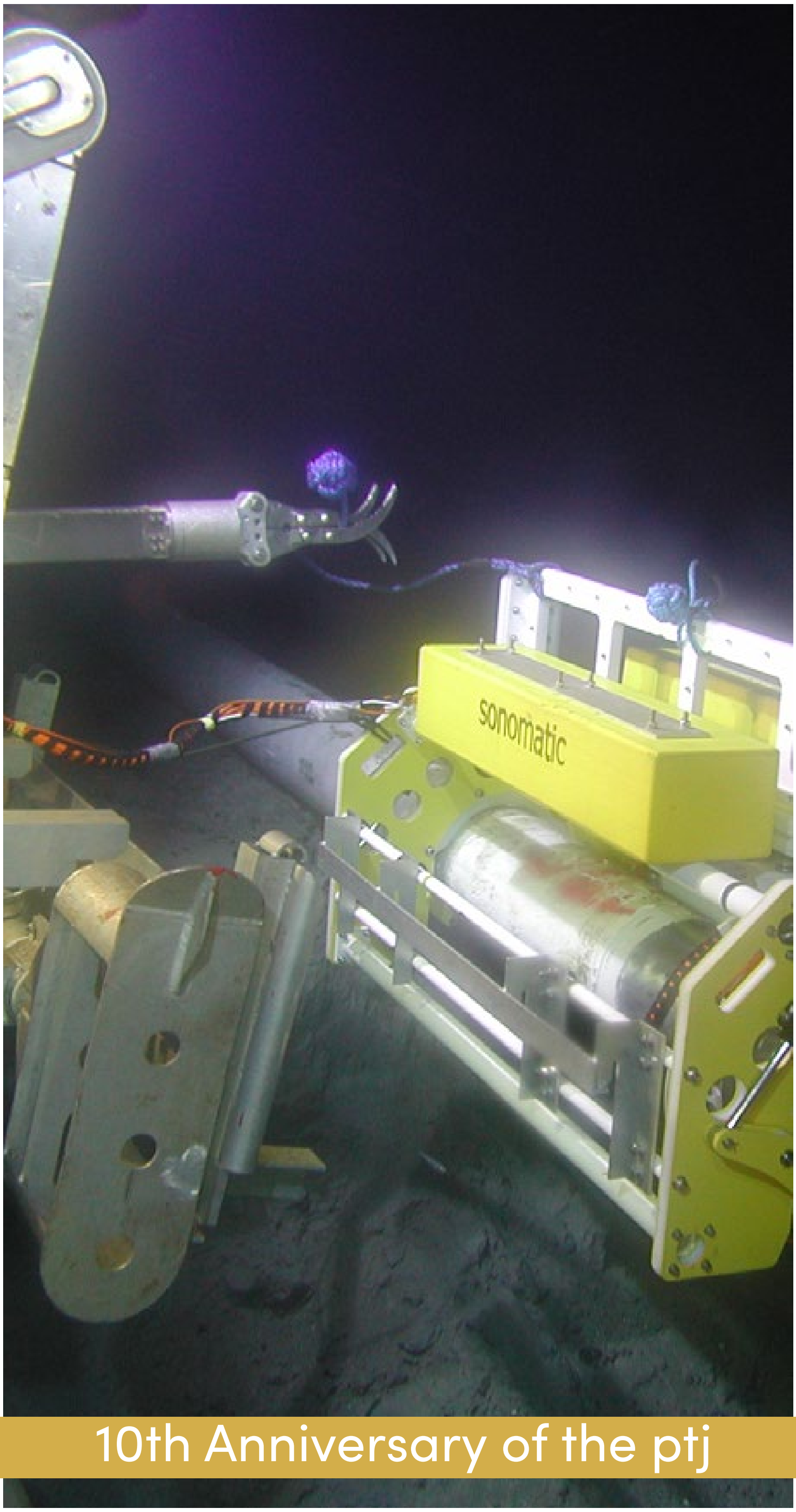
1/2023

Pipeline Technology Journal

Offshore & Subsea Technologies



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WWW.PIPELINE-JOURNAL.NET

e-ISSN 2196-4300 / p-ISSN 2751-1189

Offshore Pipeline & Subsea Technologies

Mohd Nazmi bin Mohd Ali Napiah
Custodian/Head/GTA (Pipeline)
Engineering Department,
Group Technical Solutions
Project Delivery & Technology Division

PETRONAS

Apart from typical technical and operational challenges of onshore pipelines i.e. 3rd party, corrosions, geohazards; offshore pipelines and subsea facilities have additional challenges i.e. logistics and weather-related, ultra-high pressure/temperature for ultra-deep/deep water. Thus, that's the reason why the front-end loading (FEL)/design stages are very crucial for offshore pipelines and subsea systems so that all challenges/issues are taken into consideration that the pipelines and subsea facilities can be operated and maintained with utmost reliability and integrity. Not to mention that comparatively higher cost of installation/construction, hook-up, pre-commissioning, commissioning and abandonment for offshore pipelines and subsea facilities require continuous innovations and emerging technologies so to maintain that any greenfield and brownfield project/development will be feasible throughout its entire operating life.

Having said, the role of Industrial Revolution 4.0 (IR4.0) could be the 'game changer' in the offshore field development that also include pipelines and subsea technologies. The IR4.0 elements of robotic, automation, sensors/IOTs, data analytics, advance material and advance engineering will help O&G companies or operators reduce or optimise the project/development and operation and maintenance (O&M) cost. For instance, the use of innovative pipeline joining method of mechanical interference fit connector has been used in PETRONAS and several other companies to replace conventional welding method; and the method could provide similar reliability and integrity as required by common pipeline codes and standards.

The other example would be the use of fully autonomous robotic inline inspection to inspect the condition of O&G pipelines that could provide a cost-optimization alternative. It needs to be noted that current available technologies including the innovations from IR4.0 have their limitations and operating boundaries; and it is believed that there are innovators out there that continuously challenging the status-quo so that we, the O&G companies and its stakeholders could reap the benefits of any emerging and pacing technologies, moving forward.

Your sincerely,

Mohd Nazmi bin Mohd Ali Napiah
Custodian/Head/GTA (Pipeline)
Engineering Department, Group Technical Solutions
Project Delivery & Technology Division

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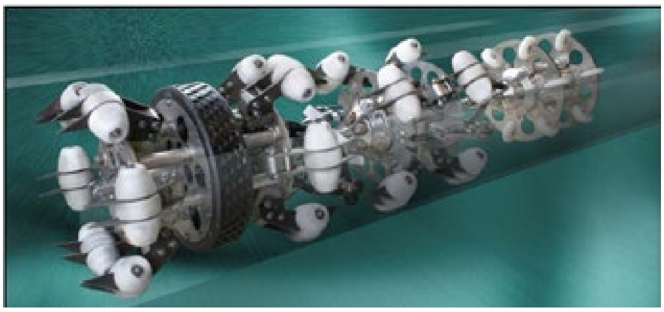
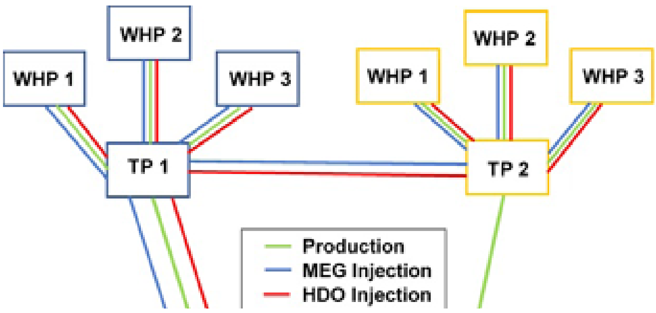
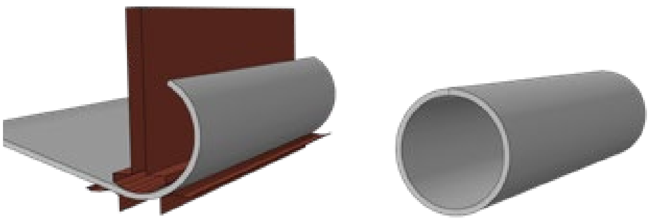
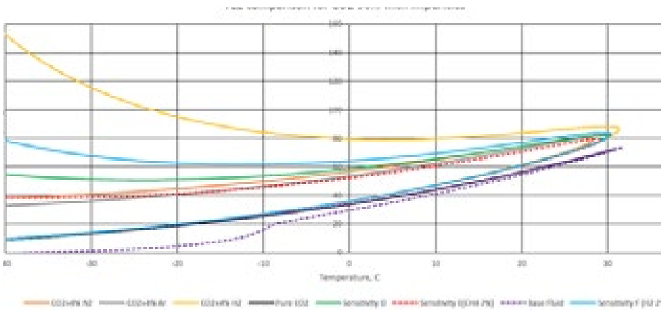
This Issue's

COMPLETE CONTENT









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www.pipeline-journal.net
ptj@eitep.de

PUBLISHER
Euro Institute for Information
and Technology Transfer GmbH
Marie-Jahn-Straße 20
30177 Hannover, Germany
Tel: +49 511 90992-10
URL: www.eitep.de

ISSN
e-ISSN: 2196-4300
p-ISSN: 2751-1189

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DE 182833034

EDITOR IN CHIEF
Dennis Fandrich
E-Mail: d.fandrich@eitep.de
Tel: +49 511 90992-22

EDITORIAL BOARD
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TERMS OF PUBLICATION
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EDITORIAL MANAGEMENT
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E-Mail: m.ritter@eitep.de
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Constantin Schreiber
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ADVERTISING
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Joining YPPE has opened up a network of likeminded pipeliners. I feel part of a movement that wants to make a difference - all whilst having fun!

Kirsty McDermott, Senior Engineer

Let's shape the future of pipelines

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ptc 2023 promotes the development of young talent in the pipeline industry

The 18th Pipeline Technology Conference (ptc) is set to take place in Berlin from May 8-11, 2023. Europe's premier address for pipeline industry professionals will offer a look into the pipeline future, with a broad range of 1-day seminars, panel discussions, technical sessions, operator round-tables, award ceremonies and social events.

ptc 2023 will bring together the industry elite – pipeline operators, industry leaders, experts, and young talent – to discuss the latest developments and advancements in pipeline technology. Key topics for 2023 will include hydrogen, methane emissions, safety & security, climate adaption, geo-hazards, CO_2 transportation and a regional focus on the booming African continent.

The gathering will also offer a multitude of technical presentations, including 6 concurrent technical tracks with more than 120 speakers. Participants will have an opportunity to learn from industry experts, network with peers, and form first-hand impressions of the latest trends and developments in the international pipeline industry. All papers will again be published on an open access basis.

Indeed, a special focus will again be devoted to the area of promoting young talent. ptc 2023 will feature a variety of opportunities for young people to get involved into the organization of the event and it will host different awards ceremonies for both students and young professionals. The EITEP Institute is committed to fostering the next generation of pipeline professionals and cooperates with different young pipeline professional communities from around the world.

The exhibition will showcase the latest products and services from leading pipeline operators and service companies. More than 85% of the exhibition stands are already booked.

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Innovation Brings Pipeline Back to Normal

Bespoke Technology Solutions Free Stuck Pig and Enable Valve Replacement, Allowing Production to Resume

R. G. LIE > T.D.WILLIAMSON

Abstract

Before the operator of a gas export pipeline offshore Asia could isolate the line and replace leaking pig trap valves on their platform and perform in-line inspection (ILI), they had to remove a serious obstacle: a cleaning pig that had stalled just beyond the pig launcher.

Because there is no standard tool for recovering a stalled pig, at least not without blowing down the pipeline, the operator contracted T.D. Williamson (TDW), who engineered, tested and deployed a bespoke recovery tool. The pig was removed in an operation that resulted in only five hours of downtime.

TDW then used in-line technology to isolate the pipeline and create a safe work zone for the valve replacement. TDW also developed a customized cleaning pig and a progressive pigging program to ensure the pipeline was sufficiently clean for both normal operation and ILI.

1. Introduction

Day in and day out, year after year, technology keeps up its end of the pipeline integrity bargain, enabling safe and efficient operation. Valves open and close effortlessly, cleaning pigs dispatch wax, water and contaminants, and the sensors of in-line inspection tools capture real-time data about cracks, dents and other anomalies. It all works like a well-oiled machine.

Of course, nothing in this world is infallible, and the occasional technical hiccup is not uncommon. In most cases, though, these problems can be resolved relatively quickly and with customary intervention.

But when a third-party service provider launched a 28-inch, bi-directional cleaning pig into a gas export line offshore Asia, they experienced more than a simple "technical hiccup." Their pig stalled just beyond the launcher isolation valve, stopping halfway into the barred production tee that prevents the pig from traveling down a branch connection. Although the pipeline wasn't completely obstructed, running a pipeline with a pig stopped inside is hardly a realistic operating scenario, even in the short term. In fact, the operator was rightly concerned that pressure and flow around the pig could eventually make a bad thing even worse, pushing the pig in far enough to block the pipeline entirely and shut down production.

Because there's no plug-and-play solution for a stalled pipeline pig — at least not without blowing down the entire pipeline, a financially and environmentally costly process — it would take engineered-to-order technology to recover the pig.

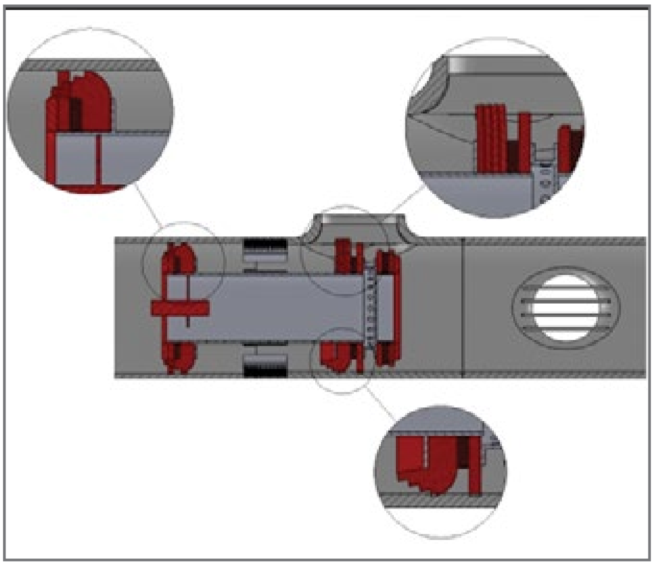


Figure 1: Bi-directional pig stuck in the barred production tee.

And that would be just the first step to bring production back to normal.

2. Avoiding Shutdown

Regular pigging activities are essential to integrity management. For gas export pipelines (GEP), though, the need is amplified. GEPs transport the entire production between the offshore field and the onshore processing terminal — in this case, hundreds of millions of standard cubic feet (MMSCF) per day. If anything causes the pipeline to go offline, the revenue stream dries up. That's an enormous risk no operator wants to take.

To avoid the possibility of shutdown, GEP operators run cleaning pigs daily, weekly or monthly, depending on production conditions. Pigging requires fully functional and well-maintained pipeline components at both the launching and receiving end of the pipeline, including pig traps, pig trap valves, and emergency shut down valves (ESDV). If any of them malfunction it can make pigging very difficult, if not impossible.

In this case, two pig trap valves located on the platform were not sealing completely, causing pressure buildup of the pig launcher during service and preventing regular pigging from being carried out. The operator had planned for their replacement and T.D. Williamson (TDW) was scheduled to deploy its in-line SmartPlug® isolation technology to create a safe offshore work zone while the pipeline remained in service.

Obviously, though, TDW couldn't launch the SmartPlug tool with a pig in the way.

With one challenge stacked on top of another, the operator needed to take action to make the pipeline piggable. That would allow them to resume normal pigging operations and perform a long overdue in-line inspection to check the pipeline's integrity. They turned the entire project over to TDW, whose multi-phase response began with the development of a bespoke pig recovery tool.

Ultimately, TDW

- Created and deployed a specially designed tool to recover the stalled pig by pulling it back to the launcher.
- Isolated the offshore section with SmartPlug® technology so the operator could replace the leaking valves, restore the integrity of the gas export line at the platform, and safely resume normal production.
- Developed a tailor-made cleaning pig and progressive pigging plan to prepare the pipeline for the intelligent pig run.

But before they could do any of that, TDW had to figure out why the other provider's pig stalled in the first place.

3. Hanging in the Balance

Pigging service providers know that a pig can stall during operation when a considerable amount of debris collects in front of it. To prevent this, they build "bypass" into the pig by drilling holes into the body or discs.

Bypass allows product to flow through and ahead of the pig as it travels through the pipeline, creating turbulence that flushes the debris or holds it in suspension.

Designing a pig with bypass requires striking a balance. Too little bypass and the pig won't create enough turbulent flow. Too much bypass and there won't be enough differential pressure behind the pig to drive it forward.

Most of the time, engineers find the middle ground. Unfortunately, in this case, the usual yin and yang of pig bypass design was slightly off. The (somewhat ironic) result: The bypass became the obstruction.

TDW engineers discovered that the pigging service provider had modified their bi-directional pig to allow a relatively large portion of gas to flow through it. On the face of it, this was not necessarily a negative: It was intended to allow for optimal turbulence ahead of the pig.

However, because of the pig's heavy polyurethane (PU) disc stack-up, more differential pressure was required to move it compared to a conventional bi-directional pig.

The imbalance was evident almost as soon as the pig was launched. Once the pig entered the barred production tee, the combination of large bypass and high differential pressure created even more bypass around the perimeter of the discs. This meant there was no longer enough differential pressure to push the pig through the tee. When a portion of the front disc package partly disengaged, creating even more bypass, insufficient drive on the discs caused the pig to stall.

4. Considering the Alternatives

With so much on the line in terms of both integrity management and throughput, the operator wasted no time considering various recovery strategies. It seemed like it might be possible to use another bi-directional pig to push the stalled pig back to the onshore receiver. However, this would increase the risk of the pig getting stuck farther into the pipeline. For example, if it became caught in one of the many bends in the subsea tie-in spool connection between the subsea pipeline and platform riser, a challenging subsea rescue would be required.

That left the project team with only one viable alternative: pulling the stalled bidirectional pig back to the launcher. While this would eliminate the risks associated with pushing the pig to the receiver, it was still no quick or simple fix. There's no standard rescue equipment to do the job.

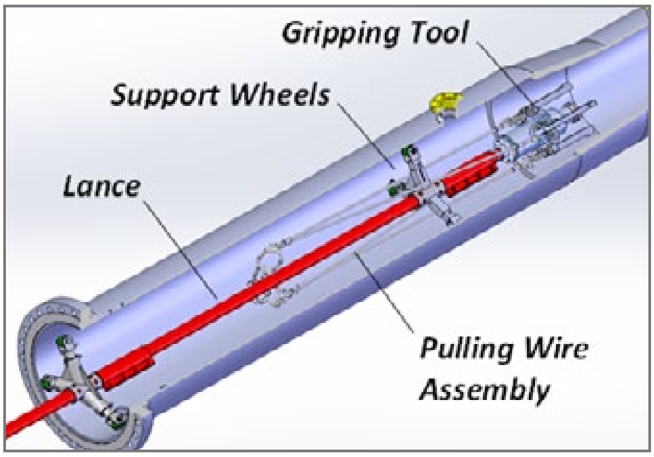


Figure 2: Lance with support and wheel assembly attached to gripping tool.

Instead, TDW engineered, designed, manufactured and tested an application-specific recovery tool at its Global Solutions Center in Stavanger, Norway.

5. First Things First

Engineers envisioned the pulling tool being a wire and hydraulic cylinder that would attach to a strong hold in the pig body on one end and a strong hold behind the launcher on the other.

One of the earliest steps in the tool design process was determining how much recovery force would be required to pull the pig back safely and successfully. The calculation was complicated by the fact that during pigging, the pig's polyurethane sealing discs fold backwards. To reverse the pig out of the pipeline would require enough pressure to flip and fold the discs in the opposite direction. If the discs failed to flip, the pig would remain stuck, unless an extreme force was exerted upon it, with potentially catastrophic results.

To conduct recovery force testing, TDW built a replica of the offshore pipeline launcher, including the barred production tee. To make the replica as authentic as possible, TDW also acquired a pig from the operator that was identical to one stalled in the pipeline.

Each test provided a better understanding of how to achieve a successful recovery.

- For the first test, technicians loaded the operator's pig into a straight section of the replica pipeline that was pressurized to the expected offshore level of approximately 3 bar (43 psi) then propelled it using water as the pigging medium. Once again, this pig stalled when it entered the barred tee. At a recovery force of 3.5 bar to 4 bar (50.7 psi to 58 psi) the discs partially burst instead of flipping, the pig didn't move and there was water leakage across the outer disc parameter.

- After inspecting the front disc pack, technicians repressurized the test pipe to 3.5 bar to 4 bar (50.7 psi to 58 psi) then reloaded and relaunched the pig. This time it moved a short distance before stalling — about a meter, or 3.2 feet — and water once again leaked across the disc perimeter. However, the front seal disc pack flipped; the rear disc pack, which was closest to the launcher, did not. When a hydraulic cylinder was used to push the pig from the test rig, every disc flipped but they were partially torn due to high stress and rear disc pack damage.

- Finally, during the third recovery test, the first of the four polyurethane discs stretched over the next three, reducing friction. All four discs flipped at a recovery force of 13 tons without touching the pipeline wall or becoming damaged.

With the optimal recovery force a known quantity, TDW engineers could move beyond their vision to a fully realized design.

6. Building on the Strong Points

Engineering a tool to pull a pig out of a pipeline involves making countless decisions, not the least of which is figuring out what part of the pig the recovery tool will grasp and how it will grip it. After all, unless the tool has a firm hold on the pig, there's no way anything will budge.

The TDW team agreed that the strongest gripping points for the recovery tool were the bypass holes, meaning the same elements that had contributed in this case to the pig stalling in the first place would be integral to the recovery process.

