and the results compared with those obtained using a Mears Wheel.

A Mears Wheel was the historical 'long hand' method the UK gas industry used for pipe sizing design before being superseded by modern analysis software. It can still be considered suitable for single pipe modelling.

The results of these checks gave the H21 Leeds City Gate project team a high level of confidence that the Synergi modelling of hydrogen was accurate.



### Step Three: Modelling the medium (blue) and low (red) pressure networks for hydrogen

Once the Synergi model was validated for accuracy in converting from natural gas to hydrogen the next step was to produce medium and low pressure Synergi models for the area of conversion.

When considering the gas distribution system one has to consider where the 'injections points' into the relevant pressure system are in relation to demand. If we first consider the gas industry pressure tiers simplistically, each pressure tier is supplied by the pressure tier above.

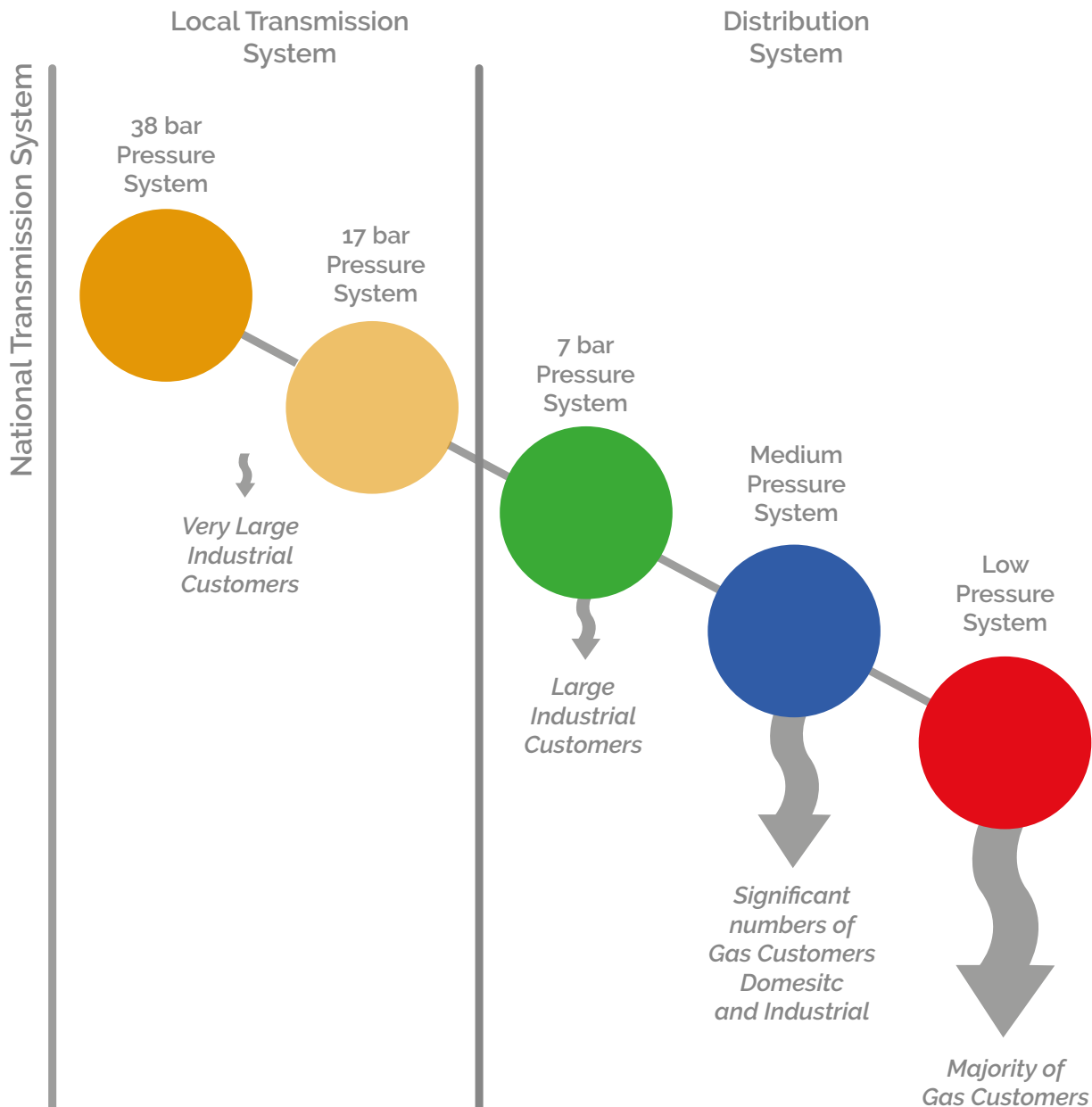


Image 3.7. Pressure Tier Cascade

In reality this is a complex web of gas mains and pressures when considering a city. The gas system does not operate as a single point for cascade as it has to manage varying supply and demand characteristics across the city and its associated suburbs. If we consider the Leeds system, the medium pressure is shown in blue, supplied at multiple points from the above 7 bar systems via Pressure Reduction Stations (PRSs). These 'injection points', have been identified with blue circles on the map.

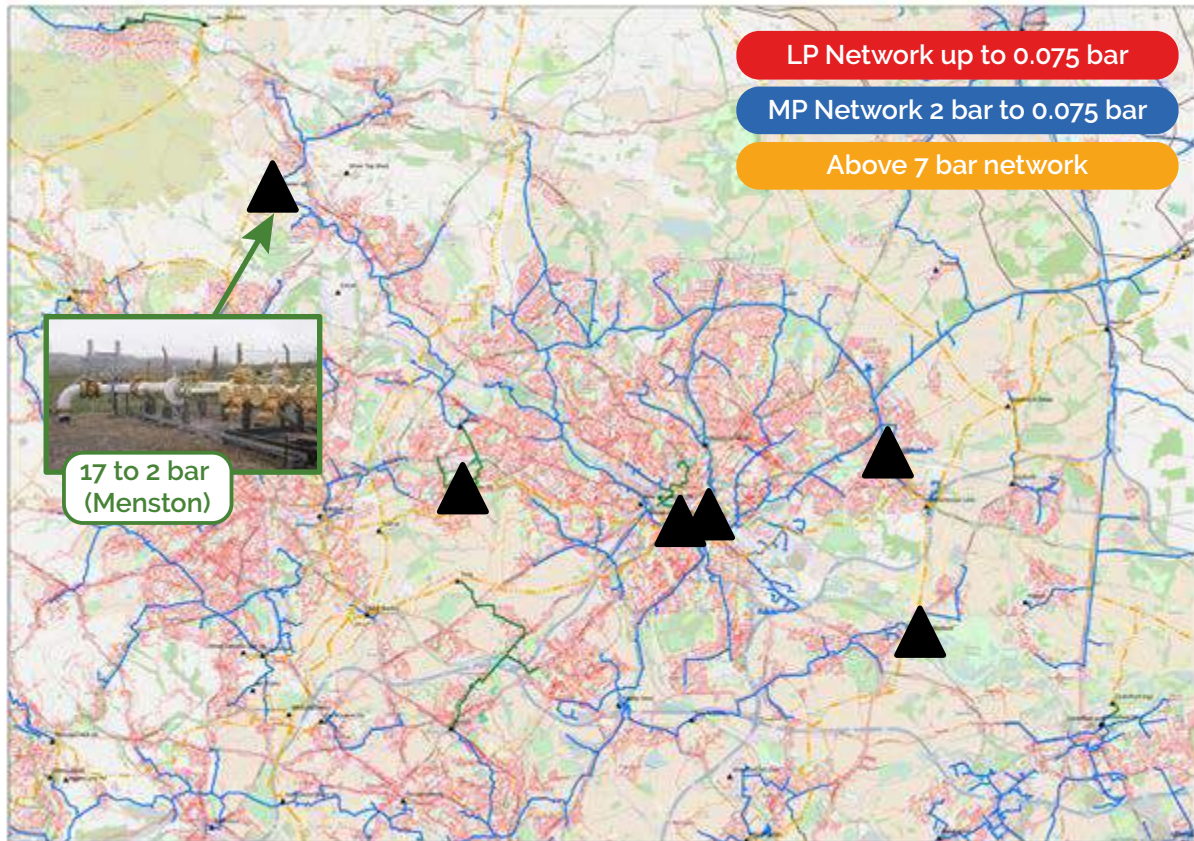


Image 3.8. *Map of Leeds Gas Network Indicating PRS Locations*

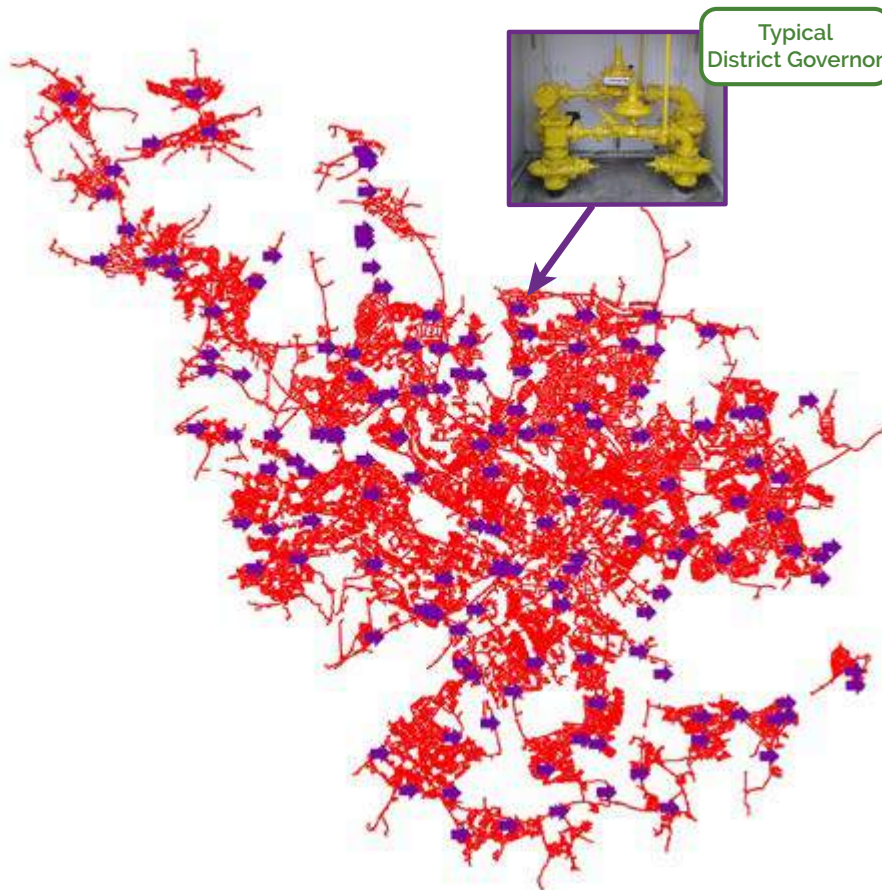
It is important to note that the above 7 bar (LTS) pipelines often do not terminate at these points, they continue to supply other points of the medium pressure system across the Gas Distribution Network (GDN) area.

In a similar manner the Low Pressure (LP) system (red), is supplied by the Medium Pressure (MP) system via district governors, known as Pressure Reduction Units (PRUs) located extensively across the city. The LP system is designed to meet a 1 in 20 peak 6 minute demand but offers no storage capability and therefore it needs many injection points to ensure supply can be maintained.

By way of analogy the network can be thought of as a large swimming pool which contains just one inch depth of water. If this swimming pool has a gigantic plug at the bottom of the pool, which is subsequently removed, a single hosepipe would not be able to maintain the water level in the pool.

Similarly in the gas industry as the 'plug' comes out of the LP system (domestic users turning on heating for example) multiple district governors (hosepipes) are required from the MP system to maintain pressure and therefore supply.

In the area of isolation there are currently circa 120 district governors maintaining supply to the LP system as shown with the purple arrows in **Image 3.9**.



**Image 3.9. Map of Leeds Gas Network District Governor Locations**

To produce the MP and LP models for analysis new hydrogen injection points were incorporated into the MP system. In some instances these would be via the existing PRU locations, while in others they would be new PRU locations taken directly from the High Pressure (HP) hydrogen transmission pipeline coming from Teesside.

Following these steps the Synergi LP and MP models could now be 'run' for hydrogen on the existing gas network for the area of isolation. These models were based on the FY5 (forecasting demand on a five-year horizon) natural gas models used by Northern Gas Networks. The results of this analysis are detailed below and show, for the gas network in the area of conversion (including pipes and pressure reduction equipment), that the MP and LP networks could supply the volume of hydrogen necessary to meet the energy requirement for a 1 in 20 peak hour/peak 6 minute demand with relatively 'minor' additional infrastructure.

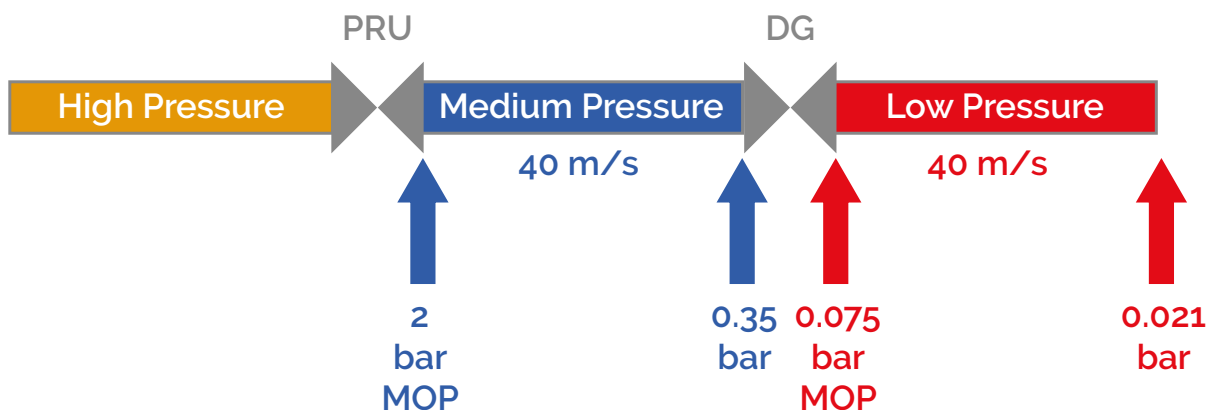
## The Results

The key results from the Synergi model are pressure and velocities of the gas in the mains. The design parameters used by Northern Gas Networks on the distribution network are defined in standard NGN/PL/NP18 Policy for Network Planning (similar policies are in use by the wider UK gas industry). For the MP and LP systems the current pressure and velocity parameters are shown in **Table 3.2**.

System	Maximum Operating Pressure (MOP)	Minimum Operating Pressure	Current Maximum Velocity
Medium Pressure	2 bar	0.35 bar*	40 m/s
Low Pressure	0.075 bar	0.021 bar	40 m/s

*Table 3.2. Current UK Gas Network LP and MP Design Parameters*

\*Minimum pressure is the statutory pressure which the network should not drop below under a 1 in 20 winter scenario. However, typically 500 mbar is the recommended minimum to allow for service design and load growth.



*Image 3.10. Existing Design Parameters for UK Distribution Networks*

The results that follow are all based around maintaining these parameters for a 1 in 20 peak demand.

### 3.3. Natural Gas to Hydrogen Conversion on the MP (blue) Network

#### Pressures:

The Synergi results for the MP network within the area of conversion indicate that pressures on the MP network running as hydrogen largely remain above the recommended minimum of 500 mbar. Results from Synergi are presented in a 'nodal' format, i.e. points on each pipe in the model are shown and colour coded to indicate the pressure range they fall within for a 1 in 20 peak hour demand.

Image 3.9 and 3.10 below represent the results of the Synergi analysis for the Leeds MP system when modelled using natural gas (the Synergi model used in the network today) compared to the results of the analysis when modelled using the five-year forecast energy demand data with a hydrogen gas network.

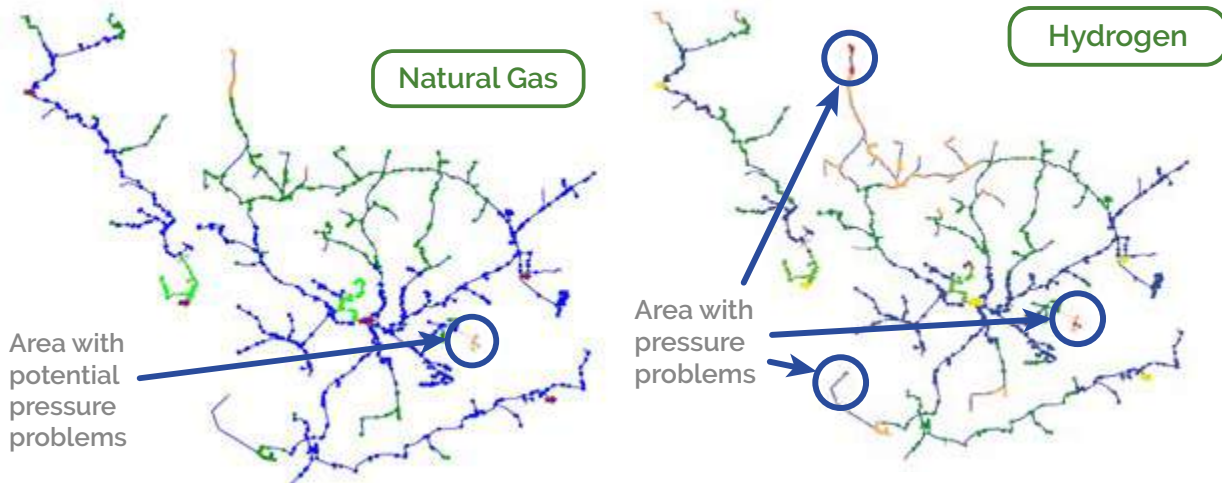


Image 3.11. *Synergi Analysis MP Network (Pressures) – Natural Gas*

Image 3.12. *Synergi Analysis MP Network (Pressures) – Hydrogen*

A red node indicates an area which would drop below the 500 mbar design recommendation under a 1 in 20 winter conditions scenario. In the network operating on natural gas there is one node modelling below 500 mbar. For the same network operating on hydrogen there are 21 nodes below 500 mbar.

The model outputs in these images are based on the injection points (PRs) configured as they are at present. With minor amendments to these input locations (which may be required for strategic reasons) only 11 nodes below 500 mbar remain within the MP network. To reinforce the MP to remove this pressure constraint would require approximately 1 km of mains reinforcement.

The difference between hydrogen with the current injection points and hydrogen with amended injection points is shown in **Image 3.13** and **Image 3.14**.

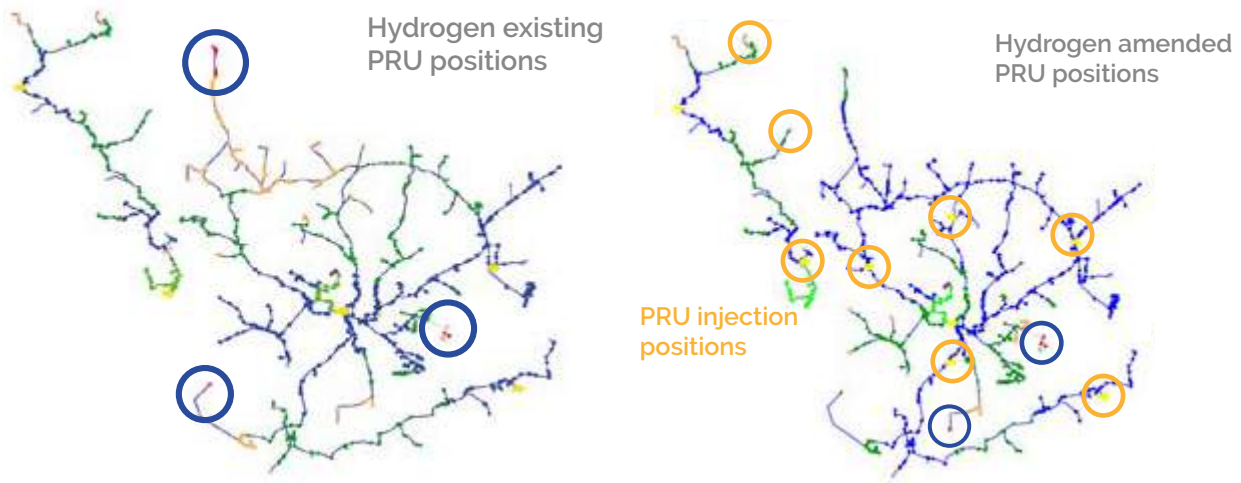


Image 3.13. *Synergi Analysis MP Network (Pressures) – Hydrogen with Existing PRU Positions*

Image 3.14. *Synergi Analysis MP Network (Pressures) – Hydrogen with Amended PRU Positions*

The costs associated with these amended PRU positions have been incorporated into **Section 6, The Hydrogen Transmission System**.

***In conclusion there are no significant pressure problems associated with converting the medium pressure system to hydrogen***



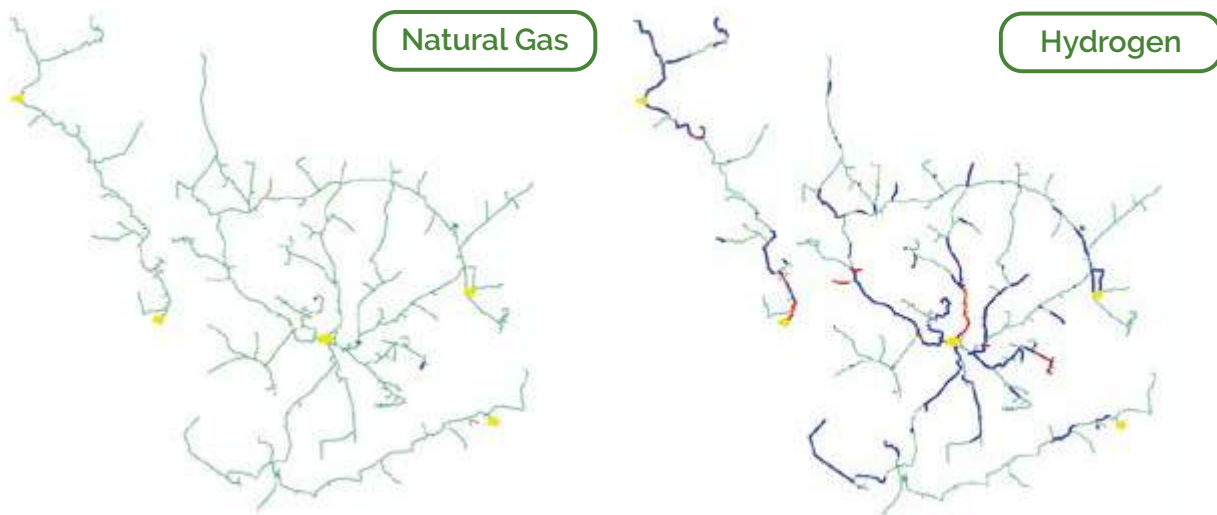
## Velocities

The Synergi results for the MP network within the area of conversion indicate that there are some velocities concerns on the MP network when converted to hydrogen.

**Image 3.15** and **3.16** represent the velocity results of the Synergi analysis for the Leeds MP system when modelled using natural gas compared to the results of the analysis when modelled as a hydrogen gas network.

It is important to understand why the gas industry has historically capped velocity in the distribution system. Velocities in the gas network have been capped for two reasons:

1. To reduce pressure loss, i.e. maintain extremity pressures; and
2. To prevent the gas picking up significant amounts of dust in the old metallic network which could lead to erosion of pipes and damage or malfunctions in infrastructures such as meters or pressure reduction equipment.

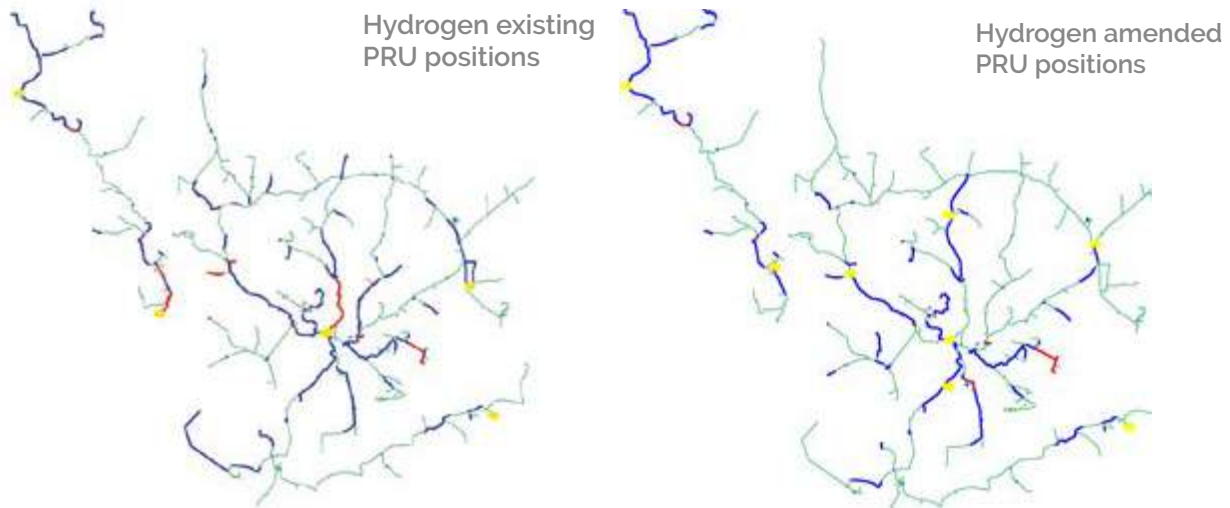


**Image 3.15. Synergi Analysis MP Network (Velocities) – Natural Gas**

**Image 3.16. Synergi Analysis MP Network (Velocities) – Hydrogen**

In the images green represents velocities below 40 m/s, blue represents velocities between 40 and 80 m/s and red represents velocities above 80 m/s under 1 in 20 peak hour demand conditions.

As in the pressure modelling scenario the model outputs in these images are based on the injection points (PRUs) configured as they are at present. When considering the new injection points to the MP system the velocity concerns significantly decrease. This can be seen in **Image 3.17** and **Image 3.18**.



**Image 3.17. Synergi Analysis MP Network (Velocities) – Hydrogen with Existing PRU Positions**

**Image 3.18. Synergi Analysis MP Network (Velocities) – Hydrogen with Amended PRU Positions**

It is important to understand that all the modelling presented is based on the worst case scenario, i.e. 1 in 20 peak hour demand design parameters. These worst case scenarios may only occur theoretically once every 20 years and it is important to put into context what the velocities in the system are for the vast majority of the time.



Table 3.3 represents the velocities in the system for a range of winter demand scenarios (100% being a 1 in 20 winter peak hour demand). It is also important to remember that peaks in demand are also not continuous throughout a winter but may happen for a short 'time snap' of two or three days over the entire winter period. In a 'typical' winter (based on an average of the last six winters in the network) demands more than 90% of a 1 in 20 peak hour demand are not common.

Velocity	DEMAND LEVEL (% OF PEAK)						
	100%	95%	90%	85%	80%	75%	70%
Length (m) > 40 m/s	52,087	42,155	37,326	32,966	26,999	20,758	14,407
Length (m) > 60 m/s	16,418	12,726	9,852	7,177	3,808	1,111	510
Length (m) > 80 m/s	3,101	1,926	546	506	506	354	254
Length (%) > 40 m/s	21.77%	17.62%	15.60%	13.78%	11.29%	8.68%	6.02%
Length (%) > 60 m/s	6.86%	5.32%	4.12%	3.00%	1.59%	0.46%	0.21%
Length (%) > 80 m/s	1.30%	0.81%	0.23%	0.21%	0.21%	0.15%	0.11%

Table 3.3. Pipe Velocities by Percentage Peak Demand Level

This is represented graphically in Chart 3.1.

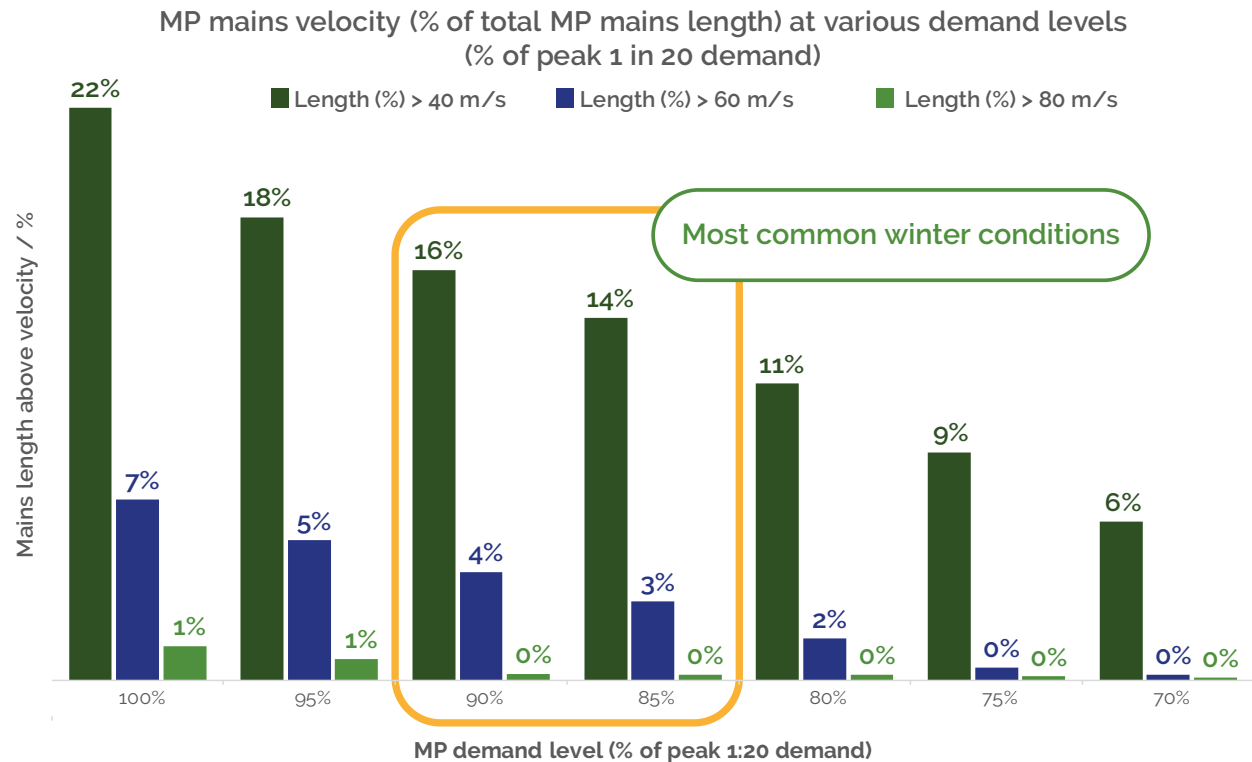


Chart 3.1. MP Mains Velocity (% of Total MP Mains Length) At Various Demand Levels (% of Peak 1 in 20 Demand)

From **Table 3.3** and **Chart 3.1** it is clear that the vast majority of the MP network has no velocity problems and there are limited areas which operate above 60 m/s or 80 m/s. These would all be easily rectified through strategic reinforcements, or it may even be considered reasonable for the short periods of time that these velocities occur.

It has already been established that the pressure drop when converting the existing gas grid to hydrogen does not pose a significant problem in the medium pressure system. Additionally as the metallic pipes in the distribution system are being replaced by PE, dust becomes a less significant issue, as it is not produced in a PE system. It is proposed that velocities up to 80 m/s in the MP system may well be considered reasonable and acceptable from an engineering integrity point of view. Providing some additional evidence for this may be beneficial and is identified in **Section 10, H21 Roadmap**, under Work Package 11. The opinion of the H21 project team is this will not be a concern and is an acceptable parameter for the hydrogen gas network.

If progressing on the assumption that 80 m/s should be acceptable in a hydrogen network only 3.1 km of existing MP main would have ongoing velocity problems. This is approximately 1.30% of all mains and would be easily corrected via strategic reinforcement.

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***In conclusion there are no significant velocity problems associated with converting the MP system to hydrogen***

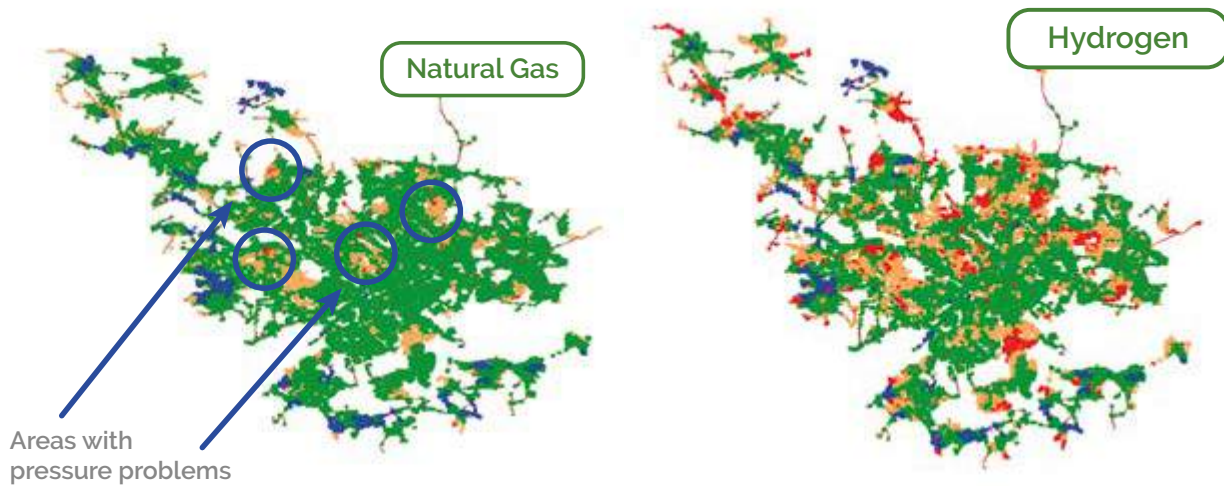


## 3.4. Natural Gas to Hydrogen Conversion on the LP (red) Network

### Pressures

The Synergi results for the LP network within the area of conversion indicate that there are several areas where pressures on the existing LP network could cause concern. These areas would fall below the 0.021 bar standard for a 1 in 20 peak 6 minute demand. As with the MP model results, from Synergi are presented in a 'nodal' format.

**Image 3.19** and **Image 3.20** represent the results of the Synergi analysis for the conversion area low pressure system when modelled using natural gas compared to the results of the analysis when modelled using hydrogen.



**Image 3.19. Synergi Analysis LP Network (Pressures) – Natural Gas**

**Image 3.20. Synergi Analysis LP Network (Pressures) – Hydrogen**

There are areas within the area of conversion already showing signs of potential pressure problems under a 1 in 20 6 minute peak demand scenario using natural gas. This becomes more critical when converting to hydrogen. These areas are indicated by amber/red on the maps. Operating on natural gas there are 174 nodes modelled at below the recommended minimum of 0.021 bar. With the network modelled as hydrogen, there are 5,394 nodes with a forecast pressure below 0.021 bar.

However, it is important to understand that the network has some options available to reduce this deficit with minimal impact. District Governors (DG) are currently set well below the maximum operating pressure (0.075 bar) of the LP network. This is because pressure and leakage are directly linked and the GDNs are incentivised to keep leakage to a minimum via OFGEM leakage model. This is a significant driver to reducing DG supply pressures to the lowest practicable values required to supply the network while meeting all regulatory required pressures.

By raising the outlet pressures of all DG by 15% on the hydrogen model, which is still within the maximum operating pressure of the LP system, the number of nodes modelling below 0.021 bar drops to 182.

Additionally, as part of the conversion process (see [Section 4, Gas Network Conversion](#)) there will inevitably be a requirement to install additional new DG as well as new mains to maintain adequate supply as the network is sectorised for isolation and conversion. This addition would likely mean that the global 15% pressure increase would not be required to restore LP pressures.

Under the current LP network configuration there are several areas that would begin to exhibit some pressure problems following a direct conversion to hydrogen. The scale of this problem can only be understood by determining what corrective measures would need to be put in place to eliminate them. Within the gas industry reinforcement schemes are undertaken every year to ensure the network can maintain the security of supply to customers based on ever changing demands. These reinforcements are generally in the form of pipe modifications and/or additional supply points from the MP network. Work has been undertaken to determine the reinforcement requirements associated with 19 of the areas where pressure problems would occur. It is worth walking through some of these designs to allow the reader to understand the corrective actions available.

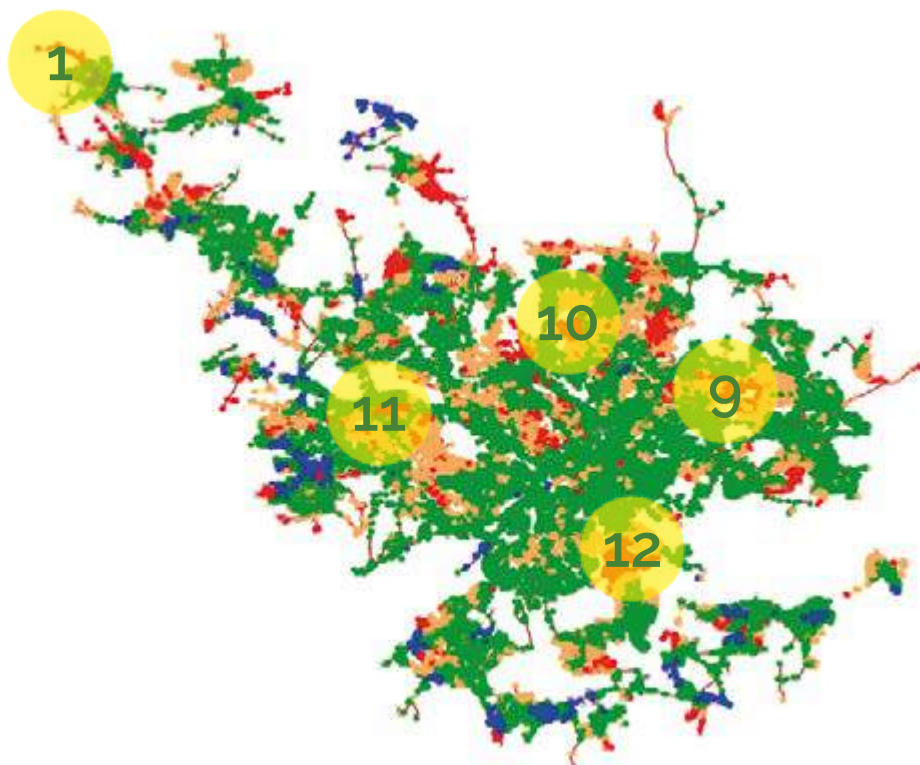


Image 3.21. *Five Detailed Areas of Reinforcement*

The following pages provide detail on the reinforcement schemes required to correct the pressure problem areas identified on the map. For ease of orientation the blue circles on the maps allow the reader to cross reference the satellite map location with the Synergi output for each area. The orange rectangles indicate the area of reinforcement.



### Area 1 Reinforcement Requirements



#### Reinforcement Requirements:

175 m of 125 mm diameter PE low pressure main laid parallel to the existing main.

Estimated Cost:  
£36,017

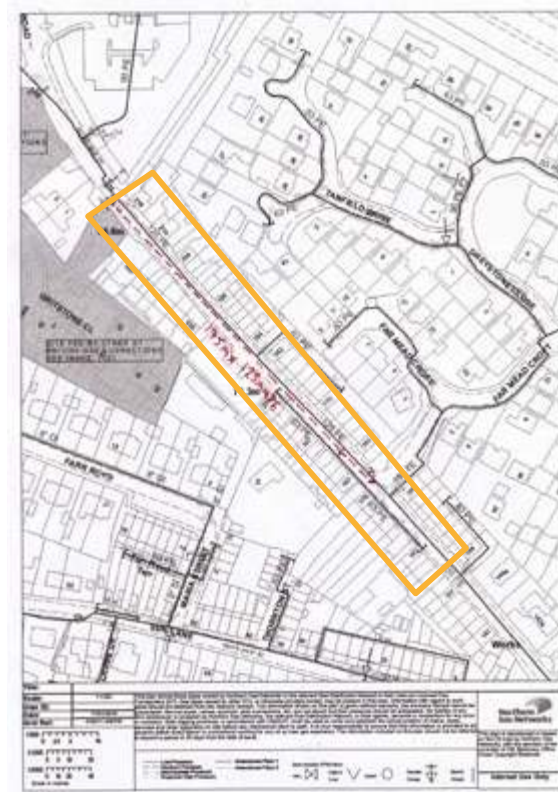
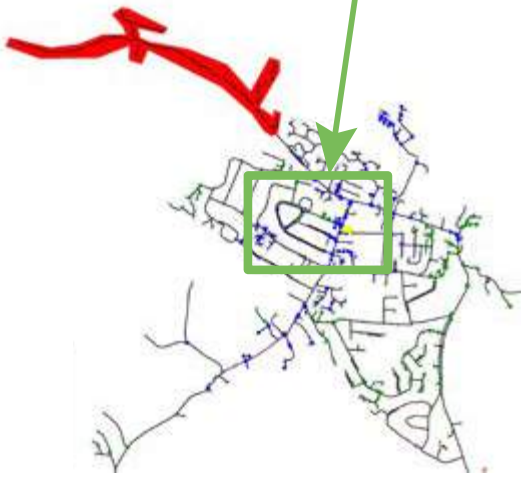


Image 3.22. Area 1 Reinforcement

### Area 9 Reinforcement Requirements



#### Reinforcement Requirements:

New district governor (MP/LP)  
150 m of 125 mm PE MP inlet.

15 m of 250 mm PE LP outlet.

320 m of 180 mm PE LP  
main laid parallel.

Estimated Cost:  
£184,591

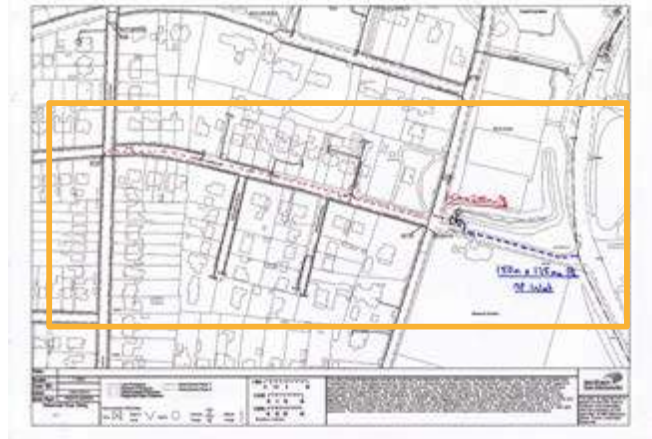
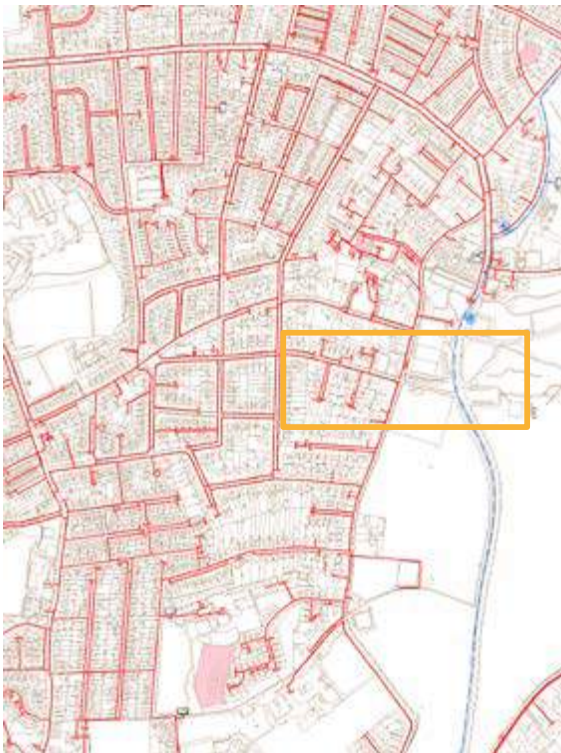
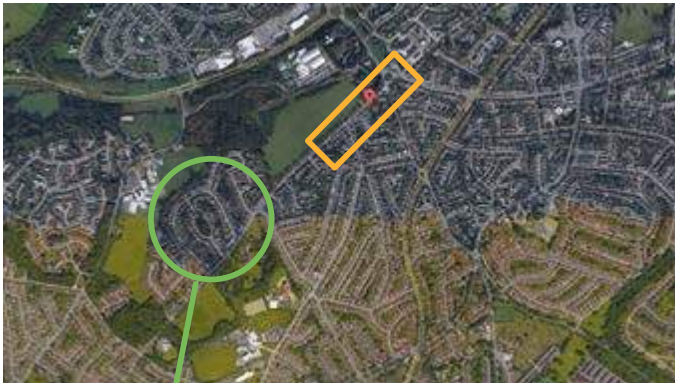


Image 3.23. Area 9 Reinforcement



### Area 10 Reinforcement Requirements



#### Reinforcement Requirements:

330 m of 250 mm PE main laid parallel.

Estimated Cost:  
£123,887

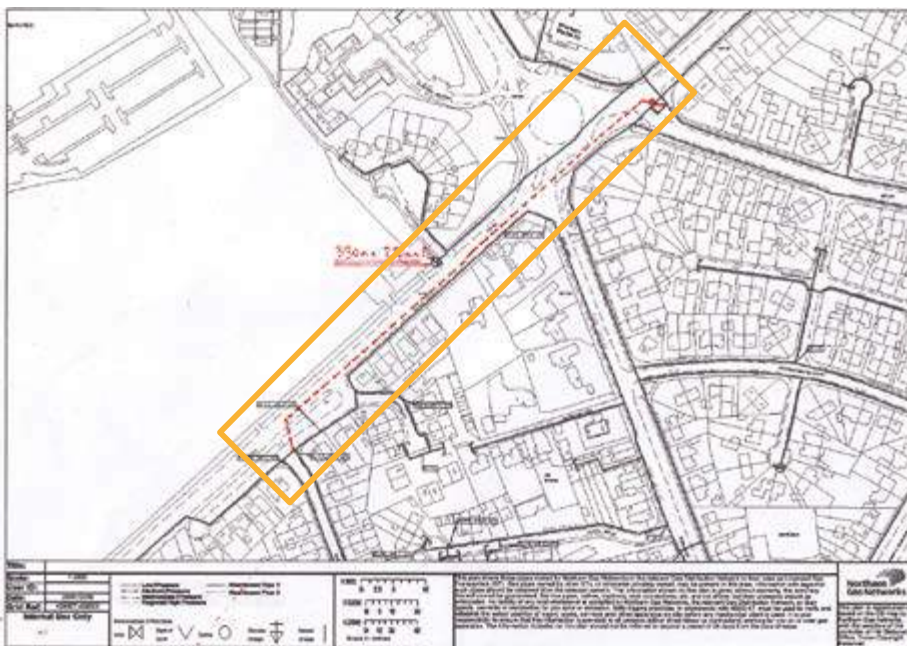


Image 3.24. Area 10 Reinforcement





### Area 11 Reinforcement Requirements



#### Reinforcement Requirements:

89 m of 250 mm PE main cross connection.

20 m of 90 mm PE main cross connection.

Estimated Cost:  
£45,641

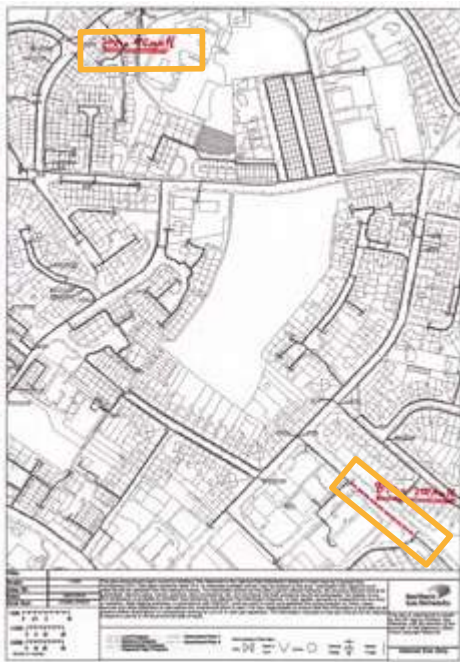


Image 3.25. Area 11 Reinforcement



### Area 12 Reinforcement Requirements



#### Reinforcement Requirements:

New district governor (MP/LP).

30 m of 180 mm PE MP inlet.

10 m of 355 mm PE LP outlet.

#### Estimated Cost:

£72,494

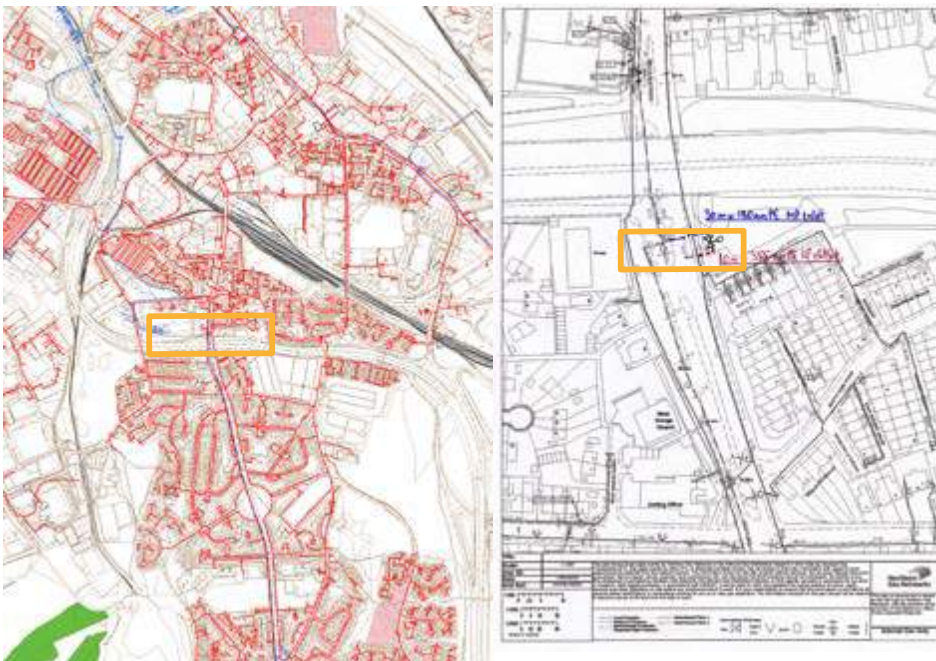


Image 3.26. Area 12 Reinforcement



The total costs of reinforcement (worst case scenario based on a desktop assessment) to correct any enhanced pressure problems when converting the low pressure system to hydrogen are summarised below. Remember that some of these areas could ultimately require these specific reinforcements within the natural gas network as they are beginning to exhibit pressure problems – the hydrogen network simply accelerates these requirements.

Area of LP Reinforcement	Cost
1	£36,017
9	£184,591
10	£123,887
11	£45,641
12	£72,494
<b>Sub Total (A)</b>	<b>£462,630</b>
<b>Average</b>	<b>£92,526</b>
<b>14 remaining reinforcements at £92,526 (B)</b>	<b>£1,295,364</b>
<b>Reinforcements required (A+B)</b>	<b>£1,757,994</b>

**Table 3.4. Reinforcement Costs**

These 19 schemes (A+B) remediate approximately 50% of the nodes below 0.021 bar and therefore if the above costs are scaled by 2.5 this should provide a reasonable indication of the costs for reinforcing the LP network. For simplicity, a total reinforcement estimate of £5 m has been determined for the H21 Leeds City Gate project area of conversion.

**Total LP reinforcements required**  
**£5,000,000**

***In conclusion, it is considered there are no significant pressure problems associated with converting the LP system to hydrogen***

## Velocities

There are no significant velocity issues which arise from modelling the LP network converted to hydrogen. Approximately 0.02% of the total LP mains within the area of conversion are forecast to be above 40 m/s and less than 0.001% above 80 m/s. These lengths are easily removed by reinforcement and might be removed as part of ongoing IMRP.

---

***In conclusion, there are no velocity problems associated with converting the LP system to hydrogen***



## 3.5. Network Capacity Conclusions

There are no significant obstacles regarding network capacity to converting the distribution system, i.e. medium and low pressure, to hydrogen. The network is of sufficient size for the conversion to take place.

The total costs associated with undertaking any remedial measures are estimated to be less than £5m for the LP network.

If there is a national decision to move towards a hydrogen conversion programme, many of these projects could be incorporated into the existing IMRP with minimal cost impact.

The vast majority of the low and medium pressure networks are being replaced as part of the IMRP. However there will be an element of retained iron mains under the current strategy. These are generally above 8 inch in diameter and/or have a zero risk score or will not be replaced under a cost-benefit analysis assessment, (i.e. minimal leakage history). The relative risks of transporting hydrogen, and any associated leakage, through these mains needs to be assessed identifies a requirement to quantify the relative risk of hydrogen in these retained metallic mains against the current risk of natural gas. The quantity of retained mains under the current IMRP within the area of conversion are summarised below

	Leeds LP (kms)	Leeds MP (kms)	Total (kms)
< = 8 inch T1 zero score pipes	5.9	12.9	<b>18.7</b>
< = 8 inch Steel pipes	142.7	15.1	<b>157.8</b>
2 inch Pipes	47.8	0.26	<b>48.0</b>
> 8 to < 18 inch non-mandatory pipes	133.2	72.3	<b>205.5</b>
= > 18 inch non-mandatory pipes	21.8	26.5	<b>48.3</b>
<b>Total</b>	<b>351.3</b>	<b>127.0</b>	<b>478.3</b>

*Table 3.5. Remaining Metallic Mains in the Area of Conversion*

Some points to consider:

- Not all mains are required to be replaced under the current IMRP.
- If the IMRP continues in its current format, around 480 kms of metallic main would remain in Leeds.
- NGN currently replace circa 500 kms of metallic mains per annum so if 480 km of mains were determined to require replacement it is a manageable amount of additional work.
- These remaining metallic mains currently would not generate a replacement project (under the IMRP) and could potentially be used to transport hydrogen (they were used to transport town gas which contains circa 50% hydrogen). Considering the relative density of hydrogen it is likely that the risk due to a leak from a hydrogen main could be lower than that of a natural gas leak. The assessment of risk from a gas leak is predominantly based on the likelihood of the escaping gas 'tracking' (moving through the ground horizontally) into nearby buildings. As hydrogen is less than  $\frac{1}{8}$ <sup>th</sup> the density of methane (the majority component of natural gas) the likelihood of this occurring is greatly reduced. This is a project identified in the **Section 10, H21 Roadmap**.
- A key element of the IMRP is replacing mains in an 'efficient' manner. In reality this means that less than 480 kms of mains would remain at the end of the programme as some of these zero risk scoring mains are often replaced as part of 'efficient projects' or are captured as part of diversions.



## SECTION 4

# Gas Network Conversion



## 4. Gas Network Conversion

### *The History*

*Conversion from one gas to another is not a new concept to the UK. For the first 150 years of the UK (and European) gas industry, gas was manufactured locally in most towns and cities and injected directly into the local distribution system. There were no transmission pipelines and individual gas companies, for example the 'Sunderland Gas Company', were responsible for the gas supply in their area.*

*This manufactured gas is referred to as 'town gas' and, at its peak, was manufactured using 26 million tonnes of coal and half a million tonnes of oil each year. The gas contained up to 50% hydrogen and was distributed around many of the mains that are still used today in the below 7 bar UK distribution system (much of which is currently being upgraded to polyethylene).*

*In August 1959 an Esso/Shell exploration team discovered an enormous natural gas field at Slochterem in the province of Groningen, Holland. This discovery led to the belief that similar gas fields could lie under the North Sea. The British government subsequently granted licences for North Sea oil and gas exploration. In September 1965 British Petroleum struck gas 40 miles off the coast of Grimsby, in what later became known as the West Sole Field.*

*In 1962, following the discovery of the Slochterem gas field, the Gas Council began research into the types of burners which would be suitable for use with this 'new' natural gas. This research was undertaken by Watson House, the Gas Councils centre for research on appliances. In the first half of 1966 a working party was established to study large-scale conversion and the final decision made in the summer of 1966 that the industry would use natural gas. This gas would be supplied directly to customers after their appliances had been modified and was announced to the public on 21st June of that year.*

*The subsequent conversion from town gas to natural gas occurred between 1966 and 1977 and included the conversion of 14 million customers and 40 million appliances, as well as all industrial and commercial customers. The conversion programme was both a technological and logistical outstanding achievement. From initiation in 1966, by 1969 the conversion of over 400,000 domestic dwellings each year was being undertaken, with a peak of over 2.3 million per year in 1971/72.*

*Reference: Charles Elliott's 'The History of Natural Gas Conversion in Great Britain'*



Theoretically, the town of Leeds could be disconnected from the natural gas supply system and, over several months or years, a large team of gas fitters could convert the city to 100% hydrogen. This approach, while technically the easiest solution, is not considered practical and would result in customers being without any form of gas supply for several months or the entire network conversion period. A conversion from one gas to another needs to be designed so as to be incremental, ensuring minimal disruption to the customer.

A more appropriate solution is presented in this section and demonstrates how the city needs to be divided into a series of zones, of perhaps 2,500 homes, where the natural gas can be disconnected and the appliances in this small area replaced or potentially converted. Each zone is then re-commissioned with hydrogen. Dividing the area of conversion into zones is a complex but necessary task. It is expected that any particular house might only be disconnected for one to a maximum of five days, dictated by the size of the conversion workforce.



## 4.1. The Process

Once it had been established that the existing gas network, with minimal reinforcement, was adequately sized to supply the heat demands of a city supplied by hydrogen, see **Section 3, Gas Network Capacity**, the next challenge was to understand what a city scale conversion strategy could involve.

### Zones of Influence

The Synergi modelling software not only allows analysis of pressure and flow but it can be used to determine zones of influence for different 'injection points' on the system, i.e. where Pressure Reduction Stations (PRSs)/District Governors (DGs) supply the medium and low pressure networks respectively. This software is used by the gas industry to model isolations on the network. The results of this modelling are frequently used to underpin the methodology for non-routine operations involving sectional isolations. A typical network isolation requirements may include:

- Isolation of areas of the network to allow replacement of old metallic mains as part of the Iron Mains Replacement Programme (IMRP).
- Reinforcement on the network due to demand growth in specific areas.
- Emergency situations, such as a major gas leak incident.
- Numerous other non-routine operations on the network.

By way of analogy, consider two scenarios where we equate one of the pressure systems (medium or low) to a large swimming pool which is filled with water by 20 water taps (equivalent to PRSs/DGs).

**Scenario One:** All taps are positioned at equal intervals across the pool and each open the same amount allowing the same amount of water to pass through. In this example, each tap would have the same zone of influence.

**Scenario Two:** One tap of the 20 is now fully open, some are shut and the remaining taps are only 10% open. In this instance the tap which is open fully would provide the largest amount of water and the water from this tap would be considered its zone of influence – considerably bigger than its zone of influence in the first scenario.



Examples of zones of influence in the low pressure systems are provided below. These are the zones of influence for the Otley area in the Wharfevalley. In the first picture all the DGs (or taps) are set to the same pressure and they all exhibit approximately the same zone of influence. In the second example the DGs in the green and blue sections are set at a lower pressure than the DG in the red area so therefore, the red area now has a much larger zone of influence. This is illustrated in [Images 4.1 and 4.2](#).

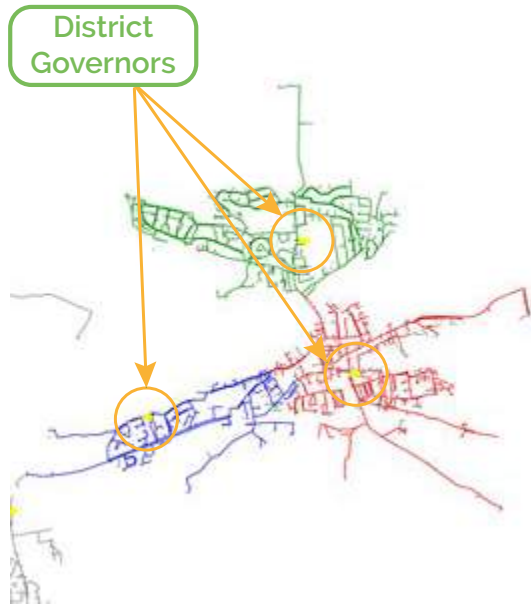


Image 4.1. Otley Zones of Influence Same Pressures



Image 4.2. Otley Zones of Influence Varying Pressures

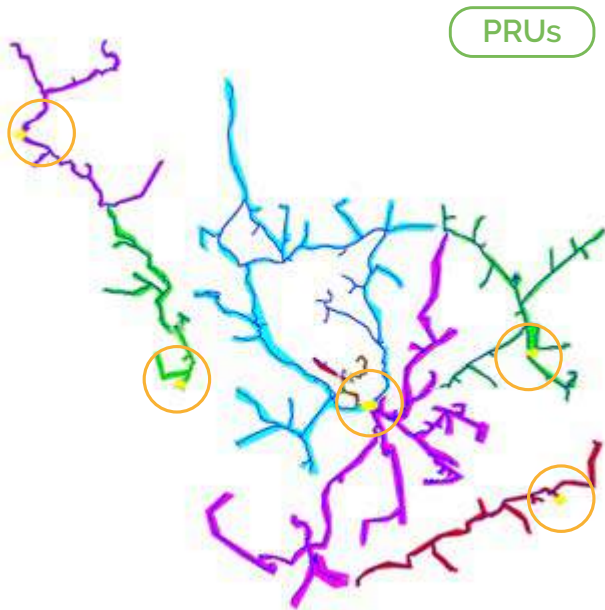


Image 4.3. Area of Conversion: MP Zones of Influence

The medium pressure network is broadly the same and the zones of influences associated with the conversion area are shown in [Image 4.3](#). The different colours represent the different zones of influence from the respective PRUs.

To develop and understand an effective conversion strategy it is important to understand the zones of influence from specific injection points. These are the points that will be closed or isolated from the current natural gas system then reconnected to the new hydrogen system. This means that only the customers in the representative zonal section are converted to hydrogen, which is isolated from the other areas (see [Section 4.1.3](#)) which will still operate on methane.

### 4.1.1. The Principle of Conversion

It is important to understand firstly that zones of influence will dictate the area to be converted. To convert a gas network the existing gas needs to be removed and replaced with the 'new' gas, as was done in the original natural gas conversion. Considering the network pressure, the process for conversion needs to be sequential from high (orange) to medium (blue) to low (red).

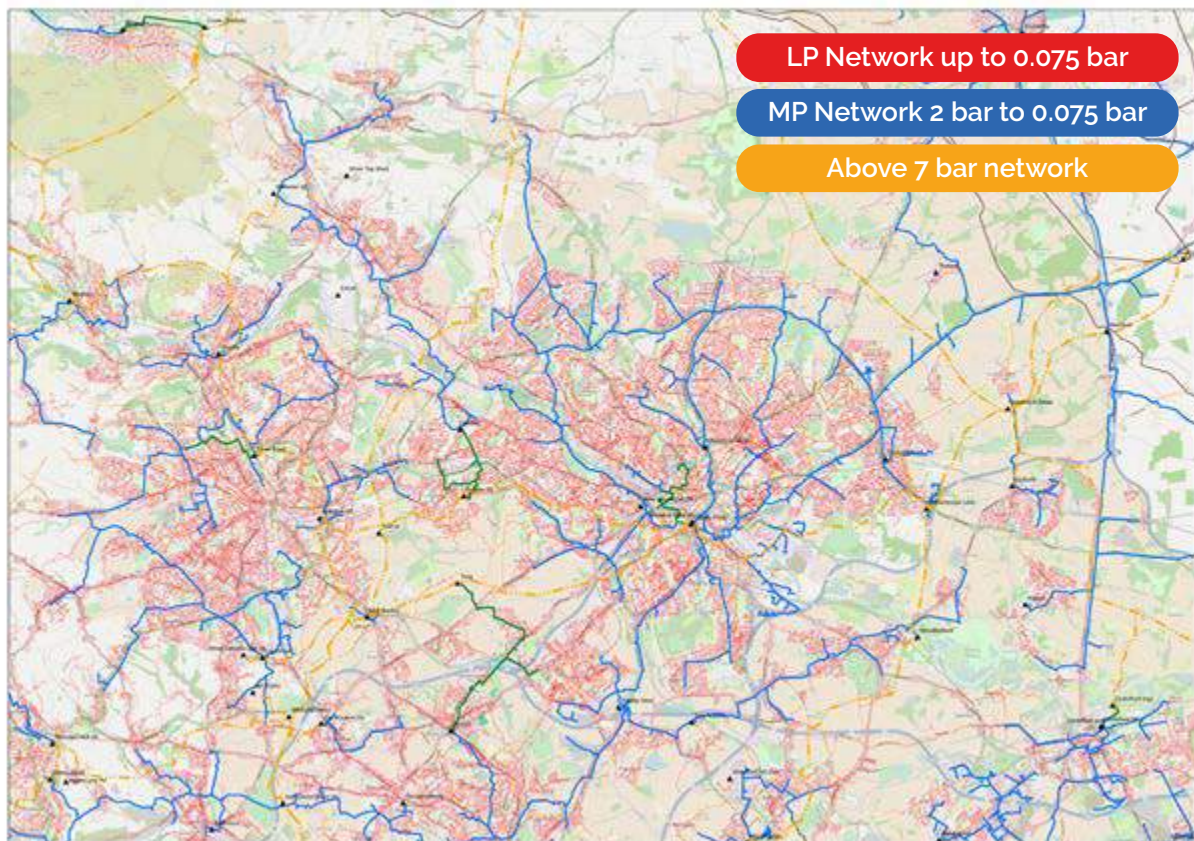


Image 4.4. *Map of Gas Network in the West Yorkshire Area*

For the project, a sample step-by-step conversion assessment has been completed to evidence the process required to allow an effective conversion to take place. This shows that conversion, even in today's integrated gas grid systems, is still achievable in a similar fashion to that undertaken in the original town gas to natural gas conversion. The final conversion strategy for the area of conversion will need thorough detailed analysis coupled with site surveys. This is identified as a key project in the **Section 10, H21 Roadmap**.

### 4.1.2. The Process for Conversion

The step-by-step approach required for network conversion is described in the following section and includes a specific example for the area of conversion.

#### The High Pressure Network

On the network map below the existing high pressure natural gas network has been highlighted in orange and the current PRSs, which are the injection points to the medium pressure system, have been identified with blue circles.

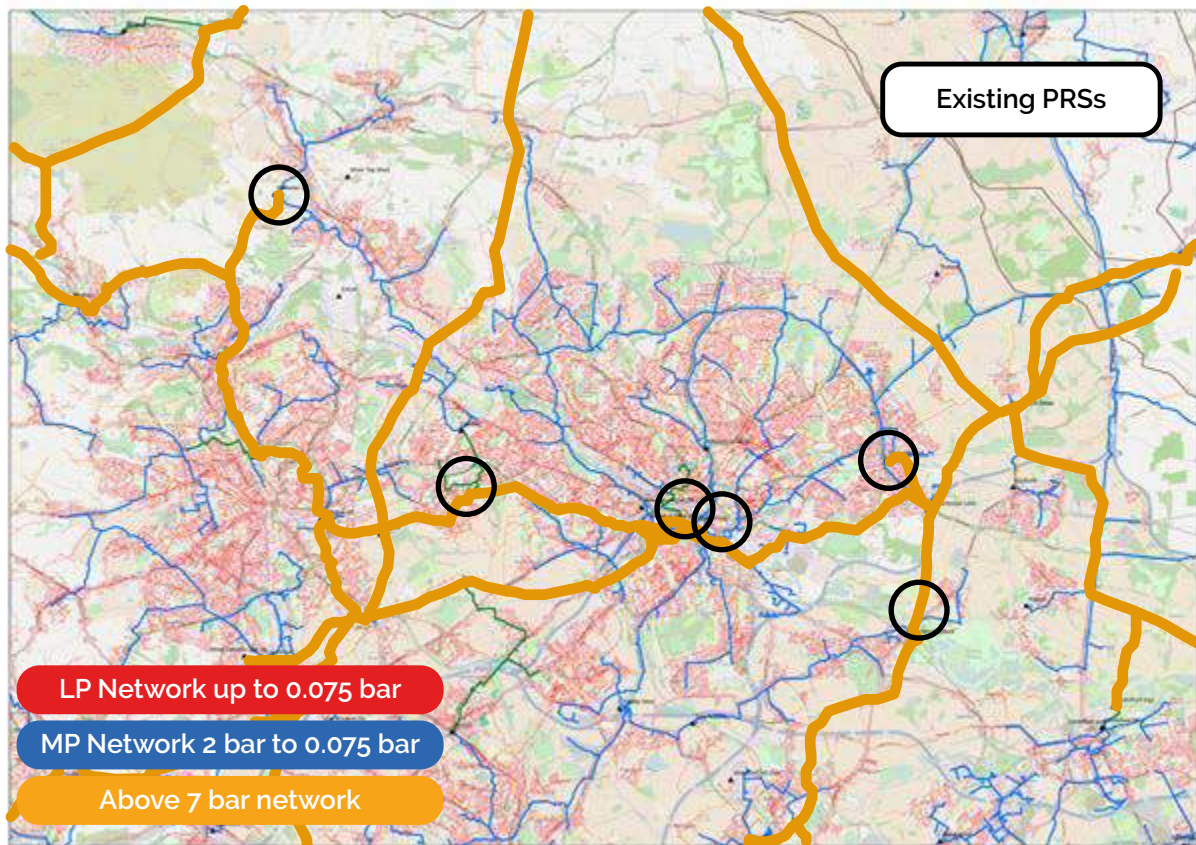


Image 4.5. Map of PRS Injection Points to the Area of Conversion

To convert from natural gas to hydrogen, these injection points need to be sequentially disconnected from the high pressure network (orange) and connected to the new hydrogen pipeline that will be coming from the hydrogen production facility and storage sites at Teesside and Hull. If each of the PRSs was connected at once the entire medium pressure, and subsequently low pressure systems, would need to be converted at the same time as there would be no remaining natural gas supply to the network. This would mean the entire conversion area would be without gas for a considerable amount of time, as the appliance conversion for the entire area of conversion would need to take place at the same time.

