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IS A NATURAL GAS BOOM COMING?

Dr. Klaus Ritter
Editor in Chief

It is clear these days that all countries with an abundance of natural gas reserves are pushing into the European market. High investments are being made for the construction of pipelines and LNG plants.

- Russia will pump up to 86.5 billion cubic meters annually to Europe via two new pipelines (Nord Stream 2 and TurkStream), starting in 2020.
- After an initial period of expansion, ten billion cubic meters will be pumped into Europe via the Southern Gas Corridor as well.
- In addition, higher deliveries of LNG from North Africa, Norway/Scotland, and the Middle East and North America (surpluses from fracking) are under discussion.

The investment required is immense - but obviously will not be spared, because additional needs will arise - such as system-relevant gas-fired power plants, which are necessary to ensure the stability of the electricity networks during further expansion to incorporate renewable energy. Lower rates of production within Europe, the upcoming L-H gas conversion, and the circumvention of the Ukraine cannot alone explain this development.

In the meantime, the transport networks in Europe are consolidated - German transmission system operators alone are investing over €4 billion according to grid development plans for the period 2016-2026.

The best available material and equipment has to be used in the construction processes — as well as the operation and maintenance — of these new installations and existing pipelines, and they will have to be operated economically and reliably for many years to come because of the high levels of investment involved. This means seeking an exchange of experience at a high international level in these international projects, in order to meet this need.

The “Pipeline Technology Conference” (ptc) and accompanying exhibition have been providing top-level exchange experience for 12 years. This is the largest relevant event in Europe. This year’s event took place from May 2 – 4 in Berlin. It included immersive seminars and a scientific poster show, at which 12 research institutes presented their works.

Over 400 participants from more than 50 countries attend the 12th ptc. They had access to 20 innovative sessions, 80 innovative lectures, and two discussion sessions with 10 policy-makers providing an overview of the state of pipeline science and technology. Session 1.1 was compiled by the DVGW. In the accompanying exhibition, 60 leading pipeline companies from all over the world were on hand for in-depth discussions.

The event provided a comprehensive discussion platform for representatives from the oil, gas, water, and product pipeline industries. It had coverd technical topics regarding onshore and offshore issues, materials, planning, construction, automation, and integrity management. An IPLOCA (International Pipeline & Offshore Contractors Association) regional meeting was also included in this year’s ptc.

A 42-member Advisory Committee, which includes members from 13 nations, provided valuable support for this comprehensive program. The committee, previously led by Dr. Klaus Ritter of the EITEP Institute together with Mr. Uwe Ringel of ONTRAS, is now led by Mr. Heinz Watzka, former Managing Director of Open Grid Europe and Mr. Dirk Strack, Technical Director TAL - Transalpine Pipeline.

You are also invited to join our new event, the Pipeline-Pipe-Sewer-Technology (PPST) Conference and Exhibition in Cairo, Egypt which will take place from 17-19 September 2017.

We are working constantly to uphold the continuous exchange within the international pipeline community. You are welcome to make use of the extensive opportunities we created. Kindly find additional information on our websites or contact us directly via mail:

- eitep@eitep.de
- www.pipeline-journal.net
- www.pipeline-conference.com
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Yours,

> Dr. Klaus Ritter, President EITEP Institute

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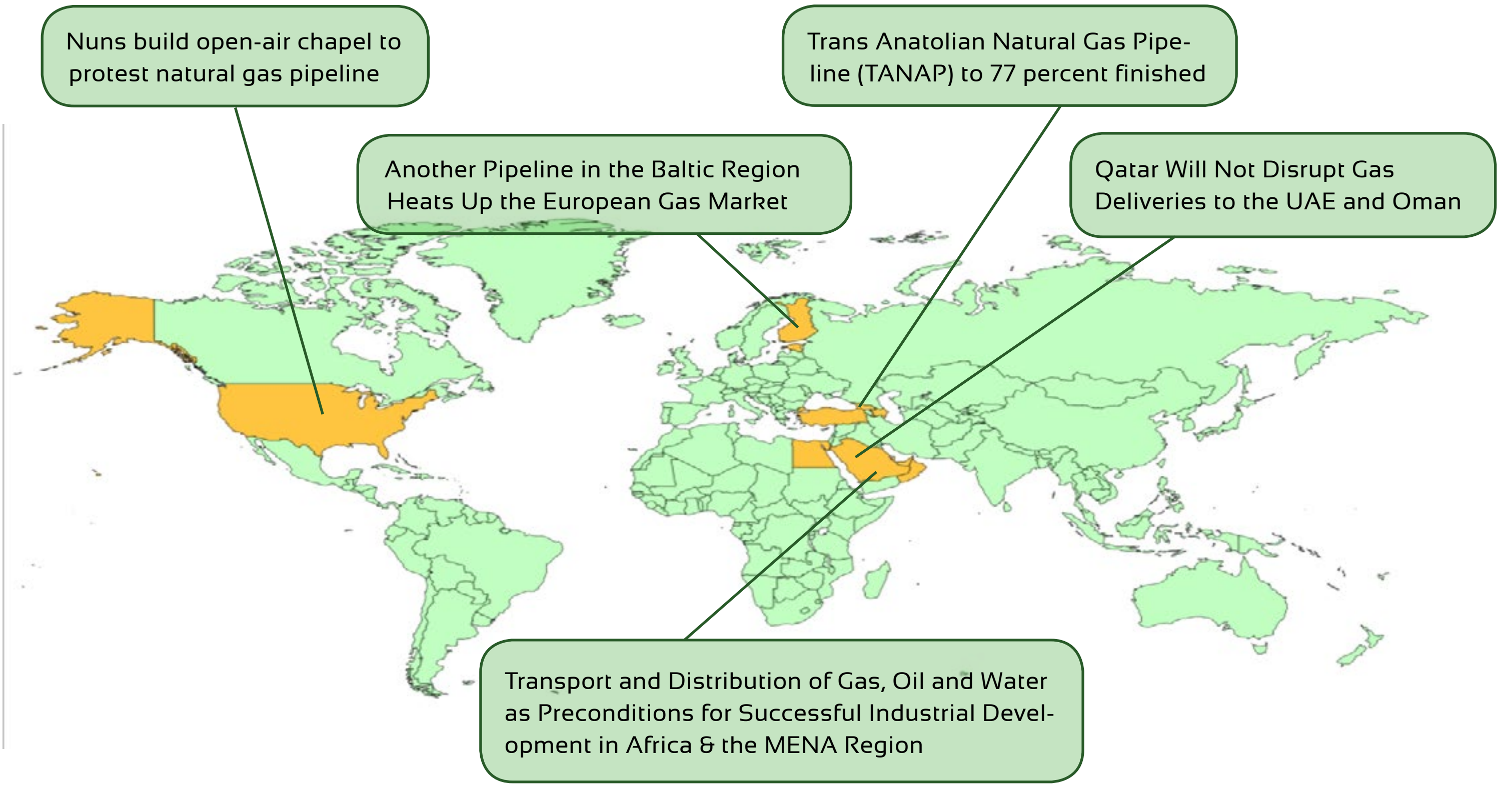

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ptj@eitep.de

Publisher
Euro Institute for Information and Technology Transfer GmbH
Am Listholze 82
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Editor in Chief
Dr. Klaus Ritter
E-Mail: ritter@eitep.de
Tel: +49 (0)511 90992-10

Editorial Board
Advisory Committee of the Pipeline Technology Conference (ptc)

Editorial Management & Advertising
Admir Celovic
E-Mail: celovic@eitep.de
Tel: +49 (0)511 90992-20

Design & Layout
Michael Hasse: hasse@eitep.de

Editorial Staff
Dennis Fandrich: fandrich@eitep.de
Mark Iden: iden@eitep.de

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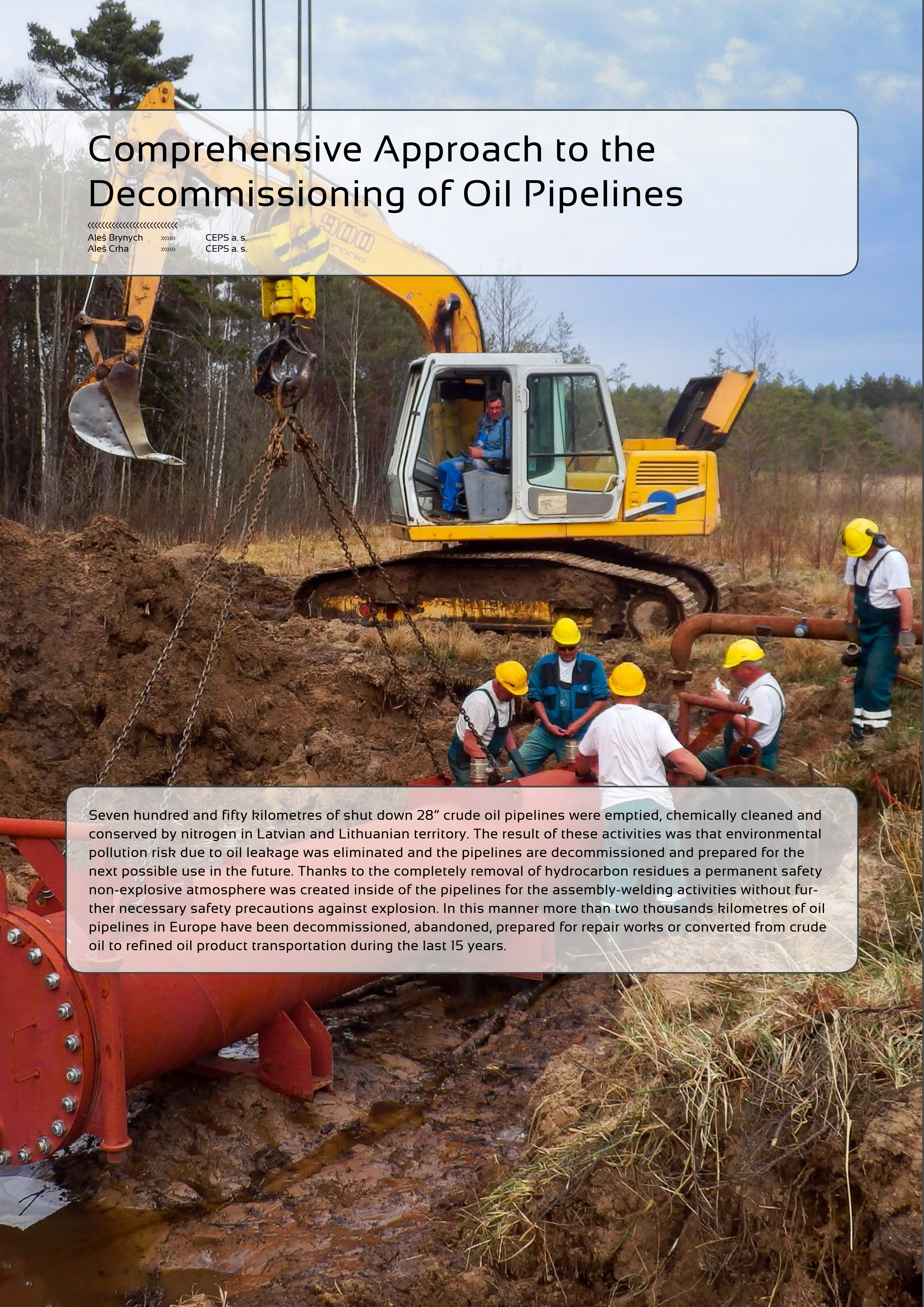


Comprehensive Approach to the Decommissioning of Oil Pipelines

Aleš Brynych »»»» CEPS a. s.
Aleš Crha »»»» CEPS a. s.

Seven hundred and fifty kilometres of shut down 28" crude oil pipelines were emptied, chemically cleaned and conserved by nitrogen in Latvian and Lithuanian territory. The result of these activities was that environmental pollution risk due to oil leakage was eliminated and the pipelines are decommissioned and prepared for the next possible use in the future. Thanks to the completely removal of hydrocarbon residues a permanent safety non-explosive atmosphere was created inside of the pipelines for the assembly-welding activities without further necessary safety precautions against explosion. In this manner more than two thousands kilometres of oil pipelines in Europe have been decommissioned, abandoned, prepared for repair works or converted from crude oil to refined oil product transportation during the last 15 years.

COMPREHENSIVE APPROACH

Combination of product displacement and subsequent chemical cleaning of pipelines transporting hydrocarbon liquids is the most effective, quick, safe and environmentally responsible pipeline cleaning solution that makes many pipeline decommissioning, remedial repair, revalidation, conversion or abandonment projects feasible because it reduces the needed shut-down time, costs and also significantly enhances safety of works.

During last 15 years CEPS used this method on more than 2000 km of 4" to 28" high pressure oil pipelines in Europe for different projects like:

- Decommissioning of unused crude oil pipelines, their conservation and integrity tests for a future use,
- Short term shut-downs of pipeline sections for multiple repair works,
- Conversion from crude oil to refined oil product service and others.

Some of the projects are described below with simply demonstration of technology and benefits of the comprehensive approach.

DECOMMISSIONING AND CONSERVATION OF CRUDE OIL PIPELINES FOR THEIR FUTURE USE

The crude oil transport through 28" pipeline system Polock – Ventspils and Polock – Mazeikiai on the territory of Lithuania, Latvia and Belarus was terminated more than 10 years ago. (See Figure 1 – Pipeline routes.) These pipelines in the total length of almost 1000 km remained full of the oil containing about 2.4 million barrels of oil.

This situation had very bad consequences for pipeline operators as their responsibility for costly maintenance and environmental risk in cases of pipeline damage caused by a corrosion or a third party remained.

At the same time this situation prevented any other use of the pipelines like transmission of refined oil products or natural gas.

For these reasons pipeline operators in Lithuania and Latvia decided to decommission 750 km of these pipelines step by step that included emptying, chemical cleaning and conservation.

Both these pipelines are lead for about 170 km from Belarus border on the territory of Baltic States in parallel.

