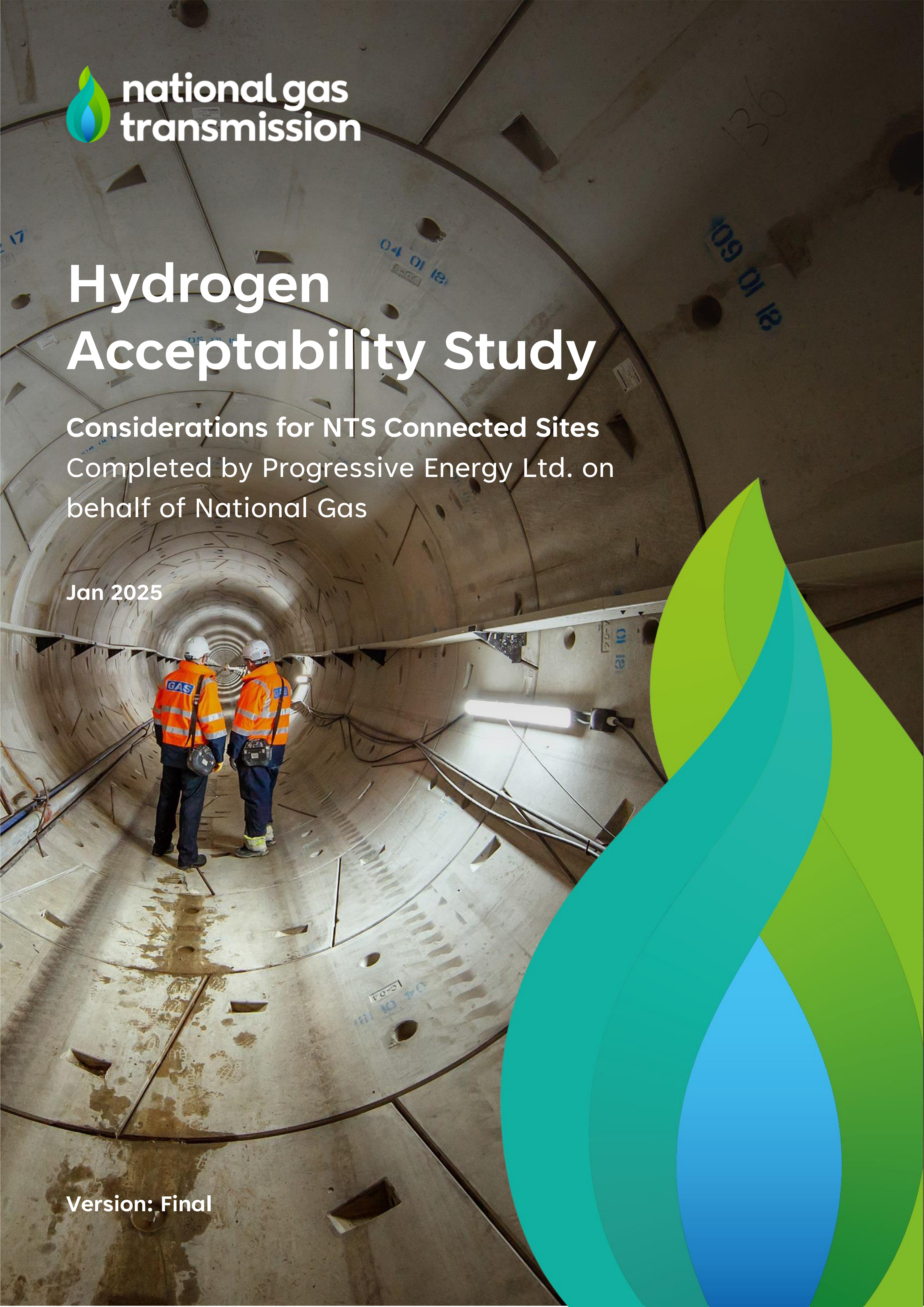

Hydrogen Acceptability Study

Considerations for NTS Connected Sites

Completed by Progressive Energy Ltd. on behalf of National Gas

Jan 2025

Version: Final

Disclaimer

This work includes the assessment of a number of phenomena which are unquantifiable. As such, the judgments drawn in the report are offered as informed opinion. Accordingly Progressive Energy Ltd. gives no undertaking or warranty with respect to any losses or liabilities incurred by the use of information contained therein.

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Abbreviations

ATEX	ATmospheres-EXplosables
CCGT	Combined Cycle Gas Turbine
CNG	Compressed Natural Gas
COMAH	Control of Major Accident Hazards
COSHH	Control of Substances Hazardous to Health
DLE	Dry Low Emission (gas turbine)
DSEAR	Dangerous Substances and Explosive Atmospheres Regulations
EGR	Exhaust Gas Recirculation
FGR	Flue Gas Recirculation
HAC	Hazardous Area Classification
HASWA	Health & Safety at Work Act
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
IFS	Industrial Fuel Switching
MAH	Major Accident Hazard
NDT	Non-Destructive Testing
NGT	Natural Gas Transmission
NTS	National Transmission System
OCGT	Open Cycle Gas Turbine
OEM	Original Equipment Manufacturer
SCR	Selective Catalytic Reduction
WI	Wobbe Index

1. Introduction

Low carbon hydrogen is expected to play an important role in achieving net zero carbon emissions within the UK, providing a flexible replacement for other carbon intensive fuels, and supporting decarbonisation efforts across a range of industrial and commercial sectors. With an extensive gas transmission network in operation today, the UK is well placed to facilitate hydrogen transportation from dispersed production sites to the wide variety of customers it services.