In reality, for conversion to take place the hydrogen transmission pipeline from Teesside would be laid in place and commissioned, but would not be physically supplying hydrogen to the network.

This is shown pictorially in the [Image 4.6](#). Existing PRSs are depicted with dark blue circles, the new injections points are green circles and the light blue circles are connection points already scheduled for removal in the 2020s to facilitate the new High Speed 2 railway line.

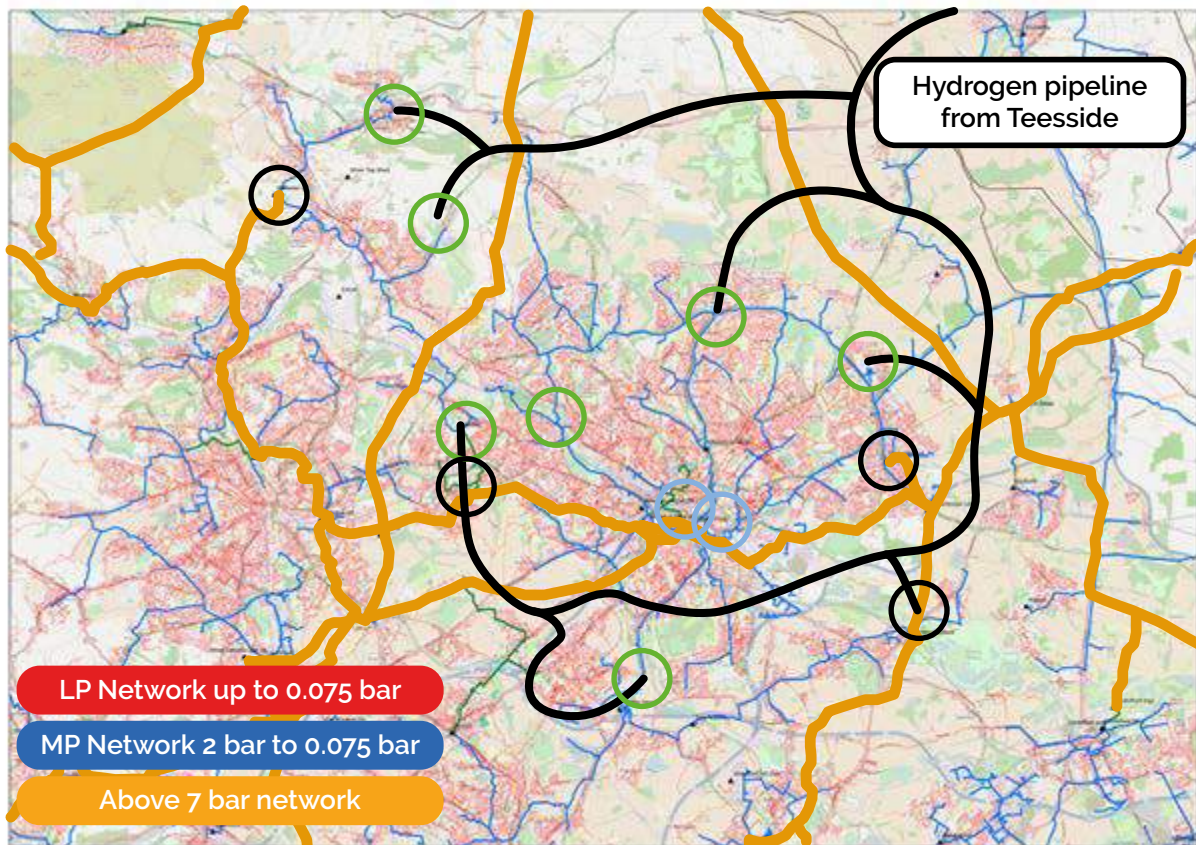


Image 4.6. *Map of Leeds Hydrogen Ring Main and PRSs*

When considering the method of transferring the connection from the high pressure natural gas (orange) network to the new high pressure hydrogen network we must first understand the impact of the medium and low pressure networks. To do this, we need to identify the zones of influence which will allow us to understand the size of the area, and therefore the number of customers, that will need to be converted.

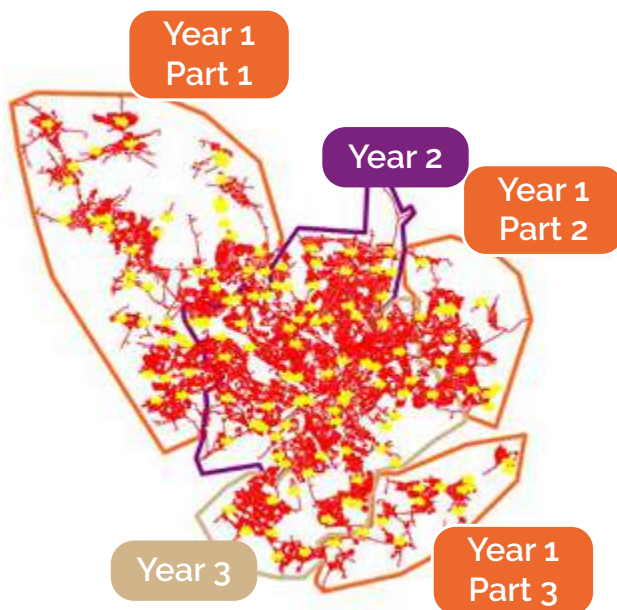
## Medium Pressure (blue) Network

To undertake the conversion analysis the project team made two assumptions.

- This is that conversion will only occur between the months of April and September; and
- Will happen over a period of three years.

This will ensure that heating is not affected (as there is low or no demand for heating during the summer months). These assumptions would be developed further as part of **Section 10, H21 Roadmap** and detailed conversion strategy assessment.

When considering the medium pressure network against a three-year conversion strategy we need to understand what the zone of influence of individual injection points are. **Image 4.7** shows the zones of influence for each injection point have been combined to enable a three-year isolation strategy for the medium pressure network. Each of the isolation years has a comparable number of customers but working in the outlying areas in the first year would allow the conversion team to develop their strategy in these less densely populated and interconnected zones.



Whilst we know these injection points could supply gas to customers within these zones of influence, we also need to be aware that these zones in reality are not physically isolated from each other. If we return to our swimming pool analogy, the water from each tap will actually mix as it fills the pool unless the swimming pool has physical sections built into it to prevent the water from each tap mixing with water from adjacent taps.

Image 4.7. MP Three Year Conversion Strategy

This is common practice in the gas industry, as part of non-routine operations, and is undertaken using a 'double block and bleed' valve configuration (**Image 4.8**).

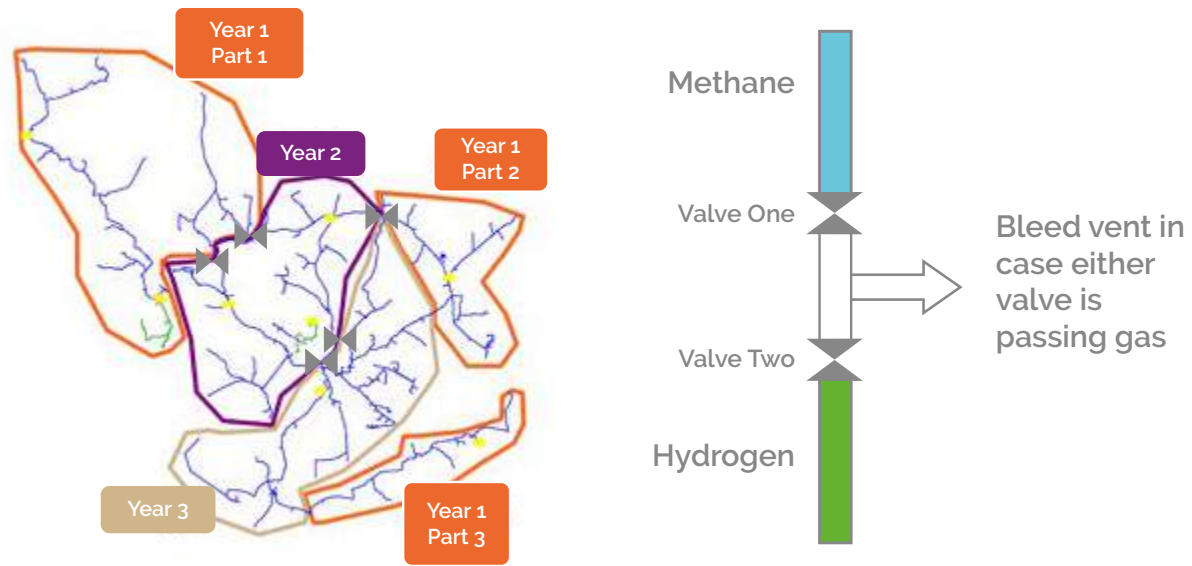


Image 4.8. *Isolation Locations on MP Network and Illustration of Double Block and Bleed Isolation Method*

These valves may already exist in the network and this would be determined as part of the H21 conversion roadmap project surveys. Also, these isolations would need to remain in place until the adjacent area was converted and therefore each area would need to be robust enough to maintain supply through the intervening winters until the entire conversion was completed.





### Low Pressure (red) Network

While we now understand the year-by-year sequential areas in which the isolation and conversion could take place, this is only part of the picture. Within each year, the areas would need to be broken down into smaller segments to ensure the level of disruption to customers is acceptable. Therefore, we would propose dividing the 'yearly zone' into monthly and, subsequently, weekly isolation zones. This will need to occur in both the medium and low pressure networks. The reader must remember that the vast majority of customers are connected to the low pressure (red) network which is in turn supplied by the medium pressure network via numerous injection points (DGs). For the medium pressure isolation shown in [Image 4.8](#) this then supplies the low pressure network as shown in [Image 4.9](#).

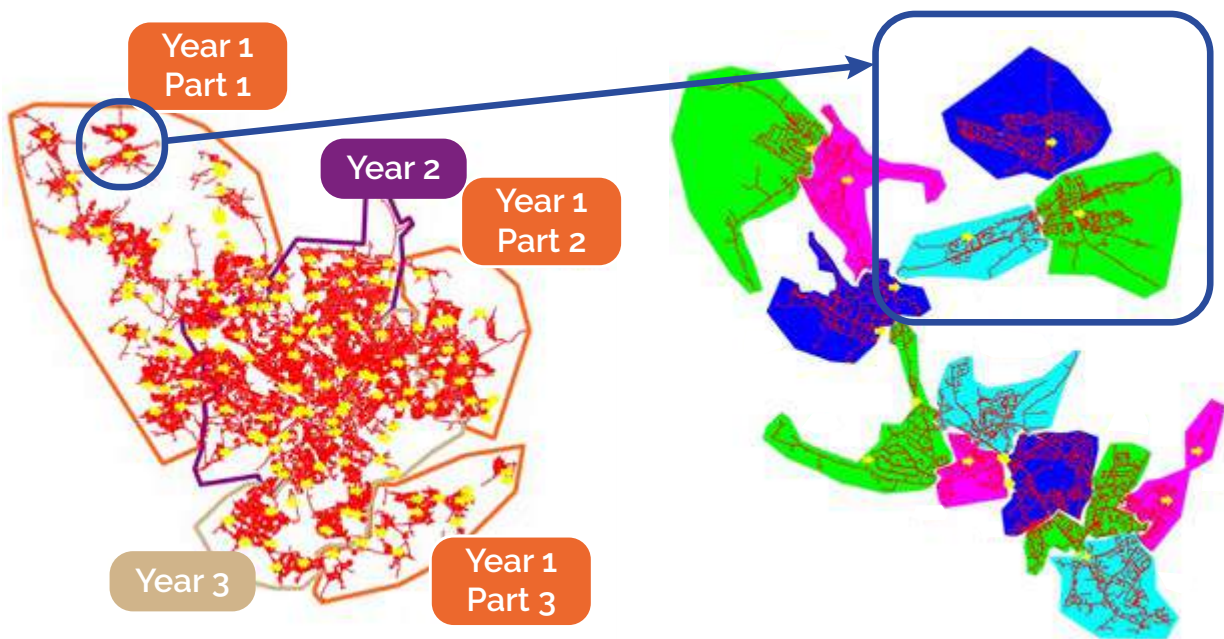


Image 4.9. LP Yearly Isolation Zones

As with the MP network, the LP network DGs have zones of influence which will require a double block and bleed arrangement. Simplistically this conversion process is illustrated in the **Image 4.10**.

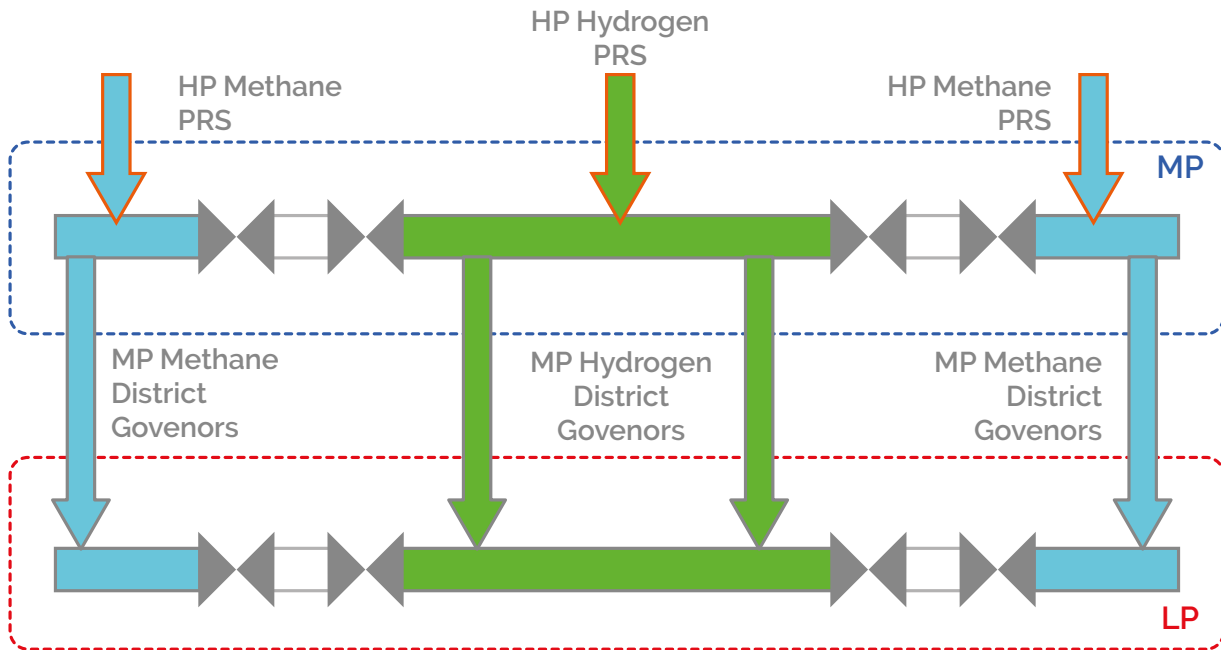


Image 4.10. *Conversion Isolation*

### 4.1.3. The Conversion of the Wharfedale Area

To fully understand the conversion process a detailed example is provided for the Wharfedale area which would be undertaken in Year One, shown in [Image 4.11](#).

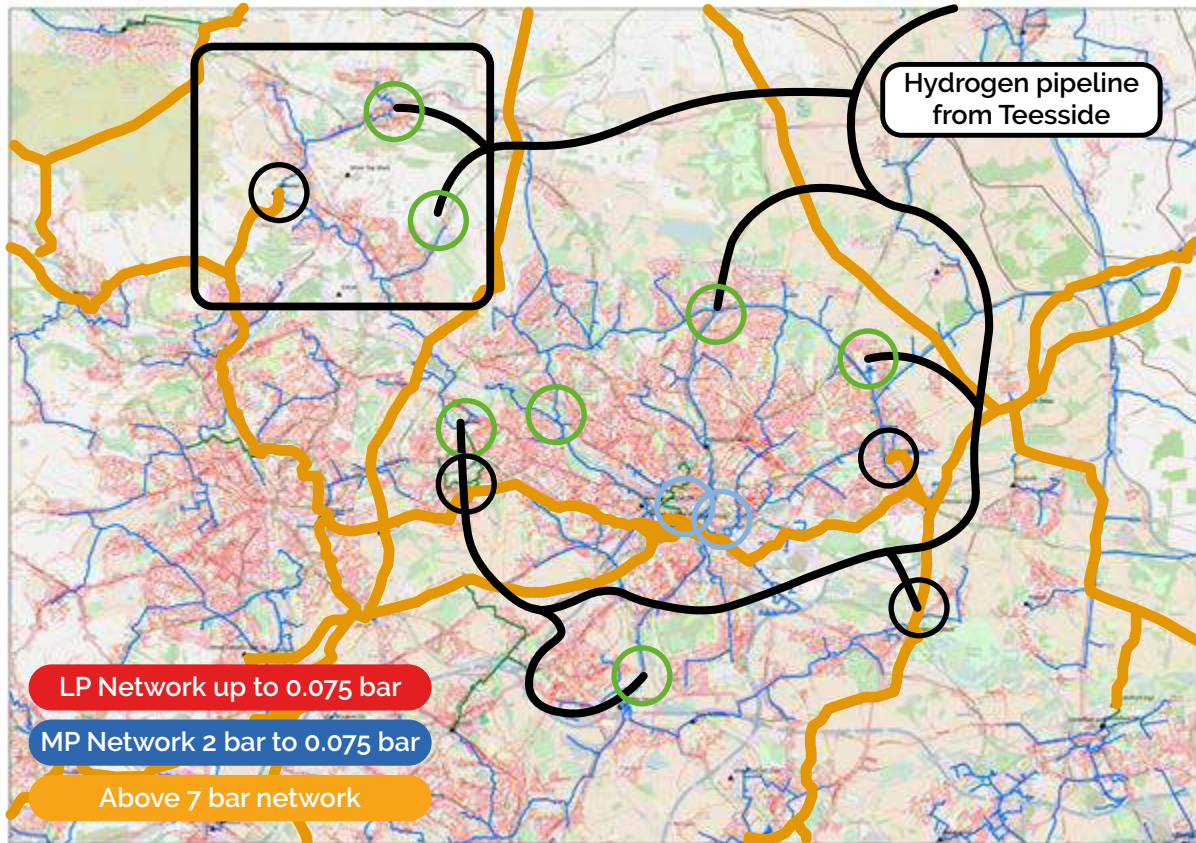


Image 4.11. *Wharfedale Area of Conversion*

When considering the optimum way to convert this area several factors will need to be considered. These include:

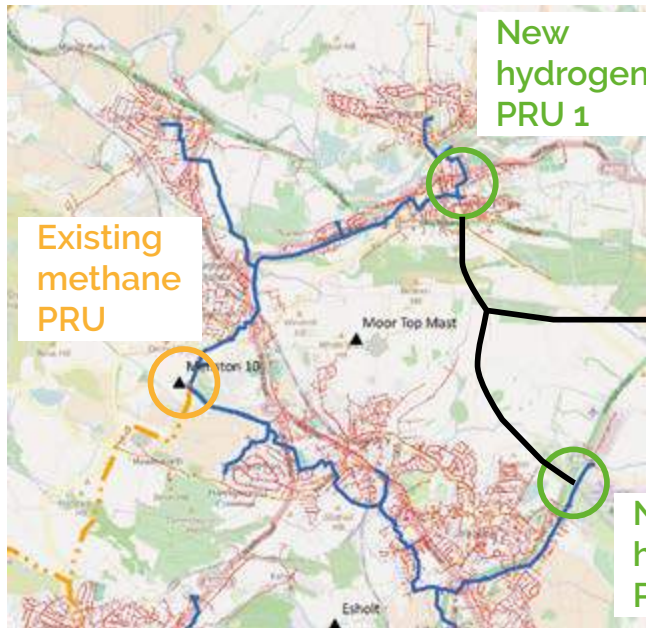
- Acceptable duration for customers to be without gas;
- The size of the conversion workforce;
- The ability and cost of maintaining temporary supplies through options such as liquid natural gas and potentially bottled gas for short periods; and
- The number of isolations required.

All these factors were considered as part of the overall conversion strategy identified in [Section 10, H21 Roadmap](#). By way of example, two detailed conversion strategies are detailed on the following pages.

### Example One: Incremental Conversion with Zone Isolations

In this example, there would be multiple specific isolations required between zones of influence. This solution would provide the smallest practicable period for customers being without gas.

#### Starting Position



Principle MP zonal isolation double block and bleed.

Note: All of the area is supplied with natural gas (methane) from the existing PRU.

This gas fills the MP and LP systems and is all that is available to the customer.

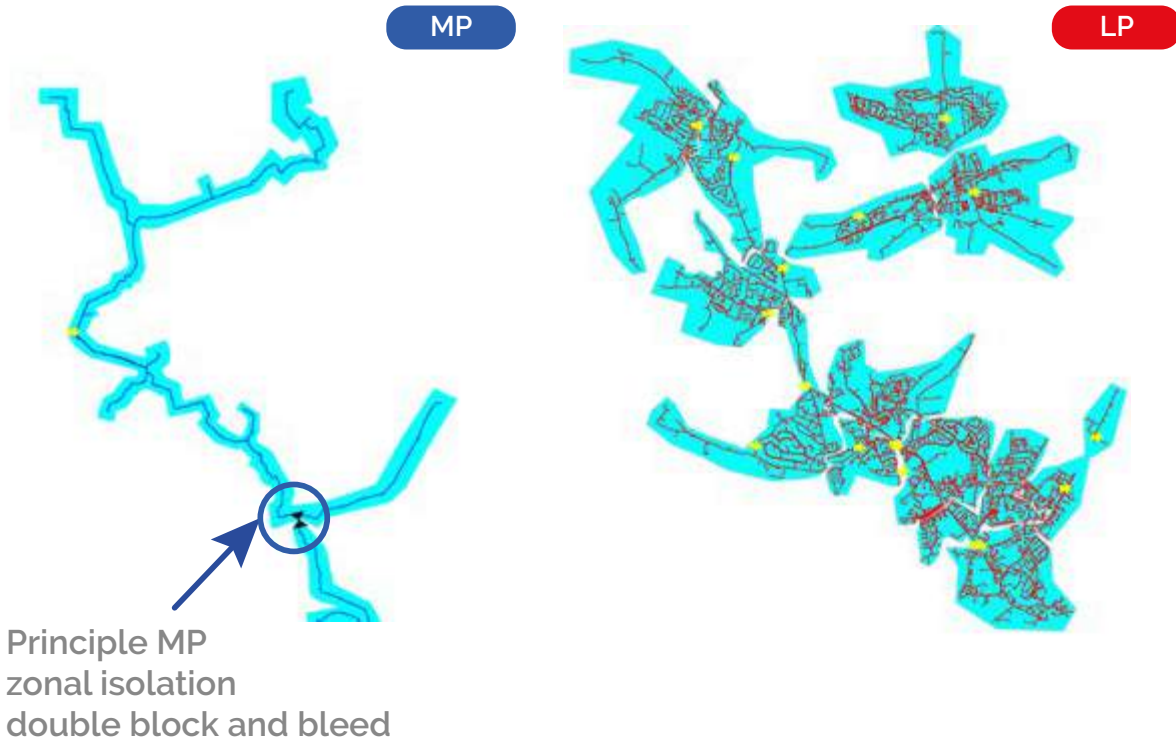
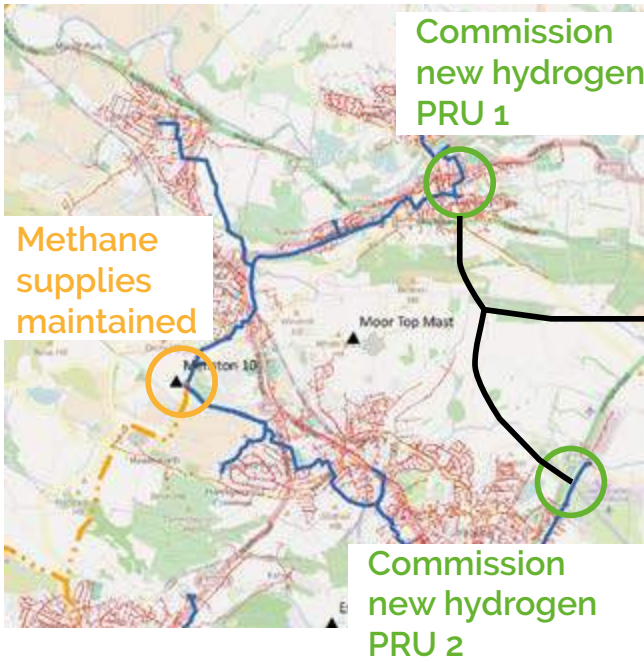


Image 4.12. Starting Position

### Step One: Dual area MP/LP Isolations 1<sup>st</sup> Conversions



#### Conversion notes:

Isolation valves are closed. Two areas north and south are simultaneously converted to hydrogen fed by new hydrogen PRU whilst remaining areas are still supplied natural gas from the current HP-MP injection point.

Valve assembly already exists - would be validated as part of surveys, others may need installation

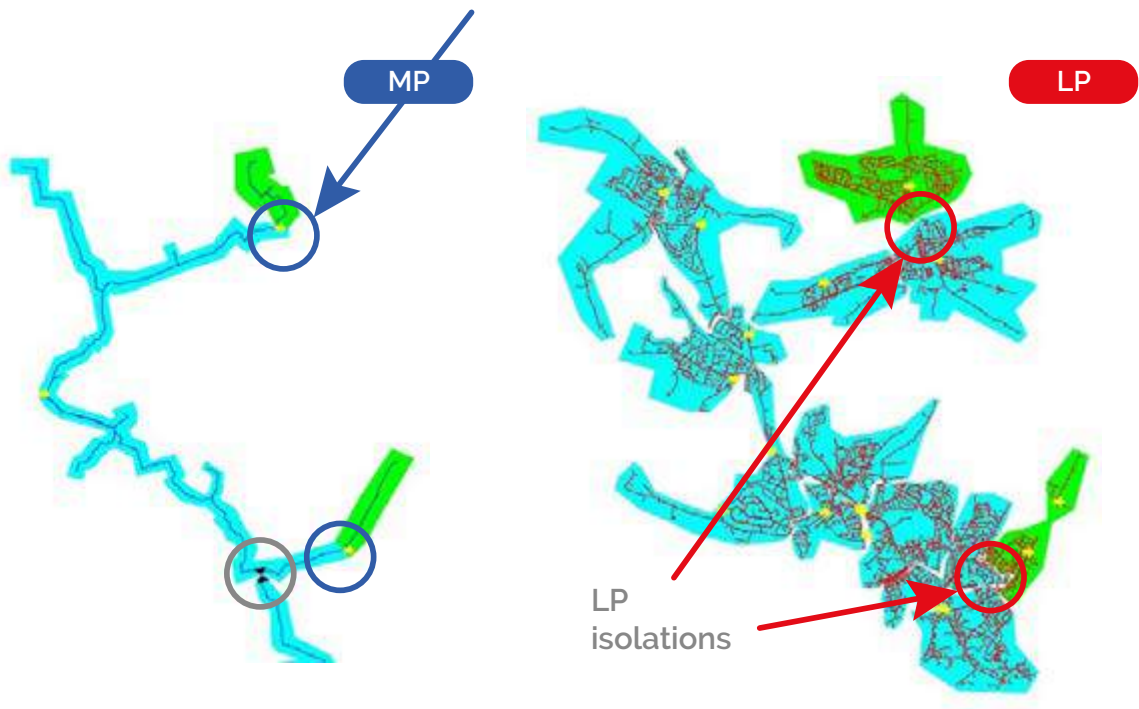
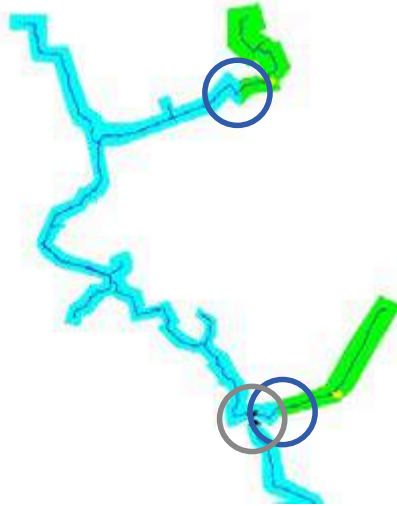


Image 4.13. Maps Step One

## Step Two: Dual Area MP/LP Isolations 2<sup>nd</sup> Conversions

MP



### Conversion notes:

Next sets of isolation valves are closed.

The next two areas north and south are converted to hydrogen whilst the remaining areas are still supplied natural gas from the current HP-MP injection point.

LP

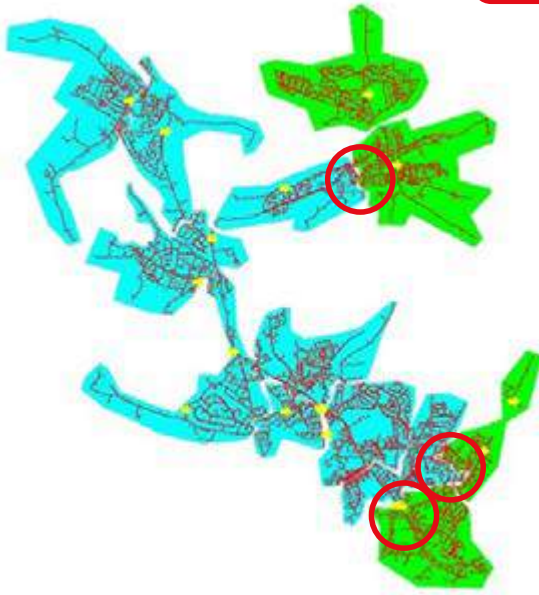
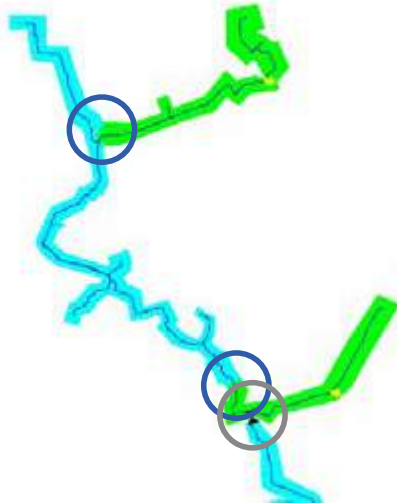


Image 4.14. Map Step Two

### Step Three: Dual Area MP/LP Isolations 3<sup>rd</sup> Conversions

MP



#### Conversion notes:

Next sets of isolation valves are closed.

The next two areas north and south are converted to hydrogen whilst the remaining areas are still supplied natural gas from the current HP-MP injection point.

LP

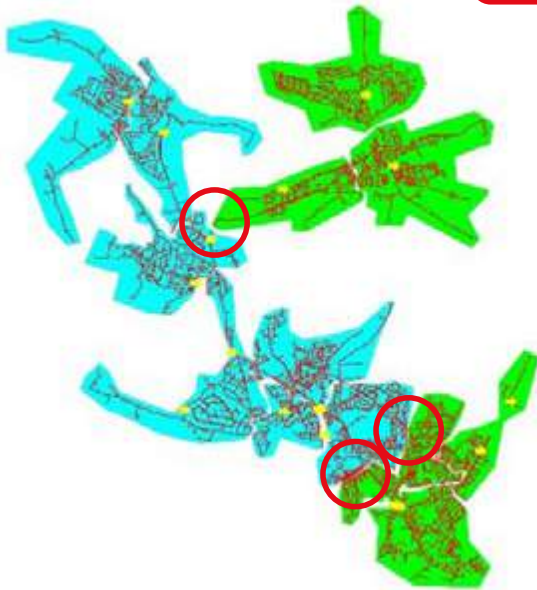
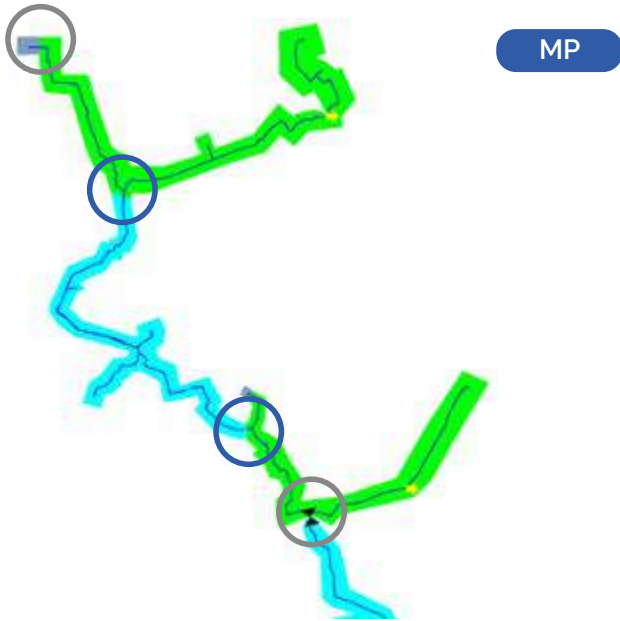


Image 4.15. Maps Step Three



### Step Four: Dual Area MP/LP Isolations 4<sup>th</sup> Conversions



**Conversion notes:**

Four areas would become isolated from the existing natural gas supply.

Grey areas would need a temporary supply from LNG or an increase in the size of the conversion workforce to cover the larger area.

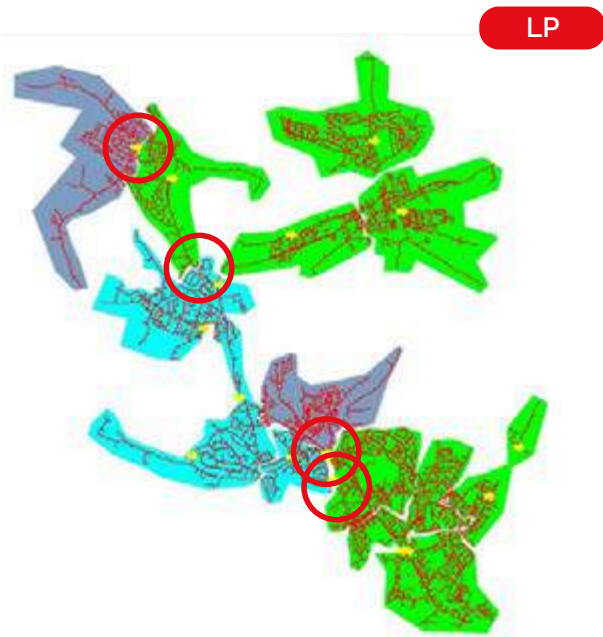


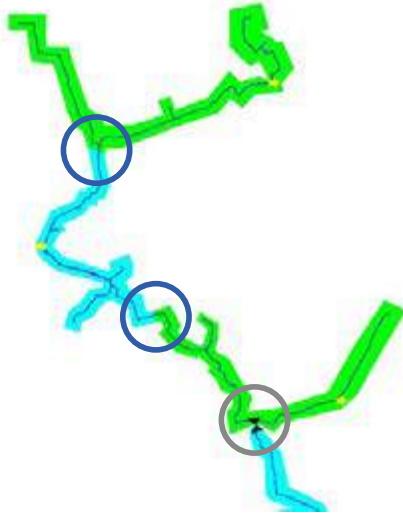
Image 4.16. Maps Step Four





### Step Five: Triple Area MP/LP Isolations 5<sup>th</sup> Conversions

MP



**Conversion notes:**

Next sets of isolation valves are closed.

Two temporarily supplied grey areas are converted as well as the adjacent small southern areas.

The remaining areas are still supplied natural gas from the current HP-MP injection point.

LP

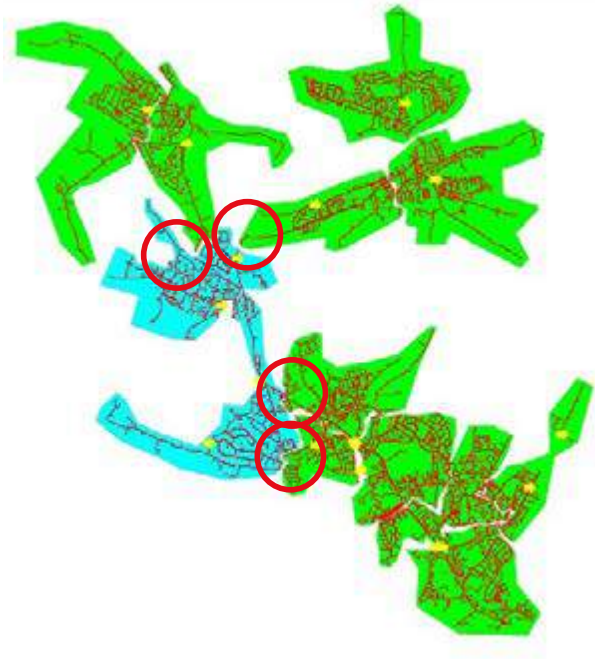
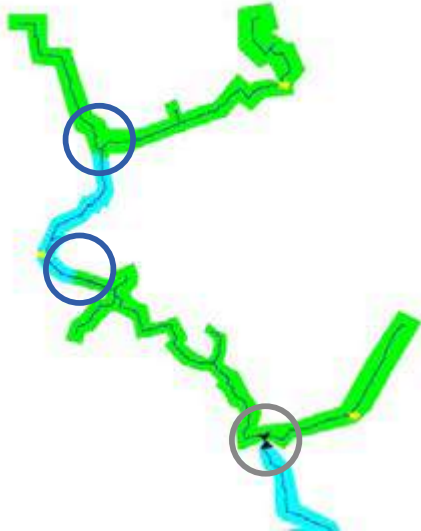


Image 4.17. Maps Step Five



### Step Six: Single Area MP/LP Isolations 6<sup>th</sup> Conversions

MP



#### Conversion notes:

Next sets of isolation valves are closed.

The next area south is converted to hydrogen.

The remaining area is still supplied natural gas from the current HP-MP injection point.

LP

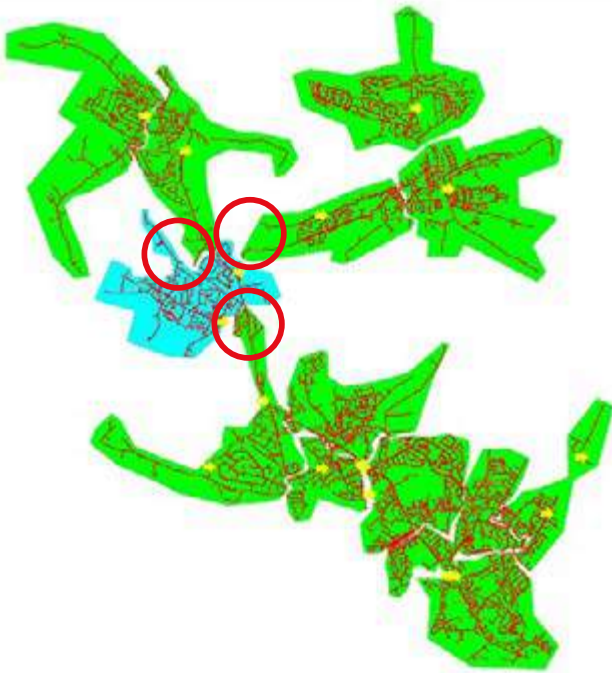
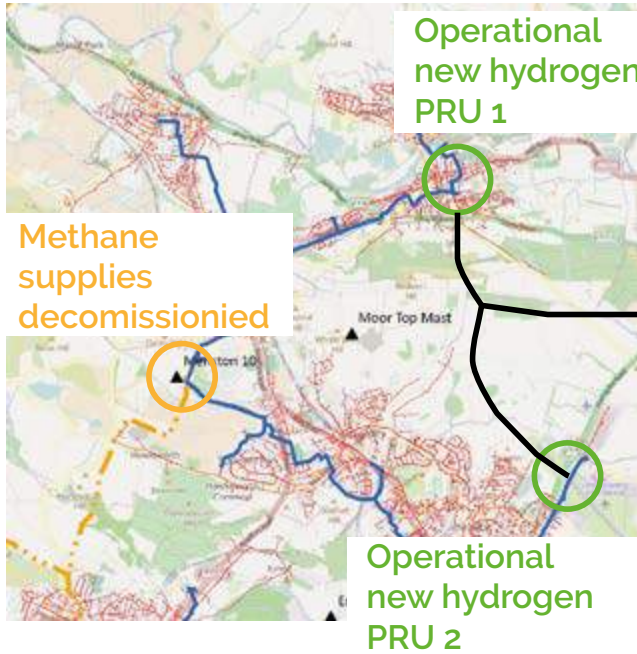


Image 4.18. Maps Step Six



## Step Seven: Final Conversion and decommission HP-MP Natural Gas PRS (Completion)



### Conversion notes:

The final area associated with this MP zone of influence is converted. The natural gas supply is decommissioned. All areas are supplied by hydrogen. The principle zonal MP isolation remains in place until conversion of the zone to the south commences whereupon this could potentially be used as one of the hydrogen sources.

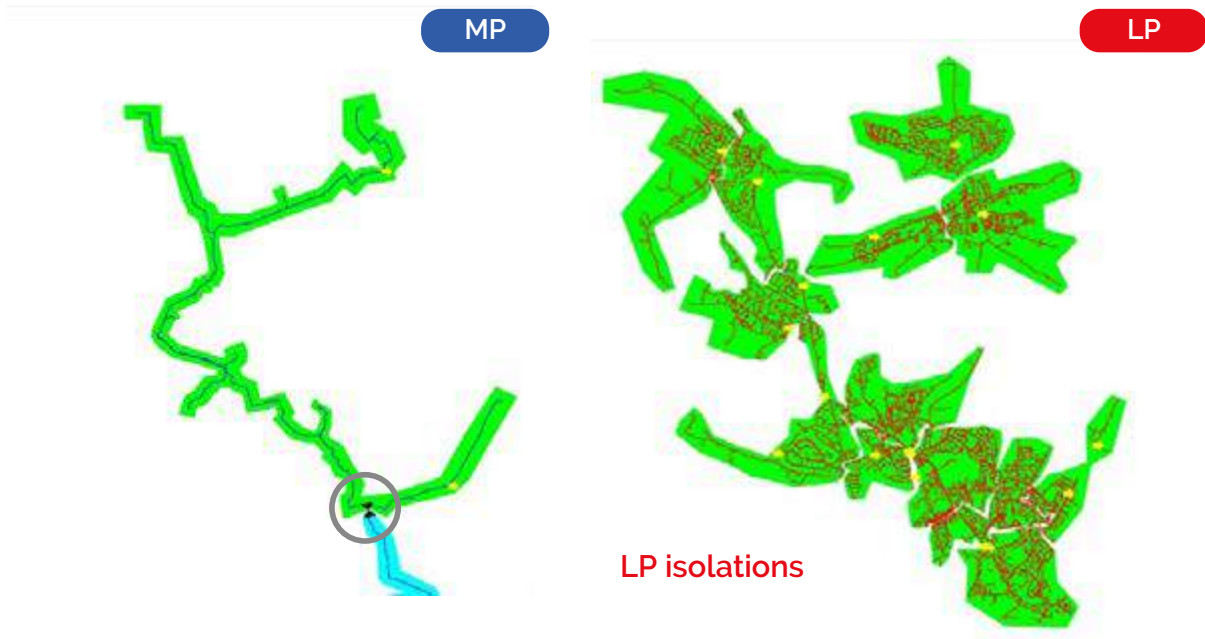


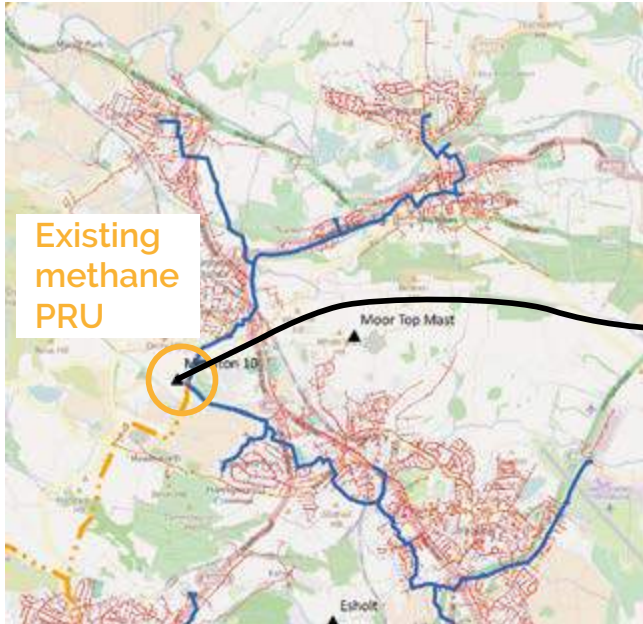
Image 4.19. Maps Step Seven

### Example Two: Minimal Network Interference

It needs to be understood that the conversion strategy provided in example one while efficient and technically effective is not the only strategy available. If it was found to be acceptable to customers to be without gas for longer to save enabling costs then a much simpler network strategy could be adopted. In this example, two new hydrogen PRSs are not installed as in Example One and instead the hydrogen connection is made directly into the existing PRS. This solution requires some mains reinforcement to be carried out to the MP network, but would remove the need to carry out staged isolations and conversions. However due to the likely extended conversion timetable unless an extensive conversion workforce were available this is unlikely to be acceptable to customers. This balance would be a key consideration as part of the detailed conversion strategy development project identified in **Section 10, H21 Roadmap**.



## Starting Position



### Conversion notes:

Principle MP zonal isolation double block and bleed.

All of the area is supplied with natural gas (methane) from the existing PRU.

This gas fills the MP and LP systems and is all that is available to the customer.

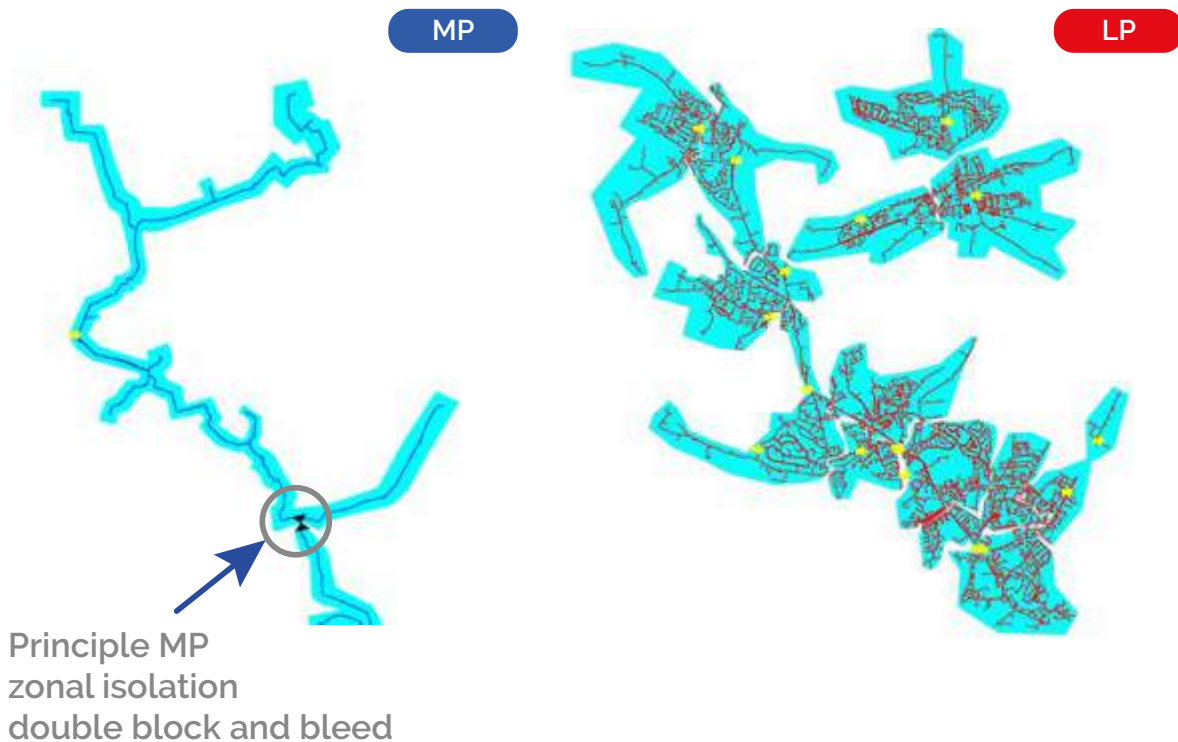
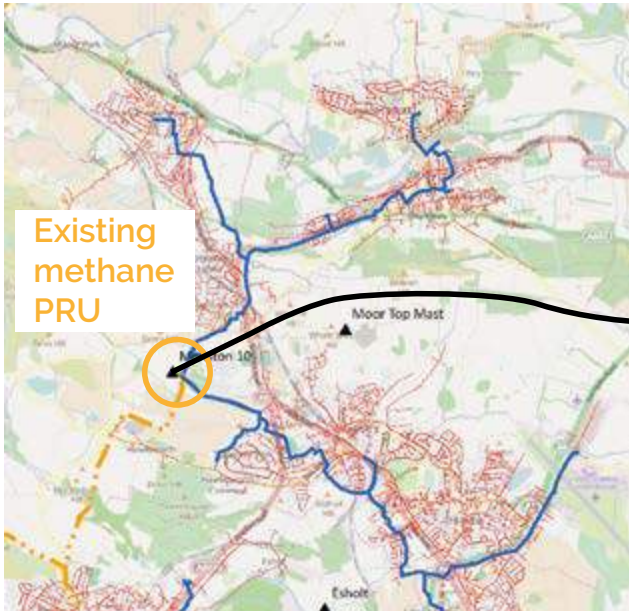


Image 4.20. Example Two Starting Position

## Step One: Decommission Existing Methane PRS and Convert to Hydrogen, Conversion of All Areas Complete



### Conversion notes:

Principle MP zonal isolation  
double block and bleed.

As there would be no alternative natural gas supply a zonal approach to the conversion could only be possible with temporary natural gas, e.g. LNG.

*Alternatively*, the entire area could be converted at once and the length of time customers are left without gas would be dictated by the size of the available workforce.

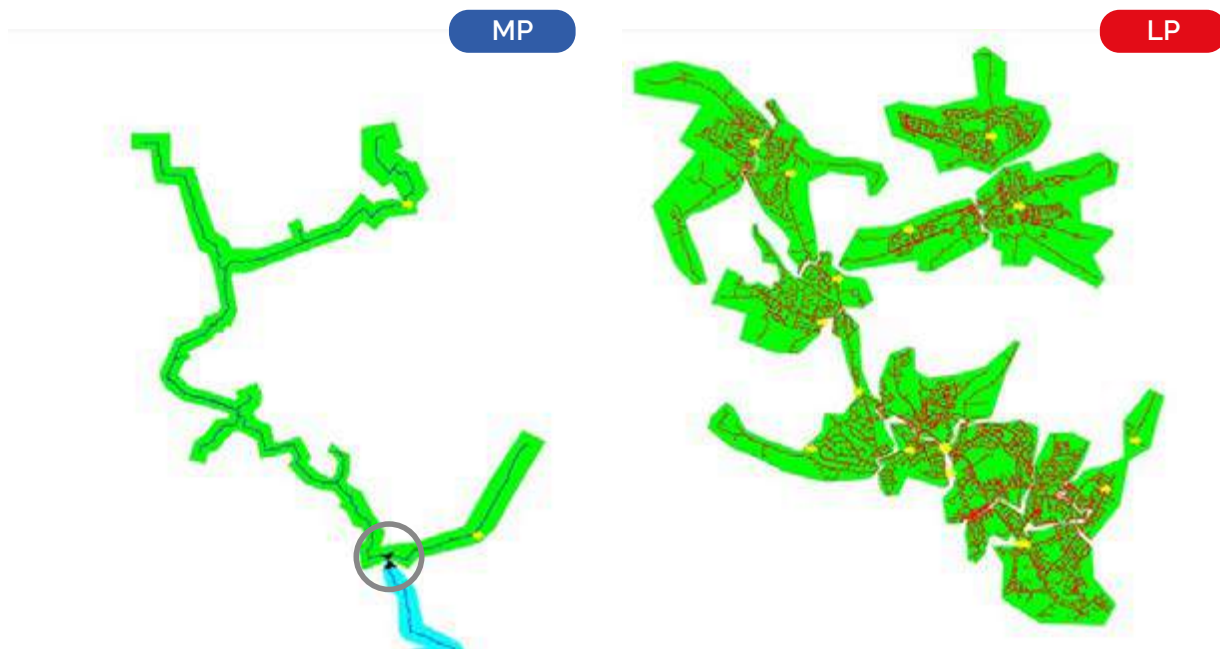


Image 4.21. Map, Example 2, Step 1

### 4.1.4. Conversion Summary

Now we understand how the conversion is possible in a specific area, recall the three-year conversion strategy based on the MP network isolations [Image 4.22](#).

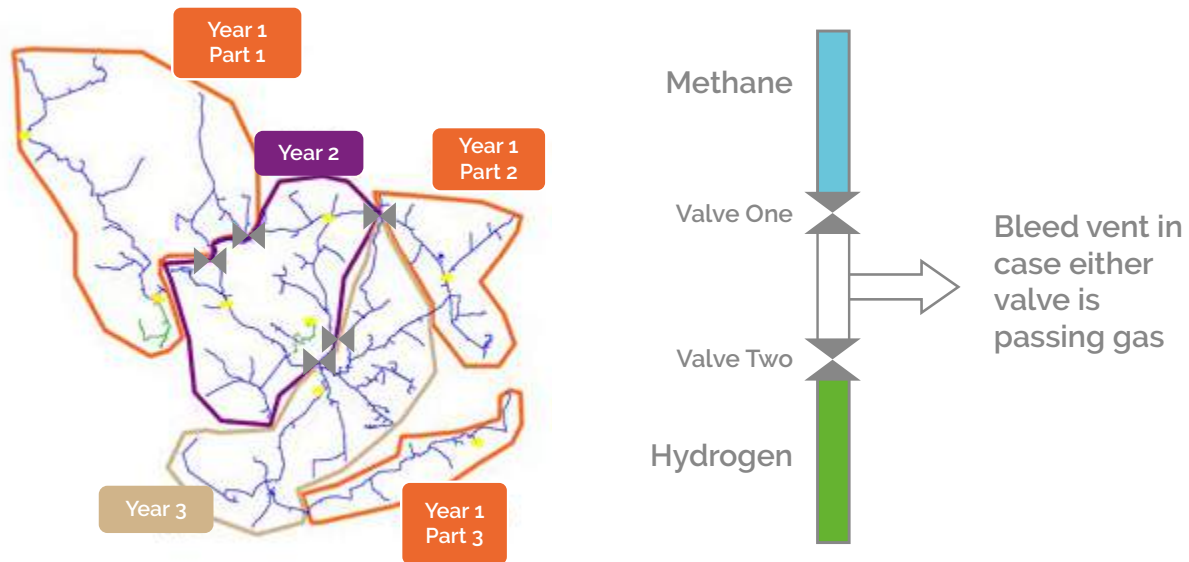


Image 4.22. *MP Three Year Conversion Strategy and Double Block and Bleed*

By the end of year one, the three orange areas would all be operating on hydrogen while the purple and beige areas would be operating on natural gas. All areas would be converted in a similar manner to that identified in the [Section 4.1.3](#) and would be timed to ensure the conversion back to the principle isolation valves, i.e. the valves that will isolate natural gas areas from hydrogen areas over winter, is complete.

***In conclusion, converting the city to hydrogen is possible with minimal modification. It will require meticulous planning coupled with site surveys, upfront enabling works, and comprehensive strategy development***

## 4.2. Network Enabling Costs for Conversion

Without undertaking the full conversion strategy including cotnsideration of workforce size, customer time without gas, temporary supplies etc. it is difficult to estimate the costs associated with network enabling work. However, to give an indication of the cost an estimate has been provided for H21 based on the following assumptions:

- In the Wharfedale scheme above there are approximately 30 isolations required across the MP and LP systems.
- When scaled up to cover the entire area of conversion this has been assumed, with a high level of confidence in the order of magnitude, to be:
  - 750 LP isolations (assume none are currently in place or are not available due to road resurfacing etc.)
  - 250 MP isolations (assume  $\frac{1}{3}$  are in place)
  - 25-30 new permanent DGs and associated mains connections to facilitate additional sector isolations.
  - An 8 inch (200 mm) double block and bleed isolation has been priced by NGNs commercial department and costs approximately £4,420. To ensure worst case scenario all isolations have been assumed as 8 inches, although in reality, many mains will be smaller than this. Therefore, the figures presented in [Table 4.1](#) are worst case scenario.

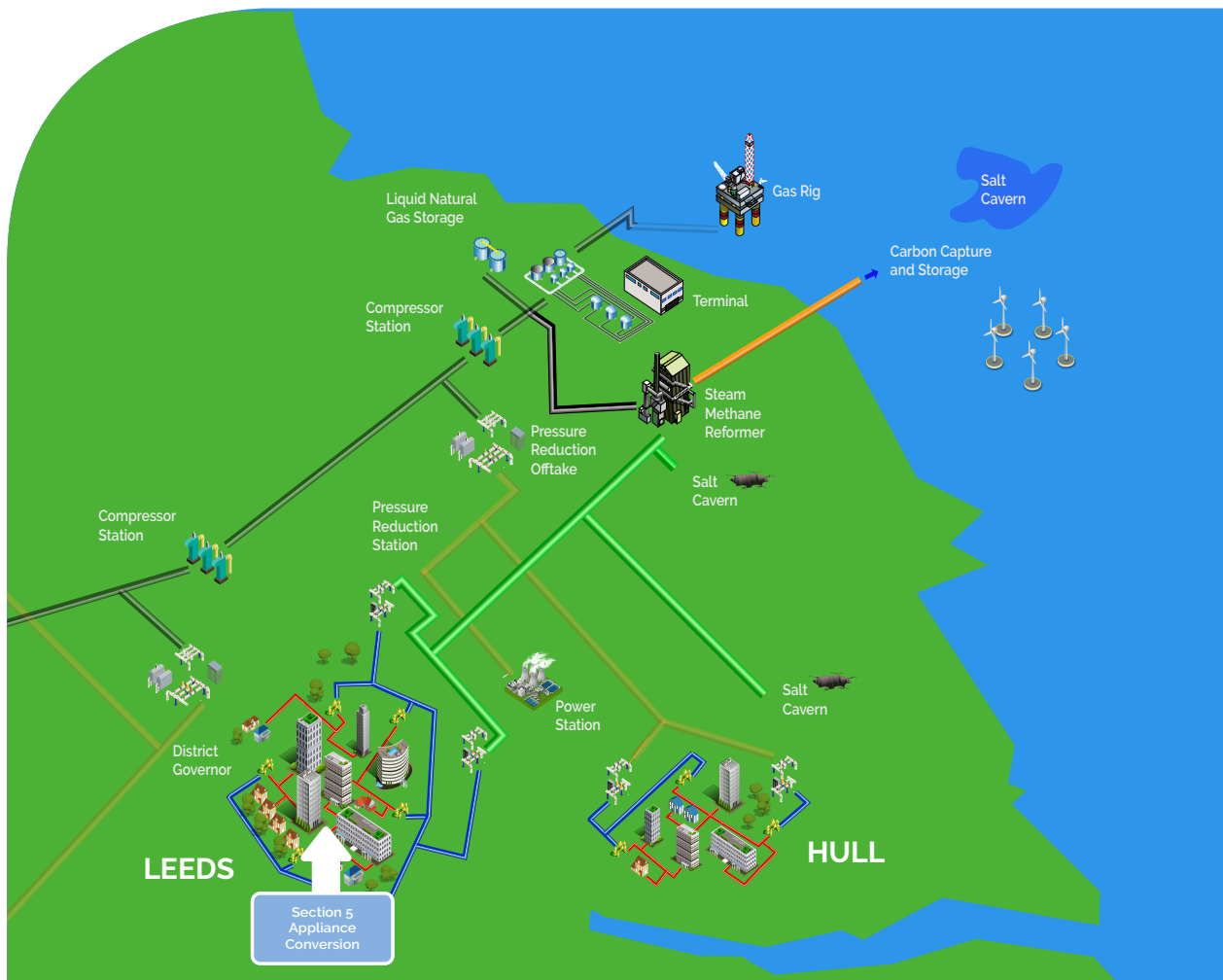
Work Type	Total Units	Unit Cost (£)	Total (£)
LP isolations (installation of double block and bleed assembly)	750	4,420	3,315,000
MP isolations (installation of double block and bleed assembly)	170	4,420	751,400
District governors and associated connections	30	50,000	1,500,000
<b>Total</b>			<b>4,726,400</b>

Table 4.1. *Network Conversion Enabling Works – Cost Summary*



## SECTION 5

# Appliance Conversion



## 5. Appliance Conversion

### Appliance Conversion History

*The original town gas to natural gas conversion occurred between 1966 and 1977 and involved the conversion of 14 million customers and 40 million appliances plus industrial and commercial customers. This was a programme of both technological and logistical outstanding achievement. From initiation in 1966 by 1969 conversion of over 400,000 domestic dwellings each year was being undertaken with a peak of over 2.3 million per year in 1971/72.*

*A key part of the conversion success was the cooperation shown by the manufacturers in developing and supplying conversion sets for both the domestic and commercial/ industrial markets. In addition to the appliance manufacturers (and their joint organisation 'the Society of British Gas Industries' (SBGI)) co-operation to respond to the need to convert The Gas Councils two research establishments were also pivotal to the success.*

*At the time of conversion, the establishment of the unified British Gas Corporation was some seven years away. Instead the gas industry was made up of 12 essentially autonomous area boards, The Gas Council stood between Ministers and these boards with a statutory role 'to promote and assist the efficient exercise and performance by area boards of their functions'. The Gas Councils research bodies, Watson House and Midlands Research Station, by dealing with domestic and industrial sectors respectively, were pivotal parts in the appliance approval process and ensured agreed standards were maintained.*

*In 1966 the Gas Council established a Conversion Executive which had the objective of reviewing area boards conversion plans, ensuring the appliance industries capabilities were in line with the conversion programme and that the correct standards were being observed, and acting as a conduit between the area boards and the Gas Council. A key policy decision from the conversion executive was to the introduction of new appliances readily adaptable to both town and natural gas and subsequently to natural gas only.*

*Technical assistance from Watson House to the appliance industry was essential to the success of the conversion programme. Their role included:*

- *Testing and approval of conversion sets and new appliances;*
- *Development of conversion sets for older appliances particularly where manufacturers were no longer in operation;*
- *Co-ordination of area board surveys to determine numbers and types of appliances prior to conversion taking place. This was essential to ensure the correct numbers of conversion sets could be ordered and manufactured in a timely manner;*

## Appliance Conversion History (continued)

- Production of the 'Watson House identification manual' with a complete description and illustration of each of the appliances totalling circa 850 domestic and nearly 300 catering appliances by the time conversion took place; and
- Provision of a mobile workshop in the area of conversion for in-field support should it be required.

One difficulty with which the appliance manufacturers and Watson House had to contend in the early days was the availability of natural gas with which to test and approve appliances. This issue has been recognised in the H21 Roadmap and is the key reason for recommending Teesside for the establishment of an appliance development and demonstration hub near the UK's only large-scale hydrogen storage salt cavern. Also, small manufacturers today often do not have research and development departments and these would need similar levels of support to that provided by Watson House which could be facilitated by companies in the market like Enertek at Hull.

Appliance conversion programmes are relatively common in the gas industry. The last major conversion in the UK was town gas to natural gas in the early 1970s but the Isle of Man only completed the conversion from LPG/air mixtures to natural gas as late as 2013. The low cost and great variety of modern appliances mean it is expected that in the domestic sector full appliance replacement is the norm, although in a commercial or industrial environment burner replacement is more likely to be viable. Fortunately many boilermakers manufacture to their own design of common backplate (the component screwed to the wall and via which the gas and water pipes run) so boiler change over should not be too onerous. There is considerable enthusiasm from the UK gas appliance industry for such a conversion programme.

Obviously all of the combustion equipment supplied by a hydrogen network must be suitable for hydrogen. Consumers cannot choose to remain on natural gas and those not wishing to convert to hydrogen would have to switch to electricity.

A key issue for the switchover of a network from natural gas to hydrogen is the conversion of appliances and equipment. There are both financial and resource/timing implications.

These are highly interdependent. Making available the hardware for replacement or conversion of all appliances and equipment within an area of conversion depends on the equipment suppliers. Particularly at the point when the market is small this will have a large effect on the prices. Whether modification or replacement is the available option will also have a significant impact on the costs. Coinciding the switchover of installed hardware and any changes required to the gas delivery system with the availability of hydrogen to the relevant network section will be challenging (see [Section 4, Gas Network Conversion](#).)

To provide a sensible estimate of the appliance conversion costs for the area of conversion engineering judgement and interpretation needs to be applied to:

- Number of meter points;
- Nature of those meter points (e.g. domestic, commercial or industrial); and
- Likely installed appliances/combustion systems.

DECC publish this for individual Middle Layer Super Output Areas (MSOA) as conveniently sized geographic areas.

To put this in perspective it is worth summarising the previous results.

- Average 2013 yearly demand = 678 MW (derived from DECC data).
- Total average yearly demand (2013) = 5.9 TWh.
- Total number of meter points in the area of conversion = circa 265,000.

From further interpretation of the MSOA data the demand profile above can be broken down to domestic and non-domestic usage. Figures are shown in [Table 5.1](#).

Usage Type	Demand	% of Total Demand	Meter Points	% of Total Meter Points
Domestic	3.6 TWh	63%	261,522	99%
Non-Domestic	2.3 TWh	37%	3,126	1%

Table 5.1. *Domestic vs. Non-Domestic Split in Area of Conversion*

Inevitably with large numbers of sites and different data sources small differences occur between databases and years. The details of these calculations and assumptions are explained in the following pages as well as how the estimate of appliances type and conversion costs within these respective domestic/non-domestic sectors has been produced.

## 5.1. Domestic

Between 1967 and 1977 about 13 million homes and 40 million appliances were converted from town gas to natural gas at a cost of (then) £563 million (i.e. £42/customer, ref National Gas Museum). This is now equivalent to £6 billion (based on the RPI) or £14 billion (based upon % UK GDP).

A similar programme was recently completed on the Isle of Man. This cost on average approximately £3,500 per property, including all work both within the property (reported at about £1,200) and in the street (reported at about £2,300/property).

The rate at which the switchover could be undertaken is crucial. The development of the hydrogen resource will inevitably be much more protracted than for the provision of natural gas. The balance between providing hydrogen supply capacity across the area of conversion and procurement and installation of the necessary hardware for users will require careful management. In particular creating sufficient consistent demand for hardware to persuade manufacturers to mass produce will be vital.

The first conversions to take place, potentially in the mid 2020s, will inevitably be the most expensive. As lessons are learnt, increasing efficiency in the process, coupled with time to standardise appliance specifics (as recommended below), should reduce these costs significantly especially if and when the conversion is incrementally rolled out across the country.

To help to prepare for a widespread transition to hydrogen the following actions could be taken:

- 1. Boilers:** Manufacturers are already using 'back plates' or 'manifolds' for ease of boiler change. This should be encouraged (or regulated) to include isolation valves to connect their boilers to the existing central heating, domestic hot water and gas supplies. This can be of their own design to suit their particular product characteristics. This is expected to reduce boiler average change times to < 2.5 hours.
- 2. Cookers:** Manufacturers should be encouraged (or regulated) to produce appliances to standard sizes and with gas connection ports in a common location. This should reduce appliance average change times to < 1 hour.
- 3. Gas Fires:** These sales are predominantly aesthetically driven, the sales documentation of such appliances could (in future) contain specific reference as to whether the appliance will be suitable for conversion to hydrogen. If manufacturers started to develop hydrogen compatible appliances their literature should begin to contain references as to how they plan to offer hydrogen conversion/replacement in the event of conversion of the customers' area.

Such potential for easy change could be promoted in the same fashion as the 'Digital Switchover'. Various government energy efficiency schemes could require hydrogen switch (HySwitch) friendly appliances. These products may be a conventional appliance, which has a specific easy conversion replacement/modification kit developed by the manufacturer reducing conversion times to less than 2 hours.

In the near term manufacturers could designate any existing appliances 'HySwitch' if they launched a bespoke hydrogen kit such that the conversion of these appliances could readily be carried out below a designated time threshold. In the longer term even more conveniently convertible appliances could undoubtedly be designed. This purposely sets the 'benchmark' of the early HySwitch boiler as fairly low. The precise route by which the appliance could be converted, i.e. by either minor part or near total replacement, would be the choice of individual manufacturers.