Beyond the Biržai pumping station they separate and one of them routes for 230 km to the Ventspils oil terminal on the Baltic Sea shore and the other to the 160 km distant oil refinery at Mazeikiai.

On request of pipeline operators CEPS worked out the engineering study of emptying, cleaning and conservation of these pipelines for their potential future use and in an international tender was nominated a general contractor.

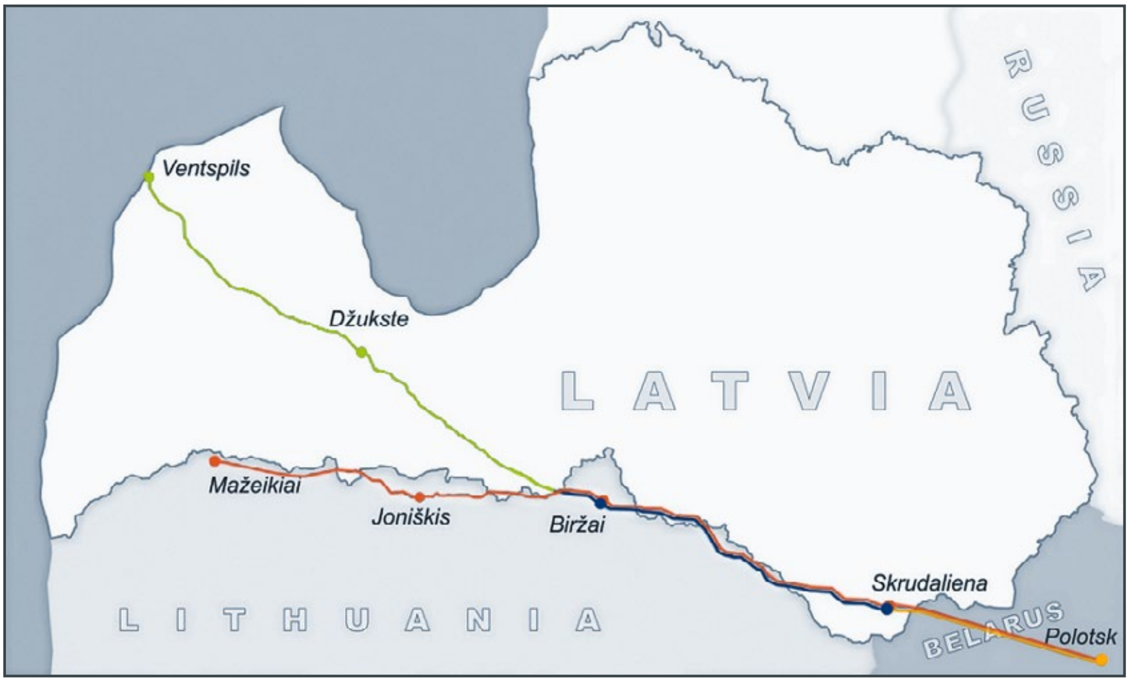


Figure 1: Pipeline routes

PREPARATION WORKS

For emptying the pipelines were divided into a total of 11 sections. Existing launching and receiving pig traps were used when possible and to the remaining section ends a CEPS temporary launchers/receivers were installed (Figure 2).

Figure 2: CEPS temporary launcher trap

Pipeline operators made all excavation and welding work as well as HT&P isolation of decommissioned pipeline parts by their own equipment and personnel.

PIPELINE EMPTYING

Two pigs were inserted into each launcher and a water batches were created by pumping water in between them. These water batches were then propelled through pipeline sections by inert nitrogen mixture containing more than 90% of nitrogen. Two CEPS mobile nitrogen generators produced sufficient volume of nitrogen to move the water batches and the whole content of the crude oil through the pipeline sections (Figure 3).

Figure 3: CEPS mobile nitrogen generators

According to the customer requirements a part of the crude oil was moved this way to reservoirs in the Mazeikiai oil refinery in Lithuania and the another part to the Ventspils oil terminal in Latvia.

At the beginning of empting the lines from Belarus border it was always necessary to bring into the movement a mass of crude oil in the length up to 330 km that was in the pipeline for several years with no movement.

The longest pipeline sections were 180 km, 2 × 150 km, 130 km and 80 km. This was possible because the elevation profile was relatively flat and the crude oil with low content of paraffin.

On the pipeline section between Belarus border and the Birzai pumping station there are several interconnections with leaking valves that could cause leaking of crude oil from a full pipeline to already emptied parallel pipeline. Instead of costly blinding of these interconnections we managed to empty both parallel 150 km pipeline sections at the same time and drive the both emptying pig trains by the same velocity in both pipelines so that this risk was eliminated.

CHEMICAL CLEANING OF THE PIPELINES

The aim of the chemical cleaning was to clean the internal pipeline surface from crude oil rests so that no environment pollution would occur in case of future pipeline damage. By removing the hydrocarbons the permanent explosion safe conditions in the pipeline allow future flame cutting, grinding and welding works to be done safely without costly and time consuming preparatory work to create safe conditions.

For the chemical cleaning special temporary CEPS launchers and receivers were fastened or welded to both ends of each cleaning section (Figure 4 and 5).

Technicians inserted several cleaning pigs to each launcher and pumped a predetermined amount of CEPS PETROSOL 1 agent to create cleaning batches with different fixed agent concentrations. The final batch of each cleaning train was water. These cleaning trains were propelled through cleaned pipeline sections with compressed air.

After that the internal pipeline surface remained completely clean without rests of crude oil (Figure 6).

"By removing the hydrocarbons the permanent explosion safe conditions in the pipeline allow future flame cutting, grinding and welding works to be done safely without costly and time consuming preparatory work to create safe conditions."

Ales Brynych

Figure 4 and 5: Temporary traps for chemical cleaning

Figure 6: Internal pipeline surface after chemical cleaning

Figure 7: Temporary reservoirs

Samples of water from the last water batch of each pig train were taken after its arrival to the receiver in order to establish the remaining content of hydrocarbons. The analyses done in an accredited testing laboratory never showed exceeding the concentrations required by local standards.

Disposal of used cleaning batches in the total volume of about 13 000 m³ was done following way:

- CEPS disposed 3 000 m³ to Mazeikiai refinery water treatment plant,
- CEPS disposed another 10 000 m³ pumping them into temporary reservoirs in Džukste and Skrudaliena pumping stations (Figure 7) using a biodegradation cleaning method. The hydrocarbons concentration in water after the cleaning reached 0.6 mg/l and therefore it was possible to pump this water into the river.

"The Combination of displacement and subsequent chemical cleaning of pipelines makes remedial repairs, revalidation, decommissioning and abandonment projects significantly quicker, cheaper and safer."

Ales Brynych

CONSERVATION OF THE PIPELINE

After completion of the chemical cleaning the pig traps were flame cut from the pipeline, the interconnections of the pipeline sections were made and free ends were blinded by cups. It was possible to make all these welding and cutting jobs safely at permanently explosion safe conditions (Figure 8) that considerably improved the efficiency of the work.

Figure 8: Flame cutting at permanently explosion safe conditions

Pipeline conservation for the protection against a future corrosion was made in two steps.

First phase (passivation of the internal pipeline surface) was done already during the chemical cleaning as a corrosion inhibitor was mixed in the last water batch used.

In the second phase after the chemical cleaning the pipeline was purged by the nitrogen mixture containing 95% of nitrogen. After that the nitrogen pressure in the whole pipeline system was increased to 3 bar. To do that CEPS used its mobile nitrogen units again (Figure 9).

BENEFITS

Above procedure of emptying, chemical cleaning and conservation brought following benefits to the pipeline operators:

- Permanent elimination of the pollution risk caused by a oil leak from the pipeline in case of its damage by corrosion or a third party intervention,
- Creating of permanent explosion safe conditions in the pipeline eliminating the explosion risk during any future work on the pipeline or any third party intervention,
- Readiness of the pipeline to a future integrity revalidation (pressure test) and possible use for transport of another product if needed,
- Considerable decreasing of future maintenance and protection costs,
- Possibility of the continuous pipeline tightness check by a pressure monitoring,
- The last but not least – considerable financial benefit from utilisation of the crude oil from the pipeline.

VERIFICATION OF THE CLEANNESS OF THE PIPELINE DURING THE SUBSEQUENT REVALIDATION

A revalidation of an 8 kilometre section of this 28" pipeline near Džukste pumping station in Latvia was done in 2013 in order to obtain data needed for a strategic decision about a future use of this pipeline.

Figure 9: Production of nitrogen mixture on the jobsite

In the process of the revalidation a repair of some known defects, hydrostatic test and TFI pipeline inspection in an off-line regime was done. The TFI inspection tool was propelled through the pipeline section by water.

The quality of previous chemical cleaning was thoroughly checked during these works.

No safety precautions to create safe conditions for welding on this pipeline were necessary and also chemical analysis of water used for hydrostatic testing and internal inspection did not show any contamination and therefore it was possible to drain it into the river.

SHORT TERM PIPELINE SHUT-DOWN FOR MULTIPLE REMEDIAL REPAIR WORKS

For more than 10 years CEPS successfully carries out comprehensive repairs of high pressure pipelines with replacement of many defective components and/or hydrostatic testing. In such cases it is very convenient to empty the pipeline with nitrogen and chemically clean the internal pipeline surface.

Than a time consuming local draining or expensive multiple isolation of pipeline section by HT&P or by using of isolation pigs, gas bags, clay plugs etc. is not necessary. After the chemical cleaning the conditions inside the pipeline are immediately safe for welding and any other work. This makes the repairs easier, faster and cheaper. The repairs can be done simultaneously on many locations, needed shut-down time is much shorter, and start of the operation after the job easier as there are no multiple isolation pigs or gas bags and no dirt from multiple clay plugs in the pipeline. Subsequent hydrostatic testing is then possible without any risk of pollution and the testing water can be easily disposed.

REPLACEMENT OF 32 PIPES IN 96 HOURS

One of many examples of this approach is the repair of 21" Druzhba crude oil pipeline in Czech Republic, where CEPS replaced 32 pieces ten-meter long defective pipes spread on about 10 km of the pipeline in 4 days. During first 2 days the pipeline was emptied and chemically cleaned and during next 2 days the defective pipes were cut out and replaced. In total 16 welding crews were working simultaneously on the pipeline, each crew replaced 2 pipes. The spread of some jobsites is shown in Figure 10.

REPAIR OF MANY DEFECTS DURING SHORT TIME SHUT-DOWN

The other examples are repairs of product lines in Czech Republic made usually during planned shut downs. Old 8" to 12" pipeline sections of the length of 50 to 90 km are shut-down for about 15 days and after draining and chemical cleaning repairs of about 100 defects are made in different pipeline locations. In cases of subsequent hydrostatic retesting the shut down time of such a pipeline section is maximum 30 days.

Figure 10: Spread of some jobsites

THE CONCLUSION

Combination of displacement and subsequent chemical cleaning of pipelines makes remedial repairs, revalidation, decommissioning and abandonment projects significantly quicker, cheaper and safer. Many repair works would not be even possible in allowed shut down time and with required level of safety without it. Instant achieving of the explosion-safe conditions after the chemical cleaning enables to repair or replace a number of pipes or pipeline components with flame cutting and welding in a remarkably shorter time. Therefore the needed downtime, costs and all risks are reduced significantly.

The risk of test water contamination with product remaining in the pipeline during hydrostatic retesting is eliminated.

Author

Aleš Brynych

CEPS a. s.

General Manager

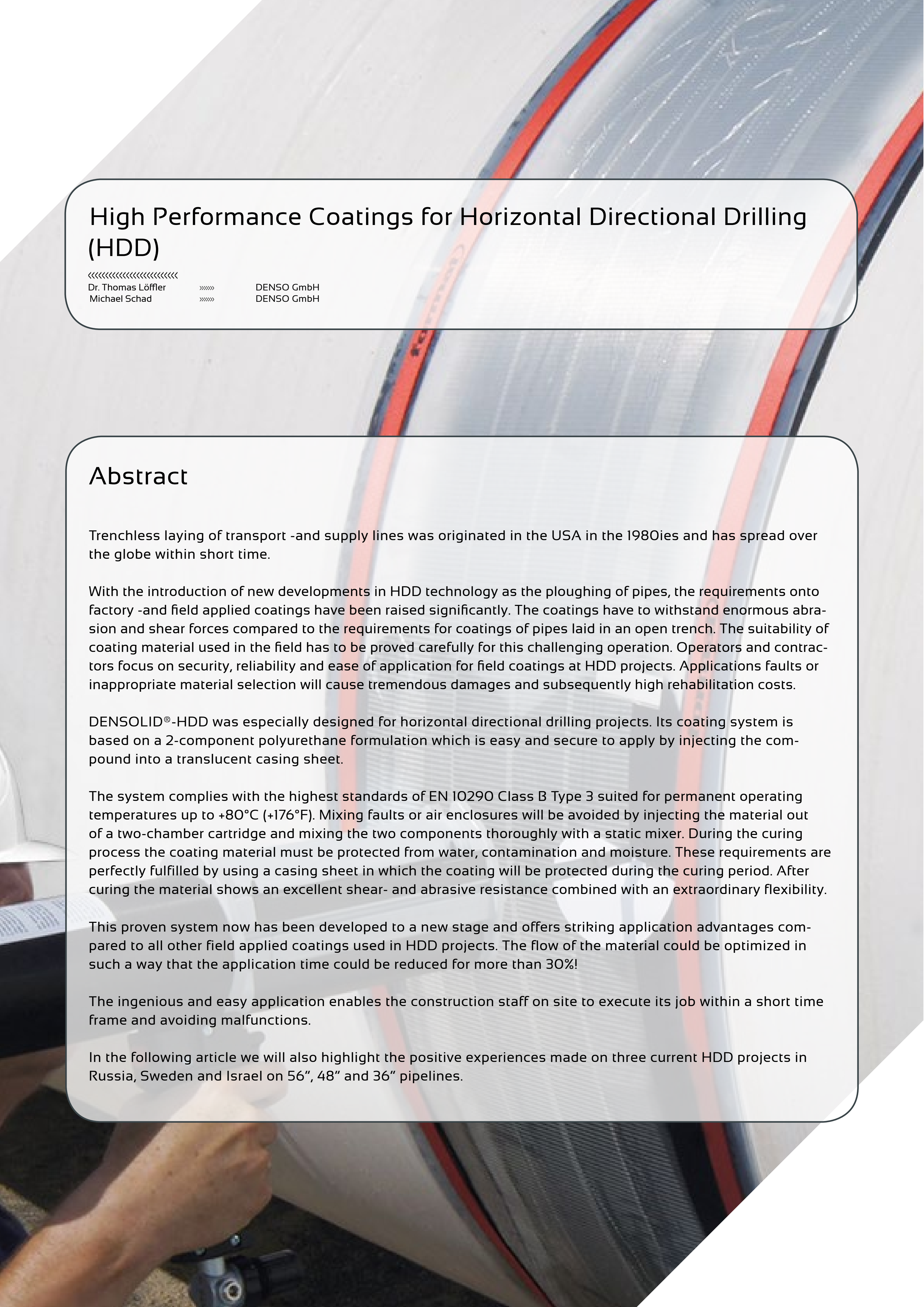
ales.brynych@ceps-as.cz

Aleš Crha

CEPS a. s.

