Aberdeen Vision Project

Final Report May 2020

Project partners & supporting companies:

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The Aberdeen Vision Project could deliver CO_2 savings of 1.5MtCO_2/y compared with natural gas

A dedicated pipeline from St Fergus to Aberdeen would enable the phased transfer of the Aberdeen regional gas distribution system to 20% then 100% hydrogen.

The study has demonstrated that 2% hydrogen can be injected into the National Transmission System (NTS) at St Fergus and its distribution through the system into the gas distribution network.

Due to unique regional attributes, the Aberdeen region could lead the UK in the conversion to large scale clean hydrogen.

A 200MW hydrogen generation plant is planned to suit 2% blend into the NTS followed by a build out to supply the Aberdeen gas networks and to enable low cost hydrogen transport applications.

Delivering a net zero greenhouse gas (GHG) target of 2050 for the UK (adopted into legislation in June 2019) and 2045 for Scotland (adopted into legislation in September 2019), as proposed by the Committee on Climate Change (Net Zero, May 2019), requires widespread application of hydrogen and the use of Carbon Capture and Storage (CCS). Scotland has an opportunity to lead, due to its resources and geography, which will help it meet a net zero GHG target date of 2045. Development of a hydrogen economy is required to service demands for some industrial processes, for road, rail and ship transport and for heating, whilst creating new economic value and jobs. Early development of clean hydrogen to enable this transition and develop appropriate experience and systems is essential.

In the short term, development of low carbon hydrogen generation at scale is likely to primarily come from reformation of fossil fuels with CCS. Once operational, the Aberdeen Vision project will provide an opportunity to enable hydrogen generation from renewables by providing a transmission network that could provide an export route for the hydrogen generated.

The North East (NE) of Scotland is uniquely suited to the early development of clean hydrogen. An assessment of locations in the UK suggests that NE Scotland is an ideal location, due to a combination of factors including; access to large volumes of gas coming onshore, an existing industrial site with sufficient space for new plant, access to CO_2 storage via an early CCS project, existing hydrogen activity in Aberdeen and along the East Coast, potential for blending and then conversion into the Aberdeen gas distribution network and the strong supply chain in the region.

A new hydrogen pipeline built between St Fergus and Aberdeen could supply the Aberdeen region gas distribution system and enable a phased transition to hydrogen, first blending up to 20% by volume and then 100% conversion. Blending to 20% is believed to be possible with no change for domestic appliances, this view is supported by early indications of the trial being conducted as part of Cadent's HyDeploy project (Cadent, 2019).

All industrial and commercial consumers that would be impacted by the conversion of Aberdeen were identified, some of which may require further assessment to confirm they can receive a 20% blend of hydrogen. Blending to 20% then conversion to 100% hydrogen could be arranged on a regional basis, with hydrogen injection via the Kinknockie, Craibstone and City Gate nodes to convert Aberdeen in a phased manner. Conversion of the gas distribution for Peterhead could precede Aberdeen as a smaller scale project closer to St Fergus, which is easily isolated.

Network analysis of the Aberdeen region has been performed suggesting that the conversion of Aberdeen to 100% hydrogen is possible as long as the reinforcement required is incorporated into current plans to carry out works on the pipelines.

The work conducted for the Aberdeen Vision Project has not identified any critical obstacles which would prevent the injection of 2% hydrogen into the National Transmission System (NTS) at St Fergus and its distribution through the system into the gas distribution network.

The Acorn Hydrogen project, a potential hydrogen supply for Aberdeen Vision, is currently in development and targeting a 200MW Autothermal Reformer (ATR) to suit a 2% by volume blend of hydrogen into the NTS. Seasonal variations are anticipated to be managed through turndown.

Conversion of Aberdeen regional gas distribution system should progress from 2% via the NTS, to 20% hydrogen and then 100% conversion via a new dedicated pipeline. 100% hydrogen conversion for the region's gas distribution would require 3 further ATR units each at approximately 200 MW of generation capacity with an availability of 84%. The St Fergus gas processing terminals themselves could potentially be converted to operate on low carbon hydrogen instead of natural gas, which would reduce the emissions of one of Scotland's largest emissions locations.

Hydrogen supply to Aberdeen could act as a catalyst for new hydrogen transport opportunities and growth in low carbon road transport.

The Aberdeen Vision provides an opportunity to begin to decarbonise industrial and domestic gas users, an area of the UK energy mix that has historically been more difficult to convert to low carbon technologies. The hydrogen demands identified in this report would result in 1.5 million tonnes of CO_2 emission savings in comparison to using natural gas, summarised in Figure 1-1.

The cost of generating low carbon hydrogen has been evaluated as, £41.85/MWh for hydrogen with CCS, compared to £19.08/MWh for natural gas, and although roughly double the price of natural gas, hydrogen is competitive with electricity at £47.68/MWh. What is not currently captured in the current natural gas price is the cost of carbon being emitted. With the UK government commitment to net zero by 2050 it is likely that a carbon pricing mechanism (ETS or carbon tax) will be used to drive down emissions by increasing the cost of carbon in order to increase the cost of unabated fossil fuels.

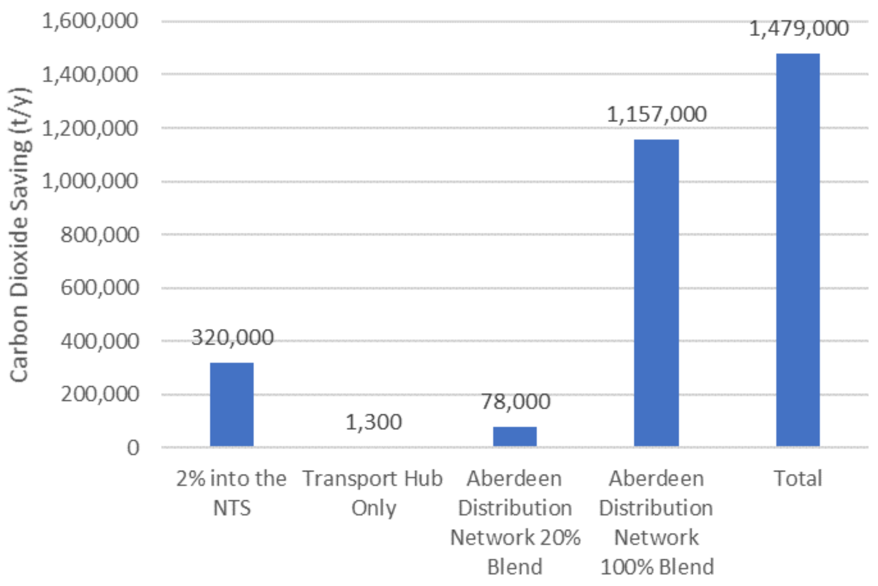

Figure 1-1: Emissions Saving Potential of the Hydrogen Demands Analysed in the Aberdeen Vision Project

To progress the Aberdeen Vision beyond this feasibility study will require Front End Engineering and Design (FEED) studies to be completed. One of the key areas to progress is the detailed design, mapping, environmental studies and consent planning for the hydrogen pipeline to Aberdeen.

The next phase of work should look to confirm the injection location at St Fergus. Six options have been considered, all of which have advantages and disadvantages. Further work should look to evaluate these options and find a compromise between cost, potential effects on process equipment and changing operational flexibility. Further network analysis focussed on the impact of increases in velocity and the extent of reinforcement required should be evaluated to enable planning for works to be carried out in time for the construction of a hydrogen pipeline between St Fergus and Aberdeen. Additionally, the potential pipeline route and build out should be evaluated in more detail to inform the connection strategy into the Aberdeen network, i.e. should the pipeline reduce in diameter between Craibstone and City Gate or would a larger diameter add value by enabling injection at additional locations on the network.

Once an initial hydrogen generation plant is operational there are additional potential hydrogen demands in the North East of Scotland. These additional demands range from supplying hydrogen into the St Fergus gas terminal itself, hydrogen power generation at the Peterhead Power Station and potential to supply hydrogen into the distilling sector. Once completed the local transmission infrastructure will provide an opportunity to stimulate additional hydrogen production from a number of potential sources such as renewable powered electrolysis and hydrogen from bioenergy with CCS. If successful, the Aberdeen Vision project could help to support the development of a decarbonised gas transmission system.

One of the key barriers is currently the Gas Safety (Management) Regulations (GS(M)R) which limits the hydrogen content of gas in the NTS to 0.1mol%. Efforts are currently underway by the Gas Quality Working Group to move the gas specification from Schedule 3 of the GS(M)R into an Institute of Gas Engineers and Managers (IGEM) standard.

2.0 Introduction

2.1 Background

The Scottish and UK Governments have both set a target to reach net zero emissions by 2045 for Scotland and 2050 for the UK, as recommended by the Committee on Climate Change. Net zero means that any emissions to the atmosphere would need to be balanced by the removal of an equivalent amount of emissions or by being prevented from entering the atmosphere, by planting trees or using CCS as examples. The UK's 2050 target is ambitious and will require the use of a wide range of decarbonisation technologies.

The majority of UK emissions come from industry, power, heat and transport, with the scale of energy consumption illustrated in Figure 2-1. The power sector has seen a reduction in emissions due to movement away from coal fired generation to natural gas and the development of low-cost renewables such as wind and solar. However, the heat and transport sectors have received much less attention from decarbonisation efforts to date and provide a greater challenge to meeting the net zero target.

Hydrogen provides the potential to support widespread decarbonisation of the UKs heat demand, through the blending or replacement of natural gas. In addition, it is likely to have an important role in industrial decarbonisation, transport and power. About 50% of the UKs energy demand is for heat and this has proven the most difficult area to decarbonise to date. The Aberdeen Vision Project is seeking to enable the use of hydrogen for heat and other applications.

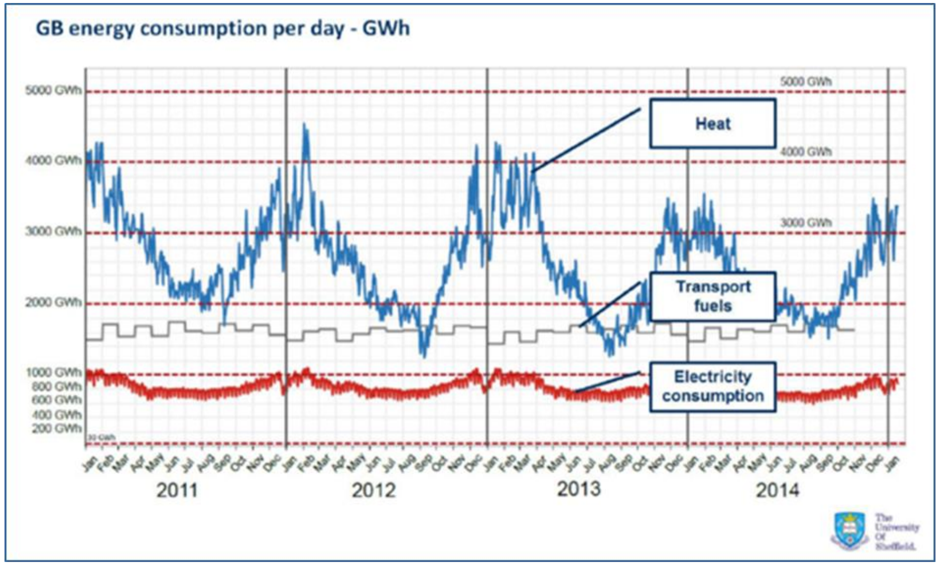

Figure 2-1: UK Energy Consumption

The Aberdeen Vision Project is designed to build upon and progress a phased transition to enable a managed implementation of the energy system towards hydrogen, Figure 2-2. It builds upon other hydrogen transformation projects (H21, HyNet, H100) and links with other SGN decarbonisation projects (Cavendish, Methilltoune). The focus for the Aberdeen Vision project is the transport and use of hydrogen produced from reformed natural gas from St Fergus in North East Scotland.

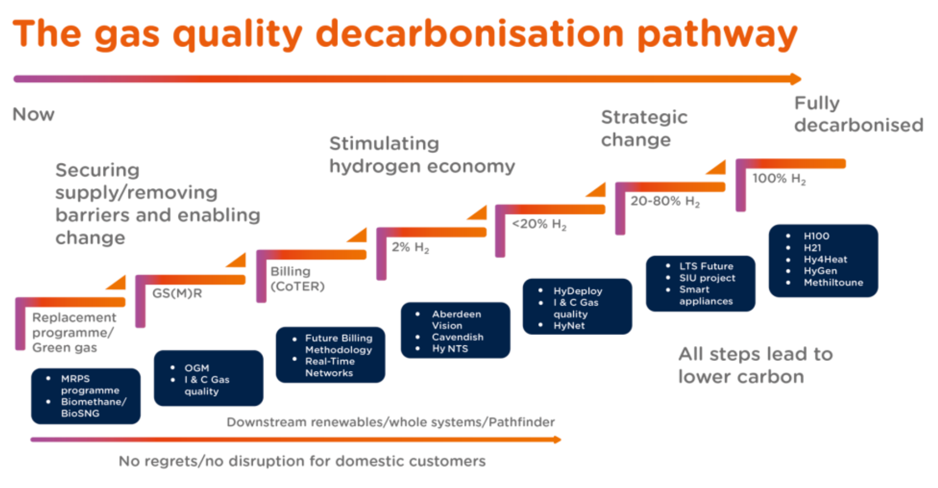

Figure 2-2: The Gas Quality Decarbonisation Pathway (Courtesy SGN)

The Aberdeen Vision Project offers synergies with Acorn Hydrogen by providing an export route for produced hydrogen through the transmission and distribution of hydrogen for heat. Acorn Hydrogen is based upon hydrogen production from an advanced autothermal reformation (ATR) technology located at the St Fergus Gas Terminal, Figure 2-3, with associated CO_2 capture, transport and storage through Acorn CCS.

The Aberdeen Vision Project offers an opportunity to reduce the carbon intensity of gas supplied to consumers. The Project takes a phased approach to initially build acceptance of hydrogen as a fuel before progressing to achieve greater decarbonisation by transitioning towards a hydrogen economy.

The Aberdeen Vision Project is a collaborative project between SGN, National Grid, DNV GL and Pale Blue Dot Energy (PBDE), assessing the potential for hydrogen export and hydrogen applications based around hydrogen production from the Acorn Hydrogen Project at St Fergus gas terminal in Aberdeenshire, North East Scotland.

Figure 2-3: Approximate Boundaries of the Four Terminals at St Fergus

2.2 Project Objectives

The objectives of the Aberdeen Vision Project are to assess the feasibility of the ability to deliver 2% hydrogen via the NTS by injection at St Fergus, to assess regional applications for 100% hydrogen and to assess how a large-scale hydrogen transition could be deployed for the Aberdeen Region.

Specifically, this work aims to provide:

- An outline of the Acorn Hydrogen project, which is looking to produce hydrogen from natural gas with carbon capture and storage located at the gas processing terminal at St Fergus. Including technology description, cost outline, hydrogen production growth and hydrogen storage capacity requirements. The Acorn Hydrogen project will provide a supply of hydrogen to the Aberdeen Vision project and CO_2 to the Acorn CCS project.
- An outline of the consenting and safety aspects of building a hydrogen production facility at St Fergus.
- An assessment of the injection process and impact of 2% hydrogen upon the NTS, based upon injection at the St Fergus gas terminal, including an assessment of injection options and the viability and challenges of transporting 2% hydrogen in the NTS.
- An assessment of the impact of 2% hydrogen upon the gas distribution network, based upon transfer from the NTS or direct injection of 2% hydrogen into the distribution network.
- A proposed approach to quantify emissions associated with the production of hydrogen by various means and its transport to point of use.
- Development of a qualitative screening approach to define the optimal location to build clean hydrogen production facilities, considering various factors.
- A conceptual design for a pipeline to transport hydrogen from St Fergus to Aberdeen.
- Network analysis to determine the effects of hydrogen on the existing Aberdeen gas networks.
- A preliminary outline for the phased conversion of the Aberdeen region gas distribution system to hydrogen including steps at 20% and 100%.
- A public summary report providing a very high-level summary of the work undertaken, for parties with limited background in the topic (Appendix 12.1).
- An assessment of near- and longer-term demand for hydrogen in the Aberdeen Region, to enable effective planning of hydrogen facilities, transportation of hydrogen and hydrogen storage facilities.
- Preparation of this final report.

2.3 Acknowledgements

The authors of this report would like to thank and acknowledge the following for their input into the project and this final report:

- SGN, National Grid and Ofgem for providing NIA funding to carry out the project.
- SGN for carrying out the network modelling and analysis of the distribution network.

- DNV GL for carrying out work on the NTS and GDN assets as well as the high level design for a new 100% hydrogen pipeline. DNV GL also carried out a peer review on the final report.

3.0 Basic Concept of Aberdeen Vision Project

3.1 Overview

The Aberdeen Vision Project, depicted in Figure 3-1 and Figure 3-2, aims to provide new market opportunities for hydrogen. The St Fergus gas terminal, 40 miles north of Aberdeen, is a key strategic National Grid asset. The terminal provides an entry point for gas being produced in the North Sea basin providing more than one third of the UK's total gas demand. The location offers an ideal opportunity to develop hydrogen blending in the NTS and gas distribution network.

Blending hydrogen with natural gas offers an opportunity to utilise the existing gas transmission infrastructure to begin to deliver a lower carbon fuel mix. Over time the hydrogen content could be increased to provide a greater level of decarbonisation and ultimately use the existing infrastructure to deliver hydrogen to consumers.

Decarbonising the gas transmission infrastructure through the introduction of hydrogen by blending could be considered an analogue to what has happened in recent years to electricity distribution through the rise of renewable power generation. In both cases the carbon emissions associated with the energy delivered will reduce over time as more hydrogen production or renewable generation is developed.

The Aberdeen Vision project focuses on the transmission of hydrogen supplied by the Acorn Hydrogen project with CO_2 being captured and sequestered as part of the Acorn CCS project.

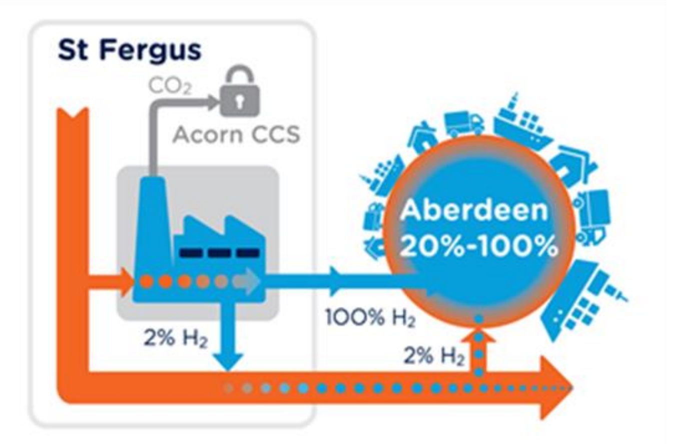

Figure 3-1: Aberdeen Vision Project Overview

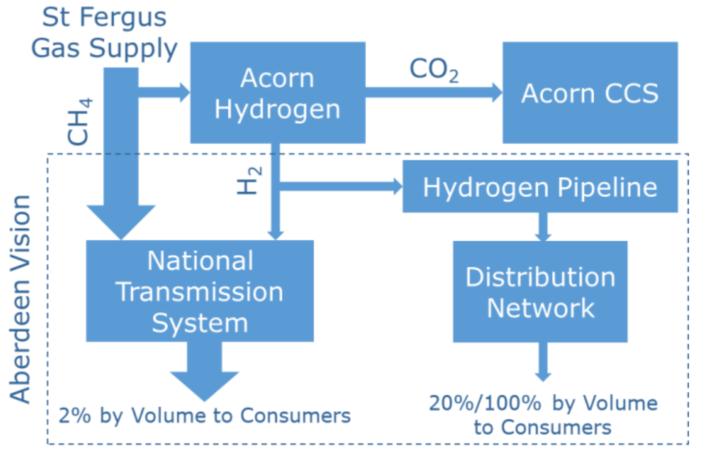

Figure 3-2: Interaction Between Aberdeen Vision and Acorn Projects

3.2 2% Hydrogen in the NTS

The Aberdeen Vision Project is intending to blend low concentrations, 2% by volume, of hydrogen into the gas leaving St Fergus. The blended gas is then transported using the existing NTS, which delivers gas both directly to customers such as power generators and offtakes serving the lower pressure distribution networks. The distribution networks will then supply blended gas to smaller industrial as well as domestic customers. The blended gas would be transported and used in the same way as natural gas is currently, users who are highly sensitive to gas specification may require additional conditioning prior to use. Although 2% may be perceived as a small percentage, due to the large volume of natural gas leaving St Fergus, it would capture 400,000 tonnes of CO_2 per year from the energy system – a carbon saving of 320,000 tonnes of CO_2 per year compared to natural gas.

3.3 20% Hydrogen in Aberdeen Distribution Network

An additional decarbonisation opportunity is to deliver a 20% by volume blend of hydrogen into the distribution network in Aberdeen. A new hydrogen pipeline would enable early decarbonisation of the distribution network independent of developments in the NTS with respect to increasing volumes of hydrogen injection. The new pipeline could connect into strategic locations around the Aberdeen distribution network and provide the opportunity to blend up to 20% hydrogen by volume into the natural gas supply at these locations. All domestic and most commercial appliances, such as boilers and gas cookers, will continue to operate safely without any modification. Some specialised industrial or commercial applications that are highly sensitive to gas composition may need to adjust their gas facilities, to receive hydrogen with one combined heat and power plant in the Aberdeen area that might be affected, further work would be required to determine whether there will be an impact to the plant and if so identify mitigating actions that can be taken. A hydrogen pipeline would also provide the opportunity to provide a supply of hydrogen for both existing and new transport refuelling locations. Converting Aberdeen to run on a 20% by volume blend of hydrogen would capture 100,000 tonnes of CO_2 per year – a carbon saving of 78,000 tonnes of CO_2 per year compared to natural gas.

3.4 100% Hydrogen in the Aberdeen Distribution Network

The low-pressure network could ultimately transition to operate on 100% hydrogen. This would mean entirely replacing natural gas with hydrogen for all the region’s heating and other uses. This conversion would require the phased transition of the distribution network by area from natural gas to hydrogen. Such a conversion to hydrogen would mean that where the network is operating purely on hydrogen, it would need to be isolated from the natural gas system. Converting the Aberdeen distribution network to hydrogen would capture 1,500,000 tonnes of CO_2 per year – a carbon saving of 1,200,000 tonnes CO_2 per year compared to natural gas. Converting Aberdeen to operate on hydrogen would remove roughly 10% of Scotland’s total CO_2 emissions.

3.5 Supporting Projects

The Aberdeen Vision Project requires a source of hydrogen production to achieve the ambition of decarbonising the gas network infrastructure. The Acorn Hydrogen Project, Figure 3-3, will enable the Aberdeen Vision Project through the construction of a 200MW hydrogen production facility at St Fergus. This first reformation plant would produce enough hydrogen for the initial phase of blending 2% hydrogen by volume into the NTS. Figure 3-4 shows the St Fergus gas terminal and how the two projects could fit in with existing infrastructure.

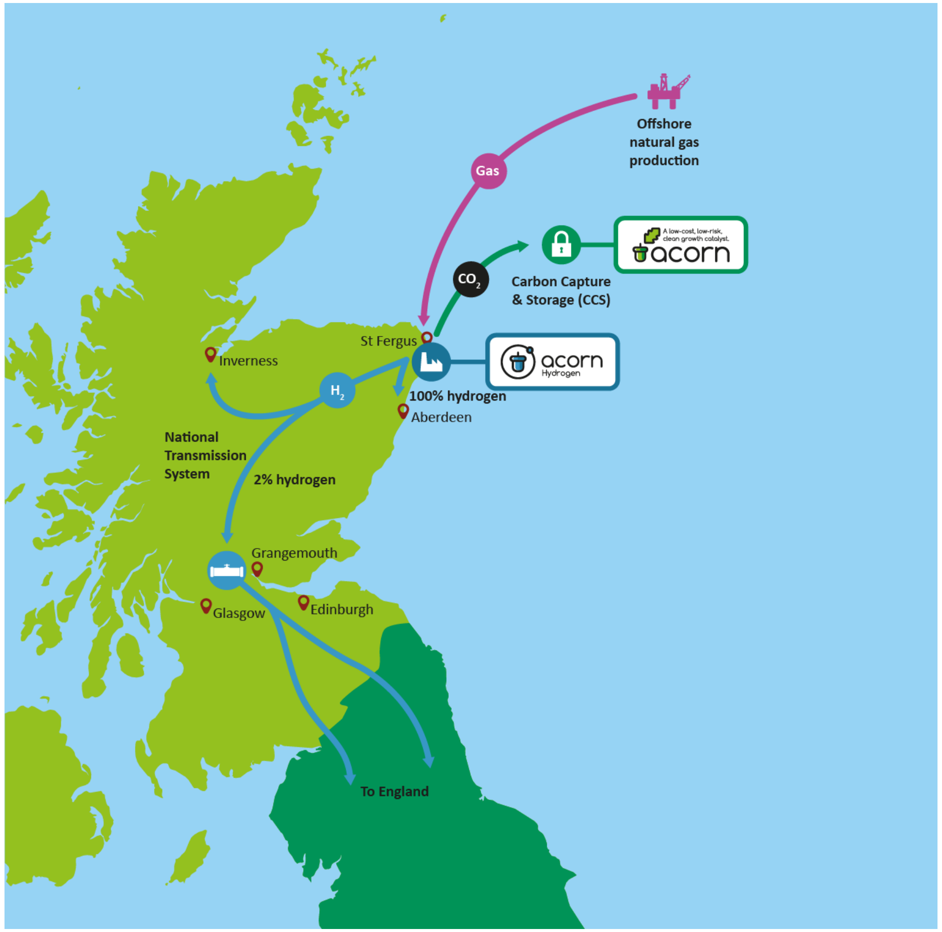

Figure 3-3: Overview of the Acorn Hydrogen Project

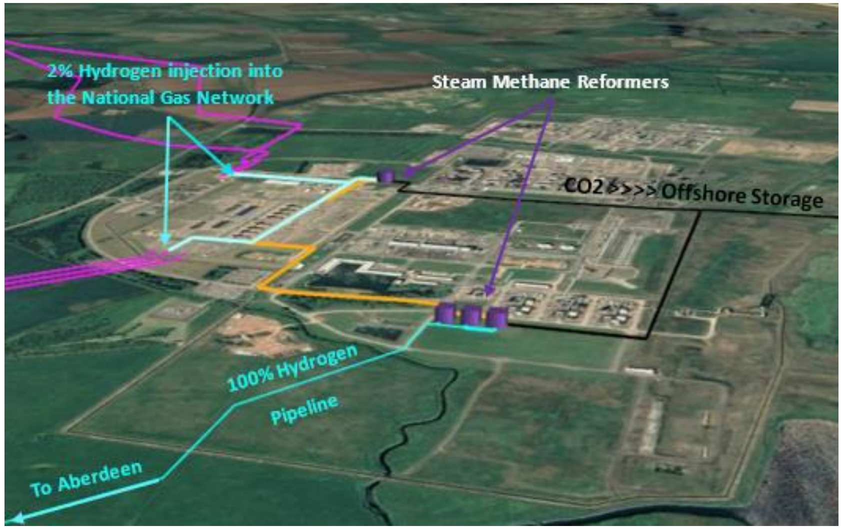

Figure 3-4: Pictorial Representation of Hydrogen Injection Infrastructure at St Fergus (Reformation plant not to scale)

For hydrogen produced by reformation of natural gas to be considered low carbon, the CO_2 emitted needs carbon capture and storage (CCS), where the captured CO_2 is safely sequestered deep underground. The Acorn CCS project, illustrated in Figure 3-5, will support both the Acorn Hydrogen and the Aberdeen Vision projects by providing a CCS service co-located at the St Fergus gas terminal.

The ability to blend hydrogen into the NTS and Local Transmission System (LTS) gas transmission systems will also be supported by learnings from other hydrogen projects that are being carried out across Great Britain. The results from each of these projects creates an evidence base to make the case for blending and subsequent conversion to 100% hydrogen gas networks.

A more detailed list of hydrogen projects along with a short description is included in Section 8.0 Table 8-1.

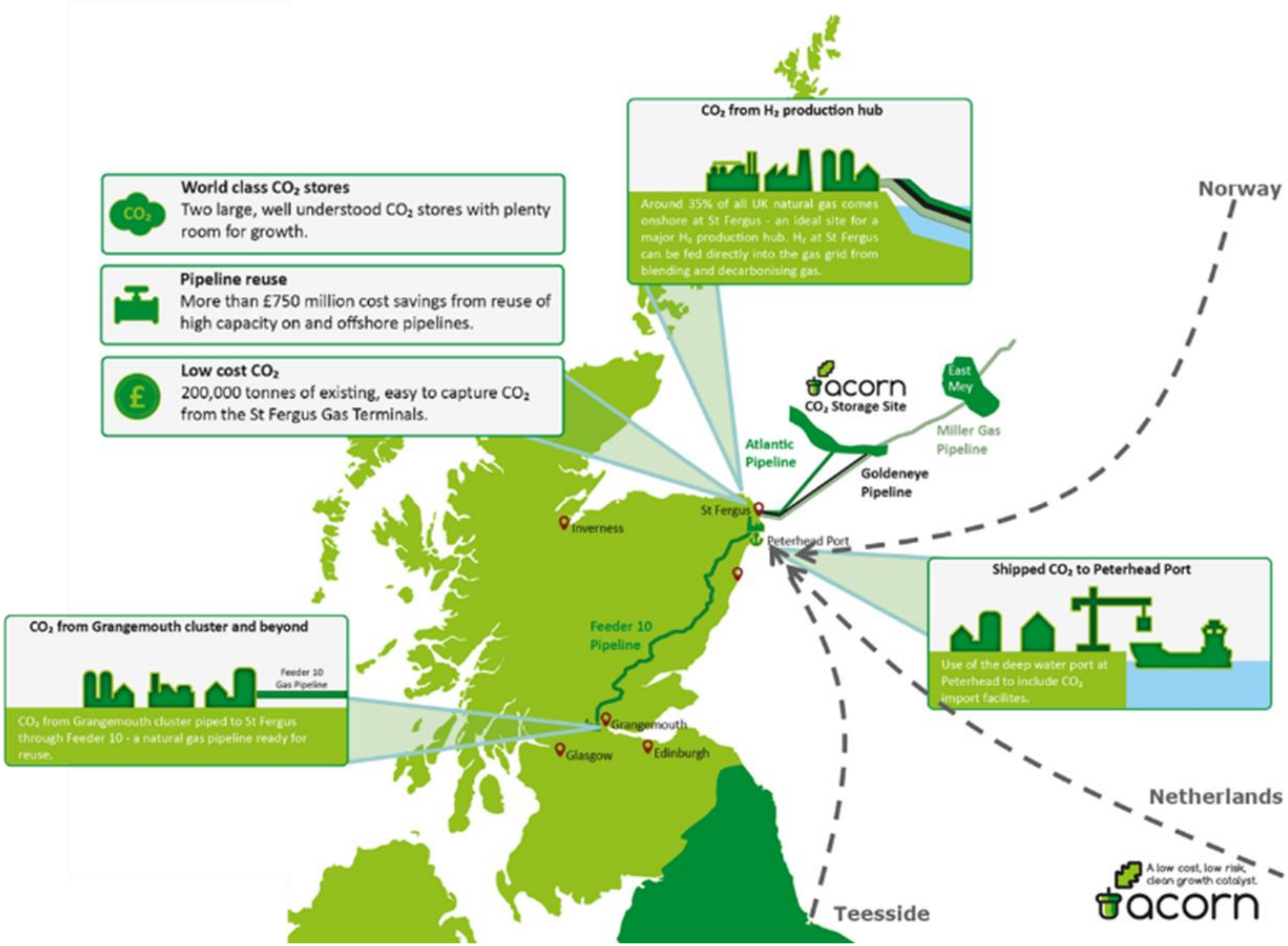

Figure 3-5: Overview of the Acorn CCS Project

4.0 Hydrogen Challenges

The key purpose of this section is to present and explain some of the technical issues identified by the project, previous research and other related projects. Investigation and resolution of these issues will result in an evidence base that can be used to support development of hydrogen systems. Section 8.0 discusses where this project has resolved some of the impacts and challenges and provides information on other projects that will help to provide the evidence base to support a transition to hydrogen. Any gaps that can still be identified are areas of further work that will need to be resolved.

The use of hydrogen presents challenges to the way the gas network is operated. The existing system has been designed to operate on North Sea gas and this is reflected in the gas quality specification, materials, design of transmission assets, legislation and commercial frameworks.

4.1 Legislation

4.1.1 Gas Safety (Management) Regulations

The quality of natural gas delivered to gas consumers is defined by the limits set in Schedule 3 of the Gas Safety (Management) Regulations, more commonly known as GS(M)R. Hydrogen content in natural gas is currently limited to 0.1 mol% for historical, rather than safety, reasons.

The GS(M)R ensure that all gas supplied to consumers are interchangeable, and that established standards of appliance performance and safety can be maintained without the need to adjust appliances. The interchangeability diagram depicts the acceptable range of gases based on a calculation that approximates the gas composition to methane, propane and nitrogen (HSE, 2007). SGN's Opening up the Gas Market (OGM) project (SGN, 2016) looked at the current limits, which are designed for North Sea gas, with respect to new gas sources entering the market (biogas, LNG etc.) and makes a recommendation to increase the range of acceptable gas, depicted in Figure 4-1.

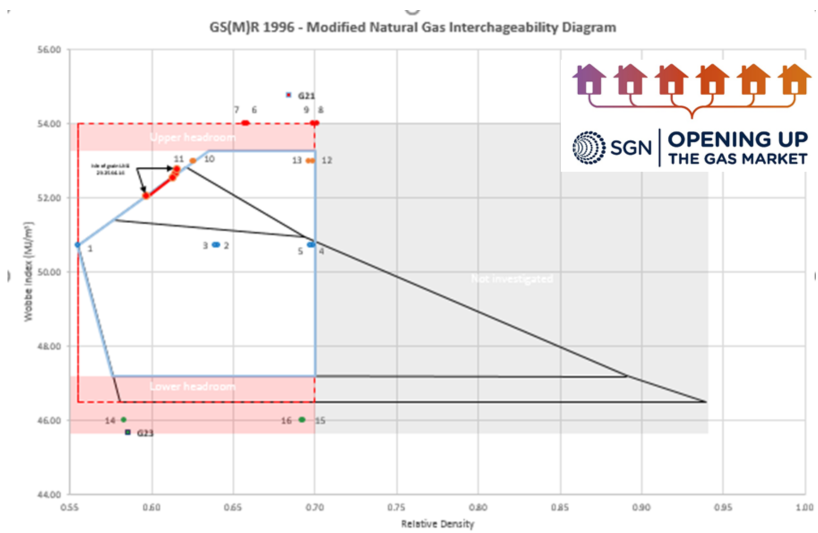

Figure 4-1: Gas Interchangeability Diagram

The GS(M)R specify the range of Wobbe Index (WI), oxygen, hydrogen and sulphur content and that there must be no liquids (water or hydrocarbon) or impurities that could impact on the network or gas appliances. An envelope of safe operation is defined together with emergency limits should there be a supply emergency. The GS(M)R are currently defined in statute and changes need to be approved by the UK Parliament.

Linked to removing barriers and enabling change in SGN's decarbonisation pathway the Institute of Gas Engineers and Managers (IGEM) Gas Quality Working Group was formed in June 2016 (IGEM , 2016). The Gas Quality Working Group was initially set up to look at the gas quality specification and investigate the impact of widening the tolerance on the network, industrial and commercial processes and appliances. Initial work focussed on looking at the WI of the gas and is detailed in SGN's Opening up the Market Report (SGN, 2016). One of the recommendations was to move the gas quality specification into an IGEM standard that will create a framework for further change via periodic review of the standard to enable alternative gas supplies to enter the network.

The Gas Quality Working Group membership comprises informed experts on gas quality across the wider gas industry with appropriate levels of engagement from different sectors. There is representation from all the gas networks (National Grid, SGN, Cadent Gas, Wales and West Utilities and Northern Gas Networks), LNG terminals, trade bodies such as HHIC, Energy UK, ICOM, Oil and Gas UK, expert gas industry consultants such as Dave Lander Consulting, Kiwa Gastec and DNV GL and UK Government with members from the Health and Safety Executive (HSE) and the UK Department for Business, Energy and Industrial Strategy (BEIS).

The Gas Quality Working Group is investigating changes to GS(M)R to increase security of supply of natural gas and, later, to enable increased levels of hydrogen. The Group is considering the evidence for widening the allowable range of WI and, at an appropriate stage, developing the framework to increase the hydrogen content.

A draft gas quality standard is currently out for consultation. This draft aims to:

- Extend the range of WI to increase security of supply.
- Simplify the interchangeable gas range by using limits on WI and relative density.
- Move Schedule 3 of GS(M)R from statute to IGEM governance to enable the gas industry to be more flexible, but no less safe, as it moves towards deeper decarbonisation.

Once comments on the draft standard have been received and considered for inclusion, the case for change will be sent to the HSE. If the HSE approves the case for change, the document will be submitted to Parliament. If approved by Parliament, Schedule 3 of GS(M)R will become an IGEM standard.

Once the gas quality specification becomes an IGEM standard, it will be possible to make further changes to the hydrogen content limit based on evidence and stakeholder engagement. The first step is likely to be 2% hydrogen by volume blended with natural gas which will support the aims of this project. As further evidence is presented the standard will evolve and may include a sectionalised approach based on the different pressure regimes that exist within the entire gas network.

4.1.2 Ofgem Direction for Measurement Equipment

Measurement equipment that relates to the Gas (Calculation of Thermal energy) Regulations is "CV-Directed" (Ofgem, 2008). Offtakes from the NTS to gas distribution networks are all under Ofgem direction. This means that measurement equipment and software require Ofgem approval. Currently none of the equipment is approved for hydrogen above the GS(M)R limit of 0.1 mol% and hydrogen is not one of the components included in the gas analysis system at the offtakes.

If 2% hydrogen by volume were present in gas leaving the NTS, then the gas analysers would need to be able to detect and measure hydrogen. Gas analysis systems need to be approved by Ofgem to comply with the Gas Cost of Thermal Energy Regulations (GCoTER). Most Ofgem approved analysis systems are gas chromatographs that use helium as the carrier gas, which is not conducive to the measurement of hydrogen. There is a potential to be able to use different carrier gases or alternative technology to measure hydrogen once they have been approved for use by Ofgem.

4.2 Commercial

Gas entry and offtakes to the NTS are governed by Network Entry Agreements (NEA) and Network Exit Agreements (NExA). Current NEAs and NExAs are based on a GS(M)R gas entering the network with additional limitations for some additional gas properties (e.g. dew point may be specified to comply with the requirement that there are no liquids present). These form a basis of the commercial arrangements between National Grid, gas producers, gas distribution networks and downstream gas users.

NEAs may need to be modified such that the WI of gas entering the network would not result in a WI less than 47.2 MJ/m^3 when blended with hydrogen. Addition of 2% hydrogen will reduce the WI by 0.5%, which means that natural gas must usually have a WI of 47.4 MJ/m^3 to be accepted at St Fergus. In addition, an increased lower WI limit could be proposed for two reasons:

1. To provide a margin of safety in the case of control failure leading to increased hydrogen injection at low gas flow rates.
2. To provide the potential to increase the percentage of hydrogen without negotiating new NEAs at a later date.

However, for St Fergus, this may not be an issue as the WI of natural gas coming onshore tends to be high enough that blending hydrogen at 2% by volume would not reduce the WI below the current lower limit.

Depending on the hydrogen injection location at St Fergus, there may need to be modifications to the gas acceptance arrangements, especially options whereby hydrogen injection is not at outgoing feeders. In these instances, there will need to be greater coordination between National Grid and the terminal operators to ensure that the resulting natural gas blend leaving St Fergus is 2% hydrogen by volume.

In a similar vein, NExAs will also need to be modified to take into consideration the potential range of gas quality and the range of hydrogen content. Due to the way in which the network is operated and how gas travels through it, once hydrogen is introduced into the network it should be assumed that hydrogen could be present anywhere within the network. Therefore, all NExAs would need to be modified and all end users would need to be consulted regarding potential for receiving 2% hydrogen by volume. A zone of influence approach may be considered to update NEAs based on the likelihood of 2mol% hydrogen being present at any location in the NTS.

End-users directly connected to the NTS and the NTS compressor fleet currently require a stable gas quality in terms of hydrogen content. Changing hydrogen content would change the CV of any fuel gas and would change the compression curve of any compressor. Prior to receiving a hydrogen blend equipment would need to be recertified by the original equipment manufacturer (OEM) to ensure that warranties are not voided. End users will be reluctant or will refuse to operate their equipment outside of OEM warranty as this will put them at risk of commercial loss. One option is to consider deblending technology to remove hydrogen from a blended natural gas supply.

Gas quality measurements at NTS offtakes are owned and operated by the gas distribution networks (GDNs) and the measurement equipment is approved by Ofgem. Currently, hydrogen is not one of the components covered by the Ofgem direction. Measurement equipment at GDNs will need to be replaced or upgraded and reapproved to be able to measure hydrogen. Customers are billed using these measurements under the flow weighted average calorific value (FWACV) billing regime.

