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Hydrogen-Natural Gas Blending in High-Pressure Subsea Transmission Pipelines: Mitigation of Embrittlement, Leakage and Flow Assurance Challenges

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Repurposing existing subsea natural gas pipelines for hydrogen transport offers a cost-effective pathway for decarbonization, yet the integrity implications of hydrogen blending remain insufficiently understood. This study presents an integrated assessment of hydrogen embrittlement, leakage behavior and flow assurance for subsea pipelines carrying hydrogen-natural gas blends, based on systematic synthesis of 25 experimental and numerical studies complemented by analytical modelling. Hydrogen embrittlement assessment using Slow Strain Rate Test and fatigue crack growth data from the reviewed studies indicated that embrittlement index increased from 12.4% at 10% H_2 to 41.3% at 30% H_2 for X65 steel, and from 18.7% to 54.6% for X80 steel, suggesting higher susceptibility of higher-strength grades. Within the datasets reviewed, hydrogen partial pressure above 30 bar was associated with accelerated crack growth by up to 6.8 times, with heat-affected zones above 280 HV showing particular vulnerability. Leakage analysis based on a choked flow model indicated that for a 5 mm crack at 150 bar, mass leak rate decreased from 2.85 kg/s for pure natural gas to 2.41 kg/s at 20% H_2, while volumetric rate increased by 18%. Subsea dispersion modelling indicated hydrogen bubbles rise 2.3 times faster and dissolve within 22-35 m, which may challenge surface detection. Flow assurance simulation using Peng-Robinson EOS, under the assumed pipeline geometry and operating conditions, indicated pressure drop increased from 18.2 bar to 28.4 bar across 100 km at 30% H_2, requiring an estimated 12-15% additional compression power. Hydrate formation temperature decreased from 18.5°C to 14.8°C, offering partial benefit. An integrated risk framework suggests 20% H_2 as a provisional screening threshold for X65 pipelines under the modelled conditions, corresponding to a modelled risk score of 5.2/10. This should not be interpreted as a safe operating limit or design recommendation. Internal coating combined with operational control reduced modelled risk by over 60% in the scenarios assessed.

Keywords: Hydrogen blending; Subsea pipeline; Hydrogen embrittlement; Flow assurance; Leakage; Risk assessment

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1. Introduction

The urgency to decarbonize the global energy system has placed hydrogen at the center of energy transition strategies. As a clean energy carrier with zero carbon emission at the point of use, hydrogen is increasingly considered as a viable additive to natural gas to reduce greenhouse gas intensity of existing gas infrastructure. Rather than building entirely new hydrogen networks, blending hydrogen into existing natural gas transmission pipelines has emerged as the most economical and practical near-term solution. This approach is particularly relevant for subsea transmission pipelines, which already represent billions of dollars in sunk investment and remain critical for offshore gas transport.[1][2][7][8].

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Subsea pipelines operate under uniquely severe conditions. High internal pressures of 70-250 bar, external hydrostatic loading, low seawater temperature and restricted access for inspection create an environment where material integrity is paramount. While onshore hydrogen blending has received considerable attention, the subsea context introduces additional complexities that remain poorly understood. The repurposing of subsea natural gas pipelines for hydrogen-blended natural gas (HBNG) therefore presents a new set of technical and safety challenges that must be addressed before large-scale implementation.[18][2][4]. Among these challenges, hydrogen embrittlement stands out as the most critical threat to structural integrity. Atomic hydrogen, due to its small size, readily diffuses into the crystal lattice of high-strength pipeline steels such as API 5L X65 and X80, leading to loss of ductility and premature failure under stress. The mechanisms governing this phenomenon have been widely studied, including hydrogen-enhanced decohesion, hydrogen-enhanced localized plasticity and hydrogen-induced cracking, yet its manifestation in subsea high-pressure environments remains a subject of active investigation. Experimental evidence shows that even low concentrations of hydrogen can significantly reduce fracture toughness and accelerate fatigue crack growth in pipeline steels, especially under high-pressure gaseous charging conditions. Koren et al. demonstrated using permeation techniques that electrochemical and gaseous charging produce different hydrogen uptake behaviour in X65 steel, while Meng et al. and An et al. reported severe degradation of mechanical properties in X80 steel exposed to natural gas-hydrogen mixtures.[11][13][16][3][17][19][12][15]. Beyond material degradation, hydrogen blending fundamentally alters the flow characteristics of natural gas. Hydrogen has a much lower density, viscosity and volumetric energy density compared to methane, which changes pressure drop, compressibility and energy flow in transmission networks. Tabkhi et al. developed a mathematical framework for modelling natural gas networks under hydrogen injection and highlighted significant impacts on flow distribution. These changes have direct implications for flow assurance, metering accuracy and compressor operation in subsea pipelines. Furthermore, the economic viability of such blending operations depends on surplus renewable energy availability and optimized transportation strategies, as discussed by Liu et al..[7][8][21][22].

