FINAL REPORT

Blending Management Approach Phase 2

National Gas Transmission

Report no.: 10589332/4, Rev. 2
Date: 2026-04-07

Project name:	Blending Management Approach Phase 2	DNV - Energy Systems
Report title:	Blending Management Approach Phase 2	Energy Strategy Advisory
Customer:	National Gas Transmission, National Grid House, Warwick Technology Park, Gallows Hill, Warwick, CV34 6DA	Holywell Park, Ashby Road, Loughborough, LE11 3GR
		Tel: +44 7807 719227
Customer contact:	[redacted]	01503799
Date of issue:	2026-04-07	
Project no.:	10589332	
Organisation unit:	DNV Services UK Ltd	
Report no.:	10589332/4, Rev. 2	

Applicable contract(s) governing the provision of this Report: PO 1000396617

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Senior Engineer

Internally in DNV, the information in this document is classified as:

	Can the document be distributed internally within DNV after a specific date? No	Yes
☐ Open ☒ DNV Restricted	--	--
☐ DNV Confidential ☐ DNV Secret	☐	☐

Additional authorised personnel for distribution within DNV:

Keywords Hydrogen safety

Rev. no.	Date	Reason for issue	Prepared by	Verified by	Approved by
0	2026-02-20	First issue	Team	SK, TI, J-AT	MJM
1	2026-03-18	Addressed client comments	Team	SK, TI, J-AT	MJM
2	2026-04-07	Added summary and conclusions and further improved the report	Team	TI, JH	MJM

DISCLAIMER

Independence, impartiality, and advisory limitations

This document contains content provided by DNV. Please note the following:

Ethical safeguards

To maintain integrity and impartiality essential to its third-party roles, DNV performs initial conflict-of-interest assessments before engaging in advisory services.

Priority of roles

This report is generated by DNV in its advisory capacity, subsequent to conflict-of-interest assessments. It is separate from DNV's responsibilities as a third-party assurance provider. Where overlap exists, assurance activities conducted by DNV will be independent and take precedence over the advisory services rendered.

Future assurance limitation

The content in this document will not obligate or influence DNV's independent and impartial judgment in any future third party assurance activities with DNV.

Compliance review

DNV's compliance with ethical and industry standards in the separation of DNV's roles is subject to periodic external reviews.

Table of contents

1 EXECUTIVE SUMMARY

Introducing hydrogen blends into the National Transmission System (NTS) is an intermediate step towards net zero. However there may be implications for how the network is managed, and downstream impacts on connected storage facilities and large industrial users. This project aims to deepen the understanding of how low-level hydrogen blends interact with existing infrastructure and protocols and assess the operational, safety, and strategic implications, particularly with regard to storage interactions, emergency response scenarios, and long-term network management strategies.

The work has been broken down into three main areas that assess how hydrogen blends affect:

1. Gas storage facilities currently connected to the NTS, including salt caverns and depleted reservoirs;
2. The adequacy of current emergency response frameworks, including constraint management tools, coordination with emergency services and the need for updates to operational documentation; and
3. The strategy for control and transportation of gas through the NTS.

Key findings for gas storage facilities are that:

- Salt caverns, the dominant UK storage type, are generally more tolerant of both hydrogen and biomethane than porous reservoirs (depleted fields or aquifers);
- Oxygen in biomethane is a primary driver of corrosion, especially when water is present. Even parts per million levels oxygen can form sulfur deposits, create acidic species, and corrode steel and equipment;
- Hydrogen introduces integrity risks, especially hydrogen embrittlement of steels, accelerated fatigue, and long-term uncertainty in porous formations. Partial pressure is a key determinant of risk;
- At 5% hydrogen, risks are generally manageable; at 20% hydrogen, several components, particularly high-strength steels, welds, springs, and stressed sections, become significantly more vulnerable;
- Surface equipment (compressors, dehydration systems, amine units, metering) is more sensitive to oxygen, hydrogen sulfide, carbon dioxide, microbial by-products, and hydrogen embrittlement. Oxygen accelerates degradation of both triethylene glycol (TEG) and amines used in dehydration and acid gas removal processes;
- Metering and gas quality monitoring assets face potential sulfur deposition issues if oxygen and hydrogen sulfide coexist in the blend; and
- The highest-risk scenarios are those with high biomethane (high oxygen) combined with 20% hydrogen where corrosion, fatigue, and operational reliability concerns coincide.

Overall, the assessment confirms that introducing low-level hydrogen blends is feasible for storage facilities, but operational controls, targeted upgrades, and risk-informed integrity management will be essential, especially for higher hydrogen concentrations or biomethane-rich blends.

Key findings for the constraint tool and emergency response frameworks review are that:

- Many existing constraint management tools are, in principle, largely unaffected by the introduction of biomethane and a 5% hydrogen blend;
- However, blended operation increases dependence on accurate gas composition tracking and on operator competence in using network modelling tools to evaluate ‘what-if’ scenarios and compressor strategies;
- Local actions taken during constraint management, particularly those that reduce natural gas flow near injection points, could unintentionally increase local hydrogen (or biomethane constituents such as oxygen and

carbon dioxide) beyond agreed specifications, requiring careful control through the Transportation Flow Advice (TFA) process and associated operational decision-making;

- Given the novel operating environment and limited practical experience of controllers with blended-gas dynamics, establishing a dedicated offline training environment is identified as an effective risk mitigation measure;
- Across the suite of pre-emergency tools (e.g. optimisation, flow swapping, market mechanisms, TFAs, locational energy actions, operating margins, capacity buybacks, and demand-side response), the principal opportunity associated with hydrogen blending is the potential to incentivise hydrogen producers, via existing market and operational signals, to increase supply into the NTS during system stress, potentially diverting hydrogen from other uses;
- Hydrogen producers that draw natural gas from the NTS for hydrogen production may also be suitable targets for interruptible arrangements and demand reduction measures;
- Biomethane entry points similarly provide supply diversity, though biomethane facilities may have limited ability to ramp output quickly and are generally less applicable to demand-reduction strategies;
- On emergency response, evidence from previous hydrogen projects and trials indicates that for low-percentage blends the overall hazard profile and emergency response decision logic remains broadly similar to natural gas, provided appropriate detection equipment and calibration are in place; and
- Planned and unplanned unavailability of a compressor must be accounted for in the reliability assessment of a compressor station and the NTS.

Key findings for the control and transportation of gas through the NTS are that:

- National Gas Transmission's operational and control systems and processes will need to be updated prior to hydrogen production coming online in order to facilitate a smooth transition to accepting hydrogen blend within the NTS;
- At a conceptual and planning stage, a more detailed understanding of the mixing that could and will occur in the NTS is required for managing hydrogen concentration levels within feeders or sections of the network. Exploring the potential hydrogen blend injection points in relation to the pipeline connectivity of sensitive users will need to be undertaken by teams with a detailed understanding of operational capability and flow dynamics in the NTS;
- The ability to both predict and track the changing gas composition within the NTS is essential for the optimal operational management of the system and to ensure that the gas composition arriving at an offtake is understood in real-time;
- The free market approach to hydrogen blend injection point connections has the potential to constrain any further blend injection, both in the NTS and lower pressure systems, because the resulting gas blend is based on the specific pressure and flow conditions. A strategic approach to allow hydrogen into gas entry terminals would maximise the amount of hydrogen that could be accepted into the NTS since these connections are at points of highest flow with maximum downstream offtakers; and
- The potential sensitivity to a hydrogen blend (fixed and variable) on sensitive users should be understood in more detail. Feasibility studies have been undertaken that have considered the impact on equipment. Matching the output from these studies more closely with future operational planning of a blended hydrogen NTS will identify any restrictions in operation and allow mitigation options to be developed.

2 INTRODUCTION

Introducing hydrogen blends into the National Transmission System (NTS) is an intermediate step towards net zero. However there may be implications for how the network is managed, and downstream impacts on connected storage facilities and large industrial users. This project aims to deepen the understanding of how low-level hydrogen blends interact with existing infrastructure and protocols and assess the operational, safety, and strategic implications, particularly with regard to storage interactions, emergency response scenarios, and long-term network management strategies.

The work has been broken down into three main areas that assess how hydrogen blends affect:

1. Gas storage facilities currently connected to the NTS, including salt caverns and depleted reservoirs;
2. The adequacy of current emergency response frameworks, including constraint management tools, coordination with emergency services and the need for updates to operational documentation; and
3. The strategy for control and transportation of gas through the NTS.

This report is arranged in chapters that discuss key aspects of each area in turn.

Gas storage infrastructure is reviewed in section 3 and 4 (sub-surface and surface infrastructure, respectively) before an assessment of the risks is made for corrosion and integrity in section 5, for fires and explosions in section 6, for the cushion gas in section 7, and for microbial activity in section 8.

The adequacy of current emergency response frameworks are reviewed in sections 9 to 11.

The strategy for gas flow through the NTS is reviewed in section 12 and the measurement and control implications assessed in section 13.

Finally, conclusions are provided for each area in section 14.

3 INTERACTION OF BLENDED GAS WITH SUBSURFACE INFRASTRUCTURE

Underground gas storage can occur in various formations, including depleted reservoirs, aquifers, and salt caverns. In all cases, the injected gas should meet transmission network specifications and is therefore considered as dry. This section outlines the principal subsurface uncertainties associated with introducing hydrogen and biomethane blends into natural gas systems.

3.1 Impact of oxygen on underground storage

A comprehensive literature review has been conducted to evaluate the risks associated with introducing biomethane into natural gas underground storage sites, with particular attention to oxygen content. Elevated oxygen levels can promote the formation of acidic species, potentially altering facility geochemistry.

Biomethane produced through anaerobic digestion contains residual oxygen (O_2) from desulfurisation processes. When injected into underground gas storage (UGS), this oxygen enters an anoxic environment, potentially triggering biological and chemical changes. In a study by Haddad[1] UGS aquifer conditions were replicated in a high-pressure reactor to examine bio-geochemical interactions among aqueous, gas, and solid phases. Oxygen was introduced at 1% of the gas phase, reflecting the maximum concentration typically found in biomethane post-desulfurisation. Observations included re-oxidation of sulfide to sulfate and cessation of sulfate-reducing activity, while quartz-based solids exhibited no notable alteration.

As part of an EU-funded project coordinated by GERG, laboratory experiments and geochemical modelling were carried out by Heriot-Watt University for DNV to assess the impact of oxygen on the mineralogy of potential subsurface storage formations.[2,3] Two reservoir sites with markedly different characteristics (depth, fluid chemistry, mineralogy, porosity, and permeability) were examined. Findings indicate that oxygen presence under the tested conditions causes minimal formation damage, although minor mineral dissolution and precipitation reactions were observed. Overall, the study confirms the geochemical stability of subsurface biomethane storage in the presence of oxygen for the two natural gas storage sites evaluated. However, site-specific geochemical assessments remain essential to account for variations in rock properties, mineralogy, and fluid composition.

Another DNV study conducted for the GERG project included consultation with gas storage operators to assess the relative risks associated with contaminants in biomethane. The survey results indicate that salt cavern operators generally perceive significantly lower risk when storing biomethane compared with operators of depleted reservoirs or aquifers, which report greater sensitivity to impurities and potential integrity impacts. Given that the UK's underground gas storage portfolio is dominated by salt cavern facilities, this suggests the UK may be in a comparatively strong position regarding biomethane storage, with inherently lower expected risk exposure than countries relying heavily on porous rock storage formations.

A Marcogaz study examined how oxygen in biomethane can negatively affect UGS.[4] Each storage facility has unique conditions such as the pressure, temperature, water salinity, wet gas regimes, and mineral interactions that influence the impact of oxygen. Consequences depend on oxygen concentration and include integrity risks, capacity loss, higher costs, and safety concerns. Corrosion, sulfur precipitation, and pyrophoric iron formation can damage wells, block valves, and disrupt operations. Sulfur deposits also reduce reservoir permeability and flow rates, while aerobic bacteria may clog pores. Even small oxygen levels (e.g. 40 ppm) have caused sulfur precipitation, highlighting the need for strict limits. Oxygen can also disturb geobiological balance in aquifers by killing anaerobic bacteria that prevent

[1] P. G. Haddad, J. Mura, F. Castéran, M. Guignard, M. Ranchou-Peyruse, P. Sénéchal, M. Larregieu, M.-P. Isaure, I. Svahn, P. Moonen, I. Le Hécho, G. Hoareau, P. Chiquet, G. Caumette, D. Dequidt, P. Cézac and A. Ranchou-Peyruse, *Sci. Total Environ.*, 2022, **806**, 150690.

[2] GERG, *Impact of Oxygen on Underground Storage: Formation Damage Evaluation*, The European Gas Research Group, Brussels, 2025.

[3] Z. Jangda, L. Boak, R. Skivington, H. Keil b, A. Daoud, M. J. Maple and A. Busch, *Gas Sci. Eng.*, 2026, **150**, 205896.

[4] MARCOGAZ, *Biomethane Acceptance in Underground Gas Storage Facilities*, MARCOGAZ, Belgium, 2022.

contamination. Despite these risks, some research suggests oxygen may mitigate hydrogen-induced steel embrittlement during gas blending, though this effect remains unproven in real-world conditions.

One gas storage operator indicated that increased oxygen content remains a concern for them given the presence of water in salt caverns, resulting in 'wet' gas during a withdrawal cycle. Within a dry environment they suggest a small increase in corrosion rate, however in the presence of a liquid, they suggest the corrosion rate could increase by up to 2–4 times. They were unable to share the evidence they had obtained for this. Whilst surface facilities at salt caverns sites often incorporate dehydration equipment, the impact is more related to corrosion of the well casing and tubing and associated components.

According to ISO 16530, corrosion of structural or pressure-containing components can compromise well integrity. Wells face internal corrosion caused by produced/injected fluids which can lead to structural integrity issues and containment loss if not managed promptly. Operators should establish a corrosion monitoring program based on risk assessment and adjust it according to inspection results.

Key elements of corrosion management programmes include:

- Selecting corrosion-resistant materials;
- Estimating corrosion rates for barrier elements over the well's design life using field data or industry models;
- Indirect measurements (sampling fluids for corrosive chemicals and reaction by-products);
- Monitoring chemical injection and inhibition;
- Isolating annuli from oxygen sources;
- Applying cathodic protection; and
- Periodic inspection of protective coatings and structural members.

If the well's use changes, it must follow a management of change process and well integrity lifecycle requirements. A well failure model and a matrix of common failure modes can streamline risk assessment, action planning, and repair response.

The key findings from the literature are:

- For aquifers and depleted reservoirs, biomethane with higher oxygen content may increase the formation of inorganic precipitates, such as iron compounds;
- Because biomethane originates from diverse feedstocks, geological variability and cushion gas requirements should be considered when assessing UGS risks;
- Biomethane injection may enhance bacterial activity, increasing the likelihood of hydrogen sulfide (H_2S) production and associated risks such as elemental sulfur formation and acidity. These concerns are more significant for aquifers and depleted reservoirs than for salt caverns; and
- To better understand oxygen's influence on bacterial hydrogen sulfide generation in salt caverns, experimental studies or hydrogeochemical simulations are required.

3.2 Impact of hydrogen on underground storage

Experience with underground storage of hydrogen-containing gas is limited. Multiple factors can threaten well integrity and cause gas leakage, including microbial corrosion, hydrogen-induced cracking, hydrogen embrittlement, cement deterioration, elastomer degradation, and caprock seal failure. The distinct characteristics and behaviour of hydrogen can introduce new risks or modify existing ones. The main uncertainties linked to blending hydrogen with natural gas are discussed below.

Hydrogen is much smaller (approximately 25%) and lighter (around 80%) than methane, which gives it higher diffusivity and mobility and lower viscosity. These properties affect storage capacity and compression requirements. They also influence hydrogen migration through porous formations and its interaction with other fluids (such as cushion gas and formation water), potentially causing effects like viscous fingering, buoyancy-driven flow, gravity override, and variations in sweep efficiency.[5]

Gravitational, viscous, and capillary forces strongly influence how hydrogen moves through porous rocks, particularly within hydrogen/methane mixtures. These forces drive processes such as gravity override and viscous fingering, which can cause the injected gas to bypass parts of the storage zone. As a result, sweep efficiency decreases, meaning less of the reservoir is effectively contacted by the working gas. This reduces the volume of hydrogen that can be injected, stored, and withdrawn, lowering working gas efficiency and potentially increasing operational costs.

Gravity segregation and the dissolution of hydrogen into formation brine can also make a portion of the injected hydrogen unrecoverable. Buoyancy driven flow and viscous fingering further control how closely the gas plume interacts with brine saturated areas. Experiments show that hydrogen fingering is sensitive to injection rate, with fingers spreading perpendicular to flow and merging into larger channels due to shielding. These long channels leave significant un-swept regions.

Viscous fingering reduces deliverability by lowering sweep efficiency during injection and withdrawal and increasing asset loss when collapsed fingers trap working gas because of capillary pressure hysteresis. It also exposes more hydrogen to brine, increasing dissolution, diffusion, and geochemical reactions. These effects typically diminish over multiple injection-withdrawal cycles as the storage zone gradually equilibrates with the surrounding formation.

Hydrogen is considerably more reactive than methane. Under certain reservoir conditions (increased pressure and temperature), reactions with minerals and fluids can accelerate in the presence of hydrogen. This may change reservoir and seal integrity and lead to the formation of undesirable compounds (such as hydrogen sulfide) during prolonged exposure. Reactivity is likely to depend strongly on both the concentration of hydrogen and how long the system is exposed to it. This suggests that even intermittent or irregular hydrogen volumes could still drive gradual mineral changes, weaken seals, or generate secondary compounds. The degree to which these effects occur will vary with factors such as mineralogy, brine chemistry, and reservoir temperature and pressure. Because these relationships are not yet well characterised in existing studies and can differ from site to site. Therefore, assessing these impacts and associated risks over the full operational life of a storage site remains essential and requires further research.[6]

Microorganisms present in the subsurface can metabolise hydrogen, resulting in gas loss and contamination through biochemical reactions. While impurities can be removed at surface facilities, preventing them within the reservoir is preferable to avoid additional costs and operational complexity.

In salt caverns, the primary concerns relate to geochemical and microbial effects. Hydrogen dissolution into cavern brine can stimulate microbial activity, producing harmful byproducts like hydrogen sulfide and causing hydrogen loss. These reactions may be intensified by specific mineral compositions in the cavern sump or walls, or by organic matter introduced during leaching or previous hydrocarbon storage. Reaction rates depend on microbial type, fluid conditions (pH, pressure, temperature, composition), and the contact area between brine and minerals. Impurity risks are generally mitigated through gas treatment and purification at surface facilities.

For porous reservoirs, the most significant uncertainties involve the geochemical integrity of the reservoir and sealing formations. Underground storage sites in porous media typically operate on seasonal injection and withdrawal cycles, with some peak-shaving sites using shorter cycles. According to the Hydrogen TCP-Task 42 Report (2025), short-term studies (several months) show no evidence that hydrogen significantly alters sealing formation properties. However,

[5] T. A. Buscheck, A. Goodman, G. Lackey, J. De Toledo Camargo, N. Huerta, F. Hoeri, G. M. Freeman and J. A. White, *Int. J. Hydrogen Energy*, 2024, **49**, 1088–1107.

[6] H. Braid, K. Taylor, E. Hough, C. Rochelle, V. Niasar and L. Ma, *Earth-Sci. Rev.*, 2024, **259**, 104975.

integrated assessments involving long-term exposure and coupled mechanical testing remain critical research areas.[7] For instance, if hydrogen gradually induces microcracks due to repetitive mechanical and thermal stresses in sealing regions (caprock, near-wellbore, cement, or faults), this could lead to slow leakage into overlying formations.

It should be noted that salt caverns experience far lower hydrogen losses than aquifers. Research by Duckwitz shows that aquifers need extra purification systems, increasing overall costs, while salt caverns with minimal microbial activity have smaller economic impacts.[8]

The CETP-funded HyLife project analysed twenty-one brine samples from salt caverns, aquifers, and depleted reservoirs across ten countries. Using standardised anoxic sampling methods, researchers found distinct microbial populations at each site. Experiments showed that porous-rock reservoirs can lose hydrogen within weeks at temperatures up to 50 °C, whereas most salt-cavern samples showed almost no activity even after a year. Although microbes in both environments consumed hydrogen quickly during the first 10 days (~0.15 mmol/day), the rate then dropped sharply.[9]

Overall, these findings confirm that salt caverns offer significantly lower hydrogen losses than aquifers, suggesting that UK storage could have a strong advantage.

To assess how gas blending affects the availability of underground gas storage sites, the following key assets are considered at a high level in the sections below:

- Wellheads;
- Subsurface safety valves (SSSV);
- Packers;
- Tubing and casing; and
- Well cementing.

A schematic diagram of well designs for salt caverns and porous reservoirs, illustrating the above assets, is shown in Figure 1 below.

[7] S. van Gessel, *Building Confidence in Underground Hydrogen Storage*, Hydrogen TCP, Paris, 2025.

[8] V. D. Duckwitza, N. Paltrinieria and K. Kyaw, *Chem. Eng. Trans.*, 2025, 119, DOI: 10.3303/CET25119021.

[9] K. Černá, J. Říha, K. Fadrhonc, P. Bombach and S. Rad, *Assessment of Potential Microbial Hydrogen Consumption in European Hydrogen Underground Storage Sites.* GET 2025 - Sixth EAGE Global Energy Transition Conference & Exhibition, Oct 2025.