### The Conversion Process.

Consideration of the demand profile of the area of conversion has been divided into the two sectors used by DECC for gas utilisation, i.e. domestic (in practice all sites with meters < 70 kW) and non-domestic. The total cost is then the sum of these. Numbers of man-days, elapsed times and staff numbers have been allocated to the domestic sector, whereas the non-domestic sector has been considered only from a financial perspective. It is envisaged that the programme will be driven by the timing and density of the domestic properties (e.g. flats or detached residences) and that the non-domestic will then follow. The utility overhead (to manage the process) has been allocated to the domestic market.

### Domestic – Switchover Process and Cost Estimates

For the analysis presented here a zone containing 2,500 properties has been used as the basis for estimating indicative costs for conversion. The complex issue of the number of isolation zones versus the size of the isolated area is considered in [Section 4, Gas Network Conversion](#).

The basic parameters used are set out in [Table 5.2](#).

Aspect	Parameter	Number	Units
<b>Isolation Zone Definition</b>	Properties in isolation zone	2,500	-
	Streets per zone	c.42	-
	Properties per street	c.60	-
	Duration of zone isolation from gas grid	5	Elapsed days
<b>Staff Definition</b>	Gas Fitters (obtained from <a href="#">Table 5.3</a> )	939	-
	Number of Management supervisors*	125	-
<b>Cost Definition</b>	Staff cost – Gas Fitters	46.30	£/h
	Staff cost – Management	73.33	£/h

Table 5.2. *Design Parameters for the Management of the Appliance Switchover Process.*

\*A management to gas fitter ratio has been adopted of 1:8.

Experience from the SGN 'Opening up the gas market' project showed that gaining high levels of consumer involvement can be achieved (approaching 90% active support and < 1% active refusal) but this takes high levels of street-by-street canvassing and skilful public relations; this has a significant cost. This is one reason for the high level of management involvement.

In order to model the effort involved in carrying out the switchover for an isolation zone of this size assumptions have been made with regards to:

- Appliance population regarding number of properties with gas appliances and the distribution of appliance types;
- Appliance population regarding the distribution of appliance types;
- Average effort required to replace appliances (by type);
- All staff are on the same pay structure; and
- Time for total zonal conversion is five days.

The values (estimates based on Kiwa-Gastec experience) used in these assumptions are shown in [Table 5.3 and 5.4](#) which shows the development of the effort estimate for the switchover process of one isolation zone containing 2,500 domestic properties.

Here it should be noted that the estimated time for switching traditional system boilers and for conversion of ovens/grills is as follows:

- Replacement of traditional system boilers (e.g. sitting room back boiler units) is time-consuming due to the number of components in these systems compared to those used with modern combi boilers, hence the estimated average time of 11 hours.
- The time required to change over an oven or grill can be less than 6 hours for a freestanding appliance, however for integrated appliances this will be significantly longer. An estimated average of 6 hours is used here.



Activity	Action	Effort (h)	Number	Total Effort (h)	Cost
Boilers	Initial house visit	1.5	2,500	3,750	£173,625
	Replacement products order	1	2,500	2,500	£115,750
	HySwitch ready boiler changeover*	2	1,250	2,500	£115,750
	Traditional Combi boiler changeover	6	750	4,500	£208,350
	Traditional System boiler changeover	11	500	5,500	£254,650
Cookers	HySwitch ready hob/freestanding changeover	1	1,000	1,000	£46,300
	Traditional hob changeover	13.5	400	5,400	£250,020
	Traditional grill/oven changeover	4	1,200	4,800	£222,240
Heaters	HySwitch ready fire/simple fire changeover	2	800	1,600	£74,080
	Traditional gas fire (complex) change over	5	700	3,500	£162,050
Other Parts	Pipework adjustment and change of fiscal meter	1	2,500	2,500	£115,750
<b>Total</b>				<b>37,550</b>	<b>£1,738,565</b>
Number of gas fitters		(37,550/40)		939	
Management		40 (5 days @ 8hrs)	125	5,000	£366,650
<b>Grand Total</b>				<b>£2,105,215</b>	
<b>Cost per property</b>				<b>£842.09</b>	

Table 5.3. Estimation of Effort Required for Appliance Switchover for One Isolation Zone Containing 2,500 Domestic Properties

\*A HySwitch product may be a conventional appliance, which has a specific easy conversion replacement/modification kit developed by the manufacturer reducing conversion times to less than 2 hours.



## Hardware Cost Estimates Based on Current Prices

Type	Hardware	Number	Unit Cost £	Total cost
Boilers	HySwitch ready boiler	1,250	850	£1,062,500
	Traditional combi boiler	750	1100	£825,000
	Traditional system boiler	500	950	£475,000
Cookers	HySwitch ready hob/freestanding	1,000	300	£300,000
	Traditional hob	400	750	£300,000
	Traditional grill/oven	1,200	450	£540,000
Heaters	HySwitch ready fire/simple fire	800	300	£240,000
	Traditional gas fire (complex)	700	450	£315,000
Other parts	Pipework	2,500	100	£250,000
<b>Total</b>				<b>£4,307,500</b>
<b>Average appliance cost per property</b>				<b>£1,723</b>

Table 5.4. Summary of Hardware Costs for Appliance Switchover for One Isolation Zone Containing 2,500 Domestic Properties

In a similar fashion to the calculation of the annual gas demand for the area of conversion (by overlaying MSOAs on the gas network maps see [Section 4, Gas Network Conversion](#)) the number of domestic consumers has been estimated. This is evaluated as 261,522 domestic meter points in the area of conversion of the 264,648 total.

For completeness an extract is shown in [Table 5.5](#).

Local Authority Code	MSOA Name	MSOA Code	Consumption (kWh)	Number of Meters	Mean Consumption (kWh per Meter)	Median Consumption (kWh per Meter)
<b>Domestic</b>						
E08000035	Leeds 002	E02002331	37,562,331	2,583	14,542	12,532
E08000035	Leeds 003	E02002332	33,088,003	2,516	13,151	12,344
E08000035	Leeds 004	E02002333	48,734,878	3,556	13,705	12,083

Table 5.5. Area Meter Information

An overhead rate covering managerial and regulatory costs have been estimated to be around 20% of the cost per property. The overall cost build per property, per 2,500 property zone and for the whole sector is given in [Table 5.6](#).

Costs	Each	For a Zone of 2,500 Properties	For All 261,522
Manpower	£842	£2,105,000	£220,201,524
Hardware	£1,723	£4,307,500	£450,602,406
GDN Overhead 20%	£513	£1,282,500	£134,160,786
<b>Total</b>	<b>£3,078</b>	<b>£7,695,000</b>	<b>£804,964,716</b>
		Per property	£3,078

Table 5.6. *Costs per Property*

This gives an overall unit cost per property of £3,078. This per property cost is broadly consistent with a cost of £3,500/property for the town gas to natural gas conversion on the Isle of Man in 2010. This final conversion figure per domestic property has been logically calculated for the area of conversion and seems reasonable assuming 2016 prices, but also the mass manufacture of hydrogen appliances which would be essential should such a conversion take place. It is appreciated that there may be some optimisation between higher capital cost and reduced hours of conversion, but this can only be quantified as detailed appliance design progresses. All of these costs are for 'entry level' hydrogen appliances. It is envisaged that householders will always be permitted to pay for upgrades to a range of high specification products (for example catalytic hobs – see later in this section).

It should be noted that while the costs have been derived on a unit cost per domestic property basis in reality the process of conversion would be run with two distinct seasons per year. Through winter the extensive survey work would be undertaken with the subsequent procurement and logistics of hardware. In summer the conversion would take place with a detailed plan and upfront knowledge on a property by property basis to ensure a smooth and swift a changeover as possible. This occurred on the original towns gas to natural gas conversion.

## 5.2. Non-Domestic (Industry, Public and Commercial)

Customers in these sectors use equipment such as larger boilers (which may be producing steam or high-temperature high pressure water) Combined Heat and Power (CHP), and process burners.

Separation rules in the gas industry make it hard to identify all of the gas users in these sectors. Therefore, information about consumption and demand profiles of these sites is generally not directly available.

However, for the basis of this study it is necessary to make appropriate engineering estimates. Efforts have been made to calculate the likely number and type of users from these sectors in the area of conversion. This has been achieved through interrogation of two data sets. Firstly, the NGN largest demand model extract and secondly, 118 areas of MSOA Non-domestic Gas data. It should be noted that throughout the gas industry the smallest commercial users (below 70 kW demand) are categorised as 'domestic' and contained within the domestic connection numbers.

There are 3,126 non-domestic sites. To estimate the demand pattern it is necessary at least to know the type of activity undertaken on a site. It would be very time-consuming to carry this out for every non-domestic site and therefore a subset of the largest demands supplied from the MP and LP networks was obtained from the Synergi models. This gave 38 sites with peak demands greater than 100 Scm/h natural gas off the MP and 89 sites with peak demands greater than 130 Scm/h natural gas off the LP. These sites were then subjected to the following steps:

- From the OS grid reference Google Earth, Google Maps and Google Street view were used to assist in determining the nature of the enterprise on each site. For example, was a site a large industrial manufacturing site, a CHP installation, or a prison.
- Based on the above identifications, typical site usage patterns, annual operating hours and hence annual gas consumption were estimated. The essence of this is shown in [Table 5.7](#).

By way of example for each of the 38 sites fed from the MP, an estimate was made as to what type of 'appliance' it was likely to be using. For example, of the 38 sites it was estimated that 18 would be using a process boiler, (e.g. was it a fabric mill, or a food factory). The capacity of this was then back calculated from its declared installed load. This totalled 18 MW of demand for process boilers for all 38 sites. Assuming process boilers operate an average of about 3,500 hrs/y (including the backup boiler) total usage within these plant is 63,000 MWh/yr. The process was repeated for the five categories listed in [Table 5.7](#).

**Assessment of Number  
Industrial Appliances Using Process Identified Above**

NGN Pressure Tier	Units	Process Boilers	Space Heating	CHP	Glass	Process
Medium Pressure 30 Connections	MW	18	132	15	44	70
	hours/year	3,500	1,000	7,000	8,500	3,000
	MW/year	63,000	132,000	350,000	374,000	210,000
Low Pressure 89 Connections	MW	9	159	6	-	41
	hours/year	3,500	1,400	3,500	-	4,000
	MW/year	31,500	222,600	21,000	0	164,000
Total MW		27	291	56	44	11
Total MWh/year		94,500	354,600	371,000	374,000	374,000
Grand Total kWh/year			1,568,100,000			

Table 5.7. *Estimated Annual Commercial and Industrial Energy Demand from the Largest Demand Low and Medium Pressure Network Connections in Leeds*

Note: Process boilers: The annual operating hours of space heating has been reduced to 1,400 hours to allow for plant oversizing. Declared gas demand is often based upon installed combustion equipment.

Space Heating: The annual operating hours has been reduced to 6,000 hours to allow for non-operation at weekends and Bank Holidays.

CHP for medium pressure, value 15: Mostly Leeds University campus or hospital.

The previous table indicates that projected demand from the 127 largest peak demand sites is 1,568,100 MWh/yr. The potential for inaccuracy is accepted but the technique does yield both reasonable and self-consistent data.

## The 118 Areas of MSOA Non-domestic Gas Data

Of the 3,126 non-domestic meter points in the area of conversion the 127 largest demand sites consume 1,568,100 MWh/yr leaving a remaining 2,999 sites of non-domestic consumers. Assuming the total of 3,126 sites consumes the non-domestic total of 2,326,627 MWh/yr this allows a further 758,527 MWh/yr of consumption by 2,999 sites.

Local Authority Code	MSOA Name	MSOA Code	Consumption (kWh)	Number of Meters	Mean Consumption (kWh per Meter)	Median Consumption (kWh per Meter)
E08000035	Leeds 002	E02002331	41,095,733	75	547,943	142,955
E08000035	Leeds 003	E02002332	5,540,664	7	791,523	124,434
E08000035	Leeds 004	E02002333	8,602,449	44	195,510	118,309

Table 5.8. *Examples of MSOA Non-domestic Data*

Further examination provides three interesting points:

- About 65 areas have fewer than 20 non-domestic meters i.e. they are essentially residential areas;
- Almost 50% of the non-domestic gas (1,151,507 MWh) was consumed in just four MSOA (out of a total of 2,326,627 MWh, 2013). Between these four areas they contain 578 individual meter points, a number too large to provide much further insight. For reference the four areas are Wakefield 014 (E02002451), Leeds 064 (E02002393), Leeds 112 (E02006876) and Leeds 111 (E02006875); and
- On inspection most MSOA areas show a non-domestic annual usage of between 200,000 to 400,000 kWh/yr. It is reasonable to assume that most of this usage will be required by 200 kW boilers similar to those found in schools, office blocks, and other large buildings.

As there are 3,126 non-domestic meter points this would provide an average of  $3,126/118 = 26$  to 27 meter-points per MSOA. About half the MSOA have 20 sites or less so an equal number probably have 30 to 40 sites. This is all in accordance with sound engineering judgement. Clarifying these values must be a priority during the next phase of any conversion programme.

Amalgamating these data sources produces the following installed boiler capacity and annual demand (Table 5.9).

Description	Meter Points	Installed Capacity kW	Annual Use MWh	%
Largest Peak Demand Sites (from NGN Data)	127	See detail above	1,568,100	67%
200 kW Sites (from MSOA Data)	2,999	599,800 (200 kW x 2,999 sites)	758,527	33%
<b>MSOA Total</b>	<b>3,126</b>		<b>2,326,627</b>	

Table 5.9. *Installed Non-domestic Capacity*



Some process plant will inevitably be affected by the reduction in flame radiance, but hydrogen flames are hot and so solutions should be possible. The technologies will tend to be scaled up versions of the domestic options. One of the advantages of hydrogen is the absence of risk of CO poisoning, and the potential for low NO<sub>x</sub> levels so flue systems (always a major cost in I&C installations) should be capable of major simplification.

Category	Change	Conversion Cost per kW Gas Capacity	Installed kW Thermal	Conversion Cost
Commercial > 70 kW (from MSOA Data)	Boiler (costed on basis of 200 kW sites)	£150.00	600,000	£90,000,000
Process Boiler (from NGN Data)	New burner	£50.00	27,000	£1,350,000
Space Heating (from NGN Data)	New boiler	£100.00	291,000	£29,100,000
CHP* (from NGN Data)	New turbine	£1,000.00	56,000	£56,000,000
Glass (from NGN Data)	New furnace	£1,000.00	44,000	£44,000,000
Process (from NGN Data)	New burner	£250.00	111,000	£27,750,000
			<b>Total</b>	<b>£248,200,000</b>

Table 5.10. *Estimated Costs for the Conversion of Industrial and Commercial Equipment to Hydrogen*

Note: CHP – the CHP cost is loosely based upon current natural gas prices.

This is equivalent to an average of £30,000 for each of the 200 kW sites plus £1.25 m for each of the 128 larger sites. This value appears credible, as some sites will be expensive (e.g. CHP) and others very modest, e.g. a large steam boiler in a food factory with a single burner.

## 5.3. Switchover Cost Estimates – All Sectors

The overall estimate has been produced by the summation of the estimates for the domestic and non-domestic sectors. It is assumed that the accounting for overhead costs in the domestic sector cost model would be sufficient to cover these costs in the non-domestic sectors. So no overhead has been included in the non-domestic cost build.

The totals are given in [Table 5.11](#).

Sector	Overall Estimated Cost
Domestic ( <a href="#">Table 5.6</a> )	£805m
Non-domestic ( <a href="#">Table 5.10</a> )	£248m
<b>Total</b>	<b>£1,053m</b>

[Table 5.11. Overall Estimates](#)





## 5.4. Conclusions

While clearly a considerable sum, the above investment will eliminate the point of use carbon emissions from Leeds and can potentially vastly reduce NOx. There are still some significant challenges regarding encouraging appliance development but there are also some opportunities that could be taken advantage of to reduce the costs of conversion over time. The key conclusion should be conversion is possible but the manufacturing industry needs to be encouraged to produce appropriate appliances both domestic and commercial/industrial. It is suggested that government and/or gas industry assistance should be restricted to a basic grade of 'entry level' appliances. These must be simple, economical and robust; householders can then be encouraged to upgrade these as they see fit. Recent contact with manufacturers is very encouraging.



## 5.5. Properties of Hydrogen

### *History of the Combustion of Hydrogen*

*Hydrogen (composing about half of town gas on volumetric basis) has been used as fuel since 1816, when the town of Preston installed gas street lighting. The following year the first gas meter was developed and installed at the gas works of the Royal Mint. In 1874 the writer Jules Verne predicted "yes, my friend I believe that...hydrogen and oxygen..., used singly or together, will furnish an inexhaustible source of heat and light, of an intensity of which coal is not capable". In 1937, an experimental hydrogen fuelled jet engine was tested at Hirth, and in 1941 besieged Leningrad converted some hundreds of cars (known as the model GAZ-AA) to provide support to the ground bases of barrage balloons. The term 'hydrogen economy' was first used by John Bockris during a talk he gave in 1970 at General Motors (GM) Technical Centre.*

*The combustion of hydrogen at atmospheric pressure in an open burner is extremely simple, so simple that there is a paucity of direct references. It only becomes of interest where a number of hydrogen appliances have been brought together to demonstrate the concept of clean technology, for example R.E. Billings, (1978). 'The Hydrogen Homestead Study'. R.E. Billings converted or built a range of gas appliances to operate exclusively on hydrogen, and as will be listed below, this trend of DIY hydrogen appliances, particularly amongst rural US environmentalists continues to this day.*

*There is no fundamental reason why a hydrogen burning appliance should (in mass production) be materially different in cost to the equivalent natural gas appliance.*

*Due to the absence of bulk supplies of low cost hydrogen there is currently no large scale market and hence no mass manufacturer of hydrogen appliances. There is however one fully certified domestic boiler (Giacomini), and a Scottish company (Almaas Technologies Limited) are currently developing a range of cooking and catering apparatus. A range of industrial burners are also readily available. There are also a range of fuel cells for the high efficiency production of electricity (at up to 60% efficiency (HHV), and sometimes electricity plus heat.*

### 5.5.1. Principles of Hydrogen Combustion

Hydrogen combusts readily releasing considerable quantities of heat. It can be burnt in air as a very high-temperature flame, or can be catalytically oxidised on the surface, for example platinum at only marginally above room temperature. Both means of combustion only generate water, although due to the high temperatures involved some hydrogen flames can generate significant quantities of oxides of nitrogen. Hydrogen was/is typically 50% of the volume of town gas and hydrogen can be burnt in so-called 1<sup>st</sup> Family gas appliances. These look very similar to conventional natural gas (2<sup>nd</sup> Family) or LPG (3<sup>rd</sup> Family) appliances but are optimised for the high flame speed of hydrogen. There is no fundamental reason why hydrogen appliances using flame combustion should be significantly more expensive than appliances for other gases. Catalytic combustion does involve the purchase of catalysts which tend to be based upon noble or transition metals which can be expensive. Apart from the very limited number of commercially available products, there are several very simple designs of DIY hydrogen appliance on the internet; these are not held up as 'good engineering' but they illustrate that in principle such appliances are simple and low cost.

Hydrogen is not directly detectable by human senses as it is:

- Odourless;
- Tasteless; and
- Colourless.

It is also:

- Non-toxic and non-carcinogenic – although it is an asphyxiant;
- Non-corrosive; and
- Is not a direct greenhouse gas, although some authorities indicate possible second order affects.

At ambient conditions hydrogen is a diatomic gas with a low density of 0.085 kg/Nm<sup>3</sup> (approximately 11% of that for natural gas) compared to 1.28 kg/Nm<sup>3</sup> for air (15 °C and 1.013 bar).



It is the lightest element and in the air its buoyancy causes it to rise and disperse rapidly (speeds of almost 20 m/s). A comparison of the energy conveyance properties of hydrogen and natural gas are summarised in [Table 5.12](#).

	Hydrogen	Methane (Natural Gas)	Air
Molecular Weight	2.02	16.04	28.9
Density 15 °C kg/Nm <sup>3</sup>	0.0855	0.6786	1.2227
HHV kJ/kg*	142,000	55,000	N/A
HHV kJ/Nm <sup>3</sup>	12,135	37,323	N/A
Wobbe Index kJ/Nm <sup>3</sup>	45901	50098	N/A
Wobbe Index Ratio	91.6%	100%	N/A
Volumetric Leak Ratio	282%	100%	N/A

Table 5.12. A Comparison of the Energy Conveyance Properties of Hydrogen and Natural Gas

\*HHV is the higher heating value of the gas, i.e. the energy released when burning hydrogen or natural gas.

Because hydrogen has a much lower density than methane it leaks from orifices much more quickly (282% of methane), but as its' calorific value is much less, the Wobbe Index (used by gas engineers to describe the energy carrying capabilities of gases) are broadly similar. For the same pressure drop, hydrogen can carry about 92% of the energy down a pipe as natural gas. In practice due to 2<sup>nd</sup> order effects it is slightly less than this.

Hydrogens high diffusivity when compared to natural gas has other effects:

- Greater ability to permeate through materials and joints, although the actual rate of diffusion through pipes is very small. It is calculated that the yearly loss of hydrogen by leakage through polyethylene (PE) pipelines amount to approximately 0.0005–0.001% of the total transported volume. (Ref: Division of Energy Conversion, University of Leuven (K.U. Leuven), Celestijnenlaan 300A, 3001 Leuven, Belgium).
- Leaks will disperse more quickly into the air due to its low density and high rate of molecular diffusivity.

As seen in [Table 5.12](#) hydrogens low molecular weight results in it having the highest energy content per unit mass (thus a kg of H<sub>2</sub> has 250% more energy than a kg of CH<sub>4</sub>) of any fuel. However its low density means that its volumetric energy content is relatively low (i.e. 1 m<sup>3</sup> of hydrogen only contains 31% of the energy than 1 m<sup>3</sup> of methane). When burned hydrogen releases only one-third as much energy per unit volume of gas as natural gas at the same pressure.

## Breakout: The Calorific Value of Hydrogen

The heating value (often referred to as the Calorific Value or CV) is the amount of heat energy released by combustion of a fuel. The 'Lower Heating Value' (LHV or net CV) is based on the assumption that the latent heat of vaporisation in water vapour from the reaction is not released whereas the 'Higher Heating Value' (HHV or gross CV) represents the total energy in the fuel. The HHV unit of energy is used to buy and sell gas in the UK, and has recently become the preferred unit within the EU.

### The Wobbe Index of Hydrogen

The Wobbe Index (WI) or Wobbe number is an indicator of the interchangeability of fuel gases such as natural gas, Liquefied Petroleum Gas (LPG), and town gas and is frequently defined in the specifications of gas supply and transport utilities. Numerically it is the higher calorific value/ $\sqrt{\text{relative density}}$

The WI of hydrogen is about 46 MJ/Nm<sup>3</sup>, this compares with > 47.20 and < 51.41 MJ/Nm<sup>3</sup> of current natural gas (primarily methane). This is because although hydrogen has only a third of the CV, it has  $\frac{1}{8}$  of the density. This similarity in WI, can lead to the conclusion that hydrogen can be burnt in conventional natural gas appliances. The much higher flame speed and low emissivity from hydrogen mean this is not the case. This similarity in WI does however mean the energy transportation properties of the gases are broadly similar.

This low volumetric calorific value has implications for storage. To store equivalent amounts of energy to that currently held in natural gas stores would require a tripling of either storage volumes or pressures (or some combination of this).

### 5.5.2. Hydrogen Safety

When considering the use of another fuel gas, in this case hydrogen instead of methane, the relative risks of this alternative fuel gas need to be understood in addition to whether an appliance can operate on such a gas.

The recent HyHouse project has offered considerable insight into this area. HyHouse involved injecting substantial quantities of both methane and hydrogen into a two storey Scottish farmhouse and measuring the relative concentrations.

To summarise, 3.4 times as much hydrogen (on a volumetric basis) was injected than methane and yet (typically) measured general concentrations were only 140% to 160% of those with methane. Bearing in mind the stoichiometric concentration, i.e. the optimum gas mixture for combustion, is only 10% v/v for natural gas and 29% v/v for hydrogen, the independent committee that oversaw the HyHouse work (this included a representative of IGEM), considered that the out-turn risk from unplanned leakage of hydrogen from a gas network was not that dissimilar to a leak of natural gas, through a similar hole.



## Breakout: The Safety of Hydrogen

Hydrogen is a flammable gas, with wide flammable limits, but the stoichiometric mixture, (i.e. the perfect mixture for combustion) is circa 29% on a volumetric basis (v/v) in air, compared with 10% v/v for Natural Gas (NG). Therefore, to get the 'perfect combustion' requires about three times the concentration of hydrogen in air. The HyHouse project showed that due to its low density and high diffusivity it was very difficult to obtain such high concentrations in a domestic property. In practice despite releasing about 3.4 times the volume of hydrogen relative to methane into an old farmhouse, the resulting concentration was only 1.2 to 1.6 times higher (all v/v basis). Having said this, hydrogen can be very dangerous similar to any flammable gas and the details of current UK natural gas design codes will certainly need modification to cover hydrogen.

The safety of a flammable gas in a particular situation and the severity of any fire and/or explosion depends on upon the following:

- The concentration of the flammable gas in the air (measured as %v/v) is relative to its stoichiometric and flammable limits. This is in turn a function of the gas's density and diffusivity.
- The speed of any consequential flame front. Higher flame speeds produce higher overpressures which are more likely to be more injurious to buildings and health.
- Whether the mixture is enclosed or in free air, and the level of obstruction within the combustion zone.
- The ignition energy used to fire the mixture.

As indicated in Table 5.13, hydrogen is flammable across a much greater range of concentrations than methane, i.e. 4 to 75%, rather than 5.3 to 15%. This would appear to make hydrogen much more dangerous, but in practice between 4 and 9%, the combustion is a fairly benign 'woosh' whereas natural gas at such concentrations is effectively a conventional gas explosion, with its ensuing damage. At higher volumetric concentrations hydrogen can generate substantial overpressures, as can any flammable gas, but as found in the HyHouse experiments even in well-sealed modern house it is difficult to realistically release enough hydrogen to obtain these high concentrations. The hydrogen just disappears. It is likely all new domestic hydrogen conversions would be fitted with an excess flow valve (similar to a fuse in an electrical circuit) that would limit the maximum gas flow. This might be pre-set at 64 kW. Such a flow-rate rate barely achieved 13-14% v/v even in the room of release. Released at concentrations (usually over 18%) within a box filled containing an array of hard objects, (e.g. steel pipes) hydrogen detonations have been reported, which a more serious form of explosion, than a conventional gas explosion or deflagration, but historically these are exceedingly rare (a hand-full worldwide in last 50 years) and with sound engineering can be completely avoided.

A summary of the wider physical properties of hydrogen in comparison to methane (CH<sub>4</sub>) and natural gas are shown in [Table 5.13](#).

Parameter	Units	Hydrogen	Methane	Natural Gas
Molecular Weight	g/mol	2.016	16.04	
Mass Density*	kg/Nm <sup>3</sup>	0.09	0.72	0.78†
Specific Gravity‡	Air = 1	0.0696	0.555	
Boiling Point	K	20.2	111.6	
Higher Heating Value	MJ/kg	142	55.5	52.2†
	MJ/Nm <sup>3</sup>	13	40	
Lower Heating Value	MJ/kg	120	50	47.1†
	MJ/Nm <sup>3</sup>	11	36	
Flammability Limits	% volume	4.0-75.0	5.3-15.0	5.3-15**
Detonation Limits	% volume	18.3-59.0	6.3-13.5	5.7-14**
Diffusion Velocity in Air	m/s	2	0.51	
Buoyant Velocity in Air	m/s	1.2-9.0	0.8-6.0	
Ignition Energy				
<i>at stoichiometric mixture</i>	mJ	0.02 (29% in air)	0.29	0.29** (9% in air)
<i>at lower flammability limit</i>	mJ	10	20	
Flame Temperature in Air	(°C)	2,045	1,875	
Flame Velocity in Air	cm/s	265-325	37-45	

Table 5.13. Comparison of Physical Properties of Hydrogen, Methane and Natural Gas

This data is taken from Data extracted from Ogden, 2008 except where indicated otherwise.

\* at Standard Temperature and Pressure.

† from the US DoE Hydrogen Databook.

\*\* from the National Hydrogen Association Factsheet – Hydrogen safety.



## 5.6. Types of Hydrogen Combustion

To provide useful energy hydrogen may be oxidised to release energy and produce water.

	HHV	LHV	Heat Release from Water Condensation:
	<b>kJ/kg</b>	<b>kJ/kg</b>	<b>kJ/kg</b>
<b>Hydrogen</b>	141,790	121,000	20,790
%	100%	85%	15%
<b>Methane</b>	55,530	50,000	5,530
%	100%	90%	10%

Table 5.14. A Comparison of the Energy Release Properties of Hydrogen and Natural Gas

The most important driver for the use of hydrogen as a fuel is the very low levels of emissions formed during combustion when compared to natural gas. There is no CO<sub>2</sub> produced and so the only pollutant created during combustion of hydrogen in air are oxides of nitrogen. This can occur as a result of the high flame temperature and the nitrogen content of air however, with careful engineering, this can be minimised or even eliminated.

For simplicity there are four main routes by which combustion of hydrogen can occur:

- Flame combustion.
- High temperature catalytic combustion.
- Low temperature catalytic combustion.
- Fuel cell.

Each of these mechanisms has different characteristics which are summarised in [Table 5.15](#).

Combustion System	Operating Temperature (°C)	Positive Characteristics Relative to Natural Gas	Negative Characteristics Relative to Natural Gas
Flame Combustion	1200 – 2,100	High heat output	Relatively high NO <sub>x</sub> , unless specifically low NO <sub>x</sub> technology employed Risk of lightback
High Temp Catalytic	500 – 1,200	Always low NO <sub>x</sub>	None
Low Temp Catalytic	> Room temperature – 500°C	Zero NO <sub>x</sub> . No risk of fire	Low specific heat output compared to a flame
Fuel Cell	> Room temperature – 900°C	Simple and robust design electric and heat output Very low NO <sub>x</sub>	None

Table 5.15. *Characteristics of Hydrogen Combustion Systems*

### 5.6.1. Flame Combustion

When burnt in a bunsen burner, hydrogen and air burn broadly similarly to natural gas and air, except that hydrogen flame front is moving more quickly so the flame tends to be smaller.

The absence of carbon means no risk of carbon monoxide or smoke. Its pale blue flame can be difficult to see, as the flame from entirely pure hydrogen emits little radiation visible to the eye. However, the presence of impurities (at even the parts per billion level) may produce a variety of colourations. If it were felt beneficial the flame can (for example) be coloured red with an extremely dilute strontium (a benign alkali earth element) solution of concentration 1 in a billion.

As indicated above, the combustion products are water vapour and some NO<sub>x</sub>. The amount of NO<sub>x</sub> produced depends mainly on the flame temperatures.

Flame combustion is a generic system which includes a range of specific types of burner including non-aerated and aerated (with partial or full pre-mixing of fuel and air). For each type there are a number of possible configurations of combustion 'head' (shape and size, with nozzles of a range of shapes and size or permeable materials giving a distributed flame, gas turbine combustion canisters and more) which provide different combustion conditions, flame temperatures, heat release patterns and consequently different levels of NO<sub>x</sub> formation. In terms of flame combustion, hydrogen can be considered as a 1<sup>st</sup> Family gas comparable with town gas (50-60% volume/volume H<sub>2</sub>).

Traditionally partially pre-mixed flame combustions were variants upon a bunsen burner, but more recently distributed combustion of a premixed gas/air blend on the surface of a plaque burner (see Remeha boiler below) can begin to function more like a catalytic burner, i.e. the hydrogen and oxygen are brought together on a hot catalytic surface.

The seminal work by British Gas (Jones, H. R. N. (1989)) provides an extensive discussion of gas-fired combustion appliance design which while focussed on natural gas also covers some of the implications for combustion of hydrogen in mixtures or alone.

The combustion of hydrogen yields about 60% more water per kWh of heat release than natural gas, a 10 kW (input) hydrogen appliance will generate about 2.3 kg/h of water. Such water is not significant regarding local outdoors climate, but should be vented external to the property. Conversely it will create considerable additional humidity where flueless appliances are used and any subsequent condensation would be a concern due to the promotion of mould growth. Existing requirements to limit ventilation has already led to the risks of higher humidity levels in modern dwellings so this subject is well understood and can be satisfactorily addressed. Interestingly 'The Hydrogen Homestead Study' presented by R.E. Billings at the second World Hydrogen Energy Conference in 1978 did not seem to pick up on this risk, and the benign nature of the emissions from hydrogen combustion was cited as an opportunity to reduce heat loss significantly by decreasing ventilation. Essentially the hydrogen flue gas (steam) can be vented externally like a conventional appliance or the whole room can be better ventilated. Both routes have their advantages and disadvantages.

Heat transfer from hydrogen flames, as for all flames, is split between conduction (which requires flame impingement on the surface of the material being heated), convection (the flue gas and air heated by the flame move and carry the heat with them) and radiation, where heat is radiated from materials at higher temperature to materials that are at lower temperature.

The water vapour generated in hydrogen flames contributes to their low radiance compared to hydrocarbon flames even though the flame temperatures may be similar. Therefore, a higher proportion of the heat from hydrogen flames must be transferred by the other mechanisms than is the case for natural gas flames, but this is not considered problematic, as the excess air level with hydrogen can be lower, with no risk of CO formation. German tests in identical domestic 20 kW boilers, reported efficiencies of 87.7% and 87.9% (HHV) with hydrogen and natural gas respectively.

Ref. Operation of 20 kWth gas-fired heating boilers with hydrogen, natural gas and hydrogen/natural gas mixtures, First test results from Phase 1 (March 1993) of the Neunburg vorm Wald Solar Hydrogen Project K. Hoelzner A. Szyszka.



## 5.6.2. Catalytic Combustion

A catalytic combustion 'burner' functions differently to burners with defined flames. They are based upon the reaction of hydrogen and oxygen on the surface of a catalyst; typically platinum, other noble metal or transition element compound. There tends to be a continuum between these products and some conventional distributed flame burners such as the sintered metal fully pre-mixed burners in modern boilers. Their advantage is operation at much lower temperatures than flame combustion, so they have lower NO<sub>x</sub> emissions and the red-hot nature of the catalyst (if operating that hot) can assist heat transfer.



Image 5.1. *Examples of Distributed Flame Gas Burners from Remeha (left) and Alpha (right)*

The British Gas book lists catalytic gas burners key points as having several key points:

- Can be diffusion (where pure hydrogen emerges from between the pores of the catalyst) or pre-mixed, where a hydrogen/air mixture emerges from the catalyst;
- Frequently consist of a pad of ceramic fibres with catalytic particles distributed evenly through the pad;
- Require method of initiating ignition source – electric pre-heater/pilot light;
- Flameless, resistant to drafts and changes in gas composition;
- High radiant efficiencies (>50%) are achievable; and
- Low NO<sub>x</sub>.

Generally speaking, switching from hydrocarbon to hydrogen retains the advantages and reduces or removes some disadvantages (no possibility of carbon deposition) Some authors (e.g. Rapport SGC 201 – Catalytic burners in larger boiler appliances Svenskt Gastekniskt Center – February 2009) even claim catalytic boilers can be much smaller. For example in [Image 5.2](#).

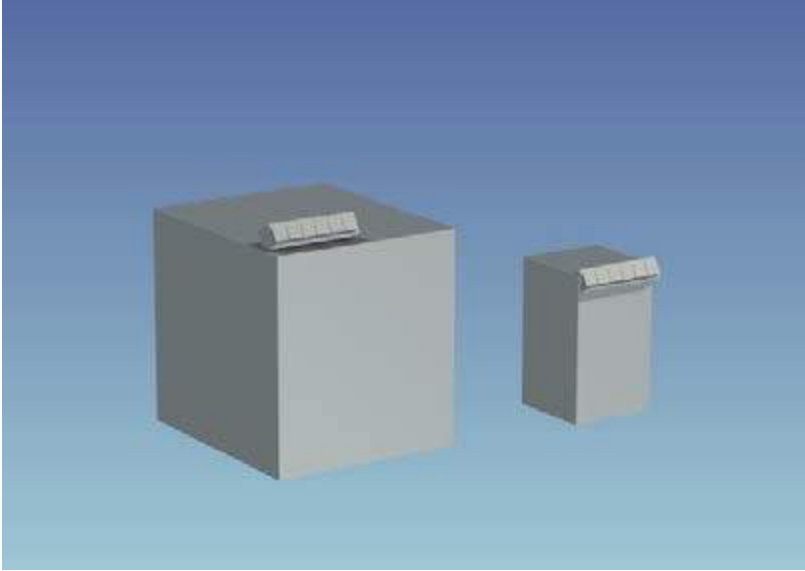


Image 5.2. *Comparison of Size of Conventional and Catalytic Boilers*

## Implications of Different NO<sub>x</sub> Levels from Flame and Catalytic Combustion

Historically the NO<sub>x</sub> levels from some domestic gas appliances (burning natural gas) were quite high, although by 2013 the average had fallen to about 80 mg/kWh (ref DECC DUKES and the UK NAEI). This compares to a modern low NO<sub>x</sub> condensing boiler of < 40 mg/kWh. If the design average gas demand of the area of conversion (732 MW) were all to be burnt in the 2013 average gas burner this equals about 500 tonnes NO<sub>x</sub> per year. This in turn can be valued at between £2.8m and £11m per year at the DEFRA lower and upper NO<sub>x</sub> valuations respectively (ref Valuing impacts on air quality: Updates in valuing changes in emissions of Oxides of Nitrogen (NO<sub>x</sub>) and concentrations of Nitrogen Dioxide (NO<sub>2</sub>) September 2015)

Appropriate catalytic hydrogen appliances can effectively eliminate NO<sub>x</sub> from the domestic combustion of gas. Although by nature of their catalysts and ingenious design, catalytic combustion is currently always more expensive than flame combustion. Unfortunately, with the current state of knowledge, the cost vs. NO<sub>x</sub> curves for hydrogen appliances are not known. With the current high state of interest in hydrogen combustion by manufacturers (to a large degree generated by this project) this information should be available in the near future, but in its absence, this matter is not explored further in this report and conversion costs have been based on switching to conventional flame combustion.

In conclusion it is possible that on a conversion from natural gas to hydrogen, there could be an opportunity to upgrade appliances with catalytic appliances which would reduce (virtually eliminate) NO<sub>x</sub> emissions. This could be offered on an 'additional payment option' whereby the homeowner could pay the difference for this additional upgrade from their traditional flame combustion appliances, although recent work with appliances manufacturers indicated their preference for DECC and DEFRA to simply set maximum NO<sub>x</sub> levels.

### 5.6.3. Fuel Cells

At this stage the project is orientated around simple combustion; however low cost, low carbon hydrogen offers considerable potential for the 'packaging' of hydrogen fuel cells to produce local electricity and heat units, (i.e. CHP). A typical low-temperature Proton Exchange Membrane (PEM) fuel cell will operate at an efficiency of 60% electricity and a further 20% heat, (i.e. 80% overall HHV), and respond within minutes. The potential ramifications of this regarding replacing central power generation and transmission are very considerable. The pipeline grade hydrogen is unlikely to be of a quality suitable for direct use, but the incentives, arising from competitive low-cost local hydrogen, should be large enough to drive the design of sophisticated hydrogen clean up units, that will take the hydrogen from the predicted 99.9% (delivered) to 99.9999(9) % purity required for PEM fuel cells. Anecdotally this is already occurring and some automotive fuel cells (which tend to have fewer operational hours than static cells) are reported to operate at up to 15 ppm CO.

The term 'packaging' is used because the development of the underlying fuel cell technology is extremely expensive, and limited to a few worldwide companies. However many of these companies only wish to sell a raw 'cell'. The integration of these into usable products for use in the home or commerce contains very considerable intellectual property, and the indication is that the UK has a significant number of companies who could produce such packages. The UK does also have companies with underpinning fuel cell knowledge and these could be particularly well placed to launch OEM products. Several manufacturers of the current generation of natural gas fuel cell use miniaturised SMR and shift reactors to produce hydrogen which is in turn fed to a PEM fuel cell and almost certainly these companies will move into selling just the hydrogen fuel cell.

In conclusion it is possible that, as with catalytic heating systems, on a conversion from natural gas to hydrogen there could be an opportunity to upgrade appliances with fuel cell appliances which would support electrical decarbonisation and help accelerate this technology. This could be offered on an 'additional payment option' whereby the homeowner could pay the difference for this additional upgrade from their traditional flame combustion appliances. Until these producers are commercially developed this option, while worth considering, is not explored further in this report and conversion costs have been based on flame combustion 'switching'.

#### Testing and Certification of Hydrogen Appliances

The EU Gas Appliance Directive, which regulates the manufacture and sale of gas appliances within the EU, already encompasses hydrogen appliances, which can be judged against the essential requirements. There is currently a shortage of Euronorms that make specific reference to hydrogen combustion, but this is readily soluble once a market is established. There will be a requirement for IGEM and the gas industry to compile installation standards.





## 5.7. Current Status of Hydrogen Appliances and Equipment

Appliances generally include such things as heaters, boilers and cookers used in domestic and small commercial settings. Equipment refers to larger scale equipment including such things as industrial boilers, industrial process burners and gas turbines.

As indicated above there are two general routes to hydrogen combustion – either flame or catalytic. There are three main questions to ask about using hydrogen as the fuel for appliances and equipment:

- Can they be operated safely?
- Do they operate effectively/efficiently with minimal atmospheric emissions?
- Are they aesthetically acceptable?

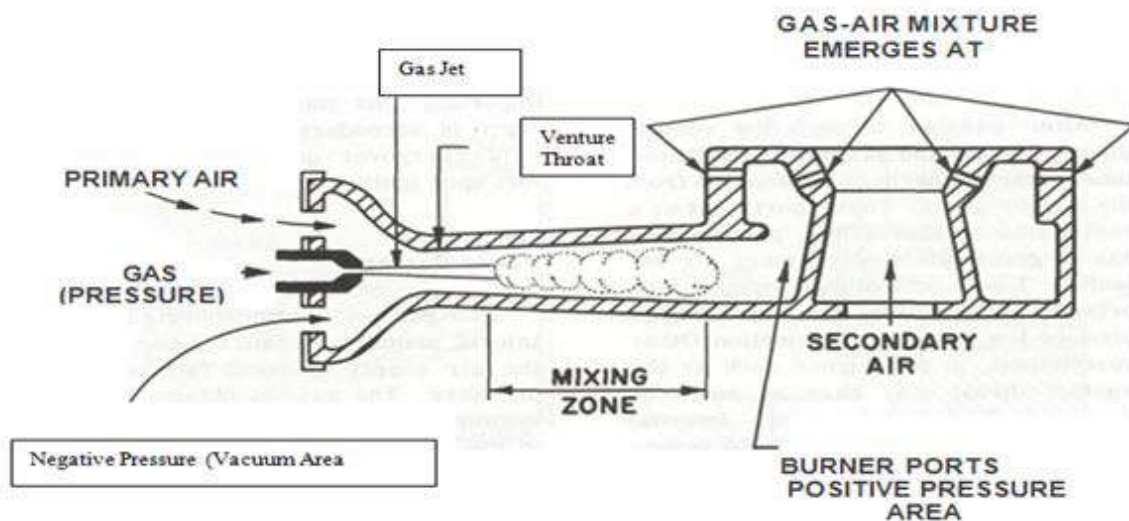


Image 5.3. Typical Natural Gas or Hydrogen Partially Premixed Gas Burner ref [www.Cielotech.Wordpress.Com](http://www.Cielotech.Wordpress.Com)

The first question can be addressed by attention to design, especially ensuring that potential risks such as lightback are 'designed out'. Lightback is where the flame ceases to be located at the exits of the gas-air mixture orifices, but ignites within the 'gas jet' (i.e. after the injector marked in black).

The second and third questions cover such issues as the effect of the low radiance and small size of hydrogen flames and high water contents of flue gases. Again design is key.

Different applications may require different solutions. The main activities for which natural gas is currently used are:

- Space heating: radiant and convective heaters;
- Water heating: boilers (for space heating systems and Domestic Hot Water (DHW) production and dedicated water heaters;
- Cooking: hobs and ovens;
- Process heating: process burners of a wide range of designs for many different industrial processes, high pressure, high temperature hot water boilers, steam boilers and steam generators; and
- Power generation: gas turbines.

Hydrogen can replace natural gas in all of these but inevitably using different designs. Since the 1970s many natural gas appliances have been successfully converted to hydrogen by academic and industrial researchers as well as by low carbon minded home enthusiasts. Many of these home conversions have been published on engineering hobbyist websites or in journals such as 'Home Power'.

Formal studies have also been undertaken such as 'The Hydrogen Homestead Study' which successfully demonstrated the use of hydrogen fuel as a replacement for natural gas in a range of appliances, and vehicles.

It is vital to stress that the current range of hydrogen appliances is extremely limited, and arguably only functional in design, because of the extremely small market for such appliances (probably less than 100 units per year). What is important is that the process of combustion is well understood and proven. Given bulk supplies of gas and a large domestic market, more sophisticated product will arrive.

## 5.7.1. Domestic Appliances

### Space Heating: Radiant and Convective Heaters

As indicated above the design of hydrogen fired domestic heaters can be very simple

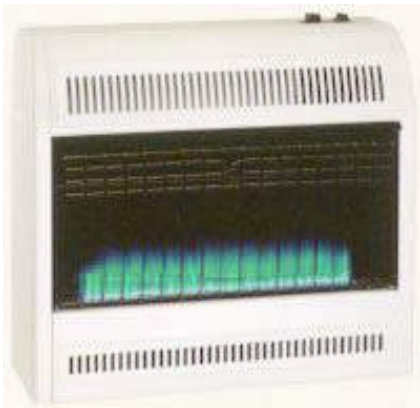


Image 5.4. Model #GFH6000 Green Flame Heater Hydrogen Fuelled Input 1.3 kW to 1.8 kW

Current designs are not aesthetically acceptable to many householders. However the UK is Europe's largest manufacturer of decorative gas fires, and there is no reason why a range of attractive gas fires could not be developed relatively quickly. Many electric decorative fuel effect fires sell well and hydrogen offers the potential of a real flame, therefore hydrogen could be regarded as less of a challenge than its electrical counterparts. It has the added benefit over natural gas of not being able to form carbon monoxide.

### Water Heating: Boilers And Dedicated Water Heaters

In modern boilers the need to have accurate control over the combustion process to minimise energy consumption and pollutant formation has resulted in the use of burners where the air supply is positively controlled. Thus, the burners are in general fully pre-mixed forced/induced draft pressure jet or distributed flame types.

An Italian manufacturer, Giacomini, have developed a highly efficient zero NO<sub>x</sub> domestic boiler. This 5 kW (nominal heat output) condensing product is fully CE marked and on the market. It employs a catalytic burner with a reaction temperature of between 250°C and 300°C. Due to these low combustion temperatures the emissions of NO<sub>x</sub>, which is formed from nitrogen in the combustion air, are zero as the combustion temperatures are not high enough for the formation mechanism to occur.

Technical data of this hydrogen boiler is provided in [Table 5.16](#) and the unit is shown in [Image 5.5](#).

Technical Detail	Unit	Value
Nominal Heat Output	kW	5.01
Nominal Heat Power	kW	5.36
Useful Efficiency (Maximum)	%	106.7
Type of Gas	N/A	H <sub>2</sub>
Inlet Gas Pressure	bar	5
Purity of Hydrogen	%	99.5
Hydrogen Consumption at Nominal Power	Nm <sup>3</sup> /h	1.67
Maximum Temperature on Catalysts	°C	400
Average Exhaust Temperature	°C	40
Maximum Hydrogen Concentration in the Reaction Channel	%	3
Pressure in Reaction Channel	mbar	30
Maximum Condensing Water in Exhaust	L/h	1.34
NO <sub>x</sub> Concentration	ppm	0
CO Concentration	ppm	0
Maximum Pressure of Water	bar	3
Water Set Temperature	°C	30-60
Water Inside the Burner	l	2.1
Net Weight	kg	40
Length	mm	888
Width	mm	520
Height	mm	314

Table 5.16. *Technical Detail of the Giacomini Hydrogen Boiler*



Image 5.5. *Giacomini Hydrogen Catalytic Boiler (Giacomini, 2011)*

Rated at only 5 kW it would have a very small market in Leeds, essentially limited to large modern properties with space for a DHW tank. Unusually the unit is floor mounted but of low profile.

Unfortunately, this product will require some modification for the mass rollout in Leeds, (for example increasing the kW rating and reducing the required gas pressure) but it does currently sell throughout Europe to the hydrogen enthusiast market and admirably demonstrates that the principle of commercial hydrogen appliances is already in existence.

Prototypes of larger boilers have also been built for example report 'Rapport SGC 201 Catalytic burners in larger boiler appliances Svenskt Gastekniskt Center – February 2009 Fredrik Silversand & Mikael Persson Fredrik Silversand & Mikael Persson Catator AB' contains a photograph of a 90 kWth catalytic burner for combustion of hydrogen at minimal excess air, to maximise thermal efficiency.

### 5.7.2. Cooking: Hobs and Ovens

There is a wide range of hydrogen fired cooking equipment already available on the internet, mostly from US suppliers, although some in the UK, e.g. ITM Power based in Sheffield, have marketed a range of hydrogen appliances. The latter was active in appliances until about 2010, when they withdrew from the market due to an absence of demand. Pure Energy still sells hydrogen appliances.



Image 5.6. *DIY BBQ*

Production: Two types available, a hydrogen cooker and a barbecue. Use: Similar to any standard cooker. Thermal output: from 500 to 5,000 W Emissions: no CO<sub>2</sub> and very low NO<sub>x</sub> emissions



Image 5.7. *Hydrogen Cooker*

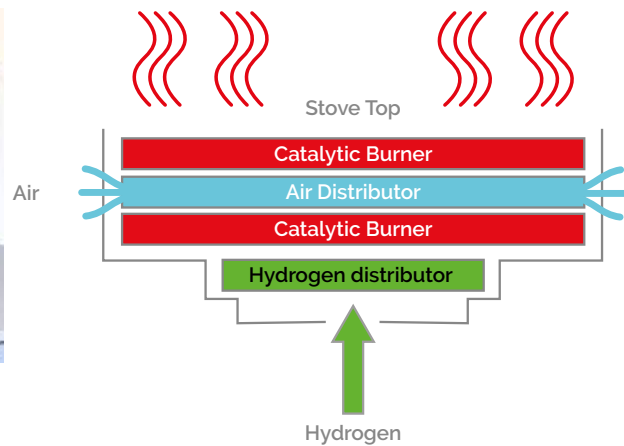
Hydrogen cooker from the Pure Energy Centre, Unit 3, Hagdale Industrial Estate, Baltasound, Unst, Shetland. ZE2 9TW United Kingdom.

Much of the US equipment seems 'homemade', but their very presence confirms that hydrogen can readily be used for cooking. Examples include DIY hydrogen burners designed and developed by Booth, D. & Pyle, W., (1993) and Pyle, W., Dabritz, J. & Healy, J., (1994). Some changes in design will be required particularly as hydrogen produces considerably more water than natural gas per kWh of heat, 0.23 kg vs. 0.14 kg respectively (see also above). While creating a higher moisture atmosphere which, for example, cooks meat better, however, this can lead to water-logged pastry and bread.

Cooker manufacturers have always adjusted the ratio of convective to radiant heat transfer to the food being cooked and there is no obvious reason why the performance on hydrogen should not be optimised.

A particularly interesting quote from the 'Hydrogen Homestead Investigation' is: "Tests of stove top burners indicate that 24 percent less energy is required to heat a pan with a hydrogen flame than with natural gas. This is possible since the pan is placed directly in the flame without fear of incomplete combustion or carbon deposition."

An example of a product with a more proven pedigree and better aesthetics is the Hydrogen-Fuelled Stove built in Switzerland. The Swiss Federal Laboratory for Materials Science and Technology (EMPA) have developed a catalytic hydrogen burner based on a highly porous silicon carbide (SiC) ceramic foam with a platinum catalyst. This burner has been developed into a domestically aesthetic kitchen stove in [Image 5.8](#).



[Image 5.8. Integrated Hydrogen Catalytic Burner \(Ulrich, V. \(EMPA\), 2015\)](#)

This catalytic burner is formed from porous SiC plates coated with a platinum catalyst and the air is provided so that combustion only occurs in the SiC layers. The burner has been integrated into an appliance by placing in a casing with a glass top to resemble current electrical domestic hotplates. This device also includes a heat exchanger that heats incoming combustion air to improve the product efficiency. Product schematics are show in [Image 5.8](#).

Almaas Technologies Limited is a small independent clean-tech company conducting hydrogen burner feasibility work with the aim to develop fit-for-purpose products of high quality and performance to support the decarbonisation of heat applications and commercialisation of low/zero carbon energy systems. Almaas Technologies have already demonstrated the conversion of catering appliances to hydrogen fuel in the UK.

### 5.7.3. Conclusions of Hydrogen Fired Domestic Appliances

The absence of a bulk piped hydrogen means no significant demand or market for hydrogen appliances and hence no mass market products available but the underpinning knowledge is well known and given suitable demand products will arrive within 2 to 3 years. A recent contract for DECC to investigate the potential for a UK hydrogen appliance chain has shown real enthusiasm especially amongst the largest players. Interestingly Enertek Ltd, probably the UK's largest outsourced gas appliance R&D Company, are based in Hull. They would be enthusiastic to provide development expertise to the large numbers of UK gas appliance manufacturers not large enough to have in-house resources.

The detail financial and contractual arrangements for the development of these hydrogen appliances will need considerable thought. From the end of WW2 to the late 1980's three fuel (gas, electric and solid fuel) industries spent in today's money in the region of £10m per year on supporting 'cutting edge' technology in the domestic and commercial sectors. Much of this was unsuccessfully spent on devices that, even at the time, looked too complex for the typical British householders use. Several 'advanced technology' fully private sector projects have similarly failed after very considerable investment; in two cases approaching £40m was spent. The situation is different in Germany where people like to showcase their new heating appliance. Because of the risks of this allocation of effort to the over-complex product, it is recommended that a simple set of basic and/or budgetary constrained hydrogen appliances are agreed, and it is the production and installation of these that this promoted by Government and the gas industry. These can for convenience be termed 'entry level'. Manufacturers will obviously be free to develop and market their own more sophisticated models, but for the success of the project it is essential the 'entry level products' are low cost, efficient, serviceable and reliable.

Obviously entrepreneurs can and will develop exciting ranges of entirely novel hydrogen combustion equipment, but for the viability of the whole project it is felt much better to a limited but well proven and low-cost range of products. Such products may require a different set of criteria to be eligible for financial support than the current understandable desire to only assist the most advanced technology.





### 5.7.4. Industrial Use of Gas and Process Burners

The UK is well-known around the world for its forced draft burners and both Dunphy Ltd and Saake Ltd offer hydrogen fired versions of such units for process use. Although not as problematic as in the domestic sector, the absence of low cost hydrogen means there are few examples of the use of these. However the literature is full of one-off trials, for example, Hydrogen Firing for a High-Capacity Rotary Kiln was performed by Coates, R., Smoot, L. & Hatfield, K., (2015). In this paper it is reported that the burners were initially fired with natural gas and then switched over to hydrogen, performing six natural gas tests and thirteen hydrogen tests. Due to the broad flammability limits of hydrogen-air mixtures, the firing rate was varied from 95 MJ/hour to 158 MJ/hour with H<sub>2</sub> air ratios from 0.3 to 3.5. Interestingly Coates, R., Smoot, L. & Hatfield, K., report that: 'A bright yellow flame, not due to impurities, allowed for ready detection of the flame, as did the bright glow of a thermocouple probe on the edge of the flame.'

They also reported that there was no unstable burning, pre-ignition or explosions observed during the investigation. There are similar published papers on the firing of ceramic kilns etc. The only concerns appear to be potentially high NO<sub>x</sub> levels, although some of the commercially available burners claim to overcome this. If NO<sub>x</sub> remained a significant problem on an industrial scale (for example from some very high-temperature furnaces) then a selective non-catalytic reduction (SNCR) technique could be employed to reduce these levels. This SNCR technique is commonly used as an NO<sub>x</sub> abatement technique and involves introducing urea into the flue gases.

In the town gas era manufacturers of large ovens were aware of the risk of delayed ignition, and British Gas supported considerable work venting (for example) bread ovens. The risks with hydrogen will be greater, and multiple overlaid safety systems will be necessary.

Whereas the conversion of some types of process firing may be challenging, hydrogen does burn with a flame broadly similar to natural gas. Depending upon the required temperature, such a conversion will always be easy when compared to firing with electricity, where temperatures are either limited by the resistive heating element or, in the case of electric arc heating, by the geometry of the plant.

DECC funding may be appropriate for some 'entry level' products. Some large manufacturers might wish to accept a cash payment towards the installation of entirely new technology (e.g. a new kiln) that can optimise the advantages of hydrogen.



Image 5.9. MAXON Wide-Range (R) Burner Running on Hydrogen. (Source: <https://www.maxoncorp.com/Directory/product/WIDE-RANGE-Burner/38/Natural-Gas-Burner-High>)

### 5.7.5. Hydrogen in Gas Turbines

Hydrogen or high hydrogen content fuel gases are available from some industrial processes.

The use of hydrogen as a fuel for large industrial gas turbines has been considered. Chiesa et al discussed the issues they performed simulations to assess the impacts. Their work found that it is possible to run gas turbines designed for natural gas on hydrogen, however the stoichiometric flame temperature must be limited to around 2,300 K to comply with NO<sub>x</sub> emission limits without post-combustion flue gas NO<sub>x</sub> abatement. Even with limiting the temperature of the flame only minor losses of efficiency were observed. The flame temperature was limited by introducing a dilutant gas into the hydrogen stream; the dilutant gases investigated were steam and nitrogen. The use of nitrogen as a dilutant led to minor decreases in efficiency. A considerable amount of work has been carried out on the safety aspects of burning hydrogen in Gas Turbines at the Health and Safety Laboratories at Buxton. The work is commercially confidential, but it is understood encouraging.

The requirements of LNG plants have already prompted gas turbine manufacturers to carry out work to extend the ability of their products to operate across wider ranges of gas specification. There is further discussion of this whole matter within Aero GT hydrogen burner characteristics. The Fusina Hydrogen project operated a GE 10 gas turbine (11.44 MWe) on Venice Lagoon in 2011. No significant operational problems were reported. The hydrogen was derived from the adjacent refinery.



## *Breakout: The Purity of Hydrogen.*

*For the detection of leakage, it is essential that the hydrogen being distributed be odourised. Unfortunately, current UK odourants, e.g. NB, a blend of T-Butyl Mercaptan (TBM) and dimethyl sulphide, are poisonous to many catalytic and fuel cell combustion systems; this is not an issue when using ordinary flame combustion (an attractive route for Leeds, at least in the short term) but it is recommended that this matter is addressed right at the beginning of developing UK hydrogen infrastructure. Similar matters surround ensuring the distributed hydrogen is of 'optimum quality'. These are all relatively simple issues, probably with limited cost implications, but getting the 'wrong' odourant or a very sub-optimal gas quality could radically affect the ability of UK industry to build upon its expertise.*

*This matter can probably be most simply addressed either by changing the odourant as currently being investigated in Japan to, for example, cyclohexene or by fitting pre-filters containing, for example, active carbon.*

*The purity of hydrogen is addressed more thoroughly in Section 2 but for appliance design purposes it is proposed that the specifications CO, CH<sub>4</sub>, and CO<sub>2</sub> in hydrogen for the project be set as follows:*

<i>CO</i>	<i>&lt; 15 ppm</i>
<i>CH<sub>4</sub></i>	<i>&lt; 100 ppm</i>
<i>CO<sub>2</sub></i>	<i>&lt; 10 ppm</i>
<i>H<sub>2</sub> purity</i>	<i>&gt; 99.98%</i>

*Being realistic however, the hydrogen is likely to be saturated with water on an occasional basis, and may contain significant quantities of dust, and other physical impurities.*

## 5.8. Conclusions

The current range of hydrogen appliances is very modest, as there is no bulk supply of hydrogen, but manufacturers are enthusiastic. Given an agreed hydrogen roll out plan between DECC, the gas industry and appliance manufacturers, ideally assisted by appropriately directed UK Innovate funding, there is no reason why a range of hydrogen appliances should not be available within 2 to 4 years. It is important that this seed-corn funding be directed towards a limited range of 'entry level' products that can cost effectively permit the conversion of large numbers of domestic and commercial properties.

**Section 10, The H21 Roadmap** identifies a requirement for a hydrogen demonstration facility at Teesside, and associated trials in non-occupied followed by occupied properties. Teesside seems the ideal location for this facility as it already has significant supplies of hydrogen stored in its existing salt caverns. In the original town gas conversion a significant problem for appliances manufacturers was the availability of natural gas with which to test and certify their appliances.



## SECTION 6

# Hydrogen Transmission System



## 6. The Hydrogen Transmission System and Associated Infrastructure

### History: UK Pipelining

*For the first 150 years of the UK industry gas was manufactured from coal locally and was referred to as 'town gas'. However, there was a period in-between conversion from town gas to natural gas when both gases were being used in the UK.*

*In North America readily available natural gas was being used extensively across specific states, notably Pennsylvania, well before the end of the 19<sup>th</sup> century. By 1950 natural gas accounted for more than 90% of fuel gas sales in the USA and by 1951 it was reported that a new gas well was being brought into production every 23 minutes.*

*By the 1940s American gas companies had begun to store natural gas in liquid form by cooling it to -160 °C, reducing its volume by 600 times. By 1954 Conch International Methane Limited had introduced refrigerated barges for transporting liquefied natural gas over long distances. In February 1959 the first LNG delivery to the UK was made to a purpose built facility at Canvey Island, Essex. Over the next year, 12,000 tonnes of gas were imported in this trial venture.*

*In 1961 the Gas Council committed to contracts to import 300,000 tonnes of LNG per annum from a vast gas reservoir that had been discovered beneath the Sahara. At the time, this infrastructure project was the second biggest in Africa after the Aswan Dam. Storage facilities at Canvey Island had to be greatly increased to match this new rate of import and in May 1966 it was announced an extra 84,000 tonnes of capacity was to be constructed. This provided the UK with enough LNG to supply 10% of its needs.*

*Even though this gas was too rich for burners, the relatively small amount of natural gas available (compared to towns gas) meant the gas could be blended with the town gas to produce an immediately usable product. This product, however, was only usable when it could be made available to gas customers. As a result, a high pressure (45 bar) gas transmission pipeline was constructed from Canvey Island to Leeds, a distance of 200 miles. (Charles Elliott – History of Natural Gas Conversion in Great Britain)*

### Hydrogen Transmission Pipelines

*Transmission pipelines transport hydrogen through a pipe as part of the hydrogen infrastructure. A hydrogen transmission pipeline connects the point of production with the point of demand. The technology is well established and proven. The Rhine-Ruhr hydrogen pipeline was the first hydrogen transmission pipeline. Constructed in 1938 the initial pipeline was 240 km long. This has been extended over its operational history and is now 600 km in length and is still in operation today. As of 2004, there are 900 miles (1,450 km) of hydrogen pipelines in the US and 930 miles (1,500 km) in Europe.*

In order to transport the hydrogen from the production facility and associated storage caverns to Leeds, a new hydrogen transmission pipeline will be required. This system connects the SMRs to the storage sites that support the system and then onto to the local distribution customers.

It is likely that the production and storage facilities will be located on the east coast (see [Section 2, Demand vs. Supply](#)). Therefore to supply the hydrogen economically a high pressure pipeline will be required to transport the gas to the area of conversion. This pipeline will operate at 40 bar to provide enough capacity for moving the gas and to economically size the pipeline. There will be associated equipment such as block valves, inspection facilities, and pressure reduction stations (required to reduce the pressure at the injection points to the medium pressure system).

[Image 6.1](#) shows an example configuration of the hydrogen transmission system (HTS) and associated pipeline infrastructure required to accommodate the proposed hydrogen production and transportation.





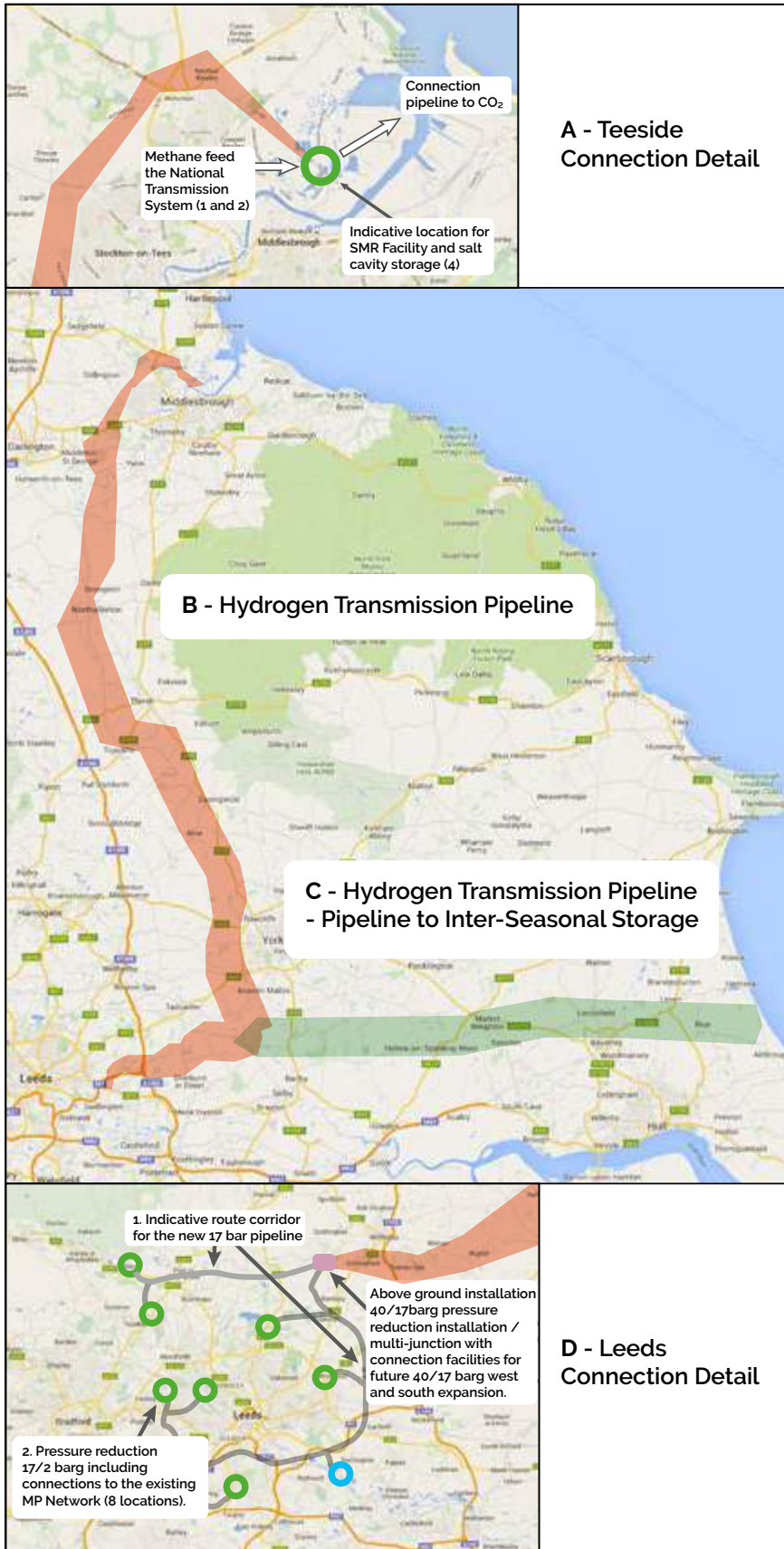


Image 6.1. Indicative Route Corridor of HTS and Associated Connections

The HTS can be divided into four discrete components:

1. Connections at Teesside. Connections here are threefold as the production plant produces hydrogen, carbon dioxide and consumes natural gas.
  - Hydrogen pipeline.
  - Carbon dioxide network connection.
  - Natural gas supply.
2. The hydrogen transmission pipeline to Leeds.
3. The hydrogen transmission pipeline to the inter-seasonal storage facilities.
4. Connections at Leeds. This will include pressure reduction from 40 bar to 17 bar to feed the Leeds ring main and subsequently the 17 bar to 2 bar PRU connections to the existing MP Leeds distribution network.

High pressure pipelines within the UK are numerous, and the UK has significant experience building both the NTS and LTS over the last 50 years as well as various other chemical pipelines to undertake such a task.

Whilst the suggested route corridor is practical for this level of study, the final location of the hydrogen production facility and associated storage will be determined as part of future work. This will include other stages such as, front end design, planning, and economic assessments. In order to provide an indication of cost, the route corridor for the pipeline has been established based on the locational parameters identified in **Section 2, Demand vs. Supply**. Noting these parameters give the longest reasonable hydrogen pipeline route these costs can be considered to be an upper estimate of project cost at this level of detail. This pipeline could be thought of as an additional part of the LTS and, if the hydrogen economy were to be rolled out incrementally across the UK, could be the start of a hydrogen transmission system.

It should be noted that the route corridors identified and the location of associated infrastructure are indicative and have been produced to allow the pipeline cost estimates to be developed.



