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Dear readers,

Dennis Fandrich
Director Conferences

With this 3rd edition of the ptj in 2020 we are publishing 10 more articles from the 15th Pipeline Technology Conference that had to be restructured into a virtual event on short notice earlier this year.

The global pandemic is pushing us all to speed up digital transformation. For this reason, you could now see different kinds of online events and webinars popping up in your mailbox on a daily basis. But we all know that these online events will never achieve what can be created with a face-to-face meeting during a real conference and exhibition.

Nevertheless, several essential physical event benefits could already be implemented into online concepts. In addition to the pure transfer of knowledge via keynote speeches, panel discussions and technical presentations, the free networking between all participants and the comparative competition of a multitude of solutions on the market are of particular importance.

The figures from the first ever Virtual Pipeline Summit (VPS) on "Digital Transformation in the Pipeline Industry" demonstrate that this comprehensive approach is attracting great interest. More than 600 participants from 69 different countries joined the event. Almost 30% of the participants came from pipeline operators. The 2nd VPS on "Leak Detection and Third-Party Impact Prevention" will take place on 7 October 2020.

The comprehensive pool of experience that can be gained from these new formats will also be incorporated into the planning of the 16th Pipeline Technology Conference from 15-18 March 2021. In addition to the face-to-face event in Berlin, there will also be a strong online part, which will lead further interested pipeline professionals into the ptc community not only in these challenging times but also in the future.

I look forward to seeing you again in person at ptc 2021 in Berlin and to having a virtual chat during one the upcoming VPS events.