4.3 Technical

4.3.1 Pipeline Capacity

One of the main issues that the use of hydrogen presents is the reduction in energy density compared to methane. To achieve the same energy content a larger volume of hydrogen is required which would have a knock-on impact on the capacity of the gas networks. The volume increase is not a linear relationship with increasing hydrogen content.

The relationship between hydrogen inclusion as a percentage of the total volume and the increase in volume of the overall gas is shown in Figure 4-2 for a gas blend at standard temperature and pressure (IUPAC definition: 1bar and 0°C). At these conditions, you would need roughly two and a half times the volume of pure hydrogen to supply the same amount of energy as natural gas.

Introduction of a hydrogen blend into the existing gas network will act to reduce the energy capacity of the pipelines. Since a larger volume of gas is required to supply the same energy demand, there are three mechanisms by which the equivalent energy can be transported:

1. The pressure in the pipeline can be increased to keep the volume and velocity of the gas consistent with existing pipelines.
2. The velocity of the gas in the pipeline can be increased to keep the pressure of the gas consistent with existing pipelines while increasing the volumetric throughput of the system.
3. The pressure and velocity of the gas can be kept within existing design parameters by installing larger diameter pipelines and increasing the volume.

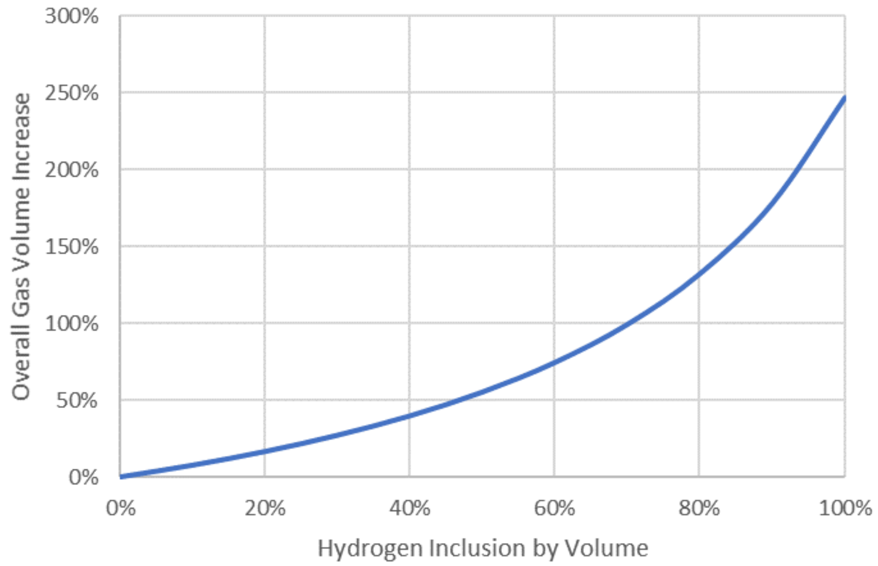

Figure 4-2: Increase in Gas Volume at Constant Energy Content at Standard Conditions (IUPAC definition: 1bar and 0°C)

For transport within existing pipelines, only options 1 and 2 above can be considered. Certain parts of the network will have some inherent flexibility / a degree of spare capacity to increase the pressure making option 1 the first consideration. Current network velocity limitations are 40 m/s for filtered gas, recent initial research into the effects of increasing the velocity in networks has identified that further tests are required where there may be an option to modify these limits (Northern Gas Networks, 2016) (SGN; Steer Energy, 2019).

The injection of hydrogen will result in an overall reduction in capacity as the maximum operating limits of the pipeline will be reached more quickly. The key limits are the maximum operating pressure of the pipeline and the maximum allowable velocity of the gas due to erosion concerns. In cases where option 3 applies there is an opportunity to be including hydrogen injection plans in current network reinforcement planning.

In practice, hydrogen can be blended into the existing networks up until the operating limits (allowing a margin for safe operation). Beyond this point, small sections of the network would require reinforcement to provide additional capacity. This provides an option to begin a phased conversion towards hydrogen distribution without having to rebuild the entire network.

For the Aberdeen Vision project a new transmission pipeline would be constructed to avoid the challenges of using hydrogen in the existing pipelines. The risk of hydrogen embrittlement is more pronounced in higher strength carbon steel pipelines at higher pressures, such as in the NTS or the highest pressure pipeline in the LTS, and, in combination with the pressure cycling associated with operating the network, there is evidence that hydrogen reduces fatigue life. However, there is evidence to suggest that the addition of oxygen into the gas stream can combat the effects of hydrogen embrittlement, the addition of oxygen is still being investigated by the network operators. A new pipeline provides the opportunity to resolve any capacity issues without the need to reinforce existing NTS or LTS pipelines as the hydrogen can be transported to the point of use/injection directly. The new pipeline can later be connected into existing LTS networks travelling west of Aberdeen to further extend the hydrogen network. Use of a new pipeline operating on 100% hydrogen also provides the flexibility to supply varying blends to different applications as well as providing a hydrogen that could be used for transport applications rather than the supply of a single blend from the NTS.

To enable more rapid decarbonisation, independent of the allowable hydrogen content in gas supplied to the NTS, a new hydrogen pipeline to Aberdeen presents a significant opportunity. Allowing 2% hydrogen to be injected into the NTS is anticipated to be much more straightforward than moving towards significantly higher concentrations due to a greater requirement for confidence in material performance in a hydrogen environment and the sensitivity of users connected directly to the NTS to gas quality at high volumes. A new hydrogen pipeline makes it possible to supply the distribution network in parallel to providing 2% hydrogen into the NTS. Due to the lower strength steels and prevalence of polyethylene pipework in the distribution network the distribution network could build an evidence base to support injection of higher hydrogen blends much sooner than the NTS and potentially be converted to run on 100% hydrogen. If a new pipeline is not used and the NTS is limited to 2% hydrogen then the distribution network offtake at St Fergus could potentially be used to transport hydrogen south, however to supply enough hydrogen for the city of Aberdeen there would need to be a significant amount of reinforcement and uprating of the network. Alternatively, hydrogen could be transported by road using tube trailers to injection points on the distribution network, but this would require a significant number of road movements to supply enough hydrogen in a 100% Aberdeen scenario. Construction of a new hydrogen pipeline to feed

Aberdeen City is the most feasible option for rapid decarbonisation of the North East of Scotland.

4.3.2 Storage

The reduction in energy density will reduce the amount of energy that can be stored within the cumulative volume of all the pipelines in the system, known as linepack. The reduced energy density will also impact natural gas storage facilities that are used to manage interseasonal demand.

As any 100% hydrogen network would need to be completely isolated from the existing NTS and local transmission system (LTS) linepack and storage facilities, these hydrogen networks will require their own storage solutions. Although a new hydrogen pipeline will include an element of linepack, to meet demand variations, large scale hydrogen storage facilities will also be required.

The University of Edinburgh has recently begun researching the potential for storage of hydrogen in the HyStorPor project (Edinburgh University, 2019), with SGN as a project partner. The HyStorPor project will seek to progress the potential for hydrogen storage in porous media and provide evidence to, expanding current storage options from salt caverns, and provide evidence to allow commercial trials to be carried out.

4.3.3 Operational Flexibility

The production of natural gas is variable and dependent on the operation of upstream assets. Aside from the technical reasons for variations in supply of natural gas due to shutdowns for example, there are also commercial reasons for adjusting production rates based on the gas price and cost of extraction. The impact of these influencing factors is a variable supply of natural gas coming on shore at St Fergus. The supply of gas is managed though storage within the linepack available in the NTS itself and inter-seasonal storage in salt caverns, aquifers and depleted gas fields.

On the demand side, there is also a large degree of daily, as well as seasonal, variation. Linepack in the NTS and LTS is currently used to help manage these daily variations. For the large inter seasonal variations additional, much larger, volumes of gas storage are required.

A hydrogen generation project needs to match the variable supply and demand for energy, illustrated by the difference in profiles in Figure 4-3 (the gap between the supply at St Fergus and the Scottish demand just indicates that gas moves south from Scotland into England). Careful management of the hydrogen generation plant will be required as a result of the differences in the energy supply and demand profiles. Where the changes are not able to be managed with operation flexibility, due to turn down limits or the speed at which the plant can ramp up/down, there will be a requirement for buffer storage that can manage periods of over and under supply, instead of plant operation trying to match the instantaneous demand.

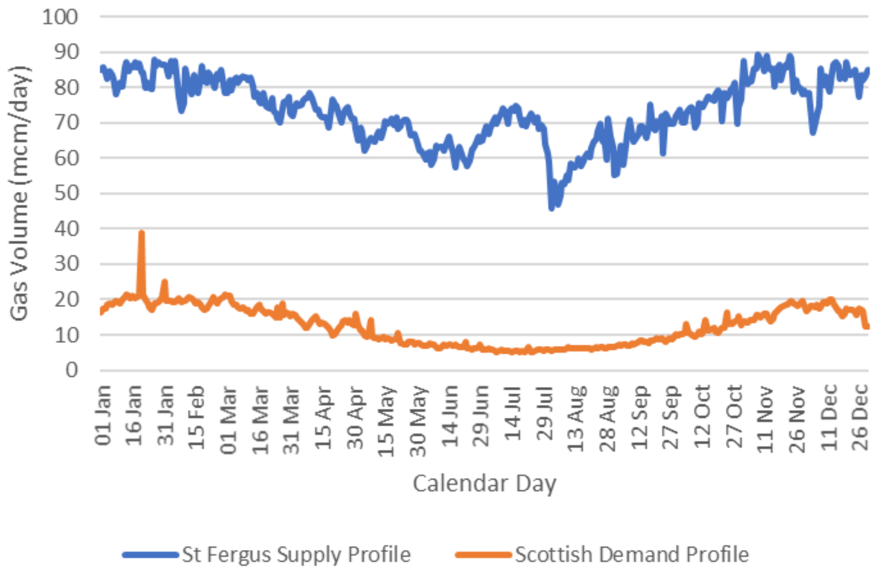

Figure 4-3: Differences in Profile Between Supply from St Fergus and Scottish Gas Demand

4.4 Materials

4.4.1 National Transmission System

There are a number of metal degradation processes which can occur in hydrogen environments. The type of attack resulting in degradation will depend on factors such as:

- Presence of other components such as water, sulphur and oxygen
- Material
- Operating temperature and pressure
- Concentration of hydrogen and exposure time of hydrogen
- Physical and mechanical properties
- Stress state
- Surface conditions
- Nature of any crack front in the material
- Microstructure

As these factors can interact, it is difficult to assign quantifiable ranges/impacts for the combined effects on the particular system.

The main mechanisms of concern with gas pipelines are hydrogen embrittlement and loss of mechanical properties. The tensile properties, elongation to failure, and fracture properties, fatigue crack growth rate, are particularly affected by hydrogen embrittlement. There are several ongoing projects that are investigating the effects of hydrogen on materials such as National Grid's HyNTS project, Cadent's HyNet project and SGN's Future of LTS project.

For embrittlement to occur, hydrogen molecules must first dissociate into atoms before they can diffuse into the metallic structure. At close to ambient temperatures, a number of metallic materials are susceptible to hydrogen embrittlement, particularly those with a body-centred cubic lattice structure. This is a particular problem with many ferritic steels subjected to mechanical stresses. Embrittlement takes place on freshly exposed metallic surfaces from surface defects or other faults as a result of stress-induced local plastic deformation processes. The material can become 'brittle' under load or stress. In general terms, the higher the strength of the steel the greater the susceptibility to hydrogen embrittlement.

The effect of hydrogen on a material can influence its yield strength, ductility, fracture toughness and fatigue behaviour. Carbon steels (San Marchi &

Somerday, 2012) such as A106 Grade B, X42 to X80 are attractive for use in pipeline materials due to their ability to be formed and welded. However, hydrogen gas can degrade the tensile ductility of carbon steel. Hydrogen can lower fracture toughness and certain metallurgical conditions can make steel susceptible to crack extension under static loading.

Hydrogen can accelerate fatigue crack growth even at low hydrogen partial pressures. Severity depends on a number of variables including hydrogen pressure, loading rate, cycle frequency and presence of welds. Limiting the magnitude and frequency of cyclic stresses can improve compatibility of carbon steels with hydrogen. Cyclic stresses are a result of operating and managing pressure within the NTS. Cyclic stresses will be site specific and dependent on location e.g. near compressor stations. In general, the LTS operates at lower stresses than the NTS.

A review of experimental data (Lee, 2016) for effects of gaseous Hydrogen Environment Embrittlement (HEE) was undertaken for several types of metallic materials. Based on materials screening test results, a qualitative HEE index rating for steels tested at 24°C under high hydrogen pressure was devised. Pipeline steel X100 had a HEE index rating of severe and steels X52, X42 a high index rating. Controlling hydrogen factors to reduce HEE effects were discussed in the review including hydrogen pressure, gas purity, welding procedures, reducing internal and applied stresses. Experimental studies have shown that embrittlement by gaseous hydrogen can be effectively inhibited by the addition of certain gas species such as O_2, CO, N_2O and SO_2. As little as 100 ppmv of oxygen mixed with 7 MPa hydrogen could effectively eliminate the hydrogen embrittlement effects on the fatigue crack growth of X42 pipeline steel as shown in Figure 4-4 (Adams, 2005). Similar results have also been demonstrated for gaseous inhibitors such as CO and SO_2. Caution should be shown as H_2S did not halt the hydrogen embrittlement effects from pure hydrogen gas. H_2S could accelerate hydrogen embrittlement more than pure hydrogen.

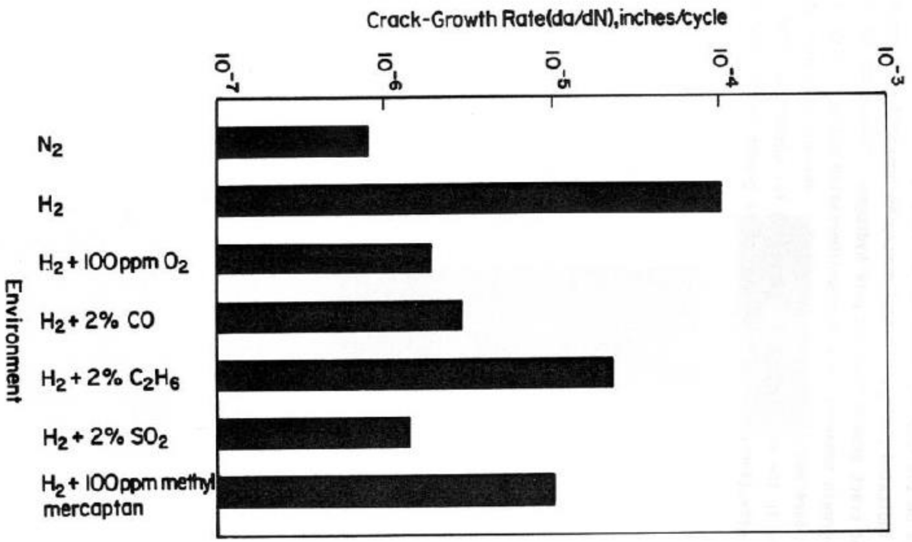

Figure 4-4 Impact of Hydrogen Gas Purity on Fatigue Crack Growth Rates for X42

Hydrogen cracking and embrittlement relies on hydrogen entering the steel and thus surface-active species such as oxygen are known to inhibit hydrogen uptake and thus embrittlement. The theory is that the oxygen forms surface oxide barriers and occupies surface sites prone to hydrogen uptake. This has been demonstrated in laboratory studies using hydrogen and oxygen mixtures. However, the addition of oxygen is not currently used to prevent embrittlement of operational hydrogen pipelines. The GS(M)R limit for oxygen is currently 0.2mol% or 2,000ppm making the addition of oxygen a viable method of reducing the impacts of hydrogen embrittlement.

ISO /TR 15916:2004 provides guidance for the application of materials in hydrogen service. This technical report was intended to assist with the objective of promoting the safe use of hydrogen as a fuel. One aim was providing key information to regulators however the guidance states that "*the degree to which these guidelines are applied will vary according to the specifics of the application*" and thus local regulators would need to decide whether the guidance is applicable for a particular case.

Table 4-1 contains a summary of the suitability of a selection of materials for hydrogen service. Transmission pipelines are generally constructed of carbon steel. The specific grade, such as Grade B, X42, X70, will depend on the strength and other properties required. Other materials such as cast iron, stainless and martensitic steels are present in various components including instrumentation.

Recent studies with hydrogen/natural gas mixtures indicate a deterioration of some mechanical properties of pipeline materials including fracture toughness and fatigue resistance (GERG, 2013). The results are very dependent on various factors including hydrogen pressure, strain rate applied during laboratory tests and the presence of impurities such as oxygen. The effect on mechanical properties is very dependent on whether hydrogen can enter the steel. Cathodically charging samples will allow atomic hydrogen to enter the steel and modify mechanical properties such as ductility and fracture toughness. Gaseous hydrogen, with a larger hydrogen molecule compared to a hydrogen atom, is less able to enter the steel structure and affect the mechanical properties. Therefore, it is important to take account of the experimental details to understand the impact on the steel mechanical properties.

Material	Gaseous Hydrogen Service	Liquid Hydrogen Service	Remarks
Aluminium and its alloys	Suitable	Suitable	Negligibly susceptible to hydrogen embrittlement
Copper and its alloys	Suitable	Suitable	Negligibly susceptible to hydrogen embrittlement
Iron, cast, grey, ductile	Not Suitable	Not Suitable	Not permitted by relevant codes and standards
Nickel and its alloys	Evaluation required	Evaluation required	Susceptible to hydrogen embrittlement
Steel, austenitic steel with >7% nickel (such as 304, 304L, 308, 316, 321, 347)	Suitable	Suitable	May make martensitic conversion if stressed above yield point at low temperature
Steel, carbon (such as 1020 and 1042)	Evaluation required	Not suitable	Susceptible to hydrogen embrittlement. Too brittle for cryogenic service.
Steel, low alloy (such as 4140)	Evaluation required	Not suitable	Susceptible to hydrogen embrittlement
Steel, martensitic stainless (such 410 and 440C)	Evaluation required	Evaluation required	Susceptible to hydrogen embrittlement. Too brittle for cryogenic service.
Steel, nickel (such as 2.25%, 3.5%, 5% and 9% Ni)	Evaluation required	Not suitable	Ductility lost at liquid hydrogen temperature

Table 4-1: Suitability of Selected Materials for Hydrogen Service at NTS Pressure

4.4.2 Distribution Network

A wide variety of materials are found in the distribution network and downstream in domestic meter installations and appliances:

- Distribution pipeline (e.g. pipe material, joint, seals)
- Regulators (e.g. diaphragms, spindles, coatings)
- Meters (e.g. internal components, coatings, seals)
- Domestic appliances (e.g. seals, valves, coatings)

The principal pipeline materials are medium and high-density polyethylene (PE), cast and ductile iron and steel (Figure 4-5). There is also a limited amount of asbestos and polyvinyl pipeline materials present.

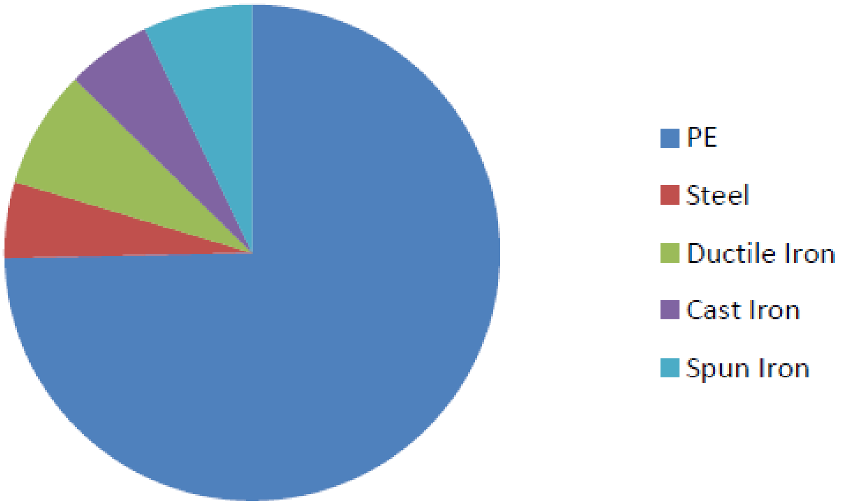

Figure 4-5: Pipeline Materials Present as % of Total Pipe Length in Low Pressure Gas Distribution Network

Other materials present include:

- Elastomers such as nitrile rubber (NBR) used in O-ring seals, diaphragms etc.
- Polyoxymethylene (POM) plastic, found in meter and regulator components
- Nylon used in reinforcement in some meter diaphragms
- Epoxy coatings used for the corrosion protection of meter and regulator components etc.
- Jute (cellulose fibres) found in lead-yarn jointed cast iron gas distribution

4.4.2.1 Polyethylene (PE) Pipe Systems

Over 60% of the UK gas distribution network is now constructed from PE pipe, and a significant proportion of this was installed by insertion into an existing iron main. There are number of advantages of PE for distribution pipelines including low cost, flexibility, corrosion and good chemical resistance, and relative ease of joining.

The National Renewable Energy Laboratory (NREL) (Melania, Antonia, & Penev, 2013) stated that little interaction between hydrogen and PE is expected in terms of changes to the material.

Studies (Melania, Antonia, & Penev, 2013) found that the permeation coefficient of hydrogen through thermoplastic pipe used in US gas networks is approximately five times that of natural gas. Permeation rates for PE 100 pipes measured by KIWA Gastec (Nitschke-Kowsky & Wessing, 2012) for pure hydrogen was found to be 4.6 times higher than pure methane. The permeation rate of natural gas is considered to be very low in magnitude, and this was not considered a concern.

Foulc et al (Foulc, et al., 2006) reported on experiments to determine the permeability of common PE types to hydrogen and methane mixtures. The work found that each gas component retained its individual permeation characteristics regardless of the gas mix proportions (up to 20% hydrogen). The report stated there was no clear correlation with pressure (which ranged from 5-20 bar in the tests). The tests found that the activation energy required to initiate permeation of hydrogen through PE was ca. 2/3rds that of methane, consistent with the relatively greater ease for permeation of hydrogen compared to methane. In addition, as may be expected, hydrogen was found to diffuse more rapidly through the polymer structure, but a lower proportion was retained within the structure compared to methane. There was an indication that the pipe manufacturing process may have an influence on the diffusion process: the report, by Foulc et al, indicated that pipe diameter was a function, however this may be inferring the wall thickness, which would be more likely.

PE joint irregularities tend to result from defective jointing procedures on site, the common faults being contamination of the weld surfaces, poor temperature control (creating brittle regions) and poor alignment of the weld faces. From investigations of many PE joint failures, the leakage path is considerably larger than the molecular/microscopic scale, dwarfing any difference in molecular size, and it is considered that similar levels of leakage would occur whether hydrogen was present in the gas stream or not.

Under the HyDeploy project, the Health and Safety Laboratory (HSL) investigated the potential for deterioration of bond weld quality during electrofusion jointing and potential for loss of flexibility/elasticity affecting squeeze off techniques or seal/repair integrity of PE 80 pipe. Initial (DNV GL, 2018) results found that PE80 pipe responded well with respect to squeeze-off and electrofusion after exposure to a 20% hydrogen/natural gas mixture.

Further studies are being undertaken; SGN's H100 project is looking at leakage permeation of PE materials and joints; the H21 project is investigating leakage from metallic and PE materials retained from previous asset life/degradation evaluations used on the network since the 1960's to the present day. The H100 project also carried out further testing on PE80 pipe and fittings and concluded that there was no degradation or change to the materials.

4.4.2.2 Seals and Other Components

Many components on the gas distribution network (e.g. iron pipes, valves) will include sealing gaskets, which may be made from synthetic elastomers such as nitrile rubber (NBR), ethylene propylene diene monomer (EPDM), fluoro rubber (FKM, e.g. Viton) in newer valves or natural rubber in older components. Other polymers include polychlorotrifluoroethylene (PCTFE) polytetrafluoroethylene (PTFE), polyvinylidene fluoride (PVDF) and PE (ASME, 2014).

Rubber and plastic seals have a long history of use in hydrogen service. Most of the elastomeric materials are compatible with hydrogen. It should be noted that hydrogen can diffuse through these materials more easily than through metals.

The performance of these may be affected by contaminants in the gas stream, leading to reductions in elasticity, or other forms of degradation which may compromise the sealing effect and result in leakage. In general, the concentration of the contaminant is a key factor governing the effect on the elastomer, and pressure may also have an effect. Studies (Melania, Antonia, & Penev, 2013) have found that natural rubber and Buna S are less able to seal against hydrogen than NBR.

Data exist for permeation of hydrogen through elastomers (for examples, see Table 4-2), which is 10-20 times that of PE for the common types. There is no comparable data for permeation of methane through these seals to act as a benchmark. In addition to any greater permeation of hydrogen through the elastomer material itself, there would also be scope for greater leakage through the interface between the seal and the surface it was compressed against (typically steel or iron), due to the physical surface roughness. Leakage via this mode would again be expected to be greater (similar in magnitude to that through mechanical joints on the iron network, i.e. ca. 3 times greater).

An investigation was completed by the H100 project to further evaluate permeation through elastomeric seals.

Table 4-3 shows the suitability of elastomers for use in a hydrogen environment.

Kiwa, as part of the GERG's HIPS project (GERG, 2013) performed a review of in-house installation materials from upstream of the gas meter to the inlet connection of the gas appliance as part of the admissible concentration of hydrogen in natural gas networks (ASME, 2014). The materials reviewed included steel, copper, brass, aluminium, rubber, polyethylene, polyoxymethylene (POM), polyamide nylon (PA) and multilayer systems. Copper is a key material in in-house installations (can be up to 95% of infrastructure) and it is suitable for hydrogen service according to ISO/TR 15916:2004 (ISO, 2004).

Kiwa concluded that metals such as steel, stainless steel, brass, copper and aluminium should not be affected by mixtures of up 20% hydrogen/80% natural gas according to the reference standards. Domestic natural gas systems operate at low pressures usually in the range of 18mbar to 30mbar and permeability is very low. The sensitivity of hydrogen embrittlement is only queried for low alloy steel. At this pressure, it is unlikely to be an issue.

Material	Hydrogen Permeation Rate $x10^{-10}$ cm^{-3} S.T.P $mmsec^{-1}.cm^{-2}$ $(cmHg^{-1})$
Natural Rubber	492
Butyl rubber	74
Buna S	399
Perbunan G	158
Neoprene G	133
Hycar or 15	74
Polybutadiene	424
Polymethylpentadiene	428
Perbunan 18	251
Isoprene-methacryl-nitrile Copolymer	138
Hycar or 25	118
Polydimethylbutadiene	172
Vulcoprene A	64
Isoprene-acrylonitrile copolymer	74
Thiokol S	16

Table 4-2: Permeation of Hydrogen Through Elastomers at 25°C (European Industrial Gases Association (EIGA))

Non-metal	Suitability for gaseous hydrogen use
Asbestos impregnated with Teflon	Suitable (asbestos now avoided due to carcinogenic hazard)
Chloroprene rubber (neoprene)	Suitable
Polyester fibre (Dacron)	Suitable
Fluorocarbon rubber (Viton)	Evaluation needed to determine if material is suitable for service conditions
Polyester film (Mylar)	Suitable
Nitrile (Buna-N)	Suitable
Polyamide (nylon)	Suitable
Polychlorotrifluoroethylene (Kel-F)	Suitable
Polytetrafluoroethylene (Teflon)	Suitable

Table 4-3: Suitability of Materials for Hydrogen Service (ISO, 2004)

Material	Relative permeability
Rubber	- - -
PVC	-
HDPE	- -
Multilayer PEX-AL-PEX	+ +
Aluminium, Copper, iron brass	+ +

Table 4-4: Qualitative Comparison of Hydrogen with Different Materials Present in In-House Installations (GERG, 2013) (+ indicating increased relative permeability, - indicating reduced relative permeability)

Although permeation in polymers is higher than in metals, the permeation is still low especially at these pressures for most polymers. Kiwa did identify knowledge gaps in the literature with regards to effect of hydrogen and permeability of POM and PA, hydrogen permeation of ethylene vinyl alcohol copolymer (EVOH) layer in multilayer pipes and leakage with polytetrafluoroethylene (PTFE) connections.

NaturalHy (NATURALHY, 2010) performed a limited number of tightness tests on materials used in gas installation in houses. Static bending tests and subsequent leakage tests were performed using various hydrogen mixtures across nine steel and polymer connections. From the nine steel and polymers specimens tested, a rubber hose was the only item which failed the tightness tests.

The same study also concluded that there were no “show stoppers” with domestic gas meters with a polymeric membrane and they could reliably meter 50% volume hydrogen in natural gas.

4.5 Impact on End Users

The Industrial and Commercial Gas Quality Report, undertaken by DNV GL (DNV GL, 2018), carried out a study of the impact of changing GS(M)R for industrial and commercial consumers. The evidence gathered indicates that an initial level of 2 mol% is possible:

- The German standard for compressed natural gas (CNG) as a transport fuel (DIN 51624) has a maximum hydrogen fraction of 2 mol% and this is also stated in ISO 11439. This relates to high pressure steel vehicle CNG tanks

- All gas carrying components in a CNG vehicle are tested to a maximum of 2 mol% hydrogen
- Euromot surveyed their membership of engine manufacturers in 2012 (EUROMOT, 2012) and they recommended a limit between 2 and 5%. With the variability in underlying natural gas composition and quality, the 2 mol% limit is an appropriate initial value
- Gas turbines may be the most sensitive combustion system and gas quality limits are contractual. The limits depend on the combustor type and set up. 2 mol% hydrogen is proposed as an entry level limit, consultation with operators around acceptable limits would be beneficial in making the case for change
- In a study undertaken by GDF Suez on a 2 MW glass furnace simulator, a small increase in efficiency was observed when 2 mol% hydrogen was added to the fuel gas

Cadent is undertaking a network innovation competition (NIC) project called HyDeploy which will supply natural gas/hydrogen blend to the gas network at Keele University. Laboratory and field tests have recently demonstrated that up to 20 mol% hydrogen has almost no impact on domestic appliance performance or safety. The HyDeploy project team has presented a quantitative risk assessment on the safety of consumers and residents of producing, distributing and using hydrogen blended gas for a trial period of one year. Based on the evidence presented, HSE has recently granted an exemption which will allow the trial to go ahead.

No evidence has been found that suggests 2 mol% hydrogen will have an adverse effect on the safety of domestic appliances.

Oxygen depletion sensors (ODS) are safety devices installed on some appliances with pilot lights, including flueless water heaters, back-boiler installations and gas fires. They are designed to respond to changes in the oxygen content in the room or flue gas and safely shut-down appliances if the oxygen concentration drops resulting in vitiation that can give rise to excessive carbon monoxide (CO) emissions.

The ODS are tested for appliance certification as they are classed as a primary safety device. The tests use the G20 reference gas and are undertaken in a vitiation room or chamber so the CO concentration can be monitored as a function of the room oxygen.

Variation in gas quality can result in increased CO emission levels. Testing, undertaken by SGN as part of the Scottish Independent Undertaking's (SIU) gas quality project (SGN, 2017), showed mixed performance, but some ODS systems did provide the required safety performance. Considering the uncertain performance of these devices the SGN ODS testing project (SGN, 2019), in collaboration with Cadent, is undertaking additional studies to evaluate the performance of a range of ODS devices under strict laboratory-controlled conditions with the aim of characterising the effect of change in gas quality. The results from this study will establish if there is a clear impact on the operation of these safety devices.

A blend of 2 mol% hydrogen is not anticipated to impact the way that these devices operate.

4.6 Security of Supply

Whether natural gas is being used to heat domestic properties, raise steam on a chemical plant or generate power, there are consequences for being unable to provide energy into a home or business. The existing natural gas grid system is backed up with storage and interconnectors that can import natural gas from international infrastructure to provide energy when UK gas supplies are lower than demand.

Where hydrogen is being blended into a natural gas stream, the security of the hydrogen supply is a minor concern with low inclusions of hydrogen as the system can fall back to using natural gas if no hydrogen is available assuming that the gas quality stays within acceptable limits to consumers. As the inclusion of hydrogen increases, security of supply will become a greater concern as the impact on gas quality will be much larger due to a large swing in the hydrogen content of the fuel gas.

In a system where hydrogen is being used as the only fuel source, extra measures will need to be taken to ensure that the hydrogen supply is resilient. A system that can consistently despatch hydrogen can be achieved through a combination of storage, to supply hydrogen at times when there is no/insufficient generation, a suitable level of redundancy and additional generation capacity in the form of extra modules of plant or processing trains to provide a backup supply. Both of these measures will increase the capital cost of a hydrogen development and a balance will need to be found between the generation capacity of the plant, level of redundancy and the storage volumes required.

4.7 Planning for Conversion

As hydrogen has a lower energy output than natural gas, some of the existing pipes within the network may have insufficient capacity to deliver the energy required. This will mean that some reinforcement of the intermediate pressure (IP), medium pressure (MP) and low pressure (LP) networks will be required, more so for conversion than hydrogen blending. Other factors would be considered as part of any current future reinforcement plan i.e. current planned replacement and reinforcement schemes plus the potential to deliver increased amounts for hydrogen transport use that can be strategically addressed as a long term conversion planning process.

As the complete conversion of the Aberdeen network to 100% hydrogen will require the complete isolation from any natural gas networks, they will also be disconnected from infrastructure previously used to provide storage and security of supply, such as higher pressure tier pipelines in the form of line pack and access to national storage sites. The new high pressure hydrogen pipeline will provide line pack storage to the new network however, additional storage to maintain security of supply and balance hydrogen production rates will need to be considered further in any 100% hydrogen system.

Conversion will require careful planning and management of both the injection points of hydrogen and where the existing network can be isolated. Depending on how the conversion is carried out, there may be a requirement for a fairly substantial hydrogen network to connect hydrogen generation sources into different points in the network, particularly in areas where the network is constrained.

There may be an opportunity to utilise the existing NTS for transmission of a hydrogen blend to consumers and use technology to separate the hydrogen from natural gas, referred to as “deblending”. Deblending provides an opportunity to maintain consumer flexibility by providing streams of natural gas, hydrogen or a specific blend of the two rather than being limited to the NTS specification. Hydrogen can be removed from a natural gas stream by utilising existing technologies such as pressure swing adsorption (PSA), cryogenic separation, membrane separation and electro-chemical separation.

5.0 Case for Decarbonisation at St Fergus

5.1 Rationale for St Fergus

St Fergus has been selected as the best location for a project to generate hydrogen from a hydrocarbon reformation process. Reformation of hydrocarbons allows for the bulk production of hydrogen at low unit costs. To demonstrably reduce carbon emissions, the carbon must be captured and permanently sequestered, regardless of where in the process, i.e. pre/post-combustion, the CO_2 is produced. In order to sequester CO_2 at scale, storage in the subsurface is required. St Fergus then provides an ideal location for hydrogen production with natural gas coming onshore from the North Sea and an abundance of potential CO_2 storage locations offshore.

Roughly 35% of the UK's current annual gas demand comes onshore at the St Fergus terminal where it is processed and compressed before entering the NTS. This provides a feedstock for the long-term input to hydrogen reformation plants. In addition, it is a significant volume that presents the opportunity to demonstrate the benefits of using hydrogen by initially blending a small amount into the existing gas grid. However, before any hydrogen blending can occur there would need to be a change to the Gas Safety (Management) Regulations (GSMR) (1996) as the current limit is less than 0.1% hydrogen on a molar basis. There is ongoing work being carried out through the Institute of Gas Engineers and Managers (IGEM) that is looking to develop a new standard that will be used to accommodate the change to hydrogen. There are also a range of demonstration projects either underway or being planned such as; HyNet, H100 and H21. These projects will initially seek to prove blending of hydrogen up to 20% by volume before proving the ability to deliver 100% hydrogen.

St Fergus is an existing industrial site, with appropriate skills and experience of managing industrial gases and suitably distant from an urban conurbation.

Figure 5-1: Key Attributes of St Fergus for Hydrogen Production

Carbon Capture and Storage (CCS) is required for the produced hydrogen to have emissions reduction benefit. The CO_2 emissions can be stored in the subsurface deep below the North Sea, which, in this area, has been extensively studied across the Acorn CCS Project (Pale Blue Dot Energy, 2018), the Peterhead CCS Project (Shell, 2016), the Caledonia Clean Energy Project (Summit Power, 2018), the Captain Clean Energy Project (CO2 Deepstore; Summit Power, 2013) and through oil and gas exploration activity. Based upon significant study work and existing oil and gas production data, the Oil and Gas Authority (OGA) has issued a CO_2 Storage Licence to Pale Blue Dot Energy for the Acorn CCS Project.

Additionally, the Acorn CCS Project plans to reuse existing oil and gas infrastructure to reduce the capital costs of transport and storage of CO_2. There are three existing pipelines from St Fergus (Atlantic, Goldeneye and the Miller Gas System (MGS)) that are no longer in use for oil and gas operations and are available for CO_2 transport. The Atlantic and Goldeneye pipelines have been the subject of significant study, as part of the Acorn CCS project and previous CCS projects, and are considered suitable for CCS.

The gas terminal at St Fergus represents an ideal location for hydrogen production for blending into the NTS, or use locally, with captured CO_2 being transported offshore for sequestration.

5.2 Hydrogen Generation Technologies

An important facet of producing hydrogen is the emissions intensity; the production route must either have inherently low emissions or the carbon must be captured for hydrogen to be a low carbon energy vector. Broadly speaking hydrogen production can be split into two primary technologies, electrolysis and hydrocarbon reformation. Within these two overarching definitions there are a variety of techniques and processes that can be used to generate hydrogen.

Reformation technologies are largely based around reacting hydrocarbons, typically methane as it is the smallest hydrocarbon molecule, to produce hydrogen and CO_2. The hydrogen is then separated out from the reaction mixture into a product stream. Reformation technologies like steam methane reformation are commercially available and have been used extensively.

Steam methane reformation can be used to create a range of chemical feedstocks such as synthesis gas, hydrogen, carbon monoxide and hydrocarbon fuels. The reformer reacts methane with steam at high temperature and pressure in the presence of a nickel catalyst. Reformation of natural gas is the most common method of producing bulk hydrogen commercially.

The first stage of the reformation reaction is the reaction between methane and steam to produce carbon monoxide and hydrogen:

$$CH_4 + H_2O \rightleftharpoons CO + 3H_2$$

This reaction is strongly endothermic, ΔH_f = 206 kJ/mol, requiring reactants to be heated. The heat is usually supplied indirectly by the combustion of natural gas. Further hydrogen can be generated by reacting the carbon monoxide in the water-gas shift reaction:

$$CO + H_2O \rightleftharpoons CO_2 + H_2$$

The water-gas shift reaction is mildly exothermic, ΔH_f = -41 kJ/mol, and increases the overall conversion efficiency of natural gas into hydrogen. A typical steam reforming process is roughly 65-75% efficient on an energy basis. Most of this energy is lost to the environment as heat.

Advantages:

- Bulk production of hydrogen
- Conventional, well understood process

Disadvantages:

- CO_2 needs to be captured from flue gas at a low concentration
- Flue gas is at atmospheric pressure

A partial oxidation (POX) reactor relies on the incomplete combustion of any hydrocarbon feedstock to produce hydrogen. The reaction is exothermic, burning hydrocarbons in a limited oxygen supply, producing hydrogen and carbon monoxide:

$$C_mH_n + \frac{m}{2}O_2 \rightleftharpoons mCO + \frac{n}{2}H_2$$

The oxygen requirement of a POX reactor is usually supplied by an air separation unit (ASU). Using an ASU to provide clean oxygen reduces the overall size of the reactor and increases the purity of the product. The carbon monoxide that is produced can be fed into a water-gas shift reactor to produce more hydrogen just like the SMR process. The energy efficiency of a POX reactor is typically around 70-80%.

Advantages:

- Flexible feedstocks
- No additional fuel gas required

Disadvantages:

- Requires ASU
- Additional reactors needed to convert carbon monoxide

Autothermal reformation (ATR) is the combination of an SMR and POX into a single reactor. The feed enters the reactor and is partially oxidised in a zone that replicates a POX process before entering a catalytic bed that behaves like an SMR process. Pure oxygen is required in the initial POX equivalent reaction zone and a catalyst is required in the SMR equivalent reaction zone. Combining the two types of reforming into a single reactor allows the heat released from the partial oxidation reaction to provide the energy for the endothermic SMR reaction. ATR reformers can achieve energy efficiencies around 80%.

Advantages:

- Commercially available technology that is well understood
- High pressure steam can be generated
- No flue gas generated

Disadvantages:

- Requires a combination of both ASU and catalyst

At present hydrogen generation at scale would need to use a reformation technology. Electrolyser units that are commercially ready today tend to have hydrogen generation capacity in the region of 1MW. The hydrogen generation requirement for blending 2% by volume into the NTS will be in the region of 200MW.

If hydrogen is going to play a pivotal role in the UK reaching the net zero target by 2050 then investment in large scale hydrogen generation needs to happen in the short term. While generation using electrolysers with renewable power has a role to play in decarbonisation, particularly in the storage and transport of constrained renewable power, the technology is still some time away from being deployed at scale.