## 6.1. HTS Teesside Connections

Image 6.2 represents a simplistic diagrammatic representation of the anticipated connection and pipeline arrangements at Teesside. This includes:

Section	Description
1	Minimum Offtake Connection (MOC) to the HP NTS for the SMR natural gas supply
2	High pressure natural gas pipeline connection to the SMR
3	Carbon capture pipeline from the SMR to CCS infrastructure
4	Hydrogen pipeline connecting the SMRs to the salt cavity storage (intraday/seasonal storage)

Table 6.1. Assumed Technical Parameters



Image 6.2. Representation of Connections at Teesside

Section	Pipeline Description	Product	Operating Pressure (bar)	Diameter (mm)	Assumed Length (km)
1	Minimum Offtake Connection (MOC)	Natural gas	70	N/A	N/A
2	Natural gas pipeline from LTS/NTS to SMR facilities	Natural gas	70	250	1
3	CO <sub>2</sub> pipeline from SMR facilities to CCS pipeline.	CO <sub>2</sub> (super critical liquid)	140	200	1
4	Hydrogen pipeline from SMRs to intraday storage	Hydrogen	40	200	1

Table 6.2. *Technical Parameters – Teesside Connections*

### Teesside Connection Section 1 Minimum Offtake Connection:

To provide the supply of natural gas to the production facility, a connection will be required to the high pressure network. This will require the construction of a Minimum Offtake Connection (MOC), complete with fiscal metering and telemetry.

#### *Breakout: Minimum Offtake Connection*

*A connection to the NTS is referred to as a minimum offtake connection. This is essentially a new valve connected (via a live gas operation) to the NTS to provide a new gas supply. Most connections will serve one of the UKs GDN offtakes feeding directly into the LTS. In the H21 Leeds City Gate project, this connection would supply gas direct to the hydrogen production facility.*



The cost estimate assumes the connection pipelines and associated infrastructure will be constructed using standard and well established techniques.

MOCs are designed and constructed by the pipeline owner/operator. The developer submits a request for a connection to the gas network through the Application to Offer (A2O) process, as set out in the Uniform Network Code (UNC). A connection to the National Transmission System (NTS) currently takes up to three years to complete, with costs in the region of £3 m for a typical 'green field' site. Costs for connections to the Local Transmission System (LTS) can be considerably quicker and less expensive. Connections to both the NTS and LTS can be constrained by network capacity at the connection location and are usually subject to network capacity studies prior to a connection offer being made.

The NTS Feeder 6 pipeline (30 inch Maximum Operating Pressure (MOP) 85 bar) runs close to the anticipated location for the SMR facilities; there is also an LTS pipeline (12 inch MOP 38 bar) close by. Both pipelines could be suitable to supply the natural gas required for hydrogen production (subject to network capacity studies).

As a connection to the NTS is less likely to have network capacity constraints, and represents the highest cost and longest timescale this option has been used in developing the cost estimate for the scheme.

### **Teesside Connection – Section 2 Natural Gas Pipeline:**

To transport the natural gas to the SMR facilities, a short section of pipeline will be required.

To achieve the flows required to the SMR facilities the initial design calculations demonstrate that the pipeline will need to be 250 mm diameter, approximately 1 km in length with a Maximum Operating Pressure (MOP) of 70 bar.

This specific pipeline diameter and length fall outside the threshold to be considered a Nationally Significant Infrastructure Project (NSIP). However, we consider the pipeline would be viewed as part of the overall scheme and would, therefore, need consent as part of the required Development Consent Order (DCO) for the entire project using the NSIP criteria for the entire scheme (i.e. all sections of the HTS could be considered collectively).

We have assumed the pipeline would be designed and constructed as part of the main works design and build contract for the overall hydrogen transmission system, and would be constructed using 'main-laying' techniques by the construction contractor. It is usual for this type of contract that the developer would purchase the line pipe required for the project, and this is reflected in the cost estimating methodology.



### Teesside Connection – Section 3 CO<sub>2</sub> Pipeline:

A by-product from the process of hydrogen production is carbon dioxide (CO<sub>2</sub>). It has been assumed that the CO<sub>2</sub> will be transported to the proposed Teesside Collective Carbon Capture & Storage (CCS) network.

This will entail the design and construction of a short pipeline, approximately 1 km in length. The pipeline will transport the CO<sub>2</sub> as a dense phase fluid. Initial design calculations have identified the pipeline will need to be 200 mm diameter with an MOP of 140 bar.

As with the natural gas pipeline it has been assumed that this CO<sub>2</sub> pipeline would be progressed as part of the overall scheme and may, therefore, need consent as part of the Development Consent Order (DCO) for the entire project may be given. Also, as with the natural gas pipeline, we envisage the CO<sub>2</sub> pipeline design and construction would form part of the main works design and build contract and be constructed in a similar manner.



### Teesside Connection – Section 4 Hydrogen Pipeline:

It is envisaged that a short length of hydrogen pipeline will be required to connect the SMR facilities to the intraday salt cavity storage site.

The length of the hydrogen pipeline will be determined by the final location of the SMR facilities and the salt cavity storage site. However, it is beneficial to site the SMR facilities as close as is practical to the salt cavity storage site.

The SMR facilities will deliver hydrogen at a predetermined pressure and maximum flow rate. We have therefore assumed this short section of hydrogen pipeline will need to be 200 mm diameter and operate at an MOP of 40 bar.

As with the natural gas and CO<sub>2</sub> pipelines it has been assumed that this would be consented, designed and built as part of the main works contract.

### Teesside Connection – Cost Summary:

This estimate has been developed as part of a pipeline 'bottom-up' cost estimate process typical to any pipeline estimate undertaken in the gas industry.

Table 6.3 provides a summary breakdown of the CAPEX costs associated with the Teesside connections:

Section	Description	Estimated CAPEX (£'000)
1	Minimum Offtake Connection (MOC)	£3,000
2	Natural gas pipeline from LTS/NTS to SMR facilities	£1,440
3	CO <sub>2</sub> pipeline from SMR facilities to CCS pipeline.	£1,930
4	Hydrogen pipeline from SMRs to salt cavern storage (intraday)	£1,420
<b>Sub Total:</b>		<b>£7,790</b>

Table 6.3. *Cost Summary – HTS Teesside Connections*

## 6.2. B and C – The Hydrogen Transmission Pipelines

To transport hydrogen from the production and storage facilities at Teesside to the Leeds distribution network and to the inter-seasonal storage sites north of Hull cross country hydrogen transmission pipelines will need to be constructed.



Image 6.3. Indicative Route Corridor of HTS



The main hydrogen transmission pipeline (Section B) will originate with a connection to the hydrogen production facilities/proposed salt cavity storage facility in the vicinity of Seal Sands, and terminate at a Pressure Reduction Installation (PRI), north east of Leeds. The pipeline will connect to a further hydrogen pipeline (Section C), through a multi-junction arrangement, connecting the hydrogen transmission pipeline (Section B) to the proposed inter-seasonal storage facilities to the north of Hull.

It is worth remphasizing that this pipeline route is for the purpose of cost estimation only. It would, by necessity, need to be confirmed in later design and planning phases.

To support the cost estimating process, an indicative schedule was developed. This was based on typical durations for similar pipeline projects constructed in the UK over the last decade, and assuming the current consenting processes would be applied to the scheme. The overall timeline for this programme is simplistically represented in [Section 9, The Next Steps - Program of Works](#) and is anticipated up to 6 years duration.

### Planning and Consents

Under the current regime, a major cross-country pipeline scheme of this nature would most likely be classified as a NSIP and require a DCO be granted by the secretary of State.

This requires the developer to carry out surveys to identify all feasible route corridors for the proposed pipelines, identify landowners and interested parties affected by the proposed pipeline routes and undertake consultation to determine the preferred route corridor and final route alignment for the pipelines. Once the preferred route corridor has been identified a detailed Environmental Impact Assessment (EIA) is required, from which an Environmental Statement (ES) produced. In parallel with these activities easement purchase and land compensation negotiations would be undertaken.

The indicative programme indicates a period of 30 months for these activities. The pipeline cost estimate has used historical project data from similar cross country pipeline projects to estimate the likely durations and costs.



## **Breakout: NSIP Criteria**

*The following criteria determine if an infrastructure pipeline qualifies as an NSIP, taken from Section 20 (Planning Act 2008) Gas Transporter pipe-lines.*

- (1) The construction of a pipe-line by a gas transporter is within Section 14(1)(f) only if (when constructed) each of the conditions in subsections (2) to (5) is expected to be met in relation to the pipe-line.*
- (2) The pipe-line must be wholly or partly in England.*
- (3) Either—*
  - a) the pipe-line must be more than 800 millimetres in diameter and more than 40 kilometres in length, or*
  - (b) the construction of the pipe-line must be likely to have a significant effect on the environment.*
- (4) The pipe-line must have a design operating pressure of more than 7 bar gauge.*
- (5) The pipe-line must convey gas for supply (directly or indirectly) to at least 50,000 customers, or potential customers, of one or more gas suppliers.*
- (6) In the case of a pipe-line that (when constructed) will be only partly in England, the construction of the pipe-line is within section 14(1)(f) only to the extent that the pipeline will (when constructed) be in England.*
- (7) "Gas supplier" has the same meaning as in Part 1 of the Gas Act 1986 (c. 44) (see section 7A(11) of that Act).*

## **Technical Assumptions**

There are currently no hydrogen pipelines in the UK that run cross country. However, there are pipelines distributing hydrogen to multiple users on Teesside across the chemical complexes at Seal Sands, Billingham, and Wilton. There are hydrogen pipelines in service around the globe. There are also pipelines of similar design for the transportation of other fluids like ethylene in the UK. Current regulations and design standards already encompass hydrogen, and the study is based on those current regulations such as the Pipeline Safety Regulations and standards such as British Standards Institutes PD 8010 and BS EN 14161. The guidance also exists from the European Industrial Gases Association (EIGA), specifically for the design and construction of hydrogen transmission and distribution pipeline networks.

The distance and design of the pipeline are such that pipeline compression, to help move the gas through a pipeline, is not required. The production facility will provide an inlet pressure to the transmission pipeline of 40 bar; initial calculations demonstrate that the pressure drop on the transmission pipeline will deliver an outlet pressure of no less than 20 bar.

A pipeline diameter of 650 mm and a MOP of 40 bar have been calculated to accommodate the anticipated maximum peak day demand for the scheme, see [Section 2, Demand vs. Supply](#).

We have assumed that the pipeline and installation design would be awarded to a Main Works Contractor under a Detailed Design and Construct contract. The indicative programme has an allowance of 6 months for tender and contract award and a period of 12 months for Detailed Design activities.

### Pipeline Materials

The hydrogen transmission pipeline will be built an appropriate steel as defined by the relevant design codes.

Hydrogen can have different effects on many metallic materials which are well known. These include embrittlement which occurs at elevated pressures. These include steels (especially high strength steels), stainless steel, and nickel alloys. Therefore, design codes recommend lower strength steel pipe is used for the design of hydrogen transmission pipelines although the recommended types of steel are already used in pipelines such as API 5L grade X52. [Table 6.4](#) specifies the anticipated pipe specification for the hydrogen transmission pipeline:

Section	Dia (mm)	Operating Pressure bar	Material Grade	Length (km)
B	650	40	L360	114
C	450	40	L360	76

Table 6.4. HTS Pipeline Sectional Details

Cost metrics for pipelines are well known and established from historical projects. Costs can be adjusted using typical factors in the industry based on inflationary movements, market changes, and material cost changes. Here the cost metrics are based on established historical norms and have been market tested through initial quotations from a steel pipe manufacturer. The indicative programme developed for the scheme identifies a period of 18 months for manufacture and delivery of line pipe.

## Pipeline Construction

Cross country pipelines are usually constructed between April and October to avoid damage to agricultural land, with advanced activities such as site establishment, construction of pipe storage facilities and environmental mitigation measures undertaken in February and March. Due to the length of the transmission pipelines, it has been assumed that the Main Works Contractor will adopt a two season build, with pipeline spread 'winterised' over the intervening winter period to provide environmental protection. The pipeline will be constructed using standard construction methodologies, by an experienced pipeline construction contractor.

Cross-country construction of natural gas pipelines is a well-established technique that can be applied to all welded steel pipelines whether they transport natural gas or hydrogen. Construction is undertaken on a 'production line' basis, i.e. by a series of different specialist 'crews' who each perform a specific function and move along the pipeline route in order.

Individual operations can move forward at a rate of 500 m to 1 km a day. Typically cross country pipeline construction will include the following activities:

- Working width preparation;
- Fencing;
- Pre-construction drainage;
- Topsoil strip;
- Pipe stringing (lay out the pipe along the working width);
- Field bending;
- Pipe welding and inspection;
- Non-destructive weld testing;
- Joint coating;
- Trench excavation;
- Lower and lay;
- Backfill;
- Pipeline tie-ins;
- Reinstatement;
- Post-construction drainage;
- Hydrostatic testing; and
- Commissioning (final gauge plate and calliper surveys, drying and commissioning).

In addition, special crews will be established for operations such as crossings, (e.g. road, rail, river, and canal).



There are several trenchless construction techniques that would be utilised for the majority of road, rail, river, and canal crossing. These include;

- Auger boring.
- Tunnelling (including pipe-jacks).
- Micro-tunnels.
- Horizontal Directional Drilling (HDD) (Image 6.4)



Image 6.4. Horizontal Directional Drill (HDD)

Across rural areas the pipeline will be laid to contour at a depth of cover of 1.2 m; the minimum depth of cover for roads, rivers, and canals is 2 m. The pipeline may be laid deeper at specific locations and crossings. The final depth would be determined following extensive surveys by the detailed design.

After the pipeline has been laid it will be cleaned and tested. This will take the form of a hydrostatic test (undertaken in sections) which involves filling the pipeline completely with water and raising the pressure to a predetermined level for a 24 hour period.

Following successful hydrostatic testing of the pipeline the test water will be removed from the pipeline and the pipeline dried prior to commissioning. This will be achieved by introducing super dry air along the pipeline and vacuum drying until the required 'dew point' is achieved.

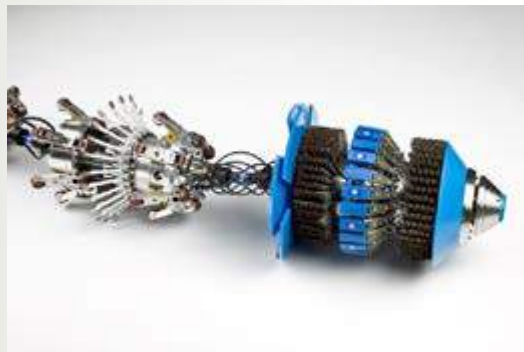
To ensure the integrity of the constructed pipeline coating a Cathodic Protection (CP) system will be installed. CP systems work by passing a small electric current through the completed pipeline which reverses corrosion currents present in the soil by the creation of a pipe to soil negative potential at any small defects to the pipeline's epoxy coating.

Following commissioning the pipeline will be internally mapped using an in-line inspection tool, known as a Pipeline Inspection Gauge (PIG). The PIG passes through the length of the newly installed pipeline to produce a 'fingerprint' to give an indication of the initial condition within the first twelve months of pipeline operation. As part of the ongoing maintenance regime, subsequent runs will compare the information from the 'fingerprint' run with the current condition to give an indication of and deterioration and maintenance requirements.

### *Breakout: Pipeline Inspection Gauge (PIG) Trap Facilities*

*A pipeline inspection gauge is a mechanical device which is loaded into the pipeline from pipe trap facilities at either end (loading and receiving traps) of a pipeline. The PIG travels through the pipeline 'pushed' along by the flow of the gas. After its journey, the onboard computer data is downloaded and analysed by pipeline experts to ascertain the condition of the pipeline and establish if any remediation or maintenance works are required.*

*This is typically undertaken on a ten yearly cycle. Below is a typical example of a PIG trap facility.*



## Cost Summary: The Hydrogen Transmission Pipelines (Sections B and C)

This estimate has been developed as part of a pipeline 'bottom-up' cost estimate process typical to any pipeline estimate undertaken in the gas industry. [Table 6.5](#) provides a summary breakdown of the CAPEX costs associated with the hydrogen transmission pipelines.

Section	Description	Estimated CAPEX (£'000)
B	Section B – Hydrogen transmission pipeline from the SMR facilities to the Pressure Reduction Installation (PRI)/multi-junction situated north east of Leeds	£125,090
C	Section C – Hydrogen transmission pipeline from the deep salt cavity storage facilities (inter-season) to the Pressure Reduction Installation (PRI)/multi-junction situated north east of Leeds	£71,000
<b>Sub Total:</b>		<b>£196,090</b>

Table 6.5. *Cost Summary – HTS Pipeline*



## 6.3. Connections to the Leeds Distribution Network

To connect the hydrogen production and storage to the customers at Leeds, connections will be required to the existing Leeds distribution network. This will entail construction of a new 17 bar ring main, with connections to the existing MP distribution network at strategic points.

Image 6.5 represents a simplistic diagrammatic representation of the anticipated connection and pipeline arrangements. This includes:

Section	Description
1	17 bar hydrogen pipeline from the Pressure Reduction Installation (PRI) at the termination of the hydrogen transmission pipelines
2	Connections to the existing MP Leeds distribution network through new PRSs

Table 6.6. Leeds Connection Elements



Image 6.5. Representation of Connections at Leeds



## Section 1 – 17 Bar Pipeline (Distribution Ring Main)

To connect the hydrogen transmission system to the existing Medium Pressure (MP) network at Leeds, a new ring main will need to be constructed. The ring main will start at the Pressure Reduction Installation (PRI) at the end of the main transmission pipeline. The ring main will run around the north and south of Leeds and connect into the existing MP network at 8 locations around the city. The pipeline will be approximately 24 km in length. The precise routing of the pipeline and locations for the connections to the existing Leeds MP network will be confirmed through the detailed design process.

Initial design calculations demonstrate that a 400 mm diameter pipeline, with a Maximum Operating Pressure (MOP) of 17 bar, will be required to accommodate the volumes of hydrogen required for the Leeds area. Although there have been recent technical advances in the development of HDPE pipeline materials, we have allowed for the construction of a steel pipeline (grade X52). The pipeline MOP has been specifically designed to negate the need for pre-heating at the 17 bar/2 bar pressure reduction facilities. Pre-heating on gas sites is only required for pressure drops greater than 15 bar and add significant cost and land footprint to pressure reduction sites. The 17 bar hydrogen distribution ring main would be designed and constructed as part of the Main Works Contract.

It is important to note that whilst this works has been included in the price for the HTS system in reality during GD2 (2021 to 2029) NGN will have a requirement to build an almost identical natural gas ring main around the city to accommodate removal of the current 17 bar system to facilitate the High Speed 2 rail link.



## Section 2 – Connections to the Existing Leeds MP Network

The hydrogen system will require connections to the existing Medium Pressure (MP) network in Leeds. Hydrogen will then be delivered to end users through the existing Leeds distribution network.

Initial calculations demonstrate that this can be achieved through eight connection locations. In the cost estimate, our 'worst case' scenario has been priced with the construction of seven new PRUs and conversion of one existing facility.

**Image 6.6** represents a typical PRU on the natural gas distribution network.



**Image 6.6.** *Typical Distribution Network PRU*

### Leeds Connection – Cost Summary:

This estimate has been developed as part of a pipeline 'bottom-up' cost estimate process typical to any pipeline estimate undertaken in the gas industry. [Table 6.7](#) provides a summary breakdown of the CAPEX costs associated with the Leeds connections.

Section	Description	Estimated CAPEX (£'000)
1	17 bar hydrogen pipeline (distribution ring main)	£20,540
2	Connections to the existing MP Leeds distribution network at eight locations 17 bar to 2 bar (seven new build PRUs and modifications to one existing PRU)	£5,850
<b>Sub Total:</b>		<b>£26,390</b>

Table 6.7. *Cost Summary: Connections at Leeds*



## 6.4. Operating Costs (OPEX)

Once constructed and commissioned the hydrogen transportation system will incur ongoing operation and maintenance costs. An assessment has been made of the likely operational and maintenance costs associated with the scheme. The hydrogen pipeline and associated infrastructure will have a design life of 40 years. Therefore, OPEX costs have been annualised assuming 40 years of operation with adjustments for inflation.

The maintenance regime adopted for the hydrogen transportation system and the associated infrastructure will be determined by legislation. Certain components of the system will be subject to inspection regimes specified in legislation, such as the Gas Safety Management Regulations (GMSR), Pressure System Safety Regulations (PSSR) and Pipeline Safety Regulations (PSR). [Table 6.8](#) details the likely operation and maintenance costs;

	Cost (unit)	Design Life (Yrs)	Annual OPEX by Category (£'000)
Management and Administration	per annum	40	42
Surveillance	per annum	40	27
Pigging and On-Line Inspection (OLI) Runs	10-yearly	40	63
Cathodic Protection Surveys	per annum	40	75
CIPS Survey – ‘Dig ups’	per annum	40	126
Leakage Surveys			incl.
Labour	per annum	40	168
<b>Total Yearly OPEX</b>			<b>500</b>

Table 6.8. HTS Operating Costs

## 6.5. Hydrogen Transportation System Conclusions

To enable a cost estimate for the HTS and associated infrastructure to be developed a potential route corridor for the HTS was identified. It should be noted that the route corridors identified and the location of associated infrastructure are indicative and have been produced to allow the pipeline cost estimates to be developed.

This estimate has been developed as part of a pipeline 'bottom-up' cost estimate process typical to any pipeline estimate undertaken in the gas industry. The overall estimate for the hydrogen transmission system is:

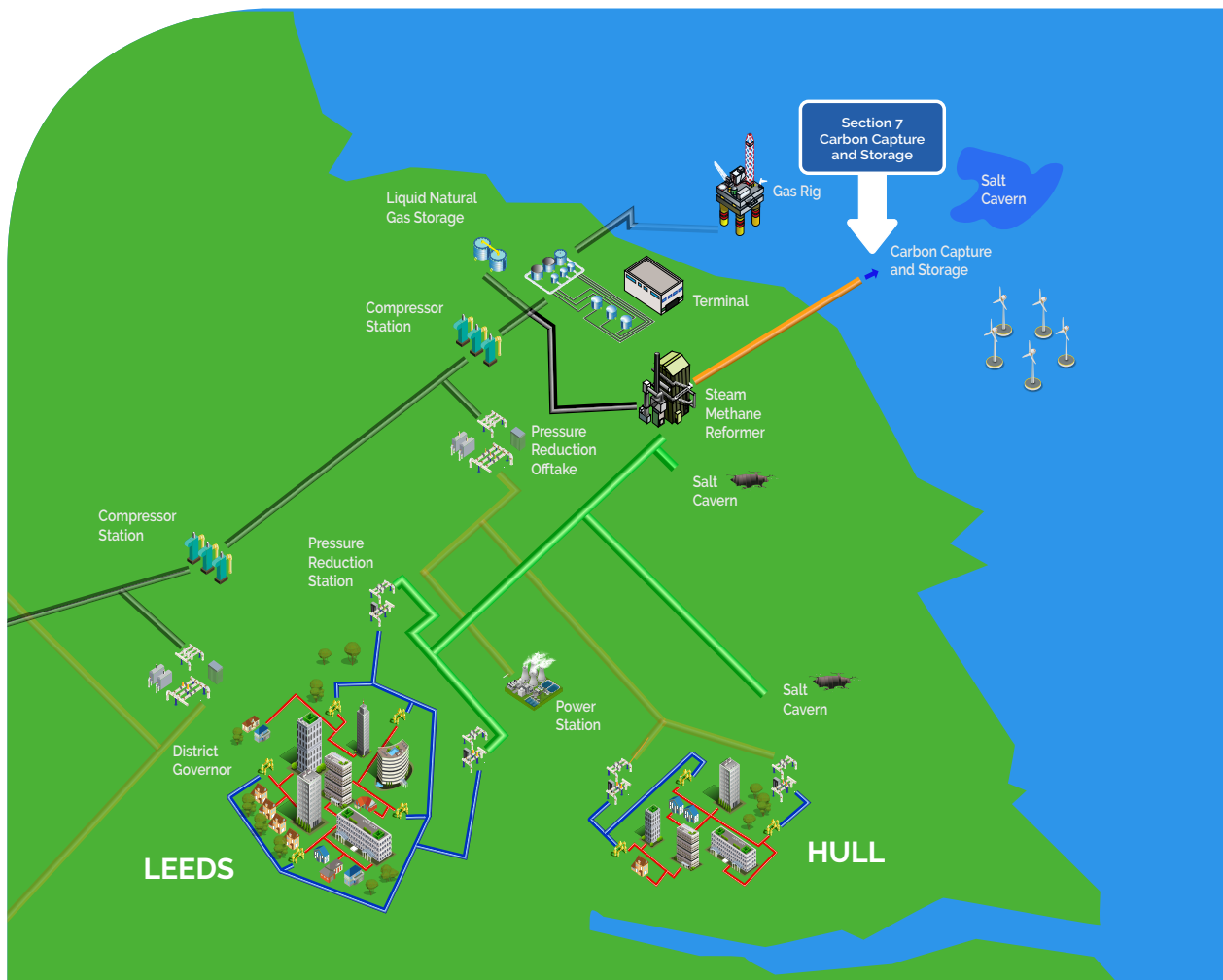
Cost Summary (£'000 m)	Capital Costs	Operating Costs per annum (£'000s)
Connections at Teesside	£7,790	N/A
Section B – Hydrogen transmission pipeline from the SMR facilities to the Pressure Reduction Installation (PRI)/multi-junction situated north east of Leeds	£125,090	N/A
Section C – Hydrogen transmission pipeline from the deep salt cavity storage facilities (inter-season) to the Pressure Reduction Installation (PRI)/multi-junction situated north east of Leeds	£71,000	N/A
17 bar hydrogen pipeline (distribution ring main)	£20,540	N/A
Connections to the existing MP Leeds distribution network at eight locations 17 bar to 2 bar (seven new build PRUs and modifications to one existing PRU)	£5,850	N/A
Operating costs as per Section 6.4	N/A	500
<b>Total</b>	<b>£230,270</b>	<b>500</b>

Table 6.9. Cost Summary – HTS and Associated Connection

***A proposed design for the HTS and associated infrastructure has been costed at £230 million CAPEX and £500,000 per annum OPEX***

## SECTION 7

# Carbon Capture and Storage



## 7. Carbon Capture and Storage

### History: Summary of Global CCS

Carbon Capture and Storage (CCS) technology is proven and in use around the world, with 15 large-scale CCS projects operational. Statoil has been implementing CCS at the Sleipner field, Norwegian North Sea, for 10 years. The technology of CO<sub>2</sub> transport and injection have been in use for more than 30 years for enhanced oil recovery in the United States. Separation of CO<sub>2</sub> from gases has been an industry standard process for over 40 years. Three CCS projects which started operation in 2015 are summarised below.



*Boundary Dam: The world's first large-scale CCS project in the power sector, at SaskPower's Boundary Dam facility in Saskatchewan, Canada, has just celebrated one year in operation.*

Image 7.1. Provided by SaskPower

*Quest: Launched in Alberta, Canada in November 2015, the Quest project is capable of capturing approximately 1 Mtpa of CO<sub>2</sub> from the manufacture of hydrogen for upgrading bitumen into synthetic crude oil.*



*Quest is the first large-scale CCS project in North America to store CO<sub>2</sub> exclusively in a deep saline formation, and the first to do so globally since the Snøhvit CO<sub>2</sub> Storage Project became operational in Norway in 2008.*

Image 7.2. Provided by Shell

*Uthmaniyah: Launched in Saudi Arabia in July 2015, the Uthmaniyah project is the first operational large-scale CCS project in the Middle East. The project is capable of capturing around 0.8 Mtpa of CO<sub>2</sub> from a natural gas liquids recovery plant for injection into the Uthmaniyah production unit for Enhanced Oil Recovery (EOR).*

2016 and 2017 will be significant years for CCS with seven large-scale CCS projects due to come on stream. Importantly these will show CCS in action in many different countries including the United States, Canada, the United Arab Emirates (UAE) and Australia, as well as across many industrial sectors. It will take the number of large-scale projects in operation to 22.

## 7.1. UK Carbon Capture and Storage position

The rationale of replacing natural gas with hydrogen is based on the premise of a significant reduction in carbon emissions. Current economics show the cost advantage of SMR+CCS vs. renewable, but it is accepted that this study presumes that CO<sub>2</sub> sequestration service is available 'over the fence'. The timing of the simultaneous delivery of both the production of hydrogen and disposal of carbon may be difficult but it is also not essential. SMRs can be retrofit with CO<sub>2</sub> capture capability so the critical point in any future hydrogen conversion decision is *knowing* that CCS is under development. The two do not necessarily have to be available at the same point in time (see [Section 9, Next Steps – The Programme of Works](#) for political timelines). Some considerations when reviewing the CCS impact on a hydrogen conversion are provided below:

- The technology chosen of post-combustion scrubbing of the flue gases means these SMRs can be operated without the CCS section of the plant commissioned.
- Hydrogen is a low carbon energy vector, which can be generated from fossil fuels with CCS, biomass or renewable via electrolysis. Its use is not dependent upon CCS, but CCS is a good bridgehead to enable the demonstration of hydrogen distribution at a predicatable price.
- By providing a long-term base load, not subject to the vagaries of the international market (like for example steel), such SMR+CCS plant could act as the perfect catalyst to bring forward CCS pipelines.

### UK CCS Position

The focus to date has been on power generation with CCS. DECC have run two competitions between 2007 and present to select a project to fund. Despite many projects coming forwards, neither competition has resulted in a project being selected. Most recently in November 2015 funding was withdrawn from Peterhead and White Rose CCS projects, with value for money being the reason cited.

Front End Engineering Design (FEED) has been completed for six CCS projects;

- Peterhead to Miller Enhanced Oil Recovery.
- Don Valley to Endeavour with EEPF funding.
- Kingsnorth to Hewett in Demo 1.
- Longannet to Goldeneye in Demo 1.
- Peterhead to Goldeneye in Demo 2.
- White Rose to Endeavour in Demo 2.

Two other power CCS projects have been proposed;

- Teesside (Progressive Energy); in various configurations.
- Caledonia Clean Energy Project (Summit Power) at Grangemouth. A gasified coal project currently undertaking a feasibility study with DECC funding.



The focus for industrial CCS, capturing CO<sub>2</sub> from industrial sources, has been at Teesside. The Teesside Collective has published several reports which build into a business case for industrial CCS. Similar studies are getting underway at Grangemouth.

Pale Blue Dot is currently completing a Strategic UK CCS Storage Appraisal Study, which has selected and appraised five additional CO<sub>2</sub> storage sites, deep underground and offshore, around the UK.

The UK is well positioned for CO<sub>2</sub> storage in the southern and central North Sea and East Irish Sea, with capacity for storing UK emissions and potentially emissions from other European countries.

**Image 7.3**, shows the availability of UK carbon capture and storage sites. (From the Strategic UK CCS Storage Appraisal Project).

There are many other candidate storage sites around the UK with significant storage potential and in summary the key message is 'The UK has lots of storage'.

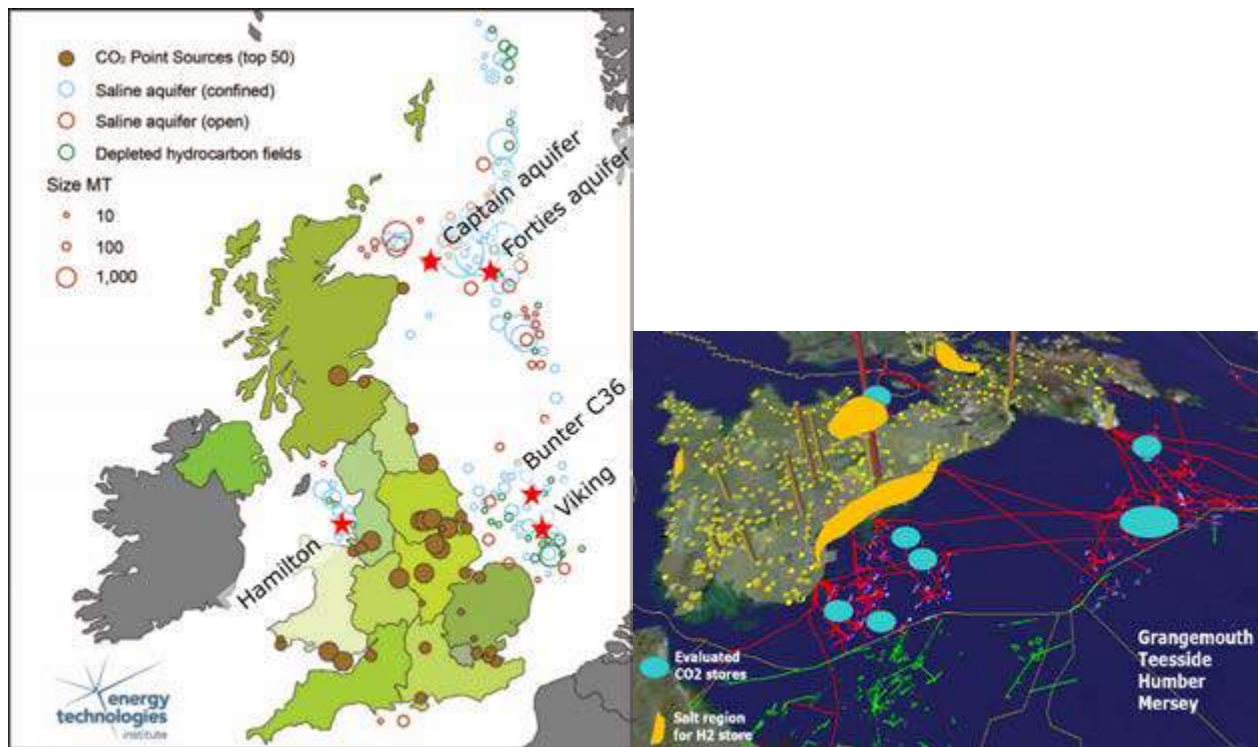


Image 7.3. UK CCS availability

### 7.1.1. The Reason for the Involvement of the Public Sector in CO<sub>2</sub> Disposal

There is a very long history of public sector involvement, in both the organisation and oversight of the 'waste' disposal sector. This includes domestic refuse, nuclear waste and flood water. The allocation of costs associated with carbon emissions from large combustion/process plant have strong political overtones, and this coupled with the very large investments required and not insignificant technical risk can result with inaction becoming the easiest route.

The advantage of using SMR+CCS plants as the backbone of any sequestration pipeline then becomes very important. These plants will operate 365 days/year (8,760 hrs/year) and can be designed to have a fairly flat CO<sub>2</sub> export line, (i.e. with more storage), and the CO<sub>2</sub> is a concentrated source. There are not the impurities likely to arise from coal gasification plants. The growth in CO<sub>2</sub> to be disposed of could be planned, especially if it was confirmed that Teesside, as in the H21 Leeds City Gate project, was to be the centre for hydrogen production for the North East.

It is thought useful to consider the advantages public sector support of Industrial CCS (such as this) over support for CCS on a power plant operating in a 'free market'. By virtue of the substantial energy use and technical complexity of CCS on a power plant, the economics of the whole generating station must be changed. This adjustment is likely to be very material regarding the 'cost merit' order of the plant; this raises the potential of commercial claims from disadvantaged competitors, and can (in-turn) easily end in over-complex legal documents, especially if the CCS process itself is relatively unproven in a retrofit situation. Industrial CCS is very different. The scale is smaller, there is no half-hourly merit order and (for the design chosen) the CCS is an 'add-on'. The project should be contractually much simpler, and there should be little need to involve the market supervision authorities provided that the whole deal is transparent and viable.



## 7.2. Teesside Collective Report (Taken from the 2015 Industrial CCS on Teesside Business Case)

As discussed in **Section 2, Demand vs. Supply**, the location of the SMRs (at this conceptual stage and subject to detailed design) has been selected at Teesside. This is for three reasons; firstly, it is in the UK's largest chemical industrial heartland, secondly, it has available salt caverns and finally it has a well-developed proposed carbon capture scheme. The Teesside and Tees Valley region are one of the largest industrial clusters in the UK covering a diverse sector base of chemicals, petrochemicals, steel production, and energy companies. The cluster employs approximately 12,000 people generating a GDP of £10 bn and exports of £4 bn per annum. The Teesside collective report has proposed a comprehensive carbon capture and storage scheme, some of the outputs from that report are presented below.

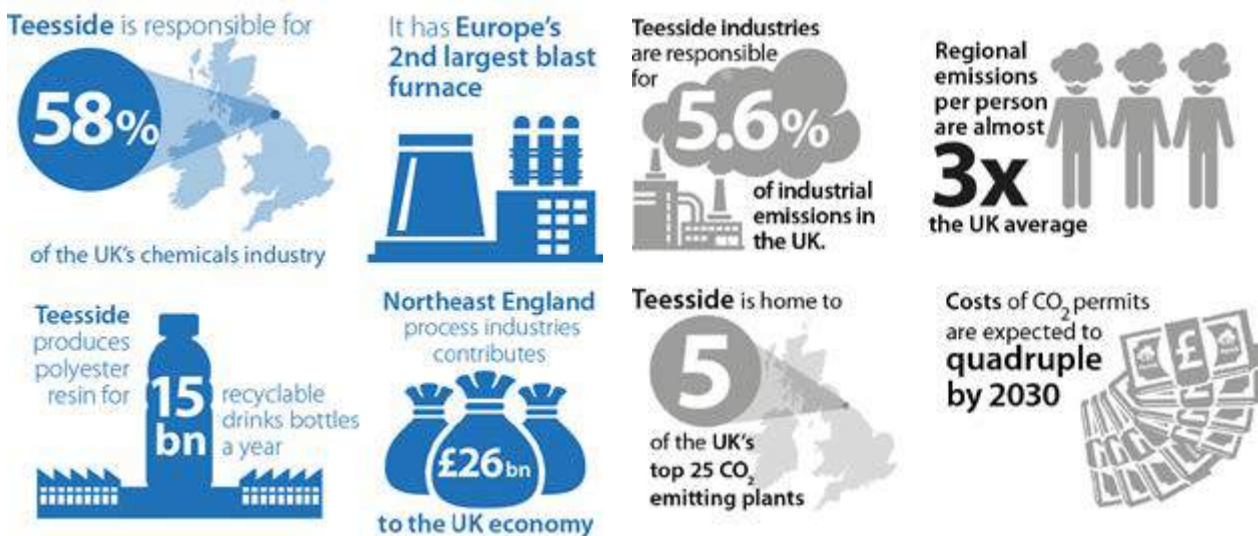


Image 7.4. Teesside Collective Report Summary

This initial study had four industrial partners: Sahaviriya Steel Industries (SSI), GrowHow, BOC and Lotte Chemicals. The work focused on building a business case for an industrial CCS (ICCS) network on Teesside beginning with the CO<sub>2</sub> emissions from the production sites of the four industrial participants. The location of these sites and the many other industrial sites on Teesside are shown in [Image 7.5](#).

[Image 7.6](#) illustrates the five elements of the ICCS project. In this report all the key elements of an industrial CCS network: capture, gathering, transportation and storage are considered.



Image 7.5. The Teesside Collective Five Industrial Partner Locations

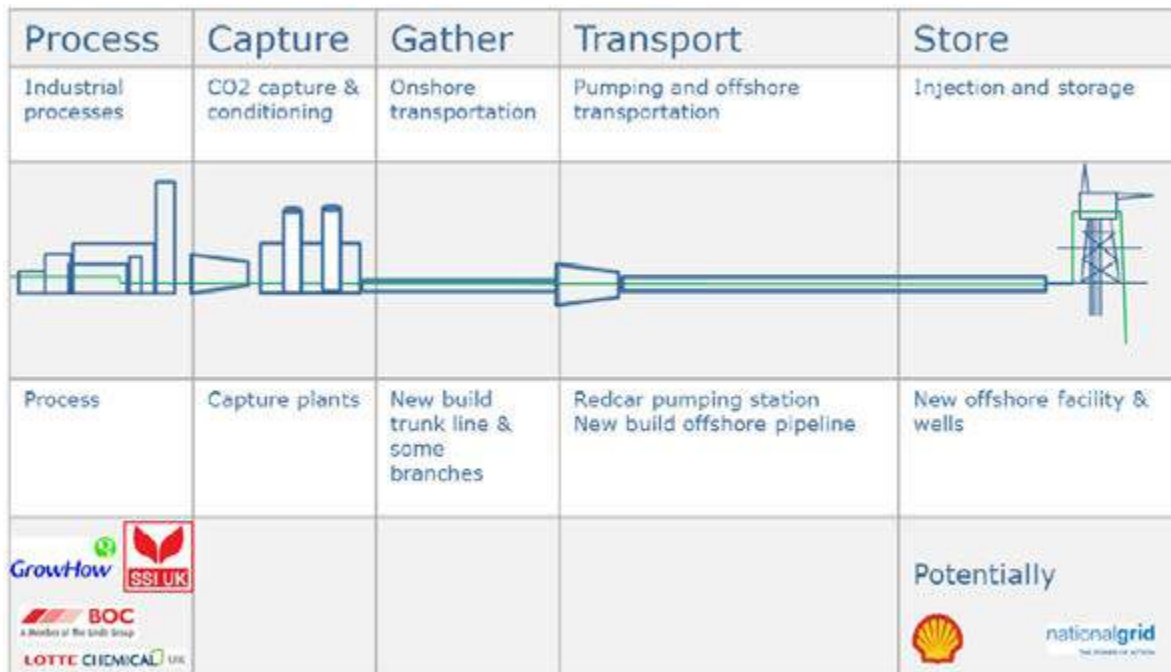


Image 7.6. The Five Elements of the ICCS Project

## 7.3. Carbon Capture from Steam Methane Reformers Using a Post-combustion Scrub of the Flue Gases

The technology chosen for this report recommends post-combustion capture of the CO<sub>2</sub> and comprehensive details are provided within the **Technical Breakout** below. Recovered heat is used within the SMR for pre-heating, but there is an excess of good quality heat in the form of steam from the process. This can be used to produce power for site utilities or export.

Additionally, the steam is also very useful when capturing the CO<sub>2</sub> flue gases from the process. There are a number of process options and proprietary technologies to capture the CO<sub>2</sub>. For this project the simplest and most common process is to scrub the mixed gases in an absorber tower by contact with MEA (monoethanolamide), a liquid which preferentially binds with CO<sub>2</sub>. The liquid is collected at the bottom, leaving the flue gases with much lower CO<sub>2</sub> concentrations. A typical economic design would reduce the CO<sub>2</sub> emissions by a factor of 10.

The MEA liquid, now rich in CO<sub>2</sub>, goes into a regenerator tower which is heated by the excess steam from the SMR. This 'drives-off' the CO<sub>2</sub> from the liquid. The MEA is sent back to the absorber tower, and the CO<sub>2</sub> gas is dehydrated and compressed for export from the plant to the shared CO<sub>2</sub> transport system.



## Technical Breakout

Alternative configurations for carbon capture from SMR plant.

The final recommendations of this report focus entirely on conventional designs of SMR to which carbon capture has been added. This is the correct decision for such first generation plants, where the major innovation is the distribution of bulk hydrogen, not the details of its production. However, this short section does detail options that could be available in the medium term which may:

reduce costs;

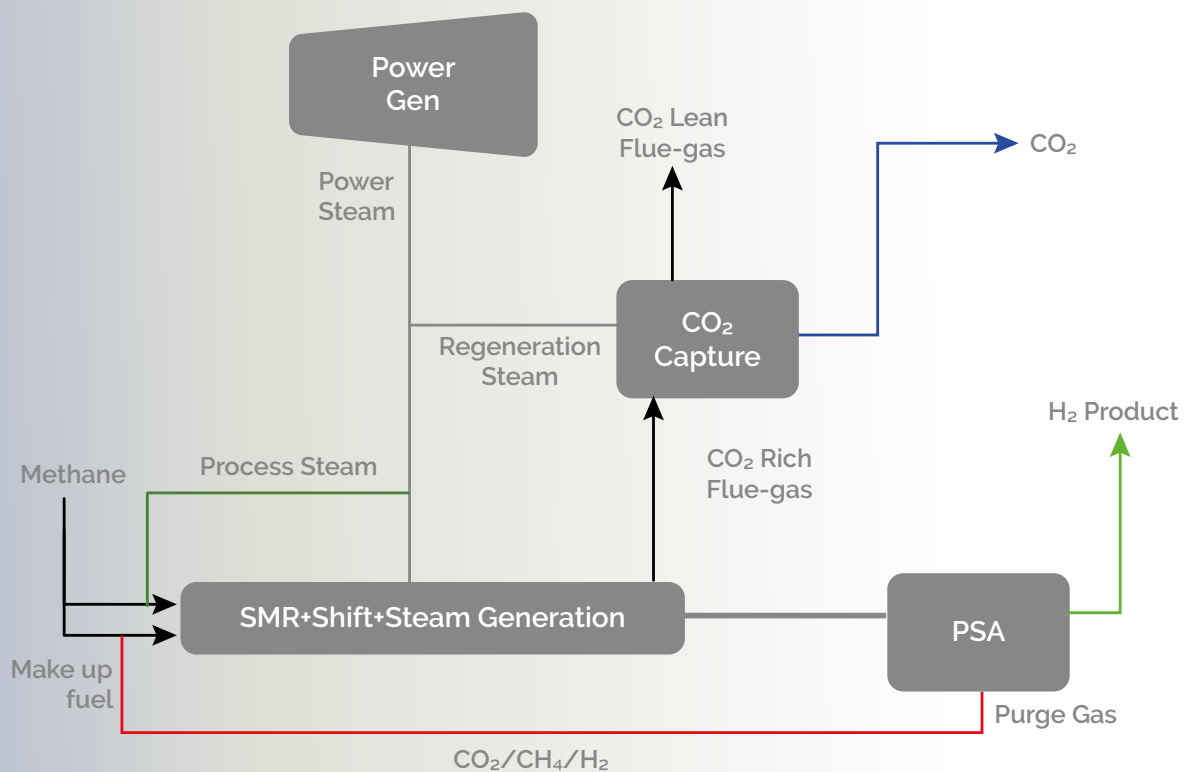
increase SMR thermal efficiency; and

increase % CO<sub>2</sub> capture.

There are two main alternatives for the SMR hydrogen production process with capture.

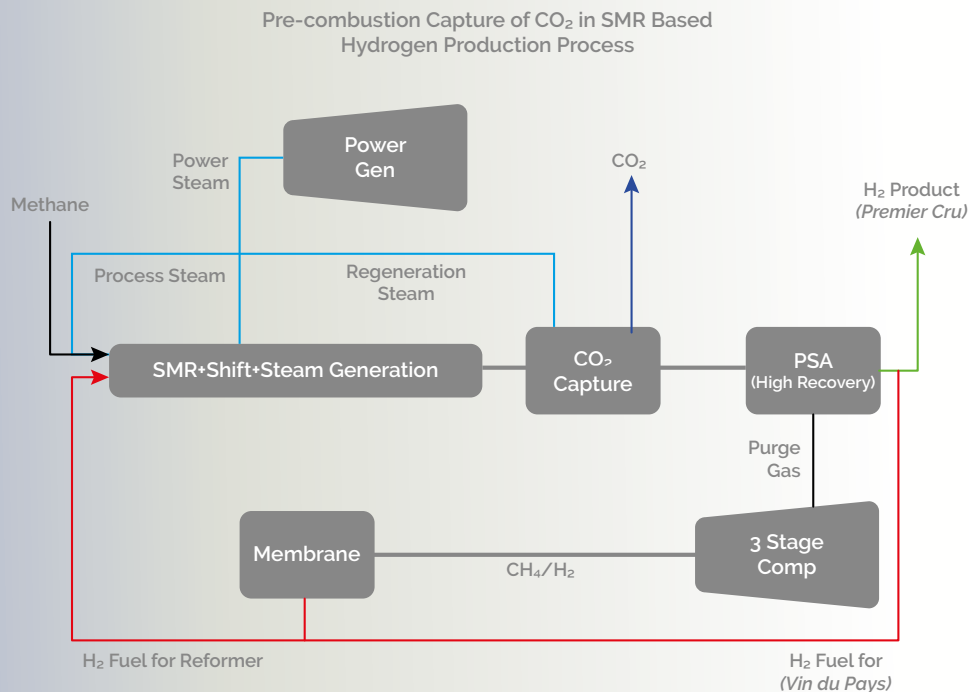
- 1) *Post-combustion capture of CO<sub>2</sub>. A flue gas scrubbing column is fitted downstream of a conventional process (the route adopted here). It is the route currently recommended by AMECFW.*

Post-combustion Capture of CO<sub>2</sub> in SMR Based Hydrogen Production Process



## Technical Breakout (continued)

- 2). The other is to install capture in the syngas stream, (i.e. the high pressure gas stream within the plant), and to recycle the methane in the Pressure Swing Adsorption (PSA) off-gas after first separating it in a membrane. This is described as pre-combustion.



Both processes have been roughly simulated with the intention of establishing the carbon footprint and the overall conversion efficiencies. A secondary objective was to explore the extent to which the heat and power requirements of the capture unit could be provided by the waste energy streams from the basic hydrogen process. Two variants of each process were simulated to gauge sensitivity to export hydrogen purity/recovery performance of the PSA unit.

A few basic process assumptions were made for the comparative simulations. These are summarised below

- For all cases feed is preheated to 600°C in the furnace convection section. The reformer operates at 20 bara. A steam carbon molar ratio of 3:1 is used. HT and LT Shift reactions are at about 400°C and 220°C. Recovery of CO<sub>2</sub> for post combustion cases is 90% and for the pre-combustion case 98%. For the two post-combustion cases the PSA operates at 80% and 90% recovery of hydrogen respectively.
- For the two pre-combustion cases the PSA operates at 70% and 90% respectively. The PSA purge gases are compressed in a three stage reciprocating compressor to 20 bara at which point they pass through a membrane which separates most of the hydrogen limited by the partial pressure on the permeate side which operates at around 1.1 bara.

## Technical Breakout (continued)

The main results indicate that the pre-combustion cases have a slightly better carbon footprint and this is mainly due to the better CO<sub>2</sub> capture efficiency which more than offsets the slightly lower energy conversion efficiency to hydrogen product. The concept is that the pure hydrogen product from the PSA will be split into two fractions. The first production from a new on line bed will be 'premier cru' very pure hydrogen. The tail end production of the beds approaching breakthrough of other components will be routed to the reforming furnace as fuel gas.

The pre-combustion case uses a large amount of the product hydrogen for firing the reformer so this arrangement will allow the export hydrogen to be very pure. For the post combustion case it will be necessary to partly fire the reformer with hydrogen to the extent that the export hydrogen reaches the necessary purity. The effect can be achieved also by early bed regeneration which reduces the hydrogen recovery and increases the hydrogen content of the PSA purge gas. As the hydrogen directed to fuel for the reformer is only needed at low pressure there is opportunity to recover some energy by turbo expansion.

The results are summarised in the table below.

Comparison of residual CO<sub>2</sub> emission factors for pre and post-combustion capture options.

Case Description	Post Capture 90% Hydrogen Recovery	Syngas Capture 70% Hydrogen Recovery	Post Capture 80% Hydrogen Recovery	Syngas Capture 90% Hydrogen Recovery
Fuel supply penalty	0.135	0.135	0.135	0.135
Overall energy conversion efficiency	0.76	0.70	0.73	0.72
CO <sub>2</sub> emission from fuel supply (fraction)	0.18	0.19	0.18	0.19
CO <sub>2</sub> emission due incomplete capture	0.13	0.03	0.14	0.03
CO <sub>2</sub> capture fraction	0.90	0.98	0.90	0.98
<b>TOTAL CO<sub>2</sub> emitted as fraction in net feed</b>	<b>0.31</b>	<b>0.22</b>	<b>0.32</b>	<b>0.22</b>
Emission gm/kWh	57.2	40.9	59.4	39.8
NG emission factor (DEFRA 2015 Scope 1)	184.45	gm/kWh		
NG emission factor (DEFRA 2015 Scope 1 +3)	209.28	gm/kWh		



## Technical Breakout (continued)

*These values are self consistent and evaluated to compare different SMR+CCS cycles. The design of post capture 90% efficiency plant described here is slightly different to that used in the costed example detailed below, and therefore has a slightly different carbon footprint, changing the ratio of on-site to purchased power is also significant.*

*It should be noted that these figures are for comparison only. Due to heat losses and other internal process inefficiencies which have not been modelled the emissions are expected to be slightly higher than these numbers. Note that Scope 1 emissions are those directly from combustion of a fuel and Scope 3 emissions are 'Well To Tank' (WTT) which are the additional emissions associated with extracting and transporting a fuel.*

*The energy flows have not been inspected in detail. However it can be expected that the surplus energy released in the process will be sufficient to power the capture process and recycle methane compression requirements. The system will need to be engineered to produce LP steam for regeneration at appropriate temperature and pressure and also include a steam turbine powered generator to convert any surplus steam into power for the CO<sub>2</sub> export and methane recycle compressors as well as for pumping process liquids.*

## 7.4. Carbon Footprint of H<sub>2</sub>i System

The rationale for any natural gas to hydrogen conversion programme must be a net reduction in emissions of carbon dioxide and other greenhouse gases, expressed as their carbon dioxide equivalent in line with the Kyoto Protocol, but quantifying this can be complex. When comparing the carbon emissions of any product or service it is vital to compare like with like, and to define the boundary conditions in a coherent fashion. Commonly carbon emissions are compared at three different levels and for meaningful discussions it is vital to agree the concepts behind these. Without this society can make erroneous decisions. These three levels are:

- 1. Scope 1:** These are the direct emissions within the system boundary of the end user and hydrogen production facilities (typically from a boiler or vehicle). From stationary plant they are usually evaluated at gm/kWh of fuel. For natural gas they are typically 184 gm CO<sub>2</sub>e/kWh<sub>HHV</sub> (Defra/DECC data set 2015). These are the values used in the EU Emission trading scheme (EU-ETS). They usually make no allowance for the carbon dioxide emitted in transport.
- 2. Scope 2:** Typically allows for these carbon emissions for additional energy inputs to the system such as electricity from the grid.
- 3. Scope 3:** Goes even further than Scope 2 and endeavours to capture the embodied carbon emitted in material inputs to the system, for example, liquefying the natural gas in Qatar, transporting it in refrigerated ships, storing it in LNG depots, re-gasifying it and compressing it into the NTS. Allowing for all these can raise the 'true' carbon footprint of such gas to 230 gm/kWh this is, incorporated in Scope 2 and 3. In practice DEFRA calculate a smaller 'average' value for current UK gas supplies. Such calculations can easily become disproportionate but it is important to understand their real importance.

Out of scope emissions are often associated with biomass and land use changes and are not addressed for this hydrogen production method. For many years it was believed that burning North American wood imported into the UK was an entirely benign and carbon neutral concept, until Prof. MacKay (DECC August 2014) pointed out the possibility of substantial emissions of CO<sub>2</sub> that could be associated with cutting down of some woodland on fragile eco-systems.

This project avoids all the complexities of 'sustainable carbon' and the potential for food competition from agro-fuels.

### 7.4.1. Establishing the CO<sub>2</sub> Emissions for H21 Leeds City Gate

In the UK DEFRA publish emission factors which UK organisations should use to calculate and report their CO<sub>2</sub> emissions. Some of these factors are revised each year to reflect changes, for example in the energy mix of grid electricity or emissions in the natural gas supply chain. The latest year for which factors are available is 2015 and these values have been used to evaluate the carbon emissions from burning natural gas when this is burned as fuel. The Defra/DECC natural gas emission is 184.45 gm CO<sub>2</sub>e/kWh<sub>HHV</sub> (Defra/DECC data set 2015, Scope 1 emission) emitted directly from the combustion of natural gas and a further 24.83 gm CO<sub>2</sub>e/kWh<sub>HHV</sub> (Defra/DECC data set 2015, Scope 3 emission) by the natural gas supply system making a total of 209.28 gm/kWh for the present natural gas supply. The same factors have been used to estimate what the emissions from the H21 Leeds City Gate system will be. This system will take natural gas, convert it to hydrogen and permanently store most of the carbon content underground as CO<sub>2</sub>.

#### The Carbon Footprint of the H21 System

There are three areas to consider when evaluating the emissions of the H21 system:

1. **Scope 1** emissions associated with the production of hydrogen and carbon at the SMR.
2. **Scope 2** emissions include the electrical consumption of the plant and the compression requirements (both CCS and hydrogen).
3. **Scope 3** include the embodied emissions of natural gas outside the system boundary. The Scope 2 emissions of natural gas are small and assumed to be incorporated in Scope 3.



## Scope 1 Emissions Associated with the Production of Hydrogen and Carbon Dioxide at the SMR

The main emissions from the H21 system will be from the steam methane reforming (SMR) plants which convert natural gas to hydrogen and capture approximately 90% of the carbon in the feedstock. The reported efficiencies of conversion of SMR+CCS plant are complicated. The highest values for SMR (stand-alone) are reported for plant which export considerable steam (as might be required on a refinery with a large steam demand), and then there is a trade off between efficiency and capital cost. The highest practical efficiency (HHV basis) of a simple SMR (without CCS) is circa 88%, with 11.2% of the energy potentially exported as steam and 76.8% of the energy exported as hydrogen (ref. Analysis of the Thermal Efficiency Limit of the Steam Methane Reforming Process X. D. Peng\* Air Products and Chemicals, Inc., 7201 Hamilton Boulevard, Allentown, Pennsylvania 18195-1501, United States 2012). The steam rate is 6.5 kg per kg of H<sub>2</sub>.

Simulations carried out for this project of the basic SMR process (with CCS) indicate that 68.4% of the energy in the natural gas feedstock is retained in the hydrogen product on an HHV basis. The remaining 31.6% is released as heat much of which is converted to steam but with some carried away in hot stack gases from the reforming furnace. When carbon capture is added most of the steam is required by the capture process and the stack gases are fully cooled by the capture process so that this heat is now rejected by the cooling system. However the overall conversion efficiency remains the same. As indicated in the Technical Breakout some other SMR configurations may produce higher efficiencies of conversion to hydrogen but these are much less proven.

- The carbon footprint of the SMR+CCS has been evaluated as follows:
  - The carbon footprint of the natural gas feedstock = 184 gm/kWh.
  - With no carbon capture capability and an efficiency of 68.4% = 269 gm/kWh (184/0.684).

90% of the carbon dioxide will be captured by the CCS system therefore the direct CO<sub>2</sub> emissions from this process are 26.97 gm/kWh (Scope 1).



## Scope 2 Emissions Include the Electrical Consumption of the Plant and the Compression Requirements (both CCS and Hydrogen)

The system utilises electric power to drive pumps and fans for the carbon capture process (CCP) and the large compressors which send the captured CO<sub>2</sub> to storage. The SMR plant could in principle generate this power from the waste heat produced by the conversion process. However this requires additional equipment and the simplest concept is to import this power from the UK electrical grid. This would result in an additional emission of 18.49 gm/kWh (DEFRA emission factor 2015).

The system requires a certain amount of hydrogen to be stored to ensure all demands in winter and during peak hours during the day are met. The hydrogen has to be compressed to very high pressure of up to 300 bar for winter storage and intermediate pressure of up to 100 bar for daily peak shaving resulting in additional power consumption. This compression will be remote from the location of the conversion plants and will draw additional power from the grid intermittently. The additional emissions associated with this based on these maximum storage pressures are 4.07 gm/kWh (DEFRA emission factor 2015). The additional emissions associated with this based on these maximum storage pressures are 4.07 gm/kWh (DEFRA emission factor 2015) making the total 49.53 gm/kWh.

Total Scope 2 emissions are thus:

- Hydrogen/carbon production = 26.97 gm/kWh.
- Electric requirements for SMR plant = 18.49 gm/kWh.
- Electrical hydrogen compression requirements = 4.07 gm/kWh.
- Total emissions = 49.53 gm/kWh.

This Scope 2 is believed to be the most honest and transparent comparison with the present direct emissions from natural gas. It allows for both the increase in carbon associated with the loss of efficiency from the SMR process, as well as the reduction in carbon from CCS.

A general reduction in the carbon footprint of the imported electricity would increase carbon savings, as would an increase in self-generated electricity from a more sophisticated steam system. This could have the following systems;

- A high pressure system for power generation followed by.
- A low pressure steam system for the amine regeneration in the carbon capture plant (CCP).

The CO<sub>2</sub> capture process has a significant heat demand, for such low grade heat getting the balance between these two systems, (i.e, HP for power generation and LP for the CO<sub>2</sub> capture), is difficult. HP steam would likely have more value if used to generate electrical power, which could be used internally or exported to the grid. The latter will increase plant capital cost and operational complexity, but decrease Scope 2 emissions. This is not thought likely to materially change the economics of the whole process.



Unfortunately the natural gas used in the UK has significant embodied carbon. Its production involves the emission of significant quantities of up-stream CO<sub>2</sub> associated with its processing, possible liquefaction and subsequent shipping from distant locations around the world. DEFRA include this in their set of factors at a rate of 24.83 gm/kWh The SMR+CCS efficiency of 68.4% then raises this to 36.3 gm/kWh (24.83/0.684) of hydrogen bringing the total emissions to 85.83 gm/kWh. Many of additional emissions may occur outside the UK.

Scope of Emissions	H21 System (gm/kWh)	Natural Gas (gm/kWh)	% Reduction in Emissions
Scope 1	26.97	184.45	85%
Scope 1+2	49.53	184.45	73%
Scope 1+2+3	85.83	209.28	59%

Table 7.1. Summary of H21 Emissions Levels by Scope

### Comparison of H21 and Existing Natural Gas Emissions (CO<sub>2</sub> emissions in gm per kWh)

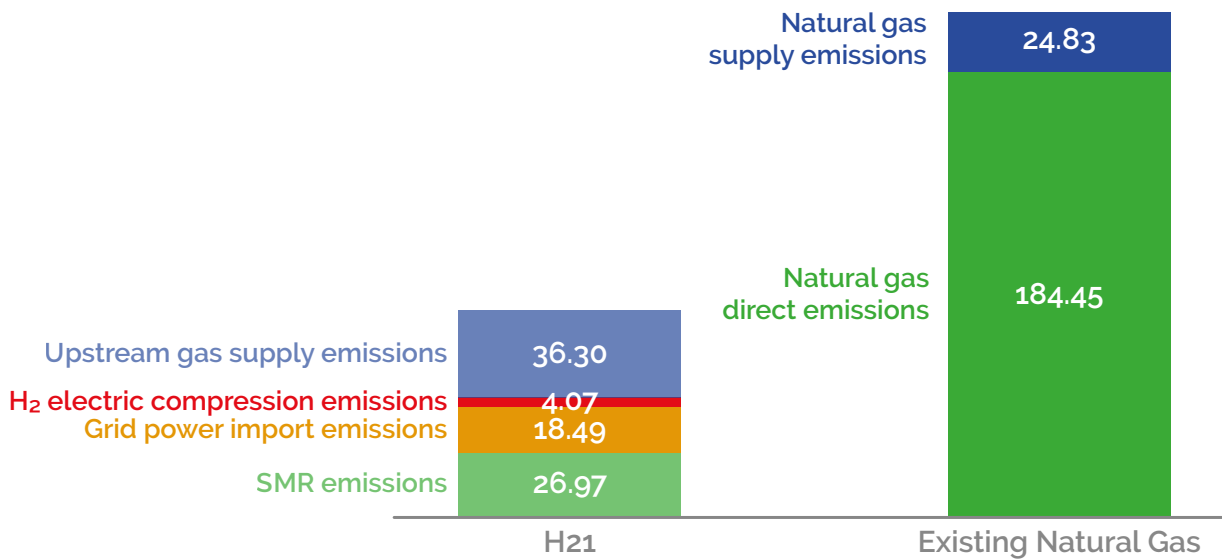


Chart 7.1. H21 vs. Natural Gas CO<sub>2</sub> Emissions

**Table 7.2** compares the carbon footprints of several fuels. All are taken from the DECC/Communities Standard Assessment Procedure (SAP) 2012 used to assess the CO<sub>2</sub> emissions from domestic and commercial buildings. Unfortunately DEFRA use a slightly different value for natural gas. This is included for reference.

Fuel	gm/kWh	Notes	% SAP Natural Gas
Mains gas	216		100%
<b>Mains Gas DEFRA</b>	<b>209</b>	<b>DEFRA data</b>	<b>97%</b>
Bioethanol	140	Any bio source	65%
Biodiesel	123	Any bio source	57%
Biogas	98	Inc anaerobic	45%
<b>H<sub>2</sub> SMR+CCS</b>	<b>86</b>	<b>Scope 1+2+3, Table 7.1</b>	<b>40%</b>
H <sub>2</sub> SMR+CCS	49.6	Scope 1+2	23%
Wood pellets	39		18%
Logs	19		9%

**Table 7.2. Comparison of the Carbon Footprint of Hydrogen from SMR+CCS with Other Fuels**

It can be seen that this SMR+CCS hydrogen (even from plant not optimised for carbon emission reduction) is substantially less than bio-ethanol, biodiesel and even biogas. If some hydrogen were to be made from excess renewable electrical energy or even nuclear power it is likely to have a very low or low carbon footprint. Hydrogen itself is not a greenhouse gas, it has been suggested it can be a second order greenhouse gas, (i.e. interfere with some atmospheric processes which reduce greenhouses gases), but as this will only occur through leakage the effect is minimal. Possibly the most important factor is that this carbon footprint of hydrogen from SMR+CCS is transparent and readily verifiable. Depending upon the precise source the figures for biomass related products can have high degrees of uncertainty and the calculations are still subject to academic debate. The carbon footprint of gas from mixed biomass and waste streams are particularly complex.

## 7.4.2. Total yearly volume of captured carbon

Table 7.3 reports the tonnes per year of CO<sub>2</sub> sent to disposal during a year operating at design output. Most years will export less than this.

	Unit	On-site Emissions
Natural Gas	gm/kWh	184
Leeds design (average year)	GWh/yr	5.94
Emissions CO <sub>2</sub>	Tonnes/yr	1,093,000
Change with H21	Tonnes/yr	933,000
<b>SMR</b>		
Conversion rate	%	68.40%
Natural gas to SMR	GWh/yr	8.68
CO <sub>2</sub> Teesside	Tonnes/yr	1,600,000
% CO <sub>2</sub> to CCS	%	90%
CO <sub>2</sub> to storage	Tonnes/yr	1,440,000
CO <sub>2</sub> to atmosphere	Tonnes/yr	160,000

Table 7.3. H21 Leeds City Gate – Total Annual Volume of Captured CO<sub>2</sub>

For the purposes of the H21 Leeds City Gate project a £40 price per tonne for carbon has been assumed on day one. This is in line with the 'Global status of CCS: 2015 summary report'. As scale is a critical factor in costs for CCS this initial £40 per tonne is the upper end of any forecast and an appropriate reduction overtime has been provided for illustrative purposes in **Section 11, H21 Vision**.

**Total costs for carbon capture per annum**  
 = 1,500,000 tonnes/yr. x £40/tonne  
 = £60 m pa (Year One)



Another example of the advantage of developing CCS using hydrogen from SMR+CCS is that the storage of hydrogen after production smoothes out the variation of inter-seasonal natural gas demand and CO<sub>2</sub> disposal. Both of these will lower costs. Gross variations of CO<sub>2</sub> to sequester will increase the difficulties of managing pressures in the underground disposal zone as well as complicate compressor design. A relatively constant rate of CO<sub>2</sub> production, except early Autumn (when maintenance can be carried out) involves less commercial risk which is always an issue for plant operators.



## 7.5. Conclusion

The assumption of this report has very much been that CO<sub>2</sub> sequestration will be available 'over the fence' as and when required. A recent report by the ETI (Progressing Development of the UK's Strategic Carbon Dioxide Storage Resource a Summary of Results from the Strategic UK CO<sub>2</sub> Storage Appraisal Project April 2016) highlights that between 3 and 5 million tonnes per year of CO<sub>2</sub> is required for cost effective disposal at between about £11 and £17/tonne. Leeds will produce about 1.5 million tonnes of CO<sub>2</sub>/year, so ideally the planned conversion soon after of Newcastle upon Tyne or Sheffield would reach this number which really starts to offer the economies of scale. SMR from natural gas with the subsequent storage of hydrogen can provide an advantageously constant level of CO<sub>2</sub> for disposal.

The fitting of carbon capture plant to an SMR is a well proven technology, although there are still a variety of ways of configuring the system circuits. The compression and disposal of the supercritical CO<sub>2</sub> to under-sea is also becoming more routine. Unfortunately CCS disposal is one of those technologies that offers very large economies of scale, so any first scheme is going to be expensive. SMR+CCS however offers a low cost, well proven route to low carbon hydrogen providing a 73% reduction in Scope 1 emissions.



