Hydrogen as a Fuel for Industry: Technical and Safety Challenges

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Low carbon hydrogen is a promising fuel for decarbonising industrial sites due to its clear environmental benefits compared to natural gas. However, the switch to hydrogen as a fuel poses technical and safety challenges that must be addressed such that risks remain As Low As Reasonably Practicable (ALARP).

The Department for Business Energy and Industrial Strategy (BEIS) commissioned AECOM and ESR Technology to undertake early-stage assessments of the technical and safety implications of switching to hydrogen gas, as a direct replacement for existing natural gas use, at seven industrial sites spanning different industries, sizes and complexities. The challenges that such sites will face when switching to hydrogen were explored, including the need for new or modified infrastructure and equipment. This paper describes the common technical and safety challenges sites face with a future switch to hydrogen as a fuel along with recommendations for how sites can address these challenges.

Introduction

Background

The Department for Energy Security and Net Zero (DESNZ), the successor to the Department for Business Energy and Industrial Strategy (BEIS), is working with industry and regulators to deliver a range of research, development and testing projects to assess the feasibility, costs and benefits of using 100% hydrogen for heat. The evidence generated will inform strategic decisions[1] on the role of low carbon hydrogen as a replacement for natural gas heating, which will help determine whether and the extent to which parts of the gas grid are repurposed or decommissioned in the longer-term.

As part of the work on hydrogen heating, the government is looking at the impact to end users of switching from natural gas to 100% hydrogen. A study was jointly conducted by AECOM and ESR Technology, on behalf of BEIS, to survey industrial end users of natural gas to help understand the technical feasibility, economics and safety of sites switching to 100% hydrogen. The study was completed in partnership with seven volunteer industrial sites located away from the industrial clusters and which will likely be impacted by decisions on the future of the natural gas grid[2]. For each of the seven sites a safety report and an overall engineering business case report were prepared to help understand the implications of switching to hydrogen and to compare those impacts at a high-level to alternative decarbonisation option. Whilst the detailed survey reports are commercially sensitive; the purpose of this paper is to help disseminate learnings to other industrial sites and to wider industry. This paper describes the most common technical and safety challenges identified from the seven sites surveyed. For individuals or organisations interested in further details, a summary report containing a more comprehensive description of the work performed, preliminary CAPEX & OPEX estimates, consequence modelling, DSEAR assessments and other study findings is available online[3].

The study was focussed on industrial end users of natural gas and understanding the technical feasibility, economics and safety for them to switch to 100% hydrogen. The study is not intended to apply directly to non-industrial end users because of the differences between end user environments, gas pressures and the quantities of gas consumed which may have significant impacts on the Technical, Safety and Economic assessments conducted in the study.

Sites Surveyed

Table 1 gives a summary of the nature of sites studied. These sites were chosen because of the range of applications and sectors meaning they may not be a fully representative sample of UK installations. Therefore, care needs to be taken with the outcomes of these reports and confirmatory work may need to be done to provide further confidence in any general conclusions.

The sites selected contain a high proportion of direct fired equipment where the flame / combustion products come into contact with the product. These are often more product specific compared to indirect applications such as boilers and heaters where water and steam is used to transfer heat to the process. For the sites studied over 90% of the installed gas equipment was used for process heat.

[1] https://www.gov.uk/government/publications/uk-hydrogen-strategy

[2] https://www.gov.uk/government/publications/industrial-decarbonisation-strategy

[3] https://www.gov.uk/government/publications/future-of-hydrogen-in-industry-initial-industrial-site-surveys

Table 1. Case Study Organisations

Organisation	Industry Sector	Type of Gas Use	Annual Gas Use	Annual Total Energy Use
Site 1 – Other Industry 1	Primary Plastics	Industrial steam boilers, ovens, water heaters, space heaters, flare pilot & ignition packages	83,000 MWh	143,000 MWh
Site 2 – Food & Drink 1	Food & Drink	Industrial ovens, fryers, air handling units, water heaters	18,000 MWh	20,000 MWh
Site 3 – Metals 1	Non-ferrous metals	Furnaces, gas torches, burners, water heaters and space heaters	28,000 MWh	32,000 MWh
Site 4 – Vehicles 1	Vehicle Manufacturing	Industrial ovens, air handling units, recuperative thermal oxidisers, water heaters and space heaters	Limited site extent: 29,000 MWh Whole site: 246,000 MWh	Limited site extent: 29,000 MWh (gas only) Whole site: 364,000 MWh
Site 5 – Minerals 1	Non-metallic minerals	Aggregate dryer	35,000 MWh	35,000 MWh
Site 6 – Metals 2	Metal Packaging	Industrial ovens, recuperative thermal oxidisers, water heaters and space heaters	6,000 MWh	9,000 MWh
Site 7 – Food & Drink 2	Food & Drink	Germination kilning vessels, roasters, grain dryers, thermal fluid heaters, water heaters, space heaters	42,000 MWh	50,000 MWh

