Requalifying Existing Gas Pipelines for Hydrogen Service

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GAS

Field compression
Gas processing
Pipelines:
- Infield
- Gathering
- Distribution
- Transmission

Refinery brownfield

RENEWABLES

Civil balance of plant
HV cable installation
O&M building
Roads
BESS
Thermal
Hydrogen

WATER

Trunk Transfer pipelines
Water pump stations
Water storage facilities
Pressure relieving stations

MINING

Slurry pipeline
Earthworks
Facilities
Recycled water

HV LINES

Civil scope of works including project management

Defence

Fuel tanks
Pavement

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Hydrogen Infrastructure	Hydrogen pipeline	Facilities	Engineering Commissioning	Electrical HV

Background

- Hydrogen is a highly versatile and environmentally friendly fuel that has the potential to significantly reduce carbon emissions in various sectors of the economy, such as transportation and energy production. It is a clean-burning fuel that produces only water when burned, making it an ideal alternative to fossil fuels.

- Repurposing existing gas pipelines for hydrogen transportation is a cost-effective solution that can save time and money. Still, it requires a clear and regulated requalification process to maintain pipeline integrity. This involves a detailed evaluation of the pipeline's current condition and ability to safely handle hydrogen gas.

- In this presentation, we will discuss how to enhance the current requalification approach for hydrogen service, including more detailed inspections and testing protocols.

Current Codes and Standards

Mechanical and safety codes applicable to hydrogen application:

- **ASME B31.12** Hydrogen Piping and Pipelines
- **AS 2885** High Pressure Pipeline Systems Standard
- **EIGA IGC Doc 121/14** Hydrogen Transportation Pipelines
- **NFPA 2,** Hydrogen Technologies Code
- **ASME Section VIII, Division 3, Article KD-10** Special Requirements for Vessels in Hydrogen Service
- **ISO 11114-4** Test methods for selecting steels resistant to hydrogen embrittlement
- **AFPM Doc AM-12-50** Recommended Practice for Valves Used in Hydrogen Service
- **AS 19880.3:2020** Gaseous hydrogen - Fueling stations Valves
- **NACE Standard TM0284** test method for evaluating the resistance of pipeline and pressure vessel steels to HIC
- **NACE MR0175 / ISO 15156** addresses requirements for selecting and qualifying service used in H2S-containing environments.

Current Research
APA and German Studies

APA Hydrogen Conversion Technical Feasibility Study – Is currently testing on sections of its Parmelia Gas Pipeline (43 km Section of the 416 km Pipeline)

- The purpose of their study is to comprehend and quantify the impact hydrogen has on the pipeline material, ensuring that the safety of the pipeline can be appropriately assessed.
- A series of tests were performed on the samples including; chemical composition, tensile tests, DWTT and charpy v-notch, fatigue tests and fracture tests.
- The results were positive confirming that pipeline threats are almost unchanged by changing the fluid, and confirmed that pipe steel generally met the requirements of ASME B31.12.

DVGW Project SyWest H2 – Performed fracture-mechanical tests on cross-sections of typical pipeline steel grades to investigate the suitability for hydrogen transmission

- To allow hydrogen transmission within the German gas grid, it was critical to obtain a full assessment of the hydrogen suitability of different steel components.
- The results showcased that all pipeline steel grades investigated are fundamentally suitable for hydrogen transmission.