**SECTION 8**

**Finance and  
Regulation**



## 8. Finance and Regulation

### *History of Regulation*

*The key legislation is the Gas Act 1986 [this repealed all previous legislation] which has subsequently been amended as industry arrangements developed but fundamentally this established the structure. Gas Transporter, Shipper and Supplier licences are issued by powers under the Gas Act. The introduction of supply competition in 1996 required a contract between Transco and gas shippers and the Transco Network Code was introduced to meet this need. This became the Uniform Network Code when National Grid sold four distribution networks in 2005. In the following 11 years there have been nearly 600 proposals raised to modify the Uniform Network Code. The Supply Point Administration Agreement which governs relationships between transporters and suppliers was introduced in 2006 and the Smart Energy Code in 2010.*

*Since privatisation, regulated utility companies in the UK have found it relatively easy to access debt funding from a variety of sources, including sterling bond markets, bank facilities, US Private Placements and loans from the European Investment Bank. Debt investors are attracted to the low business risk provided by the relatively stable and predictable cash flows and local monopoly status inherent in UK utility companies as well as the stable regulatory regimes under which they operate. Indeed, in setting cost of debt allowances regulators have argued that these features have historically enabled regulated utility companies to raise debt more cheaply than similarly rated corporates in other sectors. Whole Business Securitisation (WBS) structures, which offer lenders security over shares as well as a number of enhanced covenants, have enabled some utility companies to achieve very high levels of gearing relative to the value of the regulatory asset base.*

This section will provide details on financing the H21 Leeds City Gate project via regulatory finance and the subsequent impact on customers' bills. It will also provide a unit cost evaluation of the project in £/kWh if it was not financed using regulatory business models. Finally, a comparison of the cost per tonne of carbon saved is presented as well as some additional regulatory considerations.

## 8.1. Summary of Costs for the H21 Leeds City Gate project

Throughout report we have established the costs associated with all aspects of the project. These are now summarised in [Table 8.1](#).

Project Area	Cost Incurred (£m)	Ongoing Costs Each Year (£m)
Network Capacity and Conversion preparatory work (Section 3 and 4)	10	
<b>Hydrogen Infrastructure/Conversion Costs</b>		
Steam Methane Reformer costs (Section 2)	395	
Intraday Salt Caverns (Section 2)	77	
Inter-season Salt Caverns (Section 2)	289	
Appliance Conversion (including all domestic, commercial and industrial users) (Section 5)	1,053	
Hydrogen Transmission System (Section 6)	230	
<b>Ongoing OPEX costs</b>		
Carbon Capture and Storage (Section 7)		60
SMR/Salt Cavern/HTS Management (Section 2)		31
Additional Energy Used for Hydrogen Production and Carbon Capture (Section 2)		48
<b>Total</b>	<b>2,054</b>	<b>139</b>

Table 8.1. *H21 Leeds City Gate Project Costs*

## 8.2. Hydrogen Conversion – The Regulatory Finance Model

Whilst we have presented all the costs associated with the project we also need to consider the methodology for financing and the real impact on customers' bills. In order to do this, we need to understand the current and future levels of gas distribution network investment, the future level of investment required to convert Leeds to hydrogen and how the regulatory financing mechanism works in terms of socialisation of costs and amortisation of return for the industry.

### 8.2.1. Existing Investment

The UK gas industry has been undertaking the Iron Mains Replacement Programme (IMRP) REPEX programme, since 2002. This is a 32 year programme which is driven by the Health and Safety Executive and is essential to reduce risk to life and property associated with gas leaking from the UK's gas distribution system. The REPEX programme is delivered in line with an established industry risk reduction model which ensures the highest risk gas pipes (mains) are replaced as a priority each year. These are replaced as part of efficient pipe replacement projects, i.e. the top risk mains are replaced as well as surrounding lower risk mains to produce economically advantageous schemes. In addition, the gas industry is also financially incentivised, using the OFGEM approved gas industry leakage model, as part of its regulatory price control obligations to reduce leakage from its network.

The REPEX programme, currently accounts for a significant proportion of UK gas distribution network costs, note Northern Gas Networks RIIO-GD1 business plan is £1.2 bn over 8 years. As well as reducing risk and greenhouse gas emissions it is also reducing part of the OPEX associated with gas distribution networks, specifically leakage repair costs. This is because as more iron mains are replaced there is an associated reduction in the number of leaks on the network, and therefore a proportionate reduction in the number of repairs required.

In effect, this means that for the majority of the last two decades the gas industry customers have been funding, via regulatory price controls, the upgrade of the distribution system reducing risk, reducing leakage (and therefore greenhouse gas emissions), and installing a material which will be in a suitable condition to transport hydrogen (polyethylene mains). This programme has been funded as part of the transportation element which makes up gas customers bills utilising the gas distribution networks ability to 'borrow money' against its residual asset value (RAV).



## 8.2.2. A Background to Regulatory Finance

### This section covers:

- Background on the Gas Distribution Industry (GDI) and the costs involved in running the networks
- How OFGEM regulates the industry through the new RIIO framework
- The different expenditure types and how revenue allowances are set
- Where Gas Distribution Networks (GDNs) get their income from to run their businesses, and how they collect it
- How this impacts end customers

### The Gas Distribution Industry

Within the UK there are four GDN companies who own the network of pipes which transport the gas to all UK users, each covering an area of the UK as shown in [Image 8.1](#).

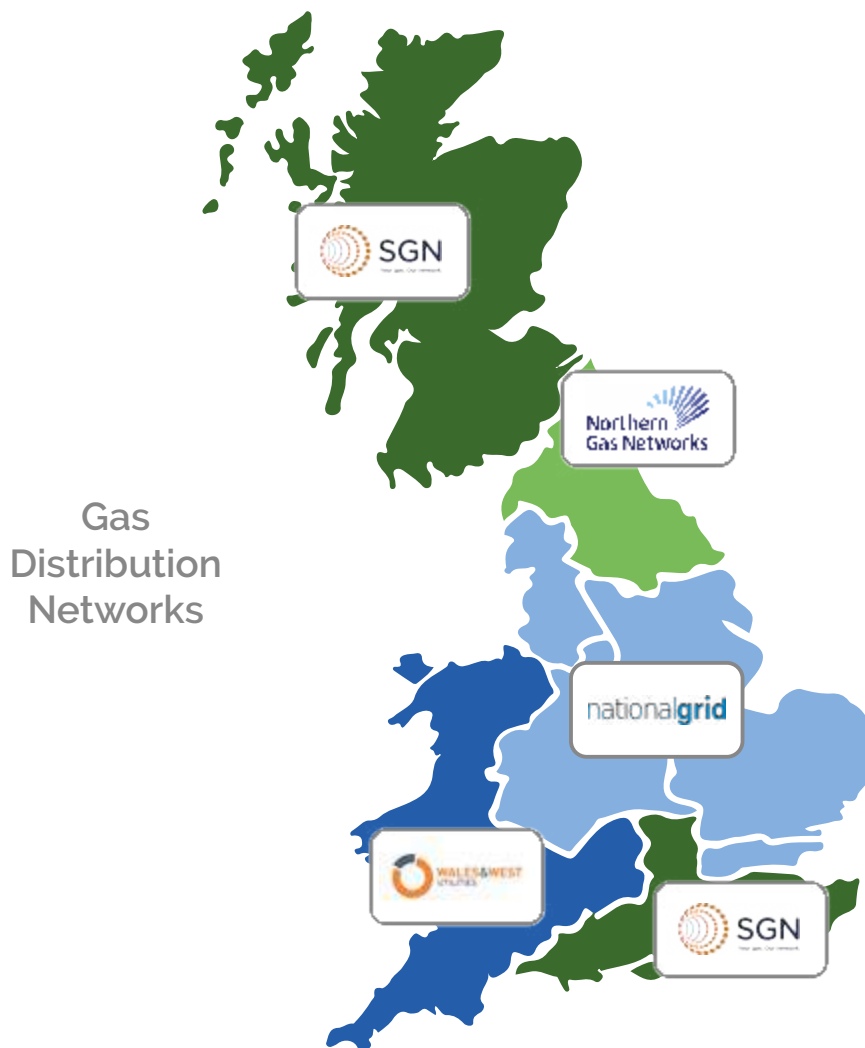


Image 8.1. Gas Distribution Industry Overview

GDNs don't produce or sell the gas, they transport it through a vast network of underground pipes. They manage the network to ensure on the worst possible winter's day (1 in 20 winter peak – see [Section 3, Gas Network Capacity](#) and [Section 4, Gas Network Conversion](#)) gas will continue to flow into people's homes and businesses.

The networks are faced with three types of costs to maintain this level of service;

- **Operating Expenditure (OPEX)** – the costs involved with maintenance, emergency services, repair costs and back office overhead costs.
- **Capital Expenditure (CAPEX)** – equipment, such as Pressure Reduction Units (PRUs) and district loggers will need to be replaced when at the end of their useful life and new infrastructure (for example mains and District Governors (DGs)) may be required when new customers connect to the network. Additional CAPEX is needed to replace vehicles and IT systems as well.
- **Replacement Expenditure (REPEX)** – costs involved with replacing old iron pipes with new plastic pipes. There is an HSE requirement to replace almost all iron mains within 30 metres of a property within a 30 year period (known as the 30/30 programme). The REPEX programme is due to be completed by 31<sup>st</sup> March 2032. Please note the REPEX programme and the IMRP are interchangeable for the purposes of this report.

Across the UK on average TOTEX costs (the collective name for OPEX, CAPEX, and REPEX) are circa £2 bn per year. In addition to this, there is £0.4 bn per year to manage the National Transmission System (NTS). As such network companies receive income to cover these costs which they manage through a regulatory price control process known as RIIO.





## RIIO

RIIO stands for: **Revenue = Incentives, Innovation and Outputs**. OFGEM established the RIIO framework, which came into effect on 1<sup>st</sup> April 2013 for GDNs.

The first RIIO GDN 'price control period' is running for 8 years having started on 1<sup>st</sup> April 2013 and ending on 31<sup>st</sup> March 2021 (this period is also known as RIIO-GD1).

Baseline **Revenue** allowances were set for each network company which provides income to cover OFGEMs view on an efficient level of costs to run each network. The bulk of the allowances relate to TOTEX as detailed above. However, additional allowances are also given for non-controllable costs (for example business rates, leakage, OFGEM license fee), financeability costs to cover off capital funding requirements and also corporation tax. These revenue allowances are what OFGEM is expecting network companies to charge their customers.

GDNs have the opportunity to earn additional income through a range of **Incentives** during RIIO. Customer service improvements and reducing leakage volumes, the amount of gas 'lost' predominantly through leakage in the transportation network, are examples of two of the incentives where extra income can be earned. Delivering TOTEX costs lower than OFGEM allowances also benefits the GDNs but an element of the outperformance is shared with their customers as well.

GDNs can receive funding for **Innovative** projects which deliver long-term improvements in how they and the industry operate.

There is also a comprehensive list of **Output** performance measures; categorised into six key areas:

- Network safety.
- Network reliability.
- Customer service.
- New connections.
- Social obligations.
- Protecting the environment.

GDNs receive their income from gas shippers but ultimately this is funded by all UK gas customers.



## Expenditure Types and the Link to Revenue Allowances

GDNs know in advance their base revenue allowances for the 8 years of RIIO-GD1. This was calculated through Ofgem's Price Control Financial Model (PCFM). The principles for revenue allowances are largely categorised into two areas depending on whether the costs being funded are considered to be capital or operating expenditure.

**OPEX:** Revenue allowances are given in the year the expenditure is incurred. Areas such as emergency costs, repair costs, non-controllable OPEX and back office support costs are all areas where GDNs incur costs every year and also receive income in the same year to fund these activities.

**OPEX allowances are known as 'Fast Money' for revenue purposes.**

**CAPEX:** there are three areas relating to CAPEX as follows;

- 1. Regulatory Asset Value (RAV) Depreciation:** The capital investment returned to GDNs via a revenue allowance is called RAV Depreciation. It's returned over the life of an asset, on average 45 years, on a reducing balance basis (known as the sum of digits depreciation methodology). **Chart 8.1** shows the profile if £1 m was spent showing the highest amount of income in Year 1 at £43 k reducing down to nil by Year 45.

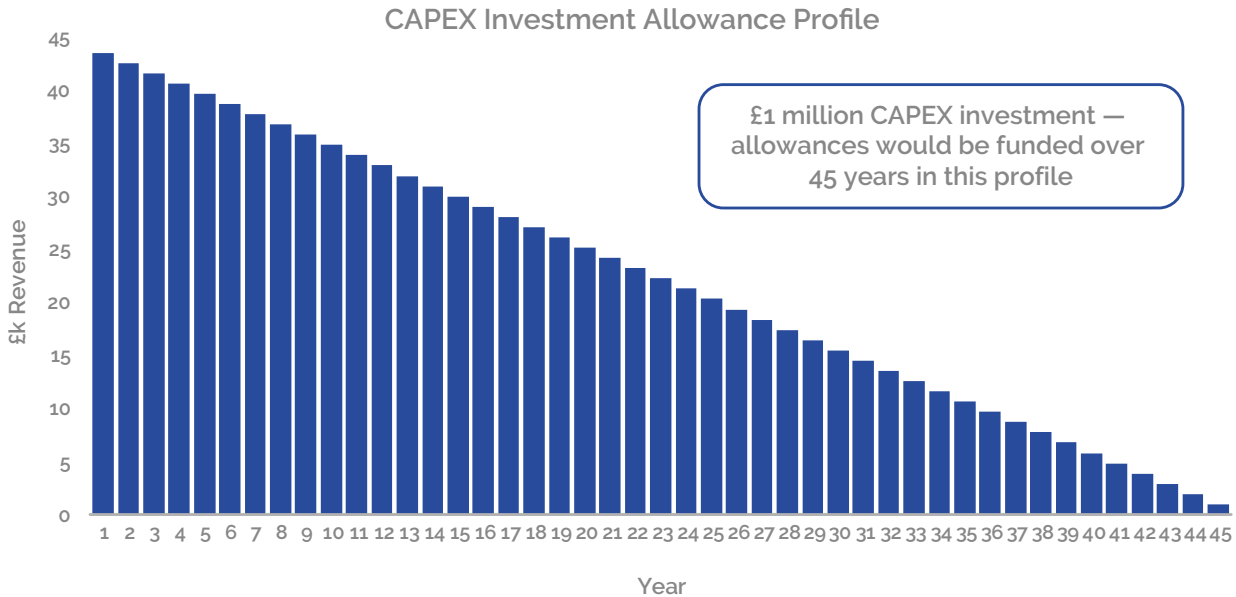


Chart 8.1. RAV Depreciation

**CAPEX allowances are known as 'Slow Money' for revenue purposes.**

2. **RAV and Return:** Any expenditure incurred is added to network's RAV and depreciated in line with the above profile. During an asset's life, GDNs can earn a **return** to cover costs incurred in financing based on the balance of RAV outstanding at any given point.

OFGEM's assumption for the gas distribution industry is that any capital investment will be funded 65% by debt and 35% by equity. This ratio is used to calculate the Weighted Average Cost Of Capital (WACC). During an asset's life, a return is earned to cover off the costs of funding the investment in this way – i.e. the interest costs linked to the debt and the returns required by equity investors.

The current WACC value (real) as published by OFGEM in November 2015 is:

- **Cost of Debt: 2.38%**
- **Cost of Equity: 6.70%**
- **Notional Gearing: 65.00%**
- **WACC: 3.89%**

3.89% would be applied to the GDN's RAV balance to generate the return element within the revenue allowances.

Note the treatment of REPEX:

3. **REPEX allowances:** REPEX is on a transition to be funded in the same manner as CAPEX. By regulatory Year 2020/21 all of the REPEX investment will be funded as slow money – i.e. any REPEX investment will be funded over a 45 year period through a depreciation allowance and a return on the RAV. This is a significant change and is being phased equally across the 8 years of RIIO-GD1, in Year 2013/14 the proportion of REPEX funded through fast money is 50% and by Year 2020/21 this will be nil as shown in [Table 8.2](#).

<b>REPEX FUNDING</b>	<b>13/14</b>	<b>14/15</b>	<b>15/16</b>	<b>16/17</b>	<b>17/18</b>	<b>18/19</b>	<b>19/20</b>	<b>20/21</b>
% funded fast money	50%	43%	36%	29%	21%	14%	7%	0%
% funded slow money	50%	57%	64%	71%	79%	86%	93%	100%

Table 8.2. *REPEX Funding*

It is worth noting at this stage that when the REPEX programme is complete by 2032, there will not be an immediate reduction in revenue terms. This is because from Year 2020/21 all REPEX is funded over a 45 year period via the depreciation and return allowance there will be a gradual reduction over future years. REPEX will stop, but revenue allowances will continue until 2077 due to the mechanics described above.

## Summary of Industry Revenue Allowances

Table 8.3 shows the GDI base allowed revenue for the 8 years of RIIO-GD1 split into the categories described above. It also shows other areas such as non-controllable OPEX (rates, leakage, OFGEM licence fee and pension costs), pension deficit funding, OFGEM income awarded for being at the efficiency frontier and corporation tax.

### INDUSTRY REVENUE ALLOWANCES (£M NOMINAL)

	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
<b>TOTEX funding</b>								
Fast pot – REPEX	456	398	338	275	215	147	77	-
Fast pot – OPEX	870	848	843	869	889	909	907	912
RAV depreciation	843	880	836	860	941	1,047	1,161	1,299
Return on RAV	707	722	734	755	785	818	852	886
<b>Other areas</b>								
Non-controlable OPEX	683	697	704	716	734	755	776	797
Tax allowance	46	33	211	230	253	256	255	266
Pension deficit funding	64	66	67	69	72	74	77	80
Frontier rewards	18	18	18	19	20	20	20	20
<b>Total Base Allowed Revenue £m</b>	<b>3,688</b>	<b>3,663</b>	<b>3,908</b>	<b>3,972</b>	<b>4,026</b>	<b>4,124</b>	<b>4,124</b>	<b>4,260</b>

Table 8.3. *Industry Revenue Allowances*

## Where Do GDNs Get Their Income From?

GDNs receive their income monthly to run their businesses. **Image 8.2** shows the flow of income from a gas consumer through to a GDN

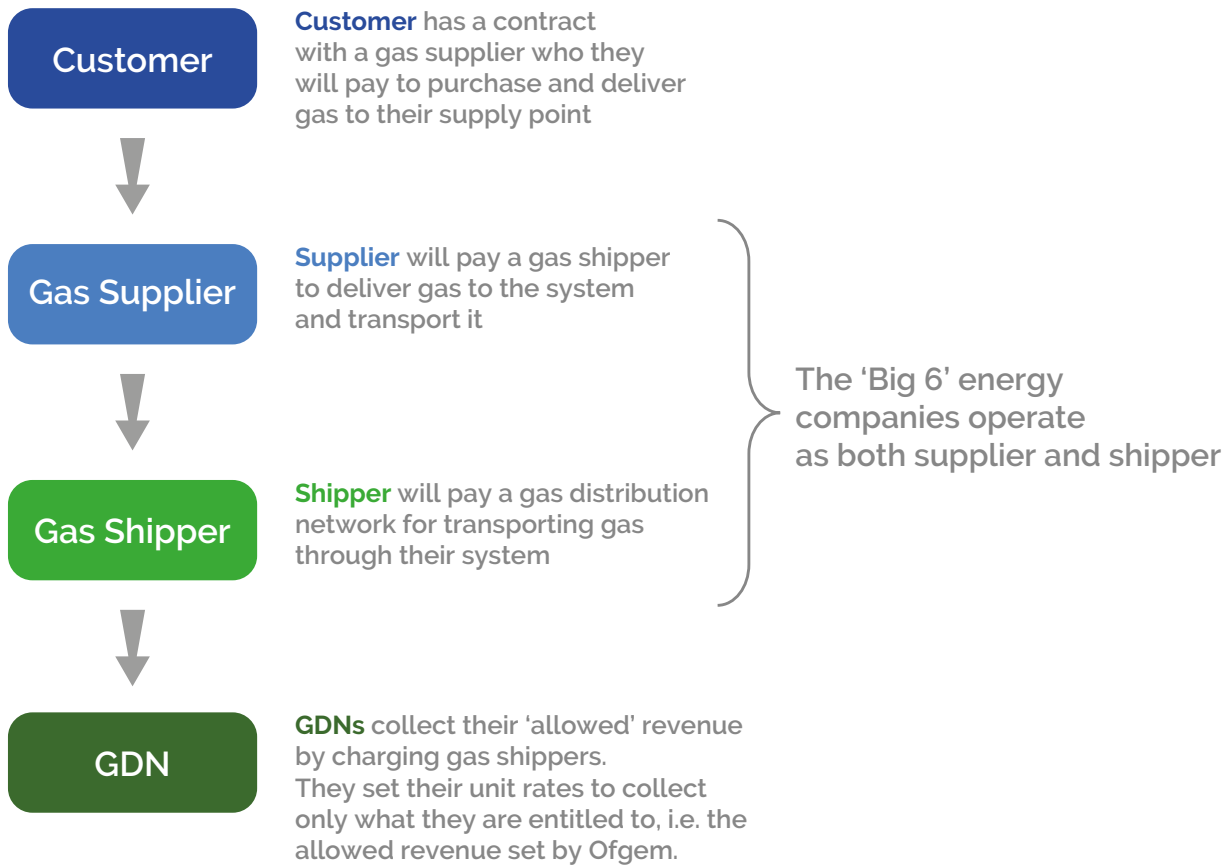


Image 8.2. *GDN income*

- Every month gas shippers will pay GDNs for using their network. The rates that are set by GDNs are calculated only to collect what they are permitted under the OFGEM license.
- Via charges being flowed upstream GDN costs are ultimately passed on to the end customer through their gas bills.
- GDN charges represent circa 17% as a proportion of an average gas bill based on current prices. The breakdown of an average gas bill is shown in **Chart 8.2**.

• **On What Basis Do GDNs Collect Their Income?**

The method of collecting income is largely linked to the capacity requirements of the network in order to meet the peak requirement on a 1 in 20 winter's day. Only a very small proportion of GDN revenues are collected based on actual gas usage (circa 3%). We have seen in recent years that capacity requirements are reducing by circa 3% per year. Every supply point in the UK has a registered capacity figure which is the peak 1 in 20 requirement. GDNs charge a unit rate against the supply point's peak capacity requirement.

If this capacity requirement drops, or if the number of gas customers drops, GDNs are still entitled to collect the same amount of allowed revenue. If GDNs did nothing to their unit rates their income would fall, and they would not collect what they are entitled. Therefore, GDNs will increase their unit rates to cover any shortfall (or reduce unit rates if a surplus).

**Image 8.3** shows an example for one supply point – if a GDN needed to collect £130 and had a unit rate of £1. The starting position is a peak day capacity requirement of 130 kWh, but this drops to 126 as shown below.

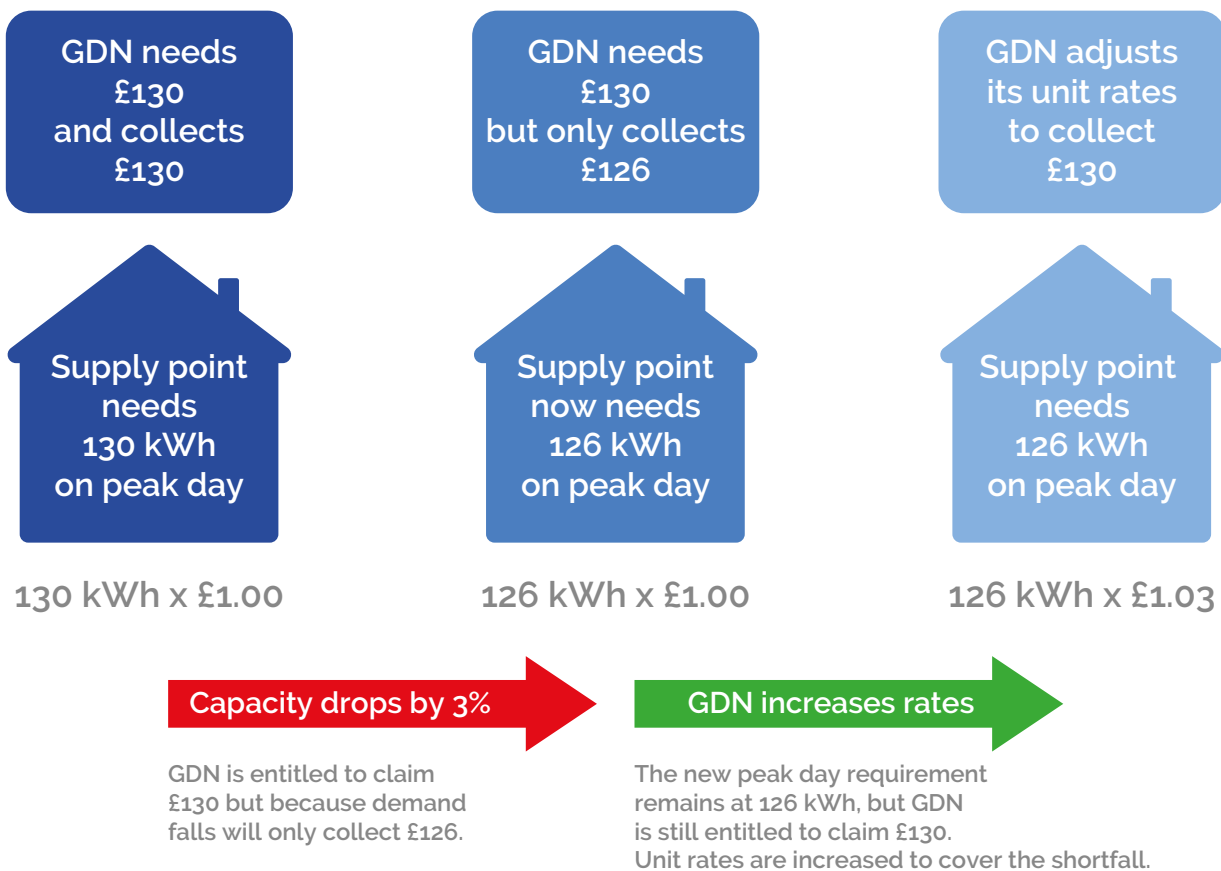


Image 8.3. GDN Capacity Impact

GDNs aim to forecast how much capacity is dropping and build this into their unit rates to minimise any under or over recoveries in future years.

## The Breakdown of a Gas Bill

The above summarises the mechanism of GDN charges and how they receive income to run their businesses. As shown [Image 8.3](#) network costs are ultimately passed up the chain to form part of an end customer's gas bill. [Chart 8.2](#) shows the breakdown of an average gas bill.

Total Customer Gas Bill

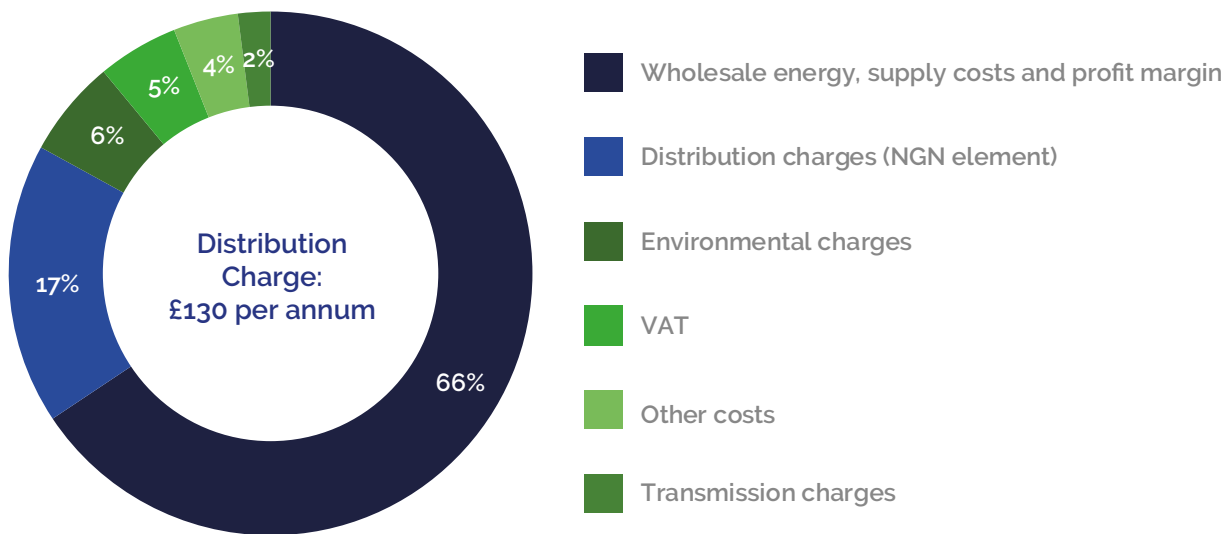


Chart 8.2. UK Gas Bill Component Parts

Based on the current average Annual Quantity (AQ) of 14,200 kWh and a peak day requirement of 121 kWh for an average domestic property this would generate an average GDN charge of £130 per year.

**Currently, if an average gas bill was £750 then GDN charges would represent circa 17% of the total gas bill.**

GDN charges expressed in terms of customer bill impact is a key metric that is presented in the OFGEM annual report. The latest 8-year forecast for RIIO-GD1 highlights that GDN charges are falling starting at £134 in Year 2013/14 and forecasted to be £121 by Year 2020/21. **Table 8.4** shows the breakdown by GDN as presented in the 2014/15 OFGEM annual report.

14/15 Prices (£)	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
National Grid: East of England	126	121	121	112	114	115	113	111
National Grid: London	146	142	149	142	134	139	135	132
National Grid: North West	132	123	125	122	114	118	117	115
National Grid: West Midlands	130	129	124	119	118	122	120	118
NGN	128	131	133	125	122	121	122	123
Scotland	132	133	123	132	122	124	124	123
Southern	147	140	136	136	131	135	131	130
WWU	126	125	119	121	124	123	122	120
<b>Industry</b>	<b>134</b>	<b>130</b>	<b>129</b>	<b>126</b>	<b>122</b>	<b>125</b>	<b>123</b>	<b>121</b>

Table 8.4. *GDN Charges 2014/15 OFGEM Annual Report*



## Key Messages

- RIIO is the price control framework implemented from 1<sup>st</sup> April 2013 for Gas Distribution. The first period is RIIO-GD1 and will run for 8 years.
- OFGEM regulates the gas distribution industry and sets GDN expenditure allowances for OPEX, CAPEX, and REPEX. GDNs have the opportunity to outperform these allowances and earn additional incentives.
- Revenue allowances are largely split between fast and slow money principles which distinguish between OPEX and CAPEX.
- GDNs charge shippers based on their capacity requirements needed on a 1 in 20 winters day. Unit rates are set so that GDNs only collect what they are entitled to as set out in the OFGEM licence.
- If the capacity requirements of shippers/end customers drop, GDNs will increase their unit rates, so they collect the same revenue. If the number of gas users reduces, everyone else will pick up a higher proportion of GDN costs, so they still collect the same.
- GDN costs are ultimately fixed costs passed on to the end customer as part of their gas bills.



### 8.2.3. Current Regulatory Finance Long-term Projections – No Hydrogen Conversion

This section covers:

- The 'current' scenario – if all existing methodologies were rolled forward how would GDN charges change over a long term horizon.
- This uses current Price Control Financial Model (PCFM) revenue methodology extended out to regulatory Year 2052/53 to establish the allowed revenue and customer bill each year.
- For this exercise, it uses Northern Gas Networks data as an illustration only.

#### Current Scenario Assumptions

Calculating actual/forecast allowed revenues for the RIIO-GD1 period (2013/14 – 2020/21) can be completed through the OFGEM PCFM but for this exercise, we needed to forecast beyond RIIO-GD1.

The following assumptions were made for this analysis to enable a longer term view – note the base position for this analysis is the November 2015 OFGEM PCFM with all methodologies extended until Year 2052/53, the last year of RIIO-GD5.

**All assumptions and outputs NGN believe to be directionally accurate based on current methodology/knowledge – however this information has not undergone strenuous audit as defined by the OFGEM DAG requirements.**



- Forecast revenues to Year 2020/21 are in line with the latest revenue profile produced every quarter for gas shippers.

Thereafter:

- A 5% reduction in TOTEX allowances has been assumed at the start of each 8 year period – this is a conservative assumption. Note that with effect from regulatory Year 2032/33 REPEX expenditure allowances are nil as the 30/30 programme has been completed.
- All current PCFM methodologies continue as is:
  - Current split of fast/slow money rolled forward (65% fast/35% slow) for OPEX and CAPEX;
  - The 45-year sum of digits RAV depreciation method for all new additions, with 100% REPEX capitalisation from Year 2020/21 onwards; until Year 2031/32 when the REPEX programme is complete;
  - Return on RAV using a WACC with notional gearing at 65%, cost of equity at 6.7% and cost of debt at 1.75% from Year 2021/22 onwards; and
  - Long term RPI assumption is +3%.
- Incentive income continues at the same rate as RIIO-GD1. It does not assume any outperformance in future years from the TOTEX incentive mechanism.
- Revenue smoothing has been applied as we exit RIIO-GD1 and enter RIIO-GD2 to remove a large drop at the transition. Revenue smoothing is an activity which OFGEM completes prior to finalising revenues to ensure a robust profile and remove any potential financing issues as a result.
- A key assumption throughout all the analysis that follows is that the gas industry will maintain the same number of customers. For NGN this is 2.7 million supply points, and nationally this is 21.5 million supply points. This assumes from an investment perspective that we will need to keep a similar level of CAPEX to maintain our commitment around 1 in 20 peak conditions.

### Results Summary from the Current Scenario

- As expected the revenue profile starts to decline as networks complete the REPEX programme. Due to the nature of how REPEX is funded, over 45 years from 2020/21, there is a gradual decline from Year 2032/33 onwards rather than an immediate reduction in customer bills.
- Customer bills are quoted for an average domestic property within the NGN network in line with recent methodology in OFGEMs annual report. The current domestic annual quantity is 13,967 kWh in the NGN network.
- Average allowed revenues per year within the RIIO-GD1 period are **£400 m** reducing to **£299 m** in RIIO-GD5 (2015/16 prices).
- Average bills within RIIO-GD1 are **£127**. Over the longer term with the completion of the REPEX programme by RIIO-GD5 average bills would be **circa £94** (in 2015/16 prices).
- To re-iterate the average bill calculation assumes the same number of gas users in the NGN network. If the number of users was to fall this would result in remaining users picking up a larger proportion of the network costs and vice versa.

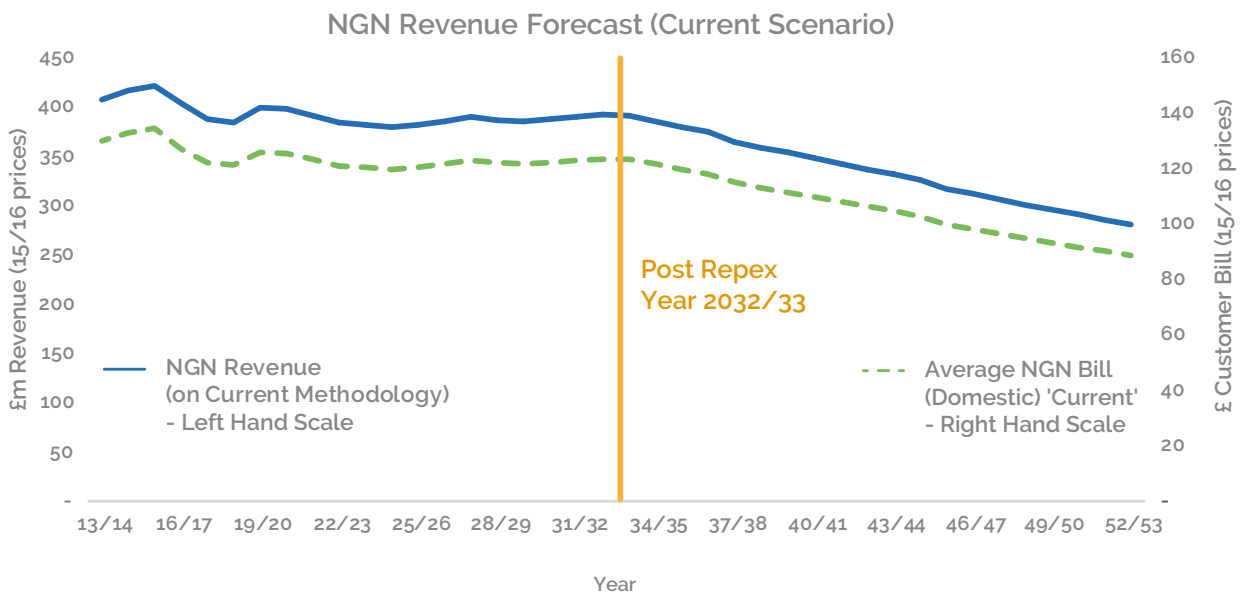


Chart 8.3. NGN Revenue Forecast (Current Scenario)

**NGN (CURRENT) PRICES (2015/16)**

	<b>RIIO-GD1</b>	<b>RIIO-GD2</b>	<b>RIIO-GD3</b>	<b>RIIO-GD4</b>	<b>RIIO-GD5</b>
Revenue (Avg Yr)	£400 m	£383 m	£386 m	£346 m	£299 m
Average GDN element of Customer Bill	£127	£121	£122	£109	£94

 Table 8.5. *Customer Bill Impact – Transportation Charge Only*
**Total Customer Bill Forecast**

So far we have focused primarily on the gas distribution element of a gas bill and how this is forecast to change over time. As shown in the pie chart previously ([Chart 8.2](#)) the gas distribution element represents a small proportion of the overall gas bill, and customers will be faced with a total bill of much higher (circa £750).

Over the longer term horizon, home improvement efficiencies should deliver savings in the non-distribution element of the gas bill. The introduction of initiatives such as smart meters, increasing new build properties, insulation, solar energy and other initiatives should deliver additional savings.

To demonstrate this the following % saving in the non-distribution element of a domestic bill has been applied:

	<b>2016-30</b>	<b>2030-35</b>	<b>2035-40</b>	<b>2040-45</b>	<b>2045-50</b>	<b>2050+</b>
Saving from current	0.00%	3.00%	6.00%	9.00%	12.00%	15.00%

 Table 8.6. *Energy Efficiency Over Time*

Under the current scenario this would result in the following profile:

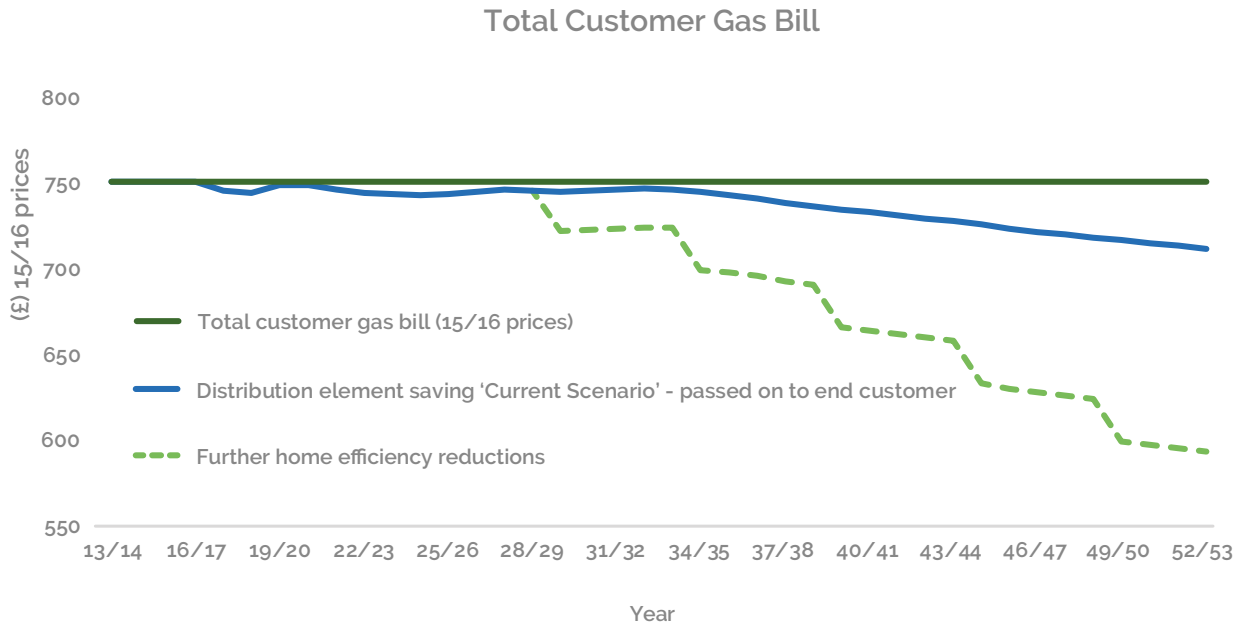


Chart 8.4. *Total Customer Gas Bill*

15/16 prices (£)	RIIO-GD1	RIIO-GD2	RIIO-GD3	RIIO-GD4	RIIO-GD5
Current average bill £	750	750	750	750	750
GDN reduction	-	(5)	(6)	(18)	(33)
Efficiency savings	-	-	(31)	(66)	(106)
<b>Total Gas Bill</b>	<b>750</b>	<b>745</b>	<b>713</b>	<b>665</b>	<b>611</b>
GDN element of gas bill	127	121	122	109	94
% of total gas bill	17%	16%	17%	16%	15%

Table 8.7. *Total Customer Bill Impact – (Total Bill)*

- In **Chart 8.4** if the starting point was the current total gas bill of £750; then:
  1. As shown previously, the distribution element of the bill will reduce – by 2052/53 this will reduce by £39 which will be passed on to end customers.
  2. If further home efficiencies were implemented in the above profile, then the customer bill would reduce by £118 in 2052/53.
- The GDN proportion of a gas bill will, therefore, fall from circa 17% in RIIO-GD1 to circa 15% in RIIO-GD5.

### Key Messages:

- There is not an immediate drop in revenue when the REPEX programme finishes because of how it is funded over 45 years.
- Average transportation charge in domestic bills would drop by circa 26% from £127 in RIIO-GD1 to £94 in RIIO-GD5.
- It assumes no reduction in gas users throughout.
- Analysis has primarily focused on the GDN element of a gas bill – however efficiency savings have also been considered resulting in the **total gas bill** falling by both the GDN reduction and also home efficiency savings.



## 8.2.4. Regulatory Finance Long Term Projections – H21 Leeds City Gate Undertaken in RIIO-GD2

### Expenditure Forecast for Leeds City Hydrogen Project

Table 8.8 shows the forecast costs to cover converting 264,000 supply points in the area of conversion to hydrogen – both in terms of implementation costs and ongoing OPEX costs.

COSTS SUMMARY	Costs Incurred Prior (£m)	Conversion Costs (£m)	Total (£m)	Costs Year 1 (£m)
<b>NGN Funded</b>				
CAPEX – reinforcement/readiness	10		<b>10</b>	
<b>Hydrogen Specific Costs</b>				
OPEX – Labour		527	<b>527</b>	
OPEX – Appliances		527	<b>527</b>	
OPEX – SMR Efficiency Loss			-	48
OPEX – Carbon Capture/Storage			-	60
OPEX – Maintenance			-	31
CAPEX – SMRs	395		<b>395</b>	
CAPEX – Salt Caverns	366		<b>366</b>	
CAPEX – HTS	230		<b>230</b>	
TOTEX	1,001	1,053	<b>2,054</b>	139

Table 8.8. *Expenditure Forecast*



The SMR efficiency loss has been calculated by assuming that 47% more gas would be needed to meet consumer demand via hydrogen. Based on Leeds, this would result in an additional 2.8 Terawatt/95 million therms applied with an assumed cost of 50 pence per therm.

50 pence per therm is the actual price NGN has paid to purchase gas, on average, in the last 3 years, to replace any lost from the network via leakage. It is known within the industry as the 'Heren' price and the charge only relates to the purchase of gas, (i.e. it excludes any other costs in the bill such as transmission/distribution charges).

#### This section covers:

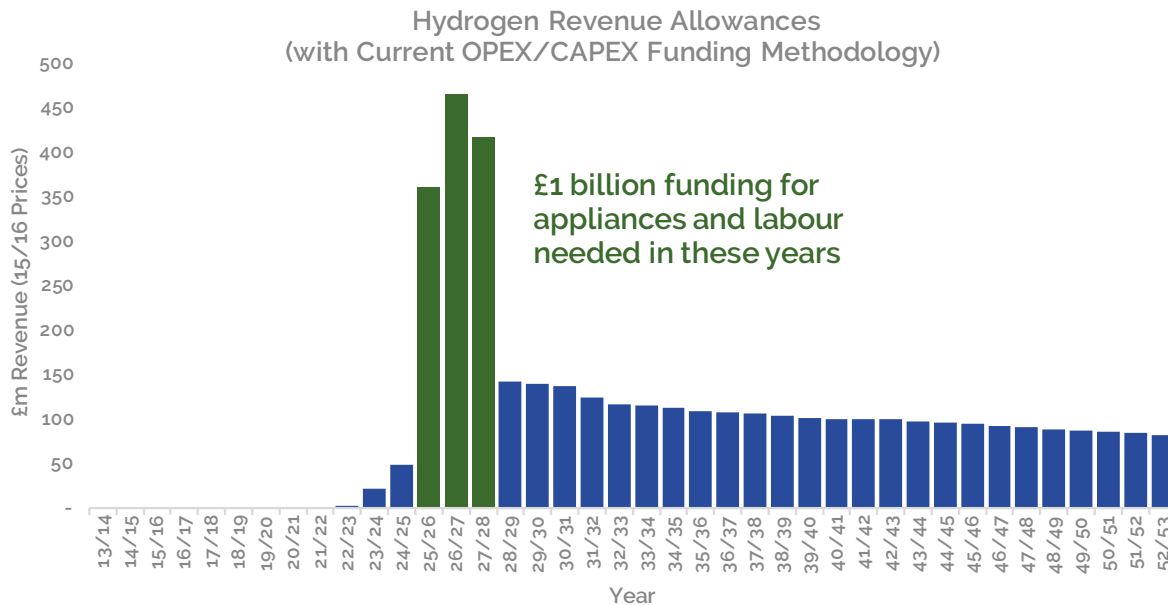
- Two options of regulatory finance changing the proportions of fast/slow money. Each option includes:
  - If the above hydrogen expenditure was added to GDN allowances how would this impact on allowed revenues and customer bills?
  - It also considers which gas customers could pay for the Leeds project – i.e. would just gas users in the NGN network pay for this scheme or could it be socialised and spread across all UK users?

For simplicity all costs have been forecast from 2023 onwards with conversion taking place between 2026 and 2029. In reality costs will begin slightly earlier for the design/build years of the hydrogen production and HTS systems as indicated in [Section 9, The Next Steps – Programme of Works](#). These are small costs overall and would not make a material change to the finance modelling presented in this section.



### Option 1: Using the Current Fast/Slow Money Logic

- OPEX and CAPEX for the hydrogen project has been applied through the existing regulatory allowances methodology.
- For OPEX this means a £1 bn investment is needed in the first 3 years of the project between 2026 and 2029 for conversion of customers' appliances and the associated labour costs of this activity. Thereafter, ongoing OPEX costs of circa £139 m (CCS/SMR efficiency loss/SMR/salt caverns/HTS operations) a year would be funded through the fast money approach.
- £1 bn of CAPEX investment is needed prior to the project go-live between years 2023 and 2025. This would be funded through the slow money logic returning monies over a 45 year period via the depreciation and return on RAV logic.
- Using this logic the **Chart 8.5** shows the phasing of hydrogen allowed revenues needed.



**Chart 8.5. Hydrogen Revenue Allowances (with Current OPEX/CAPEX Funding Methodology)**

The next section demonstrates how the above revenue profile would impact on customers bills, if:

1. Hydrogen revenue allowances were just charged to NGN customers (2.6 million users).
2. If the allowances were socialised and spread across all UK customers (21.5 million users).

Because of the logic used there will be a spike in bills in years 2025/26 – 2027/28. The extent of this spike is impacted by the number of users this will be spread across, as shown in **Chart 8.6**.

### Customer Bill (Transportation Charge Only) - Hydrogen Impact

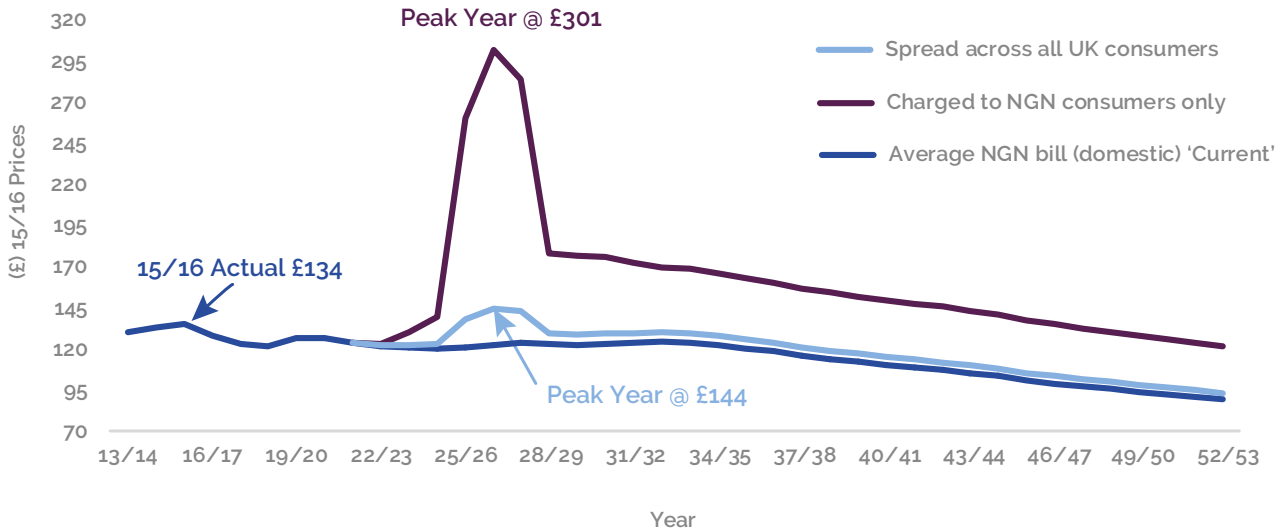


Chart 8.6. Customer Contribution to Transportation Charge, Option 1

Customer Bills (15/16 prices) Average Year	RIIO-GD1	RIIO-GD2	RIIO-GD3	RIIO-GD4	RIIO-GD5
NGN (current) (£)	127	121	122	109	94
NGN bill if NGN customers fund everything (£)	127	197	178	153	129
% Increase from current position	0.0%	58.0%	38.5%	35.9%	36.4%
NGN bill if costs socialised nationwide (£)	127	130	127	114	99
% Increase from current position	0.0%	7.2%	4.8%	4.5%	4.5%

Table 8.9. Customer Bills, Transportation Only (2015/16 prices) Average Year, Option 1

If everything was charged to NGN customers only there would be a significant increase in the GDN element of the bill, especially in the years where OPEX investment is needed – peaking at £301 as shown in [Chart 8.6](#).

- If these costs were socialised and spread across all UK customers then in the peak year bills would increase to circa £144 in the NGN region. On average in RIIO-GD2 bills would increase by £9/+7.2% per year when compared with the current scenario. **Note this is a 7.2% increase on only the distribution element on a gas bill, not the entire bill.**

- This analysis also excludes any comparisons to a 'do nothing' scenario – if we continued to use gas in the same way for the foreseeable future how many other costs would be passed on to end customers? I.e. air quality fines from local councils. Whilst the bill increases in these illustrations it does not compare this against any alternative future scenarios.
- It also does not take into account any other savings in the total customer bill because of efficiency measures, e.g. smart metering/home insulation measures etc.

### Option 2: An Alternative Option to Potentially Reduce the Spike in Bills

In both scenarios there is a spike in bills because of the OPEX costs needed. If the project is implemented then it would form part of a regulated price control process where all costs and financing factors are considered as a whole, with the focus on output measures, network financeability and customer bills.

One potential way of reducing the 'spike' could be to treat **all of the implementation costs as slow money** and receive allowances for these over a 45 year period – via the depreciation and return on RAV allowances. This would result in the £1 bn of appliance and labour costs funded over a 45 year period instead of a 3 year period as shown in Option 1.

However this is at odds with how current OPEX costs are funded and is shown here for illustrative purposes only – a much wider review of the factors mentioned above would need to be considered with any change in funding method – **financeability issues in particular**.

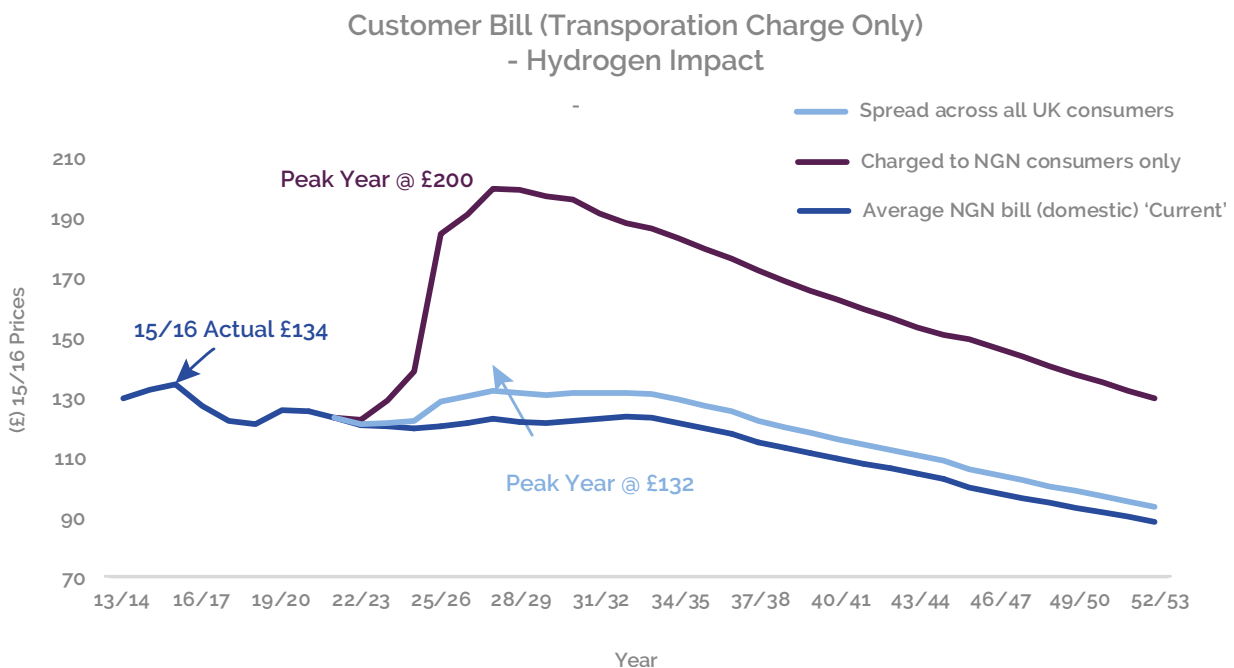


Chart 8.7. Customer Contribution to Transportation Charge, Option 2

Customer Bills (15/16 prices) Average Year (but with OPEX as slow money)	RIO- GD1	RIO- GD2	RIO- GD3	RIO- GD4	RIO- GD5
NGN (current) (£)	127	121	122	109	94
NGN bill if NGN customers fund everything (£)	127	161	187	161	139
% Increase from current position	0.0%	32.7%	54.0%	48.1%	48.1%
NGN bill if costs socialised nationwide (£)	127	126	130	115	100
% Increase from current position	0.0%	4.1%	6.7%	6.0%	5.9%

Table 8.10. *Customer Bills, Transportation Only (2015/16 prices) Average Year, Option 2*

- In the scenario where NGN funds everything across 2.6 million customers then bills remain significantly higher than current run rate. The peak year at £200 is still 60% higher than the current scenario.
- Where costs are socialised, and NGN customers pick up a share of the costs, then the impact is lower than Option 1. On average during RIO-GD2 the bill would increase by circa 4.1% compared to 7.2% in Option 1. **Note this is a 4.1% increase on only the distribution element on a gas bill, not the entire bill.**

### Long Term Efficiency Impact on the Total Customer Gas Bill

As with the 'no hydrogen conversion' scenario we have focused primarily on the gas distribution element of a gas bill and how this is forecast to change over time. It is important to also reflect the impact in total gas bill (circa £750) when considering the H21 Leeds City Gate conversion project.

To demonstrate this the following percentage efficiency savings have been assumed (currently circa £750 per annum) as demonstrated below,

	2016-30	2030-35	2035-40	2040-45	2045-50	2050+
<b>Saving from current</b>	0.00%	3.00%	6.00%	9.00%	12.00%	15.00%

Table 8.11. Energy Efficiency Savings Over Time

This would result in the following customer bill profile, please note both [Chart 8.8](#) and [Table 8.12](#) represent the impact on customer bills when costs are socialised across all UK customers.

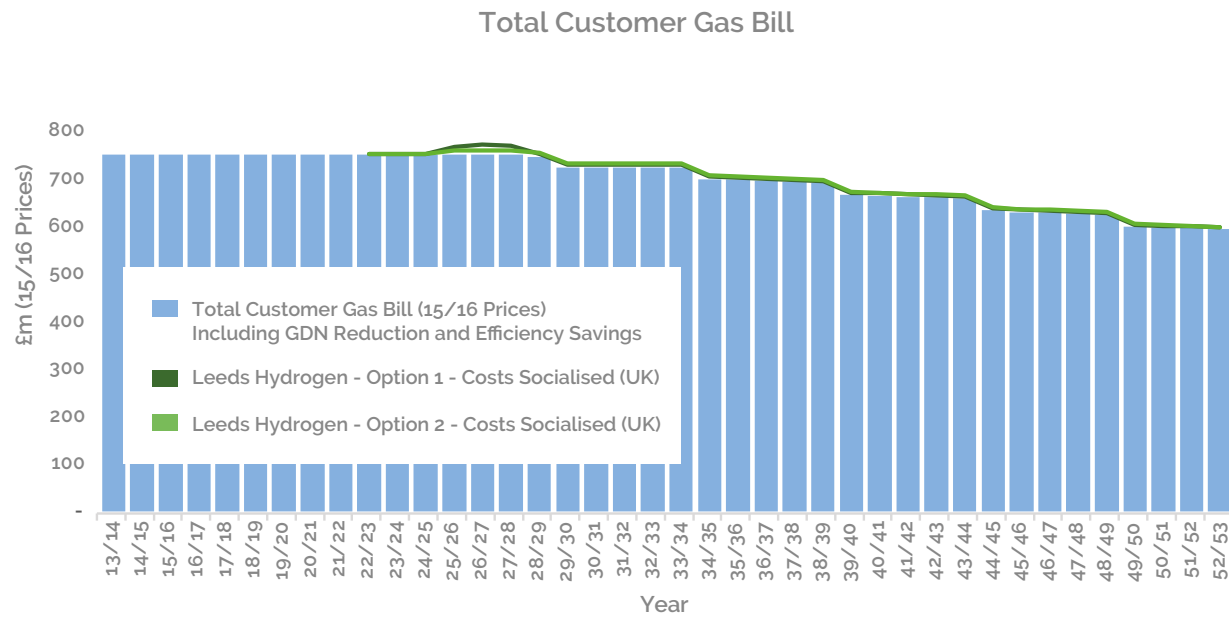


Chart 8.8. Total Customer Gas Bill

(15/16 prices)	RIIO-GD1	RIIO-GD2	RIIO-GD3	RIIO-GD4	RIIO-GD5
Total gas bill (£)	750	749	713	665	611
Leeds hydrogen bill impact – Option 1 (£)	-	8	6	5	4
Revised total gas bill – Option 1 (£)	750	758	719	670	615
Change %	0.0%	1.1%	0.8%	0.7%	0.7%
Leeds hydrogen bill impact – Option 2 (£)	-	5	8	6	5
Revised total gas bill – Option 2 (£)	750	754	721	672	617
Change %	0.0%	0.6%	1.1%	0.9%	0.9%

Table 8.12. *Customer Bills (2015/16 prices) Average Year, Option 1/2*

The biggest increase from the current scenario is in year 2026/27 where under Option 1 it adds £22 (2.9%) to the annual bill and £8 under Option 2 (1.1%).

### Key Messages:

Two alternative methods of calculating hydrogen allowed revenue have been considered:

- On the existing methodology which shows allowed revenues earlier in the project lifecycle because of the upfront OPEX costs needed; and
- As an illustration only and not considering other factors such as network financeability – if the £1bn of OPEX costs could be treated as slow money which would spread the funding over 45 years.

We have also considered which customers could pay for the Leeds hydrogen project:

- Charging the costs just to NGN customers more than doubles the bill contribution to the transportation charge when using current methodology and adds at least 50% in the slow money option.
- Socialising the costs across all UK customers is the best option to minimise the impact on customer's bill.

***The impact on the total customer bill has been considered with the biggest gap being a £22 increase to the annual bill in Year 2026/27 under existing regulatory methodologies***

## 8.3. Hydrogen Gas Cost per Kilowatt Hour

Although it is likely, and also more affordable, that most of a hydrogen conversion programme is funded in a regulatory price control model, it is still felt useful to show the unit cost of hydrogen/kWh if not financed using the regulatory methodology.

Gas supply companies and gas users in Leeds will have the same commercial relationship and security of supply as they do now, just that the kWh they use will be in the form of hydrogen rather than natural gas. On the way to Leeds, the gas supply company's natural gas will be converted to hydrogen as a common transmission service. The common service would be responsible for procurement of the additional energy required for the conversion process. Costs noted here are for the service company.

The following costs for H<sub>2</sub>+CCS reflect the full cost of the system described above, based on existing facilities costs and high level operating costs, including energy used to run the hydrogen production system. These require further development of the designs to reduce the normal uncertainty of costs at this stage. It excluded the kWh cost of the energy bought by gas suppliers and passed through as equivalent kWh in the form of hydrogen.

It is important to note that these are costs for year one, but a scaling hydrogen economy will see reducing costs per kWh. The following factors will reduce this cost:

- Costs for carbon capture will significantly decline as scale increases.
- Operating costs for hydrogen production and storage facility will decline with scale from the current 4%.
- Intraday storage costs will decline as more linepack becomes available in the expanding hydrogen transmission system.
- Unit costs of appliances and conversion will decline with scale.
- As by-product hydrogen and hydrogen via electrolysis (as a result of constrained energy) becomes available costs could decrease.

Additionally, no account has been taken for the following which should be considered when looking at an incremental UK roll out conversion strategy as well as H21 Leeds City Gate:

- Storing hydrogen in summer to re-use from the inter-seasonal store in winter will significantly improve the cost of the efficiency loss as more gas will be produced in summer (at lower costs) to fill the store. This gas will then be used to supplement production in winter.
- Additional to the declining costs listed above there is the possibility of wholesale gas price increasing over time. It should be noted that in a scaling hydrogen economy could well have a mixture of SMRs and coal gasifiers/black bin waste gasifiers producing the hydrogen. This would potentially give the larger system more operational flexibility and insulate against varying fuel prices for different feedstocks.



The costs for hydrogen in the H21 Leeds City Gate project are as follows and have been calculated using the design parameters identified in [Table 8.13](#) as described in [Section 2, Demand vs. Supply](#).

Key Design Parameters	Unit	Value	Comment
<b>Demand 2013 (Section 2 and 3)</b>			
Domestic Demand 2013	kWh	3,614,000,000	DECC Data
Non-domestic Demand 2013	kWh	2,327,000,000	DECC Data
Average Annual Demand	kWh	5,940,000,000	DECC Data
Annual Hydrogen Production	kWh	5,940,000,000	DECC Data
Average Demand	MW	678	Equals Annual divided by hours in year.
Design Supply SMR+CCS	MW	732	Design based upon 8% uplift

Table 8.13. *Key Design Parameters*

First we can consider the cost per kilowatt hour for hydrogen excluding the Point of use upgrade costs, i.e. the appliance conversion costs. These are shown in [Tables 8.14, 8.15 and 8.16](#).

**EXPENDITURE FOR 1<sup>ST</sup> CONVERSION (PRODUCTION)**

Item	Unit	Number	Cost £/kWh H <sub>2</sub>	Comment
Storage LP (Section 2)	£	76,641,000	N/A	Includes cushion gas
Storage HP (Section 2)	£	289,055,555	N/A	Includes cushion gas
Cost of SMR (Section 2)	£	395,000,000	N/A	Excludes commissioning gas to stores
GAS network additional work (Section 3)	£	10,000,000	N/A	N/A
HTS (Section 6)	£	230,000,000	N/A	N/A
CAPEX Total	£	1,000,696,555	N/A	Total investment for hydrogen production and transportation infrastructure
WACC	%	4.5%	N/A	2015 real costs
Depreciation period	yrs	45	N/A	Network depreciation
Approx. net accounts finance cost	£	30,000,679	0.0051	Excludes allowed return on capital
Annual CAPEX depreciation	£	22,237,701	0.0037	Cost divided by annual kWh
<b>Annual fixed finance charges TOTAL</b>	<b>£</b>	<b>52,238,380</b>	<b>0.0088</b>	<b>CAPEX/ Total average demand</b>
Annual O&M (SMR/Salt caverns 4%)	£	30,427,862	N/A	N/A
Annual O&M (HTS)	£	503,328	N/A	N/A
<b>Annual O&amp;M</b>	<b>£</b>	<b>30,931,190</b>	<b>0.0052</b>	<b>O&amp;M cost divided by annual kWh</b>
<b>Sub Total (Production)</b>			<b>£0.0140 (A)</b>	<b>Production cost/Av year kWh</b>

Table 8.14. *Expenditure for 1<sup>st</sup> Conversion (Production)*

**VARIABLE COSTS**

Item	Unit	Number	Cost £/kWh H <sub>2</sub>	Comment
Cost of natural gas for SMR use	£/kWh	0.018	N/A	This would likely be cheaper if the gas network were to purchase this gas using the Heren price index
Cost of natural gas (pass-through)	£/kWh	0.018	N/A	Average large user cost of gas for (using average of DECC figures for the last 3 years)
Efficiency of SMR+CCS	%	68.4	N/A	N/A
Cost of natural gas for conversion and capture	£	49,403,299	0.0083	NG bought for processing and CCS
Pass-through gas cost (NG to H <sub>2</sub> )	£	106,936,255	0.0180	Gas supplier unit cost pass through
<b>Total use of natural gas</b>	<b>£/kWh H<sub>2</sub></b>	<b>156,339,554</b>	<b>0.0263</b>	<b>Equals cost of natural gas for SMR (sum of figures above)</b>
Scope 1 emission from natural gas	kg/kWh NG	0.184	N/A	The chemical CO <sub>2</sub> footprint of natural gas
Scope 1 emissions from conversion	kg/kWh	0.269	N/A	Embodied CO <sub>2</sub> footprint of hydrogen
CCS efficiency of collection	%	90	N/A	Net 0.027 kg/kWh
CO <sub>2</sub> to CCS	kg/kWh H <sub>2</sub>	0.2421	N/A	90% of direct emissions
Cost of supercritical CO <sub>2</sub> disposal	£/tonne	40.00	N/A	Initial T&S hub charge
<b>Cost of CO<sub>2</sub> disposal</b>	<b>£/kWh H<sub>2</sub></b>	<b>0.01</b>	<b>0.0097</b>	<b>Cost of CO<sub>2</sub> disposal</b>
CO <sub>2</sub> emitted by SMR to atmos:	kg/kWh	0.03	N/A	Real emission of CO <sub>2</sub> to atmosphere
Cost of EU-ETS certificate	£/tonne	20.00	N/A	2015 actual cost €7.56 or £5.5/tonne
<b>Cost of CO<sub>2</sub> to atmosphere</b>	<b>£/kWh</b>	<b>0.00</b>	<b>0.0005</b>	<b>Cost of emission permit</b>
<b>Sub Total (Variable Costs)</b>			<b>£0.0365 (B)</b>	

Table 8.15. Variable Costs

**TOTAL COSTS**

Item	Unit	Number	Cost £/kWh H <sub>2</sub>	Comment
Total cost of hydrogen (excluding point of use conversion, current distribution+sales etc.) <b>(A+B)</b>	£/kWh	N/A	0.0505	Includes value of energy storage
Existing 'gas' transportation costs	£/kWh	N/A	0.0103	OFGEM cost of delivery gas to consumers/kWh. This pays for existing network
Billing etc.	£/kWh	N/A	0.0052	OFGEM cost of gas billing to consumers/kWh
Environmental levy	£/kWh	N/A	0.0018	N/A
Cost of retail hydrogen (excluding margin)	£/kWh	N/A	0.0679	Sum of figures above
OFGEM average EBDITA	%	6.0	0.0041	N/A
<b>Sale price hydrogen excluding point of use conversion</b>			<b>£0.072 (C)</b>	<b>N/A</b>
VAT	%	5	£0.004	N/A
<b>Sale price hydrogen excluding point of use conversion</b>			<b>£0.076</b>	<b>N/A</b>

 Table 8.16. *Total Costs*

If we now consider the cost of the appliance conversion the cost per kilowatt hour for hydrogen is summarised in [Table 8.17](#) below:

**Expenditure for 1<sup>st</sup> conversion – Appliances (Section 5)**

Item	Unit	Number	Cost £/kWh H <sub>2</sub>	Comment
Conversion of domestic property	£	805,000,000	N/A	See Section 5
Conversion of non-domestic	£	248,000,000	N/A	See Section 5
Total for Appliance Conversion	£	1,053,000,000	N/A	Free issue and installation of boilers, burners etc.
Interest at WACC	%	4.5	N/A	N/A
Depreciation period	yrs.	15	N/A	Prudent life of domestic appliances
Appox. net accounts finance cost	£	27,848,840	0.0047	N/A
Annual CAPEX depreciation	£	70,200,000	0.0118	N/A
<b>Annual fixed finance charges TOTAL</b>	<b>£</b>	<b>98,048,840</b>	<b>0.0165</b>	<b>This is annual interest divided by annual kWh</b>
<b>Sub Total (Appliances)</b>			<b>£0.0165 (D)</b>	<b>N/A</b>
<b>Sale price of hydrogen including point of use conversion (C+D)</b>			<b>£0.088</b>	<b>N/A</b>
VAT	%	5	£0.004	N/A
<b>Sale price hydrogen including point of use conversion</b>			<b>£0.093</b>	<b>N/A</b>

Table 8.17. *Expenditure for 1<sup>st</sup> Conversion - Appliances*

These two costs of hydrogen are essentially 'well to gas meter', and 'well to sofa' respectively, including full interseasonal storage, allowance for annual maintenance of the system, etc. These costs should not be compared with either electricity at the power station terminals or heat at the district heat power plant. Conventionally neither of the latter contain these full system costs.