There are a number of mature reformation technologies available such as the Steam Methane Reformer (SMR) which takes methane and steam as inputs and produces hydrogen and CO_2. These units tend to focus on generating hydrogen as a feedstock for chemical manufacture such as ammonia and methanol production. What is less developed among these technologies is the generation of low carbon hydrogen. Placing the focus on generating hydrogen as efficiently as possible, from an energy perspective, and capturing the CO_2 that is produced requires these commercially available technologies to be combined.

5.2.1 Emissions Performance

Hydrogen has seen increasing attention as a clean energy vector to provide heat and power while only emitting water at the point of use. As with most products the full life cycle needs to be considered to account for the net emissions to atmosphere. The emissions associated with hydrogen arise from the production method (and the emissions associated with all the inputs thereto) and its transport to the point of use.

Discussion around different methods of producing hydrogen has become increasingly complicated. A range of colour designations are being used to describe the source of the hydrogen, with colour designations tending to be based upon the technology that is used rather than the emissions intensity.

Green hydrogen is usually used to describe hydrogen produced by the electrolysis of water using renewable electricity. Blue hydrogen refers to hydrogen produced from fossil fuels with carbon capture and storage (CCS), brown or grey refers to hydrogen produced from fossil fuels without CCS. Pink hydrogen refers to hydrogen produced by electrolysis powered by nuclear energy.

Emissions associated with hydrogen from electrolysis depend upon the source of electricity and other emissions involved with getting the hydrogen to the point of use. If the electricity is produced from fossil fuels without carbon capture the emissions can be significant, using estimated carbon factors published by the UK government (Department for Business Energy and Industrial Strategy , 2019) current grid electrolysis has an intensity of 187.7gCO_2e/kWh with forecasts of electricity carbon intensity potentially reducing this to 106.7gCO_2e/kWh by 2030. Emissions associated with hydrogen production from natural gas with CCS can be low, 27.2gCO_2e/kWh, depending on the capture efficiency and emissions associated with transporting the hydrogen, as the carbon will be isolated from the atmosphere, stored and not emitted.

A methodology for evaluating the carbon emissions associated with hydrogen production is included in Appendix 12.2.

A graded scale of emissions performance offers the following benefits over the current colour designations:

- A graded scale allows for more clarity on the full emissions associated with a variety of hydrogen production methods.
- Novel hydrogen generation technologies can be easily accommodated.
- A graded scale provides a fact-based approach to support the overall opportunity to decarbonise using hydrogen, avoiding emotive measures that tend to divide the hydrogen debate.
- Mixing and blending of hydrogen streams can be accommodated within a graded scale.
- A graded scale allows for a more quantitative analysis.
- The methodology proposed offers the ability to account for emissions that may be overlooked otherwise, such as transport emissions to the point of use.

Adoption of any environmental performance system would be dependent on a need to evaluate hydrogen generation technologies based on the decarbonisation potential. Currently, evaluating the decarbonisation potential is likely to be carried out as part of a long-term environmental strategy or may be mandated by a public body looking to support low carbon technologies. Should a carbon price be introduced, the emissions performance of the hydrogen generation technology will be a much more prominent consideration. Decarbonisation incentive schemes, which could take the form of something like the renewable heat incentive or renewable energy feed in tariffs, could also be linked to an emissions performance standard.

Overall, the system of using colours to describe hydrogen emissions is not particularly useful and can complicate discussion making it more difficult to provide assurance to buyers of hydrogen that the product they are purchasing meets their environmental expectations.

However, there are other factors that differentiate hydrogen production methods. Hydrogen from electrolysis is much purer than hydrogen from reformed natural gas (without extensive clean up), making it suitable for fuel cell applications.

Although not discussed in this report in detail the global warming potential of hydrogen itself should be given some consideration. Leakage of hydrogen will increase the amount of hydrogen in the atmosphere, contributing to global warming. The Global Warming Potential (GWP) (1Tg/y for CO_2) of hydrogen over a 100 year lifetime has been determined to be 5.8 Tg/y (Derwent, et al., 2006) which is much less than the GWP of methane over 100 years at 28 Tg/y (Stocker, et al., 2018). It should also be noted that the lifetime of hydrogen in the atmosphere is much less than methane at 2.5 years in comparison to the 12.4 years that methane remains present.

5.2.1.1 Objectives and Scope

The objective of this work is to outline a methodology that can define the Emissions Performance Standard (EPS) for hydrogen at a specific location, produced in a specific way.

The output of the methodology should give a clear indication of how the hydrogen ranks in terms of Emissions Performance Standard while remaining technology agnostic. One of the complexities that the methodology will aim to overcome is addressing the impact of blending hydrogen from different production methods.

This scope of this report was based on the following aspects:

- Development of a methodology and set of assumptions for determining the EPS of hydrogen, including the generation from primary energy and transport emissions where these can be quantified.
- Application of the methodology, by way of example, to a range of hydrogen produced by different technologies.
- Comparison and analysis of EPS from the examined examples.

5.2.1.2 Proposed Emissions Performance Standard

This work proposes the use of a simple emissions performance chart analogous to the energy efficiency rating that accompanies an appliance or building. Using a chart with clearly defined bands allows for a more meaningful comparison between different hydrogen production options. The energy performance charts are already in use and therefore make it more straight forward for someone with minimal knowledge of emissions assessment to tell at a glance where the technology sits on an emissions scale. Examples of energy efficiency rating charts for buildings and appliances are shown in Figure 5-2. It should be noted that appliance and building ratings use measured efficiencies that are related to running costs, currently we are able to measure emissions reductions but cannot relate this to costs or savings without a mechanism like a carbon price.

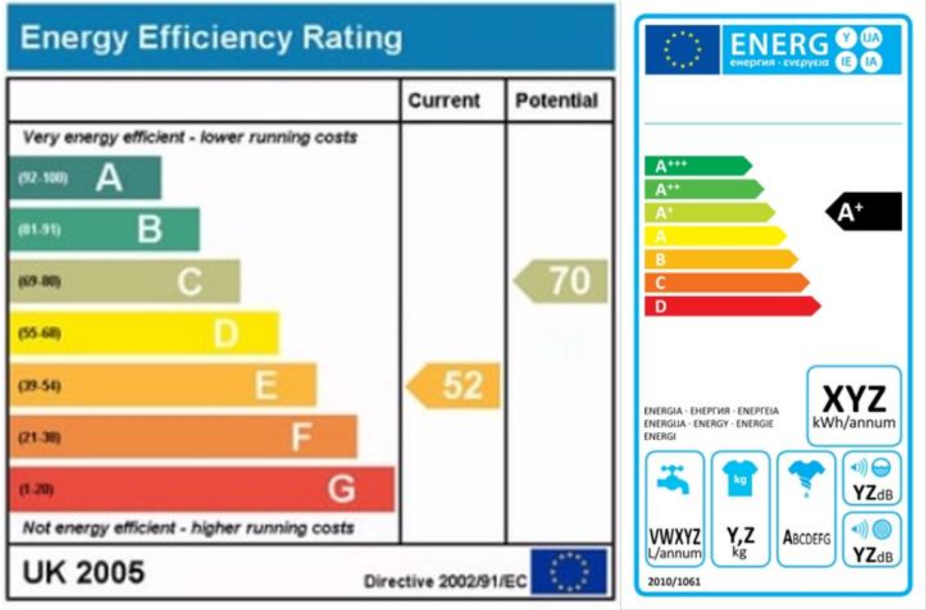

Figure 5-2: Energy Efficiency Ratings for Buildings (left) and Appliances (right)

The use of a progressively graded scale could be combined with a tiered incentive scheme to drive decarbonisation efforts. Technologies that deliver deep decarbonisation could be eligible for greater levels of support than technologies that only make marginal improvements to emission reductions providing a mechanism to rapidly drive down carbon emissions.

The units that are being used to categorise the emissions performance are grams of CO_2 emitted to the atmosphere per kWh of hydrogen generated. The emissions performance is based on the energy content of the produced hydrogen as this provides a more meaningful comparison between hydrogen, the fuels that it might displace and alternative low carbon energy vectors, such as biofuels and electricity. These same units are also used extensively in terms of carbon factors that can be used to make estimates of carbon intensity of processes and transportation.

The proposed bands for the hydrogen emissions analysis are set out in Table 5-1 and illustrated in Figure 5-3. These ranges have been developed to classify production methods that approach carbon neutral as Class A, with Classes A+ to A+++ representing production methods that are increasingly carbon negative. Classes B through D are intended to progressively rank technologies that achieve carbon reductions with Class D being set at a level that is just below the emissions factor for natural gas, this is to encourage displacement of natural gas use with lower carbon alternatives.

The A+ to A+++ categories are intended to provide a means to evaluate the potential for negative carbon emissions in a situation where a source of low carbon hydrogen could in future offset the use of any unavoidable carbon emitting energy source.

The limits for the EPS have been designed to provide an indication of the decarbonisation potential for hydrogen at the point of use, however the same methodology could also be used to evaluate the impact of displacing alternative energy vectors, as long as the same frame of reference is used.

Figure 5-4, illustrates the emissions potential of a number of hydrogen generation technologies. In order to provide a simplified example of how the scale would work the figures used here do not include any benefits associated with energy recovery or any emissions associated with transport. To properly compare different production methods details of differences across the full chain would need to be known. As a reference point the emissions of hydrogen production using natural gas are included.

Class	Lower Limit – greater than or equal to (gCO_2/kWh)	Upper Limit – less than (gCO_2/kWh)
A+++	<-200	-200
A++	-200	-100
A+	-100	0
A	0	100
B	100	200
C	200	300
D	300	>300

Table 5-1: Proposed Limits for Emissions Performance Bands

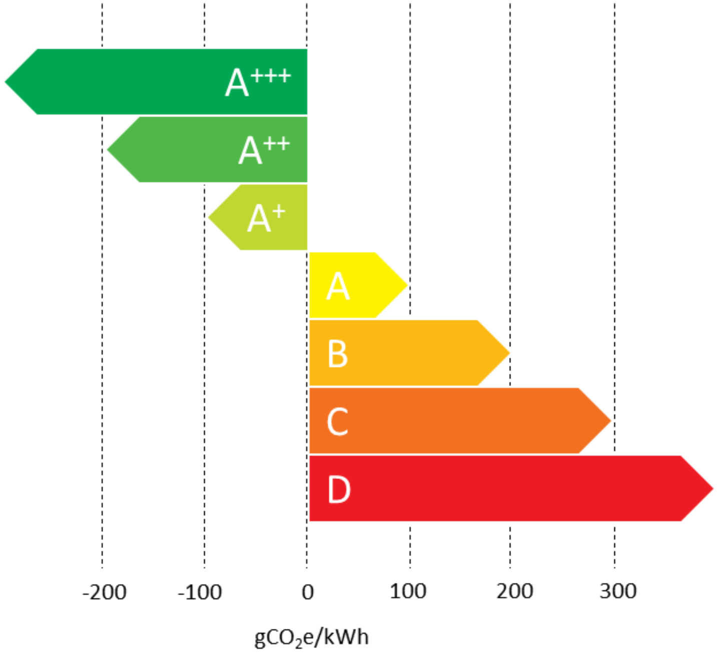

Figure 5-3: Proposed Emissions Performance Chart

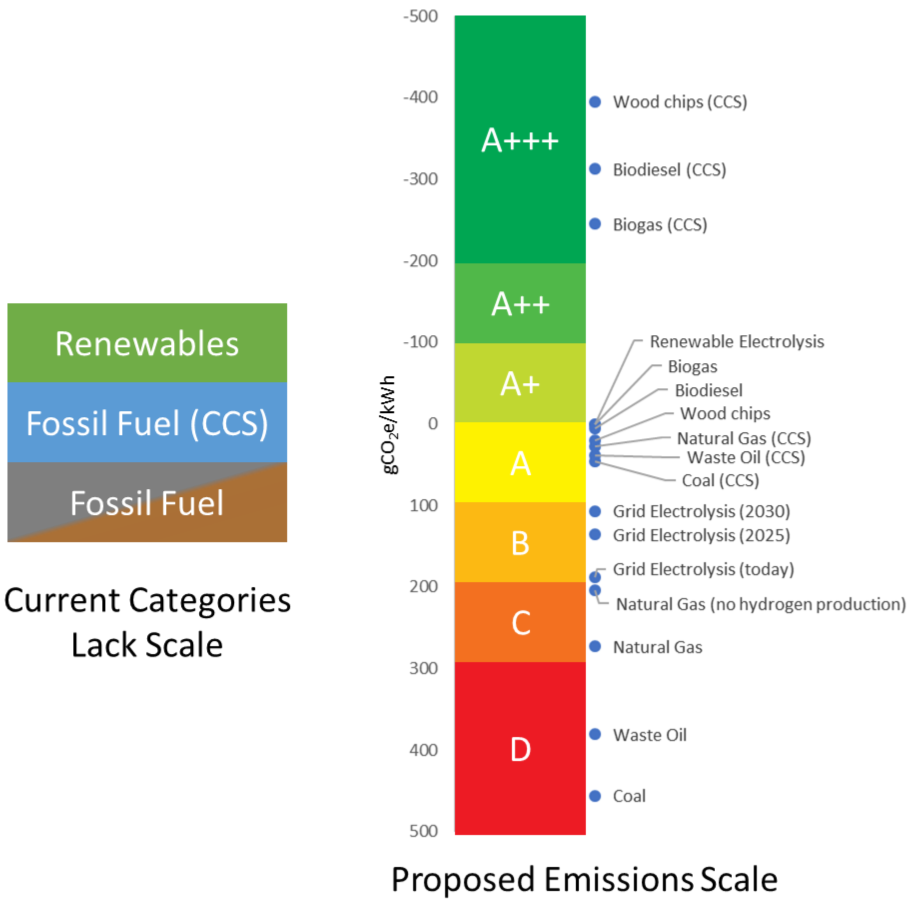

Figure 5-4: Emissions Performance of Hydrogen Generation Methods Compared Against Existing Category Definitions

The coloured bars indicate where common definitions of hydrogen colours would apply; reformation of fossil fuels being referred to as either brown or grey, reformation of fossil fuels with CCS being referred to as blue and hydrogen from renewable electrolysis being referred to as green. Although these existing colour definitions could be extended to cover a wider range of technologies there is still room for interpretation and confusion, with three potential colours that can be applied to reformation of methane to natural gas. In contrast using an EPS that focuses on an initial carbon assessment there should be less confusion once a grade has been calculated.

Although the A+++ category offers significant negative carbon potential there is a limit to the amount of biological resource that can be grown for energy within the UK. These resources could be imported but then the emissions associated with transporting these goods would need to be included to ensure that more CO_2 is not emitted due to transport than is being avoided by using biological resources.

Emissions from electrolysis using grid electricity are relatively high due to the associated carbon intensity of grid electricity (the carbon intensity of grid electricity being a function of the types of generation being used to produce it); and the efficiency of converting the electricity into hydrogen. The carbon factor for today's electricity is based on the figure published by BEIS as part of the supplementary guidance for the Treasury's Green Book (HM Treasury, 2013). The carbon intensity of the UK grid is predicted to fall in the future as more clean power generation capacity is brought online. Emissions factors for electricity in 2025 and 2030 are also sourced from the supplementary guidance to Treasury's Green Book.

The carbon intensity of electricity used to produce hydrogen could also be lowered through a power purchase agreement that utilises a lower carbon generation method than the grid average. A power purchase agreement is a method of using the grid infrastructure as a "transport link" between a customer and a supplier of energy, in this scenario the customer could choose to only buy power from renewable sources of generation.

The emissions figures in Figure 5-4 above and later in Figure 5-5 are indicative and hydrogen projects should carry out an analysis based on the specifics of their own process and business plan, however it will be important that a common methodology is adopted.

In cases where hydrogen streams are mixed the overall emissions performance can be calculated for each stream being blended and emissions proportioned according to how much of the overall energy each stream contributes.

An incentive scheme designed to encourage decarbonisation and stimulation of a hydrogen economy would need to be supported by a longer term strategic view driven by UK Government. Support for hydrogen could use similar mechanisms to the subsidies and schemes used to support low carbon heat and power generation such as the renewable heat incentive and feed in tariffs. The EPS could then be utilised as a tool for evaluating potential hydrogen projects and be used to determine the level of support that is available, directly tying the decarbonisation potential of a technology to financial support. This would, in principle, help the rapid development of technologies that were able to produce significant decarbonisation opportunities following a similar development progression as wind and solar technologies in the renewable power sector.

5.2.1.3 Estimating Performance

A best practice methodology for calculating the emissions performance is included in the appendices in Section 12.2.

For hydrogen generation projects that are at a feasibility or concept level there may not be enough information known to determine the full life cycle impacts of the production process. Should the level of definition prevent a detailed assessment of the carbon emissions to be performed an estimate can be generated using carbon factors and processing assumptions. As the technology matures assumptions can be revisited and more detail can be incorporated into the emissions analysis.

DEFRA publishes an array of carbon factors that can be used to calculate the emissions performance of hydrogen generation. The list covers a large number of factors across scope one (direct emissions to atmosphere as a result of operational activity), scope two (indirect emissions arising as a result of the use of electricity or steam by the process) and scope three (indirect emissions resulting from the use of consumables and other operational activities). There may be a requirement to find additional information, particularly for scope three emissions, for processes that consume proprietary chemicals in the generation of hydrogen as an example.

Using the DEFRA published carbon factors and some base assumptions for the generation of hydrogen emissions, figures have been calculated for a range of fuels. In the following analysis hydrogen is assumed to be produced by a syngas reformation process for most fuels or by an electrolysis process where the primary input is electricity. The conversion efficiency of the primary fuel is assumed to be 75% both for reformation processes and for electrolysers, which is considered to be representative although different technologies will have slightly different efficiencies. Where reformation processes are assumed to be fitted with carbon capture the capture efficiency is assumed to be 90%. In the case of electrolysis there is assumed to be no carbon capture, however the carbon factor for electricity from three different time periods is included; today’s figure, a projection for 2025 and a projection for 2030.

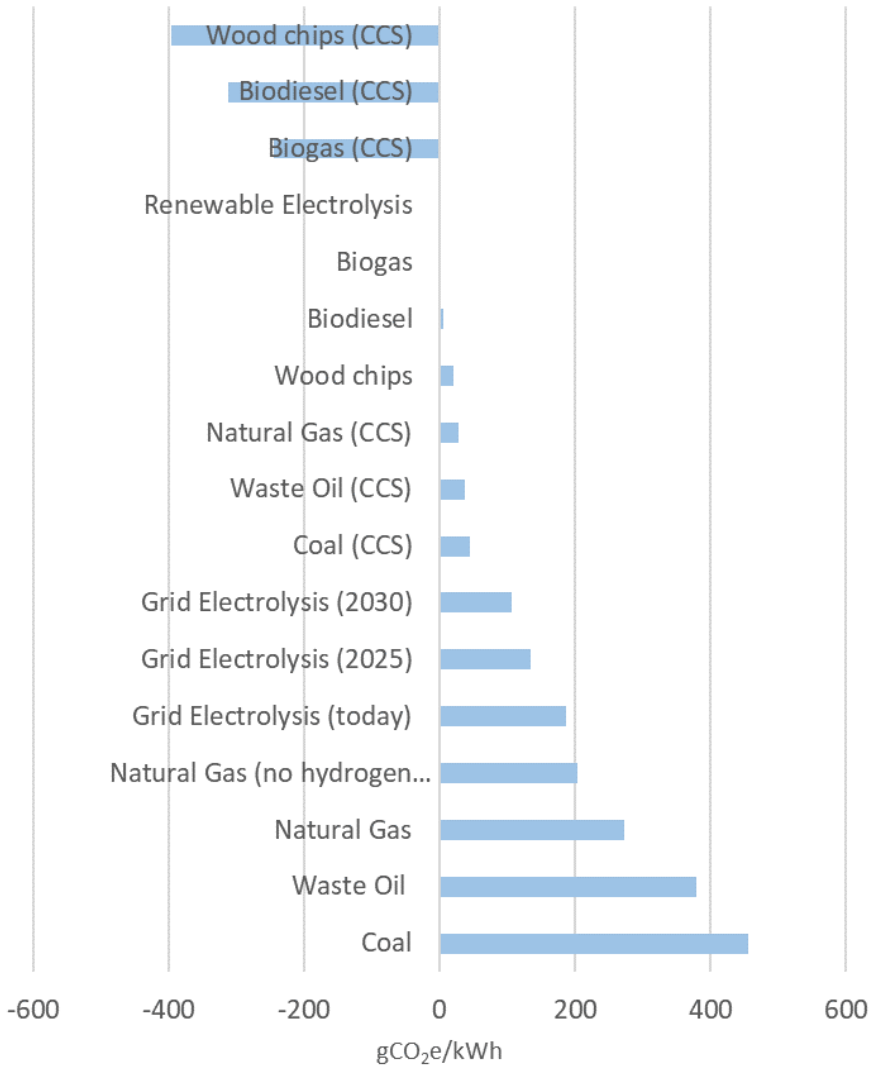

Figure 5-5: Emissions Analysis of Hydrogen Production Methods

The results of this analysis are presented in Table 5-2. This estimating methodology is only intended to give a rough indication of the decarbonisation potential of different production methods at a high level. Where specific technologies are being considered the emissions calculations should be much more thorough. No allowance has been made within this estimation for the scope two and three emissions of these technologies or for the transport emissions, it focuses purely on scope one emissions from the use of the primary fuel.

The net emissions that are calculated in Table 5-2 allow for the comparison of the CO_2 emissions between different technologies. This can drive change by informing decision making in terms of the amount of CO_2 emitted per kWh of hydrogen generated. However, currently this decision is only influenced by perceived long term financial risk of emitting carbon, i.e. today companies are only likely to choose a lower carbon option – that may cost more – due to a long term strategic view that anticipates a carbon price or similar mechanism coming into force. Once a mechanism has been brought in that places a meaningful cost on CO_2 emissions the net emissions factor will then be able to be linked directly to financial performance in the same way that buildings and appliances are measured by their efficiency and therefore running costs.

The net emissions for hydrogen production from natural gas using CCS are 27.2gCO_2e/kWh. For comparison the carbon emissions associated with the use of natural gas, excluding transport elements, are 204gCO_2e/kWh. The current emissions associated with power from the UK grid are 140gCO_2e/kWh indicating that hydrogen would need to be produced from a technology that ranks in the bottom half of rank B or better to see a decarbonising benefit.

Type	Fuel	Unabated (gCO_2e/kWh)	Process Efficiency	CO_2 Generated (gCO_2e/kWh)	Capture Efficiency	CO_2 Captured (gCO_2e/kWh)	Net Emissions (gCO_2e/kWh)	Class
Biomass	Wood chips with CCS	15.1	75%	455.9	90%	410.3	-395.2	A+++
Biofuel	Biodiesel with CCS	3.8	75%	351.3	90%	316.2	-312.4	A+++
Biogas	Biogas with CCS	0.2	75%	272.5	90%	245.2	-245.0	A+++
Electricity	Renewable Powered Electrolysis	0.0	75%	0.0	0%	0.0	0.0	A
Biogas	Biogas	0.2	75%	0.3	0%	0.0	0.3	A
Biofuel	Biodiesel	3.8	75%	5.0	0%	0.0	5.0	A
Biomass	Wood chips	15.1	75%	20.1	0%	0.0	20.1	A
Gaseous	Natural Gas with CCS	204.4	75%	272.5	90%	245.2	27.2	A
Liquid	Waste Oil with CCS	285.2	75%	380.2	90%	342.2	38.0	A
Solid	Coal with CCS	341.9	75%	455.9	90%	410.3	45.6	A
Electricity	Grid Electrolysis (2030)	80.0	75%	106.7	0%	0.0	106.7	B
Electricity	Grid Electrolysis (2025)	101.5	75%	135.3	0%	0.0	135.3	B
Electricity	Grid Electrolysis (today)	140.8	75%	187.7	0%	0.0	187.7	B
Gaseous	Natural Gas (no hydrogen production)	204.4	100%	204.4	0%	0.0	204.4	C
Gaseous	Natural Gas	204.4	75%	272.5	0%	0.0	272.5	C
Liquid	Waste Oil	285.2	75%	380.2	0%	0.0	380.2	D
Solid	Coal	341.9	75%	455.9	0%	0.0	455.9	D

Table 5-2: Summary of Hydrogen Production Emissions Analysis

5.2.1.4 CertifHy

Between 2014 and 2016, the CertifHy project brought together multiple stakeholders to develop:

- A common European-wide definition of green hydrogen.
- A hydrogen 'Guarantee of Origin' (GO) scheme deployable across Europe.
- A roadmap for implementation.

The project's aim is to create the path forward for a concrete and actionable Guarantee of Origin (GO) scheme with a pilot demonstration of the hydrogen GO scheme and the creation of a Stakeholder Platform to give the scheme its legitimacy. The project will define the scheme's governance, as well as its processes and procedures over the entire GO life cycle: from auditing hydrogen production plants, certification of Green or Low Carbon hydrogen production batches, through issuing, trading to "usage" of GOs

The project was funded by the Fuel Cells and Hydrogen Joint Undertaking (FCH JU), the public-private partnership that manages H2020 funds allocated to hydrogen and fuel cell technologies. The project was coordinated by Hinicio, with the Dutch Energy Research Centre ECN, TÜV SÜD and Ludwig Bölkow Systemtechnik as consortium partners. A large variety of global players support it as affiliated partners such as Air Liquide, Air Products, AkzoNobel, Areva H2Gen, BMW, Colruyt Group, EDF, Group Machiels, Hydrogenics, Linde, OMV, Shell, Total and Uniper that were part of the on-going step-by-step consulting process throughout two years.

Today, over 95% of all hydrogen is generated from fossil fuels and from which the CO_2 is released to the atmosphere, causing climate change. Premium Hydrogen is hydrogen produced with low carbon emissions and includes CertifHy Green Hydrogen and CertifHy Low Carbon Hydrogen. CertifHy Green Hydrogen refers to hydrogen generated by renewable energy with carbon emissions 60% below the benchmark emissions intensity threshold (defined as GHG emissions of the hydrogen produced by steam reforming of natural gas). CertifHy Low Carbon Hydrogen is hydrogen created by non-renewable energy with emissions below the same threshold.

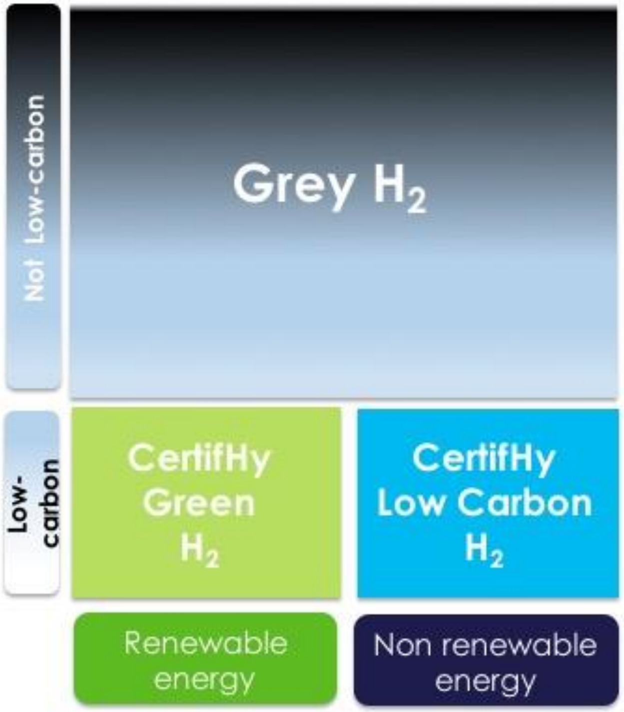

Figure 5-6: CertifHy Hydrogen Terminology

A GO labels the origin of a product and provides information to customers on the source of their products. It operates as a tracking system ensuring the quality of a product, such as hydrogen or electricity. The proposed Premium Hydrogen GO system, similar to the existing green electricity GO scheme, decouples the green attribute from the physical flow of the product and makes Premium Hydrogen available EU-wide, independently from its production sites. The GO scheme for Premium Hydrogen includes the GO governance; eligibility and registration of production plants; the GO and information content; issuance, transferability and cancellation; the registry system and trading platform.

The CertifHy approach has developed a considerable body of material, engaged widely and developed an approach now in pilot use to ensure the origin of produced hydrogen is clear.

The EPS approach proposed in this report is a different approach to address many of the same challenges. As hydrogen enters more widespread use the need to understand its emissions profile become ever more important. Our approach has been to apply the EPS colour bar efficiency rating, with which most individuals and businesses are familiar and to quantify overall emissions to the point of use. The characteristics of the two approaches are shown in Table 5-3. The benefits and drawbacks of the two approaches are shown in Table 5-4.

It is possible that both approaches could be used, in order to gain the benefits each provide.

Characteristic	CertifHy	EPS
Quantification	2 categories, above or below a specific limit	7 range defined bands
Heritage	Guarantee of origin based system	EPS based system
Boundaries	Includes all production factors	Includes all production factors and transport to the point of use
Exclusions	Transport to point of use Capital construction	Capital construction
Maturity	Fully developed system with multiparty engagement in pilot phase	Concept under initial development

Table 5-3: Characteristics of EPS vs CertifHy

	CertifHy	EPS
Benefits	Distinguishes between green and blue hydrogen	Wider range of quantified categories Widespread public familiarity with the approach Clarity over potential for improvement in emissions Application to negative emissions Inclusion of all emissions up to the point of use Applicable to a wide range of existing and new hydrogen production technologies which may not be easily categorised as renewables or not
Drawbacks	Limited visibility over actual emissions Single 'pass/fail' type approach No inclusion of hydrogen transport to the point of use	Lack of connection to costs without incentive scheme or a meaningful cost of emitting CO_2

Table 5-4: Benefits and Drawbacks of EPS vs CertifHy

5.3 Acorn Hydrogen

The Acorn Hydrogen Project is based at St Fergus and is considering an Advanced Autothermal Reaction (ATR) Reformation Process, with Johnson Matthey Low Carbon Hydrogen (LCH) technology at its core. This will deliver an energy and cost-efficient process for hydrogen production from North Sea gas, whilst capturing and sequestering CO_2 emissions to prevent climate change.

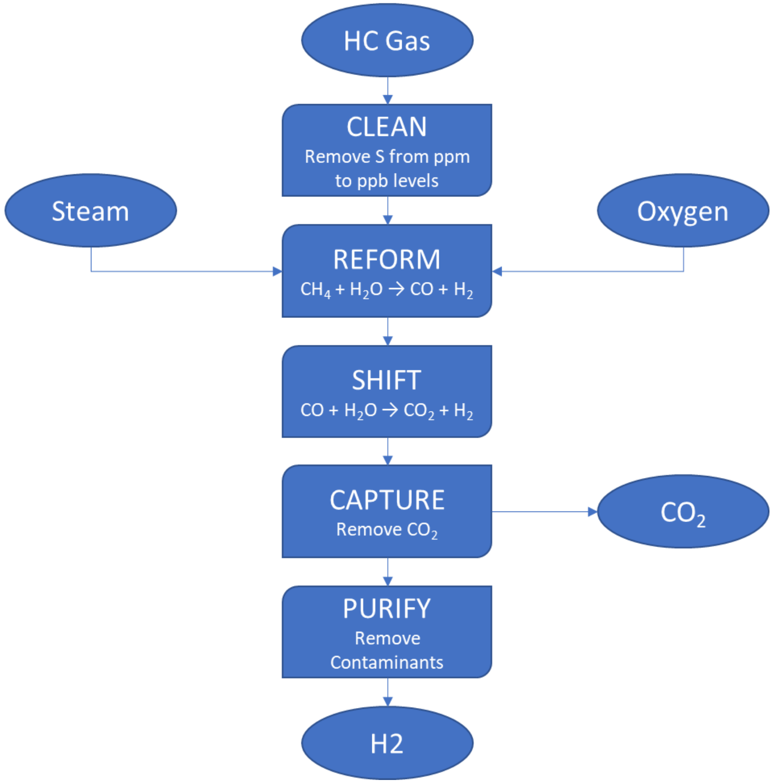

Figure 5-7: Base Case Hydrogen Generation Process (from natural gas to hydrogen and CO_2)

Acorn Hydrogen will help the UK to address the recommendation by the Committee on Climate Change, as an early project in the development of a UK strategy for decarbonised gas, driving the future use of the gas grid in the UK under a 'low-regrets' opportunity, whilst facilitating the future deployment of low-carbon hydrogen at scale. The project will synergise with the North East Carbon Capture, Usage and Storage alliance (NECCUS) which is looking at decarbonisation projects. In conjunction SGN also have a strategy that involves looking at decarbonisation potential across the whole east cost of Scotland's gas networks that could include future integration into the Aberdeen Vision project e.g. Dolphyn offshore green hydrogen generation project (ERM, 2020).

The project is initially considering a hydrogen generation capacity of 200MW, with hydrogen outputs shown in Table 5-5 below. This capacity has been targeted to enable early decarbonisation of the NTS through the implementation of a 2% by volume hydrogen blend leaving the St Fergus gas terminal.

	Power	Energy	Mass	Volume
	MW	GWh	T	kNm3
Hourly Output	200	0.20	6	67
Daily Output	200	5	144	1,602
Annual Output	200	1,752	52,604	584,852

Table 5-5: Summary of Hydrogen Generation Capacity

The plant could become the first operational low carbon hydrogen plant in Europe, as soon as 2024, enabled for early development by the Acorn CCS Project which is under development at the same location.

The Acorn Hydrogen Project is currently in a Technology Concept Selection (Feasibility) Study Phase and, if successful, will be followed by Front-End Engineering Design (FEED). Through these two phases, the objective is to deliver the final process concept and transfer this into an Acorn specific engineering design, with the necessary consents, commercial model development, transfer of hydrogen and CO_2, and stakeholder engagement, to reach a Final Investment Decision (FID), which is anticipated to be in 2022. This will enable the project to move into a detailed design and construction phase.

The work will support other significant hydrogen projects in the UK, such as H21 and HyNet, and will build upon work already conducted through projects such as Acorn, HyDeploy, Hy4Heat, H100 and provide a clear governmental signal on the potential future use of the gas grid.

St Fergus has been selected as the best location for the Acorn Hydrogen Project to generate hydrogen from a hydrocarbon reformation process. Reformation of hydrocarbons allows for the bulk production of hydrogen at low unit costs. To demonstrably reduce carbon emissions, instead of moving the point in the process where the CO_2 enters the atmosphere, the CO_2 must be captured and permanently sequestered. In order to sequester CO_2 at scale storage in the subsurface is required. St Fergus then provides an ideal location for hydrogen production with natural gas coming onshore from the North Sea and an abundance of potential CO_2 storage locations offshore.

The build out for additional hydrogen generation could target a number of local uses, outlined in Figure 5-9, or to feed into more ambitious regional conversion projects like SGN's industrial cluster and gas networks project shown in Figure 5-8.

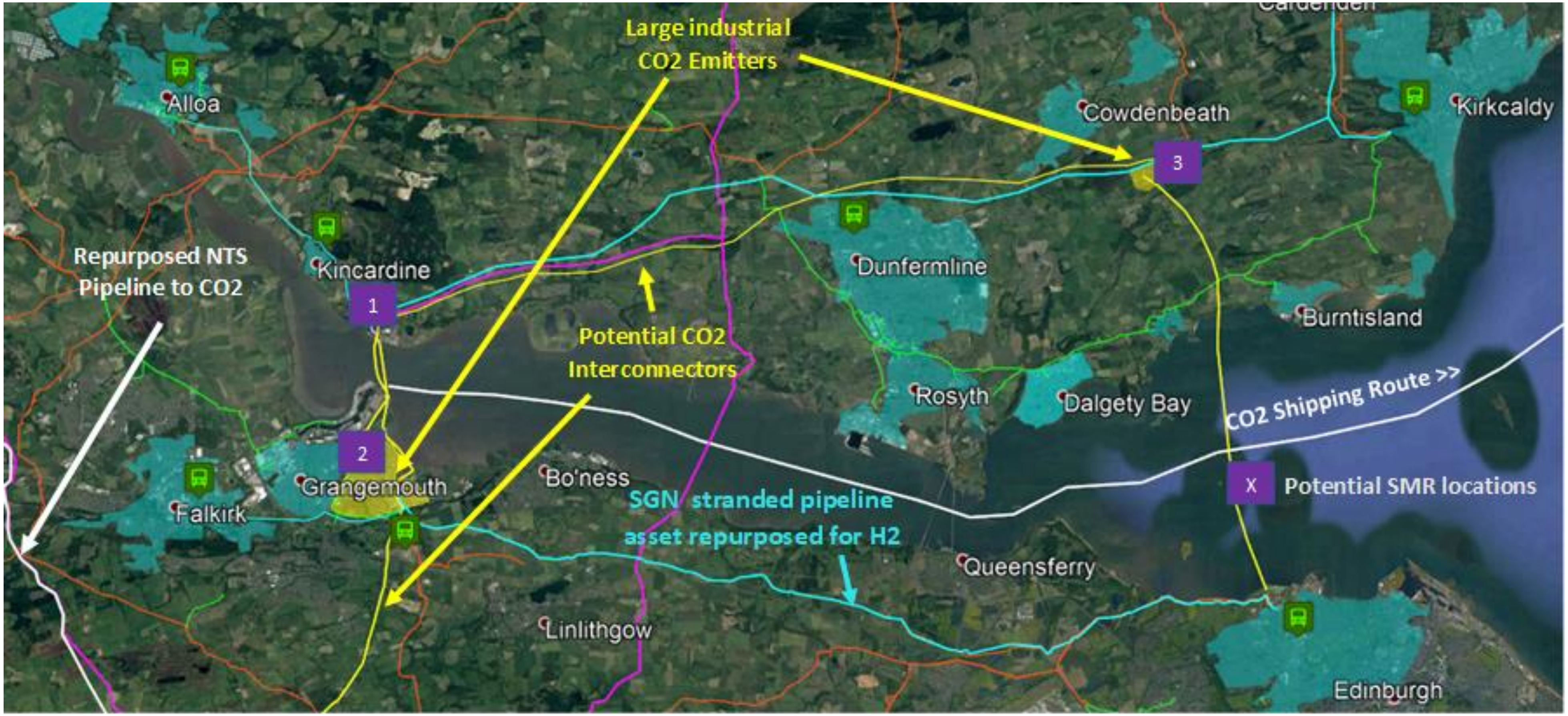

Figure 5-8: SGN's Industrial Cluster and Gas Networks Project

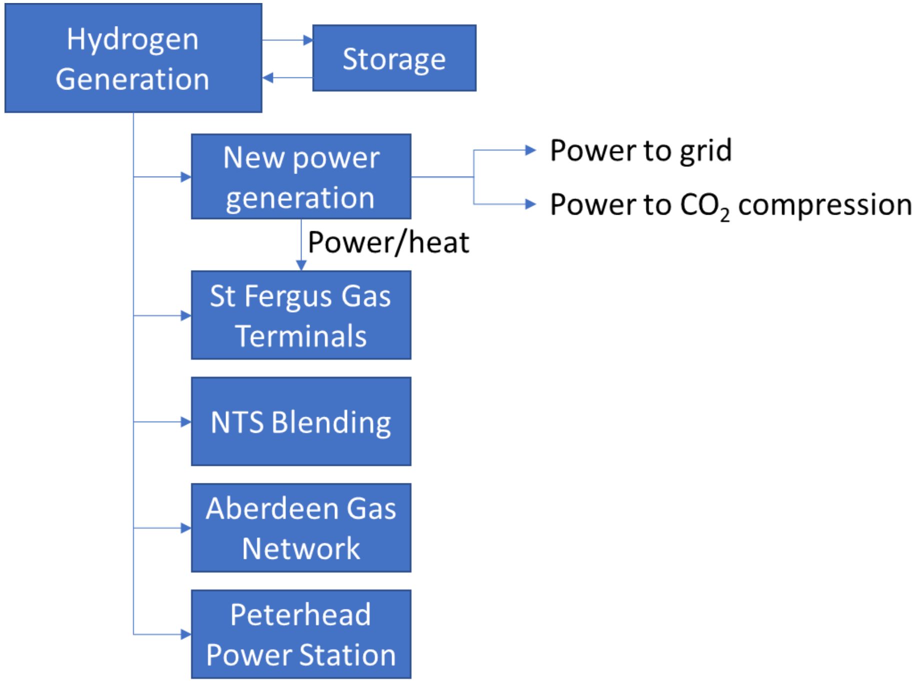

Figure 5-9: Potential Applications for Acorn Hydrogen

The cost of producing hydrogen has been calculated based on the ATR system cost and a CO_2 transport and storage fee of £13/t This shows that the cost of producing hydrogen with CCS is £1.39/kg; the cost of CCS adds only 10p/kg. This compares favourably with the cost of hydrogen from grid powered electrolysis, which in Aberdeen is being sold at £10/kg. There is potential for electrolyser costs to come down significantly in the future as the technology is anticipated to follow a similar decline in costs to the development of wind and solar. Hydrogen costs are detailed further in Section 7.0.