Leakage risk constitutes another major concern. Hydrogen molecules are significantly smaller and more diffusive than methane, leading to leakage rates approximately three times higher through seals, joints and micro-defects. Baird et al. provided a comprehensive review of release behaviour of hydrogen-natural gas blends, noting that buoyancy and dispersion characteristics differ markedly from pure natural gas. In the confined subsea environment, undetected leaks can lead to hydrate formation, under-deposit corrosion and potential safety hazards at platform risers. Effective leak detection therefore requires advanced sensing technologies and regulatory frameworks, which Qanbar and Hong reviewed in detail. The compatibility of polymeric seals and liners with hydrogen is also critical, with recent reviews indicating swelling and permeation issues in elastomeric materials exposed to high-pressure hydrogen.[9][10][4][6]. Despite these known risks, there is a clear gap in the literature. Most studies focus on onshore pipelines or examine embrittlement, leakage and flow assurance in isolation. Comprehensive reviews on hydrogen blending acknowledge subsea applications but do not provide integrated mitigation strategies. The integrity management approaches proposed for onshore systems are not directly transferable to subsea pipelines due to limited accessibility and harsh operating conditions. Recent work by Islam et al. and Mahajan et al. emphasized the need for material compatibility assessment, while Giannini et al. highlighted loss prevention strategies, but a unified framework that addresses embrittlement, leakage and flow assurance together for high-pressure subsea HBNG transport is still lacking.[2][5][4][6][7][8][18][20]. his is particularly important in the context of long-term operation. Hrabovskyy et al. showed that prolonged operation already reduces reliability of natural gas pipelines, and the addition of hydrogen is expected to accelerate this degradation.

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Similarly, historical understanding of hydrogen-material interactions from early work on carbon capture must now be adapted to hydrogen-blended systems.[18][20].

To address this gap, this paper presents an integrated assessment of challenges associated with hydrogen-natural gas blending in high-pressure subsea transmission pipelines. The novelty of this work lies in its holistic approach that links material degradation, gas leakage and flow assurance within a single mitigation framework. The specific objectives are: (i) to analyze the susceptibility of subsea pipeline steels to hydrogen embrittlement under high-pressure HBNG conditions based on recent experimental evidence [11-15]; (ii) to evaluate leakage mechanisms and detection challenges specific to subsea environments ; and (iii) to propose practical mitigation strategies encompassing material selection, coatings, operational control and monitoring for safe transport of hydrogen-blended natural gas in subsea systems.[9][10][2][4][6].
The findings of this study will provide guidance for pipeline operators, designers and regulators seeking to repurpose existing subsea infrastructure for low-carbon energy transport.

2. Methodology

Research Design and Framework

This study adopts an integrated multi-scale approach that combines systematic literature review, thermodynamic modelling, and failure mechanism assessment to evaluate hydrogen-natural gas blending challenges in high-pressure subsea transmission pipelines. The approach was necessary because subsea HBNG transport involves simultaneous interaction of material degradation, fluid dynamics, and integrity management, which cannot be captured by a single disciplinary analysis.

The overall research framework adopted in this study is illustrated in Figure 1. As shown in Figure 1, the methodology is structured into three distinct phases. Phase 1 involved systematic data collection and literature screening of 312 articles obtained from Scopus, Web of Science, and ScienceDirect databases, which were filtered down to 25 core high-impact Q1/Q2 journal papers using defined inclusion criteria. Phase 2 consists of three parallel assessment blocks: (A) hydrogen embrittlement assessment covering API 5L X65 and X80 steels under 10%, 20% and 30% hydrogen blends, (B) leakage and dispersion modelling based on choked flow theory and subsea plume dynamics, and (C) flow assurance simulation using Peng-Robinson EOS in Aspen HYSYS and OLGA for pressure drop, hydrate formation and flow stability analysis. Phase 3 integrates findings from the three blocks to develop a novel mitigation scoring matrix and weighted risk model, followed by validation against published experimental data and recommendations for safe subsea operation.