Financial Manager

crha.ales@ceps-as.cz



High Performance Coatings for Horizontal Directional Drilling (HDD)

Dr. Thomas Löffler »»» DENSO GmbH
Michael Schad »»» DENSO GmbH

Abstract

Trenchless laying of transport -and supply lines was originated in the USA in the 1980ies and has spread over the globe within short time.

With the introduction of new developments in HDD technology as the ploughing of pipes, the requirements onto factory -and field applied coatings have been raised significantly. The coatings have to withstand enormous abrasion and shear forces compared to the requirements for coatings of pipes laid in an open trench. The suitability of coating material used in the field has to be proved carefully for this challenging operation. Operators and contractors focus on security, reliability and ease of application for field coatings at HDD projects. Applications faults or inappropriate material selection will cause tremendous damages and subsequently high rehabilitation costs.

DENSOLID®-HDD was especially designed for horizontal directional drilling projects. Its coating system is based on a 2-component polyurethane formulation which is easy and secure to apply by injecting the compound into a translucent casing sheet.

The system complies with the highest standards of EN 10290 Class B Type 3 suited for permanent operating temperatures up to +80°C (+176°F). Mixing faults or air enclosures will be avoided by injecting the material out of a two-chamber cartridge and mixing the two components thoroughly with a static mixer. During the curing process the coating material must be protected from water, contamination and moisture. These requirements are perfectly fulfilled by using a casing sheet in which the coating will be protected during the curing period. After curing the material shows an excellent shear- and abrasive resistance combined with an extraordinary flexibility.

This proven system now has been developed to a new stage and offers striking application advantages compared to all other field applied coatings used in HDD projects. The flow of the material could be optimized in such a way that the application time could be reduced for more than 30%!

The ingenious and easy application enables the construction staff on site to execute its job within a short time frame and avoiding malfunctions.

In the following article we will also highlight the positive experiences made on three current HDD projects in Russia, Sweden and Israel on 56", 48" and 36" pipelines.

INTRODUCTION

Trenchless installation creates a specific set of requirements for corrosion prevention: It is essential, that the protection system is flexible for an easy absorption of pipeline movement, especially during the drilling process. The system must also show an exceptionally high abrasion and shear strength. DENSOLID®-HDD, an innovative polyurethane (PUR) coating is designed for trenchless pipe-laying by horizontal directional drilling (HDD).

Pipeline sections up to 3.000m and pipe diameters up to 60" (DN 1.500) can be laid in trenchless methods. More than 7.500km of pipelines are laid per year worldwide by trenchless technologies.

Trenchless construction includes tunneling, micro-tunneling, pipe ramming, pipe jacking, pipe boring and horizontal directional drilling.

Steel pipes are protected against corrosion and mechanical impact by using a factory (mill) coating. However, some parts of a pipeline, such as welded joints, have to be coated on the construction site. The range of field joint coatings for trenchless pipe-laying, which resist these high mechanical stresses while showing a remarkable flexibility, is limited. Field joint coating for conventional pipe laying methods like tape systems or heat shrink sleeves without reinforcement would fail under these severe conditions. The field coating for trenchless pipe-laying has to withstand enormous abrasion forces and high shear forces, compared to coatings laid in an open trench.

Operators and contractors focus on security, reliability and ease of application for field joint coatings that are used at HDD projects. Application faults or inappropriate material selection can cause tremendous damage, costs and project delays.

Several coating systems for HDD projects are currently available and applied, depending on the individual conditions at construction site.

GRP-systems (Glass fibre Reinforced Plastics) for instance show superior mechanical properties. However, the application of these GRP systems proved to be very problematic as they have to be executed in several layers and working processes, which caused many application faults on site or resulted in an execution only by special trained service companies.

Another important aspect is the geometry of the applied field joint coating. Only field joint coatings in-line with the factory coating (Figure 1) propose a high security field joint coating.

The target is to achieve an equal technical performance level to the factory coating by the field (joint) coating, thus providing an unbroken chain of quality and security. This requirement will not be fulfilled by special reinforced Heat Shrinkable Sleeves, which are also in use for trenchless measurements.

"DENSOLID®-HDD now has been developed to a new stage and offers striking application advantages compared to all other field applied coatings used in Horizontal Directional Drilling (HDD) projects."

Michael Schad

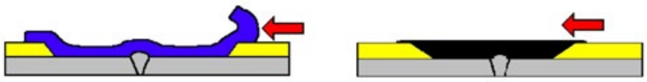


Figure 1: Field joint coating on top of the factory coating (left) and in-line with factory coating (right)

Therefore Field joint coatings for trenchless pipe-laying methods should be used in line with the adjacent factory (mill) coating to provide optimal sliding friction. Besides the optimal sliding friction, coatings should also provide extremely hard and - at the same time - flexible properties, characterized by very high abrasion and shear resistance. For the field joint coating a polyurethane resin based system is to be preferred as the mechanical properties of a suited factory coating (e.g. polypropylene) and the PUR (Polyurethane coatings without Reinforcement) coated field joint coating will show the same high technical level. The polyurethane coating will be applied by casting, injecting or spraying onto the prior grit blasted and cleaned steel surface.

While providing the high technical performance level on site by the field coatings, the ease on site application has to be considered, too. This, alongside reducing the risk of human mistakes and providing a high standard of corrosive and mechanical protection is a key character. Of course the selected coating system must fulfil all relevant international standards for field coatings.

DENSO GmbH Germany offers a further improved system for the field coating of welded joint areas of steel pipes with polyurethane reactive resins.

DENSOLID®-HDD

DENSOLID®-HDD is a two-component polyurethane coating for a permanent corrosion prevention of field-joints at pipes for trenchless installation processes. The material features a high hardness and abrasion resistance with very good stretch-ability and bending strengths. Therefore, this PUR-compound is especially qualified for the coating of welding seams at pipes and pipelines that are installed using the horizontal directional drilling (HDD) or the pipe-plow method.

DENSOLID®-HDD requires a one step application only. The two components of the material are provided in special two chamber cartridges, so there is no need for manual stirring of components. This ensures the correct mixing ratio of these components and enables a fast working progress.

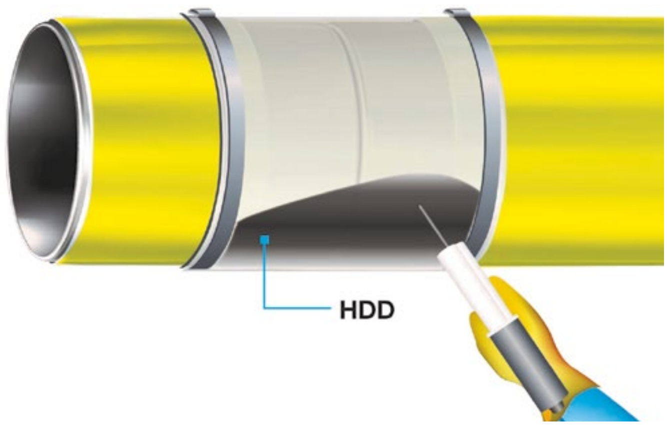


Figure 2: Injection of DENSOLID®-HDD into the casing sheet

DENSOLID®-HDD is applied easily by a special application process guaranteeing a high quality coating. Before the application, a casing of transparent polypropylene (PP) is installed above the cut-back area overlapping on the mill coating. The PP-casing is perforated with a driller to get openings in which DENSOLID®-HDD is injected (Figure 2). The drilling holes in the casing are subsequently closed by adhesive labels.

The casing can be removed as soon as the polyurethane compound is tack free, approximately after 2 hours 30 minutes at 20°C ambient temperature. The average application time per joint will be only around 20 to 30 minutes. The pipe can be pulled in 24 hours after the installation of the coating. During the curing process, the coating material will be protected from the influence of water, contamination, moisture, impact and other negative effects due to the applied casing.

In comparison to reinforced heat shrinkable sleeves and glass fibre reinforced materials (which must be applied in several layers), DENSOLID®-HDD, as an one single layer application, will be applied in half the time.

One of the greatest advantages of the DENSOLID®-HDD coating is its thickness. As the thickness of the product coating corresponds to the thickness of the factory (mill) coating, no shearing will occur. In addition, it can be used for operating temperatures up to +80°C (+176°F) and it is even compatible with factory coatings made of PE, PP, PUR, PA and EP with GRP-reinforcement. An equal and smooth surface will be achieved in the requested thickness even above the welding bead.

"DENSOLID®-HDD allows for very effective corrosion prevention with great mechanical protection. It withstands the impact (severe shear, abrasion and bending stresses) on construction materials used in trenchless pipe laying, whilst still being flexible enough."

Michael Schad

CASE STUDIES

In 2013, in the region of Krasnodar (Russia), a part of the pipeline extension of the unified gas supply system (UGGS) for gas supply to the South Stream gas pipeline had to be buried in a trenchless system. The welding seams of the gas pipe with a nominal diameter of 1400 mm (56") were successfully coated with DENSOLID ®-HDD in a thickness of 8 - 12 mm.

Figure 3: Application of DENSOLID®-HDD with the special two chambers cartridge

Figure 4: Pipeline with welding areas protected by DENSOLID®-HDD

The water pipeline of the Swedish water supplier Norvatten in Huddinge, close to Stockholm, also demonstrates the qualitative performance of the product.

The pipe with a nominal diameter of 1200 cm (48") had to be buried trenchless in horizontal direct drilling because the line leads through an urban residential district of the city. The construction had to be executed in winter 2015 with outside temperatures of -15° to -20°C (-20°F to -29°F). A heated tent had to be used to warm the air and to keep the pipe dry. Despite these challenging temperatures and extreme high humidity, DENSOLID ®-HDD system was applied with great success.

In Israel in 2015 and 2016 the circumstances were quite opposite. A gas pipeline of Israel Natural Gas Lines

(INGL), with the nominal diameter of 900 cm (36") and 68 km length had to be laid from Hagit to Vad Hanna. During construction DENSOLID®-HDD was successfully applied under the ambient temperatures of +35°C to +40°C (+95°F to +104°F).

CONCLUSION

DENSOLID®-HDD allows for very effective corrosion prevention with great mechanical protection. It withstands the impact (severe shear, abrasion and bending stresses) on construction materials used in trenchless pipe laying, whilst still being flexible enough.

Advantages of DENSOLID®-HDD include usage at operating temperatures up to +80°C (+176°F) and alignment of the thickness of the field joint to the factory coating, within one working step. Additionally, easy application with tailored cartridges enables construction staff to execute drilling jobs in a quick and secure way.

Compared to glass fibre compounds and reinforced heat shrinkable sleeves, the application time is significantly reduced by at least 40%, such that a great overall cost reduction is achieved. DENSO GmbH Germany offers an effective solution for protecting pipelines from corrosion and other impact that are installed using horizontal directional drilling.

Authors

Dr. Thomas Löffler
DENSO GmbH
Business and Engineering Development
loeffler@denso.de

Michael Schad
DENSO GmbH
Head of Sales International
schad@denso.de

Mitigation of Pipe End Coating Disbondment

Dr. Shiwei William Guan »»» Global Coatings Advisors/CSW Industrials

Figure 6: No coating disbondment found on these pipe ends preserved with an end cap and a SPVC tape for more than 2 years exposed in an open marine environment (Courtesy of PipeGuardTape.com)

Abstract:

Storage of coated pipes for an extended period without any preservation, especially in some marine and tropical environments which are hot, humid and salty, can lead to deterioration and rusting of pipe ends and pipe end coating disbondment. The issue has been a long term problem of the oil/gas pipeline industry, which affects the integrity of the pipe coating and the pipeline integrity. This paper discusses the mechanism, affecting factors, and corrective and preventative measures of pipe end coating disbondment.

INTRODUCTION

Fusion bonded epoxy (FBE) and threelayer polyolefin (polyethylene 3LPE or polypropylene 3LPP) are the most common external coating systems for new oil and gas pipelines. In addition, multilayer polypropylene coating (MLPP) and other FBE-based coating systems (such as polyurethane or polystyrene) can be several inches thick, providing corrosion and mechanical protection as well as thermal insulation. All these FBE based pipeline coatings have long track records of successful use, but there are occasional challenges and problems that must be addressed as part of the pipe installation process. One of these challenges and problems often met in the pipeline coating industry is pipe end coating disbondment, a delamination normally between the FBE and the steel at the cutback area of the pipe ends. The pipe ends of factory-coated pipes are often un-protected for girth weld joint applications during pipe installation.

