HyDelta 3

WP 1B – Asset Management – Repurposing offshore infrastructure

D1b.1 – Pipeline Contamination

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Executive summary

This report is part of the HyDelta 3 research program. The scope of Work Package WP1b.1 is to understand the impact of possible contamination within existing offshore natural gas networks on hydrogen purity and to define an approach for how to clean such pipelines. This work discusses the complete range of possible contamination of an upstream offshore natural gas pipeline. The key deliverable is a pipeline cleaning process that can be used to assess and clean an existing offshore natural gas pipeline and ensure that is it ready for hydrogen transport. The process is based on industry best practices for pigging pipelines combined with direct experience from of a small diameter onshore natural gas pipeline.

Samenvatting

Dit rapport maakt deel uit van het onderzoeksprogramma HyDelta 3. Het doel van werkpakket WP1b.1 is om inzicht te verkrijgen in de impact van mogelijke verontreinigingen binnen bestaande offshore aardgasnetwerken op de zuiverheid van waterstof, en om een aanpak te definiëren voor het reinigen van dergelijke pijpleidingen. Dit werk bespreekt het volledige spectrum van mogelijke verontreinigingen in een stroomopwaartse offshore aardgaspijpleiding. Het belangrijkste resultaat is een reinigingsproces voor pijpleidingen dat kan worden gebruikt om een bestaande offshore aardgaspijpleiding te beoordelen en te reinigen, zodat deze geschikt is voor waterstoftransport. Dit proces is gebaseerd op best practices uit de industrie voor het piggen van pijpleidingen, in combinatie met directe ervaring met een onshore aardgaspijpleiding met een kleine diameter.

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1. Introduction

On May 18th 2022, the Energy ministers of Belgium, Denmark, Germany, and the Netherlands signed the Declaration on the North Sea as a Green Power Plant of Europe, commonly referred to as the Esbjerg Declaration. Building on this momentum, the Ostend Declaration, introduced in 2024, represents a major expansion of this vision. In the Ostend Declaration, a coalition of nine countries—Belgium, Denmark, Germany, the Netherlands, as well as France, Ireland, Luxembourg, Norway, and Sweden—committed to transforming the North Sea into the world's largest green energy power plant. This expanded coalition aims to further accelerate the development of offshore wind energy and strengthen cross-border energy integration, driving significant advancements toward a sustainable and integrated energy system in the North Sea region.

The Declaration supports Europe in switching from fossil energy to renewable energy derived from the North Sea area and has set ambitious combined targets for offshore wind of at least 120 GW by 2030 in the North Seas. Based on the North Seas as a Green Power Plant of Europe, together we aim to more than double our total 2030-capacity of offshore wind to at least 300 GW by 2050.

Hydrogen from the North Sea, in which green hydrogen is produced offshore from wind energy and brought ashore via hydrogen pipelines, should help to unlock the enormous potential of energy production on the North Sea. For that an offshore hydrogen infrastructure is needed. Most probably Gasunie will be appointed by the Dutch Government to develop a hydrogen network at the North Sea. The development of this infrastructure will be partly based on re-using existing offshore natural gas infrastructure.

There are a significant number of publications and press releases in the public domain claiming that onshore pipeline networks are ready to transport hydrogen and that existing infrastructure is suitable for re-purposing. This information notwithstanding, for offshore pipelines some additional failure modes are still conceivable. Also, the effect of the pipeline transport characteristics on the quality of the hydrogen is still an open question. This explains why there is intensive work ongoing in several research programs in the industry to close those offshore transport knowledge gaps (link1 (TNO), link2 (IOGP)). Both projects have the character of a techno-economic feasibility study, however do not go into detail on the specific issues related to re-use of existing gas pipelines.

In this HyDelta research project the focus will be on the cleaning end re-qualification of existing offshore pipelines to ensure a reliable infrastructure.

In summary: A large-scale deployment of natural gas pipelines for hydrogen transport requires that the best possible balance between safety and cost-effectiveness can be established to allow for optimal assessment of the use of existing pipeline infrastructures. This project supports offshore infrastructure operators to make informed decisions on re-using existing natural gas infrastructure for hydrogen purposes.

2. Scope of Work

The pipelines in the North Sea have been in use for many years for natural gas transport. Over the years, contamination has remained in the pipeline. Before an existing pipeline can be re-used for hydrogen transport, it will have to be understood what contaminants are present in the system, and how they may affect hydrogen purity. So, it is important to know what contaminants can be expected and which cleaning technologies are available to remove these impurities. Therefore, this report aims to answer the following questions:

- What contaminants/pollution is to be expected?
- How can this be measured?

- What data is available already?
- What is the impact of this contamination on hydrogen purity.
- What cleaning technologies are available, and what cleaning intervals are recommended?

The scope of work is to understand the potential impact of pollution of used offshore natural gas networks on hydrogen purity and define an approach for cleaning such pipelines.

Activities:

- Desk research
- Literature review
- Interviews with operators and cleaning companies
- Workshops with experts
- Define cleaning protocol/procedure

2.1 Assumptions

- The offshore pipelines were previously in upstream natural gas service. Pipelines in oil service are not in scope. However, it is important to note that upstream natural gas pipelines often transport a mixture of gas and condensates. This mixture is separated for processing before export, but the export lines typically receive the combined mixture once again.
- This study is to cover all possible contaminants in upstream natural gas production as specific pipelines for re-purposing have not been chosen.
- This study will not be specific for one particular pipeline, but a generic approach for upstream offshore gas pipelines in the Netherlands.
- Flexible risers and other non-ferrous components are not in scope.

3. Hydrogen Purity Standards

The hydrogen transported via a future hydrogen backbone may still contain a number of impurities. Regardless of whether the hydrogen specification is 98 or 99.5% purity, the impurities may prevent the customer from using the hydrogen immediately. These impurities may be a result of the production method followed and purification of the hydrogen for the infeed into the hydrogen network. In addition, a limited part may also be the result of residual products in the pipeline at the time of the natural gas service.

For applications where the hydrogen is burned directly, it is generally believed that a limited amount of impurities, such as those already present in the natural gas systems, will not cause any problems. For this work, it is assumed that the desired hydrogen purity is Grade A according to ISO 14687. Table from the ISO standard is reproduced below. Grade A hydrogen meets the 98% minimum mole fraction

Table 1 Hydrogen and hydrogen-based fuel classification by application. ISO 14687

Type	Grade	Category	Applications	Clause
I Gas	A	–	Gaseous hydrogen; internal combustion engines for transportation; residential/commercial combustion appliances (e.g. boilers, cookers and similar applications)	7
	B	–	Gaseous hydrogen; industrial fuel for power generation and heat generation except PEM fuel cell applications	7
	C	–	Gaseous hydrogen; aircraft and space-vehicle ground support systems except PEM fuel cell applications	7
	D[a,b]	–	Gaseous hydrogen; PEM fuel cells for road vehicles	5
	E	PEM fuel cells for stationary appliances		6
		1	Hydrogen-based fuel; high efficiency/low power applications	
		2	Hydrogen-based fuel; high power applications	
		3	Gaseous hydrogen; high power/high efficiency applications	

[a] Grade D may be used for other fuel cell applications for transportation including forklifts and other industrial trucks if agreed upon between supplier and customer.

[b] Grade D may be used for PEM fuel cell stationary appliances alternative to grade E category 3.

Type	Grade	Category	Applications	Clause
II Liquid	C	–	Aircraft and space-vehicle on-board propulsion and electrical energy requirements; off-road vehicles	7
	D[a,b]	–	PEM fuel cells for road vehicles	5
III Slush	–	–	Aircraft and space-vehicle on-board propulsion	7

[a] Grade D may be used for other fuel cell applications for transportation including forklifts and other industrial trucks if agreed upon between supplier and customer.

