The Liverpool-Manchester Hydrogen Cluster: A Low Cost, Deliverable Project

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Contents

PAGE 01
1.0 Introduction, scope and objectives

PAGE 03
2.0 Characterisation of infrastructure in the L-M area
  2.1 Scope of the L-M Cluster Area 03
  2.2 Industrial Gas Demand 04
  2.3 Energy Delivered by Hydrogen/Natural Gas Blends 07
  2.4 Power Generation Infrastructure and Gas Demand 08
  2.5 Opportunities for Hydrogen Supply 09
  2.6 Existing Gas Transportation Infrastructure 11
  2.7 Opportunities for Offshore Storage of CO₂ 13
  2.8 Existing Hydrogen, and Wider Gas Storage Infrastructure 15
  2.9 Potential Carbon Reduction Benefits 17

PAGE 19
3.0 Characterisation of infrastructure on Humberside
  3.1 Scope of the Humber Cluster Area 19
  3.2 Industrial Gas Demand 20
  3.3 Energy Delivered by Hydrogen/Natural Gas Blends 23
  3.4 Power Generation Infrastructure and Gas Demand 24
  3.5 Opportunities for Hydrogen Supply 25
  3.6 Existing Gas Transportation Infrastructure 26
  3.7 Opportunities for Offshore Storage of CO₂ 28
  3.8 Existing Hydrogen, and Wider Gas Storage Infrastructure 30
  3.9 Potential Carbon Reduction Benefits 31

PAGE 33
4.0 Comparative analysis of candidate locations
  4.1 Scope, Objectives and Summary Methodology 33
  4.2 Deliverability of Early Stage Demonstration Projects 33
  4.3 Costs of Scaling-up to Full Hydrogen Cluster 35
  4.4 Future Reductions in CO₂ emissions 38
  4.5 Summary of Comparative Analysis 39
<table>
<thead>
<tr>
<th>Acronym</th>
<th>Full Name</th>
</tr>
</thead>
<tbody>
<tr>
<td>ASHP</td>
<td>Air Source Heat Pump</td>
</tr>
<tr>
<td>BEIS</td>
<td>Department for Business, Energy &amp; Industrial Strategy</td>
</tr>
<tr>
<td>BOS</td>
<td>Basic Oxygen Steelmaking</td>
</tr>
<tr>
<td>BioSNG</td>
<td>Bio-Substitute natural gas</td>
</tr>
<tr>
<td>Capex</td>
<td>Capital Expenditure</td>
</tr>
<tr>
<td>CCC</td>
<td>Committee on Climate Change</td>
</tr>
<tr>
<td>CCGT</td>
<td>Combined Cycle Gas Turbine</td>
</tr>
<tr>
<td>CCA</td>
<td>Climate Change Agreement</td>
</tr>
<tr>
<td>CCS</td>
<td>Carbon Capture and Storage</td>
</tr>
<tr>
<td>CFD</td>
<td>Computational Fluid Dynamics</td>
</tr>
<tr>
<td>CfD</td>
<td>Contract for Difference</td>
</tr>
<tr>
<td>CH₄</td>
<td>Methane</td>
</tr>
<tr>
<td>CHP</td>
<td>Combined Heat and Power</td>
</tr>
<tr>
<td>CO</td>
<td>Carbon Monoxide</td>
</tr>
<tr>
<td>CO₂</td>
<td>Carbon Dioxide</td>
</tr>
<tr>
<td>CoA</td>
<td>Cost of (CO₂) Abatement</td>
</tr>
<tr>
<td>CoG</td>
<td>Coke Oven Gas</td>
</tr>
<tr>
<td>CoS</td>
<td>Cost of (CO₂) Storage</td>
</tr>
<tr>
<td>CV</td>
<td>Calorific Value</td>
</tr>
<tr>
<td>DLN</td>
<td>Dry Low NOx (combustors)</td>
</tr>
<tr>
<td>ETI</td>
<td>Energy Technologies Institute</td>
</tr>
<tr>
<td>EU ETS</td>
<td>European Union Emissions Trading Scheme</td>
</tr>
<tr>
<td>EU IED</td>
<td>EU Industrial Emissions Directive</td>
</tr>
<tr>
<td>EU MCPD</td>
<td>EU Medium Combustion Plant Directive</td>
</tr>
<tr>
<td>DfT</td>
<td>Department for Transport</td>
</tr>
<tr>
<td>FOAK</td>
<td>First-of-a-kind</td>
</tr>
<tr>
<td>GB</td>
<td>Great Britain</td>
</tr>
<tr>
<td>GDN</td>
<td>Gas Distribution Network (Operator)</td>
</tr>
<tr>
<td>GHG</td>
<td>Greenhouse Gas</td>
</tr>
<tr>
<td>GVA</td>
<td>Gross Value Added</td>
</tr>
<tr>
<td>GS(M)R</td>
<td>Gas Safety (Management) Regulations</td>
</tr>
<tr>
<td>GWh</td>
<td>Gigawatt-hours</td>
</tr>
<tr>
<td>GJ</td>
<td>Gigajoule</td>
</tr>
<tr>
<td>Acronym</td>
<td>Full Name</td>
</tr>
<tr>
<td>---------</td>
<td>-----------</td>
</tr>
<tr>
<td>H₂</td>
<td>Hydrogen</td>
</tr>
<tr>
<td>HP</td>
<td>High Pressure</td>
</tr>
<tr>
<td>HSE</td>
<td>Health and Safety Executive</td>
</tr>
<tr>
<td>IMRP</td>
<td>Iron Mains Replacement Programme</td>
</tr>
<tr>
<td>IP</td>
<td>Intermediate Pressure</td>
</tr>
<tr>
<td>ktpa</td>
<td>Thousand tonnes per annum</td>
</tr>
<tr>
<td>LP</td>
<td>Low Pressure</td>
</tr>
<tr>
<td>LTS</td>
<td>Local Transmission System</td>
</tr>
<tr>
<td>MAC</td>
<td>Marginal Abatement Cost</td>
</tr>
<tr>
<td>MJ</td>
<td>Megajoule(s)</td>
</tr>
<tr>
<td>MP</td>
<td>Medium Pressure</td>
</tr>
<tr>
<td>Mt</td>
<td>Million Tonnes</td>
</tr>
<tr>
<td>MtCO₂pa</td>
<td>Million Tonnes of Carbon Dioxide per annum</td>
</tr>
<tr>
<td>MWh</td>
<td>Megawatt hour(s)</td>
</tr>
<tr>
<td>MWth</td>
<td>Megawatt hour(s) thermal</td>
</tr>
<tr>
<td>NIA</td>
<td>Network Innovation Allowance</td>
</tr>
<tr>
<td>NOx</td>
<td>Nitrogen Oxides</td>
</tr>
<tr>
<td>NTS</td>
<td>National Transmission System</td>
</tr>
<tr>
<td>OEM</td>
<td>Original Equipment Manufacturer</td>
</tr>
<tr>
<td>Ofgem</td>
<td>Office for Gas and Electricity Markets</td>
</tr>
<tr>
<td>Opex</td>
<td>Operational Expenditure</td>
</tr>
<tr>
<td>RIIO</td>
<td>Revenue = Innovation + Investment + Outputs</td>
</tr>
<tr>
<td>SOx</td>
<td>Sulphur Oxides</td>
</tr>
<tr>
<td>SMR</td>
<td>Steam Methane Reformer</td>
</tr>
<tr>
<td>tpa</td>
<td>Tonnes per annum</td>
</tr>
<tr>
<td>TWh</td>
<td>Terawatt hour(s)</td>
</tr>
<tr>
<td>TWhpa</td>
<td>Terawatt hour(s) per annum</td>
</tr>
<tr>
<td>vol.</td>
<td>By volume</td>
</tr>
<tr>
<td>UK</td>
<td>United Kingdom</td>
</tr>
</tbody>
</table>
1.0 INTRODUCTION, SCOPE AND OBJECTIVES

Emissions from natural gas combustion and use are the largest source of greenhouse gas (GHG) emissions in the UK. The use of hydrogen in place of natural gas, in principle, offers a potential route to long term, widespread, decarbonisation of gas distribution networks, as shown by the Leeds City Gate (‘H21’) study. The purpose of considering conversion to hydrogen is to deliver widespread carbon abatement across the UK at lower cost than alternative decarbonisation strategies.

The Government is to finalise and publish the long-awaited ‘Clean Growth Plan’ along with an Industrial Strategy White Paper in Autumn 2017. Conversion from natural gas to hydrogen, potentially on an incremental basis, would likely represent a major opportunity for new industrial growth. This might be through the longer term stability or potential expansion of existing (newly decarbonised) energy intensive industry or through business opportunities and growth created from new technologies developed to facilitate the transition to hydrogen as the UK becomes a global leader and major exporter of equipment and skills. Job creation and the resulting gross value added (GVA) to the economy could therefore be significant in delivery of the goals of the Industrial Strategy Challenge Fund (ISCF).

The core requirement is to supply low carbon hydrogen in bulk, matching production to distribution network demand at an affordable cost. The H21 study concluded that to do so reliably, hydrogen is best produced by reducing natural gas in steam methane reformers (SMRs) fitted with Carbon Capture and Storage (CCS). The study proposed that the considerable inter-seasonal and daily fluctuations in network demand can be managed by storing hydrogen in underground salt formations. It concluded that the SMRs with associated carbon dioxide (CO$_2$) capture should be located near to where CO$_2$ transport and storage infrastructure was likely to be created and noted that candidate locations for this are Teesside, Humberside, Grangemouth and the Liverpool-Manchester (L-M) area. Two of these, Humberside and the L-M area, are within the Cadent Gas Ltd (‘Cadent’) network and are also industrial ‘clusters’ with significant populations.

The work reported here builds upon the approach proposed in the H21 project by focussing on defining ‘low carbon’ hydrogen supply and distribution systems in Humberside and the L-M area at a system scale sufficient to supply a large city. Both the Humber and L-M clusters are close to salt deposits which are suitable for both daily and inter-seasonal storage of hydrogen (for initial or expanded projects). Furthermore, new large-scale gas Combined Cycle Gas Turbine (CCGT) plants, widely assumed as likely anchor projects for CCS infrastructure, have been consented in both cluster areas, confirming that they are both strong candidates as locations for the first CCS clusters and hence as locations for a hydrogen supply system.

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http://www.northerngasnetworks.co.uk/document/h21-leeds-city-gate/

2. The term ‘low carbon’ hydrogen is used to define hydrogen that is produced and distributed without significant emissions of CO$_2$. 
Government policy on CCS is under review but it is noteworthy that both cluster areas have a strong technical case for hosting the first CCS network. Demonstration of the business case for a hydrogen supply system at either location would strengthen the CCS business case, and as CCS is essential for deployment of hydrogen on the network, either would enhance the prospect for the hydrogen conversion initiative.

This study specifically examines a strategy for a pathway to hydrogen conversion of the network. This starts by delivery of a complete project involving domestic, industrial users along with bulk hydrogen production from natural gas. It also seeks to justify the inclusion of CCS infrastructure as part of the core project, thus avoiding the need to rely on the assumption that CCS will progress as a result of a revitalised CCS strategy driven by the power sector.

In summary, the objectives of the study are to:

- Provide a clear view of current infrastructure in both the L-M area and Humberside, which might be repurposed to enable supply, transport, storage and industrial use of hydrogen and associated CO₂ from hydrogen production;
- Based on the analysis of existing infrastructure, to determine which, of the L-M area or Humberside, represents the most attractive ‘area’ for the development of a hydrogen network;
- Explore the technical and engineering issues associated with the use of hydrogen to reduce CO₂ emissions from manufacturing industries and to provide guidance on its potential as an emissions reduction approach;
- To determine how the use of hydrogen in industry might function as an enabler for the wider use of hydrogen in the natural gas network to supply both the commercial and domestic sectors;
- Determine the potential for the use of hydrogen in large-scale power generation and to give high-level consideration to the role such use might have in managing seasonal and daily supply and demand fluctuations;
- Provide guidance on the most cost-effective configuration for low carbon hydrogen production, supply and transport in the selected area, recognising technical, commercial, market and financing issues;
- Scope the practicality of CCS infrastructure for a standalone project not predicated on major infrastructure created as part of a major power generation scheme, given the uncertainty in current policy; and
- Outline the next steps to advance towards a first deliverable project proposition.
2.0 CHARACTERISATION OF INFRASTRUCTURE IN THE L-M AREA

The content of this section is based on engagement with industry in the L-M area, along with review and analysis of secondary data. We have also been supported by Cadent in respect of data relating to gas demand of some major users.

2.1 Scope of the L-M Cluster Area

Figure 2.1 presents the specific scope of the geographical area and the associated gas distribution network (operated by Cadent) considered as the ‘L-M Cluster’ area for the purposes of this study. It should be noted that the gas network in part of the Cluster area, situated to the South West, is operated by Wales and West Utilities (WWU). As a result, the related pipes are not presented in Figure 2.1 and the gas use of industrial sites located outside of the Cadent area (but within the L-M Cluster) is excluded from the analysis in Section 2.2.

Figure 2.1: L-M Cluster Area and Cadent Gas Network

Note: Area includes all ‘L’ postcodes, all ‘CH’ postcodes, PR8, PR9, WA1-WA15, WA55, WA88, WN3-WAS, WN8, LL11-LL14, CW6-CW10, M31, M44
2.2 Industrial Gas Demand

Further to work commissioned by the Department of Energy and Climate Change (now the Department for Business, Energy and Industrial Strategy - BEIS) in 2015, we have sought to allocate gas demand across the following eight industry sectors (along with an ‘other’ category, for businesses which fall outside this classification):

1) Chemicals;
2) Glass;
3) Food and Drink;
4) Oil and Gas;
5) Ceramics;
6) Cement;
7) Pulp and Paper;
8) Metals; and
9) Other.

Power generation in CCGT plants for export to the electricity transmission grid is considered separately in Section 2.4.

2.2.1 Comparison with Gas Demand across other Sectors

As summarised in Table 2.1, based on data provided by Cadent, total natural gas use by industry (users with demand > 5.9 GWh/annum) connected to the distribution network within the L-M cluster was 11,039 GWh in 2015. This represents 21% of the 52,928 GWh consumed by such industrial users across the whole Cadent network and, as presented in Table 2.2, around 11% of the total industrial gas consumption in Great Britain (GB) of 99,729 GWh in 2015. Total gas consumption (domestic and non-domestic) in the cluster was 47,631 GWh in 2015, which represents 11% of total GB gas consumption (at distribution level) of 495,656 GWh in 2015.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Natural Gas Consumption (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial (sites &gt;5.9 GWh) gas consumption (2015)</td>
<td>11,039</td>
</tr>
<tr>
<td>Commercial gas consumption (2014)</td>
<td>16,331</td>
</tr>
<tr>
<td>Domestic gas consumption (2014)</td>
<td>20,261</td>
</tr>
<tr>
<td>Total gas consumption</td>
<td>47,631</td>
</tr>
</tbody>
</table>

Notes:
1. Excludes gas consumption delivered directly from the national transmission system (NTS)

This is listed as ‘Iron and Steel’ in the BEIS reports and therefore we have used a slightly broader definition.

BEIS (2016) Historical gas data: gas production and consumption and fuel input 1920 to 2015, August 2016
### Table 2.2: Natural Gas Consumption Data for Great Britain

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Natural Gas Consumption (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial gas consumption (2015)</td>
<td>99,729</td>
</tr>
<tr>
<td>Total non-domestic (including industrial) gas</td>
<td>187,824</td>
</tr>
<tr>
<td>consumption (2015)</td>
<td></td>
</tr>
<tr>
<td>Total domestic gas consumption (2015)</td>
<td>308,749</td>
</tr>
<tr>
<td>TOTAL GAS CONSUMPTION (2015)</td>
<td>495,656</td>
</tr>
</tbody>
</table>

Notes:
1. Excludes gas consumption delivered directly from the NTS

### 2.2.2 Sectoral Analysis of Gas Consumption

The provision of information (as detailed in Section 5.0) as to how processes and generation plant in specific industry sectors might be adapted or retrofit to accommodate a switch to hydrogen (or hydrogen/natural gas mixtures) will most usefully inform analysis of the changes that are likely to be needed at a macro-level.

Table 2.3 presents total gas use by industrial sector. This has been drawn from information provided by Cadent, but also triangulated with data modelled from site emissions published for ‘large point sources’ in the UK’s National Atmospheric Emissions Inventory (NAEI).

The largest consumer of natural gas in the L-M Cluster area is the ‘Chemicals’ sector, which used 2,568 GWh in 2015. This is followed by the ‘Food and Drink’ sector (1,835 GWh), the ‘Oil and Gas’ sector (1,691 GWh) and the ‘Glass’ sector (1,691 GWh), which are all some way larger than the next biggest gas user, the ‘Pulp and Paper’ sector, at 890 GWh.

The consumption of ‘Other’ industry sectors, which include automotive, textiles and aggregates is also significant at 2,091 GWh. However, investment in determining the technically and commercially attractive approaches to using hydrogen will have most impact (in respect of emissions abatement per pound spent) if this is focused on industries within which there is some consistency of processes, i.e. the Chemicals, Food and Drink, Oil and Gas and Glass sectors. Detailed analysis of the potential for conversion to hydrogen in these (and in the four other main industry sectors) can be found in Section 5.0.

The data in Table 2.3 shows that sites in the Pulp and Paper and Glass sectors have higher average natural gas use than those in the Chemicals sector. This might suggest that they should be prioritised, as conversion of the same number of plant would have a larger impact.

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5 See [http://naei.defra.gov.uk/data/map-large-source](http://naei.defra.gov.uk/data/map-large-source)

6 Note that olefin production at Stanlow refinery is included under the Oil and Gas sector, as it cannot be easily separated from wider gas use at the site
Table 2.3: Sectoral Natural Gas Consumption (2015)

<table>
<thead>
<tr>
<th>Sector</th>
<th>Number of Sites</th>
<th>Natural Gas Use (GWh)</th>
<th>Average Natural Gas Use (GWh) Per Site</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chemicals</td>
<td>25</td>
<td>2,568</td>
<td>103</td>
</tr>
<tr>
<td>Food and Drink</td>
<td>36</td>
<td>1,835</td>
<td>51</td>
</tr>
<tr>
<td>Oil and Gas</td>
<td>5</td>
<td>1,691</td>
<td>338</td>
</tr>
<tr>
<td>Glass</td>
<td>8</td>
<td>1,506</td>
<td>188</td>
</tr>
<tr>
<td>Pulp and Paper</td>
<td>5</td>
<td>890</td>
<td>178</td>
</tr>
<tr>
<td>Metals</td>
<td>2</td>
<td>271</td>
<td>135</td>
</tr>
<tr>
<td>Ceramics</td>
<td>2</td>
<td>171</td>
<td>85</td>
</tr>
<tr>
<td>Cement</td>
<td>1</td>
<td>16</td>
<td>16</td>
</tr>
<tr>
<td>Other</td>
<td>81</td>
<td>2,091</td>
<td>26</td>
</tr>
<tr>
<td>TOTAL</td>
<td>165</td>
<td>11,039</td>
<td>67</td>
</tr>
</tbody>
</table>

Notes:
1. Includes only sites with > 5.9 GWh/annum natural gas consumption, which are connected to the Local Transmission System (LTS)
2. Excludes sites such as Runcorn (Inovyn) and Ince (CF Fertilisers) which are connected to the NTS

There are many large industrial gas users in the L-M Cluster. For example in 2016, 4,856 GWh was consumed by just 10 companies. This is 10% of the total gas used in the area. The locations of these large gas users are shown in Figure 2.2.

Figure 2.2: Location of 10 Selected Large Industrial Natural Gas Users

Source: Map data ©2017 Google
Site specific consumption data provided by Cadent suggests that, for some sites, there was a significant variance between minimum and maximum levels of monthly gas consumption during 2016. This was likely the result of a range of factors including changing market and trading conditions and scheduled or unscheduled downtime for plant maintenance. However, in the context of planning the potential scale and structure of hydrogen production (and CO₂) storage infrastructure, it is the combined monthly swings across all sites that is more important. For ten of the largest sites, total monthly gas consumption is presented in Table 2.4. This averages 405 GWh/month and ranges from a low in June of 353 GWh to a high in January of 482 GWh.

### Table 2.4: Total Monthly Gas Consumption of 10 Large Gas Users (2016)

<table>
<thead>
<tr>
<th>Month</th>
<th>Natural Gas Consumption (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>482</td>
</tr>
<tr>
<td>February</td>
<td>449</td>
</tr>
<tr>
<td>March</td>
<td>425</td>
</tr>
<tr>
<td>April</td>
<td>381</td>
</tr>
<tr>
<td>May</td>
<td>358</td>
</tr>
<tr>
<td>June</td>
<td>353</td>
</tr>
<tr>
<td>July</td>
<td>378</td>
</tr>
<tr>
<td>August</td>
<td>378</td>
</tr>
<tr>
<td>September</td>
<td>362</td>
</tr>
<tr>
<td>October</td>
<td>430</td>
</tr>
<tr>
<td>November</td>
<td>436</td>
</tr>
<tr>
<td>December</td>
<td>423</td>
</tr>
<tr>
<td>AVERAGE</td>
<td>405</td>
</tr>
<tr>
<td>LOW (June)</td>
<td>353</td>
</tr>
<tr>
<td>HIGH (January)</td>
<td>482</td>
</tr>
</tbody>
</table>

### 2.3 Energy Delivered by Hydrogen/Natural Gas Blends

Whilst using 100% hydrogen would produce complete decarbonisation of the natural gas distribution network, in the shorter term, blending of hydrogen with natural gas represents a more readily deliverable alternative. Consequently, we have modelled the likely energy delivered by hydrogen to the industrial, commercial and domestic sectors in L-M Cluster area, based on 5% and 20% by volume (vol.) blends as shown in Table 2.5.

At a 5%vol. blend, hydrogen would replace 768 GWh (1.6%) of natural gas within the cluster area, with this increasing to 3,438 GWh (7.2%) at a 20% blend. The CO₂ emissions reductions associated with delivering these proportions of hydrogen into the network are examined in Section 2.9.

### Table 2.5: Potential Energy Delivered by Hydrogen Blends (GWh)

<table>
<thead>
<tr>
<th>Sector</th>
<th>100% Hydrogen Substitution</th>
<th>5%vol. Hydrogen Blend</th>
<th>20%vol. Hydrogen Blend</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial (sites &gt;5.9 GWh)</td>
<td>11,039</td>
<td>178</td>
<td>797</td>
</tr>
<tr>
<td>Commercial</td>
<td>16,331</td>
<td>263</td>
<td>1,179</td>
</tr>
<tr>
<td>Domestic</td>
<td>20,261</td>
<td>327</td>
<td>1,463</td>
</tr>
<tr>
<td>TOTAL</td>
<td>47,631</td>
<td>768</td>
<td>3,438</td>
</tr>
</tbody>
</table>
2.4 Power Generation Infrastructure and Gas Demand

As presented in Table 2.6, there are three large scale operational CCGT plants in the L-M Cluster area; Connah’s Quay, Rocksavage and Carrington\(^7\). All are connected to the NTS rather than Cadent’s distribution network, and therefore are of less direct relevance to this study than the industrial gas users described in Section 2.2. However, it is important to provide related analysis of CCGT plant in the context of their operating profiles and demand for natural gas. Both of these factors might potentially influence the design and configuration of a future hydrogen cluster, as CCGTs could also potentially play a role in helping to manage fluctuations in demand from industry and households, as discussed further in Section 6.0.

The data in Table 2.6 shows that whilst the theoretical maximum gas demand of 54,578 GWh in respect of these three plants is significant, the actual demand of 2,395 GWh is significantly lower than the demand of 11,039 GWh from industry within the L-M Cluster area. This is the result of very low load factors for Connah’s Quay and Rocksavage, which have been operating for 20 and 18 years respectively\(^8\). All three plants struggle to compete in the current electricity market and therefore now solely operate as ‘peaking’ or ‘reserve’ plant, effectively being switched on only for short periods of the day when demand, and therefore prices, are at their highest.

Rocksavage is scheduled to realise revenues via ‘T-4’ contracts to provide reserve power in the Capacity Market (CM) for the 2018/19, 2019/20 and 2020/21 delivery years, whilst Connah’s Quay will do the same for the latter two delivery years. At the same time, Carrington gained a ‘new build’ capacity market contract for these latter two delivery years. However, whilst we would expect actual natural gas use to increase in future years as a result of Carrington coming online, the age of Connah’s Quay and Rocksavage is such that they might be expected to close (unless retrofit, for which the business case would be challenging) in the next 3-6 years.

It should also be mentioned that Trafford Power (a subsidiary of Carlton Power) has received planning consent to build a 1,520 MW CCGT plant at Trafford in Manchester. The plant won a CM contract in the 2014 auction but has not been able to subsequently reach financial close to enable construction. Despite being given an extension by Government until December 2016 to meet its milestone commitments under the CM contract, it remains unclear, at the present time, whether this has been achieved.

As mentioned above, the data presented within Table 2.6 demonstrates that annual natural gas demand from CCGT stations is less than 25% of the gas consumed by industry in the L-M Cluster area. However, should coal-fired stations close in line with recent Government legislation, and Trafford Power reach financial close to come into operation alongside the new Carrington station, gas consumption by CCGT plant on in the L-M Cluster area may increase significantly.

### Table 2.6: Gas Demand from CCGT Plant in the L-M Cluster Area (2014)

<table>
<thead>
<tr>
<th>Site Name</th>
<th>Operator</th>
<th>Year Started</th>
<th>Peak Electrical Output (MWe)</th>
<th>Theoretical Max. Annual Gas Demand (GWh)</th>
<th>Actual Gas Use (GWh)</th>
<th>Load Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Connah’s Quay</td>
<td>E.ON UK</td>
<td>1996</td>
<td>1,380</td>
<td>24,533</td>
<td>2,029</td>
<td>8%</td>
</tr>
<tr>
<td>Rocksavage</td>
<td>Intergen</td>
<td>1998</td>
<td>810</td>
<td>14,400</td>
<td>366</td>
<td>3%</td>
</tr>
<tr>
<td>Carrington(^7)</td>
<td>ESB</td>
<td>2016/17</td>
<td>880</td>
<td>15,644</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td></td>
<td></td>
<td><strong>3,070</strong></td>
<td><strong>54,578</strong></td>
<td><strong>2,395</strong></td>
<td></td>
</tr>
</tbody>
</table>

Notes:
1. Carrington did not commence operation until late 2016/early 2017

\(^7\) Deesside CCGT power station requested that its license was revoked by Ofgem in May 2015 and so is understood to no longer be operating. See [https://www.ofgem.gov.uk/sites/default/files/docs/2015/06/deeside_power_electricity_generation_revocation_consolidated.pdf](https://www.ofgem.gov.uk/sites/default/files/docs/2015/06/deeside_power_electricity_generation_revocation_consolidated.pdf)

\(^8\) As Carrington has only just commenced operation, only limited data is available
2.5 Opportunities for Hydrogen Supply

As part of either a demonstration project or full-scale deployment, there is potential to generate hydrogen from new large-scale production facilities, including those which use the following processes:

- Conversion of natural gas, using an SMR or alternative technology;
- Production of hydrogen-rich synthetic ('syngas') from gasification of residual oils (refinery bottoms) or coal;
- Bio-H2 production from bio-substitute natural gas (Bio-SNG) produced via gasification of biomass (including waste); and
- Electrolysis of water (commonly known as ‘power-to-gas’ - P2G).

As presented in Table 2.7, there are also a number of existing sources of hydrogen, which might be captured for use in the L-M Cluster. A number of these sites are also major gas users. These sources of hydrogen are also presented spatially in Figure 2.4 and discussed in more detail in Section 6.0 in the context of providing additional supplies of hydrogen to help balance supply and demand on the network.

The data in Table 2.7 demonstrates that (whilst not wholly transparent) there are material and diverse existing sources of hydrogen potentially available in the L-M Cluster area. In contrast to some other geographies this is not only a potentially important ingredient for cost-effective, meaningful demonstration projects, but provides some hydrogen supply resilience and also can function as a catalyst for wider future deployment of a hydrogen cluster and network.
### Table 2.7: Potential Existing Sources of Hydrogen in the L-M Cluster Area

<table>
<thead>
<tr>
<th>Site Name</th>
<th>Operator</th>
<th>Sector</th>
<th>Method of Hydrogen Production</th>
<th>Volumes and Quality</th>
</tr>
</thead>
<tbody>
<tr>
<td>Runcorn</td>
<td>Inovyn</td>
<td>Chemicals</td>
<td>Hydrogen is produced as a by-product of the chlorine production process</td>
<td>The chloro-alkali process produces significant volumes of hydrogen, which a simple mass balance analysis suggests are likely to be &gt;10 ktpa. Inovyn previously used the majority of this to fire an onsite boiler. Its heat requirements, however, are now met by two new energy from waste (EfW) facilities (operated by Viridor), such that the boiler is now redundant</td>
</tr>
<tr>
<td>Ince</td>
<td>CF Fertilisers</td>
<td>Chemicals</td>
<td>CF Industries uses hydrogen to produce ammonia via the Haber- Bosch process. Hydrogen is produced on-site via SMR</td>
<td>Hydrogen is produced specifically as an input to the main manufacturing process. Spare hydrogen production capacity would rely on a fall in demand for ammonia</td>
</tr>
<tr>
<td>St Helens</td>
<td>BOC</td>
<td>Chemicals</td>
<td>BOC supplies hydrogen to Pilkington Glass (at St Helens) for the production of float glass products from a small offsite SMR</td>
<td>The float glass process uses hydrogen as a reducing agent, but the volume supplied is relatively small</td>
</tr>
<tr>
<td>Stanlow</td>
<td>Essar</td>
<td>Oil &amp; Gas</td>
<td>Hydrogen is produced as a by-product of the cracking process used to produce petroleum products from crude oil</td>
<td>Stanlow produces significant volumes of hydrogen from the cracking process, which we estimate are &gt;40 ktpa. The majority of this is currently used to generate heat on-site. Essar has indicated, however, that it would consider switching fuels to natural gas if a more valuable option could be found for the hydrogen</td>
</tr>
</tbody>
</table>

### Figure 2.4: Potential Existing Sources of Hydrogen in the L-M Cluster Area
2.6 Existing Gas Transportation Infrastructure

2.6.1 Onshore natural gas Network
The natural gas distribution network (operated by Cadent) in the L-M Cluster area is presented above in Figure 2.1 in Section 2.1. Across this network, it will be important to identify relevant points for injection of hydrogen. The siting and number of these connection points will depend upon the detailed design of the future Cluster including the likely blend of hydrogen and the industrial customers to be supplied.

2.6.2 Onshore Hydrogen Pipelines
As mentioned briefly in Table 2.7, there are currently two known pipelines transporting hydrogen in the L-M Cluster Area, as follows:

- A pipeline connects Inovyn’s site at Runcorn (where hydrogen is produced as a by-product of chlorine production), with Solvay at Warrington; and
- A pipeline connects BOC’s St Helens site to Pilkington Glass (also at St Helens), where hydrogen is supplied to support float glass production.

The potential for use of these pipelines to support an initial project or longer-term large-scale deployment of a hydrogen network is discussed in Section 6.0.

2.6.3 Offshore Gas Pipelines
Any large-scale production of hydrogen to fuel a large city or cluster will involve the use of fossil fuels and simultaneously result in significant production of CO₂. Consequently to provide significant decarbonisation, the hydrogen system must be coupled with CCS. In the UK, underground storage of CO₂ is only permitted offshore.

At present, one major 20” gas pipeline runs from the Liverpool Bay complex of oil and gas fields, which are operated by ENI, to the Point of Ayr gas terminal. As presented in Figure 2.5, this pipeline then runs on from Point of Ayr to E.ON’s Connahs Quay CCGT plant. Once production of natural gas ceases at Liverpool Bay, it may well be possible to repurpose this pipeline for reverse flow of CO₂ resulting in particularly low costs for future CO₂ transport for the potential L-M Cluster. In the shorter term, should it be necessary, CO₂ from any demonstration project could potentially be sent for storage via ship or smaller pipeline for example from the Mersey estuary close to the likely sources of hydrogen production. Such an approach would also depend upon a suitable CO₂ storage site being available. The likelihood of this is discussed in Section 2.7.
In addition to the Liverpool Bay complex, there is even greater CO$_2$ storage capacity at Centrica’s Morecambe Bay complex, also in the East Irish Sea. The pipeline from Morecambe Bay runs into Centrica’s Rampside gas terminal in Barrow-in-Furness, which is outside the L-M Cluster area. However, it could still represent a strategic asset in respect of large-scale deployment of a hydrogen network in the wider North West region in the future.

The capacity and suitability of both the Liverpool Bay and Morecambe Bay complexes to store CO$_2$ are both discussed further in Section 2.7.
2.7 Opportunities for Offshore Storage of CO$_2$

2.7.1 Liverpool Bay Fields

The Liverpool Bay complex is shown above in Figure 2.5. The complex is operated by ENI. It comprises the integrated development of six offshore oil and gas fields in the East Irish Sea. ENI (and formerly with joint venture partner, BHP Billiton) produces (or has produced) oil from the Lennox, Douglas and Douglas West fields, which is then treated at the Douglas Complex and piped 17 km to an oil storage barge ready for export by tankers. Gas has been produced from the Lennox, Hamilton, Hamilton North and Hamilton East fields. After initial processing at the Douglas Complex, the gas is piped along a 33 km subsea pipeline to the Point of Ayr gas terminal for further processing. It is then sent by onshore pipeline to E.ON’s CCGT plant at Connah’s Quay.

Production of oil and gas in Liverpool Bay began in 1996, but is now coming towards the end of production. The Hamilton gas field represents the best candidate for CO$_2$ storage and is identified in a recent extensive ETI study as within the ‘top 20’ best storage reservoirs in UK waters.$^8$ A reasonably detailed ‘storage development plan’ for Hamilton was also developed as part of the same study, as it was further short-listed as one of five priority sites.$^{10}$

Data published by BEIS shows that from a production of 2,617 million m$^3$ in 2003, the complex produced only 122 million m$^3$ in 2015, with the majority of this appearing to come from Lennox. We understand, however, that the fields are likely to continue to produce gas until the early 2020s.

The ETI study estimates that Hamilton has a CO$_2$ storage capacity of 130 million tonnes (MT)$^{11}$. It suggests that in the first instance (13-14 years) CO$_2$ should be injected in the gas-phase. However, it is also proposed that to inject 5 MtCO$_2$/annum (the required injection rate assumed in the study), it would be most cost-efficient to transport CO$_2$ in liquid-phase and then manage the low temperature effects of the phase change to gas using heating during the first development period. Consequently, as a result of the relatively high annual volume used in the ETI study, the work proposed a new CO$_2$ pipeline from Point of Ayr.

