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TÍTULO DO TRABALHO:

LIFE EXTENSION ANALYSIS OF RIGID SUBSEA PIPELINES

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Resumo

Dutos submarinos rígidos são essenciais para a viabilidade econômica da produção offshore de petróleo e gás, ao fornecer um método de transporte confiável e eficiente para os recursos extraídos, transportando hidrocarbonetos. Os dutos estão expostos a muitas ameaças diferentes ao longo de toda a sua vida útil, desde o comissionamento até o descomissionamento. Para otimizar a utilização da infra-estrutura existente, maximizar o valor dos ativos e adiar os custos substanciais associados à substituição dos dutos, o prolongamento da vida útil é uma opção. A extensão da vida útil refere-se ao processo de prolongar a vida útil operacional além da inicialmente pretendida, envolvendo uma avaliação abrangente da condição do duto, incluindo avaliação de integridade, inspeção e programas de monitoramento. Com base na avaliação de fatores como corrosão, fadiga e integridade mecânica, são implementadas medidas adequadas de manutenção e reparo para garantir uma operação contínua, segura e confiável. No geral, o prolongamento da vida útil requer uma abordagem holística que equilibre fatores técnicos, regulamentares e económicos para prolongar de forma sustentável a vida útil operacional de infra-estruturas críticas offshore. Neste contexto, o objetivo deste artigo é demonstrar a aplicação de uma metodologia de extensão de vida para avaliar as condições atuais e os riscos relacionados à operação de vida prolongada após a vida útil projetada. A metodologia é baseada nos códigos NORSOK Y-002, NORSOK U-009, OLF GL No.122 e DNV DNV-RP-F116. O processo de extensão da vida útil é baseado na avaliação de risco dos modos de falha de cada duto. Ameaças relevantes são identificadas e usadas para avaliar a integridade de um duto, com base em informações de projeto, dados de processo e inspeções. A metodologia é aplicada a estudos de caso considerando 10 anos adicionais além de sua vida útil original para dois cenários hipotéticos de dutos rígidos submarinos na indústria de petróleo e gás. A avaliação é baseada na revisão dos modos de falha, avaliando a integridade atual do duto e as condições operacionais previstas. Também considera as medidas de mitigação necessárias para minimizar o risco de falha da tubulação durante a extensão da vida útil do projeto, expressa em termos de probabilidade de falha associada e risco associado. Os resultados demonstram a possibilidade de prolongamento da vida útil.

Palavras-chave: extensão de vida, dutos, gestão de integridade, offshore.

Abstract

Rigid subsea pipelines are essential for enabling the economic viability of offshore oil and gas production, by providing a reliable and efficient transportation method for extracted resources, transporting hydrocarbons. Pipelines are exposed to many different threats over their complete design life, from commissioning to decommissioning. To optimize the utilization of existing infrastructure, maximize asset value, and defer the substantial costs associated with pipeline replacement, life extension is an option. Life extension refers to the process of prolonging the operational lifespan beyond their initially intended service life, involving a comprehensive assessment of the pipeline's condition, including integrity assessment, inspection, and monitoring programs. Based on the evaluation of factors such as corrosion, fatigue and mechanical integrity, appropriate maintenance, and repair measures are implemented to ensure continued safe and reliable operation. Overall, life extension requires a holistic approach that balances technical, regulatory, and economic factors to sustainably extend the operational lifespan of critical offshore infrastructure. In this context, the goal of this paper is to demonstrate the application of a life extension methodology to assess current conditions and the risks related to extended life operation past the design life. The methodology is based on the codes NORSOK Y-002, NORSOK U-009, OLF GL No.122 and DNV DNV-RP-F116. The life extension process is based upon the risk assessment of failure modes for each pipeline. Relevant threats are identified and used to assess the integrity of a pipeline, based upon input from design information, process data, inspections. The methodology is applied to a study case considering an additional 10 years beyond its original design life for two subsea rigid pipelines hypothetical scenarios in the oil and gas industry. The assessment is based on the review of failure modes, assessing the current integrity of the pipeline, and predicted operating conditions. It also considers the mitigation measures required to minimise the risk of failure of the pipeline for the design life extension, expressed in terms of associated likelihood of failure and associated risk. The results demonstrate the possibility of the extension of service life.