[b] Grade D may be used for PEM fuel cell stationary appliances alternative to grade E category 3.

with less than 20,000 µmol impurities.

The specific composition for hydrogen for non-fuel applications is also provided in ISO 14687, which is depicted in Table 2 on the next page.

Table 2 Fuel uality specification (Table 4 in ISO 14687)

Constituents (assay)	**Type I** Grade A	Grade B	Grade C	**Type II** Grade C	**Type III**
Hydrogen fuel index[a] (minimum mole fraction, %)	98,0 %	99,90 %	99,995 %	99,995 %	99,995 %
Para-hydrogen (minimum mole fraction, %)	NS	NS	NS	95,0 %	95,0 %
Impurities (maximum content)					
Total gases	20 000 µmol/mol	1 000 µmol/mol	50 µmol/mol	50 µmol/mol	
Water (H_2O) (mole fraction, %)	Non-condensing at all ambient conditions[b]	Non-condensing at all ambient conditions	[c]	[c]	
Total hydrocarbon	100 µmol/mol	Non-condensing at all ambient conditions	[c]	[c]	
Oxygen (O_2)	[b]	100 µmol/mol	[d]	[d]	
Argon (Ar)	[b]		[d]	[d]	
Nitrogen (N_2),	[b]	400 µmol/mol	[c]	[c]	
Helium (He)			39 µmol/mol	39 µmol/mol	
Carbon dioxide (CO_2)			[e]	[e]	
Carbon monoxide (CO)	1 µmol/mol		[e]	[e]	
Mercury (Hg)		0,004 µmol/mol			
Sulfur (S)	2,0 µmol/mol	10 µmol/mol			
Permanent particulates	[g]	[f]	[f]	[f]	
Density					[f]

Key

NS: Not specified

[a] The hydrogen fuel index is determined by subtracting the "total non-hydrogen gases" expressed in mole percent, from 100 mole percent.

[b] Combined water, oxygen, nitrogen and argon: maximum mole fraction of 1,9 % (19 000 µmol/mol).

[c] Combined nitrogen, water and hydrocarbon: maximum 9 µmol/mol.

[d] Combined oxygen and argon: maximum 1 µmol/mol.

[e] Total CO_2 and CO: maximum 1 µmol/mol.

[f] To be agreed between the supplier and the customer.

[g] The hydrogen shall not contain dust, sand, dirt, gums, oils or other substances in an amount sufficient to damage the fuelling station equipment or the vehicle (engine) being fuelled.

The Gasunie/Hynetwork Hydrogen Specification has been published and is available [1] EESEA gas also a specification for hydrogen [2].

Table 3 Hydrogen specification from Gasunie/Hynetwork

Table 1: Indicative quality specifiaction Hydrogen Network Netherlands

Constituents	Unit	Min.	Max.
Hydrogen (H_2)	mol/mol %	99,5	
Total sum of hydrocarbons including CH_4 (CXHY)	mol/mol %		0,5
Oxygen (O_2)	µmol/mol (ppm)		10
Total sum of inerts (N_2, He, Ar)	mol/mol %		0,5
Carbon dioxide (CO_2)	µmol/mol (ppm)		20
Carbon monoxide (CO)	µmol/mol (ppm)		20
Total sulphur including H2S (S)	µmol/mol (ppm)		3
Formic acid (CH_3OOH)	µmol/mol (ppm)		10
Formaldehyde (CH_2O)	µmol/mol (ppm)		10
Ammonia (NH_3)	µmol/mol (ppm)		10
Halogenated compounds	µmol/mol (ppm)		0,05
Water dewpoint (H_2O)	ºC @ 70 bara		-8
Hydrocarbon dewpoint	ºC @ 1 - 70 bara		-2
Wobbe index	MJ/m³ (n)	45,99	48,35
All other impurities	Shall not contain solid, liquid or gaseous material that might interfere with the integrity or operation of pipes or any gas appliance		

Table 2: Temperature

Property	Unit	Min.	Max.
Gas temperature	ºC	5	30

Several hydrogen purity specifications are also summarized in the Table 4 below.

Table 4 Comparison of Hydrogen composition

Parameter	DVGW G 260 H2, Group D	proposed by DNV, KIWA*	DVGW G 260 H2, Group A
Hydrogen	≥ 99.97 mol%	≥ 99.5 mol%	≥ 98 mol%
Non-H2 gases	≤ 300 ppm	≤ 0.5 mol %	≤ 2 mol %
Water (dew point)	5 ppm	≤ - 8 °C at 70 bara	200 or 50 mg/m³
NMKW	2 ppm	< 0.5 mol% incl. CH_4	-
Methane	100 ppm		
KW condensation point	-	≤ - 2 °C at 1 - 70 bara	≤ - 2 °C at 1 - 70 bara
Oxygen	5 ppm	10 ppm	0.001 mol-% (=10 ppm) / 1 mol-% (=10,000ppm)
Carbon dioxide	2 ppm	20 ppm	2.5 / 4 mol-% (=40,000 ppm)
Carbon monooxide	0.2 ppm	20 ppm	0.1 mol-% (=1,000 ppm)
Total sulphur	0.004 ppm	3 ppm	10 mg/m³ (with odorization)
Ammonia	0.1 ppm	10 ppm	10 mg/m³ (NH_3 + amines)

The key message is while there are general agreements on the composition of hydrogen specifications, there is not 100% consensus on what the possible contaminants could be, and what are the allowable levels of contamination. In addition, if an upstream natural gas pipeline is being re-purposed for hydrogen service, there could be additional contaminants in the pipeline not covered in the above specifications. A detailed list of possible contaminants in upstream offshore natural gas pipelines is discussed in the next section of this report.

4. Contaminants

This chapter describes some of the most common contaminants that can be found in upstream offshore natural gas pipelines, and their sources, effects, and mitigation methods. The information presented is based on a combination of literature review and in-house expertise. The contaminants include sulfur and H_2S, organo-halogens, solids and waxes, mercury and others. Each of these contaminants poses different challenges and risks for the pipeline integrity and safety. The following sections provide more details on each contaminant and its characteristics.

4.1 Sulfur and H_2S

Sulfur in oil and gas extraction primarily comes from the sulfur-containing compounds present in crude oil and natural gas reservoirs. These compounds include hydrogen sulfide (H_2S) and various organic sulfur compounds such as mercaptans, sulfides, and thiophenes.

During the extraction process, when natural gas is brought to the surface, these sulfur-containing compounds are also brought up. Hydrogen sulfide, in particular, is often found in natural gas deposits and can be released during drilling and production operations. Overall, sulfur in oil and gas extraction primarily originates from the sulfur compounds naturally present in the hydrocarbon reservoirs. These can vary from reservoir to reservoir and change over the lifetime of the field production. For example, reservoirs initially H_2S free, can start to produce H_2S later in life, especially if water injection or other enhanced recovery methods are used.

Possible Risks

1. **Safety Concerns**: H_2S is highly toxic, even at low concentrations. Inhalation of H_2S gas can cause respiratory irritation, nausea, headaches, and in high concentrations, it can be fatal. Workers in oil and gas extraction facilities are at risk if proper safety measures are not in place to monitor and mitigate H_2S exposure.

2. **Corrosion**: H_2S can cause corrosion in pipelines, equipment, and infrastructure associated with natural gas production, processing, and transportation. This corrosion can weaken structures and lead to leaks or failures, posing safety hazards and causing costly damage.