As for the tool itself, engineers designed it so spring-loaded pulling arms would engage or click in place inside the bypass holes then a locking mechanism lance would install the recovery tool onto the pig body. The tool configuration also included:

- Lance support wheel assemblies to centralize the locking lance in the pipe.

- A pulling wire arrangement.

- A hydraulic pulling cylinder furnished by TDW that included a "strong hold" anchor point arrangement supplied by the operator.

TDW also decided to use the pinger receptacle inside the stalled pig as a guidepost for inserting the gripping tool into the bypass holes. And to overcome poor visibility inside the pipeline, they incorporated a camera system into the recovery tool. This would help technicians "see" when the gripping tool successfully engaged inside the pig

7. Tested: Technology and Timelines

Engineers returned to the test rig, this time with the manufactured recovery tool in hand. Their goal was to assess the performance and efficacy of the entire tool, down to estimating how long the onsite procedure would take.

Figures 3-4: Recovery operation offshore.

TDW performed the recovery test using the operator-furnished bidirectional pig, now equipped with new discs. The engineering team monitored the amount of force required for the recovery tool to overcome inertia — the maximum encountered pulling force on the pig was measured at 15.4 tons or 360 bar (5221 psi) of hydraulic pressure in the pulling cylinder — and visually inspected the recovery tool and pig body post-test to ensure integrity. The dry run also enabled TDW to optimize procedures and to record the time it took to assemble the lance, engage the tool and retrieve the pig under nearly real-world conditions. With every hour the pipeline would be shut down for the recovery costing the operator valuable production, this test provided ample confidence that the pig could be rescued on an acceptable timeline.

In fact, once onsite, it took only five hours for TDW crews to:

- Open the quick-opening closure on the launcher.
- Assemble the lance and gripping tool and insert them into the pipeline.
- Lock the pig gripping tools into the pig bypass holes.
- Hook up the pulling wire.
- Begin the recovery operation.
- Retrieve the pig from the launcher.

All the planning, preparation and innovation had paid off. Now, with an obstacle literally no longer in their way, the SmartPlug team could take the project reins and prepare the line for valve replacement.

8. Creating a Safe Work Zone

Over time, normal wear and tear can take a toll on valves' internal seals and seat rings, causing them to leak. As a result, valve repair or replacement is considered somewhat routine.

But before any repair or replacement project can take place, operators first have to choose how they'll create a hydrocarbon-free work zone. The options are to depressurize the entire line or isolate just the affected section, which is done either by hot tapping and plugging or by using in-line technology.

Considering the enormous product volumes that gas export lines transport, it's no wonder operators try to avoid depressurizing them. A prolonged shutdown can run into the millions of dollars and require flaring off several hundred million cubic feet of gas, which is highly undesirable, especially when the world is watching its emissions. In this case, around 300 MMSCFS of inventory loss would incur if the pipeline was depressurized and, compared to in-line isolation, it would take an additional six or seven turnaround days, including the time involved to re-pressurize the pipeline.

Selecting the TDW SmartPlug in-line isolation system helped the operator avoid those losses.

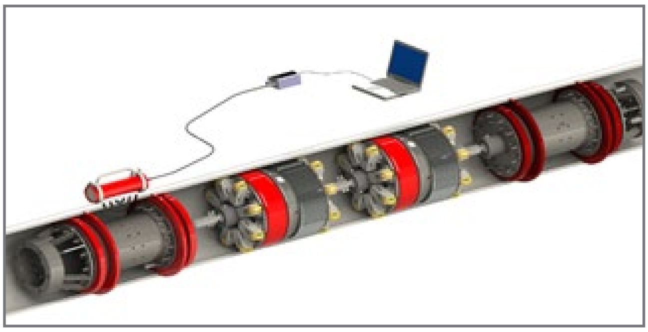


Figure 5: SmartPlug® isolation tool.

Bidirectionally piggable, SmartPlug technology is introduced into the pipeline via the pig launcher then propelled by pipeline product or pumps and compressors to the isolation point, where it is remotely activated. Internal hydraulics engage the gripping elements and the sealing element on the pipe wall then downstream pressure is reduced to create differential pressure across each plugging module, maintaining a fail-safe isolation.

9. Nothing Left to Chance

Safety is always a top priority during pipeline isolations. Personnel injuries, loss of life or asset damage are all unacceptable.

Before any SmartPlug operation, it's standard practice and a DNV Type Approval requirement to collect technical information about the pipeline and to prepare engineering documents, including design premises, pipe stress calculations, isolation operation procedures and a piggability study that assesses the tool's ability to negotiate the pipeline safely and be retrieved from it.

To ensure the risk management of this project, TDW conducted hazard identification (HAZID) and hazard and operability analysis (HAZOP) studies. Engineers identified and uploaded potential areas of risk into a risk matrix, with probability of occurrence and consequence used to determine risk (risk = probability x consequence). More than 60 action items were identified for risk mitigation.

Following factory acceptance testing in Stavanger, TDW mobilized the SmartPlug tool to the worksite. Technicians lifted and loaded the tool into the pig trap then used a treated seawater pumping service to pig it 47 meters (154 feet) to the predetermined location. A safe isolation was established against the shut-in pressure of approximately 110 bar (1595 psi). Monitoring the annulus pressure between the two plug modules for four hours verified each was sealing properly. That gave the operator and project team the confidence they needed to begin the valve replacement.

Figure 6: Loading the SmartPlug into the launcher.

After a leak test verified the integrity of the new seal rings and valves, TDW equalized the pressure differential across the SmartPlug tool, unset the plug modules and pigged the tool back to the launcher using pipeline gas pressure.

Figure 7: Retrieval of the SmartPlug tool from the launcher barrel.

With the stalled pig removed from the pipeline and the pig trap valves replaced, just one step remained in this multi-faceted project: making sure the operator could put the stuck pig incident firmly behind them forever.

10. Custom Cleanliness Reduces Risk

While an unusual confluence of technical difficulties led to the stalled pig, the operational and financial implications were just too great to risk a repeat occurrence.

Figure 8: First Vantage pig at launcher

To minimize the possibility of the scenario happening again, TDW developed a customized cleaning pig to fit the requirements of the offshore pipeline system.

Based on the proven technology of the VANTAGE® multipurpose cleaning pig, the bespoke pig incorporated adjustable bypass, with jetting nozzles to prevent debris from building up during operation. TDW further boosted its cleaning capabilities by adding spring-loaded, angled polyurethane blades. Because the blades also cause the pig to rotate while it travels through the pipeline, the pigging discs experience more uniform wear, meaning they require only routine maintenance.

TDW also designed a progressive pigging program – with the customized pig at the centerpiece – to ensure the offshore section of the GEP was sufficiently clean for both normal operation and an upcoming in-line inspection (ILI). If any dirt or debris interferes with ILI tool sensors contacting the interior pipe wall, the data they return can be inaccurate or incomplete.

In progressive pigging, cleaning begins with a less aggressive pig then works its way up. Because this pipeline had not been pigged in more than two years and the last run had returned significant amounts of debris, the progressive pigging program was particularly conservative: if any single pig run removed too much debris, it would increase the risk of the pig stalling. After five runs, the pigging program met the operator's cleanliness specifications. The operator resumed normal production and normal pigging, with fully functional valves and sound pipeline components.

Like every other aspect of modern life, technology plays a major role in the everyday operation of the world's pipelines. It's reassuring to know that when technical problems occur, innovative, customized tools and techniques can be put into place to solve them. In other words, while we all know technology can save time, money and other assets, there are times it can also save other technology.

AUTHOR

Rolf Gunnar Lie
T.D. Williamson
Director Sales, Eastern Hemisphere, East
Rolf.Gunnar.Lie@tdwilliamson.com

Intelligent Solutions for Inspection of Challenging Pipelines- Case Study: 10” Rigid Offshore Oil Riser Inspection for Wall Thickness and Cracks

A. ENTERS, T. S. KRISTIANSEN, U. SCHNEIDER > ROSEN NORWAY

Abstract

Since the introduction of in-line inspection tools (ILI) more than 50 years ago, there have always been pipelines that were considered unpiggable. Typically, it is a combination of various circumstances relating to pipeline design, operating conditions, and/or characteristics of the medium that prevents a successful in-line inspection using traditional methods. Today however, solutions are available which allow the internal inspection of pipelines formerly deemed “unpiggable”. Special ILI tools can inspect these challenging or difficult to inspect pipelines.

The system introduced here is capable to measure crack depth and profile quantitatively, whereby data is collected on the way in and out, and results are visible in real time. Tethered technologies are capable of inspecting pipelines with a 6" or larger diameter, and up to 24 km in length.

This paper will explain the technologies used and the specifications achieved. Furthermore, the unique ability of the system to navigate complex pipeline geometry will be explained through a case study of a 10" offshore oil riser. During this inspection, the tethered tool safely negotiated a total accumulated bend angle of 1,188° (17 bends) whilst successfully inspecting the pipeline for wall thickness and cracks.

1. Introduction

The pipeline network world worldwide is ageing, therefore, it needs to be maintained and its integrity assessed. This is done since more than 50 years with so-called in-line inspection tools or inspection pigs (ILI) for different kind of defects. However, there have always been pipelines that were considered unpiggable. Typically, it is a combination of various circumstances relating to pipeline design, operating conditions, and/or characteristics of the medium that prevents a successful in-line inspection using traditional methods. However, often there are solutions possible with very special ILI tools for these challenging pipelines.

The system introduced here is capable to measure crack depth and profile quantitatively, whereby data is collected on the way in and out, and results are visible in real time. Tethered technologies are capable of inspecting pipelines with a 6" or larger diameter, and up to 24 km in length.

2. Principle of Tethered Tool

Although the TUM, which stands for Tethered Ultrasonic Measurement, is typically tailor-made for a special project, the typical composition consists of the following:

- One or two crawlers/tractors in the front – depending on the pull forces required – will pull the complete tool into the pipeline and push it back on the return run.
- The pulling/pushing modules are followed by project-specific modules:
  - ◊ For UT geometry and wall thickness with pulse echo vertical beam technology,
  - ◊ For geometrical anomalies as dents, ovalities and further restrictions, and for metal loss and wall thickness defects as pittings, all kind of metal loss, wall thinning and lamination,
  - ◊ For crack detection with shear wave technology,
  - ◊ And/or for crack detection and seizing with TOFD (Time of Flight Diffraction),
  - ◊ For corrosion inspection with eddy current technologies.
- Modules for data storage are also part of the tool train.
- If the tool is inspecting a pipeline within a clear product as water or naphtha, a camera can also be

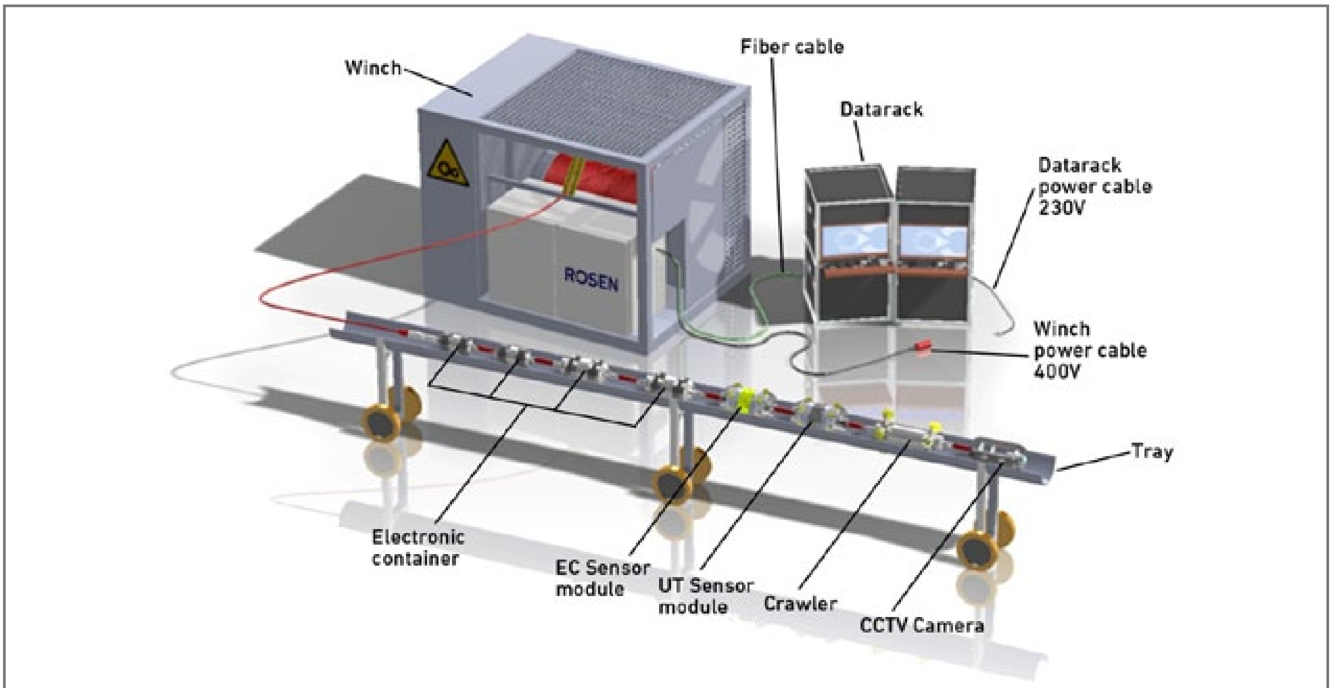


Figure 1: TUM principle

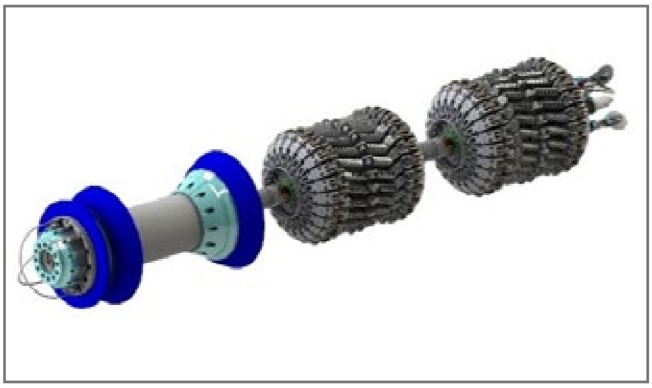


Figure 2: Conventional ILI tool

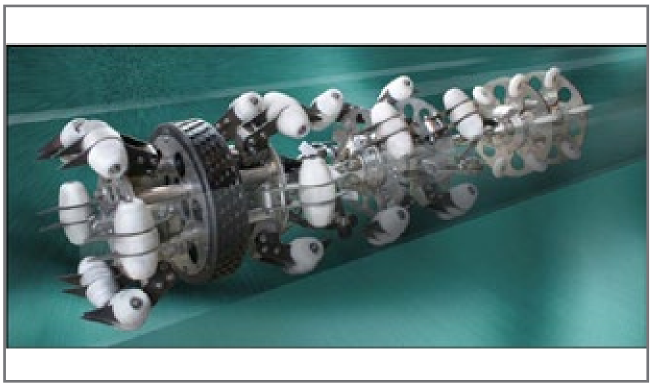


Figure 3: TUM module

installed in the front of the tool.

- For very special tasks even a grinding tool was added for grinding out internal girth weld penetrations and internal cracks.

- The tool is connected via a cable coming from a winch with the control unit. The cable has four functions: to bring the energy to the tool (the tool does not have a battery pack), to transfer the data in real time to the control unit, to control the movement of the crawler, and last but not least as a safety line. If the crawler cannot move anymore and the tool would get stuck, it can be pulled back with up to, for example, 2 tons.

The main differences between a conventional, free-swimming, unidirectional pumped tool and a tethered bi-directional self-propelled tool are the following: Conventional tools go from A to B and get their driving pressure via its cups and/or discs. The sensor carrier is typically flexible. The ROSEN TUM tool has no cups or discs and a lot of bypass. It is extremely lightweight, made of titanium and runs on wheels. The sensor carrier is a stiff ring. The main purpose of the lightweight tool and wheels is to require only very little pulling forces and almost no friction in order to be able to inspect longer sections even through many bends.

Another differentiation against conventional tools is that we need big winches to do the job. The picture shows winches for different lengths, so far successfully completed up to 12 km, up to 24 km possible depending on the amount of bends, bend angles and pipeline configuration (two- or three-dimensional).

A series of different crawlers and tractors are available for all diameters and forces up to 500 kg pulling force each; 6" to 48" has been done already, up to 56" can be easily prepared. The technologies used as ultrasonic pulse echo in liquid lines for geometry, wall thickness and crack detection, ultrasonic pitch and catch TOFD for crack detection, as well as seizing and eddy current technologies for corrosion/metal loss in dry/gas pipelines were all explained many times before. Therefore, we will start straight with the case study.

Figure 4 and 5: Winches of different lengths

Figure 6 and 7: Crawler and tractor

3. CaseStudy: 10" Rigid Offshore Oil Riser Inspection for Wall Thickness and Cracks

The picture above shows a typical challenging pipeline – a riser from platform to subsea – which makes the use of a conventional tool extremely expensive, because the pig receiver would need to be fabricated and installed subsea. Thus, the pipeline inspection would have to be operated with the assistance of a diving support vessel. However, there was a better solution.

It is much easier and cheaper to use the ROSEN TUM tethered self-propelled bi-directional UT tool which can perform geometry, wall thickness and crack inspection in one go. This tool can be launched and received from a trap at that platform without the need for a diving support vessel and a subsea trap, making it the right choice for this project.

The above-mentioned pipeline was chosen by the operator during a risk assessment of all unpiggable pipelines they had at this platform. After the assessment, it was categorized as high risk for the operation. Therefore, an inspection solution needed to be developed. Different vendors were invited, however, the ROSEN solution was chosen for further validation. The special challenge with this pipeline was the amount of bends (and the total angle). If somebody would like to try for themselves how the required pulling forces increase when pulling a thick cable or a garden hose through a combination of bends, they will notice that every additional bend adds friction. Therefore, the amount and angle of bends are in most cases the limiting factor for a tethered inspection. Other vendors can typically handle between three and four 90° bends.

During the first discussions, the target was to inspect a section of nearly 200 m including up to eleven 90° bends and as well as two 2.4° vertical miter bends.

Figure 8: Offshore platform

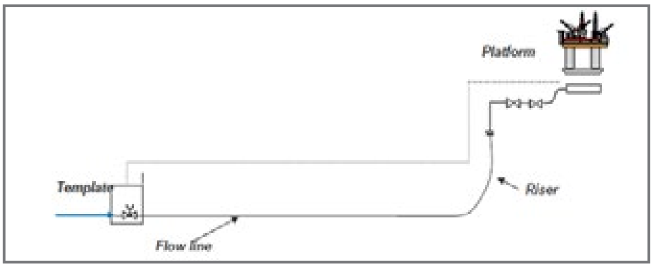


Figure 9: Platform with riser

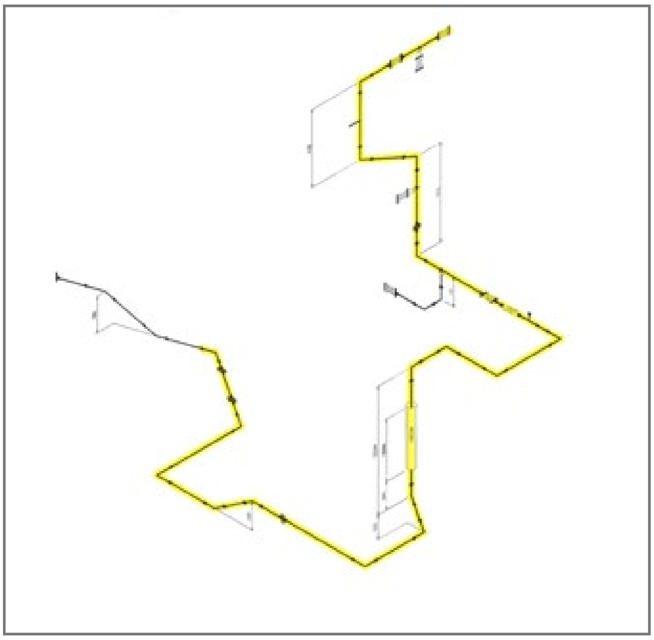


Figure 10: Challenging offshore riser with many bends

For this riser inspection, the main issue was the pullback force of the tool. In case a tethered crawler tool is losing power, the tool needs to be pulled back via the winch.

The pulling force of the 10" tractors are approximately 200 kg each and not the limiting factor for the inspection of this riser.

In order to confirm that the passage and retrieval through eleven 90° bends is feasible, a tool was developed and tested successfully in a test loop in our facility in Bergen, Norway. The main purpose of the tests was to demonstrate that the tool could be retrieved by the umbilical.

Based on the friction profile from the test loop (the pullback forces as function of tool position in the loop), we could correlate the figures with the riser configuration. This way, we were able to obtain a figure for the required pullback forces in case the tool lost power within the riser system. After extensive testing, the inspection with UT wall thickness and TOFD for cracks was conducted successfully and showed good results.

4. The Reinspection Project

A few years later, our company received the contract for re-inspection. This time, the challenge was to crawl a bit further (+130 m total length >300 m) into the horizontal subsea section including another six bends.

Figure 12: Riser test

Here are some pipeline details:

- Nom. OD 10.75", length ~17km
- Inspection length >300m
- Max. depth ~150m
- Wall thickness 16-18 mm
- Medium during production/inspection: crude oil/diesel
- No flow rate during inspection

Again, there has been done a lot of crawler testing prior to mobilization at the ROSEN Norway premises

Figure 11: Test loop in Bergen

in Bergen, including measuring:

- Pull and pullback forces with different tandem crawler configurations in water filled pipe.
- Pull and pullback forces for eight different tool train configurations in water filled pipe.