A site survey was conducted by the project team for each of the seven sites to familiarise themselves with the site and obtain key information integral to evaluating the safety impacts of switching to hydrogen as a fuel. The objectives of the site visits were to:

- Identify systems and equipment handling or using natural gas (e.g. supply, metering, distribution pipework and end consumers)
- Identify the capacity, gas usage and operating conditions of gas equipment (e.g. line sizes, operating pressure)
- Identify potential release sources (e.g. pressure relief vents, valves, flanges, instrumentation)
- Record ventilation conditions around each release source (e.g. freely ventilated, building ventilation)
- Identify current risk controls related to natural gas use on site (e.g. isolation, gas detection, ignition control, emergency procedures)
- Establish current site practices with respect to Dangerous Substances and Explosive Atmospheres Regulations (DSEAR) risk assessments and Hazardous Area Classification (HAC).

The following sections summarise firstly the technical challenges and secondly the principal safety challenges faced by industrial sites in a future switch to hydrogen based on the findings of the seven site surveys.

Technical Challenges

The technical assessment considered a series of options for full or partial hydrogen conversion along with a best non-hydrogen decarbonisation alternative. In addition to the question of whether an end-user item of equipment can be converted or replaced with a hydrogen fuelled alternative, the assessment considered supply infrastructure across the site, the associated control and instrumentation equipment and the ventilation around items of equipment and infrastructure including the gas network operator's interface equipment.

The site visits identified both direct fired and indirect fired equipment which operate with natural gas as a fuel which could potentially be upgraded or replaced to make them *Hydrogen Ready*[4].

'Direct fired' applications are those in which the energy release and products of combustion come into direct contact with the product or process environment. Energy transfer can occur through a combination of radiative and convective mechanisms. Direct fired applications will generally be excluded from the requirements of the Medium Combustion Plant

[4] The term *Hydrogen Ready* refers to equipment that is optimally designed to run with a 100% hydrogen gas supply but is initially configured to run on natural gas. This equipment may require a minimum number of components to be changed at the point of switch over but will have been specifically designed to facilitate this process.

Directive (MCPD), as they use the gaseous products of combustion for direct heating, drying or other treatment of materials. This is particularly relevant as the MCPD imposes limits on allowable NOx emissions and in switching from natural gas to hydrogen NOx emissions are of concern, as the production of NOx is greater at the higher flame temperatures that can result from hydrogen combustion. However, limits on NOx may still be imposed if ‘installation’ listed activities [7] are performed or where there is potential for product impact.

‘Indirect fired’ applications are those in which the energy release and products of combustion do not come into direct contact with the product or process environment. The combustion energy transfers to and is conducted through a heat transfer surface into the product or process environment, the heat transfer surface physically separates the combustion from the product or process environment. Indirect fired applications will generally be included under the requirements of the Medium Combustion Plant Directive (MCPD), as they use the gaseous products of combustion for indirect heating. NOx emissions are therefore also of concern for indirect fired applications.

Note that because the site selection process largely prioritised direct fired applications there are potentially fewer examples of indirect applications than would be typical in a larger sample of industrial sites.

Best Alternative (non-hydrogen) solutions may include electrification and use of renewable energy sources or renewable energy power purchase agreements and can provide an opportunity in the short term for a site to reduce its emissions for existing use of electricity and where there is capacity to electrify more equipment. Where capacity is not available there will be a longer term requirement to upgrade on-site and network supply capacity.

The techno-economic assessment was carried out consistent with an AACE Class 4 level estimate based upon normal market conditions in 2021 GBP. No allowances have been made for market activity in light of Brexit, COVID-19 or energy price volatility due to more recent geo-political events.

Cost data for hydrogen has been sourced from the Hydrogen Production Costs 2021 report on the basis of central figures from the low carbon ‘green’ hydrogen. Hydrogen costs have been based upon levelized cost of hydrogen at central fuel prices for Proton Exchange Membrane (PEM) electrolysis, where PEM electrolysis is the highest Levelised Cost of Hydrogen (LCOH) technology for green hydrogen production, assuming that maximum and minimum bounds are represented by the extremes of curtailed and industrial retail values. A mark-up is assumed between LCOH and retail pricing to account for profit margin and costs associated with transportation and storage based upon gas market trends. Green Book supplementary guidance has been used for natural gas, electricity and carbon prices.