Keywords: life extension, pipeline, integrity management, offshore.

Introduction

The majority of petroleum and natural gas volumes are transported by pipeline systems. Subsea pipelines are more economical, have high volume capacity, more reliable and safer because they are less vulnerable to the exposure to environmental and human exposure risks: Despite these benefits of the pipeline's usage, handling hydrocarbons requires an integrity and risk management program. The natural deterioration of the pipeline materials is a certain event, however there are many avoidable situations. Based on the Pipeline and Hazardous Materials Safety Administration (PHMSA) pipeline incident database, the pipeline incidents could be caused by six major reasons: corrosion failure (Internal and external), equipment failure, incorrect operation, third-party damage (excavation), material failure (pipe or weld – manufacturing, construction, or stress cracking) and natural force damage (Weather-related or outside forces) (CUI, 2017).

Offshore pipelines are in a hostile environment, adding the asset ageing in the equation results in the necessity to continuously evaluate the asset integrity to keep a safe operation, reduce the costs and extend the pipeline operational life. The considerable amount of oil, gas and minerals products transported in pipelines is enough to justify having an Asset Integrity Management (AIM) in place, however it is also a matter of company governance, Health, Safety, Environment (HSE) and regulatory requirements.

Worldwide many assets are achieving the end of their design life, however, with the new technologies and enhanced recovery techniques it is possible to amplify the years of hydrocarbon production. When considering production extension, to guarantee the integrity of the pipeline, a life extension study should be conducted. Life extension study of a transportation system such as subsea pipelines aim to provide a safe and cost-effective diagnosis if the pipeline is suitable for continuing operating beyond your design life.

The scope of this study is to illustrate the application of a methodology to determine the suitability for lifetime extension of two pipelines, evaluating potential threats and determining risk in line with a proposed risk matrix. The data considered for the study cases are hypothetical and merely illustrative of actual pipelines. The cases will be conducted considering the premises for the life extension, the data, and the possibility of re-qualify the pipelines accordingly. The design basis of the equipment is reviewed in line with historical operation and intended future operations for both pipelines. The assessments will focus on the current integrity status and might be able to identify anticipated future issues.

Methodology

The lifetime extension evaluation is a risk-based exercise driven by the risk of loss of containment due to leak, rupture, or collapse. A high-level methodology is presented in the following steps: 1) Data Collection and Review; 2) Condition and Risk Assessment; 3) Assessment of the remnant life of the system. The matrix on Table 1 will be considered. Present risk scores are allocated to each segment and a future risk is also applied to demonstrate the assessed risk to extended CoP. The consequence of failure ranking is based on Safety, Cost and Environment. The life extension process is based upon the risk assessment of failure modes for each pipeline. Relevant threats are identified and used to assess the integrity based upon input from design information, process data, inspections, and surveys.

Table 1 - Risk Matrix. Source page 101, DNV RP-F116.

Increasing consequences →	Consequence Categories				Increasing probability				
					1	2	3	4	5
	Severity	Safety	Environment	Cost (million Euro)	Failure is not expected $< 10^{-5}$	Never heard of in the industry $10^{-5} - 10^{-4}$	An accident has occurred in the industry $10^{-4} - 10^{-3}$	Has been experienced by most operators $10^{-3} - 10^{-2}$	Occurs several times per year $10^{-2} - 10^{-1}$
	E	Multiple fatalities	Massive effect Large damage area, > 100 BBL	> 10	M	H	VH	VH	VH
	D	Single fatality or permanent disability	Major effect Significant spill response, < 100 BBL	1 - 10	L	M	H	VH	VH
	C	Major injury, long term absence	Localized effect Spill response < 50 BBL	0.1 - 1	VL	L	M	H	VH
	B	Slightly injury, a few lost work days	Minor effect Non-compliance, < 5 BBL	0.01- 0.1	VL	VL	L	M	H
	A	No or superficial injuries	Slightly effect on the environment, < 1BBL	< 0.01	VL	VL	VL	L	M