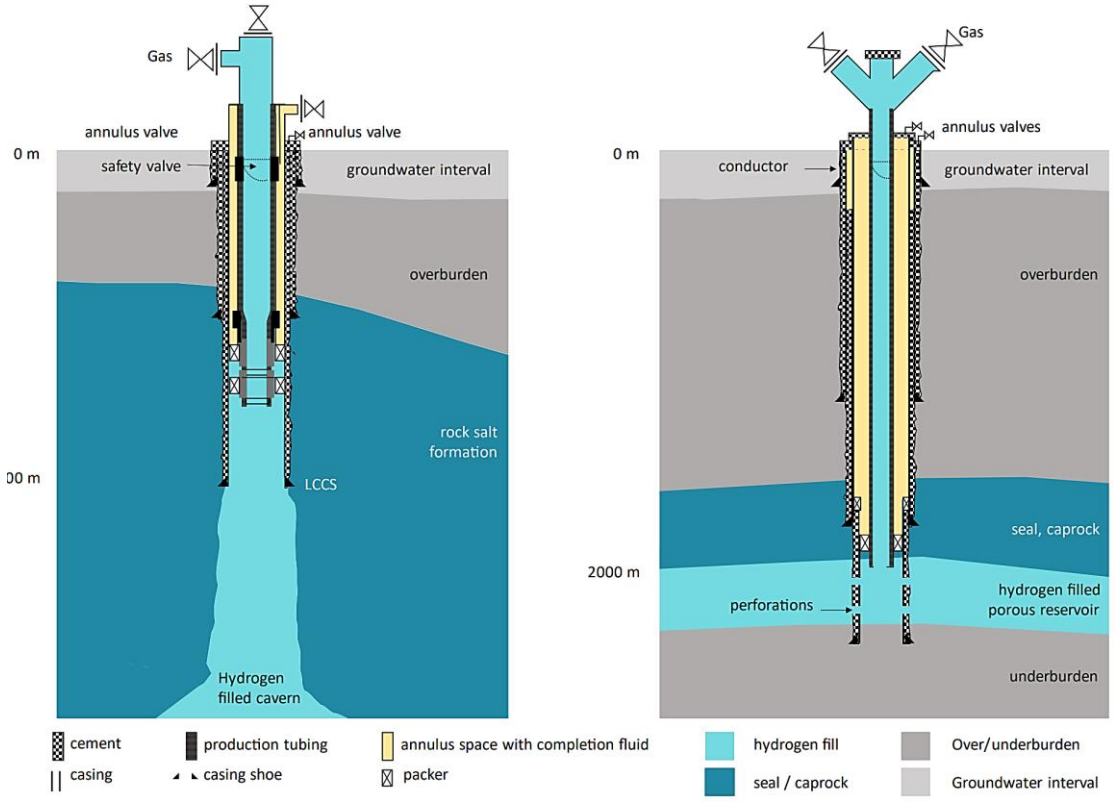


Figure 1 Schematic diagrams of well designs for salt caverns (left) and porous reservoirs (right).[10]

3.2.1 Wellheads

A wellhead is a standard component of every gas well, designed to connect the vertical wellbore to the horizontal piping that links the well with surface facilities. It also regulates gas flow into and out of the storage reservoir. For hydrogen, critical factors include the leak-tightness and durability of flanges and seals exposed to hydrogen. Existing UGS wellheads should be evaluated for hydrogen compatibility.

3.2.2 Subsurface safety valves

The subsurface safety valves (SSSV) are an essential safety device in gas storage wells, intended to shut off the well during an incident to prevent uncontrolled gas release. If hydraulic pressure is lost, the valve closes automatically, acting as a barrier provided it can block flow effectively. Hydrogen-specific considerations include:

- SSSVs often use high-strength precipitation-hardened stainless steel, which is susceptible to hydrogen embrittlement. Material compatibility of metals and seals must be assessed to avoid malfunction; and
- Hydrogen blending may require higher flow velocities, necessitating design adjustments to withstand increased slam forces.

Current experience with hydrogen compatibility of standard oil and gas SSSVs is limited. Initial laboratory and field tests have shown no major issues, and their ability to block hydrogen flow has been demonstrated. There is growing consensus that standard SSSVs can be used with minor modifications.[11]

[10] S. van Gessel, *Building Confidence in Underground Hydrogen Storage*, Hydrogen TCP, Paris, 2025.

[11] M. Grange, G. Hévin and H. Djizanne, *HyPSTER: 1st demonstrator for Green Hydrogen Storage in France*, Solution Mining Research Institute, Fall 2023 Technical Conference, 2023.

3.2.3 Packers

A packer is a downhole tool used during well completion to seal the annular space between the casing and production tubing, enabling controlled injection, withdrawal or treatment. A typical packer assembly includes a mechanism to anchor it against the casing or liner wall (such as slips) and an expandable elastomeric element to provide a reliable hydraulic seal.

[redacted]

Ongoing work focuses on testing metallic components for hydrogen-related issues like embrittlement and evaluating elastomer integrity under rapidly changing pressures. Existing test protocols use nitrogen gas for performance verification under various pressure and axial load conditions, but there is no evidence of similar tests with hydrogen.

Elastomers, commonly used in packer and plug bodies, are polymers with elastic properties that allow stretching and recovery to their original shape. Their elasticity depends on some gas permeability, which can lead to gas penetration. Rapid compression and decompression of gas within the polymer may compromise elastomer durability. While elastomers have long been used in natural gas and chemical industry applications, their use in hydrogen transport and storage systems is less common. Technical requirements for elastomers and metallic components are generally well understood, and several elastomer types are available that are compatible with hydrogen gas.

3.2.4 Tubing and casing

Hydrogen can penetrate steel casings and connectors, leading to embrittlement, blistering, or fatigue cracking, particularly at high-stress points such as thread roots and welds. Casing, tubing, liners, and other metallic components must be constructed from steels or alloys capable of withstanding exposure to gases such as hydrogen, hydrogen sulfide (H_2S), and carbon dioxide (CO_2). Over the past five years, extensive research has evaluated the performance of standard API 5CT tubing in both dry and wet hydrogen environments. Testing typically involves applying static loads under a hydrogen atmosphere to assess susceptibility to embrittlement. Certain steel grades designed for ‘sour service’ exhibit resistance to atomic hydrogen from H_2S and have shown acceptable performance in hydrogen-rich conditions.

Uncertainty regarding steel behaviour is more significant for Oil Country Tubular Goods (OCTG) due to their high yield strength requirements compared to other steel well components. During operations, the integrity of casing, tubing, and packers is routinely monitored through annulus pressure checks, a standard practice in underground gas storage. Potential leakage paths include bypassing the production packer into the annulus, migration through production tubing, or failure of seals in the wellhead/tree assembly. Similar monitoring approaches can be applied when storing blended gases.

3.2.5 Well cementing

In well construction, cement is used to anchor the casing within the drilled section. It occupies the annular space between the casing and the surrounding formation, then hardens to create a secure seal. This seal acts as a secondary barrier to prevent fluid migration along the casing and also protects the steel from corrosive formation fluids. Cementing is a standard procedure in the oil and gas industry, and numerous formulations have demonstrated excellent integrity and durability, making them suitable for natural gas applications. The suitability of a cement system depends on its composition, the placement process, and operating conditions.

Factors such as cycling, microbial activity, and chemical interactions can degrade cement, causing micro-annuli formation and potential gas pathways. Global data shows that 55% of well component failures occur in casings and 32.5% in wellheads, with corrosion as primary cause.[12]

Some research indicates no significant geochemical or structural changes in wellbore cements under hydrogen conditions, but these generally involve controlled lab conditions. Long-term operational data are limited to four

[12] G. Kaya and A. D. Taleghani, *ASME Open J. Engineering.*, 2025, **4**, 040804.

underground hydrogen storage (UHS) salt caverns in the UK and USA, along with historical town gas storage sites, all of which have shown no cement failures. However, hydrogen-specific field tests have so far been short-term (up to one year), so extended monitoring is needed to confirm performance. Based on current knowledge, experience with underground gas storage, and optimised well designs, no major technical challenges are anticipated.[13]

Potential leakage pathways for hydrogen resemble those seen in UGS and natural gas wells, though some mechanisms are unique to hydrogen. For example, hydrogen may accelerate steel corrosion or migrate through micro-annuli caused by imperfect cement bonding. These risks are well understood and can be mitigated through established monitoring techniques such as cement bond logs and ultrasonic tools. Additionally, corrosion inhibitors must be evaluated for hydrogen compatibility and adjusted if necessary.

[13] A. N. Corina, V. Soustelle and J. Ter Heege, *New Experimental Data on Reactions Between H_2 and Well Cement and Effects on Fluid Flow and Mechanical Properties of Well Cement*, H2020 HyUSPRe project report, TNO Applied Geosciences, Utrecht, 2023.

4 INTERACTION OF BLENDED GAS WITH SURFACE INFRASTRUCTURE

Gas storage facilities consist of both subsurface and surface infrastructure. Underground components include wells and pipelines, while surface installations typically feature flowlines, metering systems, processing units, compressors, and gas treatment plants for removing hydrogen sulfide and water.

Under current storage conditions, water is the primary factor driving corrosion concerns. Corrosion can occur in wells, pipelines, network accessories such as water pockets, and surface equipment like dehydration towers, particularly upstream of treatment units during gas withdrawal. Beyond water and its mineral content from aquifers, other corrosive agents must be considered. These include gases naturally present in the stored product, such as carbon dioxide and hydrogen sulfide, as well as substances introduced during industrial processes, such as oxygen.

Oxygen is often injected during upgrading operations to aid in hydrogen sulfide removal in biogas treatment facilities. However, the presence of oxygen significantly increases corrosion risk. Corrosion behaviour depends on multiple factors such as water content, flow conditions, water chemistry, and gas composition, including carbon dioxide and hydrogen sulfide. In assessing corrosion, it is also important to consider whether a protective passivation layer forms on the material surface, as this can slow corrosion rates.

Introducing hydrogen into infrastructure originally designed for natural gas exposes system components directly to hydrogen gas. This interaction can lead to hydrogen absorption in certain materials, initiating degradation mechanisms collectively referred to as hydrogen embrittlement (HE). According to ASME B31.12:2023, HE is defined as the reduction in metal ductility caused by hydrogen uptake. This effect can compromise material performance by lowering elongation and fracture toughness while increasing susceptibility to fatigue. The likelihood of embrittlement depends on factors such as material strength and hydrogen partial pressure. Hydrogen exposure may also cause changes in material properties, including reduced fracture resistance, crack formation in metals, swelling in polymers, and the aggravation of existing defects.

Understanding hydrogen’s impact on different materials is therefore critical before repurposing existing infrastructure for gas blend service.

Therefore, the following sub-sections examine how oxygen exposure in biomethane and hydrogen blends affects above-ground equipment at gas storage sites. The assessment of risks associated with introducing the gas blend into storage facilities is presented in section 5.

4.1 Gas dehydration

When gas is stored in salt caverns or porous reservoirs, it encounters formation fluids and absorbs moisture, even if it was initially dry. Before re-injection into the gas network, the withdrawn gas must be dehydrated to protect downstream equipment and meet gas quality standards. In underground gas storage, the most widely used dehydration technologies are triethylene glycol (TEG) absorption, silica-gel/aluminosilicate adsorbent, and temperature swing adsorption (TSA).

In TEG systems, glycol circulates counter-current to the wet gas inside a dehydration column, absorbing water from the gas stream. The water-rich glycol is then regenerated for reuse. However, TEG degrades over time. Studies show that higher TEG concentrations correlate with lower corrosion rates. This effect is attributed to reduced carbon dioxide solubility and diffusivity, increased solution viscosity, decreased water activity, and lower polarity. Additionally, in the presence of small amounts of hydrogen sulfide (e.g. 2 ppm), corrosion rates drop further due to the formation of protective iron sulfide (FeS) layers, a phenomenon well documented in literature.

Oxygen ingress into glycol systems accelerates oxidative degradation, particularly of TEG, producing acidic compounds that cause equipment corrosion, operational inefficiencies, and increased maintenance. Greater oxygen content in the gas stream leads to faster glycol oxidation and acidification. The resulting degradation products influence the type and severity of corrosion observed. To ensure reliable dehydration performance and extend equipment life, it is critical to control oxygen exposure, monitor glycol degradation, and maintain system integrity.

In a laboratory investigation by Høisæter, the influence of oxygen concentration on TEG oxidative degradation was examined by conducting four experiments using pure TEG at 100 °C with oxygen levels of 1%, 6%, 12%, and 24% in the gas stream.[14] TEG degradation was tracked with GC-FID analysis, and the results demonstrated a strong dependence on oxygen concentration: no measurable TEG loss occurred at 1% O_2, whereas a 50% reduction in TEG concentration was observed at 6% O_2, confirming that higher oxygen exposure significantly accelerates degradation. Currently, the oxygen content in UK biomethane is limited to 1%. This suggests that TEG units should remain stable and not deteriorate when operating with a pure biomethane feed.

Introducing hydrogen into infrastructure originally designed for natural gas exposes system components to gaseous hydrogen, which can lead to absorption in certain materials and trigger degradation mechanisms collectively known as hydrogen embrittlement (HE). The risk of HE depends on factors such as material strength and hydrogen partial pressure. This phenomenon can alter material properties, reducing fracture toughness, promoting crack formation in metals, causing swelling in polymers, and exacerbating existing flaws.

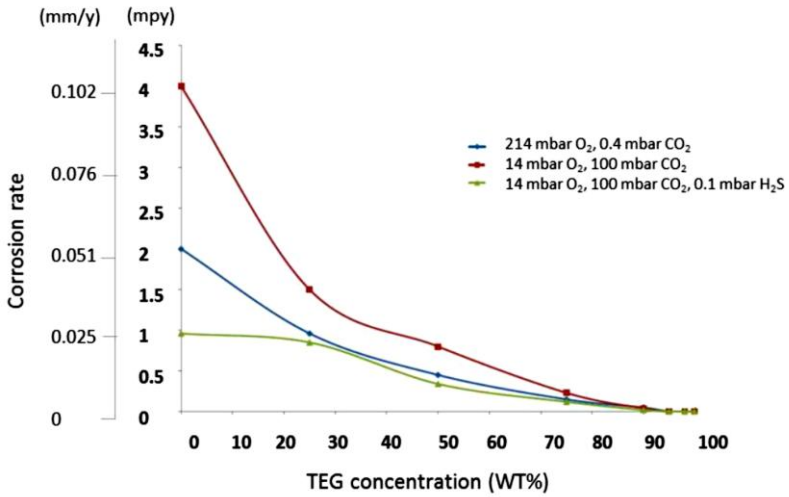


Figure 2 Corrosion rate in TEG/water showing the effect of TEG concentration on decreasing corrosion.[15]

Most piping and fittings in gas treatment facilities are typically carbon steel. When hydrogen is blended with natural gas, molecular hydrogen can dissociate into atomic hydrogen at steel surfaces and diffuse into the metal lattice. Over time, this diffusion reduces ductility and increases susceptibility to cracking under static or cyclic loads. HE is most prevalent in metals with body-centred cubic (BCC) crystal structures, such as carbon steels and certain iron grades.

To mitigate these risks, ASME B31.12:2023 specifies hardness and strength limits for hydrogen service: line pipe should not exceed 250 HV10 in hardness, and tensile strength for both pipe and welds must remain below 690 N/mm^2 (100 ksi). Similarly, IGEM/TD/13 Edition 2 Supplement 1 recommends avoiding steel grades above L485 (X70) unless qualified for hydrogen use. Historically, higher-strength steels have been avoided due to increased HE susceptibility. However, given the low hydrogen concentration (<20%) and reduced pressure before dehydration, the risk of embrittlement in carbon steel remains minimal.

Gas treatment units also include stainless steel components, such as valve parts. Austenitic stainless steels, including ASTM A312 grades 304, 304L, 316, and 316L, offer superior resistance to HE compared to other stainless steels. Their performance depends on alloy composition and microstructure. Secondary phases like ferrite or martensite can introduce vulnerability. ASME B31.12 notes that susceptibility in single-phase austenitic steels is influenced by nickel content, with grades containing >12 wt% nickel (e.g. 316) being more suitable for hydrogen service due to nickel's

[14] K. K. Høisæter, V. Buvik, S. V. Gonzalez, S. J. Vevelstad and H. K. Knuutila, *Chem. Eng. Sci.*, 2024, **287**, 119706.
[15] S. S. Esteban R. Ugarte, *J. Energy Resour. Technol.*, 2022, **144**, 042001.

stabilising effect on the austenitic phase. Consequently, components made from these alloys are generally considered highly resistant to hydrogen-induced embrittlement.

4.2 Gas compression

Most underground gas storage sites use centrifugal compressors to boost the pressure of NTS gas for storage in depleted reservoirs or salt caverns. [redacted]

4.2.1 Hydrogen

Storengy, in information provided for this project, has some comments on their compressor units for the 100% hydrogen case as follows:

> '*The lower molecular weight of hydrogen would impact the performance of our centrifugal compressors used to move gas in and out of storage around half of the time. Lower molecular weight significantly reduces the effectiveness of centrifugal gas compressors. One of the challenges facing the hydrogen industry is the difficulty in developing a centrifugal compressor suitable for 100% hydrogen due to it's low molecular weight. The compressor effectiveness is related to how much kinetic energy the impellor can impart on the gas. This kinetic energy is then converted to a pressure increase by the diffuser element.*
>
> *A quick example: comparing methane (MW = 16) and hydrogen (MW = 2)*
>
> $KE = 0.5 * MW * V^2$
>
> *For the same impellor tip speed (V), hydrogen receives eight times less energy than methane. This requires more compression stages and higher tip speeds to achieve the same pressure increase. We haven't carried out any studies into exactly how our machines would handle a blend at this stage*.'

Storengy's comments on impellor tip speed are supported by studies for the US Government[16] on reference designs for hydrogen centrifugal compressors. The research showed that the low molecular weight of hydrogen compared to air required an increase in impellor tip speed by a factor of 3.8 which increases the stress in the rotor by a factor of 14.4. The result was that the maximum pressure ratio in a single stage is limited by structural aspects rather than aerodynamics.

However, the overall molecular weight of a 5% hydrogen blend into natural gas is similar to that of natural gas alone. Thus, the increase in impellor tip speeds may be within the current operating windows of the compressor. If the compressor is driven by a gas turbine (gas generator) then fuel use is likely to increase when using a 5% blend.

The potential for hydrogen embrittlement would also need to be considered. API 617[17] has limits on materials used in hydrogen service:

> *'6.2.1.12 Materials that have a yield strength in excess of 827 MPa (120,000 psi) or hardness in excess of Rockwell C 34 are prohibited for use in hydrogen gas service where the partial pressure of hydrogen exceeds 689 kPa (100 psi gauge) or the hydrogen concentration exceeds 90 molar percent at any pressure.'*

This limitation would prevent the use of high strength materials to address the impellor tip speed issue. It could also limit the pressure achievable from a compressor using high strength materials. A partial pressure of 689 kPa would be achieved at a discharge pressure of 13780 kPa (138 bara) which is below the storage pressure used in many depleted reservoirs and salt caverns.

[16] F. A. Di Bella, *Development of a Hydrogen Pipeline Centrifugal Gas Compressor*, Concepts NREC Project No. 10195, Technical memo. no. 1785, 2015.
[17] *Axial and Centrifugal Compressors and Expander-compressors*, API Standard 617, Nineth edn., April 2022.

Generally, natural gas centrifugal compressors can often handle low-percentage hydrogen blends without replacement, if very high strength materials are not present, more significant blends may necessitate speed adjustments or redesign. Changes in speed of sound, density, and viscosity of the gas require recalibration of compressor settings and may decrease capacity.[18] In discussion with internal compression subject matter experts, they indicated in their previous studies into the impact of hydrogen blending by volume, 5% hydrogen has minimal impact on the performance of a compressor.

Reciprocating compressors are currently the industry standard for hydrogen compression. They have a proven track record in sectors such as chemicals, offering a wide and controllable range of capacities and pressures while handling variable operating conditions. For blending hydrogen, compressors will operate at the upper limits of today's envelope due to the combination of large volumes, high flow rates, and elevated discharge pressures. At this scale, reciprocating compressors present challenges related to their size, weight, and pulsating operation.

Hydrogen contamination from lubricants during compression is another concern. Oil-free reciprocating compressors are currently limited to pressures of about 200 bar, which is generally sufficient for deep salt cavern storage but may not meet requirements for porous reservoirs at greater depths.

4.2.2 Biomethane

Reciprocating and screw compressors are compatible with biomethane and were studied extensively for reverse compression duty in the Central Injection Hub Financial Model and Reverse Compression for Biomethane Injection study[19] sponsored by NGN, WWU, EIC and ENA.

Centrifugal compressors are not common in biomethane service. Fujita and Miyazaki studied the effect of gas composition on centrifugal compressor performance using process simulations.[20] Three cases were investigated, the most applicable to biomethane was a 95% methane, 1% ethane, 1% oxygen, 1% nitrogen and 2% hydrogen sulfide blend. It was found that the adiabatic efficiency of this blend was better than blends with increased ethane and nitrogen (2% and 3% respectively). However, the authors did not model a natural gas composition for comparison so the loss of effectiveness compared to the current situation is still unclear. Further simulations with a more representative biomethane composition would allow the effects to be clarified.

4.3 Acid gas removal unit

For salt cavern storage, dehydration is essential, and sulfur/hydrogen sulfide removal may be necessary depending on formation conditions. These processes are well known in UGS but will need adaptation for gas blending service. Uncertainty remains regarding the quantity and duration of hydrogen sulfide generation from microbial or geochemical activity.

Gas withdrawn from underground storage may contain hydrogen sulfide or a combination of hydrogen sulfide and carbon dioxide, making it 'sour.' Processing involves removing water and acid gases, primarily hydrogen sulfide and carbon dioxide. Acid gas removal typically uses adsorption or absorption techniques, with alkanolamine-based solvents such as MEA, DEA, and MDEA widely employed for gas sweetening. Carbon steel components in amine units often form a protective iron sulfide layer when exposed to hydrogen sulfide, which helps reduce corrosion rates.

Corrosion in amine plants mainly results from gas dissociation within the amine solution. Acidic corrosion, which occurs in low-pH zones, is particularly severe and is intensified by high gas concentrations, elevated temperatures, and rapid flow rates. Hot sections of the plant such as reboilers and heat exchangers are most susceptible, often experiencing erosion-corrosion due to the removal of iron sulfide scale. Rich amine flashing, caused by pressure or temperature

[18] B. Zhang, N. Xu, H. Zhang, R. Qiu, X. Wei, Z. Wang and Y. Liang, *Appl. Energy*, 2024, **358**, 122594.

[19] M. Hassaan, *Biomethane Study: Stage 1 Central Injection Hub Financial Model and Reverse Compression for Biomethane Injection Report*, 834-01-BMDO-000-D, 2021.

[20] D. Fujita and T. Miyazaki, Int. J. Energy Production Management, 2024, **9**, 181–186.

changes, can lead to vapor-phase formation with low amine content and localised low pH, further increasing corrosion risk.[21]

Amine degradation occurs through thermal and oxidative mechanisms, with oxidative degradation being less understood. Oxygen accelerates this process, producing corrosive compounds and reducing solvent efficiency. Oxidative reactions lead to rust or scale formation, impacting corrosion rates and cleaning performance. Additionally, suspended iron sulfide solids in the solution can cause operational issues such as foaming, plugging, and frequent filter replacements.[22]

Similar to the dehydration unit, the potential for hydrogen-induced embrittlement and its adverse effects on materials in the acid gas removal unit should be evaluated across the range of available materials. However, the hydrogen concentration in the blended gas remains relatively low (<20%).