Finally, equipment and team were mobilized, and a temporary trap was installed with stuffing box (cable penetration) as well as guide wheels for routing the cable. Further, the winch was placed, the computer equipment was positioned in a habitat and the function tests were done. A special stuffing box with cable feeder and hydraulic seal closing clamp was designed, manufactured and tested to 100 bars for these inspections. The cable feeder was designed in order to reduce cable friction at the stuffing box location and the hydraulic seal closing clamp was made in order to make the stuffing box "water tight" in case of a sudden pressure surge in the pipeline. The winch used had a 1.2 km umbilical with breaking load of 2,000 kg and normal pulling force of 1,000 kg. The winch was certified for ATEX zone 2.

Two different tool train configurations were used:

1) For wall thickness measurements and sonar (UTWM + Sonar)
2) For wall thickness measurements and time-of-flight crack measurement of the corroded areas (UTWM + TOFD)

In order to see a blocked pipeline (closed valve or similar), a sonar was mounted in the front of the tool. Sonar is used as a method for locating objects in space and under water by means of emitted sound pulses. Two electrical crawlers were run in tandem configuration. This configuration has been designed for increased

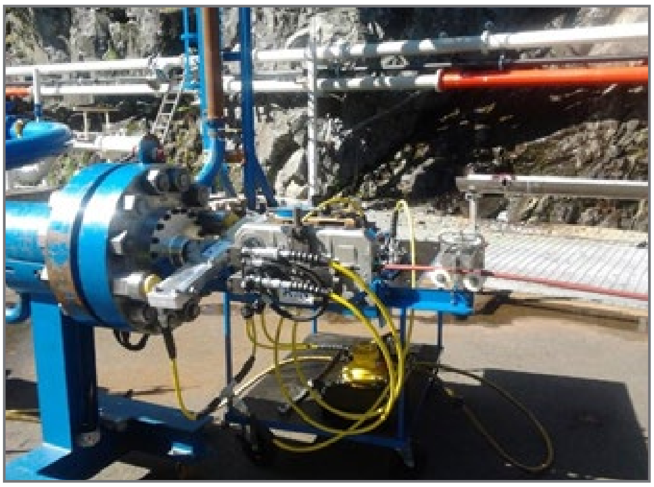


Figure 13: Trap door with stuffing box and cable feeder

pulling force to ensure that the tool can negotiate through difficult to pass pipeline components like slippery valves, tees etc. An ultrasonic sensor carrier with 160 UT probes was used along with two odometers measuring the travelled distance and tool velocity. The movement of the odometers triggers the data collection.

Therefore, if the tool train stands still, data is not collected. However, the inspection can be carried out with only one odometer working. Moreover, a purpose-made scanner equipped with TOFD probes is used to scan any features. Straight beam PE probes are installed to position the scanner correctly against girth welds to be assessed. When deploying TOFD sensors at corroded features in parent material, the TUM-WT tool position will be used to determine correct positioning of the TOFD tool.

Finally, the pipeline was shut down, the tool made its way into the pipeline for approximately 300 m collecting wall thickness data on the forward and return run. After that, the tool was modified from TUM-Sonar to TUM-TOFD configuration, tested and re-launched again.

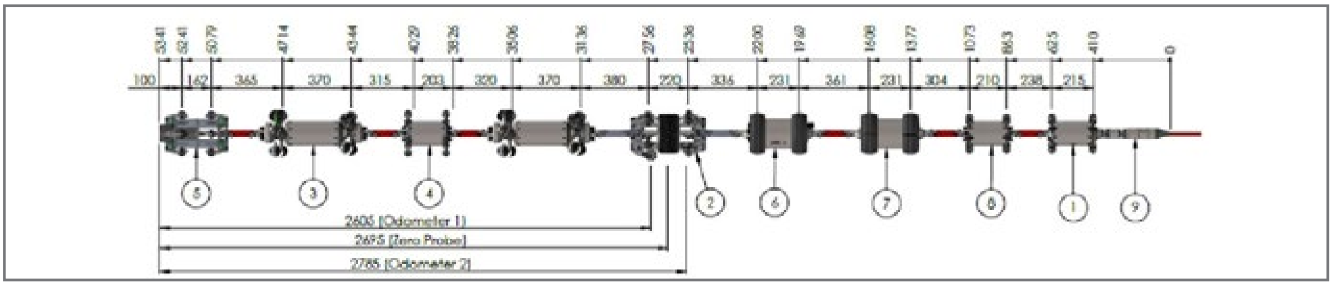


Figure 14: Inspection tool train – TUM-WT-Sonar, the tool with WT + TOFD had one module more

Figure 15: Experts control tool movement and recorded data

During the run many pull- and pull-back force measurements were done on preselected distance in order to calculate the friction coefficient of the riser and to be sure to be able to return in even the worst case. Furthermore, during testing and the actual inspection activities, two operators were on deck operating the umbilical winch, tool train and umbilical etc. and two operators in the habitat were in charge or operating the computers: Propulsion & UT/Sonar. During the second run, the tool stopped at some pre-selected girth welds to make full circumferential TOFD scans. Scans were also conducted in any areas that appeared conspicuous (like splash zones) from the wall thickness data collected during the first run.

After presenting a site report which typically shows the most severe detected defects, the equipment and the team were demobilized and the detailed analysis could be started. The data evaluation team were now able to work with four data sets for wall thickness (two times forward and two return runs) and two data sets for the TOFD crack analysis. The full length and circumference of the targeted pipe section was successfully inspected and the collected data were of very good quality, meeting the required specification.

5. Summary and Benefits

As a result of a risk assessment of some offshore unpiggable pipelines, the riser has been categorized as 'high risk' for the operation. Therefore, an inspection solution needed to be developed. Different vendors were invited, the ROSEN tethered solution was chosen for further validation. Extensive testing (especially crawler testing) in a test loop was performed already prior to the first inspection. The successful inspection was repeated some years later with longer inspection distance and more bends to pass (record of totally 1,188°), 17 bends in total. The benefits of the tethered solution were the following:

- The tethered approach avoided the need for subsea launching and associated cost, risk and production downtime.
- The unique flexibility of the tethered system allowed for the safe negotiation of complex bend configuration (total accumulated bend angle of 1,188° where others are restricted to maximum three and four times 90°)
- A tethered system allowed for in-line TOFD inspection, which enhanced the accuracy of WT readings and additionally provided crack inspection.

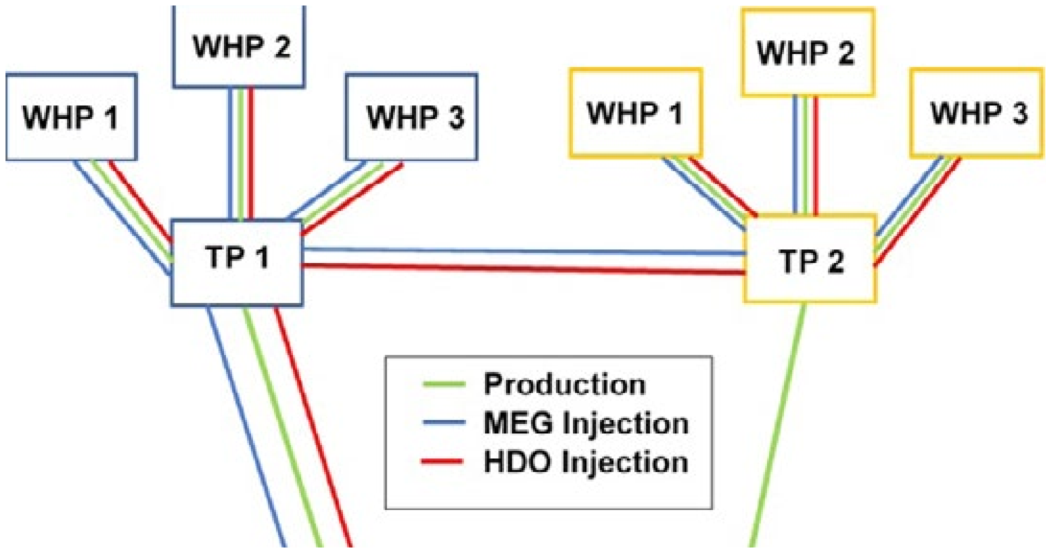
The final report was delivered and the service was performed to the full satisfaction of the operator, on schedule and without any incidents or accidents. Highly accurate UT and TOFD data allowed for a fitness-for-purpose evaluation, specific decision making and the continued safe operation of the riser.

AUTHORS

Abco Enters
ROSEN Norway
Senior Sales Manager
aenters@rosen-group.com

Thor Ståle Kristiansen
ROSEN Norway
Managing Director
tkristiansen@rosen-group.com

Ulrich Schneider
ROSEN Norway
Business Development Manager
Region World-Wide
ulschneider@rosen-group.com



An Innovative Approach to Optimize Trunkline Cladding Requirements for an Offshore Gas Field Development

Q. SALEEM, R. AL-SHIBAN, M. AL-MANSOUR, L. SEONG TEH > SAUDI ARAMCO

Abstract

Subsea pipelines such as flowlines, trunklines etc. are an integral part of all offshore field developments. Sour service conditions as encountered by production pipelines of gas fields require CRA clad pipe due to high risk of localized corrosion initiation and penetration rate in carbon steel. This paper presents an innovative approach to optimize cladding requirements of trunklines of an offshore gas field development.

This approach involves removal of concrete coating from flowlines as well as from cladded section of trunklines for enhancing fluid cooling. The cladding length of each subsea trunkline was significantly reduced as compared to concrete coated case. The impact of removal of concrete coating on other disciplines required minor modifications which were outweighed by the reduction in trunkline cladding. The proposed approach was successfully applied to reduce cladding length of two subsea trunklines by more than 70% which resulted in significant cost savings and project schedule improvement.

1. Introduction

Subsea pipelines such as in-field flowlines, trunklines, test lines etc. are an integral part of all offshore field developments. Sour service conditions as encountered by production pipelines of gas fields require CRA clad pipe due to high risk of localized corrosion initiation and penetration rate in carbon steel. Production fluid is a wet sour natural gas, containing high concentration of carbon dioxide and hydrogen sulphide. Oxygen, sand or bacteria is not envisaged. Liquid formation water production is expected, increasing the bicarbonates, TDS and chlorides content of the aqueous phase. Organic acid and their salts formation is expected as well as elemental sulphur.

Corrosion simulation indicated accelerated corrosion rates with high pitting risks in the water-wetted carbon steel pipeline bottom section due to H_2S-CO_2 corrosion. Laboratory testing for top-of-the-line corrosion (TLC) showed that the TLC risk was high for carbon steel [1-6]. As a result, the risks of H_2S-CO_2 corrosion and TLC should be mitigated by the combination in effective selection of corrosion resistant alloy (CRA) and/or internally coated carbon steel coupled with corrosion inhibition batch treatment. In correspondence of the higher temperature sections of the production lines and at trunkline inlet, the integrity of coating system is doubtful and CRA cladding is used to prevent corrosion. Further downstream, where temperature decreases, coating should provide corrosion mitigation as intended. This is supplemented by batch corrosion inhibitor treatment to account for protection of the internal pipeline metal surface that is exposed due to any coating defect and in case of any internal coating integrity issues.

Consequently, the in-field flowlines are required to be cladded as they are exposed to high temperature which prohibits the use of internally fusion bonded epoxy (FBE) coated pipe. The production from the offshore gas fields are transported to land via subsea trunklines or export lines which see lower temperatures than those experienced by in-field flowlines. This allows a major length of the trunkline, seeing low temperature, to be internally FBE coated whereas the remaining length is required to be cladded due to high temperature exposure. Hence, two different types of internal protection are used in one subsea trunkline considering the maximum service temperature.

The means to optimize the cladding requirements of subsea trunklines are very attractive as they can offer significant reduction in project capex costs. This is attributed to the fact that the cost of cladded pipe can be three to five times the bare carbon steel depending on the pipe size. On the other hand, the cost of internally FBE coated pipe is only 10-15% higher than that of bare carbon steel option. The other benefits include significant schedule improvement resulting from the clad length reduction and welding time associated with cladded pipe. From operation and integrity management point of view, cladding optimization results in uncomplicated maintenance which leads to reduction in opex costs as well as schedule improvement. Furthermore, the cladding optimization will also result in less environmental impact.

2. Innovative Approach

This paper presents an innovative approach to optimize cladding requirements of subsea trunklines of offshore gas field developments. This approach involves removal of concrete coating from the in-field flowlines as well as from the cladded section of trunklines for enhancing the fluid cooling. Concrete coating applied to subsea pipelines has low thermal conductivity which prohibits the heat transfer to sea water and subsequent temperature drop along the pipeline length. However, the removal of concrete coating can accelerate the cooling of the fluid resulting in significant temperature drop along a shorter length of the pipeline which is highly desirable for the optimization of cladding requirements of subsea trunklines. Flow assurance analyses with and without the concrete coating are required to establish the trunkline temperature profiles to identify the transition point from internal cladding to internal coating.

This approach requires re-assessment of subsea pipeline on-bottom stability [7-11] and protection requirements due to removal of concrete weight coating. The exclusion of concrete coating may require either increase in steel wall thickness or use of alternative stabilization measures to meet the requirements of on-bottom stability. Furthermore, pipeline protection is required to be ensured under impact scenario resulting from for example due to dropped objects and pull over/

hooking scenario. In addition, the impact of removal of concrete coating on other mechanical design activities such as free span analysis, bottom roughness analysis, subsea crossings design, pipeline end expansion & spool analyses and in-service buckling assessment is also evaluated. The approach used for optimization of trunkline cladding requirements also requires assessing the effect of concrete coating removal on other disciplines including materials, welding, internal corrosion, cathodic protection system, pipeline external coatings and field joint coatings.

3. Application of Innovative Approach

The proposed approach was successfully applied to reduce the cladding length of two subsea trunklines of an offshore gas field development as shown in Figure 1. The sour gas from wellhead platforms (WHP) is gathered at two tie-in platforms (TP). From each Tie-In Platform the gas is conveyed to the onshore facility through a dedicated trunkline. For Hydrate prevention, a dedicated MEG system is provided and MEG is blended with corrosion inhibitor. For sulphur deposition prevention heavy diesel oil (HDO) is injected at each wellhead platform.

The innovative approach presented in this paper was applied in two phases. In the first phase, concrete weight coating was removed from in-field flowlines shown in Figure 1. Consequently, flow assurance analyses indicated a faster temperature drop along the trunkline length and subsequent significant reduction in cladding length of both trunklines as shown in Table 1.

The on-bottom stability analysis as per DNV-RP-F109 [12] of in-field flowlines required increase in steel wall thickness from 16.66mm to 19.05mm to compensate the removal of concrete coating. Furthermore, pipeline protection assessment as per DNV-RP-F107 [13] indicated that the increased wall thickness provides higher level of protection than concrete coating. This is attributed to lower permanent dent depth during dropped object impact scenario and higher bending stiffness

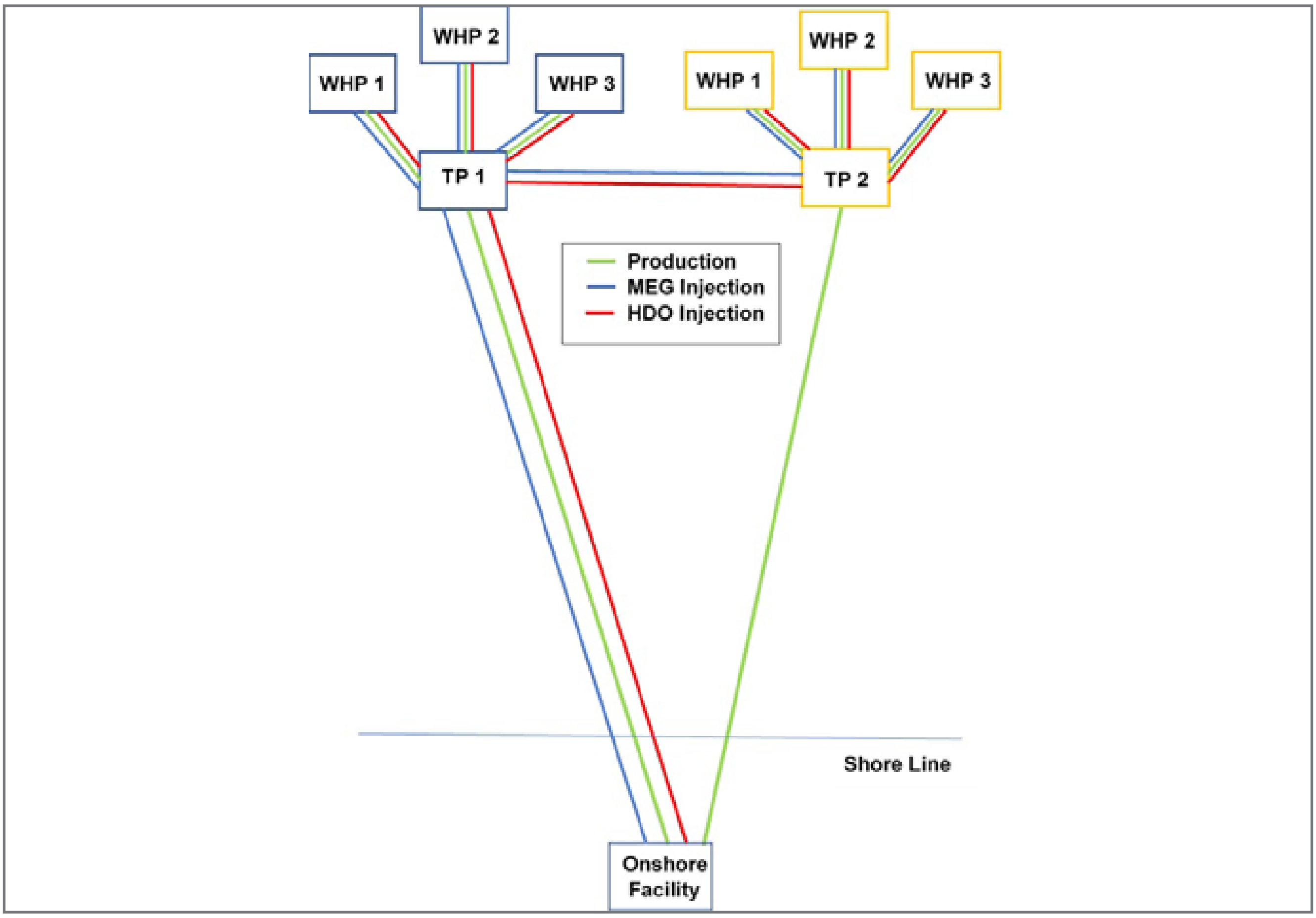


Figure 1: Layout of Offshore Gas Field and Onshore Facility
(WHP: Wellhead Platform, TP: Tie-in Platform)

Trunkline	Clad length as per Base Case (km)	Clad length after concrete removal from flowlines (km)	Reduction (km/%)
Trunkline I	10.71	5.91	4.8/44.8
Trunkline II	14.26	8.7	5.561/38.99

Table 1: Cladding Length Reduction from Phase I

during anchor dragging scenario. Along flowline corridor spool sections, concrete weight coating was maintained as per the recommendations from dropped object study. Along closure and tie-in spools, the concrete weight coating was removed since this pipeline section (i.e. externally FBE coated with 19.05mm wall thickness) is already stable against environmental loads and buoyancy without the need of additional stabilization weight. As part of cathodic protection system design, re-design of flowline bracelet anodes was required due to removal of concrete coating.

In the second phase, concrete weight coating was removed from the cladded section of both trunklines shown in Figure 1. Flow assurance analyses showed even faster temperature drop along the trunkline length and subsequent further reduction in cladding length of both trunklines as shown in Table 2.

The on-bottom stability analysis as per DNV-RP-F109 [1] of trunklines required increase in steel wall thickness from 28.58mm to 31.75mm to compensate the removal of concrete coating. Furthermore, pipeline protection assessment as per DNV-RP-F107 [2] indicated that the increased wall thickness provides higher level of protection than concrete coating. This is attributed to lower permanent dent depth during dropped object impact scenario and higher bending stiffness during anchor dragging scenario. Along trunkline corridor spool sections, concrete weight coating was maintained as per the recommendations from dropped object study. Along closure and tie-in spools, the concrete weight coating was removed since this pipeline section (i.e. externally FBE coated with 31.75mm wall thickness) is already stable against environmental loads and buoyancy without the need of additional stabilization weight.

Free span analyses of trunklines indicated an increase in allowable free span length in both as-laid (temporary) and operating conditions. The increase in allowable span length during temporary condition is attributed to increase in steel wall thickness and reduction in total outside diameter. Whereas, the reduction in axial compression along the cladded sections during operation resulted in higher allowable free span length. On-bottom roughness analyses of trunklines showed significant reduction in intervention works in terms of post-lay mattresses and grout bags. The increase in allowable free span length and reduction of pipeline vertical uplift contributed to fewer intervention works. Crossing design of trunklines identified reduction of pre-lay and post-lay intervention works for crossing configurations.

Trunkline end expansion analyses showed slight increase of end expansion during hydrotest condition due to the reduction of pipe weight from removal of concrete coating. On the other hand, the decrease in end expansion was seen for operating case, which implies that reduction in temperature has more dominant effect on end expansion than the decrease in pipe weight. Trunkline spool assessment indicated lower spool stress levels for the operating condition whereas

Trunkline	Clad length after concrete removal from flowlines (km)	Clad length after concrete removal from Trunklines (km)	Reduction (km/%)
Trunkline I	5.91	1.99	3.919/66.3
Trunkline II	8.7	2.78	5.920/68.05

Table 2: Cladding Length Reduction from Phase II

insignificant stress variation was observed for the hydrotest condition. The removal of concrete coating led to an increase in carbon steel wall thickness, however, it does not have any impact on line pipe manufacturing, welding and non-destructive testing (NDT). From internal corrosion perspective, the temperature drop in internally coated sections of trunklines helps with potential slight mitigation of the fluid corrosiveness and potential increase of the corrosion inhibitor efficiency.