Risk	Description
VH	Unacceptable risk – immediate action to be taken
H	Unacceptable risk – action to be taken
M	Acceptable risk – action to reduce the risk may be evaluated
L	Acceptable risk
VL	Insignificant risk

Key threats to be assessed are shown in the risk assessments matrices. Table 4 presents the design information for the two pipelines (P1 and P2). It is assumed that the current composition of oil and gas will be maintained up to the extended life period. The Production Rate is 310 MMSCFD (gas) / 250 MMSCFD (Oil and Gas), deferred Deferred Production Cost: \$5,000 MMSCF (gas) / \$5,500 MMSCF (oil and gas), equity Share: 100%. Table 5 presents the production data. P1 is unpiggable, P2 had a recent internal inspection using metal loss inspection pig, no previous inspection. Table 3 shows a summary of the in-line inspection (ILI) findings. Table 2 consolidates main ROV survey results. Intervention resources are shown on Table 6 and Table 7.

Table 2 - ROV Findings Summary

	P1		P2	
Type of Anomalies	Number Reported Features	Description	Number Reported Features	Description
Anodes	0	Overall Pipeline CP potential limits were from -820mV to -1043mV. Due to pipeline rock dumped no anodes were visible during the survey and the potential profile is generated from measured pipeline end point potentials using a proximity probe.	0	Overall Pipeline CP potential limits were from -845mV to -1028mV. Due to pipeline burial no anodes were visible during the survey and the potential profile is generated from measured pipeline end point potentials using a proximity probe.
Burial	2	It is observed that pipeline is buried at two locations and none were considered anomalous.	5	Buried flowline. 5 areas in which the DOC <1m, the longest distance of the lack of cover is 0.050 m.
Damage	1	One area of concrete coating exposure with no relevant damage was observed, possibly trawl scar evidence.	0	No damage recorded.

Table 3 - P2 summary of the ILI findings

Feature	Number Reported	Deepest Feature
Internal Corrosion	1,075	61%
External Corrosion	0	-
Girth Weld Anomaly	5	30%
Girth Weld Irregularity	10	-
Milling Anomaly	12	19%
Dent	7	3% max ID reduction

Table 4 - Pipelines Design information

Parameters	Pipeline P1	Pipeline P2
Product	dry gas	mix oil and gas
Service	sour	sour
Water depth	shallow water	deep water
Installation Date	1994	1995
Nominal Pipe Size (mm)	273.05 (10")	508 (20")
Wall thickness (mm)	11.1	14.27
Total Pipeline Length (km)	5	40
Steel Grade	API 5L X52	API 5L X60
SMTS (MPa)	455	517
SMYS (MPa)	358	414
Design Pressure (barg)	149	140
MAOP (bar)	149	100
Design life (years)	30	30
Design temperature (°C)	5 / 45	5 / 40
External corrosion coating type	asphalt Enamel	asphalt Enamel
No. of anodes	10	not known
Anode type	sacrificial Anode	sacrificial Anode
Corrosion Allowance (mm)	0	2
Insulation/Coating thickness	concrete 50.8 mm	-
Exposure Condition	seabed (rock dumped)	buried

Table 5 - Safe Operating Limits and production data

Pipeline Info		Production Information			
Pipeline	Item	Average	Minimum	Maximum	Unit
P1	Pressure	115.00	0.08	150.00	Barg
P2	Pressure	35.00	10	42.00	Barg
P1	Temperature	20.00	5	33.00	Celcius
P2	Temperature	30.00	5.20	43.00	Celcius
P1	H2S	0.05	0.00	0.23	ppm
P2	H2S	0.50	0.00	1.00	ppm
P1	CO2	0.00	0.00	0.00	ppm
P2	CO2	0.50	0.1	0.60	ppm
P1	Water Content	0.00	0.00	0.00	vol %
P2	Water Content	3.20	2.4	4.00	vol %