4.4 Monitoring and metering

Gas quality monitoring and regulatory/legislative compliance typically uses established gas chromatography (GC) and metering techniques. Gas chromatography is a flexible analytical chemistry approach that can be optimised to provide detailed analysis of complex gas mixtures. The GCs used around the transmission network must be able to provide accurate, reliable measurements at a reasonable analysis period. This continuous monitoring provides confidence that the overall gas quality meets legislative and contractual requirements.

[redacted]

The difference in instrument response to a combined nitrogen and oxygen peak would result in the nitrogen component being incorrect, and 1 mol% oxygen would give a calorific value 0.2% greater than the true value, which is within the allowed measurement uncertainty. As this is within the acceptable operating range, the impact is small, especially as it is unlikely that the 1 mol% oxygen content will persist for extended time periods without being mixed and diluted. Clearly this issue is resolved if the instruments are capable of separating oxygen from nitrogen and if the calibration gas contains oxygen.

[redacted]

[21] T. B. Jorgensen, J. Thompson, M. Sarma, K. Abada and K. Liu, *Oxygen Solubility in Aqueous Amine Solvents with Common Additives Used for CO_2 Chemical Absorption*, in Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies (GHGT-16), 2022.

[22] T. B. Jorgensen, K. Abad, M, Sarma, M, I. Guzman, J, G. Thompson and K, Liu, *Int. J. Greenhouse Gas Control,* 2022, **116**, 103646.

[redacted]

[redacted]			

[redacted]

Maintaining the integrity and repeatability of metering systems on the NTS is critical for ensuring a reliable measurement of the gas entering and leaving the network. A range of meters are used across the network and are subject to change with advancing technologies and potential changes to the gas being transported (for example the blending on hydrogen).

The present list includes ultrasonic and mechanical meters such as turbine, orifice plates and venturi meters. The full metering systems also require a flow computer which takes the signal from the meter and combines it with gas quality information, and pressure and temperature data to provide volumetric, mass and energy flow rates.

[redacted]

Ultrasonic meters work on the principle of measuring the time between transmitting and receiving an ultrasonic beam through the gas being measured. [redacted]

[redacted]

Another consequence of oxygen in the gas stream is that the coexistence of hydrogen sulfide and oxygen within the infrastructure can create conditions that accelerate corrosion, primarily through the formation of elemental sulfur (S_8). Desublimation of sulfur is the most common pathway for the deposition of sulfur within natural gas networks. Generally, this occurs within pressure reduction equipment as a result of adiabatic cooling (which causes supersaturation) however supersaturation can also be reached through other mechanisms such as chemical reactions and direct/indirect cooling. Deposition may occur on the internals of flow meters, potentially resulting in a loss of accuracy and erratic flow readings due to flaking and shedding of sulfur. For turbine meters, it generally results in an over estimation of the flow whilst for orifice plates it is often an under estimation of flow.

Once elemental sulfur is present, its strong oxidising nature can cause highly localised corrosion (pitting), especially when moisture is available. This risk increases with fluctuations in the gas dew point, such as when a dryer fails before biomethane is injected into the distribution network.

Additionally, small amounts of sulfur may travel with the gas and deposit in pressure regulators and gas monitoring assets, potentially leading to operational issues like clogging due to sulfur precipitation requiring increased maintenance especially of filters.

Storengy has some comments on their investigation into elemental sulfur:

> *'The gas drying process that we use (counter-flow triethylene glycol dehydration) is a very effective particulate scrubber. This causes particulates from our gas withdrawal stream to accumulate in the TEG circulation system and block filters. We have carried out analysis of these particulates and found them to be predominantly iron carbonate and elemental sulfur. Analysis of particulate deposits up-stream of the dehydration system shows make-up to be predominantly iron oxides and iron sulfate. These deposits are exposed to air before analysis so their composition may have changed between the process and the analysis e.g. iron sulfides react rapidly with oxygen to form iron oxides + sulfur.'*

Storengy have not proven the formation mechanism for elemental sulfur, however, they suggested below:

> *'We are seeing more H_2S, causing sour corrosion in our pipelines and iron sulfide accumulation in our process. This is then reacting with oxygen either in the gas stream, or during air purging for maintenance, before we can sample it. If it reaches our TEG system, we believe there is a reaction with the organic components present in TEG that is converting it to iron carbonate and releasing elemental sulfur. Not clear on where the H_2S could be from – is it coming from the NTS or is it being generated in storage. We have sampled two wells for microbial activity in the sump and not had a positive result.'*

We note that the formation mechanism is currently unclear, but an increase in oxygen content may lead to further elemental sulfur deposits. This requires further investigation.

5 CORROSION AND INTEGRITY RISKS IN STORAGE FACILITIES

The purpose of this section is to identify key risks, evaluate the compatibility of existing infrastructure, and assess potential impacts on NTS operability. In addition, the study outlines mitigation measures to ensure safe and efficient storage operations under blended gas conditions.

To achieve this, six potential gas blending scenarios were first defined. A risk assessment methodology was then developed to quantify the associated risks for each scenario, focusing on hydrogen content and excess oxygen levels.

5.1 Gas blending scenarios

According to EN 16723[23] the allowable limits for trace components in biomethane are as follows:

- **Hydrogen sulfide (H_2S)**: 5 mg/m^3;
- **Oxygen (O_2)**: 0.001% at network entry, or up to 1% where gas does not flow to sensitive installations; and
- **Carbon dioxide (CO_2)**: 2% at network entry, or up to 4% where gas does not flow to sensitive installations.

Typical NTS network entry agreement limits are similar:

- **Hydrogen sulfide**: 5 mg/m^3;
- **Oxygen**: 0.001 mol%, although Gas Safety (Management) Regulations allows 0.2 mol% at pressures above 38 bar and 1 mol% up to 38 bar. With increasing biomethane connections to the NTS being made there is potential for localised exemptions to permit 1 mol% oxygen; and
- **Inerts**: 7.0 mol%, subject to carbon dioxide being not more than 2.5 mol%.

Based on these specifications, the worst-case concentrations (1% O_2 and 4% CO_2) were used for calculations. For blending assumptions between natural gas (NG) and biomethane, three scenarios were considered:

- **High natural gas / Low biomethane**: 90% natural gas and 10% biomethane; and
- **Medium natural gas / Medium biomethane**: 50% natural gas and 50% biomethane; and
- **Low natural gas / High biomethane**: 10% natural gas and 90% biomethane.

Considering two blending options for hydrogen, with less than 5% and less than 20% hydrogen content, the six defined scenarios are presented in Table 3 below.

Table 3 Gas blending scenarios for this study.

Scenario	1	2	3	4	5	6
Natural gas	High	Medium	Low	High	Medium	Low
Hydrogen	≤5%	≤5%	≤5%	≤20%	≤20%	≤20%
Biomethane	Low	Medium	High	Low	Medium	High
Oxygen	0.08%	0.46%	0.85%	0.07%	0.39%	0.71%
CO_2	1.83%	2.71%	3.58%	1.54%	2.28%	3.01%
H_2S	5 mg/m^3	5 mg/m^3	5 mg/m^3	5 mg/m^3	5 mg/m^3	5 mg/m^3

[23] EN 16723, Natural Gas and Biomethane for use in Transport and Biomethane for Injection in the Natural Gas Network, Part 1, 30th November 2016.

5.2 Risk assessment methodology

To evaluate the impact of gas blending on the operational life and integrity of natural gas storage assets, a corrosion risk assessment was developed. This approach identifies scenarios and assets most susceptible to degradation when operating outside their original design specifications. The methodology consisted of the following steps:

1. **Identification of failure modes and mechanisms**: All potential failure modes were identified for each scenario, based on established degradation mechanisms, to ensure a comprehensive understanding of asset vulnerabilities.
2. **Impact assessment**: Each scenario was assessed by determining the 'severity of damage' (extent of degradation or failure) based on the influencing factors. This step linked individual asset failures to overall system operability.
3. **Recognition of data limitations**: Confidence level (level of uncertainty) particularly for hydrogen and biomethane were acknowledged. The absence of long-term performance data introduced uncertainty, which was factored into the assessment.
4. **Qualitative risk ranking**: A qualitative ranking approach was adopted, relying on expert judgment, engineering experience, and available evidence to prioritise assets by relative risk across scenarios.
5. **Recommendations for future actions**: Based on the risk assessment, recommendations were formulated to guide mitigation strategies and further research.

Figure 3 illustrates the methodology applied in this assessment.

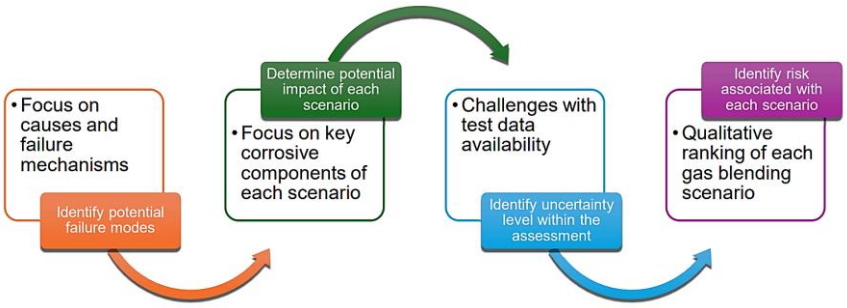


Figure 3 Risk assessment steps adopted in this study.

4.2.1 Damage mechanism review and likelihood evaluation

Damage mechanisms describe the processes that cause a component to deteriorate over time, ultimately reducing its ability to function as intended. Understanding these mechanisms is critical for assessing the long-term reliability of materials and systems. For this project, we applied a structured five-step approach:

1. **Material selection**: We reviewed both carbon steel (CS) and stainless steel (SS) options.
2. **Fluid analysis**: The properties of the blended gas and its interaction with these materials were examined, as they often influence degradation.
3. **Identification of likely mechanisms**: Based on material characteristics and environmental conditions, we determined which degradation processes were most probable.
4. **Assessment of influencing factors**: Operational parameters such as temperature, pressure, and other variables were considered for their potential to accelerate or mitigate damage.

5. **Severity evaluation**: Each mechanism was rated for likelihood and severity using available data and engineering judgment.

This systematic review forms the basis for risk assessment and mitigation planning within the gas blending study. When assigning a likelihood of failure, the criteria outlined in Table 4 are used to score each damage mechanism.

Table 4 Influencing factors on the likelihood of failures.

Row	Influencing Factors	Likelihood of Failure		
		High	**Medium**	**Low**
1	Industry Experience	Known to occur frequently	Known to occur infrequently	Never know to have occur
2	Operating Changes	Major changes in operations since designed	Minor changes in operations since designed	Operations as per design
3	Analysis/tests	Significant concerns raised through analysis/test	Notable concerns raised through analysis/test	No concerns raised through analysis/test
4	Wall loss/Crack Formation	Significant concerns about wall loss and crack formation	Notable concerns about wall loss and crack formation	No wall loss and no crack formation

4.2.2 Confidence level (level of uncertainty)

The uncertainty level in corrosion risk estimation is closely tied to the quality and relevance of data from trials, laboratory tests, and literature. Confidence that the assigned risk reflects real operating conditions improves as more reliable information becomes available. Assets or scenarios were flagged as highly uncertain when one or more of the following applied:

- Industry experience could not be applied;
- Little or no experimental or laboratory data existed; and
- Performance depended on multiple operating variables

By combining these factors, we established a risk-based ranking system to prioritise the most critical components and scenarios.

4.2.3 Risk matrix

For the qualitative risk assessment of injecting blends of biomethane, hydrogen and natural gas into above-ground gas storage infrastructure, the following risk matrix has been defined to represent the level of each risk (Figure 4).

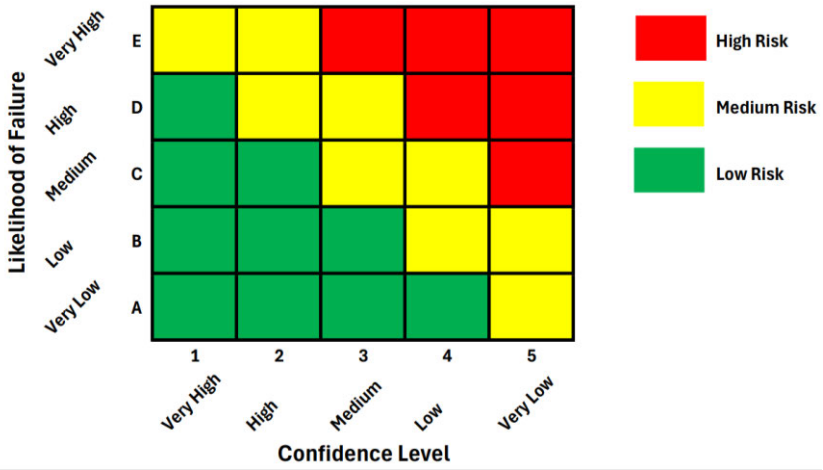


Figure 4 Risk matrix for this project.

5.3 Literature review on oxygen corrosion

Oxygen plays a critical role in corrosion processes when water is present. Acting as a strong oxidising agent, it accelerates carbon steel corrosion and forms iron oxides. The simplified anodic and cathodic reactions are shown in the equations below:

$$Anode \qquad Fe \rightarrow Fe^{2+} + 2e^{-}$$

$$Cathode \qquad {}^{1}/_{2}\, O_2 + H_2O \rightarrow 2OH^{-}$$

$$4Fe + 3O_2 \rightarrow 2Fe_2O_3$$

Xue et al. studied the effect of dissolved oxygen in an aqueous sodium bicarbonate ($NaHCO_3$) solution on low-carbon steel plates. Dissolved oxygen levels measured during different test phases were 8 ppm, 310 ppb, and 2.1 ppb. Their findings indicate that during the initial immersion period, higher dissolved oxygen concentrations resulted in increased corrosion rates for carbon steel samples. Despite this Figure 5 shows that the maximum corrosion rate observed (26.2 µm/y) remains relatively low, likely due to the buffered nature of the solution and the limited oxygen content.[24]

[24] F. Xue, X. Wei, J. Dong, I.-I. Nabuk Etim, C. Wang and W. Ke, *J. Mater. Sci. Technol. (Shenyang, China)*, 2018, **34**, 1349–1358.

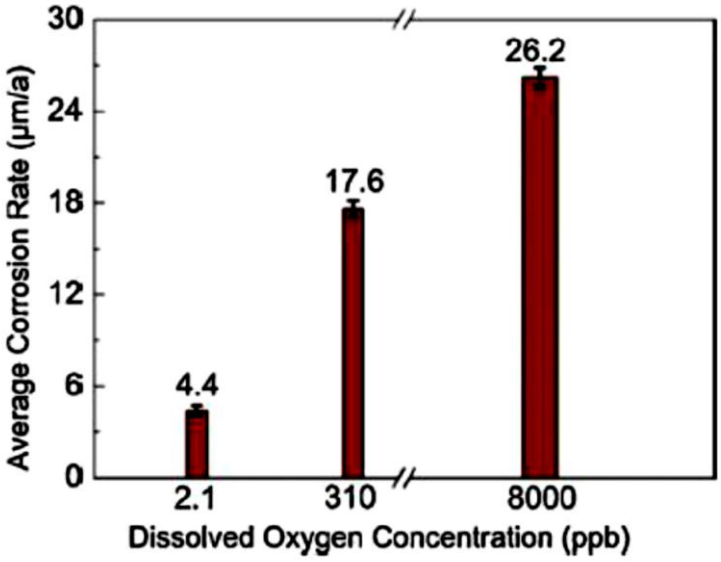


Figure 5 Average corrosion rate of low carbon steel with different oxygen concentrations.[24]

In gas blending conditions, oxygen rarely occurs in isolation. The following will examine its combined influence with carbon dioxide and/or hydrogen sulfide, both with and without oxygen.

Research on biomethane containing various trace components indicates that these can interact synergistically, intensifying corrosion. This effect arises from an increased number of chemical reactions within gas blends, leading to:

- Formation of additional trace compounds, complicating corrosion mechanisms; and
- Acid generation, which lowers pH and increases environmental aggressiveness.

Experimental evidence of complex corrosion scale formation confirms that multiple reactions occur simultaneously. The composition of these scales depends on the specific trace elements present and the prevailing environmental conditions.

5.3.1 CO_2-induced corrosion

When free water is present in the system, it becomes saturated with CO_2, forming carbonic acid (H_2CO_3). Higher CO_2 partial pressure lowers pH, increasing corrosion risk unless a stable $FeCO_3$ layer forms. Under favourable conditions, increased CO_2 promotes bicarbonate and carbonate formation, enhancing $FeCO_3$ film development.

Adding oxygen to a CO_2 corrosion system has two major effects:[25]

- **Accelerated corrosion**: Oxygen introduces an additional cathodic reaction, increasing corrosion rates; and
- **Inhibition of protective film formation**: Oxygen oxidises ferrous ions to ferric ions, preventing $FeCO_3$ formation and instead producing non-protective iron oxides.

The expected corrosion scale composition for CO_2–H_2O–O_2 environments is illustrated in Figure 6.

[25] I. S. Cole, D. A. Paterson, P. Corrigan, S. Sim and N. Birbilis, *Int. J. Greenhouse Gas Control*, 2012, **7**, 82–88.

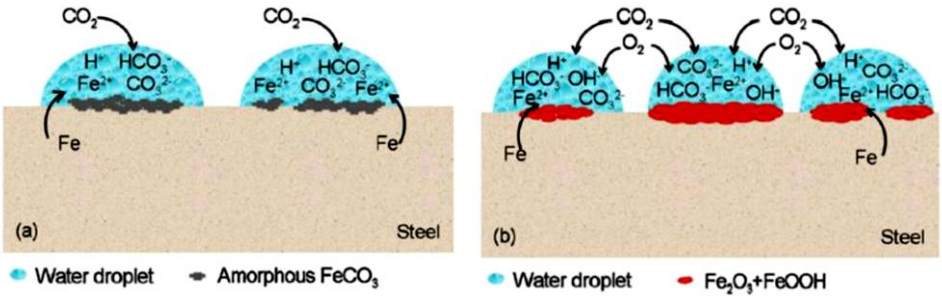


Figure 6 Composition of the corrosion scale in a) CO_2-H_2O and b) CO_2-H_2O-O_2 environments.[26]

4.3.2 Synergistic effects of CO_2, H_2S, and O_2 on corrosion

In environments containing CO_2, H_2O, and H_2S, corrosion scales typically exhibit a two-layer structure:[26]

- **Outer layer**: Primarily composed of iron sulfide (FeS); and
- **Inner layer**: Mainly iron carbonate ($FeCO_3$).

When oxygen is introduced into this system, the corrosion scale becomes more complex, suggesting additional reactions. Oxygen reacts with H_2S to form elemental sulfur, which deposits on steel surfaces and subsequently reacts with iron to produce FeS. Furthermore, the interaction between O_2 and H_2S promotes water phase precipitation, increasing electrolyte availability and accelerating corrosion rates.

In oxygen-free conditions, corrosion mechanisms depend on CO_2 and H_2S concentrations. Iron carbonate tends to form quickly, while iron sulfide develops more slowly. However, in the presence of oxygen, these protective films can oxidise, releasing elemental sulfur and CO_2, which further destabilises the system.

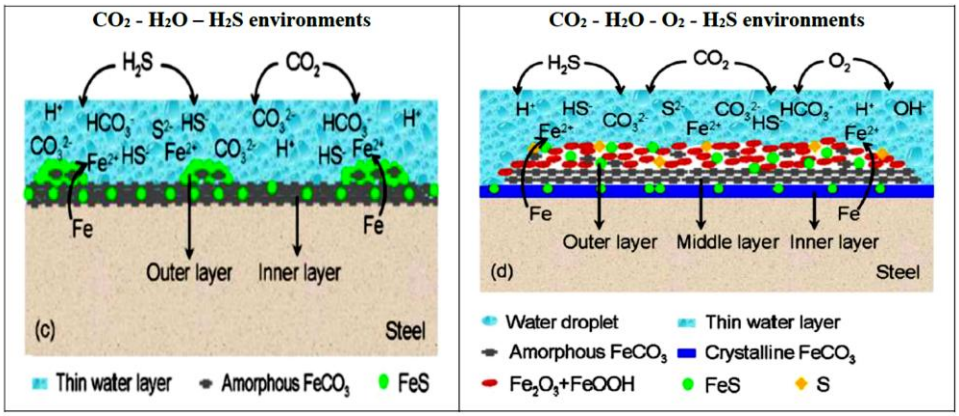


Figure 7 Composition of the corrosion scale in CO_2-H_2O-H_2S with and without O_2.[26]

A four-year study by Lyle et al. evaluated internal corrosion rates under offshore conditions with varying levels of H_2S, CO_2, O_2, chloride, and bicarbonates. Tests on carbon steel (1018 grade) were conducted in stagnant environments (pH 6, no chloride) at 35 bar total pressure, with oxygen concentrations of 100 ppmv (0.001%), 1000 ppmv (0.1%), and 10,000 ppmv (1%). Results showed that:

- In the absence of CO_2 and H_2S: corrosion rates increased significantly with higher O_2 levels (from <5 µm/year to ~106 µm/year);

[26] Y. Xiang, M. Xu and Y.-S. Choi, Corros. *Eng., Sci. Technol.*, 2017, **52**, 485–509.

- In the presence of H_2S or CO_2 individually: similar trends were observed, with higher O_2 leading to higher corrosion rates; and
- When both H_2S (0.03 bar) and CO_2 (0.7 bar) were present: corrosion rates remained around 40 µm/year across all O_2 concentrations, indicating oxygen still influences corrosion but less dramatically under combined acid gas conditions.