In Great Britain, the National Transmission System (NTS) is the highest pressure tier of gas transportation. As operator of the NTS, National Gas Transmission (NGT) deliver energy to where it is needed in every part of the country. National Gas keep households warm and underpin their quality of life. For business, NGT fuel growth and innovation, and are now looking to the future, by developing the hydrogen transmission system of tomorrow. NGT recognise the significant role they have to play in delivering affordable energy security for the UK throughout the journey to net zero and beyond, and understand their vital role in decarbonising their own system and providing hydrogen solutions for the UK. This will grow the economy, create skilled jobs, and provide export opportunities to meet the economic growth ambition for our country.

National Gas Transmission are therefore leading a work programme under the title of ‘Project Union’, to develop a transition pathway which includes repurposing assets to transport 100% hydrogen. Project Union’s scope includes the evaluation of the existing NTS to determine its suitability for repurposing for hydrogen service, identifying those areas where new infrastructure will be required, and working with stakeholders including Gas Distribution Network (GDN) operators, customers, regulators, and others to ease and optimise the Net Zero transition.

National Gas Transmission also recognise that hydrogen blending is an essential step in the transition to the UK’s future hydrogen economy as it provides an alternative offtake for H_2 producers. Through strategic connections this would stimulate the low carbon hydrogen market whilst a hydrogen-only network is built. This is crucial as analysis indicates that a 20% hydrogen blend by volume on the NTS could accommodate 50 TWh of hydrogen a year, saving almost 10 million tonnes of carbon annually. Thus, by blending we can meet Government’s targets to hydrogen production including 10GW of capacity by 2030 (British Energy Security Strategy). Maintaining compatibility in the UK Transmission network with our European counterparts is also essential to mitigate the requirement for deblending costs, ensure security of supply and facilitate wider access to markets for UK produced hydrogen.

This study therefore involves working with key stakeholders, including NTS direct connected sites who may equally require some modification to their assets to support the gradual transition to hydrogen.

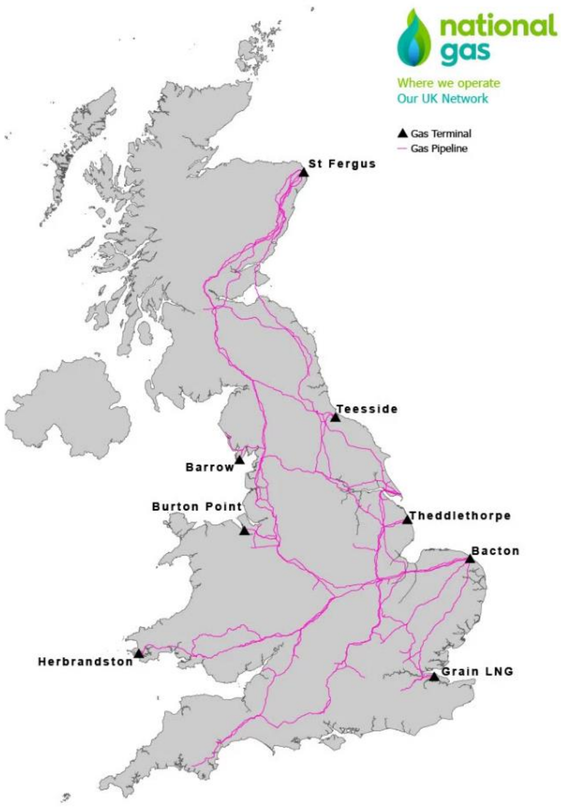

Figure 1-1: Overview of the Nation Transmission System (NTS) network.

In support of this aim, Progressive Energy Ltd were commissioned to assess any potential technical issues relating to the adoption of hydrogen, or a blend of up to 20 vol% hydrogen in natural gas, by industrial processes operated by customers which are directly supplied by the NTS.

This ‘Hydrogen Acceptability Study’ profiles existing NTS connected sites and aggregates their equipment into technologically similar archetypes, which are then assessed to identify any potential hydrogen fuel switching constraints for that particular archetype. This document provides a summary of the work conducted under the study.

The scope of the study is limited to potential technical and safety impacts, and at this stage does not consider the commercial viability of any potential upgrades that could facilitate fuel switching, nor the potential impact on equipment warranties.

2. Executive Summary

This work is conducted under the 'Hydrogen Acceptability Study', which was designed to be completed in three separate phases.

- **Phase 1:** Understand profile of NTS direct connect sites and their equipment
- **Phase 2:** Aggregate list of sites into technologically similar archetypes
- **Phase 3:** Investigate hydrogen fuel switching constraints for each archetype

Phase 1 & 2 of this study identified the following selection of technology archetypes that can be widely applied to the NTS directly connected industrial customers:

1. Gas Turbine
2. Gas-fired Reciprocating Engine ('Reciprocating Engine')
3. Indirect Firing
4. Direct Firing
5. Chemical Feedstock
6. Storage
7. Compression, Expansion and Gas Conditioning

Phase 3 of this study was focused on identifying the generic impacts of fuel switching from natural gas to a 20 vol% hydrogen blend and 100% hydrogen for each of the technology archetypes.

A gas characteristics review was first conducted to highlight how the gases would behave differently in an industrial setting and identify potential implications for plant design and operation. Building on this work, a desktop-based impact assessment was then conducted to investigate the safety, technological and regulatory impacts that could arise during the fuel switching process.

A selection of NTS directly connected industrial customers were engaged and studied to apply the findings of the impact assessment against real-life applications, and to help understand the extent of changes required for sites to enable a switch to a 20 vol% hydrogen blend and 100% hydrogen. The sites were selected, amongst other reasons, to ensure complete coverage of each of the technology archetypes.