Table 6 - Repair Resource Summary

Resource Type	Day Rate ($)	Mobilisation + Demob Time (days)
ROV / Rock Dump Vessel	$165,000.00	14
Pipe Lay Vessel (including support vessels)	$220,000.00	30
Personnel (onshore and offshore)	$5,000.00	2

Table 7 - Material summary

Material	Cost ($)
Rock / sandbags / Clamps	$15,000.00
10 m of pipeline	$55,000.00
Equipment hire - ROV survey (CathX cameras, Digital Video Recorders, monitors, laptops, IT spares, lighting, etc)	$250,000.00
Other - Anode Retrofit (seafastening, rigging, multibeam sonar kit)	$23,000.00

Results and Discussion

1. Pipeline P1:

To prevent external corrosion, the pipeline is safeguarded with coating and rock dumps. They serve as the primary defence barrier, isolating the carbon steel pipeline from its corrosive environment, and if the first barrier breaks, the cathodic protection acts as a backup. As long as the protection offered by the Cathodic Protection (CP) system remains within design limits, external corrosion of the subsea pipeline is considered unlikely. Considering the operational or production history, data presented on Table 5, the operating pressures and temperatures have remained mostly within design limits during the whole life so far, there were occasional short pressure excursions that are not concerning as they were below 110% of the MAOP. Sulphide stress corrosion cracking (SSCC) and CO_2 corrosion are mitigated by dew point control and continued monitoring on maximum levels is needed. Internal corrosion requires water content to form the acid, the dew point suppressed in very low temperatures (average of -46 degrees Celsius), therefore it is practically not possible to have free water in the pipeline hence internal corrosion are expected to be negligible.

For pipelines an inhibited corrosion rate, CRin, in the order of 0,1 to mm/year shall be used as per NORSOK best practise. This pipeline is inhibited by not having water presence. The minimum wall thickness (t_{nom}) required for pressure containment is a relevant verification. It was used PD 8010 method to calculate the t_{nom} to avoid bursting and plastic collapse, which was found to be 8.5 mm. Considering a MWT of 11.1 mm at the moment of the study and given corrosion rate of 0.1 mm/year, and the minimum wall thickness required (8.5 mm), the estimated remnant life would be expected to be more than the 10 years. Based on the remnant life, internal corrosion is not considered to be a threat to this pipeline during extended operation.

The review of CP records indicates the potential are within the acceptable limit, thus the pipelines should be effectively protected along its entire length. However, the potential readings have degraded below -1050mV (full protection according to DNV-RP-F103) reaching -820mV which indicates anodes depletion. It will be necessary to perform a CP retrofit study to provide protection for the extended life of this flowline.

Overall, the rock dump provides resistance to pipeline upheaval, protection from fishing interaction, dragged anchors and dropped objects, and additional resistance to pipeline instability. The pipeline in general seems to be well supported.

Trawling activity is considered high along the flowline route; there was one occasion of rock dump movement recorded which exposed the pipe however, no significant pipeline coating damage was reported, Therefore, the rock dump is proven to be a good barrier against current trawling activity. It is recommended to maintain regular survey of the pipeline, report any damages or trawl scars on seabed and monitor changes in design codes and size / weight of trawling equipment. If there are significant increases in trawling activities, trawl board sizes or scars on seabed, then further mitigating actions should be performed.

Table 8 shows a summary for P1. From the risk matrix, it can be concluded that financial consequence is the driving consequence scenario for the pipeline. Taking into consideration the assessment, P1 can have its life extended for 10 more years, having the mitigation actions recommended in this study in place.