3. **Environmental Impact**: Sulfur compounds, including H_2S, contribute to air pollution. When natural gas containing sulfur is burned for energy, it releases sulfur dioxide (SO_2) and other sulfur-containing compounds into the atmosphere, which can contribute to acid rain, smog formation, and adverse health effects.

4. **Regulatory Compliance**: Many jurisdictions have regulations limiting the amount of sulfur and H_2S allowed in natural gas. Gas producers must comply with these regulations to ensure the gas meets quality standards before it can be transported and sold.

4.2 Oxygen

In general, natural gas reservoirs are considered oxygen-free environments. This is primarily because natural gas formation occurs deep underground, typically in conditions where oxygen is scarce or absent.

1. **Formation Process**: Natural gas forms over millions of years from organic matter buried deep underground. The formation process involves the decomposition of organic material (such as

plankton and algae) under high pressure and temperature conditions. This process occurs in sedimentary basins deep beneath the Earth's surface, where oxygen levels are extremely low or non-existent.

2. **Anaerobic Conditions**: The environment where natural gas forms is typically anaerobic, meaning it lacks oxygen. Anaerobic conditions are conducive to the preservation and transformation of organic matter into hydrocarbons like methane, which is the primary component of natural gas. The absence of oxygen prevents the organic matter from fully oxidizing and instead allows it to undergo transformation into fossil fuels.

3. **Migration and Entrapment**: Once formed, natural gas migrates through porous rock formations until it becomes trapped beneath impermeable layers of rock, forming reservoirs. These reservoirs are often located deep underground, where oxygen does not penetrate due to the impermeability of the overlying rock layers.

While natural gas reservoirs are generally oxygen-free, it's important to note that trace amounts of oxygen may be present in some reservoirs due to geological processes or contamination. However, these levels are typically very low and not significant enough to support combustion or oxidation reactions within the reservoir. At a concentration level of 0.1%, oxygen is already problematic for various catalysts used in chemical processes.

Oxygen present in natural gas pipelines would therefore come from external sources. This is often from leaking pumps, valves, or from maintenance activities.

Possible Risks

The presence of oxygen in natural gas production can pose several risks, particularly in terms of safety, operational integrity, and environmental impact:

1. **Fire and Explosion Hazard**: Natural gas, which is primarily composed of methane, is highly flammable. If oxygen is introduced into a natural gas environment, it can create explosive mixtures that pose a significant fire and explosion hazard. Even small amounts of oxygen can increase the likelihood of combustion, especially in confined spaces or during handling and transportation processes.

2. **Corrosion**: Oxygen can promote corrosion in pipelines, equipment, and storage tanks used in natural gas production and transportation. Corrosion can weaken infrastructure, leading to leaks, failures, and potentially hazardous situations. Corrosion is particularly concerning in environments where moisture is present, as oxygen can react with water to form corrosive compounds.

3. **Quality Control**: Oxygen contamination can affect the quality of natural gas and its suitability for various applications. High levels of oxygen may impact the heating value of the gas, interfere with combustion processes, and cause operational issues in downstream equipment such as heaters, boilers, and engines.

4.3 Mercury

Mercury can be present in gas reservoirs as well as in associated formations and fluids. Here are some sources of mercury in natural gas extraction:

1. **Geological Formation:** Mercury can naturally occur in geological formations where oil and gas are found. It may have been deposited along with sediments during the formation of the reservoir or introduced through volcanic activity or other geological processes.

2. **Crude Oil and Natural Gas:** Mercury can be present in crude oil and natural gas as trace contaminants. It can exist in various forms, including elemental mercury and mercury compounds. The concentration of mercury in oil and gas can vary depending on the source and geological characteristics of the reservoir.

3. **Drilling Fluids and Additives:** Some drilling fluids and additives used during the drilling process may contain mercury or mercury-containing compounds. These substances can come into contact with drilling equipment, fluids, and formations, potentially leading to mercury contamination in extracted oil and gas.

4. **Formation Water:** Water produced along with oil and gas (referred to as formation water or produced water) can contain dissolved or suspended mercury. Mercury may leach into formation water from surrounding rock formations or from reservoir fluids during the extraction process.

Possible Risks

Mercury in natural gas production can pose several risks to human health, the environment, and industrial processes. Here are some of the key risks associated with mercury:

1. **Human Health Hazards**: Mercury is highly toxic, and exposure to even small amounts can have adverse health effects on humans. Inhalation of mercury vapors can cause respiratory problems, neurological disorders, and kidney damage. Workers in natural gas production facilities, as well as nearby communities, may be at risk of exposure if proper safety measures are not in place.

2. **Environmental Impact**: Mercury released into the environment can bioaccumulate in ecosystems, leading to contamination of soil, water, and wildlife. Once mercury enters the food chain, it can biomagnify, with concentrations increasing as it moves up through the food web. This can pose risks to aquatic organisms, birds, and mammals, including species consumed by humans.

3. **Corrosion and Equipment Damage**: Mercury can cause corrosion in pipelines, processing equipment, and storage tanks used in natural gas production and transportation. Corrosion can weaken infrastructure, leading to leaks, failures, and potential safety hazards. Mercury

contamination can also damage sensitive equipment and instrumentation used in gas processing facilities.

4. **Operational Challenges**: Mercury contamination in natural gas can present operational challenges for gas processing and refining facilities. Mercury can interfere with process equipment, catalysts, and purification systems, reducing operational efficiency and increasing maintenance costs. It can also impact product quality and compliance with environmental regulations.

4.4 Organo-halogens

Organo-halogens, which are compounds containing carbon, hydrogen, and halogen atoms (such as fluorine, chlorine, bromine, or iodine), can be found in oil and gas extraction processes through various sources:

1. **Naturally Occurring Halogens**: Halogens are naturally occurring elements found in the Earth's crust and can be present in geological formations where oil and gas are extracted. Halogens may be released into the extracted fluids during drilling, production, and processing operations.

2. **Chemical Additives**: Organo-halogen compounds may be intentionally added to drilling fluids, completion fluids, and hydraulic fracturing fluids to improve performance or achieve specific objectives during oil and gas extraction. For example, certain biocides, corrosion inhibitors, and drilling mud additives may contain organo-halogens.

3. **By-products of Chemical Reactions**: Organo-halogens can be formed as byproducts of chemical reactions that occur during oil and gas production and processing. For example, chlorinated hydrocarbons may be formed during chlorination processes used for water treatment or as a result of reactions between hydrocarbons and chlorine-containing compounds.

4. **Microbial Activity**: Microbial communities present in oil and gas reservoirs and associated formations can also contribute to the production of organo-halogens through metabolic processes. For example, some microorganisms are capable of producing halogenated organic compounds as part of their metabolic pathways.

Possible Risks

The risks associated with organo-halogens in natural gas production can vary depending on the specific compounds involved and their concentrations. However, here are some general risks associated with organo-halogens in natural gas production:

1. **Environmental Impact**: Some organo-halogen compounds are persistent organic pollutants (POPs) that can bioaccumulate in the environment and pose risks to ecosystems and wildlife.

These compounds can be toxic to aquatic organisms and may have long-term effects on biodiversity and ecosystem health.

2. **Human Health Hazards**: Exposure to certain organo-halogen compounds can pose health risks to workers in natural gas production facilities and nearby communities. Depending on the specific compounds involved, exposure may occur through inhalation, ingestion, or dermal contact. Health effects can range from respiratory irritation and skin sensitization to more serious effects such as neurotoxicity, reproductive toxicity, and carcinogenicity.