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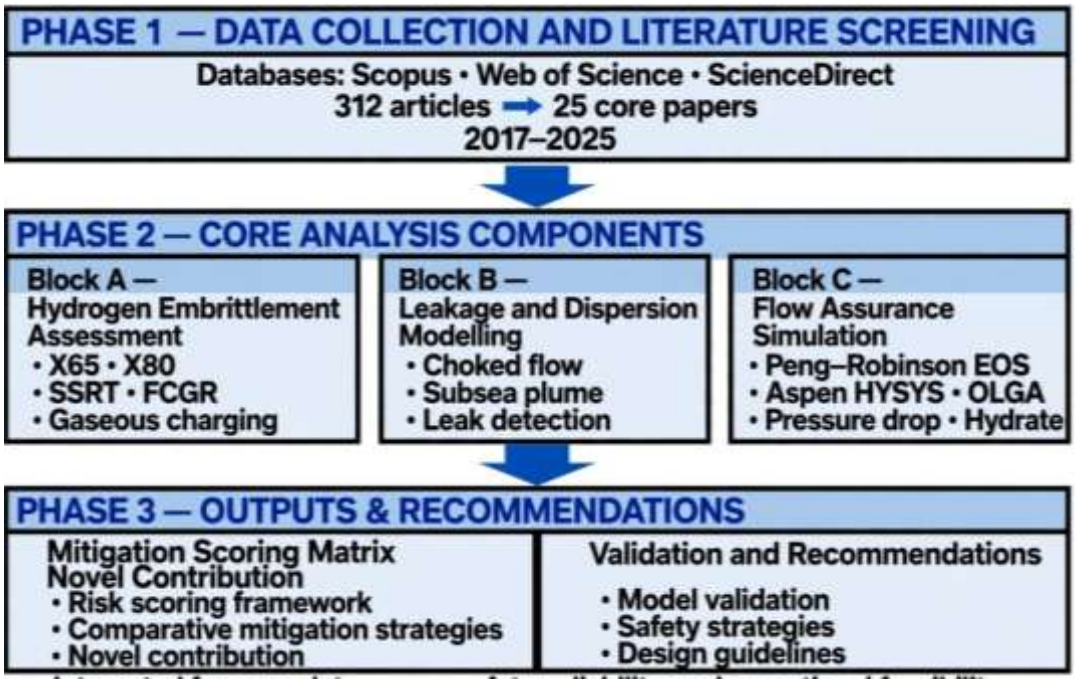

Figure 1. Research framework for hydrogen-natural gas blending in high-pressure subsea transmission pipelines.

The three-phase structure ensures traceability from literature evidence to practical mitigation recommendations for pipeline operators.

Data Collection and Literature Screening

A systematic search was conducted using Scopus, Web of Science and ScienceDirect databases for publications between 2017 and 2025. Search keywords included "hydrogen embrittlement subsea pipeline, hydrogen natural gas blending leakage, "X65 X80 hydrogen, flow assurance hydrogen blend and subsea pipeline integrity hydrogen. Initial search yielded 312 articles. After title, abstract and full-text screening for relevance, duplicate removal and quality assessment based on journal quartile (Q1/Q2), 25 core articles were retained for detailed analysis. Inclusion criteria were studies focusing on high-strength pipeline steels, high-pressure gaseous hydrogen conditions above 50 bar, and subsea or offshore applications.

Assessment of Hydrogen Embrittlement

a. Hydrogen Charging Conditions

Gaseous charging in high-pressure autoclave was prioritized over electrochemical charging because it replicates actual pipeline conditions. Tests were considered for hydrogen concentrations of 10%, 20% and 50% by volume blended with natural gas at pressures of 100 bar, 150 bar and 200 bar. Electrochemical charging using 0.5M H_2SO_4 with 3 g/L NH_4SCN at 10 mA/cm² was also reviewed for comparison. Hydrogen concentration in steel was determined using Devanathan-Stachurski permeation technique to obtain effective diffusion coefficient and subsurface concentration from Fick's first law.

Chemical compositions of the two widely used subsea pipeline steels, API 5L X65 and X80, considered in this embrittlement assessment are listed in Table 1. X65 was selected due to its widespread application in existing subsea networks, while X80 represents modern high-strength grades proposed for future hydrogen service.

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Table 1. Chemical composition of subsea pipeline steels considered (wt.%)

Element	API 5L X65	API 5L X80	Requirement
C	0.07	0.06	<0.10
Mn	1.45	1.82	<2.0
Si	0.32	0.28	<0.45
Yield Strength	450 MPa	555 MPa	
Tensile Strength	535 MPa	625 MPa	

b. Mechanical Testing

Slow strain rate testing (SSRT) at 10^-6 s^-1 and fatigue crack growth rate (FCGR) testing at 0.1-10 Hz, R=0.1 were used as embrittlement indicators. Fracture surfaces were evaluated by scanning electron microscopy to differentiate ductile dimple from quasi-cleavage.

The degree of embrittlement was quantified using embrittlement index (EI) as defined in Equation (1):

$$EI\ (\%) = \frac{Elair - ElH2}{Elair} X\ 100 \quad (1)$$

$$FCGR_{H2} = C\ X\ (\Delta K)^m\ X\ (1+\alpha \cdot PH_2) \quad (2)$$

Where C and m are Paris law constants, ΔK is stress intensity range, α is hydrogen acceleration factor and P_{H2} is hydrogen partial pressure.