Without storage from gas networks there is a potential for power prices to increase as the electricity network would need to account for seasonality currently managed by the gas networks.

Unit Costs	Natural Gas	Hydrogen	Hydrogen with CCS
Mass (£/kg)	0.26	1.29	1.39
Volume (£/kNm3)	171.29	115.97	125.42
Energy (£/MWh)	19.88	38.69	41.85

Table 5-6: Summary of the Unit Costs of Producing Hydrogen

Comparing the cost of hydrogen versus the average prices of unabated natural gas and electricity; hydrogen is twice the cost of natural gas per MWh and around 80% of the price of electricity based on an electricity price of £47.68/MWh, illustrated in Figure 5-10.

It should be recognised these energy price comparisons do not include sensitivities like the energy networks being required to match heat demands that are currently managed by gas networks, which may have significant impact on future electricity prices.

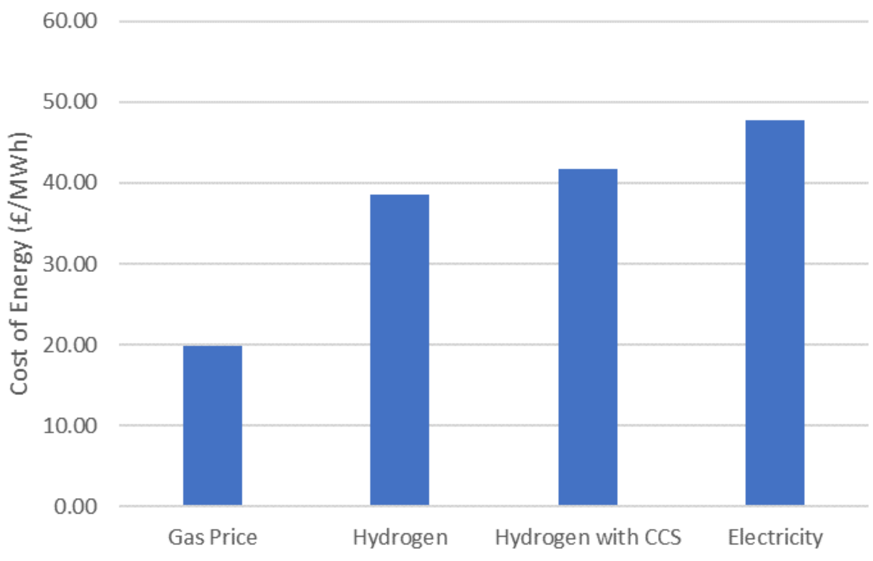

Figure 5-10: Comparison of Energy Costs from Different Sources

5.4 Acorn CCS

The Acorn CCS Project, also located at St Fergus, is a low-cost, low-risk carbon capture and storage project, designed to be built quickly, taking advantage of existing oil and gas infrastructure and a well understood offshore CO_2 storage site. The project is planning to reuse an existing redundant pipeline for CO_2 transportation to the Acorn Storage Site, where CO_2 will be injected two kilometres below the seabed, via a new subsea well, into the Captain Sandstone aquifer. Here, carbon dioxide will be kept out of the atmosphere by layers of secure impermeable shales. Pale Blue Dot Acorn holds both a Lease Option from Crown Estate Scotland and a CO_2 Storage Licence from the Oil and Gas Authority (OGA) for development of the Acorn CO_2 Storage Site.

Acorn is an important catalyst for clean growth in the north east of the UK and beyond. Located at the St Fergus Gas Terminal, an active gas processing site, where around 35% of all the natural gas used in the UK comes onshore, this makes it an excellent location to construct and operate new industrial facilities (such as hydrogen generation) and to initiate an early CCS transport and storage hub.

The seed infrastructure can be developed further by adding future CO_2 shipping through Peterhead deep-water port, to and from Europe and Teesside, and connection to UK national onshore transport infrastructure such as the Feeder 10 pipeline, which could be repurposed to bring additional CO_2 from emissions sites in the industrial central belt of Scotland.

Through the build-out options, (Figure 5-12) the Acorn CCS Project provides an international CO_2 storage hub in the Central North Sea that unlocks CO_2 transportation and storage solutions for other UK carbon capture and storage (CCS) clusters.

The Acorn Project is listed at a European Union Project of Common Interest (PCI) eligible for funding under the Connecting Europe Facility (CEF). Funding has been provided under this facility to support Feasibility Phase activity, which is now complete and for funding FEED which will be ongoing until the end of 2020. BEIS CCUS-Innovation funding is also supporting FEED costs along with co-funding from industry.

The project schedule is shown in Figure 5-11 with FEED completing in early 2021. Following FEED, it is expected that some time is required to complete project financing and commercial arrangements, after which a Final Investment Decision (FID) can be taken. CO_2 injection operations are expected to commence in 2024.

The CO_2 that is captured from the hydrogen reformation process will require conditioning and compression before it can be transported offshore for storage. The main concerns surrounding the CO_2 specification are the water content, to prevent corrosion of offshore infrastructure, as well as removing or reducing other contaminants that will affect operability, including hydrogen. The costs for this conditioning have been assumed to be borne by the compression and conditioning plant at St Fergus and does not form part of the hydrogen plant.

The CO_2 from the hydrogen plant will be compressed to export pressure before it enters the offshore pipeline, which will have been repurposed from its original use. The offshore pipeline will be connected to the injection well(s) by a short length of infield pipe. CO_2 will be injected initially through a subsea dual completion well and permanently stored in the Acorn storage site.

As further hydrogen generation is developed at St Fergus, additional (single bore) subsea injection wells will be drilled offshore up to the capacity of the offshore pipeline (~5MtCO_2/y). Should further increased rates of CO_2 storage be required, additional pipelines will be reused, including the Atlantic Pipeline which runs from St Fergus to the eastern end of the Acorn Storage Site.

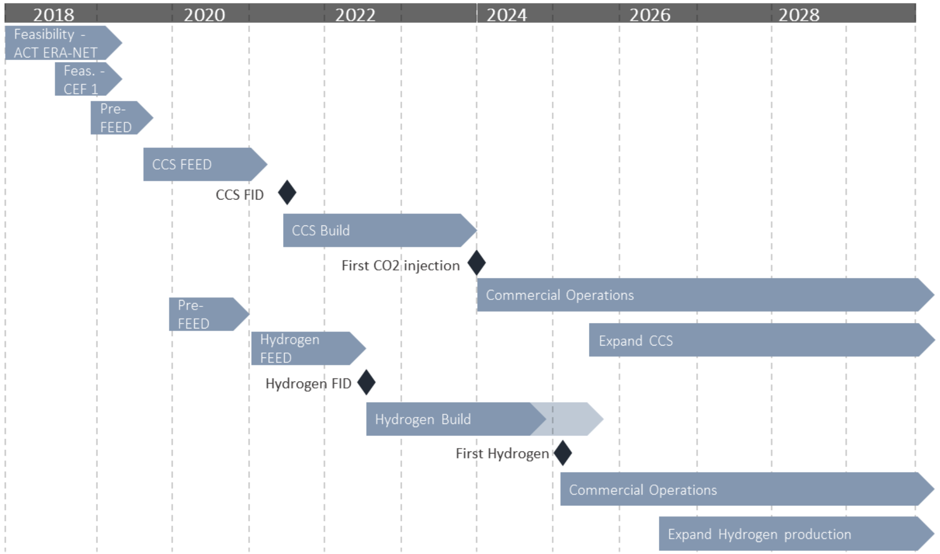

Figure 5-11: Acorn schedule

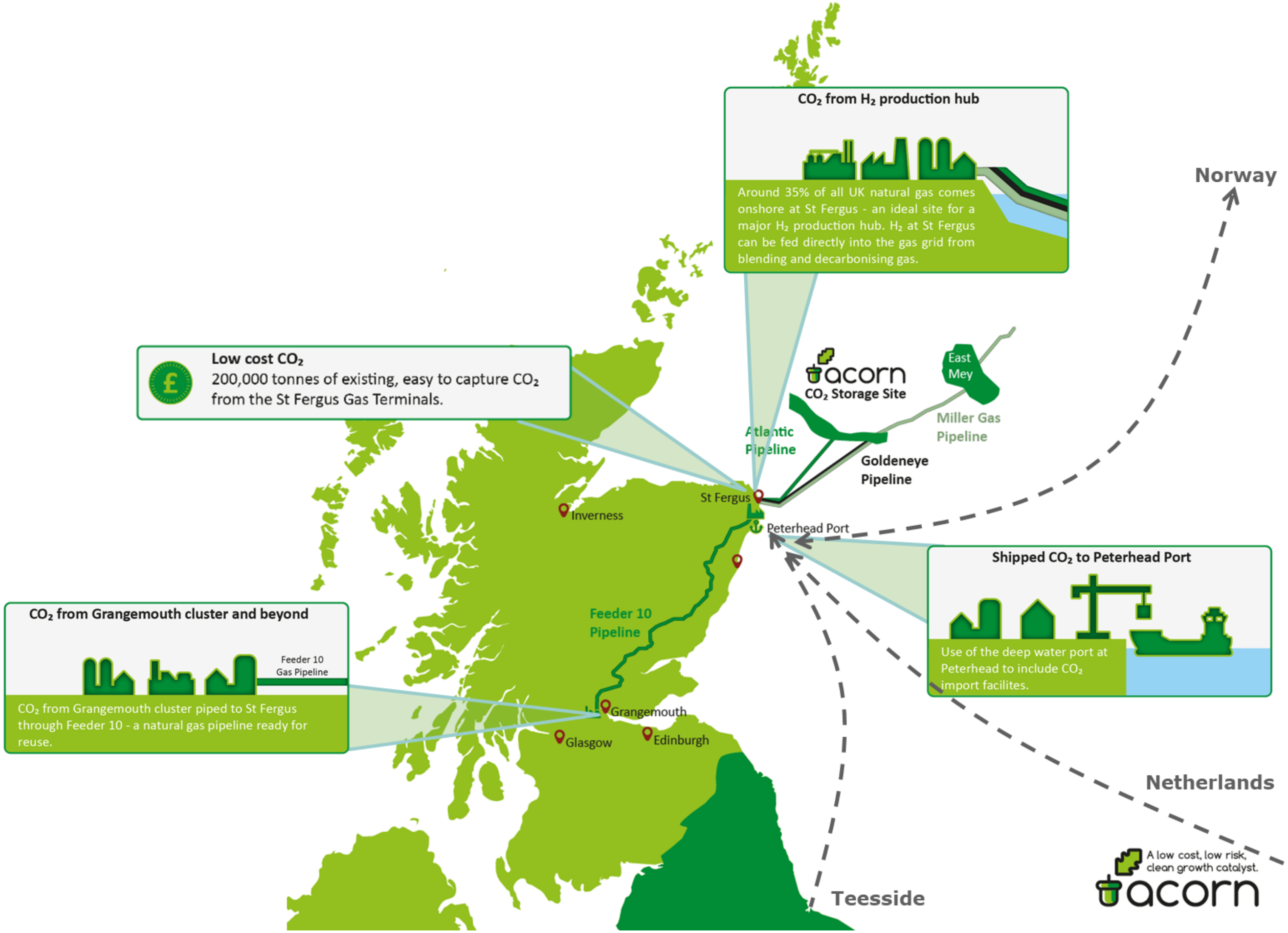

Figure 5-12: Summary of Acorn build out

6.0 Project Delivery

6.1 Hydrogen in the NTS

An initial target of injecting up to 2% hydrogen by volume into the NTS is being considered. At 2% by volume this study indicates that there will not be a material impact on safety, or the gas quality received by the majority of end users – some particularly sensitive users may require the hydrogen to be removed before they could use the gas. Deeper decarbonisation can then be driven over time by ramping up the amount of hydrogen that is blended into the system. As the hydrogen content increases there will need to be a phased transition of end use equipment to units that can operate effectively with increasing hydrogen content.

Blending hydrogen at St Fergus will need to account for the variation in gas flow through the terminal. Figure 6-2 shows what the capacity of hydrogen generation would have needed to be to supply 2% by volume of hydrogen into the gas flowing through St Fergus over the past three years. The bars represent the minimum and maximum daily flows in each month with the plotted line representing the monthly average. The maximum operating capacity is shown for a 200MW reformation plant as well as the minimum operating capacity when turned down to 40%. When calculating the amount of hydrogen that should be blended into the gas stream the overall energy value of the gas flow was kept the same as if the NTS was being operated on natural gas.

Hydrogen generation capacity required would vary between a monthly minimum of 110MW (daily minimum of 77MW) and a monthly maximum of 250MW (daily maximum of 262MW). The average hydrogen output that would have been required over the past three years is around 172MW of hydrogen generation. There may be opportunities to manage the hydrogen generation by utilising turn down ratios, storage or by including additional hydrogen demand (such as power generation) that can be operated as required. The National Grid long term forward forecast for gas throughput at St Fergus is relatively flat, providing confidence in using this history as a guide to future volumes and variance.

The base case for the analysis is to use a 200MW reformation plant, which would provide sufficient hydrogen for blending 2% hydrogen by volume across the majority of the year with minimal storage requirement by utilising the plant turn down range. Injection of less than 2% hydrogen by volume is not anticipated to be an issue and exceeding this limit is anticipated to be treated in the same way as gas that doesn't meet GS(M)R specification is currently treated.

Figure 6-3 shows how the load factor for a 200MW hydrogen generation plant would vary based on the historic gas flows in the NTS. In some years, over the winter months, the required load factor to ensure a 2% by volume hydrogen blend would be over 100%; suggesting that in these months the actual volume percentage of hydrogen being blended could drop below 2%. Injection of less than 2% hydrogen by volume is not anticipated to be an issue as the energy demand would be made up by natural gas, customers sensitive to gas composition could receive advance warning from St Fergus to mitigate the risk to their process. The use of hydrogen storage is an alternative to support the maintenance of a constant 2% hydrogen flow.

The turndown ratio of the plant is an important consideration determining the design capacity. The LCH process being considered by the Acorn Hydrogen Project has an anticipated turndown ratio to 40% and so a 200MW reformer should always be capable of supplying 2% hydrogen into the NTS based on the historical flows. Using the operational flexibility and temporary storage the hydrogen production volumes can be managed to supply a consistent hydrogen content into the NTS.

The historical gas supply data has been used to generate an average annual profile for use in storage calculations. The profile was generated by averaging the gas throughput for each calendar day over the preceding four years, i.e. calendar day 1 corresponds to the average throughput of the 1st of January in 2018, 2017, 2016 and 2015.

Under the most stringent scenario, maximum plant uptime, there is a large requirement for storage. This assumes that the hydrogen plant operates at full capacity whenever it is producing hydrogen and that 2% hydrogen injection into the NTS is maintained throughout the year, including when the plant is shut down for maintenance. Under these conditions there is a requirement for 3,700MW (90GWh / 2,700t/ 30,000kNm^3) of hydrogen storage, illustrated in Figure 6-1. This storage requirement can be rationalised by taking advantage of the operational flexibility of the plant, reducing the output of the plant to match the hydrogen demand, and by accepting that there may be times where the plant is unable to provide enough hydrogen to achieve a 2% by volume blend (i.e. avoiding injecting hydrogen during a plant shutdown would dramatically reduce the peak storage requirement).

If there is no buffer storage at all the plant would still be able to operate however there would be greater risks associated with the hydrogen export depending on how quickly the plant can react to changes in the St Fergus gas throughput. If the plant was generating more hydrogen than could be accepted into the grid there may be a requirement to flare hydrogen, this would carry a penalty in terms of the energy efficiency and the decarbonisation potential but also in the plant economics as product would be lost. If there is notice of changes in gas flow through St Fergus this risk is reduced as long the as the plant can achieve suitable turn down limits and rates.

If the NTS specification were increased beyond 2% Table 6-1 gives a rough indication of how much generation capacity would need to be installed at St Fergus to increase the hydrogen percentage by volume to 10% and 20% hydrogen in the NTS at St Fergus.

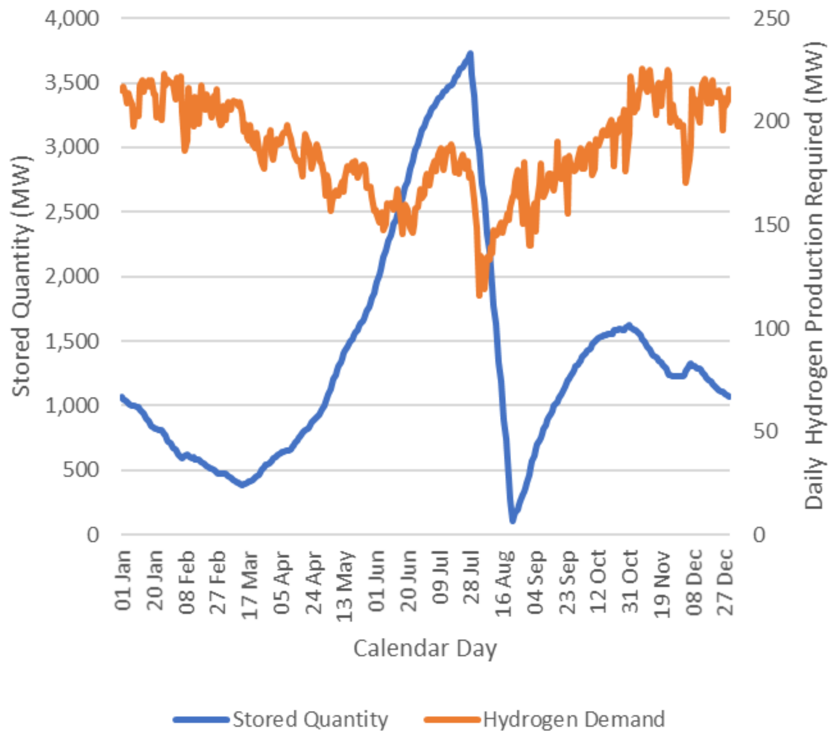

Figure 6-1: Maximum Storage Requirement for 2% Blend into the NTS

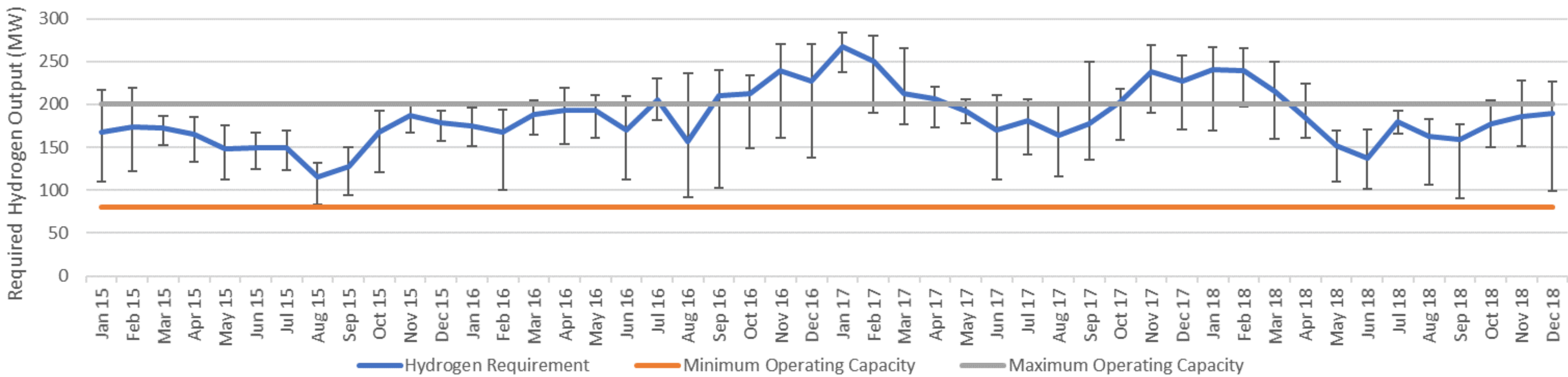

Figure 6-2: Historical Gas Flow through St Fergus Converted into Hydrogen Demand, Operating Capacity Based on 200MW Reformer

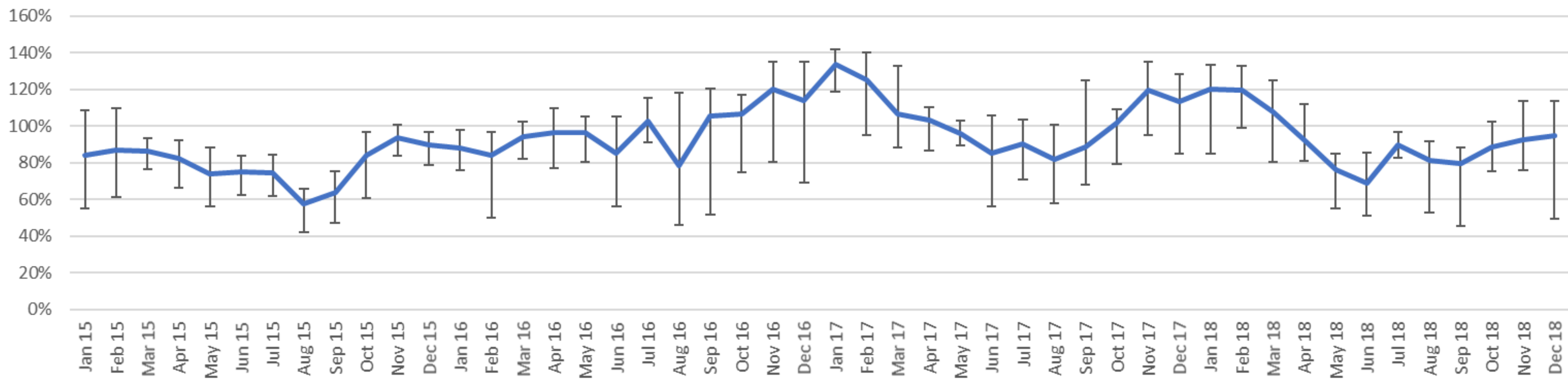

Figure 6-3: Utilisation of a 200MW Hydrogen Generation Plant for Blending 2% by Volume

Hydrogen Blend (by vol)	Average (MW)
2%	187
10%	990
20%	2,144

Table 6-1: Hydrogen Generation Requirements for St Fergus NTS Blending

Driving deeper decarbonisation using hydrogen would require substantial investment in hydrogen generation capacity as the hydrogen content of the NTS is increased. A relatively small increase to 10% by volume of hydrogen would require an annual average hydrogen generation of just less than 1GW.

Security of supply becomes a fundamental concern when moving towards higher volumes of hydrogen blending. With the 2% case if the hydrogen plant is unavailable then the fall back is to rely on the natural gas flow to satisfy energy demand, the consequence being a reduction in decarbonisation. However, in a 100% hydrogen case, security of supply is of paramount importance, when natural gas cannot be used as a fallback. Storage and resilience become much more important.

6.1.1 Injection Considerations

The National Grid terminal at St Fergus is an important asset: it is the network entry point for three delivery facility operators (DFOs). The DFOs (North Sea Midstream Partners (NSMP), Shell Esso and Ancala) provide up to 118 mcm/day of gas into the NTS, typically delivering 25-50% of daily GB gas requirements.

A simplified schematic of St Fergus is given in Figure 6-4. Gas from NSMP enters St Fergus and, through a legacy arrangement, the gas is compressed from approximately 40bar to NTS pressure. There is flow measurement on the gas entering from NSMP to ensure efficient operation of the compression plant. Gas entering the National Grid terminal at St Fergus from Ancala and Shell/Esso must meet the NTS pressure.

Under normal operation, all the gas flows through the mixing plant and into the five feeders leaving St Fergus. This arrangement is to ensure that the gas compositions across all five feeders leaving St Fergus are as similar as possible. In addition to the five feeders, there are also offtakes for the Peterhead Power Station and the local SGN distribution network from manifolds fed by Feeders 10, 11 and 12.

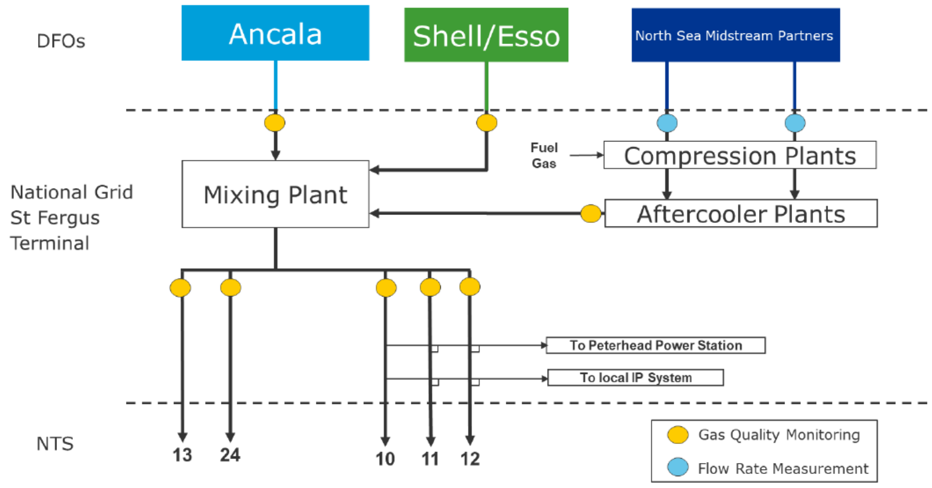

Figure 6-4: Schematic of St Fergus (Normal Operation)

There is an offtake from Feeder 11 at Kinknockie and an offtake from Feeder 13 which feeds the Aberdeen-Inverness HP system. The five feeders re-join at the Aberdeen compressor station manifold where there is a further offtake to the local Aberdeen system.

This is what can be considered as normal operation. Fuel gas connections are available from both NSMP stream, the Shell/Esso stream and from a manifold on Feeders 10-12. Peterhead Power Station and the local Intermediate Pressure gas system are also fed from manifolds on these three feeders.

Due to its importance for the delivery of gas to the UK, St Fergus has been designed and is operated in a manner to ensure security of natural gas supply. As a result, there is no single place downstream of the mixing plant where hydrogen could be injected into National Grid's St Fergus Terminal and ensure that the five feeders leaving St Fergus have the same composition. It is possible to isolate individual feeders for maintenance whilst maintaining flows through the other pipelines. There are also occasions when the mixing plant can be bypassed.

The average monthly flow rates through St Fergus are given in Figure 6-5. From the operational data, there are instances where there is zero flow from each of the DFOs supplying St Fergus.

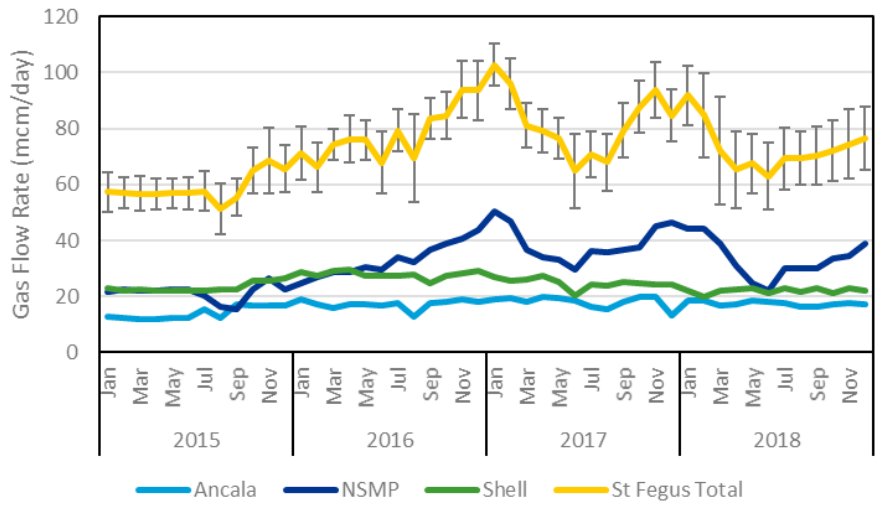

Figure 6-5: Average Monthly Flow Rates (Error Bars: Standard Deviation)

The Gross Calorific Value (CV) of gas entering St Fergus is given in Figure 6-6. The average CV the of gas entering St Fergus between Quarter 1 2014 and Quarter 4 2018 was 39.5 MJ/m^3.

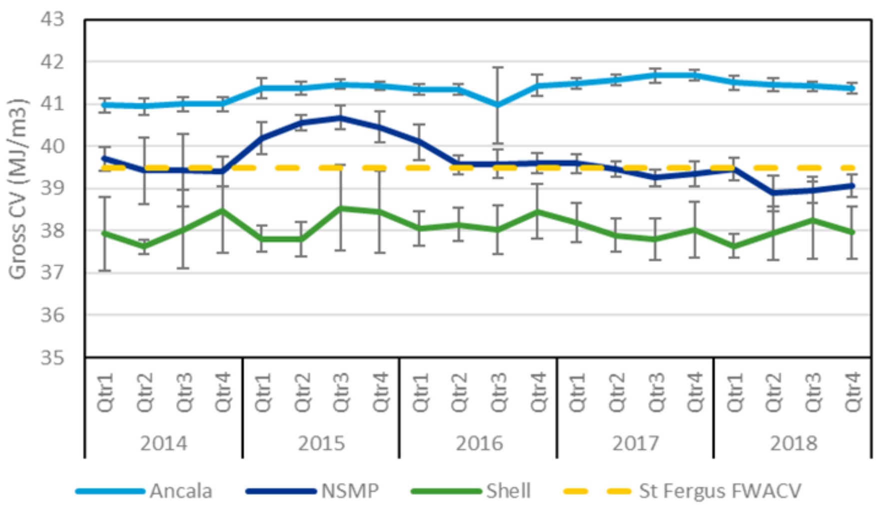

Figure 6-6: Gross Calorific Value of Gas Entering St Fergus

Blending 2 mol% hydrogen into natural gas will reduce the CV, and as a result WI, of the gas being delivered to the end users. On average, the CV of a NG blended with 2% hydrogen will be reduced by approximately 1.4 % from the CV of the initial natural gas. The WI of a NG blended with hydrogen will be reduced by approximately 0.5% from the WI of the initial natural gas. Some example GS(M)R compliant gases are given in Figure 6-7. The arrows on the figure shows the change of CV and WI once hydrogen is added.

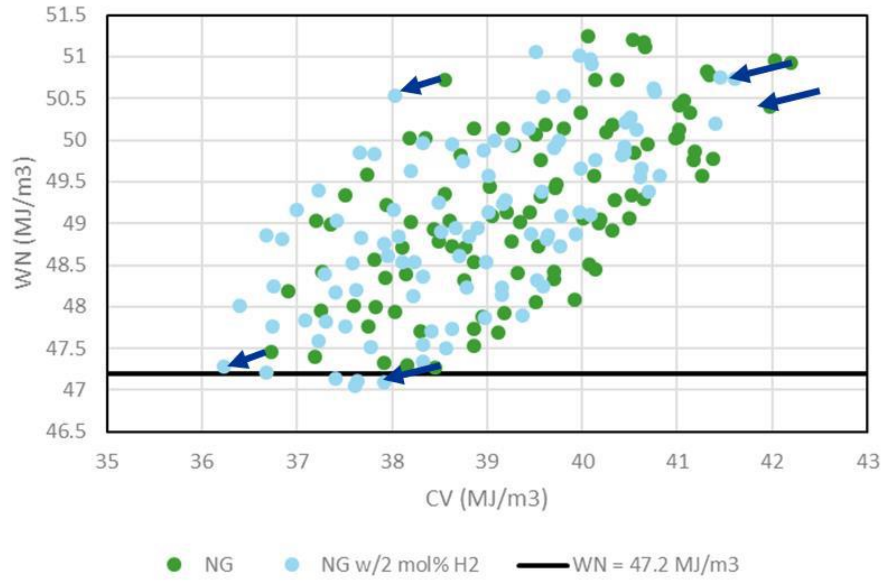

Figure 6-7: Change of CV and WI after the Addition of 2% Hydrogen by Volume

Therefore, depending on the starting gas quality, the WI of the blended gas could, in principle, be less than 47.2 MJ/m^3 – the minimum WI permitted in the current GS(M)R. Based on the observed reduction of WI by 0.5% and the addition of 2 mol% hydrogen, the minimum WI of natural gas being accepted at St Fergus would need to be increased to 47.4 MJ/m^3. In practice, the WI of gas delivered from St Fergus is usually at the upper end of the GS(M)R range.

The fundamental requirements for injection of hydrogen are as follows:

- Hydrogen content in the gas exiting St Fergus must not exceed 2 mol%

- Gas exiting St Fergus must meet current GS(M)R requirements with an exemption for hydrogen content greater than 0.1 mol%
- The amount of hydrogen being blended into the gas network must be known
- There must be no (or minimal) disruption of gas flow from St Fergus in the event of a problem with the hydrogen blending process

Two schemes for a gas entry unit (GEU) are shown in Figure 6-8 and Figure 6-9. Both systems include:

- Hydrogen Compression: hydrogen compression from the hydrogen plant outlet pressure (circa 30 barg) to injection pressure. Injection pressure will depend on the location within the St Fergus Gas Terminal
- Hydrogen Control System: A flow ratio control valve (FRCV) and associated controller that takes gas quality and flow measurement inputs upstream of the injection point and the pressure of the hydrogen supply to control the hydrogen injection rate such that the resulting gas blend contains no more than the specified levels of hydrogen and that the minimum WI of the final blend is not breached. In order to meet turndown requirements, it may be necessary to have two FRCVs in parallel operating in a split range manner.
- A static mixer to ensure that the resulting gas is well mixed before it reaches the gas quality measurement instruments located downstream. The static mixer may not be required if there is sufficient length of pipework to provide turbulence between the injection point and the gas flow rate. This distance will depend on the diameter of the natural gas pipeline. For St Fergus, the greatest distances required would be on Feeder 24 which is a 48" pipe. Based on Feeder 24, the following distance of straight-line flow would be required:
    - Flow Rate and Gas Quality Measurement Upstream of the Hydrogen Injection Point: 5-20D (6 to 24 m) upstream and downstream. This distance will depend on the type of meter chosen for this point.
    - Gas Quality Measurement Downstream of the Hydrogen Injection Point: 20D (24 m) of straight pipe is required upstream of the gas quality sensor.
- Downstream Gas Quality Measurement: Measurement downstream of the hydrogen injection point. This gas quality measurement should be linked to an emergency shutdown (ESD) system. The system will shut off the hydrogen supply in the event of the hydrogen concentration in the blended gas exceeding the setpoint (either for H2 content or blended gas WN), hydrogen control system failure, or no flow of natural gas from upstream of the hydrogen injection point. The reaction time and reliability of the gas quality analysis system will need to be chosen to meet safety and reliability requirements.
- Emergency shut-down valves (ESDV) to isolate the hydrogen injection system in the event of a terminal ESD or a malfunction of the hydrogen injection system.
- Non-return valves to prevent backflow of natural gas into the hydrogen system
- Isolation valves and venting to allow maintenance of the hydrogen system independently of the main gas line

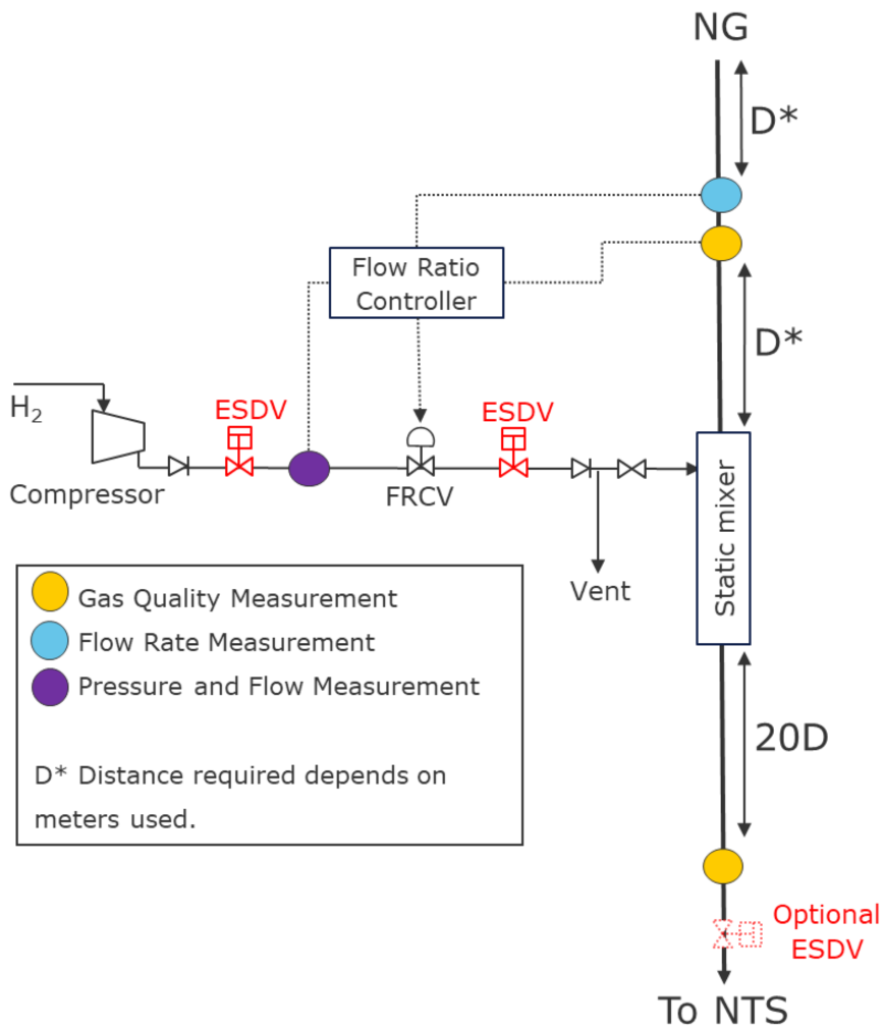

Figure 6-8: Gas Entry Unit 1 (GEU1) for Injection of Hydrogen at St Fergus

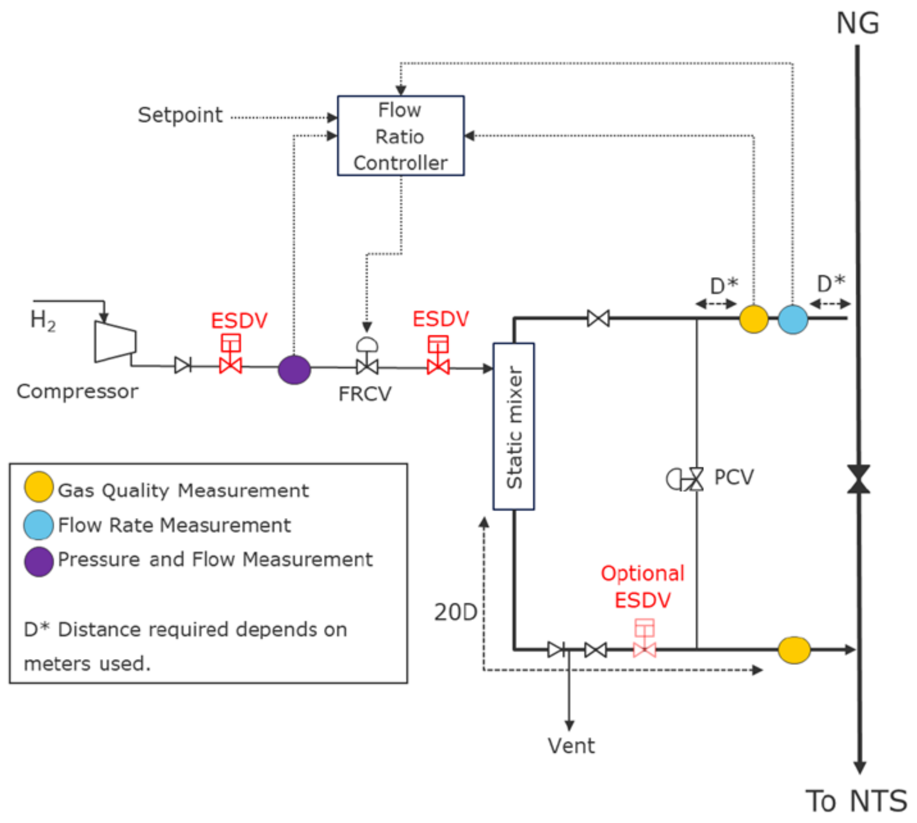

Figure 6-9: Gas Entry Unit 2 (GEU2) for Injection of Hydrogen at St Fergus

GEU1 assumes injection directly into the natural gas line and is superficially the simpler option, however the more complex GEU2 offers several advantages:

- No equipment needs to be installed into the existing St Fergus pipework with the exception of two tees and an isolation valve.

- The unit includes a bypass equipped with a pressure control valve (PCV) to prevent a failure of the hydrogen injection system interrupting gas flow.
- Such a unit could be constructed as a skid which could include all gas flow and gas quality instruments necessary for injection and their associated mixing sections – this may give more flexibility as regards injection location.

The gas entry unit will need to be designed and appropriately safety integrity level (SIL) rated. Note that for both units an additional emergency shut down valve could be located downstream of the hydrogen injection point if it is identified that slugs of hydrogen or low WI gas contained in the pipework should not be delivered to customers. In the case of the simpler GEU1 operation of this valve may result in the temporary reduction of gas supply.