As part of cathodic protection (CP) system design, re-design of trunkline bracelet anodes for cladded sections was required due to removal of concrete coating. The modifications to anode geometry ensured a smother passage over rollers and inside the tensioners during installation thereby reducing any risk of slippage or damage. Furthermore, the anode gap was filled with solid PU which ensured further mechanical protection to anodes cables and will also increase the anode resistance to slippage force. Following the modifications, anodes can still be preinstalled in coating yard and pass through tensioner and roller without any problem. CP system design calculations required anode spacing to be decreased to one anode every three joints.

The removal of concrete coating from trunkline cladded section has no impact on pipeline external coating which remains the same i.e. fusion bonded epoxy (FBE). Due to the removal of concrete coating, increased coating break down factor was considered for the cathodic protection design. The viscoelastic multi-layer coating on the clad section field joint was required to be replaced by FBE field joint coating system to mitigate any potential coating damage during pipe laying. Furthermore, the FBE coating thickness at the field joint was required to be modified to 625-1125 microns from the standard requirement of 625-1000 microns.

4. Implementation

The innovative approach for optimizing the cladding length of subsea trunklines was implemented in company standards and procedures by mandating the methodology presented in this paper to be employed. This ensured that the removal of concrete weight coating (if feasible e.g. by slight increase in wall thickness) is always explored given that it can lead to significant benefits such as cooling of production fluid and consequent reduction in costly cladding requirements. Furthermore, it can also increase the pipeline allowable free span length and can lead to significant reduction in intervention works required for free span corrections, stress hot spots as well as crossing configurations. As a final step, the effect of concrete coating removal on other disciplines including materials, welding, internal corrosion, cathodic protection system, pipeline external coatings and field joint coatings shall also be assessed and approval should be obtained from engineering department. As demonstrated in section 3, the alternative approach for optimizing the cladding length significantly reduced the final cladding requirements of subsea trunklines which resulted in:

- Less environmental impact
- Significant cost savings (Capex and Opex)
- Schedule improvement
- Uncomplicated maintenance
- Reduced downtime

5. Concluding Remarks

This paper presents an innovative approach to optimize cladding requirements of subsea trunklines of offshore gas field developments. This approach involves removal of concrete coating from the in-field flowlines as well as from the cladded section of trunklines for enhancing the fluid cooling. As trunklines were required to be cladded only up to the length where fluid temperature was above 120 ºF (and internally FBE coated elsewhere), the cladding length of each subsea trunkline was significantly reduced as compared to concrete coated case. The impact of removal of concrete coating on flow assurance, pipeline mechanical design, cathodic protection and field joint coating systems was also evaluated. Although some of these activities required minor modifications, however, they were outweighed by the reduction in trunkline cladding requirements. The proposed approach was successfully applied to reduce the cladding length of two subsea trunklines by more than 70% which resulted in significant cost savings and project schedule improvement. The innovative approach presented in this paper can be used to significantly reduce the cladding requirements of subsea trunklines of offshore gas field developments. The optimization of trunkline cladding will result in reduction of capex costs as well as schedule improvement will lead to early start up.

6. Acknowledgement

The authors would like to thank Saudi Aramco management for permission to publish this paper.

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AUTHORS

Qasim Saleem
Saudi Aramco
Engineering Specialist
qasim.saleem@aramco.com

Riyadh Al-Shiban
Saudi Aramco
Engineering Consultant
riyadh.shiban@aramco.com

Mana Al-Mansour
Saudi Aramco
Engineering Consultant
mana.mansour.1@aramco.com

Lay Seong Teh
Saudi Aramco
Engineering Specialist
layseong.teh@aramco.com

Offshore Pipelines and stability assessment of Submerged Slopes under Seismic Conditions

P. PSARROPOULOS[1], Y. TSOMPANAKIS[2], N. MAKRAKIS[2] > [1]NATIONAL TECHNICAL UNIVERSITY OF ATHENS, [2]TECHNICAL UNIVERSITY OF CRETE

Abstract

Depending on the prevailing bathymetrical and geotechnical conditions, the integrity of offshore pipelines is threatened by potential slope instabilities that occur at the seabed or at the bottom of lakes. In addition, submarine slides are more frequent in seismic regions. The instability of onshore slopes under seismic conditions is undoubtedly a challenging problem in geotechnical earthquake engineering, while the quantitative assessment of the seismic stability of submerged slopes is even more demanding. Consequently, the current study investigates this complex phenomenon of offshore geotechnical earthquake engineering. After a brief overview of the recent related work of the authors' group and the available pseudo-static methods of the literature, an improved analytical method is proposed. An indicative parametric study demonstrates that the new approach estimates more accurately the factors of safety, leading thus to less conservative (i.e., more cost-effective) design of offshore pipelines near potentially unstable submarine slopes.

1. Intorduction

During the last decades, various offshore structures have been designed and constructed worldwide, while many more are expected to be developed in the near future. Offshore structures can be characterized by rather limited dimensions (e.g., fixed platforms, wind turbines, etc.), while there exist offshore lifelines crossing hundreds of kilometers (i.e., gas pipelines, cables, etc.). Typically, such structures are designed to face various threatsthat depend on the seabed characteristics and the potential geohazards of the region (Dean, 2010). The main offshore geohazards are submarine slides, faults, strong ground shaking, liquefaction, salt diapirs, shallow gas and dissociation of gas hydrates, mud volcanoes and hydrodynamic forces from waves and currents. It is evident that the geotechnical engineers and engineering geologists must identify offshore geohazards with respect to potential triggers, event severity and frequency, potential failure modes and the probability, as well as the consequences of a failure (Randolph&Gourvenec, 2011).

In areas that are characterized by moderate to high seismicity, such as the Mediterranean Sea, offshore earthquake-related geohazards may have a negative impact on offshore structures. The prevailing geomorphological and geological conditions in a specific area (e.g., deep canyons which present slides or rockfalls or flat areas with very soft sediments), in conjunction with active tectonics, may lead to earthquake-related geohazards such as: strong ground motion, seismic fault rupture at the seabed, soil liquefaction phenomena, volcanic eruptions, and various types of slope instability at the seabed.

Submarine slides are common and very effective mechanisms of sediment transfer from the shelf and upper slope to deep-sea basins, in which enormous volumes of sediments can be transported on very gentle slopes over distances exceeding tens of kilometers. Such events can severely damage various offshore structures, such as fixed platforms, pipelines and cables. It is well known that due to excess pore pressure the risk of offshore landslides is high, even for slopes with very low inclination, i.e., slope angles ≤ 0.5°(Randolph& Gourvenec, 2011). Potential sources for excess pore pressure are: (a) the shear strain induced contraction with pore pressure generation and softening during the slide process causing progressive failure and retrogressive sliding, (b) the rapid deposition, (c) increase of the slope angles due to fault rupture of seabed erosion, (d) melting of gas hydrates releasing methane gas and water, (e) wave loading, (f) earthquake-induced shear strains generating excess pore pressures and (g) human activities such as drilling, and construction installation (Locat & Lee, 2002). For example, Kvalstad et al. in 2005 investigated the above phenomena for the case of the Storegga slide which occurred almost eight thousands years ago and affected an area of 90,000 km² (see Figure 1).

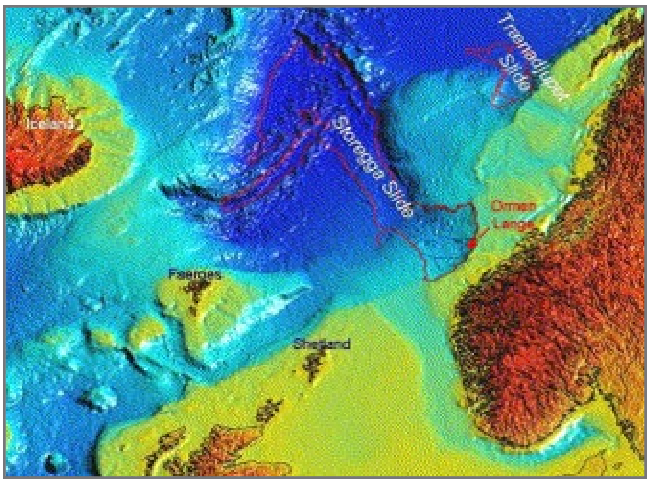

Figure 1: Location of the Storegga slide offshore Norway (after Kvalstad et al., 2005)

Research on understanding the mechanisms and the related risks due to submarine slides has been intensified in the past decades, mainly due to the increasing number of deep-water oil and gas fields that have been discovered and exploited. The impact of submarine slides on offshore pipelines has been thoroughly investigated (Zakeri, 2009).In recent years, elaborate numerical models have been utilized for the simulation of landslides (Dey et al. 2016).Moreover, different rheological models have been used to investigate the slide movement in analytical or numerical investigations (Boukpeti et al. 2012). Useful conclusions can be drawn from data that are continuously collected from both recent and older submarine slides worldwide (Camargo et al. 2019).

Factor of Safety (FS) against slope stability constitutes a useful engineering tool for structural integrity assessment of any structure in the examined region. With respect to seismic slope instability, the horizontal and vertical inertial forces that are expected to be developed on the soil mass during a seismic event may decrease dramatically the factors of safety, leading thus to higher risk of failure (Psarropoulos & Antoniou, 2014). Usually, slope stability assessment is performed via pseudo-static limit equilibrium analyses, which estimate the factors of safety under seismic conditions based on certain simplifications. Typically, they are based on the assumption that the induced seismic accelerations may be represented as equivalent external static forces.

This "pseudo-static approach" is popular in engineering practice as it is relatively simple and straightforward to implement. Its similarity to the static limit-equilibrium analyses usually conducted by geotechnical engineers makes computations easy to perform and understand. Nevertheless, the accuracy of the pseudo-static approach is governed by the accuracy with which the simple pseudo-static inertial forces represent the complex dynamic inertial forces that actually occur during an earthquake (Kramer, 1996). Despite the progressive development of more advanced analytical and/or numerical methods, the use of the pseudo-static approach in seismic slope stability analyses and the interpretation of pseudo-static factors of safety are extremely useful for offshore engineering and are used in the design of offshore structures.

The current paper tries to shed some light to these crucial issues in the field of offshore geotechnical earthquake engineering, emphasizing on planar slides under seismic conditions. After a brief overview of the recent related work of the authors' group and a literature review of the available solutions for static and pseudo-static slope stability assessment, an improved analytical expression is proposed for submerged soil slopes. Subsequently, a parametric study has been conducted taking into account the main parameters involved (i.e., the mechanical properties of the geomaterials, the geometry of the slope, and the imposed seismic acceleration levels).

2. Offshore Gas Pipelines Subjected to Submarine Landslides

As aforementioned, offshore natural gas pipelines are large-scale infrastructures which may extend for hundreds of kilometers and reach hundreds of meters depths. Kinematic distress due to submarine geohazards is a critical and frequently unavoidable threat for such pipelines, especially in deep water, where they are laid directly on the seabed under adverse and uncertain conditions. More specifically, submarine landslides and debris flows consist a critical geohazard for offshore pipelines. The investigation of pipe distress under the above phenomenon can be conducted utilizing analytical and/or numerical models. Previous studies of the authors' group (e.g., Chatzidakis et al., 2019 & Chatzidakis et al., 2020) have focused on analytical models which, although can be inferior in terms of accuracy compared to elaborate numerical models, exhibit the advantages of faster solution, automated calculations and compatibility with a wide range of software, while they can be easily implemented into guidelines and applied in practice.

The response of offshore pipelines under lateral distress due to a landslide has been investigated in a limited number of studies so far through the development of analytical and numerical models. Yuan et al. (2012a & 2012b) proposed two analytical models for both surface-laid and buried offshore pipelines. These studies assumed bi-linear lateral soil resistance and constant axial tension. In the sequence, Yuan et al. (2015) and Chatzidakis et al. (2019) improved the above methodology by introducing varying axial tension and tri-linear lateral soil resistance, respectively.

As shown in Figure 2, Chatzidakis et al. (2019) developed an analytical methodology for the investigation of pipe response under lateral kinematic distress due to a submarine slide or a debris flow. The investigation focuses on deep water conditions where the pipeline is usually laid directly on the seabed. Extra emphasis is given on the soil resistance, where a tri-linear model is used in compliance with the recent DNV GL (2017) guideline. The proposed model was validated against both analytical and numerical models, based on the finite-element (FE) method. Finally, a parametric study was carried out for different loading scenarios using realistic input data for the pipe and soil properties taken from the design and geotechnical survey of the Trans Adriatic Pipeline project (TAP, 2013a & 2013b).

The main findings of this investigation can be summarized as follows:

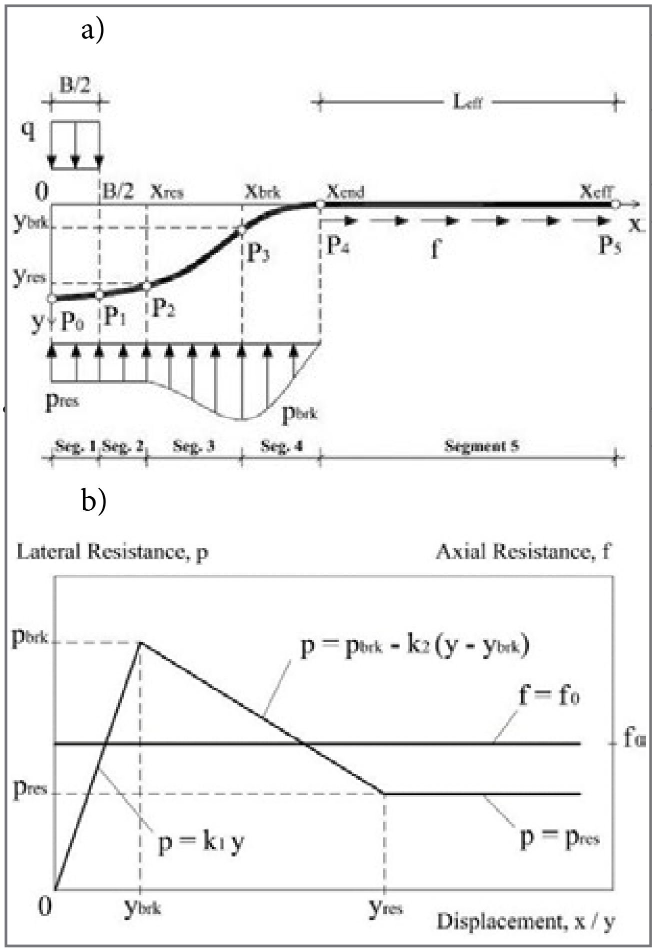

Figure 2: Analytical model description (a) and soil resistance models (b)

However, for constant drag force and increasing landslide width, the laterally dislocated part of the pipeline normalized with respect to the landslide width is constant.

- The fact that tensile strains occur along the longest part of the pipe in all cases, is considered beneficial, since such pipelines are vulnerable to compressive strains due to local buckling phenomena. Compressive strains appear for small drag forces and especially for small landslide widths; hence, it is recommended to avoid regions with potential narrow landslide areas.

- In all examined cases, the pipeline material response remained elastic, i.e., no plastic strains occurred and compressive strains were lower than the critical limit for local buckling.

A similar work has been presented by Chatzidakis et al. (2020),investigating the more general case of oblique loading conditions.

3. Optimal Route Selection with the Minimum Risk of Landslides

Another recent work by the authors (Makrakis et al., 2022) has presented a smart decision-support tool which focuses on the optimal route selection of offshore lifelines, and especially high-pressure gas pipelines, against the potential earthquake-related geohazard of submarine landslides. This investigation combines the advanced capabilities of GIS with efficient (semi-)analytical models, in order to realistically assess the response of offshore pipelines when subjected to axial or oblique loading due to submarine slides.

In this case the pseudo-static slope stability analysis has been utilized which is widely used in engineering practice in order to assess the seismic response of slopes. The calculated Factor of Safety under pseudo-static conditions (FS_{PS}) indicates whether the examined slope is stable(i.e., $FS_{PS} \geq 1$) or unstable (i.e., $FS_{PS} <$ 1) under seismic conditions. The following analytical formula, that was firstly introduced by Morgenstern (1967) and further modified by Haneberg et al. (2013) among others, has been used:

$$FS_{PS} = \frac{c/\cos^2\theta + z\cdot(\gamma' - k\cdot\gamma\cdot\tan\theta)\cdot\tan\varphi}{z\cdot(\gamma'\cdot\tan\theta + k\cdot\gamma)} \quad (1)$$

wherec represents the soil cohesion, while φ and θ denote the friction and slope inclination angles, respectively. Moreover, z represents the depth of the seabed sediments, and γ′ denotes the buoyant unit weight of the soil, which is equal to γ^'=γ-γw, where γ and γw are the unit weight of soil and water, respectively. Finally, k refers to the pseudo-static seismic coefficient, which quantifies in a simplified manner the impact of horizontal inertial force due to horizontal seismic excitations.

In reality, a vertical seismic excitation also exists, which leads to a vertical inertial force, but it is usually neglected as its impact is considered marginal (Kramer, 1996). To perform the seismic stability assessment of offshore slopes, a proper value for the pseudo-static horizontal seismic coefficient, k, has to be selected according to the acceleration levels of the examined region that correspond to the selected seismic scenario(s). As reported by Melo & Sharma (2004), due to the flexibility of soil slopes, the peak acceleration values that occur during an earthquake are instantaneous, thus, seismic coefficients used in common engineering practice correspond to much lower acceleration values compared to the anticipated peak accelerations. Under this perspective, k, can take constant values ranging from 0.05 to 0.25, or it can be a ratio (1/3 to 1/2) of maximum accelerations. As shown in Figure 3, the application of the proposed smart tool in the Adriatic Sea results in five alternative pipeline routings, which are compared with the constructed route of TAP. The proposed routes differ in length, but also in the way they cross the seismically unstable slopes of the examined region, as well as the areas characterized by steep inclination. Nevertheless, it should be stressed that the comparison with TAP route is indicative, due to the lack of all data and the resulting simplifications.

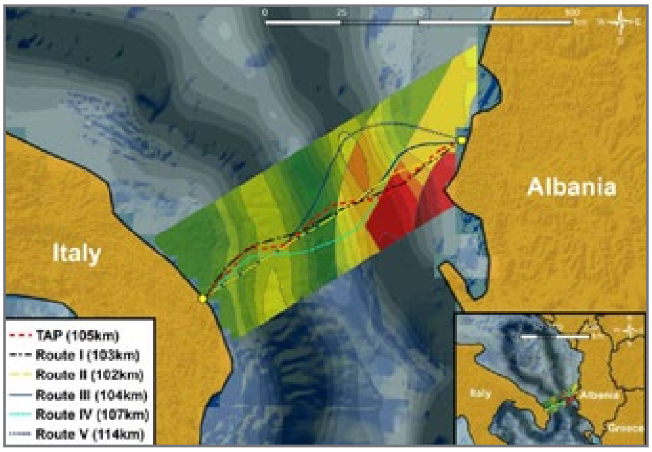

Figure 3: Application of the smart decision-support tool in the Adriatic Sea for the optimal routings of offshore pipeline subjected to axial or oblique loading

The main findings of this study are the following:

- The examined area in the southern Adriatic Sea is prone to offshore geohazards and especially submarine landslides, mainly at the eastern Adriatic Sea near Albania.
- Under static conditions the submarine slopes are stable even at the steep inclination zones, in contrast to seismic conditions, where the factor of safety significantly decreases, regardless of slope inclination.
- The 475-year return period scenario is not critical compared to the one for the 2475-year return period, which results in unstable slopes near the Albanian coastline. Hence, optimal route selection of offshore pipelines should be performed for a severe seismic scenario (e.g., 2475-year return period) due to the high importance of such critical infrastructure.
- Larger axial force and landslide length result in greater compressive axial force for the pipeline routings which cross vertically the unstable slopes and are examined against axial distress.
- Pipeline routings which cross the hazardous areas under a certain angle are examined against oblique distress, and the maximum tensile and compressive strains for the examined crossing angles, landslide widths and impact forces, are below the acceptable limits.
- The safest pipeline route has taken into account both the slopes with large inclination, as well as the slopes that are unstable for the 2475-year return period scenario.

The presented results highlight the capability of the smart tool to successfully support the engineers in quantifying both the geohazard and the pipeline response in order to design a route, considering the critical and non-critical areas that should be avoided or crossed under certain conditions/restrictions. Optimal route selection could noticeably reduce the length and the consequent cost of a lifeline, while increasing safety levels. In any case, in complex real-life projects the procedure of optimal route selection is not a straightforward task. Consequently, it should not be based on engineering judgment and design experience, since it can be achieved in a more efficient manner via less subjective decision-support tools.

4. Slides on Infinite Planar Surfaces

A translational slide is actually a movement of the upper mass of soil or sediments above a planar surface parallel to the surface of either the ground or the seabed, under the assumption that it has an infinite length. The movement of the soil may be represented in a simplified manner by a rigid block sliding on an inclined planar surface. Considering a vertical segment of a soil slope inclined at an angle θ, characterized by height z, thickness h ($=z \cdot \cos\theta$), and unit length in the third direction, four different cases can be examined:

(a) soil slope under static conditions, (b) submerged soil slope under static conditions (with a horizontal water table above the slope), (c) soil slope under seismic conditions, and (d) submerged soil slope under seismic conditions. In the general case of a soil slope under static conditions, the factor of safety is given by the following well-known expression:

$$FS_{ST} = \frac{\frac{c}{\cos^2\theta} + z \cdot \gamma \cdot \tan\varphi}{z \cdot \gamma \cdot \tan\theta} = \frac{c + h \cdot \gamma \cdot \cos\theta \cdot \tan\varphi}{h \cdot \gamma \cdot \sin\theta} \quad (2)$$

where γ, c and $\varphi$are the unit weight, the cohesion and the angle of internal friction of the soil, respectively.