Sincerely yours

Dennis Fandrich, Director Conferences, EITEP Institute

THIS ISSUE'S COMPLETE CONTENT

THIRD SPECIAL EDITION WITH PTC PAPERS

AUGUST 2020 / SPECIAL EDITION

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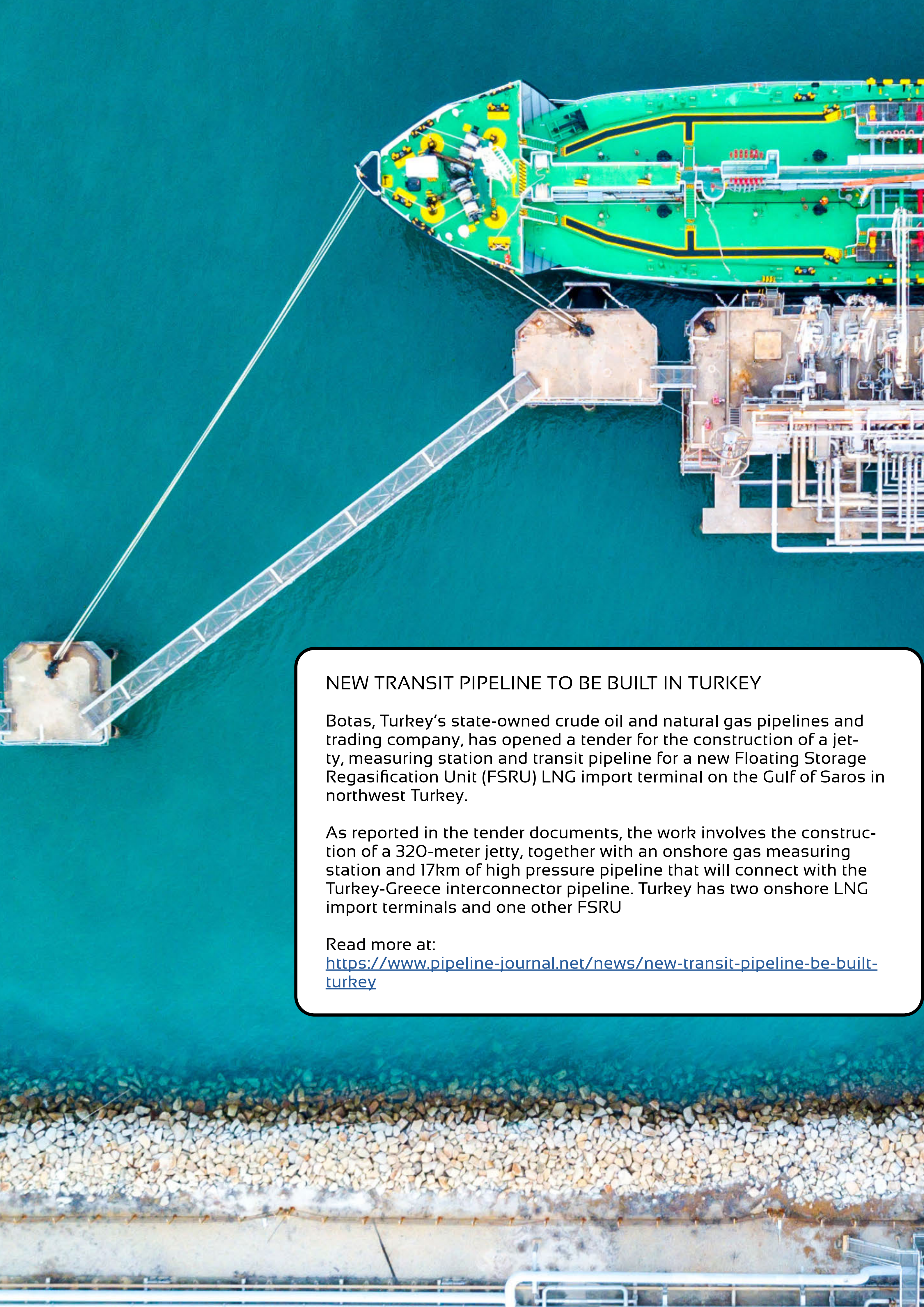
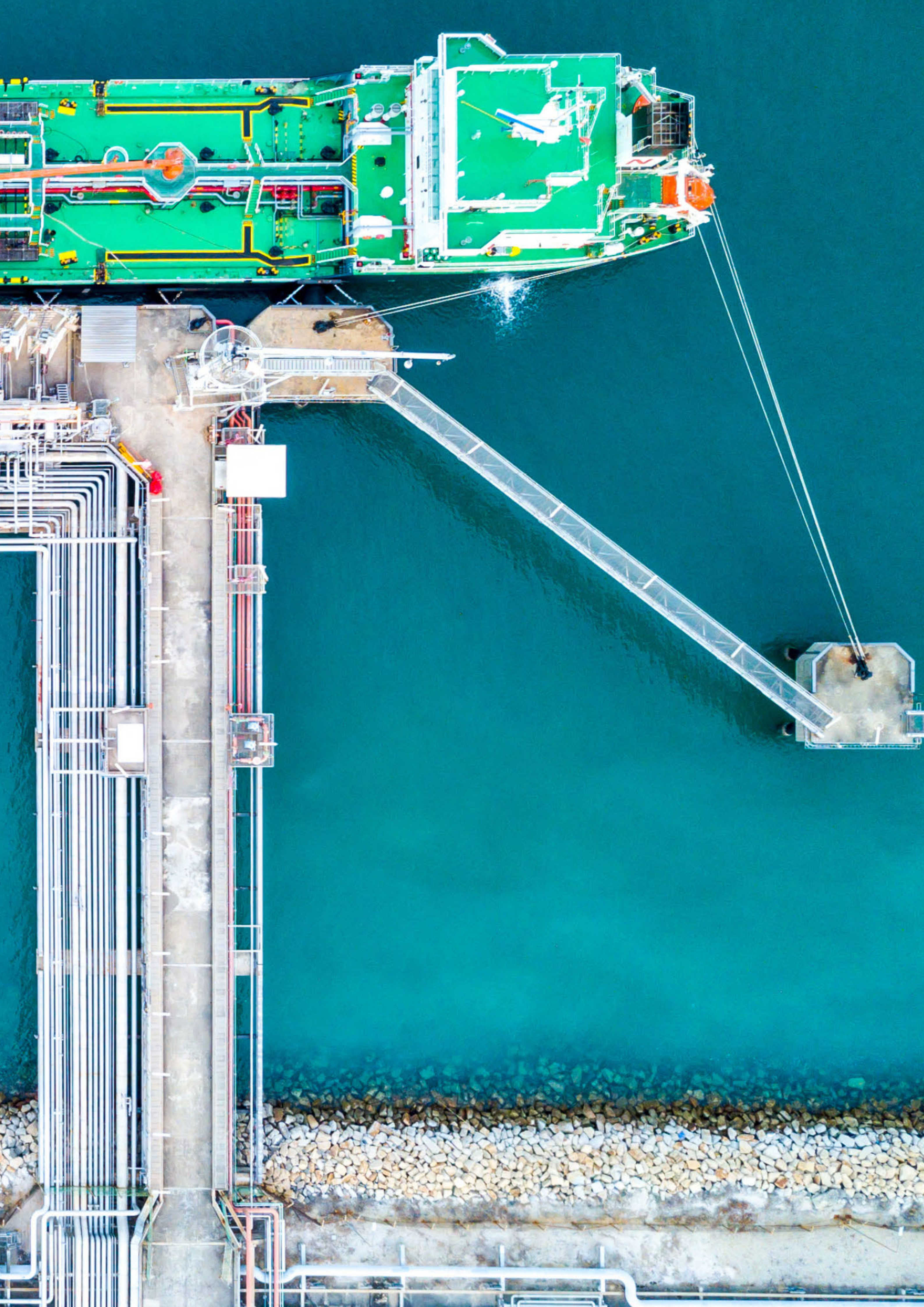