There are a number of potential locations for hydrogen injection at St Fergus. At each hydrogen injection location, a gas entry unit will need to be considered. Figure 6-8 and Figure 6-9 show example gas entry units. For each of the options the instruments currently installed that could meet part of the gas entry unit analytical and control requirements are indicated and new instrumentation identified. The first option for St Fergus would be injection of hydrogen into each of the five feeders leaving St Fergus, Figure 6-10.

6.1.1.1 Injection Location Option 1

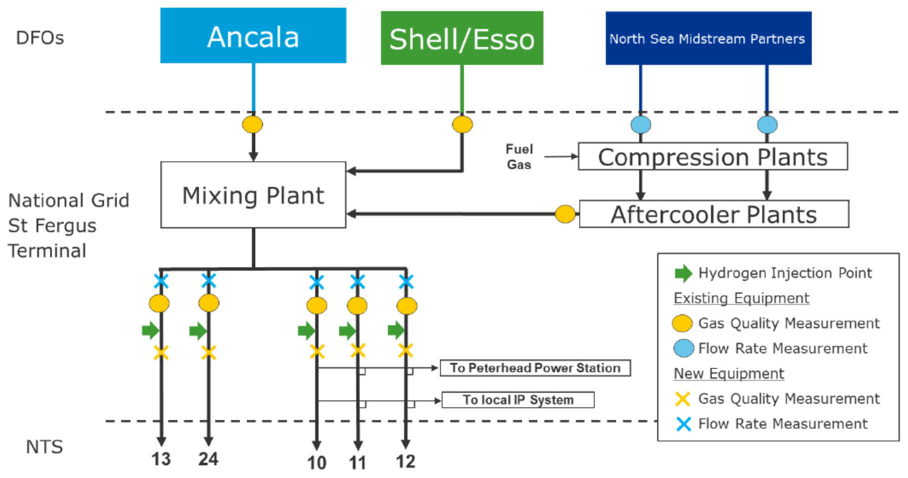

Figure 6-10: St Fergus Hydrogen Injection Location: Option 1

The advantages of this option are:

- Maintains the current St Fergus operational philosophy.
- The composition of gas in the five feeders remains the same.
- Hydrogen is only present on outgoing lines leaving St Fergus. Therefore, no changes to the compression plant or fuel gas system on the site are required.
- No changes required to the fuel gas arrangement with Shell.

The disadvantages of this option are:

- Five injection points are required; therefore, there is a higher cost related to new hardware.
- For the gas quality measurement, downstream of the hydrogen injection point, there may not be sufficient space to get the straight-

line flow for effective measurement. A static mixer could resolve this issue.

- Hydrogen would need to be compressed from 30 barg to NTS pressure.

6.1.1.2 Injection Location Options 2 and 3

The second and third options would be for injection downstream of either the Ancala (Figure 6-11) or Shell (Figure 6-12) gas quality monitoring, respectively, as it enters St Fergus. To achieve 2 mol% hydrogen at the outlet of St Fergus, there will be higher concentrations of hydrogen in different parts of St Fergus – potentially up to 100 mol% hydrogen upstream of the mixing plant when Ancala/Shell are not flowing. 2 mol% hydrogen would be achieved downstream of the mixing plant.

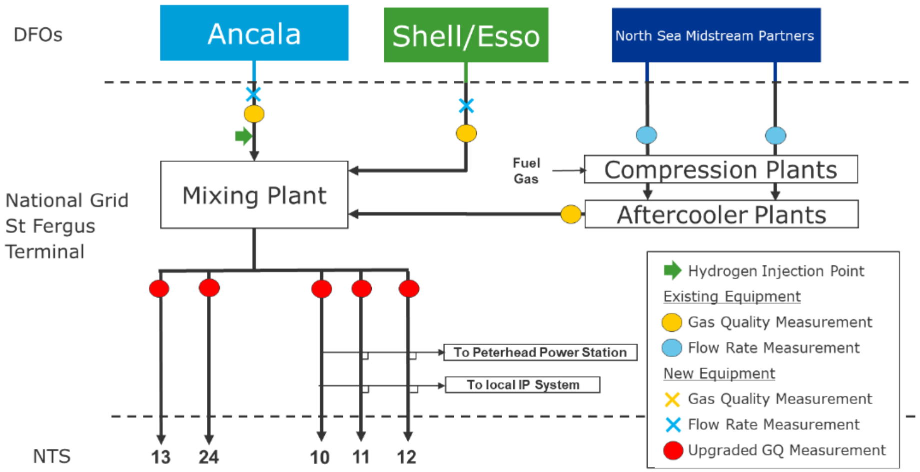

Figure 6-11: St Fergus Hydrogen Injection Location: Option 2

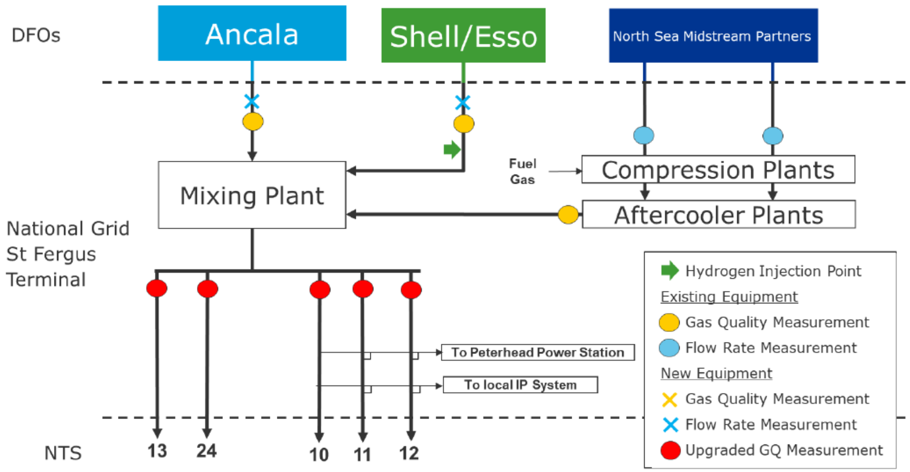

Figure 6-12: St Fergus Hydrogen Injection Location: Option 3

The advantages of these options are:

- A single injection point is needed
- Mixing will take advantage of the current St Fergus mixing plant. Therefore, less space will be required upstream and downstream of the gas quality measurement on the feeders to achieve effective gas quality measurement.

The disadvantages of these options are:

- The current St Fergus operational philosophy will need to change.
- There is a potential for hydrogen to be present in the fuel gas to the compressors and to Shell at potentially greater than 2 mol% hydrogen. Therefore, the process units being supplied by these sources of gas will need to be checked for compatibility with hydrogen which may be greater than 2 mol%.

- Additional flow measurement would be required to monitor and manage the overall hydrogen injection.
- Control complexity - feedback from all 3 metering streams is needed to ensure 2% hydrogen not exceeded.
- Hydrogen would need to be compressed from 30 barg to NTS pressure

6.1.1.3 Injection Location Option 4

The fourth option of hydrogen injection into St Fergus is upstream NSMP partners compression plants, Figure 6-13. To achieve 2 mol% hydrogen at the outlet of St Fergus, there will be higher concentrations of hydrogen in different parts of St Fergus – potentially up to 100 mol% hydrogen through the compressors. 2 mol% hydrogen would be achieved downstream of the mixing plant.

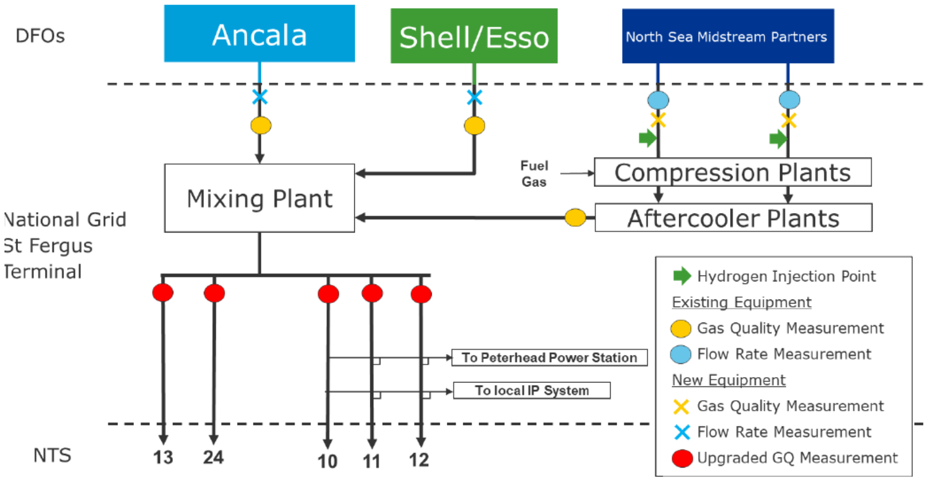

Figure 6-13: St Fergus Hydrogen Injection Location: Option 4

The advantages of this option are:

- Hydrogen would need to be compressed from 30 barg to 40 barg to match the operating pressure of the gas entering from NSMP. The rest of the compression could be undertaken by the existing compression assets.
- Mixing will take advantage of the current arrangement of St Fergus. Therefore, less space will be required upstream of the gas quality measurement on the feeders to achieve effective gas quality measurement.

The disadvantages of this option are:

- Arrangement with NSMP may need to be revisited regarding compression of non-NSMP gas.
- The compressors will need to be assessed for the impact of hydrogen with the natural gas. This would need to be completed by approaching the compressor manufacturer and the compressors may need to be re-wheeled. 2 mol% hydrogen may be acceptable as part of the gas that is being compressed gas, but higher percentages may not be suitable. Therefore, two trains of compressors may need to be operated.
- The current St Fergus operational philosophy will need to change.
- There is a potential for hydrogen to be present in the fuel gas to the compressors and to Shell. Therefore, the process units being supplied by these sources of gas will need to be checked for compatibility with hydrogen which may be greater than 2 mol%.
- Additional flow measurement would be required to monitor and manage the overall hydrogen injection.

- Control complexity - feedback from all 3 metering streams is needed to ensure 2% hydrogen not exceeded.

6.1.1.4 Injection Location Option 5

Option 5 is the blending of hydrogen into the gas at one or more of the individual Shell, Ancala or NSMP terminals. Details of the process schemes with these individual plants are not available but essentially the requirements for hydrogen injection locations and analysis would be broadly similar to those for options 2 to 4. It should be noted however that the Ancala terminal has two separate process facilities and the NSMP terminal has 3 gas processing trains so there may be a need for multiple blending facilities within each of the latter two.

The advantages of this option are:

- Hydrogen compression may be avoided if a suitable low pressure location is found for blending in the host terminal(s).
- Mixing will take advantage of the current arrangement of St Fergus. Therefore, less space will be required upstream of the gas quality measurement on the feeders to achieve effective gas quality measurement.

The disadvantages of this option are:

- Commercial agreements with the individual gas terminal will be needed to accept and inject hydrogen and for the additional compressor duties they will incur.
- Control complexity - hydrogen blending will need to take account of the rates for each gas terminal if the target rate of 2% hydrogen is to be met with injection at only one or two of the upstream terminals. This will require coordination of blend based on overall gas rate and gas quality measurements fed back to the upstream plants from St Fergus.
- The host gas terminals will need to be assessed for the impact of additional hydrogen on their process streams.
- The fuel gas to compressors at St Fergus will potentially see a hydrogen blend. This would require approaching the compressor manufacturer to determine operability on a hydrogen blend and the compressors may need to be re-wheeled. 2 mol% hydrogen may be acceptable as part of the gas that is being compressed gas, but higher percentages may not be suitable. Therefore, two trains of compressors may need to be operated.
- The current St Fergus operational philosophy will need to change.

6.1.1.5 Injection Location Option 6

In addition to the options presented above, option 6 is the potential to isolate a single feeder for hydrogen injection. The chosen feeder would then supply a >2% hydrogen blend to the Aberdeen compressor station where the gas would mix with the flow from the other feeders.

To avoid delivery of >2% hydrogen to customers the feeder chosen must have no gas offtakes prior to its recombining with other Feeders at Aberdeen Compressor station. This methodology has the advantage of only requiring a single hydrogen injection point resulting in better control and isolation of hydrogen. However, it would require changing the operating philosophy of the NTS, reduce the options for network configuration for the whole system and would require careful monitoring and complex control to ensure that the blend produced at Aberdeen did not exceed 2% hydrogen and met GS(M)R. This is especially important as the high hydrogen feeder will contain a large inventory of ‘off-spec’ gas.

The following table, Table 6-2, summarises the options discussed above. More information surrounding each of the options would be required to make a recommendation at this stage of the project.

Option	1	2 & 3	4	5	6
Description	At the Feeders	Downstream of Ancala or Shell Gas Quality Monitoring	Upstream of NSMP Compressors	Connection outside of NG	Dosing to an individual Feeder
No. of Injection Points	5	1	2	1-?	1
No. of new GQ measurements	5	-	2	1-?	1
No. of New Flow Measurements	5	2	2	2+	5
No. of Upgraded GQ measurements	-	5	5	5	5
Advantages	Maintains current St Fergus operational philosophy Composition of the five feeders remains the same No changes to the compression plant or site fuel gas system No changes required to compressor fuel gas arrangement with Shell	Single injection point Uses existing mixing plant	H_2 compression only needed from 30 to 40 barg Uses existing mixing plant	Hydrogen compression may be avoided if a suitable Mixing will take advantage of the current arrangement of St Fergus.	Single injection point No impact on St Fergus
Disadvantages	Five injection points needed Extra space or a static mixing may be needed to ensure H_2 mixing H_2 needs compression from 30 barg to NTS pressure.	St Fergus operating philosophy must be changed Potential for H_2 in fuel gas Additional flow measurement needed to allow control of H_2 injection rate H_2 needs compression from 30 barg to NTS pressure Control complexity	NSMP agreement will need revision May require compressor modifications St Fergus operating philosophy must be changed Potential for H_2 in fuel gas Additional flow measurement needed to allow control of H_2 injection rate Control complexity	Commercial agreements with the individual gas terminals will be needed May require compressor modifications Control of dosing will be complex and needs to be coordinated between terminals St Fergus operating philosophy must be changed Potential for H_2 in fuel gas	High hydrogen blend input to NTS Complex control needed to avoid overdosing of final blend at Aberdeen High inventory of hydrogen rich gas in the isolated feeder Reduces flexibility of NTS Feeders from St Fergus

Table 6-2: Summary of Injection Options

6.2 Aberdeen Network Analysis

Modelling was conducted by SGN on the Aberdeen <7bar supply system to analyse the impact on operation under two scenarios; a 20% mixture of hydrogen and a 100% conversion of the grid to hydrogen.

The <7bar supply system consists of the Intermediate-Pressure (IP) (2-7bar), Medium-Pressure (MP) (0.4-2bar) and Local Medium-Pressure (Local MP) (0.16-1bar) grids. These all supply governors feeding into the Low-Pressure (LP) networks that operate at up to either 50 mbar, or 75 mbar.

The greater Aberdeenshire area is supplied by eight Transmission Regulator Stations (TRS). In this report however the focus is on converting the Aberdeen city area to hydrogen. Therefore, only the areas supplied by three TRS (Aberdeen City Gate, Craibstone, and Kinknockie) are considered. In the future the whole Aberdeenshire may be connected however at the moment that is considered beyond the scope of this report.

Hydrogen scenarios were also modelled on the existing LP networks; Aberdeen city was chosen due to it being the main network on this system along with two smaller low pressure networks which were deemed to be representative of the typical isolated networks servicing towns and villages in the area. There are 22 separate low pressure networks on the Aberdeen grid. To provide an adequate range of networks one was chosen in the north of the Grid fed from MP (Mintlaw) and one was chosen from the south fed from IP (Cove Bay). Both of these small LP networks were also selected as the lowest pressures on these networks are close to the 21mbar statutory requirement pressures; implying without analysis that reinforcement would be required, should they be converted to either 20% blend, or 100% hydrogen.

Lastly, it is to be understood that this modelling analysis is a high-level overview, that the gas distribution network is subject to continuous change due to; ongoing replacements, reinforcements, diversions, and connections/disconnections. It is expected a more in-depth study will be required to determine the full scope and routes of replacements and reinforcements which are identified as a requirement to enable the scenarios described as part of this document. Further alterations to these requirements may be required on completion of other industry studies which will investigate the impact of Hydrogen on steel mains and its impact on Pressure Reduction Installations.

Due to potential issues surrounding hydrogen in metallic mains the entire model was converted to a point where it could be considered equivalent at a high level to being fully PE. PE is typically modelled with a higher efficiency than metal mains (0.97 PE vs 0.89-0.93 for Metallic) due to less leakage and smoother pipes.

To carry out the partial replacement within the model, all HDPE and PE mains were unchanged. Steel mains were also left unchanged due to the issues with inserting mains requiring open cut replacement, it was therefore considered that all steel mains would have been replaced with PE, size for size, in an open cut replacement. From this an example replacement of all iron mains was conducted. This was done by inserting the mains and upsizing where appropriate to limit pressure drops, per existing replacement design philosophy.

Please note this is not a comprehensive method and greater pressure drops may be expected due to future choices around replacements, insertions, and abandonment. This was however considered a suitable method for the high-level study carried out for this report. This method was based on losing no capacity due to mains replacement, i.e. where capacity is lost due to insertion it can be regained by replacement upsize/reinforcement.

Any reinforcement figures identified due to the blending/conversion of the network to hydrogen are considered, again, to be absolutely conservative, minimum lengths. This is due to the expected variation in the final replacement designs and more so due to potential routing issues were not considered when analysing reinforcements (crossings, wayleaves etc.).

The main considerations/ assumptions due to the high level nature of this work are as follows:

- It was considered that there would be no specific impact on capacities of governors other than the change in flow. It may be that governor capacities are varied by hydrogen or that governors function in ways other than intended with hydrogen.
- When designing out the replacement of iron in Aberdeen it was considered that all iron mains would be replaced. The method for this replacement is expected to vary when greater consideration is placed on growth and potentially routing issues etc.
- When designing reinforcements, no consideration was given to the routes taken, therefore the lengths are considered to be conservative minimums.
- Steel was considered to have been replaced as size for size open cut.
- The potential reinforcement and issues that would be seen in connected system exit point (CSEP) sites run by independent gas transporters were not considered at this stage. Further engagement work would be required to confirm if these sites have the ability to be safely and easily converted. To provide a sense of scale there are approximately 150 CSEPS on Aberdeen LP and 40 on Aberdeen MP-IP. Each CSEP will normally provide gas to between 5 and 500 homes.

6.2.1 Velocity of Hydrogen

When modelling a 100% hydrogen scenario it was found that average velocities greatly increase due to the increased overall flow caused by the lower CV of hydrogen.

The modelling work presented is based on the worst case scenario, i.e. the 1 in 20 peak hour demand design parameters, this level of demand would only occur, theoretically, once every 20 years. The 1 in 20 design case is important in the context of the gas velocity as the velocities will be much less under normal operation.

Recent work by SGN on the Real Time Network project (SGN, 2020) has demonstrated that for the trial area, when using real time data supported by a new model for variable diversity, a reduction in peak demand has been indicated. Depending on a range of variables relating to consumer population and asset base, other networks will likely be subject to variations in their peak demand, albeit this would not necessarily mean a reduction. With this in mind, it is conceivable that some networks may also see similar reductions in modelled peak demand, however this is subject to each network being modelled with relevant datasets. For the purpose of this evaluation the results of the Real Time Network project have not been considered.

The velocity increase to maintain the equivalent energy flow through the same sized pipework is approximately 3.5 times that of natural gas. While pressure drops were less significant due to the lower viscosity, many networks surpassed their current maximum velocity of 40m/s, as outlined in gas networks NP18 Policy for Network Planning. This change was not fully accounted for in the mains requiring reinforcement therefore the cost of reinforcement will likely be higher, if the 40 m/s limit is to remain un-changed. Table 6-3 shows the change in the average velocity of a network and the number of mains which will breach the 40m/s policy under peak 6 minute “1:20” winter conditions.

The move to 20% hydrogen has a much smaller impact and if the 40m/s policy is maintained then a minimal amount of reinforcement is required for 20% blending in both MP and IP networks.

For the 100% converted network there is minimal impact on the LP network with less than 0.7% of the total LP mains forecast to be above 40m/s. These lengths are easily remediated by reinforcement or can be included in a replacement programme, in line with current replacement policy, prior to the time of conversion.

The MP-IP network shows significant lengths of MP-IP mains that will be above 40m/s when moving towards 100% hydrogen as highlighted in Table 6-3, Figure 6-14 and Figure 6-15.

Figure 6-16 shows a breakdown of the impact of hydrogen on MP-IP mains by grouping the total lengths affected into velocity ranges.

A similar evaluation of the impacts of hydrogen on velocity in the network was undertaken as part of the H21 Leeds City Gate project (Northern Gas Networks, 2016) and delivered similar results concluding:

The vast majority of MP network had no velocity problems and there are limited areas that operate above 60m/s or 80m/s, which could all be easily rectified through strategic reinforcements, or it may even be considered reasonable for the short peak periods of time that these velocities could occur.

In addition, as the metallic pipes in the distribution system are being replaced by PE, dust becomes a less significant issue, as it is not produced in a PE system. It is proposed that velocities up to 80m/s in the MP system may well be considered reasonable and acceptable from an engineering integrity perspective. Further work on this subject was identified as part of the H21 roadmap and the opinion of the H21 project team was that a new parameter of 80m/s will not be a concern and acceptable in a hydrogen network.

Based on the assumption that 80m/s is acceptable as the velocity limit, although this has yet to be proven by the H21 project, approximately 8.5km of existing MP-IP mains would have ongoing velocity problems in the Aberdeen network, equating to less than 1% of all mains, which would be easily corrected through strategic reinforcement.

In conclusion, there are no significant velocity problems associated with converting the Aberdeen distribution network to 100% hydrogen.

Network	Average velocity (m/s)			Number and length (m) of Mains above 40m/s					
				Base		20%		100%	
	Base	20%	100%	Number of mains	Total length	Number of mains	Total length	Number of mains	Total length
Aberdeen MP-IP	7.00	8.32	23.22	5	215	25	1,728	698	67,351
Aberdeen LP	2.66	2.95	8.21	2	4	3	12	65	1,119

Table 6-3: Average Velocity on the Aberdeen MP-IP Network and LP Network

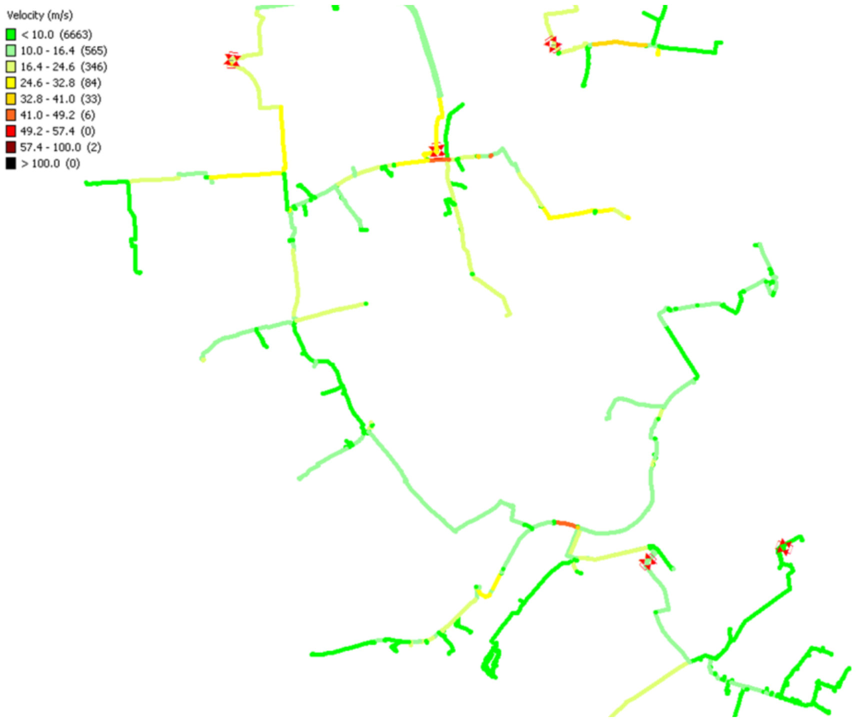

Figure 6-14: Baseline Velocity in Network for Natural Gas 1 in 20 Demand

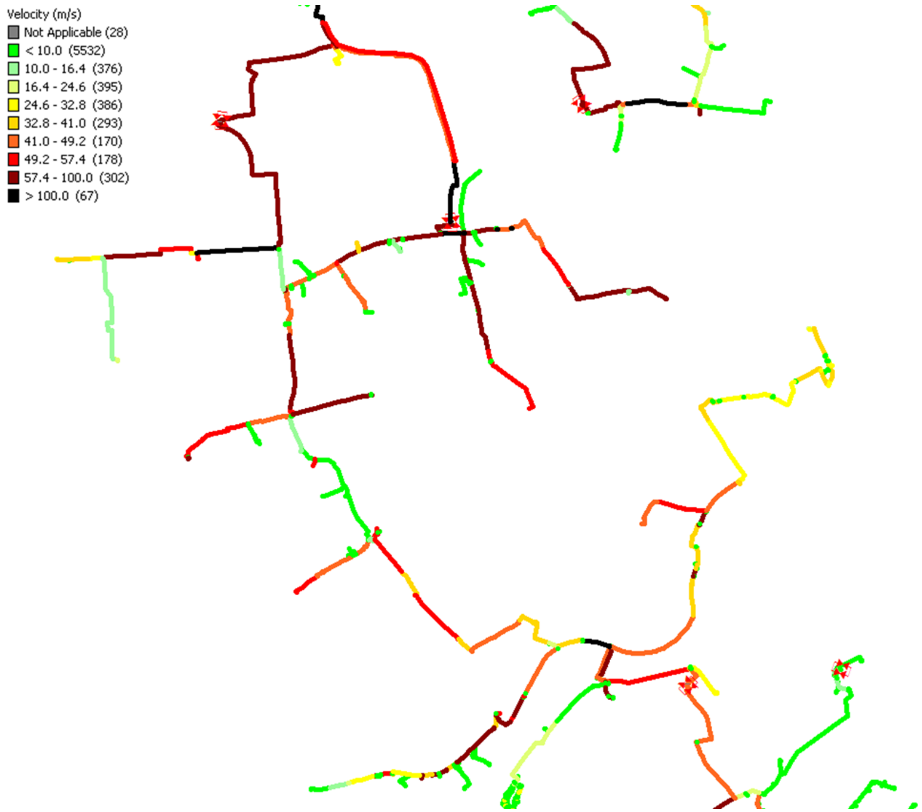

Figure 6-15: Velocity in Network for 100% Hydrogen 1 in 20 Demand

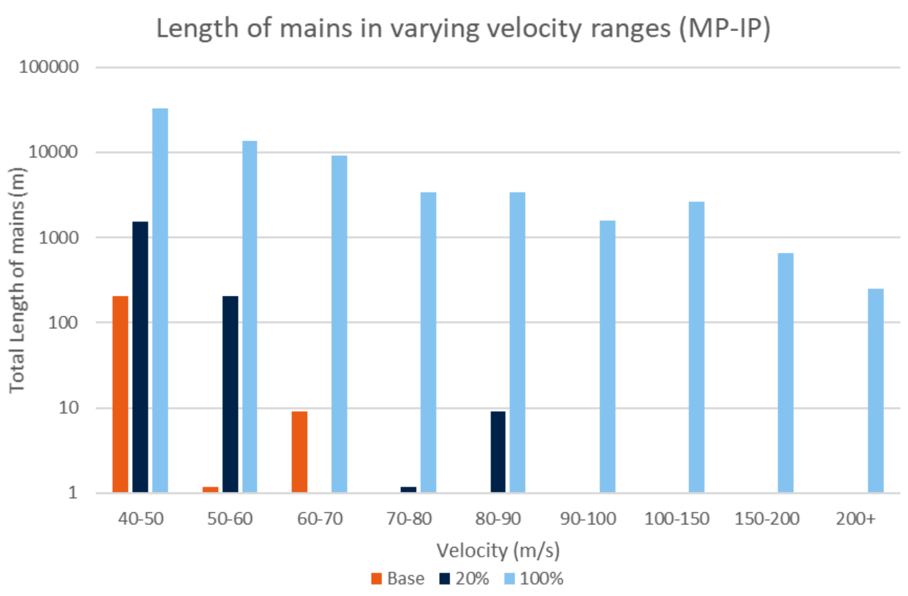

Figure 6-16: Impact of Injecting 100% Hydrogen on the Velocity in the Network

6.2.2 Reinforcement

6.2.2.1 Mains

Table 6-4 shows the approximate length of mains-laying reinforcement required for each network. Please note that this reinforcement will vary depending on the feasibility to uprate a networks operating pressure range along with, depending on the growth of specific and localized demand, any governor capacity-based reinforcement. Cove Bay and Mintlaw are representative of the LP networks fed from the Aberdeen MP/IP and the figures above should not be viewed as the predicted total reinforcement requirement to enable these hydrogen scenarios.

6.2.2.2 District Governors (MP/IP to LP)

From analysing flows it was found that transitioning to 20% hydrogen should only impact the District Governors (DGs) which are already at close to capacity (4 in Aberdeen, and Mintlaw DG). However, 100% hydrogen would cause at least 16 DGs and 8 District Pressure Governors (DPGs (IP/MP) to exceed their capacity. A summary of this is shown in Table 6-5. There is a reasonable degree of uncertainty around these figures due to lack of knowledge of about the impact of hydrogen on DGs, their components, and their maximum flow rate. This is to be investigated as part of further feasibility studies.

Scenario:	20%	20%	100%	100%
	Length (m)	% Network	Length (m)	% Network
Aberdeen local MP	0	0	2500	5.8
Aberdeen MP	1000	0.7	5300	3.6
Aberdeen IP	3000	2.3	5000	3.9
Aberdeen LP	1000	0.2	7500	1.35
Cove Bay*	100	0.4	250	1
Mintlaw*	260	2.6	300	3

Table 6-4: Minimum Reinforcement Length Required

Scenario:	Base	2030 Base	20%	100%
	Total # of PRIs	# out of capacity	# out of capacity	# out of capacity
Aberdeen MP-IP	20	0	0	8
Aberdeen LP	29	6	4	19
Cove Bay	8	0	0	1
Mintlaw	4	1	1	1

Table 6-5: Total Number of Governors that will be Pushed Out of Capacity

6.2.3 Aberdeen MP-IP Analysis

The Aberdeen MP-IP network connects to the High Pressure and distributes gas (at between 2-7bar) to supply customers in Aberdeen and the neighbouring coastal region between Muchals in the south and Peterhead in the north. The MP legs coming off the grid extend it further up to Mintlaw and New Leeds in the North and west to Newmachar.

6.2.3.1 Material

The full material makeup of The Aberdeen MP-IP network is detailed in Figure 6-17.

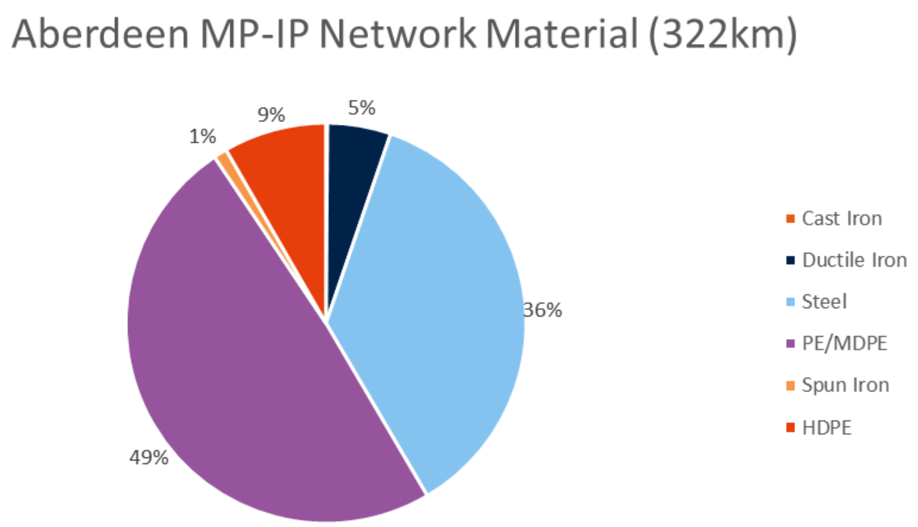

Figure 6-17: Breakdown of the Material make up of the Aberdeen MP-IP Network

To better display the variation between pressure tiers, the chart has been split into three sections. One for each pressure tier; local medium, medium and intermediate, shown in Figure 6-18, Figure 6-19 and Figure 6-20.

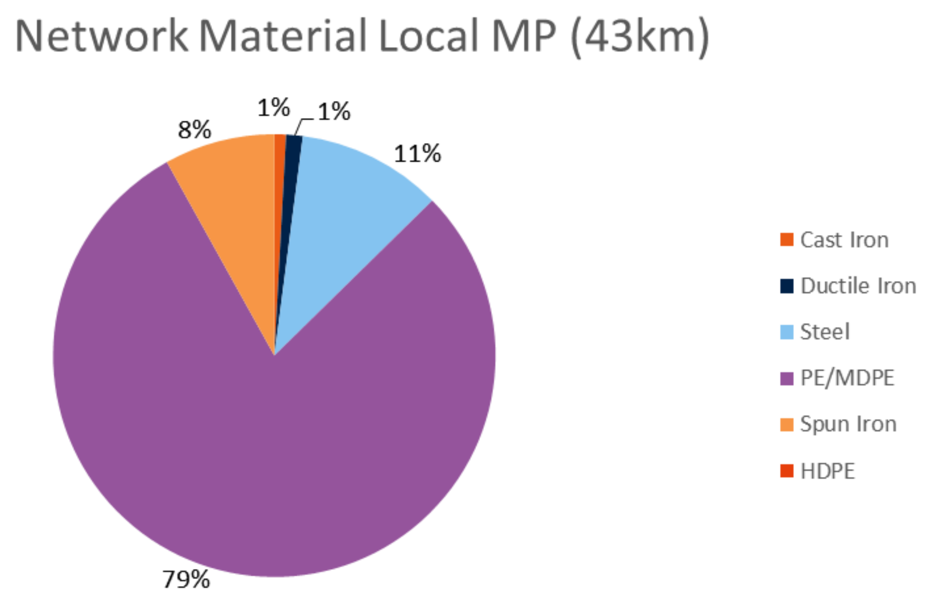

Figure 6-18: Breakdown of the Material Makeup of the Aberdeen Local MP Network

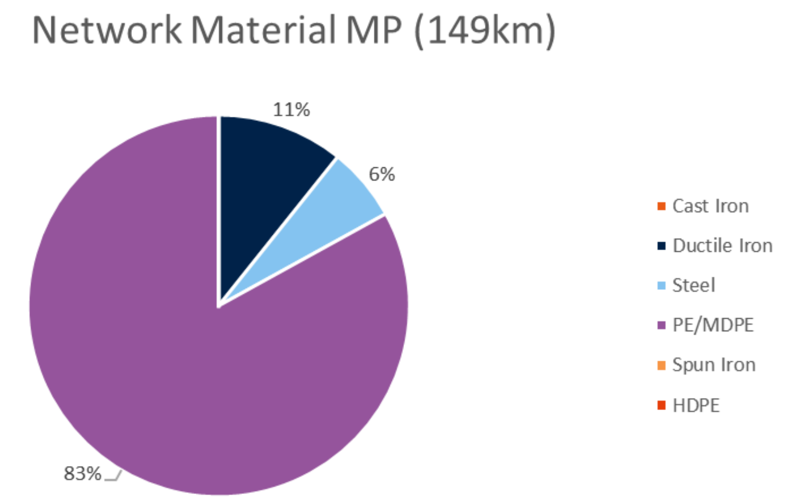

Figure 6-19: Breakdown of the Material Makeup of the Aberdeen MP Network

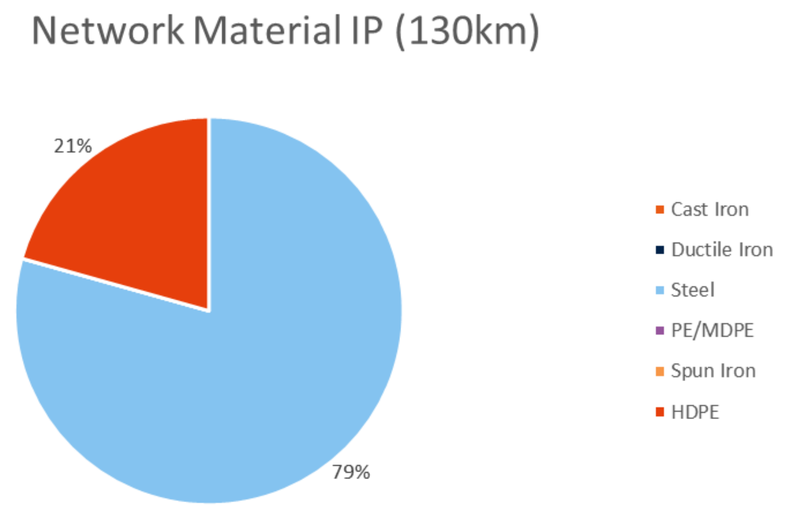

Figure 6-20: Breakdown of the Material Makeup of the Aberdeen IP Network

6.2.3.2 PRI Flows

As shown in Table 6-6 and Table 6-7, several of the DPGs would be pushed out of capacity with a 100% hydrogen scenario. A 20% scenario appears to not cause notable capacity issues on the Aberdeen grid. As discussed in section 6.2.2.2 however, there is still further feasibility work required to confirm the affect that hydrogen will have on the capacity of PRIs.

Please note that the capacities for the TRS are variable dependant on inlet pressure therefore they have been given as a range. Kinknockie is limited by the flow meter which can only function at up to 30 kscm/h.

TRS	Capacity (kscm/h)	Base (scm/h)	20% (scm/h)	100% (scm/h)	2030 base (scm/h)	2030 20% (scm/h)	2030 100% (scm/h)
City Gate	42-280	49,712	55,082	163,615	57,656	63,884	189,761
Craibstone	40-250	93,118	103,199	297,272	117,269	129,965	374,373
Kinknockie	30	23,422	25,956	71,609	25,183	27,908	76,992

Table 6-6: Current and Expected Flows in the Three TRS Stations Feeding the Aberdeen Network

DPG	Capacity scm/h	Base (scm/h)	20% (scm/h)	100% (scm/h)	2030 Base (scm/h)	2030 20% (scm/h)	2030 100% (scm/h)
Abbotswell Road	72,600	27,971	32,369	89,488	32,447	37,548	103,807
Ardallie Church	407	8	9	26	9	11	31
Ashhill	38,000	25,333	29,561	83,034	29,386	34,290	96,319
Badentoy	X	10	12	32	12	13	37
Clola	7,473	1,248	1,447	4,018	1,447	1,679	4,661
Dyce Drive	4,600	599	695	1,930	695	807	2,239
Ellon	20,136	5,961	6,914	19,197	6,915	8,021	22,269
Kingswells Home Farm	X	2,743	3,182	8,834	3,182	3,691	10,248
Logie Buchan	4,658	1,930	2,231	6,139	2,239	2,588	7,121
Peterhead	13,381	10,803	12,531	34,791	12,532	14,536	40,358
Quarry Road	13,381	8,658	9,941	27,018	10,043	11,531	31,340
Rowett	7,474	2,397	2,780	2,509	2,780	3,225	2,910
Scotstoun	17,703	9,738	11,303	31,436	11,296	13,111	36,466
Tedder Road	10,864	5,194	6,024	16,725	6,025	6,988	19,402
Tullos	X	63	73	202	73	84	234
Waulkmill	3,000	1,072	1,244	3,452	1,244	1,442	4,005
Wellington Road	7,474	606	702	1,950	702	815	2,262

Table 6-7: Current and Expected Flows in the DGP Stations on the Aberdeen Network

6.2.3.3 Local MP

The local medium pressure network in Aberdeen can deliver a 20% hydrogen blend with no reinforcement. Reinforcement would be required to transport 100% hydrogen. The options for this would be either 2.5km of mains-laying reinforcement or uprating of the Local MP system (1bar to 160mbar) to operate at MP (2bar to 350mbar) pressures, this however would most likely require changes to the PRI and full replacement of the remaining 17% of metallic mains (totalling 9km).

6.2.3.4 MP (2bar to 350mbar)

For the medium pressure network to carry a 20% blend of hydrogen, 1km of mains would be required on the section of the network feeding Cruden bay.

For the medium pressure sections to carry 100% hydrogen there would be reinforcement required on the Cruden Bay leg and on the leg between Scotstoun and Logie Buchan DPGs, totalling 5.3km.

6.2.3.5 IP

With both sections of the IP the key barrier to full hydrogen conversion is the amount of steel. As shown in section 6.2.3.1 the IP network in Aberdeen is 79% steel which amounts to 103km of mains.

A 20% hydrogen scenario would require some reinforcement at the tails of the network. Approximately 3km of large diameter mains would be necessary for this to minimise pressure drops on the worst tails of the network.

In a 100% hydrogen scenario a minimum of an additional 5km of reinforcement mains would be required to tackle the highest pressure drops at the tails of the network. In particular pressure drops are expected at the inlets to the DPGs feeding the local MP from the north.