Assuming the unit weights of the soil above and below the water table (bulk and saturated unit weights) to be the same, γ, the weight **W'** of a submerged segment ABCD will be:

$$W' = \gamma' \cdot a \cdot z \quad (3)$$

where γ^' (=γ-γ]_W)is the effective unit weight, derived by subtracting the unit weight of water, γw, from γ. Repeating calculations, the overall factor of safety under static conditions and assuming a horizontal water table above the slope is given by:

$$FS'_{ST} = \frac{c/\cos^2\theta + z \cdot \gamma' \cdot \tan\varphi}{z \cdot \gamma' \cdot \tan\theta} = \frac{c + h \cdot \gamma' \cdot \cos\theta \cdot \tan\varphi}{h \cdot \gamma' \cdot \sin\theta} \quad (4)$$

It is noted that if, apart from the weight $W = \alpha \cdot z \cdot \gamma$, a vertical buoyancy force $AW = \alpha \cdot z \cdot \gamma w$ exists, Eq. (4) is derived. Assuming that the segment ABCD (with weight $W = \gamma \cdot \alpha \cdot z$) is subjected to a horizontal seismic excitation (which is represented via a pseudo-static seismic coefficient k), the aforementioned equations should include an additional horizontal inertial force $E = k \cdot W$. Note that in reality a vertical seismic excitation also exists, which leads to a vertical inertial force. Nevertheless, its impact is considered to be less important, and therefore it is usually neglected.

Under this perspective, the factor of safety under pseudo-static conditions is given by:

$$FS_{PS} = \frac{c/\cos^2\theta + z \cdot \gamma \cdot (1 - k \cdot \tan\theta) \cdot \tan\varphi}{z \cdot \gamma \cdot (\tan\theta + k)} = \frac{c + h \cdot \gamma \cdot \cos\theta \cdot (1 - k \cdot \tan\theta) \cdot \tan\varphi}{h \cdot \gamma \cdot \cos\theta \cdot (\tan\theta + k)} \quad (5)$$

In the special case that $k = 0$ (i.e., static conditions), $FS_{PS} = FS_{ST}$ and Eq. (5) converges to Eq. (2).

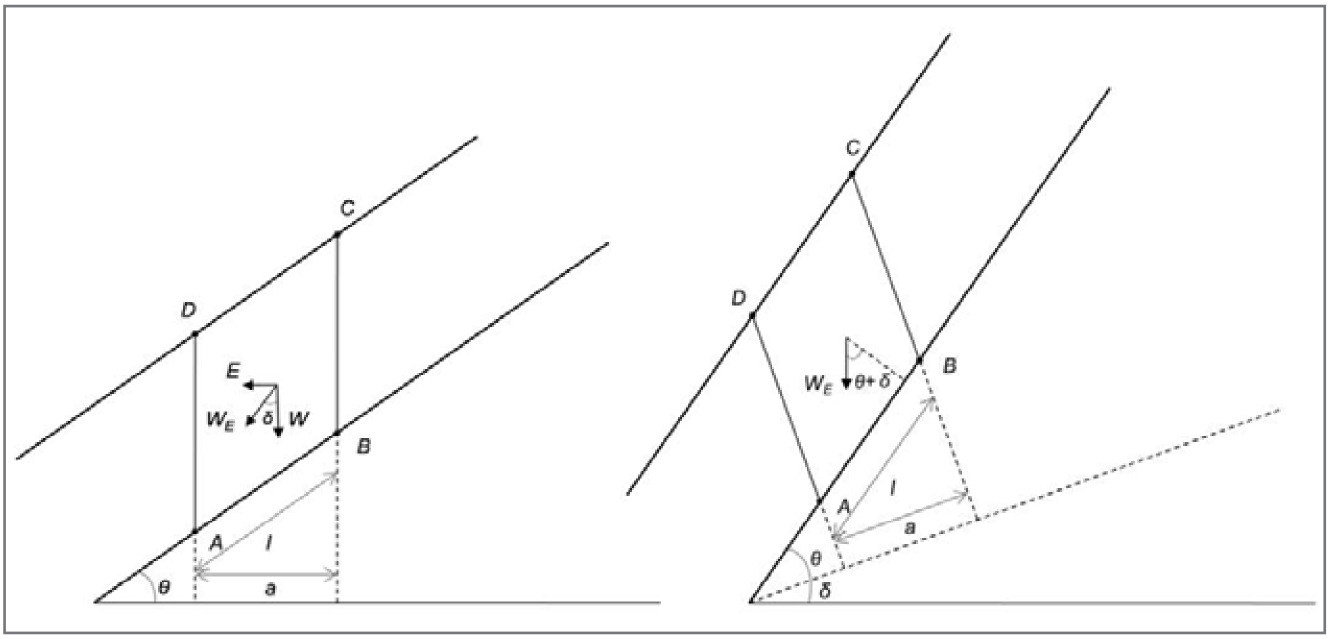

Figure 4. Rotation of the model in order to change the orientation of the resultant force WE to vertical.

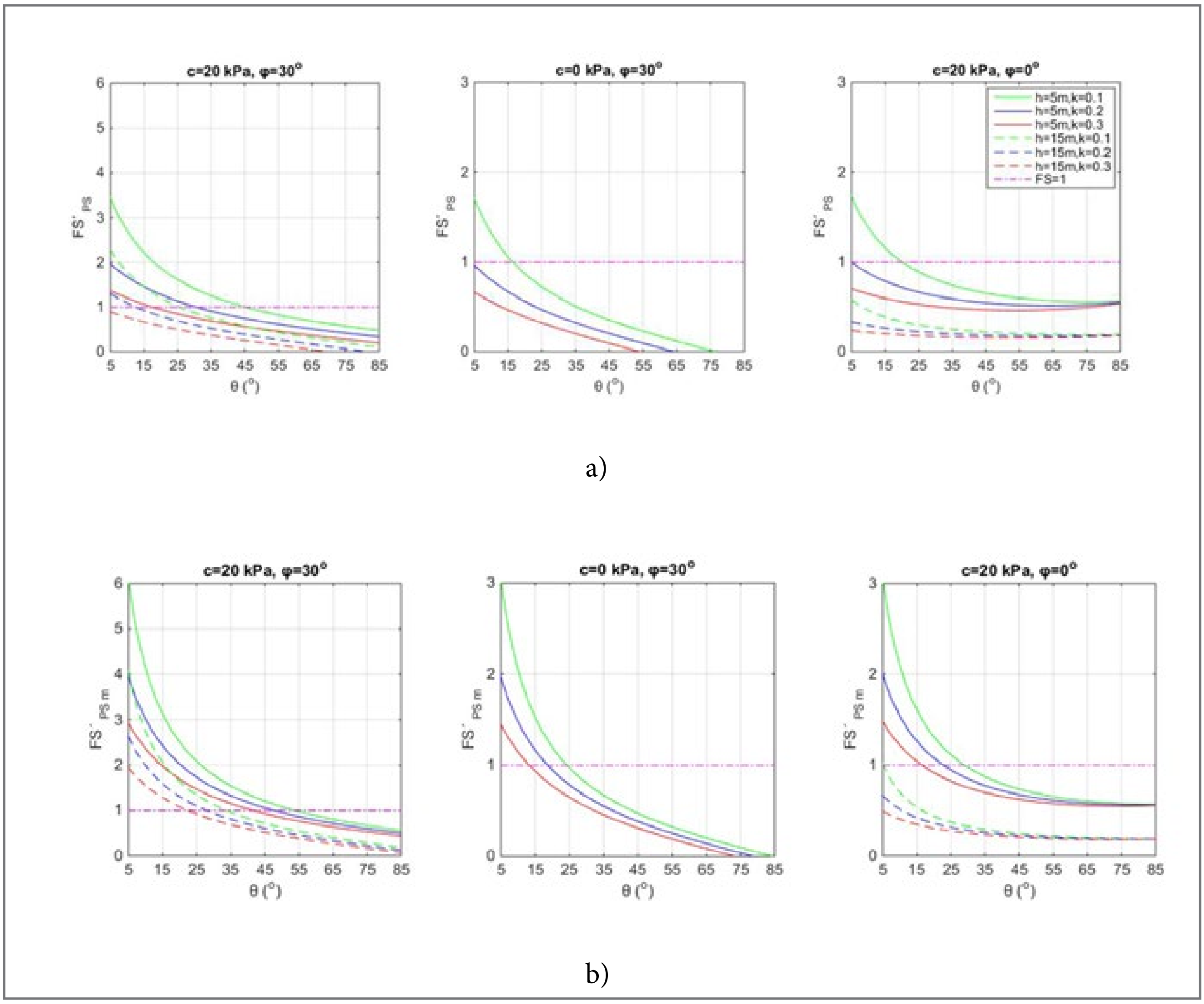

Figure 5: Factor of Safety for a planar slide for submerged seismic conditions using (a) the conventional approach and (b) the proposed formula.

As aforementioned, the pseudo-static seismic coefficient k is a fraction of peak acceleration at the surface of the seabed. The selection of the proper k value(s) should take into account the acceleration levels at the seismic bedrock, in conjunction with the potential aggravation due to the presence of soft sediments and/or topographic irregularities of the examined region. In addition, it is noted that offshore lifelines are designed for long-term conditions, i.e., a large return period is used, a fact that results in higher values of k.

When the segment ABCD is submerged and subjected to a horizontal seismic excitation, the impact of vertical buoyancy and the horizontal inertial force E are taken into account. Note that E is equal to k·W, where W (= m·g) is the weight of the body. This hypothesis is undoubtedly valid, since the inertial forces are applied to the mass of the body, regardless of the gravitational field and the hydrostatic conditions. In the general case, the factor of safety under pseudo-static conditions of a submerged soil slope is given by:

$$FS'_{PS} = \frac{c/\cos^2\theta + z\cdot(\gamma' - k\cdot\gamma\cdot\tan\theta)\cdot\tan\varphi}{z\cdot(\gamma'\cdot\tan\theta + k\cdot\gamma)} = \frac{c + h\cdot\cos\theta(\gamma' - k\cdot\gamma\cdot\tan\theta)\cdot\tan\varphi}{h\cdot\cos\theta(\gamma'\cdot\tan\theta + k\cdot\gamma)} \quad (6)$$

Note that Eq. (6) coincides with Eq.(1) which has been used in the aforementioned study of Makrakis et al. (2022).

5. Improving Seismic Stability Assessment of Submerged Slopes

The aforementioned methodology was introduced in the '60s (e.g., see Morgenstern, 1967)in order to assess the stability of cohesive submarine slopes under seismic conditions and has been adopted in several scientific publications. Furthermore, several researchers have used the above equations, while others have used them for pipeline routing (Haneberg et al., 2013). Nevertheless, this formula is erroneous since the presence of a horizontal inertial force E can be combined with the vertical gravitational force W. As shown in Figure 4, the outcome of W and E is an inclined force W_E, and therefore, an equivalent model can be developed, in which the coordinate system has been rotated so that the force W_E is vertical. The angle of the aforementioned rotation, δ , is equal to arctan(k).In this case, the equivalent weight W' is equal to the volume V (= α·z·γ'=l·cosθ·z·γ') multiplied with the corresponding modified unit weight γ' E=γ'·√(1+k²).

In the general case the factor of safety under pseudo-static conditions of a submerged soil slope is given by:

$$FS'_{PS} = \frac{c + [(z\cdot\gamma'\cdot\cos\theta\cdot\cos(\theta+\delta)\cdot\sqrt{1+k^2}]\cdot\tan\varphi}{z\cdot\gamma'\cdot\cos\theta\cdot\sin(\theta+\delta)\cdot\sqrt{1+k^2}} \quad (7)$$

Based on well-known trigonometric equations, and taking into account that δis equal to arctan(k), the following equation is obtained for the factor of safety under pseudo-static conditions of a submerged soil slope:

$$FS'_{PS} = \frac{c/\cos^2\theta + z\cdot\gamma'\cdot(1 - k\cdot\tan\theta)\cdot\tan\varphi}{z\cdot\gamma'\cdot(\tan\theta + k)} = \frac{c + h\cdot\gamma'\cdot\cos\theta\cdot(1 - k\cdot\tan\theta)\cdot\tan\varphi}{h\cdot\gamma'\cdot\cos\theta\cdot(\tan\theta + k)} \quad (8)$$

Note that Equation (8) is analogous to Equation (5) that corresponds to the case of an onshore dry slope under pseudo-static conditions, with γ in Equation (5) being replaced by γ'. Figure 5depicts the Factor of Safety (FS) for a planar slide for submerged seismic conditions using: (a) the conventional approach and (b) the proposed formula. Various cases of geometry (h), soil properties (c and φ) and applied acceleration (k) have been examined. It is evident that the new approach leads to higher FS, being thus less conservative.

6. Conclusions

The instability of the seabed during earthquakes is a critical issue in offshore engineering, as it can threaten the safety and/or the serviceability of offshore and/or near-shore structures. Typically, seismic slope stability assessment is performed using pseudo-static methodologies based on certain simplifications that convert the dynamic problem to an equivalent static one. Under this perspective, the current study has focused on the stability of submarine slopes under seismic conditions.

More specifically, a thorough investigation of the available analytical solutions of the literature has revealed that they do not include all forces caused by the applied horizontal acceleration. This fact can lead to inaccurate slope stability assessment. More specifically, the presented results demonstrate that existing approaches substantially underestimate the factors of safety, especially for moderate to high acceleration levels. In other words, the slopes that have been assessed in the past may not be so vulnerable as they are considered to be, leading thus to conservative and costly design solutions for offshore and/or near-shore structures and lifelines. For instance, in the case of a pipeline the obtained small values of factors of safety would lead to increased design requirements, expensive mitigation measures, or even rerouting.

Conclusively, the proposed modification of factor of safety calculations can be considered as a significant improvement, while the parametric study has highlighted the impact of various factors on the instability of a submarine slope from an engineering perspective. Future extension could adopt more elaborate soil constitutive models and examine other failure types, e.g., planar slides of finite length and circular slides. In addition, apart from pseudo-static approaches, the inclusion of all potential buoyancy forces should also be studied under real dynamic conditions, where all components of acceleration vary with time.

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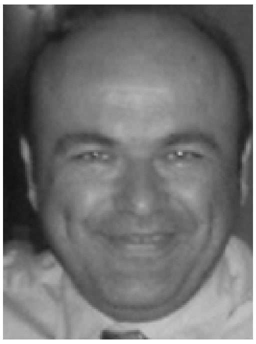
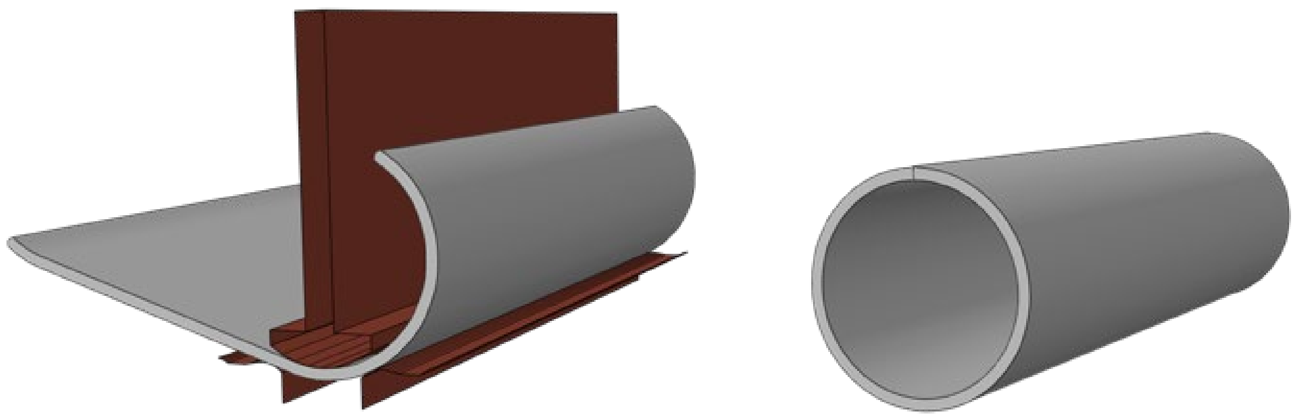
AUTHORS

Prodromos Psarropoulos
National Technical University of Athens
Structural & Geotechnical Engineer
prod@central.ntua.gr



Yiannis Tsompanakis
Technical University of Crete
Professor of Computational Dynamics & Earthquake Engineering
jt@science.tuc.gr

Nikolaos Makrakis
Technical University of Crete
Surveying & Earthquake Engineer
makr.nickos@gmail.com



Numerical prediction of material properties and structural response of JCO-E offshore pipes

A. STAMOU[1], I. GAVRIILIDIS[1], C. PALAGAS[2], E. DOURDOUNIS[2], N. VOUDOURIS[2], A. TAZEDAKIS[2], S. A. KARAMANOS[1] > [1] UNIVERSITY OF THESSALY, [2] CORINTH PIPEWORKS

Abstract

The present paper presents the application of advanced finite element tools to predict the influence of cold-forming on material properties and collapse resistance of steel JCO-E pipes. Results are obtained for a thick-walled 30-inch-diameter pipe, corresponding to diameter-to-thickness ratio value less than 20. The numerical simulations are supported by experimental tests determining the material properties of steel pipe and steel plate, which are used for forming the JCO-E pipe, and accounts for the influence of heat-treatment on pipe material and its effects on collapse capacity is discussed. The numerical results are also correlated with recent full-scale collapse experiments performed in C-FER, while both experimental data and numerical results are compared with the DNV-ST-F101 standard predictions, and suggestions on the value of fabrication factor are made, considering the material strength recovery due to heat treatment. Finally, the influence of heat treatment on material strength recovery and the collapse capacity is discussed.

1. Introduction

Large diameter and thick-walled line pipes, which are candidates for both deep offshore applications, are mainly manufactured by cold forming and expanding long plates. In this process the plate is deformed significantly in the inelastic range of its material, and a circular configuration (pipe) is obtained from the initial flat configuration (plate) through the following sequential steps: (a) crimping of plate edges, (b) "J" phase, where the forming tool (punch) forms the one side of the plate through a series of consecutive punching steps and the plate obtains a J-shape, (c) "C" phase, where the other side of plate is deformed by the punch in a manner symmetrical to that followed in J phase, (d) "O" phase, where a quasi-round configuration is obtained, (e) welding stage where the plate ends are welded, and (f) expansion phase where a mechanical expander is used to expand the pipe and finally obtain the desired characteristics. These cold-forming steps affect the geometry, such as cross-sectional ovality and wall thickness, and the material properties of the final product [1].

Previous works have reported the effects of cold-forming manufacturing process on the material properties of the finished line pipe, and outlined the reduced collapse capacity of cold-formed pipes when compared with the seamless pipes [1]. During the expansion phase of JCO-E, the pipe material is plastically deformed in the circumferential direction, leading to reducing the compressive strength of the pipe material, due to Bauschinger effect. The compressive strength of pipe material is an important factor that controls the structural performance of pipeline under external pressure loading conditions, and thus it is of major concern in offshore applications. However, it is possible to alleviate the material strength degradation with mild heat treatment of the line pipe during the coating cycle of the pipe [2], resulting in higher external pressure capacity.

The present paper continues the authors' research on collapse performance of "heat treated" and "as fabricated" JCO-E pipes [3], focusing on the influence of cold-forming process on the geometric and the material properties of the fabricated pipe. The manufacturing process of a thick-walled 30-inch-diameter line pipe is simulated using a two-dimensional (2D) finite element model. The steel plate thickness is 39 mm. Furthermore, its structural response under external pressure is calculated and compared with the results obtained by a three-dimensional (3D) analysis that simulates the full-scale experiment performed in C-FER [3]. The beneficial effect of heat treatment on the compressive strength of pipe material and on the collapse strength of the pipe is also examined. The numerical predictions of the collapse pressure are also compared with the predictions of DNV-ST-F101 [4] formula. Finally, the variation of mechanical properties through the pipe thickness is discussed and its influence on the external pressure capacity of the pipe is investigated.

2. Numerical modelling

2.1 Description of JCO-E manufacturing process

The JCO-E manufacturing process is simulated using a quasi-two-dimensional (2D) finite element model referred to as "Model 1". In this model, the inelastic response of the steel plate material is described with a user-defined material subroutine (UMAT) which employs a nonlinear kinematic hardening plasticity model developed and implemented by the research team in previous works [5]. The finite element model simulates rigorously the final line pipe product from the initial flat configuration of plate to the series of consecutive mechanical steps, and the final circular configuration of pipe after unloading from the expansion stage. The numerical analysis is performed using ABAQUS/Standard finite element package [6].

The forming parameters for simulating the JCO-E manufacturing process of the 30-inch-diameter line pipe have been provided by Corinth Pipeworks S.A. (CPW). More specifically, geometric parameters, such as the dimensions of the plate, the forming dies, the punch, the expander segments, and kinematic parameters, such as initial positions and displacements of each part, constitute the basic input information for simulating the fabrication process in a realistic manner.

A 3D schematic representation of the JCO-E manufacturing process is shown in Figure 1. The crimping stage is simulated by considering the inner die (upper) fixed and letting the outer die (lower) move upwards, and subsequently bend the plate edges up to a desired deformation level. The stage is completed by drawing back the outer die, causing the plate to unload elastically. Figure 1 presents the J-C-O steps (b, c and d in Figure 1) that follow after crimping step in the numerical analysis. In these steps, the plate is subjected to several punching steps, which are forcing the plate to progressively deform under local bending and unloading conditions across the plate width. The number of punching steps is the same between the two crimped edges (J and C steps). Final punching occurs at the centre of plate width, so that a quasi-circular configuration is obtained after unloading. Followingly, the two plate edges come into contact by applying a mechanical load on their lateral surfaces. The subsequent step of welding is not performed in the current simulation, since the welding process induces small residual stresses in the pipe and therefore, it has negligible effect on the buckling pressure of the pipe, as demonstrated in a previous study [7]. The last step of the manufacturing process is the expansion stage, as shown in Figure 1, where twelve expander segments are displaced outward in the radial direction, expanding the pipe, so that the pipe diameter size is controlled.