Traditionally, it has been believed that for single layer FBE or dual layer FBE (DLFBE) coatings, delamination in the cutback area of the pipe ends is a rare occurrence, but for multilayer systems it is not uncommon[1]. Another belief is that the pipe end coating disbondment is due to very high concentration of residual stresses developed at the cutback interface between the steel and the three or multiple polyolefin coating system, as a result of thermal mismatch between the steel and the coating system. The stress concentration factor (SCF) at the cutback area is a function of cutback angle and polyolefin topcoat thickness. The high shear and peeling stress can disbond the coating system from steel. Normally, a smaller cutback bevel angle (<30o) and thinner polyolefin topcoat can reduce SCF and thus prevent a pipe end from coating disbondment[2]. To further prevent the FBE disbondment, a FBE toe (typically 3-5 mm or longer) is established to shift the high SCF to FBE/copolymeric adhesive layer of the three or multiple polyolefin coating system, to help out to eliminate the pipe end disbondment.

However, many failures of recent oil and gas pipeline projects have suggested that the above believing is not the case. Storage of coated pipes for an extended period without any preservation, especially in some marine and tropical environments which are hot, humid and salty, can still lead to deterioration and rusting of pipe ends and pipe end coating disbondment. The pipe end coating disbondment occurred regardless of whether the pipe coating was just a FBE/DLFBE or a multi-layered system, whether the cutback bevel angle was <30o or not, and whether and what length of a FBE toe was used.

In a pipeline project in South East Asia, pipe end disbondment occurred with well-applied single layer FBE coated pipes after a 6-month storage in an open environment (Figure 1). In an Australian offshore pipeline project, the coating end disbondment issue occurred, after 8 months of exposure to an open environment, on a few MLPP coated pipes with a FBE toe of >20 mm in length which was significantly longer than the typical 3-5 mm, intending to significantly reduce the SCF (Figure 2).

Figure 1: End Disbondment of a FBE pipe coating

Figure 2: End Disbondment of a MLPP coating with a FBE toe (of >20 mm length vs. typically 3-5 mm)

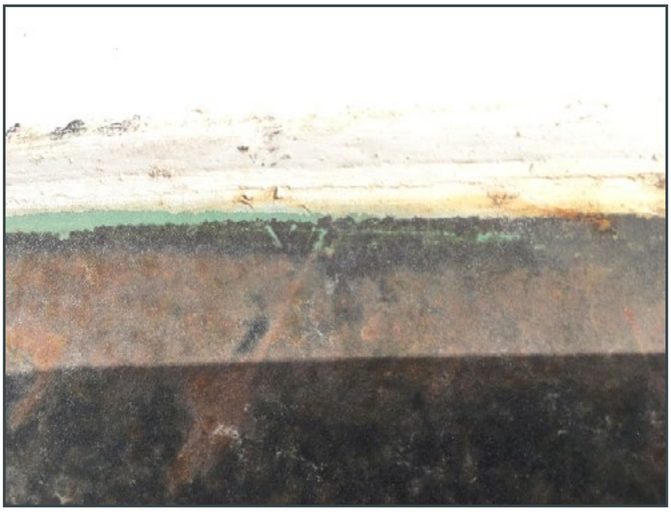


Figure 3a: End disbondment on a pipe with the FBE toe remained

Figure 3b: End disbondment on a pipe with the FBE toe disappeared

In a 3LPP pipeline project in the Middle East, pipe end coating disbondment occurred when the cutback bevel angle was well below <30o (Figure 3a and Figure 3b) and with a 3-5 mm FBE toe. The first pipe (shown in Figure 3a) had some areas showing a 2-5 mm FBE toe remained but coating disbondment still occurred in some areas around the circumference of the pipe, delaminating between the FBE and the steel, after over 1 year exposure in an open environment. The second pipe (shown in Figure 3b) had most FBE toe disappeared, with some traces of FBE left in the toe area. Like the first pipe, the cutback bevel angle of the second pipe was less than 30o, complying with the project specification requirement. Some gouge damage on the cutback and the FBE toe were found from the investigated pipe ends of the first and the second pipe. However, localized end disbondment spots between good FBE toe and rust steel were also evident, suggesting that the use of FBE toes did not provide a sufficient protection to the pipe end from end disbondment when exposed to an open environment, and that the gouge damage on the FBE toes was not the key root-cause of the issue.

MECHANISM

Poorly formulated or applied FBE coating can lose its bond to steel when exposed to moisture. FBE is a semi-permeable membrane, i.e., it absorbs water and allows it to pass through the coating. At room temperature, it absorbs most of the water it will accept within the first two days to a level of less than 1%[3] by weight. FBE coated pipes, if stored prior to installation for months or even for weeks in a hot and high humidity environment, will absorb water into their coating film. More moisture can be absorbed by the FBE in the cutback area with the help of accumulation of dust and debris formed on the unprotected pipe ends.

Water absorbed into the FBE polymer matrix has a plasticizing effect and can lower the glass transition temperature (Tg) of FBE. The moisture absorption along with other environmental aging, such as temperature cycling (day and night), UV degradation, and rusting will degrade the FBE mechanical properties, weakening the bonding of the FBE to the steel substrate. Over time, disbondment can occur.[4-5]

The following mechanism is presented for the development of end disbondment of a FBE based pipeline coating:

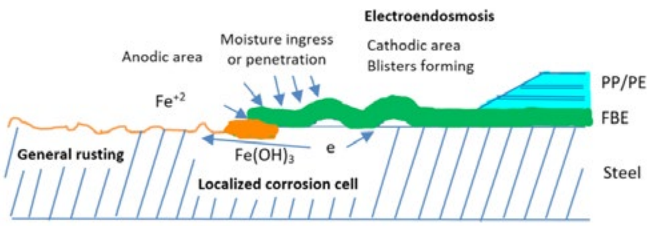


Figure 4 :The mechanism of end disbondment of a FBE/3LPO pipeline coating

Step 1. Rusting occurs along the entire cutback area where the steel was uncoated or unprotected due to the loss of effectiveness of any temporary coating applied over the cutback area for transit. The rust formation of the pipe ends was due to accumulation of moisture, dust and debris on the steel surface.

Step 2. At the cutback area, a localized corrosion electrochemical cell is formed around the steel/coating transition line. On the left, the rusting and unprotected steel is the anode, and on the right the steel protected under the FBE or 3LPO coating is the cathode. The anodic reaction is:

$$Fe \rightarrow Fe^{+2} + 2e^{-}$$

The cathodic reaction occurs under the FBE/3LPO coating, a very short distance away from the rusting steel (anode):

$$H_2O + \frac{1}{2} O_2 + 2 e^- \longrightarrow 2 OH^-$$

Remembering that soluble sodium and chloride ions from the environment do not participate in the reaction, the overall reaction of the electrochemical reaction is

$$Fe + \frac{1}{2} O_2 + + H_2O \longrightarrow Fe^{+2} + 2 OH^- \longrightarrow Fe(OH)_2 \downarrow$$

Ferrous hydroxide precipitates from solution, however this compound is unstable in oxygenated solutions and is then oxidized to the ferric salt:

$$Fe(OH)_2 + \frac{1}{2} H_2O + \frac{1}{4} O_2 \longrightarrow Fe(OH)_3$$

The final product is the familiar rust. Furthermore, these electrochemical reaction processes are affected by the presence of other ions, such as Na^+, Ca^{2+}, Cl^-, $SO42^-$, from the environment, which serve as an electrolyte, and thus accelerate the rust formation. Over time, at the steel/coating transition line the localized formed corrosion product would absorb more moisture and grow, with its volume taking up a larger volume than the steel. This physically forces the coating off from the substrate. Eventually this would lead a localized edge delamination when the physical force exceeds the adhesive bonding strength of the FBE coating to the substrate (Figure 4).

In addition to the electrochemical reactions above, electroendosmosis also occurs around the steel/coating transition line at the cutback area. The metal steel underneath the localized cathodic area contains an excess of negative electrons, therefore making it a negative surface. Water or moisture then trends to ingress through the FBE coating/steel interface or penetrate from the coating surface through the coating film toward the negatively charged cathode. The end result is the formation of cathodic area blisters of the FBE coating near the steel/coating transition line, very similar to the situation of coating blistering formation during a cathodic disbondment (Figure 1). The osmotic pressure generated in the blaster will eventually break the FBE-steel bonding strength and delaminate the coating from the substrate.

Coating end disbondment is thus caused by the combination of above electrochemical reactions and electroendosmosis blistering. The end disbondment breaks the ligament to link the anode with cathode to widen the rusted steel area. The adjacent steel under the coating without rusting becomes then the new cathode and the same processes repeat to widen the rusted area. It is normally called rust creepage or under film corrosion process. Initially, the disbonded area looks like half of a blister or half of a cathodic disbondment. The semicircle begins at the interface between the FBE and the steel in the cutback area. The shape of the disbonded area implies that there is an initiation point where an electrochemical reaction begins and creates the disbondment (Figure 1). Multiple initiation sites can later result in multiple disbondments growing together and a loss of adhesion around the circumference of the pipe.

CONTRIBUTING FACTORS

Several factors will affect the deterioration of pipe ends and end disbondment of pipe coatings during long term storage:

- Storage environmental conditions of coated pipes prior to pipeline installation: Water absorption and rust formation can occur with coated pipes stored for several weeks or longer periods prior to construction, particularly at a hot, high humidity and salty environment (i.e. tropical and marine). Wet and dry cycles will also accelerate repeated corrosion cells and increased electroendosmosis blistering during disbondment growth, leading larger coating disbondment with often growth rings.1 The degree of rust creepage also depends on the salt content, atmospheric humidity, temperature cycles, and the residual stresses. In Southwest Asia, the Middle East, Australia, and the Gulf of Mexico, the local environments could easily facilitate the coating rust creepage progress and pipe end coating disbondment if no adequate corrosion protection. The need for temporary corrosion protection of external and internal surfaces during storage and transportation shall be considered during design/engineering for later inclusion in fabrication and installation specifications.
- Properties of the coating and adhesive: Properties of different types of coating components affect their ability to withstand deterioration and end disbondment, including: moisture absorption, density, hardness and elasticity, tensile strength, coefficient of thermal expansion, stress relaxation, thermo-oxidation/UV and heat ageing resistance, etc. Only proven coating and adhesive materials shall be used for a pipeline project and new materials shall be evaluated and carefully qualified.
- Thickness and cutback configuration of the mainline coating: At pipe coating cutbacks, stress concentration is related to coating thickness and cutback bevel angle. The higher the pipe coating thickness and more acute cutback bevel angle, the higher the residual stress concentration and thus the easier the pipe end coating disbondment[2]. As moisture and rust weakens the bonding strength of the base coating layer to the steel substrate but the SCF remains unchanged over the environmental aging, over time the coating will disbond at the cutback once the resultant shrinking force from the stress concentration exceeds the adhesive force of the coating-steel interface. Bevel angles of a pipe coating cutback shall

be 30o or less, and the use of 3-5 mm FBE toe is sufficient to reduce the stress concentration.
- Quality of the factory applied coating: End disbondment of a pipe coating can be a result of already poor adhesion due to improper surface preparation or improper decontamination in the plant coating process. Improper surface preparation results in poor angular surface profile and contaminations. Improper coating application results in too high coating porosity, too low application temperature for the FBE, etc. Aside from selection of the coating material which may be specifically required by the client, the other factors are the applicator's responsibility.
- Type of pipe materials: The industry knows rarely about the impact of pipe material types on the factory coating quality and then the pipe end coating disbondment. New pipe materials such as high strength steels (X80/X100 or higher), CRA cladded or lined pipes, stainless steels, etc. pose additional challenges to pipe coating application and pipe coating quality relative to plain carbon steel or lower grade pipes. During the FBE application, a steel pipe undergoes various heating processes and cycles. These new pipe materials would show different characteristics of heat retention and heat soak across the pipe, causing higher fluctuations of temperatures and sometimes cold pipe ends[6]. This phenomenon has posed new challenges, requiring adjustments and additional controls of the coating application processes to ensure good wetting of the FBE powders onto the substrate for good adhesion.

CORRECTIVE AND PREVENTATIVE MEASURES

Corrective and preventative measures can be taken, in order to mitigate the deterioration of pipe ends and end disbondment of pipe coatings. These measures include:

- Design and select a pipe coating system which can be thinner, less absorbent to moisture, more UV and thermal stable, and is less or not constrained by the shrinkage-stress factor.
- Pipe coaters to improve their process capability in order to produce higher quality pipe coatings and to deliver an effective preservation program for long term pipe storage. This is true particularly when the current industry coating standards or project coating specifications have not been specific enough to cover the requirements on coating application of special pipe types, on pipe preservation for long term storage, and on pipe end configuration/protection against end coating disbondment.
- Review and improve related coating application processes for the selected coating system: for examples, to tighten up surface preparation and application temperature control in order to enhance the adhesive strength of the coating to the substrate, to apply multiple layers for thick coating systems rather than in one single coat in order to reduce the stress build-up, and to make correct cutback configuration and FBE toe in order to reduce/minimize the stress concentration.
- Repair localized end disbondment prior to pipe installation: 1) Provide specifications and work instructions to field contractor to repair localized end disbondment prior to pipe installation (Figure 5a and 5b). 2) If the localized end disbondment cannot be repaired, set up a remedial procedure on these pipes to brush back the disbonded coating until sound and tightly adhered coating, and then apply a suitable field joint coating or temporary protective system prior to pipe installation.
- Develop and implement an effective temporary preservation method and program, in order to protect the pipe end cutback and the pipe coating during long term storage. 1) Require a proper preservation system and process on uncoated pipe ends not only for transit but also for long term storage of more than 3 months from the date of completion of the coating application. 2) Add requirements of regular monitoring and inspection of proper preservation of coated pipes to prevent or reduce pipe end disbondment. 3) Set up inspection procedures and criteria to identify those pipes which are to be repaired for localized end disbondment, or to be remediated by brushing the entire cutback, or to be completely stripped and re-coating.