6.2.4 Aberdeen LP Analysis

Aberdeen is Scotland's third most populous city, situated on the North East coast. The LP network is supplied from local MP, and its length is 556km, consisting of 454km of PE and 102km of metallic mains.

Aberdeen, while a large gas network, is controlled from a single profile group of governors, which operates robustly with limited pressure issues.

6.2.4.1 Material

The makeup of the Aberdeen LP network is shown in Figure 6-21. It is primarily PE with 75km of spun iron making up most of its 102km of metallic mains.

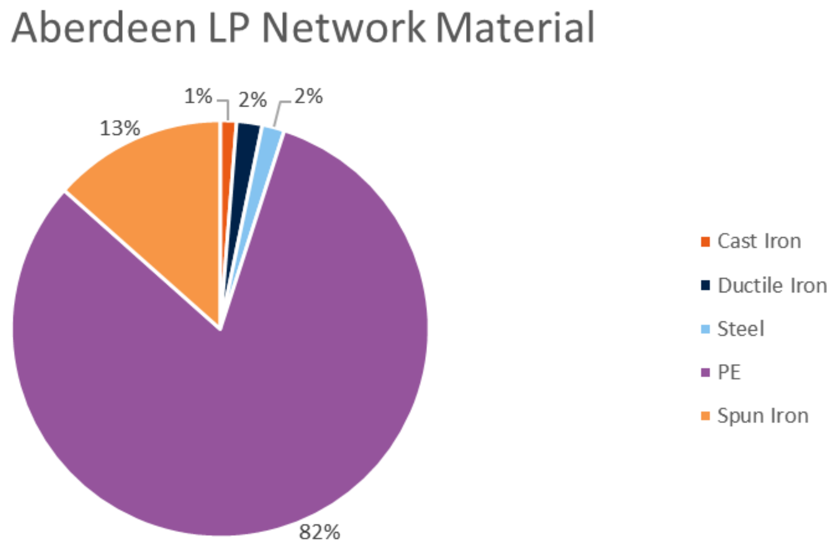

Figure 6-21: Breakdown of the Material Makeup of the Aberdeen LP Network

6.2.4.2 PRI Flows

As shown below all governors which are not flowing close to capacity will be able to handle the increase in flow from 20% hydrogen. The governors showing as above capacity at 20% are already close to capacity on the natural gas model based on historical records (Mannofield and Mounthooly are earmarked for replacement while Ashgrove and Ferryhill are currently under investigation to confirm their capacities). 100% hydrogen, however, will cause a large increase in flows and potentially a further nine DGs are required, of which two (Morningfield and Tedder Road), are expected to be replaced before 2030 due to new-builds at development sites.

DG Aberdeen	Capacity (scm/h)	Base (scm/h)	20% (scm/h)	100% (scm/h)	2030 base (scm/h)	2030 20% (scm/h)	2030 100% (scm/h)
Bucksburn South DG	8,005	1,119	1,377	4,377	1,354	1,666	5,296
CHAPEL FARM RRI	X	2	2	5	2	2	7
Don Street RRI	X	46	53	148	56	65	179
FORESTERHILL DG	16,592	2,068	2,385	6,493	2,502	2,886	7,856
CARDEN PLACE DG	14,817	10,155	11,777	32,731	12,288	14,250	39,605
ASHGROVE ROAD DG	5,500	5,386	6,244	17,355	6,517	7,555	20,999
BRIDGE OF DEE DG	8,462	4,458	5,193	14,565	5,394	6,283	17,623
COTTON STREET DG	18,873	8,301	9,669	27,170	10,044	11,699	32,876
CROMWELL ROAD DG	8,462	4,986	5,780	16,024	6,032	6,994	19,389
FERRYHILL DG	5,000	4,640	5,380	14,914	5,615	6,510	18,045
GARTHDEE DG	5,819	1,669	1,937	5,380	2,019	2,344	6,509
GEORGE STREET DG	905	663	769	2,123	803	930	2,569
MANNOFIELD DG	3,900	3,634	4,208	11,632	4,397	5,092	14,074
MARKET STREET DG	27,804	4,320	5,030	14,128	5,227	6,087	17,095
MASTRICK DG	13,661	5,732	6,635	18,337	6,936	8,029	22,188
MORNINGFIELD DG	3,799	3,238	3,736	10,225	3,918	4,521	12,373
MOUNTHOOLY DG	6,200	6,024	6,977	19,281	7,290	8,442	23,330
QUARRY ROAD DG	9,211	3,591	4,158	11,480	4,346	5,032	13,891
QUEEN'S ROAD DG	11,575	4,095	4,738	13,048	4,955	5,733	15,788
SCHOOL ROAD DG	6,423	2,640	3,076	8,650	3,194	3,722	10,467
SMITHFIELD DG	7,427	3,254	3,725	9,956	3,937	4,507	12,047
TEDDER ROAD DG	4,492	3,807	4,416	12,263	4,607	5,343	14,838
TULLOS DG	6,372	4,377	5,066	13,966	5,296	6,130	16,898
Hareness Road DG	X	1,269	1,472	4,086	1,535	1,781	4,944
Hillocks DG	4,220	1,322	1,520	4,126	1,600	1,839	4,993
KINCORTH DG	8,207	4,070	4,719	13,104	4,924	5,710	15,856
Queens Link DG	1,880	262	304	843	317	367	1,020
Sheddocksley DG	3,040	656	761	2,111	793	920	2,555
Stoneywood DG	4,083	1,733	2,004	5,518	2,097	2,425	6,677

Table 6-8: Current and Expected Flows in the DGs on the Aberdeen LP Network

6.2.4.3 LP Reinforcement

Based on theoretical analysis and an appropriate replacement program it should be possible for 20% hydrogen to be managed with increases to governors and a minimum of 1km of main laying to deal with the most severe pressure drops linked to pressure loss at governor outlets.

Reinforcement required for 100% hydrogen with replacement considered, and the network operating at 50mbar, would consist of a minimum of 7.5km of large diameter "spine" mains across the network. The location of these reinforcement mains would vary depending on the size and scope of spine mains replaced as part of the conventional mains replacement program over the coming period.

The total cost for this >7.5km of reinforcement would not be considered significant. Note, however, that costs will increase if there is a need to replace mains due to predictions around the velocities exceeding >40 m/s.

The length of mains-laying reinforcement required could be reduced if the network was constructed/converted to full PE and the network could be approved to be uprated to 75mbar throughout. This would require a significant feasibility study addressing the additional complexities. An uprating of this size of network has not been attempted and would require further remedial works to mitigate additional risks.

6.2.5 Cove Bay LP Analysis

Cove Bay is a suburb to the South East of Aberdeen, which has a population of approximately 7000. The LP network is 25km long and is mainly PE. It is supplied from the IP network to the south of Aberdeen, energised upstream at City Gate TRS.

To enable a 20% scenario, the northern DG settings can be increased to 50mbar from 33mbar, as well as a requirement to lay further reinforcement of 100m.

To enable100% hydrogen, the northern DG settings can be increased to 50mbar from 33mbar, as well as a further mains-laying reinforcement of 250m. Furthermore, in a 100% scenario it is likely that Whitehills Meadow DG would need to be replaced. This might not be the case however as there is a chance it will already have been replaced in 2030 due to planned development in the area.

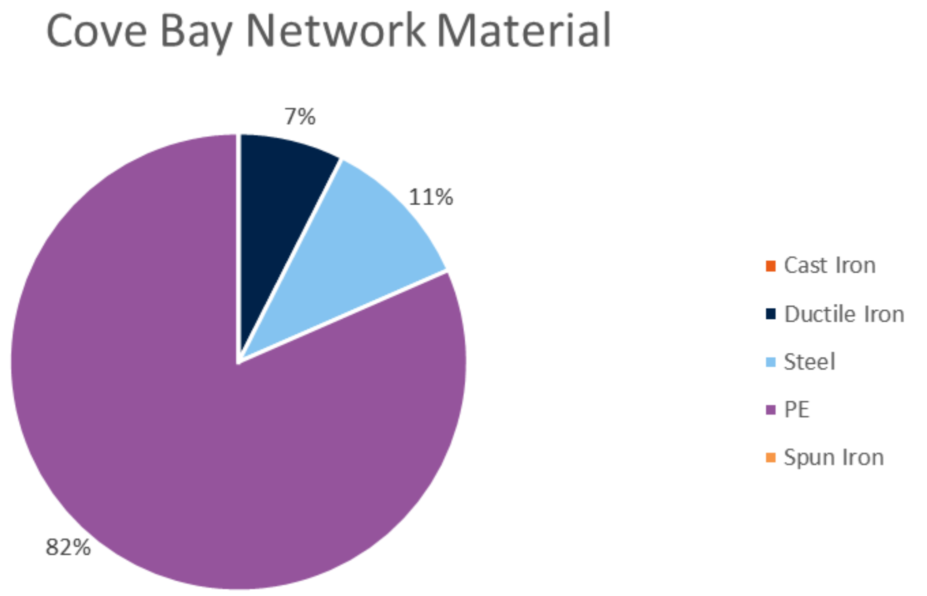

Figure 6-22: Breakdown of the Material Makeup of the Cove Bay LP Network

DG cove bay	Capacity (scm/h)	Base (scm/h)	20% (scm/h)	100% (scm/h)	2030 base (scm/h)	2030 20% (scm/h)	2030 100% (scm/h)
Altens (Cove Bay) DG	4,960	474	502	1393	550	582	1616
Cove Road DG	7,995	1,270	1,345	3,734	1,474	1,560	4,331
Cove Village DG	4,295	502	531	1,475	582	616	1,711
Loirston Mains DG	4,779	169	179	497	196	207	576
Minto Avenue RRI	X	33	35	99	39	41	114
MINTO DRIVE	X	26	27	77	30	32	89
Souterhead Road RRI	X	96	102	284	112	118	329
Whitehills Meadow DG	453	362	384	1,065	420	445	1,236

Table 6-9: Current and Expected flows through the DG and RRIs on the Cove Bay LP Network

6.2.6 Mintlaw LP Analysis

Mintlaw is a large village of approximately 2,700 people situated 40km north of Aberdeen. The LP network in Mintlaw is 10.16km long and 100% PE. It is supplied from a northern MP tail of the Aberdeen MP-IP grid. This tail is supplied by Clola DPG which is in turn energised from the 7bar grid linked to Kinknockie National Grid offtake.

For Mintlaw to be converted to 20% hydrogen it is expected that 260m of 180mm PE reinforcement would be required.

For Mintlaw to be converted to 100% hydrogen it is expected that 300m of 180mm PE reinforcement would be required.

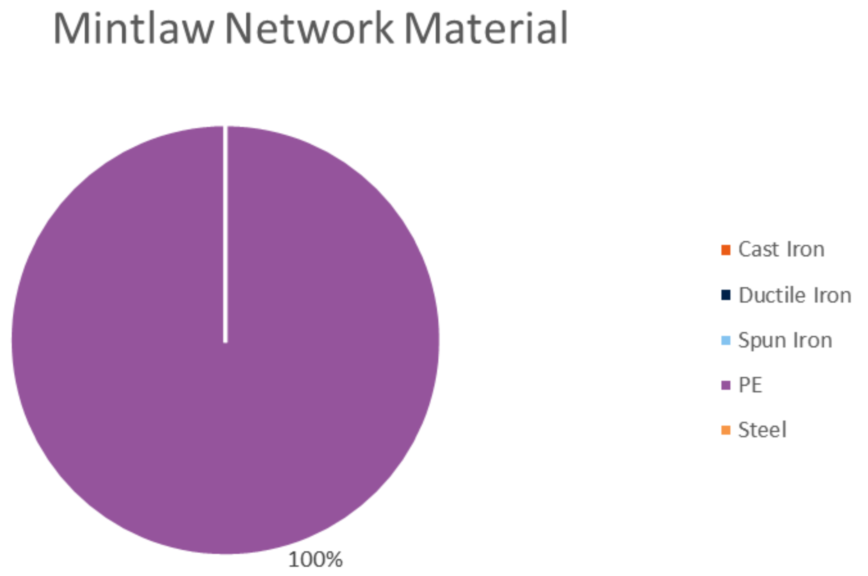

Table 6-10: Breakdown of the Material Makeup of the Mintlaw LP Network

DG Mintlaw	Capacity (scm/h)	Base (scm/h)	20% (scm/h)	100% (scm/h)	2030 base (scm/h)	2030 20% (scm/h)	2030 100% (scm/h)
MINTLAW D.G.	900	851	943	2,620	1,030	1,142	3,170
ACADEMY GARDENS R.R.I	X	61	67	187	73	81	227
SOUTH ROAD R.R.I	X	14	16	44	17	19	53
SOUTH ROAD D.G.	X	76	84	234	92	102	283

Table 6-11: Current and Expected flows through the DGs and RRIs on the Mintlaw LP Network

6.3 Hydrogen Pipeline

A new pipeline is proposed to connect the hydrogen generation plant at St Fergus to the Aberdeen distribution network. The installation of a new pipeline, in combination with the prevalence of polyethylene pipe in the distribution network, will allow for the injection of hydrogen at higher concentrations than might be permissible in the NTS. Aside from the material concerns, such as hydrogen embrittlement which can potentially be managed through the addition of oxygen, there may be some commercial considerations that restrict the amount of hydrogen that can injected into the NTS due to the impact on large industrial users that may be sensitive to gas quality changes. The use of a new pipeline also enables the conversion of sections of the distribution network to 100% hydrogen which will require isolation from the NTS. Conversion of the entire network would be a vast undertaking and would realistically need a phased approach to minimise disruption to end users.

To enable blending of hydrogen from a plant at St Fergus into the distribution network, a new hydrogen pipeline would be required to avoid disruption to the NTS. A purpose built hydrogen pipeline allows for the transport of pure hydrogen at high pressure to targeted injection locations where hydrogen can either be blended with natural gas supplied by the NTS or to an isolated area of the network that has been converted to pure hydrogen.

Hydrogen injection into the lower pressure regional distribution system could commence at 2%. This percentage could then be increased over a period of time or converted in significant percentage steps to 100% hydrogen. For the purposes of this study concentrations of 2%, 20% and 100% hydrogen have been considered.

The construction of a pure hydrogen pipeline also affords the option of being able to install offtakes that could feed hydrogen transport refuelling infrastructure and allow additional future integration of offshore green hydrogen projects currently being considered by SGN as an additional connection to the new pipeline, south of Aberdeen City.

6.3.1 Pipeline Capacity

The size of the pipeline that would be required to provide sufficient hydrogen to supply Aberdeen city and surrounding independent networks along with additional capacity for the growing interest in transport. A suitable route has been identified that could transport hydrogen from St Fergus to either a termination point near the ‘old’ Aberdeen Exhibition and Conference Centre

(AECC) or to a point close to the existing Craibstone Transmission Regulator Station (TRS). At either of these termination points, a separate system would then be developed to provide the hydrogen to appropriate entry points into the existing gas network.

It was agreed that a St Fergus inlet pressure of 70barg be utilized and that the line should be of the same diameter throughout to enable intelligent pigging to be undertaken along the full length of the pipeline.

Table 6-12, provided by SGN, summarises the current peak natural gas flows, along with the 2030 estimate of the peak natural gas flows, of the TRSs feeding the Aberdeen city and surrounding independent networks. The peak flow is based around a worst case "1:20" winter scenario. St Fergus demand has been excluded as this network is fed from a TRS located inside the St Fergus compressor station and as such will not require any demand from the pipeline.

As with most pipelines that are not utilised at 100% capacity throughout the day, there will be some linepack available. The amount of linepack was not calculated as part of this feasibility study and more discussion around the need for hydrogen storage is included in Section 7.4.

Please note that the 2030 flows are generally for guidance only but can be used to give an idea of how demand is expected to grow, however, these have been used to determine potential pipe sizing.

The DNV GL software package "Synergi-Gas" was used to calculate the required pipe sizing. The input parameters are shown below:

TRS	Current peak natural gas flow (scmh)	2030 peak natural gas estimate (scmh)
Craibstone	82,900	110,000
Citygate	46,000	63,000
Kinknockie	21,800	28,000
Kintore	11,200	15,000
Westhill	5,800	5,800
Peterculter	10,200	13,000
Maryculter	6,500	7,200
Kemnay	1,100	1,500
Total natural gas	185,500	243,500
Total hydrogen equivalent	598,423	785,531

Table 6-12: Current and Predicted Natural Gas Demand for Aberdeen Local Transmission Stations

Hydrogen properties used:

- Molecular weight: 2.0
- Liquid volume: 0.8
- HHV: 12.11
- Specific gravity: 0.0696
- Viscosity: 0.00876 cP

Pipeline parameters used:

- Inlet pressure: 70 bar
- Pipe length: 53.24 km
- Pipe material: ST

The demands used were the current peak gas demand, and the expected peak gas demand for 2030 with a conversion factor of 3.226, based on the differences in energy density on a lower heating value basis, to obtain the hydrogen equivalent demand.

The results, shown in Table 6-13 below, of the various runs conclude that a 425mm (17”) pipeline would give sufficient pressure at the demand points.

Int. Dia.	Outlet Pres. (barg) – 2030 Demand (786 kscmh)	Outlet Pres. (barg) – Current Demand (598 kscmh)
475 mm	53.96	61.16
450 mm	47.68	58.05
425 mm	37.21	53.35
400 mm	10.53	45.77
375 mm	Not run, Negative Pressure Expected	31.54
350 mm	Not run, Negative pressure expected.	-26.0

Table 6-13: Outlet Pressure for Various Sizes of Pipeline

The use of 450mm (18”) diameter pipeline is recommended as this is a standard size of pipeline and also gives additional capacity should the need arise without adding any significant cost to the overall project.

6.3.2 Pipeline Route Options

Two pipelines route options were considered.

Option 1

The first terminates at a point close to the existing TRS at Craibstone.

The route corridor is selected to avoid the existing populated areas at Ellon and Dyce, including the airport.

The route crosses:

- One existing National Grid pipeline at two locations, near Thunderton and northwest of Ellon,
- Various SGN intermediate pressure and medium pressure pipelines at multiple locations.
- It is not known whether any other pipelines would be affected, e.g. the Forties crude line between St Fergus and Grangemouth.

If this route was selected, then a lower pressure pipeline would be required to transport the hydrogen further south of Aberdeen to other key locations around the existing gas network. This network may be extensive as it will need to follow the existing LTS and intermediate pressure (IP) systems and feed into all the existing nodes. As this line would likely run at a lower pressure, then it would only be possible to blend the existing network with hydrogen up to 20%, as the capacity of this line would be insufficient to deliver the full demand required.

It is estimated that an 18” pipeline would cost c£1m per km to design and build, so this would give a project cost for the pipeline of c £53m

Option 1a, would terminate at Craibstone TRS and facilitate connection to the existing IP networks north of Aberdeen at Kinknockie TRS and on the outskirts of Aberdeen at Craibstone TRS. An additional pipeline would be required to be routed from Craibstone TRS to Aberdeen Citygate TRS to ensure the entire Aberdeen city network can receive a 20% blend and subsequently be converted to hydrogen.

This option would also allow the development of hydrogen fuelling stations near both Craibstone and Citygate TRS's.

This option would add on c£1.5m to the project, which is considerably less expensive than running a transmission pipeline, and also allows a narrower pipeline corridor.

Option 2

The second route option terminates at a point close to the old AECC at the Bridge of Don

- The route corridor is selected to minimise the River Ythan crossing north of Newburgh.
- The route runs in close proximity to a National Grid pipeline southwest of Peterhead.
- The route crosses various SGN intermediate pressure and medium pressure pipelines at multiple locations.

It is not known whether any other pipelines would be affected, e.g. gas pipeline between St Fergus & Peterhead Power Station, Forties crude line between St Fergus and Grangemouth.

This option would cost in the region of £44m for the pipeline and would require further extension to the larger key TRSs in order to support a 100% conversion.

This option could also be routed around the North side of Aberdeen and connect into the network at Craibstone, but this is not the preferred option.

Figure 6-23 shows the 2 pipeline route options.

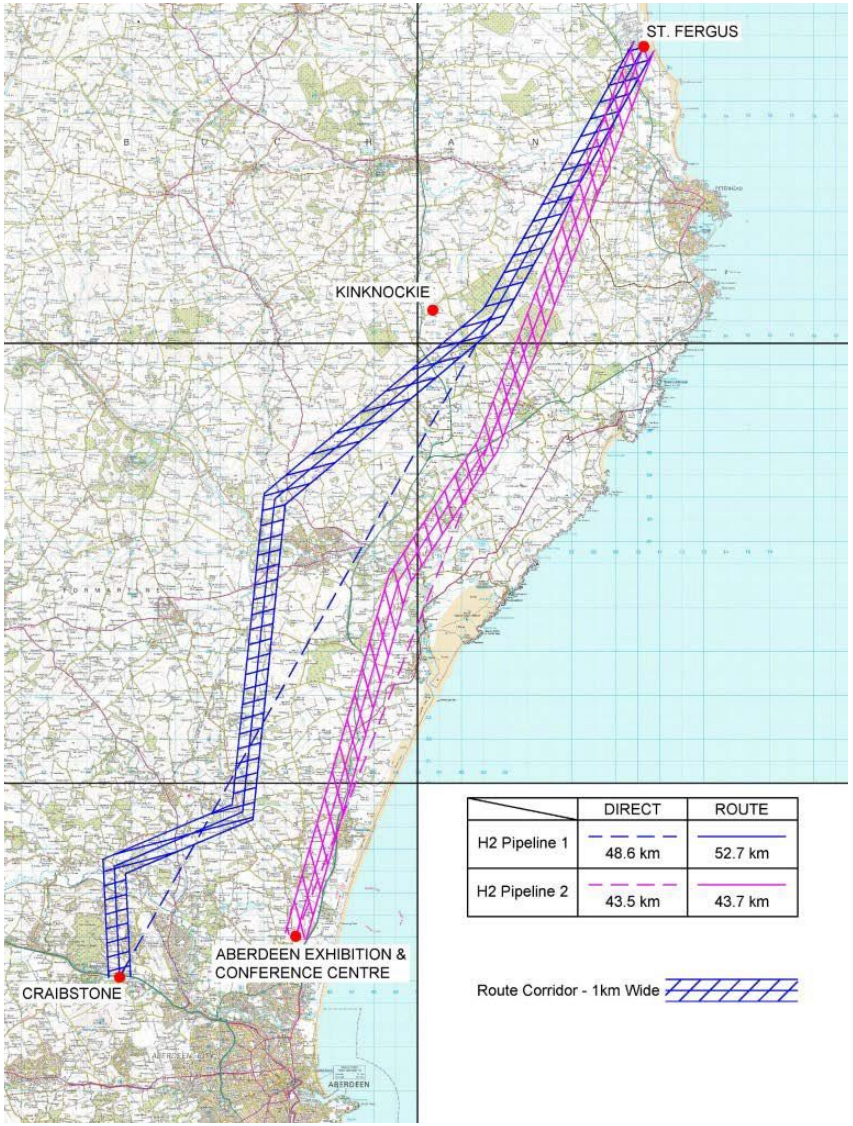

Figure 6-23: Pipeline Route Options

Of the options, Option 1a is the preferred route based on the desired end point and increased flexibility of route choice further inland. Craibstone, the HP line (and other connection options inland), are preferred locations for hydrogen connection. The 'old' AECC was considered as a potential destination for the pipeline, because SGN were considering the site for the H100 project.

6.4 Hydrogen Blend to Aberdeen City

Aberdeen and the coastal towns from Fraserburgh in the north to Muchalls in the south are fed from nine sources, two offtakes directly from the NTS at St Fergus and Kinknockie, as well as Aberdeen Citygate, Craibstone, Kemnay, Peterculter, Maryculter, Kintore and Westhill, all of which are fed from the "Northern 69 bar" LTS. This LTS system, in turn is supplied from the NTS via offtakes at Aberdeen Compressor Station and Burnhervie.

Several intermediate and medium pressure systems transport the natural gas to the district governors which in turn feed the low-pressure networks that supply the domestic and non-domestic customers in the locality.

Figure 6-24 shows a map of the Aberdeen gas network and the locations of hydrogen injection points.

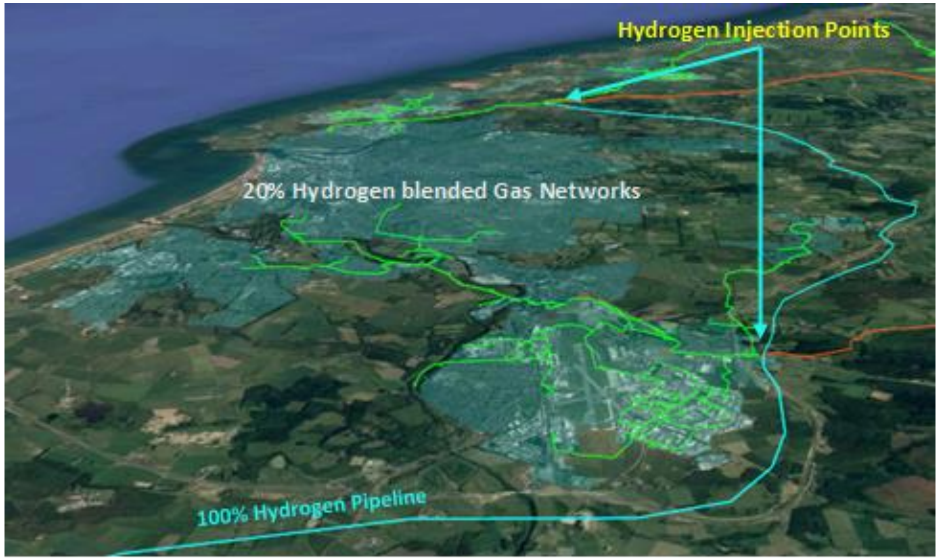

Figure 6-24: City of Aberdeen Blended Gas Networks

Within this area of interest Table 6-14 identifies the current and peak flow at each of the TRS's. The number of customers within the area of interest is approximately 98,000.

There are also several large industrial loads on this grid. A breakdown of all customers above 500scmh is provided in Table 6-15 (provided by SGN).

TRS	Current peak flow (scmh)	2030 peak estimate (scmh)
Craibstone	82,900	110,000
City gate	46,000	63,000
Kinknockie NTS Offtake	21,800	28,000
Kintore	11,200	15,000
Westhill	5,800	5,800
Peterculter	10,200	13,000
Maryculter	6,500	7,200
St Fergus NTS Offtake	7,000	8,500
Kemnay STRS	1,100	1,500
Total Demand	192,500	252,000

Table 6-14: Current and Predicted Flows at Each TRS

The majority of these customers use gas for heating and cooking, so it is anticipated that there would be no major issue in converting to varying degrees of hydrogen blend within the network. The one exception may be the CHP unit and it will be necessary to confirm that this is suitable for conversion to a hydrogen rich environment.

As hydrogen has a lower energy density than natural gas, some of the existing pipes within the network will have insufficient capacity to deliver the amount of hydrogen required. This will mean that some reinforcement of the IP, MP and LP networks will be needed as part of the conversion at the various levels of hydrogen blending. This reinforcement can be delivered strategically to assist with the conversion.

Property Name	Street	Post Code	Total_AQ (kWh)	Peak Load (scmh)
Arjo Wiggins Site 61	Stoneywood Terrace	AB21 9AB	418,299,400	7,726.16
United Fish Products ltd	Greenwell Road	AB12 3AY	30,684,391	914.1
Aberdeen Royal Infirmary	Cornhill Road	AB25 2ZN	257,354,000	4,317.5
Univerity of Aberdeen	Regent Walk	AB24 3FX	50,186,434	1,309.1
Seaton Energy Centre	School Road	AB24 1TU	21,040,526	1,167.97
CHP Unit	Woodhill Court	AB16 5PW	13,980,477	520.68
Woodend Hospital	Eday Road	AB15 6XS	14,000,000	521.21

Table 6-15: Industrial Gas Demands Above 500scmh

Pipeline routing option 1a, would enable injection of 20% hydrogen into the local Aberdeen area via the existing Craibstone and Citygate TRSs. Additionally, a connection at Kinknockie TRS would prepare the remaining northern section of the Aberdeen network to initially benefit from blending prior to complete isolation and 100% conversion to a hydrogen network.

The remaining independent networks at Kemnay, Kintore, Westhill, Maryculter and Peterculter can all be connected as part of a wider introduction of hydrogen by strategic sectionalisation and utilisation of the existing LTS.

Figure 6-25 shows the distribution network and the potential routing of a new hydrogen pipeline.

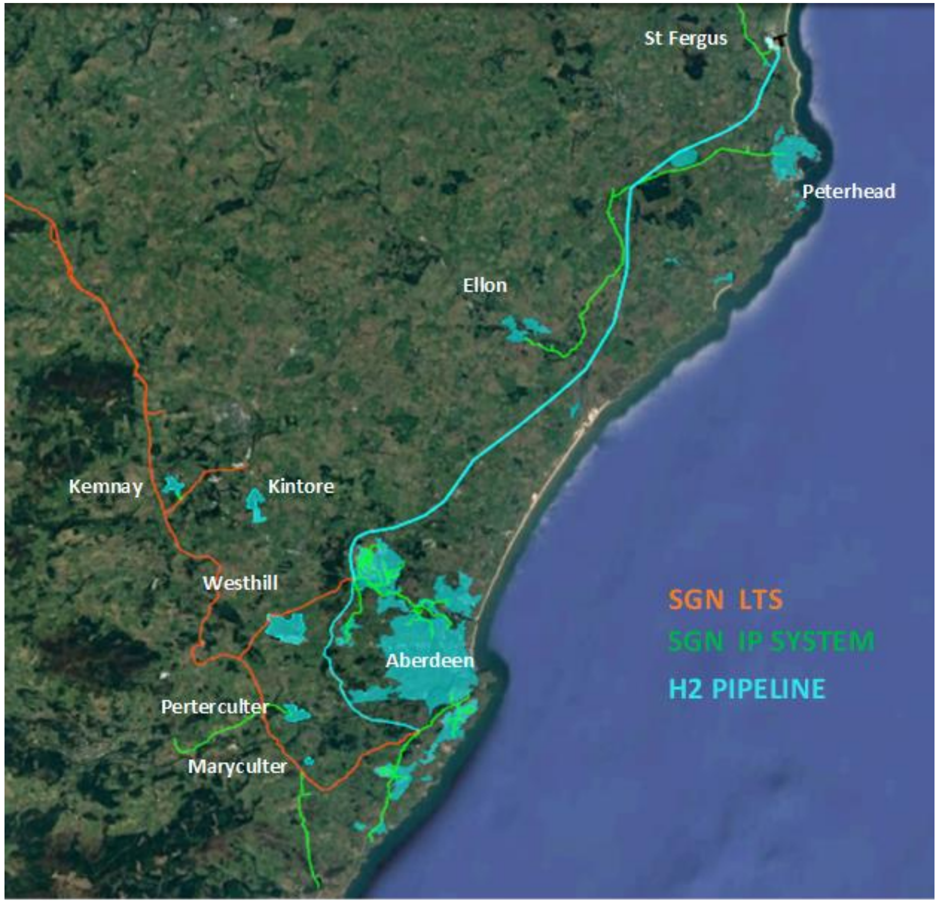

Figure 6-25: Gas Distribution Network between Aberdeen and Peterhead

Focusing on the natural gas flows through the three key feeds into the Aberdeen network, the peak hydrogen production rates have been calculated in Table 6-16. It should be noted that these figures are the peak instantaneous flows and are not representative of the average annual production rate, when using hydrogen storage this means that the production capacity of the plant will be less than the quoted flows. To estimate the annual generation requirements a load curve for Aberdeen has been produced based on the load demand of the Scottish local distribution zone, which was subsequently scaled to the peak Aberdeen demand.

Within the local distribution network, it should be feasible to target a 20% by volume blend of hydrogen without adversely affecting end consumers. Since the hydrogen generation volumes associated with lower blends are very modest for the Aberdeen region adaptation of the network to operate with a 20% blend has been targeted.

Offtake	Natural Gas		2030 Peak Hydrogen (MW)			
	Current Peak Flow (sm^3/hr)	2030 Peak (sm^3/hr)	2% Vol	10% Vol	20% Vol	100%
Craibstone	82,900	110,000	6.69	35.5	76.8	1,142
City gate	46,000	63,000	3.83	20.3	44.0	654
Kinknockie	21,800	28,000	1.70	9.0	19.6	291
Total	**192,500**	**252,000**	**12.22**	**64.8**	**140.4**	**2,087**

Table 6-16: Gas Demand for Aberdeen with Hydrogen Production Demands

Figure 6-26 illustrates the generation profile that would be required to supply Aberdeen with a 20% by volume blend of hydrogen. This demand would require an average annual demand of 45MW of hydrogen generation, this assumes the plant operates at a constant output year round. The large spike early in the year is due to the “Beast from the East” a particularly cold period that influenced the gas demand across the UK that has skewed the average demand over this period.

For a 20% by volume blend of hydrogen the average annual demand will be around 45MW of hydrogen generation, however this demand will swing between a minimum of 18MW and a maximum of 140MW. To maximise the decarbonisation potential this swing would need to be managed with storage, however there is an opportunity with a blend to reduce the hydrogen content over periods of higher energy use.

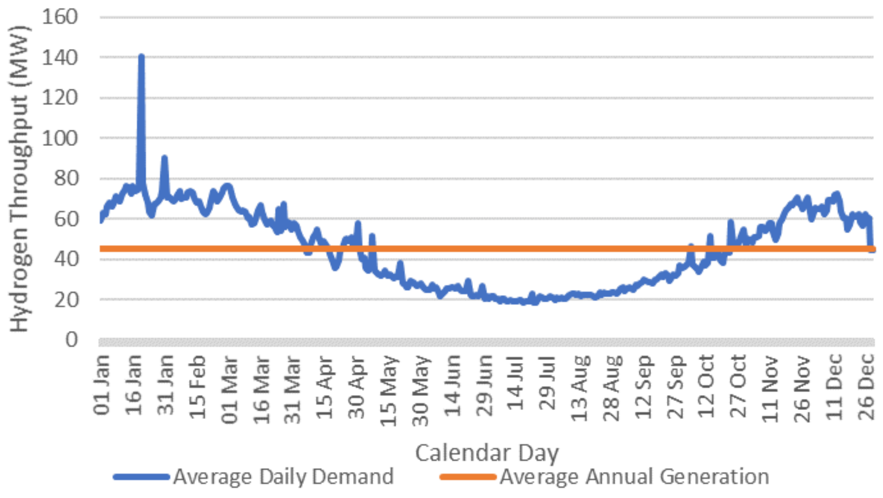

Figure 6-26: Average Annual Profile of Hydrogen Generation Requirement to Supply 20% Hydrogen by Volume to Aberdeen

6.5 Hydrogen Conversion of Aberdeen City

Complete conversion of Aberdeen City will be a significant undertaking. Moving to operation of the network on 100% hydrogen will require complete isolation from the existing network, replacement of appliances for end users and assurances that all identified reinforcements and material issues have been resolved. Security of hydrogen supply becomes a key consideration at this point as any major interruption in hydrogen supply would result in cessation of gas supplies and the existing network would no longer be the fallback position as with blending. Figure 6-27 shows the Aberdeen gas network highlighting where the network needs to be isolated from the NTS. Figure 6-28 shows where hydrogen refuelling stations could be located in the 100% conversion scenario.

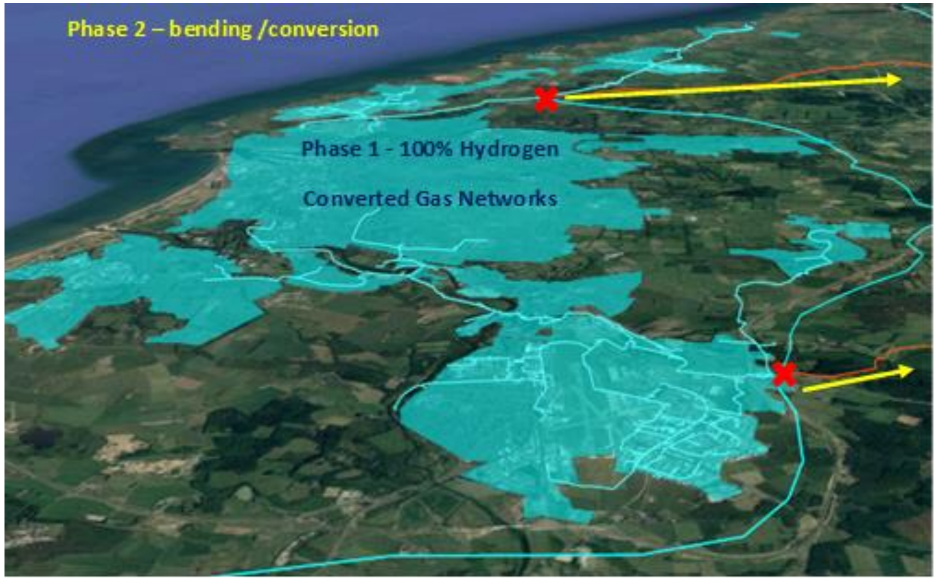

Figure 6-27: Conversion of Aberdeen Gas Neworks to 100% Hydrogen

Figure 6-28: Aberdeen Gas Network and Potential Locations for Hydrogen Transport Refuelling Stations

The generation profile for 100% hydrogen for the Aberdeen network (not including the surrounding independent networks), illustrated in Figure 6-29, requires an annual average generation of 674MW and assumes the operation of four 200MW reformation modules with a combined availability of 84%. Each module is assumed to operate at maximum capacity. Only one plant is assumed to shut down for maintenance at a time. Figure 6-30 and Figure 6-31 shows the same information in GWh/day and T/day rather than MW. Security of supply and resilience are addressed by assuming that multiple modules at 200MW will be installed and that hydrogen storage to provide inter-seasonal supply of hydrogen and for unplanned shutdowns. The flow of hydrogen into and out of storage is shown in Figure 6-32

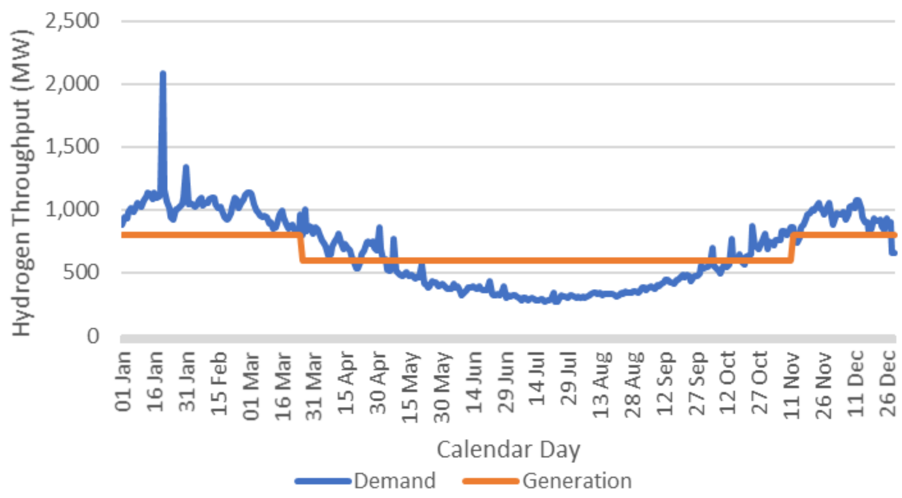

Figure 6-29: Hydrogen Requirement in MW for 100% Conversion of Aberdeen

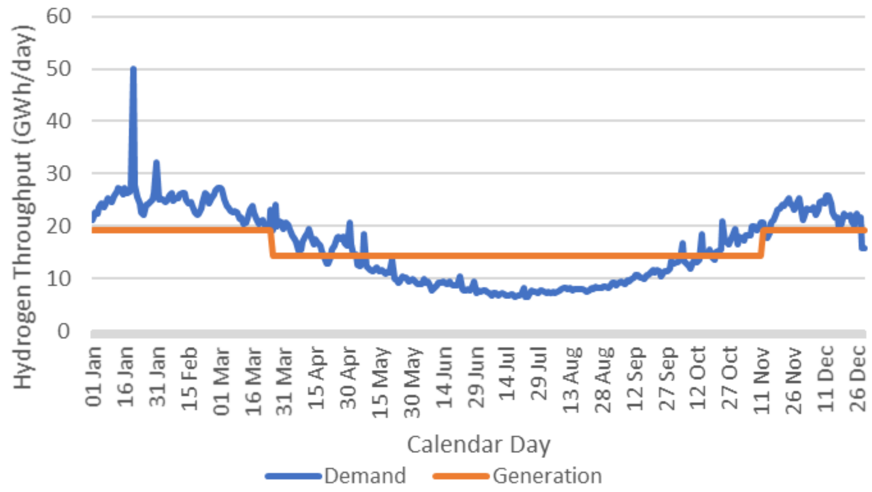

Figure 6-30: Hydrogen Requirement in GWh/day for 100% Conversion of Aberdeen

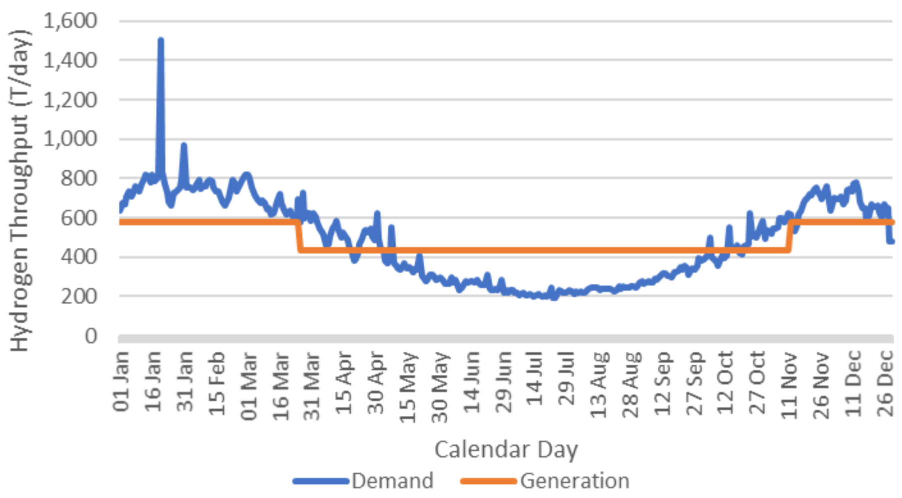

Figure 6-31: Hydrogen Requirement in T/day for 100% Conversion of Aberdeen

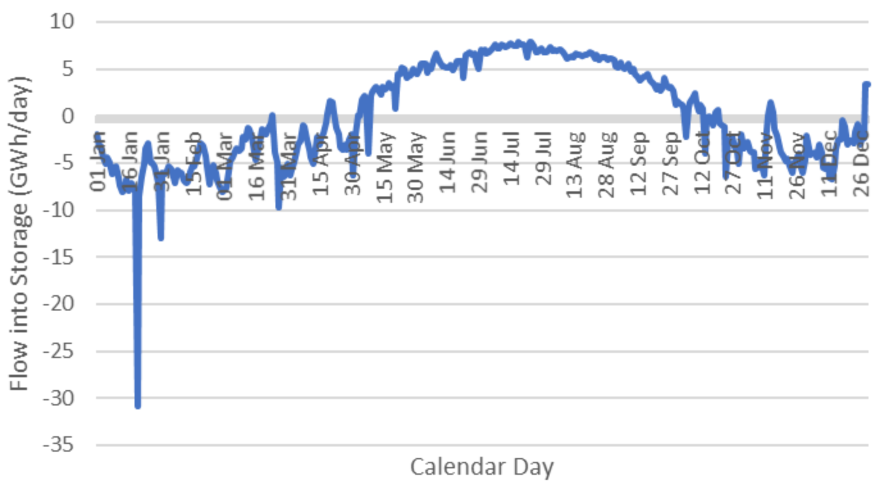

Figure 6-32: Energy Flow into and out of Storage

The total storage requirement for hydrogen would be in the range of 900GWh. However, storage quantity does not account for the turndown ratio of the production plant or make any allowance for variability between years, i.e. it does not consider the 1 in 20 severe year demand. More work is required to determine what the storage requirement would be when accounting for turndown (which should reduce the volume required) and the 1 in 20 severe demand (which will increase the volume required) as the severe demand has implications on security of supply and the network operation. The storage inventory is illustrated in Figure 6-33.