NEW TRANSIT PIPELINE TO BE BUILT IN TURKEY

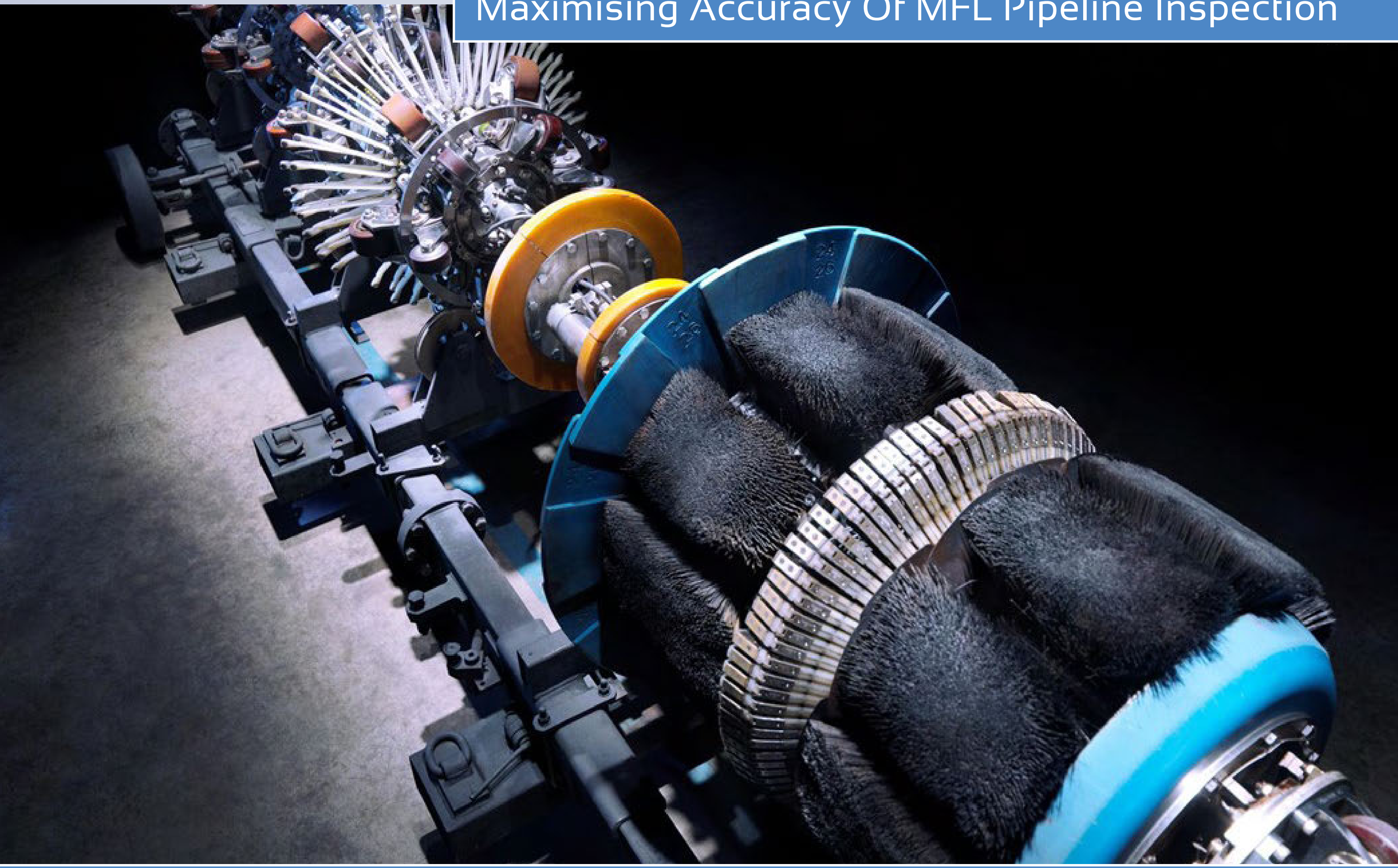
Botas, Turkey's state-owned crude oil and natural gas pipelines and trading company, has opened a tender for the construction of a jetty, measuring station and transit pipeline for a new Floating Storage Regasification Unit (FSRU) LNG import terminal on the Gulf of Saros in northwest Turkey.