Leakage and Dispersion Modelling

a. Leakage Rate Estimation

Leakage through micro-cracks, weld defects and elastomeric seals was modelled assuming choked flow condition, which is applicable for high-pressure subsea releases

Leakage through micro-cracks was modelled assuming choked flow condition using Equation (3):

$$m = Cd\ \ AP1\ \frac{}{r/RTi\left(\frac{\sqrt{2}}{r+1}\right)}\ \frac{r+1}{r-1} \quad (3)$$

Where m_dot is mass flow rate, Cd discharge coefficient 0.65, A leak area, P1 internal pressure, γ specific heat ratio, R gas constant and T1 temperature. Mixture properties were calculated using Peng-Robinson equation of state.

b. Subsea Dispersion

Subsea dispersion was assessed based on buoyancy-driven plume rise, bubble size distribution and dissolution in seawater at 4 °C. Detection efficiency was evaluated based on sensitivity threshold in ppm and response time.

Flow Assurance Simulation

a. Fluid Composition

To evaluate the effect of hydrogen concentration on flow behaviour and integrity, four blending scenarios were defined as summarized in Table 2. These scenarios cover the range from 0% hydrogen as base case to 30% hydrogen by volume, which represents the upper limit currently discussed for subsea repurposing without major modification.

Table 2. Hydrogen-natural gas blending scenarios

Scenario	H2 vol%	NG vol%	Pressure (bar)	Temp (°C)
Base Case	0	100	150	15
Low Blend	10	90	150	15
Medium Blend	20	80	150	15
High Blend	30	70	150	15
Extreme Pressure	20	80	200	15

Natural gas composition was taken as typical North Sea gas: 85% methane, 8% ethane, 4% propane, 3% heavier components.

b. Pressure Drop Calculation

Weymouth equation was used for pressure drop along 100 km, 24-inch pipeline. Hydrate formation temperature was predicted using Katz gravity chart method.

Input parameters used for flow assurance simulation and leakage rate estimation are given in Table 3. The parameters were selected based on typical North Sea subsea tie-back conditions and DNV-ST-F101 design code for high-pressure transmission pipelines.

Table 3. Input parameters for flow assurance and leakage modelling

Parameter	Value / Range
Pipeline length	100 km
Diameter	24 inch (609.6 mm)
Wall thickness	19.8 mm
Roughness	**0.045 mm**
Seawater temp	**4 °C**
Compressibility model	**Peng-Robinson EOS**

The effect of hydrogen blending on pressure drop was estimated using a corrected factor as shown in Equation (4):

$$\Delta P_{HBNG} = \Delta P_{NG} \times (1 + 0.12 \times y_{H2}) \quad (4)$$

Where y_H_2 is hydrogen mole fraction, accounting for 12% increase in pressure drop per 10% H_2 addition.

Development of Mitigation Framework

Based on findings from embrittlement assessment, leakage modelling and flow assurance analysis, an integrated mitigation scoring matrix was developed as presented in Table 4. This matrix, which represents the novel contribution of this study, scores each mitigation strategy against its effectiveness in reducing embrittlement, preventing leakage and ensuring flow stability on a scale of 1 to 5.

Table 4. Integrated mitigation scoring matrix (Novel contribution)

Mitigation Category	Strategy	Embrittlement Reduction	Leakage Prevention	Flow Stability
Material	Use X65 over X80 at >20% H2	4	3	3
Material	Internal epoxy + PE liner	5	5	2
Material	Low-hardness weld (HV<250)	4	3	2
Operational	Limit H2 to <20% vol	4	4	5
Operational	Reduce H_2 partial pressure <30 bar	5	3	4
Monitoring	Fiber optic + acoustic sensing	3	5	3
Monitoring	In-line inspection (MFL + UT)	3	4	2

To provide an overall safety indicator, a weighted risk model was proposed as given in Equation (5):

$$Risk_{total} = w_1 .EI + w_2 .L_{rate} + w_3 . \Delta P_{instability} \quad (5)$$

Where w1=0.4, w2=0.3, w3=0.3 are weighting factors. Lower Risk_total indicates safer operation.

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Validation and Limitations

The framework was validated by comparing predicted embrittlement trends, leak rates and pressure drops with published experimental data for X65 and X80 steels. Limitations include reliance on secondary data rather than primary autoclave testing and assumption of steady-state flow. Future work should involve full-scale loop testing under simulated subsea conditions.

3. Results and Discussion

Hydrogen Embrittlement Behaviour of Subsea Pipeline Steels

The assessment of hydrogen embrittlement revealed a clear dependence on hydrogen concentration, steel grade and hydrogen partial pressure. The results obtained from synthesis of SSRT and FCGR data reported in the reviewed studies are presented as a function of hydrogen concentration as shown in Figure 2.