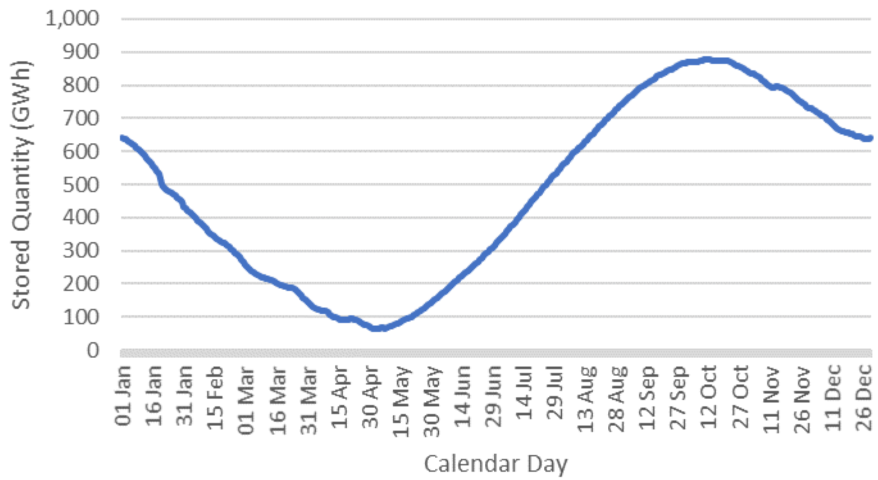

Figure 6-33: Stored Quantity of Hydrogen over a Year

The approach to decarbonisation considered most suitable at this conceptual stage is to enable a phased approach of blending hydrogen into the Aberdeen region prior to complete conversion.

- 2% injection into the NTS at St Fergus that will not only feed Aberdeen but will migrate to all lower tier networks, subject to the zone of influence for NTS gas leaving St Fergus.
- Construction of a new pipeline transporting 100% hydrogen from St Fergus, with offtakes at Kinknockie and Craibstone, with a lower pressure pipeline supplying the TRS at Citygate.
- Injection of 20% blended hydrogen into the distribution system at Craibstone, Kinknockie and Citygate.
- Isolation of the Aberdeen network from the existing LTS system at Kinknockie, Craibstone, and Citygate TRS locations following a planned conversion to 100% hydrogen of the Aberdeen network.
- Further expansion on a regional basis travelling westward using the additional capacity from the new hydrogen pipeline to convert the remaining Aberdeen independent networks i.e. Kintore/Kemnay, Westhill, Peterculter & Maryculter at some point in the future.

As neither the new hydrogen pipeline to Aberdeen or the NTS blending options are contingent on the success of the other, it would be feasible to start with either or run the projects concurrently.

The conversion strategy requires further development to assess:

- Clarity of objective for either full 100% conversion to hydrogen versus phased transition using hydrogen blending
- Clarity of the steps for % phasing of the hydrogen transition in the Aberdeen network
- Benefits/desire for all at once regional changeover versus staged conversion of smaller areas
- The new supply points to local areas that will be required to ensure that sufficient capacity is available in future due to the larger pipe sizing required for hydrogen as opposed to natural gas.
- The extent of any reinforcement required in conjunction with existing/future planned reinforcement and upgrade projects to address to the lower energy availability within a hydrogen network as opposed to natural gas.

Based on this strategy, conversion options require further review and design of;

- Assessment of the regions for phased conversion to 100% hydrogen and any additional infrastructure or equipment required
- Assessment of the distribution system materials based on in situ records and development of plans for changing any unsuitable materials/infrastructure/equipment
- Detailed route map and planning for the hydrogen supply pipeline
- Limits available for the acceptability of various blends of hydrogen to operate with existing customers appliances.
- Assessment of zones to be converted to determine resource and timescales to make ready for conversion along with the acceptable limits for customers to operate with no gas whilst during the conversion process.

6.6 Decarbonisation Potential

The Aberdeen Vision project presents significant potential to begin to decarbonise energy usage in the UK while making the most of existing infrastructure. Injection of 2% hydrogen by volume into the NTS would save 320,000t/y of CO_2 emissions, injection of 20% blend of hydrogen into the Aberdeen distribution network would save 78,000t/y of CO_2 emissions and conversion of the Aberdeen distribution network to 100% hydrogen would save 1,157,000t/y of CO_2 emissions. Conversion of the entire gas throughput of the St Fergus gas terminals would capture 55,000,000tCO_2/y representing an enormous opportunity for further decarbonisation of the UK's energy supply.

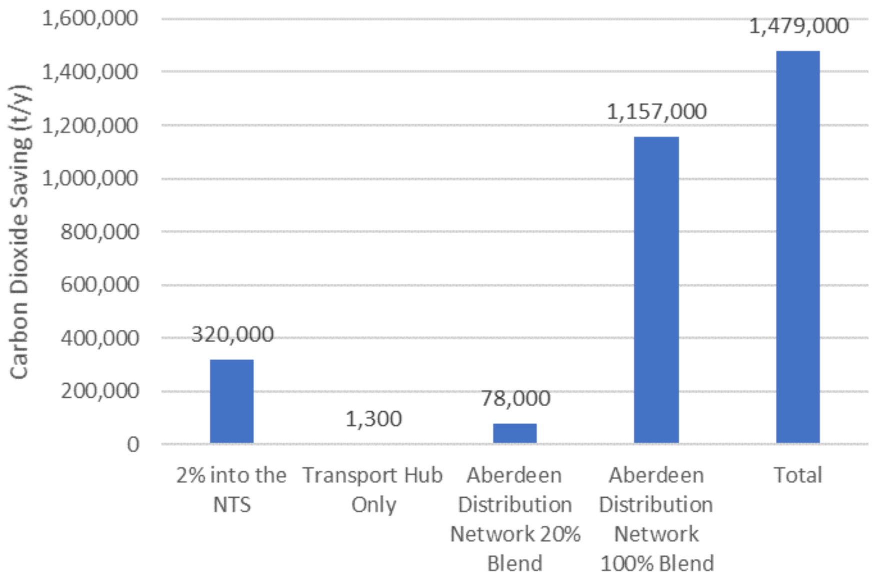

Figure 6-34: Carbon Savings Associated with Aberdeen Vision Plans

The CO_2 emissions savings are calculated by taking the CO_2 emissions associated with the hydrogen plant from the CO_2 that would be emitted if that energy was derived from natural gas. The hydrogen emissions are based on the Johnson Matthey LCH flow scheme which, due to the CO_2 capture, has a plant CO_2 emission factor of 0.008tCO_2e/MWh compared to a natural gas emissions factor of 0.204tCO_2e/MWh. If the CO_2 is not captured hydrogen generation would release more CO_2 compared to natural gas due to the energy losses associated with conversion, hence the CO_2 capture and storage element is crucial to enable decarbonisation.

7.0 Cost of Hydrogen

For hydrogen generated from natural gas to be considered low carbon the CO_2 cannot be emitted and must be captured and sequestered. This will increase the cost of a hydrogen generation project as there will be a need to either construct and operate carbon capture and storage infrastructure or to pay a transport and storage fee to an entity that provides a sequestration service.

There is currently hydrogen produced in Aberdeen for transport refuelling, which is produced by electrolysers at a cost of approximately £10/kg. Due to the purity of hydrogen required for fuel cell use it is likely that additional purification would be needed for hydrogen produced from reformation of natural gas. The most cost-effective way to implement this additional purification is likely to install a conditioning plant where the hydrogen offtake for transport is located to avoid the need to purify hydrogen used for heat. The cost of any additional purification required for hydrogen transport applications has not been considered within this report.

7.1 Hydrogen Generation with Carbon Capture

The cost of hydrogen generation covers all costs associated with producing the hydrogen from natural gas and any separation and conditioning to allow it to be injected into the networks. There may be additional purification costs for the use of hydrogen in fuel cells. The overall cost of generation will be dependent on the technology that is used for reforming natural gas. Table 7-1 summarises the operational assumptions that have been used for the LCH hydrogen generation process.

The import power assumption in Table 7-1 is largely due to the power required by the air separation unit. There may be a potential synergy with production of hydrogen from electrolysis in that the produced oxygen could be captured and used in the reformation process. However, if the electrolyser and reformer were not in close proximity new infrastructure to transport the oxygen would be needed.

The prices for power, natural gas and carbon were taken from the Digest of UK Energy Statistics (Department for Business, Energy and Industrial Strategy, 2018). All other prices and assumptions are based on Pale Blue Dot Energy norms.

Assumptions	Unit	Value
Plant Availability	%	95.0 %
Plant Load Factor	%	69.6 %
Peak Import Power	MWe	21.5
Peak NG Feed Flow Rate	kg/h	34,578
Peak Product Hydrogen Flow Rate	kg/h	10,771
Carbon mass fraction in NG Feed	Frac	0.723
Peak CO_2 Capture Rate	kg/h	88,632
Indirect CO_2 Emissions from Power Import	kg/MWh	34
Natural Gas LHV	kWh/kg	12.9
Hydrogen LHV	kWh/kg	33.3
Hydrogen Density	kg/Nm^3	0.090

Table 7-1: Operational Assumptions Used to Calculate the Cost of Hydrogen Generation

The largest item of capital expense for hydrogen generation is the syngas producing block, which is the bulk of the reformation technology. With the LCH concept the CO_2 capture and compression facilities combined are less than a quarter of the total capital cost.

Capital Element	Cost (£M)
Pre-Licensing, Technical & Design	1
Regulatory, Licensing & Public Enquiry	3
Syngas Production	53
CO_2 Capture	11
CO_2 Compression	23
Utilities	39
Infrastructure Connections	6
Owner's Costs	9
Total Capital Expenditure	145

Table 7-2: Capital Costs Associated with Hydrogen Production and Carbon Capture

It should be noted that although the LCH process offers cost savings due to the capture of CO_2 at pressure the regeneration of the solvent will still release the CO_2 at atmospheric pressure resulting in the need for CO_2 compression.

The cost of the natural gas feed is the most dominant operating expense accounting for nearly 75% of the total operating costs over a 25-year life. The operating costs shown in Table 7-3 are for full utilisation of the plant over the time frame, i.e. 200MW of generation across the full year.

There may be cost savings that can be realised through better heat integration of the hydrogen generation flow scheme and by utilising novel technologies that are still under development to provide efficiency savings in the carbon capture and hydrogen purification elements of the process. There may be additional savings associated with manufacturing learnings as more plants are constructed.

Operating Cost Elements	Cost (£M)
Direct Labour	15
General Overheads	16
Insurance and Local Taxes	63
Syngas Unit Maintenance	40
Other Units Maintenance	27
Solvent Make-Up Cost	23
Catalyst and Chemical Consumption	12
Import Power	110
Natural Gas Feed	917
CO_2 Emissions	36
Total Operating Expenditure	1,258

Table 7-3: Total Hydrogen Generation Operating Expenditure Over a 25-year Plant Life

7.2 CO_2 Transport and Storage Fee

The costs associated with the transport and storage of CO_2 will change dramatically depending on how transport and storage is integrated into the project. If the CCS aspects are owned and operated under the same entity that is carrying out the hydrogen generation then the capital and operating costs of the transport and storage infrastructure would need to be included for the overall project. If a transport and storage service is procured by the hydrogen generating plant then a transport and storage fee will need to be paid for the sequestration service.

Depending on the utilisation of the Acorn CO_2 Storage site the unit cost of CCS will range from £38/t, for very low flowrates, through to £11/t when the infrastructure is fully utilised. For the purposes of the Aberdeen Vision project a notional CO_2 transport and storage fee of £13/t has been assumed. Ultimately the actual fee that will be charged will be dependent on the storage costs, the CO_2 storage business model and the level of Government support provided to an early CCS project.

7.3 Unit Cost of Storage

The cost of producing hydrogen has been calculated based on the ATR system cost and a transport and storage fee of £13/t. This shows that the cost of producing hydrogen with CCS is £1.39/kg; the cost of CCS adds only 10p/kg. This compares favourably with the cost of hydrogen from grid powered electrolysis, which in Aberdeen is being sold at £10/kg.

Unit Costs	Natural Gas	Hydrogen	Hydrogen with CCS
Mass (£/kg)	0.26	1.29	1.39
Volume (£/kNm3)	171.29	115.97	125.42
Energy (£/MWh)	19.88	38.69	41.85

Table 7-4: Summary of the Unit Costs of Producing Hydrogen

Comparing the cost of hydrogen versus the average prices of unabated natural gas and electricity; hydrogen is twice the cost of natural gas per MWh and around 80% of the price of electricity based on an electricity price of £47.68/MWh, illustrated in Figure 5-10.

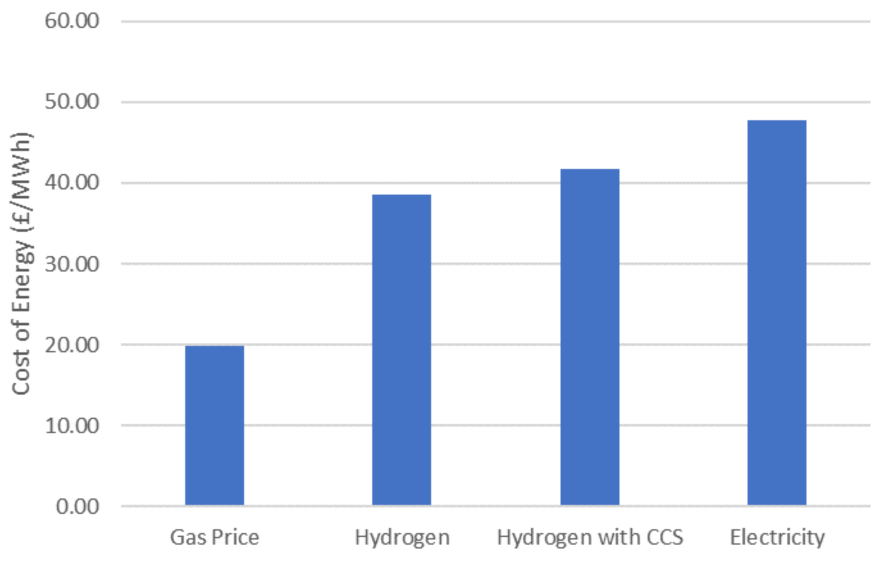

Figure 7-1: Comparison of Energy Costs from Different Sources

The electricity price used as a reference point is the current price of electricity, no allowance has been made for the comparison of decarbonisation through electrification. If technologies such as heat pumps are used to decarbonise heat then the electricity price is likely to increase to reflect the requirements for additional infrastructure and to manage the consequences of seasonal demand that are currently managed by the gas networks.

7.4 Hydrogen Storage

With the export of hydrogen being governed by the gas throughput of St Fergus some storage for hydrogen is necessary. A storage buffer would allow the plant to continue to export hydrogen when it would otherwise be constrained and allow more time for the plant to ramp up and down to meet the hydrogen demand.

At a very high level the Miller pipeline has been considered as a hydrogen store, noting that there is also interest in utilising the Miller pipeline to transport CO_2. The miller pipeline is 240km long, 762mm (30”) in diameter and constructed of API 5LX65, high frequency welded, carbon steel. The suitability of the Miller pipeline for hydrogen storage would be subject to further work to understand the impact of hydrogen on the metallurgy and the impact of pressure cycling on the fatigue of the pipeline. The Miller pipeline is estimated to be able to store around 600t of hydrogen.

Before the Miller pipeline could be used for storage there will be requirement to qualify its suitability for hydrogen storage, which will include a study on material suitability and pressure cycling as well as an intelligent pigging run to assess the condition of the pipeline.

A very high level estimate of the costs associated with using the Miller pipeline for storage are presented in Table 7-5. This is intended to be an indicative estimate of the cost of intra day buffer storage, not long term seasonal storage.

Cost Item	Cost (£M)
Intelligent PIG	18.08
Materials Assessment	0.01
Compressor	3.40
Aftercooler	0.12
Pipework	0.50
Technical Allowance	0.80
Commissioning	2.29
Total	**25.21**

Table 7-5: Order of Magnitude Cost Estimate of Using Miller for Hydrogen Storage

The Miller pipeline may be able to provide some intra-day storage to manage the flowrate of hydrogen into the NTS.

For inter-seasonal storage a cost estimate has been based on the information available from the H21 North of England project (Northern Gas Networks, 2018). The H21 project outlines a requirement for 8,052GWh of storage capacity at a capital cost of £1,991 million and an operating cost of £63 million per year. Assuming an operational life of 30 years the lifetime unit cost of storage using these costs is £129 million per GWh of storage capacity.

The cost of hydrogen storage to the generator is likely to take a very different form to the unit costs presented above, depending on the business model that is adopted by the hydrogen storage industry. One model that could be adopted is for the hydrogen storage facility to take advantage of differences in hydrogen price between periods of high demand, winter, and low demand, summer. The assumption is that the hydrogen market develops in a similar manner to the current natural gas market.

7.5 Build Out

The cost of building out the project will largely be driven by increasing needs for storage and the construction of a hydrogen pipeline to Aberdeen. The build out costs have been based on the construction of multiple 200MW modules of hydrogen generation plant. There may be an opportunity to reduce costs – particularly in the 100% Aberdeen scenario – by considering the use of a larger plant capacity.

Hydrogen storage costs have been calculated using similar assumptions from the H21 North of England project (Northern Gas Networks, 2018) and are summarised in Table 7-6. The calculated unit cost of storage is applied to a storage estimate for each scenario. The storage quantities for the supply of hydrogen are slightly higher due to the added element of security of supply when compared to the requirement for buffer storage when blending into the NTS, this assumption results in a slightly higher unit cost of hydrogen and would need to be confirmed in further stages of design work.

Parameter	Value	Unit
Storage Quantity	8,052	GWh
Capex	1,991	£M
Opex	63	£M/y
Design Life	30	Years
Calculated levelized cost of storage	302,000	£/GWh

Table 7-6: Levlised Cost of Storage Based on Information from H21 North of England

Table 7-7 presents a summary of the build out costs for the range of scenarios considered. There are three main scenarios; 2% hydrogen blended into the NTS, 20% hydrogen blended into the Aberdeen distribution network and 100% conversion of the Aberdeen distribution network. An additional version of each scenario is presented where the reformation plant operates at 100% utilisation, these scenarios are intended to show what the minimum unit cost of hydrogen would be for the investment in infrastructure required at each stage of the project.

The cost of hydrogen storage is expected to be monetised by including the cost of storage in the hydrogen price. This is in line with how natural gas storage infrastructure is monetised currently, the consumer pays a charge associated with gas storage infrastructure. An analysis of the impact of the cost of storage on consumer bills was out of scope for this project, however it is recognised as a gap that needs to be addressed in the move towards a hydrogen economy.

The 20% Aberdeen case, scenario 3 in the table, shows the highest unit cost of hydrogen. The unit cost is high due to the low level of utilisation of the reformer, the scenario assumes that the smallest unit size available is 200MW and that there is no other hydrogen demand. In reality, it is likely that if a pipeline to Aberdeen was built, and 200MW was the smallest available reformer, the excess hydrogen production would be injected into the NTS or another hydrogen application to improve the module utilisation and decrease the unit cost of hydrogen.

It should be noted that the module capex estimate does not include an allowance for connection and control, which will need to be looked at in more detail in the next phase of work. The operating costs are also varied based on the utilisation of the reformation module, although there will be an element of fixed opex the cost of natural gas is the single largest component and so this is assumed to be a fair approximation for a high level comparison.

Scenario	No. Modules	Generation (MW)	Plant Utilisation	Hydrogen Produced (GWh)	Storage Quantity (GWh)	Plant Capex (£M)	Plant Opex (£M)	Pipeline Capex (£M)	Hydrogen Storage Fee (£M)	Total Cost (£M)	Unit cost (£/MWh)
1) 2% NTS	1	187	94%	33,979	90	145	1,176	0	6	1,327	39.06
2) 2% NTS + full utilisation	1	200	100%	36,341	90	145	1,258	0	6	1,409	38.77
3) 20% Aberdeen	1	45	23%	8,177	229	145	283	53	69	550	67.30
4) 20% Aberdeen + full utilisation	1	200	100%	36,341	229	145	1,258	53	69	1,525	41.96
5) 100% Aberdeen	4	674	84%	122,470	879	581	4,238	53	265	5,138	41.95
6) 100% Aberdeen + full utilisation	4	800	100%	145,365	879	581	5,031	53	265	5,930	40.79

Table 7-7: Summary of Cost Estimation for Hydrogen Production Build Out

8.0 Resolving Impacts and Challenges

Resolving the impacts and challenges of using hydrogen as a clean energy vector will be achieved at a sector wide level. To enable rapid development of hydrogen projects there is a need for knowledge sharing between projects and across industry. Table 8-1 details the hydrogen projects that are being carried out across the UK.

As each of these projects progresses, they contribute to the evidence base to promote the conversion of existing infrastructure to hydrogen.

Scotland has the most advanced suite of ready to deliver industrial and domestic decarbonisation projects in the UK. The Hydrogen Coast from Orkney to Aberdeen to Fife is ready to contribute to Scotland being 'net-zero' by 2045 with affordable and deliverable projects which work together to encompass the full transition to a hydrogen economy. The benefits and opportunities of these projects extend well beyond Scotland, acting as a catalyst for other projects and hubs across the UK.

Decarbonising the UK is an environmental and social necessity and a major economic opportunity. Central to this is the potential to utilise low-carbon hydrogen as a replacement to fossil fuels within the UK's energy networks. The north east of Scotland has potential to be a major hydrogen hub for the decarbonisation of the UK. Significant projects are already underway in the region to make this opportunity a reality.

The Scottish Government recognises the importance of hydrogen and published the UK Hydrogen and Fuel Cells Roadmap (E4tech; Element Energy, 2016), Scottish Government has also supported a number of hydrogen demonstration projects including the Aberdeen Hydrogen Fuel Cell Bus Project and the Surf N Turf Project in Orkney among others.

The Department for Business Energy and Industrial Strategy (BEIS) also recognises the hydrogen opportunity with £390 million of investment in hydrogen and low carbon technology to help industry cut emissions as the UK moves towards net zero by 2050 (Departement for Business Energy and Industrial Strategy, 2019). The funding includes:

- £40 million Hydrogen and Fuel Switching Innovation fund to explore how the technology can be rolled out across the UK to help cut emissions
- £100 million competition to enable greater supply of low carbon hydrogen for use across the economy to help businesses decarbonise
- £250 million Clean Steel Fund to support the iron and steel industry, which currently accounts for 15% of industry emissions, to transition to a low carbon future, including using hydrogen

8.1 Legislation

There are a number of projects being carried out that are aiming to build an evidence base to support changing the gas quality specification within GS(M)R. The key parties involved are the IGEM Gas Quality Working Group and projects like H100 (Project complete by 2022), H21 (Phase 1 ends in 2021 with build out vision 2029-2035), HyNet (project complete by 2026) and HyDeploy (1st trial in 2020, 2nd in 2021).

8.2 Commercial

Further work will need to be carried out to understand the impacts of hydrogen on existing network entry and exit agreements. In addition, the Ofgem direction for measurement equipment does not include hydrogen as one of the components to be measured, resulting in a gap in the market for qualified hydrogen meters/analysers. The impact of hydrogen on the FWACV billing regulations also needs to be quantified and any modifications to the regulations that are required needs to be identified. These commercial elements tend to be a consistent requirement across the majority if not all hydrogen projects.

8.3 Technical

Where hydrogen is introduced into existing infrastructure, the capacity of the network needs to be assessed. This will involve network analysis and modelling by the network operators to identify the extent of reinforcement that might be required. In addition, there are projects looking at the storage potential for hydrogen within the UK such as Centurion P2G, HyGen, HySecure and HyStorPor.

8.4 Materials

A number of projects, such as Hy4Heat (demonstrations start in 2021) and HyDeploy (trials in 2020 and 2021), are investigating the impact of hydrogen on various elements of the overall network including pipeline materials, valves seals and appliances. These projects will also determine what the impact on end user appliances is under hydrogen operation.

Project name	Project Lead	Description
Aberdeen Vision Project	SGN / NG / PBDE / DNVGL	Outline the possibility of using advanced hydrogen production at St Fergus. And to discuss the technology and safety requirements for the transportation and storage of CO_2 from hydrogen production. Identify the planning consents and environmental permits that would be required. This will also outline the health and safety related aspects of plant development as well as identification of relevant key HSE regulations. Highlight the impact on the network, including materials, instrumentation, hazardous areas etc. It will also assess the end user impacts such as appliances, in particularly safety apparatus including oxygen depletion systems (ODS) and various other sensors. Describe the introduction of hydrogen into the NTS and the implications for the wider gas network, including interconnectors, storage, Liquified Natural Gas (LNG) etc. Development of an emission performance chart for hydrogen production
Acorn Hydrogen	Pale Blue Dot Energy	The Acorn Hydrogen project aims to construct a natural gas to hydrogen reformation plant at St Fergus where co-located CCS facilities will transport captured CO_2 offshore for sequestration with the produced hydrogen being injected into the NTS.
BioH2	NG	Investigate the potential for hydrogen production from waste through potential conversion of the BioSNG plant that gasifies waste into syngas, possible with relatively minor modifications to the plant.
Cavendish	NG/ SGN / CADENT	Determine the viability of utilising existing infrastructure to enable the Isle of Grain region to supply decarbonised hydrogen to London and the South East. Ascertain what additional infrastructure would be required if the Isle of Grain was to supply all of London's hydrogen, including the identification of critical environmental issues and ecosystem mapping of stakeholders. Generate a reference design showing the outline of a hydrogen system linking the Isle of Grain to London and the South East. Generate a business case showing the economic and environmental benefits to consumers and UK PLC. Develop a roadmap with next steps for hydrogen development in the region
Centurion/P2G	Storengy UK	A project exploring the electrolytic production, pipeline transmission, salt cavern storage and gas grid injection of hydrogen. The feasibility of placing a 100MW electrolyser at the INOVYN Runcorn site will be assessed.
Dolphyn	ERM	The project looks to utilise the vast UK offshore wind potential to power electrolysers to produce hydrogen from the water the turbines float on. Large 10MW turbines consisting of desalinisation technology and PEM electrolysers will feed hydrogen at pressure via a single flexible riser to a sub-sea manifold with other turbines' lines. The gas is then exported back to shore via a single trunkline.
East Neuk	SGN	A techno-economic assessment of the energy system. The project will examine the use of hydrogen as a medium for using excess electrical energy which is currently constrained in East Neuk, Fife.
Gas Decarbonisation Pathways	SGN / Energy Networks Association	This project will build on existing knowledge to set out and appraise the pathway for gas network decarbonisation and build knowledge and understanding in several key areas. The project forms part of the key strategic objective to push the frontiers of the decarbonisation through a whole systems approach.

Project name	Project Lead	Description
H100	SGN	The H100 project is looking to construct and demonstrate the UK's first network to carry 100% hydrogen. The project is built up of a series of smaller projects that focus on each key aspect of hydrogen research. These will develop the evidence to enable progress towards the construction and physical operation of the UK's first 100% hydrogen network. Workstream A is examining the technical and commercial feasibility of constructing a new dedicated network capable of providing 100% hydrogen to approximately 300 homes and businesses. This includes research to ensure the impacts of distributing and using hydrogen are understood, in comparison to natural gas. This will enable the development of the safety case that will ensure the reliable and safe operation of the network. Workstream B is the feasibility and FEED studies. These are identifying and evidencing the potential regulatory, technical and physical issues that need to eb overcome in preparation for construction and operation of the network. This will cover issues associated with transportation, production, storage and utilisation.
H21 NIC	NGN / SGN / CADENT / WWU	A study to present the quantified safety evidence between natural gas and 100% hydrogen used within the existing GB gas distribution networks. Considered in two phases 1a - Aims to establish whether there will be any changes in leakage levels to the UK's low/medium/intermediate pressure gas distribution network assets when pressurised with 100% hydrogen. While phase 1b - will involve 'consequence' testing and ignition testing trials at DNV-GL's research centre at RAF Spadeadam in Cumbria, examining various characteristics of how hydrogen behaves in comparison to natural gas. Following this phase 2 will occur which will involve testing of operational procedures.
H21 NoE	Northern Gas Networks	This project builds on the original Leeds City Gate, presenting a conceptual design for converting the North of England to hydrogen between 2028 and 2035.
HG2V	CADENT	Determine whether the gas network can be re-purposed to create added value from existing infrastructure. We will investigate the contaminations made by the hydrogen supply chain, in order to determine whether a cost-effective separation/purification system can be developed which allows hydrogen to be taken from the gas grid, either pure hydrogen (100%) or hydrogen-enriched natural gas, and used at hydrogen refueling stations for fuel cell vehicles.
Hy4Heat	BEIS	Hy4Heat is exploring whether replacing natural gas (methane) with hydrogen for domestic heating and cooking is feasible, and could be part of a plausible potential pathway to help meet heat decarbonisation targets. To do this the programme is seeking to provide the technical, performance, usability and safety evidence to demonstrate whether hydrogen can be used for heat in buildings.
HyDeploy 1	CADENT / NGN	HyDeploy Stage 1 is an energy trial hosted at Keele University. It will explore the potential of blending hydrogen (up to 20%) into the normal gas supply to reduce carbon emissions.
HyDeploy 2	CADENT / NGN	HyDeploy stage 2 is an energy trial building on the HyDeploy stage 1 work. A further two trials will be developed in the North of England seeking to further develop the safety case for the distribution and utilisation of a 20% blend of hydrogen.

Project name	Project Lead	Description
HyGen	SGN	HyGen is a feasibility study examining the local production and storage of hydrogen at three possible sites: Levenmouth in Fife, Aberdeen and Machrihanish in Campbelltown. This project will consider each site for the development of a 100% hydrogen infrastructure in the three locations and contemplate the scalability to the wider area. The study will examine the use of existing and or new facilities, the selection of the most likely suitable technology and a commercial evaluation of each site. All the sites are unique and the potential of each shall be ascertained in the project. The future scale up for use in transport and heat for each site will also be considered.
HyNet NW	CADENT / PEEL	A project in the NW of England to develop a low carbon industrial cluster using CCUS and hydrogen with a focus on the Merseyside estuary region.
HyPER	Cranfield University	Bulk Hydrogen Production by sorbent Enhanced steam Reforming
HySECURE Project	INOVYN	A study into the potential for grid-scale storage of bulk hydrogen in salt caverns in mid Cheshire with potential to store approximately 2,000 tonnes of hydrogen at a much lower cost than above ground storage.
HyStorPor	Edinburgh University / SGN	The project will address key questions related to the large scale geological storage of hydrogen. Laboratory experiments will be used to assess the storage of hydrogen in porous rocks.
I0071 H2 Clusters	CADENT	A study to identify synergies between the Humberside and Merseyside clusters SMR facilities designed to supply hydrogen to the gas network and local manufacturing industry, power generation and the required CCS infrastructure at the two clusters. Determine the potential market for hydrogen in manufacturing industry and power generation and provide guidance on the most cost effective configuration for low carbon hydrogen related facilities.
The Future of LTS Project	SGN	A project to evaluate the future role of the Local transmission system (LTS). Including a feasibility study to establish if the existing 25-mile LTS from Granton in Edinburgh to Grangemouth could be revalidated or re-purposed in the context of a decarbonised gas grid.
M1 Wind Hydrogen Fuel Station	ITM Power	The facility develops ITM Power's modular commercial platform for hydrogen generation systems, Power-to-Gas and refuelling solutions. The system is designed so that energy from the wind turbine is used to provide power for some of the buildings on the Advanced Manufacturing Park, with excess energy being used by the electrolyser to generate hydrogen gas. The gas is then compressed and stored ready for dispensing into hydrogen fuel cell vehicles.
Methilltoune	SGN	This project will study the resilient supply of zero carbon hydrogen to support the demonstration of a scalable 100% hydrogen distribution. The project will operate at a significantly larger scale than current systems. This is linked with the SGN H100 project and will provide the hydrogen from offshore wind via electrolysis. The produced hydrogen will then be used in the H100 project.

Table 8-1: Summary of Ongoing Hydrogen Projects

9.0 Development Plan

Due to the development phase, feasibility study, of the project and the relatively short study programme, engagement and communication activities are focused on a targeted list of project-enabling stakeholders. Meetings have been held and are ongoing with a wide range of stakeholders, such as governments and councils, partners, asset owners, industry bodies and regulators/consenting bodies. Opportunities to highlight the benefits for hydrogen generation at St Fergus to a broader stakeholder group have been utilised during the project. The final findings described in this report will be used by SGN, National Grid and Pale Blue Dot Energy to engage the support of stakeholder to move to the next development phase, concept study.

When the project moves into its next phase a more detailed stakeholder engagement and external communication plan will be developed in order to ensure that all aspects of stakeholder engagement and relationship management are considered. The forward plan will reflect the nature of the project and external environment at that time, along with the views and involvement of project partners.

To progress the option within the Aberdeen Vision project to blend hydrogen into the NTS there should be a focus on developing NTS connection. The connection needs to provide suitable control so that hydrogen can be blended within gas quality specifications. The best location to tie into the NTS also needs to be identified taking cognisance of the operating methodology of the St Fergus gas terminals. Operation flexibility of the gas network is crucial with National Grid at times by passing the mixing plant and needing to isolate individual Feeder pipelines. There is also a need to identify any direct connections from the NTS that might be sensitive to the addition of hydrogen into the gas supply. This might require deblending technology at these locations to ensure that sensitive equipment is still able to run should hydrogen blending be pursued.

The next phase of development work should also look to progress the option to build a pipeline to Aberdeen, confirming the capacity assumptions alongside forecasts of potential hydrogen demand. The route can also be looked at in more detail including extensions of smaller pipelines from Craibstone to the tie in point at City Gate. As part of this work a study into additional build out connections could be considered to target a greater area of the Aberdeen distribution network for conversion to hydrogen.

Conversion of a greater area of Aberdeen would require further network analysis to determine the extent of reinforcement that would be required, this will inform a potential schedule for introducing hydrogen into the wider distribution network building out from the current starting point of Kinknockie, Craibstone and City Gate. Identifying the reinforcement required also helps to inform forward planning for maintenance work and upgrades that are already being planned as part of day to day operation.

The Aberdeen Vision Project will be supported by the development of the Acorn CCS and Acorn Hydrogen projects. The Acorn CCS project provides a route to CO_2 export and sequestration enabling the generation of low carbon hydrogen at St Fergus. The Acorn Hydrogen project will provide an initial source of hydrogen that is targeting a blend of hydrogen into the NTS as the hydrogen export route. The development timelines for these projects are presented below in Figure 9-1.

The hydrogen pipeline between St Fergus and Aberdeen could be considered as a build out from the initial Acorn Hydrogen project. However, if the impacts and challenges are resolved in time then export of hydrogen into the Aberdeen distribution network could form part of the base case hydrogen export strategy for the Acorn Hydrogen project. The earliest that hydrogen could be exported to Aberdeen is estimated to be 2025.

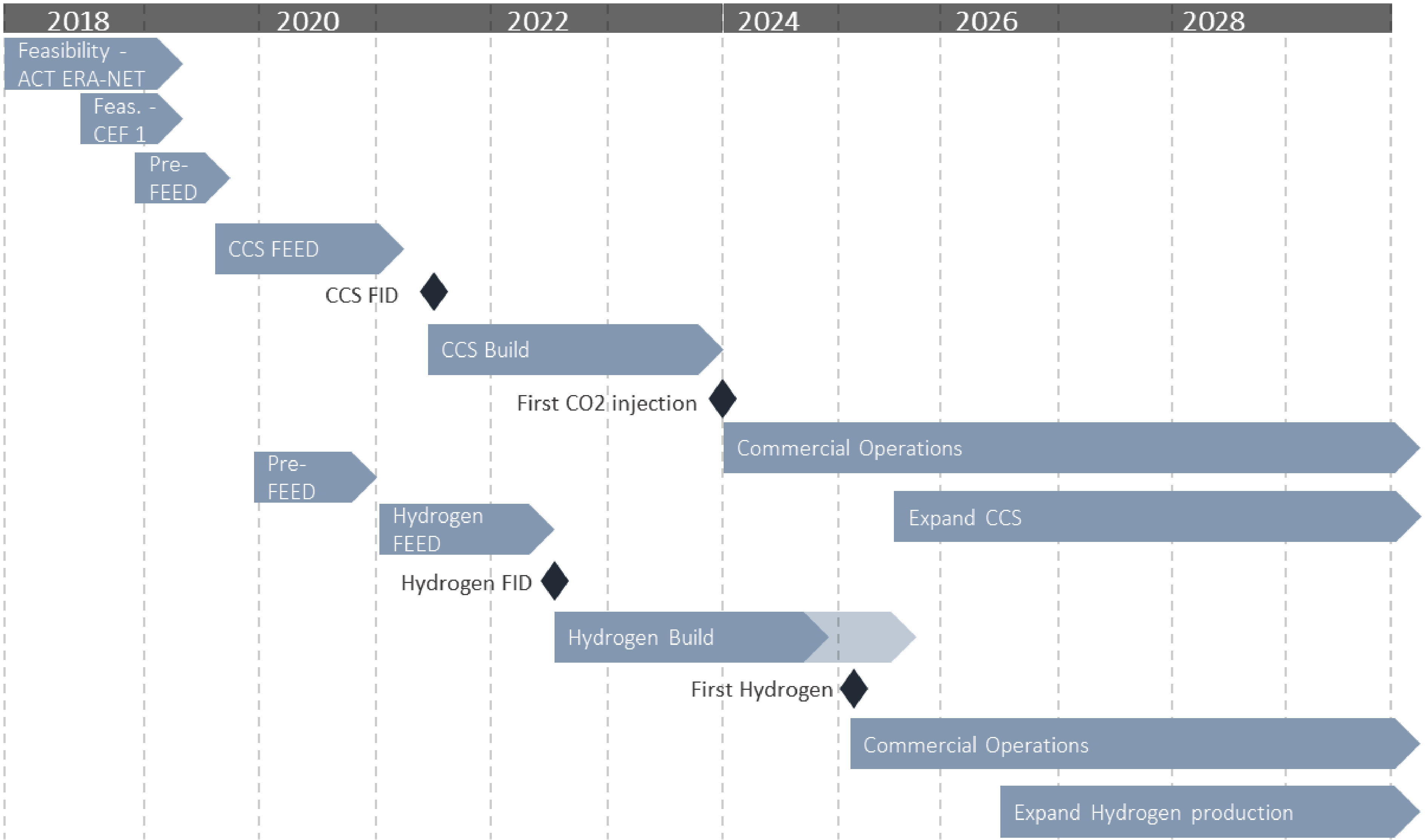

Figure 9-1: Schedule for the Development of the Acorn CCS and Acorn Hydrogen Projects

10.0 Conclusions and Recommendations

10.1 Conclusions

1. In the short term, production of hydrogen at scale to initiate the decarbonisation of the gas grid will initially come from reformation of natural gas. For the hydrogen to be considered low carbon, CCS is essential.
2. St Fergus presents an attractive location for reformation of natural gas due to the volumes of natural gas coming onshore, access to the NTS for hydrogen export, the existing industrial site and co-location with the Acorn CCS project for the sequestration of CO_2 captured during the reformation process.
3. No critical obstacles have been identified which would prevent the injection of 2% hydrogen into the NTS at St Fergus and its distribution through the gas distribution network.
4. A 200MW ATR is planned to produce 2% hydrogen blended into the NTS and enable modular build out to supply Aberdeen, to supply industry and to enable low cost hydrogen transport applications.
5. Although the cost of hydrogen generation with CCS (£41.85/MWh) is roughly double that of current natural gas energy prices (£19.08/MWh) it is competitive with electricity (£47.68/MWh). Note, electricity price is based on existing power demand profiles and is likely to increase to accommodate the significant variances in demand associated with gas energy networks
6. Due to unique attributes of the region, the Aberdeen area could lead the UK in the conversion to large scale clean hydrogen.
7. A dedicated pipeline from St Fergus to Aberdeen would enable the phased conversion of the Aberdeen regional gas distribution system to 100% hydrogen.
8. The production of hydrogen at St Fergus presents a significant decarbonisation opportunity with injection of 2% by volume into the NTS saving 320,000tCO_2/y, injection of a 20% by volume blend into the Aberdeen distribution network saving 78,000tCO_2/y and converting the Aberdeen distribution network saving 1,157,000tCO_2/y. Converting all of the natural gas that flows through the St Fergus gas terminals would capture 55,000,000tCO_2/y representing a huge opportunity to decarbonise the UK's energy use.
9. Hydrogen production at St Fergus could supply 2% by volume into the NTS and also supply a new dedicated hydrogen pipeline to the Aberdeen regional gas distribution system to provide a 20% by volume blend and ultimately 100% conversion. Supply of hydrogen into the NTS and the Aberdeen distribution network could occur independently or concurrently as each project is not dependent on the other. 100% hydrogen conversion for the Aberdeen region's gas distribution would require 3 further ATR units each at ~200MW of generation capacity with an availability of 84%.
10. Conversion to 20% and then 100% hydrogen could be arranged on a regional basis, with hydrogen injection via the Kinknockie, Craibstone and City Gate nodes to convert Aberdeen to hydrogen in a phased manner.