As reported in the tender documents, the work involves the construction of a 320-meter jetty, together with an onshore gas measuring station and 17km of high pressure pipeline that will connect with the Turkey-Greece interconnector pipeline. Turkey has two onshore LNG import terminals and one other FSRU

Read more at:
https://www.pipeline-journal.net/news/new-transit-pipeline-be-built-turkey



Maximising Accuracy Of MFL Pipeline Inspection



Ben Scott, Stephen Farnie > Baker Hughes

Abstract

There have been significant advances in magnetic flux leakage (MFL) in-line inspection (ILI) technologies in recent years. These have led to improvements in Probability of Detection (POD), Probability of Identification (POI) and Probability of Sizing (POS).

Whilst often the main focus of these advancements is the inspection vehicle itself, the end product of an inline inspection service is reliable and accurate data. This end product is influenced by various technological factors which include: recognition & detection algorithms; complex sizing models; robust and rigorous processes and; highly trained and skilled data analysts.

This paper explores all the main factors that contribute to delivering the reliable and accurate inspection reports that pipeline operators demand today. This review will be supported by extensive comparison of 'as reported' data vs 'in ditch' findings. This is particularly valuable for operators of inaccessible pipelines, where proving ILI performance is at least challenging, and often not possible.

INTRODUCTION

Pipeline operators must balance key concerns while running a business (Figure 1). Protecting people, the environment, and the reputation of the industry remain the highest priority, whilst maximizing the ongoing returns to shareholders from major investments is always a focus.