For a smaller annual volume it is likely that the existing pipeline and much of the existing infrastructure could be adapted for CO$_2$ storage. The ETI study provides relatively detailed pre-FEED cost estimates for the drilling of new wells and changes to platforms and facilities that would be required to facilitate CO$_2$ injection. This data has been used as a basis to estimate the CO$_2$ transport and storage costs for a lower volume of CO$_2$ in Section 7.1.

The Hamilton field is also much closer to land than most other offshore oil and gas fields, which reduces the cost of transport. Relative to other options identified in the ETI report across the country, it appears that Hamilton represents a particularly attractive location both for transport and storage of CO$_2$.

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$^8$ ETI (2016) Progressing development of the UK’s Strategic Carbon Dioxide Storage Resource, April 2016 http://www.eti.co.uk/news/eti-project-identifies-cost-effective-ccs-storage-sites-off-the-uk-coast/


$^{11}$ Information taken from the Strategic UK CCS Storage Appraisal Project, funded by DECC, commissioned by the ETI and delivered by Pale Blue Dot Energy, Axis Well Technology and Costain. See https://s3-eu-west-1.amazonaws.com/assets.eti.co.uk/legacyUploads/2016/04/ETI-licence-v2.1.pdf
2.7.2 Morecambe Bay Fields

As presented in Figure 2.6, the Morecambe Bay fields are operated by Centrica and include Morecambe North, Morecambe South, Millom, Dalton, Hodder, Calder, Rhyl and Crossans. North and South Morecambe are by far the two largest fields.

In the aforementioned ETI study, both Morecambe North and Morecambe South are also identified in the top 20 UK offshore reservoirs for storage of CO₂. South Morecambe is the larger, with a theoretical storage capacity of 855 MT, whilst the capacity of North Morecambe is calculated to be 180 MT.

First gas was produced from Morecambe Bay in 1985 and it is understood that North and South Morecambe are likely to continue producing throughout the 2020s and likely beyond.

The Hamilton field, which is available for repurposing for CO₂ storage in the early 2020s, as discussed in Section 2.7.1, represents the most likely ‘catalyst’ for CO₂ storage in the East Irish Sea. The combined capacity (of Morecambe North and South) of over 1 Billion tCO₂ means, however, is such that Morecambe Bay could play a critical long-term role in storing CO₂ from a potential future L-M Hydrogen Cluster.

Figure 2.6: Morecambe Bay Gas Fields in the East Irish Sea
2.8 Existing Hydrogen, and Wider Gas Storage Infrastructure

As highlighted and explored in the H21 study, to manage daily and seasonal fluctuations in energy demand, both diurnal and seasonal storage facilities will ultimately be required to support a large, low carbon hydrogen supply system to supply the L-M Cluster as well as those further afield.

Fortunately, the Cheshire ‘Basin’ is home to two huge salt-bearing formations; the lower Northwich Halite Formation and the upper Wilkesley Halite Formation. As a result of the impermeable nature of salt, such strata are ideally suited to the creation of storage cavities for gases. Salt caverns have been used to store hydrocarbons and hydrogen since the late 1950s, with hydrogen having been stored in caverns on Teesside for the last five decades.

Natural gas storage originally took place in naturally occurring salt caverns, but more recently, these have been specially engineered to the desired size and spacing (between caverns). As presented in Table 2.8, five such developments are currently operating near to the L-M Cluster area, which amount to a total current storage capacity of 455 million m³ (mcm). Whilst these caverns are unlikely to be immediately turned over to hydrogen storage, this may be possible in the future, which might reduce the cost of developing new assets to support the potential hydrogen cluster in the L-M area. This is particularly important as not only would caverns for containing hydrogen be required, but these require servicing with additional brine caverns and pipelines. Most such additional infrastructure is already in place at these existing gas storage sites.

In addition, a further 1,548 mcm of capacity is either consented or awaiting consent. It is notable that some projects are struggling to reach financial close, and therefore should some of this consented capacity not be used for storage of natural gas, it may be possible to amend existing consents for storage of hydrogen should this be required in the near term. At the very least, some of the work that has been undertaken by developers in respect of site selection and characterisation might be reused in respect of developing hydrogen storage sites.

It should be noted that the Energy Technologies Institute (ETI) has recently commissioned a major study to provide analysis of the potential for hydrogen storage across the UK, which is likely provide a greater level of technical detail than presented here.13

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12 A further 200 mcm of capacity is under construction and will shortly be operational.
**Table 2.8: Existing and Planned Onshore Salt Caverns in NW England**

<table>
<thead>
<tr>
<th>Site Name</th>
<th>Number of Caverns</th>
<th>Lead Operator / Developer</th>
<th>Status</th>
<th>Year of Start of Operation</th>
<th>Current / Intended Usage</th>
<th>Capacity (Million m³ natural gas)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Holford</td>
<td>8</td>
<td>E.ON Gas Storage UK</td>
<td>Operating</td>
<td>2013</td>
<td>Natural gas storage</td>
<td>160</td>
</tr>
<tr>
<td>Stublach</td>
<td>28</td>
<td>Storengy (GDF Suez)</td>
<td>Part operating1</td>
<td>2014-2020</td>
<td>Natural gas storage</td>
<td>400²</td>
</tr>
<tr>
<td>Hole House</td>
<td>4</td>
<td>EDF Trading</td>
<td>Operating</td>
<td>2001</td>
<td>Natural gas storage</td>
<td>75</td>
</tr>
<tr>
<td>Holford H-165*</td>
<td>4</td>
<td>Inovyn</td>
<td>Operating</td>
<td>1984</td>
<td>Natural gas storage</td>
<td>0.175</td>
</tr>
<tr>
<td>Hill Top</td>
<td>10</td>
<td>EDF Trading</td>
<td>Operating</td>
<td>2016</td>
<td>Natural gas storage</td>
<td>20</td>
</tr>
<tr>
<td>Presall</td>
<td>19</td>
<td>Halite</td>
<td>Consented</td>
<td>n/a</td>
<td>Natural gas storage</td>
<td>900</td>
</tr>
<tr>
<td>King St</td>
<td>9</td>
<td>King St Energy</td>
<td>Consented</td>
<td>n/a</td>
<td>Natural gas storage</td>
<td>348</td>
</tr>
<tr>
<td>Holford Extension</td>
<td>19</td>
<td>Keuper Gas Storage</td>
<td>Awaiting DCO outcome</td>
<td>n/a</td>
<td>Natural gas storage</td>
<td>500</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td><strong>2,403³</strong></td>
</tr>
</tbody>
</table>

Notes:
1. Some caverns still under construction
2. Currently only 200 Million m³ operational, with a further 200 Million m³ either planned or under construction
3. Currently a total of 455 Million m³ operational
4. Previously operated by Cadent (as National Grid Gas Distribution)

In addition to gas storage in onshore salt caverns, natural gas or hydrogen might also be stored in offshore salt caverns. In principle hydrogen could similarly be stored offshore, and whilst the costs would be likely greater than onshore storage, there are likely to be fewer constraints in terms of consenting and the potential for larger caverns for seasonal storage and therefore possible economies of scale.

Stag Energy’s proposed Gateway project in the East Irish Sea would be the first development of this nature in the UK.¹⁴ Stag was seeking to develop a working gas storage capacity of 1.52 Billion m³ and received planning consent in 2008. However, it is understood that the company failed to progress an associated liquefied natural gas (LNG) terminal and so the storage project has been abandoned.

¹⁴ See [http://www.gatewaystorage.co.uk/](http://www.gatewaystorage.co.uk/)
2.9 Potential Carbon Reduction Benefits

The total CO$_2$ emissions from consumption of natural gas by industry (by sector) in the L-M Cluster area are presented in Table 2.9. This shows that a switch to 100% hydrogen in industry would result in a CO$_2$ reduction of 2.2 Million tonnes per annum. This would represent around 11% of all CO$_2$ emissions from natural gas by industry in the UK.

Given the potential to blend CO$_2$, it is also important to consider the reduction in CO$_2$ emissions, which would be delivered by 5% and 20%vol. blends of hydrogen. The data in Table 2.9 demonstrates that a 5%vol. blend of hydrogen across the whole of the gas distribution network in the L-M cluster area would deliver an annual CO$_2$ reduction of 0.15 Million tonnes, which equates to 1.6% of total CO$_2$ emissions. Similarly, a 20%vol. hydrogen blend could deliver an annual reduction in CO$_2$ emissions of 0.7 Million tonnes, equal to 7.2% of current levels in the L-M Cluster area. In the wider context, a 20% blend supplied to the L-M Cluster area would equate to around 0.7% of total CO$_2$ emissions from natural gas consumed across all GB distribution networks.

Table 2.9: Full Potential Emissions Reductions from Hydrogen to Industry

<table>
<thead>
<tr>
<th>Sector</th>
<th>100% Hydrogen Substitution (tCO$_2$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chemicals</td>
<td>513,679</td>
</tr>
<tr>
<td>Glass</td>
<td>283,763</td>
</tr>
<tr>
<td>Food and Drink</td>
<td>366,999</td>
</tr>
<tr>
<td>Oil and Gas</td>
<td>338,129</td>
</tr>
<tr>
<td>Ceramics</td>
<td>51,498</td>
</tr>
<tr>
<td>Cement</td>
<td>3,255</td>
</tr>
<tr>
<td>Pulp and Paper</td>
<td>178,050</td>
</tr>
<tr>
<td>Iron &amp; Steel</td>
<td>54,165</td>
</tr>
<tr>
<td>Other</td>
<td>418,193</td>
</tr>
<tr>
<td>TOTAL</td>
<td>2,207,729</td>
</tr>
</tbody>
</table>

Notes:
1. Includes only sites with > 5.9 GWH/annum natural gas consumption, which are connected to the LTS
2. Excludes sites such as Runcorn (Inovyn) and Ince (CF Industries) which are connected to the NTS

Table 2.10: Emissions Reductions (tCO$_2$/annum) from Hydrogen

<table>
<thead>
<tr>
<th>Sector</th>
<th>100% Hydrogen Substitution</th>
<th>5% vol. Hydrogen Blend</th>
<th>20% vol. Hydrogen Blend</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial (sites &gt;5.9 GWh)</td>
<td>2,207,729</td>
<td>35,578</td>
<td>159,367</td>
</tr>
<tr>
<td>Commercial</td>
<td>3,266,237</td>
<td>52,637</td>
<td>235,776</td>
</tr>
<tr>
<td>Domestic</td>
<td>4,052,230</td>
<td>65,303</td>
<td>292,513</td>
</tr>
<tr>
<td>TOTAL</td>
<td>9,526,196</td>
<td>153,518</td>
<td>687,656</td>
</tr>
</tbody>
</table>
Table 2.11 provides analysis of emissions from the same large natural gas users in the Cluster area as identified above. The total reduction in CO$_2$ emissions associated with moving just these ten sites to a 100% hydrogen fuel would be 0.97 million tonnes per annum, which equates to over 10% of total emissions from all gas use in the whole L-M Cluster area.

The approach towards such a goal, whether as part of a single switch or a more phased process over time is explored in respect of different types of gas use (boiler, CHP, furnace etc) and different industries in Section 5.0, and in respect of a wider gas network decarbonisation strategy for the L-M Cluster in Section 6.0.

**Table 2.11: CO$_2$ Reduction from 100% Hydrogen to 10 Large Industrial Sites**

<table>
<thead>
<tr>
<th>Industry Sector</th>
<th>Emissions Reduction (tCO$_2$/annum)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil &amp; Gas</td>
<td>168,351</td>
</tr>
<tr>
<td>Pulp &amp; Paper</td>
<td>151,208</td>
</tr>
<tr>
<td>Food &amp; Drink</td>
<td>159,347</td>
</tr>
<tr>
<td>Glass</td>
<td>161,255</td>
</tr>
<tr>
<td>Glass</td>
<td>96,184</td>
</tr>
<tr>
<td>Chemicals</td>
<td>60,753</td>
</tr>
<tr>
<td>Other</td>
<td>49,519</td>
</tr>
<tr>
<td>Chemicals</td>
<td>44,998</td>
</tr>
<tr>
<td>Chemicals</td>
<td>41,216</td>
</tr>
<tr>
<td>Food &amp; Drink</td>
<td>38,355</td>
</tr>
<tr>
<td>TOTAL</td>
<td>971,187</td>
</tr>
</tbody>
</table>

Notes:
1. Does not include large sites for which load factor data was not available
2. Excludes sites which are connected to the NTS

The potential emissions reductions presented in Table 2.9 to Table 2.11 assume that the production and supply of hydrogen does not result in any CO$_2$ emissions.

At present, to produce sufficient volumes of hydrogen will require the conversion of gas via SMR, via auto-thermal reformation or via gasification of solid fossil fuels (potentially either refinery residue oils or coal), combined with CCS infrastructure to capture, transport and store associated CO$_2$.

The production of bio-hydrogen from waste (which has a high biomass content) is another potential alternative. Bio-hydrogen is produced as a step in the production of bio-SNG and which currently being demonstrated. This route could be an important contributor, especially because of its ability to produce ‘negative’ CO$_2$ emissions via the use of local sources of waste. However, given the availability of sustainable biomass resource, it would need to act in concert with fossil-derived hydrogen production.

Similarly, at present, P2G applications are constrained by the amount of low cost electricity (for example, from constrained windfarms), which is available to achieve a sufficiently low cost for hydrogen at meaningful and consistent volumes. However, the ability to site electrolysers wherever hydrogen is required means that they are likely to make an important contributor once hydrogen networks become more established.

The above options are all low carbon sources of hydrogen. However, all have some associated CO$_2$ emissions aside from bio-hydrogen, which could potentially deliver ‘negative’ emissions, and therefore carbon abatement will be lower than presented above.

Analysis of likely methods of hydrogen production and supply to support the different phases of development of a future L-M Hydrogen Cluster is undertaken in Section 6.0.
3.0 CHARACTERISATION OF INFRASTRUCTURE ON HUMBERSIDE

The content of this section is based on engagement with industry in the Humberside area, along with review and analysis of secondary data. We have also been supported by Cadent in respect of data relating to gas demand of some major users.

3.1 Scope of the Humber Cluster Area

Figure 3.1 presents the specific scope of the geographical area and the associated gas distribution network (operated by Cadent) considered as the ‘Humber Cluster’ area for this study. It should be noted that the gas network in part of the Cluster area, situated to the North, is operated by Northern Gas Networks (NGN). As a result, the related pipes are not presented in Figure 3.1 and the gas use of industrial sites located outside of the Cadent area (but within the Humber Cluster) is excluded from the analysis in Section 3.4.

Figure 3.1: Humberside Cluster Area and Cadent Gas Network

Note: Includes all ‘HU’ postcodes and all ‘DN’ postcodes aside from DN21, DN22
### 3.2 Industrial Gas Demand

As for the L-M area, further to work commissioned by DECC (now BEIS) in 2015, we have allocated gas demand across eight industry sectors (along with an ‘other’ category, for businesses which fall outside this classification). Power generation in CCGT plants for export to the electricity transmission grid is considered separately in Section 3.4.

#### 3.2.1 Comparison with Gas Demand across other Sectors

As summarised in Table 3.1, based on data provided by Cadent, total natural gas use by industry (users with demand > 5.9 GWh/annum) connected to the distribution network in the Humber Cluster area was 3,887 GWh in 2016. This represents 7% of the 52,928 GWh consumed by such industrial users across the whole Cadent network and 2% of total industrial gas consumption in GB of 99,729 GWh in 2015.

Total gas consumption (domestic and non-domestic) in the Humber Cluster area was 15,738 GWh in 2015, which represents around 3% of total GB gas consumption (at distribution level) of 495,656 GWh in 2015.

### Table 3.1: Natural Gas Consumption Data for Humber Cluster Area

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Natural Gas Consumption (GWh)¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial (sites &gt; 5.9 GWh) gas consumption (2015)</td>
<td>3,887</td>
</tr>
<tr>
<td>Commercial gas consumption (2014)</td>
<td>5,423</td>
</tr>
<tr>
<td>Domestic gas consumption (2014)</td>
<td>6,428</td>
</tr>
<tr>
<td>Total gas consumption (2014)</td>
<td>15,738</td>
</tr>
</tbody>
</table>

Notes:
1. Excludes gas consumption delivered direct from the NTS

### 3.2.2 Sectoral Analysis of Gas Consumption

The provision of information (as detailed in Section 5.0) as to how processes and generation plant in specific industry sectors might be adapted or retrofit to accommodate a switch to hydrogen (or hydrogen/natural gas mixtures) will inform analysis of the changes that are likely to be needed at a macro-level.

Table 3.2 presents total gas use by industrial sector. This has been drawn from information provided by Cadent, but also triangulated with data modelled from site emissions published for ‘large point sources’ in the UK’s National Atmospheric Emissions Inventory (NAEI).\(^{16}\)

The largest consumer of natural gas in the Humber Cluster area is the Chemicals sector, which used 1,065 GWh in 2015. This is followed by the Glass sector with 433 GWh, the Metals sector with 330 GWh and the Food and Drink sector with 273 GWh. There are no major sites (i.e. sites with >5.9 GWh annual gas consumption) in the Humber Cluster area in the Ceramics, Cement or Pulp and Paper sectors.

The consumption of ‘Other’ industry sectors, which include automotive, textiles and aggregates is also significant at 1,589 GWh. The data suggests, however, that investment in determining the technically and commercially attractive approaches to using hydrogen will have most impact (in respect of emissions abatement per pound spent) if this is focused on the Chemicals, Glass, Metals and Food and Drink sectors.

The data in Table 3.2 also suggests that sites in the Chemicals, Glass and Metals sectors have higher average natural gas use than those in other sectors. This suggests that they should be prioritised over other sectors, as conversion of the same number of plant would have a larger impact.

#### Table 3.2: Sectoral Gas Consumption of Sites connected to LTS (2015)

<table>
<thead>
<tr>
<th>Sector</th>
<th>Number of Sites</th>
<th>Natural Gas Use (GWh)</th>
<th>Average Natural Gas Use (GWh) Per Site</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chemicals</td>
<td>6</td>
<td>1,065</td>
<td>177</td>
</tr>
<tr>
<td>Glass</td>
<td>2</td>
<td>433</td>
<td>217</td>
</tr>
<tr>
<td>Food and Drink</td>
<td>14</td>
<td>273</td>
<td>19</td>
</tr>
<tr>
<td>Oil and Gas(^2)</td>
<td>1</td>
<td>12</td>
<td>12</td>
</tr>
<tr>
<td>Ceramics</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Cement</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Pulp and Paper</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Metals</td>
<td>5</td>
<td>515</td>
<td>103</td>
</tr>
<tr>
<td>Other</td>
<td>27</td>
<td>1,589</td>
<td>59</td>
</tr>
<tr>
<td>TOTAL</td>
<td>55</td>
<td>3,887</td>
<td>67</td>
</tr>
</tbody>
</table>

Notes:
1. Includes only sites with > 5.9 GWh/annum natural gas consumption, which are connected to the LTS
2. Excludes both Lindsey and South Humber refineries, both which are connected to the NTS

\(^{16}\) See [http://naei.defra.gov.uk/data/map-large-source](http://naei.defra.gov.uk/data/map-large-source)
There are many large industrial gas users in the Humber Cluster. For example in 2016, 2,863 GWh was consumed by just 10 companies. This is 18% of the total gas used in the area. The locations of these large gas users are shown in Figure 3.2.

Site specific consumption data provided by Cadent suggests that, for some sites, there was a significant variance between minimum and maximum levels of monthly gas consumption during 2016. This was likely the result of a range of factors including changing market and trading conditions and scheduled or unscheduled downtime for plant maintenance. However, in the context of planning the potential scale and structure of hydrogen (and CO₂) storage infrastructure, it is the monthly swings combined across all sites that are more important. For the ten largest sites, total monthly gas consumption is presented in Table 3.3. This averages 159 GWh/month and ranges from a low in August of 142 GWh to a high in June of 173 GWh.¹⁷

¹⁷ As the British Steel plant was not operating in January 2016 (or in October to December 2015), this month has effectively been excluded from the analysis
Table 3.3: Total Monthly Gas Consumption across 10 Large Users (2016)

<table>
<thead>
<tr>
<th>Month</th>
<th>Natural Gas Consumption (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>113¹</td>
</tr>
<tr>
<td>February</td>
<td>155</td>
</tr>
<tr>
<td>March</td>
<td>169</td>
</tr>
<tr>
<td>April</td>
<td>158</td>
</tr>
<tr>
<td>May</td>
<td>164</td>
</tr>
<tr>
<td>June</td>
<td>173</td>
</tr>
<tr>
<td>July</td>
<td>161</td>
</tr>
<tr>
<td>August</td>
<td>142</td>
</tr>
<tr>
<td>September</td>
<td>168</td>
</tr>
<tr>
<td>October</td>
<td>165</td>
</tr>
<tr>
<td>November</td>
<td>170</td>
</tr>
<tr>
<td>December</td>
<td>168</td>
</tr>
<tr>
<td>AVERAGE</td>
<td>159</td>
</tr>
<tr>
<td>LOW (June)</td>
<td>142</td>
</tr>
<tr>
<td>HIGH (January)</td>
<td>173</td>
</tr>
</tbody>
</table>

Notes:
1. The large British Steel plant was not operating in January 2016 and hence that the month should be considered an ‘outlier’ in this dataset

3.3 Energy Delivered by Hydrogen/Natural Gas Blends

Whilst using 100% hydrogen would produce complete decarbonisation of the natural gas distribution network, in the shorter term, blending of hydrogen with natural gas is more readily deliverable. Consequently, we have modelled the likely energy delivered by hydrogen to the industrial, commercial and domestic sectors in Humber Cluster area, based on 5% and 20%vol. blends as shown in Table 2.5.

At a 5%vol. blend, hydrogen would replace 254 GWh (1.6%) of natural gas within the cluster area, with this increasing to 1,136 GWh (7.2%) at a 20% blend. The CO₂ emissions reductions associated with delivering these proportions of hydrogen into the network are examined in Section 2.9.

Table 3.4: Potential Energy Delivered by Hydrogen Blends (GWh)

<table>
<thead>
<tr>
<th>Sector</th>
<th>100% Hydrogen Substitution</th>
<th>5%vol. Hydrogen Blend</th>
<th>20%vol. Hydrogen Blend</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial (sites &gt;5.9 GWh)</td>
<td>3,887</td>
<td>63</td>
<td>281</td>
</tr>
<tr>
<td>Commercial</td>
<td>5,423</td>
<td>87</td>
<td>391</td>
</tr>
<tr>
<td>Domestic</td>
<td>6,428</td>
<td>104</td>
<td>464</td>
</tr>
<tr>
<td>TOTAL</td>
<td>15,738</td>
<td>254</td>
<td>1,136</td>
</tr>
</tbody>
</table>
3.4 Power Generation Infrastructure and Gas Demand

As presented in Table 3.5 and in Figure 3.3, there are four large scale operational CCGT plants in the Humber cluster area; South Humber Bank, Saltend, Keadby, Killingholme. As discussed in Section 2.4 in respect of the L-M area, it is relevant to provide analysis of CCGT plant as their potential future demand for hydrogen might influence the design and configuration of a future cluster, and they might also play a role in managing fluctuations in demand from industry and households, as discussed further in Section 6.0.

The data in Table 3.5 shows that the actual gas demand of these four stations of 11,720 GWh, which is significantly lower than the theoretical maximum gas demand of 74,044 GWh. This is the result of very low operational load factors, in particular for South Humber Bank and Killingholme, which have been operating for 21 and 24 years respectively. All four plants struggle to compete in the current electricity market and therefore now solely operate as ‘peaking’ or ‘reserve’ plant, effectively being switched on only for short periods of the day when demand, and therefore prices, are at their highest. However, it should be noted that the current level of gas demand is around three times that of industry within the Humber area.

South Humber Bank, Keadby and Saltend are all scheduled to realise revenues via ‘T-4’ contracts to provide reserve power in the Capacity Market (CM) for the 2018/19, 2019/20 and 2020/21 delivery years, whilst Killingholme has secured a CM contract for 2020/21. However, this does not guarantee any particular level of generation, just that the plant will all be available to provide reserve power if called upon to generate.

It should also be noted that CGen was granted a Development Consent Order (DCO) in September 2014 to build a 470 MW CCGT plant at Killingholme. The company has announced that it plans to bid for a CM contract at the forthcoming 2017 auction.

Table 3.5: Gas Use for Operational CCGT Plant on Humberside (2014)

<table>
<thead>
<tr>
<th>Site Name</th>
<th>Operator</th>
<th>Year Started Operation</th>
<th>Peak Electrical Output (MWe)</th>
<th>Theoretical Max. Annual Gas Demand (GWh)</th>
<th>Load Factor</th>
<th>Actual Gas Use (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>South Humber Bank</td>
<td>Centrica</td>
<td>1996</td>
<td>1,310</td>
<td>23,289</td>
<td>15%</td>
<td>3,590</td>
</tr>
<tr>
<td>Saltend</td>
<td>ENGIE</td>
<td>2000</td>
<td>1,200</td>
<td>21,333</td>
<td>35%</td>
<td>7,422</td>
</tr>
<tr>
<td>Keadby</td>
<td>SSE</td>
<td>1994</td>
<td>755</td>
<td>13,422</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Killingholme</td>
<td>Uniper</td>
<td>1993</td>
<td>900</td>
<td>16,000</td>
<td>4%</td>
<td>708</td>
</tr>
</tbody>
</table>

Notes:
1. Keadby was mothballed between 2013 and 2015 but was brought back into service in 2016
2. Killingholme is currently mothballed but is due to return to service later in 2017
3.5 Opportunities for Hydrogen Supply

As mentioned above in respect of the L-M area, as part of either a large-scale demonstration project or full-scale deployment, hydrogen may be supplied from new large-scale production facilities, including those from conversion of gas, gasification of residual oils, coal or biomass, or via electrolysis.

To our knowledge, there are two existing sources of hydrogen in the Humber; Total’s Lindsey oil refinery at Killingholme and Phillips66’s Humberside refinery at South Killingholme. These both produce and use significant volumes of hydrogen from the cracking process to create petroleum products. In 2009 at Killingholme, Total completed installation of a SMR facility to produce hydrogen for a new distillate ‘hydrotreater’. However, it is unlikely that there is significant redundancy in this SMR to produce hydrogen for other uses. During this study, it has not proved possible to engage with either Total or Phillips66 to determine the availability any hydrogen for use as fuel in wider heating applications. However, neither source should be ruled out in the future.
3.6 Existing Gas Transportation Infrastructure

3.6.1 Onshore natural gas Network

The onshore natural gas distribution network (operated by Cadent) in the Humber Cluster area is presented above in Figure 3.1 in Section 3.1. Across this network, it will be important to identify relevant injection points for injection of hydrogen. The siting of these connection points will depend upon the potential design of the future cluster, including the likely blend of hydrogen and the customers to be supplied.

3.6.2 Onshore Hydrogen Pipelines

Within the scope of this study it was not possible to identify any existing hydrogen pipelines operating in the Humber Cluster area.

3.6.3 Offshore Gas Pipelines

Any large-scale production of hydrogen to fuel a large city or cluster will simultaneously result in production of considerable CO$_2$. For such an approach to provide a route to decarbonisation, it must be coupled with CCS infrastructure at minimum cost. It is therefore appropriate to consider the potential to reuse any pipeline infrastructure near to Humber, to take CO$_2$ out to gas fields in the Southern North Sea (SNS).

As described in Section 3.6.3.1, several pipelines come ashore at the Easington Gas Terminal which is located at the mouth of the Humber to the east of Hull. Furthermore, Theddlethorpe Gas Terminal, located on the Lincolnshire coast, also receives gas from pipelines from the SNS gas fields. The terminal is relatively accessible to the Humber and so the related pipelines are described in Section 3.6.3.2.

Once production of natural gas ceases at the multitude of fields served by Easington and Theddlethorpe, in principle, it may be possible to reuse one or more of the pipelines which are connected at these locations for reverse flow of CO$_2$. If possible, this would significantly reduce the costs of future CCS transport for the potential Humber Cluster.

In the shorter term, CO$_2$ from any demonstration project could in principle be sent via ship or smaller pipeline from Immingham, which is relatively to the likely sources of hydrogen production. However, this approach would also depend upon a suitable CO$_2$ storage site being available. The likelihood of this is discussed in Section 3.7.

3.6.3.1 Pipelines into Easington Gas Terminal

The Easington Gas Terminal has four separate sites, which are operated by Perenco, Centrica and Gassco. There are four active pipelines which flow into Easington, which are summarised in Table 3.6. The most recent, the Langeled pipeline flows 519 km to the Sleipner gas field, and then onto the Nyhamma terminal in Norway.

### Table 3.6: Offshore Pipelines linked to Easington Gas Terminal

<table>
<thead>
<tr>
<th>From</th>
<th>Length (km)</th>
<th>Diameter (mm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Amethyst Platform</td>
<td>48</td>
<td>762</td>
</tr>
<tr>
<td>Sleipner Gas Field</td>
<td>519</td>
<td>1,266</td>
</tr>
<tr>
<td>Rough Gas Storage Field</td>
<td>30</td>
<td>914</td>
</tr>
<tr>
<td>West Sole Gas Field</td>
<td>70</td>
<td>609</td>
</tr>
</tbody>
</table>
### 3.6.3.2 Pipelines into Theddlethorpe Gas Terminal

As presented in Figure 2.5, the 118 km, 914 mm diameter Lincolnshire gas pipeline brings ashore gas produced in the Southern North Sea (SNS) to be processed at Theddlethorpe Gas Terminal following co-mingling at the Lincolnshire Offshore Gas Gathering System (LOGGS). In March 2016, the owner and operator of these three assets, ConocoPhillips, announced that it was considering shutting them down.\(^{20}\) This potential was being driven by the ceasing of production at related gas fields operated by ConocoPhillips. However, the pipeline and LOGGS serves a range of other fields operated by others including Centrica, BP and Perenco. At the time of writing, the future of the pipeline is unclear, but as ConocoPhillips has not made any further public comment (since March 2016) it is assumed that the assets will continue to operate in the short-to-medium term.

Also presented in Figure 2.5 is the Caister Murdoch System (CMS), which gathers gas from a large number of fields to the North East of the LOGGS. A 188 km, 660 mm pipeline, which was commissioned in 1993, transports gas from the CMS to Theddlethorpe. A further, 66 km, 610 mm pipeline into Theddlethorpe comes from the Pickerill field.

Gas from Theddlethorpe is not only sent to the NTS, but is transported via E.ON’s 500 mm pipeline to both Killingholme A power station and Killingholme B power station on the Humber.

3.7 Opportunities for Offshore Storage of CO₂

In the aforementioned CO₂ storage report published by the ETI in 2016, eight sites in SNS are identified as being within ‘top 20 prospects’ for CO₂ storage in UK waters. The study prioritised two particular sites: the Viking gas field and what is referred to as ‘Bunter Closure 36’. We have therefore focused our analysis upon these two sites, as presented in Section 3.7.1 and 3.7.2. However, it is reasonable to state that there are a multitude of other potential options in the SNS, which might be assessed in similar detail. For example, the Endurance saline aquifer was characterised and developed as a CO₂ store for the now abandoned White Rose CCS project and could be readily accessed from the Humber region.\(^\text{21}\)

\(^{21}\) See [https://www.globalccsinstitute.com/projects/white-rose-ccs-project](https://www.globalccsinstitute.com/projects/white-rose-ccs-project)
3.7.1 Viking

The Viking gas field is in the SNS approximately 90km off the Norfolk Coast and 185km from Barmston on Humberside. Its broad location is presented above in Figure 3.5. First production from the Viking Fields began in 1972 and at its peak a total of 13 platforms, from 20 wells, supplied around 10% of the United Kingdom's natural gas requirements. The Viking Transportation System (VTS) transports gas from the Viking B complex via a 26.9 km 16” pipeline to the LOGGS complex for onward transmission to Theddlethorpe. The fields’ largest shareholder is ConocoPhillips.

Viking was prioritised by the ETI as one of its chosen five sites (for which a storage development plan was developed), in part, because it is proposed that an effective development here would potentially ‘de-risk’ many other similar CO₂ storage sites in the vicinity. Viking covers a large area of many small gas accumulations, but the analysis focusses upon Viking A only as an initial phase, as this field is sufficiently depleted as to be effectively available now. The Viking A site is already well characterised with good reservoir quality and hydraulic connectivity. The cap rock sequence includes thick salt deposits which contribute to the high integrity of the location as a site for CO₂ storage. Viking A is overlain by a large secondary storage target in Bunter Closure 3 which may present significant further storage ‘upside’.

The storage capacity of Viking A calculated in the ETI study is 310 Mt. The ETI study suggests that CO₂ to be stored at Viking will require heating early in its injection life to manage the phase effectively whilst the reservoir pressure is very low. The study states that the development would require a new unmanned platform with two active injection wells and a spare, connected to the Barmston beachhead with a new 185 km 500 mm pipeline.

3.7.2 Bunter Closure 36

Bunter Closure 36 was also short-listed by the ETI as one of its five priority sites for which a storage development plan was produced. It is a structured saline aquifer in the Triassic bunter sandstone. It is located approximately 150 Km off the Yorkshire coast and a smaller ‘brother’ of the Endurance storage, which was selected by the White Rose CCS Project as part of its bid in the UK CCS Commercialisation Programme.

The ETI study calculates that Bunter Closure 36 has a storage capacity of 252 Mt. The site development proposed in the study comprises five wells from an unmanned platform with CO₂ supplied via a 160 km, 500 mm pipeline. The project plan accommodates 7 Mt/yr for 40 years through four active injectors. The study states that the project will require one further appraisal well to address remaining uncertainties with reservoir quality distribution and also aquifer connectivity.
3.8 Existing Hydrogen, and Wider Gas Storage Infrastructure

As highlighted above, to support a large hydrogen cluster on Humberside and the surrounding area to manage daily and seasonal fluctuations in energy demand, salt caverns will be required as both diurnal and seasonal storage. Humberside is home to the Zechstein Salt Basin, which lies beneath much of the North Sea and extends under this area of the East Yorkshire coastline. The salt formations in this Basin are the deepest in the UK and would allow for storage of hydrogen at higher pressures compared with some other locations. However, this can also mean higher costs due to greater energy use for compression and extraction of gases.

As presented in Table 3.7, two natural gas stores are currently operating near to the Humber Cluster area, which amount to a total current storage capacity of 626 mcm.26 As described in Section 2.8 in respect of the L-M area, whilst these caverns are unlikely to be turned over to hydrogen storage, this may be possible in the long term, and this would reduce the cost of developing new assets to support the potential growth of a hydrogen cluster on Humberside. This is particularly important as not only would caverns for containing hydrogen be required, but these require servicing with additional brine caverns and pipelines. Most such additional infrastructure is already in place at these existing gas storage sites.