Figure 5a: Surface preparation for repairing a localized spot of coating end disbondment on a 3LPE coated pipe

Figure 5b: Repair a localized spot of coating end disbondment on a 3LPE coated pipe using a primer + adhesive + PE melt stick

TEMPORARY PRESERVATION METHODS

Table 1: Various Pipe End Preservation Methods and Their Effectiveness on Preventing Coating End Disbondment in an Open Environment

	Preservation Method	Pros	Cons	Effectiveness
1	Controlled (no preservation)	No efforts and no costs	Rusting, end disbondment, field joint difficulty and cost	None
2	Tarpaulin cover	Ease of use and removal, internal protection	Need to monitor and change every 3+ months	Good with replaced covers
3	Heat shrinkable sleeve	No rust and easy factory installation, internal protection	Difficulty of removal and re-installation in stockpiling, high cost	Excellent
4	Special End cap	No rust and easy factory installation, internal protection	High cost, potential fitting issues for large diameter pipes and thick coatings	Excellent
5	SPVC End Seal Tape	Little rust and easy factory installation, easy removal	Potential adhesive residues and some tapes contain lead	Good to Excellent
6	Alkyd primer	Ease of use, cheap	Difficulty of removal, Effective less than 6 months	Poor to fair
7	Weld-Through Primer	Ease of use and removal	Effective less than 3 months	Poor to fair
8	Organic phosphate	Ease of use and removal	Effective less than 3 months	Poor to fair
9	VCI impregnated wrap	Ease of use and removal	Ease to be damaged and loss effectiveness	Poor
10	Peelable varnish	Ease of use	Difficulty of removal, Effective less than 3 months	Poor to fair
11	Water displacement oil	Ease of use and removal	Effective less than 3 months	Poor to fair

Outdoor storage of unprotected pipes for a period of up to about a year will not normally cause any significant loss of pipe wall thickness. However, unprotected stockpiles of coated in an open environment shall do nothing good to prevent coating end disbondment. Unpreserved pipe ends may also cause additional surface roughness and blistering of FBE mainline coating which would affect field joint coating application of the pipeline installation. Conditions for storage should be such that water will not accumulate internally, or externally at any supports. Applying conventional temporary preservation paints/products such as a varnish, liquid primer or a rust preservative to the cutback area has recently become common in major international pipeline projects. Over the last decade, various temporary pipe end protective products as directed by clients for their individual pipeline projects have been applied and field tested. In addition, since 2010, an industry initiative has been made in Asia Pacific to investigate and evaluate the effectiveness and efficiency of different alternatives available to mitigate the deterioration of pipe ends and end disbondment of pipe coatings storage over long periods[6]. Table 1 highlights the efficacy as well as pros and cons of various temporary preservation methods used in the industry. The use of a tarpaulin cover can further enhance the performance of any preservation measure for long term pipe storage, but torn tarpaulins shall be replaced or repositioned frequently as required. Without a tarpaulin, the use of heat shrinkable sleeves, special end caps, and SPVC pipe end seal tapes were proven to be quite effective.

SUMMARY

The leading cause of coating disbondment in the cutback area of pipe ends is environmental exposure without any preservation or poorly preserved. The degradation process initiates at a weak or damaged area of the FBE/bare steel interface and a corrosion cell starts. The mechanism includes a combination of electrochemical reactions of the corrosion cell and electroendosmosis blistering. In addition to storage environmental conditions of coated pipes prior to pipeline installation, other contributing factors of pipe end coating disbondment include: properties of the selected coating and adhesive, thickness and cutback configuration of the mainline coating, quality of the factory applied coating and surface preparation prior to the coating application, and the type of steel pipe materials. These additional factors act as intensifiers once the bonding strength of the FBE coating is reduced by the environmental exposure.

Corrective and preventative measures can be taken, in order to mitigate the deterioration of pipe ends and end disbondment of pipe coatings. These measures include: 1) Design and select a pipe coating system which can be thinner, less absorbent to moisture, more UV and thermal stable, and is less or not constrained by the shrinkage-stress factor; 2) Pipe coaters to improve their process capability in order to produce higher quality pipe coatings and to deliver an effective preservation program for long term pipe storage; 3) Review and improve related coating application processes for the selected coating system: for examples, to tighten up surface preparation and application temperature control in order to enhance the adhesive strength of the coating to the substrate, to apply multiple layers for thick coating systems rather than in one single coat in order to reduce the stress build-up, and to make correct cutback configuration and FBE toe in order to reduce/minimize the stress concentration; 4) Repair localized end disbondment prior to pipe installation, or set up a remedial procedure on the unrepairable pipes to bush the entire cutback back to where the coating is intact, and then apply a suitable field joint coating or temporary protective system prior to pipe installation; and 5) more importantly, develop and implement an effective temporary preservation program and use a proper and effective pipe preservation product/method, in order to protect the pipe end cutback and the pipe coating during long term storage.

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Author

Dr. Shiwei William Guan
Global Coatings Advisors/CSW Industrials
info@shiweiwilliamguan.com

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STUDY OF SUBSEA PIPELINE REHABILITATION STRATEGY IN MATURE FIELD BY USING INFIELD LINER METHOD FOR CAPEX AND OPEX OPTIMISATION

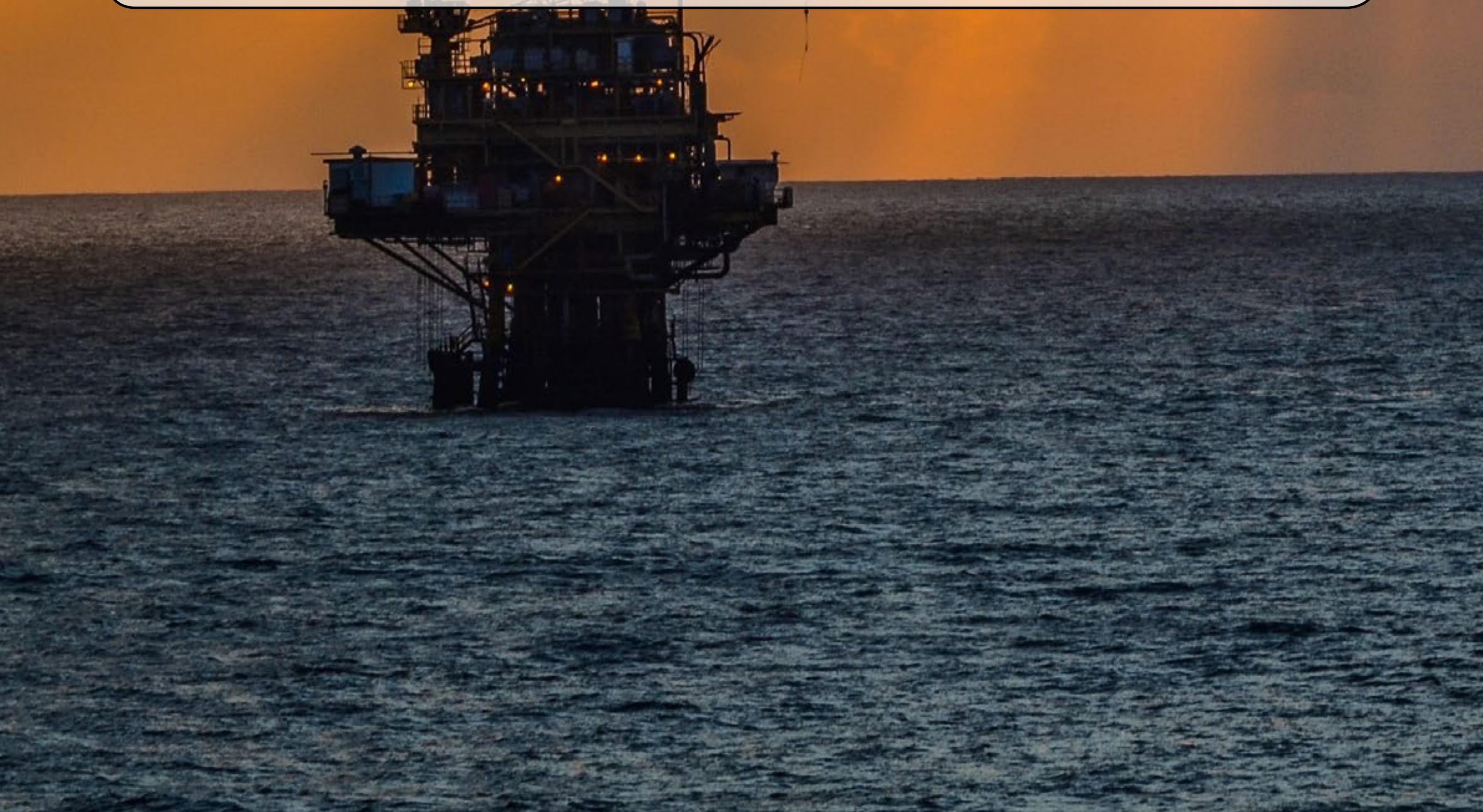
Hanto Yananto »»» PT Pertamina Hulu Energi ONWJ
Fajar Adhiyat »»» PT Synergy Engineering
Yuyung Girindra »»» PT Pertamina Hulu Energi ONWJ

Abstract

The study is initiated on transport facility of multi-phase flow at one of PHE ONWJ (Indonesian National Oil Company) asset, K-1 platform to KN-1 platform. An 8-inch pipe is being used since 2002 to transport hydrocarbon fluid between the two platforms. In December 2015 and January 2016, several leakages were found during subsea pipeline inspection. It was observed and calculated that the corrosion rate is more than 0.3 mm/y, which can be classified a very high rate. With the high corrosion rate at the pipeline, non-corrosive material need to be considered as an effective strategy for pipeline rehabilitation.

Infield liner as one of the pipeline rehabilitation strategy is being assessed on this paper. The infield liner will be compared to the other 3 options, which are flexible pipe, reinforced thermoplastic pipe (RTP), and carbon steel. Each of the option will be assessed by their performance during hydraulic simulation and the economic analysis to obtain the most economical solution for the pipeline rehabilitation strategy. The infield liner is being assessed for its installation technique and challenges, and the maintainability during operation.

As the result, all the options show the ability to perform during the hydraulic simulation. From the economic analysis, infield liner and RTP show similar economics level. The capital cost for both options is US$ 10.2 million with NPV US$ 6.9 million – 7.6 million and IRR 32% - 37%. But after included decommissioning cost, infield liner arises to be the most economical solution for the pipeline rehabilitation strategy. The installation technique of infield liner is using pull through method and it only takes 5 days. No new and specific technique is required to maintain the infield liner during operational phase. It can be concluded that infield liner is the economical and effective solution for pipeline rehabilitation strategy.



INTRODUCTION

PHE ONWJ is one of Indonesian national oil company subsidiary, Pertamina. Offshore North West Java (ONWJ) field has been operated for more than 40 years and can be categorised as a mature field. Now, the field consists 9 flow stations and hundreds of NUI platforms. About 414 offshore pipelines was installed to facilitate the transportation either fluid or gas. More than 80% of the pipelines have passed the designed service lifetime and at least about 3 pipelines need to be repaired per year due to the integrity problem. It will be very costly to perform preventive and corrective maintenance for the existing pipelines. With current trend of oil price condition, pipeline replacement strategy has to be carefully assessed to provide an economical solution to maintain base production without sacrificing the quality and safety aspects.

This study will focus on transport facility of multiphase flow at one of PHE ONWJ asset, K-1 platform to KN-1 platform. To transport hydrocarbon fluid from K-1 platform to KN-1 platform, a subsea pipeline is being used. This is a primary pipeline to transport multiphase flow with total flowrate approximately 5.9 MMSCFD, 185 BOPD, and 1368 BWPD. The pipe size is 8 inch and laid for 2.65 km. It has been operated since 2002 until now (15 years of service life time).

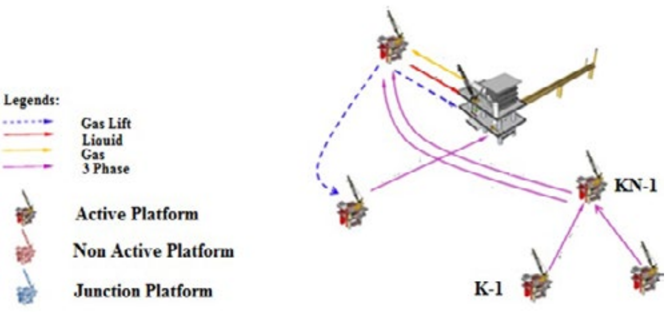


Figure 1: K area pipelines network

HYDRAULIC SIMULATION

The hydraulic simulation has been performed by using Pipesim software. The infield liner will be compared to flexible pipe, reinforced thermoplastic pipe (RTP), and carbon steel. The Pipesim then used to analyse the flow behaviour of the fluid and calculate the pressure drop, backpressure, velocity, and critical erosional velocity. The simulation was performed with input base data shown in Table 1.

"With current trend of oil price condition, pipeline replacement strategy has to be carefully assessed to provide an economical solution to maintain base production without sacrificing the quality and safety aspects."

Hanto Yananto

Boundary Condition	Value		
	Carbon Steel	RTP / Flexible Pipe	Infield Liner
Inlet Temperature	120 °F		
Liquid Flowrate	5.29 MM SCFD		
Maximum Design Pressure	750 psig		
Maximum Design Temperature	500 °F	180 °F	230 °F
Pipe Inside Diameter	193.7 mm	193.7 mm	181.7 mm
Pipe Outside Diameter	219.1 mm	238.3 mm	219.1 mm
Pipe Wall Thickness	12.7 mm	22.3 mm	18.7 mm
Pipe Roughness	0.15 mm	0.0015 mm	0.0001 mm
Undulation	3.3 m		
Ambient Sea Temperature	77-82 °F		

Table 1: Flow assurance modelling base data

From the test result, RTP and flexible pipe show that both of them have the lowest pressure drop and backpressure compared to carbon steel and infield liner. The inside diameter and the roughness of the pipe are the reason that the pressure drop between those pipes are different. Carbon steel has roughness value higher than the RTP and flexible pipe. Meanwhile, the infield liner has the smallest inside diameter and roughness. That characteristics made the infield liner gives same value of pressure drop and backpressure the carbon steel. Table 2 shows the detail result of pressure drop and backpressure.