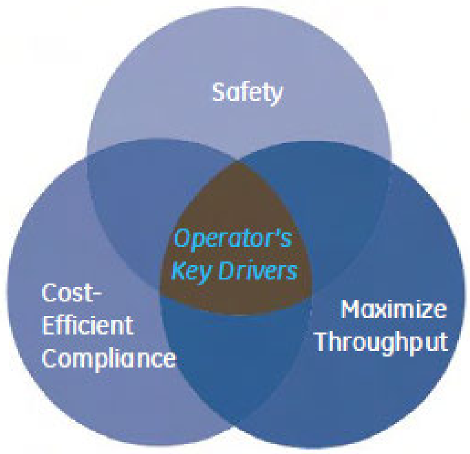


Figure 1: Key Drivers for pipeline owner/operator

These concerns become an even greater challenge in tough economic times with budgets continually under pressure. Many operators are choosing to collect a full, or enhanced inspection dataset but put priority focus and advanced analysis on targeted and problematic regions of interest. Such areas may be of high consequence or other regions identified from historic inspections or risk assessment. Whether operators are focusing on targeted areas or conducting a detailed assessment on the entire pipeline section, the accuracy of the data used, in this case in-line inspection (ILI) data, has a significant impact on the outcomes of these assessment [ref 6].

Magnetic Flux Leakage (MFL) is the most widely used ILI technology in the world today. This is largely due to its ability to deliver in a wide range of pipeline operating environments whilst maintaining high levels of accuracy. Accuracy for MFL inspection is generally measured in terms of Probability of detection (POD), Probability of Identification (POI) and Probability of Sizing (POS).

The first commercial On-Line Inspection Centre (OLIC) MFL inspections took place in the 1980s (first British Gas MFL inspection took place in 1977). Over the four decades since, there have been significant advances in MFL inspection technologies and their resulting capabilities. Whilst often the focus of these advancements is the inspection vehicle itself, the end-product of an inline inspection service is **reliable and accurate data**. This end-product is influenced by various technological factors which include: recognition & detection algorithms; complex sizing models; robust and rigorous processes and; highly trained and skilled data analysts.

This paper will first highlight how MFL ILI 'accuracy' has changed and improved over time and then focus on the following factors which all contribute to the reliable and accurate inspection service. The factors covered will be:

	Accuracy impact
- The Inspection Vehicle	POD
- Software & Feature Recognition	POD & POI
- Algorithms & Sizing Models	POS
- Data Analysts & Data Analysis Process	POI & POS
- Performance Validation, Verification & Improvement	POD / POI / POS

ACCURACY

MFL inspection accuracy is typically stated in terms of detection, identification and sizing. Each one of these is measured in terms of confidence levels, typically at 80 or 90%:

Detection or POD really means will 'it' be seen?

> Commonly defined in industry by **API 1163 (American Pipeline Institute)** as "The probability of a feature being detected by an ILI tool" or by **POF (Pipeline Operators Forum)** as "The probability that a feature with a size will be detected by the ILI tool."
>
> **Identification or POI** really means what is 'it'? Commonly defined in industry by **API 1163** as "The probability that the type of anomaly or other feature, once detected, will be correctly classified (e.g. as metal loss, dent, etc.)" or by **POF** as "The probability that a feature is correctly identified by the ILI tool."
>
> **Sizing or POS** really means what size is 'it'? Commonly defined in industry by **API 1163** as "The accuracy with which an anomaly dimension or characteristic is reported" or by **POF** as "Sizing accuracy is given by the interval with which a fixed percentage of features will be sized. This fixed percentage is stated as the certainty level."

Detection and sizing specifications are typically a key element of an ILI contract. In some of the early inspection contracts from the 1980s, the accuracy levels were not stated or 'silent' largely because the specifications were unproven or did not even exist. Some reports would merely provide a distance and Asterix*, which effectively said 'there might be something here'. Although defects identified were effectively being reported on a reasonable endeavors basis, there was enough confidence in these results for MFL inspection to be of significant value in pipeline integrity management. This value contributed to improvements over the coming years and decades.

In the later 1980s and into the 1990s, detection and sizing specifications became the norm in ILI contracts. Figure 2 shows an example of a MagneScan contract specification. Specifications were provided for pits and general metal loss, with the minimum detection for pits @ 50% WT and for general metal loss @ 30% WT. This specification was commonly known at the time as '30/50 spec'. The sizing accuracy was +/- 20% or +/- 15% WT depending on the defect type.