In addition, a further 730 mcm of capacity is either consented or awaiting consent. It is notable that these projects are struggling to reach financial close, and therefore should some of this consented capacity not be used for storage of natural gas, it may be possible to amend existing consents for storage of hydrogen should this be required. At the very least, some of the work that has been undertaken by developers in respect of site selection and characterisation might be reused in respect of developing hydrogen storage sites.

Table 3.7: Existing and Planned Onshore Salt Caverns on Humberside

<table>
<thead>
<tr>
<th>Site Name</th>
<th>Number of Caverns</th>
<th>Operator / Developer</th>
<th>Status</th>
<th>Year of Start of Operation</th>
<th>Current / Intended Usage</th>
<th>Capacity (Million m³ natural gas)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hornsea (Atwick)</td>
<td>9</td>
<td>SSE</td>
<td>Operating</td>
<td>1979</td>
<td>Natural gas storage</td>
<td>296</td>
</tr>
<tr>
<td>Aldbrough</td>
<td>9</td>
<td>SSE</td>
<td>Operating</td>
<td>2011</td>
<td>Natural gas storage</td>
<td>330</td>
</tr>
<tr>
<td>Albrough Extension</td>
<td>9</td>
<td>Statoil</td>
<td>Consented</td>
<td>n/a</td>
<td>Natural gas storage</td>
<td>330</td>
</tr>
<tr>
<td>Whitehill</td>
<td>10</td>
<td>E.ON</td>
<td>Consented</td>
<td>n/a</td>
<td>Natural gas storage</td>
<td>400</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1,356</td>
</tr>
</tbody>
</table>

Notes:
1. Three caverns were mothballed in 2015/16, such that actual capacity is somewhat lower than this at present
2. Currently a maximum of 626 Million m³ actually operational

In addition to gas storage in onshore salt caverns, natural gas or hydrogen might also be stored in offshore salt caverns. In principle hydrogen could similarly be stored offshore, and whilst the costs would be likely greater than onshore storage, there are likely to be fewer constraints in terms of consenting and the potential for larger caverns for seasonal storage and therefore possible economies of scale.

At present, Centrica’s Rough offshore gas storage facility, located 18 miles off the coast of Humberside is the largest gas storage facility in the UK. This is a depleted hydrocarbon field, and thus less suited for hydrogen storage. No proposed development to store natural gas in offshore salt caverns in the SNS have been identified in this study.

26 It should be noted that the ETI has recently commissioned a major study to provide analysis of the potential for hydrogen storage across the UK, which is likely provide a greater level of technical detail than presented here. See http://www.eti.co.uk/news/eti-appoints-atkins-to-project-to-identify-salt-caverns-suitable-for-storing-hydrogen-and-gas
3.9 Potential Carbon Reduction Benefits

The total CO₂ emissions from consumption of natural gas by industry (by sector) on Humberside are presented in Table 3.8. This shows that a switch to 100% hydrogen in industry would result in a CO₂ reduction of >0.7 million tonnes per annum. This would represent around 4% of all CO₂ emissions from natural gas by industry in the UK.

Given the potential to blend hydrogen with natural gas, it is also important to consider the reduction in CO₂ emissions, which would be delivered by 5% and 20%vol. blends of hydrogen. The data in Table 3.9 demonstrates that a 5%vol. blend of hydrogen across the whole of the gas distribution network in the Humber Cluster area would deliver an annual CO₂ reduction of 0.05 Million tonnes, which equates to 1.6% of total CO₂ emissions. Similarly, a 20%vol. hydrogen blend could deliver an annual reduction in CO₂ emissions of 0.2 Million tonnes, equal to 7.2% of current levels in the Humber Cluster area. In the wider context, a 20% blend supplied to the Humberside area would equate to around 0.2% of total CO₂ emissions from natural gas consumed across all GB distribution networks.

### Table 3.8: Potential Max Emissions Reductions from Hydrogen to Industry

<table>
<thead>
<tr>
<th>Sector</th>
<th>100% Hydrogen Substitution (tCO₂/annum)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chemicals</td>
<td>212,966</td>
</tr>
<tr>
<td>Glass</td>
<td>86,699</td>
</tr>
<tr>
<td>Food and Drink</td>
<td>54,527</td>
</tr>
<tr>
<td>Oil and Gas</td>
<td>2,382</td>
</tr>
<tr>
<td>Ceramics</td>
<td>-</td>
</tr>
<tr>
<td>Cement</td>
<td>-</td>
</tr>
<tr>
<td>Pulp and Paper</td>
<td>-</td>
</tr>
<tr>
<td>Iron &amp; Steel²</td>
<td>66,020</td>
</tr>
<tr>
<td>Other</td>
<td>317,764</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>740,358</strong></td>
</tr>
</tbody>
</table>

Notes:
1. Includes only sites with > 5.9 GWH/annum natural gas consumption, which are connected to the LTS
2. Excludes both Lindsey and South Humber refineries, both which are connected to the NTS

### Table 3.9: Emissions Reductions (tCO₂/annum) from Hydrogen

<table>
<thead>
<tr>
<th>Sector</th>
<th>100% Hydrogen Substitution</th>
<th>5% vol. Hydrogen Blend</th>
<th>20% vol. Hydrogen Blend</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial (sites &gt;5.9 GWh)</td>
<td>740,358</td>
<td>11,931</td>
<td>53,443</td>
</tr>
<tr>
<td>Non-domestic (including industrial)</td>
<td>1,084,509</td>
<td>17,477</td>
<td>78,286</td>
</tr>
<tr>
<td>Domestic</td>
<td>1,286,682</td>
<td>20,719</td>
<td>92,808</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>3,110,548</strong></td>
<td><strong>50,128</strong></td>
<td><strong>224,537</strong></td>
</tr>
</tbody>
</table>
Table 3.10 provides analysis of emissions from 10 large natural gas users, as highlighted in Section 3.2.2. The total reduction in CO₂ emissions associated with moving just these 10 sites to 100% hydrogen would be 0.58 million tonnes, which equates to over 18% of total emissions from all gas use in the Humber cluster area. The approach towards such a goal, whether as part of a single switch or a more phased process over time is explored in respect of different types of gas use (boiler, CHP, furnace etc) and different industries in Section 5.0.

As discussed above in respect of the L-M Cluster area, the potential emissions reductions presented Table 3.8 to Table 3.10 assume that the production and supply of hydrogen does not result in any CO₂ emissions. To produce sufficient volumes of hydrogen will require processing of fossil fuels along with CCS as described in Section 6.0. There remain some associated CO₂ emissions (with the exception of bio-hydrogen, which could potentially deliver ‘negative’ emissions), and therefore the emissions reductions will be lower than those presented above.

**Table 3.10: CO₂ Reduction from 100% Hydrogen to 10 Large Industry Sites**

<table>
<thead>
<tr>
<th>Operator</th>
<th>Emissions Reduction (tCO₂/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chemicals</td>
<td>146,649</td>
</tr>
<tr>
<td>Metals</td>
<td>83,017</td>
</tr>
<tr>
<td>Glass</td>
<td>76,906</td>
</tr>
<tr>
<td>Other</td>
<td>67,028</td>
</tr>
<tr>
<td>Other</td>
<td>65,957</td>
</tr>
<tr>
<td>Other</td>
<td>55,830</td>
</tr>
<tr>
<td>Chemicals</td>
<td>32,573</td>
</tr>
<tr>
<td>Other</td>
<td>23,331</td>
</tr>
<tr>
<td>Food &amp; Drink</td>
<td>10,765</td>
</tr>
<tr>
<td>Chemicals</td>
<td>10,467</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>572,522</strong></td>
</tr>
</tbody>
</table>

Notes:
1. Excludes a number of sites which are large gas users in the Humberside area, but which are outside of Cadent’s network
2. Also excludes both Lindsey and South Humber refineries, both which are connected to the NTS
4.0 COMPARATIVE ANALYSIS OF CANDIDATE LOCATIONS

4.1 Scope, Objectives and Summary Methodology
The analysis presented in Sections 2.0 and 3.0 demonstrates that both the L-M area and Humberside both contain a range of critical infrastructure, which is adaptable to support the development of future hydrogen clusters. They are both good locations in which to site hydrogen supply systems and hydrogen clusters.

The objective of this section is to provide comparative analysis of the two candidate locations to determine which is likely to represent the optimal location in respect of:

- Deliverability of early stage demonstration of hydrogen production and consumption by industry;
- The costs of a scaling-up of hydrogen production and use to deliver material deployment projects; and
- Future impact in respect of CO₂ emissions reductions across the industrial, commercial and domestic sectors.

The attractiveness of each of the two locations is discussed in relation to these criteria in Sections 4.2 to 4.4, whilst in Section 4.5, we have presented a summary matrix across all criteria to determine the most optimal location.

4.2 Deliverability of Early Stage Demonstration Projects

4.2.1 Supply of Hydrogen in the Short-term
The supply of existing sources of hydrogen will negate the need for dedicated hydrogen production infrastructure to supply a demonstration project, thus significantly reducing associated costs. As presented in Sections 2.5 and 3.5, there are four potential sources of hydrogen in the Liverpool-Manchester Cluster (Inovyn at Runcorn, CF Industries’ at Ince, BOC at St Helens and the Essar refinery at Stanlow) and two potential sources in the Humber Cluster area (Total’s Lindsey refinery and Phillips66’s Humberside refinery). Section 2.6.2 also provides information relating to two hydrogen pipelines, which already exist in the L-M Cluster area, the largest being that which runs north east from Inovyn at Runcorn to Solvay at Warrington. No such existing pipelines are in operation on Humberside.

This brief analysis demonstrates that there is greater diversity of potential supply of hydrogen in the L-M area than on Humberside. Furthermore, via engagement with some of the above organisations as part of this study (in some cases facilitated by the local industry and government groups, as discussed in Section 4.2.2) relevant tonnages of hydrogen might be available to support a demonstration project in the short term have been estimated. On this basis, it is clear that Liverpool-Manchester represents a more favourable location than Humberside in respect of supply of hydrogen to support a large-scale demonstration project.
4.2.2 Current Hydrogen Initiatives and Institutional Support

The Liverpool City Region Local Enterprise Partnership (LEP) has declared a strong interest in energy in its Strategic Growth Plan with low carbon energy identified as a key growth sector. In the context of hydrogen a planned objective is to:

“Develop a Hydrogen Gas Grid to provide cheap, low carbon heating for the City Region.”

Recently, a group involving a number of major companies; the ‘North West Hydrogen Hub’ (NWHH), has been formed to promote hydrogen related initiatives in industry and transport. Along with the Liverpool LEP, the NWHH brings together organisations which produce or use hydrogen, or which operate related technologies. The NWHH will be supportive of any hydrogen related activity which provides hydrogen infrastructure and also recognises the importance of CCS in this regard. It has, thus far, held three formal meetings (in February, May and July) attended by organisations including Inovyn, Essar, CF Fertilisers, Storengy and BOC (along with Progressive Energy) and the group plans to meet bi-monthly on an ongoing basis.

In contrast, there appears to be currently no similar groups currently operating on Humberside. The Strategic Growth Plan for Humberside is rich in its promotion of the Humber ‘Energy Estuary’, but this is largely focused on electricity production from wind and marine sources and does not give mention to either hydrogen or CCS. A more recent review of the Strategic Growth Plan does highlight that the LEP has been engaging with local industry to consult upon potential decarbonisation pathways published by Government, but again, there is no explicit mention of hydrogen or CCS.

The above analysis suggests that the L-M area is somewhat more advanced than Humberside in respect of local government and industry engagement with the concept of potential future conversion from natural gas to hydrogen as a fuel. Stakeholder engagement of this nature is a critical building block towards facilitation of demonstration projects, and therefore, in the short term at least, the L-M area appears better equipped than Humberside in this respect.

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4.3 Costs of Scaling-up to Full Hydrogen Cluster

4.3.1 Management of Fluctuations in Daily and Seasonal Demand

4.3.1.1 Initial Network

The analysis for the L-M and Humber Cluster areas in Sections 2.2 and 3.2 respectively shows that the aggregate gas demand profile of large industrial plants shows much less variation on a seasonal basis than the demand profile for domestic and commercial users. The reason for this is because natural gas is being used predominantly to supply process heat in industrial applications, with only a relatively small amount being used for space heating.

As highlighted in Section 1.0, one of the objectives of this study is to consider how the supply of hydrogen by industry could function as an enabler for supply to the wider domestic and commercial sectors. One approach to delivering upon this goal, therefore, would be to supply hydrogen at relatively high concentrations to industry via dedicated pipelines and then use a proportion of this to supply a blend to the network at a level that does not require any conversion of existing boilers and other appliances.\(^{30}\)

This approach enables the system to cope with fluctuations in demand from the household and commercial sectors, and so avoid the need for costly diurnal or seasonal underground storage. This is because:

- By maintaining the existing gas supply to industry alongside the new hydrogen pipeline, manufacturing plant would be able to ‘flex’ between different levels of natural gas and hydrogen supply;\(^{31}\) and
- The relatively ‘flat’ nature of industrial gas demand offers the potential to use ‘line-pack’ storage within the dedicated pipeline.

To be most cost effective in respect of pipeline costs, this strategic approach requires a high concentration of major gas users within a relatively small geographical area. Based upon the relative locations of the selected ten major industrial gas users located in each of the L-M and Humber Clusters, as shown in Sections 2.2.2 and 3.2.2, the latter appears best suited to deliver upon this approach due to the close proximity of seven sites around Grimsby and Immingham. However, it is notable that the two of the three largest industrial gas users sit outside this immediate area, as far away as Doncaster. This is such that the immediate cluster of seven sites had annual gas use of only around 1,000 GWh in 2016. In contrast, the large gas users in the L-M Cluster are slightly more dispersed, albeit just four sites that are all in close proximity to each other around the River Mersey had a combined annual gas use of over 2,100 GWh in 2016.


\(^{31}\) This is supported by the findings of direct engagement with industry as part of this study
4.3.1.2 Full Network

As a consequence of the large winter heating load of domestic and commercial properties, gas distribution network demand varies very significantly between summer and winter. As discussed in Section 4.3.1.2 and in the aforementioned H21 study, therefore, conversion of the existing gas networks in the L-M or Humber Cluster areas to 100% (or to a high proportion of) hydrogen will likely require storage of hydrogen in newly constructed underground salt caverns.\(^{32}\) In addition daily demand fluctuations must be managed.

As described in detail in Sections 2.8 and 3.8, storage of natural gas in salt caverns is well established and is already taking place at large scale in both the L-M area (Cheshire) and Humberside. In both locations, there are several operating caverns along with a number of further sites, which have received planning consent.

The salt deposits on Humberside are deeper than those in the L-M area. This allows for storage of hydrogen at higher pressures. As proposed in the H21 study (in relation to Humberside and Teesside), this may possibly mean that Humberside is a more suitable location than the L-M area for seasonal storage should large swathes of the network be converted to hydrogen.\(^{33}\)

At the same time, however, the parasitic compression losses associated with injecting and removing hydrogen are higher for deeper storage cavities. This may result in a set of larger, shallower storage caverns, such as could be developed in the L-M area, being cheaper than a set of smaller, deeper caverns on Humberside. Furthermore, for the same reasons, diurnal storage is also more likely to be cost effective at lesser depth in the L-M area.

4.3.2 Bulk Hydrogen Supply in the Long-term

In the short-to-medium-term, any bulk supply is likely to be from gas-manufactured hydrogen using SMRs (or similar) fitted with CO\(_2\) capture. Consequently, bulk natural gas supply to fuel these facilities will be required. Gas is currently supplied by offshore fields directly to both cluster locations; to the Theddlethorpe and Easington terminals in the Humberside area and the Point of Ayr (and Barrow) terminals in the L-M area. In the longer term, as UK and (Norwegian, in the case of Easington) gas supplies reduce there will increased reliance on import of liquefied natural gas (LNG) or potentially domestic shale gas.

There is a reasonable expectation that the UK will rely on LNG imports for >60% of its natural gas demand by 2030 (currently this level is around 45%).\(^{34}\) There are currently three major LNG terminals in the UK; two on the West coast at Milford Haven in Wales, and one on the East coast at Isle of Grain in Kent. These have a combined capacity that can meet around 50% of current UK gas demand. The NTS provides good connections to the L-M and Humber Clusters from these and other locations.

At present, there is no large-scale extraction of shale gas in the UK, and it currently appears unlikely that this will take place at such scale until the 2020s. Furthermore, it is also not wholly certain that such 'unconventional' gas supply will make a material contribution to meeting UK gas demand. As such, it is recognised that whilst hydrogen from gas currently is secure and provides the lowest cost bulk supply, this is not absolutely guaranteed in the long term. In respect of both security of supply and cost minimisation it will therefore desirable to diversify the suite of feedstocks used to produce hydrogen in the future.

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\(^{32}\) Northern Gas Networks (2016) H21 - Leeds City Gate, July 2016
http://www.northerngasnetworks.co.uk/document/h21-leeds-city-gate/

\(^{33}\) This was a supposition made in the aforementioned H21 report, in respect of the use of caverns on Humberside for seasonal storage, and shallower caverns on Teesside for diurnal storage

\(^{34}\) This will depend on the level of total gas demand, and thus what proportion can be supplied by domestic reserves
Gasification of coal is a proven technology and can produce hydrogen in bulk quantities. Both cluster areas have existing local coal import facilities (at Immingham and Port of Liverpool) to facilitate such an approach at relatively low cost. Both areas also host oil refineries. There are two in the Humber Cluster area, the Humber and Lindsey refineries, and one in the L-M Cluster area, the Stanlow refinery. Only a further three refineries are operational in the wider UK. Hydrogen is currently produced at these refineries in material quantities as part of the distillation process. The hydrogen produced can be used on site and including for on-site CHP generation. It is worth noting, however, that it is also possible to reconfigure a refinery to produce a different ‘slate’ of products and in principle, with investment, hydrogen could be produced in place of heavy fuel oil and other ‘bottom of the barrel’ products. Such hydrogen has the potential to be available in material quantities and may become economically attractive compared with alternative sources.

As noted above, hydrogen can also be manufactured from biomass. Both locations currently import significant tonnages of biomass through their ports for power generation, whilst both also produce significant tonnages of indigenous biomass, including that from wastes. Whilst hydrogen produced from such (non-waste) biomass fuel sources may struggle to compete with the price of natural gas in the short to medium term, the associated potential production of hydrogen is material in the context of overall UK gas demand. Furthermore, in carbon accounting terms, in most cases, negative emissions might be claimed for such fuel sources. Finally, hydrogen can be produced via electrolysis. At present, this is not an economically attractive route for bulk production, but is gaining some traction for potential niche applications in the UK; for example, when wind farms are ‘constrained off’ the grid, and so electricity can be procured at levels below market prices. In the future, as more onshore and particularly offshore wind capacity becomes operational, such an approach may become more economically attractive. In this context, there is further planned offshore wind capacity off the coast of both the L-M area and Humberside. However, the energy losses associated with electrolysis are such that, without a wholesale fall in the costs of wider electricity production, it is unlikely to be a viable approach for bulk hydrogen supply in the long-term.

4.3.3 Access to Expandable CCS infrastructure

The UK CCS Commercialisation Programme which focussed on CCS in the power generation sector was cancelled by Government in November 2015. During the subsequent period, the Committee for Climate Change (CCC) has reinforced the importance of CCS in delivering the carbon reductions required at minimum cost, with a focus on industrial clusters. Furthermore, Government also appears to have begun to recognise that CCS with access to low cost CO₂ transport and storage infrastructure is an essential requirement. The case for CCS infrastructure includes the use of such infrastructure to support the potential development of hydrogen networks to decarbonise the heat sector. Government is currently gathering evidence in relation to the repurposing of the gas network to hydrogen.

For some industrial sectors, notably, steel, cement and oil refining, CCS is the only means for process decarbonisation. Recognising this, UK CCS developments have focussed on four industrial cluster areas – Humberside, Grangemouth, Teesside and the L-M area. The historic presumption has been that a major CCS power generation project would be required as an anchor for investment in CCS infrastructure. In this context, both the L-M area and Humberside are host to operational and consented thermal power stations, which reinforces their attractiveness as CCS cluster. However, the volume of CO₂ captured from hydrogen production used to supply the gas distribution network may well be sufficient to justify the development of CCS infrastructure without the need for a major CCS power generation project.

It is notable that Humberside is also host to the British Steel plant, the full scope of emissions from which (i.e. including those from combustion of coal in addition to gas), would potentially represent an ‘anchor’ project for a CCS cluster. However, as a result of global market forces and the nature of the design of the plant, the long-term future of this plant is somewhat uncertain. In any event, reliance on a single industrial plant around which to plan major, long-term CCS infrastructure is unlikely to be sufficiently financially robust to attract investment.

Both Cluster areas have access to suitable multiple offshore CO₂ storage sites, which could provide very substantial capacity. As described in Sections 2.7 and 3.7, the ETI has evaluated sites accessible from each cluster. This analysis prioritises the Hamilton gas field in Liverpool Bay and the Viking A gas field (and a saline aquifer, ‘Bunter Closure 36’) off Humberside as being among the five most suitable stores for CO₂ in UK waters, and storage development plans have been produced for each site.

The cost data produced by the ETI for these sites strongly suggests that Hamilton is well positioned to provide the lowest cost transport and storage on a £/t basis for the 5 Mt CO₂/annum storage volume used in the analysis. It may also be possible to repurpose the existing gas pipeline and rig facilities for CO₂ transport and injection, making this option even lower cost. At the same time, Hamilton is closer to the shoreline than either Viking or Bunter Closure 36, thus minimising costs should a new pipeline be required. The storage costs calculated for Viking A are somewhat greater than the modelled costs for Hamilton (and the North and South Morecambe fields). This is largely the result, in simple terms, of the greater pipeline distance to the SNS.

It is important to acknowledge that the lower costs at Hamilton are such that justification of CCS infrastructure investment will require a lower CO₂ volume than elsewhere. Furthermore, as described above, in addition to Hamilton, several other oil and gas fields in Liverpool Bay represent suitable stores for CO₂, and which might provide additional future capacity. Further into the future, the Morecambe Bay gas fields, which are located just north of Hamilton in the East Irish Sea, could also be developed to provide ongoing storage capacity. As discussed in Section 2.7.2, these are less depleted than the Liverpool Bay fields, but could hold far larger volumes of CO₂, which supports the idea of long-term investment in the L-M area.

4.4 Future Reductions in CO₂ emissions

As presented in Sections 2.9 and 3.9, the CO₂ reduction of 2.2 Mt which would be delivered by supplying 100% hydrogen (via a dedicated pipeline) to 10 of the largest industrial plants in the L-M Cluster area is significantly greater than the 0.7 Mt of CO₂ which would come from supply to the equivalent group on in the Humber Cluster. That said, it is notable that CO₂ emissions from gas use via the NTS are far greater in the Humber Cluster area. This is the result of a larger number of operational CCGT plant (see Section 3.4) than in the L-M area, and also the existence of two major oil refineries in the area. However, the scope of this work and hence the related strategy being developed is focused upon use of the LTS only as the Iron Mains Replacement Programme (IMRP) for this system is producing a network capable of safely transporting hydrogen. Early stage demonstration and deployment Projects will be associated with the LTS.

The L-M Cluster area is far more populous than the Humber Cluster area, hence the emissions reductions delivered by the injection of hydrogen blends into the natural gas network would be significantly greater. Consequently, investment in a L-M Hydrogen Cluster would very likely result in far more cost-effective CO₂ reduction (in terms of £/tCO₂ abated) than at Humberside.
4.5 Summary of Comparative Analysis

Table 4.1 provides a summary of the comparative analysis undertaken above. This demonstrates that both locations represent attractive locations for the development of hydrogen clusters.

The L-M Cluster has emerged as the clear favourite. This is largely because of its potential, arising from the potential for very low-cost CCS, to host a particularly low cost initial Project with minimal complexity, a portfolio relevant pre-existing hydrogen activities and an engaged local government and industry.

The role of industry has been identified as important both in the context of:

- Offering the opportunity for substantial CO₂ emissions reductions via conversion of only a 'handful' of major gas users;
- Providing the 'backbone' for a blend of hydrogen to be injected to the natural gas network, without the short-term need to convert millions of household appliances;
- The ability to manage network demand fluctuations, thus minimising the cost hydrogen storage requirements; and
- Providing sufficient volumes of CO₂ to facilitate critical CCS infrastructure.

A pathway to substantial network conversion to hydrogen, which involves an initial Project which reduces the carbon intensity of both industrial users and the wider gas network and puts CCS infrastructure in place will deliver significant benefits to both the local area and the wider UK. This pathway, and the formulation of an initial network conversion project in the L-M area, together with the necessary enabling activities, is examined in Section 6.0.
<table>
<thead>
<tr>
<th>Key Criteria</th>
<th>Sub-Criteria</th>
<th>Liverpool-Manchester Area</th>
<th>Humber</th>
<th>Most Attractive Area</th>
</tr>
</thead>
<tbody>
<tr>
<td>Deliverability of early stage</td>
<td>Supply of Hydrogen in short-term</td>
<td>Diverse existing sources of hydrogen likely to be available to</td>
<td>Two potential sources of hydrogen, but availability uncertain</td>
<td>Liverpool-Manchester</td>
</tr>
<tr>
<td>demonstration</td>
<td></td>
<td>support demonstration</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Current hydrogen initiatives and institutional</td>
<td>Specific interest declared by the LEP and newly formed North</td>
<td>No focus on hydrogen albeit recent consideration</td>
<td>Liverpool-Manchester</td>
</tr>
<tr>
<td></td>
<td>support</td>
<td>West Hydrogen Hub</td>
<td>of wider decarbonisation pathways</td>
<td></td>
</tr>
<tr>
<td>Costs of commercial scale hydrogen</td>
<td>Management of fluctuations in demand</td>
<td>Core of four industrial sites facilitates line-pack and</td>
<td>Core of seven industrial sites facilitates</td>
<td>Liverpool-Manchester or Humberside</td>
</tr>
<tr>
<td>production and use</td>
<td></td>
<td>variable gas/hydrogen use, with major salt caverns in</td>
<td>line-pack and variable gas/hydrogen use,</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>longer-term</td>
<td>with major salt caverns in longer-term</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Bulk hydrogen supply in long-term</td>
<td>Good access to NTS for gas supply and to wider infrastructure</td>
<td>Good access to NTS for gas supply and to</td>
<td>Liverpool-Manchester or Humberside</td>
</tr>
<tr>
<td></td>
<td></td>
<td>for alternatives</td>
<td>wider infrastructure for alternatives</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Access to low cost expandable CCS</td>
<td>Good access to multiple offshore storage sites and potential</td>
<td>Good access to multiple offshore storage</td>
<td>Liverpool-Manchester</td>
</tr>
<tr>
<td></td>
<td>infrastructure</td>
<td>for reuse of infrastructure at very low cost for an initial</td>
<td>sites and potential for reuse of</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>project with a modest CO₂ volume</td>
<td>infrastructure, but only low cost if</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>using relatively large volumes of CO₂</td>
<td></td>
</tr>
<tr>
<td>Future impact in respect of CO₂</td>
<td>n/a</td>
<td>Significant emissions from industrial, commercial and</td>
<td>Reasonably significant emissions from</td>
<td>Liverpool-Manchester</td>
</tr>
<tr>
<td>emissions reductions</td>
<td></td>
<td>domestic sectors</td>
<td>industrial, commercial and domestic</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>sectors</td>
<td></td>
</tr>
</tbody>
</table>
5.0 TECHNICAL AND SECTORAL ANALYSIS

5.1 Scope, Objectives and Summary Methodology
The primary objective of this section is to identify technical and engineering constraints and opportunities for use of hydrogen across different industry sectors. To deliver upon this goal, we have undertaken a range of tasks, which can be summarised as follows:

- High level characterisation of hydrogen as an energy vector, particularly in relation to natural gas. This includes its key combustion characteristics, transportation implications and key attributes in terms of safety;

- Presentation of the key issues of using hydrogen in different applications, including:
  - As a fuel in:
    - High-temperature furnaces and kilns;
    - Boilers; and
    - Combined heat and power (CHP) plant, including reciprocating engines and Gas Turbines.
  - Chemical use, for example, in ammonia production.

- For each industry sector, to:
  - Determine the range of manufacturing plant;
  - Analyse alternative decarbonisation options;
  - Consider the issues associated with low and high proportions of hydrogen mixed with natural gas; and
  - Where possible, explore the feasibility of ‘flexing’ a mixture of hydrogen and natural gas.

The analysis in Sections 5.2 to 5.5 is supported by engagement with Cadent and with operators in each of the industry sectors, along with a thorough, systematic review of the secondary evidence base.
5.2 Characteristics of Hydrogen as an Energy Vector

Natural gas is currently the dominant gaseous fuel used in the UK, and therefore most gas-fuelled equipment is designed to operate on natural gas. Its characteristics as a fuel are therefore well understood across industry and the power generation sector.

However, hydrogen has also been extensively used as a fuel gas. Prior to the early 1970s, the UK gas network distributed ‘Towns’ gas, produced from coal gasification, which comprised up to 50% hydrogen along with primarily carbon monoxide, methane, and other alkanes. Outside the UK, Town Gas is still used in countries such as Singapore, and hydrogen is permitted in natural gas blends across Europe to varying degrees of up to 12%.

Furthermore, certain industrial sectors, including the chemicals, oil refining and steel manufacturing sectors (as discussed in Sections 5.4.5, 5.4.6 and 5.4.7 respectively), continue to successfully use by-product hydrogen as a ‘fuel’ gas.

In principle, therefore, there is historic and ongoing experience of using hydrogen as a fuel, both domestically and overseas. However, evaluating both the ability for existing infrastructure and for the development of new equipment to use hydrogen as a fuel, requires a deep understanding of its properties, in particular its combustion characteristics. Other aspects of the physical and chemical properties of hydrogen are also important, as they influence the practical ability to transport, detect and use it safely.

The quality of gas currently used in the UK public gas network is governed by the Gas Safety (Management) Regulations (GS(M)R).\[40\] In the GS(M)R, gas quality is defined primarily as a functional specification, but this also includes compositional requirements to control specific contaminants and currently limits the hydrogen component to 0.1%. At the time that the GS(M)R were conceived, this was a pragmatic limitation, as the sources of gas in use contained no hydrogen. The current drive towards decarbonisation of heat provision, however, is such that industry and Government are both interested to explore how greater volumes of hydrogen might be employed. As a consequence, the HyDeploy project (funded under the Network Innovation Competition) is seeking to secure an Exemption under GS(M)R from the HSE to trial a hydrogen/natural gas blend on a specific gas network.\[41\]

Section 5.2.1 provides a high-level overview of the key combustion characteristics of hydrogen, particularly as compared with the properties of methane, the primary component of natural gas.\[42\] Sections 5.2.2 and 5.2.3 then explore issues relating to transportation and safety aspects of hydrogen usage. Much of the information summarised in these Sections is drawn from a publication by the Health and Safety Executive (HSE), which is focused on injection of hydrogen into the gas network.\[43\]

42 Natural gas is a mix of a range of components, primarily methane, but also higher order alkanes as well as other components. It should also be noted that gas from different sources used in the UK, i.e. that produced offshore in domestic waters, that imported from Norway by pipeline or that imported by ship from multiple locations as liquefied natural gas (LNG) can have substantially different compositions
5.2.1 Key combustion characteristics

The key characteristics of hydrogen are presented in Table 5.1. These are largely drawn from work undertaken by the HSE, and are each discussed at high level below.\(^4\)

### Table 5.1: Key Combustion Characteristics of Hydrogen

<table>
<thead>
<tr>
<th>Property</th>
<th>Unit</th>
<th>Methane (CH(_4))</th>
<th>Hydrogen (H(_2))</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density(^1)</td>
<td>kg/m(^3)</td>
<td>0.68</td>
<td>0.09</td>
</tr>
<tr>
<td>Relative Density (to dry air)</td>
<td></td>
<td>0.55</td>
<td>0.07</td>
</tr>
<tr>
<td>Calorific Value (Higher Heating Value)</td>
<td>MJ/kg</td>
<td>55.5</td>
<td>141.8</td>
</tr>
<tr>
<td>Wobbe Number</td>
<td>MJ/m(^3)</td>
<td>37.7</td>
<td>12.1</td>
</tr>
<tr>
<td></td>
<td>MJ/m(^3)</td>
<td>50.7</td>
<td>45.9</td>
</tr>
<tr>
<td>Flammability Range</td>
<td>% vol</td>
<td>4.4 – 15.0</td>
<td>4.0 – 75.0</td>
</tr>
<tr>
<td>Laminar burning velocity</td>
<td>m/s</td>
<td>0.4</td>
<td>3.1</td>
</tr>
<tr>
<td>Auto-ignition temperature</td>
<td>ºC</td>
<td>600</td>
<td>560</td>
</tr>
<tr>
<td>Adiabatic Flame Temperature in Air(^2)</td>
<td>ºC</td>
<td>1,960</td>
<td>2,210</td>
</tr>
</tbody>
</table>

Notes:
1. At 15°C, atmospheric pressure and dry basis, consistent with the requirements of GS(M)R
2. The figures presented here for hydrogen and methane are examples only, as such values ultimately depend upon the assumed combustion air temperature

The most important combustion properties in terms of the differences between hydrogen and methane combustion are calorific value (CV), Wobbe Number (WN), flammability range and flame speed. The CV, WN and Relative Density (RD) for methane content within mixtures ranging from 0–100%, are presented in Figure 5.1.

### Figure 5.1: CV, WN and RD for Methane-Hydrogen Mixtures

Source: DNV-GL using GasVLe [https://www.dnvgl.com/services/gasvle-8331](https://www.dnvgl.com/services/gasvle-8331)
The CV of hydrogen on a volumetric basis is a third of that of natural gas primarily due to its low relative density. However, in terms of combustion, the WN provides the most appropriate indicator of gas interchangeability. As this is a function of CV/\sqrt{RD}, the WNs of hydrogen and methane are much closer together than the volumetric CV.\(^a\)

Table 5.1 shows that the flammable range of hydrogen, at 4% to 75%vol., is far wider than that of methane, at 4.4% to 17%vol.\(^b\) This can be calculated for methane-hydrogen mixtures using the 'Le Chatelier' rule, and is presented in Figure 5.2.\(^c\)

**Figure 5.2: Flammability Ranges for Methane-Hydrogen Mixtures**

[Image of a graph showing flammability limits for methane-hydrogen mixtures]

Source: DNV-GL using GasVLe https://www.dnvgl.com/services/gasvle-8331

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\(^a\) Note that GS(M)R currently specifies a minimum WN which, dependent on the underlying natural gas WN, would be contravened with certain hydrogen blends

\(^b\) See BS EN 60079-20-1:2010

Whilst the Lower Flammability Limit of hydrogen is broadly similar to that of methane, the Upper Flammability Limit of hydrogen is significantly higher. This means that it can be ignited over a greater range of compositions in air than methane; this has implications for the nature of the flame front, particularly when considered alongside the burning velocity.