The main conclusion from the study for a hydrogen blend is that generally most applications are capable of handling up to a 20 vol% hydrogen blend gas today, albeit with some level of modification expected (e.g. burner replacement). As most processes are optimised for a relatively constant natural gas composition, combustion tuning and other control systems may also need to be adapted to manage blend variability. Sites will also have to conduct an assessment to ensure that risks can be mitigated to ALARP ('as low as reasonably practicable'), and hazardous area classifications will need to be re-evaluated, with potential increases in zone extents and ventilation requirements. Compressors are likely to require some of the most extensive modifications to enable a switch to a 20 vol% hydrogen blend.

The evidence has suggested that the transition to 100% hydrogen is technically feasible, but would require more extensive upgrades and modifications relative to the 20 vol% hydrogen blend scenario. In some cases, such as industrial sites using gas turbines or reciprocating engines, the technology readiness for these prime movers to operate on 100% hydrogen is still in development;

there are no commercially available ‘100% hydrogen’ gas turbines or reciprocating engines available in the market today that can meet UK emission regulations at comparable loads to the NTS direct connected sites.

Many OEMs (Original Equipment Manufacturers) are setting themselves targets to develop 100% hydrogen ready equipment by 2025 or 2030 in anticipation of a shift in hydrogen availability. One of the greatest hurdles for OEMs in their 100% hydrogen development, particularly the OEMs of larger gas turbines, is that there is not currently sufficient hydrogen available to test and therefore validate their full-scale prototypes.
Furthermore, in the case of processes that use natural gas as a chemical feedstock, there are examples in which the end-products contain carbon compounds, meaning that the chemical feedstock will need to continue to contain some natural gas; 100% hydrogen will not be suitable as a feedstock for such processes.

In relation to both hydrogen blend and 100% hydrogen acceptability, the report does not identify any technically insurmountable barriers, but recognises that transition pathways are site and technology manufacturer specific. Sites will also need to consider the commercial viability of upgrades to facilitate fuel switching (which is outside of the scope of this study), recognising that the scale and cost of upgrades are expected to more significant for the 100% hydrogen scenario.

3. Technology Archetypes

Process and equipment profiling was conducted for the 54 sites directly connected to the NTS and active at the time of the study. This comprises various industrial sectors, such as power generation, petrochemicals, hydrogen production and fertiliser manufacturing amongst others. A majority of the operating sites are Power Stations, of which the Combined Cycle Gas Turbine (CCGT) is the dominant process at almost 50% of all NTS direct connected sites.

Table 3-1: Summary of industry process for each of the 54 NTS direct connected sites considered in the study.

NTS Direct Connected Sites - 54		
Power Stations - 36 (66% by site count)	**Industrial Sites - 9 (17% by site count)**	**Storage/ Compression - 9 (17% by site count)**
CCGT Note 1 OCGT Note 2 Combined Heat & Power Reciprocating Engines	Oil Refining/ Petrochemical Glass Manufacturing Paper Manufacturing Chemicals Production Turbine Testing Facility	Natural Gas Storage CNG Re-fuelling Station

Table Notes

(1) Combined Cycle Gas Turbine (CCGT) – Turbine exhaust gases sent to Heat Recovery Steam Generator (HRSG) to raise additional steam and increase overall cycle efficiency.
(2) Open Cycle Gas Turbine (OCGT) – Turbine exhaust gases sent directly to stack, without heat recovery.

A variety of different natural gas equipment is deployed across these sites to achieve their operational purpose. Despite this, there is commonality in how the gas is utilised and handled. The study developed the profile into an aggregate of seven equipment types or technologies, with similar physical and technological properties, that are expected to display common challenges in the adoption of hydrogen, or a blend of hydrogen in natural gas. These are presented as ‘technology archetypes’.

Table 3-2: Summary of natural gas equipment groups under each usage category and their aggregation into seven technology archetypes. Relative proportion across NTS direct sites shown in brackets.

Usage Category	Equipment Groups	Technology Archetype (Proportion)
Electricity / Work Generation	Gas Turbine	1. **Gas Turbine:** Natural gas combustion products used to drive a turbine (51%)
	Reciprocating Engine	2. **Reciprocating Engine:** Natural gas combustion products used to drive a reciprocating piston engine (4%)
Heat Generation (Indirect)	Boiler	3. **Indirect Firing:** Radiant and convective heat transferred to a medium via dividing partition (12%)
	Fired Heater	
Heat Generation (Direct)	Furnace	4. **Direct Firing:** Radiant and convective heat transferred to medium through direct contact with combustion gases (3%)
	Kiln	
	Oven	
	Dryer	
	Thermal Oxidiser	
Chemical Feedstock	Methane Reformer	5. **Chemical Feedstock:** Methane feedstock to a process that alters the arrangement of carbon/ hydrogen atoms (5%)
	Methane Pyrolysis	
Storage & Compression	Geological Storage	6. **Storage:** Gas storage at elevated pressures (11%)
	Mechanical Storage	
	Compressor	7. **Compression, Expansion & Gas Conditioning:** Pressure change and compositional control of gas (14%)
	Gas Conditioning	
Electricity / Work Generation	Turboexpander	

4. Gas Characteristics

To understand the potential impacts of transitioning from natural gas to a hydrogen blend and to 100% hydrogen, it is important to understand the differences in the gas properties between the fluids.

Table 4-1 outlines a number of parameters that vary between natural gas and hydrogen, and that influence the characteristics of the gas and how it will behave when processed. These contrasting parameters help identify where constraints may exist in systems and processes originally designed to handle natural gas. Hydrogen blend is reported at 20 vol% hydrogen in natural gas. Where a property is not reported in the table for this gas, it is expected to sit within the range between natural gas and 100% hydrogen.