3. **Corrosion and Equipment Damage**: Some organo-halogen compounds can contribute to corrosion in pipelines, processing equipment, and storage tanks used in natural gas production and transportation. Corrosion can weaken infrastructure, leading to leaks, failures, and potential safety hazards. Additionally, organo-halogens may interact with other chemicals in the production process, leading to fouling or degradation of equipment and reducing operational efficiency.

4.5 Siloxanes

Siloxanes can enter natural gas processes from various sources, including:

1. **Natural Gas and Crude Oil Reservoirs**: Siloxanes can naturally occur in geological formations where oil and gas are found. These compounds may originate from the degradation of organic matter or geological processes involving silicon-containing minerals. Siloxanes can be present in reservoir fluids, including natural gas, crude oil, and associated formation water.

2. **Biological Processes**: Microbial activity in oil and gas reservoirs and associated formations can contribute to the production of siloxanes through metabolic processes. Some microorganisms are capable of synthesizing siloxane compounds as byproducts of their metabolism.

3. **Industrial Sources**: Siloxanes may also enter oil and gas extraction processes from industrial sources, including the use of silicone-based materials, products, and chemicals in drilling fluids, completion fluids, and hydraulic fracturing fluids. Silicone-based additives, lubricants, and sealants used in equipment and machinery maintenance may also contribute to siloxane contamination.

4. **Water Treatment Chemicals**: Siloxane compounds may be present in water treatment chemicals used in oil and gas production and processing facilities. Certain silicone-based antifoaming agents, emulsifiers, and demulsifiers used to treat produced water and wastewater may contain siloxanes.

Possible Risks

The risks associated with siloxanes in natural gas production primarily revolve around operational challenges, environmental impact, and potential health hazards. Here are some key risks:

1. **Operational Challenges**: Siloxanes can cause operational issues in natural gas processing facilities. When present in gas streams, siloxanes can condense and accumulate in processing equipment, pipelines, and heat exchangers. This can lead to fouling, corrosion, and reduced efficiency of equipment, resulting in increased maintenance costs and downtime.

2. **Environmental Impact**: Siloxanes can have adverse effects on the environment, particularly when released into the atmosphere. When natural gas containing siloxanes is burned for energy, siloxane combustion products, such as silicon dioxide (silica), may be emitted into the air. Silica particles can contribute to air pollution and respiratory problems if present in high concentrations. Additionally, siloxanes may contaminate soil and water if released into the environment.

3. **Health Hazards**: While siloxanes themselves are generally considered to have low toxicity, combustion of siloxanes can produce harmful byproducts, including fine particulate matter and other air pollutants. Prolonged exposure to these pollutants may pose health risks, particularly to individuals with respiratory conditions or compromised immune systems.

4. **Equipment Damage**: Siloxanes can contribute to corrosion and degradation of equipment and infrastructure in natural gas production and processing facilities. Corrosion caused by siloxanes can weaken pipelines, storage tanks, and processing equipment, leading to leaks, failures, and potential safety hazards.

4.6 Amines

Amines, particularly in the context of oil and gas extraction, often refer to amine compounds used in gas treatment processes, such as amine gas sweetening. These amines can come from:

1. **Synthetic Production**: Amines used in gas treatment processes are typically synthetic compounds manufactured specifically for this purpose. These amines are produced through chemical synthesis in industrial facilities. Commonly used amines in gas sweetening include monoethanolamine (MEA), diethanolamine (DEA), and methyldiethanolamine (MDEA).

2. **Gas Sweetening Process**: Amines are widely used in gas sweetening processes to remove acidic gases, particularly hydrogen sulfide (H_2S) and carbon dioxide (CO_2), from natural gas streams. In the gas sweetening process, the amine solution reacts with acidic gases to form stable compounds, which are then separated from the treated gas stream. This process helps to improve the quality of natural gas by reducing its sulfur and carbon dioxide content.

3. **Other Applications**: Various amines are used as corrosion inhibitors to protect pipelines and equipment from corrosion caused by acidic gases or water. Amines may also be used in drilling and completion fluids, as well as in enhanced oil recovery (EOR) processes.

Possible Risks

Amines used in natural gas treatment processes like gas sweetening, can pose various risks. Here are some potential risks associated with amines in natural gas production:

1. **Health Hazards**: Amines can be hazardous to human health, especially if workers are exposed to high concentrations or if proper safety measures are not in place. Exposure to amines through inhalation or skin contact can cause irritation to the respiratory system, skin, and eyes. Prolonged or repeated exposure to certain amines may lead to more serious health effects, including respiratory sensitization, allergic reactions, and systemic toxicity.

2. **Environmental Impact**: Amines and their degradation products can have environmental implications if released into the environment. For example, amines may be discharged into water bodies through wastewater from gas processing facilities, potentially affecting aquatic ecosystems. Additionally, amines may react with atmospheric pollutants to form secondary pollutants, contributing to air pollution and smog formation.

3. **Corrosion and Equipment Damage**: Certain amines are used for their corrosion inhibition properties. However, some concentrated amines and amine degradation products can contribute to corrosion in pipelines, processing equipment, and storage tanks if not properly managed. Corrosion can weaken infrastructure, leading to leaks, failures, and potential safety hazards. Amines may also interact with other chemicals in the production process, leading to fouling or degradation of equipment and reducing operational efficiency.

4.7 Glycols

Glycols used in oil and gas production, particularly in dehydration processes, are typically synthetic compounds produced specifically for this purpose.

1. **Synthetic Production**: Glycols used in oil and gas extraction, such as ethylene glycol (EG) and diethylene glycol (DEG), are manufactured through chemical synthesis in industrial facilities. These glycols are produced from petrochemical feedstocks such as ethylene and ethylene oxide, which are derived from natural gas or petroleum sources.

2. **Dehydration Process**: Glycols are commonly used as desiccants in gas dehydration processes to remove water vapor from natural gas streams. In these processes, the glycol solution is circulated through a contactor tower where it absorbs water vapor from the gas stream. The dehydrated gas is then discharged, while the glycol-rich solution is regenerated for reuse.

3. **Other Applications**: Glycols have various other applications in oil and gas extraction beyond gas dehydration. For example, they are used as heat transfer fluids in heating and cooling systems, as well as in antifreeze formulations for equipment and pipelines. Glycols may also be used in drilling and completion fluids, as well as in hydraulic fracturing fluids.

Possible Risks

Glycols used in natural gas production, particularly in gas dehydration processes, can pose various risks to human health and, the environment.

1. **Health Hazards**: Exposure to certain glycols, particularly in their liquid or vapor form, can pose health risks to workers in natural gas production facilities. Inhalation or skin contact with glycols may cause irritation to the respiratory system, skin, and eyes. Prolonged or repeated exposure to glycols may lead to more serious health effects, including respiratory sensitization, allergic reactions, and systemic toxicity.
2. **Environmental Impact**: Glycols and their degradation products can have environmental implications if released into the environment. For example, glycols may be discharged into water bodies through wastewater from gas processing facilities, potentially affecting aquatic ecosystems. Additionally, glycols may volatilize into the atmosphere and contribute to air pollution if not properly contained or controlled.