Materials	Pressure Drop (psi/km)	Backpressure (psig)
Carbon Steel	7.17	183
RTP & Flexible Pipe	5.28	178
Infield Liner	7.17	183

Table 2: Pressure drop and backpressure result

The fluid velocity of infield liner is the highest compared to carbon steel, RTP, and flexible pipe. Carbon steel, RTP, and flexible pipe has the same value of fluid velocity because they have the same value of pipe inside diameter. The critical erosional velocity for them are the same, 22.28 m/s. Infield liner also has also the highest erosion ratio. The erosion may cause any harm if the erosion ratio is more than 1. The highest erosion ratio is only 0.271, resulting all of the materials is suitable and no erosion will be expected. Table 3 shows the velocity of the pipes.

Materials	Max. Fluid Velocity (m/s)	Erosional Velocity (m/s)	Erosion Ratio
Carbon Steel	5.30	22.28	0.238
RTP & Flexible Pipe	5.30	22.28	0.238
Infield Liner	6.04	22.28	0.271

Table 3:Fluid velocity result

There are three different flow pattern for each of the materials. RTP and flexible pipe's flow pattern is segregated and infield liner's flow pattern in transition. Meanwhile, carbon steel's flow pattern is between segregated and transition. Three of them can be categorized as a slug flow. The presence of slugging may cause another impact to pipeline itself also to the receiving facility. Inside the pipeline, the chemical injection efficiency may decrease if slugging flow is occurred. Severe slugging may also arise at pipeline-riser which may cause on production rate. The slug catcher may also need to be installed at the receiving facility to throw out slugging from the fluid system. Table 4 shows the flow pattern for each of the pipe.

ECONOMIC ANALYSIS

Economic analysis is performed to get the best result from economic perspective from four different materials option. The gross revenue is calculated based on production rate. OPEX and CAPEX for each of the option are calculated. From the revenue and expenditure, the NPV and IRR can be obtained. For the selection process, decision tree method is used to get the most economical solution.

From the gross revenue, OPEX, and CAPEX, the NPV and IRR is calculated. It is shown in Table 5 that flexible pipe gives the smallest amount of NPV and IRR percentage. In the other hand infield liner and RTP have a slightly different value of NPV and IRR.

From the Table 5, it can be seen that all the NPV values are in positive. It means that all the investment options are giving a benefit to be installed. Roughly, the highest NPV and IRR should be the best option to be used. But the value of NPV and IRR have not affected to the probabilistic calculation, which will lead to EMV calculation. The probability of success and failure have to be taken account to ensure the investment should go ahead or not.

Decision tree analysis is used to decide the most profitable investment. It is not only based on NPV but also associated with project risk and chance of success. From the available options, only carbon steel has been successfully installed in Indonesia and PHE ONWJ itself. Flexible pipe has been installed in Indonesia, but not yet in PHE ONWJ. Both RTP and infield liner have not been installed in Indonesia. The success ratio which will be applied on decision tree analysis is based on PHE ONWJ general practice.

The carbon steel is included in welding rigid pipe. RTP and infield liner will be included in the other new technology. From the table above, the decision tree analysis is performed and it is shown in Figure 2.

From the decision tree, carbon steel appears to be the most economical solution for the investment. It happens because carbon steel is commonly being used in PHE ONWJ and it makes the carbon steel has the lowest failure

Materials	Flow Pattern
Carbon Steel	Segregated/Transition
RTP & Flexible Pipe	Segregated
Infield Liner	Transition

Table 4: Flow pattern

	Carbon Steel	Infield Liner	Flexible Pipe	RTP
NPV10	$6,700,000	$7,580,000	$6,890,000	$7,600,000
IRR	34%	37%	32%	37%
Gross Sales Production				
Gross Revenue	$70,786,000	$70,786,000	$70,786,000	$70,786,000
Gross OPEX	$12,368,000	$9,936,009	$10,047,000	$9,934,000
Pipeline CAPEX	$10,552,500	$10,279,500	$11,203,500	$10,258,500

Table 5: Economic calculation

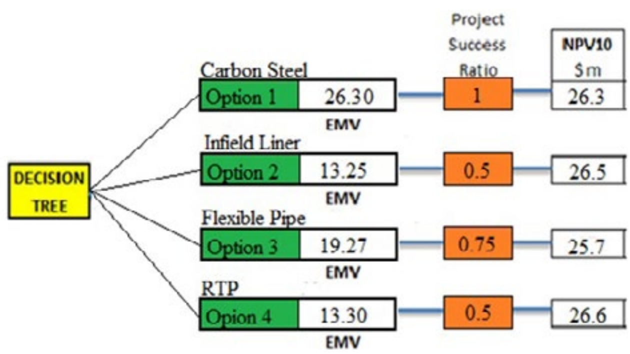


Figure 2: Investment decision tree

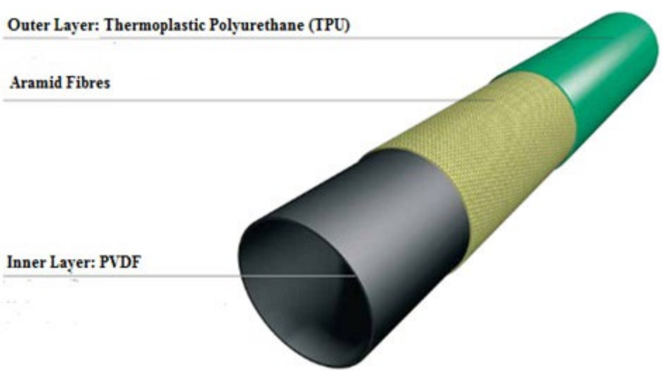


Figure 3: Infield liner materials structure

Figure 4: Folding and banding machine

ratio. Flexible pipe shows to be the second best investment option, because several other projects in Indonesia has already installed flexible pipe. RTP and infield liner with 8-inch size are considered as a new technology. It is because both options have not been installed in Indonesia and even infield liner has only been installed in several pipeline rehabilitation projects in other NOC.

At this economical calculation, decommissioning has not been taken into account. Carbon steel, flexible pipe, and RTP are installed by laying the new pipeline on the seabed. It makes the existing pipeline shall be decommissioned and environmental impact will be arisen. The cost for decommissioning will be doubled, for the existing pipeline and also the new pipeline.

Infield liner has an advantage on this. Infield liner is using the existing pipeline to be the host pipe. It makes the existing pipeline and infield liner become one unit/system. The decommissioning only take place once. No new environmental study should be performed. It may reduce the expenditure if infield liner is chosen.

MATERIAL PROPERTIES

Infield liner comprises of PVDF inner liner, a tightly woven aramid core, and an outer layer of thermoplastic polyurethane (TPU) (shown in Figure 3). Each layer has their own special capability and combined to become a reliable material to be used in pipeline rehabilitation. PVDF can provide protection to an aggressive hydrocarbon exposure conditions. In the other hand, the aramid core provides the liner with high tensile strength, pressure resistance up to 120 bar, and accommodating multiple 90 degrees' bends. TPU gives a high abrasion resistance which is very useful while installation process.

INSTALLATION PROCESS (PULL THROUGH METHOD)

The installation process can be divided into two phases, onshore and offshore works. The onshore preparation works are started by folding and banding the liner. The pulling head attachment to the liner also perform onshore. The liner from the manufacturer is in flattened condition, then it is detached from the transportation drum and directed to the folding and banding machine to form "U" shape liner. Figure 4 shows folding and banding mechanism of infield liner.

After that the liner is folded into the installation drum, which has bigger core diameter than the installation drum. The last onshore activity is installing the pulling head. The pulling head is attached using resin based clamping mechanism. It is clamped similar with the end connection attachment technique and connected to grip the liner with high pressure resin clamping. After completed all equipment and materials are transferred offshore using installation vessel.

The installation process will be performed between the two platforms. One platform is being the insertion side, and another one is where the winch and protection rollers are located. The insertion side is where the installation drum with the liner, stropping unit, lubrication unit, and protection rollers are located. The installation process started after host pipe preparation has been performed and the examination result is satisfied. Setting up of winch cable frame work and stropping units are performed. The set up will be adjusted with the platform condition to incorporate the accessibility and positioning of installation drum and winching equipment.

The insertion process is started by sending a messenger line through the host pipe to pull through the main pulling cable from the winch. The messenger line may also be called as messenger pig and sent through the host pipe with same process as pigging. After that, the main pulling cable detached from the messenger line then connected to the pulling head. Then, the winch is starting to pull the pulling cable which already connected with the liner. The liner is pulled through to entire length of the host pipe from platform one to another one. After the whole length has been pulled through, the liner is monitored for any contraction. When no further contraction happened, the liner is ready for inflation and connection. Figure 5 and 6 illustrate the insertion side and pulling side of the liner.

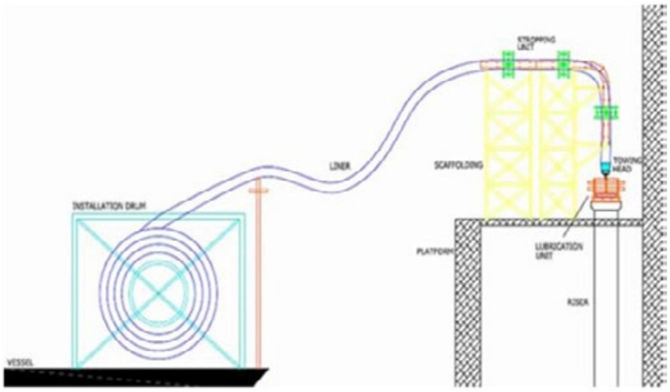


Figure 5: Liner insertion side illustration.

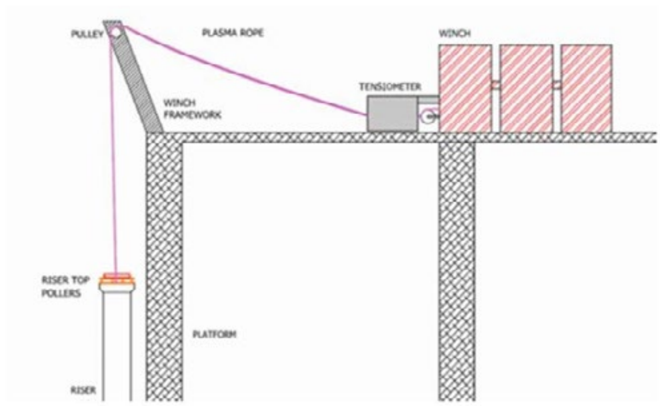


Figure 6: Liner pulling side illustration

The liner then inflated using pressurized air to break the bands and fit to the shape of the host pipe. First of all, the pressure plugs are placed at both ends of the liner and it is pressurized until seal off the open ends. The pressure is controlled at 1 bar and when a steady pressure is achieved, the pressure is released. The end connectors are installed to the liner end to seal it off and connection can be made to the existing pipe work.

After the installation process has been done, the hydrotest is performed using seawater. The hydrotest is performed at 1.5 times the operating pressure of the pipeline. The pressurizing process is performed at a maximum rate 1 bar/min to 50% of testing pressure and held for 15 minutes. Then increased 1 bar/min to 80% of the testing pressure and held for 30 minutes. Increased again to 90% of the testing pressure at 0.5 bar/min rate and held for 60 minutes. Finally, it is pressurised to the hydrotest pressure testing with 0.5 bar/min rate. It will be held for 24 hours after 4 hours stabilization period. During the hydrotest, pressure and temperature are being monitored to ensure the liner performance.

Commissioning then will be performed by re-established the pig launcher and receiver and re-attaching the existing pipe work to the new connection. Soft foam pigs will be released to remove seawater and purge with nitrogen. Then, the pipeline will be re-introduced with the hydrocarbon.

The installation process of infield liner is very fast. The pulling through rate is 10 meters in one minute. For K-1 - KN-1 pipeline, it may take times up to 274.8 minutes. The installation team will work on 2 shift on one day with total work hour 22 hours in one day. From the given work hour, it only takes half day to install infield liner using pull through method. After the insertion process has been done, the liner will be pressurised to achieve tight fit liner to the host pipe and hydrotest will be performed. Overall installation process until the system ready to operate is 2 days. It is very fast installation and the production loss will be very small. Table 7 shows the total days required for infield liner installation until ready to operate (including vessel movement)

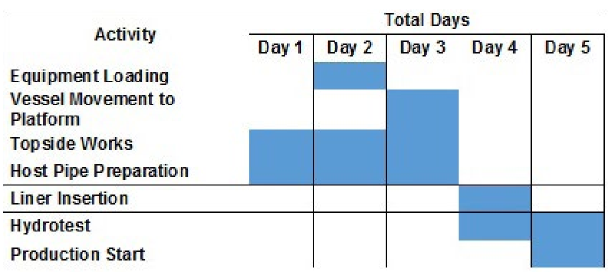


Table 7: Infield liner installation timeframe

Presently, the infield liner length is limited to 5km. There is also no jointing procedure for infield liner to accommodate length more than 5km. There is no jointing technology which may accommodate tight fit liner characteristics. The maximum length is not caused by the physical properties or abilities of the liner itself. It caused by the ability of the production system. The liner may be developed to have length more than 5km with restructuration of the liner. It may take time to develop a new structure which may have length more than 5km. For the K-1-KN-1 pipeline, the pipeline length is less than 5km. So, the length limitation of infield liner will cause no problem for K-1-KN-1 pipeline.

For installation purpose, infield liner has a very strong advantage in the vessel requirement. It only needs a standard DP2 working class vessel rather than using pipe lay barge if compared to another method. Beside the price, the availability of DP2 working class vessel is much higher compared to pipe lay barge.

MAINTENANCE & OPERATION

During the operational phase using infield liner, monitoring shall be performed to ensure the integrity of the pipeline. Several inspections shall be performed, such as: internal inspection and venting system monitoring.

Infield Liner is a composite material which is no corrosion monitoring needed. Infield liner is a softer material compared to standard carbon steel pipe, then should be treated different. Even infield liner has a very low permeability, there will be possibility any bleed off pressure in the annulus between the host pipe and the infield liner. To monitor the build-up pressure, venting system is connected to a pressure gauge.