Table 4-1: Gas property comparison table - natural gas, 20 vol% hydrogen blend, and 100% hydrogen. The values quoted are to be considered indicative to demonstrate the change in gas quality between the three gases only.

Parameter	Natural Gas	Hydrogen Blend	Hydrogen
Density (kg/ Nm^3)	0.793	0.649	0.084
Wobbe Index (MJ/m^3)	47.2 – 51.4	45.2 – 48.8	45.7
Flammability Range (vol%)	4.4 – 17	4.3 – 20	4.0 – 77
Ignition Energy (mJ)	0.21^{CH4}	0.16	0.016
Burning Velocity (m/s)	37^{CH4}	-	286
Adiabatic Flame Temperature (°C)	1941	-	2045
ATEX Gas Group	IIA	IIA	IIC

Wobbe Index is used as an indicator of the interchangeability of gaseous fuels, with the value for natural gas varying across the UK depending on source and time of year. This variability is carried forward into the Wobbe Index range reported in for a hydrogen blend. The lower limit for NTS transported gas is currently restricted to 47.2 MJ/m^3 per the GS(M)R regulations[1], but will be reducing to 46.5 MJ/m^3 in 2025 in accordance with the 2022 GS(M)R consultation response.

[1] Gas Safety (Management) Regulations 1996, Schedule 3 Content and other characteristics of gas, legislation.gov.uk, 1996, Gas Safety (Management) Regulations 1996 (legislation.gov.uk)

5. Hydrogen Acceptability Assessment

Having identified a framework of 7 different equipment archetypes and highlighting the variability in gas characteristics between natural gas and hydrogen, the study then sought to perform an impact assessment to highlight potential fuel switching constraints.

The impact assessment was divided into two parts, considering both general impacts, that are broadly applicable across each of the archetypes and then highlighting any additional archetype specific impacts.

The impact assessment was developed considering publicly available literature, experience from prior fuel switching trials and case studies conducted with 6 NTS direct connected sites, covering each of the equipment archetypes at least once.

5.1 General Assessment

5.1.1 Safety Impacts & Regulations

Industrial sites are required by the Health and Safety at Work Act (HASWA) to maintain a risk assessment for all the hazards presented to their employees, and depending on operation scale, may also be dictated by a number of safety regulations including COSHH (Control of Substances Hazardous to Health), COMAH (Control of Major Accident Hazardous) and DSEAR (Dangerous Substances and Explosive Atmospheres). Introducing hydrogen to sites through their NTS connection has the potential to change these existing risk assessments.

It is suggested that sites adopt a Management of Change process when reviewing the impact of fuel switching, including an assessment of existing controls that may require modification to appropriately manage the risk. Whilst this is a site-specific activity, some general areas for consideration are highlighted below.

Fire & Explosion Risk

A release of a flammable substance such as hydrogen or natural gas can lead to the formation of a flammable atmosphere, and subsequent fire or explosion should the gas find an ignition source. The larger flammability range and lower ignition energy of hydrogen increase its propensity for ignition, although is expected to disperse more readily in an open atmosphere due to the greater buoyancy forces. A hydrogen blend will behave much more similarly to natural gas, and indeed retains the IIA gas group classification within ATEX.

Of the sites considered within the study, vented enclosures, such as those used to house a gas turbine, are prevalent. The HyDeploy[2] study investigated the results of vented explosion experiments for gas mixtures containing 20 vol% hydrogen in natural gas, which suggest that the

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[2] Hooker, P., Gant, S. (2020): HyDeploy2: Gas Characteristics – Summary and Interpretation. Available from: https://www.h2knowledgecentre.com/content/project3118

overpressure for 20 vol% hydrogen blend is expected to be 1.2-1.4 times greater than methane at the same equivalence ratio. The overpressure is expected to be greater for 100% hydrogen.
For leakage from gas containing pipework in non-congested areas, a jet fire is the most probable scenario. Studies have shown that the individual risk factor for a jet fire is lower in most cases for pure hydrogen than for natural gas due to the higher buoyancy forces[3].

COSHH

Both natural gas and hydrogen are colourless and odourless gases, and are considered non-toxic substances under COSHH. Sites that do not already handle hydrogen (or a hydrogen blend) will be required to conduct a COSHH assessment that takes into account its specific gas properties. Many of the same exposure controls will apply for hydrogen as for natural gas, however greater ventilation rates may be necessary in enclosed spaces.

COMAH

Hydrogen and natural gas are both named substances under the Planning (Hazardous Substances) Regulations and the Control of Major Accident Hazards (COMAH) Regulations. Under these regulations any upper tier establishment is mandated to maintain a COMAH safety report that details any Major Accident Hazards (MAHs) and the measures taken to prevent such accidents and limit the consequences.
Further guidance is required from the regulators regarding whether a hydrogen blend of up to 20% vol hydrogen will be considered as natural gas, P2 flammable gas, or will be defined as a new 'named substance' and subject to different controlled inventories. Any site storing natural gas that intends to utilise the existing storage for 100% hydrogen will be subjected to stricter inventory limits, which could result in a change in COMAH classification of the site.