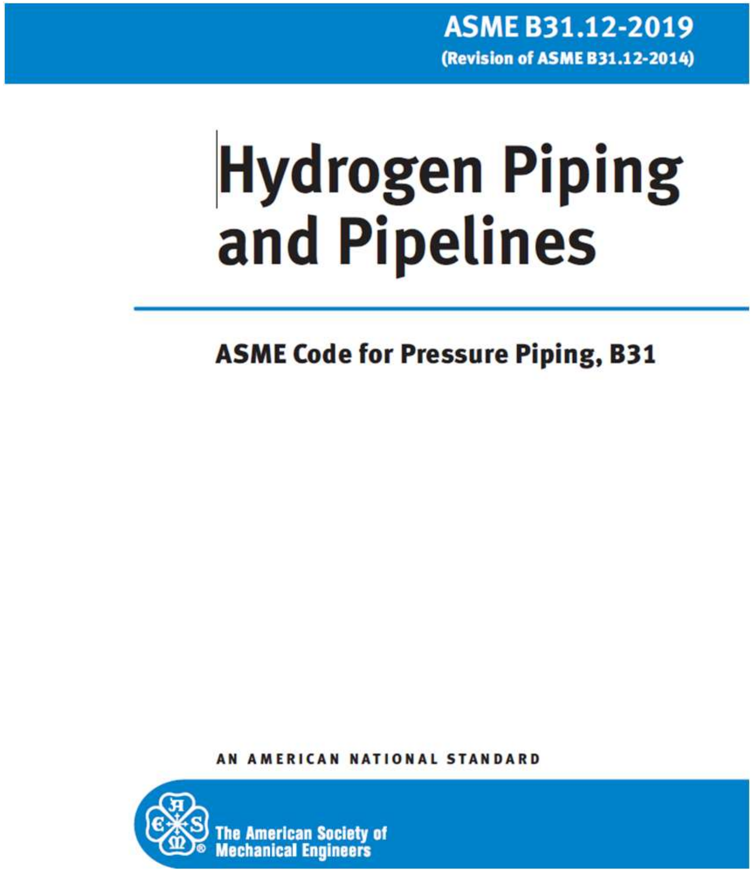
ASME Fracture Control Mechanism

Design Options

The ASME B31.12 standard offers two design options for hydrogen pipelines.

Option A – Prescriptive Design Method

Option B – Performance Based Design Method



ASME Fracture Control Mechanism

Option A – Prescriptive Design Method

Option A is the Prescriptive Design Method, and the Maximum Allowable Operating Pressure (MAOP) is limited to 40-50% of the Sm.

Sm = The maximum allowable operating stress, calculated as SMYS × Hf, where Hf is the material performance factor.

- Fracture toughness testing as per the testing procedures of Annex G of API 5L to ensure that the hydrogen pipe has adequate ductility (Brittle Fracture Control).

- Maximum ultimate tensile strength of your hydrogen pipe and weld shall not exceed 100 ksi (689 Mpa).

- Minimum specified yield strength of your material shall not exceed 70 ksi (483 Mpa).

- Existing hydrogen pipelines not designed to ASME B31.12 shall use Option A for Location Class and MAOP changes.

ASME Fracture Control Mechanism

Option B – Performance Based Design Method

Option B allows the operator to utilise fracture mechanics according to the Article KD-10 of ASME BPVC, Section VIII, Division 3 guidelines to determine if the hydrogen pipe is suitable for its intended purpose. This option can be advantageous as it offers a higher MAOP of up to 72% of Sm.

- Both hydrogen pipe and weld material shall be qualified for adequate resistance to fracture in hydrogen gas at or above the design pressure and at ambient temperature using the applicable rules provided in Article KD-10 of ASME BPVC, Section VIII, Division 3.

- Maximum ultimate tensile strength of hydrogen pipe and weld shall not exceed 110 ksi (758 Mpa).

- Minimum specified yield strength of your material shall not exceed 80 ksi (552 Mpa).

Identifying and Quantifying Existing Pipeline Damages

Pipelines are installed across a multitude of different locations, and hence, are exposed to many different environments. Over a pipelines operating lifetime, defects and damages can accrue, because of the pipeline's environment. These damages impact a pipelines integrity over its operational lifetime and can cause safety issues. There are three key defects of interest; corrosion (metal loss), which can develop into pitting and cracking.

- **Corrosion:** is one of the most crucial defects that impairs pipeline performance, accounting for approximately 30% of all equipment failures. It continuously reduces the wall thickness, quickly accelerating the formation of leaks and pipeline ruptures.

- **Pitting:** Cavities or holes are produced within the material.

- **Cracking:** Pipelines are continuously exposed to environmental impacts, external loading and ground movements, which can produce cracks within the pipe.

Pipeline Damages
Corrosion Types

The different types of corrosion experienced within transmission pipelines have been detailed below:

1. **Uniform Corrosion:** most common within pipelines, propagating uniformly across exposed surfaces.
2. **Pitting Corrosion:** non-uniform corrosion, where the metal pipe is worn away over time, creating small pits.
3. **Galvanic Corrosion:** occurs when a joint between two conductors with differing electrochemical properties while exposed to an electrolytic fluid.
4. **Crevice Corrosion:** localised areas of corrosion occurring at or immediately next to a joint.
5. **Dealloying or Selective Corrosion:** where one or more component in a solid solution are either replaced or lost through electrochemical interactions.
6. **Intergranular Corrosion:** occurring along the grain boundaries.
7. **Microbiologically Influenced Corrosion:** the presence of aerobic or anaerobic bacteria that accelerates any corrosion experienced.
8. **Stress corrosion cracking (SCC):** This is usually an external corrosion phenomenon. Factors that contribute to stress cracking are be hard spots, untempered martensite in weld areas, coating defects, microbiological activity and inadequate or improper cathodic protection schemes.

Microbiologically Influenced Corrosion

- Microbiologically Influenced Corrosion (MIC) is becoming of increasing concern which impacts a multitude of materials and sectors in society.