## 8.4. Cost per Tonne of Carbon Saved

The conversion of hydrogen has to involve the whole supply chain. At present comparison of £/tonne carbon saved can therefore only realistically be carried out against thermal insulation. This is shown in [Table 8.18](#).

Comparative costs	Unit	Cavity Wall	Internal wall	External wall
<b>Insulation</b>				
Mean energy saving	kWh/yr	1,300	2,100	2,100
Typical cost		£500	£7,000	£12,000
Footprint Natural Gas	kg/kWh	0.184	£0.184	0.184
Efficiency of condensing boiler	%	85	85	85
Footprint of heat	kg/kWh	0.22	0.22	0.22
CO <sub>2</sub> saving	tonne/yr	0.28	0.45	0.45
Life time	yrs	25	25	25
WACC	%	4.50	4.50	4.50
Annual cost	£/yr	42.50	595.00	1,020.00
Cost/tonne carbon saved	£/tonne	151	1,309	2,244

Table 8.18. *£/Tonne for Scope 1 Emissions Savings for Thermal Insulation*

**HYDROGEN**

Item	Unit	Scope 1
Emission from hydrogen	kg/kWh	0.027
Emission from natural gas	kg/kWh	0.184
Net hydrogen saving	kg/kWh	0.157
Retail cost natural gas	£/kWh	0.05
Theoretical retail cost hydrogen	£/kWh	0.093
Marginal cost hydrogen	£/kWh	0.046
Cost/tonne carbon saved	£/tonne	291.94

Table 8.19. *£/Tonne for Scope 1 Emissions Savings for H21 Leeds City Gate System*

This shows that the cost per tonne of carbon lies above cavity wall insulation but less than one-third of any solid wall insulation. Hydrogen also offers the potential for large-scale and deep de-carbonisation. Wall insulation (as above) is unlikely to achieve greater than 20% carbon saving. Considerable care must be taken with some technologies) to distinguish between claimed and delivered carbon savings. By the nature of hydrogen technology, this should not be a problem.

## 8.5. Financial Conclusions

- A hydrogen conversion would almost certainly have to be financed through a regulated price control as was the case with the original town gas to natural gas conversion.
- If this was the case the H21 Leeds City Gate project would have minimal impact on customer bills, a maximum impact being 2.9% (currently financing methodology) or 1.1% (alternative method for fast slow money) in Year 2026/27.
- In the scenario presented here, appliances upgrades are included in the regulatory finance. It may be appropriate to consider if this is the most appropriate mechanism. This is identified on in **Section 10, H21 Roadmap**.
- On a standalone project only basis the costs of H21 Leeds City Gate project to those customers within the area of conversion would be:
  - 7.3p/kWh (excluding the appliance upgrade).
  - 10p/kWh (including the appliance upgrade).
- The impact on GVA and the northern economy and subsequent UK economy has not been considered in these evaluations. It is recommended that this is undertaken to give an appropriate view on the overall picture. A conversion programme would create significant numbers of jobs associated with the physical works and wider supply chain. These jobs would be across England and, initially in the north. This would have enormous benefits for the UK and could be the anchor of the Northern Powerhouse concept.
- These costs have not considered the potential for repurposing the Local Transmission System should an incremental hydrogen conversion take place. This could allow cost effective connections and a gathering infrastructure to be developed for unconventional gases as a feedstock to the hydrogen economy.



## 8.6. Regulatory Considerations

When considering the potential conversion of a city to hydrogen, we must consider the current regulatory obstacles that need to be overcome to allow such a change to happen. For the purpose of the H21 Leeds City Gate project an overview has been provided regarding the key changes required however further analysis is identified in **Section 10, H21 Roadmap** as part of a specific regulatory project package.

The key points are considered below:

### 1. The Gas Act:

Section 48 of the Gas Act defines gas:

“gas” means—

- (a) any substance in a gaseous state which consists wholly or mainly of—
  - (i) methane, ethane, propane, butane, hydrogen or carbon monoxide;
  - (ii) a mixture of two or more of those gases; or
  - (iii) a combustible mixture of one or more of those gases and air; and
- (b) any other substance in a gaseous state which is gaseous at a temperature of 15°C and a pressure of 1013.25 millibars and is specified in an order made by the Secretary of State.

This means that a hydrogen network is included in the scope of the Gas Act.

### 2. The Uniform Network Code

The Gas Transporter Licence is issued under section 7 of the Gas Act and permits the conveyance of gas. Under their licence, each Transporter has to have a Network Code. The Uniform Network Code is limited in scope to natural gas and does not include hydrogen. Although this definition could be changed a major review of the UNC would be required to identify any consequential impacts. Some specific areas of consideration in the network code are:

### General Terms Section C

#### 3 Technical Interpretation

##### 3.1 Gas

3.1.1 In the Code, unless the context otherwise requires, “gas” means any hydrocarbons or

a mixture of hydrocarbons and other gases consisting primarily of methane which at a temperature of 15 °C and an absolute pressure of 1.01325 bar are or is predominantly in the gaseous state.

The licence also requires Transporters to accede to the Supply Point Administration Agreement (SPAA) and the Smart Energy Code (SEC). These are predicated on natural gas as far as gas transportation is concerned and would need a review to check whether they need an amendment to apply to hydrogen networks.



### 3. Additional Secondary Legislation

There are a number of pieces of secondary legislation that have significant impacts on commercial arrangements in the industry for example.

#### Gas (Calculation of Thermal Energy) Regulations (GCoTER)

GCoTER are regulations made under schedule 3 of the Gas Act 1995 (which substituted for section 12 and 13 of Gas Act 1986) and therefore would apply to hydrogen networks. However, GCoTER has hard coded values that specifically relate to natural gas and would need amending to apply to hydrogen networks.

Therefore, although the Gas Act permits gas transporters to transport hydrogen, the Uniform Network Code will require amendment and review together with other industry documents and all secondary legislation relating to the gas industry. This is identified as part of **H21 Roadmap**, details of which can be found in **Section 10**.

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***Conclusion: The Gas Act is, in principle supportive, but other documents need to be reviewed and potentially modified***



**SECTION 9**

**Next Steps -  
The Programme  
of Works**



## 9. Next Steps – The Programme of Works

It is important to understand the time required to undertake a scheme of this magnitude and also the regulatory time frames if such an endeavour was to be financed via a regulatory price control.

There are seven key areas of work that need to be undertaken for a conversion to take place, these include:

1. Delivery of the **H21 Roadmap (see Section 10)** to provide all the outstanding technical evidence that such a conversion is possible.
2. Completion of reinforcement and isolation works on the Leeds distribution system as defined in **Section 3, Gas Network Capacity** and **Section 4, Gas Network Conversion**.
3. Completion of the REPEX programme in the area of conversion.
4. Completion of a FEED/detailed design for the hydrogen supply system (HTS, SMRs, salt caverns).
5. Construction of the hydrogen supply system (HTS, SMRs, salt caverns) ready for conversion.
6. Hydrogen appliances and equipment development.
7. Conversion of Leeds.

A simplified timeline is provided which represents how these seven work packages could be progressed. It also identifies critical points in time for both regulatory business plan development and key policy decisions to be taken.

Additionally, a cost profile is provided against this timeline showing expenditure commitment both pre and post a policy decision taking place.

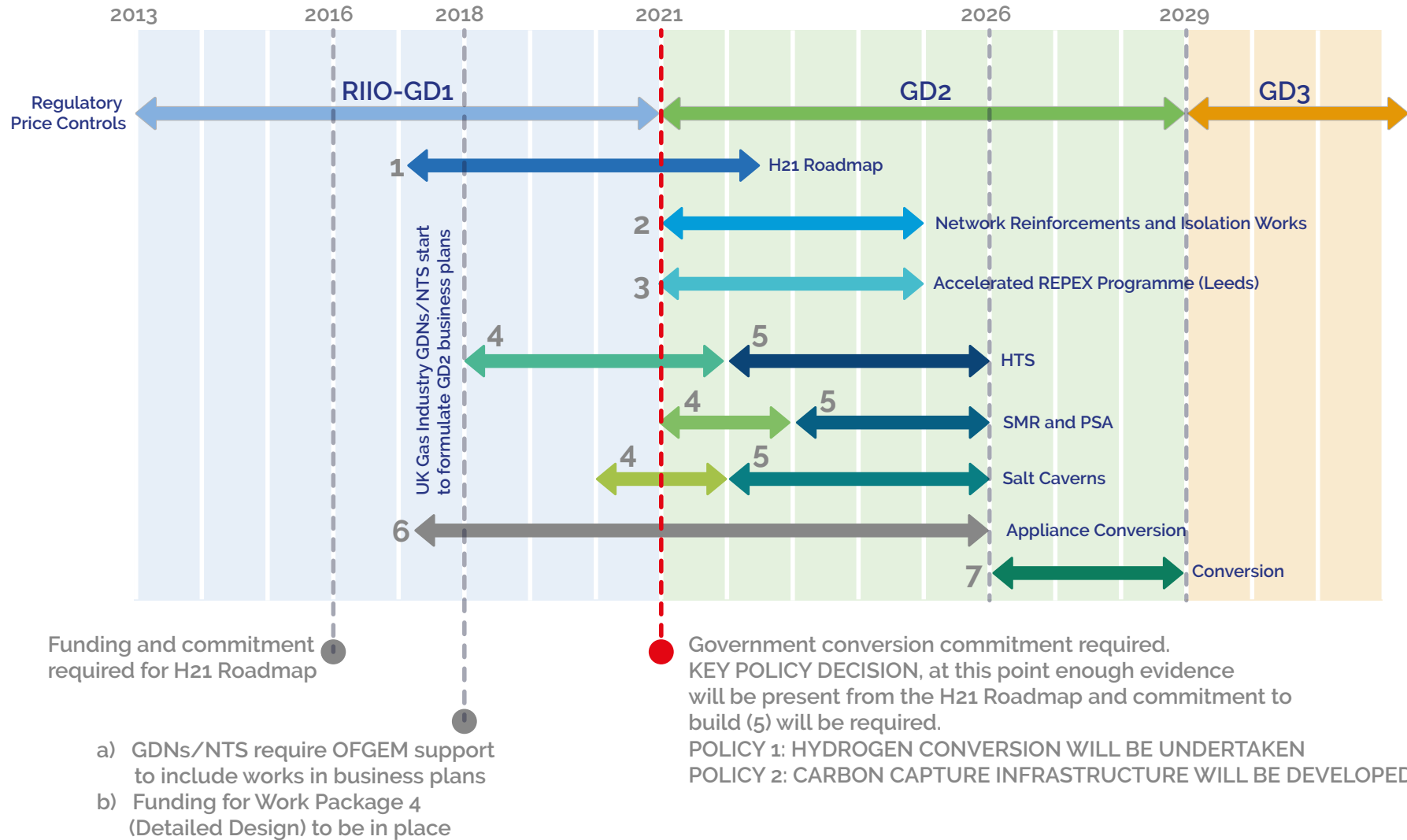
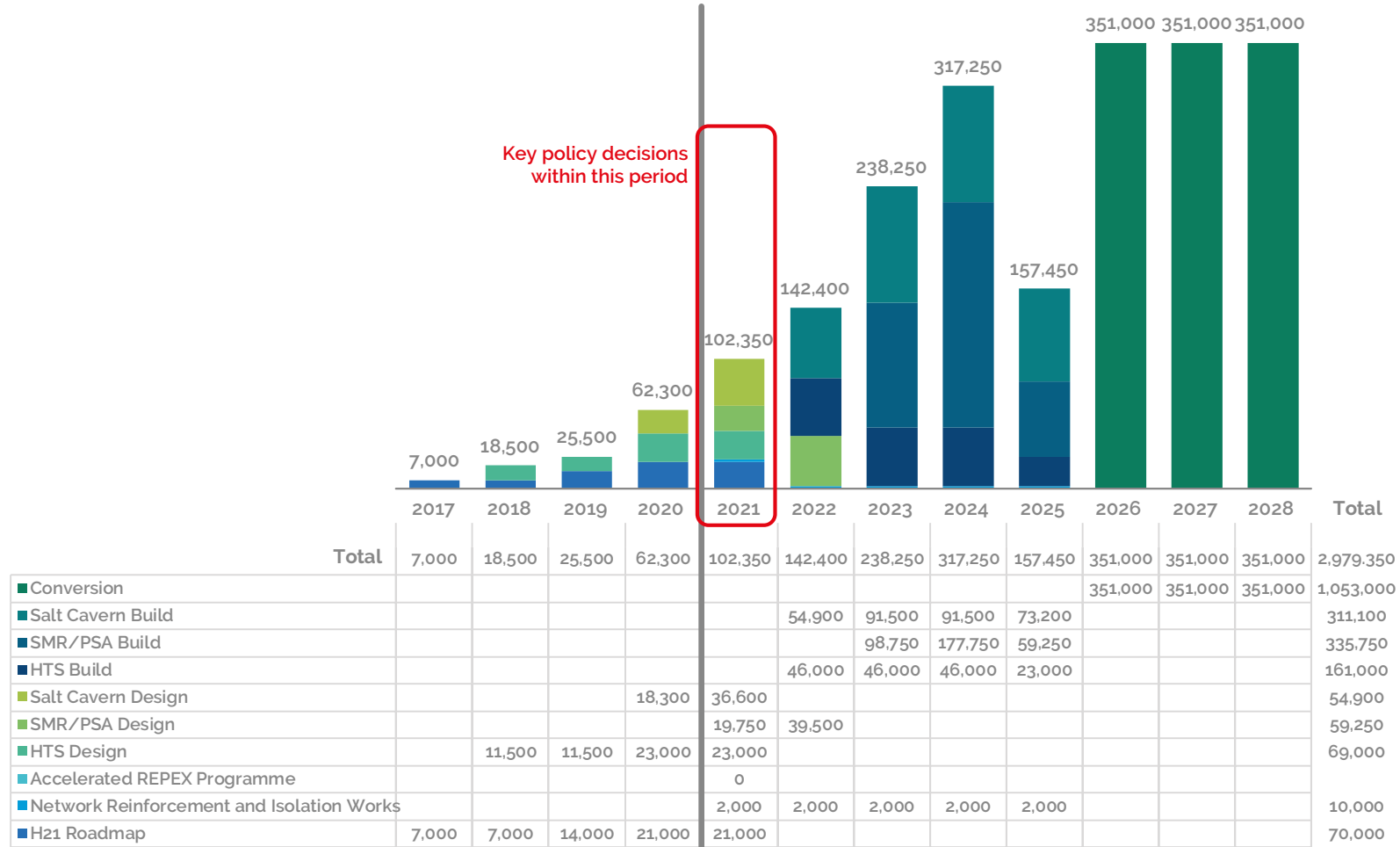


Image 9.1. Key Elements Timeline

Translating this into monetary values results in the following spend profile up to 2029 (note appliance development costs are not included), this is shown in **Chart 9.1**.

H21 Leeds City Gate Conversion Spend (£k)



## Delivery of the H21 Roadmap

The **H21 Roadmap**, detailed in **Section 10**, defines a range of projects that need to be undertaken to provide full confidence that a conversion could take place. This roadmap, if funded and managed correctly, could be completed in approximately five years. However, high levels of confidence in the viability of a conversion would be obtained during year's three to four.

## Network Reinforcement and Isolation Works

As described in **Section 3, Gas Network Capacity** and **Section 4, Gas Network Conversion** there are enabling works that would need to be undertaken within the area of conversion. These relate specifically to:

- Strategic reinforcement of the low pressure system to ensure ongoing security of supply; and
- The installation of isolation valves and associated district governors to enable conversion to take place.

To do this Northern Gas Networks (and other GDNs if the conversion were to be incremental across the UK's major cities) would need to ensure these reinforcement and isolation works were identified and forecast appropriately in the GD2 submission to OFGEM. The network would only build this type of expenditure into its GD2 business plan if there was a recognition from OFGEM that these works were needed.

Undertaking the reinforcement works associated with this scheme would not be stranded costs if a subsequent decision not to convert took place. This is because these reinforcements are in areas already indicating pressure problems under the natural gas system so ultimately reinforcements may be required at some point in the future.

## Accelerated REPEX Programme

For the first city to convert (Leeds), the REPEX programme will need to be accelerated to ensure all appropriate iron and steel mains have been upgraded to PE. If the conversion was anticipated in the 2020s the programme would need to be brought forward from the current end of 2032. This would not necessarily add to the overall costs, indeed it may reduce due to economies of scale. The HSE mandated obligations would still need to be maintained unless a deviation was agreed and approved.

To do this Northern Gas Networks would need to ensure these accelerated works were identified and forecast appropriately in the GD2 submission to OFGEM. The network would only build this type of expenditure into its GD2 business plan if there was a recognition from OFGEM that these works were needed.

It is worth noting undertaking these works would not be a stranded costs if there is a subsequent decision not to proceed with a hydrogen conversion. This is because these works would ultimately be undertaken anyway as part of the REPEX programme, they would just be undertaken under a longer timeframe.

## Design for the Hydrogen Supply System

A significant area of consideration is progression with a FEED/detailed design, including appropriate planning considerations, etc. for the hydrogen supply system which comprises the salt caverns, SMRs, and hydrogen transmission system.

This work would take up to three years to design, and it would be essential that this was undertaken and in place to enable the build of the system to tie into a conversion timeline of the mid 2020s. Failure to undertake this work will result in a significant delay to the onset of hydrogen conversion.

This timeframe also represents a specific funding problem as it is required within the timeframes of RII0-GD1. There is currently no funding provision allocated in existing regulatory business plans to undertake this work. It is recommended that these works be progressed, and appropriate funding is provided either via OFGEM or alternative sources.

## Construction of the Hydrogen Supply System

Construction of the hydrogen supply system would only commence after the policy decision to convert is taken. This ensures a minimum level of expenditure is committed prior to such a policy decision taking place.

## Hydrogen Appliance and Equipment Development

The conversion would only be able to take place once all the other work packages were concluded.

## Conversion

A critical element of work is the development and certification of a range of acceptable hydrogen appliances and equipment for the domestic, commercial and industrial market. Whilst there may be some seed corn funding provided in the H21 Roadmap it is anticipated that a significant amount of this work would be undertaken by the appliance manufacturing industry provided a clear indication was given at UK government level that hydrogen conversion is a real possibility.





**SECTION 10**

# The H21 Roadmap



# 10. The H21 Roadmap

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## History

*As with the original conversion from town gas to natural gas, it is vitally important that all evidence is acquired to provide confidence that a hydrogen conversion can take place and would pose no significant increase in risk to the public.*

*In the original conversion, the Gas Council established the conversion executive, a team which would oversee the overall conversion process. It also managed various trials and evidence gathering projects over a period of several years.*

*The H21 Roadmap presented here echoes those lessons of the past for today's modern gas industry and considers the most important aspect the establishment of an H21 Programme Team (see Work Package 0). As with the original conversion without a dedicated team in place the roadmap, delivery will be delayed or inadequately executed. This will result in delays in the ability to commit to a UK wide hydrogen conversion programme in line with the Climate Change Act targets.*

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This section provides a detailed overview of the outstanding technical/evidence based projects required to provide confidence for the UK to commit to a hydrogen conversion programme. It provides a comprehensive overview of what is required.

The H21 Leeds City Gate project provides confidence that hydrogen conversion could be technically possible. However, it is recognised that there are multiple 'enabling/confidence gathering' projects required to provide more robust technical evidence that conversion is safe and possible. The H21 Roadmap has been developed to cover three purposes:

- Investigate any outstanding technical evidence gaps.
- To prepare the correct regulatory and social frameworks to allow conversion to happen.
- To determine the overall strategy for UK wide conversion over time.



The work has been split into 16 Work Packages comprising 60 individual projects summarised below.

Work Package Type	Work Package number	Work Package Description	No of Projects
Management	0	H21 Programme Team	1
Technical Work Packages	1	Pressure Reduction	6
	2	Below 7 bar Mains Considerations	7
	3	Industrial and Commercial Appliances	4
	4	Domestic Considerations	8
	5	Multi Occupancy Buildings	2
	6	Blending	4
	7	Odourisation/Gas Detection	4
	8	Technical Standards	1
Social/Regulatory Work Packages	9	Regulation	4
	10	Public Perception/Education	1
Physical Trials	11	Appliance Demonstration/Field Trials	4
Strategic Work Packages	12	Carbon Capture and Storage	1
	13	Hydrogen Transportation	2
	14	Electrification (P2G/Micro CHP)	4
	15	Unconventional Gas	1
	16	UK Wide Development Strategy	6
<b>Total</b>			<b>60</b>

Table 10.1. H21 Roadmap – Work Package Overview

Image 10.1 provides an overview of the Work Packages and their key focus area.

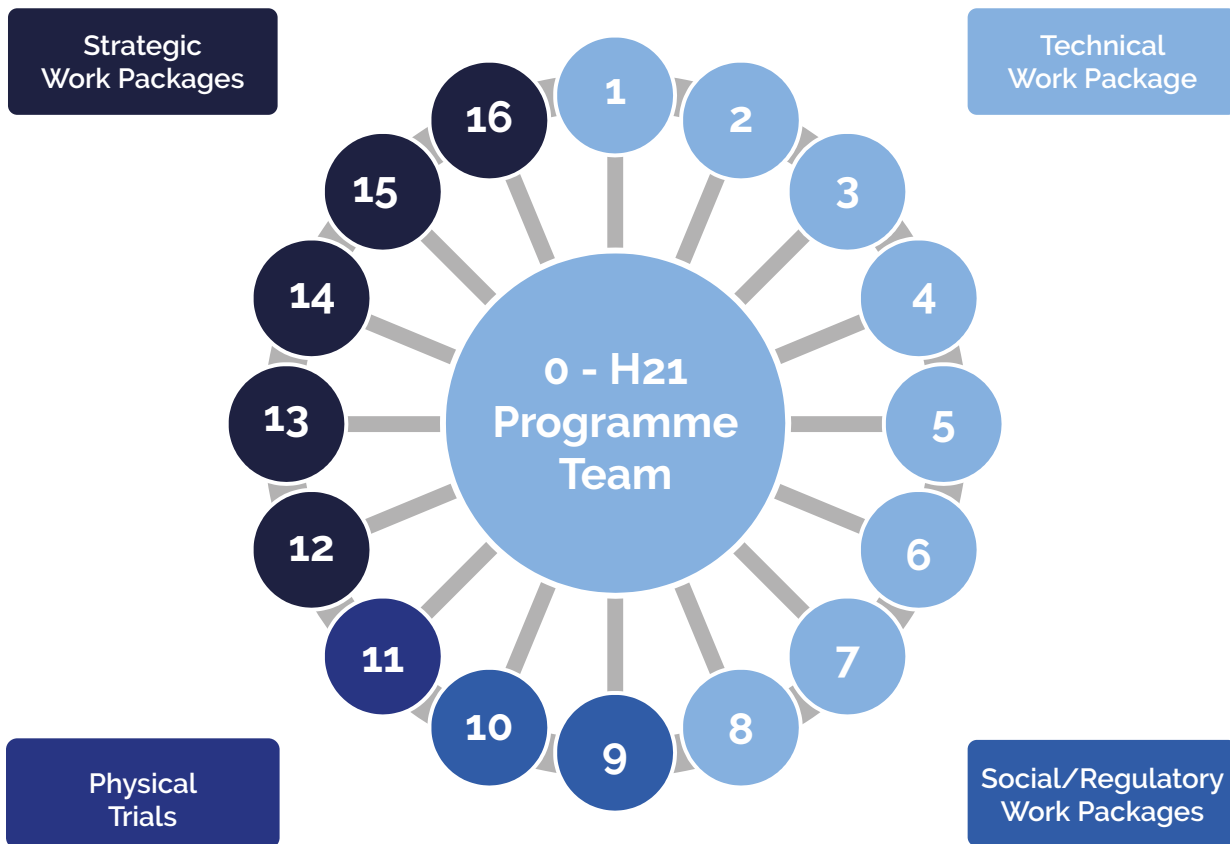


Image 10.1. *H21 Roadmap – Work Package Overview*

A work programme of this scale requires commitment, high levels of expertise and a dedicated team to develop, drive and coordinate the results.

The most critical element of this roadmap is a financial commitment to undertaking the Work Packages and, crucially, the establishment of the H21 Programme Team. Without a dedicated team in place, the roadmap delivery will be delayed or inadequately executed. This will result in delays in the ability to demonstrate the capability for a UK wide hydrogen conversion programme in line with the Climate Change Act targets.

This multi-year programme of technical/social research and demonstration is needed to provide all the evidence to de-risk a UK hydrogen conversion.

## 10.1. The Existing System

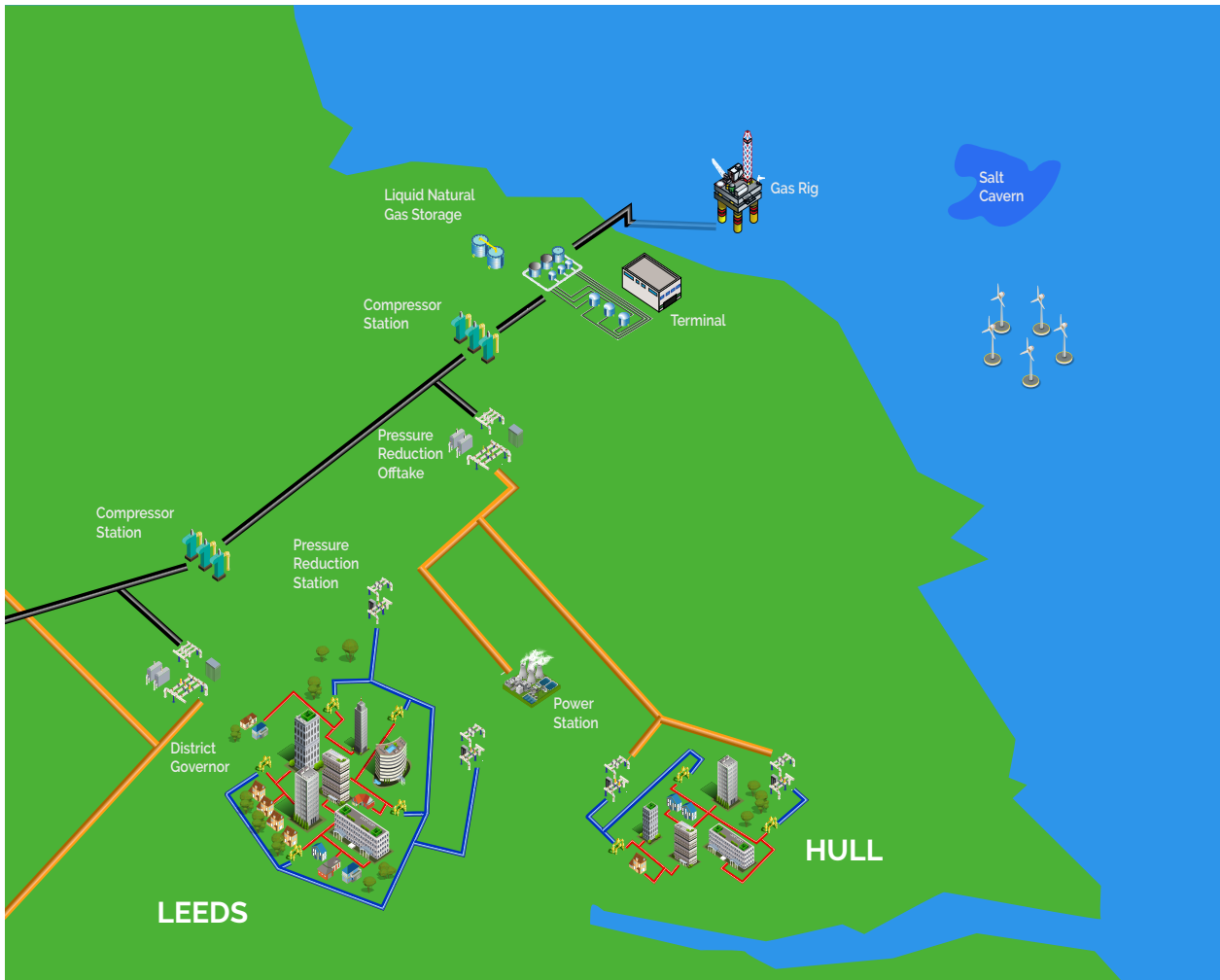


Image 10.2. *The Existing UK Transportation System*

The simplicity of the H21 concept is part of its appeal. The practicality of the project and the realistic ability to undertake the work can be shown simplistically with modifications to the existing system picture.

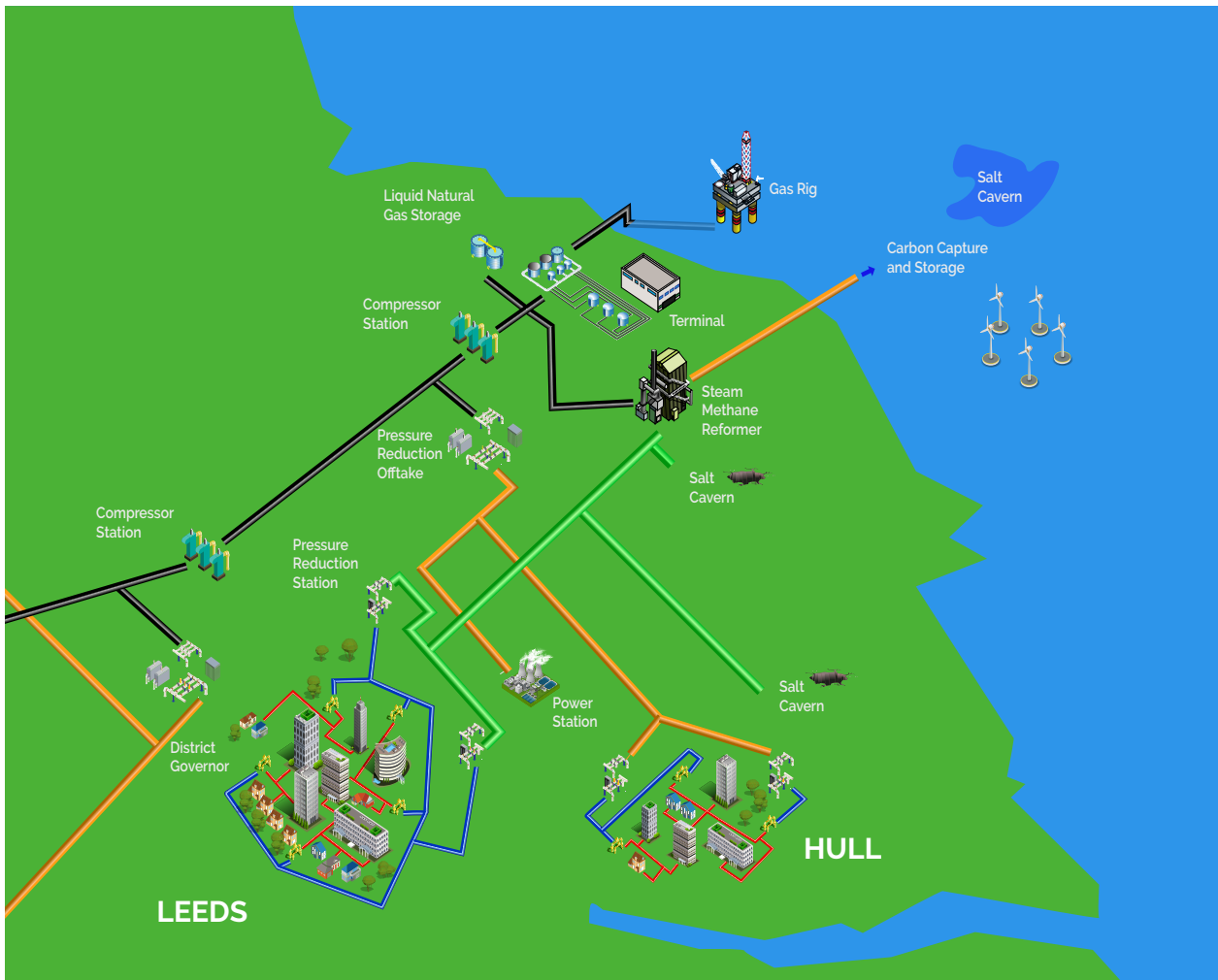


Image 10.3. *Existing System Modifications*

The end of the H21 Leeds City Gate project is not the end of the journey to a decision on conversion. The project has provided confidence that conversion is technically possible but multiple Work Packages will need to be completed to develop the strategy and provide a higher level of confidence.

## 10.2. Work Package Descriptions

The remainder of this section describes the Work Packages and associated projects. Costs for delivery of all the Work Packages (including the H21 Programme Team) have been estimated based on sound engineering judgement and are anticipated to cost between £60m and £80m in total. This excludes new appliance development, for example:

- Using catalytic combustion to reduce/eliminate NO<sub>x</sub> levels.
- Work on levels of ventilation required for flueless hydrogen combustion.
- The packaging of fuel cells etc.
- Conversion of certain specialised industrial processes.

Individual costs for each Work Package are not included in this report to ensure competitive tenders should funding for this 'H21 Roadmap' become available.

### Work Package 0. H21 – Programme Team

As with the original town gas to natural gas conversion, a programme of this scale and ambition requires a dedicated team (similar to the conversion executive established as part of the original conversion process) to ensure efficient, high quality and cost effective delivery. For the projects listed, this team is considered a minimal team to coordinate the programme.

This programme team is made up of highly competent, qualified individuals required to drive the programme forward and ensure quality and cost-effective delivery while shaping and defining (detailed scoping) each project in the Work Packages. This programme team will also coordinate the results from all the roadmap projects making the information understandable and accessible to allow strategic decisions to be made on actual conversion timelines.

It is recommended that this team should be based in Leeds. There are three key considerations for this recommendation. Firstly, to ensure ongoing support from the Leeds City region (which is the first to convert). Secondly to allow effective communication with Northern Gas Networks who are the principal network in terms of the conversion and intellectual knowledge regarding the original H21 Leeds City Gate study. Finally, it is expected that, should the conversion ultimately take place, this programme team will continue and evolve into the programme team for managing the conversion process.

The H21 Programme Team has been designed to undertake the Work Packages as per the colour coding showing in **Image 10.4**.



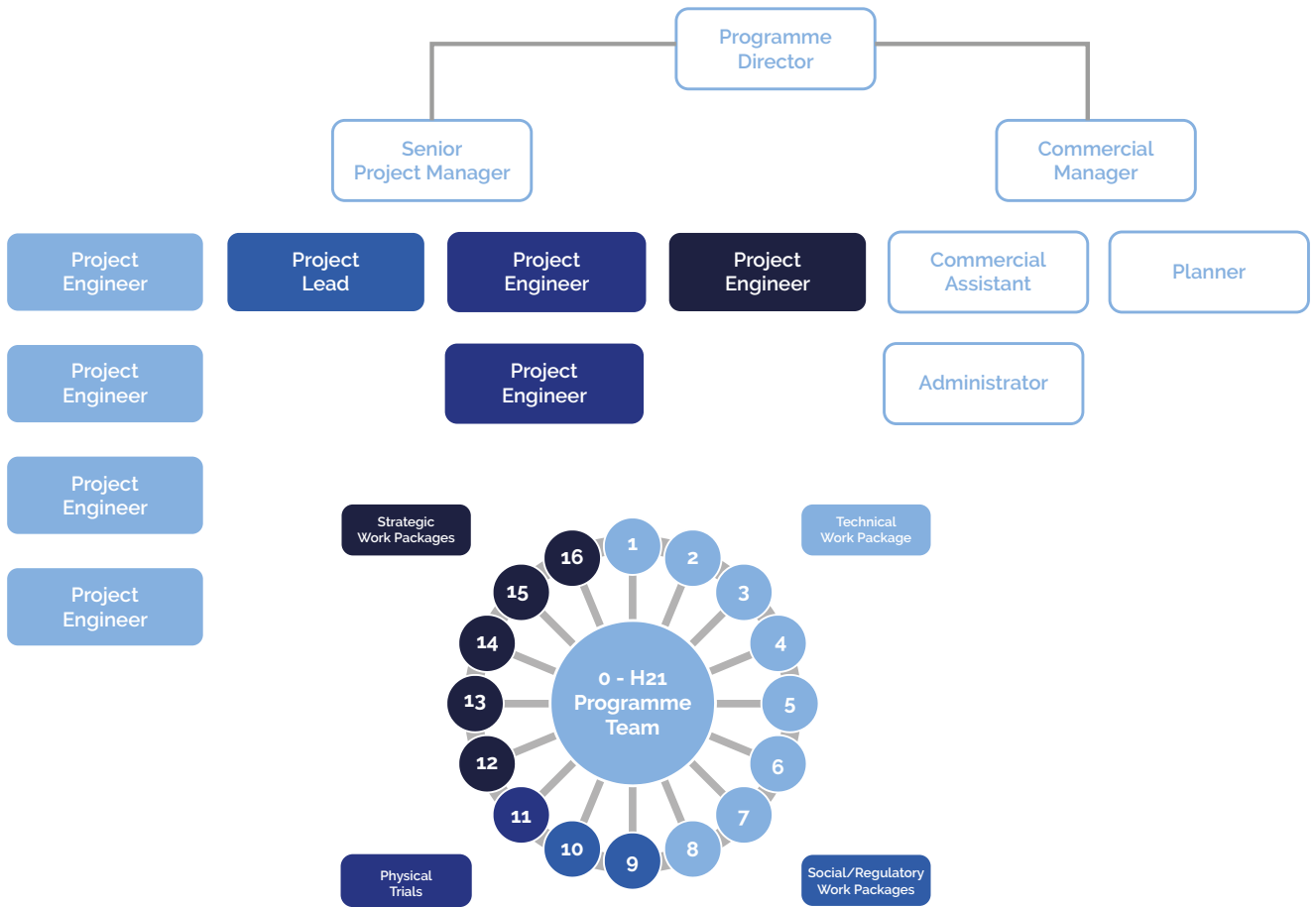


Image 10.4. *Proposed H21 Programme Team Structure*

In addition to the H21 Programme Team, the Programme Director will also have responsibility for the associated sub-teams that will be required as part of specific Work Packages and liaison back to central government on roadmap progress.

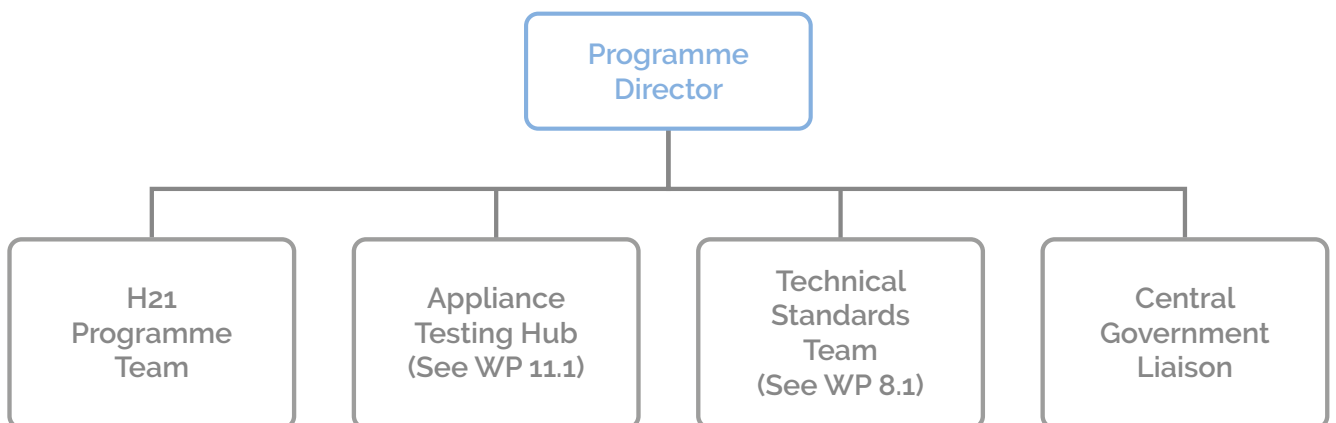


Image 10.5. *Programme Team Wider Interfaces*



The programme team is anticipated to be in place for the duration of the road map Work Packages delivery anticipated to be completed by 2021/22. In reality, should the conversion to hydrogen take place this team would extend indefinitely to manage the conversion process. The cost of this programme team are excluding back office provision e.g. finance/accounts, procurement, legal, etc. which have been assumed as to be provided via DECC/another associated body, for example, an LEP.

It is imperative that this team is established early to ensure cost effective efficient delivery of the H21 Roadmap projects. Failure to establish this team will lead to delays in delivery and consequentially in the ability to make a decision/policy commitment to hydrogen conversion.



## Work Package One: H21 - Pressure Reduction

### 1.1) H21 – PRU Performance

The operation of existing pressure reduction stations and their individual component parts needs to be robustly tested for managing hydrogen gas flows. This will include testing valves, filters, meters, slamshuts and regulators under laboratory conditions to ensure adequate operability. It will also include testing associated telemetry and pressure monitoring equipment. This project, when fully developed, will look to test different assets individually at different pressures and velocities in laboratory conditions before a final full Pressure Reduction Station test which could be undertaken on a purpose built skid unit.



Image 10.6. 'Typical' Pressure Reduction Station (PRS)



Image 10.7. Instrumentation Equipment

Significant numbers of stakeholders will be required including testing laboratories (potentially universities), industry (networks) and equipment manufacturers. Consideration should be given by the project team as to whether this project and Project 1.4 should be progressed individually in parallel or run in series to one another i.e. Project 1.1 then Project 1.4 or vice versa. This may be dictated by laboratory availability, logistics of equipment provision for testing, connection complexities and/or individual manufacturer's proactivity.

### 1.2) H21 – PRU Noise Investigations

PRUs operate in line with current guidance on acceptable noise levels for equipment as defined in gas design standards and noise regulations. The impact of hydrogen on the noise characteristics of a station will need to be assessed to ascertain if additional work will be required on existing PRUs to ensure compliance with regulation and design standards. These physical tests, which in part could be undertaken in conjunction with Project 1.1, will require testing of the assets for noise levels under different operating parameters (pressure, flow, and velocity).

If noise levels are subsequently found to be in excess of acceptable limits new acoustic enclosures (e.g. regulator housings) or noise attenuation (e.g. regulator silencers) may need to be installed on some operational equipment. In addition to understanding the noise impact of hydrogen on the gas networks pressure reduction installations this project will develop new guidance on noise considerations for PRU operations and associated acoustic enclosure modifications/requirements. This would subsequently be incorporated into Work Package 8 – technical standards.

### 1.3) H21 – PRU DSEAR Compliance

The Dangerous Substances and Explosive Atmosphere Regulations (DSEAR) and associated ATEX classifications are complied with via the SR25 IGEM design standard. These standards detail hazardous zonal classification standards around gas sites. A range of physical tests will need to be undertaken to allow the update to SR25. This will result in two 'SR25' standards one to be applicable to existing GSMR standard gas transportation (as is) and a new hydrogen network classification.



Image 10.8. Hazardous Area Classification Drawing (Large Site)

#### 1.4) H21 – District Governor Performance and Capacity

The most substantially affected pressure regulating equipment will be district governors which are extensively located throughout cities. This project will include testing a range of different district governor types (there are many), including service governors (MP/LP direct feeds to domestic properties) to ensure operational functionality is not affected when regulating hydrogen.

This project, when fully developed, will look to test different pressures and velocities in laboratory conditions. Significant numbers of stakeholders will be required including testing laboratories (potentially universities), industry (networks) and equipment manufacturers. Consideration should be given by the project team as to whether this project and Project 1.1 should be progressed individually in parallel or run in series to one another, i.e. Project 1.1 then Project 1.4 or vice versa. This may be dictated by laboratory availability, logistics of equipment provision for testing, connection complexities and/or individual manufacturer's proactivity.



Image 10.9. 'Typical' District Governors (x2)

The impact on the capacity of these governors under a hydrogen conversion is not clear and ensuring capacity is not affected by the network 1 in 20 design parameter will also form part of this project. If capacity is found to be an issue, this project will identify the appropriate measures required to rectify the problem; this could include partial or full district governor upgrades in areas converted to hydrogen (or could require no action). If action is required this can be incorporated into gas networks ongoing district governor replacement programmes. In NGN a number of district governors are replaced and/or upgraded every year.

### 1.5) H21 – District Governor Noise Investigations

District governors (DG) operate in line with current guidance on acceptable noise levels for equipment as defined in gas design standards and noise regulations. The impact of hydrogen on the noise characteristics of a DG will need to be assessed to ascertain if additional work will need to be undertaken to ensure compliance with regulation and design standards.

These physical tests, which in part could be undertaken in conjunction with Project 1.4, will require testing of current acoustic enclosures (currently designed to NGN/SP/PRS/35) and DGs for noise levels under different operating parameters (pressure, flow, and velocity). This project will allow new guidance on noise to be developed for hydrogen DG operations and acoustic enclosure (GRP Kiosk) modifications.

Specifically, for this project gas velocity should be closely considered and the impact on noise/operability when increasing velocities up to 80 m/s. This could be the new maximum velocity design parameter recommended as part of the H21 Leeds City Gate project.

### 1.6) H21 – District Governor DSEAR Compliance

The Dangerous Substances and Explosive Atmosphere Regulations (DSEAR) and associated ATEX classifications are complied with via the SR25 IGEM design standard. These standards detail hazardous zonal classification standards around gas sites. A range of physical tests will need to be undertaken to allow the update to SR25. This will result in two 'SR25' standards one to be applicable to existing GSMR standard gas transportation (as is) and a new hydrogen network classification.



## Work Package Two: H21 – Below Seven Bar Mains Considerations

### 2.1) H21 – Remaining Metallic Mains Assessment

The REPEX programme is currently delivered under a risk scoring methodology as agreed with the HSE and gas industry. This risk scoring methodology allows prioritisation of pipes for replacement based on their relative level of risk. An internal (NGN) appraisal of the 'end of programme position' needs to be undertaken to ascertain the number of remaining metallic mains in the Leeds area. This should identify the quantities by length, diameter and location as well as showing the level of risk score remaining as defined in the REPEX risk scoring model.

### 2.2) H21 – Remaining Metallic Mains Hydrogen Leakage Assessment

Under the current REPEX regime, there will be a proportion of metallic mains retained within the network. These are generally above 8 inch in diameter and/or have a very low-risk score or have not to be replaced under a cost-benefit analysis assessment (i.e. minimal leakage history). The relative risks of transporting hydrogen, and any associated leakage, through these mains, needs to be assessed. When undertaking this project, it will be important to quantify the relative risk of a hydrogen leak AGAINST the equivalent risk of an existing natural gas leak.

These 'retained' mains by default have not been replaced with plastic as a result of having a low-risk potential or high asset health integrity, i.e. minimal leaks over time. As a result, they would only need to be replaced for hydrogen transportation should it be determined that a disproportionately greater risk would occur as a result of transporting hydrogen. To undertake this project physical trials on existing mains would need to be undertaken. The gas industry has such mains across its networks that are either obsolete or can be isolated. Utilising these mains for the trials would be a cost effective 'real life' way to test the impact of hydrogen.

It is important to note that it is not anticipated that hydrogen will pose an increased risk in retained metallic mains. Indeed, when considering this project the H21 Programme Team should also consider:

- The high diffusivity of hydrogen in air (20 m/s) vs. natural gas.
- The ability of hydrogen to 'track' underground vs. natural gas.
- The level of risk that is acceptable today for our 'leaking' natural gas network, when compared to the natural gas or hydrogen network possible in 2029 (when conversion may or may not have taken place).
- Additionally it should be articulated in the overall outputs from this project that, providing hydrogen leaks represent no increase in risk, any future escapes from a hydrogen network have no detrimental impact on climate change vs. the current level and future levels of natural gas escaping the system.



### 2.3) H21 – Accelerated REPEX into Key Areas

To start the conversion process from natural gas to hydrogen the first cities to convert would need to accelerate their REPEX programmes. The current REPEX programme is risk-based and, while there is flexibility where to prioritise projects based on the 80/20 design criteria, the programme would not conclude until 2032. As a result, the conversion to hydrogen of the first cities (Leeds/Teesside/Hull (see **H21 Vision**)) would be unlikely until the mid-2030s. This may be acceptable but does delay the opportunity to decarbonise heat and also shortens the time for the incremental rollout of the hydrogen conversion programme to meet the 2050 target.

Working with NGN (as the first network requiring conversion in the next price control period) this project would understand the commercial impact and logistical challenges of accelerating its REPEX programme into Leeds, Teesside, and Hull in RIIO GD2. It should also consider any impact on the network meeting its safety obligations of the 80/20 design guidance for the REPEX programme. It would also consider the impact of accelerating REPEX into Newcastle, Bradford and Manchester for the next stage of conversion.

### 2.4) H21 – Mains Isolations to Support Conversion (See also Work Package 4 Project 4.5a)

As part of the conversion process a detailed conversion plan would need to be developed (see Work Package 4 Project 4.5). This would require strategic valves to be installed to allow a double block and bleed configuration to be in place to isolate hydrogen areas from natural gas areas as the conversion takes place. In reality, many of these valves may exist, but large numbers will need to be installed in preparation for conversion. Ideally, with early identification, these can be installed as part of ongoing REPEX work, but some will need to be retrofitted once the detailed analysis in Work Package 4 Project 4.5 has been undertaken.

### 2.5) H21 – Constrained Velocity/Pressure ‘Problem’ Area.

As part of the conversion to hydrogen, some areas will require some retrospective reinforcement to maintain pressures through 1 in 20 winters (as per current design codes). These areas should be analysed by networks in strategic cities UK wide, or minimum in Leeds/Teesside/Hull to ensure the appropriate REPEX replacement strategy is adopted e.g. open cut, live insertion, etc. This will ensure retrospective reinforcement costs are kept to a minimum and work is undertaken today bearing in mind the requirements of tomorrow.



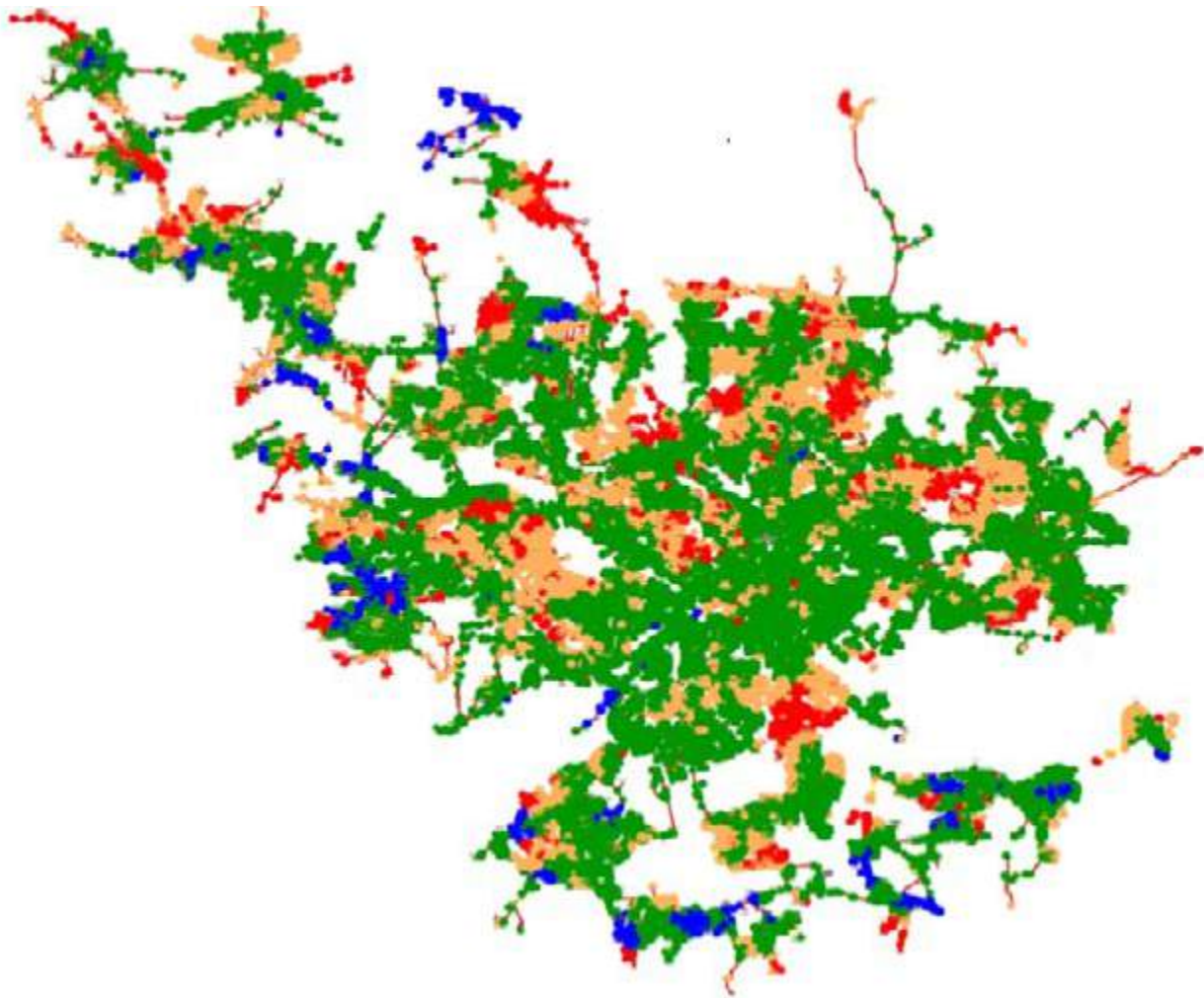


Image 10.10. *LP Network Reinforcement Requirements*

### 2.6) H21 – Hydrogen PE Mains Leakage

Evidence proving the relative level of risk for hydrogen transportation through PE mains needs to be provided. Specifically, but not limited to, consideration should be given to:

- Transition fittings i.e. where PE joins retained metallic pipes.
- Leakage from 3<sup>rd</sup> party damage i.e. where a third party causes a failure of the main, for example due to hitting it with a mechanical excavator.
- Diffusion through PE pipe walls of different wall thickness's. Note early results from Denmark are encouraging suggesting a very low level of leakage.
- Diffusion through PE mains of different ages of installation.

These potential risk of these types of leaks from a future hydrogen network should be quantified **against** existing methane to understand if there is any increased risk in a future hydrogen network.



***It should be noted that when considering the risk of specific leakage paths the H21 Programme Team should also consider the net risk position for a UK hydrogen network when compared to the natural gas network of today and the equivalent natural gas network of the late 2020s. Indeed, by the time, a hydrogen conversion takes place nearly all mains will be PE, which are butt/electrofusion welded. This in itself gives a significant reduction in risk to life and property than the network that we have in the UK today even if that future network is transporting hydrogen.***

### 2.7) H21 – Summer Flow Modelling

The UK gas industry is designed and managed to meet a 1 in 20 peak hour demand; all lower demands are based on ratios to reduce this peak usage figure (see [Section 2, Demand vs. Supply](#)). When undertaking the H21 Leeds City Gate project, one of the most significant challenge faced by the project team was establishing what the actual consumption for low demand conditions, i.e. in summer, was in the area of conversion.

In order to optimise any future detailed design the UK gas industry should establish a series of diversification curves for different community archetypes to ensure low demand, equivalent to 1 in 20 troughs, are robustly understood. Failure to adequately understand this will result in oversizing and/or undersizing of hydrogen production and storage facilities. This will result in excessive cost or security of supply issues.

In the first instance, the area of conversion identified in H21 Leeds City Gate should have ultrasonic (or other) meters installed at all the extremity locations. These should be operated for a minimum of two summers, and the actual summer demand should be calculated for the area of conversion and compared to the original study.

When considering this project the H21 Programme Team should also consider the results of SGNs 'real-time networks' 2015 NIC bid and also the results of NGNs T-Shale part one and two 2015 Network Innovation Allowance projects.

## Work Package Three: H21 – Industrial and Commercial Appliances

The funding for development of large-scale rollout for industrial and commercial conversion is anticipated to be extensive. In reality, the appliance manufacturing industry may part fund (likely with government support) and accelerate the development of these types of appliance/equipment if a policy decision on hydrogen transpires.

The first task must be to quantify to a reasonable level of accuracy the existing stock of combustion equipment and determine the minimum range of appliances necessary to replace them. This may be complex if the existing boiler house or furnace is effectively 'time expired' and needs replacing.

For the commercial heating sector, a sub-work programme will need to be established between building owners, local heating and ventilation companies, and Leeds Council building control. This will need to establish the principles to be followed for different types of boiler house. Various funding formulae will need to be agreed.

### 3.1) H21 – Industrial Gas Applications

The range of industrial gas applications within the Leeds (and other city) areas needs to be understood in detail. The H21 Leeds City Gate project has considered this in **Section 5, Appliance Conversion** but on a desktop exercise basis. It is likely further work will be required involving multiple stakeholders to help understand the industrial gas use, appliance type, and potential burner amendment configurations.

In order to undertake this work, a specific Project Manager may be required to engage with the industrial sector and compile a comprehensive range of robust information. The use of trade bodies/institutions to help facilitate contact as well as some key manufacturers/academic institutions should also be considered. If effective when scoping a comprehensive delivery strategy this project manager may also be able to undertake Project 3.3 concurrently.

This project will also provide information for Work Package 4 Project 4.5 to allow a clear conversion strategy to be developed with regional industrial users identified.

### 3.2) H21 – Industrial Conversion

Project 3.2 will build on the initial learning of Project 3.1. The project could involve physical testing, design, and certification of appropriate modifications to 'upgrade/replace' industrial gas use applications through the methane – hydrogen conversion process.

This project could be considered alongside Work Package 11 'physical trials' and could partly be undertaken at the appliance testing facility Project 11.1. This is likely to be one of the most technically challenging tasks, especially re-configuring imported equipment. The latter would have been rare in the original town gas programme.



### 3.3) H21 – Commercial Gas Applications

The range of commercial gas applications within the Leeds (and other city) areas needs to be understood in detail. The H21 Leeds City Gate project has considered this in **Section 5, Appliance Conversion** but on a desktop exercise basis. It is likely further work will be required involving multiple stakeholders to help understand in detail the commercial gas use, appliance type and potential burner amendment configurations.

See 3.1 for comment on project delivery/management.

### 3.4) H21 – Commercial Conversion

Project 3.4 will build on the initial learning of Project 3.3 (compiled as part of H21 Leeds City Gate). The project will involve physical testing, design and certification of appropriate burning modifications to 'change out' commercial gas use applications through the methane – hydrogen conversion process.

This project could be considered alongside Work Package 11 'physical trials' and could partly undertake at the appliance testing facility Project 11.1.



## Work Package Four: H21 – Domestic Considerations

### 4.1) H21 – Service Pipes

Following completion of the REPEX programme, under the current replacement regime, there may be a number of metallic service pipes remaining in the Leeds conversion area. The volume and condition of these services need to be understood; this can be done using internal NGN modelling systems, data, and projections.

Tests will be undertaken on actual services of varying materials, diameters and conditions in order to establish the level of risk. It may be appropriate to develop the current REPEX risk modelling methodology for these remaining pipes to understand which, if any, may need replacing ahead of a conversion.

### 4.2) H21 – Service Pipe Testing

The relative risks of transporting hydrogen, and any associated leakage, through retained metallic services, needs to be assessed. When undertaking this project, it will be important to quantify the relative risk of a hydrogen leak AGAINST the equivalent risk of an existing natural gas leak.

When developing this project the H21 Programme Team should consider the information provided following completion of 4.1. In addition to understanding the relative risk of retained metallic service pipes carrying hydrogen vs. natural gas consideration should also be given to quantify any increase or decrease in risk associated with a leak from a future PE service pipe. This latter piece of work will require testing of PE services with simulated leakage for a range of 'lay' scenarios and damage impacts. For example, services laid in a garden hit by a shovel at shallow depth or a service laid in a concrete drive hit by a pick axe!

It is anticipated that the gas industry will already have significant information on service pipe risks both within the REPEX model and wider industry background. The H21 Programme Team should identify and utilise this information ensuring the correct question is answered as part of this project, i.e. 'what is the relative risk of hydrogen in services when compared to existing natural gas'.

### 4.3) H21 – Meter Testing

The current meter population for gas measurement is calibrated for methane. Tests need to be undertaken across the range of network and domestic meters to understand the impact of the meter measuring hydrogen. Once the impact on metering is understood, strategies for corrective action need to be considered. These could include:

- Do nothing – the meters still work within acceptable tolerance.
- Develop a correction factor – for example, if the meters perform from an integrity point of view (safety) but has an error in terms of measurement, could a corrective factor be established for meters originally designed for methane but now operating on hydrogen.
- Partial upgrade alongside the smart metering rollout programme.
- Upgrade as part of the conversion process.



#### 4.4) H21 – Smart Metering

As with 4.3, the impact on any approved smart meter needs to be considered. Will these meters, operate on hydrogen. Consideration should be given to the impact of the smart meter rollout programme and its relative benefits in the hydrogen economy.

Following results from 4.3 and testing of smart meters on hydrogen (4.4) it may be recommended that smart meter rollout should start in areas less likely to be converted to hydrogen in the short term. This would allow time for a hydrogen smart meter to be developed or testing to establish if existing smart meters are suitable for hydrogen.

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***The smart metering programme offers a unique opportunity to undertake customer/appliance surveys at each property/priority consideration should be given to undertaking these surveys at the same time as meter installation to ensure no duplication of effort. Other considerations should also be given to this customer interaction in terms of education pieces. (See Work Package 10 – public perception)***

#### 4.5) H21 – Conversion Strategy

The range of domestic gas appliances within the Leeds (and other city) areas needs to be understood in detail. The H21 Leeds City Gate project has considered this in [Section 5, Appliance Conversion](#) but only on a desktop exercise basis. It is likely further work will be required involving multiple stakeholders to help understand in detail the domestic gas use, appliance type and potential burner amendment configurations. The work undertaken by SGN in Oban should be considered as good evidence to date for consideration by the H21 Programme Team.



This will require three significant areas of work:

#### 4.5a) H21 – Conversion Modelling, Design and Data Collation

This project will consider the practical conversion strategy for the area of conversion to 100% hydrogen. The project will include utilising the gas networks Synergi model to design an appropriate conversion strategy for the area. Additionally, this project needs to consider the potential UK rollout strategy (Work Package 16) as it may transpire that a much larger area of conversion, for example, Leeds and Bradford, needs to be considered based on a national rollout decision.

The project will include:

- Understanding lessons of the past town gas conversions
  - Literature review.
  - Interviews.
  - Etc.
- Designing the isolation strategy utilising the Synergi model for city conversion (Developing on the work presented in 2.2)
  - Isolation locations.
  - Reinforcement requirements.
- For each isolation area understanding the conversion requirements:
  - Area demographic e.g. domestic, commercial, industrial numbers.
  - Appliance types – domestic e.g. type/number of boilers, cooking, fires, etc.
  - Appliance types – commercial.
  - Appliance/burner types industrial.

The project will build on the work already undertaken by the network and will be supported by an expert Synergi modeller.

#### 4.5b) H21 – Off Network, On Gas Trials.

As part of the conversion, it may be a requirement, at least for some customers, that the isolated areas will be kept supplied with gas for essential services (cooking/hot water) by localised bottled gas supplied to their properties. NGN are already undertaking an initial investigation of this work as part of an existing Network Innovation Allowance project. This initial project may require additional work to ensure the full range of scenarios for isolation are covered to allow any conversion to be well understood and effectively executed. This could include:

- Mother/daughter fuelling.
- Bottle size.
- Security measures.
- Connection techniques.



#### 4.5c) H21 – Appliance Modifications/Development

The range of appliances for boilers, fires and cookers in the UK is extensive. Significant engagement is required with the appliance manufacturing community to consider:

- Reconfiguration of existing appliance, i.e. how/if the upgrade of burners is possible and on which appliances.
- The design of new appliances taking account of the customer demands on modern aesthetics. This should also consider the design of new appliances that can either be built ready for dual purpose or designed to enable easy conversion to hydrogen.

This project will be essential as part of the overall conversion strategy. In effect when areas are isolated the conversion engineers should know upfront exactly what is required at each customer's property, and the logistics should be in place to ensure swift replacement of parts/appliances for cost effective, timely conversion. Bad planning in the upfront stage will have more effect on customers and will cost significantly more in wasted time for the conversion team versus the cost of detailed up front surveys. In reality; this may be some seed-corn funding for entry level appliances and demonstration purposes for fires, hobs, and cookers. As with industrial and commercial considerations, it is anticipated that development in domestic appliances would cost significant amounts of money and would be accelerated and funded (at least partly) by the appliance manufacturing industry should a decision to convert to hydrogen transpire.

#### 4.6) H21 – Enhanced Ventilation of Enclosed Spaces/Compartments and Potential Use of Hydrogen Detectors

A detailed assessment of risk needs to be undertaken across the building stock and remaining metallic mains stock to see if there is any disproportionate increase in risk (when compared to natural gas) associated with hydrogen escaping from both internal and external pipework.

Additional ventilation may be deemed necessary and/or appropriate consideration could be given to hydrogen detectors being installed at potentially higher risk locations (should any be identified) at the same time as the conversion is undertaken.

This project should pull together the quantitative risk assessment from projects such as HyHouse, Hy-Occupancy (see 5.1) and the Project 2.2 and 4.2 on the H21 hydrogen Roadmap. It may transpire, and in fact is probably more likely, that no or minimal additional detection either in properties or in strategic street locations is necessary.

Even so, a range of hydrogen detectors should be available to the public should they wish to procure one for their own piece of mind. Sourcing these detectors and testing/approving for the UK Market will form part of this project.



## Work Package Five: H21 – Multi Occupancy Buildings

### 5.1) H21 – Hy-Occupancy

Building on the HyHouse project this project should enable a quantitative risk assessment to be undertaken of high occupancy buildings, for example blocks of flats. This will ensure that the risks associated with a hydrogen leak in flats/other Hy-Occupancy buildings are understood.

This work may also extend to strategic commercial and industrial properties where the volume etc. of gas release may cause a specific area of concern. For example, this could include industrial properties with a high pressure (7 bar) gas supply or properties with specific types of gas application.

### 5.2) H21 District Heating

Energy efficiency is still an important factor when considering conversion. In addition, long-term safety considerations for high rise services could suggest district heating systems, fed from the hydrogen network, for multi-occupancy/high heat demand buildings may be quite an attractive option. A study should be undertaken considering strategic areas where building specific district heating systems could be considered within the area of conversion identified in H21 Leeds City Gate. Whole life and safety reduction impact should be considered and compared to a direct like-for-like replacement to understand if there is merit in upgrading to district heating as part of the overall hydrogen economy strategy.

As part of this project, consideration could be given to district heat suppliers and availability of commercial appliances (see Work Package 3). National Grids recent District heat study (NIA), the various other studies and the Leeds LEP strategic district heat study should be considered by an independent project manager to determine if there is any merit in progressing with building specific district heating schemes in the context of a hydrogen conversion programme. This project manager could work as part of the H21 Programme Team for the duration of the project. Funding formulae will need to be established.





## Work Package Six: H21 – Blending

The H21 principles are to move to a 100% hydrogen gas network over time. It is recognised that having a higher hydrogen blend within the existing gas may be advantageous in some limited scenarios. Whilst this would never provide the type of carbon saving of an H21 scheme it may be useful to understand some blending opportunities where system integration between the electric and gas networks or by-product hydrogen usage could be in the interests of the wider UK energy system.

It should also be noted that blending, at any scale, has challenges based on intraday and inter-seasonal flow rates, billing and potentially safety at the point of consumption depending on percentage blend. It also only saves  $\frac{1}{3}$  the carbon by volume, i.e. blending up to 10% only saves 3.3% carbon (assuming 100% 'green hydrogen') due to the energy content of hydrogen. Ultimately moving to a 100% hydrogen but understanding blending opportunities as a hydrogen economy grows over time may be beneficial to the UK and should be considered. It is not the recommendation of H21 that a blended UK gas network should be aspired to or indeed that it would significantly support the challenge of the climate change act.

### 6.1) H21 – Blending Literature Review (Hyready)

The UK GSMR (Gas Safety Management Regulations) currently stipulate a maximum hydrogen content of 0.1%. A piece of work is currently scheduled to start in Europe (2016) that will try to quantify the risks of increased hydrogen content into the gas grids, e.g. up to 30%. This work is being funded by a pan-European consortium of up to 16 partners including of the four UK gas transporters.

The results of this work should be monitored/supported by the H21 Roadmap team. Blending hydrogen could have two significant benefits

1. reducing carbon emissions in areas still on methane; and
2. allowing balancing (supply vs. demand) of the hydrogen infrastructure if the existing storage is marginally insufficient at times of extreme, e.g. very mild summers.