Wang et al. conducted tests on X65 carbon steel immersed in NaCl-deionised water with CO_2 (up to 0.5 bar) and varying O_2 (0–3 ppm). Their results showed that even 1 ppm O_2 increased corrosion. At 3 ppm, pitting initiated within 24 hours, although uniform corrosion dominated. Low pH (≈5) prevented $FeCO_3$ film formation; instead, ferric oxide films developed, with thickness dependent on dissolved oxygen.[27]

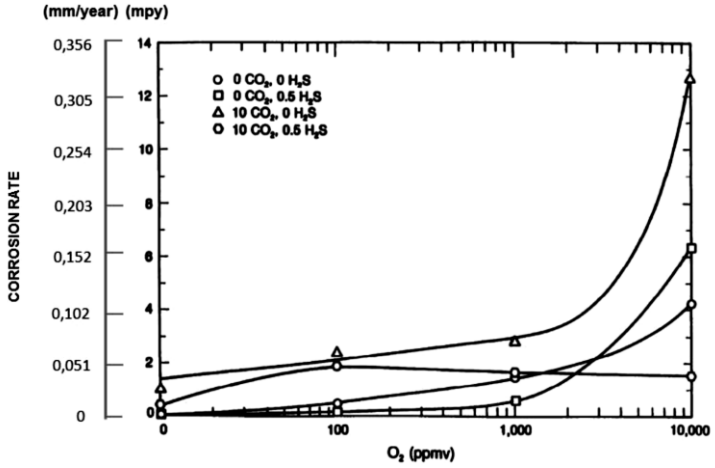


Figure 8 Corrosion rates for fully immersed samples with different oxygen content in the gas phase.[27]

5.4 Hydrogen material compatibility analysis

Hydrogen can embrittle carbon steels through molecular dissociation, adsorption, and diffusion of atomic hydrogen into the metal lattice. This process reduces fatigue resistance and fracture toughness, which is particularly significant for pipeline steels. This review focuses on conditions where hydrogen constitutes approximately 5% of a natural gas blend. The discussion begins with a brief summary of known effects of hydrogen on materials, followed by key differences when hydrogen is present in blended gas streams with trace elements. Finally, recent industry standards and guidelines for handling hydrogen in gas storage facilities are outlined.

5.4.1 Key findings from the literature

Testing of pipeline steels in hydrogen environments reveals the following trends:

- Fatigue crack growth rates increase by more than 10 times in hydrogen gas;
- Fracture toughness decreases by over 50%;
- Both fatigue crack growth and fracture resistance are strongly influenced by hydrogen partial pressure;
- Even low hydrogen levels (<1 bar) can accelerate fatigue and reduce fracture resistance;
- Steel grade and microstructure have minimal effect on crack growth rate in hydrogen;
- Higher-strength or harder steels exhibit greater susceptibility to fracture resistance loss;

[27] I. J. Duncan and H. Wange, *Int. J. Greenhouse Gas Control*, 2014, **21**, 49-60.

- Welds and base metals show similar trends for fatigue and fracture resistance when residual stresses are considered;
- Operating pressures of 50–100 bar with 5% hydrogen correspond to partial pressures of 2.5–5 bar, which remain a concern given these observed effects; and
- 5% hydrogen blends can be used with minor modifications, primarily to monitoring and maintenance practices.

5.4.2 Influence of trace components

The influence of trace components is as follows:

- **CO_2**: Studies indicate that CO_2 can amplify crack growth rates in hydrogen environments, particularly at higher stress intensity ranges (ΔK). Increasing CO_2 concentration from 0.005% to 0.5% appears to raise crack growth rates, though the effect is secondary compared to hydrogen; and
- **O_2**: Oxygen tends to inhibit crack growth at low ΔK values. Concentrations of 100–1000 ppm significantly reduce crack propagation, likely due to oxygen adsorption on crack surfaces, which slows hydrogen ingress.

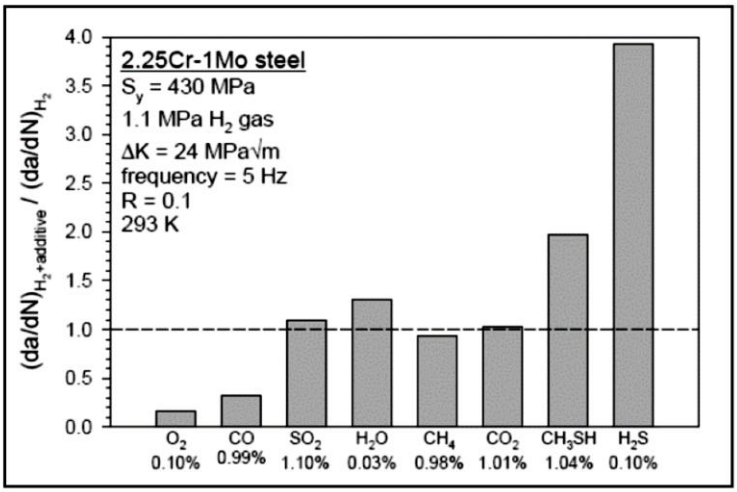


Figure 9 Effect of different trace elements on fatigue crack growth of a pressure vessel steel in 11 bar H_2 gas.[28]

A gas storage facility consists of various equipment designed to condition natural gas before it is injected into the transmission network during withdrawal. The process flow for such a site is outlined in Figure 10.

[28] R. P. Gangloff, in *Comprehensive Structural Integrity*, eds. I. Milne, R. O. Ritchie and B. Karihaloo, Elsevier Science, New York, 2003, vol. 6, pp. 31–101.

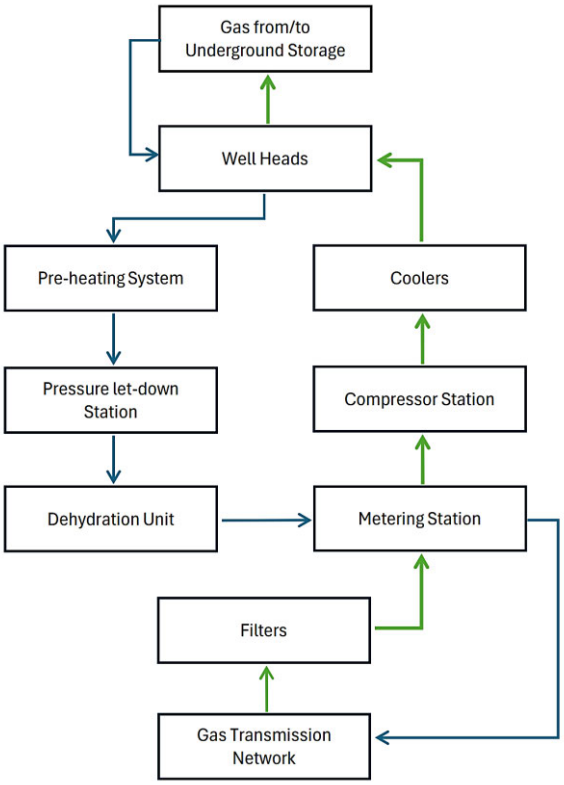


Figure 10 Surface process units in a gas storage site.

Before injection into underground storage, gas is filtered at the station entry, then its flow rate and composition are measured. Compressor units then pressurise the gas, which is cooled and directed into a cavern, aquifer, or depleted reservoir, depending on the storage type.

While underground, the gas absorbs moisture and other substances. During withdrawal, corrosion inhibitors may be added. Separators remove free liquids and solids before the gas enters the sweetening unit. The treated gas is preheated to prevent hydrate formation when pressure is reduced to near transmission pipeline levels. After pressure reduction, the gas is dehydrated to meet contractual limits. Flow rate and quality are rechecked before the gas enters the transmission network.

It is therefore essential to evaluate how trace compounds in biomethane and hydrogen blending affect the operation and integration of these assets.

5.4.3 Effect of gas pressure and hydrogen partial pressure

The percentage of hydrogen being used in a hydrogen-natural gas blend plays an important part in determining to what degree the steel will be affected.

Hydrogen partial pressure is determined by multiplying its mole fraction in the gas mixture by the total system pressure:

$$P_{H_2} = y_{H_2} \times P_{\text{total}}$$

For gas storage sites, the partial pressure of hydrogen at 5% and 20% blending is calculated across different operating pressures in Table 5.

Table 5 Hydrogen partial pressure at different gas blending pressure and percentages.

Gas total Pressure (bar)	Hydrogen mole fraction	Hydrogen Partial Pressure (bar)	Hydrogen Partial Pressure (MPa)
100	5%	5	0.5
100	20%	20	2
200	5%	10	1
200	20%	40	4
300	5%	15	1.5
300	20%	60	6

Therefore, the literature review focuses on the adverse effects of hydrogen on material properties at pressures ranging from 0.5 to 6 MPa, covering conditions for 5% and 20% hydrogen blends.

According to the California Public Utilities Commission, blends exceeding 5% hydrogen increase the risk of steel pipeline embrittlement and leakage. Research shows that accelerated fatigue crack growth becomes noticeable at 5% hydrogen, with higher concentrations adding little further acceleration.[29] Data also indicate that hydrogen's impact on fracture toughness is pressure-dependent, as illustrated in Figure 11.

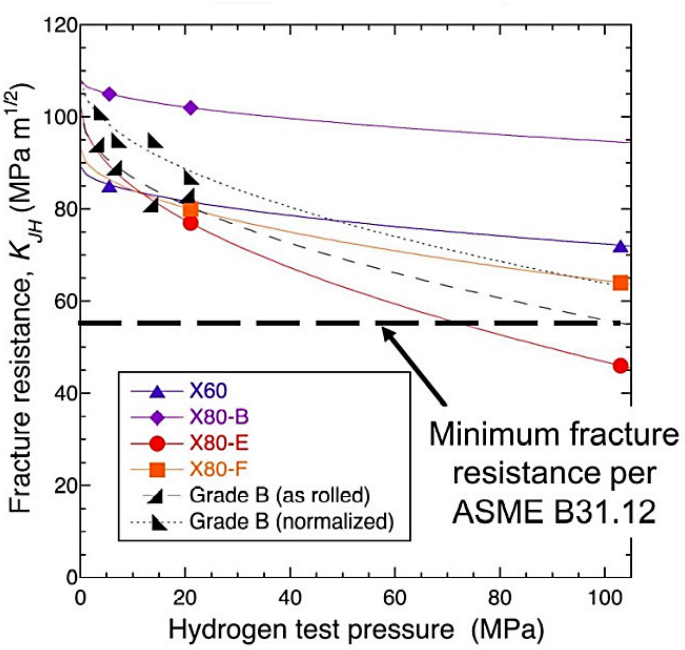


Figure 11 Fracture resistance of X60 and X80 at different hydrogen pressures.[30]

Even at low pressures, hydrogen significantly reduces fracture toughness, and this reduction is similar for a 1% hydrogen blend (with nitrogen as the balance) compared to pure hydrogen, as shown in Figure 12. However, steels used in natural gas pipelines generally have high fracture toughness, making hydrogen's detrimental effects unlikely to pose issues at typical transmission pressures.[30]

[29] M. Penchev, T. Lim, M. Todd, O. Lever, E. Lever, S. Mathaudhu, A. Martinez-Morales and A. S. K. Raju, *Hydrogen Blending Impacts Study Final Report*, The California Public Utilities Commission, San Francisco, 2022.

[30] C. San Marchi, B. P. Somerday, K. A. Nibur, D. G. Stalheim, T. Boggess and S. Jansto, in *Proceedings of the Pressure Vessels and Piping Conference*, ASME, 2012, DOI: 10.1115/PVP2011-57684.

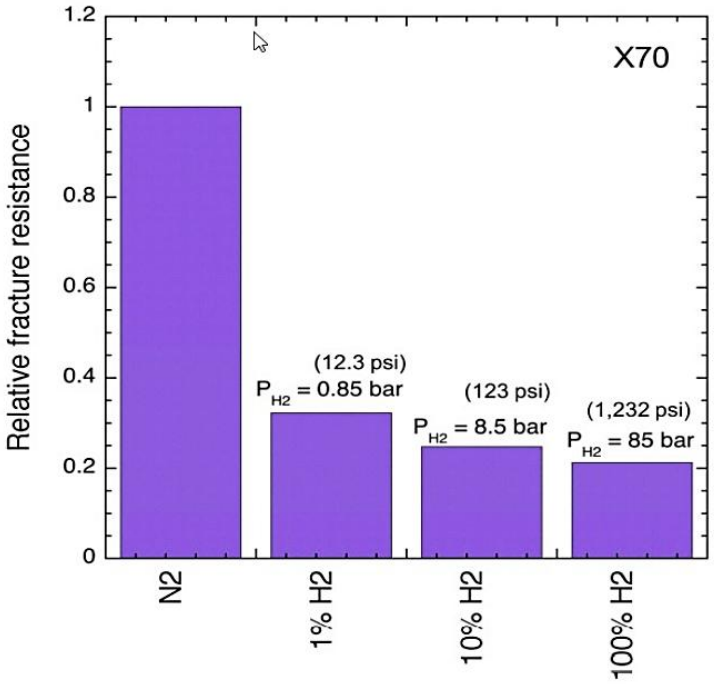


Figure 12 The impact of hydrogen gas even at low pressures on the fracture resistance of X70 steel.[31]

Oxygen has a mitigating effect on hydrogen-induced cracking in ferritic steels due to its diffusion to new crack surfaces. Figure 13 demonstrates that the presence of O_2 in hydrogen reduces crack growth rates to levels observed in air (0.1% equals 1000 ppm O_2). U.S. regulations allow natural gas to contain 0–2000 ppm O_2, which may provide sufficient mitigation against hydrogen effects.[32]

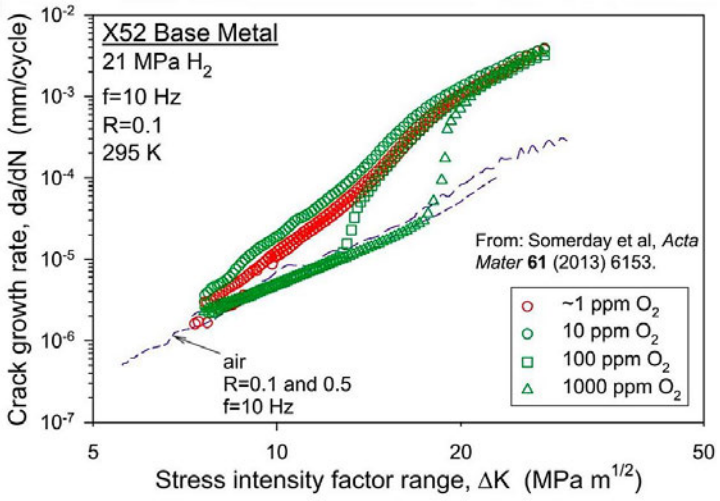


Figure 13 Testing data with X52 steel shows the percentage of 1000 ppm (1% O2) in hydrogen gas can reduce the crack growth rate.[32]

[31] J. A. Ronevich and C. W. San Marchi, *Hydrogen Effects on Pipeline Steels and Blending into Natural Gas*, Sandia National Laboratories, Livermore, 2019.
[32] M. Pfeifer, *Steel Hydrogen Embrittlement*, https://accendoreliability.com/steel-hydrogen-embrittlement/ (accessed December 2025).

5.4.4 Impact of hydrogen on carbon steel

Research shows that mild and carbon steels generally retain strength in hydrogen environments but can suffer fatigue under high cyclic stresses near or above yield stress. Higher-strength grades are more vulnerable, influenced by factors such as hydrogen partial pressure, loading rate, stress concentrations, weld hardness, and impurities. It is generally recognised that this category includes steels with tensile strengths exceeding 1,000 MPa (140 ksi) or hardness values above 30 HRC (301 HV). ASME B31.12 adopts a more conservative approach, limiting hardness to 21 HRC (235 HV) for hydrogen piping and pipelines, which corresponds to an estimated tensile strength of about 783 MPa (114 ksi).

Therefore, higher-strength steels employed in transmission networks, especially newer grades such as X120 (with tensile strength over 1,000 MPa), may be vulnerable. Another concern is that hydrogen exposure accelerates fatigue crack growth and lowers fatigue endurance in all carbon and low-alloy steels. This occurs because hydrogen reduces steel ductility, which could pose risks if pipeline pressure fluctuates. Additionally, existing defects may propagate faster due to this reduction in ductility.

Sandia reports that even gases with low partial pressures of hydrogen can accelerate fatigue crack growth in carbon steels. While certain additives in hydrogen gas can help reduce these crack growth rates, this effect has not been thoroughly studied at low load cycle frequencies. Figure 14 illustrates the relationship between fracture toughness and hydrogen gas pressure for X42 and A516 steels. In both cases, fracture toughness decreases as the gas pressure increases.[33]

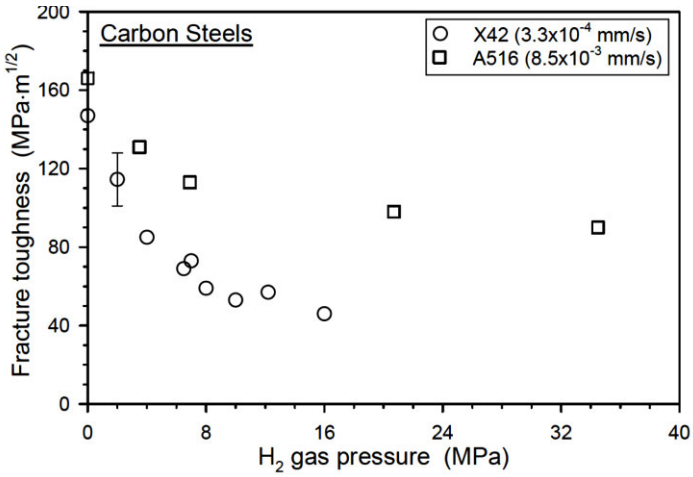


Figure 14 Hydrogen gas pressure effects on fracture toughness of carbon steel.[33]

Hydrogen gas significantly increases the fatigue crack growth rate (da/dN). Figure 15 illustrates how hydrogen affects the relationship between crack growth rate and stress-intensity factor range (ΔK) for 2.25Cr-1Mo steel. At ΔK values above 10 MPa√m, crack growth rates in hydrogen are higher than those in argon, and this difference becomes more pronounced as ΔK increases. Within the pressure range of 1 to 4 MPa, hydrogen gas pressure has little influence on fatigue crack growth rates.

[33] C. San Marchi and B. P. Somerday, *Technical Reference for Hydrogen Compatibility of Materials*, Sandia National Laboratories, Livermore, 2012.

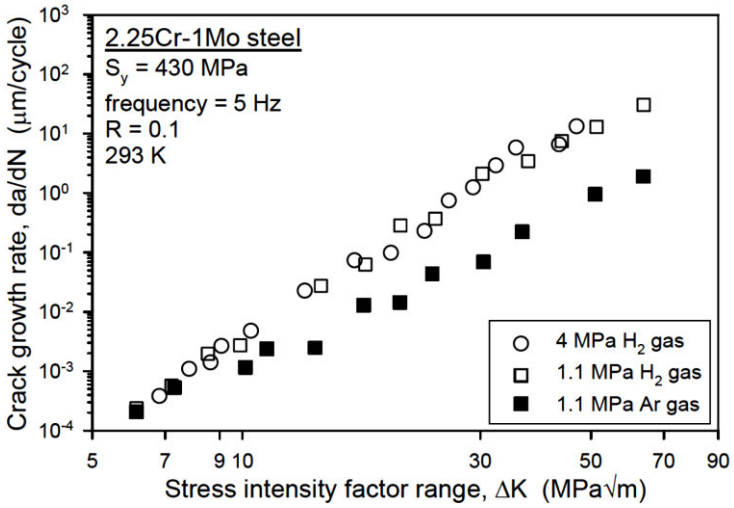


Figure 15 Fatigue crack growth rate as a function of stress-intensity factor for 2.25Cr-1Mo steel in hydrogen.[33]

5.4.5 Impact on low alloy steels

Low alloy steels, commonly used in valve components, have higher strength and may be more prone to hydrogen embrittlement. Compliance with ISO 15156-2 ensures suitability. Alloying elements like carbon, manganese, sulfur, phosphorus, and chromium increase vulnerability. Hydrogen exposure can reduce tensile strength, fracture toughness, and accelerate fatigue growth, particularly under stress concentrations.

Hydrogen gas pressure is a key environmental factor influencing K_{TH} (threshold stress-intensity factor), with the general trend showing that K_{TH} decreases as gas pressure rises. This relationship is illustrated in the K_{TH} versus gas pressure plots for low-alloy 4340 steel (yield strength = 1070 MPa) at three different temperatures in Figure 16.

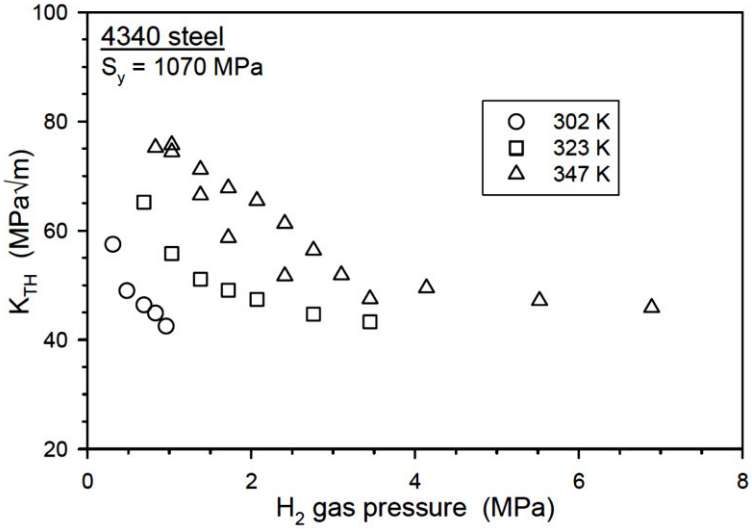


Figure 16 Effect of hydrogen gas pressure on threshold stress intensity factor.[33]

5.4.6 Impact on spring steels

Spring steels, found in regulators and valves, are designed for high yield strength and flexibility. Typically made from medium to high-carbon steels or alloyed variants, they may be susceptible to hydrogen embrittlement due to their high strength. Limited data exists on their hydrogen compatibility, and testing in fabricated form is challenging. Component-level testing is recommended to confirm suitability.

5.4.7 Impact on stainless steels

Stainless steels vary by alloy content and structure. [redacted]. Ferritic stainless steels exhibit higher hydrogen diffusivity and lower solubility compared to austenitic grades. Although data on ferritic alloys in high-pressure hydrogen environments is limited, available studies indicate that ferritic stainless steels are at least as vulnerable to hydrogen-assisted fracture as metastable austenitic grades such as 301 and 304. NASA reports classify type 430F stainless steel as severely embrittled under high-pressure hydrogen exposure.

A summary of the common types of stainless steel is shown in Table 6.

Table 6 Stainless steel classifications and susceptibility to hydrogen.