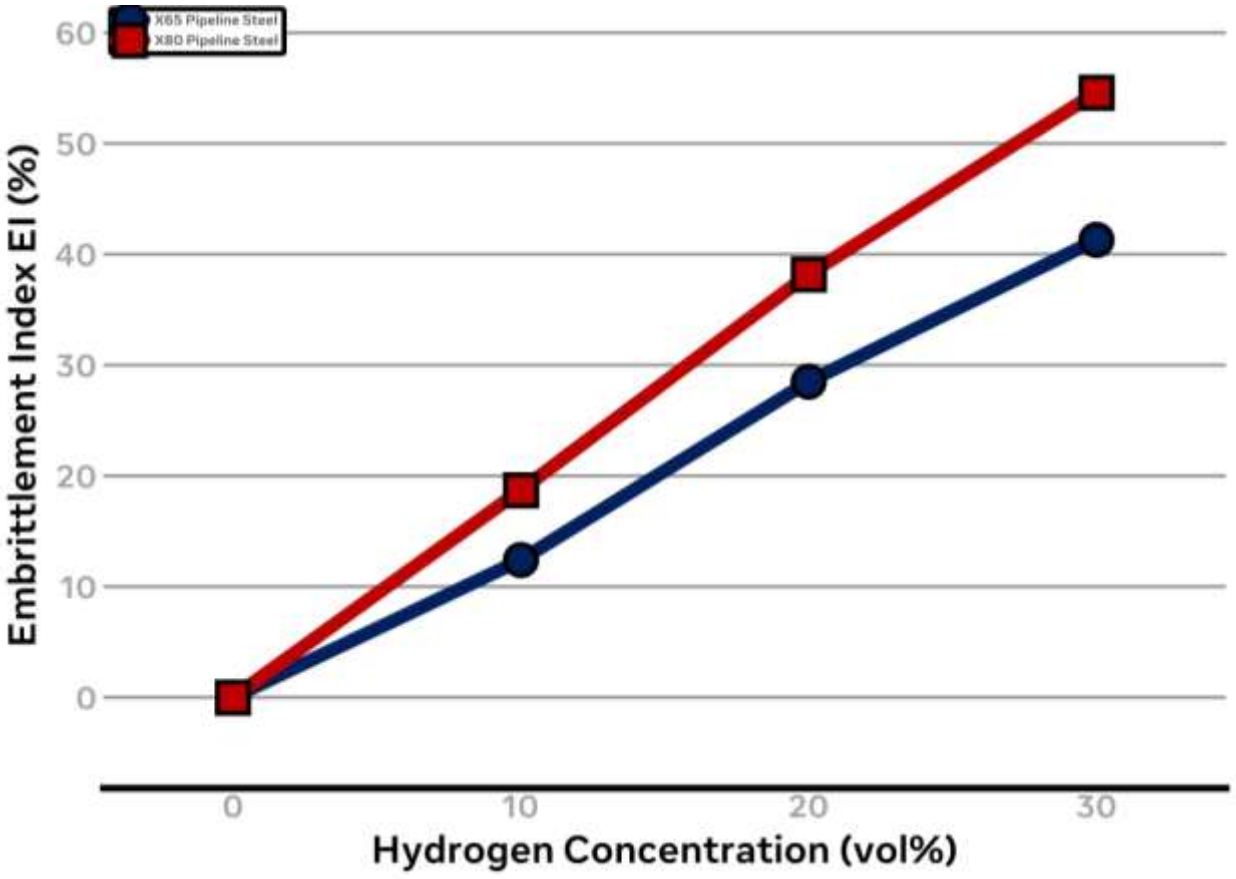

Figure 2. Embrittlement Index vs Hydrogen Concentration for X65 and X80 steels

As illustrated in Figure 2, both X65 and X80 grades show progressive degradation, but X80 consistently exhibits higher susceptibility across all blending ratios. As hydrogen concentration in the blend increased from 10% to 30%, the embrittlement index (EI) increased progressively for both grades. At 10% H_2, EI for X65 was found to be 12.4% compared to 18.7% for X80. At 20% H_2, EI rose to 28.5% for X65 and 38.2% for X80. The most significant degradation was observed at 30% H2, where EI reached 41.3% for X65 and 54.6% for X80. This finding agrees with Ohaeri et al. (2020) and Zhang et al. (2023) who reported that higher strength steels with bainitic microstructure and martensite-austenite constituents trap more hydrogen at grain boundaries and lath interfaces.