It should be noted that blending hydrogen should not have any detrimental impact on network infrastructure much of which was used with town gas which had 50-60% hydrogen content. Additionally key considerations for any potential blending need to consider the intraday and inter-seasonal demand profiles, i.e. how to keep at a set percentage hydrogen and what controls are required as well as flow-weighted average CV billing parameters (see 6.4).

### 6.2) H21 – Blending Capacity Analysis

As part of the T-shale Part one scenario modelling capacity requirements on the network are being modelled for different sources of injection. This analysis should be extended nationwide to develop a 'gas blending map' of the UK showing injection 'hotspots' for 5/10/20/30% hydrogen blends. This will allow an informed strategy on managing surplus renewable generation with gas system storage optimising the transportation infrastructure and integrating the system in the most efficient manner for the UK.



### 6.3) H21 – Blending Testing

Whilst the Hyready project may consider the effect of hydrogen blending on the network some real life testing will need to be put in place to look at the impact on various hydrogen blends on the end-use appliances. This could be undertaken in a project similar to the Oban project being undertaken by SGN. Trialling will likely be undertaken as part of lab testing and live application testing. It is recommended that this could be done at the Teesside testing facility (see Work Package 11 Project 11.1).

National Grid has submitted a project to the Network Innovation Competition in 2016 which is looking to address some of these issues. If this is awarded, the H21 Programme Team should work closely with this team to coordinate results.

### 6.4) H21 – Postcode Billing

A significant issue that arises from hydrogen blending, and indeed hydrogen designated areas, is billing (see Work Package nine). Currently in the UK customers are billed based on a Flow-Weighted Average Calorific Value (FWACV) for a network area. In effect the average level of energy in the gas at all the network offtakes (over simplified but in principle correct). If hydrogen blending were to be undertaken with local injection of hydrogen the energy content in specific areas would drop. Under the current billing methodology the bills would remain the same based on the FWACV which would penalise those customers living in a blending area.

The UK gas industry is currently undertaking work to look at localised measurement of calorific value. If this was to be rolled out billing could be undertaken based on postcode areas to ensure customers are only billed for the energy they use, not the average energy content. This would require extensive changes to existing shippers billing system as well as development of a strategy to install measuring devices in areas likely to be affected.

This project would also support the onset of any other unconventional gases and, for example could remove the need for propanation of biomethane.

In reality this project is likely to be a significant undertaking and currently National Grid/NGN are proposing putting the project forward for NIC funding in 2016. If the NIC project is awarded it would be imperative that H21 Programme Team can ensure the project covers all the possibilities for hydrogen as well as methane CV variations.



## Work Package Seven: H21 – Odourisation/Gas Detection

### 7.1) H21 – Odourisation 'Carry' Potential

Natural gas is currently odourised at the network offtakes. This process is critical to the network's safety case and the level of odourant in the gas is monitored by trained network rhinologists. This ensures the level of odourant does not exceed the industry recommended level causing undue numbers of reported gas escapes or does not drop below that standards resulting in insufficient concentrations to identify leaks.

The level of odourisation required in the hydrogen to meet current recommendations needs to be understood and this will involve physical trials. There are two scenarios to investigate.

- If the methane for the Steam Methane Reformer (SMR) is taken from the NTS the gas is unodourised and as such will need full odourisation at the offtake of the SMR.
- If the gas is taken from the Local transmission system it is already odourised and the impact of the SMR on the odourant level needs to be considered this may result in additional odourisation required after the SMR process.

### 7.2) H21 – Alternative Odourant

In the long term the hydrogen network is likely to be used for refuelling vehicles or micro CHP. The current odourant is a sulphur based compound which would damage a fuel cell and would therefore require a change. In Japan a new odourant (cyclohexene) has been trialled that is compatible with fuel cell technology, but does not have the stench associated with current EU odourants. The level of this development needs to be understood and the retrospective impact of any amendments to the UK odourisation techniques quantified.

Additionally meetings with appliances manufacturers indicate the need to specify the hydrogen gas characteristics including any colourant and the odourant. Moving to a non-sulphur odourant presents significant benefits for appliance development and should be considered from the start of the onset of the hydrogen economy to optimise hydrogen appliance design.



### 7.3) H21 – Operational Hydrogen Detection (Gasco-seeker – Leaks)

As part of the current gas industries safety case the gas transportation companies operate a 24 hour emergency response service for gas escapes. This involves, in the first instance, a 'first call operative' (FCO) attending site to assess and identify the most probable location for a gas leak. To do this each FCO has a 'gasco-seeker' which is calibrated to detect methane concentrations. For areas converted to hydrogen these pieces of equipment would need to be developed and calibrated for hydrogen. Initial discussions with manufacturers suggest this can be easily done.

In addition availability of parts per million detectors, similar to those used today to detect hard to trace leaks, needs to be established/developed.

### 7.4) H21 – Network Purging Operations

When commissioning a new gas main (i.e. purging from air to methane) a gasco seeker is used. This gasco-seeker is located at the opposite end of the pipe to that which the 'new' gas is being introduced. A reading of greater than 90% methane is required before the pipeline is considered purged with gas. Current gasco seekers would not be able to undertake this task for a 100% hydrogen purge. This would be essential to the conversion process and also the ongoing operation of a hydrogen network. This new piece (or adapted piece) of apparatus would need to be developed as part of this project.



## Work Package Eight: H21 – Technical Standards

### 8.1) H21 – Technical Standards Modifications/Development

The legislation, industry standards and Policies and Procedures (P&Ps) which govern the gas industry are both extensive and robust. They are vital to ensuring the safe efficient running of the gas system and range from the networks safety case to simple engineering instructions.

Following networks sale in 2005 many of the gas industry standards were adopted and are individually owned by the specific networks. Currently, the suite of standards broadly applicable to the gas industry can be summarised as follows:

Owner	Quantity	Comment
GDN/IDN (NGN/WWU/NG/SGN)	c. 617	These all started as the same set of documents but have subsequently been modified/updated by individual networks over the last ten years.
IGEM	57	These are formally adopted by the Networks if they choose to do so.
Gas Industry Standards	66	These are collaboratively owned by the gas industry (all the networks) and are managed via the technical standards forum.
External Legislation	74	Legislation (for example Pipeline Safety regulations, Dangerous substances and explosive atmospheres regulations.)
<b>Total</b>	<b>Over 800</b>	

Table 10.2. *Key Gas Industry Governing Documents*

These documents would need to be updated for hydrogen transportation and would require industry involvement as well as support from the wider chemicals/petroleum industries who already transport 'other' gas and hydrogen. Whilst many of these standards would require little or no amendments, others would require medium to major amendments and some total rewrites or indeed a new standard producing.

This piece of work would require a dedicated full-time team (H21 Standards Team) who could gather and compile all relevant information. This information may come from the projects on the roadmap, other industry, and international best practice. It is anticipated that this would be an extensive piece of work taking five to ten years to complete. Initially, a prioritisation system would need to be developed to enable the critical standards/'low hanging fruit' to be addressed first.

Table 10.3 has been provided to give an indication of the types of documents involved in this work.

Owner	Reference	Title	Technical Area
NGN	B11	Carbon and carbon manganese steel bends 200 mm and above > 7 bar	AGIs, fitting and plant
NGN	B12	Steel bends, reducers and cap ends > 7 bar	AGIs, fitting and plant
NGN	V14	Donkin valves fig. 555	AGIs, fitting and plant
NGN	V6 Part 1	Steel valves for use with natural gas at normal pressure above 7 bar Part 1-100 mm nominal size and above	AGIs, fitting and plant
NGN	COMAH5	Emergency plans for notifiable sites, COMAH sites and major accident hazard pipelines	Asset
NGN	NP1	Charging point on LTS systems	Asset
NGN	NP40	Network entry requirements	Asset
NGN	SSW8	Unodourised gas installations	Asset
NGN	PWC1 PT1	Acoustic cladding pt 1 pipe and equipment	Coating
NGN	HAZ2	Venting operations (manual) on installation prior to maintenance	Design
NGN	HAZ3	The zoning of pressure regulating installations operating below 7 bar	Design
NGN	CD01 pt3	Pipeline and main records, maps and surveys	Drawings/ Records
NGN	RE7	Network pipe records	Drawings/ Records
NGN	EL6	Electrical equipment and system - working on or near at operational sites	E&I
NGN	GQ6	Odour intensity monitoring	E&I
NGN	SC02	Safe control of operations - issue of permits	H,S&E
NGN	Section 09	Use of contractors	H,S&E
NGN	EM71	Gas escape - dealing with and other emergencies	Operations
NGN	EM71 Supplement	Gas escape procedure - advice	Operations
NGN	TMP6	Flueing and ventilation	Operations
NGN	MAINT 2205	Orpheus series 4 procedure isolation	Operations

Owner	Reference	Title	Technical Area
NGN	MAINT 3040	Purging	Operations
NGN	ML1	Pipe system construction - general requirements	Operations
IGEM	IGEM/SR/25 Ed2	Adoption	IGEM
IGEM	IGEM/TD/1 Ed5	Adoption	IGEM
GIS	L2	Specification for steel pipe 15 mm to 450 mm inclusive nominal size for service at pressures up to 7 bar	GIS

Table 10.3. *Document Examples.*

It should be noted that IGEM does not currently have the resource (circa 23 staff, most none technical or part time) to amend these documents. Additionally, it does not own the vast majority. It is however recommended that this 'H21 standards' team be based within IGEM reporting back to the H21 Programme Team. IGEM has four key benefits for adopting this role.

- Already the universal QA body for all 'IGE' standards.
- Recognised representative body for all the gas networks.
- Respected industry body.
- Charitable organisation.



## Work Package Nine: H21 – Regulation

### 9.1) H21 – Regulation

The gas industry is governed by the uniform network code (UNC) which dictates what can and can't be undertaken by a network. This extensive document covers every aspect of the industry and will need a considerable overhaul in certain areas to allow network conversion to hydrogen, potentially alterations to billing, capacity auctioning etc. (see 9.2 and 9.3 below).

### 9.2) H21 – Billing

Currently in the UK gas distribution networks do not own the gas, they are responsible for transportation only. If hydrogen conversion were to be undertaken alternative frameworks for managing the billing of hydrogen should be considered. To give two examples:

#### Example One:

Natural gas entering the SMR would currently be owned by multiple shippers. After the SMR process would it be more appropriate for a network to 'buy the gas (energy)' from the shipper at the SMR then sell the hydrogen (energy) to the customers within its hydrogen network location. In the water industry the networks are both transporter and billers. Could this be considered for the gas industry for areas converted to hydrogen.

#### Example Two:

When considering the efficiency energy loss at the SMR should a network be allowed an OPEX value within its regulatory business plan to fund this loss (as currently recommended in [Section 8, Financial and Regulation](#)). This would ensure individual customers within a hydrogen area are not penalised but instead the efficiency loss is socialised across all network customers.

Thought should also be given to the flow-weighted average CV billing methodology currently adopted in the UK. This allows networks to measure energy content at their offtakes from the national transmission system and calculate an average energy content (calorific value which is then used generically for billing in specific areas.

The billing system could be adapted to allow postcode billing i.e. local measurement of CV to give a more accurate area by area billing opportunity. This would allow postcode billing in hydrogen areas and/or in high blend hydrogen areas without artificially inflating bills for customers in these regions. FWACV projects are already being investigated under the NIA provision in the UK gas industry (NGN/NG) but significant 'push' and recognition of the problem needs to come from the regulator.





When converting areas to hydrogen incentives may be appropriate for a limited amount of time to support the public acceptance for the conversion. For example, if a 'postcode billing system' were adopted, it would be possible to provide a time-bound reduction in bills i.e. not paying for all the energy the customer uses. This could be funded by socialising costs across other regions of the country, which in reality would have little impact on individual bills nationally. The incentive could then 'roll' with the conversion programme essentially meaning all customers receive the benefit in the long run.

### 9.3) H21 – Security of Supply/Ownership

Currently networks have to secure capacity off the National Transmission System (NTS) on an annual basis. In a hydrogen economy which organisation would own the SMRs, the network and the storage? Indeed as the hydrogen economy grows from city to city Northern Gas Networks could be supplying cities within other network boundaries (e.g. Manchester is owned by National Grid North West).

Consideration needs to be given to how the capacity for hydrogen is booked and secured from the storage/SMR sites and who is booking what from whom. Considering the SMR/Storage could likely be located directly and intrinsically as part of the network could it be assumed that the network should own the facility as their licence to operate is predicated on maintaining gas supplies. This area needs detailed consideration and will require input from across the gas industry. This should be managed by the H21 Programme Team.

### 9.4) H21 – Finance Model Appliance Considerations

The H21 Leeds City Gate financial model recommends paying for appliance upgrades as part of the regulatory finance model. This is what occurred on the original town gas to natural gas conversion. The finance mechanism for this is unclear for example, the asset is not ultimately the networks so it would currently be dealt with as 'OPEX' however it may be advantageous to consider it as CAPEX to allow costs to be amortised over a longer period (see [Section 8, Financial and Regulation](#)). This needs detailed consideration and will need to be defined and agreed between the network regulator and the gas industry. The ability for the networks to raise capital to fund this scheme also needs to be considered against the recommended regulatory finance model.

Noting not all the UK needs to be converted to hydrogen there could be challenges with upgrading appliances in areas to convert 'for free' whilst not upgrading those areas retained on natural gas. It may be considered that, as part of the UK rollout strategy (see Work Package 16), areas which will not convert do not pay for the element of conversion associated with appliance upgrades. This will need significant review and consideration to produce acceptable recommendations.



## Work Package Ten: H21 – Public Perception

### 10.1) H21 – Public Perception

Significant consideration needs to be given to management and engagement with the public. The H21 Programme team will need to develop a robust strategy for this key area of work to ensure a smooth transition to hydrogen and a positive public attitude towards such a conversion.

- Areas to consider would include:
  - How to manage information regarding physical trials;
  - How to engage the media;
  - How to engage the public in key areas;
  - How to educate the public on hydrogen; and
  - How to give confidence in the strategy.

A full stakeholder/customer engagement plan should be developed and is anticipated that an external organisation with expertise in the area would be required to assist the process. A full review of the lessons learnt from the original town gas to natural gas conversion should be undertaken as part of this exercise.

Evidence from the SGN Oban trials confirms the importance of this work.



## Work Package Eleven: H21 – Appliance Demonstration/Field Trials

Together with the surveys of Leeds appliances this is one of the absolutely key parts of the programme.

This needs to be carried out in conjunction with the appliance manufacturers, and in a fashion and to a timetable that is mutually beneficial. The cost of customer conversion is estimated at about half of the total cost of the transition to hydrogen. It is vital that in any survey the public perceives both the conversion process and new or modified appliances as satisfactory. It is important the public perception Work Package liaises closely with these trials as they are all likely to attract significant media attention.

The following are suggestions based (to an extent) on the 1960s approach. It may be that manufacturers would seek a different route, but this will need to be agreed and planned. Particularly important must be the purchasing policy of the GDN operator. A recent investigation for DECC of the hydrogen appliance supply chain made clear (as a societal investment) this should be managed to assist the UK to optimise its potential in the hydrogen sector.

As soon as possible an SBGI/HHIC/Gas Industry working party should begin to consider these complex issues. The output will require regulatory sign-off.

### 11.1) H21 – Appliance Proving Hub (Teesside/Other Locations, e.g. Elsmere Port)

The construction of a hydrogen appliance demonstration and test facility. This will include a range of domestic, and commercial appliances in separate booths/bays within a high roof building. The building should also provide a bespoke testing area for any industrial and/or other appliance nuances. A central water supply and local control system would provide simulated DHW and CH loads to all of the boiler products. This would provide information on real appliance performance. An obvious location for this is Teesside, close to the existing hydrogen line, but an alternative location could be Elsmere Port. A very large manufacturer might choose to install their own package hydrogen plant if they felt this might increase the efficiency of their R&D team.

A central facility at Teesside should also provide the location for a small team of appliance experts providing the information and support which Watson House research and development facility supplied to the original conversion process. In addition to this facilities other product development organisations (such as Enertek a Hull based gas appliance design consultancy) could also be included in the overall appliance development process. Certification would be via existing UK Notified Bodies, such as Kiwa Gastec/BSI.



### 11.2a) H21 – Non-occupied Trials (Teesside)

As part of the trialling process and prior to undertaking the conversion in an area occupied by customers it may be prudent to undertake a conversion of 'real-life' unoccupied buildings. This trial should cover a range of buildings, for example, a small row of derelict terraces and a derelict high-rise building. This is considered very important as part of the confidence-building exercise.

The purpose of this exercise would be to undertake a conversion of these properties then simulate the properties operating as if they were occupied for a period of two years (two winters minimum). Appropriate monitoring devices would be in place and security staff would be required. These staff could be dual purpose by being based in the properties for their shifts utilising the hot water, heating, and cooking facilities.

The aim of this trial would be to provide confidence that hydrogen as a fuel within existing buildings utilising existing plumbing poses no additional risks to that of traditional natural gas. The H21 Programme Team should consider this as a key piece of media opportunity to provide the platform to move to a live trial.

The locations of these buildings should be in both Teesside and Leeds to ensure the local support in the areas first to convert. The source for the supply of hydrogen will need to be considered and will likely be by tube trailer (Leeds) or pipeline (Teesside). Ideally, a range of trials across the full range of buildings would be ideal to ensure a representative sample of both building type (terrace, flat, old, new, detached, etc.) and internal pipework condition is assessed. Different trials could be undertaken in different parts of the country to ensure national interest and support.

### b) H21 – Non-occupied Trials, Internal Pipework, and Ventilation

The purpose of this exercise would be to continue the original Hyhouse work effectively to investigate the optimum position and size of vents where hydrogen pipes pass through nominally unvented spaces. It would also validate pressure test values for internal pipework. Again the work would be comparative with natural gas.

The aim of this trial would be to provide confidence that hydrogen as a fuel within existing buildings utilising existing plumbing poses no additional risks to that of traditional natural gas. The H21 Programme Team should consider this as a key piece of media opportunity to provide the platform to move to a live trial.



### 11.3) H21 – Occupied Trials

As with the original town gas to natural gas conversion in the 1960s/70s 'live' trials will need to be undertaken in areas with 'real' customers. Ideally, similar to the Canvey Island original trial (8,000 customers) the area should be large enough to provide a comprehensive understanding of the process.

It may be the case, as with the original conversion, that several small 'live' trials are required to slowly improve the conversion process and compile lessons learnt to ensure a swift, efficient conversion when moving to a larger scale. The live trials should as a minimum provide the following information:

- Evidence that hydrogen as the fuel for existing building stock with the buildings operated in the normal manner poses no significant increase in risk to life or property.
- That conversion/replacement of old appliances can be undertaken efficiently and safely putting into place all the work undertaken in 11.1.
- That the network modelling of pressures and velocities within the mains is accurate.
- That customers are happy with the conversion and that it effectively makes no change to their everyday lives.
- That the network mains/services and district governor operate efficiently and safely with 100% hydrogen.

It is worth noting that the large 'Canvey Island' scale trial would almost definitely need to be near Teesside as it has large scale hydrogen availability and hydrogen salt caverns. The live trials in this H21 Roadmap do not include (cost wise) this type of large scale trial.

This is the type of large-scale trial which needs to be very carefully factored into the appliance manufacturers plans. The timing needs to ensure that there is a slow increase in demand for hydrogen appliances, to ensure lessons can be learnt in the event of problems. A trial also needs to ensure hydrogen appliances future rollout is not so slow and interrupted that the project loses momentum. This is going to be a substantial challenge.

The costs and scope of the conversion of such intermediate towns should be given immediate attention.



## Work Package Twelve: H21 – Carbon Capture and Storage

### 12.1) H21 – Carbon Capture and Storage

Although Carbon Capture does not need to be in place for the initial commissioning and start-up for the hydrogen economy ultimately carbon capture will be required to achieve the decarbonisation ambition of the hydrogen economy,

The H21 Programme Team should maintain close links with the CCS community to ensure the optimised form of carbon capture is adopted, and a clear strategy of when/how is in place. Specific consideration should be given to the Tees Valley and Whiterose projects as well as a watching brief/technical support to the NIA on carbon mineralisation being undertaken by NGN/W/WU.

The H21 Programme Team should be regarding economies of scale when considering the onset of carbon capture. For example, if a hydrogen pipeline is being laid from Teesside to Leeds could part or all of any carbon infrastructure be completed at the same time? Similarly, when the SMRs and salt caverns are built and commissioned could some, part or all the associated carbon capture infrastructure be completed even if it is 'hooked up' at a later date.

It is worth noting that unlike retrofitting CCS to a power station, which in turn will have to bid within a complex, very time sensitive competitive marketplace, the CO<sub>2</sub> captured from an SMR plant can be almost base load. The hydrogen storage caverns can address most of the inter-seasonal demand. This should simplify the contractual arrangements substantially.



## Work Package Thirteen: H21 – Transportation

### 13.1) H21 – Transport Opportunities

The impact of an uptake in hydrogen vehicles in converted areas needs to be considered. The primary considerations for this piece of work are to determine the likely scenarios for uptake of hydrogen vehicles over time and the associated potential demand profiles on the hydrogen grid system.

When undertaking the initial development of the SMRs and storage associated with the hydrogen conversion a broad understanding of potential future increases in demand is required. This impact could have the ability to reduce the inter-seasonal deviations in the supply/demand profile i.e. the grid is not just predominantly supplying a load for heating (winter) and cooking but also all year around transportation demand.

Understanding this will have significant benefits in ensuring future proofing of the hydrogen system (end to end) and will ensure an optimised detailed design is undertaken for the initial configuration of SMR/Storage.

In addition to the above understanding where likely fuelling would be required, for example, if all existing forecourts were converted to hydrogen it would allow networks to model future demands taking into account new hydrogen-based transport loads. This could impact on the current REPEX strategy and may include some upfront 'upsizing' of mains in areas when significant increases in transport demand would likely cause a pressure problem on the system.

Other considerations will be given to the connections points for hydrogen connection across the city. These are likely to be high pressure (HTS) connections and would be the most efficient place to build fuelling stations due to the compression requirements of hydrogen vehicles.

### 13.2) H21 – CNG Vehicle and Station Conversion to Hydrogen

An understanding of the ability to convert existing compressed natural gas fuelling stations and vehicles to hydrogen should be considered. If vehicles can easily be converted the potential uptake in hydrogen fuel could be rapid, if not it is likely to be more time with vehicle conversion to hydrogen only taking place at the point of vehicle replacement.

Similarly, there is a growing recognition of the benefits of CNG vehicles to support the move towards decarbonisation in transport. It is likely that the next 5 to 10 years will see an increase in CNG fuelling stations. Understanding how easily these stations could be converted to hydrogen in future would be advantageous to the work in 13.1 and would enable acceleration of the uptake of hydrogen vehicles if it were possible to convert/supplement.



## Work Package Fourteen: H21 – Electrification

### 14.1) H21 – Power to Gas Opportunity

There are 20 ways to produce hydrogen with varying scales, costs, and efficiencies. One of these is power to gas technology which has the significant advantage of helping balance the electrical energy system and reduce constrained costs. Power to gas is the most powerful example of network integration and the potential for this technology to supplement a hydrogen economy, i.e. input directly into the system, should be considered.

### 14.2) H21 – Localised Electrical Generation

The impact of hydrogen on electrical generation could be significant in the overall support for decarbonisation. What is the likely impact of micro-CHP on the overall electrical losses in the system, (i.e. offsetting electrical generation requirements nationally) and what is the potential take-up of this technology? This project could be considered as part of a scope extension to 13.1 transport opportunities.

### 14.3) H21 – National Electrical Generation

With the potential for the onset of a hydrogen economy would it be possible to convert existing (or build new) gas fired power stations with hydrogen as the fuel? If so what are the costs and could there be a national strategy developed for converting old/building new power stations off the new expanding HTS? Understanding the future requirements for the HTS are essential for future-proofing the initial design thereby reducing long-term costs.

### 14.4) H21 – Impact of Electrical Generation

As with the transportation Work Package, consideration should be given to the long-term opportunity of electrical generation and the potential impact on the supply demand profile for the hydrogen system. Taken to its logical conclusion, this could move the whole of the power sector from centralised to localised production. This has the advantage of reducing transmission and distribution losses from the power network and avoiding their upgrade/replacement costs which are very substantial. See Project 13.1/13.2.





## Work Package Fifteen: H21 – Unconventional Gas

### 15.1) H21 – Unconventional Gas

As with Carbon Capture the H21 Programme Team should maintain close links with the unconventional gas communities to ensure any synergies are maximised. For example, many unconventional gases may (and likely will) struggle to meet GSMR regulations. SMRs and the onset of the hydrogen economy could provide a cost effective answer to ranging gas quality as the SMR is able to accept a broad range of non GSMR specification gas whilst providing the same quality hydrogen. Effectively unconventional gas could be used as the feedstock for the hydrogen economy. The environmental benefits of substantially decarbonising unconventional gas should also be recognised.

The H21 team should consider the significant economic benefits this opportunity may provide the UK as costly processing/enriching and/or ballasting can be avoided with significant savings to UK plc.

This Work Package should also consider the opportunity for repurposing parts of the LTS as unconventional gas 'gathering' systems.



## Work Package Sixteen: H21 – UK Wide Development Strategy

All the work in this Work Package would require support from cross industry sectors and the UK gas industry and would be managed by the H21 Programme Team.

### 16.1) H21 – Storage

Storage is a complex issue when considering the supply and demand requirements for the area of Leeds identified in the H21 Leeds City Gate original study. It becomes less complex, but more uncertain, when trying to consider the wider long-term implications of a less dramatic fluctuating supply/demand inter-seasonal and intraday profile. This would occur with the onset of hydrogen transportation and electrical local and national generation.

Additional to this challenge is the storage requirements for an expanding hydrogen system i.e. as the system moves towards other cities (Bradford, Hull, Newcastle, Manchester etc). Three key areas for storage need to be considered as part of a national rollout and future-proofing programme, these include:

**The Hydrogen Transmission System (HTS).** Size and pressure of the primary hydrogen transportation system, i.e. the pipeline running from the SMRs linking the cities. A larger higher pressure pipeline will have significant linepack benefits when expanding across the country and, although would increase the upfront costs of the first converted city, this would be a small amount in comparison to the potential to dramatically reduce the overall system costs when considering national expansion.

**Salt Cavern Storage – New vs. Existing.** The UK has a significant onshore storage problem with onshore storage of gas at circa 6% vs. European equivalents of circa 25%. This is a result of having the privilege of relatively flexible north sea gas for the last 50 years. As the HTS expands to cover more cities nationwide more onshore storage will be required to maintain supply/demand across the country. Developing new onshore storage will be essential to the expansion, however, this will be essential for UK gas in the coming years with depleting north sea reserves so is not an increase in cost associated purely with the hydrogen economy. As part of this study a holistic look at storage associated with a nationwide expansion considering new, existing and line pack opportunities whilst still maintaining natural gas storage security (which would diminish as the hydrogen conversion grows) is critical.

**Compression** – understanding the compression requirements for the HTS (similar to the current NTS) is important when considering a national rollout. Compression needs to be considered for both storage requirements and moving the gas along the HTS.

### 16.2) H21 – ‘Alternative’ Hydrogen Sources

There are 20 ways to produce hydrogen with varying scales, costs and efficiencies. Understanding in more detail where, how and when these are appropriate could have a benefit to the overall hydrogen economy. It is suggested that a study of all hydrogen sources in the Leeds area be considered in the first instance (including P2G (Work Package 13). Gaining this broad understanding of hydrogen production specific to a city will allow interpretation of the impact of these other sources on a national expansion programme.



This study could allow a reduction in storage requirements and even SMR reduction and associated carbon capture if local production could support intraday and even part of inter-seasonal demand. This study would also identify areas of system integration between the electric and gas networks.

The ways to produce hydrogen (known to the author) are provided in **Table 10.4** below.

Method	Name
1	Electrolysis
2	Plasma arc Decomposition
3	Thermolysis
4	Thermochemical Water Splitting
5	Biomass Conversion
6	Biomass Gasification
7	Biomass Reforming
8	PV Electrolysis
9	Photocatalysis
10	Photoelectrochemical method
11	Dark Fermentation
12	High Temperature electrolysis
13	Hybrid Thermochemical Cycles
14	Coal Gasification
15	Fossil Fuel Reforming
16	Bio photolysis
17	Photofermentation
18	Artificial Photosynthesis
19	Photoelectrolysis

Table 10.4. *Methods of Hydrogen Production*

### 16.3) H21 – UK Wide Hydrogen Expansion

As with storage (16.1) when considering the UK-wide rollout of hydrogen conversion a detailed analysis needs to be undertaken. This is critical to understanding storage requirements and allowing a timeline with associated costs to be developed. Areas this study should consider are:

**Demand profiles for cities to convert** – this information would be supplied in the same manner as that obtained for H21 Leeds City Gate and would require extensive support from all the UK gas networks.

**Natural Gas Vs. Hydrogen infrastructure** – A holistic view needs to be provided considering which cities to convert and when, which areas to leave on natural gas and which parts of the current natural gas system may become redundant.

**Potential opportunities for repurposing any redundant parts of the existing gas system** as expansion of the HTS is undertaken. For example, this could provide feed pipelines for unconventional gas or even carbon capture pipelines for new SMRs required across the system.

### 16.4) H21 – UK Wide Rollout Estimate

As part of the overall national expansion, a detailed strategy would be developed for the rollout of a hydrogen conversion which would need to be timelined and costs estimated as a minimum up to 2050, for an example see **H21 Vision**.

### 16.5) H21 – Detailed Design, H21 Leeds City Gate

As part of the overall rollout, a detailed design needs to be undertaken for the entire system associated with the first cities to convert i.e. Leeds, Teesside, and Hull. This will include the end to end system comprising the SMRs, HTS, associated pressure reduction stations, compression, and storage. This detailed design would allow costs to be understood for the first conversions likely in the in the mid-2020s. It is recommended that this is undertaken as a matter of priority to give confidence in the overall scheme and should be started no later than 2018 (see **Section 9, The Next Steps – Programme of Works**).



### 16.6) H21 – Rollout Strategy

When considering the lessons of the past, it becomes clear that a well-defined strategy for when/how rollout will occur is critical. As part of this strategy, the following should be considered:

- When and how to engage the wider supply chain and how to effectively procure goods, (e.g. appliance conversion kits) from often sole suppliers. Consideration should be given to the 'cost yardstick' approach adopted in the town gas conversion.
- When/where and how to train the extensive workforce required for the conversion.
- When to engage the UK gas industry networks to ensure they submit works as part of their RII0-GD2 business plans. This would require OFGEM engagement and would be critical to NGN as the initial network and the NTS as the likely source point for the SMR gas feedstock. Other networks would still need to consider the impact on their REPEX strategy for where their cities are on the conversion timeline.



## 10.3. Work Package Summary

Image 10.11 provides an overview of the Work Packages and their key focus area.

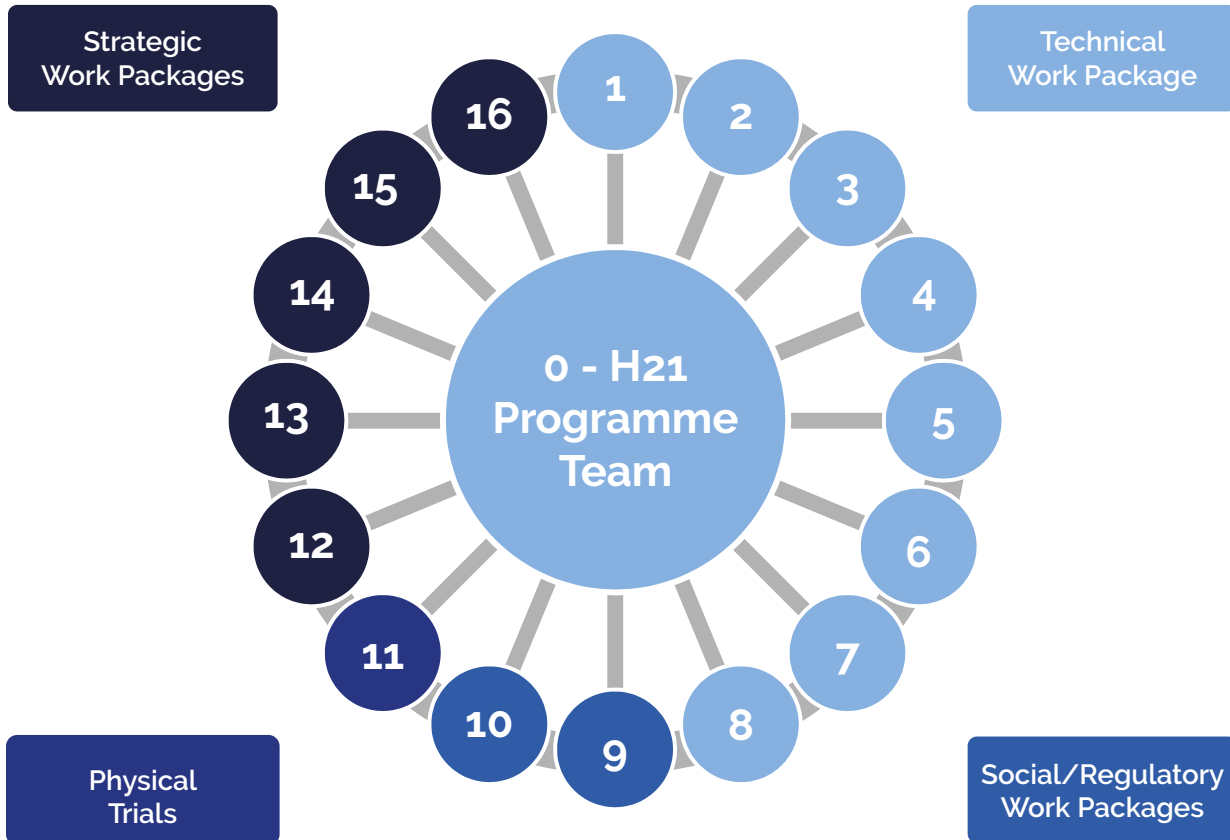


Image 10.11. H21 Roadmap – Work Package Overview

### 10.3.1. Concluding Remarks

A work programme of this scale requires commitment, high levels of expertise and a dedicated team to develop, drive and coordinate the results. Of all the projects identified within this roadmap, there are none that, on face value, are unachievable to allow a hydrogen conversion to take place in the UK.

The most critical element of this roadmap is a financial commitment to undertaking the Work Packages and, crucially, the establishment of the H21 Programme Team. Without a dedicated team in place, the roadmap delivery will be delayed or inadequately executed. This will result in delays in the ability to commit to a UK wide hydrogen conversion programme in line with the climate change act targets.

**SECTION 11**

**H21 Vision**



# 11. The H21 Rollout Vision

This section has been provided to help articulate the potential which could be generated by the establishment of the world's first hydrogen economy. Additionally how an incremental rollout of such an economy, i.e. city by city/region by region conversion, in the UK could be achieved. **It has been provided for illustrative purposes only and whilst figures have been given against documented assumptions it is recognised that this is a crude extrapolation.** However it should provide an indication of the correct 'order of magnitude' of at least two approaches to a hydrogen conversion programme.

**Providing vision pieces like this can easily be criticised and alternative notions/recommendations/assumptions put forward. That's fine! But if nothing else this section should be considered a starting point for where thought may need to be considered to move the principle of H21 forwards.**

## Summary of H21 Leeds City Gate

The H21 Leeds City Gate project provides strong evidence that conversion of a large, complex UK city to hydrogen should technically be possible. However, it is unlikely that such a strategy would be adopted for a single city as this would not meet the decarbonisation challenge of the Climate Change Act.

This section aims to provide an overview of how an incremental rollout of a hydrogen decarbonisation strategy could proceed. This incorporates decarbonisation of heat and the inevitable transition towards decarbonisation of transport, electricity generation and new industrial opportunities that would occur as a consequence of having large scale decarbonised hydrogen availability at point of use.

## 11.1. Incremental Hydrogen Economy Rollout

To provide an idea of what a UK incremental hydrogen rollout may look like two options have been presented. Option one is based around a rollout across major UK cities, Option 2 is regionally constrained to NGN customers. Costs for option one have been provided as part of a regulatory business plan finance model [Section 9, The Next Steps – Programme of Works](#). Overall capital costs for option two have been provided.



### 11.1.1. Option One, City-by-City

One significant advantage of the H21 project is that roll out across the UK can be done incrementally. In order to future proof the initial design, i.e. the Leeds conversion and associated hydrogen supply infrastructure, a clear idea of what the UK rollout strategy may be required. For example, if the ambition is to decarbonise all major cities in the UK with hydrogen the initial HTS pipeline between Teesside and Leeds would need to be 'sized' (a large enough pipe) in order to meet this future expansion. This would also take into account the future location and growth of additional SMRs and storage capacity. This would require associated connections and infrastructure to be in place (or clearly provisioned) so retrospective major modifications to the HTS are not required.

To provide some clarity on what a rollout strategy could look like an example has been provided pictorially below. It should be noted that a better and more detailed roll out strategy would be developed as part of the **Section 10, H21 Roadmap** (Work Package 16) and would likely be based on cost and carbon saving parameters. **Image 11.1** is for illustrative purposes only.

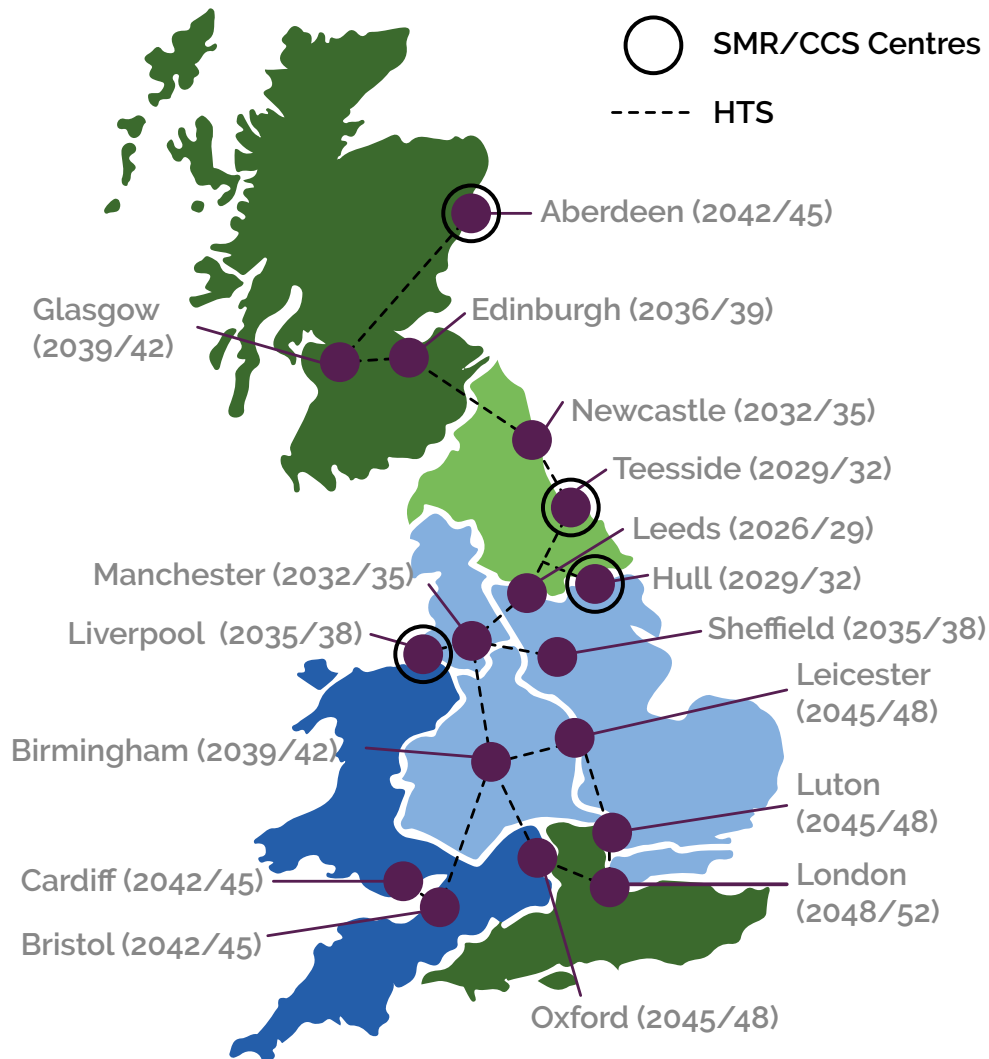


Image 11.1. H21 Rollout – Large City by City and HTS

This option is based on a future rollout strategy with the main objective being to convert major cities, providing big carbon benefits in a relatively short time whilst ensuring broad UK coverage to encourage wider benefits (transportation/electrification). As the hydrogen economy grows it would be possible to convert any smaller cities/towns along the HTS route corridor. Indeed a significant advantage of the hydrogen economy is it could accelerate or decelerate dependent on external factors. For example, alternative sources of hydrogen, finance/actual costs. **Image 11.1** is an indication of a strategy involving key cities covering about 30% of gas users. It should be noted that all other areas in this scenario could remain on a natural gas/biogas mix. Importantly, the existing high pressure natural gas network can remain in place for large industrial users such as power stations.



## Scaling Hydrogen Production and Storage Facilities

As part of any rollout strategy as well as 'where to convert' we also need to consider scaling the hydrogen production facilities (SMRs/Storage) and associated CCS infrastructure. As the hydrogen economy expands so does the requirement for additional production and storage. **Image 11.2** provides an overview of how this expansion could occur for a city by city rollout strategy.

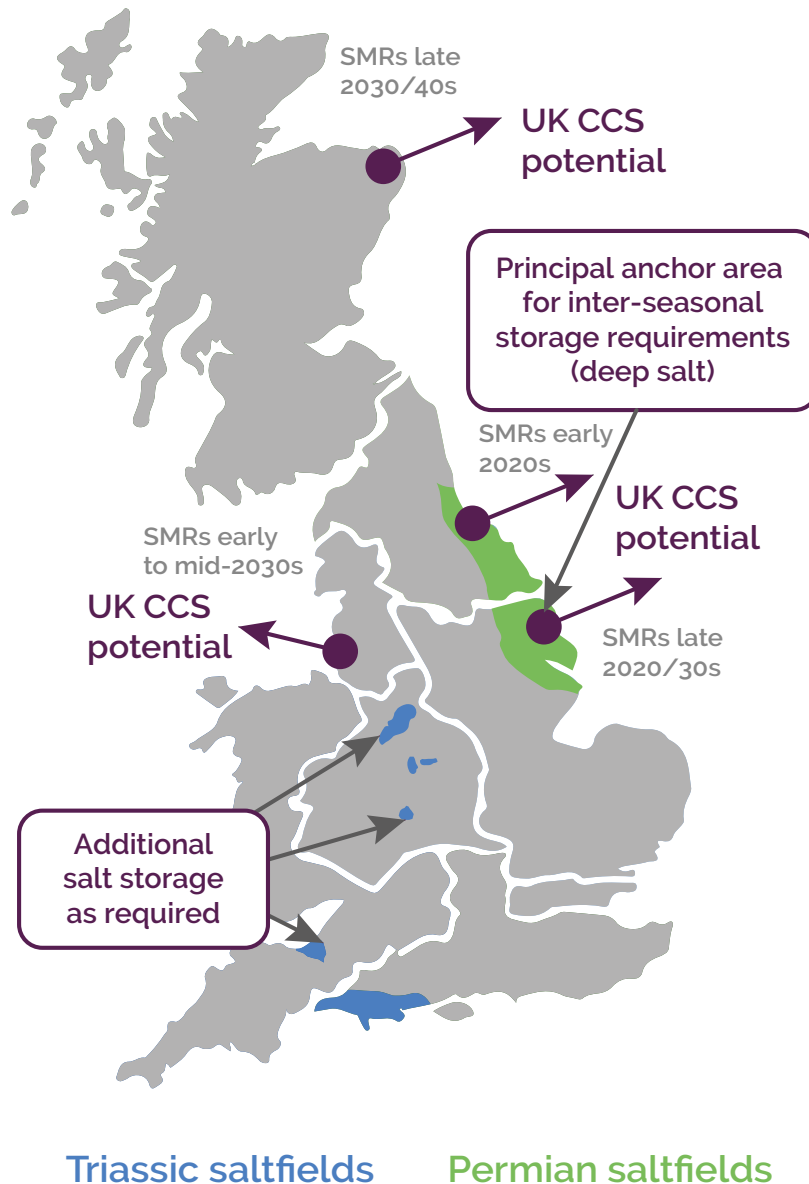


Image 11.2. *Hydrogen Production and CCS Expansion Over Time*

As the hydrogen economy grows the requirement for more hydrogen production infrastructure increases proportionately. Whilst this is significant it needs to be put into perspective and also re-iterated that this expansion would be over a long period of time, up to 40 years.

For illustrative purposes, **Image 11.3**, shows a significant increase in SMR production at the Teesside SMR and CCS location (one of the four – Teesside, Hull, Liverpool and Peterhead shown in **Image 11.2**). SMRs have been shown in addition to the existing facility. The configuration for such an extensive increase in hydrogen production, in reality, is likely to be a combination of larger and smaller plants taking advantage of economies of scale, increased efficiencies, space optimisation and operability to meet growing demand. Additionally this would be coupled with considerations for increased linepack within the expanding HTS and intraday/inter-seasonal storage as well as alternative sources of bulk hydrogen production (such as gasifiers).

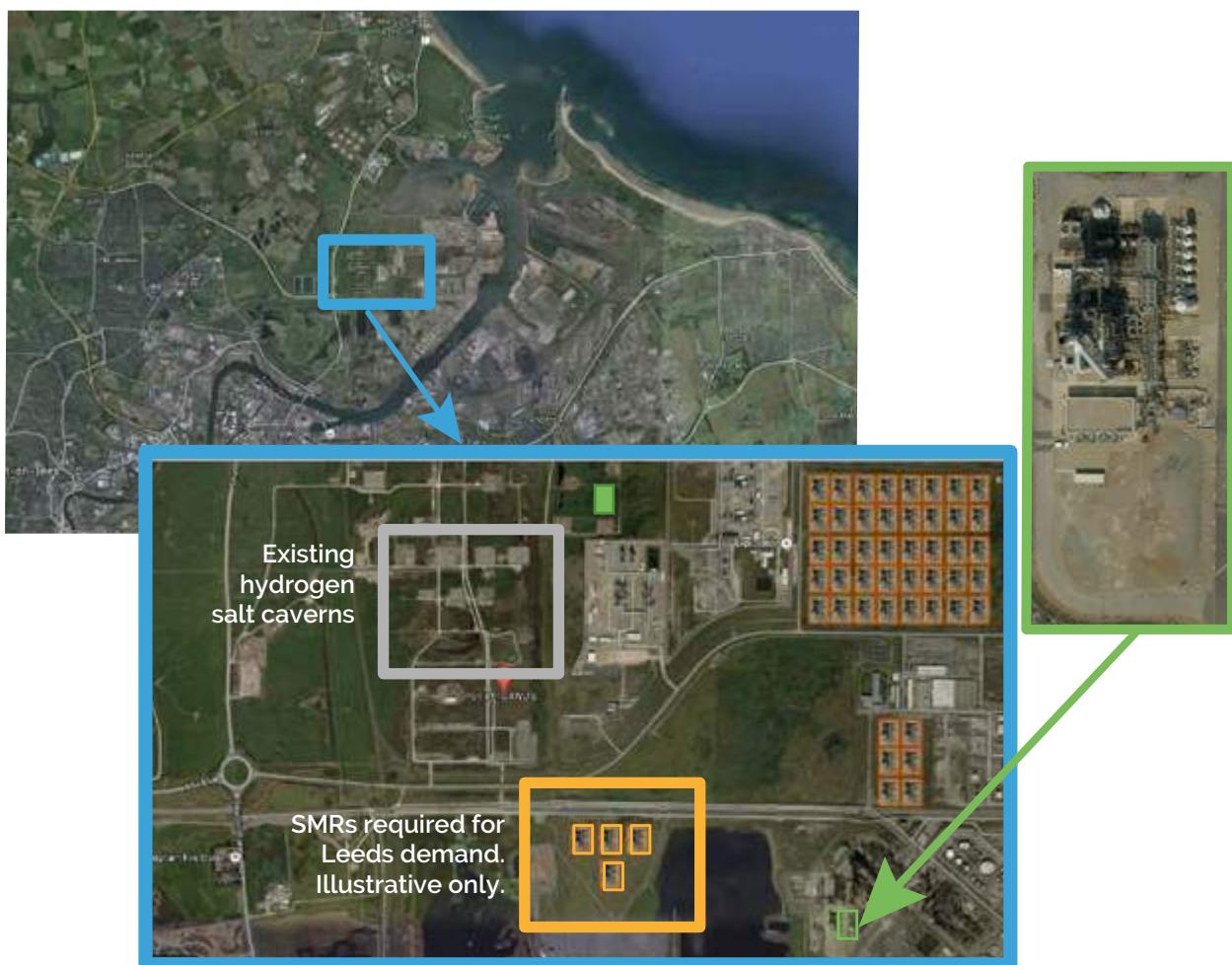


Image 11.3. *Increasing Hydrogen Production Capability at Teesside*

If such an expansion were to take place the impact on GVA in the local area for all the SMR/CCS centres would be dramatic.

## Increasing Intraday/Inter-seasonal Storage Facilities

One of the biggest challenges for decarbonising heat is being able to manage the significant intraday and inter-seasonal variations in demand profile. Whilst this has been determined for the area of conversion in the H21 Leeds City Gate project the options when undertaking a UK wide rollout need serious consideration to allow the optimised solution to be developed.

Storage of hydrogen is not a new concept or one which needs technical evidence. However as the hydrogen economy grows consideration of the type and size of storage that will be required needs to at least be conceptually developed in conjunction with the roll out strategy. We can assume with high levels of engineering confidence that there are effectively three deployed storage technologies applicable to hydrogen.

- Storage of gaseous hydrogen in pressurised containers (or linepack in pipelines).
- Storage of liquid hydrogen in refrigerated containers.
- Storage of gaseous hydrogen in underground formations (salt caverns and/or depleted hydrocarbon fields).

There are other technologies being considered but at readiness levels well below the established techniques or for low storage volume applications such as metal hydride technology.

## Inter-seasonal Storage

1. **Salt Cavern Inter-seasonal Storage** could be managed by incrementally increasing the caverns in the deep salt deposits in the Humber area on the Northeast coast. These are the deepest salt deposits in the UK and therefore represent the best opportunity for large scale storage.
2. **Depleted Gas Field Storage** whilst needing some more evidence that there is the potential to re-use existing hydrocarbon and natural gas storage sites for hydrogen storage if required. Indeed there is already a published paper considering the re-use of depleted gas storage fields in the International Journal of Hydrogen Energy 'Seasonal storage of hydrogen in depleted gas fields' which states 'There appears to be no insurmountable technical barrier to the storage of hydrogen in a depleted gas reservoir'.
3. **Cryogenic (Liquid) Storage** is likely to play a part in the overall system as the hydrogen conversion moves north and south within the country. Cryogenic storage offers significant opportunities for large scale storage as it is able to provide up to 600 times the storage by volume capacity of the equivalent ressurised storage options. It does however have the disadvantage currently of costs and efficiency losses some of which are thermodynamically unavoidable. The onset of cryogenic storage could be heavily impacted by hydrogen supply methods as the hydrogen economy expands (see **Section 11.3**).

## Intraday Storage

Intraday storage can be managed in a variety of ways as the hydrogen economy expands. Indeed the expansion makes the requirement to manage this demand swing significantly simpler than for a single city. An expanding HTS will provide large amounts of additional linepack potential that can be used to manage intraday storage, as is currently undertaken today in the UK gas industry.

Additionally this may be supplemented by salt cavern storage both at Teesside and across the salt deposits that run down the west side of the country as well as some localised high pressure storage near cities.



## Regulatory Finance Model (Option 1)

Whilst NGN have provided a detailed regulatory finance appraisal for the H21 Leeds City Gate conversion an indicative appraisal has been undertaken for the Option 1 UK wide rollout scenario.

In order to undertake this analysis the following assumptions have been made. It is accepted that this is a somewhat crude methodology and will have some errors but in terms of presenting an 'order of magnitude' representation of an incremental rollout it is considered reasonable.

**It is also worth considering that these costs are entirely associated with the hydrogen rollout but do not consider:**

- Impact on GVA.
- Impact of smoothing out natural gas demand for the UK which could remove higher winter costs, i.e. a relatively flat demand as hydrogen production still occurs in summer.
- Offset costs for alternative decarbonisation strategies, for example:
  - Large costly district heat schemes in cities due for conversion would no longer be required.
  - Electrical generation system requirements associated with decarbonising heat will no longer be required.
  - Decommissioning costs and financial compensations associated with the 'turning off' of the gas network will not be required.

Costs have been extrapolated as per **Table 11.1** presented below.

City	TIMELINE		APPLIANCE CONVERSION			HYDROGEN TRANSMISSION SYSTEM			HYDROGEN PRODUCTION		HYDROGEN STORAGE		Total (£m)				
	Year Start	Year Finish	Population guesstimate (In area to convert in millions)	Proportional variation from Leeds	Carbon capture using proportional variation mtcarbon year	Appliance conversion (£m)	Appliance conversion efficiency factor	Appliance conversion costs (£m)	HTS approximate length (miles)	Adjusted HTS Costs	Additional Compression	HTS Costs (£m)		SMR Plant	Salt Caverns	Adjustment for alternative sources/ intraday linepack with HTS	Storage Costs (£m)
Leeds	2026	2029	0.66	1.00	1.50	1,053	1.00	1,053	120	230	0	230	395	366	1	366	2,044
Teesside (Greater Area)	2029	2032	0.56	0.85	1.28	895	1.00	895	0	0	0	0	336	311	1	311	1,542
Kingston Upon Hull (City)	2029	2032	0.26	0.39	0.59	411	0.90	370	0	0	0	0	154	143	1	143	666
Newcastle (Greater Area)	2032	2035	1.12	1.69	2.54	1,780	0.90	1,602	55	105	30	135	668	618	1	618	3,023
Manchester (Greater Area)	2032	2035	2.41	3.65	5.48	3,843	0.81	3,113	45	86	30	116	1,442	1,335	0.95	1,268	5,939
Sheffield (City)	2035	2038	0.56	0.85	1.28	895	0.73	652	25	48	0	48	336	311	0.95	295	1,331
Liverpool (Greater Area)	2035	2038	1.71	2.59	3.89	2,727	0.73	1,988	35	67	0	67	1,023	947	0.95	900	3,978
Edinburgh (City)	2036	2039	0.49	0.75	1.13	790	0.73	576	120	230	30	260	296	274	0.95	261	1,393
Glasgow (Greater Area)	2039	2042	1.14	1.73	2.60	1,822	0.73	1,328	46	88	0	88	683	633	0.95	601	2,701
Birmingham (greater Area)	2039	2042	2.81	4.25	6.38	4,475	0.66	2,936	70	134	30	164	1,679	1,554	0.9	1,399	6,178
Bristol (City)	2042	2045	0.44	0.67	1.01	706	0.66	463	100	192	30	222	265	245	0.9	221	1,170
Cardiff (City)	2042	2045	0.35	0.54	0.81	569	0.66	373	40	77	0	77	213	197	0.9	178	841
Aberdeen (City)	2042	2045	0.23	0.35	0.53	369	0.66	242	145	278	30	308	138	128	0.85	109	797
Leicester (City)	2045	2048	0.34	0.51	0.77	537	0.66	352	44	84	0	84	201	187	0.85	159	797
Luton (City)	2045	2048	0.21	0.32	0.48	337	0.66	221	70	134	30	164	126	117	0.85	99	611
Oxford (City)	2045	2048	0.16	0.24	0.36	253	0.66	166	80	153	0	153	95	88	0.85	75	489
London (Greater Area)	2045	2052	8.54	12.91	19.37	13,594	0.59	8,027	20	38	0	38	5,099	4,721	0.85	4,013	17,178
<b>Totals</b>			<b>22.00</b>					<b>24,357</b>				<b>2,155</b>	<b>13,150</b>			<b>11,013</b>	<b>50,676</b>

Table 11.1. CAPEX Costs per City



CAPEX costs per city have been calculated by adding appropriate factors in two areas:

- The population size of each city against the population covered by the area of conversion in H21 Leeds City Gate.
- A range of increased efficiency factors against appliance conversion and storage as identified in the table.
- Costs associated with storage are based on salt caverns but could significantly reduce if repurposing of existing gas storage facilities (such as Rough) could be undertaken.
- No account has been taken of the offset in capital costs from alternative sources of hydrogen e.g. by-product, electrolysis, liquid hydrogen, gasification.
- No account has been taken of reducing SMR costs through economies of scale.



City	TIMELINE		CARBON CAPTURE (MT CARBON/YEAR)					SMR/SALT CAVERNS			
	Year Start	Year Finish	Population guesstimate (In area to convert in millions)	Proportional variation from Leeds	Carbon capture using proportional variation mtcarbon year	CO <sub>2</sub> £ per tonne per city	Sequestration Charge Cumulative Annual CO <sub>2</sub> Cost (£m)	Maintenance SMR/Salt Caverns efficiency adjustment	Annual Maintenance Costs per City	Cumulative Maintenance Costs (£m) per annum	Total
Leeds	2026	2029	0.66	1.00	1.50	40	60	4	31	31	139
Teesside (Greater Area)	2029	2032	0.56	0.85	1.28	40	111	4	26	57	257
Kingston Upon Hull (City)	2029	2032	0.26	0.39	0.59	30	129	4	12	69	305
Newcastle (Greater Area)	2032	2035	1.12	1.69	2.54	20	179	4	51	120	488
Manchester (Greater Area)	2032	2035	2.41	3.65	5.48	15	261	3	81	201	827
Sheffield (City)	2035	2038	0.56	0.85	1.28	14	279	3	19	220	904
Liverpool (Greater Area)	2035	2038	1.71	2.59	3.89	13	330	3	58	278	1,137
Edinburgh (City)	2036	2039	0.49	0.75	1.13	12	343	3	17	295	1,203
Glasgow (Greater Area)	2039	2042	1.14	1.73	2.60	12	374	2	26	320	1,343
Birmingham (greater Area)	2039	2042	2.81	4.25	6.38	12	451	2	62	382	1,685
Bristol (City)	2042	2045	0.44	0.67	1.01	11	462	2	10	392	1,738
Cardiff (City)	2042	2045	0.35	0.54	0.81	11	471	2	8	400	1,780
Aberdeen (City)	2042	2045	0.23	0.35	0.53	11	477	1.5	4	403	1,807
Leicester (City)	2045	2048	0.34	0.51	0.77	11	485	1.5	5	409	1,845
Luton (City)	2045	2048	0.21	0.32	0.48	11	490	1.5	3	412	1,869
Oxford (City)	2045	2048	0.16	0.24	0.36	11	494	1.5	3	415	1,887
London (Greater Area)	2045	2052	8.54	12.91	19.37	10	688	1	91	506	2,792
<b>Totals</b>			<b>22.00</b>				<b>6,084</b>			<b>4,909</b>	<b>22,004</b>

Table 11.2. OPEX Costs per City

As with CAPEX costs OPEX costs per city have been calculated by adding appropriate factors in two areas:

- The population size of each city against the population covered by the area of conversion in H21 Leeds City Gate.
- A range of increased efficiency factors associated with economies of scale in OPEX areas.

No account has been taken of the offset in operational costs from alternative sources of hydrogen, e.g. by-product, electrolysis, liquid hydrogen, gasification.



**Table 11.3** shows the rollout profile and the associated CAPEX/OPEX costs of converting each city. In total the CAPEX investment needed is £26 bn and the OPEX conversion expenditure is £24 bn, with annual OPEX costs thereafter of circa £2.8 bn per year.

Illustrative Rollout Profiles 16/17 Prices	CAPEX			OPEX	
	Years	Total CAPEX Investment (£m)	Conversion Years	Labour & Appliances OPEX Costs (£m)	Annual OPEX Costs (£m)
Leeds	20-25	991	26-28	1,053	138
Teesside	26-28	647	29-31	895	117
Kingston Upon Hull	26-28	297	29-31	370	48
Newcastle	29-31	1,421	32-34	1,602	183
Manchester	29-31	2,826	32-34	3,113	337
Sheffield	32-34	679	35-37	652	77
Liverpool	32-34	1,990	35-37	1,988	231
Edinburgh	33-35	817	36-38	576	66
Glasgow	36-38	1,373	39-41	1,328	139
Birmingham	36-38	3,242	39-41	2,936	340
Bristol	39-41	707	42-44	463	53
Cardiff	39-41	468	42-44	373	42
Aberdeen	39-41	555	42-44	242	27
Leicester	42-44	444	45-47	352	38
Luton	42-44	390	45-47	221	24
Oxford	42-44	323	45-47	166	18
London	42-44	9,151	49-51	8,027	899
<b>Total</b>		<b>26,318</b>		<b>24,357</b>	<b>2,779</b>

Table 11.3. *Illustrative Rollout Profile 2016/17 Prices*

The following analysis highlights what the above expenditure means to customer bills, under both of the options previously presented.

As with the financial modelling of H21 Leeds City Gate two regulatory finance models have been presented under two options – Option 1 being under the current regulatory fast/slow methodology and Option 2 treating the conversion OPEX costs all as slow money. This is followed by a holistic view of the actual impact in the customers bill.

### Option 1: Using the Current Fast/Slow Money Logic

Chart 11.1 shows the revenues as a result of converting each city. This follows a similar profile as shown in [Section 8, Finance and Regulation](#), with a large spike in revenues needed initially to fund the appliance and labour costs with ongoing revenue streams after for annual OPEX costs.

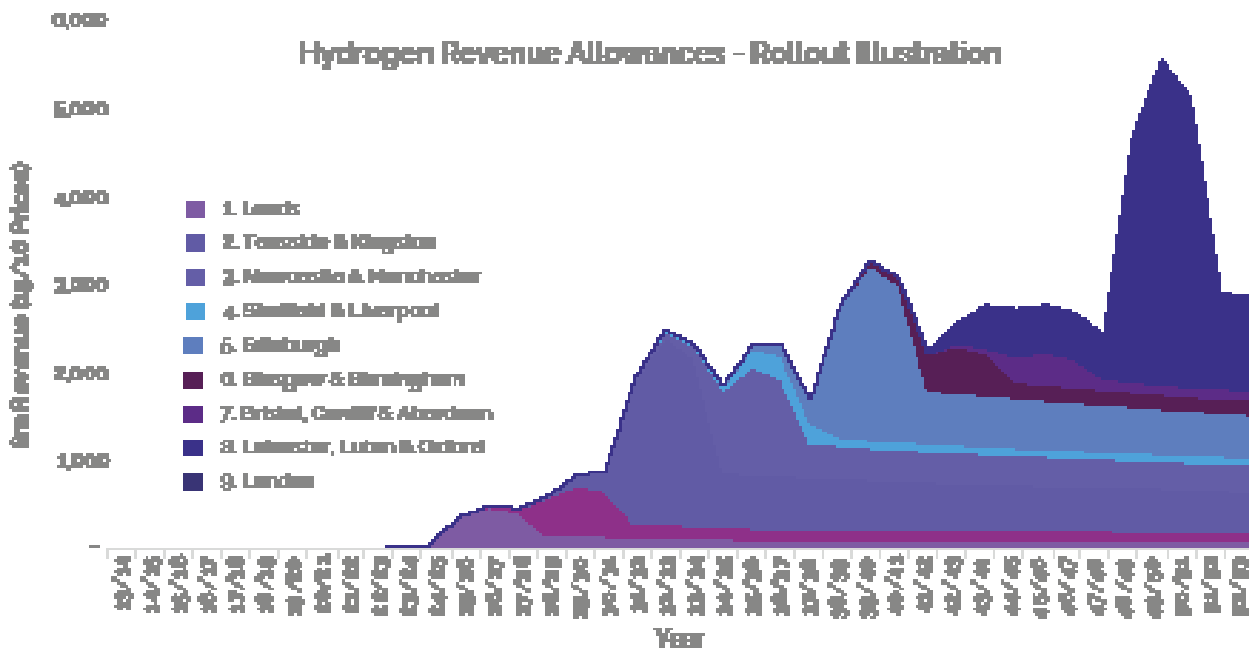
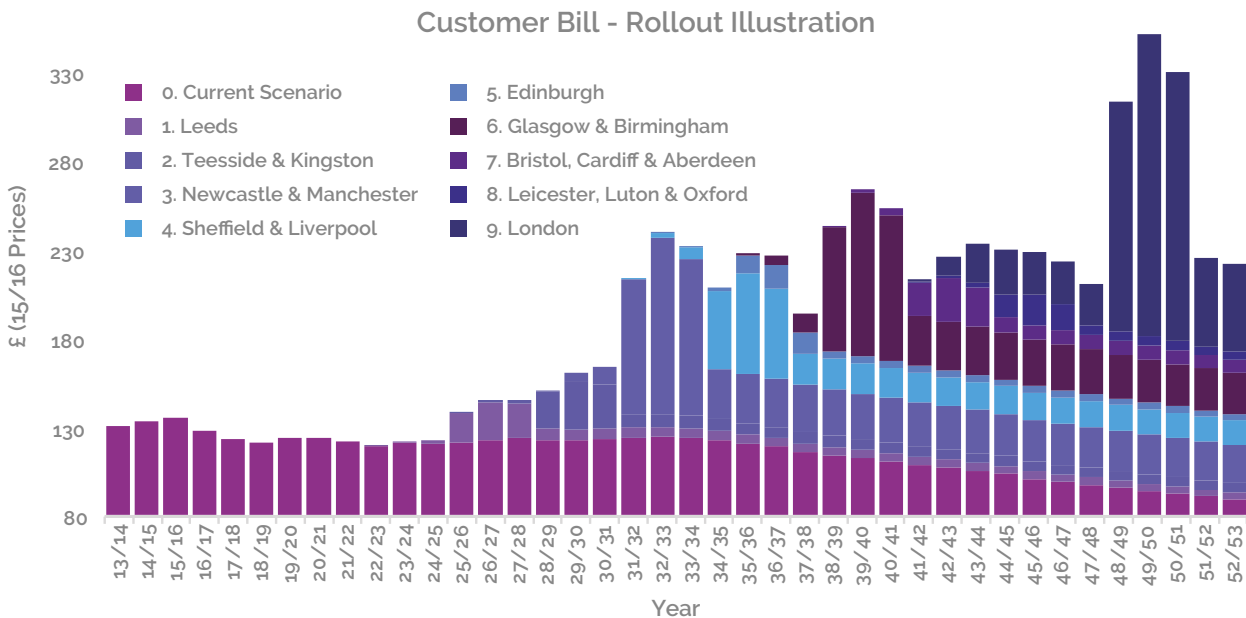


Chart 11.1. *Option 1 Hydrogen Revenue Allowances – Rollout Illustration*

- With the exception on converting London revenue allowances under this methodology would peak at £3.2 bn in regulatory Year 2039/40. Every time a city is converted there is the initial spike for conversion costs then followed by on-going OPEX maintenance costs and CAPEX monies returned over a 45 year period.
- The impact on customer bills follows a similar trend with the above monies being spread across all UK users and added on top of the current scenario as shown in **Chart 11.2**.
- The REPEX programme is completed by 2032, but there isn't an immediate drop as the costs are funded over a 45 year period. As in **Chart 11.2** there is a gradual drop in bills from 2033, but this isn't enough to offset the hydrogen programme if the rollout was funded in this way. It should be noted that these costs are only for the transportational element of the bill.



**Chart 11.2. Option 1 Customer Bill – Rollout Illustration**

## Option 2: An Alternative Option to Potentially Reduce the Spike in Bills

As described in [Section 8, Finance and Regulation](#) an alternative method could be used to fund the large scale implementation costs as slow money returned to GDNs over a 45 year period. The main differences with this approach is that it pushes income into the future rather than an initial spike. As stated in [Section 8, Finance and Regulation](#) this in an illustration only and much wider factors around network financeability would need to be considered.

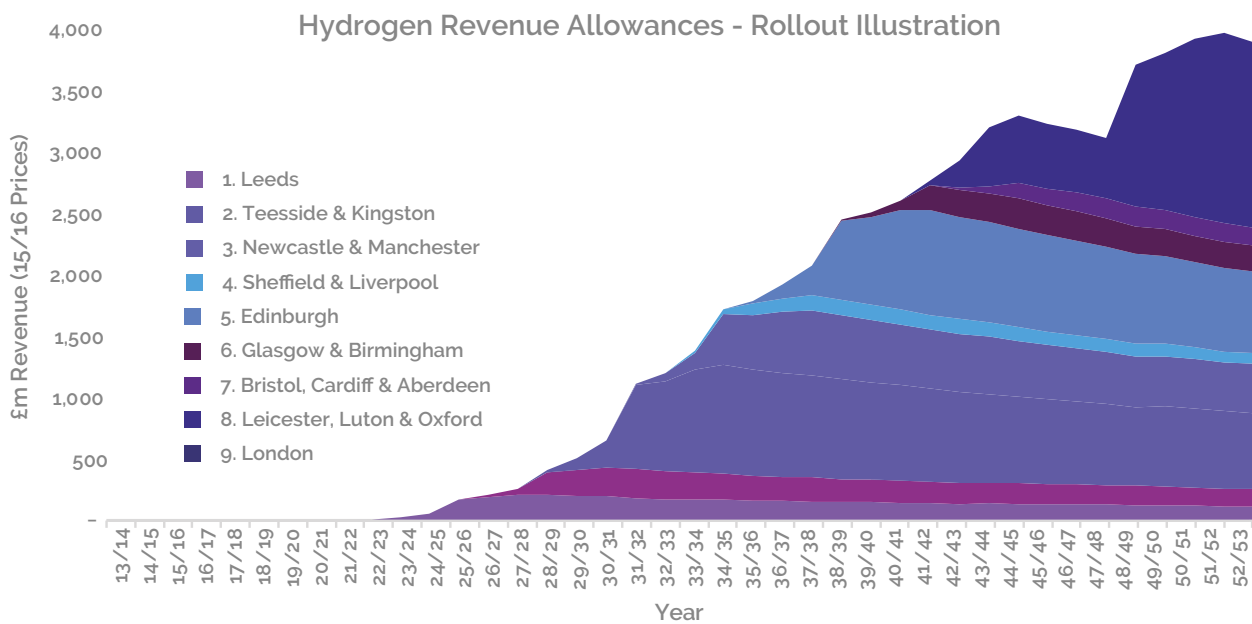


Chart 11.3. *Option 2 Hydrogen Revenue Allowances – Rollout Illustration*

- With a large scale rollout programme there is still a significant impact on customer bills if funded in either mechanism. Even under Option 2 in the peak years the GDN element of a customer bill would increase by circa £153 as shown below (excluding London period).