DSEAR

Hazardous area classification (HAC) is a critical consideration when sites transition from natural gas to a hydrogen blend and/or 100% hydrogen. In most circumstances the transition to 100% hydrogen, and to a lesser extent to a hydrogen blend, will result in a change to the hazardous area classification.
For 100% hydrogen the ATEX gas group increases in stringency from IIA to IIC, meaning that any electrical and mechanical equipment within existing hazardous zones not already rated for IIC, will need to be upgraded or relocated. Zone extents and ventilation requirements may also change.
However, a hydrogen blend is classified as a IIA fluid (as per natural gas), and will remain as IIA provided it does not contain more than 25 vol% hydrogen in accordance with IEC 60079-20-1[4]. For sites that follow IGEM/SR/25[5], the SR/25 Hydrogen Supplement 1 recommends that existing natural gas zones calculated using IGEM/SR/25 can be used for blends containing less than 10% hydrogen.

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[3] Froeling. H A J, et al (2021) Quantitative risk analysis of a hazardous jet fire event for hydrogen transport in natural gas transmission pipelines. International Journal of Hydrogen Energy – Volume 46. DOI: https://doi.org/10.1016/j.ijhydene.2020.11.248
[4] BS EN IEC 60079-10-1 - Explosive atmospheres – Part 10-1: Classification of areas – Explosive gas atmospheres
[5] IGEM/SR/25 – Hazardous area classification of natural gas installations

5.1.2 Gas Supply Train & Materials

Rate of Gas Supply

The lower volumetric energy density of hydrogen means it will need to be transported at a higher volumetric flowrate and therefore velocity to provide the same energy as natural gas using existing pipework.

The HyDelta[6] project showed that on a Higher Heating Value (HHV) basis, and within the pressure and temperature range expected for NTS direct connected sites, 100% hydrogen will require a flowing velocity between 2.9 and 3.1 times higher than an equivalent energy flow of natural gas. For a 20 vol% blend of hydrogen in natural gas, this number is between 1.1 and 1.2. Despite the higher flowing velocity, the lower viscosity for hydrogen almost entirely negates any additional pipeline pressure drop in both the 100% and blend scenario. Impact to the pressure drop across combustion burners or injectors is expected to increase, and will need to be assessed on a case by case basis.

Impact on pipework or noise is expected to be minimal when transitioning to a hydrogen blend, unless a site experiences these issues today with natural gas. A more detailed assessment should be performed for 100% hydrogen to determine if additional bracing is required.

Materials of Construction

The suitability of a material for hydrogen service depends on operating conditions, such as temperature, pressure, and loading[7]. Hydrogen embrittlement effects decrease with increasing temperature, and are most pronounced at temperatures between ambient and 149°C, and where the material is subjected to residual and/or applied stresses.

The most susceptible materials to hydrogen embrittlement are high strength steels, such as Carbon Steels, Low Alloy Steels, 400 Series Stainless Steels, Precipitation Hardened Stainless Steels, high strength nickel base alloys, and titanium and its alloys, with susceptibility increasing as material strength increases.

Natural gas pipework and assets, operating at pressures ≥7 barg, that are subject to residual and/or applied stresses, particularly those that are also susceptible to hydrogen embrittlement, should be subjected to stress analysis prior to transitioning to hydrogen blend and/or 100% hydrogen. Separately, NGT are conducting various assessments relating to hydrogen embrittlement as part of their FutureGrid testing programme[8].

5.1.3 Combustion Stability

Flame stability in pre-mixed (aerated) or diffusion burners is critical to the safe and reliable operation of a combustion process over the desired turndown range. To achieve a stable, stationary flame at the burner tip requires balance between the gas flow velocity and flame speed – a parameter that increases with hydrogen – avoiding unstable regions of flame blow-off or flashback.

[6] HyDelta (2021): WP1E – Impact of high-speed hydrogen flow on system integrity and noise
[7] San Marchi. C, Somerday. B.P (2012) Sandia Report – Technical Reference for Hydrogen Compatibility of Materials.
[8] Material assessments include: NIA_NGGT0183 - Inhibition of Hydrogen Embrittlement Effects in Pipeline Steels, NIA_NGGT0186 - Assessment of Legacy Gas Pipeline Steels to Hydrogen Embrittlement Effects, NIA_NGGT0189 - HyNTS Defect Fatigue Behaviour, NIA_NGT0226 - Modelling Hydrogen Impact on Pipeline Steels (HIPS) – Phase 1

Despite the contrast in combustion parameters, modern burners do offer some flexibility to burn a variable hydrogen blend over a wide operating range. Crude Oil refineries operating today are an example of this, where hydrogen is produced in processes involved in petrol manufacture. Excess hydrogen is typically mixed with imported natural gas and other refinery off-gases before distribution to boilers and fired heaters for combustion. The fraction of hydrogen within the fuel gas mixture commonly varies between 0-20 vol% or higher.
For combustion applications transitioning to 100% hydrogen, modification or replacement of the burner is expected, as was the case in the HyNet Industrial Fuel Switching trial at Unilever's Port Sunlight.

Industrial Example – Port Sunlight[9]

Industrial scale blending and 100% hydrogen trials have previously been conducted under the HyNet Industrial Fuel Switching (IFS) programme. In Phase 2 of the first IFS programme, hydrogen was fired in a 7MW industrial boiler (Archetype 3: Indirect Firing) at Unilever's Port Sunlight, with the demonstration designed to give the site confidence to switch an existing natural gas boiler to run on hydrogen.
The project installed a new dual-fuel hydrogen/ natural gas diffusion burner with swirl backplate, into the boiler and successfully operated on 100% hydrogen periodically over a four-week period with no loss in boiler efficiency. An image of the new gas burner head used is shown in Figure 5-1.

Figure 5-1: Hydrogen gas head inspection following the HyNET IFS trial at Unilever's Port Sunlight.