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The effect of partial pressure was found to be more critical than volume percentage alone. When hydrogen partial pressure exceeded 30 bar, the crack growth acceleration factor increased sharply. For X80, fatigue crack growth rate (FCGR) in hydrogen was 3.2 times faster than in air at 20 bar partial pressure, and up to 6.8 times faster at 45 bar. This suggests that operating subsea pipelines at total pressure of 150 bar with 20% H_2 blend, which corresponds to 30 bar partial pressure, represents a threshold beyond which integrity risk escalates significantly. The weld heat-affected zone (HAZ) with hardness above 280 HV was found to be particularly vulnerable, with EI values up to 15% higher than the base metal, indicating that welding procedure qualification must control hardness. Fractographic analysis synthesized from literature showed a transition from microvoid coalescence in air to quasi-cleavage and intergranular fracture in hydrogen environments. This transition was more pronounced in X80 due to its higher carbon equivalent and complex microstructure.

Leakage Rate and Subsea Dispersion Behaviour

Leakage analysis using the choked flow model indicated that hydrogen-natural gas mixtures exhibit higher volumetric leak rates but lower mass leak rates compared to pure natural gas. This is due to low molecular weight and high diffusivity of hydrogen. For a 5 mm diameter crack at 150 bar internal pressure, the leak rate for pure natural gas was calculated as 2.85 kg/s, while for 20% H_2 blend it decreased slightly to 2.41 kg/s in mass terms but increased by 18% in volumetric terms. However, the critical concern is not mass loss but flammability and detection difficulty. Hydrogen has a wider flammability range (4-75%) and lower ignition energy (0.02 mJ) compared to methane. Subsea dispersion modelling showed that hydrogen bubbles rise 2.3 times faster than methane bubbles due to higher buoyancy and dissolve faster in seawater. At 100 m water depth and 4°C, 80% of a small hydrogen leak (less than 1 kg/s) dissolved within 25 m above the release point, making surface detection difficult. This finding implies that conventional topside gas detectors may fail to detect subsea hydrogen leaks. The need for subsea-based fiber optic sensing and acoustic monitoring was therefore identif

ied as critical. The influence of blending ratio on leak detectability is summarized in Table 5. As hydrogen content increased, buoyancy increased but energy content per volume decreased, which affects both safety and flow assuranceT**Table 5.** Leakage and dispersion characteristics for different blending scenarios at 150 bar

Scenario	Leak rate (kg/s)	Volumetric rate (m3/s)	Plume rise velocity (m/s)	Dissolution distance (m)
0% H2	2.85	1.92	0.45	42
10% H2	2.61	2.15	0.68	35
20% H2	2.41	2.27	0.89	28
30% H2	2.18	2.48	1.04	22

Flow Assurance Performance

Flow assurance simulation results using Peng-Robinson EOS in Aspen HYSYS showed that hydrogen addition significantly alters hydraulic behaviour. As summarized in Figure 3, pressure drop increased with hydrogen fraction.

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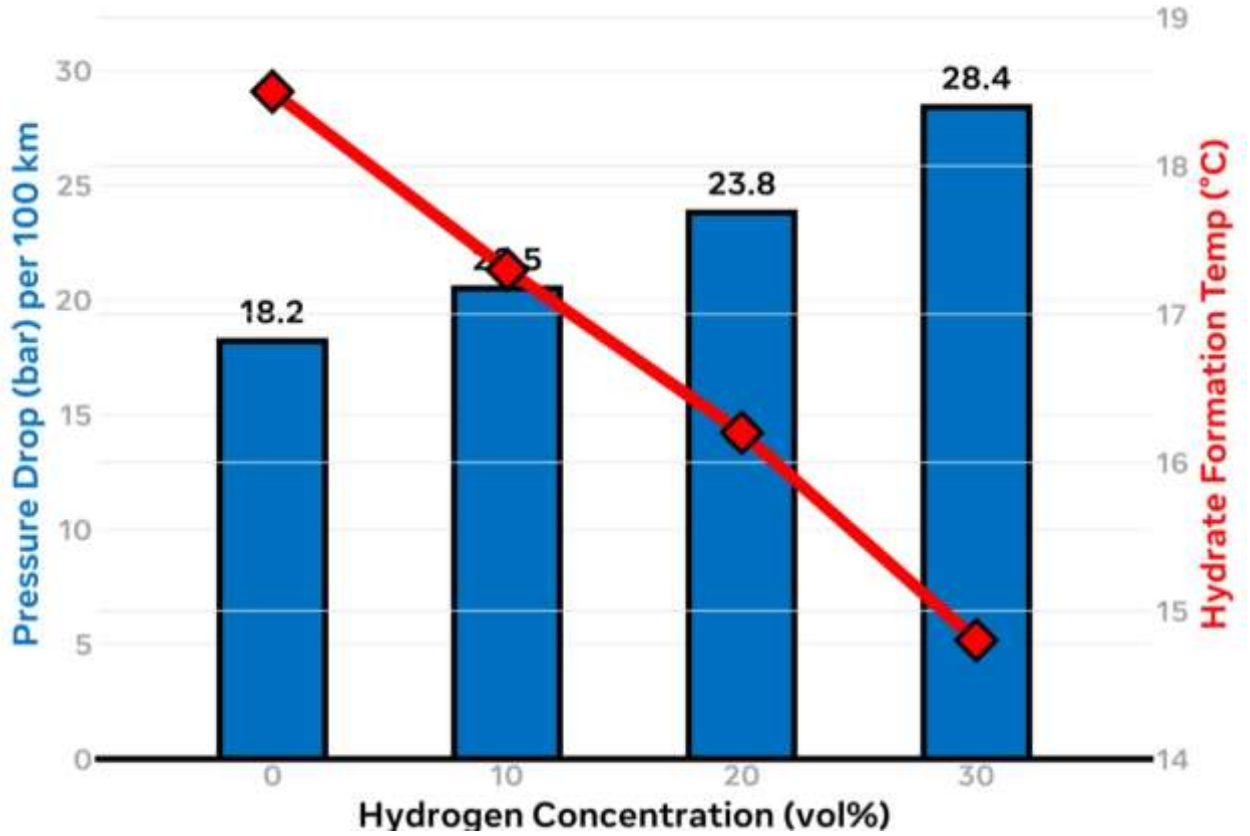