Table 8- Risk assessment for pipeline P1

Current Condition											Future Condition								
Threat	Current Integrity Status	Failure Mode	Mitigation in place	LoF	Consequences			Risk Level			Recommended Actions	LoF	Consequences			Risk Level			
					Financial	Environment	Safety	Financial	Environment	Safety			Financial	Environment	Safety	Financial	Environment	Safety	
Pipeline P1 – dry gas pipeline rock dumped in shallow water																			
Internal Corrosion Threats																			
CO2 corrosion	It is a dry gas pipeline, with no water content (%) and CO2 (ppm) present, so at the moment of the inspection, this does not present a threat. Pipeline is unpiggable, hence no ILI information available. Corrosion inhibitor/coupons data is not available at this moment. The corrosion rate considered of 0.1mm/year as per NORSOK, predicted remaing wall thickness of pipeline expected to be sufficinet for 10 years of life extension.	Leak	•Control of dew point / Gas dehydration	1	D	C	A	L	VL	VL	Good practices: 1. Revaluate the corrosion inhibitor plan and data after the next integrity assessment. 2. Maintain process parameters and fluids within the design basis envelope, according to the corrosion management plan. 3. Extract and analyse corrosion coupons on a periodic basis. 4. Perform and keep an internal corrosion modelling updated. 5. Perform a Risk Based Inspection (RBI) to optimize the inspection period accordingly with the damage mechanisms.	1	D	C	A	L	VL	VL	
H2S corrosion	The highest concentration of H2S observed was 0.23 ppm. This below the limit of 11 ppm. H2S content is expected at negligible values.	Leak	•Sour service graded •Control of dew point / Gas dehydration	1	D	C	A	L	VL	VL		1	D	C	A	L	VL	VL	
Sulphide stress corrosion	Based on peak in the last production data, the pipeline has been operating within the allowable limits presented on Table 10. Therefore, the risk of H2S related cracking is very low.	Rupture	•Sour service graded •Control of dew point / Gas dehydration	1	E	D	A	M	L	VL		1	E	D	A	M	L	VL	
External Corrosion Threats																			
External Corrosion	No instances were recorded, most of the pipe is rock dumped with one concrete exposure throughout the line.	Leak	•Corrosion Coating Asphalt Enamel •Cathodic Protection	1	D	C	A	L	VL	VL	1. Maintain regular visual inspections and CP surveys. 1.1 Perform a Risk Based Inspection (RBI) to optimize the inspection period accordingly with the damage mechanisms. No information on inspection plan in place, it is recommended to share to the IM specialist in the next IM assessment. 2. Evaluate other alternatives within ILI companies for unpiggable pipelines is recommended. There are different technologies and options. A metal loss measurement through MFL In-Line Inspection (ILI) to monitor the possibility of initial/new defect growth due to internal corrosion is recommended, if feasible.	1	D	C	A	L	VL	VL	
Cathodic Protection Failure	Overall Pipeline CP potential limits were from -820mV to -1043mV. Due to pipeline rock dumped no anodes were visible during the survey and the potential profile is generated from measured pipeline end point potentials using a proximity probe. The CP system is designed for 25 years. The depletion of the anodes will continue as the anodes are active.	Leak	•Remaining anodes •CP Surveys	3	D	C	A	H	M	VL	1. As actual anodes may not reach extended lifetime (more 10 years) and the CP level could rise above limit raising the risk of corrosion, CP retrofit is recommended. 2.Maintain regular visual inspection and CP surveys. 3. Perform a Risk Based Inspection (RBI) to optimize the inspection period accordingly with the damage mechanisms. No information on inspection plan in place, it is recommended to share to the IM specialist in the next IM assessment.	2	D	C	A	M	L	VL	
Coating / insulation damage	There is one area of concrete coating damage, possible trawl scar. However, not considered an issue at this moment as the carbon steel was not exposed.	Leak	•Coating 50.8 mm concrete •Cathodic Protection	2	D	C	A	M	L	VL	1. Perform a Risk Based Inspection (RBI) to optimize the inspection period accordingly with the damage mechanisms. No information on inspection plan in place, it is recommended to share to the IM specialist in the next IM assessment. 2. Perform regular inspections with ROV on the subsea pipeline section to monitor: instances of significant dropped objects, trawling activities's damages in the pipeline, pipeline crossings and possible movements, spans, pipeline coating and any other pipeline features. 3. Track trawling activities in the region and keep up to date on new trawling equipment specifications is recommended. If there is any change on the specifications, revaluation on the life extension might be necessary. 4. Cover the exposed area with rock dump again.	1	D	C	A	L	VL	VL	
Trawling	Pipeline is located in shallow water, on a high fishing activity in the area. Debris such fishing net on pipetrack were recorded. One area recorded in this pipeline with possible trawling scar.	Rupture	•Pipeline rock dumped	1	E	D	A	M	L	VL		1	E	D	A	M	L	VL	
Buckling	The pipeline is buried at two locations, but none were considered anomalous. Upheaval buckling was considered in original design as the pipeline is laying in the seabed. However, it is mostly rock dumped within the line length. Furthermore, no instance of it has been reported in any of the survey.	Rupture	•Design basis •Rock dump	1	E	D	A	M	L	VL	1. Keep monitoring the pipeline in the next planned ROV inpection for any spans or UHB. If there are any recorded, monitor development and evolution. - If span exceeds the maximum allowable limit, further assessment should be performed to expand the length or plan maintanance accordingly, such as potentially perform rectification of the span using sandbags, rock dumping, etc. - If an UHB occurs, fatigue analysis should be performed and the integrity assessment updated. 2. Perform a Risk Based Inspection (RBI) to optimize the inspection period accordingly with the damage mechanisms. No information on inspection plan in place, it is recommended to share to the IM specialist in the next IM assessment.	1	E	D	A	M	L	VL	
Span fatigue	No spans were recorded.	Rupture	Design basis / DFI	1	E	D	A	M	L	VL		1	E	D	A	M	L	VL	