The burning velocity is presented for a variety of hydrogen-methane mixtures in Figure 5.3. This shows that for hydrogen it is almost an order of magnitude higher than for methane. This higher burning velocity, combined with the difference in the upper flammability limit changes the nature of the flame front for hydrogen compared with methane and so needs to be taken into consideration when evaluating burner suitability/design to achieve flame stability and considerations of flash-back. This is discussed in more detail in Section 5.3.1.

**Figure 5.3: Burning Velocity for Methane-Hydrogen Mixtures**

![Diagram showing burning velocity for methane-hydrogen mixtures](image)

The flame temperature for hydrogen is also higher than for methane; for example, 2,210°C in air, compared with natural gas at 1,960°C (depending on air temperature). This not only has implications for emissions of Nitrogen Oxides (NOx), but when combined with the potential change in flame profile it is important to ensure that the materials of construction are suitable for the higher temperatures experienced by components in the burner and combustor system.

Heat is typically transferred from the combustion of a fuel to another body or substance by a combination of conduction (by direct impingement), convection (carried by the heated flue gas and air) and radiation. In the combustion of a carbonaceous fuel there are a myriad of intermediary components as well as the final products of CO₂ and water. These contribute to radiant emission and absorption. Because the only product of combustion of hydrogen is water, radiant emission from is lower than for methane, changing the balance between radiant, convection and conduction heat transfer. This has implications for the design of hydrogen combustion systems, as discussed in Section 5.3.

To ensure safe operation, flame detection is employed in combustion systems. It is important that the systems deployed are compatible with hydrogen fuel. The following three types are commonly in use:

- The most common form of flame monitor in industrial furnaces detects UV radiation. This will not only detect UV radiation but will also discriminate between the flicker of flames and the steady emission of background refractory. Such detectors are suitable for hydrogen applications;

- Ionisation flame detection is also commonly used in industrial applications, often for the pilot burner. However, pure hydrogen flames cannot be detected by ionisation, but for mixtures of hydrogen and natural gas it is important to establish the level at which ionisation will be a reliable technology; and

- Direct infra-red flame detection is not common in industrial applications, but is used for oil flame detection on dual-fuel burners that operate on oil or gas or a combination of fuels.

Due to the absence of carbon, which is the core driver for a potential repurposing of the gas grid away from natural gas, combustion of pure hydrogen produces no stack emissions of CO₂. It also emits no particulates. However, due to the higher temperature of combustion noted above, without appropriate measures, emissions of NOx are likely to be higher than those from methane combustion. This has implications for the suitability/design of hydrogen combustion burners and systems. Different types of equipment can address this in different ways, as discussed in Section 5.3. Compared with carbonaceous fuel, the higher moisture content combustion products may also need to be considered in downstream process design and plume visibility.
5.2.2 Hydrogen Transportation

The primary parameter for delivery of energy via a gas is the volumetric calorific value. Hydrogen has a calorific value on a volumetric basis of only around a third that of methane, which means that flow rates must increase to deliver the same quantity of energy. Care must be taken to ensure that pressure drops remain acceptable through pipes and the network to ensure sufficient energy can still be delivered. Modelling undertaken as part of the aforementioned H21 project demonstrated that only relatively minor network reinforcement would be required to maintain acceptable energy distribution for supply of 100% hydrogen to the city of Leeds. Like natural gas, hydrogen can also be stored as line pack in a pipeline system, as is discussed further in Section 6.0 in respect of a potential L-M hydrogen cluster.

Materials compatibility is important. Hydrogen embrittlement is an issue for high strength steel pipelines under a high partial pressure of hydrogen. Consequently, high pressure pipelines for hydrogen transmission would need to be designed specifically for this duty. However, in the lower tiers of the distribution system, not only are the operating pressures lower, but much of the network is being replaced by polyethylene pipes under the IMRP. Polyethylene is increasingly considered as being suitable for hydrogen transportation at the required pressures. Detailed assessment, including any impacts of hydrogen on jointing are being reviewed as part of ongoing work in the aforementioned H21 and HyDeploy projects.

In designing transportation and storage systems for hydrogen, the reverse Joule-Thompson effect must also be considered. Most gases cool as they expand and warm when compressed; in contrast, hydrogen warms slightly as it expands, and cools slightly when compressed. This means that care needs to be taken when reviewing thermal profiles at compressors, pressure let-down stations and storage systems.

5.2.3 Safety aspects of hydrogen usage

In order to safely transport and use hydrogen the following range of inherent characteristics must be considered:

- **Characteristics relating to leakage**
  Leakage of any gas is an important consideration for both transportation and within installations. Although the volumetric flow rate of hydrogen will be higher than for methane (for a given leak size and pressure), its lower calorific value on a volumetric basis means that the rate of energy released from such a leak is similar to that of methane. However, pure hydrogen is around eight times more buoyant in air than methane and also diffuses three times faster. Therefore in the open, it disperses and dilutes more rapidly, and so is less likely to reach the Lower Flammability Limit, which is similar to that of methane. Consequently, research undertaken by the HyHouse project concluded that the risks of significant fire and explosion were similar to that presented by natural gas, with the possible exception of very confined spaces. Diffusion of hydrogen through materials is second order compared with flow through physical leak paths for natural gas or hydrogen due to the substantially lower flux rates.

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http://www.northerngasnetworks.co.uk/document/h21-leeds-city-gate/


Ignition temperature and electro-conductivity

The auto ignition temperatures for hydrogen and methane are similar, so this does not of itself represent a significantly increased risk. However, the minimum ignition energy of a mixture does reduce with increased hydrogen concentration. Combined with hydrogen's low electro-conductivity, the risk of ignition by electrostatic discharges therefore increases, and so all equipment containing hydrogen must be appropriately earthed. The influence of other causes of ignition, including frictional sources or those from pressure releases need to be understood and appropriate area classifications considered for installations. Equipment safety class and zoning requirements under ATEX regulations need to be considered based on the appropriate gas group for methane-hydrogen mixtures.\(^{52}\) In this context, a higher safety class is likely to be required for blends (or 'mixtures') above 25% hydrogen.\(^{53}\)

The ignition energy for hydrogen is lower than that for natural gas and therefore it is easier to ignite a small leak of hydrogen by static electricity or small sparks, even though its auto ignition temperature is higher. Assuming an ignition source is present, therefore, small leaks of hydrogen can burn more easily due to its wide flammability limits.

Lower Flammability Limit

Gas detection equipment must also be suitable for both high and low hydrogen (and methane) blends. The key issue for detection is the Lower Flammability Limit which is similar for these gases. Existing gas detection can be impacted by the presence of hydrogen in natural gas, and the effects are dependent on the detection method and the activities for which the equipment is used. It is therefore important to ensure that the detection method is suitable for the application.

Odour

GS(M)R requires that natural gas transported at a pressure of below 7 barg must be odourised to give a distinctive odour so that leaks are readily detected. For blends up to 20% hydrogen (with natural gas), work by DNV-GL noted no masking of odour intensity, or change of characteristics.\(^{54}\) For distribution of hydrogen at higher blends odorant would need to be added. Furthermore, no chemical incompatibility issues have been noted between hydrogen and the current odourising compounds.\(^{55}\) However, adoption of odorants without sulphur bearing species would be preferable to avoid contamination for fuel cell applications.

Flame colour

In the event of a hydrogen fire or a leak which is subsequently ignited, its pale blue flame is not readily visible to the human eye, although contaminants will typically lead to some colour, and additives can be deliberately added to ensure this happens.

Carbon monoxide emissions

One of the biggest safety risks for combustion of natural gas is the emission of carbon monoxide. For pure hydrogen, this risk is avoided completely, but for hydrogen/natural gas mixtures it is important to ensure that complete combustion is achieved, noting the changes in flame characteristics.

Operational Procedures

It will be important to ensure that operational procedures, including detection equipment and emergency response are suitable for the range of gas compositions being considered.

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52 ATEX is the name commonly given to the two European Directives for controlling explosive atmospheres: Directive 99/92/EC (also known as 'ATEX 137' or the 'ATEX Workplace Directive') and Directive 94/9/EC (also known as 'ATEX 95' or the 'ATEX Equipment Directive')

53 According to BS EN 60079-20-1:2010


The practical safety issues associated with hydrogen, certainly when used as a blend with natural gas, are being critically assessed as part of the aforementioned HyDeploy project, where the case is being made to the HSE for an exemption to the GS(M)R hydrogen limit.\(^{56}\) For higher hydrogen mixtures, this work will need to be extended.

### 5.3 Attributes of Hydrogen Use in Different Applications

Across the different industry sectors explored in Section 5.4, the proportion of CO\(_2\) emissions from different applications (or sources) is presented in Table 5.2. As the majority of applications for hydrogen are combustion with the fuel gas used in a burner, the various types of these are briefly examined in Section 5.3.1. However, hydrogen can also be used in a range of energy and chemical applications, which use a number of types of equipment. Consequently, in Sections 5.3.2 to 5.3.5, the various design aspects and experience of hydrogen use in different generic equipment types are considered.

Table 5.2: Proportion of CO\(_2\) Emissions from Different Sources (by sector)

<table>
<thead>
<tr>
<th>Sector</th>
<th>Total Emissions (MtCO(_2))(^1)</th>
<th>Combustion (%)</th>
<th>Process/ Chemical (%)</th>
<th>Indirect Electricity (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chemicals</td>
<td>18.4</td>
<td>54</td>
<td>7</td>
<td>39</td>
</tr>
<tr>
<td>Glass</td>
<td>2.2</td>
<td>58</td>
<td>18</td>
<td>24</td>
</tr>
<tr>
<td>Ceramics</td>
<td>1.2</td>
<td>63</td>
<td>14</td>
<td>23</td>
</tr>
<tr>
<td>Food &amp; Drink</td>
<td>9.4</td>
<td>75</td>
<td>0</td>
<td>25</td>
</tr>
<tr>
<td>Oil Refining</td>
<td>16.3</td>
<td>92</td>
<td>6</td>
<td>2</td>
</tr>
<tr>
<td>Pulp &amp; Paper</td>
<td>3.3</td>
<td>73</td>
<td>0</td>
<td>27</td>
</tr>
<tr>
<td>Iron &amp; Steel(^2)</td>
<td>22.8</td>
<td>94(^3)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cement</td>
<td>7</td>
<td>24</td>
<td></td>
<td>68</td>
</tr>
</tbody>
</table>

Notes:
1. Emissions of CO\(_2\) from all fuel types (not just natural gas)
2. As the processes are so integrated, it is not possible to differentiate between emissions from combustion and those direct from the process
3. Production using a blast furnace (rather than an electric arc furnace)


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5.3.1 Burner and Flame Types

As discussed below, the impact of hydrogen addition for combustion applications will depend on the burner type and the flame type which it produces. The main difference is whether the flame is post-aerated or pre-aerated (also known as ‘non-aerated’ and ‘aerated’ respectively). With a pre-aerated flame, oxidant (generally air) is pre-mixed with the fuel gas, either in a mixer upstream of the burner (pre-mix burner) or the oxidant is mixed with the fuel gas at the burner (nozzle mix burner). In a pre-mix burner, the aeration is achieved through a variety of configurations with the oxidant typically drawn or blown into one port, and the fuel delivered into another port of a mixer which is upstream of the burner head. In a nozzle mix burner, the mixing takes place at the burner head. Most modern domestic boilers, for instance, are of the pre-mix type, but industrial burners can take both forms. Whichever way the oxidant is mixed with the fuel (pre-mix or nozzle mix) the result is a pre-aerated flame, which is sometimes also referred to as a ‘deflagration’ flame.

With post-aerated (or non-aerated) flames, no oxidant is added to the fuel, so the only source of oxygen is from the atmosphere around the flame. The fuel is delivered unmixed to the burner and only combusts when it meets oxidant in the combustion chamber. As the fuel is injected into the oxygen-rich atmosphere, it burns and produces an inert waste gas which then becomes a barrier between the fuel and oxygen. As a result, the combustion rate is dependent on the diffusion of fuel and oxygen through this barrier. This flame is sometimes also referred to as a ‘diffusion’ flame. It is cooler and less rapid than a pre-aerated flame, and therefore produces less NOx.

In practise, the designer will choose the flame to give the appropriate heat transfer and select a burner which gives that flame. However, this requires detailed consideration, depending upon the specific application. It is anticipated that future work on this area will be undertaken in relation to this study.

The presence of hydrogen in the fuel in pre-mix (‘aerated’) burners tends to increase the propensity for flash-back. ‘Flash-back’ is the phenomenon where combustion takes place at the point where the fuel and oxidant are mixed (usually at the gas injection nozzle). Experience of pre-mix radiant wall burners, which are common in the process sector for fuel-fired hydrogen reformers, shows that flash-back is unlikely to occur when the hydrogen concentration in the fuel mixture is less than 30% vol. In this application, the burner commonly uses hydrogen fuel mixtures, and specific applications have been designed for and can work well with higher hydrogen concentrations. For other pre-mix burner applications or burners where air is entrained by a fuel gas nozzle, the presence of hydrogen and its higher burning velocity may present issues and need careful consideration.

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58 For the purposes of this study, in subsequent sections, we use the term ‘pre-aerated’ to refer to such flames
59 For the purposes of this study, in subsequent sections, we use the term ‘post-aerated’ to refer to such flames
5.3.2 Furnaces and Kilns

A kiln (or furnace) is a thermally insulated chamber, which produces temperatures sufficient to complete a manufacturing process, such as hardening, drying, or chemical changes. Kiln types can be split into low temperature processes, such as those used in the food manufacturing sector, and high temperature processes, such as those used in the glass and ceramics sectors.

For low temperature processes (up to 650°C), many kilns employ 'package' burners, which can include (as a designed-together combination) a burner, blower (if necessary), fuel control, gas train, and control panel. Typical applications include fresh or recirculated air heating applications for industrial 'ovens' and dryers and industrial heating. Unlike boiler applications, heat is transferred directly to the product or process rather than through sequential transfer into water or steam. In general, such applications are therefore more amenable to the introduction of hydrogen, provided that the burner system can accommodate it. For low levels of hydrogen as a mixture (with natural gas), this is likely to be achievable without change or through modification of existing burners. Where higher hydrogen usage is required, the 'package' nature of most burners means that a replacement is more likely to be required, albeit these are usually relatively straightforward to replace. In this instance, the burner would need to be designed appropriately, and there may be scope for allowing a degree of fuel modulation. NOx control remains important, and for some applications, the increased moisture content of the combustion products in the kiln or furnace may need consideration.

High temperature applications are primarily found in the glass and ceramics sectors where kiln temperatures are as high as 1,500°C. Burners for glass applications are relatively simple bespoke configurations, typically using diffusion flames such as in glass 'tanks' where the fuel is injected into a stream of pre-heated air. In the sector, there has been some experience of burning hydrogen-rich fuel mixtures due to previous use of Town Gas. Consequently, knowledge exists to help facilitate consideration of hydrogen mixtures. When using hydrogen at such high temperatures, care must be taken in respect of potential greater degradation of arches and crowns within furnaces, which may need to be re-lined to allow higher mixtures of hydrogen. Attention will also need to be paid to the effect of the higher moisture content of the combustion product, and the possibility of increased NOx formation.

The issues relating to use of hydrogen in the glass, ceramics and food manufacturing sectors relate to are described in detail in Sections 5.4.1, 5.4.2 and 5.4.2 respectively.

5.3.3 Boilers

To provide an understanding of the technical potential for hydrogen to be burned in industrial boilers, it is necessary to distinguish between fire-tube and water-tube boilers, the issues relating to which are described in Sections 5.3.3.1 and 5.3.3.2 respectively.
5.3.3.1 Fire-tube Boilers

Many boilers in the 3–5 MWth range are of a fire-tube design, often producing saturated steam in two or three passes. In a fire-tube boiler, water surrounds the tubes containing the fire flame and hot combustion gasses, and the steam or hot water is taken off the top of the shell. The burner is typically in two parts. The oxidant (usually air) is supplied as both primary and secondary air. The primary air is mixed at the burner head with primary gas, making a pre-aerated flame. This part of the flame stabilises the remainder of the flame. To optimise heat transfer, the flame is engineered to extend along the length of the first pass of the boiler as a post-aerated flame. The secondary air and secondary fuel gas are injected into the flame unmixed. This results in a post-aerated flame producing a diffusion flame contained within the initial radiant pass. This can either be a straightforward horizontal pass or a ‘U-tube’ configuration (where the flame radiates through the products of combustion as it turns back on itself and thus protects the metalwork of the boiler from the reducing atmosphere of the diffusion flame). Subsequent passes transfer heat by convection from the combustion product gases, to the fire-tubes, and thence through the thin walled tubes into the water. Figure 5.4 shows a typical horizontal pass configuration, albeit it is acknowledged that there are a number of other possible configurations.

![Figure 5.4: Example Configuration of Horizontal Pass Fire-tube Boiler](image)

A change of fuel from natural gas to hydrogen or to a mixture of the two will modify both the flame length in the first pass and the products of combustion. As a result, it will also typically reduce the radiant heat transfer and increase the temperatures and heat removal required in subsequent passes. It is important to ensure that the system can accommodate this. In the horizontal tube-type boiler, the most vulnerable part is the tube plate at the tube ‘welds’ and it is important to ensure that these are not subject to levels beyond their design basis.

As most boilers are designed for a certain flame length based on natural gas, the different flame speed of hydrogen needs to be considered when designing for, or operating using, hydrogen. Designers should aim for a flame temperature of less than 1,300°C to minimise the formation of NOx, although in reality higher temperatures within the flame are likely. Radiation heat transfer at lower flame temperatures will be reduced but the downstream convection heat transfer can be enhanced by reducing the boundary layer or increasing turbulence within the fire tubes. The hydrogen flame speed is maximum near 57% of stoichiometry so is reduced for high excess air. Similarly, the hydrogen flame temperature (200 degrees hotter than natural gas) is also reduced for excess air conditions. The flammability limits of hydrogen allow for the flame composition to be operated at high excess air which will then reduce the differences between a natural gas flame and a hydrogen flame.
Some mixing of hydrogen is expected to be achievable without modification, although higher hydrogen mixtures would require assessment of changes to both the thermal profile within the boiler and to the burner configuration to ensure continued performance, operation within materials design limits and to achieve NOx control. A whole generation of boilers are in use with the facility to fire on gas or oil. Therefore, it is a reasonable assumption that boiler designers have the experience of using different flames (both shape and colour) in the first pass. However, users are not normally equipped to take account of significant changes in gas composition.

### 5.3.3.2 Water-tube Boilers

Many larger boilers, with an output greater than around 5 MWth, are of a water-tube design, often producing ‘superheated’ steam for large-scale manufacturing processes. These typically have multiple burners where the air flows can be configured independently in individual burners to control the combustion conditions. For example, the burners in the lower galleries can be configured to burn the fuel gas rich, and secondary air controlled in the upper galleries to produce a lean zone, the result of which is to minimise NOx emissions.

Industrial water-tube boilers were commonly equipped with duel-fuel burners, usually for natural gas and oil. As a result, such boilers can be designed to cope with some changes in the different flame temperature gradients and heat transfer mechanisms associated with fuels operating at different temperatures and emissivity. This requires not only the ability for simple change-out of fuel injectors or burners, but also resilience in the tube configuration to protect them from changes in the balance between radiant and convective heat transfer. This wider flexibility is more likely to lend itself the introduction of hydrogen-rich fuels.

The key issue for a hydrogen-rich fuel gas is the burner design. When a hydrogen-rich mixture is being fired, there will need to be more precise control of the fuel gas supply to the burners, and the higher flame temperature may require changes to the material from which the burner tip is made (e.g. to ceramic or copper).

NOx control remains an important design criteria, although flame temperature can be controlled by burner design, and the multiple burner banks, injection points for secondary air and potential for flue gas recirculation all represent tools to control this. Flue gas recirculation, achieved by mixing flue gas with incoming combustion air, can be used to modify the flame temperature as well as modify, to a limited extent, the radiant characteristics. It is also likely that some modifications to the control system would be required, including changes to the flame detection system, which would be dependent on the type installed.

To avoid the formation of a visible plume from water-tube boilers, hot air is often added to raise the temperature of the exiting gases. Using hydrogen as part or all of the flue gas will increase the water vapour content of the flue gas, so additional hot air may need to be added to avoid the early appearance of a visible plume.

Whilst there are modifications to be made to allow burning of hydrogen, however, water-tube boilers do offer high degree of fuel flexibility. Discussions with industry as part of this study indicate that mixing of 10-15%vol. is expected to be achievable without major modifications. Furthermore, the relatively flexible design should allow changes to achieve higher levels of hydrogen. In designing such modifications, it should be possible to define an appropriate operational window to accommodate a degree of fuel flexibility.
5.3.4 CHP

Two ‘prime movers’ dominate industrial gas CHP installations; Gas Turbines and reciprocating engines (both compression ignition and spark ignition). Both are available from diverse suppliers internationally and both are available in a range of sizes. There is a tendency for the smaller installations to employ reciprocating engines and for the larger ones to use Gas Turbines. The issues associated with both are described in Sections 5.3.4.1 and 5.3.4.2 respectively.

5.3.4.1 Reciprocating Engines

Reciprocating engines fall broadly into two categories, compression ignition and spark ignition. The focus of the following analysis is solely upon the use of these engines with natural gas, although it is recognised that there are a range of natural gas/diesel hybrid engines.

Development of reciprocating engines, particularly those used by industry, has been driven by a desire for improved efficiency and increased output. Manufacturers have also been driven to improve availability and reduce maintenance costs. Perhaps the most challenging factor to engine development over the past few decades, however, has been that of meeting shrinking emissions limits, with NOx representing the biggest challenge. The conflicting factor is the need also to minimise emissions of carbon monoxide (CO).

Over the years, as new environmental legislation, such the EU Industrial Emissions Directive (IED), has been introduced, engine manufacturers have developed new engines and related control systems to meet new requirements. They have also proved effective in engineering modifications to existing engines and control systems to allow them to continue to operate under the new regime, although this has not always proved to be cost-effective compared with the alternatives.

Compression-ignition engines generally operate with lower air-to-fuel ratios and higher combustion temperatures than Gas Turbines (see Section 5.3.4.2). The aim is to maximise efficiency but the result is the potential to generate relatively high levels of NOx per unit of power generated.

As a result of recent advances in the manufacture of larger and more efficient spark ignition gas engines, these are now a viable option for industrial CHP applications. These engines are based on lean-burn combustion technology, typically incorporating cooled exhaust gas recirculation (EGR). In many cases, this enables engines to meet the strict NOx emissions limits that apply in most European countries under the IED. Notably, however, some plant will also need to meet the requirements of the forthcoming EU Medium Combustion Plant Directive (MCPD). Where required, post-combustion NOx abatement can be achieved by selective catalytic reduction (SCR). A gaseous reductant, typically anhydrous ammonia, aqueous ammonia or urea, is added to the exhaust gas and is adsorbed on to a catalyst.

In terms of operation on fuels containing hydrogen, the inherent characteristics described in Section 5.2.1 need to be accommodated. For engine operation, other important parameters include the octane rating, which is similar to methane, and the smaller quenching distance for hydrogen. These factors can increase the tendency for backfire since the flame from a hydrogen-air mixture can more readily get past a ‘nearly closed’ intake valve than the flame from a hydrocarbon-air mixture.
There are existing industrial applications, for which gas engines are designed to operate on fuel gases containing hydrogen, such as coke oven gas. This is a product gas from the steel industry (see Section 5.4.7 for more detailed discussion) with a composition of 50-60%vol hydrogen and 15-50%vol methane, along with a small percentage of CO, carbon and nitrogen.\footnote{See \url{https://www.clarke-energy.com/steel-production-gas/}} For example, Jenbacher has engines can operate on coke oven gas, such as the bank of engines at the Profusa Coke Factory in Bilbao (Spain), which has been operating since 1995 with a combined rating of around 6MWe.\footnote{See \url{https://powergen.gepower.com/content/dam/gepower-pgd/p/global/en_US/distributed-power-downloads/documents/2008_qa_ref_cokegas_profusa_e.pdf}} Furthermore, MWM has larger engines operating coke oven gas, including those at Italiana Coke, which have been operating since 1993 with an installed capacity of 25MWe.\footnote{See \url{https://www.mwm.net/mwm-chp-gas-engines-gensets-cogeneration/gas-applications/references/steel-and-chemical-industry-syngas-coking-gas/italiana-coke-italia/}} The experience of hydrogen introduced into existing natural gas engines is more limited. There is an acceptance that low level hydrogen mixtures should be feasible, but increasing proportions of hydrogen will require further work with suppliers. Towards this goal, extensive work has been carried out at the University of Gent into a range of hydrogen mixtures.\footnote{Sierens, R & Rosseel, E. (1999) Variable Composition Hydrogen/natural gas mixtures for increased engine efficiency and decreased emissions, J. Eng. Gas Turbines Power 122(1), 135-140, July 1999} This research successfully demonstrated both low hydrogen mixtures (up to 15%vol) and a preliminary investigation was also carried out on the use of higher hydrogen fractions in the fuel gas. Using pure hydrogen, the tests showed that the engine could largely function reliably without backfiring, and it was concluded that that a hydrogen content of 80% or less ensured safe operation of the engine, whatever the air excess factor in these trials. This work also showed that management of NOx to maintain very low emissions would require exhaust after-treatment.

In principle, if this work could be built upon by the manufacturers of spark ignition reciprocating engines, then these may be able to extend the operational envelope to include guarantees when using hydrogen/natural gas mixtures. This could include not only apply to new engines, but, following modification to control systems, also allow existing engines to continue to operate should a blend of hydrogen be introduced to the gas network. Some reduction in energy output would have to be accommodated, the extent of which and over what fuel mix range will be design-specific.

The core areas of development required to enable the use of hydrogen in engines can therefore be summarised as:

- A need for manufacturers to modify control systems and potentially also fuel gas trains, and to prove the engines on hydrogen and on hydrogen/natural gas mixtures;
- A need for manufacturers to define operational envelopes and provide suitable guarantees; and
- Ability of users to accept a reduction in output or host additional machines to make up lost output.

It would therefore appear that there is no fundamental technical reason why spark ignition reciprocating engines should not be able to function with low levels of hydrogen mixed with natural gas. Building on the experience of those in industry relating to their expertise in firing unconventional gases, such as coke oven gas, it may well be possible to operate on higher proportions of hydrogen, certainly for new machines. However, increasing the proportion of hydrogen in an existing reciprocating engines will result in a reduction in the output power and a loss in efficiency.
5.3.4.2 Gas Turbines

The Gas Turbine industry has evolved from its aerospace roots to deliver stationary power generation in response to market demand for improved efficiency, lower emissions, and increased output.

There is considerable experience in relation to burning low CV fuel gas (or hydrogen-rich syngas) by the likes of General Electric (GE), Siemens, MHI, MAN Group and Solar/Turbomach (owned by Caterpillar). In the context of the development of a hydrogen cluster based around industry, analysis of a low proportion (5-15%) of hydrogen must be considered alongside a potential future switch to higher proportions and to 100% hydrogen.

The key hydrogen-specific issues which need to be addressed relate to start-up, delivering sufficient fuel gas and appropriate diluent, controlling combustion and, in particular, NOx formation.

There are many examples of Gas Turbines operating on fuel gases containing hydrogen, typically coke oven gases or syngas. For example, GE has an extensive reference list of different machines operating on gases ranging from 8% to over 60% hydrogen. However, it is acknowledged that in many of these cases, a mixture of hydrogen and carbon monoxide is used, rather than a mixture of hydrogen and natural gas. Siemens has a similar reference list across its range of frame sizes operating on such fuel gases and is understood to have tested its F-class machines with a hydrogen content ranging from 30% to 73% within the fuel gas.65

Successful research programmes have included a US Department of Energy (DOE) sponsored programme (from 2005 to 2015).66 This focused on Integrated Gasification Combined Cycle (IGCC) applications and achieved 60-100% hydrogen volume with well controlled NOx levels possible below 10ppmv. In addition, the European Framework 6 ENCAP programme also investigated NOx emissions along with fuel flexibility using hydrogen.67

When using high hydrogen fuels (up to 100%), GE and others add a diluent, usually nitrogen or steam, which dilutes the hydrogen to about 65%. These machines were developed and proved for the anticipated ‘IGCC with CCS’ market that was being driven by policy objectives during the period 2000-2015. As such, these machines are available today with normal commercial guarantees and full manufacturer’s support.

Much focus in the Gas Turbine Industry for conventional natural gas use has been on addressing NOx emissions, which has led to the development of Dry Low NOx (DLN) combustors.68 Based on our experience and wider industry engagement held as part of this study, it is likely that many modern DLN combustors could cope with at least 15% of hydrogen mixed with natural gas. In reality, however, more detailed site-specific analyses would need to be carried out, which considered the manufacturer, the age and design of the combustor and the exact mixture that it is intended to burn.

68 See http://www.encapco2.org/
69 Low NOx formation is achieved by mixing some air with the fuel before combustion, but not enough to allow stoichiometric combustion to take place. In the primary zone, the flame initially burns ‘lean’, with insufficient oxygen being available for a significant reaction with nitrogen. In the secondary zone of the flame, more air is added to the already rapidly travelling gasses, and the remaining fuel then burns ‘rich’, but by then the temperatures, lowered by the incoming air, are too low for significant NOx formation
For other existing Gas Turbines, introducing a small amount (about 5%) of hydrogen into natural gas would also not present a significant technical problem, but some modifications would be necessary, including:

- In some cases, swapping the existing DLN combustors for new diffuser types;
- Introducing a diluent (e.g. steam or nitrogen) to minimise NOx formation;
- Swapping out the fuel gas skid to accommodate the fuel composition changes (e.g. increased volume due to the lower CV of the fuel gas);
- Possible increase in pressure ratio to accommodate higher flame speeds and to avoid burn-back (via an additional stage in compressor); and
- Reprogramming of control software.

The effect of using hydrogen (as part of a mixture with natural gas) on the performance of gas engines is expected to be:

- Slightly enhanced output, resulting from the increased mass flow through the expansion turbine (albeit this may be balanced by the greater compressor load);
- Slightly reduced efficiency as a result of the lower flame temperatures (necessary to minimise NOx formation); and
- Slightly reduced blade life as a consequence of water droplet formation and blade surface pitting.

There would appear to be no fundamental technical reason why many Gas Turbines should not be able to function with hydrogen mixed at low levels with natural gas fuel mixtures. Higher mixtures would require either more extensive modification, or machines designed for the specific duty. In this context, it can be noted that there are examples of larger 100% hydrogen machines being offered by manufacturers for CCS demonstration projects. However, given the range of manufacturers, burner types and frame-sizes, any individual application would need to be considered on machine-specific basis.

At the same time, it must be accepted that not all existing Gas Turbines will prove to be suitable for retrofit modifications to enable hydrogen combustion, in part or in whole. Redesign work with associated testing on older models, for instance, may not be justified compared with the cost of replacing the engine with a more up-to-date model for which the work has already been done.

In summary, the core areas of development required to enable the use of hydrogen in Gas Turbines are:

- The need, for most manufacturers, to develop suitable diffusion burners for high hydrogen mixtures, introduce a diluent mechanism and modify the related control systems;
- Further testing of the above to prove the machines on hydrogen/natural gas mixtures;
- Definition of operational envelopes and determination of how to offer suitable guarantees; and
- Consideration as to whether users will accept a reduction in output or host additional machines to replace lost output.
5.3.5 Chemical use

In addition to its use as a fuel for energy generation, hydrogen is also an important feedstock for a number of chemical process industries and the oil refining sector, as discussed in more detail in Sections 5.4.5 and 5.4.6 respectively.

Distribution of hydrogen from new SMRs (with CCS), as described in this report, offers the opportunity for existing industrial users of hydrogen to decarbonise. This would require assessment of delivered hydrogen purity, but this could be addressed through standard gas treatment, such as a pressure swing absorption (PSA) plant. Conversely, existing producers of hydrogen may provide useful sources for trialling purposes or to provide system resilience, albeit such sources would effectively not be ‘decarbonised’.

In cases where natural gas is used as a chemical feedstock, the compositional variation of natural gas means that processes have to be reasonably resilient, although not necessarily to hydrogen. In most potential cases, for example where an existing SMR might receive an incoming gas supply with some hydrogen, the process will not be fundamentally upset, but may need to be slightly re-optimised.

5.4 Analysis of Potential Hydrogen use in Industry Sectors

For each of the main industry sectors for which baseline data is presented in Section 2.2.2, further information and analysis is provided in Sections 5.4.1 to 5.4.8 relating to:

- UK-wide sector size and decarbonisation options;
- Characterisation of plant energy use (and chemical demand for hydrogen);
- Opportunities for low and high levels of hydrogen mixed with natural gas; and
- The potential to ‘flex’ between natural gas and hydrogen as a feedstock.

It should be noted that for each sector, the information at UK-level relating to sector size is largely drawn from work undertaken by the former Department for Business (BIS - now part of BEIS), which was published in March 2015.70

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5.4.1 Glass

5.4.1.1 Sector Overview and Decarbonisation Options

In 2012, more than 3 million tonnes of glass were manufactured in the UK and in 2013, the glass industry posted a 2013 turnover of around £1.1 billion, with around 80% of this from container glass and 20% from flat glass.\(^71\) Revenues from the latter are also likely to have increased relatively significantly following the UK’s emergence from the global economic downturn and the related expansion of the construction sector. In 2012, a further £0.6 billion in sales can be attributed to the glass fibre and technical manufacturing sectors, such that total sector revenue is around £1.7 billion.\(^72\) Data published by British Glass states that around 6,500 people are directly employed in the sector with a further 45,000 employed in the downstream application and service industries.\(^73\)

The glass sector in the UK used 6.5 TWh of heat in 2014, with 6 TWh of this used in the melting process.\(^74\) This represented 2% of all industrial energy used in the UK in 2014. Natural gas was used to provide 81% of this energy, electricity 13%, with the remaining 6% from oil and coal. Within the L-M Cluster area specifically, as presented in Section 2.2, there are eight major glass manufacturing sites. In the area, gas use by the glass sector represented 13% of industrial gas use (for sites >5.9GWh/annum) and 3% of all gas use.

In respect of \(\text{CO}_2\) emissions, the sector was the seventh largest in the UK, with 2.2 mt\(\text{CO}_2\)pa in 2012.\(^75\) Over 58% of these emissions were from direct combustion, 18% were process emissions from thermal decomposition of materials in the furnace, with the remainder from electricity use. The container glass sector is the largest and is characterised by 12 large plants across the UK that emit a high proportion of the sector’s \(\text{CO}_2\) emissions. Similarly the flat glass sector is dominated by five large sites. In the L-M area, there is both a major glass container manufacturing site (operated by Encirc) and another four sites making different forms of flat glass (all operated by Pilkingtons). The Encirc site, together with the largest of the Pilkington sites, were responsible for around 82% of emissions from the L-M glass sector in 2016.