4.8 Oil and Grease

Oil and grease in natural gas production typically originates from several sources within the production process:

1. **Equipment Lubricants**: Machinery and equipment used in natural gas extraction, such as pumps, compressors, valves, and rotating equipment, require lubrication to reduce friction and ensure smooth operation. Lubricating oils and greases are commonly used for this purpose. During operation, these lubricants can come into contact with natural gas or produced fluids and may become entrained in the extracted gas or liquid streams.
2. **Drilling and Production Fluids**: During drilling and production operations, various fluids are used to facilitate the extraction of oil and gas from underground reservoirs. These fluids may contain oil-based drilling muds, completion fluids, or hydraulic fracturing fluids, which can contain oils, greases, and other hydrocarbons. Residual oil and grease from these fluids may remain in the wellbore or be brought to the surface along with the extracted fluids.
3. **Formation Fluids**: Oil and grease can also be naturally present in the formation fluids produced along with natural gas. In some cases, oil reservoirs may contain associated natural gas, and during extraction, oil droplets may become suspended or entrained in the gas stream. Additionally, oil and grease may be present in produced water or condensate associated with natural gas production.
4. **Maintenance Activities**: Maintenance activities conducted at natural gas extraction facilities, such as equipment cleaning, degreasing, and maintenance of storage tanks and separators, may involve the use of oil-based cleaners, solvents, and degreasers.

Possible risks

The presence of oil and grease in natural gas production can pose various risks to human health, the environment, and operational integrity. Here are some potential risks associated with oil and grease in natural gas production:

1. **Environmental Contamination**: Oil and grease releases can lead to environmental contamination if they are spilled or leaked into the soil, water, or air during production, transportation, or storage activities. Oil and grease contamination can have detrimental effects on soil fertility, water quality, and aquatic ecosystems, impacting biodiversity and ecosystem health.
2. **Air Pollution**: Volatile components of oil and grease, such as hydrocarbons, can evaporate into the atmosphere and contribute to air pollution. When exposed to sunlight and atmospheric pollutants, volatile organic compounds (VOCs) emitted from oil and grease can react to form ground-level ozone, smog, and other air pollutants, which can have adverse effects on human health and the environment.
3. **Health Hazards**: Exposure to oil and grease, particularly through inhalation of vapors or direct skin contact, can pose health risks to workers in natural gas production facilities. Oil and grease may contain toxic chemicals, such as polycyclic aromatic hydrocarbons (PAHs) and heavy metals, which can cause respiratory problems, skin irritation, and other adverse health effects. Prolonged or repeated exposure to oil and grease may also increase the risk of chronic health conditions.
4. **Operational Challenges:** Oil and grease contamination can pose operational challenges in natural gas production facilities. Accumulation of oil and grease in equipment, pipelines, and processing units can lead to fouling, corrosion, and reduced operational efficiency. Maintenance costs may increase as a result of equipment damage and downtime caused by oil and grease-related issues.

4.9 Upstream production chemicals

Various chemical products can be used during natural gas production to manage various operational issues. The chemicals can be injected at various times and at different locations over the operational lifetime of an offshore natural gas facility.

Possible products used in upstream natural gas production are:

1. **Corrosion Inhibitors**: Corrosion inhibitors are added to natural gas production systems to protect metal equipment, pipelines, and infrastructure from corrosion caused by acidic gases, water, and other corrosive substances present in the production environment.
2. **Scale Inhibitors**: Scale inhibitors are used to prevent the formation of scale deposits, such as calcium carbonate, calcium sulfate, and barium sulfate, which can accumulate in production equipment and pipelines and reduce operational efficiency.
3. **Biocides**: Biocides are chemicals used to control microbial growth and prevent the formation of biofilms in natural gas production systems. Microbial activity can lead to corrosion, fouling, and other operational issues if left unchecked.
4. **Surfactants**: Surfactants are surface-active agents that are added to drilling fluids, completion fluids, and hydraulic fracturing fluids to modify fluid properties, improve fluid performance, and enhance well productivity.

5. **Foaming Agents and Defoamers**: Foaming agents are used to generate stable foams in gas-liquid separation processes, such as gas dehydration and desalting, to increase surface area and improve separation efficiency. Defoamers are added to reduce foam formation and stabilize liquid levels in equipment.
6. **Demulsifiers**: Demulsifiers are chemicals used to break emulsions and separate water from oil and gas streams. Demulsifiers help improve the efficiency of water removal processes in production separators and dehydration units.
7. **Hydrate Inhibitors**: Hydrate inhibitors are added to natural gas streams to prevent the formation of gas hydrates, which can block pipelines and equipment and cause flow assurance problems during transportation and processing.
8. **Antifoaming Agents**: Antifoaming agents are used to control foam formation and reduce foam stability in various natural gas production processes, such as gas-liquid separation, dehydration, and desalting.
9. **Drag Reducing Agents**: Drag reducing agents (DRAs) are added to natural gas pipelines to reduce frictional resistance and increase flow rates, improving pipeline efficiency and reducing energy consumption.
10. **Emulsion Breakers**: Emulsion breakers are chemicals used to destabilize and break water-in-oil or oil-in-water emulsions, facilitating the separation of oil and water phases in production separators and treating equipment.
11. **Methanol**: Methanol is commonly injected into natural gas production systems to prevent hydrate formation.

Possible Risks

The presence of these chemicals or their residual products in natural gas production can pose various risks to human health, the environment, and operational integrity. Here are some potential risks associated with residual production chemicals in natural gas pipelines.

The use of chemicals in natural gas production can pose various risks to human health, the environment, and operational integrity. Here are some potential risks associated with the use of chemicals in natural gas production:

1. **Health Hazards**: Many chemicals used in natural gas production can be hazardous to human health if not properly handled, stored, or managed. Exposure to these chemicals through inhalation, skin contact, or ingestion can cause acute or chronic health effects, including respiratory irritation, skin sensitization, allergic reactions, neurological disorders, and carcinogenicity.
2. **Environmental Contamination**: Chemical releases or spills during handling, transportation, storage, or disposal can lead to environmental contamination of soil, water, and air. Contamination may occur through surface runoff, groundwater infiltration, or atmospheric emissions, resulting in adverse effects on terrestrial and aquatic ecosystems, wildlife, and human populations.

3. **Corrosion and Equipment Damage**: Some chemicals used in natural gas production, such as corrosion inhibitors and scale inhibitors, can contribute to corrosion or fouling of equipment, pipelines, and infrastructure if not properly applied especially in concentrated form. Corrosion and equipment damage can compromise operational integrity, increase maintenance costs, and pose safety hazards to workers and nearby communities.
4. **Biological Hazards**: Biocides used to control microbial growth in natural gas production systems can have unintended consequences, such as the development of biocide-resistant microorganisms or disruption of microbial ecosystems in soil and water environments. Excessive biocide use or improper application may lead to ecological imbalances and harm beneficial microorganisms.

4.10 Solids and fines

During natural gas production, various types of solid matter can be encountered, depending on the geological formation, production techniques, and operational processes involved. Some common types of solid matter encountered during natural gas production include:

1. **Sand and Sediments**: Sand and other sedimentary particles may be present in the formation fluids produced along with natural gas. These particles can enter the wellbore during drilling and production operations or may naturally occur in the reservoir. Sand and sediments can cause erosion and abrasion of equipment, reduce well productivity, and lead to sand production issues if not properly managed.
2. **Scale Deposits**: Scale deposits, such as calcium carbonate, calcium sulfate, and barium sulfate, can form in production equipment and pipelines due to the precipitation of dissolved minerals present in formation fluids. Scale formation can restrict flow rates, reduce production efficiency, and lead to equipment failure if not mitigated through scale inhibition and removal techniques.
3. **Formation Fines**: Formation fines are fine particles and clay minerals present in the reservoir rock that may become mobilized and produced along with natural gas. Formation fines can contribute to formation damage, reduce reservoir permeability, and impair well performance if not properly controlled or managed.
4. **Microbial Biomass**: Microbial biomass, including bacteria, fungi, and algae, may grow and proliferate in natural gas production systems, particularly in aqueous environments such as produced water or water injection systems. Microbial growth can lead to microbiologically influenced corrosion, biofouling, and souring issues if left unchecked.
5. **Sulfate-Reducing Bacteria (SRB):** SRBs produce sulfuric acid through their metabolic processes, which accelerates the corrosion of metal surfaces. This phenomenon, known as microbial-induced corrosion (MIC), is significantly influenced by SRBs, which are estimated to account for up to 80% of all MIC in natural environments.
6. **Asphaltenes**: Asphaltenes are high molecular weight organic compounds found in crude oil and natural gas condensate. During natural gas production, asphaltenes may precipitate and form solid deposits due to changes in temperature, pressure, and composition. Asphaltenes

deposition can cause fouling of production equipment, reduce well productivity, and lead to flow assurance issues in pipelines.