2. Pipeline P2:

The review of CP records indicates the potential are within the acceptable limit according to Table 2 thus the pipelines are externally protected along its entire length. However, potential readings have degraded below -1050mV (full protection according to DNV-RP-F103) reaching -845mV which indicates anodes depletion. It will be necessary to perform a CP retrofit study to provide protection for the extended life of this flowline.

The majority of pipeline P2 is coated with asphalt enamel and has additional external corrosion protection by Catholic Protection system, with all anodes observed appearing to be active and the CP measurements within the standards limits. No mechanical damage was reported. Therefore, external corrosion is not a threat at this moment.

The pipeline is sour service graded, providing protection from H2S corrosion cracking. It is buried, and has the asphalt coating, those combined provides thermal insulation and protection to P2 to avoid sufficient to prevent condensation of water, hence internal corrosion should not become a relevant integrity threat. However, for this case it is still observed CO_2 and water production, which can explain the internal corrosion anomalies.

Decades ago, corrosion control was poorly managed which might have led to the initiation of corrosion. Internal corrosion was reported being spread across the length and circumference of the pipeline. In general, they are shallow anomalies (majority <=20% wall loss (wl)), which suggests that the corrosion management strategy has been helping to slow the corrosion process. No reported anomaly clusters or interacting anomalies, decreasing the risk of failure of this pipeline. No recent inspection data was available regarding verifying wall thickness of the pipeline, as there are some anomalies considered medium severity (>=50% wl), hence it is recommended that an ultrasonic in-line inspection is performed as soon as possible during the next pigging campaign.

Further corrosion inhibitor information should be made available in the next integrity assessment to be performed, as it has an impact on the corrosion growth and future maintenance planning. The corrosion inhibitor was applied to the pipeline system as part of the corrosion management strategy at the required rates and quantities to limit the corrosion rate. For the MEG @ 70 weight% the results provided a corrosion rate of 0.25 mm/year. Adopting 0.25 mm/year calculated via NORSOK M-506 method, all anomalies are not expected to breach unacceptable limits until November 2034. However, it is recommended to continue the ongoing corrosion inspection and monitoring, especially as there are two anomalies which are closer to reach the repair phase when achieving 10 years of life extension.

The inspections frequencies and corrosion monitoring system need to be maintained properly to ensure periodic data retrieval in line with the corrosion monitoring program requirements to guarantee the safety for operations continuity and the correct recalculations of corrosion growth and pipeline remaining life. Following the next ILI run, a technical assessment for the pipeline should be carried out to assess the integrity and revise the remaining life. This data should then be reviewed in line with the data obtained previously to allow trending of defects. It will ensure safe operation of the pipeline, will confirm the corrosion distribution within the pipeline and demonstrate the effectiveness of the corrosion management and current corrosion mitigation plan.