Between 1979 and 2008, furnace energy efficiency improved by 54%.\(^76\) However, post-1996 the improvements slowed down dramatically. However, it is currently unclear as to how further emissions reductions might be achieved. The aforementioned BIS study models a number of future pathways to decarbonisation, which include a range of options such as raw materials (including recycled glass), improved process control, waste heat recovery, fuel switching, CCS, general utilities and product design. A similar list is included in the aforementioned publication from British Glass, which also cites the potential of oxygen-fuel (‘oxy-fuel’) combustion.

Production and use of hydrogen is mentioned in the BIS report, but fuel switching to hydrogen is not deployed in any modelled pathway in the study. It is stated that this is because evidence from interviews and workshops undertaken for the study suggested that hydrogen is a less attractive decarbonised fuel gas than bio-methane. However, as described in the analysis in Sections 5.4.1.3, the feedback from glass manufacturers as part of this study has been far more positive in respect of hydrogen; perhaps as a result of concerns about bio-methane availability at the desired scale and location.

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\(^71\) BIS (2015) Industrial Decarbonisation & Energy Efficiency Roadmaps to 2050, Glass Sector, March 2015
\(^74\) BIS (2015) Industrial Decarbonisation & Energy Efficiency Roadmaps to 2050, Glass Sector, March 2015
\(^75\) Ibid.
\(^76\) Ibid.
5.4.1.2 Characterisation of Plant Energy Use

Glass production involves two main methods – the float glass process that produces sheet glass, and glassblowing that produces bottles and other containers. Float glass is a sheet of glass made by floating molten glass on a bed of molten metal, typically tin, although lead and various low melting point alloys were used in the past. The Pilkington float glass process gives the sheet uniform thickness and very flat surfaces.

The manufacture of bottles and other containers starts with a stream of molten glass, at its plastic temperature (1,050–1,200 °C) which is cut with a shearing blade to form a solid cylinder of glass, called a gob. The gob is of predetermined weight just sufficient to make a bottle or other container. The gob passes into the blank moulds, two halves of which are clamped shut and then sealed from above. Air is then blown into the gob (usually in two stages) pressing it into the mould and the formed container is then moved into a Lehr (long continuous oven) where it is annealed and cooled.

In glass manufacture it is important that the flame is ‘clean’ as soot particles of any sort will spoil the product. For this reason, considerable care is exercised in the engineering of the burners, flames and heat transfer mechanisms. Diffusion burners are used in glass melting furnaces. In glass melting, it is necessary for the diffusion flame to be long enough so that it can exchange heat with the whole molten glass tank. Whilst the flame provides direct heating to the glass itself, the majority of the heat is absorbed by the firebrick arch that forms the roof of the furnace, glowing white hot: this heat is radiated back into the glass beneath.

Most glassmaking furnaces are of the regenerative type, as presented in Figure 5.5. Glass is a mixture of compounds and does not have a specific melting temperature. However, the refining of the raw materials and the blending of the components requires a high furnace temperature from 1,350 °C to 1,500 °C. To achieve this flame temperature, air pre-heated to about 1,000 °C is added to the fuel gas, the flame of which passes over the molten glass. Combustion air is provided by a blower, and heated in a brick-filled void called a regenerator. Combustion products are of no value to the furnace, and useful heat is recovered from this by exhausting them through another brick-filled regenerator, heating the bricks up to over 1,000 °C. After about 20 minutes the flows are reversed, and a change-over valve directs incoming air into the hot bricks and the cooled combustion products up the stack. A further 20 minutes later and the flow is reversed again. The goal is to achieve an acceptable thermal profile on the crown (roof) of the furnace, as shown in Figure 5.5.
Glass making furnaces (used for both container and flat glass production) typically use both electric and gas heating. Liquid glass is electrically conducting, which means that there is the potential to use resistive heating for up to about 10% of the total furnace requirement, with the other 90% coming from gas. However, this split between natural gas and electricity is a balance between process benefits and costs; thus, any significant change in the price of either natural gas or electricity could have an effect on the relative usage.

The vast majority of gas use takes place in the furnace, but natural gas is also used in other aspects of container glass production. This is in the glass forming machines, operating at 1,050-1,200°C, in the forehearts (using manifold, pre-mix burners) and then in a lehr (or ‘annealing’ kiln), which uses nozzle burners to provide heat of 400-600°C. Annealing is generally performed continuously with the glass on a conveyor belt being fed through what is essentially a long tunnel, which can take up to 40 minutes depending on the thickness of the glass.


5.4.1.3 Potential for Hydrogen Use

The issues associated with using hydrogen in glassmaking are described in Sections 5.2.1 and 5.3.2. The research and engagement with industry undertaken as part of this study suggests that existing diffusion burners could probably tolerate up to 10% hydrogen without modification, with some redesign being required for higher levels. However, this proportion of hydrogen will depend on the process and furnace-specific discussions would need to be carried out to discover the extent of the modifications.

As discussed above, the glass industry in the UK made the transition between Town Gas and natural gas and retains much of the expertise that was associated with burning low CV hydrogen-rich fuel gas in their furnaces, many of which are still in commercial operation today. Thus, adding hydrogen to natural gas would not necessarily represent anything ‘new’ in this sense, and in some cases, previous burner designs (or modified versions thereof) could potentially be re-used.

A comparison between the compositions of Town gas, natural gas and a mixture of 50% hydrogen (with natural gas) is presented in Table 5.4. In general terms, the higher the hydrogen content, the closer the fuel properties will be to Town gas. Due to the high proportion of carbon monoxide and methane (45%) in the mix, the flame speed of Town gas was about 200cm/sec. Hence adding small amounts of hydrogen to natural gas will bring its flame speed closer to this level (where previous experience exists). Beyond that point, however, detailed fluid dynamics modelling will be required to examine the effect that the different flame shape will have on the heat distribution within the furnace.

In this context, it should be noted that the burning velocity of a gas mixture cannot be accurately calculated from the burning velocities of the constituents of the mixture. The burning velocity of a fuel gas/air mixture can only be obtained reliably by experimental measurement.

For very high levels of hydrogen, i.e. 50-100% substitution of natural gas, the different types of heat within the furnace require consideration. Using natural gas, the vast majority of the heat into the melt (volume of liquid glass in the furnace) will be radiated from the furnace crown. The remaining, relatively small amount of heat will be radiant heat from the flame. With very high proportions of hydrogen, the reduced flame luminosity (see Section 5.2.1) would result in this radiant heat being unavailable, and as a consequence the temperature of the crown would fall. As a result, the reduced temperature of the melt would result in a reduction in glass production. The specific temperatures at which these changes associated with these issues occur and the related proportions of heat are very dependent upon the specific production process and type of glass being produced.

The luminosity of the flame could potentially be improved by using additives to increase the luminosity of the flame. However, care would have to be exercised to choose the additive such that this did not contaminate the liquid glass in the melt or allow soot build-up on the crown surface during the burner changeover, both which would affect the quality of the product.
Table 5.3: Comparison between Gas Compositions

<table>
<thead>
<tr>
<th></th>
<th>Town Gas (%)</th>
<th>Natural Gas (%)</th>
<th>Natural Gas +50% H₂ (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>H₂</td>
<td>50</td>
<td>50</td>
<td>50</td>
</tr>
<tr>
<td>CH₄</td>
<td>35</td>
<td>90</td>
<td>45</td>
</tr>
<tr>
<td>C₂+</td>
<td>5</td>
<td>7.2</td>
<td>3.6</td>
</tr>
<tr>
<td>Olefins</td>
<td></td>
<td></td>
<td>0.75</td>
</tr>
<tr>
<td>N₂</td>
<td></td>
<td>1.5</td>
<td>0.65</td>
</tr>
<tr>
<td>CO₂</td>
<td></td>
<td>1.3</td>
<td>50</td>
</tr>
<tr>
<td>CO</td>
<td>10</td>
<td></td>
<td></td>
</tr>
<tr>
<td>kcal/Nm³ (HHV)</td>
<td>5,897</td>
<td>9,920</td>
<td>6,333</td>
</tr>
<tr>
<td>Kcal/kg (HHV)</td>
<td>12,208</td>
<td>12,368</td>
<td>14,585</td>
</tr>
<tr>
<td>MJ/Nm³ (HHV)</td>
<td>24.68</td>
<td>41.53</td>
<td>26.52</td>
</tr>
<tr>
<td>MJ/kg (HHV)</td>
<td>51.11</td>
<td>51.78</td>
<td>61.07</td>
</tr>
<tr>
<td>Mol wt (HHV)</td>
<td>10.83</td>
<td>17.9</td>
<td>9.73</td>
</tr>
<tr>
<td>Wobbe Index (MJ/m³)</td>
<td>38.32</td>
<td>49.6 to 50.2</td>
<td>43.42</td>
</tr>
</tbody>
</table>

Notes:
1. Extracted from AIChE, 2010
2. Adapted from National Grid, 2016

The degree of flexibility to switch between hydrogen and natural gas would need to be investigated as part of a development programme, and the nature of the interventions adopted to enable hydrogen utilisation. Importantly, given the significant level of energy consumption by the sector, even a relatively small change in mixture ratio could buffer hydrogen demand for a wider network, thus reducing (or even negating) the need for hydrogen storage capacity.
5.4.2 Ceramics

5.4.2.1 Sector Overview and Decarbonisation Options

In the UK, there were more than 4.2 million tonnes of ceramic products produced in 2014.77 Between 2000 and 2010 the sector has seen more than 40% decline across all subsectors. Total revenues in 2010 were £953 million compared to £1,953 million in 2000. Since 2013, the sector has been slowly recovering, albeit sales figures are still lower than in 2007. The only exception is technical ceramics, where revenues have grown more than 30% compared to 2000.78

The brick-making sector in the UK used 3 TWh of heat in 2012. This represented just under 1% of all industrial energy used in the UK in 2012. Natural gas was used to provide 84% of this energy, electricity 13%, oil 2% and coal 1%. Within the L-M cluster area specifically, as presented in Section 2.2, there are two manufacturing sites (each with gas use of over 5.9 GWh/annum); Ibstock Brick and Chelwood Brick. Gas use by these two brick-makers represented 2% of industrial gas use and 0.4% of all gas use in the cluster area.

In respect of CO$_2$ emissions, the sector is currently the eighth largest industrial sector in the UK, with 1.2 mtCO$_2$pa in 2012.79 Over 80% of these emissions were from direct combustion or direct process emissions with the remainder from electricity use. The majority (c.70%) of emissions were from the brick-making sector, with the white wares sector being responsible for nearly 20%.

In line with the fall in output highlighted above, total energy use of the UK ceramics sector fell by around 20% between 2000 and 2008 (after which there was a rapid decline in total energy use due to the global economic downturn).80 During this period, it does not appear that the energy intensity of the sector fell by any significant margin. It is also unclear as to how emissions reductions might be achieved in the future. The aforementioned BIS study models a number of future pathways to decarbonisation, which include a range of options such as replacement of gas-fired kilns with electric kilns (using low carbon electricity), electricity grid decarbonisation, use of biomass (potentially via gasification) and CCS fitted to larger brick-making plant. Biogas is given one mention in the BIS report, but there is no mention of hydrogen.

5.4.2.2 Characterisation of Plant Energy Use

Most kilns and dryers are fired by gas, and this dominates the sector’s gas consumption. The final product determines the detailed steps of manufacture, but all ceramic manufacturing processes have a common element: the ceramic material is fired to a temperature to instigate chemical and physical changes that develop the final properties of the product, including bonding to form a rigid matrix. Firing requires raw materials (e.g. clay, sand, other natural or synthesised materials), to be prepared and formed according to various subsector processes before being heated in a kiln to temperatures between 900°C and 2,750°C. The fired product is then cooled and taken out of the kiln and possibly further processed with additional coating and firing steps or machining to produce the end product item.

The brick-making sector is characterised by simpler processes, higher adoption of more-efficient continuous kilns and larger scale of production, such that it is the most energy efficient. Refractories have an intermediate level of emissions per tonne due their simpler, but generally higher temperature, production of bulk products. The ‘white wares’ (i.e. bathroom suites and tableware) sector is the less efficient due to the multiple firing steps, greater use of less-efficient batch firing and higher air to ware densities in the kiln, whilst the ‘technical’ ceramics (such as cutting tool tips and turbocharger blades) subsector has disproportionately large emissions due to the small scale of production coupled with the higher firing temperatures employed.

77 BIS (2015) Industrial Decarbonisation & Energy Efficiency Roadmaps to 2050, Ceramic Sector, March 2015
78 Ibid.
79 Ibid.
80 Ibid.
In brick-making, engagement with industry both in the UK and other EU countries suggests that the majority of the gas consumed, around 80%, is utilised in the kiln. The dryer typically consumes around 15% of the fuel, although much of the heat for drying is also met by recycling cooling air from the kiln.

The heat distribution in a brick-making kiln varies according to the type of clay (or mixtures thereof) being fired and the type of brick being manufactured. However, the principle is the same, and is presented in Figure 5.6. A kiln operates over a 48-hour production cycle, with formed clay products entering at ambient temperature, which is gradually increased to 1,500°C to promote vitrification before slowly cooling to ambient temperature. Quartz conversion occurs at 578°C. To facilitate this lengthy process, brick kilns are typically 110-150m long with bricks loaded in 5m batches.

Low velocity burners are installed at start of brick-making process for the drying phase and high velocity burners for the high temperature baking (firing) process. High temperatures are vital to the process and control is important to ensure a consistent product quality. Along the length of the kiln, heat is recovered and reintroduced into the process, for example from the high velocity section in the middle of the kiln to the annealing section toward the outer edges to improve overall efficiency. Process gases are exhausted to atmosphere through stacks at temperatures in the 80-110°C range: on a modern kiln, these are almost invisible.

All other (non-brick) ceramic products require firing in kilns at high temperature in order for the full strength of the ceramic component to be developed. Across the UK, over 90% of the direct heat for firing of such products comes from burning natural gas, which rises to 100% for white wares. The remainder comes from relatively small amounts of LPG, gas oil, fuel oil, coal and coke.

Figure 5.6: Indicative Heat Distribution in a Typical Brick Kiln

Source: Based on discussions with UK and EU industry as part of this study

All ceramic products also require drying to remove excess moisture from the product before firing, otherwise the product may crack during firing. As for brick-making, waste heat from the kilns is usually used to provide the heat for this part of the process. Other sources of heat for drying include the combustion of natural gas (over 90%), with the remainder coming from a similar number of sources as for firing the kilns.

Spray drying of ceramics is a process that mixes the material in liquid form with hot air and sprays it into an atomiser where the water evaporates, leaving a powder which is then formed and fired. This process has been widely used in whitewares since the 1950s and for more refined and advanced ceramic materials and for which natural gas is the only fuel used in the UK.
5.4.2.3 Potential for Hydrogen Use

For brick-making, the amount of hydrogen that could be introduced into a kiln burner originally designed for natural gas will vary between manufacturers, as much work has previously taken place to ensure fuel-efficient combustion and minimal NOx formation. The introduction of hydrogen into the fuel gas will, to some extent, compromise these designs.

As described in detail in Section 5.2, and as for glass-making, the key issues associated with the use of hydrogen (mixed at low levels with natural gas) in the ceramics sector are its lower CV and WN, its higher flame speed, the potential for increased NOx formation, the lower proportion of flame luminosity in the infra-red range and the potential for the increased moisture content of the combustion product.

Our engagement with industry as part of this study suggests that the burners used in brick-making and other ceramic manufacturing kilns could probably tolerate up to 10% hydrogen without modification. However, some redesign would be required for higher levels. For example, to maintain performance and to prevent burn-back in a high velocity burner, the burner design would need to be changed and the nozzle size would need to be increased to allow a greater volume of fuel to flow.

Higher levels of hydrogen mixed with natural gas may well require new burners, although this is not unfeasible for the application. For use of 100% hydrogen, a new burner would certainly be required. Assuming that the burner design is able to deliver the necessary temperature profile in the brick kiln (which would need to be determined via Computational Fluid Dynamics (CFD), flame design and real-life testing), attention would still need to be paid to:

- The potential for the increased combustion product moisture content to affect the production process, particularly during the drying and annealing stages. This may require the development of new refractory materials to minimise the potential for moisture- or hydrogen-induced degradation mechanisms; and

- The increased moisture level in the exiting flue gases, which may lead to increased visibility as water droplets form within the cooling plume: this may require exhaust fan upgrades or gas heating (e.g. by recirculation) to increase the buoyancy and/or temperature of the emissions comfortably above the dew point.

Given the nature of application, it is expected that a degree of flexibility to vary the hydrogen/natural gas mixture could be achieved, primarily dictated by the burner design itself. Alternatively, it may be possible to consider multiple burners designed for different compositions to provide both flexibility and resilience.
5.4.3 Pulp and Paper

5.4.3.1 Sector Overview and Decarbonisation Options

In the UK in 2014, the pulp and paper sector produced 4.6 million tonnes of products and had an annual turnover of over £10 billion.\(^{81}\) The sector is characterised by a relatively small number of players (17) responsible for 80% of output, with a large number of smaller mills producing specialist products. Notably, packaging paper mills using recycled feedstock are responsible for 37% of all output.

Fossil fuel use by the UK pulp and paper industry was 16.7 TWh in 2008. The sector is a considerable consumer of heat, which represented 7% of the total industrial heat consumption in the UK in 2012.\(^{82}\) Natural gas was used to provide 81% of this heat, biomass 17% and coal 2%. Within the L-M Cluster area specifically, as presented in Section 2.2, there are five pulp and paper manufacturing sites (each with gas use of over 5.9 GWh/annum). In the area, gas use by the sector represented 8% of industrial gas use (for sites >5.9GWh/annum) and 2% of all gas use.

In respect of CO\(_2\) emissions, the pulp and paper sector is currently the sixth largest in the UK, with 3.3 MtCO\(_2\)pa in 2012.\(^{83}\) Direct emissions (73%) originate largely from steam-producing boilers and Gas Turbines producing electricity, and in particular, the ‘paper machine’, whilst imports of electricity accounts for 27% of total emissions. The SAICA Containerboard plant located in Partington within the L-M Cluster area was responsible for around 50% of emissions from gas from the sector within the area and for 7% of all industrial emissions from gas in the area in 2012.

CO\(_2\) emissions from the sector fell by over 50% between 1990 and 2012 without any significant loss in production.\(^{84}\) This demonstrates a significant fall in energy intensity, mainly achieved via efficiency improvements, plant modernisation and fuel switching away from coal. However, whilst paper-making technology has developed significantly during this period, improvements in the quality and strength of printing paper have also meant that some of the energy efficiency gains have been offset by higher energy requirements for producing higher quality papers.

It is currently unclear as to how further emissions reductions might be achieved. The aforementioned BIS study models a number of future pathways to decarbonisation, which include a range of options such as biomass CHP or boilers, industrial clustering and heat networking, substitution of electricity for fossil heat, heat recovery on ‘hoods’, improved process control, impulse drying and waste heat recovery and heat integration. Production and use of hydrogen is not mentioned in the BIS report.

\(^{82}\) Ibid.
\(^{83}\) Ibid.
\(^{84}\) Ibid.
5.4.3.2 Characterisation of Plant Energy Use

The paper machine uses up to 70% of all energy consumed by a paper mill, with the dryer section using approaching 50% of all energy. The heat supplied to the paper machine is low pressure steam at c.150°C and c.430°C steam heat in the dryer section, with some additional low-temperature heat used for heating, ventilation and air conditioning (HVAC). This heat is largely provided via the use of boilers and CHP.

In addition, depending upon the specific site, between 10% and 20% of the fuel used to generate heat in the pulp and paper sector is used for the generation of heat supplied direct to process. Direct heat is used in the following drying processes:

- Air dryers – used in the manufacture of tissue;
- Dryer hoods – which may be ‘over Yankee’ dryers as in the manufacture of tissues, or ‘over cylinder’ dryers in other sub-sectors. Within dryer hoods there may be either infrared heaters or air impingement heaters, both of which currently use natural gas burners;
- Coater dryers – these are natural gas-fired IR heaters used to dry coatings applied to paper that has already been substantially dried by cylinder dryers;\(^{\text{65}}\) and
- Pulp dryers – these are used to dry pulp-like paper products, for example, egg boxes (rather than the pulp that is the material input to the paper making process). Natural gas is fired in ovens and the product placed inside the ovens to be dried.

All of the above drier applications are relatively low temperature. Typically, at this scale, the CHP units are Gas Turbines.

\(^{\text{65}}\) The coating cannot be dried by a cylinder dryer without damaging the coating and so must be dried indirectly
5.4.3.3 Potential for Hydrogen Use

As highlighted above, the pulp and paper industry already makes extensive use of biomass and also recycles heat to generate CHP. As a result, there will be no benefit of replacing some existing CHP schemes with those burning hydrogen. However, around 50% appear still to be fired with natural gas and therefore represent opportunities for hydrogen substitution, along with existing boilers and direct-fired dryers.

The relatively simple burners used in dryers are likely to be able to accommodate low levels of hydrogen, although the specific installation would need to be assessed.

The issues associated with using low levels of hydrogen (mixtures potentially up to 15%), are discussed in Section 5.3.3. This analysis suggests that both fire-tube and water tube boilers should be feasible at this level, with the latter probably more amenable to such a change. For CHP units, as discussed in Section 5.3.4.2, low levels of hydrogen mixing may be feasible, but it will depend on the specific machine. In addition to any modifications to the burners, an increase in the hydrogen content of the fuel gas will result in a higher water content in the combustion product, which must be managed to reduce the potential for degradation of the product.

Again, as noted in Section 5.3.3.2, the overall design of water tube boilers is such that the required changes are considered to be feasible and should enable combustion of higher proportion of hydrogen. In general, water tube boilers are likely to be able to accommodate a degree of fuel flexibility. In developing the modifications required for higher hydrogen mixtures, this should be evaluated. It may also be possible to have multiple burners, thus broadening the range of fuel composition that can be accommodated.

The transmission of heat by radiation is a function of the fourth power of the temperature. The wavelength or colour of a flame also changes with temperature and flue gas composition. Hydrogen addition, up to a moderate proportion, will not adversely affect the radiation heat transmission required in pulp and paper drying, because the other radicals in the flame will be heated by the hydrogen combustion and then radiate this heat. For dryers to accommodate higher levels of hydrogen, burners may have to be replaced with units designed specifically for hydrogen rich fuels. These may be based on designs used for domestic fires of the 1950’s and 60’s, which burned Town gas. These had pre-mix flame rising in front of ceramic plates with ‘pinnacles’ or other thin strips projecting horizontally into the flame. These pinnacles were heated by convection in the flame but transmitted that heat by radiation.

Modern dryer applications are based on a similar concept, but instead utilise ceramic fibre plates in which all of the fibres are end-stacked (similar to space shuttle ‘cladding’). The pre-aerated fuel air mix is blown through this fibre plate and ignited on the downstream face. In the same way as flame arrestors, the flame flashes back into the surface of the fibre where it transfers heat by convection to the fibre ends which then radiate onto the target. The fibres are then continuously cooled by the incoming mixture. The technology therefore exists for high hydrogen-fuelled drying panels, but users may have to replace some components if their existing burners prove to be unsuitable for high hydrogen fuels.

As described in Section 5.3.4.2 (for existing Gas Turbines), modifications to accommodate high hydrogen fuels may prove to be extensive, if feasible at all. There may be some specific heaters for which this is technically feasible if a variant has been developed for a higher hydrogen fuel gas, with the required NOx emission levels. New heaters specifically designed for high hydrogen use, could, however, be installed. Fuel flexibility for radiant heater applications will depend entirely on the specific model.

\[ Q_{emitted} \propto T^4 \quad \text{(T in Kelvin)} \]
5.4.4 Food and Drink

5.4.4.1 Sector Overview and Decarbonisation Options
In the UK food and drink sector, there were more than 7,800 manufacturing companies in 2014, with an annual turnover of around £95.4 billion. In the same year, the sector also provided Gross Value Added (GVA) to the UK economy of £25.7 billion and employed around 400,000 people.87

The food and drink sector in the UK accounted for almost 34 TWh of final energy consumption in 2014. Natural gas was used to provide 66% of this energy, electricity 28% and coal 5%.88 Of total energy consumption, 54% was by boilers, with 27% from direct heating. Within the L-M Cluster area specifically, as presented in Section 2.2, there are 36 manufacturing sites (each with gas use of over 5.9 GWh/annum). In the area, gas use by the sector represented 17% of industrial gas use (for sites >5.9GWh/annum) and 4% of all gas use.

In respect of CO2 emissions, the sector is currently the fourth largest in the UK, with 9.4 MtCO2pa in 2012.89 37% of these emissions came from the production of steam and hot water production and a further 7% from direct firing and drying in ovens. A further 4% were from other direct-fired applications and another 12% and 7% from ‘fans and pumps’ and ‘stirring, mixing and conveying’ respectively.

The food and drink sector is mainly dominated by SMEs, with 86% of companies having 10 employees or less. However, there are also some very large manufacturing sites, as is demonstrated in the L-M Cluster area (see Section 2.2 for further detail). The two largest sites (Cargill and Heinz) are responsible for over 53% of sector emissions from gas.

The food and drink sector reduced its energy consumption by 28.6% over a 22-year period between 1990 and 2012.90 This was accompanied by a significant reduction in carbon intensity, as emissions fell by 7 MtCO2 between 1990 and 2012, largely driven by a switch away from coal and oil to natural gas. However, it is currently unclear as to how further emissions reductions might be achieved. The aforementioned BIS study models a number of future pathways to decarbonisation, which include a range of options such as electrification of heat (and grid decarbonisation), improved process design, biomass generation, heat recovery and sale, along with reductions in packaging. There is not a single mention of the potential to use hydrogen as a route to decarbonisation.

5.4.4.2 Characterisation of Plant Energy Use
The food and drink sector is very diverse with many sub-sectors, such as dairy, brewery, distilling, sugar, confectionery, bakery, rendering, meat processing, fish and seafood, poultry, malting, soft drinks, animal feed, oil and fat, glucose, canned food, ice cream, and pet food. Manufacturing in the food and drink sector is very diverse, using numerous individual processes. There are variations even in the production of similar products.

However, methods of heat production are far more uniform, and as discussed in Section 5.4.4.1, rely largely on natural gas. Arguably, the largest single use of natural gas is in baking ovens, where food is exposed to hot air at 110-350°C.

Natural gas is also used for such processes as melting, blanching, boiling, tempering, evaporation and pasteurisation. The vast majority of these processes are driven by either a steam-raising boiler, most likely of the water-tube variety (see Section 5.3.3.2) or via a reciprocating engine, generating both heat and power (see Section 5.3.4.1).

88 Ibid.
89 Ibid.
90 Ibid.
5.4.4.3 Potential for Hydrogen Use

As part of ovens used in the food and drink sector, existing diffusion burners could probably tolerate up to 10% hydrogen without modification. For hydrogen levels above 10%, engagement with industry for this study suggests that burner configuration may require some modification. Control system modifications should also be anticipated.

As discussed in Section 5.3.3.2, water-tube boilers should be able to accommodate low mixtures of hydrogen, potentially requiring tighter control of the fuel gas supply to the burners, and changes to the burner tip material. In general, water tube boilers are likely to be able to accommodate a degree of fuel flexibility. In developing the modifications required for higher hydrogen mixtures, this should be evaluated. It may also be possible to have multiple burners, thus broadening the range of composition that can be accommodated.

In respect of reciprocating engines for CHP production, the analysis presented in Section 5.3.4.1 suggests that assuming appropriate modifications to control systems are undertaken, there is some potential for manufacturers to extend operational envelopes to provide guarantees to allow existing engines to continue to operate should a mixture of hydrogen be used with natural gas. There has also been some experimental work on existing gas engines for high hydrogen use. However, it is unlikely that existing equipment could be modified to accommodate a major increase in hydrogen. The history of operation of engines designed to run on coke oven gas does suggest, however, that there is scope for new engines designed to operate on higher mixtures. Fuel flexibility for CHP applications, however, is likely to be more challenging than for boilers.
5.4.5 Chemicals

5.4.5.1 Sector Overview and Decarbonisation Options

In the UK, there were more than 3,000 chemicals (including pharmaceuticals) manufacturing companies in 2014, with an annual turnover of around £47 billion and approximately 156,000 employees. In 2013, over £600 million was spent by industry on R&D in the UK on chemicals and chemical products.\(^{91}\) In the ‘North West’ region of the UK (which incorporates the L-M Cluster area), data published by the North West Chemicals association states that there are 650 businesses operating in the sector, directly employing around 50,000 people and making an annual contribution of £3bn to the regional economy.\(^{92}\)

The chemicals sector in the UK used 47,706 GWh of energy in 2012, represented 16.5% of all industrial energy used in the UK.\(^{93}\) Natural gas was used to provide 47% of this energy, electricity 36%, oil 8% and coal 1%, with 9% came from ‘over the fence’ heat. Within the L-M Cluster area specifically, as presented in Section 2.2, there are 25 chemicals manufacturing sites (each with gas use of over 5.9 GWh/annum). In the area, gas use by the chemicals sector represented 23% of all industrial gas use (for sites >5.9GWh/annum) and 5% of all gas use.

In respect of CO\(_2\) emissions, the sector is currently second largest in the UK, with 18.4 MtCO\(_2\)pa in 2012.\(^{94}\) 54% of these emissions were from direct combustion, with 7% as direct process emissions and the remaining 39% from electricity use. The sector is characterised by a small number of large plants that emit a high proportion of the sector’s CO\(_2\) emissions. Ammonia production is responsible for majority of the process emissions. The CF Fertilisers’ ammonia plant located in Ince (in the L-M Cluster) was responsible for around 6% of emissions from the whole UK chemicals sector in 2012. This plant is connected to the NTS, and is therefore excluded from the analysis in Section 2.2.2. However, as discussed further below, it could be decarbonised via a direct supply of low carbon hydrogen. Notably, the three largest sites connected to the distribution network (British Salt, Eli Lilly and Solvay Interox) are responsible for over 30% of sector emissions from gas.\(^{95}\)

The energy intensity of the UK chemicals sector fell by 50% between 1990 and 2010.\(^{96}\) However, it is currently unclear as to how further emissions reductions might be achieved. The aforementioned BIS study models a number of future pathways to decarbonisation, which include a range of options such as biomass generation, energy efficiency, ‘clustering’ and heat recovery, electricity grid decarbonisation, new chemical pathways and CCS. Production and use of hydrogen from electrolysis is given vague mention in the BIS report, but there is no analysis of the potential to use hydrogen provided via a repurposed natural gas grid.

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\(^{91}\) BIS (2015) Industrial Decarbonisation & Energy Efficiency Roadmaps to 2050, Chemical Sector, March 2015

\(^{92}\) See [http://www.chemicalsnorthwest.org.uk/](http://www.chemicalsnorthwest.org.uk/)

\(^{93}\) BIS (2015) Industrial Decarbonisation & Energy Efficiency Roadmaps to 2050, Chemical Sector, March 2015

\(^{94}\) Ibid.

\(^{95}\) This excludes the emissions from the olefins production element of Essar’s Stanlow refinery, all emissions from which, for the purposes of this study have been grouped under the Oil & Gas sector

\(^{96}\) IS (2015) Industrial Decarbonisation & Energy Efficiency Roadmaps to 2050, Chemical Sector, March 2015
5.4.5.2 Characterisation of Plant Energy Use

The diversity of processes means that a single description of a chemical process is impossible. The key elements in most chemical processes are the transfer of materials and energy.

Heat is needed to provide the high temperatures necessary for many reactions and separations (including distillation, absorption, crystallisation and sedimentation). A range of technologies are used to deliver heat to chemical processes. The most widespread is the use of steam at a variety of different pressures. Steam is generated in boilers which are fired by natural gas or other fuels.

Where the relative demand for heat and electricity is appropriate, many chemical plants improve their overall energy efficiency by using CHP, provided by reciprocating engines, as described in Section 5.3.4.1. Alternatively, a boiler might be used to raise steam to both provide heat and generate electricity via a steam turbine. In 2013, CHP was used at 53 sites in the UK chemicals sector.

Furnaces are also used to provide heat directly in some processes where very high temperatures are required, for example in the cracking stage of olefin production. Furnaces provide direct radiant heat, for which natural gas or recovered waste gases are typically used as furnace fuels.

For large volume organic chemicals (e.g. plastics, rubber, pesticides, pharmaceuticals), the majority of installations require heat in the form of process steam with few processes using high temperature operations. This would also include the petrochemicals industries which have substantial use of directly fired process heaters. For the manufacture of organic fine chemicals (e.g. dyes, pigments, biocides, explosives), where production is often in small scale batch processes at modest temperatures, the heat demand is almost exclusively process steam or hot water.

It is estimated that around one third of the heat used in the organic chemicals sector is used as direct heat in Olefin production. This is represented by just five facilities in the UK with steam cracker units at Mosmoran, Wilton, Grangemouth, Fawley and Stanlow (in the L-M Cluster area). The direct heat used in these specific processes is for fired heaters providing heat into the feedstock prior to its introduction to the steam cracker unit. Some of these sites are integrated with adjacent refineries. As a result of this, refinery gas (RFG) is made available for cracker process heaters, which means that they are not dependent on grid-supplied natural gas, nor able to benefit from the introduction of hydrogen. Another factor is that, were this refinery gas not to be exported to the adjacent organic chemicals industries, it would either be burned in another application at the chemical site or flared.

Direct heat is used in the production of inorganic chemicals, notably for the production of ammonia via SMR (such as at Ince), whereby a fired heater type process furnace is used. Other gas consumers of note in the inorganic sector are in the manufacturing of titanium dioxide (TiO₂), which is a pigment commonly used in paints, printing inks, plastics, cosmetics, soap, toothpaste and food; and soda ash (or sodium carbonate), which is used in detergents, for water treatment, as an additive in food and drinks and as a feedstock for other chemical processes. In respect of the former, for which there is currently a major plant on Humberside operated by Cristal (but no similar site in the L-M Cluster area), the chloride process is favoured, which uses a substantial amount of energy, involving a pure oxygen flame or in plasma at temperatures of 1,200–1,700°C. The Solvay Interox plant at Warrington in the L-M Cluster area manufactures the latter, a process which relies on heat from gas to create several thermodynamic reactions and separation processes to form soda ash.

It is also important to note that a number of chemical processes produce hydrogen, which might be accessed to supply sufficient hydrogen for an initial demonstration project in the L-M Cluster area. As detailed in Section 2.5, there are four such sites, including the Inovyn plant at Runcorn, whereby hydrogen is produced as a by-product of the chlorine production process, the CF Fertilisers’ plant at Ince, which may have spare capacity SMRs used to hydrogen to produce ammonia and Essar’s Stanlow refinery, at which hydrogen is produced as a by-product of the cracking process.
5.4.5.3 Potential for Hydrogen Use

For the majority of heat applications in the chemicals sector, it is likely that the introduction of a small amount of hydrogen into natural gas would have only a slight impact, and existing burners would function efficiently. However, each production situation would have to be addressed specifically. For the purposes of this study, we have focused upon the olefin and ammonia production, as the L-M Cluster area is host to a major plant in each sector. We have also provided analysis of more general process heat production, which is relevant across a range of sub-sectors in the chemicals industry.