A carbon ‘tax’ has been assumed to be levied on sites where they continue to produce CO_2 through ongoing fuel combustion onsite. This has been applied to the baseline scenario for all the sites and options on site, where there is the retention of CO_2 producing combustion equipment, and is based on carbon values, which have been used as an estimate of a maximal carbon tax that could be placed on emitters. A carbon value is assumed based on the Central value from the Green Book supplementary guidance for 2022 Greenhouse gas emissions values (“carbon values”) which is used across government for valuing impacts on GHG emissions resulting from policy interventions. They represent a monetary value that society places on one tonne of carbon dioxide equivalent (£/tCO_2e). They differ from carbon prices, which represent the observed price of carbon in a relevant market (such as the UK Emissions Trading Scheme).

Further details can be found in the published report[3].

The common technical findings identified from the sites surveyed are summarised in Table 2:

Table 2. Technical Findings

Topic	Technical Finding
Cost	For the surveyed sites the 100% hydrogen solution is typically significantly cheaper on CAPEX than the best alternative (non-hydrogen) solution, which is most often electrification, due to the ability to retrofit and by avoidance of new or reinforced electrical infrastructure. A hybrid hydrogen solution may offer a lower CAPEX option in some cases.
	For the surveyed sites the 100% hydrogen solution is typically less expensive on OPEX than the best alternative (non-hydrogen) solution, which is most often electrification, but there are exceptions. The hybrid hydrogen solution may have a higher OPEX option than 100% hydrogen in most cases, but again with exceptions.
	For the surveyed sites the 100% hydrogen solution lifecycle cost is very site dependent and so is the difference to the best alternative (non-hydrogen) solution, which is most often electrification. Use of electrification results in high lifecycle costs due to a combination of Capital and Operating costs along with the level of CO_2 emissions per kWh of electricity on the long term marginal basis consumed during the projected 2025-2045 period. This results in lower CO2 emission savings relative to the baseline when compared to the hydrogen alternatives leading to a higher cost per tonne of CO_2 abated. The hybrid hydrogen solution is generally shown to be more expensive than the 100% hydrogen option in most cases.

Topic	Technical Finding
	Averaged across the sites investigated for hydrogen conversion, indirect costs[5] account for approximately 52% of the CAPEX with approximately 43% on end user conversion and 5% on site infrastructure modifications.
Availability of *Hydrogen Ready* equipment / burners	Within the scope of the study, current technical feasibility and equipment availability varies across applications. There are commercially available hydrogen equivalents for a number of end users such as various types of burner suitable for installation as part of boilers, furnaces, ovens, dryers, water heaters, and thermal fluid heater packages. Complete boiler (steam generator) packages are also available. However there are very few reference plants operating with 100% hydrogen gas.
	A number of common modifications were observed as being necessary for both direct and indirect applications. Replacement of inlet piping to burners for capacity reasons and removal of threaded fixtures are expected, as are modifications to Programmable Logic Controller and Burner Management System. Flame-eye re-tuning will also be required, and it is likely that the replacement of existing flame-eye or additional flame-eyes specifically calibrated for hydrogen flames will be required.
	Some bespoke projects and commercial development for hydrogen equivalents have been in the field of large steam generators and small 'domestic' type water heaters along with industrial roasters, ovens and fryers. These are not commercially available 'off the shelf' hydrogen equivalents and have limited reference projects.
	For certain applications such as speciality ovens, large air handling units, direct fired space heaters, gas fired torches, complete furnace packages, complete dryer packages, and complete thermal fluid heater packages there appeared to be no commercially available hydrogen equivalents.
Line size adequacy	The line capacity of existing natural gas lines is often insufficient for the hydrogen flow required to maintain the same energy flow to the end users. In the majority of sites studied approximately 50% or more of the pipework would need to be replaced because it is undersized for hydrogen service.
Increased ATEX ratings	Equipment such as regulators, fan motors and other electrical equipment present in hazardous areas will be required to be ATEX certified as IIC-T1 for hydrogen, compared to the less stringent (and cheaper) IIA-T1 required for natural gas, due to hydrogen's greater flammability compared to natural gas. In many instances, it may be possible to introduce additional ventilation, or change pipe routings or component locations to mitigate the potentially increased zoning requirements as opposed to upgrading or replacing affected equipment.
Emissions	For the surveyed sites the 100% hydrogen solution typically gives a greater reduction in CO_2e emissions than the best alternative (non-hydrogen) solution, which is most often electrification. The hybrid hydrogen solution is generally shown to be similar to 100% hydrogen in most cases.
	Burner OEMs consulted indicated that for both retro-fits and new builds further work is required to understand and predict achievable NO_x values. There is a risk that any early NO_x guarantees offered are potentially more conservative than required and indicate a need for Flue Gas Recirculation (FGR) or Selective Catalytic Reduction (SCR) being specified when not necessary, increasing the capital and operating cost.