Type	Composition	Examples	Hydrogen Compatibility based on references [ISO 15916], [NASA 1968], [ASME B31.12]
Austenitic	>18% Cr and >7% Ni	304, 304L, 316, 316L, 321, 347;	Lower susceptibility to hydrogen embrittlement
Ferritic	10-18%Cr, <2% Ni	430	Can be embrittled by hydrogen
Martensitic	12-16% Cr, <2% Ni with higher c than ferritic grades	410	Can be severely embrittled by hydrogen
Duplex	20-28% Cr, 2.5 -8% Ni, 1-4% Mo Austenite plus ferrite	2304, 329, 2205.	Can be embrittled by hydrogen (due to presence of ferrite phase)

5.4.8 Impact of hydrogen on non-metallic materials

Polymers are widely used in components such as valves and actuators, including O-rings, valve seats, and diaphragms. These include thermoplastics like nylon and PTFE, and elastomers such as FKM (Viton) and nitrile rubber.

Unlike metals, where hydrogen permeation requires dissociation into atomic hydrogen, polymers allow molecular hydrogen to permeate. Hydrogen has significantly higher permeability in polymers compared to natural gas, influenced by factors such as temperature, material type, grade, crystallinity, and manufacturing process.

Hydrogen is generally considered inert with most polymers, meaning it typically does not alter their properties. However, its effects at high pressures have not been extensively studied. Under high-pressure hydrogen exposure, some hydrogen can permeate polymers and occupy preexisting cavities within the material. When depressurised, the trapped hydrogen may expand these cavities, leading to blistering, swelling, or cracking. With advancements in fuel cell and hydrogen storage technologies, significant data has emerged on how polymers and elastomers behave under high hydrogen pressure.

Reported failures, particularly in elastomers, are often linked to rapid gas decompression. Polymer properties depend not only on chemical structure (such as chain length, side groups, branching, and crosslinking) but also on factors like molecular weight and processing history. Additives such as fillers, plasticisers, crosslinking agents, and flame retardants are commonly used to modify properties. Additionally, cooling rates during processing affect polymer crystallinity. Some standards and compatibility guides indicate that certain polymers remain stable in gaseous hydrogen environments. Table 7 summarises the compatibility of common polymers with gaseous hydrogen.

Table 7 Examples of compatible polymers with gaseous hydrogen.[33]

Chemical Name/Trade Name	Source
PTFE / Teflon	ISO 15916
CR / Neoprene	ISO 15916
Polyester fiber / Dacron	ISO 15916
Polyester film / Mylar	ISO 15916
Nitrile / Buna-N	ISO 15916
PA / Nylon	ISO 15916
NBR / Buna N	Chemical Compatibility (Emerson)
FKM / Viton	Chemical Compatibility (Emerson)
Ethylenepropylene (EPDM)	Chemical Compatibility (Emerson)
Thermoplastic elastomer (TPE)	Chemical Compatibility (Graco)
Polypropylene (PP)	Chemical Compatibility (Graco)
Polytetrafluoroethylene (PTFE)	Chemical Compatibility (Graco)
Ethylene propylene Rubber (EPR)	Chemical Compatibility (Graco)

Studies show no major impact on the mechanical properties of polyethylene. For elastomers, hydrogen permeation is generally comparable to polyethylene, though material-specific variations exist. Elastomers are commonly used in seals, which typically have small exposed areas (less than 1 mm thick), and are compressed, reducing permeation. However, leakage can occur along the seal-housing interface, which requires attention. Most elastomers, including nitrile rubber, FKM, and silicone, are generally compatible with hydrogen, though Viton requires evaluation per ISO/TR15916.

In valve seals, hydrogen permeation through elastomeric materials varies by type but is generally limited. Leakage is more likely along interfaces than through the material itself. Factors such as dynamic versus static operation, pressure and temperature cycling, and aging can affect performance. However, historical use of elastomeric seals in hydrogen applications (e.g. gas cylinders per ISO 11114-2) suggests functionality is largely unaffected. Minor swelling does not necessarily impair sealing performance.

Routine maintenance can detect issues, and leakage can be minimised through proper assembly practices, including bolting and suitable gaskets for hydrogen service.

5.4.9 Material compatibility with 20% and 5% hydrogen blends

As previously noted, hydrogen embrittlement and hydrogen-accelerated fatigue crack growth become significant at concentrations above 5% hydrogen gas, while the reduction in fracture resistance at 1% hydrogen is comparable to that observed at 100%. Claims suggesting no variation at intermediate concentrations, such as 20%, typically pertain to burner performance rather than network materials. For steels used in high-pressure natural gas networks such as gas storage sites, hydrogen-induced degradation may be relevant for transmission pipelines due to their higher operating pressures and the use of high-strength steels.

One proposed mitigation strategy for hydrogen-accelerated fatigue crack growth from existing defects is the addition of more than 1% oxygen to the gas mixture. However, oxygen has not been shown to prevent hydrogen-induced cracking, which remains a concern for high-strength steels, especially newer grades. To address this, the NaturalHy Project suggests that hydrogen transport can be managed by adapting the existing integrity management programme. The required adaptations depend on hydrogen concentration and pipeline operating conditions but are considered feasible for blends up to 50%, as hydrogen's impact on defect criticality remains minor at this level. Recommended measures include the use of advanced inspection tools such as [redacted], along with shortened inspection intervals for pipelines carrying hydrogen-natural gas blends. Inspection frequency can be determined using hydrogen concentration, operating pressure, pipeline geometry, defect characteristics from in-line inspections, and probability of failure (POF) calculations.

Also, NREL concludes that blends containing up to 15% hydrogen in natural gas can be accommodated with only minor modifications, primarily involving adjustments to existing monitoring and maintenance practices.

Pipeline/Pipework

Pipework includes compressor stations, valves, branch connections, meters, and PRIs. Carbon steel pipework strength is generally unaffected by hydrogen, but fracture toughness decreases and fatigue crack growth rates can increase by a factor of ten or more compared to air. High-stress areas (hoop stress >40% SMYS) require assessment for:

- Weld defects and fatigue from pressure cycling;
- Historic damage affecting integrity; and
- Fatigue from thermal cycling in above-ground piping.

Valves

Carbon steel valve bodies are susceptible to hydrogen embrittlement, requiring lower allowable stresses than for natural gas. While failure at 5% hydrogen is unlikely, increased inspection frequency can provide assurance.

Valve subcomponents (PTFE, Viton, NBR) may experience minor property changes (swelling, compression set), but functionality is unlikely to be compromised at low pressures or with 20% blends. Routine maintenance should detect issues.

High-strength steel springs in valves and regulators may be vulnerable to embrittlement. Due to limited test data, consider:

- Design review of valves; and
- Increased monitoring and maintenance.

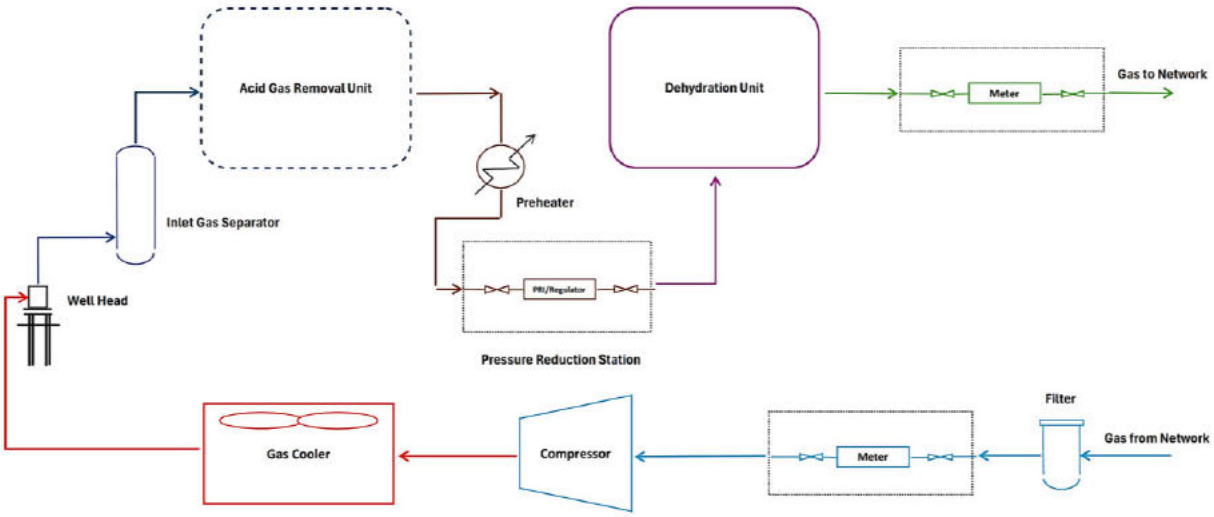
Gas Meters

Austenitic stainless-steel wetted parts are compatible with hydrogen. For non-metallic components and their functionality in the new gas composition, manufacturer guidance should be sought.

5.5 Risk assessment results

In this section, an evaluation has been carried out to determine the effects of biomethane and hydrogen blending on the surface equipment of natural gas storage facilities. The primary objective of this assessment is to understand how corrosive elements influence the structural integrity and operational performance of these installations.

As part of this project, the credible damage mechanisms applicable to above-ground gas storage facilities have been identified in accordance with the API 571 standard. Following this, the specific locations and assets most susceptible to these mechanisms were outlined by establishing corrosion loops.



Corrosion Loops Legend

Color Code	Gas Process Stage	Gas Composition and Conditions
	Injection of Blended Gas into Underground Storage	Blended NG + H_2 + Biomethane
	Compressed Blended Gas	Increased pressure, resulting in higher partial pressures of O_2, H_2, and CO_2
	Withdrawal of Blended Gas from Underground Storage	Blended NG + H_2 + Biomethane with added moisture
	Withdrawal of Blended Gas After AGRU	Blended NG + H_2 + Biomethane; acidic components have been removed
	Withdrawal of Blended Gas After AGRU and PRI	Blended NG + H_2 + Biomethane; acidic components removed and pressure reduced to network level
	Dry Blended Gas to the Network	Blended NG + H_2 + Biomethane; acidic components and water removed

[redacted]

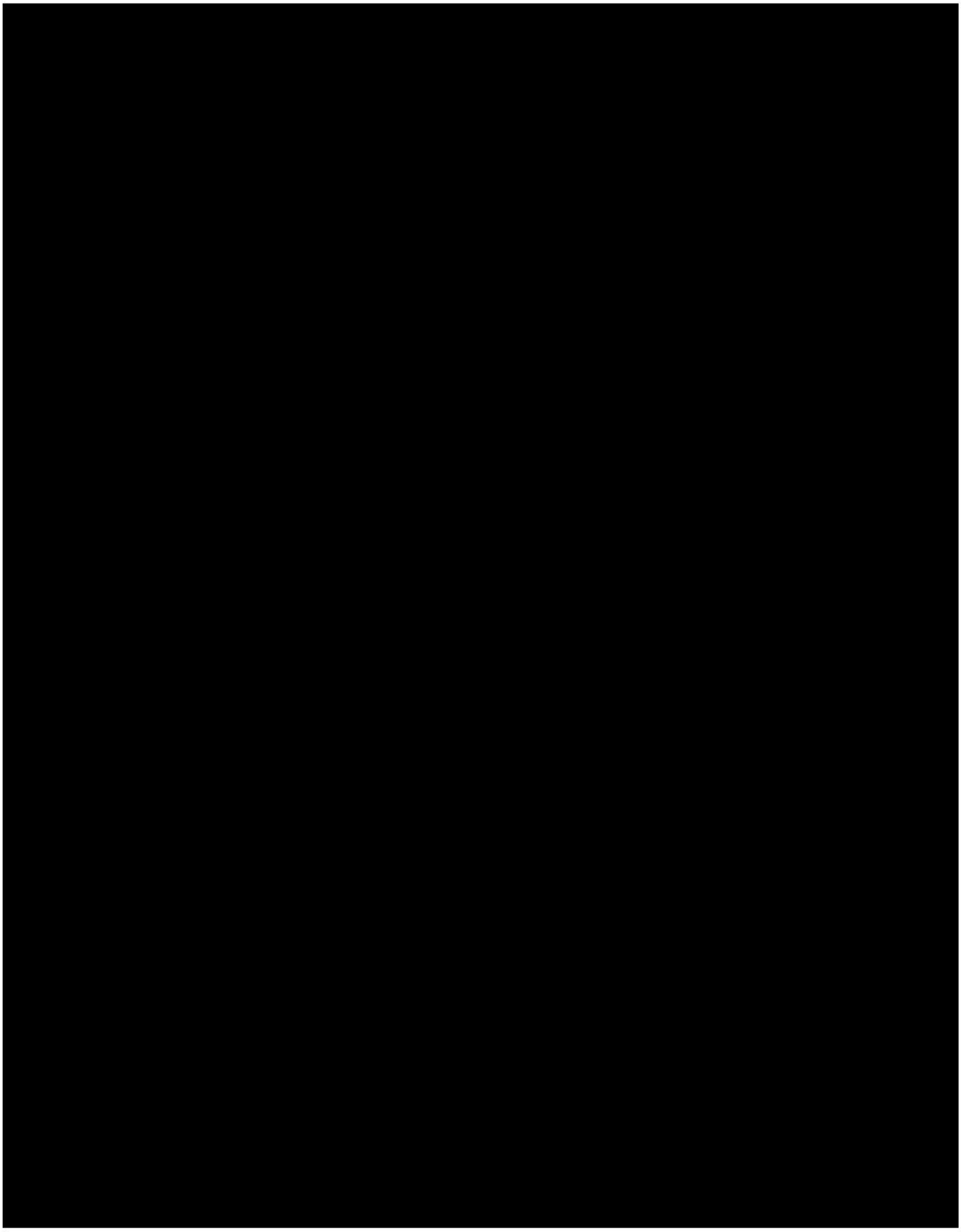
[redacted]

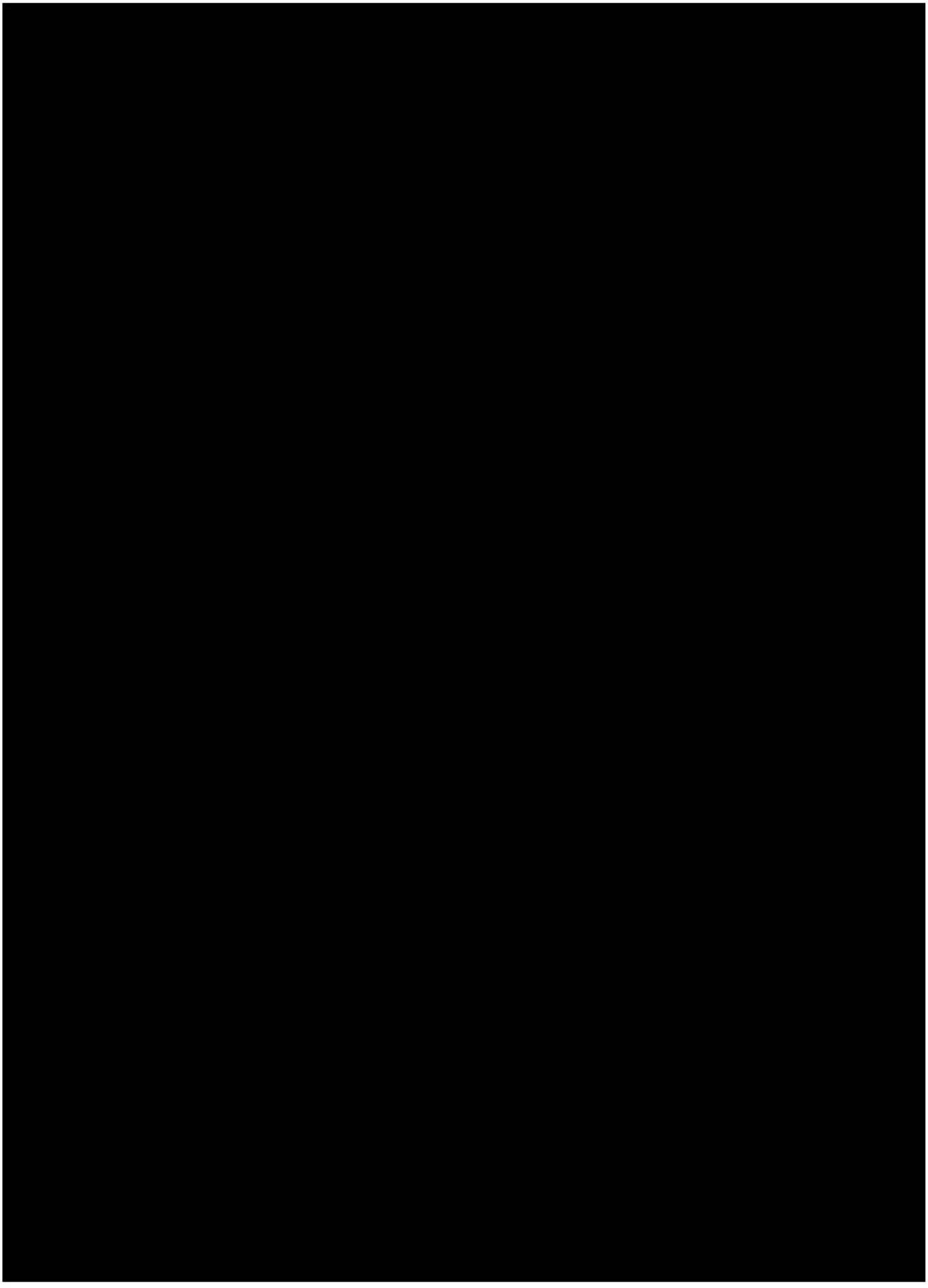
- [redacted]
- [redacted]
- [redacted]
  - [redacted]
  - [redacted]
  - [redacted]
- [redacted]
- [redacted]

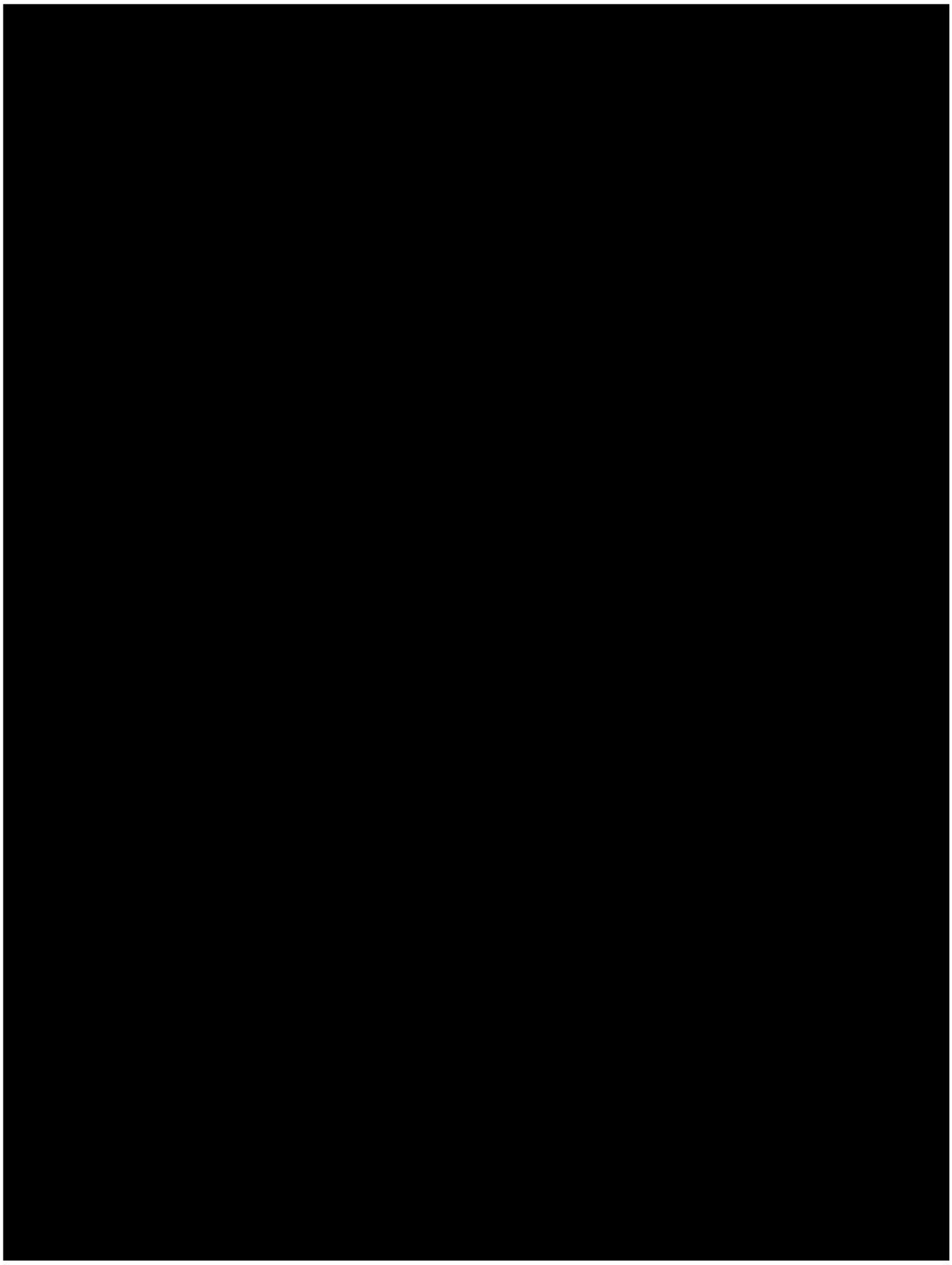
[redacted]

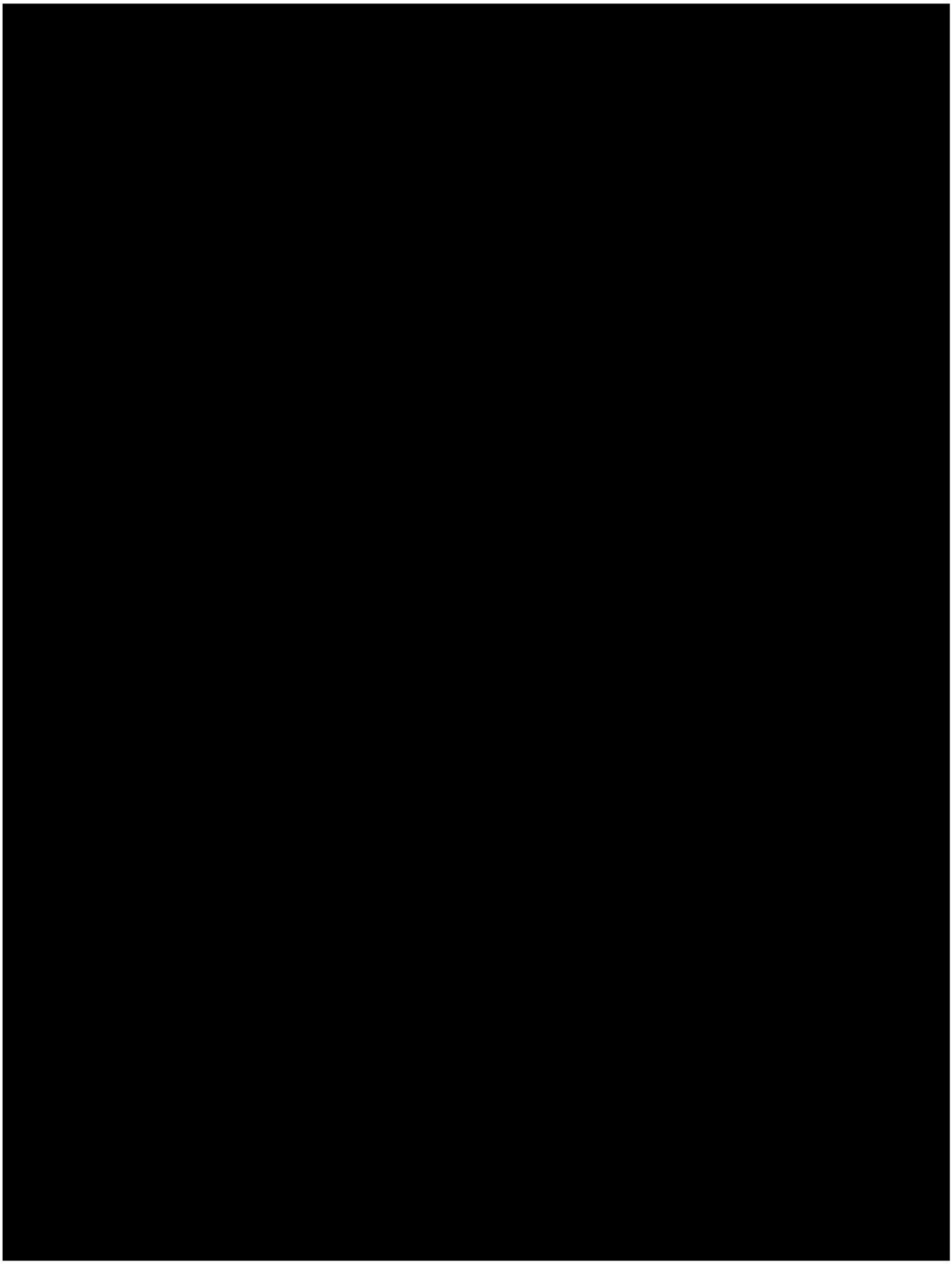
[redacted]

- [redacted]
- [redacted]
- [redacted]
  - [redacted]
  - [redacted]
- [redacted]
- [redacted]









6 RISK FROM FIRES AND EXPLOSIONS

6.1 Gas compositions

6.1.1 Blending scenarios

The resulting gas compositions used in this analysis are presented in Table 15 below. They are consistent with Scenarios 1, 2 and 3 that are described in section 5.1. A typical natural gas composition is also considered, in order to compare the hazards associated with the different gases.