Olefin Production

The olefin sector has a reduced dependency on natural gas (due to the use of refinery gas), but in the future, should demand for petroleum products fall, there may be a greater demand for external fuel. In this sense, it is notable that refinery gases can often contain up to 30% hydrogen. Table 5.4 presents the composition of a typical refinery gas, alongside that of natural gas and two hydrogen/natural gas mixtures.

### Table 5.4: Comparison between Gas Compositions

<table>
<thead>
<tr>
<th>Component</th>
<th>Refinery Gas (%)</th>
<th>Natural Gas (%)</th>
<th>Natural Gas +10% H₂ (%)</th>
<th>Natural Gas +20% H₂ (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>H₂</td>
<td>28</td>
<td>10</td>
<td>20</td>
<td></td>
</tr>
<tr>
<td>CH₄</td>
<td>28</td>
<td>90</td>
<td>81</td>
<td>72</td>
</tr>
<tr>
<td>C₂+</td>
<td>24</td>
<td>7.2</td>
<td>6.48</td>
<td>5.76</td>
</tr>
<tr>
<td>Olefins</td>
<td>10</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>N₂</td>
<td>3.5</td>
<td>1.5</td>
<td>1.35</td>
<td>1.2</td>
</tr>
<tr>
<td>CO₂</td>
<td>3.0</td>
<td>1.3</td>
<td>1.17</td>
<td>1.04</td>
</tr>
<tr>
<td>CO</td>
<td>3.5</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>M/J/Nm³ (HHV)</td>
<td>44.67</td>
<td>41.53</td>
<td>37.96</td>
<td>35.16</td>
</tr>
<tr>
<td>M/J/kg (HHV)</td>
<td>46.69</td>
<td>51.78</td>
<td>53.05</td>
<td>54.43</td>
</tr>
<tr>
<td>Wobbe Index (MJ/m³)</td>
<td>45.5 to 48.3³</td>
<td>49.6 to 50.2</td>
<td>48.4</td>
<td>47.2</td>
</tr>
</tbody>
</table>

Notes:
1. Extracted from AIChE, 2010
2. Adapted from National Grid, 2016
3. A range has been indicated for the Wobbe Index to give a range between the C₂+ being all C₂ and 50% C₂ and 50% C₃

It should be noted that the WN of the two hydrogen/natural gas mixtures are within the same range as that for refinery gas, although their volumetric CVs are both lower. Hence the volumetric flows will need to be higher for the same heat input: this may affect the associated mechanical plant, such as Induced Draught fans, which may have to be modified to deliver an increased throughput. There may also be issues associated with flame luminescence and heat transfer which can only be addressed by carrying out CFD analysis of the flame, refractory radiance and heated surfaces. To accommodate changes highlighted as a result of these analyses it may be necessary, for instance, to adjust flows through tubes, or to insert additional surface to absorb heat. Again, this will be specific to the plant being considered.
Ammonia Production

The ammonia production process is set out in a schematic in Figure 5.7. As described above, SMR of natural gas to produce hydrogen is a core element of the process. Elsewhere in the plant, natural gas is burned to produce process heat, and in this regard, it is no different in principle from any other process heating application.

Figure 5.7: Schematic of an ammonia plant using the Haber Bosch process
General Process Heating

The drying and heating processes used in chemicals production are very individual processes, and technically offer potential for partial substitution of natural gas fuel with hydrogen into burners. As discussed in Section 5.3, within these plants there are likely to be a range of burner types and size, depending on the nature of the product being heated or dried. However, it is reasonable to say that hydrogen could also be used in onsite boilers or reciprocating engines for CHP hydrogen at ammonia production sites. The issues associated with use of hydrogen in these applications are highlighted for both the food and drink, and pulp and paper industries in Sections 5.4.4.3 and 5.4.5.3, and more generally in Sections 5.3.3 and 5.3.4.1.

Any water-tube boilers used for general process heating should be able to accommodate low mixtures of hydrogen and are likely to be able to accommodate a degree of fuel flexibility. In developing the modifications required for higher hydrogen mixtures, this should be evaluated.

In respect of reciprocating engines for CHP used for general process heating, assuming appropriate modifications to control systems are undertaken, existing engines should be able to continue to operate should a low proportion of hydrogen be used with natural gas. Whilst it is unlikely that existing equipment could be modified to accommodate a major increase in hydrogen, the history of operation of engines designed to run on coke oven gas does suggest, that there is scope for new engines designed to operate on higher proportions of hydrogen.

The extent to which all of the above modifications would need to be addressed will depend upon the proportion of hydrogen within the mixture, the specific nature of the production process and plant configuration.
5.4.6 Oil Refining

5.4.6.1 Sector Overview and Decarbonisation Options

In the UK, there are six major oil refineries currently operating: Essar Stanlow (in the L-M Cluster area), Esso Fawley, PetroIneos Grangemouth, Phillips 66 Humber (on Humberside), Total Lindsey (on Humberside) and Valero Pembroke and Nynas Eastham. In 2013, it is estimated that activity in the sector resulted in GVA of £2.3 billion.\(^{98}\) However, refinery throughput has been falling fairly consistently since 1998 and three refineries have closed during the last five years with the sector under ongoing significant pressure from more competitive sites located overseas.

It is challenging to determine the heat or total energy demand of the oil refining sector. This is largely due to the high degree of process integration and use of fuels created by the refining process itself. However, the BIS study suggests that refinery gases (see discussion in Section 5.4.6.2) were used to provide 47% of total energy, catalyst coke 25%, natural gas 21% and fuel oil 7%.

Within the L-M Cluster area specifically, as presented in Section 2.2, there were five major oil and gas sites, with the largest being the major oil refinery at Stanlow, operated by Essar. It is notable that in 2016, Stanlow was the greatest user of natural gas of all sites in the area, and that this level of use represented 8% of all industrial gas demand (for sites >5.9GWh/annum) in the L-M Cluster area.

In respect of CO\(_2\) emissions, the sector is currently the third largest in the UK, with over 16.3 MtCO\(_2\)pa emitted in 2012.\(^{99}\) Based upon analysis of data relating to refineries in the US, these emissions come from a range of sources including, primarily, the combustion of hydrocarbons in boilers and furnaces (63%), coke burn-off (24%) and hydrogen production (6%).

Total emissions fell from a level of 19.7 MtCO\(_2\)pa in 2002 to the aforementioned level of 16.3 MtCO\(_2\)pa in 2012; thus a 17% over a ten-year period.\(^{100}\) This fall may have been the result of the closure of some refineries and falling output during this period, rather than a reduction in energy intensity. However, at an EU level, data suggests that there has been a 10% improvement in energy efficiency over the last 18 years, albeit this has been accompanied by greater energy use. This demonstrates that higher energy consumption does not automatically mean that refineries are performing badly, but that more complex refineries are needed to meet the demand for lighter or more complex refining products, and the energy consumption is therefore rather an indicator of what refineries do instead of how efficiently they do it.

It is unclear as to how future emissions reductions might be achieved. The aforementioned BIS study models a number of future pathways to decarbonisation, which include a range of options such as CCS, biomass, construction of completely new refineries, waste heat and energy recovery, replacement of pumps, compressors and fans, process heaters, furnaces, storage tanks, installation of CHP, utilities optimisation, improved energy management, focus on maintenance and leak detection.

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\(^{98}\) BIS (2015) Industrial Decarbonisation & Energy Efficiency Roadmaps to 2050, Oil Refining, March 2015

\(^{99}\) Ibid.

\(^{100}\) Ibid.
5.4.6.2 Characterisation of Plant Energy Use

Refineries are energy-intensive complexes: consequently energy use is constantly being optimised. As the design, crude intake and product slate of every refinery is different, it is impossible to make anything beyond generalised statements about their energy use. However, in Figure 5.8 we have presented ‘typical’ process flows, with red arrows indicating process energy inflows.

Figure 5.8: Typical Refinery Process Flows

As highlighted above, a significant amount of the energy requirements in a refinery are met by utilising by-product or waste fuel streams from within the refinery itself, hence the large number of internal fuel flows in Figure 5.8.
Fuel is consumed in process furnaces that directly provide heat to the process units and in utility boilers. Process heaters generate the largest proportion of the total energy requirement, the actual share depending on the configuration and original design of the refinery. This is alongside a large demand for steam and electricity. Consequently, many refineries incorporate gas CHP schemes, with many of these using excess refinery gas and natural gas to fuel large Gas Turbines.

The process furnaces are operated from 250-500°C. Many refining stages, however, do not require such high temperatures, and can be heated using steam, applied in many ways at different pressures and temperatures: high-pressure steam (40-100 bar) to drive turbines for large rotating machines (such as compressors and electricity generating turbines), medium-pressure steam (10-40 bar) for fractionation and separation of light hydrocarbon mixtures, and lower-pressure steam (< 10 bar) for many other applications (such as continuous heating and frost protection of piping).

Whilst the catalytic reformer within the refining process produces hydrogen, many refineries require additional volumes for processing heavier and higher sulphur crude slates, and to produce the cleaner light products demanded by the market. At many refineries, a lack of hydro-processing capacity and a cost-effective supply of hydrogen is limiting refinery throughput and operating margins. Furthermore, higher hydrogen purities are needed to boost hydrotreater capacity, achieve product value improvements and lengthen catalyst lifecycles. Consequently, more complex refineries, especially those with hydrocracking units, have installed dedicated SMRs that utilise refinery off-gas and natural gas as feedstocks. In addition, some also gasify residues to produce syngas which is subsequently converted to hydrogen (Pernis, in The Netherlands being an example).

Depending on the slate produced, therefore, there is also the potential for refineries to supply hydrogen. Where there is an excess, discussions with industry as part of this study suggest that this is usually mixed into refinery fuel gas and used in onsite heat (and power) generation. Whilst this is not low carbon hydrogen, it could have a role in providing hydrogen supply resilience. As required product slates change, particularly resulting from a reduction in demand for heavier slates, some of the former products could become potential sources of fuel for hydrogen production when integrated with CO₂ capture. More widely, refineries are also significant emitters of CO₂, and so there may be scope for further CO₂ capture and integration into CCS infrastructure.

5.4.6.3 Potential for Hydrogen Use

The recycling and reuse of fuels created as part of the refining process represents 60-75% of their energy use; this element is therefore not suitable for displacement by additionally imported hydrogen. However, refineries are constantly changing their operations to meet market demand for products and so the potential for fuel substitution may change in the future.

As mentioned above, the remaining 25-40% of energy demand is usually met using CHP schemes, which operate within at least five of the six operating UK refineries in the UK. The potential to mix hydrogen with the natural gas which is largely used to fuel Gas Turbines (which are the preferred approach at such scale) is discussed in Section HYPERLINK "5.3.4.2. This suggests that low levels of hydrogen mixing may be feasible, but it will depend on the specific machine. Unless existing Gas Turbines are already designed for operation on refinery gases, modifications to accommodate high hydrogen fuels are likely to be extensive, if feasible at all. New machines designed for high hydrogen use, however, could be installed. Fuel flexibility for Gas Turbine applications would depend entirely on the specific machine.
As discussed in Section HYPERLINK "5.3.3, low level hydrogen mixtures (up to 15%), are likely to be feasible for any boilers in operation at refineries. This is likely to be possible for both fire-tube and water tube boilers, with the latter probably more amenable to such a change. Modifications to accommodate high levels of hydrogen are likely to be feasible, but the nature of these will depend on the exact boiler configuration, and will require assessment of changes to thermal profiles in the boiler. Furthermore, in general, water tube boilers are likely to be able to accommodate a degree of fuel flexibility. As noted above, often refineries are configured to use various refinery gases in their thermal plant and there are certainly cases of hydrogen-rich gases being used in such equipment.

In respect of chemical use, as discussed in Section HYPERLINK "5.3.5, if 100% hydrogen was supplied in place of natural gas, then this could dispense with the need for SMRs at a refinery, subject to hydrogen quality.

5.4.7 Iron and Steel

5.4.7.1 Sector Overview and Decarbonisation Options

In the UK in 2016, the iron and steel sector produced 10.9 million tonnes of crude steel, employed over 31,000 people and delivered £1.2 billion of GVA to the UK economy.\(^1\)

The sector is characterised by a small number of large crude steel production sites, with a large number of rolling mills and smaller sites producing a range of products, such as coated strip, galvanised coil, tinplate and bright bar.

Total energy use by sites producing crude steel was 54 TWh in 2012. This considerable demand was such that the sector was responsible for 9% of the total industrial heat consumption in the UK in 2013.\(^2\) The sources of heat were largely provided by coal and coke (78%), with 10% coming from natural gas, 7% from coke oven gas (from coke production) and 6% from electricity. Blast furnace gas and coke oven gas are by-products of iron and coke production at the steelworks and are used internally for heating and steam production while any excess is flared.

There are no steel manufacturing sites in the L-M Cluster area but crude steel is made at the Blast Furnace- British Oxygen Furnace (BF-BOF) site owned and operated by British Steel in Scunthorpe within the Humber cluster area, as presented in Section 3.2.2. In 2016, this site represented 81% of sector gas use (for sites >5.9GWh/annum) and 15% of all industrial gas use in the Humberside cluster area.

In respect of CO\(_2\) emissions, in 2012 the iron and steel sector was the largest in the UK, with 22.8 MtCO\(_2\)pa.\(^3\) 79% of these emissions were from BF-BOF sites, with the remainder from those using Electric Arc Furnaces (EAF). It can be noted that BF-BOF process emissions are mostly direct emissions (i.e. arising from the reduction of the iron ore in the BF using coke).

The energy consumed per tonne of steel fell by over 40% between 1972 and 2012 via investment in a range of technologies which are today considered standard for any state-of-the-art steel plant.\(^4\) However, it is currently unclear as to how further emissions reductions might be achieved. The aforementioned BIS study models a number of future pathways to decarbonisation, which include a range of options such as the use of ‘advanced’ technologies (with CCS), retrofit (with CCS), stove flue gas recycling (with CCS), steam and power system upgrades and improved site and sector integration. Production and use of hydrogen is not mentioned in the BIS report.

\(^{1}\) EEF / UK Steel (2017) Annual Review 2016, March 2017

\(^{2}\) BIS (2015) Industrial Decarbonisation & Energy Efficiency Roadmaps to 2050, Iron & Steel Sector, March 2015

\(^{3}\) As reported by BIS (2015), in 2013, production and emissions rose sharply to nearly 23 MtCO\(_2\)pa following the recommissioning of the Tata Steel (now SSI UK) BF plant on Teesside. However, for consistency with the rest of this report, we have used figures from 2012

\(^{4}\) BIS (2015) Industrial Decarbonisation & Energy Efficiency Roadmaps to 2050, Iron & Steel Sector, March 2015
5.4.7.2 Characterisation of Plant Energy Use
As the site located in Scunthorpe in the Humberside cluster area uses the BF-BOF rather than the EAF steel making process, this forms the focus of the analysis in this section. As some of the processes involved result in gaseous by-products which have further beneficial potential, energy use in an integrated steelworks is complicated. To maximise efficiency, minimise waste and reduce costs, recirculation opportunities are maximised. The waste gases from the coke ovens, blast furnace and basic oxygen plant are captured and reused, either as a natural gas substitute for heating purposes, or combusted in a boiler to generate steam for electricity generation. Consequently, it is not unusual for a modern steelworks to be self-sufficient for electricity and may even be in the position to export small amounts of electricity. A Sankey diagram which provides representative energy flows in an integrated steelworks is presented in Figure 5.9.

Figure 5.9: Energy flows in an integrated steelworks

As described in Section 5.4.7.1, the prime energy imports to the process are coking coal, electricity and natural gas, the use of which can be summarised as follows:

- **Coking coal**
  This is converted to coke in ovens. The volatile constituents of the coal, including water, methane, CO and coal-tars, are driven off by baking the raw coal in an oven (or kiln) in the absence of oxygen, at temperatures usually around 1,000–1,300°C. This fuses together the fixed carbon and residual ash and drives off the volatile elements, which are described collectively as coke oven gas (COG). This is a valuable source of energy to be utilised elsewhere on the steelworks. COG usually contains >50% hydrogen, but also significant levels of methane (>30%) and limited amounts of CO₂;

- **Electricity**
  Steelworks are big users of electricity, to power fan, blowers and compressors to supply air and to move process gases around; to pump water, especially cooling water, to the various parts of the plant, but particularly to power the air separation plant from which the oxygen and other gases are derived. In a modern integrated steelworks, most of the electricity is generated on site from boilers burning blast furnace gas (BFG). These boilers also supply steam for heating requirements at the plant. The electrical requirements of steelworks are rarely perfectly balanced and most require either a small import of electricity, or are able to export a small amount.

- **Natural gas**
  Where there is, for instance, insufficient COG, BFG and basic oxygen steelmaking (BOS) gas to meet the energy demands of a steelworks, natural gas is often used as a substitute. However, the cost of natural gas is such that there is a natural driver to reuse by-product gases. For example, at Port Talbot steel plant, the BOS gases used to be flared, but a BOS gas capture plant was subsequently installed and the project costs were offset by the consequential reduction in natural gas imports to the site. Port Talbot does not have 100% coking capacity, thus, compared with the example shown in Figure 5.9, the design was imbalanced because insufficient COG was available and BOS gas is collected to restore the balance.

### 5.4.7.3 Potential for Hydrogen Use

Our analysis in this section is based on conventional Blast Furnace steelwork configurations as commercially deployed. It does not consider the role for gas in future developments of Direct Iron Reduction.

Like refineries, steelworks have the potential to be sources of hydrogen through upgrading of blast furnace or coke oven gas. However, these gases are generally already integrated into the energy flows and would require significant processing to provide consistent hydrogen of sufficient quality for other users. They would also not currently represent low carbon sources of hydrogen, although processing blast furnace gas through the water gas shift process and capturing CO₂ would offer a low-cost hydrogen production route using established technologies. More widely, steelworks are also significant emitters of CO₂, and so there may be scope for capture and integration into CCS infrastructure.

The relevance of hydrogen supply to a steelworks will depend on its overall energy balance and existing use of natural gas. Where natural gas is used, it is likely to be primarily for heating in mill operations and for use in the power station. Given the extensive use of hydrogen-rich gases already on steelwork sites these applications are likely to be able to readily accommodate both low and high levels of hydrogen mixed with natural gas. The only exception is where natural gas is deliberately used to ‘sweeten’ (or enrich) the existing gas mix.

As the combustors in most steelworks applications already have to operate flexibly, given the mix of fuel gases used onsite, there would be a high degree of fuel flexibility between natural gas and hydrogen.
5.4.8 Cement

5.4.8.1 Sector Overview and Decarbonisation Options

The Mineral Products Association (MPA) estimated that the UK cement sector sold a total of 12.4 million tonnes of product in 2014, which delivered GVA of £355 million.\(^{105}\)

The sector is characterised by a very small number of global operators and only 10 sites within Great Britain (excluding Northern Ireland).

There are no sites operating within either the L-M or Humberside cluster areas, albeit notably Heidelberg Cement’s Padeswood site is located just outside of the L-M Cluster area within Wales & West Utilities’ distribution network. It should also be noted that, whilst a different product and manufacturing process and therefore out of scope of this specific part of analysis, a major producer of lime (Singleton Birch) is located in the Humberside cluster area.\(^{106}\)

Coal and petcoke were used to provide 60% of the sector’s heat demand in 2012 (down from 94% in 1998), with the remaining 40% from solid recovered fuels (SRF).\(^{107}\) This SRF is estimated to be around 18% biomass by energy value. It is also understood that most kilns use up to 1% natural gas.

In respect of CO\(_2\) emissions, the sector is currently the fifth largest in the UK, with around 7 MtCO\(_2\)pa in 2015.\(^{108}\) 68% of these emissions were process emissions from the calcination process, 24% were emissions from the combustion of fossil fuels and 8% were from electricity use.\(^{109}\) Notably, the Singleton Birch lime plant at Melton Ross was responsible for 12% of all industrial emissions in the Humberside cluster area.

The energy intensity of the UK cement production sector fell by 26% between 1998 and 2014.\(^{110}\) However, it is currently unclear as to how further emissions reductions might be achieved. The aforementioned BIS study models a number of future pathways to decarbonisation, which include a range of options such as kiln process technology, electrical efficiency improvements, electricity from waste heat, cementious substitution, alternative raw materials (calcined), fuel switching to natural gas, fuel switching to biomass, alternative cements, fluidised bed kiln, CCS and oxygen enrichment technology.


106 In Section 3.2, this plant is classified under the ‘other’ category


109 Ibid.

5.4.8.2 Characterisation of Plant Energy Use

Today, the most common way Portland Cement is manufactured is using the ‘dry’ method. Limestone, clay, and other materials are crushed to a size of about 75mm or smaller. The crushed rock is combined with other ingredients such as iron ore or PFA (pulverised fuel ash) or fly ash. The mixture is further ground, mixed, and fed to a cement kiln.

The ground and mixed ingredients are heated to about 1,480°C in a large cylindrical steel rotary kiln lined with firebrick. These large kilns are mounted with the axis inclined slightly from the horizontal so that the finely ground raw material or the slurry can be fed into the higher end. At the lower end is the heating flame, produced by the precisely controlled burning of powdered coal, oil, alternative fuels, or gas.

As the kiln rotates the raw material tumbles down the kiln (counter flow to the flame), some of the compounds (particularly CO$_2$) are driven off in the form of gases. The remaining elements combine to form clinker. Clinker comes out of the kiln as grey spheres, about 12mm in diameter. It is discharged red-hot from the lower end of the kiln and generally is brought down to handling temperature in various types of coolers. The heated air from the coolers is fed to the kiln burners as pre-heated combustion air: this in turn mixes with the fuel to produce the high flame temperature required by the process. After the clinker is cooled, it is ground and mixed with small amounts of gypsum and limestone to form the finished cement product.

The reaction processes occurring within the kiln are not easily understood due to the wide variations in the chemistry of the raw mixture, the physical properties of the ingredients, and kiln operating conditions. Although the dry process is the most commonly found in the UK, a very small number of semi-dry and ‘wet’ kilns continue to operate. The two processes are essentially the same except in the semi-dry and wet processes, the raw materials are ground with water before being fed into the kiln and therefore require greater amounts of heat to form clinker.

Heat for clinkering is supplied by a main burner (or burners) located at the clinker outlet (lower) end of the kiln. These are usually multi–channel burners allowing for the injection of a variety of fuels into the kiln. There are also normally at least two air channels in the burner through which air is blown to control the shape of the flame developed through these fuel channels. Flame temperatures of about 2,000°C are currently required to achieve efficient transfer of heat to the clinker.

Prior to entry into the kiln, there are usually a series of pre-heaters, which are a set of vertical cyclones through which the raw meal is passed, coming into contact with swirling hot kiln exhaust gases moving in the opposite direction. In these cyclones, thermal energy is recovered from the hot flue gases, and the raw material is preheated before it enters the kiln, so the necessary chemical reactions occur faster and more efficiently. Depending on the raw material moisture content, a kiln may have up to six stages of cyclones with increasing heat recovery with each extra stage.

Following pre-heating, most modern kilns employ pre-calciners (to start the decomposition of limestone to lime), whereby fuel is fed in either mechanically or pneumatically and the air needed to support combustion again comes from the kiln exhaust and from clinker coolers.

Whilst clinker production is tolerant of a wide range of fuels, the final mix of fuels chosen must satisfy three requirements:

1) The appropriate temperature must be delivered;

2) Emission limit values must be accommodated (particularly NOx, SOx and dust emissions); and

3) The combustion products must not compromise the quality of the final product.

As a consequence combinations of fuels must be carefully managed and extensive testing programmes undertaken prior to the introduction of any new feedstocks.
5.4.8.3 Potential to Use Low Hydrogen Fuel Mixtures

Engagement with industry as part of this study suggests that hydrogen mixtures up to 20% are likely to be feasible without detriment to kiln operation. From a commercial perspective, however, it is unlikely to be attractive to substitute either coal or SRF (or other waste derived fuels) for hydrogen. As mentioned above, there is usually less than 1% natural gas used as a fuel for cement production and therefore only very limited scope for hydrogen substitution exists. Consequently, the following analysis is undertaken very much on an ‘in principal’ basis. It should also be noted that it would only be the ‘combustion’ emissions which are decarbonised by hydrogen, not the ‘process’ emissions from the calcination process.

The use of such proportions of hydrogen would mean that higher flame temperature and lower calorific value were a concern with regards kiln control and operation. Some of the existing cement kilns have previously been run on Town gas (see composition, showing high hydrogen proportion, in relation to the glass sector, in Section 5.4.1) and therefore it has been proven historically that a hydrogen mixture (albeit with CO) can be used to successfully produce cement. Currently, however, there is limited experience of hydrogen as a fuel, and little understanding of the levels at which any issues might occur.

Given the three requirements described in Section 5.4.8.2, hydrogen would seem to have potential fuel for use in cement manufacture. The flame temperature for hydrogen burning in air is around 2,210°C, depending on the stoichiometry and on air pre-heat temperature. Combustion of hydrogen produces no SOx or dust, and careful flame design can minimise the formation of NOx. The combustion product, water, will not affect the chemistry within the kiln, but the higher moisture levels in the combustion products results in a denser mix of gases. This will reduce the capacity for clinker production unless the air flow is increased to purge the gases, which will have an associated cost.

Concerns around replacement with hydrogen relate to:

- The temperature of the flame: as stated above hydrogen burns with a hotter flame than natural gas (2210°C vs. 1960°C) so ‘fine-tuning’ the temperature might be more challenging;
- Burner design: the existing burner design (probably for pulverised fuel) is expected to require modification, even if the overall kiln design (e.g. burner positions, air flows) remain effective; and
- Heat dispersion: it is expected that the kiln design and air flows would need to be adjusted to ensure that heat is effectively dispersed.

As described in Section 5.3.2, such issues would require resolution prior to any testing of hydrogen within the production process. It should also be noted that similar issues apply to the use of hydrogen in lime kilns.

For high proportions (>50%) hydrogen it is anticipated that new burner designs will be required which recognise the specific combustion characteristics of hydrogen compared to natural gas. Consequently, to progress knowledge in this area, CFD modelling and mass balance studies would need to be undertaken to identify the implications for existing kiln systems and propose related solutions.
5.5 Summary of Technical Constraints and Opportunities

This section has sought to identify technical and engineering constraints and opportunities for use of hydrogen as a substitute, in whole or in part, for natural gas in different industrial sectors. The analysis is based on a combination of literature review and engagement with industry, combined with existing knowledge held by ‘experts’ from both Progressive and its external contact network.

The analysis demonstrates that there are significant differences in the physical and combustion characteristics (e.g. density, Wobbe index, calorific value, flame temperature, speed and colour, emissivity) of natural and gas and hydrogen. These need to be further explored and understood to facilitate safe use of hydrogen, which either does not adversely impact upon the performance of existing generation plant, or which can be taken into consideration during new plant design or retrofit.

In an industrial context, hydrogen might be used in furnaces, kilns, lehrs, boilers, gas turbines, reciprocating engines, process heaters and as a chemical feedstock. Use of hydrogen in each of these technologies presents unique engineering challenges. Primarily, attention will need to be paid to:

- The burners in which hydrogen is used and the systems which control such use. These differ between applications and dependent on the age and design of the equipment, hardware changes may be necessary to restore lost efficiency; and
- The higher flame temperature associated with hydrogen, which has the potential to increase the formation of NOx. Managing this will require increased understanding of hydrogen combustion.

The above said, in most cases, reasonable confidence exists that partial substitution of hydrogen, i.e. 10-15%vol. should be possible with minimal modification to generation plant or equipment being necessary. However, to facilitate this, further work is required, on a case-by-case basis, in conjunction with the relevant OEMs (as providers of guarantees).\[111\]

The potential for substitution of hydrogen for natural gas has been considered for eight industry sectors. In many cases, there has been some experience of burning hydrogen-rich fuel mixtures due to previous use of Town Gas (which comprised up to 50% hydrogen) in the 1950s to 1970s. Consequently, there is some existing learning and experience which can be built upon for the potential reintroduction of hydrogen into fuel mix. This suggests that there should be no technical or engineering barriers that would prevent significant substitution, even up to 100% in some cases. However, there remain a number of areas where further work is required to provide sufficient confidence for such levels of use.

\[111\] OEM = Original Equipment Manufacturer
6.0 PRACTICAL DEPLOYMENT AND PATHWAY

6.1 Project Design Concept
Conversion of the gas distribution network to 100% hydrogen is under consideration as a long-term objective, and is being pursued as part of the H21 project. However, it is widely recognised that this is extremely challenging and relies upon a number of stages of detailed research, development and testing prior to any deployment.

The analysis in the sections above has focused on identifying key existing physical infrastructure and institutional arrangements in the L-M Cluster area to create a cost-effective system of hydrogen supply, distribution and usage that has potential for early deployment ("the Project"). The analysis suggests that practical deployment of hydrogen, which is material in scale, and brings immediate, real, local and wider benefits, can be put in place on relatively short timescale.

The project design concept provides material decarbonisation at an early stage and creates the platform for more extensive, subsequent decarbonisation of the gas network. The key elements of this concept can be described as follows:

1) Injection of hydrogen into the natural gas distribution network to the maximum possible level without requiring changes to gas appliances

Up to 12%vol. hydrogen is allowable in parts of the gas network in the Netherlands and even higher levels may be possible with limited changes to connected equipment in localised networks.\(^{112}\) The HyDeploy project in the UK, which is currently underway, is seeking to establish a maximum percentage of hydrogen without modification to appliances or to the gas network.\(^ {113}\) This is being undertaken via tests with up to 20%vol. hydrogen. More generally, completion of the IMRP in the area will facilitate the potential for wider use of hydrogen.

2) Conversion of selected industrial plants to high hydrogen to provide a large base-load demand for hydrogen

Natural gas is used by manufacturers in the area to fire boilers to supply steam for industrial processes, to provide high grade heat for furnaces and kilns and to fuel CHP plants. As described in Section 5.0, it is expected to be technically possible to adapt many furnaces and boilers and potentially some CHP plant to operate on a high hydrogen mixture and indeed two plants in the area already fire by-product hydrogen in boilers. Most industrial process plant operate continuously throughout the year and consequently conversion of a tranche of such sites to operate on a high hydrogen mixture could provide a near constant annual base load demand.

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3) Avoidance of the need for expensive salt cavern storage via use of industrial supply/demand to manage fluctuations in domestic demand

Overall distribution network demand varies by a factor of eight between summer and winter months, which appears to preclude the design of a cost-effective system that does not include hydrogen storage. However, the integration of an industrial base load plant converted to operate on high hydrogen via a dedicated pipeline (alongside retaining existing gas connections) with unmodified general network users supplied with a blend can be arranged to produce a smooth annual demand profile.

Short term, daily fluctuations in demand can be managed in a number of ways, all of which could be applicable at different points in time. These include:

a. The use of ‘line-pack’ in the dedicated pipelines supplying hydrogen to industrial users;

b. Variation in the hydrogen/gas mixtures supplied to both industry and the network;

c. Swinging hydrogen use between the distribution network and industrial users;

d. Use of additional by-product hydrogen available from industries in the area; and

e. Use of ‘tolerable’ variations in hydrogen production by the associated SMRs.

4) Low cost CCS such that unit CO\textsubscript{2} transport and storage costs are approximately half of those at other potential locations for a hydrogen production facility involving carbon capture

Suitable depleted oil and gas fields, are located very close to shore relative to other potential geographies (including Humberside), and are available at an appropriate time for the first project (and for expansion in the future – see Section 6.6). There is also significant potential to reuse the associated pipelines and platforms.

The Project Design Concept described above is presented schematically in Figure 6.1.
Building upon the Project Design Concept, a set of conceptual pipeline routes and configurations are presented in Figure 6.2.

In summary, many industrial manufacturing facilities, most of which are major gas users, are located in a ‘corridor’ through which the Manchester Chip Canal passes. The corridor links the coast at Liverpool Bay to the centre of Manchester and is an established route for existing pipelines. Ince Marshes is an industrial area close to the ship canal and hydrogen from a production facility located there could be piped to a range of industrial plant. The location also has straightforward access to the Liverpool Bay gas fields (see Section 2.7.1 for more information) which are expected to be available as CO\textsubscript{2} storage sites within the timeline anticipated for project realisation. A hydrogen pipeline spur to north of the Mersey river can enable industrial plants in the Liverpool area to be linked to provide an interconnected tranche. This hydrogen pipeline network also enables hydrogen to be injected (via multiple, smaller spurs) into the existing gas distribution network to provide a hydrogen/natural gas blend across the Cluster area.

Figure 6.2: Conceptual Pipeline Routes and Configurations
6.2 Variations in Network Demand

6.2.1 Demand from the Distribution Network

As described above, the intention is to inject hydrogen into the distribution network to achieve the highest hydrogen blend possible without requiring changes to gas appliances and equipment. The aim is to supply this blend to a large proportion of the distribution network covering the L-M Cluster area which incorporates Liverpool and much of Manchester (see Figure 2.1 in Section 2.1). As described in Section 2.2, the total gas demand in this area in 2016 was 47,631 GWh.

As mentioned above, up to 12%vol. hydrogen is allowable in parts of the gas network in the Netherlands. 114 The allowable level is dependent on the appliances attached to the network. For a network with limited appliance types, up to 20%vol. may be possible without requiring changes to the gas appliances and equipment. 115 The aforementioned HyDeploy project is currently aiming to test blends (of potentially up to 20% hydrogen) in a ‘closed’ gas network which forms part of the Keele University complex. 116 Consequently, to provide a blend, for example, with 10%vol. hydrogen (~ 3.4% by energy) would require the production of 1,620 GWh/annum of hydrogen to supply the L-M Cluster area.

Network demand fluctuates on a daily, weekly and seasonal basis and it will be necessary for the hydrogen supplied to follow this variation. The existing gas distribution network is designed to supply a theoretical ‘1 in 20 year’ maximum peak hour demand using the Medium Pressure (MP) network. It is intended that hydrogen will be injected into this MP system. Gas demand variations in the network are based on a proportionate decrease in the 1 in 20 year demand level by established empirical scaling factors. The 1 in 20 year demand in an area is associated with extreme cold and a particular mix of high demand on the network, largely from space heating in residential and commercial buildings.

Demand variations of a factor of 4 within a day are considered to be normal, with the need to manage variations of a factor of 2 from the mean daily demand. Demand can also vary considerably hour-by-hour. The scaling factors used for hourly demand variations throughout a day are presented in Figure 6.3.