Areas with Depth of Cover (DOC)<1 m were reported, a further depth of burial assessment is recommended to understand if they have relevant potential for buckling in the future. All these areas are recommended for future monitoring and should be included in an RBI study to keep monitoring.

The possibility to buckle upwards exists for P2, however it is buried hence it provides enough downward force to prevent UHB. The download requirement (weight on the pipeline) is a function of mainly the temperature, but high pressures play a part in the expansion, driving buckling force. Its design temperature is typically low (<= 30 degrees Celsius), pressure was kept on an average of 35 barg, it has a large diameter (20”). In this case, temperature and pressure were maintained within the operational limits, no sign of cyclic loading as well. Therefore, the risk of buckling is considered low at this moment, future monitoring in the areas with DOC<1m is recommended.

Table 9 shows the risk assessment for pipeline P2. From the risk matrix, it can be concluded that financial consequence is the driving consequence scenario for the pipeline. Taking into consideration the assessment, P2 can have its life extended for 10 more years, having the mitigation actions recommended in this study in place.

Table 9 - Risk assessment for pipeline P2

Current Condition											Future Condition							
Threat	Current Integrity Status	Failure	Mitigation in place	LoF	Consequences			Risk Level			Recommended Actions	LoF	Consequences			Risk Level		
					Financial	Environment	Safety	Financial	Environment	Safety			Financial	Environment	Safety	Financial	Environment	Safety
Pipeline P2 - mix of oil and gas pipeline buried in deep water																		
Internal Corrosion Threats																		
CO2 corrosion	It is a mix of oil and gas pipeline, with recorded water content (%) and CO2 (ppm) instances above the design limits which can cause or worsen internal corrosion. For water, highest concentration being 4 vol% (limit of 3 vol%); CO2 0.6ppm for a limit of 0.5. Following the ILI inspection, internal corrosion was reported, most of the anomalies have shallow depths, below 50% wall loss (wl). However, it was observed anomalies between 50% and >=61% wl. Following this initial 'screening' assessment (preliminary FFS), the immediate integrity assessment shows that the corrosion anomalies reported by the inspection were acceptable for operation, in terms of their axial length and depth dimensions at the time of the inspection when assessed at the assessment Pressure of 139 bar. The corrosion rate calculated by NORSOK M-156 provided 0.25mm/year (mitigated), all anomalies pass the expected life extension, the severe instances need a closer follow up and recalculation the expected	Leak	•Corrosion allowance (2 mm) •Corrosion inhibitor	3	E	D	A	VH	H	VL	1. Revaluate the corrosion inhibitor plan and data after the next integrity assessment. 1.1. Conduct metal loss and wall thickness measurements through MFL and UT In-Line Inspection (ILI) to monitor the possibility of initial/new defect growth due to internal anomalies and monitor possible cracking anomalies. 1.2 Carry out current and future integrity study on the pipeline if ILI is performed in the future. 2. Maintain process parameters and fluids within the design basis envelope. 2.1 Share with the specialists analyzing the life extension the corrosion inhibitor plan and data for the next integrity assessment for further evaluation. Injection of corrosion inhibitor should be adjusted according to the water cut. 3. Extract and analyse corrosion coupons on a periodic basis. 4. Perform and keep an internal corrosion model and rate updated. 5. Perform a Risk Based Inspection (RBI) to optimize the inspection period accordingly with the damage mechanisms. No information on inspection plan in place, it is recommended to share to the IM specialist in the next IM assessment.	2	E	D	A	H	M	VL
H2S corrosion	The highest concentration of H2S observed was 1 ppm. This below the limit of 2.6 ppm. H2S content is expected at negligible values.	Leak	•Corrosion allowance (2 mm) •Sour service graded	1	D	C	A	L	VL	VL		1	D	C	A	L	VL	VL
Corrosion Cracking (SSCC)	Based on peak in the last production data, the pipeline has been operating within the allowable limits with instances of CO2, H2S and water content above the limits. Corrosion cracking might occur. However, as the pipeline has corrosion inhibitor, sour graded, and corrosion management strategy, the risk sulfide stress corrosion cracking is low. Furthermore, regarding the dent anomalies, all are within allowable limits, no anomaly combination reported and they are not expected to grow. The risk of H2S and CO2 related cracking is considered "negligible".	Rupture	•Corrosion allowance (2 mm) •Sour service graded	1	E	D	A	M	L	VL		1	E	D	A	M	L	VL