Safety Challenges

Use of hydrogen gas instead of natural gas represents an increased inherent risk profile for industrial sites due to its different physical properties. The key hazardous properties of hydrogen have been well documented by others and are summarised in Figure 1.

[5] The indirect costs assumed include variable, fixed costs and allowances. Variable indirect costs considered were: Project Management, Works Management and Supervision, Travel and Accommodation, Site Facilities, Insurance and Permits, Corporate Costs. Fixed Indirect costs considered were: Design, Mobilisation, Contingency and Profit. Allowances considered in the indirect costs were: Design development and Brownfield integration.

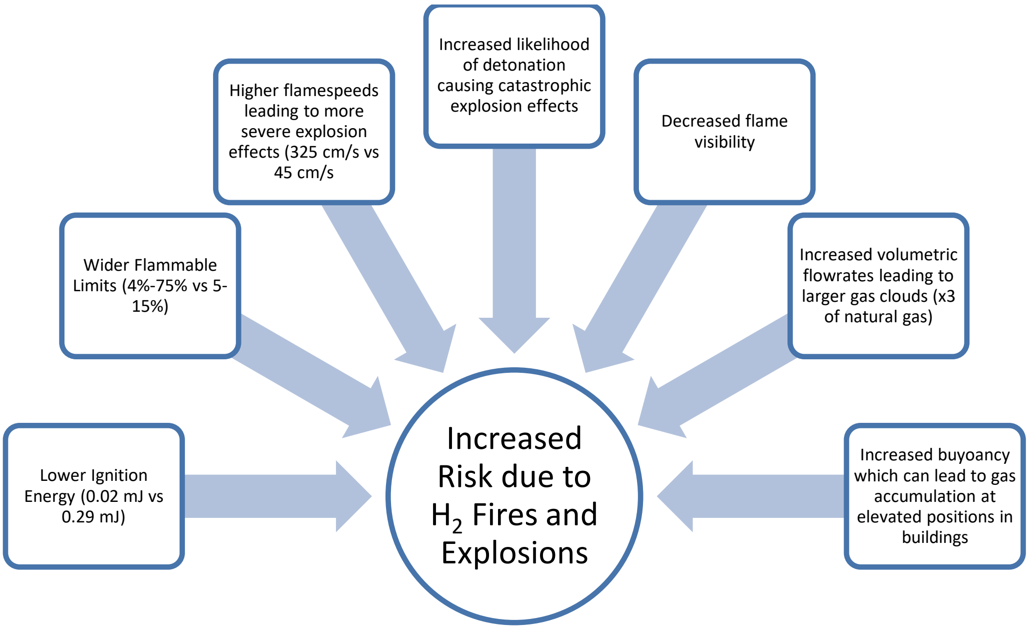

Figure 1. Key differences between natural gas and hydrogen which increase risks prior to any applied mitigations

Hydrogen has a lower ignition energy, wider flammable limits, faster flame speed and has a lower detonation energy than natural gas. If no mitigation measures are implemented, there is a potential for a significant increase in explosion risks with greater potential for injuries, fatalities and equipment and building damage when operating with hydrogen. The larger volumetric flows of hydrogen, compared to natural gas at the same conditions, can also result in a significant increase in flammable gas cloud sizes from a leak orifice of a given size – in particular for areas where ventilation is poor. The increased inherent risks of using hydrogen require sites to evaluate if additional safeguards and controls are managed such that the risk profile remains broadly equivalent to operating with natural gas and that ultimately risks are being managed to As Low As Reasonably Practicable (ALARP) in line with UK legislation.

For each of the seven sites surveyed a preliminary Hazard Identification (HAZID) study, DSEAR Risk Assessment and Consequence Assessment has been conducted to help identify new or increased risks when operating with hydrogen and help identify potential future safeguards to manage these risks. The DSEAR risk assessment followed draft IGEM guidance [1] for hydrogen installations which was in development at the time of the study and is a supplement to *IGEM/SR/25* [2] which covers natural gas installations. The draft hydrogen guidance has subsequently been updated and published as *IGEM/SR/25 Hydrogen Supplement 1* [3].

The key safety findings from the sites surveyed are summarised in Table 3.