Seasonal demand is also heavily influenced by the demand for space heating, as well as other factors. As a result, average monthly demand scaling factors, such as those presented in Figure 6.4 are used to represent these seasonal changes.
Based on the scaling factors presented in Figure 6.3 and Figure 6.4, a factor of 11.4 variation can occur between maximum and minimum gas demand across a year.

Maximum gas demand will change over future decades as decarbonisation of the economy proceeds. However, at present, it is unclear to what extent alternative sources of heat will gain traction with policy-makers and consumers and therefore the nature of future change in gas demand. In this context, it is notable that the Renewable Heat Incentive (RHI) has experienced relatively modest take-up.\(^{117}\)

A number of studies have considered future heating scenarios, BEIS latest energy forecasts include a projected 17% increase in demand from households on the distribution network by 2035.\(^{118}\) At the same time, perhaps the most comprehensive work (using the UK MARKAL model) concludes that hydrogen conversion is the key decarbonisation option to enable the gas networks to continue supplying energy to most buildings in the long-term.\(^{119}\)

A recent study for the CCC considers a set of network demand scenarios with and without decarbonisation of the gas distribution network with hydrogen.\(^{120}\) The work presents the wide range of possible long-term future scenarios for natural gas demand, from which the key findings can be summarised as follows:

- Under two scenarios (1 and 2) which do not involve substantial hydrogen use, demand on the distribution network falls considerably as consumers switch to electric heat pumps and other alternative means for heating;
- Two network demand scenarios (3 and 4) were considered which involved decarbonisation of the distribution network using hydrogen:
  - The first scenario involves conversion to hydrogen at a national scale and results in a slight uplift in total demand on the distribution network to meet a roughly constant consumer demand (given the efficiency loss in gas conversion to hydrogen); and
  - The second ‘patchwork’ scenario is focused on the north of England only, and results in a fall in total demand on the distribution network, but one that is far less material than under scenarios whereby there is no conversion to hydrogen.

The relevance of the CCC work to this study is that it suggests that maximum distribution network demand is likely to be lower than at present; at least to the extent that some industrial demand will be met by new pipeline infrastructure. Consequently, the analysis presented below in respect of the potential L-M Cluster is based on an assumption that network demand will fall by around 10%.

Detailed modelling of the network demand profile in the area is outside the scope of the current study, but is likely to form the basis of subsequent work. However, the discussion above provides sufficient understanding of the demand profile in cluster area from which to specify how the hydrogen supply system should be designed. As mentioned above, to formulate an initial project it is assumed that 1,620 GWh/annum of hydrogen must be supplied to provide a 10%vol. blend across the network. This number can be scaled to higher or lower blend percentages, and/or if necessary, for reduced or extended geographical coverage.

The annual average monthly hydrogen requirement of the proposed cluster will be 137 GWh, rising to 202 GWh during the highest demand month. This maximum demand equates to 276 MWh per hour, as presented as part of the wider daily demand per hour data in Figure 6.5.

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As presented in Figure 6.6, the variation throughout the day implies a peak demand in a winter month day of 406 MW at 7pm and a minimum demand at 4am of 100MW. This is shown in comparison with the average maximum daily demand per hour of 276 MW.
6.2.2 Industrial Demand Profile

As presented in more detail in Section 2.2, in 2016 demand from large (> 5.9 GWh/annum) industrial gas users was 11,039 GWh, which represents 23% of total demand in the L-M Cluster area. The annual usage profile for the 10 selected major industrial users (see Section 2.2) in the Cluster is shown in Figure 6.7. This demonstrates that these 10 sites, and a number of other industrial manufacturing sites in the area, operate continuously throughout the year, with the demand profile showing limited variation. The proposed industrial Cluster can therefore provide a substantial base load demand for hydrogen.

As described in Section 5.0, a substantial proportion of industrial gas use is associated with the production of high and low temperature process heat, which has the potential to convert to operating on hydrogen or high hydrogen/natural gas mixtures. Indeed two companies in the area (Essar and Inovyn) already have experience of firing hydrogen in their boilers.

By focusing on the converting of a limited number of very large individual boilers, furnaces, ovens and kilns to operate on a high hydrogen- gas mixture, there is an opportunity to secure a material level of decarbonisation in a relatively short time frame when compared with a strategy which seeks to wholly decarbonise the domestic and commercial sectors.

It is proposed that hydrogen is delivered to this cluster of industrial users by a new hydrogen pipeline system. The existing gas connection at each site would be retained and a hydrogen-gas mixture produced for each site using an ‘entry unit’. As described in Sections 6.5 below, this approach has been designed such that these major industrial users can play a key role in easing the challenge of matching SMR hydrogen production to network demand.

Figure 6.7: Natural Gas Demand from Large (>5.9 GWh/annum) Users in the L-M Cluster (2016)
6.3 Configuration of Hydrogen Supply

Detailed analysis of the proposed approach to hydrogen production is outside the scope of this work. As in the H21 study, SMR is used as the reference technology, as it is a mature technology able to produce hydrogen from gas in sufficient volume for this, and subsequent larger projects, and has the potential for incorporation of CO₂ capture. However, there are practical limits to SMR operation. In particular:

- Changes in output are limited to around 5% of design capacity per hour (in standard designs); and
- Even given appropriate time, turndown to only around 70% of full output is possible without material loss of conversion efficiency.

Hence SMRs procured to supply the distribution network cannot be readily matched to the variation in daily demand. As shown in Figure 6.5, average demand varies by a factor of around 2.5 between summer (July/August) and (December/January/February). This would result in severe under-utilisation of capital if sufficient SMR capacity was provided to meet the winter demand. However, if industrial demand is supplied separately using a high hydrogen gas, this can have a major positive impact on the ability to manage the mismatch between supply and demand on the distribution network, as described in more detail in Section 6.5.

Combining the average hourly hydrogen demand from the selected 10 selected major industrial gas users (see Section 2.2) with a 10% blend in the distribution network defines the hydrogen production requirement. Table 6.1 summarises three ‘cases’ for matching hydrogen production to demand.

- Case 1 gives the maximum substitution of demand by hydrogen. It reflects the industrial sites operating on 100% hydrogen (at average hourly demand) throughout the year, together with sufficient hydrogen to meet peak winter demand for 10% vol. hydrogen on the wider distribution network. The demand profile is shown in Figure 6.8 and would require a total of 936 MW of SMR capacity to be installed, some of which would be underutilised in the summer months;

- Case 2 depicts a minimum supply case which is maintained constant throughout the year so that the SMR capacity is fully utilised. The installed capacity (of 580MW) is able to meet the low demand in the summer months. However, there would not be sufficient hydrogen to meet both industrial demand and to maintain a constant blend supplied to the network during the winter; and

- Case 3 describes a more practical solution in which the industrial supply is maintained constant throughout the year and the level of hydrogen supplied to the network is varied to maintain a constant blend, as presented in Figure 6.9. Around 760 MW of SMR capacity is installed, which is fully utilised in the winter months and has 65% utilisation in the month with the lowest demand. The industrial demand is met by a mixture of hydrogen and natural gas when insufficient SMR capacity is available.

Table 6.1: Hydrogen Supply Scenarios for Industry and Network

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<tbody>
<tr>
<td>Industrial (100% hydrogen)</td>
<td>660</td>
<td>484</td>
<td>484</td>
</tr>
<tr>
<td>10% vol. Hydrogen Blend to Network</td>
<td>276</td>
<td>96</td>
<td>276</td>
</tr>
<tr>
<td>TOTAL SUPPLY</td>
<td>936</td>
<td>580</td>
<td>760</td>
</tr>
</tbody>
</table>

121 Alternative ‘methane to hydrogen’ conversion technologies, such as Auto thermal Reformation, are likely to have similar constraints.
The demand profile for Case 3 could be met efficiently by a ‘complex’ of three SMRs, each sized at 260 MW. All three SMRs would operate during the winter months and two during the summer. This allows each SMR to be taken offline for maintenance in rotation every three years whilst at the same time ensuring a high utilisation factor. The operating range of the SMRs means that is configuration is able to follow the annual network variation profile.

The actual sizing of the Project will depend on the size and detailed characteristics of the industrial sites involved and the optimum SMR design configuration. Case 3 provides a starting point from which the design may be optimised. The costing estimates in Section 7.0 assume this case.

**Figure 6.8: Total Average Daily Hydrogen Demand per Hour (Case 1)**

![Figure 6.8](image)

**Figure 6.9: Total Average Daily Hydrogen Demand per Hour (Case 3)**

![Figure 6.9](image)
In addition to supply by SMRs, as described in greater detail in Section 2.5, hydrogen is currently produced in the area at three main locations, all of which have the potential to supply hydrogen to the network. These are the Stanlow oil refinery, the Inovyn chlor-alkali plant, and the CF Fertilisers ammonia plant. Theoretically, up to 2 million MWh/annum might be available, although the practical volume available and which can be shown to be ‘low carbon’ might well be considerably less.

In addition, it is relevant to note that the production of bio-SNG and bio-hydrogen from waste has been successfully piloted and a demonstration project (part-funded by Cadent) is under construction in Swindon. The project design implicitly involves CO$_2$ separation and as the waste has a high biomass content ‘negative emissions’ can be achieved if commercial plants were sited near to CCS infrastructure. Further development of the Project will therefore consider how such potential sources of bio-hydrogen or bio-SNG might be best brought into the supply system.

6.4 Pipeline Infrastructure

The conceptual arrangement of a proposed project is presented in Figure 6.2. As described above, the land adjoining the Manchester Ship Canal is an existing pipeline corridor and enables access to a large number of industrial process plants, which can be supplied with hydrogen by a new pipeline. This pipeline enables access to the gas distribution system at multiple locations to enable hydrogen to be added to the MP system.

The hydrogen production and CO$_2$ capture units can be located in an industrial development area (also an Enterprise Zone) which has an NTS gas supply and provides ready access to the hydrogen pipeline corridor. This location also provides, in principal, a relatively straightforward route for a CO$_2$ pipeline, via Connah’s Quay to Point of Ayr, and thence onwards (potentially reusing the existing natural gas pipeline associated with the fields) out to the Liverpool Bay oil and gas fields (see Section 2.7.1 for more information).

6.4.1 Hydrogen Pipeline

As described above, it is envisaged, at this stage of conceptual development that the hydrogen pipeline will need to be designed to deliver between 580 MW of hydrogen (during summer months, when one of three SMRs is offline for maintenance) and 760 MW (during winter).

The hydrogen pipeline is assumed to:

- Be constructed from X60 steel;
- Operate at 17 bar;
- Be 86km in length; and
- Deliver 900 MW of hydrogen.

The flow modelling undertaken thus far indicates delivery pressure should be maintained above 7 bar to allow injection into the gas distribution system. This is based on the conservative assumption that injection into the gas distribution system only takes place at the extremities of the hydrogen pipeline system. On this basis, a scoping level pipeline assessment has shown that the resulting pipeline system consists primarily of 12” diameter pipe moving up to 16” for a short section of pipe near the SMR location and down to an 8” pipe in two other sections.
6.4.2 CO₂ Pipeline

Based on initial analysis of data relating to the gas use of the major industrial sites (see Section 2.2.2) located broadly along the hydrogen pipeline route presented in Figure 6.2 it is estimated that there will a requirement to transport and store 844-970 tCO₂/annum emitted from the SMR complex. The lower figure assumes the Case 3 arrangement above, in that the hydrogen supply to the industrial tranche is constant throughout the year at the minimum demand month level. The higher figure assumes that sufficient hydrogen capacity is installed to enable the full industrial demand from the 10 selected sites to be met by hydrogen (Case 1 above).

As set out in Table 6.2, the 10% blend of hydrogen injected to supply the network across the cluster equates to 328 tCO₂/annum produced by the hydrogen production complex. In addition, one of the UK’s two major ammonia production plants (operated by CF Fertilisers) is sited very near to the location of the proposed complex. This ammonia plant includes four existing SMRs that produce hydrogen from natural gas. As part of the production process pure CO₂ is also produced; and whilst some is sold, the remainder is currently released to the atmosphere. This CO₂ could be transported and stored at low cost (via simple compression to CO₂ pipeline pressure) and is included in the amount to be stored in Table 6.2.

As a result, the project is assumed to require the transport and storage of 1.5 MtCO₂/annum. This CO₂ would be piped from the hydrogen production complex via a 25km CO₂ pipeline to link to the existing pipeline which travels from Connah’s Quay to Point of Ayr and thence to the Liverpool Bay fields.

Table 6.2: Estimated CO₂ Transported by the Project

<table>
<thead>
<tr>
<th>Source</th>
<th>CO₂ (ktpa)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10% Network Blend</td>
<td>328</td>
</tr>
<tr>
<td>Industry</td>
<td>844-970</td>
</tr>
<tr>
<td>Industry existing</td>
<td>350</td>
</tr>
<tr>
<td>TOTAL</td>
<td>1,523 – 1,650</td>
</tr>
</tbody>
</table>
6.5 Matching Supply and Demand

As highlighted above, the inability to change hydrogen production output quickly or turn the output down below c.70% without major loss of efficiency represent constraints to project design. The operational flexibility possible gives the ability to match average seasonal demand but intra-day demand fluctuations cannot be accommodated.

Under the current conceptual design, if base load supply provides the highest average daily of 276 MW (see Figure 6.6 above) then there is a requirement over the day for a total of 1,000 MWh above this average. There is a requirement for an additional 140 MW to meet the evening peak hour. At the same time, 160 MW of excess hydrogen would be produced for 3 hours during the night.

The options for managing these daily demand fluctuations can be summarised as follows:

- **Use of line-pack in the hydrogen supply system**
  
  For the 17 bar pipeline described above, this provides 300 MWh of hydrogen ‘storage’, which is sufficient to cater for two hours of the evening peak demand even in the winter when it is highest. It is also worth noting that available line-pack increases with pressure and line capacity. Consequently, for example, if the system was designed to operate at 34 bar 600 MWh of storage would be available.

- **Changing the ratio of hydrogen to natural gas in the mix supplied to industry**
  
  Under this approach, the industrial sites effectively provide a ‘demand balancing service’, flexing the proportion of hydrogen in their mix in response to network demand. If the mix supplied to industry was flexible by ~10% (up or down), this would cater for the largest variations in network demand during winter months. In the summer months, flexing at 2.5% would be sufficient to cater for demand variations.

- **Sourcing of hydrogen from existing industrial hydrogen producers**
  
  In principle, any one of the three large hydrogen producers in the area could supply additional hydrogen to meet peak demand. However, it is acknowledged that establishing acceptable arrangements, both technically and commercially, would not be straightforward, and would not necessarily be low carbon.

- **Supply of hydrogen to others sites, which are not connected to the distribution network**
  
  Some CCGT power stations continue to operate overnight (during potential times of oversupply within the cluster) and could, in principle, accept a percentage of hydrogen alongside natural gas. In addition, some major industrial gas users are connected the NTS rather the distribution system. For such plant up to 10% could, in principle, be supplied as a mixture to fire boilers or other equipment. Furthermore, as hydrogen transport becomes more prevalent, hydrogen may be supplied to tankers or other stores during periods of low network demand during the night.

- **Small variations in hydrogen production output**
  
  As highlighted above, the preference is to operate such facilities at a constant rate, and for an SMR the rate of change of output is limited to ~ 5% of design output/hour. However, based on three SMRs operating to supply the cluster, hourly changes of up to 40 MW per hour might be acceptable.
Changes to the proportion of hydrogen in the blend supplied to the network

A gas specification with increased hydrogen has yet to be accepted. However it is noted that a 1% change in the proportion of hydrogen in a blend would result in a 25-30 MW change in the level of supply and a 0.34% change in the amount energy delivered. The ability to blend in the network will always be limited to a specific level, and so such reductions would be acceptable from a gas safety perspective.

This discussion serves to show that in-day variations can be managed in the proposed initial Project without the need for the costly construction and operation of salt cavern storage of hydrogen.

6.6 Project Extension Opportunities

The Project concept described above has been structured as a minimum cost, minimum disruption, exemplar, which would provide meaningful decarbonisation (1.5mt CO₂/annum in total) of the gas distribution network and industrial gas users, whilst also providing a base which can be extended to further decarbonise gas use. It has been designed as such so that it is ultimately deliverable in the short to medium-term, and can function as a catalyst for development of wider hydrogen supply and use.

The key requirements to enable building upon the initial project are that both sufficient additional CO₂ storage and ultimately hydrogen storage capacity, are available, as described in Sections 6.6.1 and 6.6.2.

6.6.1 Further CO₂ Storage Capacity

The Liverpool Bay and Morecambe Bay oil and gas fields, both sets of which sit in the East Irish Sea and, in principle are readily accessible from the proposed location of the SMR complex, are described in detail in Section 2.7.

Whilst the Hamilton field is the most likely option to provide storage for the initial project, we estimate that the wider Liverpool Bay complex, including Hamilton North, Douglas and Lennox, could provide a CO₂ capacity of around 250 MtCO₂. It is also our understanding that this full capacity would become available by the mid-2020s. Importantly, the fields are currently interconnected and so could be developed as a coherent CO₂ storage complex with their development as CO₂ stores integrated into the field decommissioning plan.

The nearby Morecombe Bay gas fields are larger and provide substantial further storage capacity. The estimated CO₂ storage capacity is around 850 MtCO₂ at South Morecombe and approximately 180 MtCO₂ at North Morecombe. This capacity is expected to become available in the 2030s.

It is therefore expected that in excess of 1 Billion tCO₂ storage capacity exists within relatively easy reach (compared with the majority of fields in the Southern North Sea) of the proposed SMR complex. This capacity would, for example, provide sufficient storage for 100 years of 100% hydrogen supply to the distribution network within the geographical area defined as the L-M Cluster (see Figure 2.1 in Section 2.1) or well in excess of 150 years of supply of a 20% hydrogen blend nationwide.
6.6.2 Additional Hydrogen Storage Capacity

As described in detail above, residential gas demand varies greatly between seasons, and this variation can be managed by use of a tranche of industrial gas users having relatively flat demand profile over the year. In many areas of the UK, this consistent level of industrial demand is lower than that of residential demand. Consequently, hydrogen storage (beyond those methods proposed for the initial project in Section 6.5) would be required to achieve significantly deeper penetration of hydrogen use.

As discussed in detail in Section 2.8, the Cheshire salt basin is extensive and can support a very large amount of storage, whilst additional extensive salt deposits are available just offshore in Morecambe Bay. Table 6.3 provides an indication of the scale of hydrogen conversion project that might be considered for all users on the network. This is presented in terms of the amount storage required against an example gas store (Stublach) already in use in the Cheshire basin and another consented offshore store in Morecambe Bay (Gateway).

To give an indication of the scale of the population that might be served, these potential stores have been scaled from the storage capacity calculated to be required to supply Leeds within the H21 study. This assumed a requirement for 40 days storage capacity and that alternative approaches to meeting fluctuations in demand, as described in Section 6.5 for this initial project, are not employed.

The data presented in Table 6.3 demonstrates that a future need for underground hydrogen storage does not impose any limit on the widespread adoption of a blend supplied to the network. It also demonstrates that a small number of storage sites could provide the necessary capacity for any practicable extension of the initial proposed project.

### Table 6.3: Illustrative Hydrogen Storage Capacity

<table>
<thead>
<tr>
<th>Store size (Mscm – natural gas)</th>
<th>Estimated Population Served (million)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>100% Hydrogen</td>
</tr>
<tr>
<td>H21 Project</td>
<td>209</td>
</tr>
<tr>
<td>Stublach¹</td>
<td>400</td>
</tr>
<tr>
<td>Gateway</td>
<td>1,500</td>
</tr>
</tbody>
</table>

Notes:
1. Stublach currently has 200 Mscm of capacity operational, with a further 200 Mscm either planned or under construction. It is used here as an example only. There is a further 255 Mscm of onshore storage capacity currently operating in the Cheshire Basin.
2. Stag Energy’s proposed Gateway project in the East Irish Sea received planning consent in 2008, but has not since progressed to financial close.
6.6.3 Options for Network Expansion

In addition to ‘deeper’ hydrogen conversion of the network within the L-M Cluster area itself, expansion of the project may be in terms of increased geographical coverage or facilitation of the growth of other low carbon sectors via the supply and use of hydrogen.

In terms of geographical expansion, as an example, the initial proposed project could, over time, be extended to supply adjacent urban centres with 100% hydrogen covering a population of around 10m as depicted schematically in Figure 6.10. Such a follow-on project, converting distribution networks in and around Birmingham to hydrogen would:

- Require around 400 km of pipeline;
- Comfortably capture 20 MtCO₂/annum (for which sufficient storage capacity is available in Liverpool and Morecambe Bay) CO₂; and
- Require six hydrogen storage complexes the size of Stublach or two the size of the Gateway project.

Use of hydrogen to decarbonise the distribution network in large urban regions is technically possible once suitable appliances and equipment have been developed and are widely available. Work in this area is currently being further progressed both as part of further phases of the H21 project, and shortly to be initiated as part of a new three year hydrogen research and development programme, with funding of £25 million, recently announced by Government.¹²²

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6.6.4 Replication of Current Proposed Project
The conceptual project design described above may be replicated in other regions where there is a major industrial cluster and relative ease of access to offshore CO₂ storage capacity. As set out in Section 3.0, both of these critical features exist in Humberside, alongside extensive salt deposits for hydrogen storage. Consequently, whilst the comparative analysis in Section 4.0 determined that the L-M area was a preferable cluster location, a similar project could be executed on Humberside.

It should also be noted that the industrial clusters at Teesside and Grangemouth may also be candidate sites for the type of industry-driven project proposed for the L-M area in this report.

6.6.5 Expansion into Other Markets
6.6.5.1 Power Generation
The significant ongoing growth in intermittent renewable electricity generation from wind and solar, along with forthcoming new, inflexible nuclear generation is creating the need for new approaches to balancing supply and demand on the electricity transmission network. Currently, CCGT stations provide the required ‘mid merit’ capacity, and such plant, including those operating within the L-M Cluster area (as described in Section 2.4) typically operate at a load factor of 20-50%. However, low carbon generation is needed to fulfil this role if future national carbon reduction targets are to be met. Consequently, the low carbon hydrogen network proposed above could be extended to include CCGTs which are able to operate on either 100% hydrogen, or on hydrogen/natural gas mixtures (see Section 5.3.4.2 for discussion on use of hydrogen in gas turbines).

The availability of hydrogen storage on the network would enable hydrogen production to be constant to supply CCGTs for balancing purposes, which would give full utilisation of the capital involved in fuel production (using SMRs or gasification). Such an expansion is therefore completely synergistic with the initial proposed project. The concept of large-scale electricity generation from hydrogen supported by large-scale hydrogen storage has been considered in detail by the ETI.¹²³

6.6.5.2 Road and Rail Transport
The development of the MP hydrogen network, which would be required to deliver a blend to the gas distribution network and to supply industrial plants, offers the opportunity to create a distributed regional network of hydrogen filling stations for hydrogen cars and HGVs. The hydrogen pipeline proposed is very close to at least 12 existing filling stations and close to perhaps a further 50. Hydrogen refuelling stations, including those serving bus depots and dedicated commercial fleets, close to the hydrogen pipeline system are likely to be significantly lower cost than would be the case for new ‘standalone’ hydrogen refuelling stations as has been proposed to date.

Significant progress is being made in this area within the L-M Cluster area, demonstrated by a recent funding award by the Department for Transport (DfT) to ULEMCo to trial a range of vehicles with hydrogen dual-fuel technology.¹²⁴ The advent of the kind of major low carbon source of hydrogen delivered by the proposed project would function as a major catalyst for a material transition towards decarbonisation of transport in the area.

¹²⁴ See http://ulemco.com/?p=2507
6.7 Summary of Deployment Pathway

The proposed project is a first-of-a-kind (FOAK) development which, in summary:

- At this stage of conceptual development, has been defined to supply 936 GW of low carbon heat and to capture and store 1.5 MtCO$_2$/annum;
- Involves no disruption to domestic and other distribution network users but reduces the carbon intensity of all such gas use in the cluster area;
- Provides material decarbonisation of the combustion of gas used by industry for heating purposes;
- Is able to justify the development of major, low cost CCS infrastructure (compared to alternatives) without reliance on the existence of a large power project, as has been widely assumed prior to this study;
- Does not require initial investment in hydrogen storage capacity but is sufficiently close to large salt deposits, which have the potential to provide all future hydrogen storage capacity likely to be required for project expansion; and
- Can be progressively extended (using over 1 Billion tonnes of CO$_2$ storage capacity) to support:
  - Further gas network decarbonisation;
  - Low carbon CCGT generation projects;
  - Further industrial decarbonisation; and
  - Decarbonisation of the transport sector.

The project could form an exemplar for industrial and gas network decarbonisation, which attracts inward investment to fund the new infrastructure and which provides export opportunities for the new skills and intellectual property (IP) created.

Potential approaches towards funding the initial project (and subsequent wider scale hydrogen networks) are discussed in Section 7.0, along with high-level cost data.
7.0 COSTS, FUNDING AND PROJECT DELIVERY

Whilst the proposed L-M Cluster Project (as described in Section 6.0) is at an early stage of development, it is important to provide related indicative capital and operational costs. It is also important to consider how such costs might be funded, with a focus on Financial Close for the project taking place during this Parliamentary term (i.e. prior to June 2022).

The primary objectives of this section are therefore to:

- Present indicative costs for the project, based on the work undertaken thus far and data from other studies;
- Explore how the costs of hydrogen production, supply and conversion infrastructure might be funded; and
- Examine how the costs of associated CCS infrastructure might be funded.

7.1 Modelling of Costs

Based on the conceptual project design presented in Section 6.0, the key high-level Capex lines included in the financial model for this study are shown in Table 7.1. Hydrogen production costs are scaled directly from the H21 project analysis.

This analysis suggests that Capex for the project would be of the order of £0.6 Billion compared with £2.1 Billion of Capex associated with the H21 project for an equivalent level of decarbonisation (1.5MtCO\(_2\)/annum). The main savings of the L-M Cluster Project primarily relate to:

- The need to replace gas boilers at every household in Leeds, which results in costs >£1 Billion, compared with zero need for conversion costs for households in the L-M Cluster area accepting a hydrogen blend; and
- The need for costly intraday and inter-seasonal underground salt cavern storage to supply Leeds, rather than use of industry and other methods as a means of balancing the network as proposed for the L-M Cluster area.

It is also notable that the H21 project assumed that CCS infrastructure would be in place and only incremental operating usage costs would be attributed to the project. Hence, in contrast to this study, CCS infrastructure and start-up costs were not included.

In acknowledgement of the high level of uncertainty associated with some of the line item estimates in Table 7.1 (which is expected at this stage of project development), related sensitivity analysis is presented in Section 7.1.1.2.

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http://www.northerngasnetworks.co.uk/document/h21-leeds-city-gate/
### Table 7.1: Key Capex Assumptions (Central Scenario)

<table>
<thead>
<tr>
<th>Cluster Element</th>
<th>Related Assumption(s)</th>
<th>Unit Cost (M)</th>
<th>Total Cost (M)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydrogen Production</td>
<td>3 SMRs, producing around 760 MW of hydrogen(^2)</td>
<td>£98(^3)</td>
<td>£296</td>
</tr>
<tr>
<td>Hydrogen Compression</td>
<td>SMRs to produce compressed CO(_2), which will result in no need for hydrogen compression</td>
<td>n/a</td>
<td>0</td>
</tr>
<tr>
<td>Hydrogen Injection</td>
<td>Equipment required to inject hydrogen into the new hydrogen pipeline</td>
<td>n/a</td>
<td>£24</td>
</tr>
<tr>
<td>Hydrogen Transport</td>
<td>Transport of 936 MW of hydrogen at 17 bar in new 90km onshore hydrogen pipeline from SMR complex (and nearby CF Industries) to industrial cluster(^4)</td>
<td>£1/km</td>
<td>£90</td>
</tr>
<tr>
<td>Conversion of Industry to Hydrogen</td>
<td>Modifications to boilers, engines and turbines at c.10 large industrial sites</td>
<td>£10/site</td>
<td>£100</td>
</tr>
<tr>
<td>CO(_2) Transport</td>
<td>New 25km onshore pipeline for 1.5 MtCO(_2)/annum to link from SMR complex to existing pipeline at Connah’s Quay</td>
<td>£1/km</td>
<td>£25</td>
</tr>
<tr>
<td>CO(_2) Facilities</td>
<td>Modifications to existing Hamilton platform</td>
<td>n/a</td>
<td>£27</td>
</tr>
<tr>
<td>CO(_2) Storage</td>
<td>Includes design, procurement, construction and commissioning of wells, licensing and permitting</td>
<td>n/a</td>
<td>£31</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td></td>
<td></td>
<td><strong>£593</strong></td>
</tr>
</tbody>
</table>

Notes:
1. The battery limit for CCS costs is from the inlet to the CO\(_2\) compressor from the SMRs
2. This is based on Case 3 (see Section 6.3)
3. Based on scaling of SMR Capex in H21 study
4. Costs include those for multiple ‘spurs’ to distribution network

The key high-level Opex lines included in the financial model for this study are presented in Table 7.2. This analysis suggests that Opex for the project would be of the order of £57 M/annum. This compares with the £139 M/annum associated with the H21 project with the difference in costs largely relating to the lack of need (in this project) for underground storage of hydrogen in salt caverns.

\(^1\) Related sensitivity analysis is presented in Section 7.1.1.2
Table 7.2: Key Opex Assumptions (Central Scenario)

<table>
<thead>
<tr>
<th>Cost Element</th>
<th>Related Assumption(s)</th>
<th>Cost (£M/annum)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SMR (and hydrogen injection equipment) O&amp;M</td>
<td>4% of Capex</td>
<td>12.8</td>
</tr>
<tr>
<td>Hydrogen Compression</td>
<td>SMRs to produce hydrogen at pipeline injection pressure, which will result in no need for additional hydrogen compression</td>
<td>0</td>
</tr>
<tr>
<td>Additional natural gas requirement</td>
<td>£18.77/MWh (55p/therm) price of natural gas and 74% efficiency of SMR (with CCS)</td>
<td>32.2</td>
</tr>
<tr>
<td>Electricity for CO₂ Compression</td>
<td>To 10 bar at project initiation rising up to 60 bar at end of 15-year project period</td>
<td>1.2²</td>
</tr>
<tr>
<td>Onshore Hydrogen and CO₂ pipelines O&amp;M</td>
<td>Based on scaling of costs used in H21 study³</td>
<td>0.3</td>
</tr>
<tr>
<td>Offshore CO₂ Transportation O&amp;M</td>
<td>Based on ETI / Pale Blue Dot Study (2016)</td>
<td>0.9</td>
</tr>
<tr>
<td>CO₂ Facilities O&amp;M</td>
<td>Based on ETI / Pale Blue Dot Study (2016)</td>
<td>8.3</td>
</tr>
<tr>
<td>Measurement, Monitoring &amp; Verification (MMV) of CO₂</td>
<td>Based on ETI / Pale Blue Dot Study (2016)</td>
<td>0.4</td>
</tr>
<tr>
<td>Financial Security against CO₂ leakage</td>
<td>Based on ETI / Pale Blue Dot Study (2016)</td>
<td>0.6</td>
</tr>
<tr>
<td>Injection Well ‘Workover’</td>
<td>Based on ETI / Pale Blue Dot Study (2016)</td>
<td>0⁴</td>
</tr>
<tr>
<td>Offshore Abandonment</td>
<td>Excluded</td>
<td>0</td>
</tr>
<tr>
<td>TOTAL</td>
<td></td>
<td>56.6⁵</td>
</tr>
</tbody>
</table>

Notes:
2. Year 1 cost, rising to £4.9 M/annum in year 15
3. In reality, this is likely to underestimate related Opex. However, sufficient contingency is included within allowance for SMR O&M
4. A cost of £11.6 M is modelled for Year 10 only
5. Excludes savings associated with avoidance of need to purchase EU Allowances (under the EU Emissions Trading Scheme) by industry

7.1.1 Indicative Cost of CO₂ Abatement

A meaningful metric in the presentation of the costs of different approaches to decarbonisation of the energy sector is the cost (per tonne) of CO₂ abatement. In policy-making terms, when governments are considering the ‘next best’ approach to decarbonisation, this is often known as the marginal abatement cost (MAC)ₗ. It is derived via calculation of the lifetime cost of a particular approach or technology divided by the tonnes of CO₂ abated during that lifetime. For the purposes of this study, we refer to it as the ‘cost of abatement’ (‘CoA’), which is expressed as £/tCO₂ abated.

The CoA refers to the unit cost of substituting natural gas by low carbon hydrogen and includes the cost of modifying or replacing the equipment to which gas is supplied to provide the same duty.

This CoA differs from the cost of CO₂ storage (CoS) in that under this latter metric, any CO₂ which is emitted during the either the hydrogen production or CO₂ capture or transport processes is not subtracted from the amount stored.

7.1.1.1 CoA under Central Scenario

As presented in Table 7.3, the tonnage of CO\textsubscript{2} abated by the proposed L-M Cluster Project is a function of the efficiency of the SMR, both in terms of gas production/use and with regard to the capture of CO\textsubscript{2} and the associated electricity demand. It is also a function of the counterfactual emissions from burning natural gas (in the absence of the Project). The total abatement for the Project is 1.2 MtCO\textsubscript{2}/annum.

Table 7.3: Annual Abatement from the L-M Hydrogen Cluster Project

<table>
<thead>
<tr>
<th>Parameter</th>
<th>MtCO\textsubscript{2}/annum</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total produced by SMR(^1)</td>
<td>1.38</td>
</tr>
<tr>
<td>Total capture by SMR (@ 90% capture rate)</td>
<td>1.24</td>
</tr>
<tr>
<td>Total emitted by SMR(^2)</td>
<td>0.18</td>
</tr>
<tr>
<td>Counterfactual emissions from gas for equivalent heat delivered(^3)</td>
<td>1.02</td>
</tr>
<tr>
<td>Total abated by SMR</td>
<td>0.84</td>
</tr>
<tr>
<td>Total abated from CF Fertilisers</td>
<td>0.35</td>
</tr>
<tr>
<td>OVERALL ABATEMENT</td>
<td>1.19</td>
</tr>
</tbody>
</table>

Notes:
1. Based on an SMR producing 5.55 TWh of hydrogen per annum at 74% efficiency
2. Uncaptured emissions from SMR and emissions associated with electricity demand including CO\textsubscript{2} compression. As mentioned above, hydrogen compression is not required
3. Excludes net uplift in emissions associated with upstream gas production for reference or counterfactual, consistent with H21

In its simplest form, the CoA is the sum of the capital and operational costs over the project life divided by the total carbon abated. It is useful to consider this approach as it provides insights into the relative importance of the factors contributing to the CoA. However as explained below a more accurate estimate requires the use of an appropriate discounting methodology.

On this basis, as shown in Table 7.4, and using the cost assumptions presented in Section 7.1, an estimate for the CoA for the Project is around £90/tCO\textsubscript{2}.