Table 15 Gas blending scenarios for this study.

Scenario		Natural Gas	Blend 1	Blend 2	Blend 3
Natural gas		All	High	Medium	Low
Biomethane		None	Low	Medium	High
Composition (mol%)	Methane	89.290	84.550	87.113	87.151
	Ethane	4.438	4.203	2.087	1.375
	Propane	1.275	1.208	0.600	0.395
	Butane	0.668	0.633	0.314	0.207
	Pentane	0.216	0.204	0.102	0.067
	Hexane	0.026	0.025	0.012	0.008
	Nitrogen	2.387	2.260	1.592	1.359
	Carbon dioxide	1.699	1.828	2.713	3.582
	Oxygen	0.000	0.080	0.461	0.852
	Hydrogen	0.000	5.019	5.007	5.004

6.1.2 Thermodynamic properties

Physical properties of the gases shown in section 6.1.1 have been calculated using DNV's GasVLe package[34] at 15 °C and atmospheric pressure, based on the compositions detailed in Table 15. The results are presented in Table 16. Other calculation methods and gas compositions would give slightly different values, but the general trends in the properties can be seen here. These characteristics affect the risks associated with use of gas. For example, the density can be used to identify how buoyant a gas is, and the gross calorific value can be used to indicate the amount of radiant energy released when a gas is burnt.

Table 16 Thermodynamic properties of gases.

Property	Natural Gas	Blend 1	Blend 2	Blend 3
Molecular Weight (g/mol)	18.204	17.460	17.022	17.075
Gross Calorific Value (MJ/m^3)	39.075	37.597	36.023	35.182
Lower Flammability Limit (% vol/vol)	4.80	4.77	4.97	5.08
Upper Flammability Limit (% vol/vol)	15.14	15.81	16.02	16.22
Density (kg/m^3)	0.762	0.730	0.712	0.714
Ratio of Specific Heat Capacities	1.293	1.297	1.306	1.309
Dynamic Viscosity (Pa.s)	1.089×10^{-5}	1.091×10^{-5}	1.097×10^{-5}	1.101×10^{-5}

[34] GasVLe thermodynamic property calculator, https://www.dnv.com/services/gasvle-8331/, (accessed January 2026).

The effects of the changes in the thermodynamic properties are discussed further in the following sections, but it can be seen that the differences between the gas compositions are relatively small.

6.2 Calculation of risk

The inclusion of oxygen in biomethane introduces additional considerations for fire and explosion risk, through two main factors:

- Potential changes to failure mechanisms and failure frequencies associated with any material compatibility changes; and
- Gas characteristic changes related to the gas composition affect the consequences of a release.

The presence of hydrogen in the gas blends could potentially change the failure mechanisms and frequencies due to hydrogen embrittlement of steels. However, the blends also contain oxygen at concentrations ranging from 800 ppm to 8520 ppm. Research has shown that the presence of oxygen in a hydrogen containing gas can effectively inhibit the embrittlement mechanisms that can occur in pure hydrogen. San Marchi et al[35] found that even 100 ppm oxygen prevented accelerated fatigue crack growth in 14 barg hydrogen and delayed the onset of accelerated fatigue crack growth at hydrogen pressures up to 210 barg. The tests also found that the reduction in fracture toughness was completely prevented by 100 ppm oxygen at hydrogen pressures up to 21 barg and the effect reduced significantly at a hydrogen pressure of 210 barg. Thus, at the oxygen concentrations within the blends considered here, hydrogen threat modes should be inactive.

Equally, the oxygen in the biomethane would only lead to enhanced corrosion in the presence of liquid water. For gas storage the blend should be compliant with the National Gas Transmission Network Entry Agreement specification for water dewpoint (–10 °C at 85 barg) and thus the presence of liquid water is not credible for equipment before cavern entry. Gas exiting the caverns can contain more water, but the storage sites have effective corrosion management for equipment before the dehydration train and will meet the NTS entry specification for equipment after the dehydration train. Thus, enhanced internal corrosion with the blends for surface assets would be improbable.

Thus, for this study it can be assumed that the oxygen prevents hydrogen related failure modes and that the biomethane has the same failure modes as natural gas. Thus, changes to failure mechanisms and frequencies are not considered further in this study.

The effect of different gas compositions on the consequences of an accidental release is considered further below.

6.3 Outflow rate

The outflow rate from a leak is dependent on several factors including:

- The properties of the gases, which are discussed in section 6.1.2;
- The failure mode. For example, interference damage from accidental impacts tends to result in larger holes than failure modes such as corrosion. Each failure mode has an associated distribution of hole sizes that could also depend on factors such as the material and wall thickness of a pipe; and
- The location of the release. For small holes in buried pipes, where the release does not have sufficient energy to form a clear route to the atmosphere, the presence of the soil restricts the outflow. This results in flow that is near-laminar and hence less difference between the gas compositions considered here. Near-laminar flow can also occur from small leaks from above ground equipment when the flow path is restricted. Further details are

[35] Joe Ronevich, Chris San Marchi, Robert Kolasinski, Konrad Thurmer, Norm Bartelt and Farid El Gabaly, *Oxygen Impurity Effects on Hydrogen Assisted Fatigue and Fracture of X100 Pipeline Steel*, PVP2018-84163, ASME 2018 Pressure Vessels and Piping Conference, 15th to 20th July 2018.

given below. For many above ground releases, or larger below ground releases that have formed a crater, the outflow exhibits outflow characteristics closer to turbulent behaviour.

For example, if hydrogen in added to natural gas, the density of the gas decreases, as shown in Table 16 in section 6.1.2. The proportion of biomethane in the mixture also affects the gas density. At a fixed operating pressure, decreasing the density results in the mass outflow rate decreasing but the volumetric outflow rate increasing. The outflow rate also increases with increasing operating pressure. For this reason, it is important to specify what is meant by 'outflow rate'.

Although most outflow models and risk assessments express releases in terms of the mass outflow rate, the volumetric outflow rate is more relevant when considering gaseous releases of different types. A greater volumetric outflow rate produces a larger flammable cloud outdoors, or reaches a flammable concentration within an enclosure more quickly, and is more likely to reach ignition sources. This effect depends on the flow regime.[36]

For turbulent flow, the volumetric outflow rate is inversely proportional to the square root of the density of the gas. For example, the volumetric outflow rate for Blend 2 is calculated to be around 3% greater than the natural gas outflow rate, as shown below.

$$\frac{\sqrt{Density\ of\ natural\ gas}}{\sqrt{Density\ of\ Blend\ 2}} = \frac{\sqrt{0.762}}{\sqrt{0.712}} = 1.034$$

The differences between Blend 1, Blend 2 and Blend 3 are even smaller, which shows that natural gas and biomethane behave in a similar manner. The addition of hydrogen has a greater effect than the proportion of biomethane in the mixture.

For laminar flow, the volumetric outflow rate is proportional to the dynamic viscosity of the gas. There is less than 1% difference in the laminar outflow rates when comparing any of the four gas compositions with one another.

The energy flow rate in the released gas can be calculated by taking into account its calorific value, from Table 16 in section 6.1.2. The energy outflow rates for the three blends are between 93.0% and 98.3% of the natural gas value. The energy outflow rates for the three blends are within 2.5% to 5.7% of one another. This shows a small change in the energy content of the gas that is potentially available for a fire or explosion, as discussed further below.

6.4 Gas dispersion

The distances at which released gas remains flammable affects the risk in terms of potential flash fires and explosions within confined or congested areas. Section 6.1.2 shows that the gas compositions considered in this study have similar flammability limits.

- The Lower Flammable Limit (LFL) lies between 4.8% gas in air and 5.1% gas in air for the four compositions that are detailed in section 6.1.1; and
- The Upper Flammable Limit (UFL) lies between 15.1% gas in air and 16.2% gas in air for the same four compositions.

It is important to note that the lower flammable limit is more relevant for risk calculations since it represents the starting point where the gas is flammable, and this varies only slightly with the gas composition. Although it is theoretically true that concentrations above the UFL cannot burn, a mixture above the UFL likely has a mixture nearby where the concentration lies between the LFL and UFL. Hence, any leak that forms a cloud above the LFL is likely to be flammable somewhere.

[36] A. J. Garrison and S. Gant, *An Investigation into the Change in Leakage when Switching from Natural Gas to Hydrogen in the UK Gas Distribution Network*, 9th International Conference on Hydrogen Safety, Edinburgh, September 21st to 24th 2021.

Table 17 shows some example dispersion distances to the LFL concentration for the four gas compositions, for some example steady state release conditions. All the distances are measured horizontally from the release location at a height of 2 metres above the ground, which represents the effects experienced by people who are at ground level. The vertical releases are modelled at ground level with reduced momentum, to represent a failure of a below ground pipeline. The horizontal releases are modelled from a point 2 metres above the ground, into open air, to represent a failure of an above ground piece of equipment. In all cases, the hazard distances quoted are the maximum values predicted over a range of wind speeds from 0 m/s to 10 m/s.

[redacted]

Note that hazard distances are often quoted to the nearest integer number of metres, to avoid giving a false impression of precision. The results are given to one decimal place here so that the differences between the gas compositions are clearer. In some cases, the hazard distance given to the nearest metre is the same for more than one gas composition.

Table 17 Effect of gas composition on example dispersion distances.

Pressure (bar)	Hole Diameter (mm)	Release Direction	Distance to LFL (metres)			
			Natural Gas	Blend 1	Blend 2	Blend 3
50	25	Vertical	3.3	3.5	3.3	3.2
		Horizontal	18.9	19.4	18.8	18.3
	100	Vertical	15.4	16.1	16.1	14.8
		Horizontal	100.2	102.6	102.6	96.7
85	25	Vertical	4.5	4.7	4.5	4.3
		Horizontal	27.4	28.1	27.1	26.3
	100	Vertical	20.9	21.8	20.7	20.9
		Horizontal	138.2	140.5	135.8	132.5

The following points are noted for these results:

- The dispersion distances associated with vertical releases are noticeably smaller than those associated with horizontal releases, for a given pressure and hole size. This is typical when measuring the extent of the flammable plume close to the ground;
- For all the example releases, Blend 1 gives the greatest predicted dispersion distances. This is the case with low biomethane content but with 5% hydrogen included;
- As the biomethane content of the mixture is increased, the dispersion distance decreases; and
- For a given release, the greatest dispersion distance is no more than 9.3% larger than the smallest dispersion distance. This shows that the predictions are not particularly sensitive to the gas composition within the range considered in this analysis.

The differences in the dispersion distances are partly due to changes in the LFL concentration, and partly due to other factors such as the gas density and the outflow rate that is discussed in section 6.3. Typically, the change in the volumetric outflow rate is the most important factor, which influences whether the dispersion distance increases or decreases as the composition is changed.

6.5 Consequences of fires

Most failures on below ground pipelines or above ground pipework or equipment lead to gas being released to the atmosphere, with the possibility of a fire upon ignition. Either the pipe is exposed already when it is struck, or an activity such as excavation causes the failure and introduces a path to the atmosphere at the same time.

Table 18 and Table 19 show some example fire hazard distances for the four gas compositions, for some example steady state release conditions. All the distances are measured horizontally from the release location at a height of 2 metres above the ground, which represents the effects experienced by people are ground level. The vertical releases are modelled at ground level with reduced momentum, to represent a failure of a below ground pipeline. The horizontal releases are modelled from a point 2 metres above the ground, into open air, to represent a failure of an above ground piece of equipment. In all cases, the hazard distances quoted are the maximum values predicted over a range of wind speeds from 0 m/s to 10 m/s.

The following measures of thermal hazards are used:

- 12.5 kW/m^2 is a thermal flux above which wood, and hence many buildings, would be expected to ignite after exposure for at least a few minutes[37,38]. It would cause around 1% of people to become fatalities after exposure for 1 minute and 1st degree burns in around 10 seconds;[38] and
- 6.3 kW/m^2 is a thermal flux that represents the maximum safe level for escape[37], or maximum flux that can be withstood for 30 seconds by personnel with appropriate clothing.[39] It would not be expected to ignite buildings or cause failures in pipework or equipment.

Many other references are available that give slightly different, but similar, harm and damage criteria. These measures are indicative and intended to show the differences between the gas compositions.

These calculations were carried out using DNV's [redacted] risk assessment package, and are consistent with the dispersion calculations that are presented in section 6.4.

Note that hazard distances are often quoted to the nearest integer number of metres, to avoid giving a false impression of precision. The results are given to one decimal place here so that the differences between the gas compositions are clearer. In some cases, the hazard distance given to the nearest metre is the same for more than one gas composition.

[37] Chemical Industries Association, *Guidance for the Location and Design of Occupied Buildings on Chemical Manufacturing Sites*, 3rd Edition, 2010.
[38] Technica Ltd, *Techniques for Assessing Industrial Hazards – A Manual*, World Bank Technical Paper 55, February 1990.
[39] API 521, Pressure-Relieving and Depressuring Systems', 7th Edition, June 2020.

Table 18 Effect of gas composition on example thermal hazard distances related to building ignition and fatality of people.

Pressure (bar)	Hole Diameter (mm)	Release Direction	Distance to 12.5 kW/m^2 (metres)			
			Natural Gas	Blend 1	Blend 2	Blend 3
50	25	Vertical	19.4	18.9	18.7	18.7
		Horizontal	37.0	36.6	36.3	36.3
	100	Vertical	62.5	61.7	61.7	61.3
		Horizontal	132.7	131.6	131.6	131.1
85	25	Vertical	25.4	24.7	24.5	24.6
		Horizontal	43.7	43.1	46.7	46.6
	100	Vertical	78.9	77.6	77.0	77.0
		Horizontal	165.8	163.5	162.6	162.6

Table 19 Effect of gas composition on example thermal hazard distances related to escape of people.

Pressure (bar)	Hole Diameter (mm)	Release Direction	Distance to 6.3 kW/m^2 (metres)			
			Natural Gas	Blend 1	Blend 2	Blend 3
50	25	Vertical	25.7	25.1	24.8	24.8
		Horizontal	37.0	36.6	36.3	36.4
	100	Vertical	92.0	90.6	90.6	90.3
		Horizontal	158.4	156.7	156.7	155.8
85	25	Vertical	33.9	33.0	32.8	32.8
		Horizontal	49.7	47.5	47.2	47.1
	100	Vertical	117.9	115.7	114.2	114.2
		Horizontal	199.2	196.5	195.4	195.4

The following points are noted for these results:

- The hazard distances associated with vertical releases are noticeably smaller than those associated with horizontal releases, for a given pressure and hole size. This is typical when measuring the extent of the thermal effects close to the ground;
- For all the example releases, the base natural gas composition gives the greatest thermal hazard distances;
- As the biomethane content of the mixture is increased, the thermal hazard distance decreases; and
- For a given release, the greatest 12.5 kW/m^2 distance is no more than 8.4% larger than the smallest distance. Similarly, the greatest 6.3 kW/m^2 distance is no more than 5.5% larger than the smallest distance. This shows that the predictions are not particularly sensitive to the gas composition.

The differences in the thermal hazard distances are mainly due to changes in the energy outflow rates that are discussed in section 6.3. Although other factors such as surface emissivity affect the thermal radiation effects experienced near the release, they are unlikely to vary significantly with changes to the proportion of hydrogen or biomethane within the gas composition.

6.6 Consequences of explosions

Some releases from above ground pipework or equipment can enter confined or congested regions, and hence generate overpressure effects upon ignition. This is also possible for below ground pipelines, in principle, but it is less likely to occur unless the release is within, or close to, a site boundary. For natural gas and hydrogen blend pipelines that run cross country, the thermal hazards described in section 6.5 tend to dominate the overall predicted risk.

Any ignitions of unconfined vapour clouds would not be expected to produce significant overpressure hazards for the gas compositions considered in this assessment. This is not the case for pure hydrogen releases, but for the gas compositions considered here, it is necessary for a release to interact with a confined or congested area in order to have the potential to pose an explosion risk.

Table 20 and Table 21 show some example overpressure hazard distances for the four gas compositions, for some example vapour cloud sizes. All the distances are measured horizontally from the release location. The following measures of overpressure hazards are used:

- 200 mbar is an overpressure level that would be expected to cause severe damage to houses;[40,41] and
- 40 mbar is an overpressure level that would be expected to break windows in houses.[40,41]

Many other references are available that give slightly different, but similar, harm and damage criteria. These measures are indicative and intended to show the differences between the gas compositions.

The overpressure predictions were produced using the TNO Multi-Energy model,[42] which is commonly used in quantitative risk assessments. DNV's proprietary models were not used because the TNO model has fewer inputs and is not linked to the dispersion calculations in the same way, which simplifies the study. DNV's models would give slightly different predictions, but it is expected that the overall trends and conclusions would be the same as presented here. The inputs to the TNO model are only the size of the vapour cloud and thermodynamic properties from section 6.1.2 that define the energy content of the gas. The initial release conditions are not important, as this scenario represents the formation of a flammable cloud at the stoichiometric concentration at atmospheric pressure, after the release has occurred and not immediately ignited. The calculations were carried out a 'Level 7' explosion severity, which is commonly used in the TNO Multi-Energy model to represent a severe deflagration (but not a detonation).

Note that hazard distances are often quoted to the nearest integer number of metres, to avoid giving a false impression of precision. The results are given to one decimal place here so that the differences between the gas compositions are clearer. In some cases, the hazard distance given to the nearest metre is the same for more than one gas composition.

Table 20 Effect of gas composition on example overpressure distances related to significant building damage and harm to people outdoors.

Volume of Cloud (m^3)	Distance to 200 mbar (metres)			
	Natural Gas	Blend 1	Blend 2	Blend 3
10	11.0	10.9	10.8	10.8
100	23.6	23.5	23.3	23.2
1,000	50.8	50.7	50.2	50.0
10,000	109.5	109.2	108.2	107.8

[40] HSE, Safety Report Assessment Guide: LPG, PM/Technical/03, https://www.hse.gov.uk/comah/sraglpg/index.htm, (accessed January 2026),

[41] Association of Oil and Gas Producers (OGP), *Risk Assessment Data Directory, Vulnerability of Plant/Structure*, Report 434-15, March 2010.

[42] W.P.M. Mercx, A.C. van den Berg and D. van Leeuwen, *Application of Correlations to Quantify the Source Strength of Vapour Cloud Explosions in Realistic Situations*, TNO Report PML 1998-C53, October 1998.

Table 21 Effect of gas composition on example overpressure hazard distances related to minor building damage and harm to people indoors.

Volume of Cloud (m^3)	Distance to 40 mbar (metres)			
	Natural Gas	Blend 1	Blend 2	Blend 3
10	42.1	42.0	41.6	41.5
100	90.7	90.5	89.7	89.4
1,000	195.5	195.0	193.3	192.7
10,000	421.2	420.0	416.4	415.1

For all the example cases, the base natural gas composition gives the greatest overpressure hazard distances. For a given cloud size, the largest predicted 200 mbar hazard distance is no more than 1.6% greater than the smallest predicted hazard distance. Similarly, the largest predicted 40 mbar hazard distance is no more than 1.5% greater than the smallest predicted hazard distance. This illustrates that the explosion hazards associated with the four different gas compositions are very similar.