Table 3. Safety Findings

Topic	Safety Finding
Loss of Containment / Explosion Consequences	Leaks from the high-pressure gas distribution system coming into a site (e.g. pressure let-down and metering equipment) had the greatest potential for damage and fatalities on neighbouring areas. Metering and pressure let-down is often housed in an enclosure where hydrogen can accumulate whilst also featuring the highest gas pressures on-site. For the sites surveyed this was not found to be a significant issue, because the equipment was located in a remote area, on industrial sites where industrial neighbours were sufficiently remote that the change from natural gas to hydrogen made no material difference to offsite risk. However, this is a site configuration specific risk and needs to be considered further.
	For COMAH sites (such as Site 1 - Industrial Other) or other sites that store large quantities of flammable, toxic or environmentally harmful materials the impact of an increase in explosion effects must be assessed carefully on a site by site basis. Increased explosion loads could necessitate rerouting of hydrogen pipework or relocation of existing storage/vessels/tanks holding flammable and toxic materials. Any such modification is likely to have significant cost implications.
	If a deflagration to detonation transition (DDT) of a hydrogen gas cloud were to occur, then peak overpressures could exceed 10 barg causing catastrophic damage to the immediate surroundings. It is widely acknowledged that a DDT event is far more likely for confined or congested hydrogen explosions than equivalent natural gas explosions [4]. The conditions under which a DDT would occur are complex and would need to be evaluated on a case by case basis, but removal of

Topic	Safety Finding
	congestion can reduce the risk of detonation. It is therefore important to ensure that the areas around buildings with gas regulating equipment are clear of vegetation or other obstructions.
Internal Equipment Explosions	A particular concern identified from the surveys is the adequacy of existing safety systems on combustion equipment to prevent internal hydrogen explosions. The adequacy of all gas combustion equipment and associated burner management systems (BMS) will need to be checked with the supplier and upgraded or replaced prior to a switch over to 100% hydrogen. BMS reliability will need to be sufficiently high that risks can be demonstrated to be ALARP when considering the increased severity of internal hydrogen explosions.
	Pre-mixed burners, where air is mixed with gas upstream of the burner itself, were identified on a number of the sites surveyed. Due to the higher flame speed and much wider flammable range for hydrogen these configurations may require significant changes or complete replacement to avoid the potential for damaging internal pipework explosions.
	The security of gas systems against reverse air ingress into vents, flares and burner supply lines will need to be checked along with gas equipment maintenance procedures to prevent air ingress which could lead to pipework explosions. Hydrogen has a much wider flammability range than natural gas meaning that comparatively small amounts of air ingress could create a flammable mixture internal to pipework that would not for natural gas.
	For any equipment with explosion venting (or explosion suppression) equipment present, the design will need to be reviewed and major changes may be required due to the higher flame speeds of hydrogen; in some cases it may not be practical to provide adequate explosion relief for existing equipment.
Gas Equipment	Equipment used in industrial sites typically have a long operating life and quite often have been in situ for a long period of time. Standards have been reviewed and updated in that period so while the gas equipment was acceptable at the time of installation, it may now not meet current best practice. Safety measures for legacy equipment will require appraising from scratch for hydrogen operation as this is a fundamental change from the original design basis that has the potential to invalidate existing safety measures.
	Any existing gas equipment will need to be validated as being safe to operate with hydrogen. Example considerations include: material compatibility, leak tightness, higher flame temperatures, lower energy density, higher volumetric flows. The security of gas systems against reverse air ingress will also need to be checked to prevent potential pipework explosions as hydrogen has a wider flammability range than natural gas.
	Hydrogen embrittlement is a known issue, particularly for high strength steels. Hydrogen effects on elastomers/polymers and other materials is an area of ongoing research. Further study is required to determine the material compatibility of existing systems. It is also recognised that the positive identification of all materials used in a site’s gas distribution system may be a difficult task on older sites and therefore replacement is likely to be the preferable solution.
	Further investigation is required to confirm if hydrogen can be reliably used as a pilot flame for flare stacks including in poor weather conditions.
	Investigation is also required into the leak tightness of screw and compression jointing techniques, along with material compatibility, for hydrogen service
Gas Burners	Several of the sites surveyed carry out manual ignition sequences of burners. It may not be safe to continue to do so when operating with hydrogen. An alternative burner arrangement (e.g. controlled by BMS) or other demonstration that the current arrangement is safe in hydrogen service will be required.
	One site surveyed made use of hand held gas torches fed by a common gas header. As hydrogen burns with a clear or low visibility flame, handheld gas torches may need to be upgraded to have flame detection and automatic shutdown, but it is unknown if such devices exist with adequate reliability. An alternative solution is to explore installing a separate fuel supply (e.g. propane) just for handheld torches or if impurities can be added to the hydrogen supply to ensure the flames remain easily visible. The low visibility flame of hydrogen fires could result in accidental burns to workers, unintended ignition of flammable or combustible materials and increase difficulty in determining if a gas torch is ignited with the potential for accidental gas releases.
Ventilation	For gas pipework and equipment located inside buildings or enclosures it was commonly found that sites existing ventilation arrangements would be inadequate for hydrogen and would lead to revised zones (typically Zone 2) encompassing unrated electrical and mechanical equipment. Whilst this equipment could in theory be replaced with ATEX rated equipment it will probably be more