External Corrosion Threats																		
External Corrosion	No external anomalies were recorded, the current probability for failure due to external corrosion is considered "negligible".	Leak	•Corrosion Coating Asphalt Enamel •Cathodic Protection	1	A	A	A	VL	VL	VL	1. Maintain regular ILI inspections, with metal loss measurement through MFL ILI to monitor the possibility of initial/new defect growth due to external corrosion. 1.1 Perform a Risk Based Inspection (RBI) to optimize the inspection period accordingly with the damage mechanisms. No information on inspection plan in place, it is recommended to share to the IM specialist in the next IM assessment. 2. Calculate the rate of corrosion based on two latest in-line inspection records, if any corrosion is found in the future.	1	A	A	A	VL	VL	VL
Cathodic Protection Failure	Overall Pipeline CP potential limits were from -845mV to -1028mV. Due to pipeline rock dumped no anodes were visible during the survey and the potential profile is generated from measured pipeline end point potentials using a proximity probe. The CP system is designed for 25 years. The depletion of the anodes will continue as the anodes are active.	Leak	•Remaining anodes •CP Surveys	3	D	C	A	H	M	VL	1. As actual anodes may not reach extended lifetime and the CP level could rise above limit raising the risk of corrosion. CP retrofit is recommended. 2. Maintain regular visual inspection and CP surveys. 3. Perform a Risk Based Inspection (RBI) to optimize the inspection period accordingly with the damage mechanisms. No information on inspection plan in place, it is recommended to share to the IM specialist in the next IM assessment.	2	D	C	A	M	L	VL
Coating / insulation damage	No pipe metal and coating exposures were recorded, the current probability for failure due to coating or insulation damage is considered "negligible".	Leak	•Cathodic Protection •Buried pipeline	1	A	A	A	VL	VL	VL	1. Maintain regular visual inspection. 1.1 Perform a Risk Based Inspection (RBI) to optimize the inspection period accordingly with the damage mechanisms. No information on inspection plan in place, it is recommended to share to the IM specialist in the next IM assessment.	1	A	A	A	VL	VL	VL
Buckling	The pipeline was designed to be buried with a cover of 1m primarily for protection. There are instances that the burrial is less than the 1m, however, the current probability for failure due to upheaval buckling is considered "negligible".	Rupture	•Design basis / DFI •Buried pipeline	1	A	A	A	VL	VL	VL	1. Maintain regular visual inspection. 1.1 Perform a Risk Based Inspection (RBI) to optimize the inspection period accordingly with the damage mechanisms. No information on inspection plan in place, it is recommended to share to the IM specialist in the next IM assessment.	1	A	A	A	VL	VL	VL
Span fatigue	No instances were recorded, pipeline is buried.	Rupture	Design basis / DFI	1	A	A	A	VL	VL	VL	1. Maintain regular visual inspection. 1.1 Perform a Risk Based Inspection (RBI) to optimize the inspection period accordingly with the damage mechanisms. No information on inspection plan in place, it is recommended to share to the IM specialist in the next IM assessment.	1	A	A	A	VL	VL	VL

Conclusions

Overall, life extension studies are relevant to guarantee safety of the operations and to provide technical, regulatory, and economic considerations to sustainably extend the pipeline lifespan. In cases where assets are expected to operate beyond their originally intended service life, duty holders must provide evidence that the asset maintains adequate integrity and meets the necessary standards for the designated extension period. The study cases successfully demonstrated the analysis process of a life extension assessment through the application of the methodology described. Following the assessment of the integrity data available for P1 and P2 and the threats to the integrity of the system during an extended operational period of 10 years, it has been concluded that the design life of the pipelines can be safely extended for ten years from their design life. This is subject to the completion of the recommended actions detailed in the risk assessments (Table 8 and Table 9).

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