During the trial, the flame was found to be stable throughout the firing range, even when high levels of excess air were used. Inspection of the dual-fuel gas head following the demonstration also indicated stable and reliable combustion and flame at the burner tip. Furthermore, the post-demonstration NDT (Non-Destructive Testing) showed no evidence of change in the condition of the boiler following operation on hydrogen.

[9] HyNet Industrial Fuel Switching Programme (2022)

5.1.4 Environmental Stack Emissions

It is commonly reported that increasing the concentration of hydrogen blended with natural gas will increase the level of NO_x emissions due to higher combustion temperatures, however the actual impact is very much application and operating conditions specific and is influenced by factors including burner geometry, degree of air pre-mixing and excess oxygen[10].
Most studies appear to conclude that transitioning to 100% hydrogen will result in a net increase in overall NO_x emissions without additional abatement, although the impact for a hydrogen blend is less significant, with a number of trials reporting an initial reduction in emission levels.

Industrial Example - NSG Greengate[7]

During the HyNet IFS trial on the NSG Greengate float glass furnace, an overall increase in NO_x emissions was observed as the concentration of hydrogen was increased as shown by the data in Figure 5-2 Measured NO_x emissions from an increasing blend of hydrogen are compared to the expected values for natural gas at the same level of excess air, which is a parameter known to influence NO_x emissions in this application. The analysis suggested a 20-30% increase in NO_x emissions when firing 100% hydrogen in comparison to natural gas, which was within acceptable limits and the capacity of existing abatement equipment for the site.

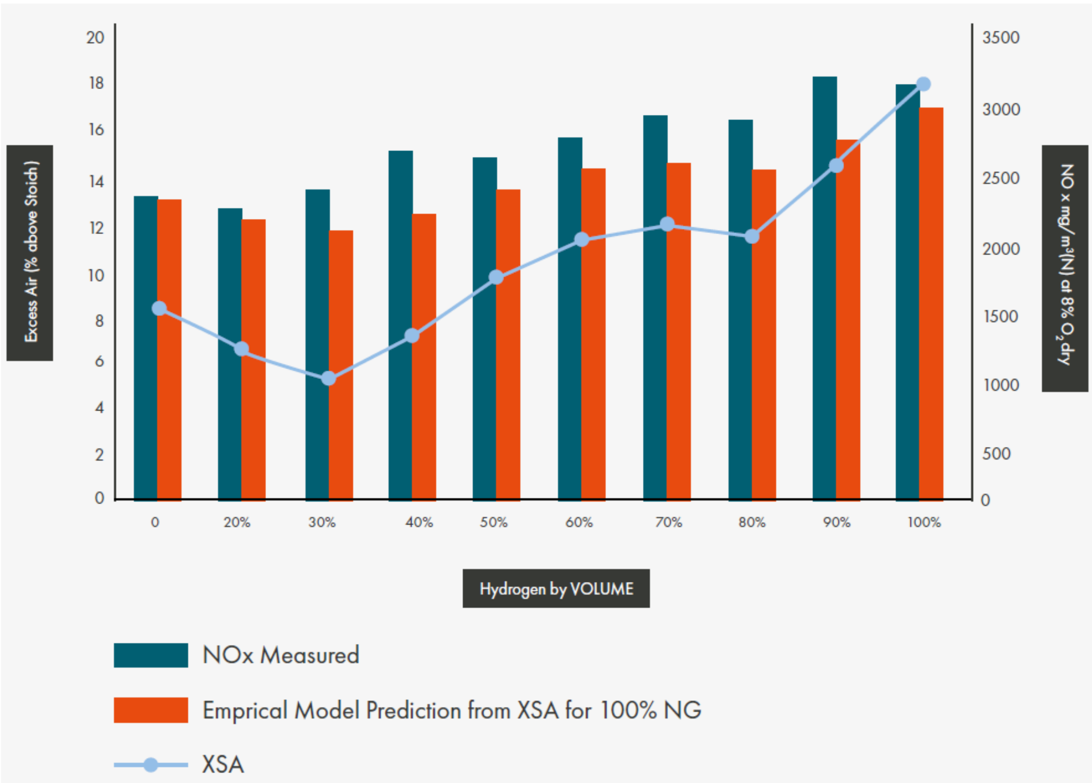

Figure 5-2: Measured NO_x emissions from an increasing blend of hydrogen are compared versus the estimated value for natural gas, calculated using NSG's empirical model for excess air.

[10] Madeleine L. Wright, Alastair C. Lewis (2022): Emissions of NO_x from blending of hydrogen and natural gas in space heating boilers

Each site will need to conduct a NO_x impact assessment when considering hydrogen combustion, the results of which will be burner and operating conditions specific. Depending on the results, it may be necessary to consider NO_x abatement options, such as:

- Modifications to burner operation and excess air
- Installation of Low-NO_x burners
- External Flue Gas Recirculation (FGR)
- Selective Catalyst Reduction (SCR)
- Unit de-rate

5.2 Archetype Specific Assessment

In addition to the general impacts described in the previous section, each of the equipment types are likely to exhibit a number of 'archetype specific' constraints, applicable because of the unique design or operation of that equipment. Where relevant, these archetype specific constraints are outlined in the sections below.