Topic	Safety Finding
	practicable to improve ventilation such that a Zone 2 NE classification can be defined instead or by relocating gas equipment outside of buildings.
	Additional ventilation was often required at high level, in accordance with IGEM guidance for hydrogen installations [3], as hydrogen is highly buoyant and could collect at roof level if high level ventilation is not present. Nearly all meter houses surveyed required increased ventilation area, especially at high level, to maintain the current zone classification when operating in hydrogen service.
	Where practicable, gas supply systems inside enclosures and buildings should operate below 100 mbarg, e.g. by locating pressure regulators outside buildings. Doing so leads to zones of NE as long as ventilation can be demonstrated to exceed 1.5 air changes per hour (ACPH).
DSEAR / ATEX HAC	Outdoor gas supply pipework tends to result in a Zone 2 of Negligible Extent (NE) for the operating pressures commonly found at industrial sites (<2 barg) as long as the pipework was routed through uncongested areas (i.e. areas with good natural ventilation).
	The most common source of adverse conditions (as defined in IGEM/SR/25 [2]) identified from the sites surveyed was associated with flexible hoses and rotating equipment (vibration source), in particular gas booster compressors. Adverse conditions result in significantly larger hazardous areas for hydrogen than for natural gas which can encompass previously non-ATEX rated equipment. No coastal sites were visited as part of this work, but it is likely that these sites would also require significantly increased hazardous areas for hydrogen operation due to being classified as operating in adverse conditions.
	Where Hazardous Areas are unavoidable, tighter ignition control will be required due to the much lower ignition energy of hydrogen (~10 times lower than natural gas). For example, to maintain compliance with the EPS (2016) Regulations [5], more stringent IIC-T1 ATEX rated equipment would be required versus an IIA-T1 ATEX minimum rating for natural gas. Every meter house surveyed was already fitted with electrical equipment which would be suitable for hydrogen service (IIC-T1 ATEX), but this cannot be assumed, and other locations that could potentially become hazardous areas often had unrated electrical equipment present; in some cases this included major plant items.
Pressure Relief Vents	Applying the draft IGEM guidance for calculating hydrogen hazardous areas [1], Hazardous Area Classification (HAC) extents around vent tips would increase significantly with hydrogen and, depending on vent location and configuration, this could result in additional requirements for ATEX rated equipment versus natural gas. Vents with non-ideal vent tip configurations (e.g. downwards or impeded) have the most significant implications for some sites with hazardous area radii increasing to encompass non-rated ground level equipment.
Working practices	Safe systems of work will need to be revised to better manage sources of static charges, such as clothing, within hazardous areas and when performing maintenance work on gas systems due to the increased ignition risk. From the sites surveyed, the use of anti-static clothing for personnel in operational areas was not common practice except for at the COMAH site visited (Site 1 - Industrial Other).
	Sites will be required to update existing Risk Assessment Method Statements (RAMS) and Standard Operating Procedures (SOPs) associated with work on gas systems to reflect the difference in hazards posed by hydrogen compared to natural gas. For example, tighter ignition control and purging and venting procedures will become more critical with less tolerance for residual air in gas systems.
	There is an industry need to ensure that sufficient Gas Safe engineers are trained and familiar with hydrogen to carry out installation and maintenance activities for future changeover to hydrogen. In some areas there is a higher tolerance operating with natural gas than with hydrogen and there will be less margin for error, requiring increased rigour in safety procedures.
Flame, Fire and Gas Detection	Existing fire / flame detection and gas detectors will require recalibration or replacement to work for hydrogen due to hydrogen’s different characteristics. Adding flammable gas detectors, where not already installed, is likely to be ineffective except in areas where there is a significant risk of gas accumulation.
	Hydrogen fires burn with a clear or low visibility flame which could result in people on escape routes being unable to correctly identify the edge of flames. This could lead to confusion and incorrect decision making during evacuations. Sites will be required to consider this in emergency response planning and personnel training. Providing onsite emergency response teams with suitable thermal imaging equipment for hydrogen fires, is strongly recommended.

Topic	Safety Finding
Gas boosters	Gas boosters are commonly used where there was a need to boost low pressure gas to the operating pressure of gas burners (e.g. industrial ovens). The integrity of existing gas boosters is unlikely to be adequate for hydrogen and were found in the DSEAR review to result in HAC Zone 2 extents of several meters.
Hydrogen Combustion	Due to the nature of hydrogen combustion (increased water vapour, higher flame temperatures but lower thermal radiation), there could be significant impacts on product quality or adverse reactions with materials in exhaust systems. The product quality is more pertinent to sites where final products are directly heated by a hydrogen flame or where combustion products flow over the product. Some potentially complex cases were identified at food manufacturers and also for paint curing ovens which will require further research. One case of concern was where reactive (e.g. metal) dusts may gather in exhaust systems there is a potential for an exothermic reaction to occur due to higher moisture levels in combustion gases.