It should be noted that the example calculations given here assume that the flammable cloud has the same volume for all four gas compositions. This is appropriate if the calculation represents a fixed congested volume and the gas release is large enough to fill that fixed volume, and only that fixed volume contributes to the explosion consequences. However, in some cases, a smaller release could fill a portion of that fixed congested volume, and the limiting factor is the size of the flammable cloud. As noted in section 6.3, the volumetric outflow rates of the blends are all slightly greater than that of natural gas. In addition, as noted in section 6.1.2, the flammable concentration range could be larger for a blend than for natural gas (although not necessarily), These factors could combine to give a slightly larger flammable volume for a blend than for natural gas. However, this difference would be minor and does not change the conclusion that all four gas compositions give similar explosion consequences for a given release type.

6.7 Conclusions

This section considers the effect that gas composition has on fire and explosions following an accidental release from a pipeline or site. Three different combinations of biomethane and hydrogen blending into natural gas are considered, along with the base natural gas composition. The focus of this note is on events that could occur on transmission pipelines or sites such as gas storage facilities.

The following conclusions are made, for any combination of natural gas and biomethane and for hydrogen content of up to 5% by volume:

- Potential changes to failure mechanisms and failure frequencies associated with any material compatibility changes are assumed to be minor. This means that the change in risk is dependent only on the gas characteristics related to the gas composition, and how they affect the consequences of a release;
- The volumetric outflow rate is expected to vary be around 3% from the smallest prediction to the largest. The energy outflow rates are greater, with the values for the blends being up to 7% smaller than the natural gas value. The energy outflow rates for the three blends are within 6% of one another;
- The blend with low biomethane content and 5% hydrogen included gives the greatest dispersion distances. For a given release, the greatest dispersion distance is up to 9% larger than the smallest dispersion distance;
- The base natural gas composition gives greater thermal hazard distances than any of the blends. For a given release, the greatest thermal hazard distance is up to 8% larger than the smallest dispersion distance; and
- The base natural gas composition gives greater overpressure hazard distances than any of the blends for the same volume of flammable gas. For a given cloud size, the largest predicted explosion hazard distance is up to

2% greater than the smallest predicted distance. Even if the potential differences in flammable cloud volume are taken into account, the explosion hazard distances are very similar for all gas compositions considered in this study.

This shows that the dispersion, fire and explosion hazard distance predictions are not particularly sensitive to the gas composition within the range analysed. In most cases, the hazards are smaller for a blend than for the base natural gas composition, and overall the risks are expected to be similar for all mixtures or natural gas, biomethane and hydrogen up to 5% by volume.

7 CUSHION GAS INTERACTIONS

Cushion gas plays an important role in underground gas storage by maintaining a minimum pressure within a cavern or reservoir in order to ensure integrity and sufficient withdrawal rates. When introducing blends of hydrogen or biomethane to existing cushion gas, this may have an impact on thermodynamics, the performance of the storage reservoir or cavern and the long-term composition of the cushion gas itself. Differences in density and compressibility at high pressure may result in stratification of hydrogen within blended gases. These cushion gas interactions are more relevant when considering storage of pure and blended hydrogen.

Ultimately, cushion gas requirements are dictated by a number of different factors, these include;

- Depth and pressure conditions for the storage site;
- Reservoir permeability and porosity;
- Operational considerations, i.e. the deliverability and how quickly the gas is required to be produced, number of wells etc; and
- Gas properties.

For injection of blended gases, there needs to be an understanding of the level that may occur within the reservoir and associated cushion gas. The amount of mixing will be influenced by the site-specific parameters, including pressure, temperature, wettability as well as the overall residence time within the reservoir. If a reservoir is cycled regularly, you might expect that limited mixing may occur and the overall impact on the existing cushion gas is limited. For storage sites that are less frequently cycled, more mixing may occur. Modelling studies to understand the behaviour of blended gases for each site should be considered to truly understand the impact.

With respect to cushion gas economics and the impact of blended gases. Existing natural gas storage facilities will have already made capex investments into cushion gas; the impact of injected blends may be important from an asset valuation perspective. When discussing with a storage operator, they had concerns regarding mixing of hydrogen within their natural gas cushion gas and changing the overall economic value of that cushion gas.

7.1 Hydrogen

The current literature on cushion gas dynamics with respect to the storage of hydrogen focuses on the storage injection of pure hydrogen into existing natural gas storage caverns or reservoirs rather than the injection of a natural gas and hydrogen blend. As well as this, much of the literature is focused on the potential deployment of alternative cushion gases in the development of pure hydrogen storage facilities as a means of reducing capex investments. However, the interaction of residual natural gas and potential mixing with pure hydrogen injection provides some insight into mechanisms that may be relevant for injection of natural gas/hydrogen blends.

7.1.1 Depleted gas fields

Within porous media mixing occurs as a result of two processes, diffusion and convective spreading (referred to as dispersion).[43] Diffusion is a slower process that tends to be more pronounced on longer timescales, with its impact reduced with high pressures and tortuosity (the twisted nature of a flow pathway).[44] Typically mixing in the subsurface tends to be governed by dispersive effects. Field observations from the Underground Sun Conversion project[45] show that hydrogen mixes readily with in situ methane and that the produced gas stream tends to become a well-mixed blend over time, with rapid hydrogen breakthrough during withdrawal phases demonstrating that dispersive processes and reservoir flow dominate over simple diffusion.

[43] R. K. Jha , A. K. John, S. L. Bryant and L. W. Lake, *SPE J.*, 2009, **14**, 41–49.
[44] H. A. Williams, N. Heinemann, I. L. Molnar, F. de Mesquita L. Veloso, T. Gladding and T. L. Rashwan, *Int. J. Hydrogen Energy*, 2025, **102**, 1116–1129.
[45] A. Jahanbakhsh, L. Potapov-Crighton, A. Mosallanezhad, N. T. Kaloorazi and M. M. Maroto-Valer, *Renew. Sustain. Energy Rev.*, 2024, **189**, 114001.

Where buoyancy forces dominate over viscous and dispersive effects, stratification of gas mixtures may be expected. This arises from density differences between natural gas and hydrogen causing gravity separation. This separation also increases the surface area interface between the two gases, also increasing mixing effects.

The Underground Sun Conversion project found there was limited stratification within their small, compartmentalised reservoir, with mixing taking place.[26] The potential for stratification of blends is dependent upon both the specific blend composition and the site-specific subsurface conditions and as such cannot be treated as universal. Reservoir heterogeneity can limit the amount stratification as well as the residence time of the injected blend based on planned injection and withdrawal cycles. However, with higher injection rates, effects such as viscous fingering may become more pronounced. This occurs when a low-viscosity fluid displaces a higher-viscosity fluid, i.e. hydrogen displacing water or oil.[46] However, this is potentially only a greater concern for a pure hydrogen storage site as opposed to the hydrogen blends relevant to this project.

A 2026 study investigated field-scale dispersion between hydrogen and methane cushion gas in underground hydrogen storage and co-relation with gravity segregation. Dispersion was shown to induce up to 18% hydrogen losses in the first year of operation and up to 12% at ten years. High pressure and low temperatures resulted in greater gravity segregation of hydrogen from cushion gas but had no impact on mixing. Higher porosities resulted in more mixing, whereas permeability was shown to increase segregation. Dispersion was shown to alleviate the effects of gravity segregation by lessening the density contrasts that drive it. Figure 18 indicates the different mechanisms at play.[47]

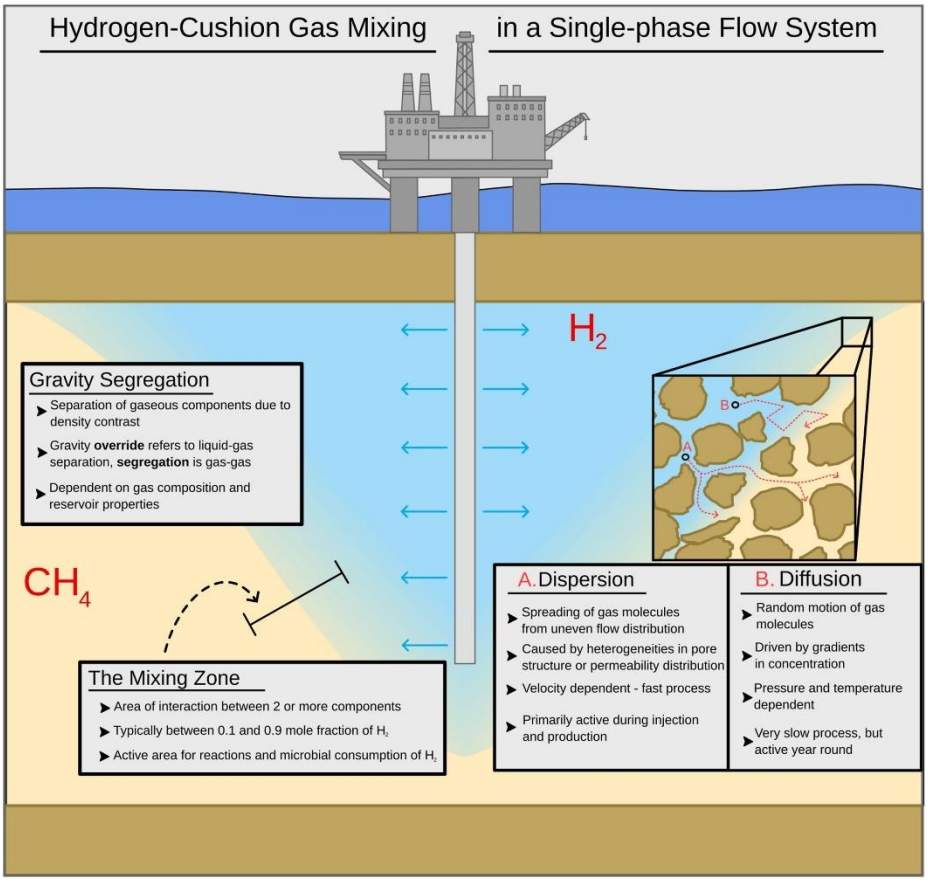


Figure 18 Simplified conceptual diagram (not to scale) of mixing in a single-phase flow system between hydrogen and methane showing three key processes: diffusion, dispersion, and gravity segregation. In a real system secondary oil or water phases would complicate the distribution and trapping of components (from ref. 47).

[46] H. Zhang, Y. Zhang and M. Arif, *Adv. Colloid Interface Sci.*, 2026, **347**, 103701.

[47] S. Marchbank, N. Heinemann, M. Wilkinson, K. Edlmann and I. L. Molnar, *Int. J. Hydrogen Energy*, 2026, **223**, 154166.

7.1.2 Salt caverns

To date, no natural gas/hydrogen blends have been stored in salt caverns, and the associated operational impacts have not yet been characterised. Any consideration of blended-gas storage in caverns should therefore account for the potential for gas stratification. The likelihood of stratification increases under seasonal storage conditions, where long periods without injection or withdrawal allow gases to remain relatively static.[48] Under a theoretical non-flowing scenario, and in the absence of diffusion processes that occur in porous media, a vertical cavern height of approximately 1 km could produce a compositional gradient, with the hydrogen concentration varying from about 3% at the cavern floor to about 2% at the ceiling in a mixed hydrogen–natural gas column.[28] Stratification in salt caverns can be mitigated operationally. A suggested measure is to install a double-string completion, where a secondary, shorter tubing string is suspended alongside the primary string to promote circulation and mechanical mixing within the cavern.

However, in discussion with a gas storage operator, they suggested that they had not observed any stratification of gas within their caverns. The evidence they put forward for not observing this behaviour is linked to the levels of moisture recorded during a withdrawal cycle. Typically, the storage operator injects dry gas at ~20 ppm moisture and during a withdrawal cycle they immediately observed 120–180 ppm moisture levels, suggesting a good degree of mixing within the cavern. They believed the mixing was driven by both the velocity and turbulence of gas entering during an injection cycle as well as convection cycle forming within the cavern. During injection the gas may be at temperatures above or below the temperature of the salt formation (thought to be 25°C), leading to the formation of a convection cycle, with higher temperatures experienced closer to the cavern walls and colder temperatures in the centre of the cavern.

[48] K. Domptail, *Emerging fuels – Hydrogen SOTA, Gap Analysis, Future Project Roadmap*, Pipeline Research Council International, Chantilly, 2020.

8 MICROBIAL ACTIVITY IMPACTS

8.1 Hydrogen

When hydrogen is stored underground, microorganisms present in the reservoir can cause changes to the composition of the gas. Microbiological communities present in underground storage sites are capable of sulfate reduction (sulfate to sulfide), methanogenesis (carbon dioxide to methane), acetogenesis (carbon dioxide to acetic acid), and iron reduction (ferric to ferrous ion) by using hydrogen as an electron donor resulting in microbiologically influenced corrosion (MIC) risks, acid production, souring, and microbial plugging (see Table 22).

Table 22 Typical microorganisms related to hydrogen storage.[49]

Class of microorganism	Main storage impact	Hydrogen Consumption (nM hour^{-1})	Temperature (°C)	Salinity (g L^{-1})	pH
Methanogens $¼HCO_3^- + H_2 + ¼H^+ \rightarrow ¼CH_4 + ¾H_2O$	H_2 loss by CH_4 production, clogging	Laboratorial: 0.008–5.8x10^5 Oil and gas fields: 0–1185 Wells: up to 4533	Optimum: 30–40 Critical: 122	Optimum: <60 Critical: 200	Optimum: 6.0–7.5 Critical: 4.5–9.0
Sulfate reducers $¼SO_4^{2-} + H_2 + ¼H^+ \rightarrow ¼HS^- + 2H_2O$ $H_2 + S \rightarrow H_2S$	H_2 loss by H_2S production, corrosion, clogging	Laboratorial: 0.005–130x10^5 Oil and gas fields: 0.05–351 Wells: up to 2544	Optimum: 20–30 Critical: 113	Optimum: <100 Critical: 240	Optimum: 6.0–7.5 Critical: 0.8–11.5
Homoacetogens $4H_2 + 2CO_2½HCO_3^- + H_2 + ¼H^+ \rightarrow ¼CH_3COO^- + H^+ + 2H_2O$	H_2 loss by CH_3COOH production, clogging	Laboratorial: 0.02–5.0x10^5	Optimum: 20–30 Critical: 72	Optimum: <40 Critical: 300	Optimum:6.0–7.5 Critical: 3.6–10.7
Iron(II) reducing bacteria $2FeOOH + H_2 + 4H^+ \rightarrow 2\ Fe^{2+} + 4H_2O$	H_2 loss by Fe(II) production, clogging	Laboratorial: 0.005–2.2x10^5	Optimum: 0–30 Critical: 90	Optimum: <40 Critical: 200	Optimum: 6–7.5 Critical: 1.6–>9

Note: Data determined at varying hydrogen exposure concentration, substrate concentration, temperature and organic matter availability.
Note: Source data, see footnote 50.

Microbiological impacts of underground hydrogen storage depend on various factors such as the type of reservoir, environmental conditions (temperature), water chemistry (pH, salinity, nutrients), rock permeability, and microbiological community composition. Because of complex interplay be-tween these factors, it is challenging to use a generalised approach to assess the microbiological impacts. Instead, a site-specific comprehensive risk assessment during site selection for underground hydrogen storage is required. This risk assessment should include investigation of different microbiological impacts, losses in hydrogen, contamination of hydrogen, and environmental conditions exacerbating microbiological influence when selecting sites for underground hydrogen storage. This risk assessment may be performed as a preliminary desktop study followed by a detailed laboratory testing simulating field conditions to investigate the microbiological impacts.

From the existing hydrogen caverns no microbial activity has been publicly reported so far. Halophilic microbes have been seen to occur in saline subsurface environments however, whether they will have significant impacts when hydrogen is injected into salt caverns remains unknown and requires further study.[49]

Hydrogen contamination by bacterial metabolism products (or metabolites) should be considered and investigated, depending on composition of the residual brine, stored gas (pure or blended hydrogen), and impurities caused by reactions between hydrogen and inter-beddings other than rock salt.[49]

In discussion with a gas storage operator, they indicated they have conducted studies hoping to identify microbial activity at two of their cavern sites with no positive results. They have however observed evidence of sulfur-based

[49] N. Dopffel, B. A. An-Stepec, P. Bombach, M. Wagner and E. Passaris, *Int. J. Hydrogen Energy*, 2024, **58**, 1478–1485.
[50] N. Heinemann, J. Alcalde, J. M. Miocic, S. J. T. Hangx, J. Kallmeyer, C. Ostertag-Henning, A. Hassanpouryouzband, E. M. Thaysen, G. J. Strobel, C. Schmidt-Hattenberger, K. Edlmann, M. Wilkinson, M. Bentham, R. S. Haszeldine, R. Carbonell and A. Rudloff, Energy Environ. Sci., 2021, 14, 853–864.

reactions occurring within their systems. Their main concern remained the consumption of hydrogen to generate hydrogen sulfide, accelerating the corrosion of pipelines.

In oil and gas operations, microbial activities can become relevant during water-flooding processes. As such mitigation strategies and biocide treatments have been established. For above ground operations, mitigations typically involve a combination of mechanical removing biofilms combined with biocide injections. However, for subsurface applications there are challenges associated with injection rates and the penetration of the biocide within the reservoir. A well-established natural inhibitor is nitrate, used to stimulate growth of nitrate reducers, which act to outcompete 'problematic' microorganisms.[51] Mitigation strategies for bacterial hydrogen consumption are currently under investigation as part of the HyLife project, with a novel microbial control assessment program in development. Table 23 outlines the potential biocides and natural inhibitors that are being tested through the program:

Table 23 A list of select potential common biocides and natural inhibitors proposed to test against UHS brine-enriched H_2-consuming cultures during the HyLife project.[52]

Non-oxidising biocide	Oxidising Biocide	Natural inhibitors	Temperature (°C)	Salinity (g L^{-1})	pH
Methanogens ¼HCO_3^- + H_2 + ¼H^+ → ¼CH_4 + ¾H_2O	H_2 loss by CH_4 production, clogging	Laboratorial: 0.008–5.8x10^5 Oil and gas fields: 0–1185 Wells: up to 4533	Optimum: 30–40 Critical: 122	Optimum: <60 Critical: 200	Optimum: 6.0–7.5 Critical: 4.5–9.0
Sulfate reducers ¼SO_4^{2-} + H_2 + ¼H^+ → ¼HS^- + 2H_2O H_2 + S → H_2S	H_2 loss by H_2S production, corrosion, clogging	Laboratorial: 0.005–130x10^5 Oil and gas fields: 0.05–351 Wells: up to 2544	Optimum: 20–30 Critical: 113	Optimum: <100 Critical: 240	Optimum: 6.0–7.5 Critical: 0.8–11.5
Homoacetogens 4H_2 + 2CO_2½HCO_3^- + H_2 + ¼H^+ → ¼CH_3COO^- + H^+ + 2H_2O	H_2 loss by CH_3COOH production, clogging	Laboratorial: 0.02-5.0x10^5	Optimum: 20–30 Critical: 72	Optimum: <40 Critical: 300	Optimum:6.0–7.5 Critical: 3.6–10.7
Iron(II) reducing bacteria 2FeOOH + H_2 + 4H^+ → 2 Fe^{2+} + 4H_2O	H_2 loss by Fe(II) production, clogging	Laboratorial: 0.005-2.2x10^5	Optimum: 0–30 Critical: 90	Optimum: <40 Critical: 200	Optimum: 6–7.5 Critical: 1.6–>9

8.2 Biomethane

There has been comparatively little investigation into associated microbial impacts with the storage of biomethane and the influence of increased oxygen concentrations within the subsurface. A study in preparation conducted a multiphase reactive transport modelling study to understand the potential for biogenic hydrogen sulfide production in a deep sandstone aquifer (used for natural gas storage currently).[53] The key findings are as follows, noting that these modelling results are not yet validated by field measurements from the modelled storage sites:

- Over twelve injection and withdrawal cycles hydrogen sulfide concentrations initially increased followed by a plateau as sulfate becomes depleted in the gas-dominated zone of the reservoir. Hydrogen sulfide then accumulated in the deeper parts of the reservoir becoming constrained by the interface between the gas and the aquifer. Towards the final injection and withdrawal cycles the aquifer provides a source of sulfate. Hydrogen sulfide generation is ultimately limited by the availability of sulfate.
- The reservoir mineralogy exhibits small changes due to the activity of sulfate reducing bacteria, without a significant change in porosity. This suggests the performance of the storage site may not be impacted.

[51] L. M. Gieg, T. R. Jack, and J. M. Foght, *Appl. Microbiol. Biotechnol.*, 2011, **92**, 263–282.

[52] A. B. An Stepec, K. Černá, K. Wunch, S. Schmidt, S. Stephant, S. Rad and N. Dopffel, *Developing innovative mitigation approaches for underground hydrogen storage management*, 85th EAGE Annual Conference and Exhibition, 2024, pp.1–5.

[53] J. Guo, I. Sin, L. De Windt, A. Petit, L. Jeannin, D. Segura and P. Egermann, *Microbial H_2S Generation in Large-Scale Aquifer Gas Storage: Multiphase Reactive Transport Insights for Potential Biomethane-Natural Gas Blend*, 2026, DOI: 10.2139/ssrn.6032333.

However, the dissolution of gypsum within the reservoir can sustain microbial hydrogen sulfide generation over longer timescales. Reactive iron-bearing minerals can enable the abiotic trapping of dissolved hydrogen sulfide through the formation of iron(II) sulfide, highlighting the importance of accessory mineral composition in reservoir souring as well as the need to conduct site specific mineralogical characterisation prior to gas storage.

[redacted] [redacted]

[redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted]

- [redacted] [redacted]
    - [redacted] [redacted]
    - [redacted] [redacted]
- [redacted] [redacted]
    - [redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted] [redacted]

- [redacted] [redacted]
- [redacted] [redacted]
- [redacted] [redacted]
- [redacted] [redacted]
- [redacted] [redacted]
- [redacted] [redacted]

[redacted] [redacted]

[redacted]

[redacted] [redacted]

[redacted]

- [redacted] [redacted]

[redacted] [redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted] [redacted]

[redacted]

[redacted]

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted] [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]. It [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[55] *Hydrogen Blending Management Approach WP4: Technical Summary*, Report no. 247218-00-PR-REP-004, Wood, 2025.