7. **Drilling Cuttings**: During drilling operations, solid cuttings, rock fragments, and drilling mud residues may accumulate in the wellbore and production tubing. Drilling cuttings can interfere with well productivity, hinder fluid flow, and require removal through well intervention or workover operations.

8. **Black Powder**: Black powder is a mixture of iron sulfides, iron oxides, and other contaminants like dirt, sand, and hydrocarbons. It is primarily formed due to the corrosion of the pipeline material, which reacts with contaminants such as hydrogen sulfide (H2S), carbon dioxide (CO2), and water.

9. **NORM (naturally occurring radioactive material):** NORM in pipelines typically originates from the geological formations where oil and gas are extracted. These formations contain naturally occurring radionuclides such as uranium, thorium, and their decay products, including radium-226 and radium-228. These radionuclides can dissolve in the produced water, a byproduct of oil and gas extraction.

Possible Risks

The presence of solids and fines in natural gas production can pose various risks to operational and mechanical integrity. Here are some potential risks associated with solids encountered during natural gas production:

1. **Equipment Damage**: Solid particles, such as sand, scale deposits, paraffin, and hydrates, can cause abrasion, erosion, and mechanical damage to production equipment, pipelines, valves, and other components. Equipment damage can lead to increased maintenance costs, production downtime, and safety hazards if not properly addressed.

2. **Flow Restriction**: Solid deposits, such as scale, sand and formation fines, can accumulate in production tubing, flowlines, and pipelines, causing flow restrictions and pressure losses. Flow restrictions can reduce production rates, impair well performance, and increase pumping requirements, resulting in decreased operational efficiency.

3. **Corrosion and Integrity Issues**: Solid deposits, microbial biomass, and other contaminants can promote corrosion and integrity issues in production equipment and infrastructure. Microbial activity, for example, can lead to microbiologically influenced corrosion (MIC), while scale deposits can create localized corrosion cells. Corrosion and integrity issues can compromise asset reliability, increase safety risks, and lead to environmental releases if left unaddressed. This is key risk for pipelines that have not been in active service for a period of time. Or may not have been properly laid up.

4. **Health and Safety Risks**: Solid matter in natural gas production systems can pose health and safety risks to workers, contractors, and nearby communities. Exposure to hazardous materials, such as drilling cuttings, scale, and chemicals, can lead to respiratory problems, skin irritation, and other adverse health effects. This is a key risk for solids that naturally radioactive (NORMs).

4.11 Interaction of hydrogen with contaminants

Under normal transport conditions, hydrogen typically remains chemically inert and does not react with most contaminants. However, certain impurities can either accelerate or inhibit the adverse effects associated with hydrogen. According to some informal observations, surface films could block gaseous hydrogen from entering the steel structure, possibly lowering hydrogen embrittlement (HE). The influence of water vapor is variable; some studies indicate it can lower the Fatigue Crack Growth Rate (FCGR), while high-purity hydrogen shows minimal impact. Laboratory research [3],[4],[5] has shown that carbon monoxide (CO) can partially impede HE depending on its concentration, acting as a deterrent to hydrogen adsorption. The exact role of carbon dioxide (CO_2) remains unclear, with conflicting reports suggesting it can slow, have no effect, or even promote FCGR due to its interaction with hydrogen. Some studies [6] have reported that CO_2 reduces the FGCR and HE, while others [7] have found no effect or an enhancement of the FGCR due to the combined influence of CO2 and hydrogen [8]. The effect of gas impurities on the pipe steels under representative operation conditions is unknown and is under investigation now.

In 2014, DNV conducted a study on the interaction of hydrogen with black powder and mine dust in natural gas pipelines [9]. The interaction between the components of black powder (including mine dust) and hydrogen was considered (under normal transport conditions, temperature -5 to 50 °C and pressure < 80 bar). A summary of this study is provided below.

At room temperature, hydrogen is not very reactive unless a catalyst (e.g. platinum or palladium) is applied to reduce the activation energy. In applications with a catalyst, the reaction with hydrogen takes place on the catalyst surface, which absorbs hydrogen and other molecules to accelerate the contact between them. Iron or iron oxide sometimes also acts as a catalyst in reactions with hydrogen, but these reactions take place under specific conditions (including high temperature and pressure). Hydrogen is di-atomic, and at high temperatures, the molecules will break down into single atoms of hydrogen. These are very reactive.

A literature review has found no possible reactions with hydrogen for the following components in black powder:

Iron sulphides (FeS, F_3S_4, FeS_2), Iron carbonates ($FeCO_3$, $Fe_2(CO_3)_3$), and Iron oxide (Fe_3O_4)

The following reactions are possible between components of black powder and hydrogen:

<u>Iron oxide (Fe_2O_3):</u>
$Fe_2O_3 + 3H_2 \rightarrow 2Fe + 3H_2O$ (reaction at 1000 °C)

<u>Iron hydroxide (FeOOH):</u>
$2FeOOH \rightarrow 3H_2 \rightarrow 4H_2O + 2Fe$

<u>Hg sulfide (HgS):</u>
$HgS + H_2 \rightarrow Hg + H_2S$ (reaction at 340 °C)

<u>Sulphur (S):</u>
$S + H_2 \rightarrow H_2S$ (reaction at 150 – 200 °C)

<u>Carbon (C):</u>
$C + 2H_2 \rightarrow CH_4$ (reaction at 400 °C, 300 bar and catalyst)

It can be concluded that under normal pipeline transport conditions, no chemical reactions are expected between hydrogen and components in black powder. In addition, no relevant information was found about possible accumulation of hydrogen in black powder.

5. Hydrogen quality measurements

In order to monitor the quality of hydrogen in the pipelines during transport, additional measuring equipment may need to be used (measuring contaminants at ppm and ppb level). The currently used equipment such as a Danalyzer gas chromatograph is unsuitable for monitoring the various hydrogen specifications.

DNV carries out quality measurements for hydrogen refueling stations, among other things, often referring to EN 17124:2018 – Hydrogen fuel – Product specification and quality assurance.

The following technologies can be utilized to quantify the different contaminants in hydrogen.