- MIC has been defined as any corrosion affected by the presence or activity, or both, or microorganisms. Hence, MIC does not describe a single mechanism for corrosion, rather, it is a collective term for a variety of different mechanisms through which microorganisms alter the kinetics of corrosion reactions by their presence or activity.

- There is currently worldwide research being undertaken on the potential impacts of MIC, discussions are disconnected as sharing of information is confidential. This hinders progress, especially when issues with laboratory-based experiments are already prevalent, as they operate under strict anaerobic or aerobic conditions. In reality, the oxygen level would vary.

Non-Destructive Testing (NDT) Methods

NDT methods have been developed for in-line pipeline inspection for pipeline discontinuity detection and safety evaluation. Conventional technologies include;

- Radiographic Testing (RT)
- Ultrasonic Testing (UT)
- Eddy Current Testing (ECT)
- Magnetic Flux Leakage

However, these technologies are only able to be performed on uncovered pipelines, they are not appropriate for buried existing pipelines. Thus, for requalification purposes, in-line service testing becomes the most desirable choice.

- In-Line Service Test -> Intelligent Pigging

Non-Destructive Testing Methods

In-Line Inspection

- Inline inspections are deployed to ensure pipeline fitness-for-service.
- Some ILI companies has recently developed sensors which provide an estimation of the yield strength and tensile strength of every pipe spool, supported and validated by a few carefully selected field verifications based on mobile hardness, steel composition and ball indentation technologies.
- One crucial challenge for ILI in hydrogen pipelines is the impact on the tool by hydrogen itself. The properties of hydrogen pose issues for the current conventional ILI tool designs and configurations which have been optimised for hydrocarbon applications, occurring at pressures ≤ 105 bar and temperatures ≤ 80 °C.

Risks of Hydrogen Damage

Hydrogen Damage – General

- Hydrogen damage is complex and ensuring early-stage hydrogen damage detection is critical for ensuring integrity of the operating pipeline. While operating temperature and hydrogen pressure are the key causes of hydrogen damage, there are a multitude of additional contributing factors including; carbide stability, applied/residual stresses, grain size and weld type.

- It is critical that the impact of introducing hydrogen gas into an existing steel pipeline is understood, as it is our responsibility to ensure the pipeline's operation is both safe and reliable.

- Constant direct contact between a metal pipeline and hydrogen gas will result in dissolved hydrogen atoms diffusing into the steel. While the immediate impact of this may be negligible on the pipeline's operation, with permanent exposure crack propagation is increasingly promoted.

Risks of Hydrogen Damage

- A summary of the defects have been presented (left).
- There are two main causes for deterioration within the pipeline: stress corrosion cracking (SCC) and hydrogen-induced cracking (HIC). Both of these contribute to hydrogen embrittlement (HE), which negatively impacts the mechanical properties of the alloy, with a reduction in the tensile ductility and notched tensile strength. Consequently, promoting hydrogen-assisted fatigue.
- General hydrogen damage can be observed in cracking, specifically type 1 and 2 sulfide stress cracking. This occurs when a loading is applied to the corroded areas.

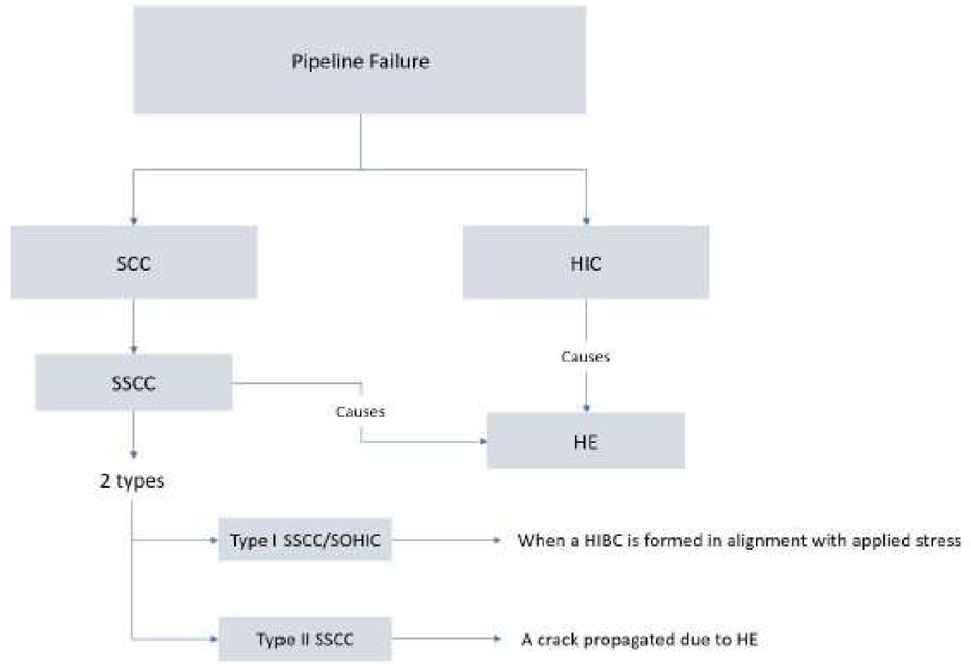


Figure 1. A summary of the types of hydrogen damage seen in pipeline steel.