Technical Recommendations

The ability for sites to retrofit or replace their equipment so that it is suitable for hydrogen service will depend on them demonstrating the feasibility of operating such equipment in conjunction with Original Equipment Manufacturers (OEMs). Table 4 summarises the common technical recommendations arising from the site surveys.

Table 4. Technical Recommendations

No.	Recommendation
T1.	Additional engagement is required from OEMs to better understand the extent of modifications required, NO_x guarantees, and impacts on operation (e.g. temperature profiles, efficiencies, thermal rating, control system changes, material suitability, equipment durability) of switching equipment to hydrogen as a fuel. OEMs should consider the implications of recent BEIS work on Hydrogen Ready Industrial Boilers [6].
T2.	Further work is required by OEMs, particularly those providing complete packages, to develop commercial hydrogen versions of their equipment ranges. Availability of funding to support their development could encourage OEMs who are hesitant to invest prior to major hydrogen uptake or switchover. An assessment will have to be made by government as to the extent to which existing programmes like Industrial Energy Transformation Fund, Industrial Hydrogen Accelerator, Industrial Fuel Switching 1 & 2, and the Industrial Clusters programme provide sufficient imperative to manufacturers to create *Hydrogen Ready* solutions.
T3.	Further work is required for OEMs to develop *Hydrogen Ready* boosters/compressors for low pressure applications.
T4.	Further work and study are required to understand the impact of the higher moisture content from hydrogen combustion on processes such as ovens and dryers, and if this will have an impact on air flow rates, product flow rates, quality, and fuel consumption. Some potentially complex cases were identified involving combustion products which will require further research at food manufacturers.
T5.	Industrial sites will be required to positively identify all materials within a site's natural gas infrastructure if it is to be repurposed for hydrogen, in particular valve trims and non-metallic components at joints and valves. Whilst hydrogen embrittlement is a known issue, particularly for high strength steels, hydrogen effects on elastomers/polymers and other materials is an area of ongoing research. Further study is required to determine the material compatibility of the existing system. It is also recognised that the positive identification of all materials used in a gas distribution system may be a difficult task on older sites. It may therefore be more cost/time efficient to construct parallel replacement piping; this may be mandated based on the line capacity and size of the pipework required for hydrogen versus natural gas.
T6.	Though flowmeters suitable for hydrogen flow measurement exist, a recognised fiscal hydrogen flowmeter is still an area requiring further development. The possibility to modify existing fiscal natural gas flowmeters to work for hydrogen also requires further investigation.
T7.	Further work is required to understand the potential demands on the supply chain in assessing the changes required for bespoke end-user equipment, and the ability to provide equipment at the rate required for potential conversion or retrofitting.

Safety Recommendations

Table 5 contains the key recommendations for industrial sites to consider prior to a future switch to hydrogen as a fuel. A qualitative ranking of the relative difficulty of implementation, based on the sites surveyed, is provided to highlight which safety recommendations may be difficult or costly to implement for industrial sites:

Table 5. Safety Recommendations

No.	Recommendation	Difficulty of implementation
S1.	The properties of hydrogen are sufficiently different to natural gas that existing site risk assessments and operating procedures should be reviewed and updated for hydrogen service.	Low
S2.	Pipe sizes, materials and jointing methods used onsite could require changes for hydrogen service when considering the lower energy density of hydrogen, the risk of hydrogen embrittlement, hydrogen leak tightness and higher hydrogen flame temperatures. Sites should evaluate the suitability of current gas pipework for operating with hydrogen and replace or upgrade if found not to be suitable.	Medium to High depending on gas system complexity
S3.	Gas burners and burner management systems (BMS) will need to be reviewed and updated, to ensure safe operation, including combustion air flows, purge cycles, flame detection, gas isolation systems, the potential for air ingress and explosion relief. Premix burners may be a particular issue due to the potential for an explosion in the supply pipework when operating with hydrogen.	Medium to High common issue across all sites visited.
S4.	Hydrogen is flammable to much higher concentrations in air than natural gas and a flame can propagate much faster leading to a much greater explosion hazard if air is present. A more thorough approach to design, maintenance and operation to prevent air ingress into gas pipework (e.g. reverse flow, purging procedures) will be required.	Low to Medium common issue across all sites visited,
S5.	DSEAR risk assessments and Hazardous Area Classifications (HAC) will need to be updated to reflect operating with hydrogen.	Low
S6.	HAC around pressure relief vents can increase significantly for hydrogen and could now encompass non-ATEX rated equipment. This needs to be checked and is a particular issue for “non-ideal” vent configurations (e.g. goose neck vents). A revised vent configuration would potentially mitigate the need for larger HAC zones	Low to Medium for the majority of sites visited - minor changes to vents can avoid large HAC zones.
S7.	Enclosures and buildings may not have sufficient ventilation, including at high level, to avoid hydrogen accumulating to flammable concentrations. Hydrogen has a higher volumetric flow than natural gas at the same hole size and pressure (~3 times greater) and is more buoyant. A review of building ventilation should be conducted to determine if it is adequate when equipment is in hydrogen service.	Low to Medium for the majority of sites visited only minor changes to ventilation is required but some sites may require more extensive changes.
S8.	Hazardous areas are expected to increase around equipment in hydrogen service. Other equipment located withing hydrogen hazardous areas (e.g. a Zone 2 area) will require enhanced ATEX ratings suitable for hydrogen gas (or an alternative solution). Following completion of the DSEAR risk assessment/ HAC (see recommendation S5) sites should ensure that all electrical and mechanical equipment located within the defined HAC is suitably ATEX rated.	Medium to High for the majority of sites, problematic HACs can be avoided by simple measures. Where hazardous areas cannot be avoided installing ATEX rated equipment could be very costly
S9.	Site procedures (RAMS, SOPs etc) will need updating to reflect the extra hazards posed by hydrogen, such as increased ignition risks from electrical items, electrostatic charges (e.g. clothing), higher volumetric flows during venting and the importance of inerting procedures.	Low

Discussion and Conclusion

The study assumed a future conversion of the mains gas supply to 100% hydrogen. The key barriers to complete substitution for natural gas at industrial sites identified by this work are:

- Confidence in the security of supply of hydrogen. During initial implementation there is a concern that the hydrogen supply system will have lower availability and reliability than the current natural gas supply system. Dual fuel systems for all end users are not available or in development, thus further work is required to understand if back-up systems could be feasible, and this is likely to be site specific.
- The economics of conversion to hydrogen, including initial capital expenditure and the uncertainty in hydrogen pricing.
- The number of end users of natural gas who do not have commercially available hydrogen equivalents.
- Demonstration that a 100% hydrogen gas supply can achieve a broadly equivalent level of risk to life as for natural gas i.e. at a level considered tolerable by both industry and the wider UK population. It is recognised that to achieve a similar level of risk to natural gas that modifications to existing gas equipment and associated infrastructure will need to take place to make them safe to operate with hydrogen as a fuel.

A key barrier to the most common alternative decarbonisation option of electrification will be the high variability of the energy loads for major users. This peaking nature may be unpalatable for electricity suppliers and sites may struggle to agree an economically feasible supply contract. Discussions and investigation with the DNO and electricity suppliers would be required to resolve this supply risk.

By adherence to Relevant Good Practice (RGP) for design and operation of any future hydrogen gas supply equipment the likelihood of a Loss of Containment (LOC) can remain broadly equivalent to current natural gas systems. There are potentially significant increases in explosion risk when switching to hydrogen and there will be a need to consider additional mitigation measures to help control this risk, in particular for combustion equipment. The ultimate requirement will be to demonstrate that risks associated with a change to hydrogen as a fuel have been reduced to ALARP. This is considered to be achievable by sites implementing RGP, but it is anticipated that there will be significant costs for some sites to achieve this. RGP for using hydrogen as a fuel is at a comparatively early stage of development but will build on lessons learnt from decades of natural gas use alongside hydrogen experience from the process industries. For industrial sites, the greatest need for RGP relates to the design, construction and operation of hydrogen combustion equipment and there needs to be an ongoing assessment of safety standards in order to provide adequate input for RGP. For example, further work is required to understand the acceptability of BS EN 161 (Automatic shut-off valves for gas burners and gas appliances) and BS EN 746 (Industrial thermoprocessing equipment) for hydrogen service and the impact the sizing of creep relief valves and releases from the tail pipe has on hazardous areas.

The feedback from sites engaged with this work has been that the safety reports had increased their awareness of the safety challenges of hydrogen and moderately increased their concern about using hydrogen safely, but that the safety mitigations suggested were generally acceptable. The majority of sites were interested in using hydrogen after reviewing the reports and assuming there was a reliable supply of hydrogen available most sites could see hydrogen as a lead option for their sites. Sites also indicated that further support, work and guidance would be useful, and that being part of this study had made them more inclined to use hydrogen.

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