5.2.1 Archetype 1: Gas Turbine

Similar to other combustion processes, Gas Turbines can experience increased combustion temperatures and NO_x emission with increasing hydrogen content in the fuel supply. Due to the higher temperatures, pressures and more extreme combustion conditions experienced, a number of other constraints can arise, including:

- Higher autoignition risk due to lower ignition delay time
- Higher flashback risk due to higher flame speed or lower ignition delay time
- Combustion dynamics / modified thermo-acoustic amplitude level and frequencies
- Higher burner pressure drop due to lower Wobbe Index
- Reduced lifetime / need for more cooling of hot gas path components due to increased heat transfer

Despite these challenges, Gas Turbine OEMs (Original Equipment Manufacturers), such as General Electric, Alstom, Siemens, Kawasaki and Mitsubishi, continue to make progress in developing a portfolio of 'high-hydrogen' acceptability products.
In a 2020 White Paper[11], Siemens reported developing a SGT-2000E (~198 MW) gas turbine application for a customer in the petrochemical industry, that could operate up to 27 vol% hydrogen whilst maintaining NO_x emissions below 50 mg/ Nm^3. It stated that the upgrades to the standard capacity was achieved through incremental changes to the geometry of the burners to improve flashback resistance at higher hydrogen contents. It reported that the changes can also be retrofitted to existing SGT-2000E installations.
Progress has also been made developing 100% hydrogen ready Gas Turbines, with Kawasaki reporting successful trials in 2020[12] utilising a dry low NO_x combustion technology, and more recently Siemens reporting 100% hydrogen firing with its SGT-400 model as part of the Hyflexpower demonstration project at a paper plant in Saillat-sur-Vienne[13]. At the time of this study, gas turbine manufacturers do not yet offer commercially available technology that is

[11] Siemens (2020): Hydrogen power with Siemens gas turbines.
[12] https://global.kawasaki.com/news_200721-1e.pdf
[13] https://www.hydrogeninsight.com/power/correction-siemens-energy-burns-100-hydrogen-in-industrial-gas-turbine-in-energy-storage-pilot/2-1-1535850

capable of 100% hydrogen firing and NO_x emission performance in line with UK/ EU regulations, although is in development and expected to be available by 2030.

OEMs typically offer retrofit options for their current fleet of installed gas turbines to increase the hydrogen acceptability of the unit. The base level of hydrogen acceptability is installation dependent, although many OEMs report their standard gas turbines can accept up to 10 vol% hydrogen in natural gas without change. Figure 5-3 is a high-level summary of the modification roadmap for Siemens and their DLE (Dry Low Emissions) combustion systems. As each installation is different, all OEMs recommend a plant specific FEED (Front End Engineering Design) study that will review required changes to both the gas turbine and ancillary equipment.

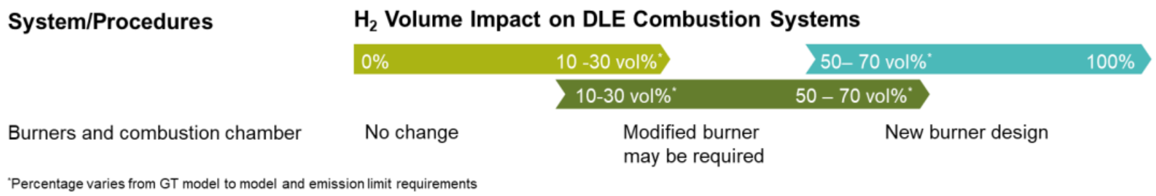

Figure 5-3: Hydrogen acceptability roadmap for Siemens DLE combustion systems

5.2.2 Archetype 2: Reciprocating Engine

The reciprocating engine archetype represents a relatively small proportion of the NTS direct connected end users, with three sites having ‘medium speed’, 10 to 20 MW prime movers. In addition to combustion challenges previously discussed, reciprocating engines are also susceptible to engine knock, particularly due to the reduced methane number of hydrogen.
To assess hydrogen acceptability, sites should first engage with their equipment manufacturer, as many OEMs report that their existing reciprocating engines are able to operate today on a blend of hydrogen up to 20% with little to no modifications. As a minimum however, sites without an existing anti-knock protection system would be recommended to include this as part of their hydrogen blend transition.
For 100% hydrogen acceptability, further reciprocating technology development is required. A number of OEMs offer commercially available 100% hydrogen units today, although this is limited to smaller, ‘high speed’ engines that are of single digit MW in scale. Larger, 100% hydrogen reciprocating engines are expected to become available in late 2020s/early 2030s.
Retrofit options are available for existing units, and typically consider changes to engine compression ratios, ignition timing, and the geometry of the cylinder head.

5.2.3 Archetype 3: Indirect Firing

Of all the equipment archetypes presented in this study, indirect firing applications have likely had the most extensive hydrogen acceptability trials to date, with many successful examples of existing processes firing high hydrogen content fuel today, such as within oil refineries and petrochemical facilities.

Sites should engage with the manufacturer of their combustion burners, who can advise on any limitations of their existing technology and any modifications required to overcome these constraints.

5.2.4 Archetype 4: Direct Firing

Aside from the firing constraints applicable across all combustion applications, direct fired processes also need to consider the impact on product quality from variations in the composition of the combustion gases. An increase in the hydrogen content of the fuel will directly increase the concentration of water in the combustion gases.

Float glass manufacturing is a direct fired application present amongst NTS direct connected sites, and in which the quality of the final product is known to be sensitive to the composition of the combustion gas atmosphere. This potential concern was investigated as part of the HyNet IFS trials conducted at NSG's Greengate Glassworks site, and did not report any product quality impacts from the blend and 100% hydrogen firing that was conducted in the melting area of the site furnace.

Fuel switching trials were also conducted at the site as part of the HyDeploy project[14], were the full 55 MW furnace was operated on a hydrogen blend over a period of 5 days. The trial produced a batch of sheet glass, which passed all product quality testing.