[redacted]

[redacted]

[redacted]

[56] REMIT, https://www.nationalgas.com/our-businesses/remit, (accessed January 2026).
[57] Short Term Access to System Flexibility Allocation Methodology, https://www.nationalgas.com/sites/default/files/documents/5920-ShorttermFlexAllocationMethodologyv21.pdf, (accessed January 2026).
[58] Entry Capacity, https://www.nationalgas.com/our-businesses/entry-capacity, (accessed January 2026).
[59] Off-Peak / Interruptible Capacity Scaleback and Restoration, https://www.nationalgas.com/sites/default/files/documents/Capacity Scaleback and Restoration_0.pdf, (accessed January 2026).
[60] Margins Notices & Gas Balancing Notifications, https://www.nationalgas.com/our-businesses/margins-notice-gas-balancing-notification, (accessed January 2026).

[redacted]

[61] Capacity Guidelines, https://www.nationalgas.com/sites/default/files/documents/Capacity Guidelines June 2022.pdf, (accessed January 2026).
[62] Locational Energy, https://www.nationalgas.com/sites/default/files/documents/5918-LocationalEnergyActionsv1.pdf, (accessed January 2026).
[63] Offtake Flow Reductions, https://www.nationalgas.com/sites/default/files/documents/Offtake Flow Reduction.pdf, (accessed January 2026).
[64] Margins Notices & Gas Balancing Notifications, https://www.nationalgas.com/our-businesses/margins-notice-gas-balancing-notification, (accessed January 2026).
[65] Demand Side Response, https://www.nationalgas.com/our-businesses/system-operation/demand-side-response, (accessed January 2026).
[66] DSR Annual Report, https://www.nationalgas.com/sites/default/files/documents/DSR Annual Report 2024-25.pdf. (accessed January 2026).

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[67] Assessment of Impact of hydrogen on NGGT policies, management procedures, standards and work procedures, FutureGrid Project Phase 1C, Report no.10305081-02, DNV.

[68] HyNTS Operational Methodologies Workshop Action Summary, Report no. 10510386-4-REP-001, DNV.

[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]

	LTSF		be updated to reflect recording accurate gas composition and quantities of released gas. Including RIDDOR reportable releases.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

69 H21 Phase 2: Ignition Considerations for Network Procedures, Report no. EA/20/18, HSE Science Division, 2021.

[redacted]

[redacted]

[redacted] [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[70] National Hydrogen Safety Assessment Final Report, September 2024.

[redacted]

[redacted]

[71] The Pipeline Safety Regulations 1996, UK SI 1996 No. 825.

[redacted]

[redacted]

[redacted]

[redacted]

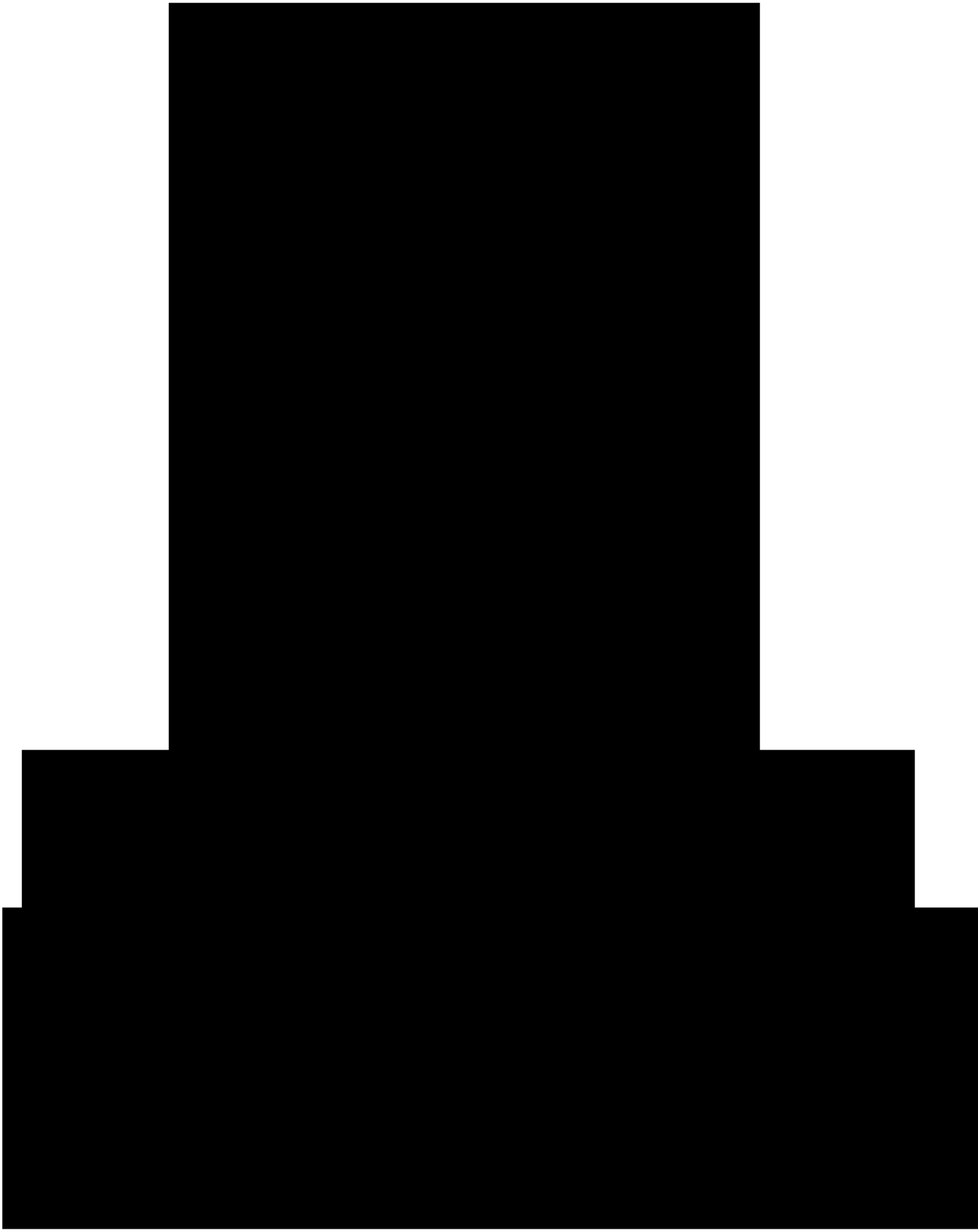
[redacted]

[redacted]

[redacted]

[redacted] Changing supply patterns, https://www.nationalgas.com/our-businesses/system-operation/market-change, (accessed January 2026).

[redacted]



[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted].

[redacted]

[redacted] [redacted]

[redacted]

[redacted]

[redacted]

[redacted] [redacted]

[redacted]

[redacted]

[redacted] [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

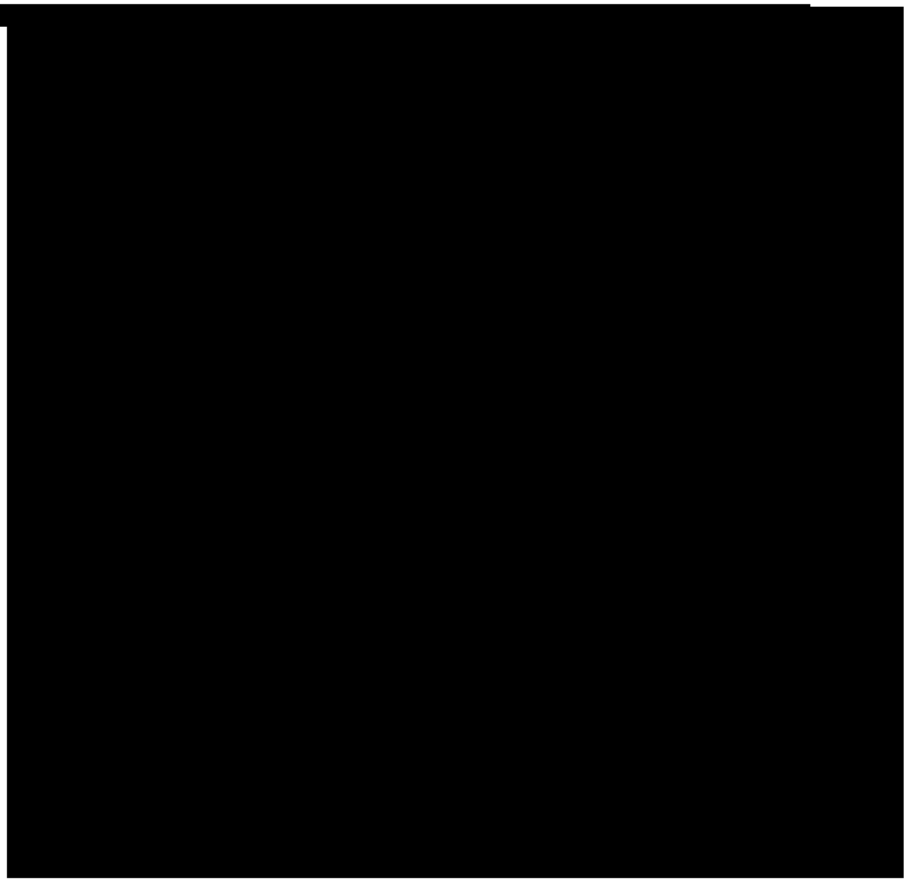
[redacted]

[redacted]

- [redacted]
- [redacted]

[redacted]

[redacted]



[redacted]

- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

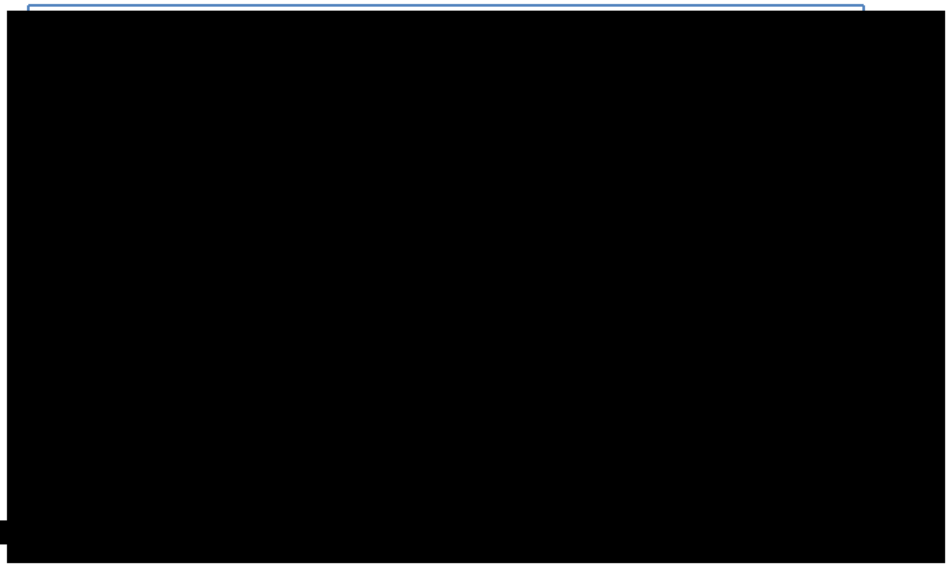
[redacted]

[redacted]

- [redacted]
- [redacted]

[redacted]

[redacted]



[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[73] G. Li, M. Moyer and H. Bidmus, *Optimizing Blended Hydrogen Uniformity Within Natural Gas Pipeline Distribution Networks*, in Proceedings of the 14th International Pipeline Conference, Calgary, Canada, 2022.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]

[74] For readers who like to know the numbers, the blend percentages in this figure are derived from the following relative flows (to 1dp): flow from the terminal 500, flow at each offtake 100, first (larger) hydrogen injection 10.5, second (smaller) hydrogen injection 6.8.

[75] https://www.nationalgas.com/our-businesses/gas-terminals

[redacted]

[redacted]

- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]

  [redacted]

[76] The current blend confirmation point equipment would need to be assessed for suitability.

[redacted]

- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

77 National Transmission System Hydrogen Blending: Stakeholder Engagement

[redacted]

[redacted]

[redacted]

[redacted] ability to ring fence specific feeders or pipelines will depend on the point at which hydrogen is injected and may require alterations at compressor stations and multi-junctions. As discussed in section 12.4, injection into flowing gas

[redacted]

[78] Hydrogen Deblending in the GB Gas Network, Project no. NIA_NGGT0156, National Gas Transmission, 2021.

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[79] *CEN SFGas GQS – Recommendations and considerations on Wobbe index aspects related to H-gas – Final report*, 2020, https://www.gasgovernance.co.uk/sites/default/files/related-files/2023-08/CEN%20SFGas%20GQS%20%E2%80%94%20Recommendations%20and%20considerations%20on%20Wobbe%20index.pdf, (accessed January 2026).

[80] HSE, A guide to the Gas Safety (Management) Regulations 1996 (as amended), TSO (The Stationery Office), 2024. https://www.hse.gov.uk/pubns/priced/l80.pdf (accessed January 2026).

[redacted]

[redacted]

[redacted]

[redacted]			
[redacted]			
[redacted]			
[redacted]			
[redacted]			
[redacted]			
[redacted]			
[redacted]			
[redacted]			
[redacted]			
[redacted]			
[redacted]			
[redacted]			
[redacted]			

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]					
[redacted]					
[redacted]					

- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]					
[redacted]					
[redacted]					
[redacted]					
[redacted]					
[redacted]					

- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] GB.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]

[81] System Management Principles Statement, National Gas Transmission, 2024. https://www.nationalgas.com/sites/default/files/documents/System%20Management%20Principles%20Statement,%20v.12.0%20-%20Approved.pdf

[82] L. Frearson, *Hydrogen Blending Infrastructure of the NTS National Innovation Allowance (NIA) Work Package 5: Standards and Reporting Project Summary Closeout Report*, Premzero, Report no. PRZ-0005-REP-0000-0500, Issue 02, 2025.

[redacted]

- [redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] are introduced into [redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] [redacted]

[redacted]

[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[83] A. Robinson, *Market review of GC options for hydrogen in natural gas measurement*, DNV report no. 10512240-01, 2025.

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[84] A. Robinson, *Variable Gas Blend Market Review*, DNV report no. 2402738.

[redacted]

[redacted]

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[85] Repeatability is the short-term (within minutes) variation or dispersion in results obtained with the same meter in the same setup.
[86] Reproducibility is the day-to-day or week-to-week dispersion in results obtained with the same meter.
[87] H2Ref, https://h2ref.eu/, (accessed January 2026).
[88] Transferability is the (short-term) reproducibility of results obtained with one gas to another gas.

[redacted]

[89] Hydrogen Blending Management Approach WP4: Technical Summary (Doc Ref: 247218-00-PR-REP-004, July 2025).

14 CONCLUSIONS

The technical, operational, and safety implications of introducing low level hydrogen blends (≤5% and ≤20%) and biomethane containing up to 1% oxygen into the National Transmission System have been assessed in this project, including a qualitative risk evaluation of six blended gas scenarios. The key outcomes of this study are summarised below:

1. Subsurface storage feasibility

Salt caverns show low reactivity and minimal microbial hydrogen loss, making them well-suited to hydrogen blends. Porous reservoirs (depleted fields/aquifers) exhibit significant uncertainty: risks include hydrogen loss to brine, microbial consumption, mineral alteration, and microcrack-induced leakage, none of which have quantified long-term rates.

2. Biomethane oxygen content drives corrosion risk

Oxygen promotes CO_2–O_2–H_2S synergistic corrosion, deposition of elemental sulfur, and accelerated steel degradation. Salt caverns report lower sensitivity but corrosion in wet withdrawal phases remains a concern.

3. Hydrogen embrittlement becomes significant at elevated pressure and >5% blends

Carbon steel and high-strength steels show significant reductions in fracture toughness and accelerated fatigue crack growth as hydrogen partial pressure increases.

4. Surface facility vulnerabilities are blend-dependent

Compressors: 5% blends manageable; 20% blends push materials and impeller designs toward performance limits. Dehydration (TEG) and amine sweetening systems are vulnerable to oxygen-induced degradation. Valves, springs, and elastomers may require requalification for 20% hydrogen.

5. Risk assessment (for storage)

Scenario 1 (5% H_2, low biomethane) → Lowest risk; comparable to natural gas baseline.

Scenarios 4–6 (20% H_2) → Hydrogen embrittlement becomes a credible mechanical integrity threat.

Scenarios 3, 5, 6 (high biomethane) → High O_2 & CO_2 cause major corrosion increases.

Accordingly, the following steps are proposed for further action to support UGS facilities:

   a. Conduct site-specific assessments for UK storage geology by including UK-specific caprock mineralogy, salt cavern variability, legacy well conditions, and microbial profiles; and

   b. Establish a hydrogen- and oxygen-specific integrity management framework including material requalification for high-strength steels, packers, springs, and welds in likely future hydrogen scenarios and strengthen corrosion control for biomethane-rich blends by implementing oxygen and carbon dioxide monitoring, improved glycol and amine management, and enhanced corrosion inhibitor programmes.

6. NTS interactions with storage operators

   a. Currently injected gas will meet the requirements of GS(M)R and network entry agreements and thus has a known composition. In the future the presence of biomethane and hydrogen may result in a more varied gas composition requiring storage. As the storage operator may incur risks dependent upon the composition of the injected gas it will be necessary to modify the current gas storage connection agreements to include notification of injected gas composition (and limits on some components) in addition to the current limits of gas composition exiting storage. This could include

allowing the storage operator to refuse gas depending on composition (at present they can only refuse if storage is full).

b. National Gas Transmission will need to understand the composition of gas that could enter storage sites on a near real time basis to meet the modified gas storage connection agreements and limit the potential for adverse effects for the gas storage operator.

7. Constraint management and emergency response

The analysis demonstrates that while the NTS will face new operational considerations as hydrogen and biomethane blending increases, the existing emergency response and constraint management framework remains broadly robust, requiring only targeted updates rather than wholesale redesign.

The NTS continues to face three key categories of supply risk: Gas Deficit Emergencies (GDEs), Safety Monitor Breaches (SMBs), and Critical Transportation Constraints (CTCs). The underlying causes of these events remain unchanged and are driven by supply quality, high demand, unplanned outages, and infrastructure failures.

Most tools used to manage GDE and CTC scenarios are expected to remain effective with the introduction of up to 5% hydrogen blends and higher biomethane penetration. However, the operational impacts of alternative gases, particularly differences in energy density, gas quality, and compressor behaviour must be factored into modelling and operational decision-making.

Hydrogen and biomethane producers offer additional flexibility to support the NTS during constraints. In particular, hydrogen producers may be incentivised through existing commercial mechanisms (e.g. OCM trades, demand-side response, interruptible capacity) and could provide rapid, localised support during CTCs. Biomethane offers added supply but with less ability to ramp production quickly.

Hydrogen blending introduces risks associated with:

- Reduced energy density, affecting constraint resolution;
- Potential exceedance of quality limits if flows are reduced near injection points;
- Modelling accuracy and operator competence with modified gas compositions; and
- Compressor wear and increased planned/unplanned unavailability.

These risks can be mitigated through improved modelling, competence training, gas composition tracking, and updated maintenance strategies.

Temporary or localised operation above 5% hydrogen could offer a new constraint management tool, but can only be adopted after:

- Demonstrating safety through the Gas Safety Case;
- Obtaining exemptions under GS(M)R; and
- Proving that affected assets and end users can tolerate higher concentrations.

Such scenarios remain unlikely in the near term.

Hydrogen blends up to 5% do not significantly alter hazard distances, ignition behaviour, or emergency decision thresholds. Existing PRE procedures, classification of escapes, and evacuation criteria require review with the main updates required relating to:

- Ensuring suitable hydrogen-capable detection equipment is available and correctly calibrated;
- Updating training to reflect blend-specific behaviour; and

- Maintaining consistency in competency frameworks across the Gas Industry.

Several areas such as evacuation distances, venting, flaring, flow stopping, and ignition studies need continued research, some of which is underway through ongoing NIA projects and hydrogen trials. This evidence will be essential for future updates to NTS emergency and operational procedures.

8. Flow assessment

To facilitate a smooth transition to accepting hydrogen blend within the NTS, it is expected that National Gas Transmission will have the systems and processes embedded within the business ahead of hydrogen production coming online; preparedness in National Gas Transmission and hydrogen production timelines should be aligned.

At a conceptual and planning stage, a more detailed understanding of the mixing that could and will occur in the NTS is required for managing hydrogen concentration levels within feeders or sections of the network. Exploring the potential hydrogen blend injection points with the pipeline connectivity of sensitive users would need to be undertaken by engineers with a detailed understanding of the NTS and could result in modifications to equipment and a reconfigured operation of the NTS. The ability to both predict and track the changing gas composition within the NTS is essential for the optimal operational management of the system and to ensure that the gas composition arriving at an offtake is understood in real-time.

The free market approach to hydrogen blend injection point connections could have the potential to constrain any further blend injection, both in the NTS and lower pressure systems, because the resulting gas blend is based on the specific pressure and flow conditions and so should be avoided.

The potential sensitivity to a hydrogen blend (fixed and variable) on sensitive customers should be understood in more detail. Feasibility studies have been undertaken that have considered the impact on equipment. Matching the output from these studies more closely with future operational planning of a blended hydrogen NTS will identify any restrictions in operation and allow mitigation options to be developed.

15 RECOMMENDATIONS

The following recommendations are suggested to develop a more detailed understanding of the topics discussed in this report and the effect on the NTS.

Key recommendations from the storage review are:

1. [redacted]
2. [redacted]
3. [redacted]

Key recommendations for the constraint tool and emergency response frameworks review are that:

4. To expand the understanding and implications of planned and unplanned unavailability of compressors it is recommended that further work is undertaken regarding revised assumptions related to compressor maintenance intervals and failure probability models.

Key recommendations for the control and transportation of gas through the NTS are that:

5. Undertake a focused study to provide a detailed understanding of the impact that a free market approach to hydrogen blend injection point connections has the potential to constrain any further blend injection, both in the NTS and lower pressure systems.
6. Undertake a focused study combining the conclusions from previous feasibility studies on the impact that hydrogen blend has on equipment with the future operational planning of a blended hydrogen NTS to help identify any restrictions in operation and allow mitigation options to be developed.
7. [redacted]

About DNV

DNV is the independent expert in risk management and assurance, operating in more than 100 countries. Through its broad experience and deep expertise DNV advances safety and sustainable performance, sets industry benchmarks, and inspires and invents solutions.

Whether assessing a new ship design, optimizing the performance of a wind farm, analyzing sensor data from a gas pipeline or certifying a food company's supply chain, DNV enables its customers and their stakeholders to make critical decisions with confidence.

Driven by its purpose, to safeguard life, property, and the environment, DNV helps tackle the challenges and global transformations facing its customers and the world today and is a trusted voice for many of the world's most successful and forward-thinking companies.