Risks of Hydrogen Damage

Most commonly HIC is the leading cause for HE resulting in pipeline deterioration.

Hydrogen Induced Cracking (HIC)

The risk with hydrogen cracking is that the internal damage can develop for an extended time prior to detection. It works when atomic hydrogen accumulates at interstitial locations (voids, grain boundaries, dislocations), where hydrogen can recombine to a molecular form. Very high internal pressure is generated at this immediate vicinity, resulting in cracking.

Hydrogen Embrittlement (HE)

This invasion of the metal lattice by individual hydrogen atoms is known as hydrogen embrittlement, and results in the metal-metal atomic bonds being weakened, which has a detrimental effects on the pipeline's mechanical properties. Elongation at failure is strongly impacted by HE.

Hydrogen embrittlement accelerates defect growth under fatigue and fracture toughness. Hence, to guarantee a minimum factor of safety to clients, it is irrefutable that the requalification process is detailed thoroughly.

Other Considerations for Inclusion

Safety Separation Distance

To prioritise safety, as per ASME B31.12, it is recommended that:

- A minimum clearance of 450 mm between every buried hydrogen pipeline and any other existing underground structure is maintained.
- If multiple hydrogen pipelines are placed within the same trench, they must have a vertical separation of at least 150 mm of well-compacted bedding. They must also adhere to a horizontal separation of at least two pipe diameters but no greater than 230 mm.
- Warning tape shall be positioned 150 mm above the service line.
- It is recommended that the pipeline lay above ground whilst installing valves and pressure control stations. However, if this is not plausible, a concrete vault with sufficient ventilation may be appropriate.

Other Considerations for Inclusion

Depth of Cover

It is critical to adjust the current depth of cover requirements for hydrogen transmission. For natural gas pipelines it is standard that the depth of cover is 750-900 mm, however, with the adjustment to hydrogen transmission the recommended depth of cover as per ASME B31.12 shall be:

a) Normal excavation: DOC ≥ 900 mm
b) Rock excavation: DOC ≥ 600 mm
c) Agricultural areas: DOC ≥ 1200 mm

The final DOC will be based on the results of the risk assessment.

Further, a minimum clearance of 450 mm between all buried hydrogen pipelines and any other underground structure must be maintained.

Required Testing for Requalification

When converting steel pipelines from natural gas to hydrogen use, three requirements must be considered:

1. Maximum allowable operating pressure cannot exceed 15168 kPa (2200 psi).

2. A physical sample of the pipe at every 1.6 km of the pipeline is required to determine the chemical and physical analysis of the pipe material if the original mill certificates are unavailable.

3. If the pipe material cannot be quantified by either option above, the MAOP must be selected to limit hoop stress to 40% SMYS of the pipe at all points along the pipeline.

Required Testing for Requalification

These four testing types are methods that can be utilised to examine the safety and structural integrity of the pipeline and identify any leaks throughout. These tests should be undertaken after the required examinations and repairs have been made.

1. Hydrostatic Testing: uses a liquid to pressurise the pipeline for an elected duration, visually inspecting the external surface.

2. Pneumatic Testing: utilises air or gas to pressurise the pipeline for an elected duration of time.

3. Alternate Testing: If both hydrostatic and pneumatic testing methods are not feasible, then only consider an alternative testing method.

4. Sensitive Leak Testing: ensures tightness by conducting a low-pressure leak test throughout the pipeline

When conducting these tests, it must be ensured that only compatible test fluids are used and tested at a high enough pressure to detect leaks without causing damage to the system.

Conclusion

- Requalifying existing pipelines for hydrogen service (up to 100% Hydrogen content) is allowed as per ASME B31.12 and EIGA IGC Doc 121/14; however, both codes' requirements are high-level and restrictive in how conversions can be managed.

- Examples of steels that have been proven for hydrogen gas service are conventional ASTM A106 Grade B, ASTM A53 Grade B, and API 5L Grades X42 and X52 (PSL2 grades preferred), as well as microalloyed API 5L Grade X52.

- Existing pipelines with significant internal MIC or crack-like anomalies are unsuitable for hydrogen service.

- The results of HIPS (Hydrogen in Pipeline Systems) study show that an admixture of up to 10 % by volume of hydrogen to natural gas is possible in some parts of the natural gas system.