5.2.5 Archetype 5: Chemical Feedstock

Whilst there exists a wide variety of natural gas Chemical Feedstock processes in industry, methane reforming is typically the most prominent, and indeed is present within NTS direct connected sites. These processes are commonly used to produce hydrogen as an intermediatory in the manufacturing of other chemicals such as ammonia, however reforming processes specifically targeting carbon monoxide (CO) yield also exist.

Addition of up to 20% hydrogen into the feedstock of a methane reforming unit is expected to have minimal impact on the quantity of hydrogen produced, but would reduce the yield of CO due to the lower carbon content of the feed. This may also introduce new throughput constraints that should be evaluated on a site-specific basis.

Beyond the general impacts previously discussed, the study identified no new chemical reaction hazards associated with introducing hydrogen into the feed stream. Within a 100% hydrogen scenario, existing reforming plants could retain their natural gas supply and be repurposed to supplement the UK hydrogen production.

5.2.6 Archetype 6: Storage

Gas storage will remain critical infrastructure in a hydrogen economy, supporting the balance between supply and demand. In transitioning an existing subsurface gas storage facility to accept hydrogen, sites will need to consider a number of impacts including gas storage capacity, cushion gas requirements and mixing of in-situ gas with the injected hydrogen.
When hydrogen is stored in subsurface structures, it can be subjected to various reactions that consume the gas and potentially introduce contaminate species, such as H_2S. Sites should consider the different geochemical, and biochemical reaction pathways that can occur when

[14] https://hydeploy.co.uk/app/uploads/2022/06/HYDEPLOY2-THIRD-OFGEM-PPR.pdf

hydrogen is stored underground, as this may influence requirements for additional above-ground treatment processes.

Despite these challenges, new build sites for 100% hydrogen are under development within the same types of geological structures as is used for natural gas storage, increasing confidence in the ability to store hydrogen and confidence that the equipment will become available.

A consideration when repurposing existing natural gas storage to store hydrogen is that the composition of any extracted gas could be a mixture of hydrogen and natural gas, due to any residual natural gas within the reservoir, particularly during the first few cycles of injection and extraction. If the intended end use is 100% hydrogen, deblending facilities may be necessary. NGT are considering deblending at industrial scale as part of FutureGrid Phase 2.

5.2.7 Archetype 7: Compression, Expansion and Gas Conditioning

Compression

Due to the lower density of hydrogen, it is expected that a 15% increase in volumetric flow rate is required to deliver the same energy for a blend as with natural gas. Centrifugal compressor impeller speeds may need to be increased to achieve the same compression ratio, or the number of impellers and impeller length increased. Compressor drivers could be the limiting factor, particularly if fixed speed, and so may require upgrading to provide additional power to achieve the same compression ratio as with natural gas.

For 100% hydrogen, existing compressors will require significant upgrades (such as higher power drivers, larger cylinders / greater number of impellers) and likely an increase in the number of compressor stages to achieve the same compression ratio at an equivalent energy delivery capacity as natural gas.

Expansion

Although hydrogen has a negative Joule-Thomson Coefficient, and therefore increases in temperature during expansion, a 20 vol% hydrogen blend behaves in the same manner as natural gas. Existing expanders used for cooling are therefore expected to be suitable for operation with a hydrogen blend, albeit a greater degree of pressure drop may be required to achieve the same outlet temperature.

To date there is little research available regarding the suitability of turboexpanders for use with hydrogen blend and/or 100% hydrogen. However, given that they are comprised of a gas turbine (without the combustion process) and compressor, the same hydraulic limitations that apply to gas turbines and compressors discussed earlier in this report are expected to apply to turboexpanders.

Gas Conditioning

Gas conditioning typically encapsulates drying and removal of impurities such as sulphur. For Joule-Thomson based dehydration units, similar constraints as described under ‘expansion’ would apply.

In principle absorption and adsorption-based dehydration processes should still be effective in dehydrating a hydrogen blended gas and 100% hydrogen, but could become limited by volumetric throughput.

There is little research available on the suitability of existing natural gas desulphurisation processes for hydrogen and so more development is required in this area to understand any specific constraints.

6. Study Conclusions

The Hydrogen Acceptability Study was commissioned to assess the safety and technical issues relating to the adoption of 100% hydrogen and a variable blend of hydrogen (up to 20% by volume) in natural gas, for industrial processes operated by customers which are directly served by the NTS.

The main conclusion from the study is that generally most applications are capable of handling up to a 20 vol% hydrogen blend gas today, albeit with some level of modification expected (e.g. burner replacement/ compressor upgrades). Sites should conduct a safety assessment to ensure that risks on their facility remain acceptable, or are sufficiently mitigated. Hazardous area classifications will also need to be re-evaluated, with potential increases in zone extents and ventilation requirements.

The evidence has suggested that the transition to 100% hydrogen is technically feasible, but would require more extensive upgrades and modifications relative to the 20 vol% hydrogen blend scenario. In some cases, such as industrial sites using gas turbines or reciprocating engines, the technology readiness for these prime movers to operate on 100% hydrogen is still in development.

6.1 Next Steps

In relation to both hydrogen blend and 100% hydrogen acceptability, the report does not identify any technically insurmountable barriers, but recognises that transition pathways are site and technology manufacturer specific.

Sites should therefore conduct a specific assessment in collaboration with equipment manufacturers and site engineers to better understand in detail, the potential safety, technical, environmental, and economic impacts of transitioning to a hydrogen blend and 100% hydrogen. Following completion of this study, a gap assessment and transition pathway should be developed. For some technologies, this may include additional hydrogen firing trials.

In a number of areas further research and development is also required from equipment manufacturers, in particular to support 100% hydrogen acceptability within allowable combustion emission limits.

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