Table 7.4: Cost of CO\textsubscript{2} Abatement from L-M Hydrogen Cluster Project

<table>
<thead>
<tr>
<th>Cost Element</th>
<th>£/tCO\textsubscript{2}</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capex</td>
<td></td>
</tr>
<tr>
<td>SMR Complex</td>
<td>17.7</td>
</tr>
<tr>
<td>Hydrogen Injection</td>
<td>1.4</td>
</tr>
<tr>
<td>Hydrogen Pipeline</td>
<td>5.4</td>
</tr>
<tr>
<td>Conversion of Industry</td>
<td>6.0</td>
</tr>
<tr>
<td>CO\textsubscript{2} pipeline</td>
<td>1.5</td>
</tr>
<tr>
<td>Offshore Facilities</td>
<td>1.6</td>
</tr>
<tr>
<td>CO\textsubscript{2} Storage</td>
<td>1.9</td>
</tr>
<tr>
<td>Opex</td>
<td>Based on all activities in Table 7.2</td>
</tr>
<tr>
<td>TOTAL</td>
<td>89.7(^1)</td>
</tr>
</tbody>
</table>

Notes:
1. Equates to a CO\textsubscript{2} storage cost of £67.1/t
7.1.1.2 Sensitivity Analysis

As this is a conceptual study, accurate project parameters are not yet available and so it is relevant to provide an indication of the sensitivity of the results to changes in key variables. Table 7.5 presents variations in value for five key parameters, with the results shown in Table 7.6 in respect of the resulting total CoA for the Project.

Testing of the impacts of each five of these variables individually gives a CoA range of £78-105/tCO₂. However, modelling of all relevant 'low' values together, along with the combination of all 'high' values, gives a range of £70–131/tCO₂.

Table 7.5: Assumptions for Sensitivity Analysis

<table>
<thead>
<tr>
<th>Variable</th>
<th>Assumption</th>
<th>Low</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>SMR Capex</td>
<td></td>
<td>-30%</td>
<td>+50%</td>
</tr>
<tr>
<td>Costs of additional natural gas</td>
<td></td>
<td>-40%</td>
<td>+40%</td>
</tr>
<tr>
<td>Conversion costs for industry</td>
<td>n/a</td>
<td></td>
<td>£200M</td>
</tr>
<tr>
<td>Capex of offshore pipeline for CCS</td>
<td>n/a</td>
<td></td>
<td>£66M¹</td>
</tr>
<tr>
<td>Capex of offshore facilities</td>
<td>£12M²</td>
<td></td>
<td>£106M³</td>
</tr>
</tbody>
</table>

Notes:
1. Cost for a new offshore pipeline should reuse of the existing pipeline not be possible. Cost based on data from ETI / Pale Blue Dot (2016)
2. Assumes that far greater amounts of topside infrastructure could be reused and that there would be far less disruptive change to the existing rig
3. Based on data from ETI / Pale Blue Dot (2016) for new offshore facilities

Table 7.6: Results from Sensitivity Analysis

<table>
<thead>
<tr>
<th>Variable</th>
<th>Cost of CO₂ Abatement (£/tCO₂)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SMR Capex</td>
<td>83</td>
</tr>
<tr>
<td>Costs of additional natural gas</td>
<td>78</td>
</tr>
<tr>
<td>Conversion costs for industry</td>
<td>n/a</td>
</tr>
<tr>
<td>Capex of offshore pipeline for CCS</td>
<td>n/a</td>
</tr>
<tr>
<td>Capex of offshore facilities</td>
<td>89</td>
</tr>
</tbody>
</table>

Notes:
1. Cost for a new offshore pipeline should reuse of the existing pipeline not be possible. Cost based on data from ETI / Pale Blue Dot (2016)
2. Assumes that far greater amounts of topside infrastructure could be reused and that there would be far less disruptive change to the existing rig
3. Based on data from ETI / Pale Blue Dot (2016) for new offshore facilities
7.1.1.3 Cost Comparison with Alternative means of Decarbonisation

There has been significant historic work undertaken by Government and the CCC in respect of the CoA of different approaches to decarbonisation of energy generation, notably in respect of options to create a low carbon electricity supply system. Such options include replacement of coal and gas generation with renewables, nuclear or fossil plant with CCS. It is notable that the options for widespread decarbonisation of heat are more limited and less established. Over 80% of heat is produced by combustion of gas and the substitution of gas by low carbon hydrogen has the potential for decarbonisation of the sectors in which heat is needed.

For heat supply in residential and commercial buildings, air source heat pumps (ASHPs), supplied by low carbon electricity, have been proposed as a means of decarbonisation by policy-makers. In specific industrial applications, the use of biomass in industrial boilers is possible. However, not only is the supply of sustainable biomass limited, but the costs of fuel and replacement boilers are significant, whilst industrial applications requiring high grade heat are precluded. As a result, the potential of biomass for industrial heat decarbonisation is limited both in scope and scale.

The results presented in Table 7.7 also include the CoA from the H21 study for that specific project configuration, which is designed to substitute natural gas with 100% low carbon hydrogen in the city of Leeds. The calculation methodology used to model the CoA for the L-M Cluster Project is not identical to that used for the H21 project in the way that ‘Scope 2’ emissions are calculated and the approach to discounting. The upper range of £104/tCO₂ presented in Table 7.7, therefore, involves discounting of the costs and the benefits of CO₂ abatement at a 4% discount rate, typical of the rate used to assess social benefit for initiatives of this type.

It is important to acknowledge that the objective of H21 study was to establish the technical feasibility of hydrogen conversion of a city, not to structure the lowest cost project. This study of the L-M cluster, however, shows that a pathway exists to achieve competitive emissions abatement by selective, incremental substitution of natural gas with hydrogen. It also suggests that a deployment pathway that delivers carbon abatement at a significantly lower cost can be developed.

The analysis presented in Table 7.7 also compares the CoA for the L-M Cluster Project with common large-scale technologies supported in the electricity sector to give a comparator in terms of value for money. Nuclear and offshore wind have been chosen as established technologies for which support levels are fairly well defined. The CoA for ASHPs has also been estimated to provide a comparator for heat provision in the residential and commercial sector. The results show that the CoA associated with the L-M Cluster Project is comparable with that associated with large-scale power generation technologies, which have strong policy support. This comparability comes despite this being a FOAK project, which also requires deployment of a considerable amount of new CCS and hydrogen delivery infrastructure.


129 Scope 2 emissions are those associated with all aspects of the production and supply of low carbon hydrogen, in this case from natural gas. Upstream emissions associated with the production of gas and its transport for conversion vary between supply sources and are not included in this analysis.
Importantly, the natural uncertainties around the data currently available to calculate the CoA of the Project and potential differences in the methodology do not negate the conclusion that the CoA is similar to those of nuclear and offshore wind. This is supported by modelling of the effect on the CoA of increases in the cost of a number of key parameters. The combined effect of an increase in all of these would result in a highest estimated CoA of £154/tCO$_2$\textsuperscript{130}. Notably, increases in individual or only a number of these parameters, which is a more likely scenario, produces lower estimated CoAs.

It is clear that the approach to decarbonisation of heat presented here represents very good value for money (VfM) when compared to air source heat pumps. However, it should be noted that the L-M project is mostly applicable to urban areas whereas the strength of the heat pump proposition is its suitability to more rural environments, including those not served by gas.

Ultimately, this analysis supports the conclusion that investment in the proposed L-M Hydrogen Cluster Project would represent a low cost, ‘no regrets’ project that could function as a catalyst for further gas network decarbonisation at a lower cost than alternative means of carbon abatement.

### Table 7.7: Comparison of CoA with Alternatives

<table>
<thead>
<tr>
<th>Approach to Decarbonisation</th>
<th>CoA (£/tCO$_2$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proposed L-M Hydrogen Cluster Project</td>
<td>90 – 104$^1$</td>
</tr>
<tr>
<td>Nuclear</td>
<td>125$^2$</td>
</tr>
<tr>
<td>Offshore Wind</td>
<td>131$^2$</td>
</tr>
<tr>
<td>H21 Project</td>
<td>292</td>
</tr>
<tr>
<td>Air Source Heat Pump</td>
<td>768$^3$</td>
</tr>
</tbody>
</table>

Notes:
1. Derived using H21 cost data. Upper range applies a 4% discount rate. Inclusion of ‘Scope 3’ emissions would increase the upper range to around £109/tCO$_2$
2. Based upon the levelised cost of electricity equivalent to the current ‘administrative strike’ price under the Contract for Difference (CfD) mechanism and assuming that power generation via CCGT at a levelised cost of £55/MWh and a carbon intensity of 0.343t/MWh is displaced
3. Based on the current level of support for ASHPs under the Renewable Heat Incentive (RHI) and assuming 215 kgCO$_2$/kWh carbon intensity of electricity generation in 2020 (as per National Grid’s ‘slow progression’ scenario in its 2016 Future Energy Scenarios) and a coefficient of performance (COP) of 2.51, as set out in BEIS’ 2016 RHI Impact Assessment

\textsuperscript{130} This is based on a 50% uplift in SMR Capex, a 40% uplift in the cost of additional natural gas, a £100 million uplift in industry conversion costs, a £166 million uplift in offshore CO$_2$ pipeline costs (if a new pipeline is required) and a £106 million uplift in the cost of offshore facilities (if a new rig is required)
7.2 Funding

The current market and regulatory framework does not encourage investment in either low carbon hydrogen supply or use, and there is also no mechanism in place to support the development of associated CCS infrastructure.

It is understood that BEIS is considering long-term market frameworks for supporting low carbon hydrogen use for heat. It is further understood, that it is separately considering possible market arrangements for CCS.

The commentary below is intended to inform a more detailed dialogue between Government, regulators and industry aimed at putting in place arrangements which enable the Project defined in Section 6.0, and other projects of a similar nature, to be deployed. Such initial projects would represent a catalyst for both wider supply of low carbon hydrogen in bulk for heat, industrial and power uses, whilst also putting in place essential CCS infrastructure to service such future developments.

However, whilst the two potential market models are described separately below, it should be emphasised that they are strongly interrelated and so must be developed in parallel. There are interdependencies between the two models in terms of their eventual functionality and the ability to allow a FID to be reached for the Project. Ideally the policy and regulatory teams engaged in their development should contain some of the same individuals. This would ensure that teams were fully abreast of these interdependencies such that they are able to develop appropriate models concurrently.

7.2.1 Potential Hydrogen Funding Model

The most recent work in relation to potential funding structures to enable repurposing of the natural gas grid to hydrogen was a study published by the CCC, and undertaken by Frontier Economics (‘Frontier’). As mentioned above, BEIS has also recently awarded a contract to Frontier to undertake more detailed consideration market and regulatory frameworks for a repurposed gas network.

The H21 Project proposed that the costs of converting the gas distribution network to operate on low carbon hydrogen and the costs of operation should be included in the RIIO framework. Allowable GDN expenditure, recoverable under the RIIO model, is determined against six ‘Output Measures’, one of which is ‘protecting the environment’. The purpose of reducing the carbon intensity of the gas supplied to consumers is to reduce CO₂ emissions to protect the environment, suggesting that it is legitimate to consider that such expenditure be included within distribution charges.

Reductions in CO₂ emissions produces a public benefit and it is appropriate that, in the absence of a commercial justification, the costs above those associated with business as usual, are spread across all who may benefit. Hence costs may be funded either by Government or by consumers. Inclusion in the distribution charge framework provides this socialisation of costs across all gas consumers.

The framework for Distribution Charges includes:

- A ‘System Capacity’ Charge;
- A ‘Customer Capacity’ Charge;
- A ‘System Commodity’ Charge; and
- For large customers (>72,000 kWh/annum), a ‘Fixed Customer’ Charge.

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131 Towards this goal, BEIS has recently awarded a consultancy contract to Frontier Economics to undertake a study relating to ‘Consideration of a range of market and regulatory frameworks that could support a repurposed or reconfigured GB gas network’. See https://www.delta-esourcing.com/respond/9R95QA6GG5


133 RIIO stands for ‘Revenue set with Incentives to deliver Innovation and Outputs’. See https://www.ofgem.gov.uk/network-regulation-riio-model
This multi-dimensional charging mechanism ensures that, broadly, the charges paid by consumers are in proportion to their connected capacity. Industrial gas consumers pay more than domestic and commercial consumers, which suggests that inclusion of the costs of conversion and supply of hydrogen would be implicitly ‘fairly distributed’.

However, as there are different costs associated with different heating solutions, there is a need to consider in more detail how customer fairness might be addressed. This is because customers in a given area would have no choice but to use hydrogen (unless they switched to another form of heating) if it was the only fuel supplied by the network in their area. For example, if a gas network operator converts some of their customers to hydrogen, they may be asked to meet the costs of this switch (without any discernible performance benefit). At the same time, another set of customers in an adjacent area (but potentially supplied by the same network) could remain supplied by natural gas at a lower cost. As a result, such an approach is unlikely to attract sufficient political will unless refined to address the issue of fairness. Towards this goal, the H21 study proposed that such costs should be socialised across the whole GDN area in which conversion takes place, or possibly socialised across the wider UK.

Distribution charges are set to recover costs and provide a fixed return on expenditure. The level of cost recovery can be set annually, or more frequently if appropriate, and can include both fixed costs and costs related to the energy delivered. This stable cost recovery mechanism ensures that the Cost of Capital for GDNs is low, which minimises costs to consumers.

As described in detail in Section 6.0, the project proposed here involves the development of infrastructure to reduce the carbon intensity of gas and distribute it to consumers. In summary, the key elements include:

- The use of a hydrogen production complex to process natural gas to produce pure hydrogen and remove and capture CO₂ for transmission offshore for storage in depleted oil and gas fields;
- The provision of pipelines to supply hydrogen to industry and allow injection and blending of hydrogen in the medium and low pressure and distribution networks; and
- The facility to manage fluctuating network demand by arranging for a number of large industrial users to operate on high hydrogen-natural gas mixtures, the hydrogen content of which may be flexed to:
  - Ensure that the specification of blended gas into the network remains within specification; and
  - Allow ‘steady state’ hydrogen production within the capability of the production facility.

All three of the above infrastructure elements are essential infrastructure to reduce the carbon intensity of the gas network, thus allowing related financial support to fall within the scope of the RIIO cost recovery mechanism. In this respect, however, it will be important to determine whether, for this FOAK innovative Project, key parts of the supply chain (for example, SMRs or storage infrastructure) can be considered to be within the RIIO price control mechanism.

The hydrogen blend level in the network is to be chosen so that modification of domestic and commercial consumers’ equipment is not required, which as discussed in Section 7.1, will significantly reduce costs compared with those proposed in the H21 study. However, some modification will be required in respect of the industrial furnaces, boilers and other plant at the industrial sites which will operate on a high hydrogen mix and provide the ability to manage fluctuating network demand. The sites involved will be in the EU Emissions Trading Scheme (ETS) ‘traded’ sector and will also be party to Climate Change Agreements (CCAs). It will be considerably more cost efficient and commercially less complex for the conversion costs associated with use of hydrogen and provision of this essential ‘balancing’ or ‘demand management’ service for this first project at least to come within the RIIO mechanism.
As described in respect of funding in Section 7.2.2, CCS will be an essential part of any large-scale hydrogen network. The method of funding CCS must involve socialisation of costs. The choice is whether this should be across taxpayers or gas consumers. The CCS infrastructure described above is an integral part of the Project and it may be appropriate to include such costs within the RIIO model. However, Government would benefit from avoidance of part of its decommissioning liability for the gas fields and it is difficult to argue that this benefit should be at the expense of gas consumers. CCS infrastructure is for the common good and its costs should be fully socialised.

In summary, the proposed project:

- Provides cost effective CO₂ abatement as presented in Section 7.1.1.3 and therefore provides a no regrets first step towards decarbonisation of heat for industry and for all consumers;
- Can subsequently be extended to include other adjacent geographies, as described in Section 6.6.3, thus building upon the hydrogen and CCS infrastructure and experience developed in this first phase; and
- Could be replicated in other regions which include the potential for low cost access to offshore CCS infrastructure and concentrations of industry able to accommodate fluctuations in demand and benefit from decarbonising their heat produced from gas. Towards this goal, the potential for a similar project based around the Humber region has been identified in this study, for which baseline data is provided in Section 3.0.

It therefore appears suitable for funding under the RIIO mechanism. Ofgem is scheduled to launch a consultation on the scope and arrangements for the next RIIO charging period in December 2018. These price control reviews for gas distribution (GD2) and transmission (T2) are currently expected to be finalised in December 2020, and will determine network cost allowances, revenues, and incentives for the period 2021-28.

The evidence in this study suggests that, to ensure consistent timing with the decommissioning programme for offshore infrastructure (to be used for CCS), it is critical that related cost allowances are included in the forthcoming price control review. In the absence of any such allowance, it is unlikely to be possible to reach Financial Close on the Project in time to prevent decommissioning of this infrastructure or incurring unnecessary costs to maintain the field infrastructure in a usable form. A less attractive alternative, however, and one proposed by Frontier in the aforementioned CCC study, is for a ‘well-specified uncertainty mechanism’ to be put in place for the forthcoming RIIO period, which is effective for ensuring that the price control allowances do not preclude rapid changes in network operations to meet alternative demand scenarios.

Another important issue raised by the CCC/Frontier is that, should there be major changes to fuels and/or technologies used in the gas networks (alongside wider deployment of other approaches to heat decarbonisation, for example heat pumps and heat networks), the recoverability of network investment may become more uncertain. Consequently, this greater uncertainty may result in the need for a different type of investor with a greater risk appetite, in respect of technology risk and longer-term stranded-asset risk, than the current suite of pension fund investors.
7.2.2 Potential CCS Funding Model

CCS is a multi-sector approach to decarbonisation having potential applications in power, heat supply and manufacturing process industries. Experience from the UK CCS Commercialisation Competition highlighted the challenge of managing counterparty risks between the investors in the plant to which capture is fitted, the pipeline owner and the CO\textsubscript{2} store owners. This ‘cross chain’ risk became very evident during the development, construction and operational phases of new full chain CCS projects. It also became clear from the CCS Commercialisation Programme that private investors were unwilling to accept long term CO\textsubscript{2} storage risks at the levels of return available.

A Parliamentary Advisory Group headed by Lord Oxburgh, and encouraged by BEIS, considered the issues in delivering CCS infrastructure in the UK.\textsuperscript{134} The Group recommended that CO\textsubscript{2} transport and storage infrastructure was funded separately from the plant incorporating CO\textsubscript{2} capture, and suggested that Government should accept both cross-chain and long-term risks. The report also recommended that to help deliver early projects Government should create separate transport and storage and capture companies and own these itself, subsequently selling the companies to private investors once CCS is well established.

This is an approach echoed in a recent study undertaken to develop a high-level business case for CCS on Teesside.\textsuperscript{135} However, this study, commissioned by Teesside Collective, also proposes upfront Capex funding from Government of £127 million to capture 0.73 MtCO\textsubscript{2}pa elements at three industrial facilities in the region. In addition, it proposes an ‘oversized’ CO\textsubscript{2} pipeline with around 5 Mtpa capacity. This is in contrast to the approach in this study to develop a low cost (but ‘no regrets’) CCS project and to the funding approach for hydrogen production and conversion proposed for the L-M area, as described in Section 7.2.1.

Consistent with the findings of the report headed by Lord Oxburgh, engagement with a range of Government, academic and private sector organisations as part of this study suggests that a successful market model, which would support delivery of the proposed L-M Hydrogen Cluster Project, would be based on the following principles:

- That long-term storage risk should be underwritten by Government;
- That the investment risk in low carbon hydrogen production and supply should be isolated from the investment risk in CCS infrastructure;
- That CO\textsubscript{2} storage is a ‘social’, non-competitive service the costs of which should be socialised using monies (available at low cost of capital) from either Government or gas consumers, or from a mix of both; and
- That there is no clear business case for private sector investment in pure CO\textsubscript{2} storage and so Government participation is difficult to avoid.


The project proposed in this study and the aim of further work in relation to funding mechanisms will be designed to:

1) **Minimise costs of CCS infrastructure development**

   The Liverpool Bay gas fields are close to the end of their economic life. Costs will be minimised if the time between cessation of hydrocarbon production and the start of CO₂ storage is minimised. To achieve this requires careful forward planning and collaboration between the offshore hydrocarbon field activities and the development of the hydrogen supply system. As presented in section 7.4 below, this development process implies the need for collaboration to begin around five years before Financial Close of the Project.

As presented in respect of costs in Section 7.1, to the extent possible, the intention of this project will be to reuse existing offshore infrastructure, including rigs and pipelines. There is also some possibility of being able to reuse a small number of the existing wells (previously used for oil and gas extraction) in converting the fields for CO₂ storage.

2) **Minimise field decommissioning costs**

   Reuse of existing infrastructure will not only minimise CCS Capex, it will also reduce or wholly avoid decommissioning costs for an extended period if infrastructure can be repurposed for CCS. Decommissioning involves removal and disposal of rigs, and in some cases pipelines, and also the suitable ‘abandonment’ of wells. The costs are field dependent, but across the portfolio of UK oil and gas fields equate on average to a minimum of several hundreds of million per field.\(^{136}\)

3) **Ensure Maximum Economic Recovery (MER) from the fields**

   The possibility of continued oil and gas production from part of the Liverpool Bay field complex whilst also injecting and storing CO₂ will need to be examined. If this were possible it would successfully demonstrate the link between MER and the use of oil and gas fields for CCS, as operational costs could be shared between the two uses;

4) **Explore the potential for avoidance of decommissioning to materially reduce Government funding of offshore CCS infrastructure**

   In line with the principles outlined above, CCS must be viewed in the context of both Government and operator liabilities for decommissioning of offshore oil and gas infrastructure. Under the current regime, Government is responsible for 50% of these decommissioning liabilities. Hence reuse of offshore infrastructure for CCS would mean that this forecast Government spend on decommissioning could instead be diverted to support CCS. This suggests that the net cost to Government of providing such CO₂ transport and storage infrastructure has the potential to be relatively low for the Project.

The focus of this study and future related work (as defined above) has been to design a low-cost CCS infrastructure for the Project, which captures and stores a material amount of CO₂ (1.5 Mtpa). This approach is essential to minimising the funding requirement from Government and therefore reducing the burden on the tax-payer and energy consumers. As demonstrated in Sections 4.3.3 and 7.1, the analysis in this study suggests that the L-M Cluster area currently represents the lowest cost location for CCS in the UK.

As mentioned above, CCS infrastructure, once in place, will be used for emissions reduction relating to heat in several sectors (domestic, commercial and industrial) and also potentially for decarbonising electricity and transport, where hydrogen transport is adopted. It is therefore recommended that BEIS, the Oil and Gas Authority (OGA) and HM Treasury engage with Cadent and with other stakeholders in this project and other key projects (for example, H21) to develop the market model and regulatory framework necessary to facilitate such critical, enabling decarbonisation infrastructure.

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\(^{136}\) In January 2017, Wood Mackenzie estimated that the total decommissioning cost for North Sea oil and gas fields to be £24 billion with £17 billion of this investment required over the next five years. See https://www.ft.com/content/9b1d17d0-d425-11e6-b06b-680c49b4b4c0
7.3 Summary of Cost and Funding Analysis

In respect of the indicative costs of the proposed project, the analysis undertaken above suggests that:

- Based on the reference data available, the Capex for the project would be of the order of £0.6 Billion. This compares with £2.1 Billion associated with the H21 project for an equivalent level of decarbonisation (1.5MtCO$_2$/annum). The difference largely relates to the need to replace hundreds of thousands of household and commercial boilers in the H21 project and also the need for hydrogen storage in underground salt caverns;

- The Opex for the project would be of the order of £57 M/annum. This compares with £139 M/annum associated with the H21 project. Again, the difference in costs largely relates to the lack of need (in this project) for any underground storage of hydrogen in salt caverns;

- The CoA of the project is around £90/tCO$_2$. Sensitivity testing of the impacts of variations to five key gives a range of £70-131/tCO$_2$. This can be compared with the H21 project, whereby (using what appears to be a similar methodology) the costs are presented as £292/tCO$_2$; and

- Compared with alternative forms of low carbon generation, such as offshore wind, nuclear and heat pumps, the proposed L-M Hydrogen Cluster represents the most cost-effective means of abating CO$_2$. At the same time, the H21 project has demonstrated that conversion of the gas network to 100% hydrogen is preferable in abatement cost terms to installing air source heat pumps at all domestic and commercial properties.

Ultimately, the analysis suggests that investment in the proposed Cluster would represent a low cost, no regrets project that could function as a catalyst for further gas network decarbonisation at a lower cost than alternative means of carbon abatement.

In respect of funding the investment risk in low carbon hydrogen production and supply should be isolated from the investment risk in CCS infrastructure. The two market models, whilst separate, are interdependent and should be developed in parallel. In summary, therefore, the analysis in this study suggests that:

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http://www.northerngasnetworks.co.uk/document/h21-leeds-city-gate/
The Project should be funded under the RIIO price control mechanism\textsuperscript{138}

Considering the issues relevant to development and execution of the Project and drawing upon evidence published by the Committee on Climate Change (CCC), there is potential for funding of the complete hydrogen network under RIIO.\textsuperscript{139} The integrated nature of the hydrogen and CCS elements of the Project, its potential significance in terms of decarbonisation and its ground-breaking, FOAK nature suggest that it may also be appropriate for CCS expenditure to be included within the RIIO mechanism (at least for this first project). Ofgem is scheduled to launch a consultation on the scope and arrangements for the next RIIO charging period in December 2018, to be finalised in December 2020. This will determine network cost allowances, revenues, and incentives for the period 2021-28. The next three years of engagement with Ofgem and the wider Gas Distribution Networks (GDNs) will therefore be critical;

The funding requirement from Government for CO$_2$ transport and storage can be reduced via transfer of decommissioning costs

Consistent with a report from the Parliamentary Advisory Group headed by Lord Oxburgh, the research undertaken for this study suggests that CO$_2$ transport and storage infrastructure should be considered separately from the plant incorporating CO$_2$ capture.\textsuperscript{140} This will separate the development, construction and operational risks associated with the onshore and offshore parts of the Project. There is no clear business case for private sector investment in pure CO$_2$ storage, whilst there is also a need for Government to underwrite certain CCS-specific risks. Consequently, in view of the fact that CCS is also a ‘social’, non-competitive service for which costs can be socialised, Government participation is needed to support deployment. The potential for Government to transfer its 50\% share of decommissioning costs at Liverpool Bay to fund CO$_2$ storage could be an important lever in this respect. The Department for Business, Energy and Industrial Strategy (BEIS) must therefore engage with the Oil and Gas Authority (OGA) and HM Treasury to develop a suitable investment model, which allows FID to be secured within the timeline for decommissioning at Liverpool Bay.

To inform the wider timeline to facilitate project delivery in Section 8.2, we have provided analysis of related market and regulatory risks for both the hydrogen and CCS networks in Section 8.1.

\textsuperscript{138} RIIO is Ofgem’s performance based model for setting gas distribution network companies' price controls (Revenue = Incentives + Innovation + Outputs). See https://www.ofgem.gov.uk/network-regulation-riio-model


8.0 PROJECT RISKS AND TIMELINE

8.1 Summary of Project Risks
As described in Sections 5.0 and 6.0 with regard to technical risks, and in Section 7.2 in respect of market and regulatory risks, there are a range of uncertainties to overcome during the development phase before a Final Investment Decision (FID) could be made on the proposed L-M Cluster Project. These risks can broadly be categorised into four areas and are summarised as follows:

1) Technical risks relating to hydrogen production and supply
   a. Design of the hydrogen production system to enable delivery of sufficient energy to both selected industrial sites and a blend to the network without the need for geological storage of hydrogen;
   b. Determination the maximum, permissible level of hydrogen which can be injected into the gas network gas, informed by the results of the HyDeploy blend test programme;
   c. The need to subsequently perform a related demonstration test of this maximum permissible level of hydrogen in the public gas distribution network to confirm regulatory arrangements and public acceptance;
   d. The design and demonstration of suitable blending units to safely deliver a hydrogen blend to the distribution network and to supply a high hydrogen/natural gas mixture to selected dual-fuelled industrial sites; and
   e. Demonstration of the maximum level of hydrogen for safe operation of what will be ‘dual-fuelled’ (natural gas and hydrogen) furnaces, kilns, ovens, boilers, CHP plants at industrial sites, without any impact on site performance.

2) Technical risks relating to CO₂ transport and storage
   a. Design of a suitable system to transport CO₂ from the hydrogen production complex (and any other CO₂ capture locations included in the project configuration; for example, at CF Fertilisers’ ammonia production site) to the existing gas pipeline connection at Connah’s Quay;
   b. Repurposing of the existing pipelines, which currently transport natural gas from Liverpool Bay fields to Point of Ayr and then Connah’s Quay, for reverse flow of CO₂; and
   c. The need to undertake the studies needed to secure a CO₂ storage licence from Government (assuming this function is repatriated from the EU).
3) Risks relating to the Low Carbon Hydrogen Market Framework

a. In the absence of a market for low carbon hydrogen against which investment can be justified, a support mechanism must be designed. A straightforward option is for the complete system to be funded within the rate base of the GDNs, socialising these costs across all gas users within the GDN area or possibly within the wider UK;

b. There is a need to move quickly. The next Ofgem review (under the RIIO mechanism) to define allowable spend by GDNs in the period 2021 – 2029, commences at the end of 2018 and all related decisions will likely need to be made by 2020;

c. In the absence of full funding within via the GDN rate base, a suitable alternative mechanism will need to be defined and put in place by Government within a similar timeframe; and

d. For the proposed L-M Hydrogen Cluster Project, this timing is critical in respect of the potential to gain low cost access to critical CO₂ transport and storage infrastructure prior to finalisation of alternative plans for decommissioning.

4) Key Risks relating to the CCS Market and Regulatory Framework

a. HMG must decide to support CCS, evaluate support options, select a preferred option and if necessary pass the necessary legislation before making support available to qualifying projects. This will inevitably take several years but ought to be possible within the next Parliament provided an early start is made;

b. It is relevant to note the interaction between Government support for CCS and its liability for hydrocarbon field decommissioning, in that the latter has the potential to ‘reduce’ the costs of the former. However, to be effective, the timing of a FID for the complete project must be undertaken well in advance of the final time at which cost-effective decommissioning of the gas fields can take place. In the case of Hamilton, this is around 2023. Hence this sets the timescale for approval of a field Decommissioning Plan by the OGA which involves repurposing the field as a CO₂ store; and

c. Approval must be gained to store CO₂ as required under the EU CCS Directive, or any legislation subsequent to the UK leaving the EU.
8.2 Potential Timeline to Facilitate Project Delivery

An indicative timeline for the L-M Hydrogen Cluster Project is set out in Figure 8.1. Alongside the high-level phases of project development, a number of wider policy and activities, which sit along the critical path to development, have also been included. The key considerations to note in respect of Figure 8.1 can be summarised as follows:

- **The Project Definition** phase commenced in late 2016, focusing on the conceptual design of the project along with stakeholder engagement, with the first core output being this study. Under the Network Innovation Allowance (NIA), Funding has been agreed for the next phase of Project Definition to April 2018, the key aims of which, in summary, are to:
  - Identify limits, then design and specify trials of hydrogen in a real industrial context, including potentially those on commercially operating furnaces/kilns, boilers and CHP plant;
  - Agree heads of terms with industry ‘hosts’ for these commercial-scale trials;
  - Identify a suitable location in the L-M Cluster area as a candidate for a test of a hydrogen blend in the public network (at a level informed by the HyDeploy test programme which will be integrated into this project);
  - Design the network demonstration test, including hydrogen supply, test programme, regulatory approvals and stakeholder management;
  - Identify suitable network injection points, blending equipment and monitoring and undertake related network modelling (informed by the urban centre modelling for the H21 project);
  - Determine appropriate hydrogen production technology and arrangements to meet industry plus network blend requirement;
  - Work alongside ENI, the operator of the Liverpool Bay oil and gas fields, to develop optimum CO₂ transport and storage arrangements, recognising requirement to minimise costs for initial project but benefits of storage complex being capable of expansion; and
  - Undertake business case development and financial assessment of preferred network conversion Project and identify options for funding of full Project including network, industrial and CCS elements.

- The Project Definition will be ‘frozen’ prior to undertaking the full Project **FEED studies**. These will be started when it is clear that it is likely regulatory support from Government and Ofgem will be forthcoming. The programme below assumes that these run from early 2020 for 18 months:
  - The FEED studies will need to include all hydrogen production, pipeline transport (hydrogen and CO₂) and CO₂ storage elements.

- **Consenting and Licensing** processes will essentially run from early 2019:
  - Planning consent will be required not only for the onshore hydrogen and CO₂ pipelines, but also for the hydrogen production complex;
  - Furthermore, environmental permits for each element of this infrastructure will also be needed; and
  - A CO₂ storage license will also need to be obtained.

- As discussed in Section 7.2.1, there must be positive engagement in the **RIIO-GD2 price control review**:
  - This will potentially enable the costs of hydrogen production and supply infrastructure to be socialised across gas consumers;
As discussed in Section 7.2.2, a suitable CO₂ storage financing structure must be developed:

- This requires engagement between ENI, BEIS and the OGA (and wider stakeholders) that allows Government and the operator to avoid or at least defer their respective shares of offshore oil and gas decommissioning liabilities;

- This must be agreed in advance of FID. Cessation of production of gas from the Liverpool Bay fields is estimated to be in 2023, but the decision to decommission will be made earlier;

Whilst challenging, it appears possible that it might be possible to achieve FID within the current Parliament (before June 2022) if it runs its full term, provided:

- Early attention is given by Government to the development and enactment of arrangements for CO₂ transport and storage funding; and

- There is a successful outcome from the RIIO-GD2 price control review to allow costs to be socialised within GDNs.

Figure 8.1: Indicative Timeline for Project Development

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<tr>
<td>PROJECT DEFINITION</td>
<td>HYDEPLOY (BLEND TEST IN PRIVATE NETWORK)</td>
<td>PUBLIC NETWORK BLEND TEST</td>
<td>SMR COMPLEX CONSENTING</td>
<td>PIPELINE CONSENTING</td>
<td>CO₂ STORAGE LICENSING</td>
<td>PROJECT FEED STUDIES</td>
<td>FINAL INVESTMENT DECISION</td>
<td>CONSTRUCTION</td>
</tr>
<tr>
<td>LOCAL AND NATIONAL STAKEHOLDER ENGAGEMENT PROGRAMME</td>
<td>DEVELOPMENT OF CO₂ STORAGE FUNDING MECHANISM</td>
<td>RIIO-GD2 PRICE CONTROL REVIEW</td>
<td>ESTIMATED CESSION OF PRODUCTION FROM GAS FIELDS</td>
<td>RIIO-GD2 PERIOD (TO 2018)</td>
<td>GENERAL ELECTION</td>
<td>GENERAL ELECTION</td>
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