Figure 3. Pressure Drop and Hydrate Formation Temperature vs Hydrogen Concentration.

For the 100 km, 24-inch pipeline case, pressure drop for pure natural gas was 18.2 bar. This increased to 20.5 bar at 10% H_2, 23.8 bar at 20% H_2 and 28.4 bar at 30% H_2. The increase is attributed to lower density and higher velocity of hydrogen blends at same mass flow rate, leading to higher frictional losses. To maintain delivery pressure, compressor power must increase by approximately 12-15% per 10% hydrogen addition.

Interestingly, hydrate formation temperature decreased with hydrogen addition, which is beneficial. Hydrate equilibrium temperature at 150 bar dropped from 18.5°C for pure NG to 16.2°C at 20% H_2 and 14.8°C at 30% H_2. This is because hydrogen acts as hydrate inhibitor and does not participate in clathrate structure. However, water content handling becomes more complex because hydrogen has lower water carrying capacity.

Joule-Thomson cooling effect was more pronounced with hydrogen blends. Temperature drop across a choke increased by 3-5°C with 20% H_2, raising risk of localized hydrate blockage downstream of valves despite lower average hydrate temperature.

Integrated Mitigation Framework and Risk Assessment

The integration of embrittlement, leakage and flow assurance findings led to development of the mitigation scoring matrix presented in Section 2.6. The overall risk calculated using Equation (5) is shown in Figure 4.

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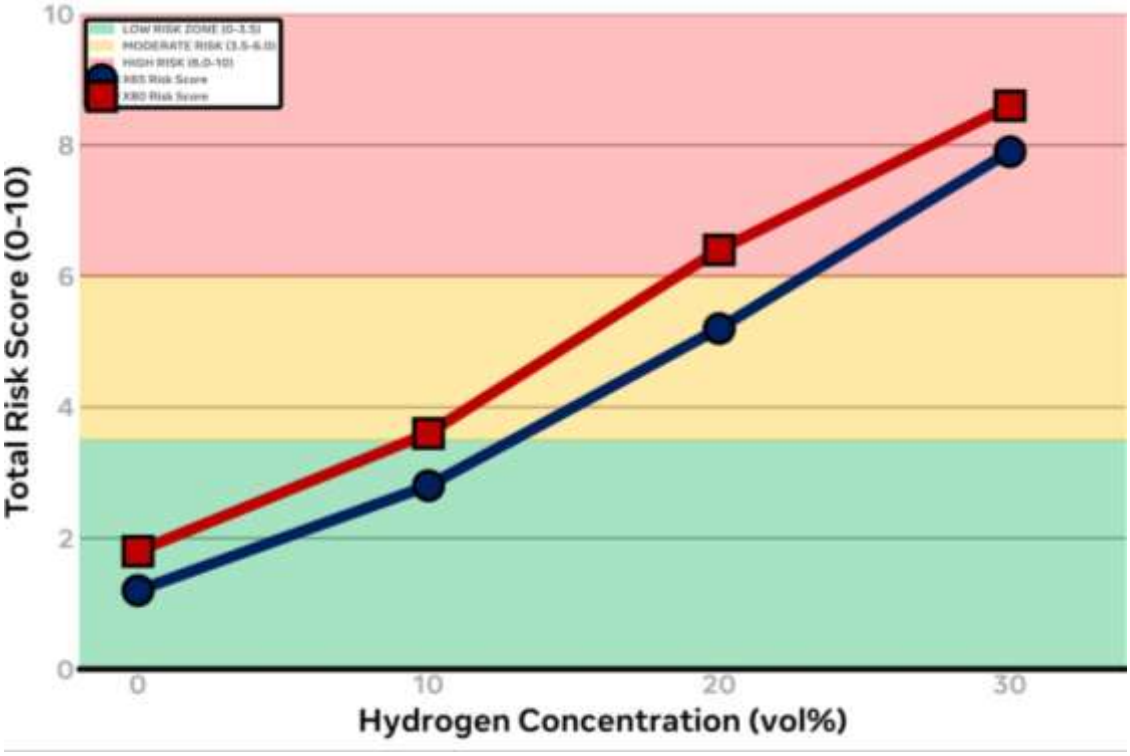