The vents are welded on to spool pieces that already connected to the riser pipes. The venting point is connected to the pressure gauge and bleed off valve point. If any potential build-up gas pressure within the annulus, the venting point could also be able to vent it off. It is recommended to perform vent pressure monitoring for at least once a month. Build up pressure may lead into liner collapse. Even repeated cycles of collapse and inflation test has been performed to the liner, it will be better to avoid any of this. The liner may be not failure, but the flow condition will change when the liner is no longer tight fit to the host pipe.

The temperature also has to be monitored frequently. Heat transfer from the hydrocarbon will be transferred through the liner to the host pipe. The temperature shall be not higher than the design temperature of the host pipe. However, to ensure more reliable liner system, the temperature should not be higher than design temperature of the liner system.

Cleaning is not commonly being used at the lined pipelines. However, if the cleaning is required, only soft foam pig is allowed to remove loose debris or fluids inside the liner. The pigging activity is similar to the common carbon steel pipe. To ensure that the operator aware to the different operational activity, the operating procedure must be cleared about the restriction. More detail about pigging restrictions are:

- 3 lb/ft3 density or less bare foam pigs
- Ball, hard plastic, metal based, or encapsulated plastic pigs are prohibited

"The infield liner shows it strong ability to withstand with the hydrocarbon condition, very fast installation time, no significant monitoring, and an economical option to be used as a pipeline rehabilitation strategy."
Hanto Yananto

During installation and operation, in carbon steel or another common type of pipe materials are susceptibility to any defect. It can be caused by mechanical, chemical, or both. A simple scratch on the surface material can be a stress concentration which may lead into failure.

During installation interaction between outer layer of infield liner and the host pipe may cause any defect. Infield liner is using TPU material as an outer layer, which is claimed to have strong ability to withstand the contact between host pipe and the liner. The outer layer incorporates repair/patching ability prior to installation. The outer layer also works as a sacrificial layer designed to protect the whole liner. The outer layer plays no role after the liner successfully installed tight fit to the host pipe.

During the operation, there is no repair procedure for inner layer of infield liner. The PVDF layer is a polymer type material which has high resistance to erosion and chemical reaction. But, if any leakage happens to the infield liner, no repair technique can be performed and it has not been developed. It may be another consideration to apply infield liner as the new pipeline system.

CONCLUSION

From the study above, several conclusions can be made as follows:

- Pressure drop and backpressure for all the materials are still tolerable and will not cause any problem to the production flow. The highest pressure drop and backpressure is 7.17 psi/km and 183 psig for carbon steel and infield liner.
- The velocity of fluid in infield liner is the highest, 6.04 m/s.
- The erosion ratio for all the materials are still acceptable with ratio lower than 1. The highest erosion ratio is 0.271 for infield liner.
- The flow pattern for all type of materials are identified potentially slug with intermittent or segregated flow.
- From the economic analysis, infield liner and RTP show similar economics level. The capital cost for both options is US$ 10.2 million with NPV US$ 6.9 million – 7.6 million and IRR 32% - 37%.
- The decommissioning cost for infield liner is the smallest compared to the other materials. Carbon steel, RTP, and flexible pipe will cost twice in decommissioning because it is considered as two pipes (the existing pipe and the new pipe).
- The installation process of infield liner using pull through method only takes 5 days including topside works, vessel movement, and vessel loading to fully operate.
- The infield liner length is limited to 5 km and has no joint procedure. There is also no repair procedure if the liner is damaged. The outer layer of infield liner is designed to be sacrificed during the installation process. It is claimed to withstand the contact between host pipe and the outer layer.
- During operation, only soft foam pig can be deployed to clean any debris. Venting system should be monitored at least once a month.

After analyzing all the information regarding to the infield liner installation, it can be concluded that infield liner is a suitable material and viable option. The infield liner shows it strong ability to withstand with the hydrocarbon condition, very fast installation time, no significant monitoring, and an economical option to be used as a pipeline rehabilitation strategy.

Authors

Hanto Yananto
PT Pertamina Hulu Energi ONWJ
Conceptual Development Team Leader (Brownfield)
hanto.yananto@pertamina.com

Fajar Adhiyat
PT Synergy Engineering
Project Enginee
fajar.adhiyat.15@aberdeen.ac.uk

Yuyung Girindra
PT Pertamina Hulu Energi ONWJ
Engineering Manager
yuyung.girindra@pertamina.com

Composite Repairs - Application for the Long Term Reinforcement of Mechanical Damage to High Pressure Pipelines within Europe

James Knights »»»» Clock Spring Company

Abstract

Composites sleeves are an extremely popular alternative to cut and replace, welded sleeves and clamps for the repair of up to 80% external metal loss defects. Composites have an excellent proven track record with over 100 composite sleeve repairs being installed daily in over 80 countries. Composites have also been developed, tested and peer reviewed as being suitable for the reinforcement of mechanical damage on liquid and gas pipelines. This paper looks at the European and International research undertaken regarding the reinforcement of mechanical damage including dents, gouges and vandalism with reference to both ASME B31.4 (2016) and ASME B31.8s (2014), and provides clarification on where a composite sleeve repair would be suitable, and where it would not. The paper then gives examples of where European operators of both liquid and gas pipelines have installed composite sleeve repairs over mechanical damage and provides a justification as to why these repairs were suitable and highlights the cost and time benefits of selecting a composite sleeve over other code accepted methods to complete an pipeline-in-service repair.

INTRODUCTION

European pipeline operators work hard to ensure there pipelines are protected from external corrosion, extremely successfully on most occasions. It is however, much more challenging for pipeline operators to keep their pipelines safe from the general public. While the pipelines are buried, well-marked, and permission is meant to be sourced before digging near a pipeline occasionally a member of the public will cause mechanical damage to a pipeline. This paper defines mechanical damage to include dents, gouges and vandalism. Dents and gouges on the pipeline tend to be caused by agriculture and construction within Europe. Composite Sleeves are a suitable repair for most types of mechanical damage on pipelines, this paper looking at ASME B31.4 (2016), ASME B31.8s (2016), ASME PCC2 Article 4.1 (2015) and ISO 24817 (2015) demonstrates where a composite repair would be suitable to repair a pipeline, provides examples of good practice where composite repair has been utilised to repair mechanical damage, and also highlights where the use of a composite sleeve would not be suitable for the repair of mechanical damage.

PIPELINE CODE/GUIDELINE ACCEPTANCE

The four main codes/guidelines utilised to allow the repair of mechanical damage using composite repairs are ASME B31.4 (2016), ASME B31.8s (2016), ASME PCC 2 Article 4.1 (2015) and finally ISO 24817 (2015). ASME B31.4 (2016) considers the repair of liquid pipelines, table 451.6.2.9-1 "Acceptable Pipeline Repair Methods" allows a Composite Sleeve type repair for the repair of a gouge or groove repair as long as inspection is completed to ensure there is no cracking present within the repair location and the proprietary tested hardenable (incompressible) filler is utilised to ensure adequate load transfer from the defect to the composite sleeve. Within ASME B31.4 (2016) table 451.6.2.9-2 allows the repair of dents using composite sleeves under, including and exceeding 6% of the pipes outside diameter (OD) proving the dent is checked to ensure no cracks are present prior to the installation of the repair. ASME B31.4 (2016) for dents also requires a hardenable (incompressible) filler is utilised to constrain the dent passing loads from the pipe wall to the composite.

ASME B31.8s (2016) considers the repair of gas pipelines. Table 7.1-1 "Acceptable Threat Prevention and Repair Methods" considers the repair of pipe damaged by a third-party. ASME B31.8s (2016) states a Composite Sleeve type repair may be utilised to repair "previously damaged pipe", defined as being a delayed failure mode such as dents and/or gouges, and also states "vandalism" to the pipeline can be repaired. To utilise a composite sleeve to repair mechanical damage on a gas pipeline in accordance with ASME B31.8s (2016) utilising composite sleeves as with ASME B31.4 (2016) the defect location will require inspection for stress risers, which must be removed from the pipe wall prior to the repairs installation. ASME B31.8s (2016) as with ASME B31.4 (2016) also requires the defect to be filled with an uncompressible filler to act as a load transfer mechanism from the pipe to the composite.

It is highlighted by the author ASME B31.4 (2016) and ASME B31.8s (2016) both refer to a composite sleeve type repair rather than a composite wrap type repair. Laughlin and Leewis (2010) highlights the difference between a composite sleeve and a composite wrap type repair. A composite wrap type repair is a wet applied "bandage" to the pipe, where the main structure of the composite is manufactured on the pipe, making quality control particularly difficult. A composite sleeve type repair is manufactured in a factory under controlled conditions – such as a "Clock Spring – Composite Sleeve" type repair and is then bonded to the pipeline. A composite sleeve type repair allows much greater repeatability, quality and predictability in the pipeline repair installed at the mechanically damaged repair location. Figures left and right below show the difference between a Composite Sleeve and a Composite Wrap type repair.

Figure 1: Composite Sleeve Installation (Left) and Wet Wrap Installation (Right)

Composite wrap type repairs are typically designed and installed following the ASME PCC2 Article 4.1 (2015) and ISO 24817 2015 guidelines. Unlike a composite sleeve type repair each repair has to be designed and engineered with a non-standard repair installed at each location. Composite Sleeves are manufactured to ensure each repair installed should be the same, removing any variability and greatly reducing the potential for installation errors. ASME PCC2 Article 4.1 (2015) page 143 allows composite repairs to be installed where there is external damage to the pipeline including dents, gouges, fretting or wear (at supports). The responsibility of repairing mechanical damage using ASME PCC2 Article 4.1 is placed on the pipeline operator/composite repair manufacture to use "best industry practice" to ensure the repair installed is suitable. This is highlighted to pipeline operators to ensure they make sure if they use a composite wrap on a pipeline repair they carry out a full and suitable risk assessment to ensure the repair they are installing will perform as they require for the lifetime they require.

Finally ISO 24817 (2015) table 1 summarises the suitability of composite repairs, the table is shown below:

Type of defect	Applicability of repair system (metal pipes)	Applicability of repair system (GRP pipes)
General wall thinning	Y	Y
Local wall thinning	Y	Y
Pitting	Y	Y
Gouges/Dents	R	R
Blisters	Y	R
Laminations	Y	R
Circumferential cracks	Y	R
Longitudinal cracks	R	R
Through-wall penetration	Y	R

Y Implies generally appropriate.

R Implies can be used, but requires extra consideration, i.e. will the composite repair reduce locally the stresses acting on the defect. For the case of gouges/dents or cracks, it will be required to assess whether application of the repair will stop future crack growth or whether a conservative assumption about the ultimate length of the crack is required. If either assessment is negative, then application of a composite repair is not appropriate.

Table 1: ISO 24817 - Applicability of repair systems table.

Table 1 of ISO 24817 (2015) permits the use of composite repairs for Gouges and Dents among other repair methods providing "extra consideration" is taken as detailed within the table. As with ASME PCC2 Article 4.1 (2015) with ISO 24817 (2015) it is up to the pipeline operator to assess the defect and assess the composite repair they wish to install to ensure it will be suitable for the defect they wish to repair.

The pipeline literature allows for the repair of mechanical damage utilizing composite repairs. It is extremely important however, the pipeline operator/owner takes the time to ensure the repair they wish to use to repair their mechanical damage is suitable and will constrain the mechanical damage, preventing the thin section of pipe wall fatiguing under pressure cycles, potentially causing a loss of containment. The ASME B31.4 (2016) and ASME B31.8s (2016) guidelines provide much greater guidance on the suitable use of repairs and repair considerations than the ASME PCC2 Article 4.1 (2015) and ISO 24817 (2015) guidelines. The following paragraphs will provide some case studies showing the best industry practice utilized to check the repair prior to installation of the repair and validate the repair utilizing literature and testing on mechanical damage repaired utilizing composite sleeves.

DENT REPAIR

Fatigue testing of dents within GRI Report No. GRI 97-0143 "Evaluation of a Composite System for the repair of mechanical damage in Gas Transmission Lines" demonstrates that fatigue life for dressed mechanical defects is extended by an order of magnitude over grinding as the sole repair. All stress concentrations in the dent were removed in accordance with the ASME B31.4 (2015) and ASME B31.8s (2015) codes, and the dent areas inspected for surface cracking. Figure 2 shows the comparison testing completed utilizing 60 sections of dented pipe, which were fatigue tested to failure.

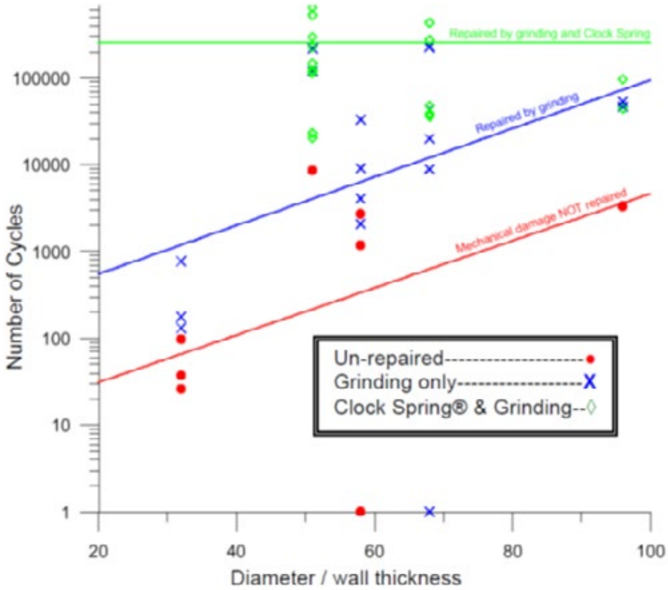


Figure 2: DENT Number of Cycles as a Function of Pipe Diameter to Wall Thickness Ratio

Cycles to failure are plotted against Diameter / Wall thickness ratio (D/t). Analysis yields several observations:

1. At a D/t of 60, the fatigue life for partially repaired defects is approximately one order of magnitude greater than the fatigue life of un-repaired defects.
2. The fatigue life of fully repaired defects is approximately two orders of magnitude greater than un-repaired defects.
3. Fatigue life of un-repaired and partially repaired defects increases with increasing D/t. There is not enough data from this test to estimate the trend line for fully repaired data so it is shown flat.