11. Network analysis has been performed suggesting that the conversion of Aberdeen to 100% hydrogen is possible as long as the reinforcement is incorporated into current plans for carrying out work on pipelines.
12. Conversion of the gas distribution network in Peterhead could precede Aberdeen as it is a smaller scale project closer to St Fergus and is easily isolated.
13. The North East of Scotland is well suited to the early development of low-carbon hydrogen due to a combination of factors including; access to large volumes of gas coming onshore, access to CO_2 storage via an early CCS project, existing hydrogen activity in Aberdeen and along the East Coast, potential for blending and then conversion into the Aberdeen gas distribution network and the strong supply chain in the region.
14. There are additional potential hydrogen conversion targets in the North East of Scotland including the St Fergus gas terminals which could be fuelled by hydrogen and conversion of Peterhead power station.
15. An Emissions Performance Standard (as proposed) could form the basis for comparing the whole-chain emissions associated with hydrogen production from different sources.
16. Hydrogen supply to Aberdeen for gas conversion could act as a catalyst for new hydrogen transport opportunities and growth in hydrogen fuelled road transport.
17. Although initially the project will use a hydrogen source generated from fossil fuels, with CCS, the project will enable renewable generation of hydrogen by providing a hydrogen transmission network.
18. As a result of this work it is recommended that efforts to change the GS(M)R are accelerated to enable inclusion of hydrogen at levels consistent with this report.
19. The FEED studies required to convert Aberdeen and Aberdeenshire to hydrogen in a phased manner should be progressed. Detailed design, mapping and relevant environmental studies and consent planning for the hydrogen pipeline to Aberdeen.

10.2 Recommendations

1. Six options for injection into the NTS at St Fergus have been considered, all of which have advantages and disadvantages. Further work should look to evaluate these options and find a compromise between cost (injection at all five feeders), potential effects on process equipment and changing flexibility and operational flexibility.
2. More detailed network analysis focussing around the impact of increasing velocity and the extent of reinforcement required should be evaluated to enable the reinforcement works to be planned and carried out in time for the construction of a hydrogen pipeline between St Fergus and Aberdeen.
3. A more thorough evaluation of the potential pipeline route and build out strategy should be conducted to inform the connection strategy, i.e. should the pipeline reduce in diameter between Craibstone and City Gate or would a larger diameter pipeline add value by enabling injection at additional locations.
4. The development and qualification of hydrogen meters and gas analysis equipment appears to be a current gap in the market for measurement of

hydrogen offtake from the NTS in the 2% scenario as well as approved hydrogen meters in the 100% hydrogen scenario.

5. Should a hydrogen emissions performance scheme be pursued, the potential to link it to or set up an incentive scheme would help to drive deeper decarbonisation of existing energy demands.
6. Development of new composite pipeline materials may offer advantages over PE pipeline systems for hydrogen networks

11.0 References

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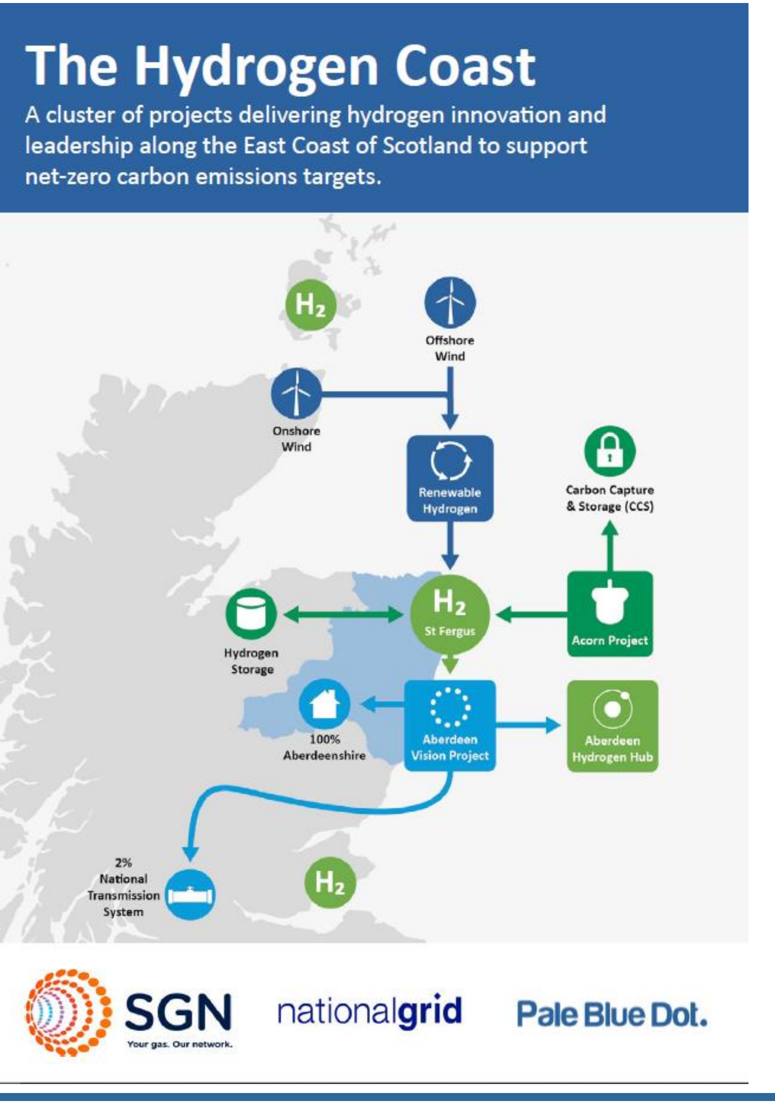
12.0 Appendices

12.1 Hydrogen Coast Document

A copy of the Hydrogen Coast report is included here and is available to download as a pdf online:

https://paleblublog.files.wordpress.com/2019/09/sgn-summary_digital.pdf



The Hydrogen Coast

Introduction

Scotland has the most advanced suite of ready to deliver industrial and domestic decarbonisation projects in the UK. The Hydrogen Coast from Orkney to Aberdeen to Fife is ready to contribute to Scotland being 'net-zero' by 2045 with affordable and deliverable projects which work together to encompass the full transition to a hydrogen economy. The benefits and opportunities of these projects extend well beyond Scotland, acting as a catalyst for other projects and hubs across the UK.

Decarbonising the UK is not only an environmental and social necessity, it is a major economic opportunity. Central to this is the potential to utilise low-carbon hydrogen as a replacement to fossil fuels within the UK's energy networks. The north east of Scotland has significant potential to be a major hydrogen hub in the UK and central to the decarbonisation of the UK. Significant projects are already underway in the region to make this opportunity a reality. This brochure provides information about some of the exciting projects and initiatives to enable hydrogen growth and decarbonise the North East Scotland and beyond.

The role of hydrogen

In the UK, around half our energy is used for heat (heating homes, cooking etc). The majority of this is currently provided by natural gas, which emits carbon dioxide (CO_2) when used. Replacing some or all of this by blending hydrogen into the National Transmission System (NTS) will help reduce CO_2 emissions.

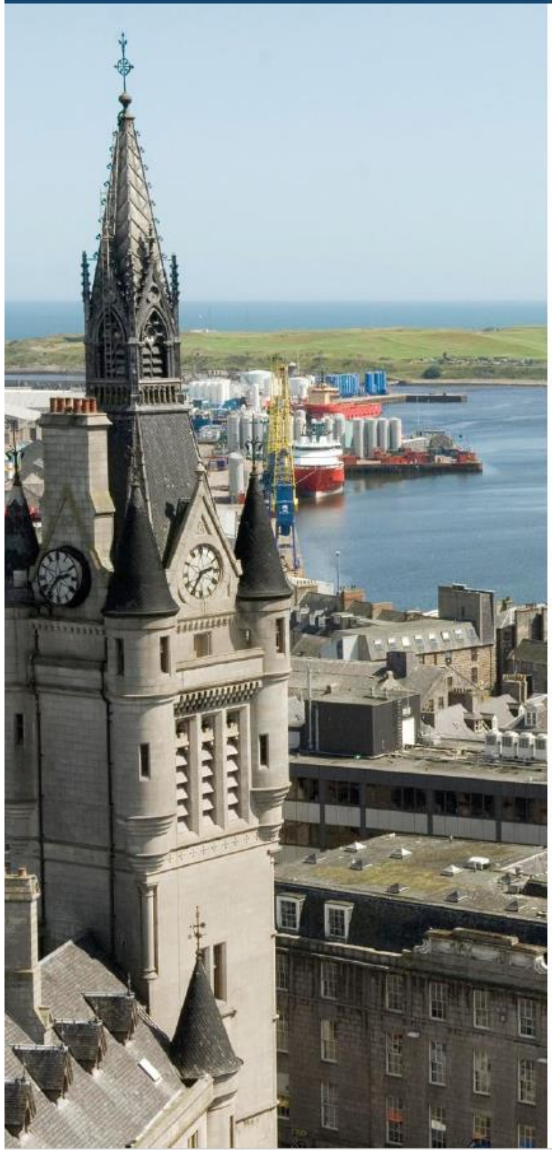
Hydrogen is also a key enabler in the broader energy transition providing a clean energy source for use in transport and industry. Hydrogen can be produced and used in a number of ways offering flexible low-carbon options for deployment across the energy mix.

Aberdeen is leading the way with hydrogen transport.

The role of North East Scotland

The north east of Scotland is the right place, with the right assets and the right projects to lead the way in developing a hydrogen economy. The region is:

- An established world class energy hub with the skills and talent available to deliver a low-carbon hydrogen economy.
- Already using hydrogen within local transport systems.
- Rich in renewable resources which are already being used to generate hydrogen and have significant potential to produce more.
- A key strategic interface between incoming North Sea gas and the national gas transmission system, making it a natural choice for producing and using hydrogen from natural gas with carbon capture and storage (CCS).
- Leading the way for CCS in the UK with access to well research, world class CO_2 stores and the ability to use decommissioned oil and gas infrastructure to access these stores in a low risk, low cost way
- Able to support the decarbonisation of the major Scottish industrial cluster at Grangemouth through reuse of infrastructure.



The Aberdeen region is a world class energy hub leading a low-carbon economy and at the forefront of hydrogen technology in Europe.

Producing hydrogen in North East Scotland

North East Scotland has massive potential to produce significant volumes of low-carbon hydrogen now and into the future. There are significant marine and wind energy resources available, which, as shown on Orkney through the Surf 'n' Turf project, can be effectively used to create hydrogen for use within energy systems. In addition, the future opportunity to generate significant levels of hydrogen from floating deepwater offshore wind turbines is being explored by the Dolphyn ERM project.

In the meantime, St Fergus has many attributes which make it an ideal location for the production and storage of low-carbon hydrogen from natural gas with CCS and the subsequent blending into the grid and deployment to other applications.

Hydrogen at St Fergus

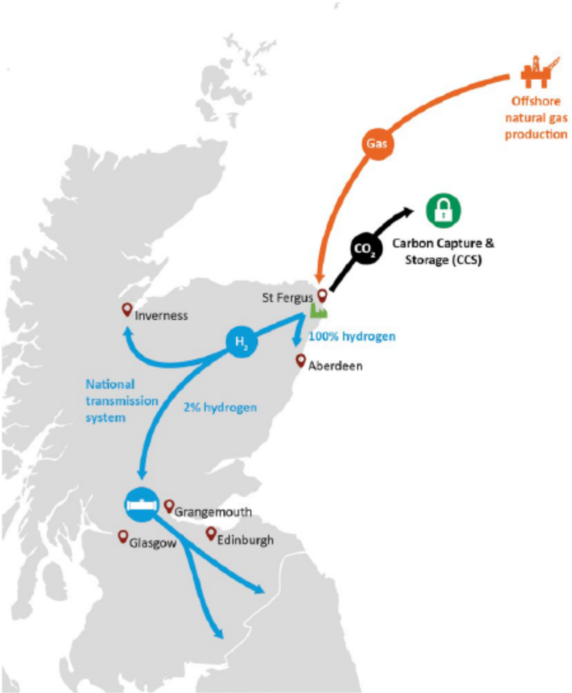
Natural gas supply
St Fergus is the gas processing terminal for about 35% of the UK's gas and is forecast to continue to be so out to 2040 and beyond.

St Fergus Gas Terminal Industrial Site
The coastal gas processing terminal at St Fergus is an existing industrial site, which is suited to the construction of large scale hydrogen production facilities.

Hydrogen export by blending
Blending hydrogen into the national gas transmission system from one 'unit' at St Fergus will decarbonise 1.4% of the UK's gas and abate 500,000t/yr of CO_2

CO_2 transport by existing infrastructure
There are three offshore gas transmission pipelines that are no longer required for petroleum use that can be redeployed for offshore CO_2 transport.

CO_2 storage capacity offshore
Scotland has significant quantities of internationally renowned CO_2 storage resource in the offshore area close to St Fergus.



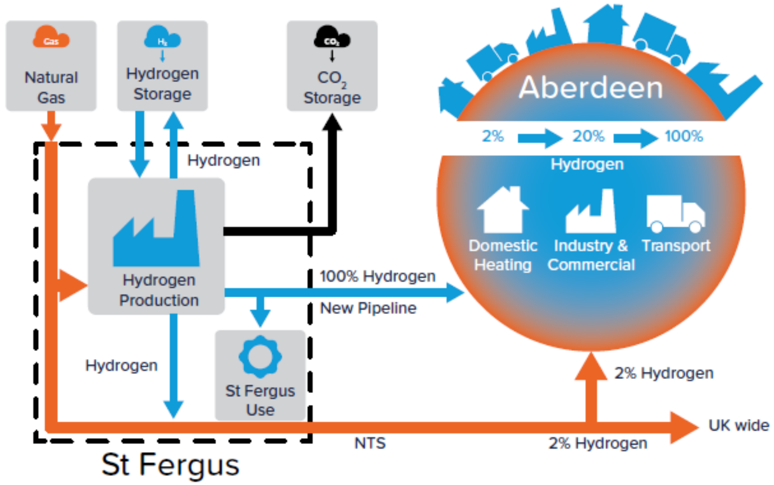
Acorn Hydrogen

The Acorn Hydrogen Project, being led by Pale Blue Dot Energy, with support from UK Government, is a hydrogen production facility being developed at St Fergus.

The facility would take natural gas from the North Sea and process it through methane reformation to produce hydrogen. A by-product of this process is CO_2, which would be captured and transported offshore for permanent storage deep underground below the Central North Sea by the Acorn CCS project.

The Acorn Hydrogen Project plans allow for the phased increase in the production of hydrogen over time, and potential options for hydrogen storage are also being developed. The Acorn Hydrogen project is one of several in the UK looking at hydrogen to replace natural gas. HyNet in North West England and H21 Leeds City Gate Project in Leeds are two of the others with ambitious long-term plans to deliver a hydrogen economy.

The Aberdeen Vision Project



Phased trials

In addition to the Aberdeen Vision Project, the H100 project is also being progressed by SGN. This project is building an evidence base into the socio-economic and technical issues associated with hydrogen deployment, so as to satisfy the needs of customers and stakeholders. Part of this study will include a long-term field trial of 100% hydrogen use in 2-300 houses, on the east coast of Scotland.

Linking supply and demand in the hydrogen economy

Aberdeen City Council has been deploying hydrogen technologies particularly in relation to hydrogen vehicles for over five years. The Council has a clear strategy for supporting hydrogen deployment in the region. In particular, the Council wants to maximise the economic opportunity to the well established, skilled supply chain in the region through the development of a Hydrogen Hub.

The Hub will act a catalyst for the integration and connectivity of the hydrogen economy in the region. The programme will link supply projects with demand projects and seek to support and facilitate these projects as a public sector partner.

The Aberdeen Vision Project

The Aberdeen Vision Project is a collaborative project between SGN, National Grid and Pale Blue Dot Energy. It has developed a phased approach to the use of hydrogen from St Fergus to support the future decarbonisation of national and Aberdeenshire gas transmission systems.

Phase 1

2%

2% hydrogen in the grid

Initially, low concentrations of hydrogen (2%) would be blended into all the natural gas leaving St Fergus. This blended gas can then be transported in the National Transmission System, before being distributed in lower pressure networks to users across Scotland and Northern England. This blended gas can continue to be used exactly as the natural gas is currently.

Although 2% sounds small, because of the large amount of natural gas leaving St Fergus, it would remove 400,000 tonnes of CO_2 per year from the energy system; equivalent to the CO_2 produced by 85,000 cars.

Phase 2

20%

20% hydrogen to Aberdeen

To achieve further decarbonisation a blend of 20% hydrogen could be fed into the gas supply in the Aberdeen and Aberdeenshire region. This would involve building a new pipeline from St Fergus to Aberdeen to transport pure hydrogen which would then be injected at 3 strategic locations to feed the gas distribution system and also provide a local 100% hydrogen hub for transport and other applications.

Most domestic and commercial applications such as boilers and gas cookers will continue to operate safely without any modification. Some specialised industrial or commercial applications may need to adjust their gas facilities.

Phase 3

100%

100% hydrogen

Once operation has been proven at 20%, the low pressure network could look to operate on 100% hydrogen. This would mean entirely replacing natural gas with hydrogen for all the region's heating and other uses. This conversion would require the phased transition of the region's distribution network by area from natural gas to hydrogen.

Other hydrogen transition projects in the UK are currently assessing the changes needed to appliances in order to facilitate this change. It is expected that such a transition would be similar to the changeover from town gas to natural gas which took place in the 1960s and 70s. Converting the North East of Scotland gas system to hydrogen would cut another 700,000 tonnes of CO_2 per year; that's equivalent to the CO_2 produced by 150,000 cars.

Acorn carbon capture & storage (CCS)

Large scale, low-carbon hydrogen can be produced from natural gas with CCS. Acorn CCS is the most advanced CCS project in the UK and offers a low-cost, low-risk CCS project co-located with Acorn Hydrogen at St Fergus. Acorn CCS is designed to be built quickly by taking advantage of existing oil and gas infrastructure and a well understood offshore CO_2 storage site. The CO_2 storage site has been licensed by the UK Government to Pale Blue Dot Energy.

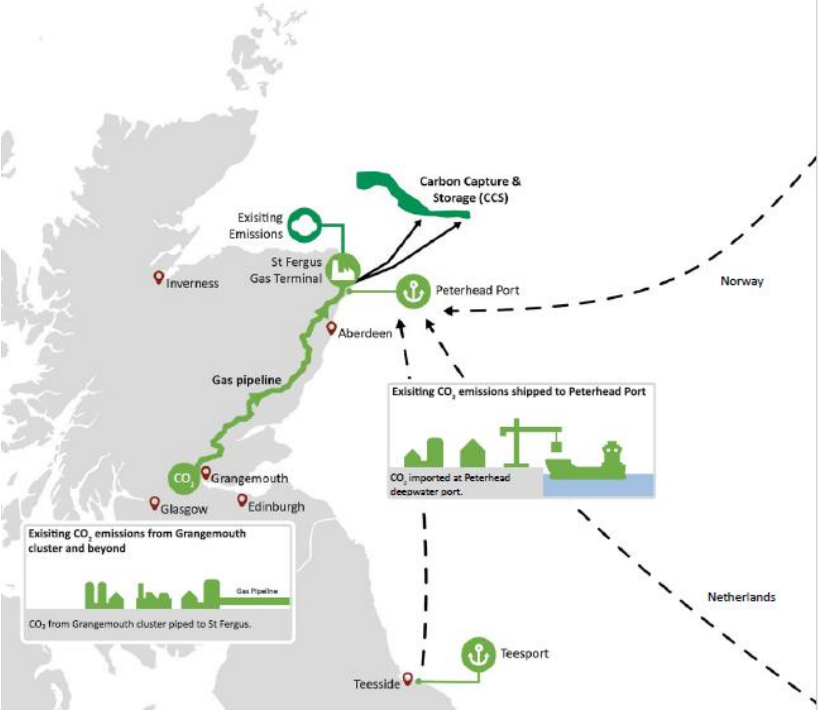
Acorn CCS has multiple options for the capture and import of CO_2 for offshore transport and storage.

These include:

- The capture of existing emissions at St Fergus
- Emissions from future hydrogen production at St Fergus
- The import of CO_2 by vessel to the deep water port at Peterhead
- Connection to industrial cluster at Grangemouth via an existing onshore gas pipeline.

The Acorn CCS Project has sufficient demonstrable storage capacity to store CO_2 from multiple sources. Importantly, the early delivery of this project can provide initial storage to other industrial regions throughout the UK, allowing them to invest with confidence to deliver a low-carbon economy.

St Fergus gas terminal



A major economic opportunity

The north east of Scotland, with the right support, can rapidly begin to decarbonise energy systems throughout the UK during the early part of the 2020s.

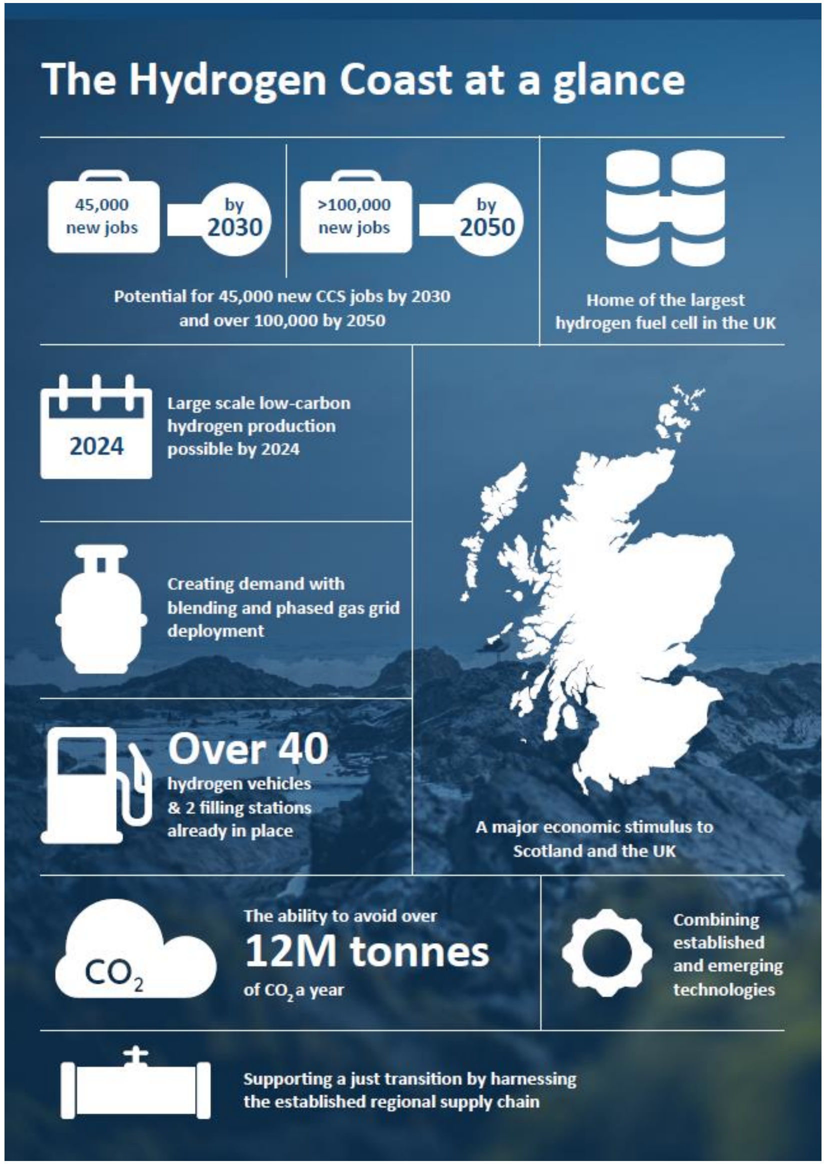
The Hydrogen Coast can catalyse widespread decarbonisation across the whole of the UK and is well positioned to maximise the learnings and opportunities for hydrogen production from renewable sources and in alternative locations. The Hydrogen Coast would provide:

- A major hydrogen production facility with CCS at St Fergus.
- A hub for offshore renewable hydrogen storage with direct connection to the national transmission network.
- An economic opportunity for the deep-water port at Peterhead providing CCS infrastructure for UK-wide decarbonisation projects.
- Energy transition job creation, building on the skills within the region.
- A contribution to decarbonised gas grid nationally and in Aberdeenshire.

The hydrogen economy is a huge economic opportunity for the UK. Ricardo Energy & Environment, in their UK business opportunities of moving to a low-carbon economy work for the Committee on Climate Change (CCC), estimate the low-carbon economy in the UK could grow 11% per year between 2015 and 2030, four times faster than the rest of the economy, and could deliver between £60bn and £170bn of export sales by 2030.

Initial estimates reported by The Centre for Energy Policy at University of Strathclyde in the economic opportunity for a large-scale CO_2 management industry in Scotland report, suggests that by 2030 anywhere between 7,000 and 45,000 UK jobs could ultimately be associated with Scotland, securing 40% of the carbon storage element of a European CO_2 management market.

By 2050 this could rise to between 22,000 and 105,000 jobs and more as the industry extends to low-carbon fuel supply.



Hydrogen Coast projects

The Hydrogen Coast is happening as a result of the proactive and innovative work being done on projects along the East Coast of Scotland. These leading projects are pioneering the energy transition and paving the way towards net zero.

Hydrogen Coast projects	Project proponents & supporters
Aberdeen Vision Project, Aberdeen	SGN and National Grid with Pale Blue Dot Energy and DNV GL
Acorn Hydrogen, St Fergus	Pale Blue Dot Energy, Department for Business, Energy and Industrial Strategy (BEIS), The Scottish Government
Acorn CCS, St Fergus	Pale Blue Dot Energy, EU Innovation and Networks Executive Agency, BEIS, The Scottish Government and Industry Partners
Aberdeen Hydrogen Bus Project, Aberdeen	Aberdeen City Council, EU High Vlo City and Fuel Cell and Hydrogen Joint Undertaking (FCHJU), Innovate UK, Stage Coach, First Group, The Scottish Government, Scottish Enterprise, Scottish Hydro Electric Power Distribution, SGN
The Hydrogen Hub, Aberdeen	Aberdeen City Council, Scottish Enterprise, Opportunity North East
Surf'n'Turf, Orkney	Orkney Island Council, EMEC Orkney, ITM Power, EU, FCHJU, The Challenge Fund, Scottish Government, Local Energy Scotland, Community Energy Scotland
Dolphyn ERM Project, offshore	ERM, Engie, Tractabel Engie and ODE
H100, Fife	SGN
HyStorPor, offshore	University of Edinburgh
BigHit, Orkney	Orkney Islands Council, EMEC
Flotta Terminal, Orkney	OGTC
HyDIME, Orkney	Ferguson Marine, Orkney Islands Council, EMEC, HSSMI
Methiltoune, Fife	SGN
Dundee Bus Project, Dundee	Dundee City Council

Document supported by

12.2 Environmental Performance Standard – Best Practice Estimation Methodology

The frame of reference, or battery limits, of the analysis determine the overall level of emissions that need to be considered. The battery limits describe a defined boundary between two areas of responsibility, in the context of the emissions analysis this should be the full plant boundary considering all of the inputs that cross the boundary into the plant, activities on the plant and any product or waste streams that exit the plant boundary.

To allow general comparison of a range of hydrogen production methods the analysis should begin with the primary energy carrier that is used to generate the hydrogen. For a reformation process this is likely to be natural gas, although a range of hydrocarbon sources could be used such as oil or coal. To allow a comparison with the emissions associated with electrolysis the primary energy input that needs to be considered is the fuel source for power generation. Consideration of the energy source used to generate the electricity is important as it can result in a huge discrepancy in a comparison between power from unabated coal and wind power for example.

To enable comparison of technologies, the end point of the analysis should be on the produced hydrogen at the point of use. Although there may be emissions associated with the use of hydrogen this is not considered in this methodology. For the purposes of comparing different methods of producing and transporting hydrogen the point of use is suitable.

For the hydrogen generation process, there are a range of ancillary emissions that should be considered between the primary energy input and the point at which hydrogen is produced. Emissions associated with power import and steam use should be considered as well as emissions arising from chemical consumption.

Considerations should also be made for the potential to recover energy from the process if it leads to the reduction in use of energy from another source. Energy that is recovered and used to offset existing steam or electricity demands presents an opportunity to reduce the overall emissions.

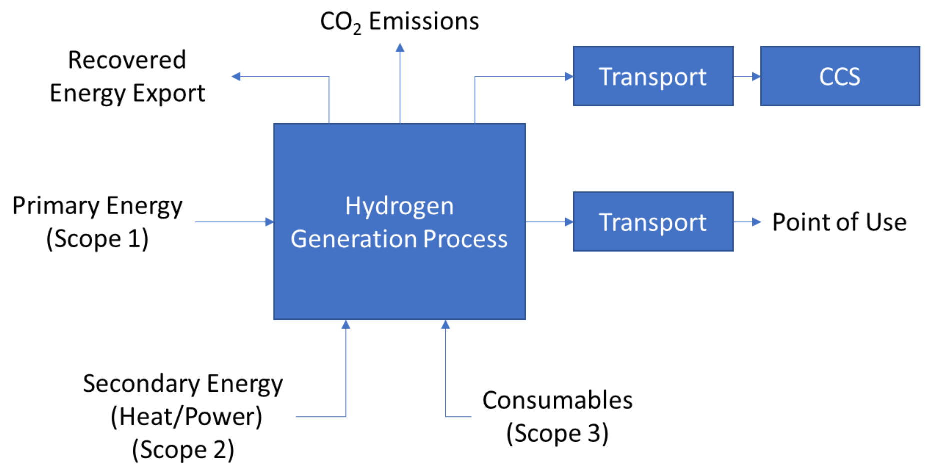


Figure 12-1: Battery Limits Diagram for Emissions Performance Analysis

Scope one emissions are the direct emissions to atmosphere as a result of operational activity.

In a reformation process without CCS this would be all the CO_2 released in the flue stack. The amount of CO_2 will be proportional to the carbon intensity of the primary energy feedstock. Biomass sources will have lower emissions than fossil fuels, as an example. The scope one emissions will be calculated directly from the mass and energy balances.

Scope one emissions for electrolysis should include the primary energy feedstock used to generate power as part of the overall plant. If the electrolyser is powered by grid electricity, then these emissions will be covered under the scope two emissions.

Scope two emissions are the indirect emissions arising as a result of the use of electricity or steam by the process. Steam emissions will depend on the fuel that is used and the efficiency of the system, which can be calculated from a mass and energy balance of the system.

Imported power emissions will vary dependent on the source of electricity generation. There are a variety of carbon factors that have been calculated for emissions associated with a range of generation options. Where a private wire is used or a power purchase agreement is in place, a specific carbon factor can be used otherwise the carbon factor for the emissions intensity of grid power should be used.

Scope three emissions are indirect emissions resulting from the use of consumables and other operational activities.

Scope three emissions will be able to be calculated from the flowsheet and mass balance for a technology. These emissions may include activities such as chemical consumption, transport of material, effluent processing and disposal.

Where energy that can be recovered from the process is used to offset the use of primary energy sources there is an emission offset that should be accounted for. In this situation the energy recovered should be used for an existing energy demand that was previously being met by primary energy to avoid incentivising utilising energy for its own sake.

Consideration should also be made, where appropriate, to the transport of hydrogen from the point of production to the point of use. This will allow for comparison of the emissions performance of centralised and distributed models of hydrogen generation which is important in cases where the emissions at the point of production are very low but the location is distant from the demand. If the transport method is not low carbon the emissions could be higher than using a slightly higher emitting, but local, production technology.

The overall emissions associated with producing hydrogen can be calculated from the flows in and out of the battery limits, Figure 12-1. It should be noted that this is intended to represent emissions at the point of use and does not consider what the hydrogen is being used for. In a full life cycle analysis, the use of the hydrogen could have a large impact on the overall emissions of a project.

We have excluded emissions associated with capital projects, i.e. construction activity and to limit the assessment to operating activities. This is because;

- The construction emissions across the entire system are complex to identify and quantify.
- Some of the construction emissions may not be relevant
- Some of the construction emissions will be historical

As society transitions towards a lower carbon economy, emissions associated with construction are likely to come under greater scrutiny. Management of the amount of carbon released during construction is likely to come from legislation, for example, increasing the energy efficiency of buildings.

Included below are some example battery limits diagrams for some commonly considered methods of producing hydrogen.

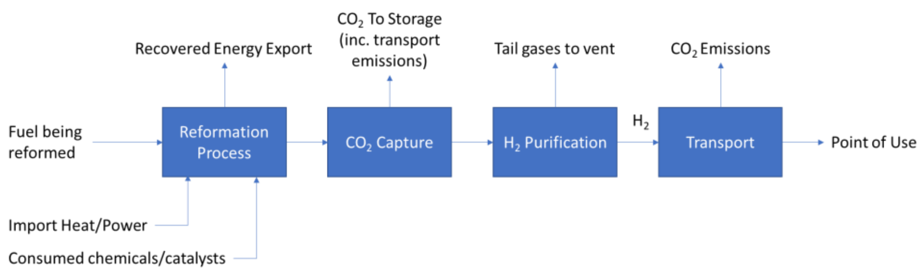


Figure 12-2: Battery Limits Diagram for a Generic Reformation Process

Depending on the technologies that are used during the reformation process, CO_2 capture and hydrogen purification stages the above battery limits diagram may not wholly represent the scope two and scope three emissions, this diagram is intended to be illustrative rather than completely representative.

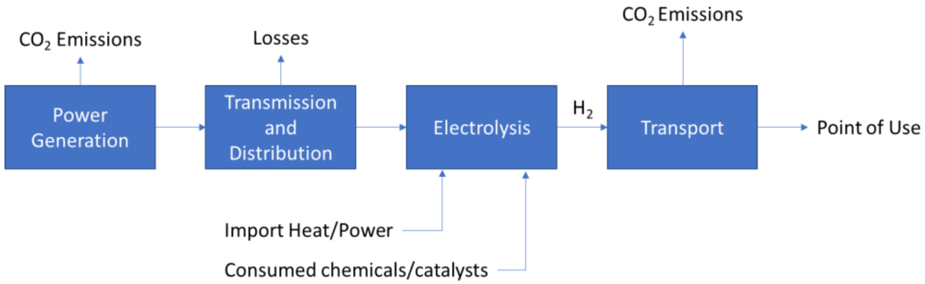


Figure 12-3: Battery Limits Diagram for Electrolysis using Grid Electricity

An important consideration in the case of producing hydrogen from electrolysis, Figure 12-3, is the carbon intensity of the power generation. Rather than expand the battery limits to include each and every power generation plant there are resources available to either use a carbon factor to estimate the carbon intensity of power generation of sources that report the current values based on the mix of generation that is active at any moment, Figure 12-4 (National Grid ESO, 2019).

The back end of the analysis would be very similar as the transmission and distribution of the electricity to the electrolyser and the transportation of the hydrogen to the point of use need to be considered in both scenarios.

With renewable generation some projects will feed an electrolyser directly and avoid losses associated with transmission and distribution through the grid. Also, in situations whereby export of electricity could be constrained, wind power is a good example of this, the power generated can still be harnessed and stored as hydrogen instead of being lost.

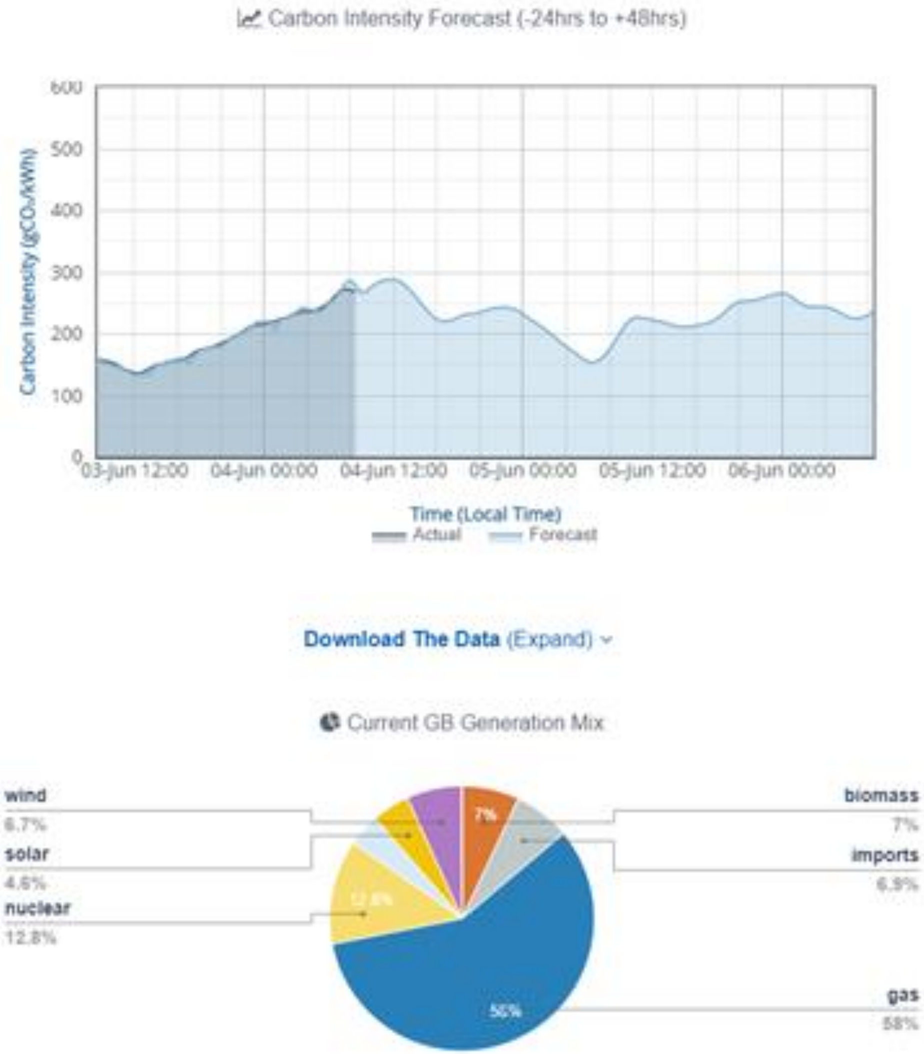


Figure 12-4: UK Grid Carbon Intensity on 4th June 2019