Table 5. Summary of detection methods for contaminants in hydrogen (DNV)

Component	**Concentration range**	**Measurement technique**	**On-line/off-line**
Hydrogen	0 – 100 mol %	Gas Chromatograph + thermal conductivity detector (TCD)	On-line
Total hydrocarbons	0 – 1000 ppm	Gas Chromatograph + flame ionization detector (FID)	On-line
Oxygen	0 – 1000 ppm	Gas chromatograph + TCD or electrochemical sensor	On-line
Inerts (N_2, Ar, He)	0.5 – 2.0 mol %	Gas Chromatograph + TCD	On-line
Carbon dioxide	0 – 20 ppm	Gas Chromatograph + TCD or Fourier Transform Infrared Spectroscopy FTIR	On-line
Carbon monoxide	0 – 20 ppm	FTIR	On-Line
Total sulfur (o.a H_2S en COS)	0 – 5 ppm	Micro Gas chromatograph + ion mobility detector (IMS)	On-line
Formic acid	0 – 10 ppm	FTIR	On-line
Formaldehyde	0 – 10 ppm	FTIR	On-line
Ammonia	0 – 10 ppm	FTIR	On-line
Halogen hydrocarbons	0 – 50 ppb	Gas Chromatograph + Mass Spectrometer (MS)	Sampling + off-line
Water	0 – 500 ppm	Tunable Diode Laser Absorption Spectroscopy (TDLAS)	On-line

6. Pipeline cleaning process

Based on the inventory of potentially hydrogen-polluting components present in a natural gas transport pipeline, a methodology has been developed for offshore natural gas pipelines. The purpose is to ensure the natural gas pipelines are sufficiently cleaned in order to be able to re-use them for hydrogen service. This methodology takes into account the requirements set out in EIGA - IGC doc 121/14 Hydrogen pipeline systems. However, the EIGA mainly describes the case of a new hydrogen pipeline, and although re-qualification is discussed, no new requirements are set. EIGA requires that the pipeline must be dry and free of flash rust and welding debris and other foreign materials.

This section describes in detail the proposed offshore pipeline cleaning process, following the high-level steps in the figure below. This process is based on industry best practice for traditional pipeline cleaning with additional input from a 2018 project with DNV and Gasunie to re-purpose an onshore natural gas pipeline to hydrogen service [10].

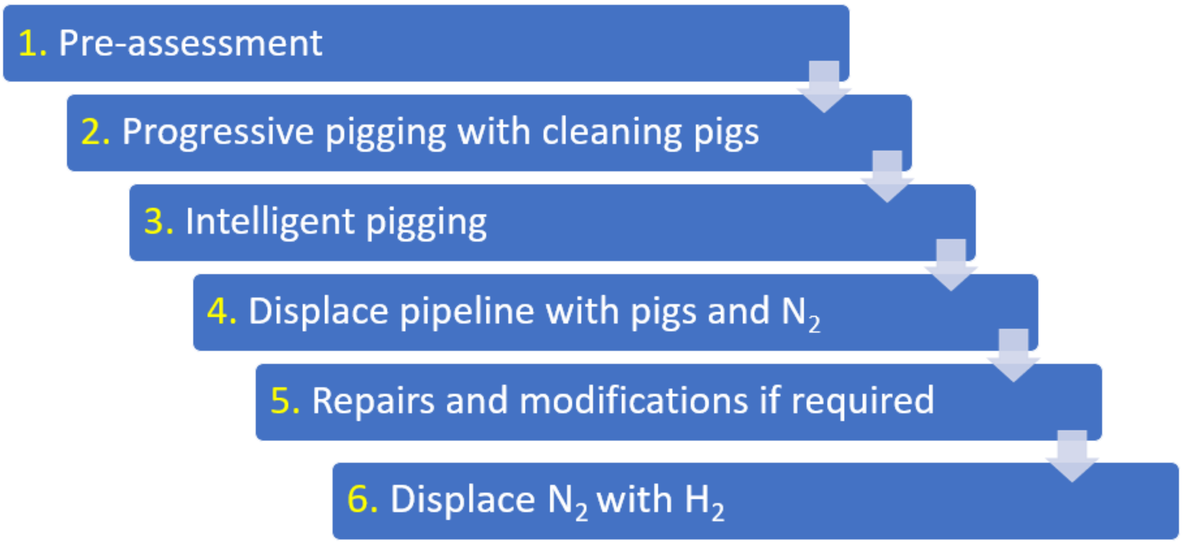

Figure 1. High-level offshore pipeline cleaning process

6.1 Pre-Assessment for contamination

Before proceeding to the physical cleaning stage, the first step is to conduct a pre-assessment of the particular offshore pipeline or section of pipeline to be readied for hydrogen service.

The pre-assessment starts with a review of all existing records, analysis, and documentation on the history of the pipeline while it was in natural gas service. At a minimum, this review should include the following:

- Gas analysis, water analysis, pigging records, pigging debris analysis.
- Chemical treatment and corrosion management plans.
- Previous inspection results (ILI).
- Production history- changes in gas production, composition, volumes, water analyses, water dew point, hydrocarbon dewpoint.
- Pipeline suspension records – confirm how the pipeline operation was stopped and the current state of decommissioning.

- Operational history – verification of any modifications or repairs that would make pigging/cleaning challenging (change in wall thickness, tight bends, removal of pigging facilities, passing valves).
- Confirmation of pipeline pigging capability. Pig sender/receiver condition and condition of pigging/isolation valves at each end of the pipeline.
- Verification or absence of internal flow coating.

After the review and the quality/availability of the documentation, it will be necessary to perform an operational risk assessment. The scope and level of detail of the risk assessment will depend on the level of uncertainty of the current condition with respect to contamination and the ability to be cleaned. If the documentation suggests the pipeline condition is not fully known, or there are gaps in the operational history, it is recommended to try to gather additional data. This could include gathering samples for analysis or site visits to confirm the current condition of pipeline isolation equipment.

It is strongly recommended that the operational risk assessment or HAZID be completed after the document review before proceeding to the pigging and cleaning stages. This assessment must consider.

- Side branches, dead legs and possible bypasses in associated piping.
- Valve isolation requirements and valve integrity assessment.
- Launcher/receiver integrity assessment or temporary pigging facilities.
- Sufficient working space for sending and receiving pigs and facilities to collect pigging debris.
- Contingency plans for stuck pigs.

6.2 Pipeline Pigging and Chemical Cleaning

This step is focused on pre-cleaning using pipeline pigs to remove loose contamination and liquids.

Assuming the natural gas offshore pipeline is currently still in service and is equipped with facilities for pigging, pig the intended route during natural gas transport service with a BiDi (bidirectional) pig and monitor the amount of contamination carried (both the amount of liquids and the amount of solids). Repeat this step a few times until the contamination captured is less than 1-2 liters of solid/liquid (depending on the pipe diameter: 1 liter for up to 12 inches; above that, 2 liters).

If the pipeline is not in active service, the pre-assessment review and risk assessment must estimate the current condition of the pipeline.

If the current condition is known, the pipeline can be pigged same as above with a BiDi pig pushed with high pressure nitrogen. Typically, the pipeline would be pigged from the offshore to onshore direction.

If the current condition is not known due to incomplete records, then then the pipeline should be cleaned using a progressive pigging strategy. Progressive pigging consists of a series of pigging operations, starting with inefficient sealing pigs moving up to more aggressive and efficient pigs as confidence grows. The goal of this strategy is to reduce the chance of a stuck pig or creating a pile of debris in the pipeline ahead of the pig. The time and cost of multiple pig runs is typically less than the time and effort required to remove a stuck pig from a pipeline, especially an offshore pipeline.

In progressive pigging, the first pigs to be run are made from soft foam material, non-aggressive pigs, that can prove the pipeline can be successfully pigged and will sweep soft loose material and some liquids. Depending on the amount and nature of the contamination, these pigs can be increased in hardness, aggressiveness (brushes) and diameter. These pigs will remove solids and liquids until the pipeline becomes clean. The number of pig runs will depend on how much material is in the line.

It is expected that for almost all cases of natural gas service, BiDi pigging or a progressive pigging program with a few runs will be sufficient to meet the target cleanliness requirements, which can be found below:

- For pipelines <12 inch (DN 300) less than 1L of liquid/solids
- For pipelines >12 inch (DN 300) less than 2L of liquid/solids
- Hydrocarbons; maximum 1000 ppm
- Water dewpoint < -8°C @ 70 bar.