Dents are regularly repaired across Europe on both oil and gas pipelines, typically due to third party damage. The following is a case study of good industry practice showing how the repair was undertaken. Figure 3 shows both the dye penetrant test and magnetic particle inspection being utilised to ensure no cracks are present. Should cracks be found these would have to be ground and removed following a suitable risk assessment prior to the installation of the composite sleeve repair.

Once testing had confirmed there was no cracking present the dent was filled with MA441 uncompressible filler material, and a mould placed over the filler, allowing the filler to cure for 2 hours. Once the filler had cured the mould was removed and the original profile of the pipe was restored.

Once the dent had been filled and the original profile of the pipe had been restored a standard composite sleeve installation was completed. The composite sleeve as shown by the testing will increase the number of pressure cycles the dent can withstand prior to failure by a factor of approximately 2. The composite sleeve works by constraining the dent, preventing the shoulder of the dent from work-hardening during pressure cycles of the pipeline. Figure 5 shows the completed repair.

GOUGE REPAIR

Further fatigue testing, this time of gouges was also tested and reported within GRI Report No. GRI 97-0143. The fatigue testing completed is shown by figure 6. Several observations from the testing shown in figure 6 can be made, as detailed below:

1. The fatigue life of a dent with a gouge decreases with increasing gouge depth.
2. The fatigue life of partially repaired defects is greater than un-repaired defects by two orders of magnitude at the 15% gouge depth.
3. The fatigue life of fully repaired defects is greater than un-repaired defects by three orders of magnitude at the 15% gouge depth.

Figure 3: Inspection of a Dent Prior to Repair

Figure 4: Dent filled using a mold to restore the original profile of the pipe.

"While the pipelines are buried, well-marked, and permission is meant to be sourced before digging near a pipeline occasionally a member of the public will cause mechanical damage to a pipeline"

James Knights

Figure 5: Completed composite sleeve repair over a dent

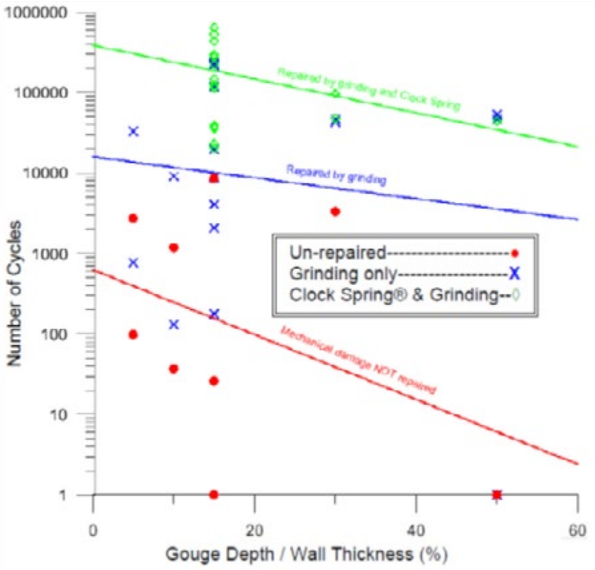


Figure 6: Number of cycles as a function of gouge depth

Gouges are also a common occurrence throughout Europe. The following provides a case study of good industry practice where a gouge has been repaired on a pipeline utilizing composite sleeves. The first step to the repair is shown by figure 7.

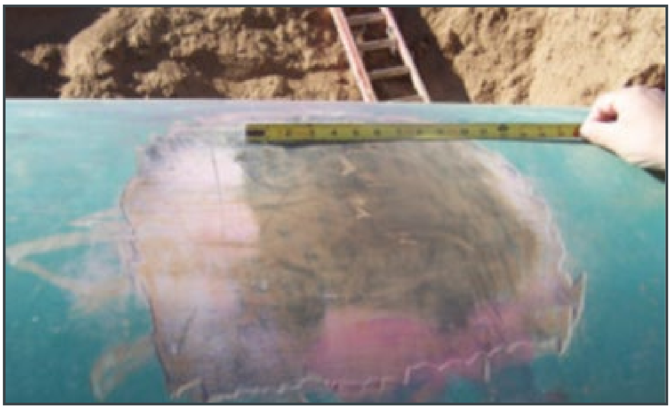


Figure 7: Gouge Defect inspected by a dye penetrant test and recorded

Once it has been confirmed there are no cracks or stress risers present, or they have been ground and removed a standard composite sleeve application can be completed.

Figure 8: Incompressible filler applied into the gouge defect

Figure 9: Composite Sleeve Installed

CONCLUSION

One of the challenges of operating a pipeline is keeping it safe from the general public, this is a difficult task which unfortunately will occasionally lead to mechanical damage occurring. It is important pipeline operators are aware of the methods available to them for the repair of mechanical damage and to have a plan in place for when they encounter it. The ASME B31.4 (2016) and ASME B31.8s (2016) pipeline codes allow composite sleeves, not composite wraps to be utilized to repair mechanical damage, as long as the defect is inspected and any cracks or stress risers are removed from the defect. The ISO 24817 (2015) and ASME PCC 2 Article 4.1 (2015) guidelines allow mechanical damage to be repaired utilizing both composite sleeves and composite wraps. For pipeline operators it is important for them to fully assess the composite they want to utilize to repair their pipelines mechanical damage, not all composite repairs are the same. Any composite repair supplier offering their repair method on mechanical damage should be able to back up their claims of repair suitability with valid and independent testing.

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Author

James Knights

Clock Spring Company

L.P., Regional Sales Manager

james@clockspring.com

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WELCOME TO THE 12TH PIPELINE TECHNOLOGY CONFERENCE

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REPORT

From the 2nd to the 4th of May, representatives of the international gas, oil, water, and product pipeline sectors met in Berlin at the Pipeline Technology Conference (ptc), the largest event for the industry in Europe.

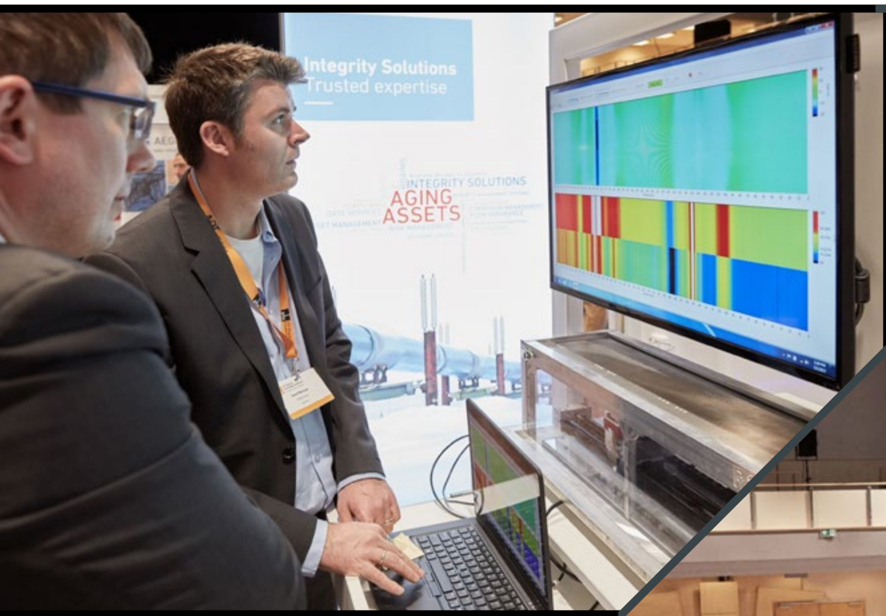
In addition to the established focus on operations and repairs, pipeline construction is also taking on an increasingly important role at the ptc. For the first time, the International Pipeline & Offshore Contractors Association (IPLOCA) held its Regional Meeting as part of the ptc. On the first day of the conference, participants in the meeting were also invited to visit the accompanying exhibition, where they were able to learn about new developments from a variety of construction-specific exhibitors.

With its own Job & Career Market for employers and job applicants and a few new exhibitors, the accompanying exhibition has once again grown in size. Visitors were able to learn about new developments and have in-depth discussions at a total of 58 stands. 90% of the exhibitors have already announced their plans to participate in the next ptc.

The entire conference program offered a range of networking opportunities. On the evening before the conference, the 43 members of the Advisory Committee, together with the speakers, session chairs, and exhibitors, were invited by the organizer to a Pre-Conference Reception. The following evening, the traditional get-together sponsored by the ROSEN Group was held as part of the exhibition. A special highlight was a dinner at the Wasserwerk Berlin, where the historic industrial architecture of the 100-year-old pumping station provided a unique backdrop for an unforgettable meal, complete with musical entertainment.

Workshops and seminars on "Pipeline Leak Detection" and "In-Line Inspection of Onshore and Offshore Pipelines" followed the end of the ptc at noon on the 4th of May.

The 13th Pipeline Technology Conference will be held again in Berlin from the 12th to the 14th of March, 2018. The conference will be held next year in parallel with the "Pipe and Sewer Conference," as part of the new "Pipeline-Pipe-Sewer-Technology Conference & Exhibition." More information on opportunities to participate can be found at www.pipeline-conference.com. In addition, a "Pipeline-Pipe-Sewer-Technology Conference & Exhibition", in which the ptc will play a large role, will be held in Cairo, Egypt from the 17th to the 19th of September (www.pipelinepipesewer.com).



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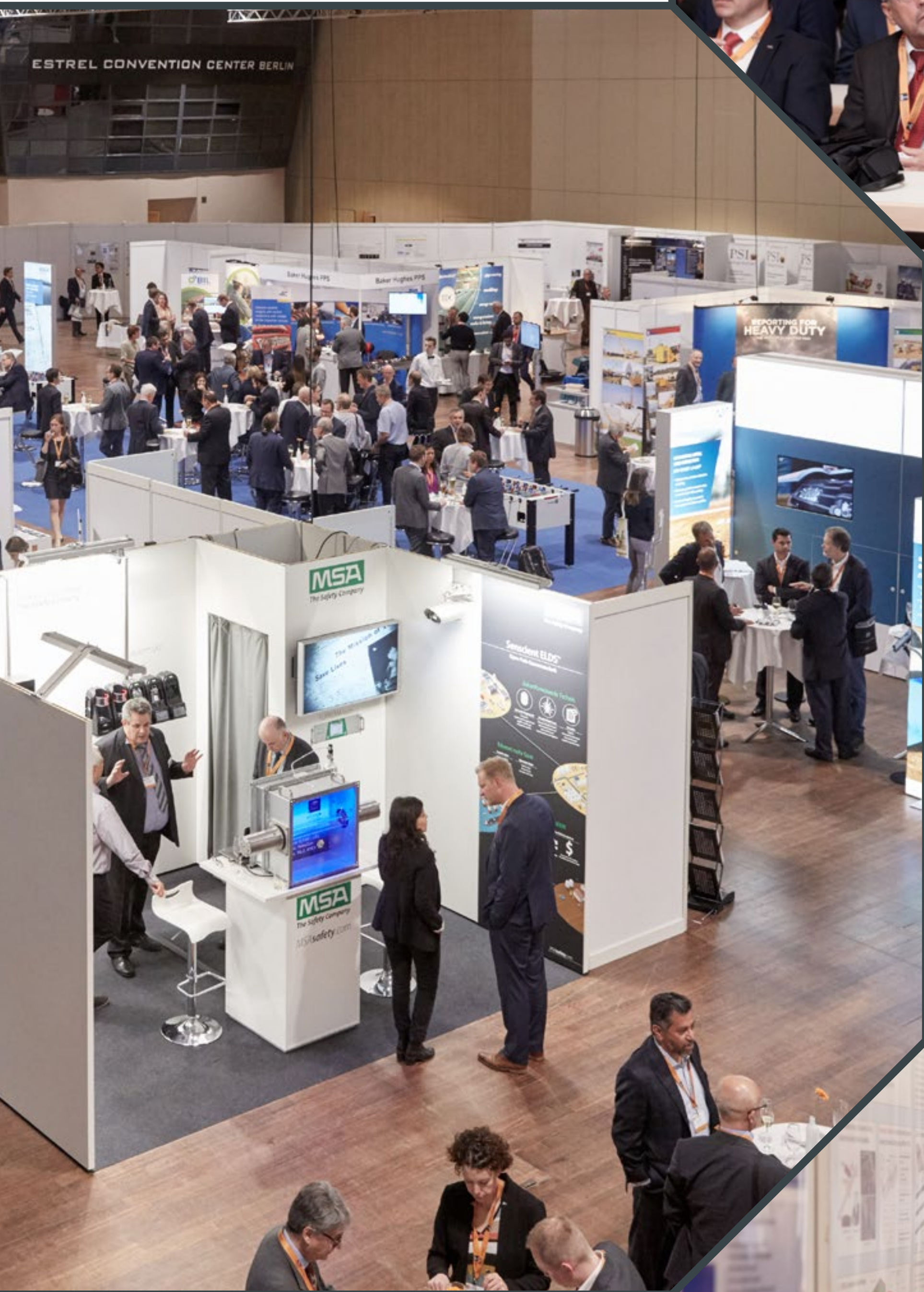

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Offensive approach: We push forward and generate attention to our career market directly at the universities. We also collect CVs from international graduates and experts and forward it directly to you.

Webseite

Continuous promotion : Your vacancies are published on the Pipeline Technology Journal (ptj) website for a year. In Addition, the ptj contains your vacancies too.

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Dead on target: We send your vacancies or your company profile to our database of 50.000 international pipeline professionals.

International Events

Physical appearance: The job & career market has an individual booth during all EITEP events in Berlin, Cairo and upcoming event locations.

Questions?

Please contact Mr. Admir Celovic for further information and booking requests.

celovic@eitep.de
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13TH PIPELINE TECHNOLOGY CONFERENCE

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ptc

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13th Pipeline Technology Conference (ptc)	**12-14 May 2018**	**Berlin, Germany**

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