In the 2D finite element analysis of the manufacturing process, the forming tools and dies are modelled as analytical rigid surfaces, whereas four-node reduced integration generalized plane strain continuum elements (denoted as CPEG4R in ABAQUS/Standard) are used in the deformable plate, so that the conditions are similar to those imposed in a real pipe mill, and therefore the out of plane deformation during the process is taken into account. More specifically, twelve elements have been used in the through thickness direction of plate, and the size of elements in the circumferential direction is chosen equal to 16% of thickness. The contact between the plate and the rigid surfaces is modelled using a "master-slave" algorithm with frictionless contact property; in the contact pair the undeformed rigid bodies of dies and tools represent the master surfaces, whereas the deformable plate constitutes the slave surface. Special care is given during the JCO steps to avoid the relative motion between the punch surface and the upper side of plate during punching.

2.2 Material model

The sequence of punching steps across the plate width during the JCO process results in significant plastic deformation of the plate. Each punching step imposes local bending, and therefore the outer and the inner part of the plate wall is deformed under tension and compression, respectively. Furthermore, the expansion step strengthens the pipe material of the outer pipe wall further in tension, making it vulnerable to reverse loading, due to the Bauschinger effect. Since reverse loading conditions exist at the outer part of the pipe wall, when external pressure is uniformly applied on the pipe surface, an appropriate plasticity model should be employed to account for the Bauschinger

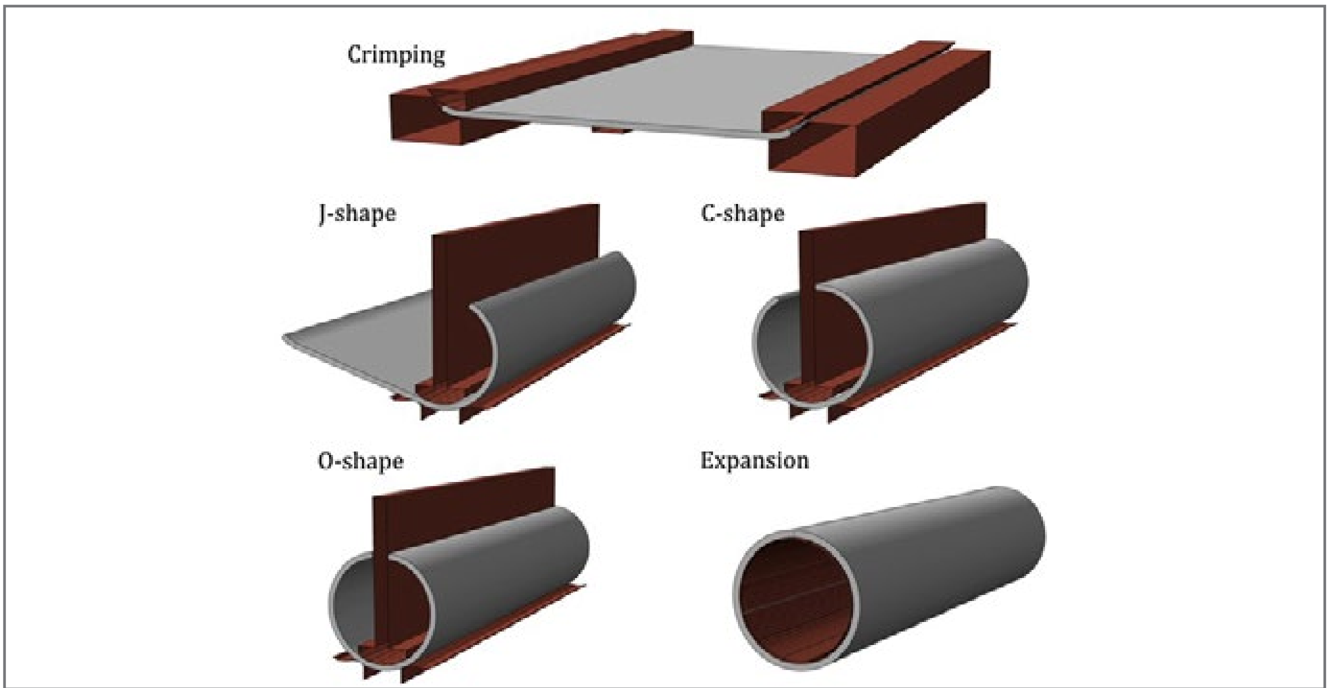


Figure 1: Schematic representation of JCO-E manufacturing process; (a) Crimping, (b) J-phase, (c) C-phase, (d) O-phase, (e) Expansion.

effect, simulating the material response under reverse or cyclic loading stress paths. Herein, a Von Mises model with plasticity nonlinear kinematic/isotropic hardening is employed, and is described in more detail by Chatzopoulou et al. [5].

A series of experiments, which are representative of the deformation history during the JCO-E manufacturing process, have been carried out to determine the material properties of the X60 steel grade material of the plate and calibrate the plasticity model. The experimental procedure consists of tension-compression-tension loading on specimens extracted from the steel plate at different locations and orientations following the recommendations of SEP 1240 [8]. Figure 2 presents the experimental stress-strain curve of the X60 steel plate material and the corresponding numerical fit from the plasticity model.

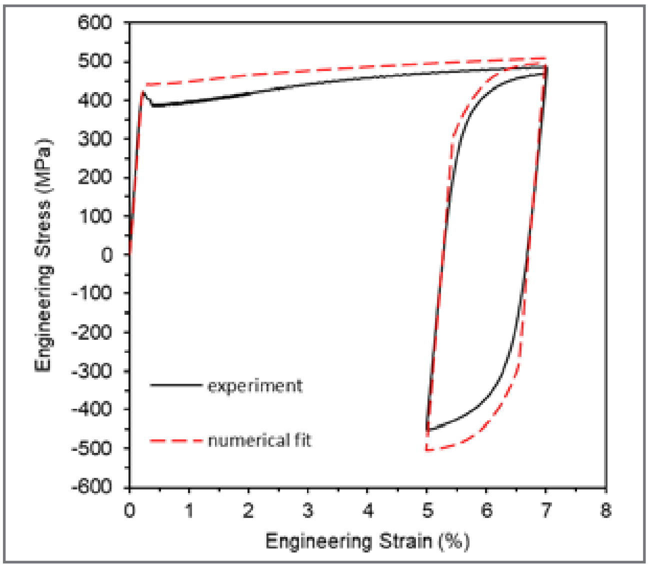


Figure 2: Experimental curve of the X60 steel plate, and the corresponding numerical fit.

3. Numerical results

3.1 Simulation of JCO-E manufacturing process

The deformation configurations of the plate during the manufacturing process are shown in Figure 3 for the initial crimping step and the subsequent “J”, “C” and “O” steps. In the present numerical analysis, fifteen punching steps are applied during the JCO steps. After removal of forming tool (JCO punch), a secondary forming tool referred to as “finishing press” (Figure 4) is used to reduce the gap by imposing two extra bending steps on the two crimped sides of the plate configuration after the O-step, as shown in Figure 4b and Figure 4c. The final gap is depicted in Figure 4d and is significantly lower than the one obtained after the O-step (Figure 4a). The initial gap (Figure 4a) and the final gap (Figure 4d) are in accordance with measurements with actual 30-inch-diameter pipe provided by CPW. At the end of the extra punching step, the final gap (Figure 4d) is closed and the two plate edges are kept in contact, using a “no separation” contact algorithm.

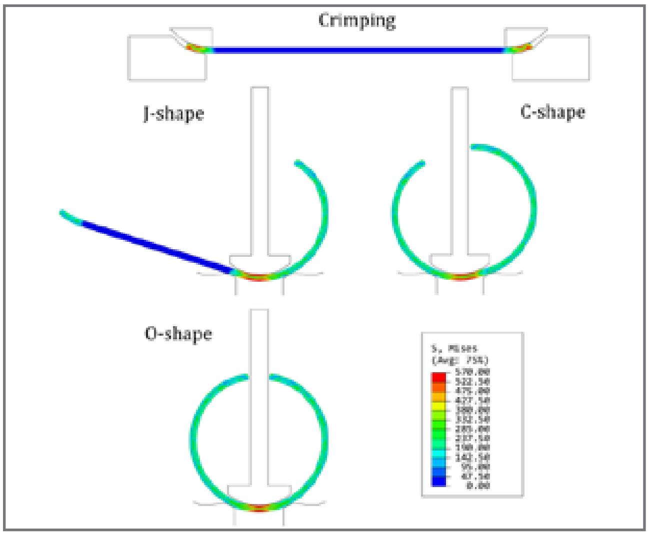


Figure 3: Plate deformation during JCO manufacturing process prior to welding; von Mises contour plot.

The nearly circular pipe configuration obtained after gap closing and welding is referred to as JCO pipe, as shown in Figure 5a. Subsequently, expansion of the JCO pipe is performed, as shown in Figure 5b, using twelve expander segments that move radially outwards. The final configuration of pipe, obtained after removing the expander segments, is referred to as “JCO-E pipe” and corresponds to the final product of the fabrication process, as shown in Figure 5c. The amount of expansion induced in the pipe is quantified in terms of the so-called “expansion strain” (ε_E), expressed by:

$$\varepsilon_E = \frac{C_E - C_W}{C_W} \qquad (1)$$

where C_E and C_W are the lengths of pipe circumference after (Figure 5c) and before (Figure 5a), the expansion phase respectively. The expansion strain expression adopted in the present study is also adopted in pervious works [1], [5], [7]. The expansion strain value should be considered as a permanent strain of the final line pipe shape. The expansion strain applied on the JCO pipe of Figure 5, is equal to 1.30%, which

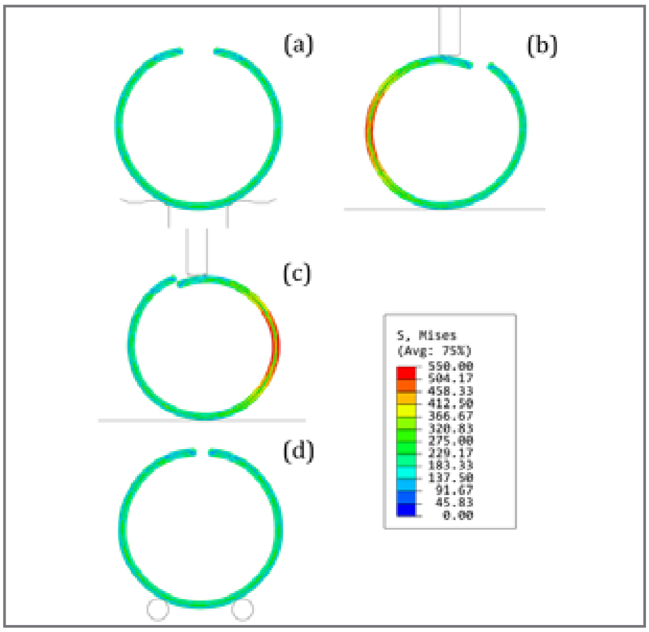


Figure 4: Deformation sequence of JCO pipe under the finishing press; von Mises contour plot.

is an approximate value of the actual expansion magnitude of the 30-inch-diameter pipe fabricated in the pipe mill. Considering this amount of expansion, the inner diameter of the JCO pipe at 0, 45 and 90-degree locations from the weld seam is 675mm, 675mm and 679mm, respectively, while the corresponding values of the JCO-E pipe are 687mm, 686mm and 686mm. The numerical predictions of the inner diameter of both configurations (JCO and JCO-E) are in very good agreement with actual measurements at the corresponding locations.

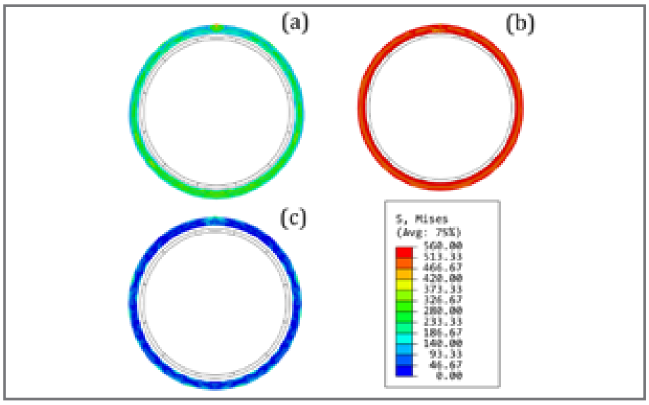


Figure 5: Deformation sequence of expansion phase, resulting in the final pipe geometry of the JCO-E pipe; von Mises contour plot. (a) Before expansion (JCO pipe), (b) at maximum expansion (here ε_E=1.3%), (c) final stage after unloading (JCO-E pipe).

3.2 Effect of expansion on the geometry and, pipe structural integrity in deep water

The finite element model presented in section 2 is capable of simulating rigorously the JCO-E manufacturing process and the structural strength of the pipe under external pressure loading. Following the step of unloading from expansion (JCO-E pipe), uniform external pressure is applied on the outer surface of the pipe. During the pressurization step, the modified Riks' algorithm is employed to capture the maximum pressure at the onset of collapse and trace the post-buckling response.

In JCO-E pipes, the expansion strain ε_E is an important parameter with significant influence on the resistance of pipes under external pressure. The effect of expansion on the collapse pressure (P_{co}) of the JCO-E pipe under consideration is shown in Figure 6, considering a wide range of expansion strain values (ε_E). For small values of ε_E (up to 0.7%), P_co is an increasing function ε_E. For ε_E values ranging between 0.7% and 1.8%, the P_{co} value remains nearly constant. It is worth noticing that the maximum collapse pressure is equal to 37.9 MPa at 1.69% expansion strain, whereas at 1.30% strain (an approximate value of the expansion strain used in the pipe mill) the P_{co} value is only 1% lower. Increasing the ε_E value beyond 1.8% the collapse pressure reduces, as shown in Figure 6. This is attributed to the Bauschinger effect, which decreases the circumferential compressive strength. Also note that the maximum allowable expansion strain, according to DNV-ST-F101 standard [4], is 1.50%, which falls within the optimum range of expansion.

The effect of expansion strain on the geometric configuration of line pipe is also investigated. The residual cross-sectional ovality (O_o) of the pipe at the end of the fabrication process is measured, using the following expression:

$$O_o = \frac{D_{max} - D_{min}}{D} \quad (2)$$

where D_{max} and D_{min} are the maximum and minimum values of the outer diameter, and D is the nominal value of the outer diameter. The interaction between the cross-sectional ovality and the applied expansion strain is shown in Figure 6 for the 30-inch-diameter JCO-E pipe under consideration. The results demonstrate that the cross-sectional ovality after the JCO stage before expansion, is approximately equal to 0.6%. Subsequently, increasing the expansion strain, the cross-sectional ovality of the pipe decreases. This reduction is observed up to about 1.3% expansion

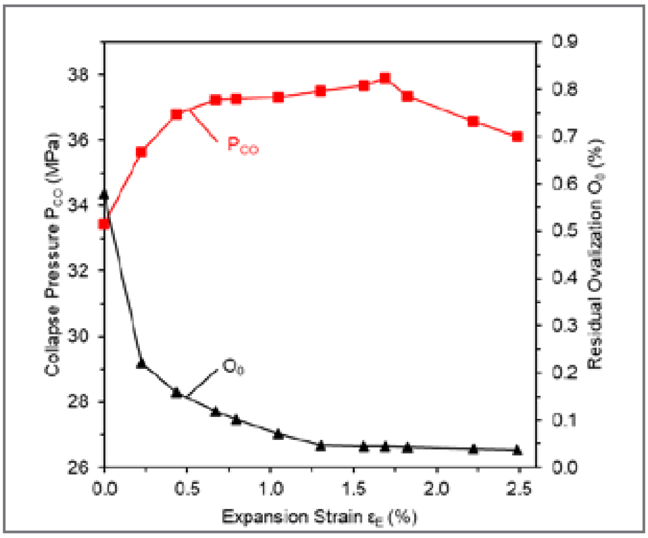


Figure 6: Effect of expansion on residual cross-sectional ovality (O_0) prior to pressurization and the corresponding collapse pressure (P_{co}).

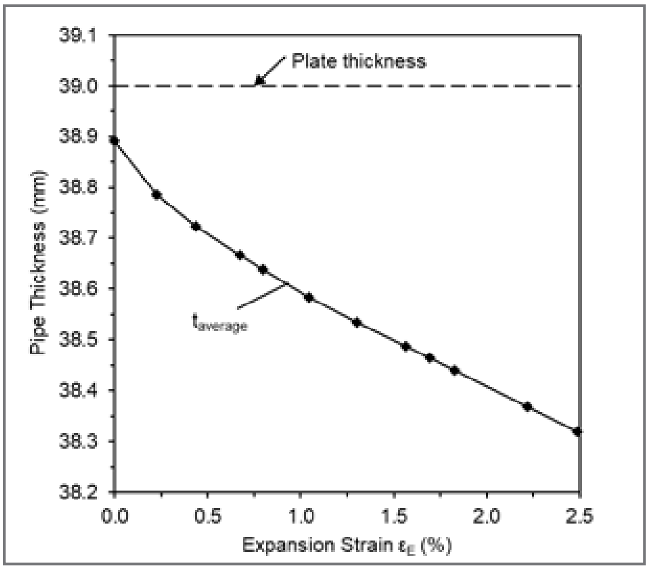


Figure 7: Effect of expansion strain on the average wall thickness of the JCO-E line pipe, compared with the plate thickness.

strain, reaching a value lower than 0.05%, while further increase of expansion strain has negligible effect on the ovality of the JCO-E pipe.

Figure 7 presents the average thickness of the JCO-E pipe under consideration (final product) with respect to different expansion levels and is also compared with the initial thickness of plate (39mm). The numerical results demonstrate that the average wall thickness of the line pipe decreases with increasing expansion strain in a quasi-linear manner, due to "Poisson" effect in the inelastic range of steel material. The results also show that the thickness of the JCO pipe (before expansion) is reduced by 0.1mm with respect to the initial plate thickness, and this is due to local bending induced by the punching steps during the J-C-O phases, as shown in Figure 7 at zero expansion strain.

3.3 Effect of mild heat treatment on pipe collapse capacity

The collapse performance of JCO-E line pipes under external pressure has been studied in a previous work by the authors [3]. In that work, the effects of mild heat treatment on the compressive strength of the line pipe material and on the collapse pressure were examined. This heat-treatment corresponds to a typical coating process of the line pipe. A thermally-treated pipe, manufactured by CPW, with the geometric and material characteristics of the 30-inch JCO-E pipe under consideration was subjected to full-scale collapse test [3]. The collapse test procedure was also numerically simulated, using a three-dimensional (3D) finite element model (Model 2), accounting for the material properties of the as-fabricated (AF) and the heat-treated (HT) conditions.

Material stress-strain curves have been obtained experimentally from uniaxial compression tests on coupon specimens extracted and machined from the outer part of AF and HT pipes in the circumferential direction. The experimental curves at 90, 180 and 270-degree locations around the circumference are averaged, and the corresponding responses are shown in Figure 8. Furthermore, the stress-strain curve of the X60 grade steel (plate material) is shown in Figure 8. The Bauschinger effect, due to reverse loading, is clearly shown in Figure 8 in terms of the reduced proportional limit of the AF and the HT curves, compared with the plate material curve. Additionally, the comparison between the AF and the HT curve demonstrates the beneficial effect of mild heat treatment on material strength (material strength recovery).

The experimental and numerical results on the collapse pressure are summarized in Table 1. The results include the numerical collapse pressure obtained from Model 1 described in Section 2, at 1.30% expansion strain, which is an approximate value of the expansion strain used in the pipe mill. The collapse pressure values obtained from the two numerical models are in good agreement. Furthermore, the numerical prediction of the full-scale collapse pressure is also very successful. Finally, Table 1 shows that the collapse pressure is increased by 13% for the case of the heat-treated pipe, compared with the as-fabricated pipe.

Model 2			Model 1	Full-scale test (HT)
Plate	AF	HT	AF	
44.6	38.5	43.4	37.5	43.4

Table 1: Experimental and numerical results of collapse pressure results (in MPa).

The collapse capacity of the 30-inch-diameter JCO-E pipe is also quantified using the DNV-ST-F101 design standard [4]. The results are presented in Table 2 for two values of fabrication factor (a_{fab}) namely 0.85 and 1 to account for the as-fabricated (AF) and heat-treated (HT) material properties. The collapse pressure predictions using the specification formula appear to be conservative compared to the experimental and numerical results of Table 1, and this is attributed to the high value of ovality parameter proposed by the standard (0.5%).

4. Conclusions

The manufacturing process and the collapse performance of a thick-walled 30-inch-diameter JCO-E pipe (D/t≈20) is investigated, using advanced numerical tools. A two-dimensional (2D) finite element model is used (Model 1), which simulates the manufacturing process of the JCO-E pipe and predicts its collapse pressure. The geometric characteristics of the fabricated pipe predicted by Model 1 are in very good agreement with measurements provided by the pipe mill. The effects of pipe expansion on its geometric characteristics and on its external pressure capacity are also examined. Increasing the expansion level up to about 0.7%, the cross-sectional ovality of the fabricated pipe is reduced and the corresponding collapse pressure is increased. For expansion strain values between 0.7% and 1.8%, the value of collapse pressure remains nearly constant, whereas for expansion strain

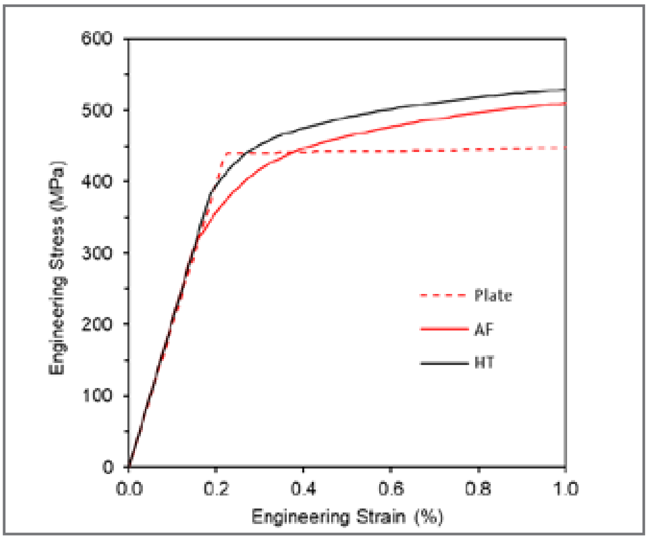


Figure 8: Averaged experimental compressive stress-strain curves at the outer part of pipe before and after the heat treatment, and plate material curve.

values beyond 1.8%, the collapse pressure decreases. The average wall thickness of JCO-E pipe is computed for different values of expansion strain, and the results indicate a quasi-linear dependance of pipe wall thickness on the expansion level.