The above requirements are independent of pipeline length [11].

If the progressive pigging program is not effective, there is an option to supplement the pigging with a chemical cleaning program. This is only recommended if the progressive pigging program cannot deliver the cleanliness requirements.

The chemical cleaning program is typically carried out by specialist contractors in conjunction with chemical solution providers. The chemicals used in the cleaning operation are typically chosen by analysis of the debris coming from the pipeline. Laboratory testing can be used to help select the most effective chemical treatment. Options available are:

- Hydrocarbon solvents such as diesel, xylene, toluene, etc.
- Or specialist pipeline cleaning products such as N-SPEC [12]

Regardless of the chemicals used, they will need to be removed after by additional pigging pushed with nitrogen. No chemical residue must be left in the pipeline after cleaning. Also, any chemicals used offshore for cleaning should meet the OSPAR requirements [13].

6.3 Displace natural gas with nitrogen

This step entails displacing natural gas with nitrogen using a pig-run and preserving the pipeline under a low-pressure nitrogen atmosphere.

After pigging, displace any natural gas with nitrogen and use a separating pig. The nitrogen quality should be monitored at the end of the pipeline for hydrocarbon content and water dew point. Nitrogen should be 99.9% purity to limit oxygen content. Below is an example of a pipeline purge with nitrogen showing how the contamination can reduce as the nitrogen purge progresses.

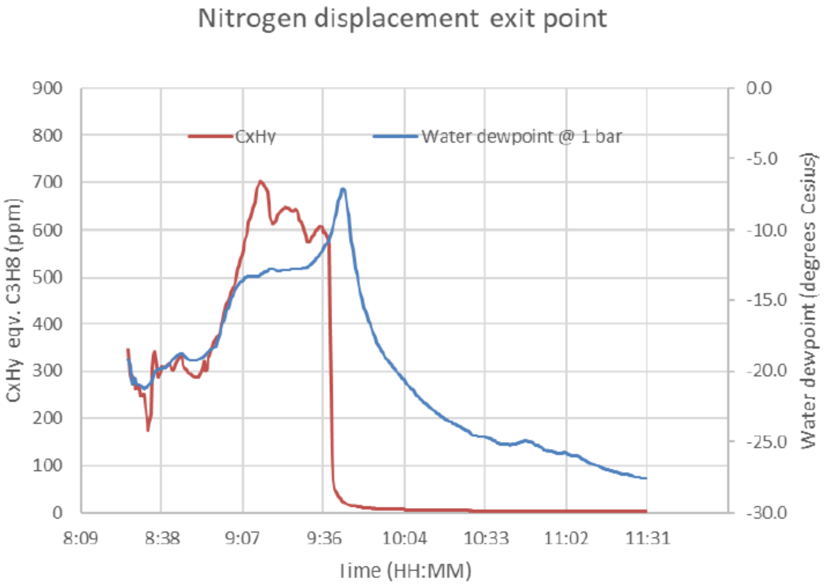

Figure 3. Total hydrocarbon and water dewpoint at pipeline exit during purge with nitrogen [14]

The pipeline should be left under a nitrogen pressure of 2-3 bar overpressure. The hydrocarbon concentrations in the nitrogen should be monitored for a bi-weekly period (which indicates the extent to which volatile components are still present in the pipe section that are released at low pressure). In the event of persistent increases in concentrations of hydrocarbons above 0.1 % by volume, an additional nitrogen purge must be carried out. During this phase, also check the mercury levels (as far as detectable at ng/m3 level).

6.4 Repairs and Modifications

This step includes a modification period under low-pressure nitrogen atmosphere. If required, maintenance/replacement of valves should be carried out. Caps should be placed on branches that are no longer operational, etc. Concentrations of volatile components (including hydrocarbons and mercury) in the nitrogen atmosphere due to desorption from pipe components should be monitored.

The pipeline section should be disconnected from the natural gas transport network to eliminate the risk of future cross-contamination. The connecting valves between the pipe section and other parts containing natural gas should be closed. Isolation on the basis of a single valve is not permitted. The complete physical separation of the hydrogen network from the natural gas network is essential in this regard. Mechanical jobs, i.e. work on valves, branches, etc. can then be carried out.

6.5 Cleaning Pigs with Nitrogen

The next step involves cleaning with a pig-run under a nitrogen atmosphere. Monitoring of contaminants in hydrogen (e.g. nitrogen, hydrocarbons and mercury) should be conducted and also testing with criteria. In case of rejection, the pipe should be purged again with nitrogen.

A cleaning pig-run using a BiDi (bi-directional) pig should be performed under nitrogen while monitoring the contamination found. Depending on the contamination found (welding grains etc. or whether liquids have also come with it), an extra pig-run should be performed if necessary until the pig is found dry and clean in the receiver. If the pig still brings a lot of greasy substances, a methanol run (approx. 20 m3 to be specified on the basis of pipe diameters) between pigs can be considered but be aware that even a methanol run will not be able to completely clean dead legs. During a methanol run, one should check for the volume of methanol deployed at the launcher and recovered volume at the receiver. After a methanol run, siphons should be emptied and valves should be drained. It is recommended to wait to transfer hydrogen until a pipeline section involved can become part of an operational hydrogen network (i.e. allow residual volatile components from the natural gas operation phase to evaporate into the nitrogen for as long as possible monitoring phase, preventing them from contaminating the hydrogen in the initial phase).

6.6 Displace Nitrogen with Hydrogen

This step involves the displacement of nitrogen to hydrogen using a pig-run.

Hydrogen should be introduced into the network with a BiDi-pig as a separation between the gases (if desired, consider using a second pig (50-100 m distance between the pigs) to limit potential back-mixing (this also limits the influence of branches that are considered dead ends). Perform this at a hydrogen pressure of approximately 5 -10 bar. Hydrogen pressure can then be increased to the operational value and operation of the network can continue.

6.7 Pigging in Hydrogen service

Currently pigging of hydrogen pipelines in not common in the pipeline industry and is only carried out by specialist operators of hydrogen pipelines. However, pigging during cleaning, commissioning and maintenance of hydrogen pipelines is a safety critical operation. Besides the increased explosion risk with hydrogen compared to natural gas, hydrogen is lower density than natural gas so speed control of the pig could be challenging.

Guidance for the safe launching and receiving of pigs in hydrogen service is provided in a reference from T.D. Williamson [15].

In addition to safety concerns, there are also possible material compatibility issues with hydrogen. Modifications of metallic components (brushes, magnets, etc.) may be required for hydrogen specific service. Also, some of the elastomers and polymeric materials may not be fully suitable for hydrogen service. Increased risk of static electricity is also possible and should be part of any pre-job risk assessment.

7. Conclusion

The contaminants found in natural gas transmission pipelines are very diverse in nature. A distinction is made between solids, liquids and volatile/gaseous components. This last group of components will largely be removed during displacement with nitrogen, before switching to hydrogen. The focus is therefore on the solids and liquids (volatile or not). The solids consisting of, among other things, sand, black powder, coating particles, lubricating grease, etc., which may or may not have been lubricated with oils, glycols and natural gas condensates, in short, a greasy feeling mass. The pipe walls are partly contaminated with this mass, has been collected in siphons, dead ends and in valve cavities. The amount of contamination present per pipe section is a question mark. In order to be able to estimate the degree of pollution present in a natural gas transmission pipeline, it is necessary to base itself on quantities and qualitative descriptions found after a pig run. It should be noted that materials enclosed in dead ends and at branch ends are not removed with a pig-run. To this end, a cleaning protocol is proposed in Chapter 6.

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