### Customer Bill - Rollout Illustration

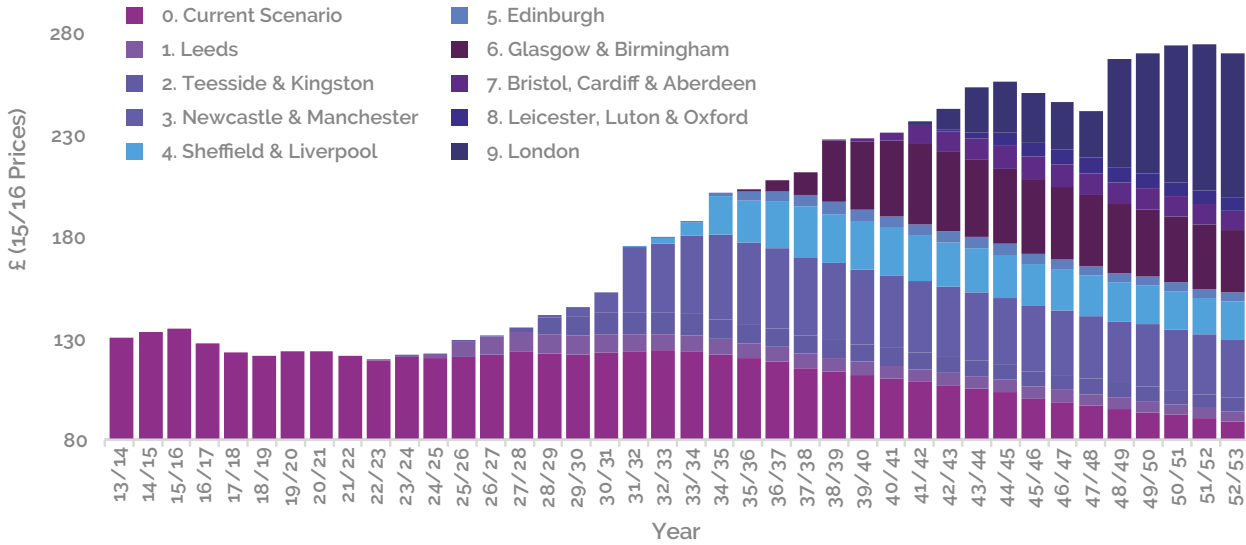


Chart 11.4. Option 2 Customer Bill (Transportation Element Only) – Rollout Illustration

The difference in customer bills between the two options is shown below (transportational part of bill only):

### GDN Customer Bill Difference Between Options 1 and 2

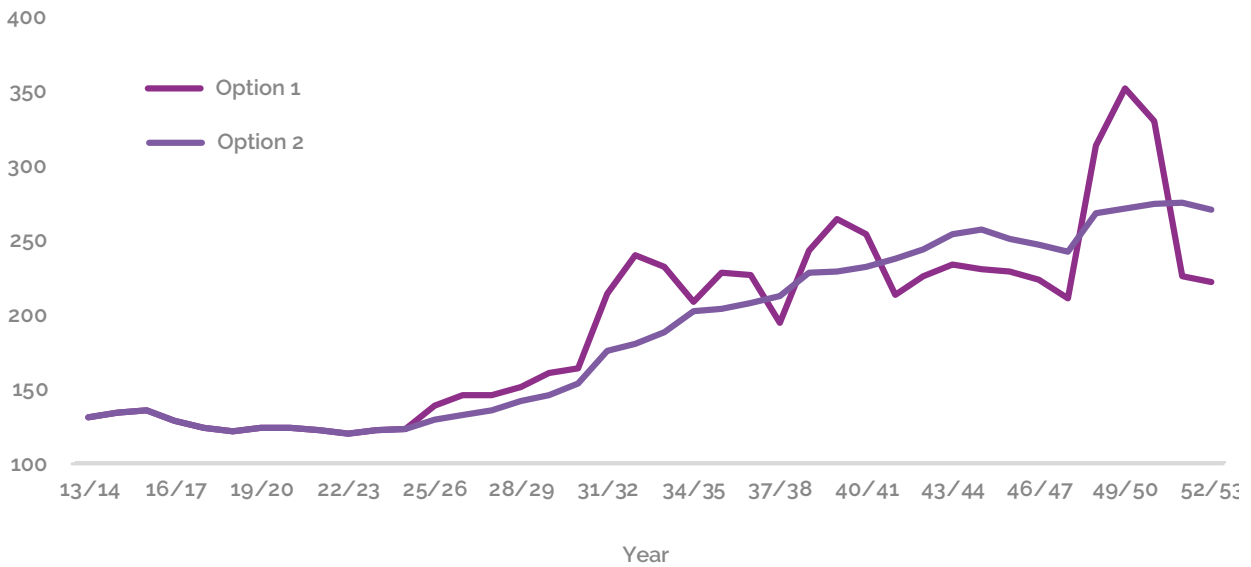


Chart 11.5. GDN Element of Customer Bill – Difference Between Options



## Impact with Long Term Efficiency Savings on the Total Customer Gas Bill

The analysis shows the increase in the GDN expenditure needed as a result of hydrogen implementation; it does not take into account any changes in other areas of the total customer bill.

To demonstrate this percentage efficiency savings in the overall bill have been projected against the increase in regulatory expenditure to provide a view of net impact over time. As in [Section 8, Finance and Regulation](#) the efficiency savings have been assumed as follows.

	2016-30	2030-35	2035-40	2040-45	2045-50	2050+
<b>Saving from current</b>	0.00%	3.00%	6.00%	9.00%	12.00%	15.00%

Table 11.4. *Energy Efficiency Savings Over Time*

(Currently gas bills are circa £750 per annum).

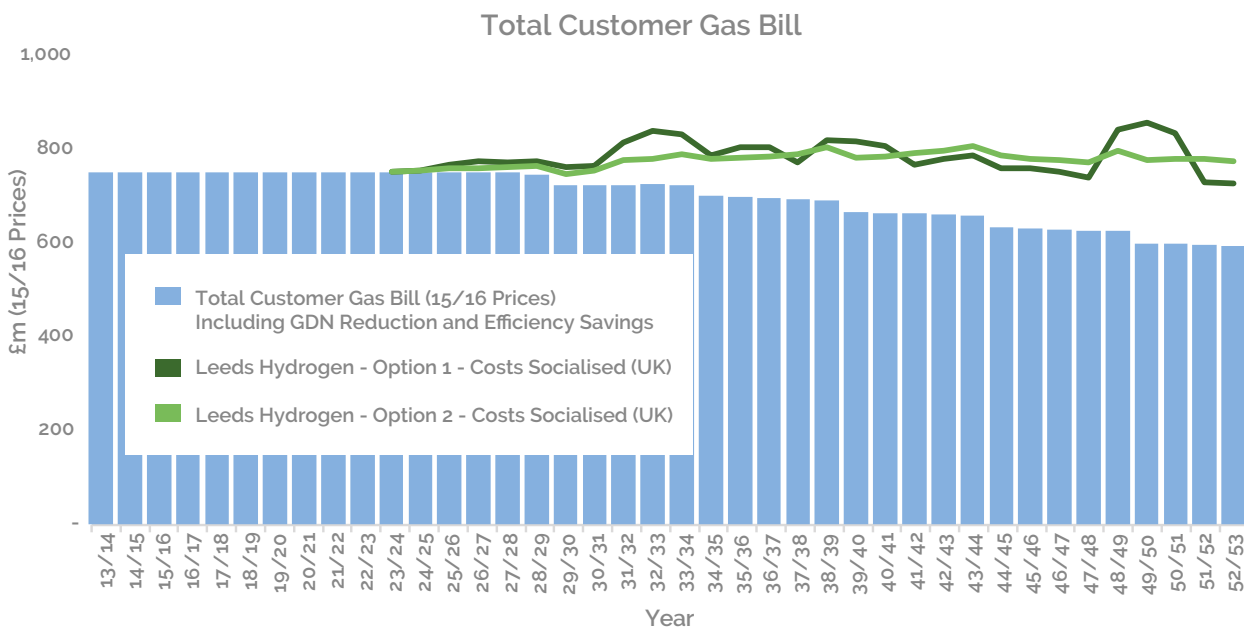


Chart 11.6. *Total Customer Gas Bill*

(15/16 prices)	RIIO-GD1	RIIO-GD2	RIIO-GD3	RIIO-GD4	RIIO-GD5
Total gas bill (as per section 2') (£)	750	749	713	665	611
Revised total gas bill – Option 1 (£)	750	761	800	788	779
Change %	0.0%	1.5%	12.1%	18.4%	27.5%
Hydrogen rollout bill impact Option 2 (£)	-	6	59	126	167
Revised total gas bill – Option 2 (£)	750	756	773	792	778
Change %	0.0%	0.9%	8.3%	19.0%	27.3%

Table 11.5. *Total Gas Bill*

Section 2 total gas bill shows customer bill inclusive of both GDN savings

- After including efficiencies in the total customer bill and a full scale hydrogen rollout customer bills would increase over the 30 year period by circa 15% in Option 1 and circa 14% under Option 2.
- The peak year under Option 1 is 49/50 @at £855 per annum and under Option 2 is 43/44 @ at £806 per annum.
- It is worth noting that whilst Option 2 will remove any initial spikes, it is pushing more income and charges for the customer into later years.
- The % reduction applied in the non-distribution element of the customer bill is a key part of this analysis and is a large factor in mitigating the impact of a hydrogen rollout.

## Key Messages:

- With a large scale rollout programme there is a significant impact in the **GDN element of customer bills** over the longer term under either of the options in line with the current regulatory funding framework. Option 1 has an initial spike on implementation whilst Option 2 has a gradual increase over time.
- To implement a large scale rollout programme there would need to be a full review of alternate funding mechanisms to minimise the customer bill impact whilst also considering networks financeability issues.
- However this analysis excludes any other impacts customers will be facing over the longer term – i.e. if we 'do nothing' how much additional cost will customers be facing vs. the hydrogen costs above, i.e. air quality penalties passed on to all UK customers, electrification of heat etc.
- The **total customer bill when applying an assumed efficiency saving** shows levels circa 15% above current levels when a UK hydrogen rollout programme is completed. A 3% saving is assumed from 2030 growing to a 15% saving by 2050 due to energy efficiency measures which helps partially offset the GDN hydrogen bill increase.



### 11.1.2. Option 2 – Regional Rollout

This second is less ambitious and is based on a conversion of 90% of the 2.6 million customers within NGN.



Image 11.4. *UK Gas Distribution Networks*

This could include conversion of most of Berwick on Tweed, Rothbury, Carlisle, Whitehaven, Haltwhistle, Sunderland, Morpeth, Newcastle, Gateshead, Durham, South Shields, Darlington, Hartlepool, Middlesbrough, Harrogate, York, Bradford, Leeds, Halifax, Ripon, Hull, Goole, Wakefield, Barnsley, Hebden Bridge and Todmorden.

This area contains approximately 6 million people, i.e. roughly the population of Denmark or Finland. It therefore offers a technology suitable for worldwide role out. Conversion of local transport to hydrogen would reduce the cost per kWh of hydrogen delivered. Assuming that the SMR reactors were placed at Teesside, then carbon dioxide to CCS would be about 13 million tonnes/year. This is projected to be sufficient volume to reduce the cost of CO<sub>2</sub> disposal to £10/tonne.

## Scaling Hydrogen Production and Storage Facilities

As part of a regional rollout strategy we also need to consider the hydrogen production facilities (SMRs/Storage) and associated CCS infrastructure. As the hydrogen economy expands so does the requirement for additional storage and production. For a regional approach like this it is likely that the hydrogen production facilities identified in **Image 11.2** would only occur at Teesside and the Humber area as the hydrogen economy in this scenario would not reach the Liverpool and Peterhead CCS/industrial centres.

## Scaling Intraday/Inter-seasonal Storage Facilities

As with Option 1 the storage requirements for both intraday and inter-seasonal demand would likely be a combination of available storage technologies but anchored with the original salt cavern concept. If re-purposing of the Rough natural gas storage facility to hydrogen could be undertaken and/or use of various depleted hydrocarbon storage sites in the area could be developed this could significantly decrease the costs.



## Capital Costs (Option 2)

Simple extrapolation from the H21 Leeds City Gate model (about 260,000 connections) would indicate a capital investment of the following;

- Total number of NGN customers = circa 2,600,000
- Converting 90% of those customers = 2,340,000

## Conversion of Appliances

- H21 Leeds City Gate costs for conversion of appliances = £1,053 m (for 260,000 connections)
- Therefore 2,600,000 connections = 10,530 m @ 90% = £9,048 m

## Hydrogen Infrastructure (SMRs/Salt caverns/HTS)

- H21 Leeds City gate costs for conversion of appliances = £1,000 m (for 260,000 connections)
- Therefore 2,600,000 connections = 10,000m @ 90% = £9,000 m

## Total costs for Option 2

Item	Cost (£)
Appliance conversion 90% all NGN customers	£9,048,000,000
Hydrogen infrastructure	£9,000,000,000
<b>Total</b>	<b>£18,048,000,000</b>

Table 11.6. *Total Capital Costs Regional Rollout*

Note, these figures take no account of economies of scale, alternative storage etc.

By comparison this investment is very similar to the Hinckley C nuclear power station, but provides full 'well to sofa' conversion. The nuclear power station option excludes the cost of any inter-seasonal storage, power transmission/distribution infrastructure or the conversion of homes and industry to electric heating. Preliminary design works could be started in 2018 and conversion finished by the mid 2030s.

### 11.1.3. Hydrogen Economy Rollout, Additional Considerations

When designing a rollout strategy like this the following additional considerations would need to be resolved:

- What high pressure industrial users, currently connected to the high pressure (above 7 bar) natural gas network, could be converted to hydrogen along the HTS route corridor. Or, should these users be retained on the natural gas local transmission system until their operation is due for upgrade as part of a normal plant lifecycle costs.
- Should the major cities rollout, option one, have provision for parallel conversion of smaller cities and towns. For example at the same time as converting Sheffield/Liverpool also retrospectively start converting Wakefield/Dewsbury etc. in the West Yorkshire area. This could support maintaining local conversion work force levels whilst also allowing national coverage as quickly as possible.
- Should a strategy focus on major cities (Option 1) or major urban centres (Option 2) or both? For example all of West Yorkshire (Leeds/Bradford/Wakefield/Dewsbury/Huddersfield/Castleford/Halifax etc.), then all of the North West, (Manchester/Stockport/Rochdale/Bolton/Wigan/Blackburn/Preston etc.). This may reduce overall costs for conversion as the work is focused in strategic areas. It could also significantly delay reaching the two largest cities, Birmingham and London, due to resources availability and practical considerations for UK pipelining and SMR/storage design and build timelines.
- Should a conversion strategy consider the installation of Micro-CHP units where appropriate as part of a 'part/contributory funded' option for customers? This could rapidly accelerate the uptake of this technology whilst providing a real economic benefit to customers in converted areas. It would also accelerate the wider decarbonisation of electricity through offsetting generation requirements and removing the 7% network losses.
- Could the HTS be designed and built as quickly as possible down to London along the route identified in **Image 11.1**. This may allow accelerated connection of hydrogen refuelling stations and therefore the onset of hydrogen vehicles. Effectively this would mean building all the hydrogen transmission network first alongside a slower city by city conversion programme. This option may not be seen as appropriate as it may not provide a no regrets incremental rollout. If, in the unlikely event the conversion was halted half way down the country, the HTS could be significantly oversized and underutilised.
- Having a much larger HTS designed for future expansion could significantly offset the requirement for intraday storage as linepack availability becomes more viable.

There are of course many variations of how a rollout strategy could be established and this needs significant consideration guided by practical industry involvement over the next few years.

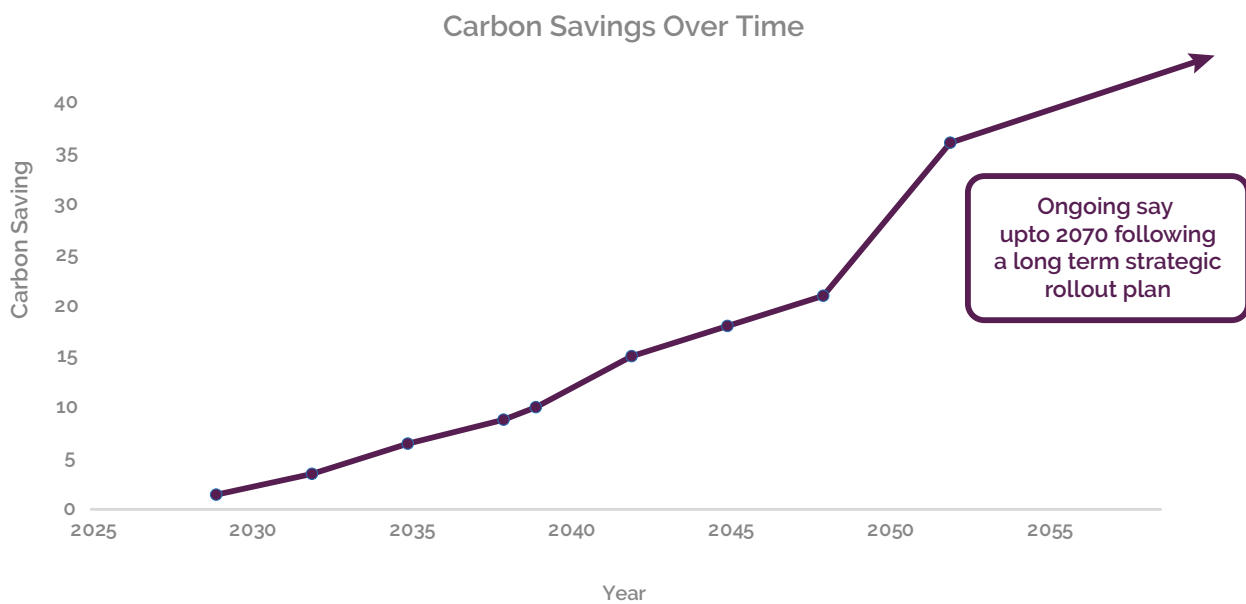
The above considerations are very much gas industry lead, but it may well be appropriate to consider the implications of availability of CCS. The assumption of this report has very much been that CO<sub>2</sub> sequestration is available 'over the fence' as and when required. A recent report by the ETI (Progressing Development of the UK's Strategic Carbon Dioxide Storage Resource a Summary of Results from the Strategic UK CO<sub>2</sub> Storage Appraisal Project April 2016) highlights that between 3 and 5 million tonnes per year of CO<sub>2</sub> is required for cost effective disposal at between about £11 and £17/tonne. Leeds will produce about 1.5 million tonnes of CO<sub>2</sub>/year, so ideally the planned conversion soon after of Newcastle or Sheffield would reach this number which really starts to offer the economies of scale. SMR from natural gas with the subsequent storage of hydrogen can provide an advantageously constant level of CO<sub>2</sub> for disposal.

Appliance conversion will become logistically easier and significantly cheaper as lessons are learnt from the early cities and hydrogen compatible (HySwitch) and/or dual fuel appliances begin to take a firm foothold in the market. To allow flexibility in a rollout programme it is critical that the HTS is designed in a way to ensure it is 'broadly' future proof. For example retrospective conversion of cities would be easily achievable providing connection points from the HTS to these cities (or regions) have already been put in place and the HTS pipes have been sized accordingly.

It has been established that the start of the hydrogen economy practically needs to be in the north of England making use of the salt caverns for inter-seasonal storage, CCS availability and chemical heartlands. It could then expand West/South/North to suit any strategy, including as many (or as few) urban areas as desired bearing in mind practicalities of workforce availability and logistics.



**Chart 11.7** shows how decarbonisation of heat can be achieved over time. The gradient of the graph will be determined by the rollout strategy underpinned by the requirement for higher or lower levels of decarbonisation which can be determined by the funding availability. When considering a rollout strategy too high a rate may be bad as it will overload suppliers and training, and lessen learning. Too slow and the execution fails to impact 2050 target or even the Paris Agreement timescale. A slow rate may not support supplier and skills or may not drive product innovation and new business plans.



**Chart 11.7. Carbon Savings Over Time**

## 11.2. The Impact of Other Forms of Decarbonised Gas

When considering a future rollout strategy we must also consider the potential expansion in the availability of the 'bio' forms of methane. These primarily may include:

1. Bio-methane produced through anaerobic digestion.
2. Bio-SNG – produced via 100% black bag waste gasification.
3. Bio-gas produced via gasification with associated carbon capture and use of bio fuel feedstock. This option is considered less likely due to availability of the feedstock. Additionally if the UK were developing a hydrogen economy the gasifier would be more beneficial producing hydrogen.

If there is a significant rise in the availability of decarbonised methane supplies it may be appropriate that the conversion to hydrogen only includes the major cities as presented in Option 1. It should be noted however that the process for bio-SNG production in the first shift reaction produces hydrogen. This is then 'upgraded' to methane in a process which loses an addition 16% of the energy. It would seem more sensible to use black bag waste gasification to produce hydrogen to add to a hydrogen economy than methane.

The incremental nature of the hydrogen conversion rollout allows the strategy to be amended and modified to react to new technologies, or significant shifts in availability of bio-methane supplies (say up to 15% of UK gas demand) which may or may not become available.

It is important to remember that the strategy adopted needs to meet the challenge of the Climate Change Act, i.e. an 80% reduction in carbon emissions by 2050. To achieve this all UK gas consumers do not need to be converted to hydrogen and indeed the overall UK strategy needs to consider all the energy requirements from a UK gas mix, for example:

If the UK gas demand landscape in 2050 is comprised of the following:

- 60% hydrogen.
- 10% bio-methane.
- 30% natural gas.

This mix could still meet (or surpass) the challenge of the climate change act when considering the whole energy system. For example as well as low carbon heat areas to consider would be:

- Transportation (offsetting diesel/petrol emissions)
  - What is the uptake in hydrogen vehicles?
  - What is the uptake in methane fuelled vehicles?
  - What are the other opportunities within the hydrogen economy (ferrys, trains, planes etc.).
- Electrification
  - What is the uptake in local generation from hydrogen, i.e. Micro-CHP offsetting national generation requirements and removing 7% losses in the electrical networks?
  - National generation; what is the UK position on hydrogen fuelled CCGTs supporting decarbonisation of electric generation.
- Energy efficiency – what percentage reduction in net energy requirement has the UK achieved?
- Additional gas grid users. As the costs of regulatory finance are shared by all customers connected to the grid increasing grid demand (for example for road transport and local electric generation) will further reduce the cost impact in the overall bill of a hydrogen conversion, more users of the gas grid results in more ability to share the cost of conversion?

Additionally after the 2050 target the hydrogen economy can still continue to grow and hydrogen generation may have become available from alternative sources around the world. This is discussed further in **Section 11.3**.



## 11.3. Hydrogen Production – Market ‘Push and Pull’

In order to start the decarbonisation of heat through hydrogen conversion the only viable way is to produce the large amounts of hydrogen required through steam methane reformation. However, as the rollout of the hydrogen economy grows there will be other options that could become available.

### The Market-push Effect

Thinking about this simplistically, a significant barrier to a hydrogen economy is mass hydrogen availability at point of use. In order to address this issue government policy is required, in the same way it was required for the original towns gas to natural gas conversion, to effectively ‘push’ the UK energy market towards a hydrogen conversion, For example, a policy statement could be:

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***‘The UK is committed to an incremental hydrogen conversion. This will be in line with the strategy being developed for a hydrogen conversion programme rollout up to 2050. The heating fuel in the gas grids within the areas identified for conversion will be a gas of 99.9% purity hydrogen’***

Having generated this initial push which could then be managed and funded through regulatory business plans, see [Section 8, Finance and Regulation](#) there could

be a retrospective market pull across the hydrogen supply chain as certainty of a hydrogen economy would have been established.

### The Market-pull Effect

Once a definite move towards a hydrogen economy is established it would inevitably create a retrospective market pull both nationally and globally. This market pull is likely to affect all ends of the hydrogen supply chain including hydrogen production and hydrogen utilisation technologies. Hydrogen utilisation technologies would include anything and everything that can be fuelled via hydrogen. This is not discussed further in this report but more detail can be found in Innovate UK’s 2016 hydrogen roadmap project.



## Supplementary Hydrogen Production

Hydrogen can currently be produced in circa 20 ways which vary in terms of volume, cost and technology readiness levels. The decarbonisation of heat via hydrogen is most practically achieved with Steam Methane Reformers (SMR) as the principal source. However, as the hydrogen economy grows there will be additional hydrogen production methods including those currently available and those not yet commercially developed that are likely to contribute. Some examples are provided below.

- **By-Product hydrogen:** A number of production methods rely on another required product, such as in refineries and chlor alkali plants. Locally this may be economic but is not a secure supply. Such a process, if without embodied CO<sub>2</sub> is ideal, but is dependent on the viability of the primary process. As the hydrogen economy grows areas with significant by product hydrogen availability (generally larger industrial areas including Teesside, Liverpool and Grangemouth) will be able to utilise their hydrogen by injecting it directly into the hydrogen gas grid system. This could become an additional resource and will provide a supplementary supply which can help support/offset capital costs of SMRs and storage requirements.
- **Electrolysers:** Whilst not currently economic or low carbon when supported by the deep pool of the current UK electricity grid, electrolysers remain an option in a portfolio of hydrogen supply for a hydrogen distribution system. For example a low cost, offshore wind farm of gigawatt scale may find that rather than sell electricity it should export its energy in the form of piped hydrogen to a hydrogen grid with its intrinsic energy storage. This is likely to offer significant balancing capability to a decarbonised electricity grid. A hydrogen gas system would remove the significant existing barrier which currently prevents the opportunity for system integration between the UK electric and gas grid systems imposed by current gas quality standards and billing methodologies.
- **Nuclear:** An undeveloped approach is use of very high temperature nuclear reactors to dissociate hydrogen in water, but this is not yet available.
- **Gasifiers:** Represent another large scale form of hydrogen production in a technology established across the world. Gasifiers have up to 500 MW output and designs use a range of feedstocks including coal, residual black bag waste, and bio fuels. The potential for gasifiers producing hydrogen should be investigated further especially as a mix of gasifier technology and SMR hydrogen production in an expanding hydrogen economy would provide insulation from feedstock price fluctuations, i.e. the cost of natural gas vs. alternatives.



## Bulk 'Green' Hydrogen Production

Whilst the UK is limited in its capabilities to produce hydrogen at large scale via renewable technology there are areas of the world that have almost unlimited capability. It is possible to imagine a world where, following a market-push within the UK, a global market pull for hydrogen production could occur.

Areas of the world with large land availability and significant sunlight hours, but without an equivalent demand for the potential decarbonised electricity, could begin to produce hydrogen at large scales via electrolysis to be shipped in liquid form. This would be achieved in a similar way to how liquid natural gas is commonly shipped around the world today. In the longer term future this large scale 'green' hydrogen could reduce the requirement for fossil fuel feedstock and carbon capture from SMRs. It could also significantly reduce the UK's capital cost commitment to its expanding hydrogen economy as the hydrogen production facilities are delivered 'elsewhere'.

If this system were to transpire it could allow areas with surplus electrical energy availability to balance their system whilst creating a secure, sustainable feedstock for other areas of the world.

Additionally this Liquid Hydrogen Gas (LHG) industry would support the inter-seasonal storage requirements of the UK as the hydrogen conversion develops. For illustrative purposes this has been represented pictorially below.

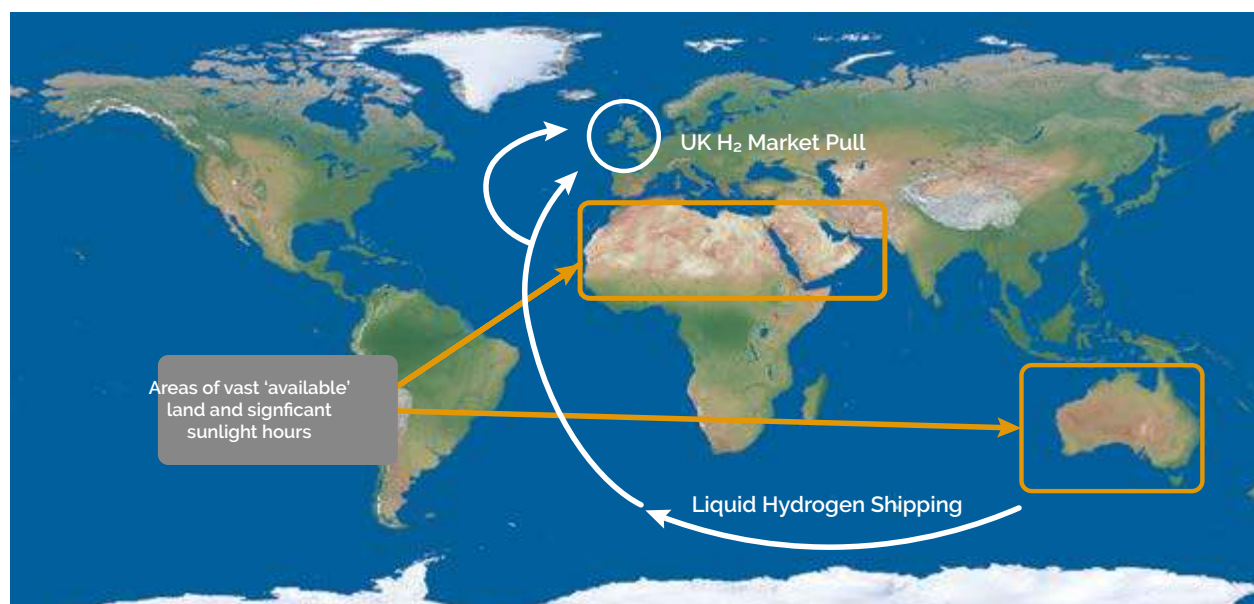


Image 11.5. *Liquid Hydrogen Economy*

Whilst this worldwide hydrogen production economy may seem a long way off there are already projects emerging around the world investigating the possibility. The most notable being in Norway where NEL ASA (NEL), SINTEF, Statoil, Linde Kryotechnik, Mitsubishi Corporation, Kawasaki Heavy Industries, NTNU and The Institute of Applied Energy, among others, initiated the project Hyper, a feasibility study of the potential for large scale hydrogen production in Norway for export to the European and Japanese markets. The project has received a 14 MNOK grant from the ENERGI-programme of the Research Council of Norway.

SINTEF Energy Research is the host organisation and the lead research partner for project Hyper. The aim of the project is to study the feasibility, as well as enable the planning, construction, and operation of a commercial decarbonised hydrogen production, liquefaction, and export facility based on Norwegian fossil and renewable energy resources.

Hyper has Kawasaki Heavy Industry as one of the partners, this will be useful for the transport of bulk liquid hydrogen by ship. Hyper should build on design studies already carried out by Japan and Australia, which are considering very similar scale of shipments at about 250,000 tonnes per year into Japan. This would use brown coal gasification with CCS, and H<sub>2</sub> delivered cost is estimated as 30 Yen/Nm<sup>3</sup>.

[https://www.iea.org/media/workshops/2014/asiahydrogenworkshop/1.17\\_IEAWSKHIR2\\_Kawasaki.pdf](https://www.iea.org/media/workshops/2014/asiahydrogenworkshop/1.17_IEAWSKHIR2_Kawasaki.pdf)



## 11.4. Carbon Capture

### Carbon Capture and Storage UK Potential

Whilst the H21 principle is to dispose of the carbon dioxide 'over the fence' it is important to understand the scale of CCS availability in the UK. Whilst it is not within the scope of this report to provide comprehensive details, such details can be found in the recently published ETI report 'Progressing Development of the UK's Strategic Carbon Dioxide Storage Resource – A Summary of Results from the Strategic UK CO<sub>2</sub> Storage Appraisal Project (April 2016)'

The full report details the capacity related to the mapping of 579 store sites. An extract from the ETI report says:

"In 2012, the ETI and its partners completed a study to build an inventory of all the potential CO<sub>2</sub> Storage locations in the UKCS". This UK Storage Appraisal Project was the source of a national CO<sub>2</sub> storage resource database called CO<sub>2</sub> stored now made publicly available and being further developed by the Crown Estate and British Geological Survey. Through a systematic process, this work identified almost 600 potential storage sites and developed an outline description and the first nationwide assessment of the CO<sub>2</sub> storage capacity resource using a consistent methodology. In total some 78 GT of potential CO<sub>2</sub> storage resource was identified. Whilst almost all of this potential has been discovered by existing drilling, very little (circa 140 MT) of this resource has been matured through appraisal characterisation towards being FID ready. The outcome of this project moves much more of this resource from being an unclassified contingent resource to a classified contingent resource with a viable development plan and thereby significantly improving confidence regarding its availability for deployment.

A step in the report was screening on known, accessible data, of representative structures. The report references 37 specific sites which met the high hurdle to qualify as potentially strategic storage sites. Beyond this there were many other excellent sites which present a rich diversity of storage resource. Together the qualified inventory had a combined CO<sub>2</sub> stored capacity of 8.3 GT (average 224 MT per site). This 8.3 GT is then quite similar to the targets further examined.

In the context of a UK wide hydrogen rollout relying predominantly on SMR with CCS production of hydrogen a 100 mt/y x 2 cycles of 40 year assets = 8 GT is entirely reasonable therefore providing 80 years with of hydrogen production viability which, over time, will inevitably be produced via diverse sustainable sources.



The relative attractions of grid conversion for CCS are:

- The flow rates of CO<sub>2</sub> from heat decarbonisation can be much less variable than from power, (due to having H<sub>2</sub> storage to smooth peaks and troughs).
- Decarbonising heat is the most efficient use of CO<sub>2</sub> transport and storage systems in terms of £CO<sub>2</sub> stored/kWh energy to consumer.
- Heat enables decarbonised hydrogen for transport, which is then an even more effective use of CO<sub>2</sub> storage, to address all vehicle emissions and city air quality problems.
- Most importantly – distributed low carbon hydrogen unlocks innovation for end users and further leverages the UK's comparative advantages in low carbon energy.

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***To summarise there is no shortage of CCS availability in the UK to progress a UK incremental rollout of hydrogen for long term decarbonisation of the UK Gas grid.***

### **Carbon Capture Utilisation**

Whilst carbon capture utilisation is in its infancy it is important to keep the prospects of this technology within the long term vision of a UK hydrogen conversion rollout strategy. Cambridge Carbon Capture Ltd, (CCC), are developing technology that can potentially capture CO<sub>2</sub> profitably by converting it to a mineral by-product with commercial uses. It can be used to capture CO<sub>2</sub> either pre or post combustion and does not rely on the availability of geological CO<sub>2</sub> storage or CO<sub>2</sub> pipeline infrastructure. CCC are also developing technology that can generate electricity whilst capturing and converting CO<sub>2</sub>.



### 11.4.1. Description of Carbon Capture and Mineralisation

Carbon Capture and Mineralisation (CC&M) is a method of permanently capturing CO<sub>2</sub> using mineral carbonation, effectively converting CO<sub>2</sub> into a stable and commercially useful mineral. Carbon mineralisation involves reactions of magnesium or calcium oxides (typically contained in mineral silicates and industrial wastes) with CO<sub>2</sub> (dilute in the atmosphere or exhaust gases, or as captured pure CO<sub>2</sub>) to give inert carbonates. Due to the lower energy state of carbonates compared to CO<sub>2</sub>, these reactions release significant amounts of energy and, in nature, occur spontaneously (but slowly). It is this energy that CCC's technology is able to harness and convert to electricity. Vast amounts of suitable and readily accessible mineral silicates exist – many times more than is needed to sequester all anthropogenic CO<sub>2</sub> emissions.



Image 11.6. *Pamukkale Lakes in Turkey, Natural Formation of Calcium Carbonate from Volcanic CO<sub>2</sub>*

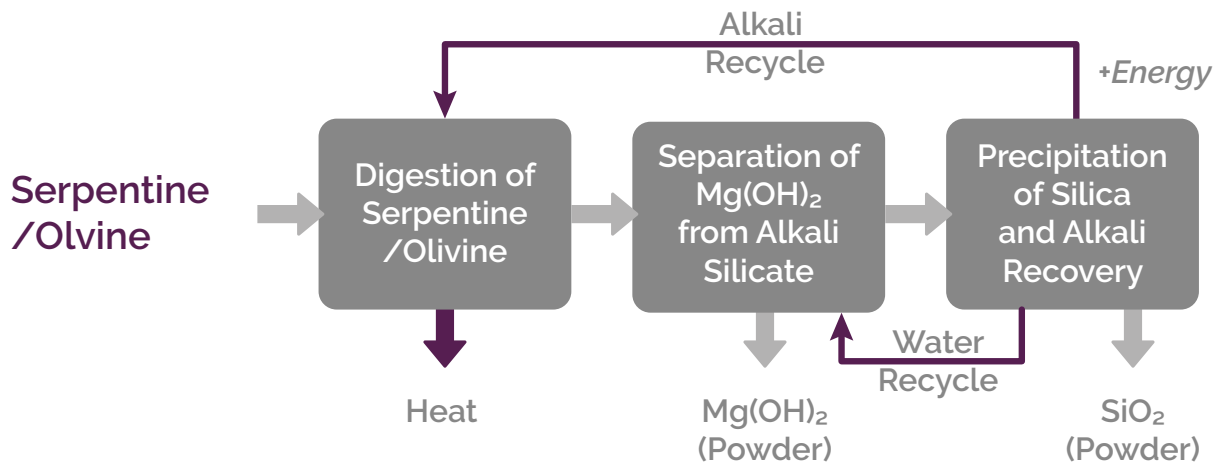
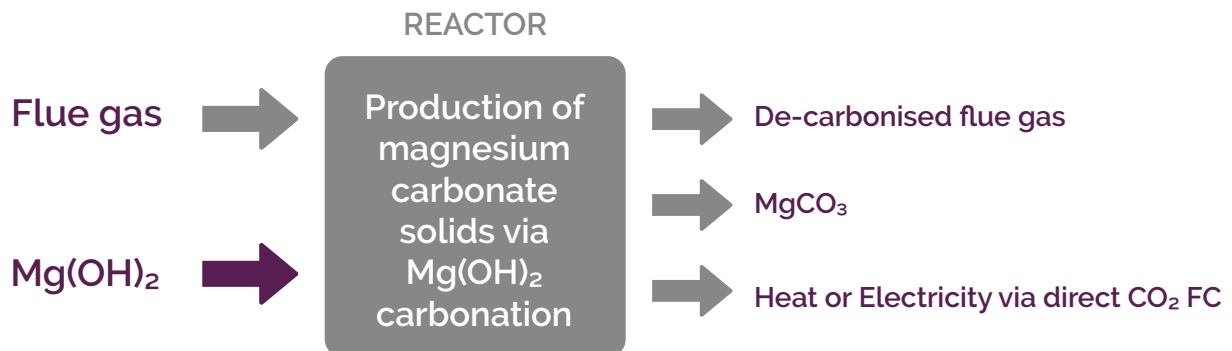
Slow speed of reactions of natural silicate rocks and the large amounts of minerals that must be handled, typically 2-3 tonnes rock per tonne of CO<sub>2</sub>, are the primary challenges for commercially viable industrial mineral carbonation applications. Processes that accelerate kinetics and maximise materials values with minimal additional costs and environmental impacts are the focus of R&D by Cambridge Carbon Capture and others around the world.

CC&M technologies are still in their infancy; some commercial pilot schemes have been developed using calcium carbonation technologies, the most notable being Skyonics in the US, (<http://www.skyonic.com/projects/capitol-skymine-plant>). Cambridge Carbon Capture's technology is different in that it is much less energy intensive and produces streams of highly valuable by-products, the sale of which has the potential of making CO<sub>2</sub> capture a profitable process rather than being a cost to energy production and use.

CCC's process is based on low cost and abundant magnesium minerals such as olivine and serpentine. The overall natural weathering and carbonation of olivine and serpentine rocks to form silica and magnesium (bi)carbonate occurs in nature but the natural reactions are extremely slow. CCC's technology involves the same overall carbonation reactions, but a very different route. CCC have identified and experimentally demonstrated the feasibility of a sequence of low-energy treatment steps that significantly accelerate reaction kinetics and enable easy separation of by-products. CCC's carbon capture and mineralization technology consumes magnesium hydroxide, capturing and converting the CO<sub>2</sub> to form magnesium carbonate. In order to make the process economic at a large scale, a viable source of cheap and abundant magnesium hydroxide is required. CCC has developed a low energy route to making magnesium hydroxide from commonly found olivine or serpentine. The process produces a number of valuable by-products including:

- Metals – nickel, iron, chromium.
- Rare earth metals.
- Silica oxide powders – Amorphous Precipitated Silica (APS).
- Magnesium carbonate.

APS has many commercial uses but can be used in the manufacture of vehicle tyres to reduce rolling resistance, improving vehicle efficiency. Current APS prices limit the market for these tyres so an abundant supply of low cost APS could lead to a very large market for this mineral. Magnesium carbonate can be used in a number of industrial applications such as fire retardant plastic fillers, it can also be used as a building material either in block or sheet form where it's fire retardant properties and low carbon production would offer significant commercial advantage. **Image 11.7 and 1.8** describe CCC's two-stage process and the direct CO<sub>2</sub> fuel cell generating electricity from the conversion of CO<sub>2</sub>.

Image 11.7. CCC's Process to Produce Low Cost Magnesium Hydroxide for CO<sub>2</sub> CaptureImage 11.8. CCC's CO<sub>2</sub> Capture Process

## Economics

CCC's technology has the potential to strip CO<sub>2</sub> from industrial flue gases for less than the current carbon price, with the potential to offset this cost or even make a profit from sale of semi-precious metals and other mineral by-products from the process, see **Image 11.9**. CCC's technology is applicable to all land and sea-based industrial emitters of CO<sub>2</sub>. CCC has further intellectual property enabling the generation of electricity from the carbonation process using their patented direct CO<sub>2</sub> fuel cell technology.

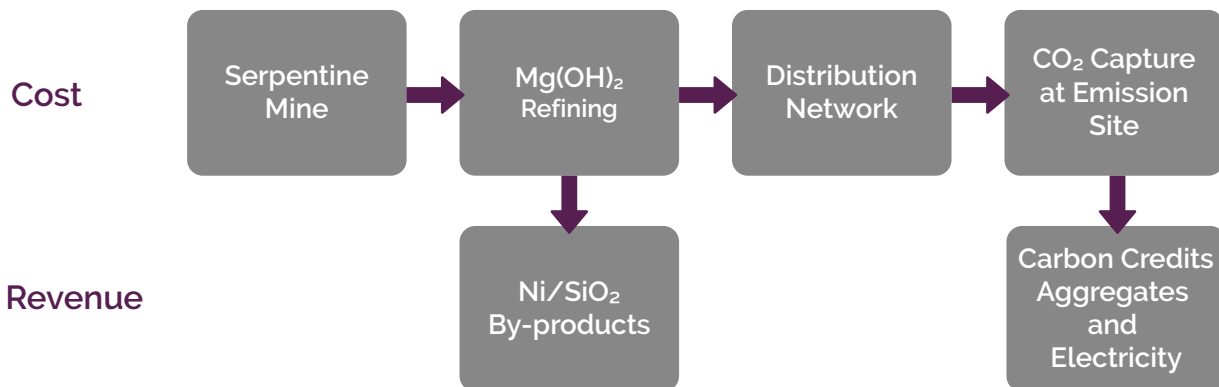


Image 11.9. *Process Cost Model*

## Integration of CCC's Technology with SMR Technology

Integration of CCC's technology would be relatively straightforward. As with the CCS option, a CCC plant would be built alongside the SMR plant. The main difference between SMR with CCS and the CCC concept is that the CCC CO<sub>2</sub> scrubber would take the place of the Pressure Swing Adsorption (PSA) stage. CCC's CO<sub>2</sub> scrubber consumes magnesium hydroxide and outputs pure hydrogen and magnesium bicarbonate. The magnesium bicarbonate would then pass to a further reactor where it is heated using heat recovered from the SMR exhaust gases to convert it to magnesium carbonate and CO<sub>2</sub>. The released CO<sub>2</sub> could either be sold as a by-product or sent back to the CO<sub>2</sub> scrubber to be re-absorbed. Finally, the flue gases from the SMR, having first been cooled by the heat recovery stage, pass through a second CCC CO<sub>2</sub> scrubber before being vented to the atmosphere. The magnesium bicarbonate solution from this reactor is then fed to the magnesium carbonate conversion stage of the process alongside the outputs of the hydrogen CO<sub>2</sub> scrubber. Image 11.10 shows a schematic of the integrated carbon capture and SMR plant.

## Integrated Carbon Capture and SMR Plant

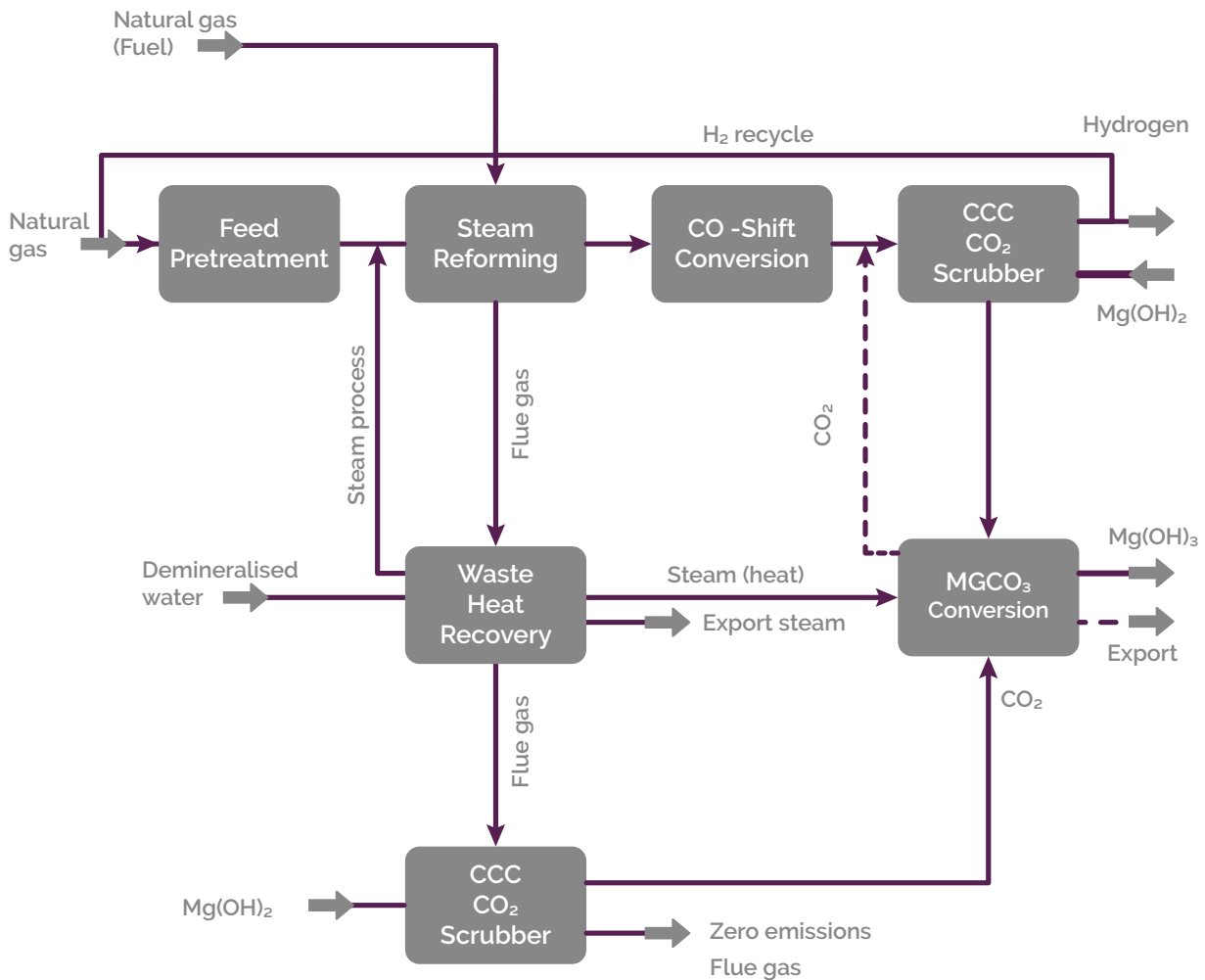


Image 11.10. *Schematic of the Integrated Carbon Capture and SMR Plant*

### Integration of CCC's Technology within the H21 Rollout Vision

CCC's CO<sub>2</sub> capture technology involves the consumption and production of bulk materials as well as the provision of CO<sub>2</sub> from the SMR process. As a result in an expanding hydrogen economy the siting of any carbon capture facility utilising CCU would require good transportation links, either by road, rail or sea.

The CCC process consumes and produces large quantities of materials directly proportional to the amounts of CO<sub>2</sub> being captured. An example of the quantities involved in capturing carbon through this process is provided below. **Table 11.7** quantifies the inputs and outputs of the CCC capture process based on this CO<sub>2</sub> capture requirement:

MATERIAL	Input (tonnes)	Output (tonnes)	Transport
CO <sub>2</sub>	1,224,000		Pipeline
Magnesium Hydroxide	1,627,920		Road/Rail
Magnesium Carbonate		2,350,080	Road/Rail
<b>Total</b>	<b>2,851,920</b>	<b>2,350,080</b>	

Table 11.7. *Total Inputs/Outputs for Capture of Large Scale CO<sub>2</sub> Output*

Total tonnage by road and/or rail would therefore be 4 million tonnes per annum, total tonnage by pipeline 1.2 million tonnes.

In terms of transportation costs, the cheapest form of transport for bulk materials is by sea, followed by pipeline, rail then road. The comparative costs will vary greatly with availability and proximity of existing infrastructure, population density and local landowner levies. However, it is valid to prioritise locations on the basis of the proximity of seaports and existing rail and road infrastructure whilst minimising pipeline length and avoiding pipelines through areas of high population density or crossing significant road or rail infrastructure.

In conclusion it is clear that in the longer term carbon capture utilisation technology may offer a complementary alternative to CCS requirements. It has potential to generate revenue therefore reducing costs of hydrogen production and the criteria for establishing viable sites for this technology, i.e. near ports/rail heads, are met by the SMR expansion locations as presented in this Section.

## 11.5. H21 Vision Conclusions

A hydrogen economy presents many opportunities to decarbonise not just heat but wider energy and transport.

Whilst the conversion is not free it can be financed in a way which could have minimal impact on customers' bills.

An optimised, no regrets, strategy should be developed for the incremental rollout of a hydrogen UK gas grid conversion programme.

A commitment to a long term hydrogen conversion strategy could act as the catalyst for the onset of the UK carbon capture and storage industry offering a constant, reliable long term source of carbon to any infrastructure provider. This could then facilitate CCS on many other industrial and power generation assets.

Development of a UK hydrogen vision and ultimately a policy decision can be achieved through the **H21 Roadmap identified in Section 10**. Such a move by the UK would set it apart as the market leader and could create significant benefits to the future UK economy.





# Schedules

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# Chart Schedule

<b>1. Introduction</b>	<b>10</b>
<b>2. Demand vs. Supply</b>	<b>28</b>
Chart 2.1. Scaling of Demand When Considering the Monthly Factors	31
Chart 2.2. Scaling of Demand When Considering the Within Day Ratios	31
Chart 2.3. Combined Inter-Seasonal and Intraday Factors for the Forecasted Demand Over the Year	33
Chart 2.4. Yorkshire Actual Daily and Seasonal Demand Levels 2009 to 2015	33
Chart 2.5. Estimated Yorkshire LDZ peak 6 minute demand for March 2009 to May 2015	35
Chart 2.6. Minimum Days Storage Against H <sub>2</sub> Production to Meet Demand	45
Chart 2.7. SMR Supply vs. Demand	58
Chart 2.8. 2013 Winter Storage Demand	59
Chart 2.9. Demand and Seasonal Storage Changes MWh/day	65
Chart 2.10. Seasonal Storage	66
Chart 2.11. Supply Profile For Peak Day Design	68
<b>3. Gas Network Capacity</b>	<b>85</b>
Chart 3.1. MP Mains Velocity (% of Total MP Mains Length) At Various Demand Levels (% of Peak 1 in 20 Demand)	98
<b>7. Carbon Capture and Storage</b>	<b>208</b>
Chart 7.1. H <sub>2</sub> vs. Natural Gas CO <sub>2</sub> Emissions	223





<b>8. Finance and Regulation</b>	<b>229</b>
Chart 8.1. RAV Depreciation	235
Chart 8.2. UK Gas Bill Component Parts	240
Chart 8.3. NGN Revenue Forecast (Current Scenario)	245
Chart 8.4. Total Customer Gas Bill	247
Chart 8.5. Hydrogen Revenue Allowances (with Current OPEX/CAPEX Funding Methodology)	251
Chart 8.6. Customer Contribution to Transportation Charge, Option 1	252
Chart 8.7. Customer Contribution to Transportation Charge, Option 2	253
Chart 8.8. Total Customer Gas Bill	255
<b>9. Next Steps – The Programme of Works</b>	<b>269</b>
Chart 9.1. Spend Profile Over Time	271
<b>11. The H21 Rollout Vision</b>	<b>321</b>
Chart 11.1. Option 1 Hydrogen Revenue Allowances – Rollout Illustration	334
Chart 11.2. Option 1 Customer Bill – Rollout Illustration	335
Chart 11.3. Option 2 Hydrogen Revenue Allowances – Rollout Illustration	336
Chart 11.4. Option 2 Customer Bill (Transportation Element Only) – Rollout Illustration	337
Chart 11.5. GDN Element of Customer Bill – Difference Between Options	337
Chart 11.6. Total Customer Gas Bill	338
Chart 11.7. Carbon Savings Over Time	346



# Image Schedule

<b>1. Introduction</b>	<b>10</b>
Image 1.1. Existing UK Transportation System	14
Image 1.2. UK Gas Pressure Tiers	15
Image 1.3. Current Gas Transportation System Ownership	17
Image 1.4. End-to-End Energy System	19
Image 1.5. H21 Leeds City Gate – Original Concept**	21
Image 1.6. H21 Leeds City Gate – Amended Concept	22
Image 1.7. Area of Conversion*	24
<b>2. Demand vs. Supply</b>	<b>28</b>
Image 2.1. MSOA Area Example*	36
Image 2.2. 21,000 Mc <sup>3</sup> /h H <sub>2</sub> Electrolysis Plant	49
Image 2.3. A Typical SMR Plant – Picture Courtesy of BOC	51
Image 2.4. Existing BOC 36.4 MMSCFD (c. 150 MW) SMR at Teesside**	51
Image 2.5. Simple Block Flow of an SMR and CO <sub>2</sub> Capture Plant	55
Image 2.6. H21 Leeds City Gate SMR Train Configuration	56
Image 2.7. Salt Dome Salt Cavern	61
Image 2.8. Salt Caverns At Teesside**	61
Image 2.9. Local Salt Deposits and Salt Cavern Storage (Extract from ETI Report)	64
Image 2.10. Local Large Natural Gas Salt Cavern Storage (Courtesy of SSE)	64
Image 2.11. Teesside and East Riding Underground Gas Storage**	71
Image 2.12. UK Salt Deposits and Salt Cavern Storage (From ETI Report on Hydrogen)	78
Image 2.13. UK Carbon Capture Availability (From 'Strategic UK CCS Storage Appraisal Project)	78
Image 2.14. Seal Sands Industrial Area**	80



<b>3. Gas Network Capacity</b>	<b>85</b>
Image 3.1. Screenshot Synergi	86
Image 3.2. Network Data Logger	86
Image 3.3. Map of Leeds*	87
Image 3.4. Map of Area of Conversion*	88
Image 3.5. Synergi Model Natural Gas Parameters	89
Image 3.6. Synergi Model Hydrogen Parameters	89
Image 3.7. Pressure Tier Cascade	90
Image 3.8. Map of Leeds Gas Network Indicating PRS Locations*	91
Image 3.9. Map of Leeds Gas Network District Governor Locations	92
Image 3.10. Existing Design Parameters for UK Distribution Networks	93
Image 3.11. Synergi Analysis MP Network (Pressures) – Natural Gas	94
Image 3.12. Synergi Analysis MP Network (Pressures) – Hydrogen	94
Image 3.13. Synergi Analysis MP Network (Pressures) – Hydrogen with Existing PRU Positions	95
Image 3.14. Synergi Analysis MP Network (Pressures) – Hydrogen with Amended PRU Positions	95
Image 3.15. Synergi Analysis MP Network (Velocities) – Natural Gas	96
Image 3.16. Synergi Analysis MP Network (Velocities) – Hydrogen	96
Image 3.17. Synergi Analysis MP Network (Velocities) – Hydrogen with Existing PRU Positions	97
Image 3.18. Synergi Analysis MP Network (Velocities) – Hydrogen with Amended PRU Positions	97
Image 3.19. Synergi Analysis LP Network (Pressures) – Natural Gas	100
Image 3.20. Synergi Analysis LP Network (Pressures) – Hydrogen	100
Image 3.21. Five Detailed Areas of Reinforcement	101
Image 3.22. Area 1 Reinforcement**	103
Image 3.23. Area 9 Reinforcement**	104
Image 3.24. Area 10 Reinforcement**	105
Image 3.25. Area 11 Reinforcement**	106
Image 3.26. Area 12 Reinforcement**	107



<b>4. Gas Network Conversion</b>	<b>113</b>
Image 4.1. Otley Zones of Influence Same Pressures	116
Image 4.2. Otley Zones of Influence Varying Pressures	116
Image 4.3. Area of Conversion: MP Zones of Influence	116
Image 4.4. Map of Gas Network in the West Yorkshire Area*	117
Image 4.5. Map of PRS Injection Points to the Area of Conversion*	118
Image 4.6. Map of Leeds Hydrogen Ring Main and PRSs*	119
Image 4.7. MP Three Year Conversion Strategy	120
Image 4.8. Isolation Locations on MP Network and Illustration of Double Block and Bleed Isolation Method	121
Image 4.9. LP Yearly Isolation Zones	122
Image 4.10. Conversion Isolation	123
Image 4.11. Wharfedale Area of Conversion*	124
Image 4.12. Starting Position*	125
Image 4.13. Maps Step One*	126
Image 4.14. Map Step Two	127
Image 4.15. Maps Step Three	128
Image 4.16. Maps Step Four	129
Image 4.17. Maps Step Five	130
Image 4.18. Maps Step Six	131
Image 4.19. Maps Step Seven*	132
Image 4.20. Example Two Starting Position*	134
Image 4.21. Map, Example 2, Step 1*	135
Image 4.22. MP Three Year Conversion Strategy and Double Block and Bleed	136



<b>5. Appliance Conversion</b>	<b>139</b>
Image 5.1. Examples of Distributed Flame Gas Burners from Remeha (left) and Alpha (right)	166
Image 5.2. Comparison of Size of Conventional and Catalytic Boilers	167
Image 5.3. Typical Natural Gas or Hydrogen Partially Premixed Gas Burner ref <a href="http://www.Cielotech.Wordpress.Com">www.Cielotech.Wordpress.Com</a>	170
Image 5.4. Model #GFH6000 Green Flame Heater Hydrogen Fuelled Input 1.3 kW to 1.8 kW	172
Image 5.5. Giacomini Hydrogen Catalytic Boiler (Giacomini, 2011)	174
Image 5.6. DIY BBQ	175
Image 5.7. Hydrogen Cooker	175
Image 5.8. Integrated Hydrogen Catalytic Burner (Ulrich, V. (EMPA), 2015)	176
Image 5.9. MAXON Wide-Range (R) Burner Running on Hydrogen. (Source: <a href="https://www.maxoncorp.com/Directory/product/WIDE-RANGE-Burner/38/Natural-Gas-Burner-High">https://www.maxoncorp.com/Directory/product/WIDE-RANGE-Burner/38/Natural-Gas-Burner-High</a> )	179
<b>6. The Hydrogen Transmission System</b>	<b>184</b>
Image 6.1. Indicative Route Corridor of HTS and Associated Connections	186
Image 6.2. Representation of Connections at Teesside	188
Image 6.3. Indicative Route Corridor of HTS	193
Image 6.4. Horizontal Directional Drill (HDD)	198
Image 6.5. Representation of Connections at Leeds	201
Image 6.6. Typical Distribution Network PRU	203
<b>7. Carbon Capture and Storage</b>	<b>208</b>
Image 7.1. Provided by SaskPower	208
Image 7.2. Provided by Shell	208
Image 7.3. UK CCS availability	210
Image 7.4. Teesside Collective Report Summary	212
Image 7.5. The Teesside Collective Five Industrial Partner Locations	213
Image 7.6. The Five Elements of the ICCS Project	213



<b>8. Finance and Regulation</b>	<b>229</b>
Image 8.1. Gas Distribution Industry Overview	232
Image 8.2. GDN income	238
Image 8.3. GDN Capacity Impact	239
<b>9. Next Steps – The Programme of Works</b>	<b>269</b>
Image 9.1. Key Elements Timeline	270
<b>10. The H21 Roadmap</b>	<b>275</b>
Image 10.1. H21 Roadmap – Work Package Overview	277
Image 10.2. The Existing UK Transportation System	278
Image 10.3. Existing System Modifications	279
Image 10.4. Proposed H21 Programme Team Structure	281
Image 10.5. Programme Team Wider Interfaces	281
Image 10.6. 'Typical' Pressure Reduction Station (PRS)	283
Image 10.7. Instrumentation Equipment	283
Image 10.8. Hazardous Area Classification Drawing (Large Site)	284
Image 10.9. 'Typical' District Governors (x2)	285
Image 10.10. LP Network Reinforcement Requirements	289
Image 10.11. H21 Roadmap – Work Package Overview	319





<b>11. The H2i Rollout Vision</b>	<b>321</b>
Image 11.1. H2i Rollout – Large City by City and HTS	322
Image 11.2. Hydrogen Production and CCS Expansion Over Time	324
Image 11.3. Increasing Hydrogen Production Capability at Teesside**	325
Image 11.4. UK Gas Distribution Networks	341
Image 11.5. Liquid Hydrogen Economy	351
Image 11.6. Pamukkale Lakes in Turkey, Natural Formation of Calcium Carbonate from Volcanic CO <sub>2</sub>	355
Image 11.7. CCC's Process to Produce Low Cost Magnesium Hydroxide for CO <sub>2</sub> Capture	357
Image 11.8. CCC's CO <sub>2</sub> Capture Process	357
Image 11.9. Process Cost Model	358
Image 11.10. Schematic of the Integrated Carbon Capture and SMR Plant	359

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\*\* © Google Images



# Table Schedule

<b>1. Introduction</b>	<b>10</b>
Table 1.1. The UK gas transportation system	11
<b>2. Demand vs. Supply</b>	<b>28</b>
Table 2.1. Monthly and Daily Turndown Ratios	30
Table 2.2. MSOA Examples	37
Table 2.3. Sheffield Average Annual Temperatures	38
Table 2.4. Inter-seasonal Storage	67
Table 2.5. Intraday Storage Meeting Peak Day Demand	69
Table 2.6. H21 Leeds City Gate Storage Requirements	72
Table 2.7. Hydrogen Production System Cost Summary	83
<b>3. Gas Network Capacity</b>	<b>85</b>
Table 3.1. Properties of Natural Gas and Hydrogen	89
Table 3.2. Current UK Gas Network LP and MP Design Parameters	93
Table 3.3. Pipe Velocities by Percentage Peak Demand Level	98
Table 3.4. Reinforcement Costs	108
Table 3.5. Remaining Metallic Mains in the Area of Conversion	110
<b>4. Gas Network Conversion</b>	<b>113</b>
Table 4.1. Network Conversion Enabling Works – Cost Summary	137



<b>5. Appliance Conversion</b>	<b>139</b>
Table 5.1. Domestic vs. Non-Domestic Split in Area of Conversion	141
Table 5.2. Design Parameters for the Management of the Appliance Switchover Process.	143
Table 5.3. Estimation of Effort Required for Appliance Switchover for One Isolation Zone Containing 2,500 Domestic Properties	145
Table 5.4. Summary of Hardware Costs for Appliance Switchover for One Isolation Zone Containing 2,500 Domestic Properties	146
Table 5.5. Area Meter Information	146
Table 5.6. Costs per Property	147
Table 5.7. Estimated Annual Commercial and Industrial Energy Demand from the Largest Demand Low and Medium Pressure Network Connections in Leeds	149
Table 5.8. Examples of MSOA Non-domestic Data	150
Table 5.9. Installed Non-domestic Capacity	151
Table 5.10. Estimated Costs for the Conversion of Industrial and Commercial Equipment to Hydrogen	152
Table 5.11. Overall Estimates	153
Table 5.12. A Comparison of the Energy Conveyance Properties of Hydrogen and Natural Gas	157
Table 5.13. Comparison of Physical Properties of Hydrogen, Methane and Natural Gas	161
Table 5.14. A Comparison of the Energy Release Properties of Hydrogen and Natural Gas	162
Table 5.15. Characteristics of Hydrogen Combustion Systems	163
Table 5.16. Technical Detail of the Giacomini Hydrogen Boiler	173

<b>6. The Hydrogen Transmission System</b>	<b>184</b>
Table 6.1. Assumed Technical Parameters	188
Table 6.2. Technical Parameters – Teesside Connections	189
Table 6.3. Cost Summary – HTS Teesside Connections	192
Table 6.4. HTS Pipeline Sectional Details	196
Table 6.5. Cost Summary – HTS Pipeline	200
Table 6.6. Leeds Connection Elements	201
Table 6.7. Cost Summary: Connections at Leeds	204
Table 6.8. HTS Operating Costs	205
Table 6.9. Cost Summary – HTS and Associated Connection	206
<b>7. Carbon Capture and Storage</b>	<b>208</b>
Table 7.1. Summary of H2i Emissions Levels by Scope	223
Table 7.2. Comparison of the Carbon Footprint of Hydrogen from SMR+CCS with Other Fuels	224
Table 7.3. H2i Leeds City Gate – Total Annual Volume of Captured CO <sub>2</sub>	225



<b>8. Finance and Regulation</b>	<b>229</b>
Table 8.1. H21 Leeds City Gate Project Costs	230
Table 8.2. REPEX Funding	236
Table 8.3. Industry Revenue Allowances	237
Table 8.4. GDN Charges 2014/15 OFGEM Annual Report	241
Table 8.5. Customer Bill Impact – Transportation Charge Only	246
Table 8.6. Energy Efficiency Over Time	246
Table 8.7. Total Customer Bill Impact – (Total Bill)	247
Table 8.8. Expenditure Forecast	249
Table 8.9. Customer Bills, Transportation Only (2015/16 prices) Average Year, Option 1	252
Table 8.10. Customer Bills, Transportation Only (2015/16 prices) Average Year, Option 2	254
Table 8.11. Energy Efficiency Savings Over Time	255
Table 8.12. Customer Bills (2015/16 prices) Average Year, Option 1/2	256
Table 8.13. Key Design Parameters	258
Table 8.14. Expenditure for 1st Conversion (Production)	259
Table 8.15. Variable Costs	260
Table 8.16. Total Costs	261
Table 8.17. Expenditure for 1st Conversion - Appliances	262
Table 8.18. £/Tonne for Scope 1 Emissions Savings for Thermal Insulation	263
Table 8.19. £/Tonne for Scope 1 Emissions Savings for H21 Leeds City Gate System	264
<b>9. Next Steps – The Programme of Works</b>	<b>269</b>
<b>10. The H21 Roadmap</b>	<b>275</b>
Table 10.1. H21 Roadmap – Work Package Overview	276
Table 10.2. Key Gas Industry Governing Documents	302
Table 10.3. Document Examples.	304
Table 10.4. Methods of Hydrogen Production	316





<b>11. The H2I Rollout Vision</b>	<b>321</b>
Table 11.1. CAPEX Costs per Cit	329
Table 11.2. OPEX Costs per City	331
Table 11.3. Illustrative Rollout Profile 2016/17 Prices	333
Table 11.4. Energy Efficiency Savings Over Time	338
Table 11.5. Total Gas Bill	339
Table 11.6. Total Capital Costs Regional Rollout	343
Table 11.7. Total Inputs/Outputs for Capture of Large Scale CO <sub>2</sub> Output	360