The collapse pressure calculated from Model 1 compares very well with the collapse pressure from a three-dimensional (3D) model that simulates the full-scale collapse test (Model 2). Using Model 2, the effect of mild heat treatment on the collapse pressure is investigated, considering the stress-strain curve before (AF) and after heat treatment (HT). The results show that P_co in the HT pipe is increased by 13%, compared to the AF pipe, verifying the beneficial effect of heat treatment. Collapse pressure predictions obtained from the DNV-ST-F101 collapse formula are compared with the numerical and experimental results. The comparison shows that the DNV-ST-F101 formula provides reasonable yet conservative collapse pressure predictions for the pipe under consideration.

DNV-ST-F101 formula parameters	$\alpha_{fab} = 0.85$	$\alpha_{fab} = 1$
• AF yield strength: 464 MPa (at 0.5% total strain of AF stress-strain curve in Figure 8) • HT yield strength: 490 MPa (at 0.5% total strain of HT stress-strain curve in Figure 8) • Elastic properties of steel: E=207 GPa, v=0.3 • Diameter: 761.4 mm (average value of outer diameter [3]) • Thickness: 38.29 (averaged value [3]) • Minimum value of ovality proposed by the standard: 0.5 %	35.0	41.4

Table 2: Collapse pressure predictions (in MPa) using the DNV-ST-F101 [4] collapse formula for the as-fabricated (AF) and heat-treated (HT) conditions.

5. Acknowledgments

The authors would like to thank Dr Konstantinos Antoniou for his help and contribution on the first stages of the present investigation.

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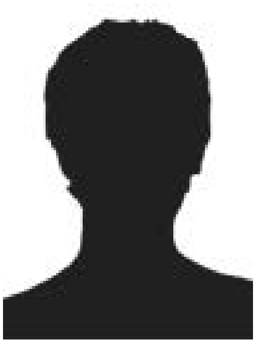
AUTHORS

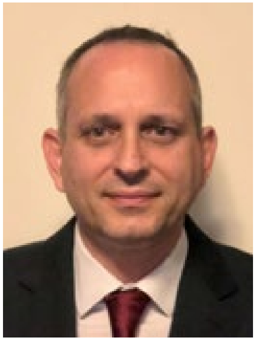
Aris Stamou
University of Thessaly
Ph.D. candidate
aristamou@uth.gr



Ilias Gavriilidis
University of Thessaly
Post-Doctoral Researcher
ilgavrii@uth.gr

Christos Palagas
Corinth Pipeworks
Engineering and Technology Manager
cpalagas@cpw.gr

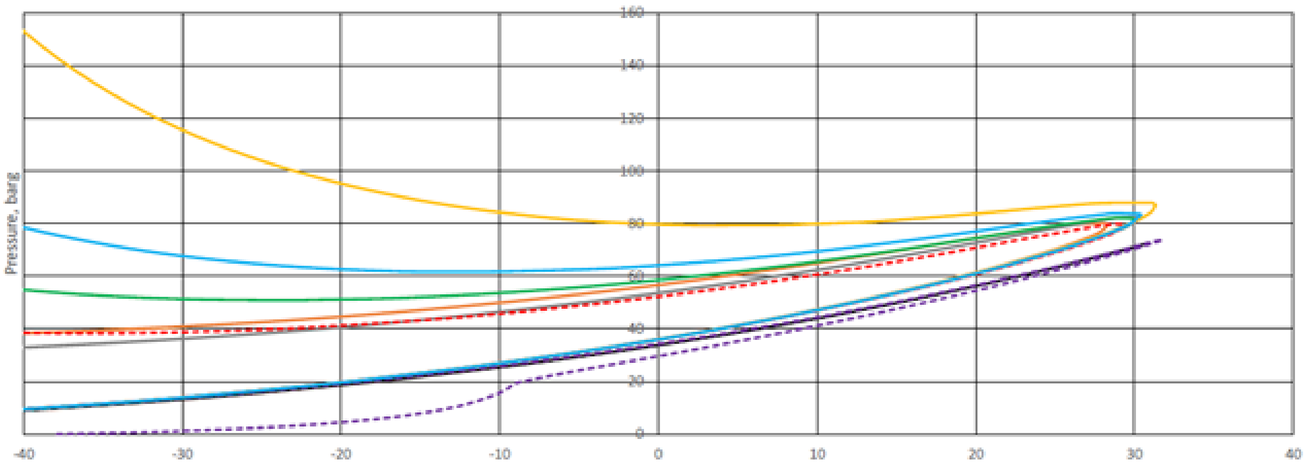
Efthimios Dourdounis
Corinth Pipeworks
Head of Technical Analysis
edourdounis@cpw.gr



Nikos Voudouris
Corinth Pipeworks
Research & Development Senior Manager
nvoudouris@cpw.gr

Athanasios Tazedakis
Corinth Pipeworks
Chief Technology Officer
atazedakis@cpw.gr

Spyros A. Karamanos
University of Thessaly
Professor of Structural Mechanics
skara@mie.uth.gr



Repurposing Hydrocarbon Pipelines to Transport CO2: PETRONAS' Study

F. AZIZ, K. A. KARIM, IR. H. HUSSIEN > PETRONAS

Abstract

PETRONAS is considering pipeline repurpose option for one of its CCS projects in Malaysia. One of the opportunities identified is to repurpose existing gas export pipelines, 24in and 30in with combined distance of 200km from offshore to onshore. Existing technical frameworks from available standard and internal resources for pipeline repurpose have been reviewed.

This is to provide complete approach to pipeline repurpose. Qualitative risk assessment (QRA) for pipeline repurpose is presented by discussing technical recommendations made by the feasibility study team.

This feasibility study involves CO2 characterization, review of existing hydraulics analysis, fitness for service (FFS) result review, Battelle Two Curve Method (BTCM) check against existing pipeline toughness and sour compatibility check. Existing pipeline capability limits are established to provide clarity if PETRONAS able to transport CO_2. Further analyses are identified accordingly to address the established limits.

1. Introduction

In 2020, PETRONAS has embarked on its Net Zero Carbon Emission (NZCE) by 2050 target. The mission sets the company's business activities to be carbon neutral by 2050. Among efforts conducted by PETRONAS to achieve the target is the implementation of carbon capture and storage (CCS).

One of the proposed CCS projects is to sequester volume of CO_2 in Table 1. CO_2 will be injected into depleted gas reservoir offshore peninsular Malaysia. The depleted reservoir is part of the earliest gas complex developed by PETRONAS which consists of:

I. 1 no Central Processing Platform (CPP)

II. 2 nos wellhead platform (WHP)

III. 1 no 24in x 50km gas pipeline from CPP to collector platform

IV. 1 no 30in x 150km gas export pipeline from collector platform to onshore gas terminal

Group Technical Solutions (GTS), the engineering arm of PETRONAS, together with asset owner initiated a study to determine the feasibility of repurposing the pipelines. The mechanical properties of the pipelines are listed in Table 1.

This paper will share the assessment approach as well as the findings by achieving below objectives:

I. To identify approach employed for pipeline repurpose and to map with existing internal technical framework.

II. To highlight qualitative risk assessment (QRA) recommendations for pipeline repurpose scenario and outcomes of CO_2 fluid characterization study.

III. To elaborate technical challenges associated with pipeline repurpose.

IV. To provide high level costing of newly built pipeline.

V. To discuss way forwards for CCS detail engineering including study and validation.

	Pipeline 1	Pipeline 2
Size (in)	24	30
Wall Thickness (mm)	14.3	17.10
Design Pressure, MAOP (barg)	130	
Commissioning Date	1982	
Material	Carbon Steel	
Grade	API 5L X-60	
Target CO2 Volume for Proposed CCS Project		
Option	**Volume (MTPA)**	
1	1.19	
2	1.6	
3	8.3	
4	11.84	

Table 1: Pipeline Mechanical Properties and Proposed Volume

2. CO2 Pipeline Repurpose Technical Framework

In general, there are two main existing standards for design and operation of CO_2 pipeline namely DNV-RP-F104[1] and BS 27913[2] which outline basic requirements of designing CO_2 pipeline which encompasses description of CO_2 properties, concept development and specific design criteria, materials and pipeline design, construction, and operation.

2.1 Repurpose Approach as per DNV-RP-F104

While BS27913 provides only general statement of compliance to pipeline repurpose, DNV has laid out essential steps to repurpose existing pipeline which covers:

I. Existing pipeline integrity assessment

II. Hydraulics study

III. Safety evaluation

IV. Integrity reassessment & pipeline modification

Corrosion defects are assessed in item i and iv that involve estimating remaining life of pipeline using standard pipeline fitness for service (FFS) method. As opposed to using actual corrosion rate upon years of previous operation, the corrosion rate for repurpose pipeline is derived from CO_2 corrosion analysis for specific operating cases. For pipeline repurpose, the new operating parameters are determined by hydraulics study analyzing design cases which are normal operation, shutdown, and start-up. An important input to hydraulics study is fluid characterization study whereby CO_2 stream compositions are analyzed to develop its phase envelope based on various EoS.

Analysis on sudden release of CO_2, dispersion (onshore) and dilution (offshore), is an integral part of the safety evaluation. The results of the analysis become the basis for operator to reassign the location class of the pipeline.

2.2 PETRONAS Existing Internal Technical Framework

An internal guideline of PETRONAS pipeline life extension (PLES) methodology has been established. The guideline is timely to cater increasing demand of pipeline repurpose studies within PETRONAS. The methodology is illustrated in Figure 1 which existing pipeline integrity assessment and integrity reassessment & physical modification are the integral parts of the methodology.

Pipeline integrity assessment comprises evaluation of pipeline integrity against various threats which can be external corrosion, internal corrosion, stress corrosion cracking, manufacturing defects, construction defect, equipment failure, weather condition and external load, third party damage and incorrect operations. However, corrosion is one of the biggest problems contributing to leaks and ruptures of pipelines. Typically, all metal loss defects are treated the same as corrosion defect that is gauged by assigning safe working pressure related to the defect and to be compared against MAOP. This ratio is referred as Estimated Repair Factor (ERF).

As such for pipeline repurpose would consist of:

I. Determination of remaining life of pipeline based on the remaining wall thickness against corrosion rate.

II. Predicting subsequent metal loss based on new operating condition with CO_2 followed by determination of remaining life of the pipeline at the end of intended life extension period.

3. Risk Assesment and related Repurpose Analyses

3.1 Qualitative Risk Assessment

Qualitative risk assessment (QRA) has been performed by project team to provide clarity on the technical risks that are collectively agreed by the stakeholders. The QRA was carried out based on available information Pipeline 1 and Pipeline 2. The recommendations made are as follow:

I. Rec #1: Significant presence of H_2S seriously affects pipeline material compatibility as the pipelines are not designed as sour service. Preliminary assessment is required to determine appropriate sour region as per NACE MR-0175(4) recommendation.

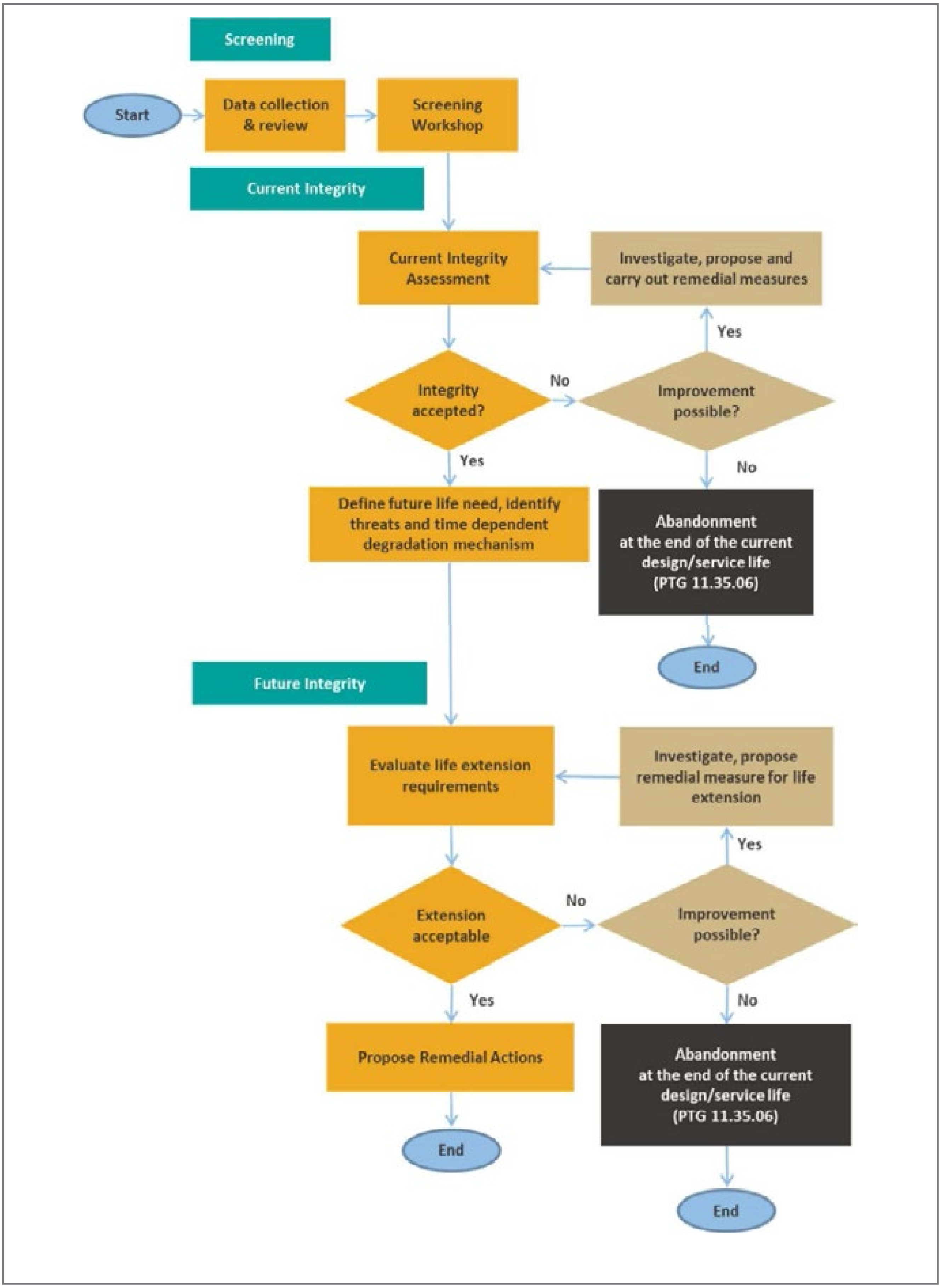


Figure 1: PETRONAS Framework on Pipeline Life Extension Study (PLES)

II. Rec #2: Charpy impact testing was performed at 10°C as opposed to API5L recommendation, 0°C. Charpy re-testing may be required. Battelle Two Curve Method (BTCM) is required to analyze if the toughness is sufficient to resist running ductile fracture (RDF).

III. Rec #3: Repurpose may involve pressure testing. Using water as a testing medium may initiate corrosion if the drying is not properly done. Worst, water will stubbornly retain in corroded profile of the pipeline. Hence, technical rationalization is required to determine the criticality of pressure testing. Alternative fluid may be used instead of water for the pressure test medium.

IV. Rec #4: Thermodynamics behavior of CO_2 must be established to understand the phase behavior of CO_2 across pipeline length.

3.2 Hydraulics Analysis

3.2.1 CO_2 Fluid Characterization

The proposed development concept is expected to receive CO_2 from 2 main sources namely inherent and post-combustion. For the purpose of this study, 2 main compositions have been analyzed namely 99% CO_2 (base fluid) and 96% CO_2 with impurities sensitivity (worst-case).

Base case specification is sourced from foreign CO_2 supply where PETRONAS plans to provide transportation and storage service (T&S-as-a-service) to foreign emitters. For the worst-case scenario, the composition has been established based on overwhelmingly CO_2 condition with sensitivity of impurities including N_2, Ar and H_2.

Four equation-of-states (EoS),GERG-2008, PR78, SRK, CPA had been tested which then compared against Span & Wagner. The comparison was made to establish accuracy against density of pure CO_2. As a result, GERG-2008 persistently demonstrated smallest variance of 0.01% against pure CO_2 density during export, arrival and depressurization (seabed) cases.

Hence, GERG-2008 EoS had been chosen to further establish phase envelope of CO_2 stream composition. Water limits of 500ppm and 100ppm have been considered and incorporated in the phase envelope. Pipeline operating conditions developed in the steady state hydraulics analysis was then mapped accordingly in the phase envelope.

Based on fluid characterization result in Figure 2, composition with 4mol% of H_2 have the largest area of 2-phase region compared to other studied compositions. This condition imposes operational challenge which the bubble point at 0°C is found to be around 80barg compared to 50-60barg for other studied compositions. Hence, to select operating window to transport CO_2 with 4mol% H_2 can be challenging. Hence, it has been advised that H_2 content to be limited to 2mol% (max), named as worst-case phase envelope. All other impurities such as N_2, Ar, CH_4 are not impacting the phase envelope as greatly as H_2.

3.2.2 Steady State Hydraulics Result

Steady state hydraulics analyses were initially performed without the constraint of pipeline repurpose. The analyses were modelled based on 200km pipeline with a landing pressure of 65barg during the early injection life. This has caused the results to be tailored for sizing of newly built pipeline only. For pipeline sizes ranging from 8-inch to 24inch, the highest required departing pressure is 200barg.

The results of the hydraulics analyses were mapped on 96mol% CO_2 composition case with 2mol% H_2. Solubility line for 500ppm and 100ppm water specifications are also incorporated in Figure 2. The operating conditions are outside of water dewpoint of both water limits. Also, it is away from hydrate line. Hence this CO_2 composition would be manageable within the required operating pressure range for pipeline sizes from 8-inch to 24inch.

3.2.3 Hydraulics Sizing Sensitivity

The proposed pipeline sizes for Option 1-4 are 8, 10,16 and 18in respectively. However, the sizes of Pipeline 1 and Pipeline 2 are larger, 24in and 30in.

Hydraulically, bigger pipeline size would have lesser pressure loss and able to deliver larger volume. Since the existing pipeline sizes are larger, supposed there would be no issue to match intended CO_2 volume in

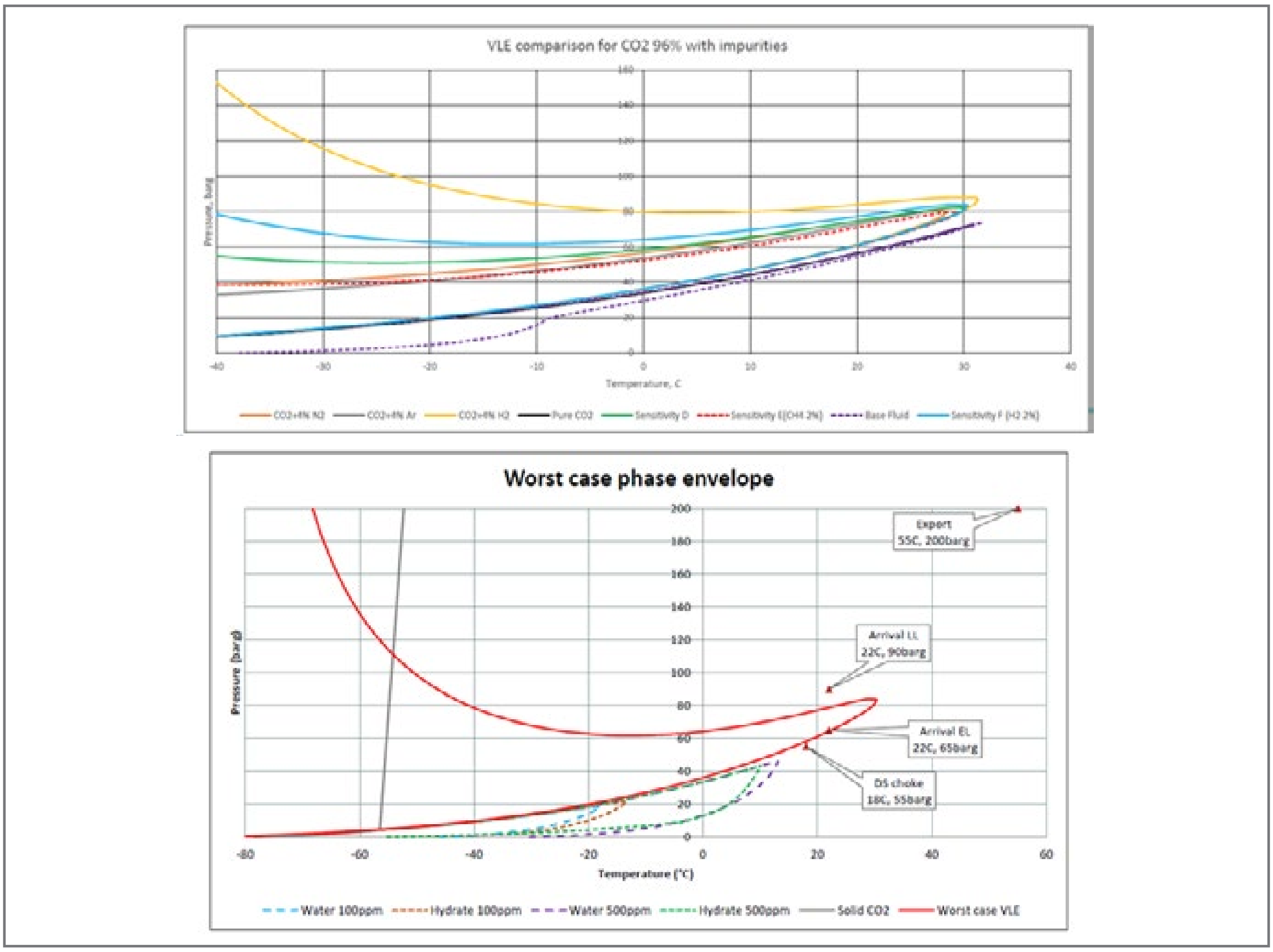


Figure 2: Various composition phase envelope & worst-case phase envelope

Pipeline 1 and Pipeline 2. Further hydraulic analysis is required to determine backpressure for 150km and 50km in 30in and 24in respectively. Hence the departing pressure would be much lower than 200barg for any of the proposed flowrate, desirably below MAOP of 130barg. We reckon for the lowest flowrate, the required departing pressure is most likely to be within the strength of existing pipeline.