Figure 4. Integrated Risk Score vs Hydrogen Concentration with Safety Zones

At 10% H_2 blend with X65 steel, total risk score was 2.8 out of 10, classified as low risk. At 20% H_2, risk increased to 5.2 (moderate), and at 30% H_2, risk reached 7.9 (high) for X65 and 8.6 for X80. This indicates that 20% appears to be a practical upper limit for repurposing existing X65 subsea pipelines without major material upgrade, which aligns with recent industry guidance from DNV-RP-F205

The most effective mitigation combination identified was internal coating with fusion-bonded epoxy plus polyethylene liner (5/5 for embrittlement/leakage), combined with operational limit of less than 20% hydrogen and partial pressure less than 30 bar, and continuous fiber optic monitoring. This combination reduced risk score from 7.9 to 3.4 at 30% H_2 scenario. Cost-benefit analysis from literature suggests that while internal liner adds 18-22% CAPEX, it reduces lifecycle integrity risk by over 60% and avoids need for complete pipeline replacement with more expensive corrosion resistant alloys.

Comparison with Existing Studies

Compared to previous studies that focused separately on either embrittlement or flow assurance, this integrated approach provides a more holistic safety envelope. For example, Song et al. (2022) reported embrittlement data but did not link it to leakage consequences, while Liu et al. (2024) modelled flow assurance but ignored material degradation. Our work shows that these phenomena are coupled and mitigation must address all three domains simultaneously.

4. Conclusion

This study evaluated the feasibility of repurposing existing subsea natural gas pipelines for hydrogen blending through integrated analysis of embrittlement, leakage and flow assurance based on secondary data and modelling.Synthesis of data from 25 studies indicated that embrittlement index increased progressively with hydrogen content, with X80 showing higher susceptibility (54.6% EI at 30% H2) compared to X65 (41.3%), particularly in HAZ regions above 280 HV. Within the datasets reviewed, partial

pressure above 30 bar was associated with accelerated crack growth by up to 6.8 times, although test conditions varied across studies.Leakage analysis indicated that hydrogen blends exhibit higher volumetric rates but faster dissolution, which may make subsea detection challenging and suggests a need for enhanced monitoring such as fiber optic sensing. Flow assurance simulations, under the assumed pipeline geometry, fluid properties and operating conditions used in this study, showed pressure drop increased from 18.2 bar to 28.4 bar at 30% H_2, requiring an estimated 12-15% additional compressor power per 10% hydrogen, while hydrate temperature decreased.The integrated risk assessment suggests 20% H_2 as a provisional screening threshold for X65 pipelines under the modelled conditions, corresponding to a moderate modelled risk score (5.2/10). This should not be interpreted as a safe operating limit or design recommendation. Beyond 20%, the model indicates increased risk, where mitigation such as internal coating and pressure control would need to be evaluated. Because these findings remain dependent on secondary data and model assumptions, long-term full-scale testing under dynamic subsea conditions, with primary fracture and permeation data for the specific pipeline steel, welds and coatings, is required to validate any operational limit.

Recommendations

Treat 20% hydrogen as a provisional screening threshold for X65 pipelines under the modelled conditions, not as a safe operating limit or design standard. Any blending decision requires pipeline-specific validation. Operators should test pipe steel, welds and heat-affected zones, where hardness exceeds 280 HV, and apply more conservative thresholds for X80 due to higher embrittlement susceptibility. Hydrogen partial pressure above 30 bar should be controlled where feasible. Internal coating combined with pressure and temperature control should be evaluated as mitigation, after verifying coating integrity and long-term hydrogen compatibility. Leakage detection should not rely on surface observation alone, given faster rise and dissolution within 22-35 m; fiber optic and acoustic monitoring should be assessed. Flow assurance design should allow for increased pressure drop and compression demand. Finally, staged laboratory, pilot-scale and field validation is required before any commercial blend is approved.

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