3.3 Current Integrity Assessment: Fitness for Service (FFS)

As a well-established company, PETRONAS has developed an end-to-end web-based pipeline integrity management system, i-PIMS, which integrates full integrity cycle of a pipeline from fitness-for-service (FFS), linear referencing, risk assessment to integrity management plan (IMP) of respective pipeline.Fitness for Service (FFS) assessment of 30in and 24in pipelines has been retrieved from i-PIMS. FFS inputs are sourced from the latest intelligent pigging (IP) inspection results, 2013 and 2014 respectively.

3.3.1 Integrity Condition of Pipeline 1 & Pipeline 2

In general, Pipeline 1 reported low defects of as shown in Figure 3. The lowest Psafe is 150barg with the earliest year Psafe to be challenged is 2028. The contributing defects are all due to internal corrosion and cluster of worse defects are distributed into several KPs. They are within KP35-44, KP59, KP71, KP79 and KP 156 with remaining lives vary from 2028 to 2043. Majority of the defects are axial slotting and pinhole types.

Based on 2014 fitness-for-service (FFS) exercise, the lowest Psafe is 134barg with the earliest Psafe to be challenged is in 2024. Contributing defects are due to internal and external corrosion. Cluster of worse defects are distributed into two locations, at the start and at the end of the pipeline, KP0.02-KP0.13 and KP 40-43 respectively. Based on FFS assessment result, the remaining life of worse defects vary from 2024 to 2035 and majority of the worse defects are external.

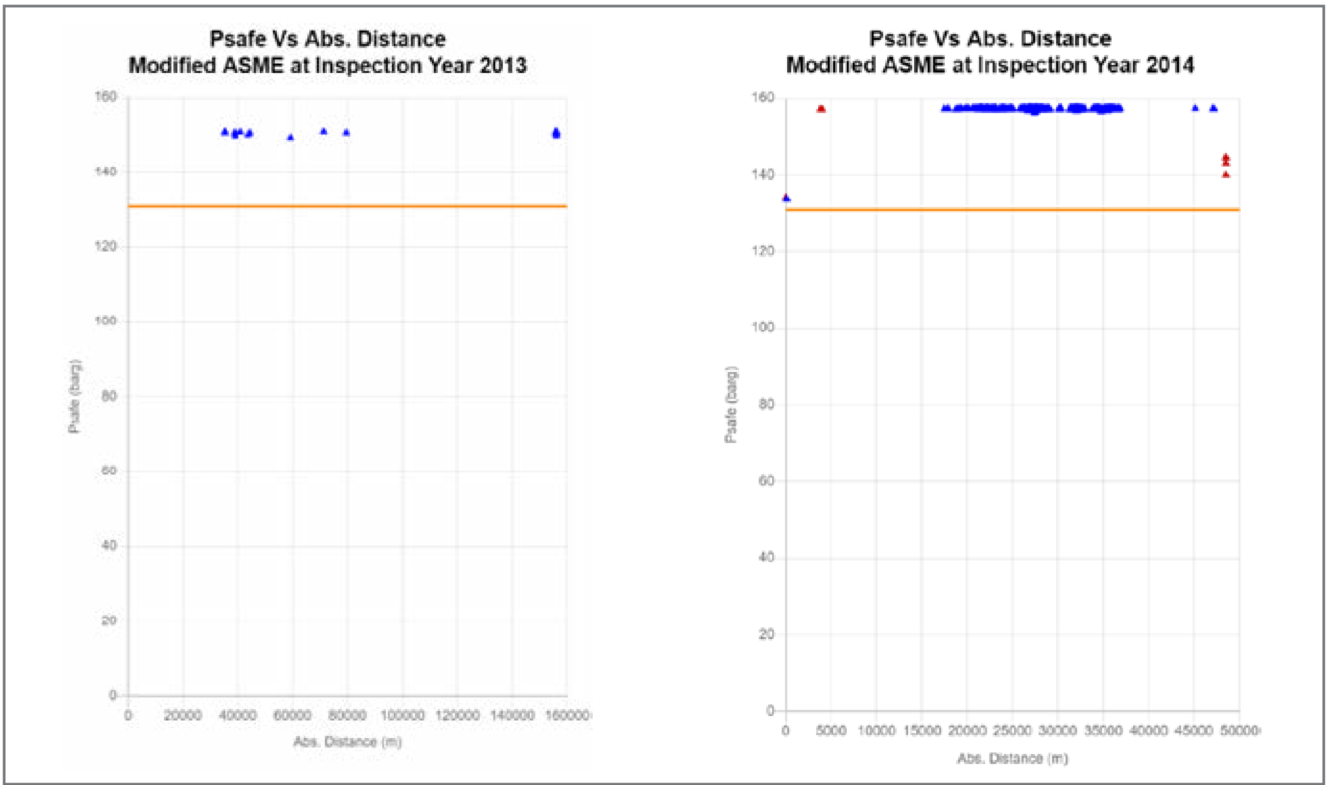


Figure 3: Psafe of Pipeline 1 and Pipeline 2 (excerpt from i-PIMS, PETRONAS)

3.4 Resistance to Running Ductile Fracture (RDF): Battelle Two Curve Method (BTCM)

Running ductile fracture (RDF) is a prominent failure mode for CO_2 pipeline. RDF is initiated when CO_2 is quickly depressurized from pipeline that causes temperature to drop drastically as energy is released. Consequently, the pipe material become brittle and easily torn longitudinally.

There are 2 forces related to RDF. The driving force that tears open the pipe due to internal pressure release i.e. depressurization and the toughness of the pipe material that resist the tearing from propagating.

In this study, the driving and resistance forces are calculated using PETRONAS' internal calculation program, enhanced Battelle Two Curve method (e-BTCM). As the team sighted mill certificate dated 1983, it was found that Charpy test was carried out at 10°C. As the current API SPEC 5L[3] requires Charpy test to be carried out at 0°C, retesting using actual pipe sample is strongly proposed.

Figure4 shows the results of e-BTCM calculation by incorporating actual SMYS (441-448MPa), UTS (570-590MPa), CVN value (154.8J at base metal) and DWTT value (756.6J). It appears that:

I. Direct proportional relationship between CVN value and initial release pressure for 65°C and 55°C cases. The higher the initial release pressure, the higher the CVN value required to resist the driving force.

II. As the release pressure increase, CVN of 1000J is obtained from the calculation which may indicate insufficient pipe thickness to resist RDF.

III. As opposed to item i, an unusual CVN trending of for 20°C case has been mapped. The CVN value is inversely proportional to initial release pressure.

IV. Due to item iii, a thorough review of internal calculation program may be required following finding of item iii.

3.5 Preliminary Sour Material Compatibility Assessment

A preliminary sour assessment has been performed by considering 130barg MAOP as the highest operating pressure of the pipeline with 200ppm and 9ppm H_2S concentration. The results are mapped as per Figure 5.

As shown, 9ppm of H_2S concentration will produce H2S partial pressure PH_2S of 0.117kPa whereby 9ppm

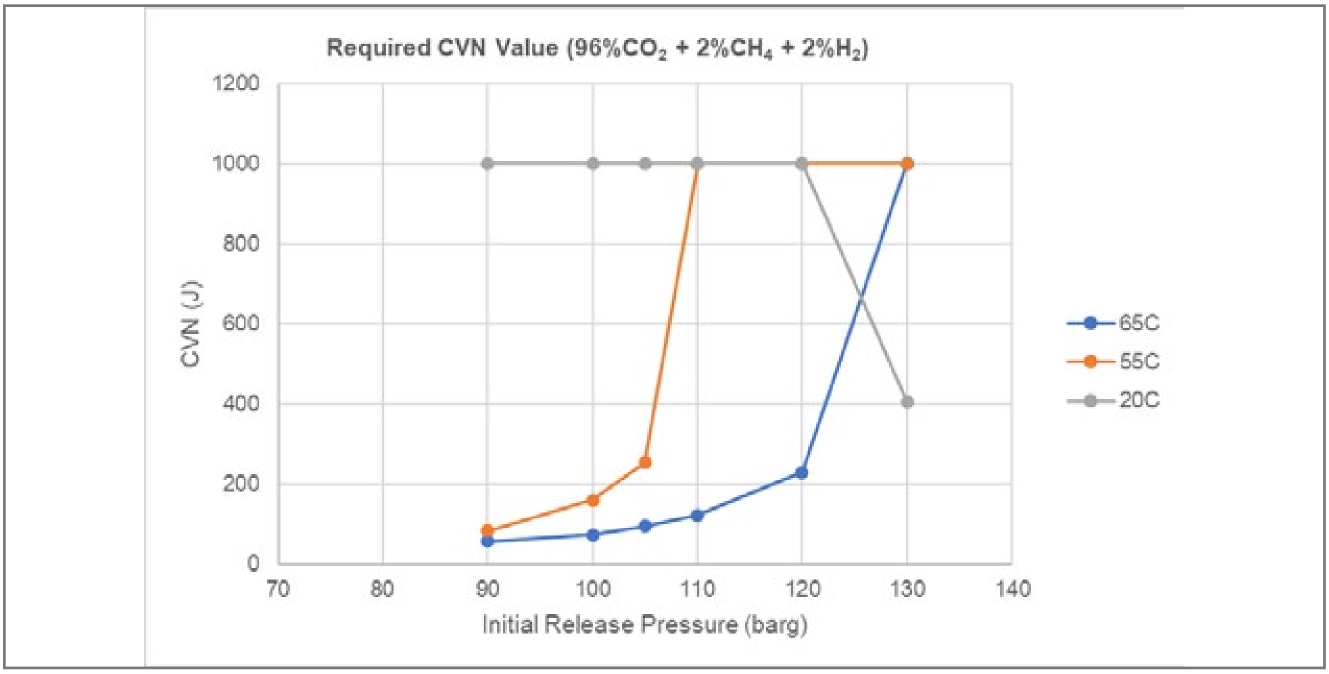


Figure 4: Pipeline 1 BTCM Result

can be well adopted as the H_2S limit. To stretch it further to the limit, 20ppm will result PH_2S of 0.26kPa. With 200ppm of H_2S concentration would certainly require treatment prior to flow into the pipeline.

3.6 Technical Discussions

Above sections demonstrate the result of preliminary assessments performed by the study team. The results provide further technical clarity on the feasibility of pipeline repurpose.

Qualitative risk assessment (QRA) which attended by all stakeholders is an effective exercise to gauge the overall technical risks and recommendations to address them accordingly. With risk assessment in place, probability of pipeline repurpose to fail is minimized.

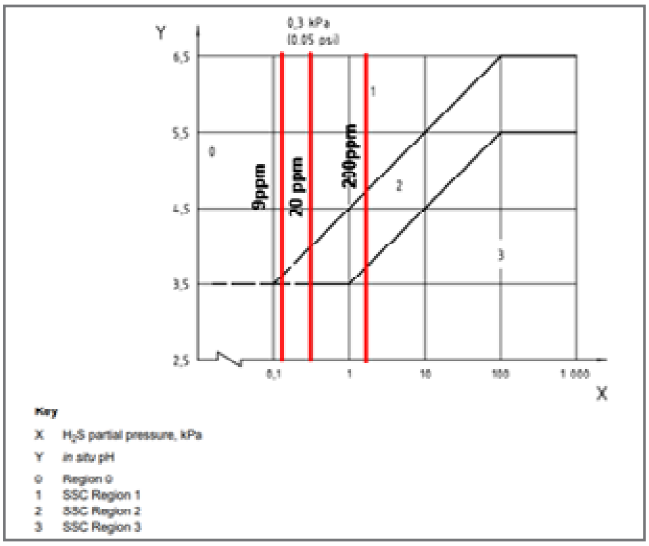


Figure 5: Preliminary Sour Assessment. (Figure excerpt from NACE MR 0175)

Currently, existing hydraulics analysis only consider newly built pipeline case that requires departing pressure up to 200barg to transport dense phase CO_2 for 200km distance with the highest proposed size as 18in. Given the size of Pipeline 1 and Pipeline 2 are 30in and 24in respectively, the study team believe there is an opportunity to further reduce pipeline operating pressure below MAOP.

The integrity status of Pipeline 1 and Pipeline 2 is well understood. The remaining life of both pipelines are estimated based on corrosion rate of existing natural gas product. To obtain remaining life for future use, it would require new set of corrosion assessment with credible design cases e.g. insufficient drying case and normal operating case.

Pipeline 1 and Pipeline 2 remaining life can be further extended by repairing the worst defect locations respectively. Consequently, the remaining life can be extended between 10-20 years. The result of the corrosion analysis consequently set the requirement for operational control measures, monitoring as well as repair strategies. This must be performed prior to the decision of using the existing pipeline for CO_2 transportation.

To meet the requirement to resist RDF can be challenging. We are in the view that the input parameters and ambient temperature are not within the capacity e-BTCM software. Further discussion would be required with the software owner. As of current, it appears that rather than flowing in dense phase, it may be wise to consider flowing in gas phase and further re-compression is required at the injection site. This must be proven with cost comparison of purchasing additional compressor against laying new 200km pipeline. The cost discussion can be found in subsequent section. Material compatibility to H_2S only applicable to 9ppm H_2S concentration of 130barg MAOP. The H_2S limit for the system is 20ppm.

3.7 Pipeline Cost Estimation

As explained above this section presents budgetary estimate of an 18in offshore pipeline EPCIC project. Awareness on the pipeline cost shall assist decision maker to decide on the right direction of CCS facility concept.

The assumptions are:

I. Pipeline size of 18in x 19.05mmWT

II. Carbon steel, non-sour, LSAW.

III. Distance of 200km from onshore CCS Hub to offshore injection site.

IV. Shore approach construction included.

V. Using s-lay installation method. Conservative lay-rate assumption of 1.8km/day.

VI. Pipeline life 25 years with 4 nos of intelligent pigging operation.

High level costing in Table 3 should provide guidance to compare against installing and operating compressor option. Also, it can be the input to cost benchmarking exercise typically performed in CCS project.

Pipeline Limit	Value	Remarks
Pressure, MAOP (barg)	130	Existing pipeline MAOP as per design
Size (in)	30 & 24	Pipeline hydraulics to be reassessed based on these sizes.
Lowest P_{safe} (barg)	150 & 134	Respectively for Pipeline 1 and Pipeline 2 Opportunity to increase remaining life by performing necessary repair at the defect location.
Max pressure to avoid RDF (barg)	TBA	The proposed pipeline ambient temperature may be outside capacity of existing in-house software. Further validation with calculation program owner is required.
H_2S Limit at MAOP (ppm)	20	H_2S concentration of 200ppm is not feasible for repurpose case.

Table 2: Superiority of coextruded Tapes

No	CAPEX	Cost (USD Mill)
1	Engineering	14.7
2	Material procurement; Linepipe with coating	153.0
3	Offshore installation including offshore spread, pre-commissioning, and shore approach	67.3
	CAPEX Total	**235.0**
4	Contingency 20%	**47.0**
	OPEX	
	Pipeline maintenance for 25 years of operating	**33.0**
	Total Life Cycle Cost	**315.0**

Table 3: Cost Estimation for Newly Built Pipeline

4. Conclusion

Existing technical frameworks of pipeline repurpose provide sufficient guidance for design engineer to initiate the feasibility study. The framework is developed to address technical and safety integrity of existing pipeline. PETRONAS framework of PLES can also be harmonized with repurpose framework suggested by DNV-RP-F104. The feasibility study is useful to establish the limit of existing pipeline capability against future use. With limits in place, detail analysis can be identified accordingly to shed more clarity to pipeline repurpose. Upon completion of detail analysis, technical authority should be able to decide either to proceed or not to proceed on repurpose option. Although the current results have not given clear positive direction, the economic values would justify advancing the study with further technical analyses, material testing and upgrade scope capability of existing software.

Studying the feasibility of pipeline repurpose should be the priority when opportunity arises. This can be motivated from challenging economic driver of a CCS development project. Unlike build new option, the technicalities of pipeline repurpose is not as straightforward. Thus, expert judgement will be required whereby in this case RDF and requirement of material testing. As reader may find different and unique circumstances when dealing with repurpose, at minimum this paper should provide general idea on how to approach pipeline repurpose option.

5. Acknowledgement

We would like to acknowledge several key parties who have made important contribution to this study. Among them are Upstream Centre of Excellence (COE), CO_2 Focus Area Group of Project Delivery & Technology (PD&T), Flow Assurance Centre (FAC). Also, thanks to Group Technical Solutions (GTS) of PETRONAS that pushes every boundary to deliver the best technical solutions within PETRONAS and outside to a larger industry.

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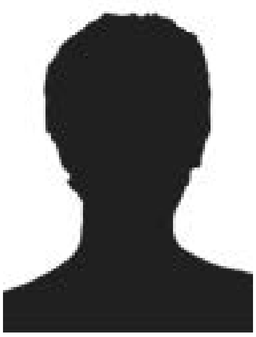
AUTHORS

Faisal Aziz
PETRONAS
Sales lead for Pipeline of the Future program
mfaisal_aziz@petronas.com

Khairul Anuar Karim
PETRONAS
Head of Pipeline Engineering with GTS
anuarkarim@petronas.com



Ir. Hayati Hussien
PETRONAS
Custodian of Pipeline Engineering with GTS
hayati.h@petronas.com

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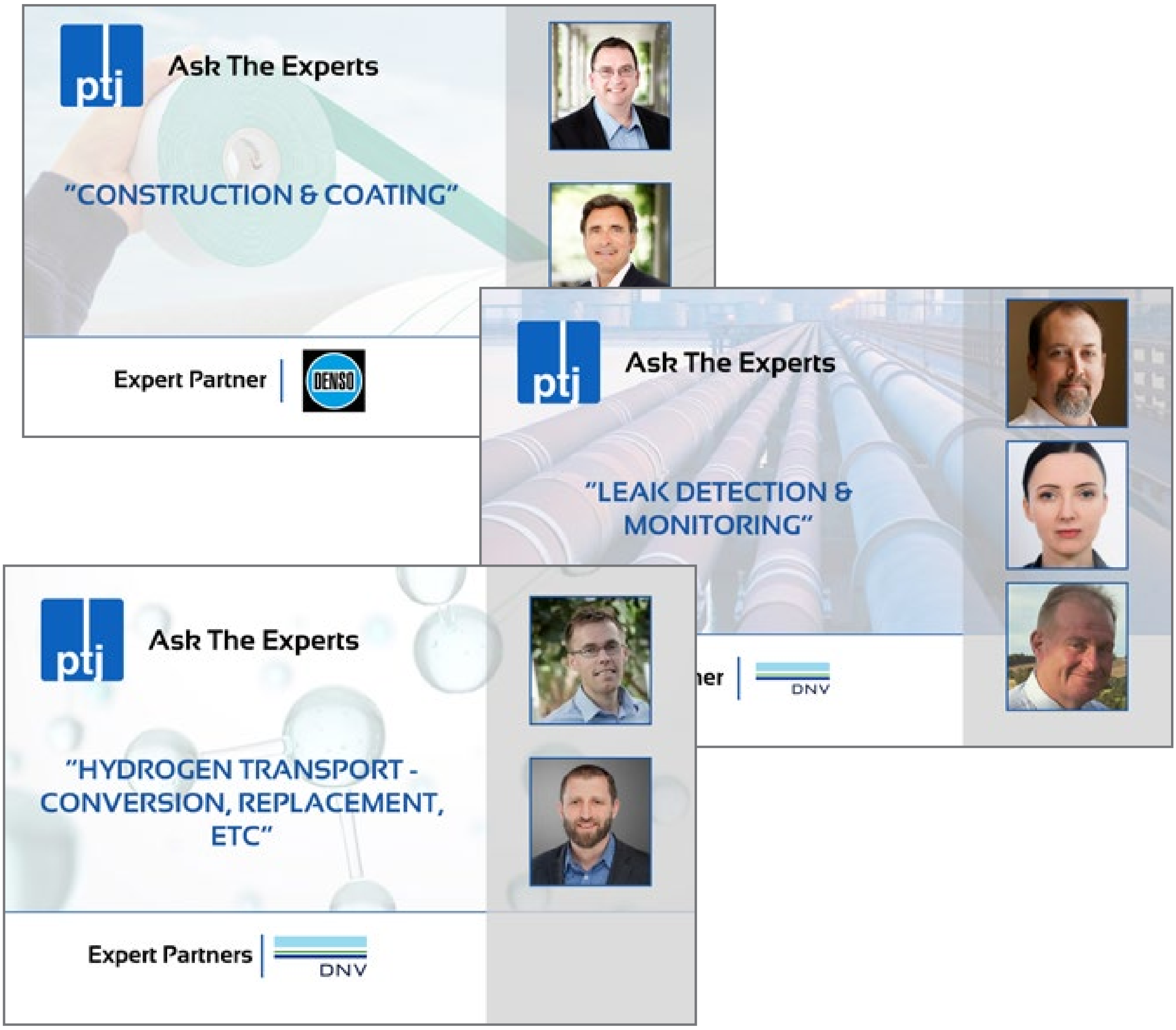

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