In the 15-20 years that followed, the specifications improved and evolved to cover a greater range of defect, sizes, types (typically quoted according to POF feature category) and improved levels of accuracy. Table 1 below provides the inspection accuracy from the Baker Hughes fleet: This is the MagneScan fleet's, industry leading 'Super High Resolution Plus' (SHRP) specification. Today the minimum detection and sizing level is from 4% and +/-8% of local wall thickness, compared to 30% and +/-15% from 20 years earlier.

This comparison shows how much the accuracy of an MFL inspection has changed over the past 20+ years.

Table 1: MagneScan SHRP detection & sizing accuracy

		General metal loss	Pitting	Axial grooving	Circumferential grooving	Pin hole	Axial slotting	Circumferential slotting
Reference dimensions (length x width)		4t x 4t	2t x 2t	4t x 2t	2t x 4t	0.5t x 0.5t	2t x 0.5t	0.5t x 2t
Super High Resolution *Plus*	Min. Depth At 90% POD	4%	6%	6%	4%	13%	13%	4%
	Depth Sizing accuracy	±8%	±8%	-13% +8%	-8% +13%	-13% +8%*	-18% +8%	-8% +13%
	Width Sizing accuracy	±12mm ±0.47 in	±12mm ±0.47 in	±12mm ±0.47 in	±12mm ±0.47 in	±7mm ±0.28 in	±12mm ±0.47 in	±12mm ±0.47 in
	Length Sizing accuracy	±7mm ±0.28 in	±4mm ±0.16 in	±7mm ±0.28 in	±7mm ±0.28 in	±4mm ±0.16 in	±7mm ±0.28 in	±7mm ±0.28 in

Table 1: MagneScan SHRP detection & sizing accuracy

ETECTION, SIZING AND LOCATION ACCURACY FOR 150MM TO 1400MM FOR SEAMLESS MANUFACTURED PIPELINES

	METAL LOSS CATEGORY		
	Pitting <(3tx3t)*	**General >(3tx3t)***	**Gouging**
Minimum Depth for Accurate Sizing	0.5t with surface dimension greater than: (t/2+10mm)x(t/2+10mm)	0.3t	If w>2t or 15mm**=0.5t If w>3t or 25mm**=0.3t
Sizing Accuracy *(Depth)*	±0.2t	±0.15t	If w>2t or 15mm**=±0.2t If w>3t or 25mm**=±0.15t
Sizing Accuracy *(Length)*	±10mm	±20mm	±20mm
Location Accuracy *(Axial)*	±0.2m between the feature and the reference girthweld and ±1% of stated distance between reference upstream girthweld and identification location reference		
Location Accuracy *(Circumferential)*	±7.5 degrees which for ease of reference is stated to the nearest half hour clock position		

Figure 2: Extract from a MagneScan ILI contract from the 1990s

FACTOR 1: THE INSPECTION VEHICLE

An ILI service starts with a successful run of the inspection vehicle. The design and performance of the vehicle is critical to successful navigation through the pipeline, but perhaps more importantly delivers the ability to detect (POD) defects along the pipeline with enough information to allow the data analysis process to confidently identify (POI) and size (POS) these detected defects.

In 2008 Baker Hughes introduced a new MFL technology system to the industry: the latest generation of MagneScan inspection vehicle. The 6" system launched at the time (Figure F1.1) made use of industry leading electronics and sensing technology to enable step change improvements in sensor spacing, scan pitch and operating parameters. These advancements, and recent others have contributed to the successful roll out of the latest generation MagneScan vehicle to its current capabilities covering 6 – 42" diameter range.

Figure F1.1: Baker Hughes latest generation MagneScan

Previous Baker Hughes reports and publications [ref 1, 2, 3] explain in detail how these vehicle attributes contribute to achieving specifications being delivered today (Table 1). Notably, studies identified that the vehicle alone can only take specification improvements so far.

Specifically, it was found that there is a non-linear relationship between sensor density and signal sizing performance. There is an optimal sensor density above which detection and subsequent sizing performance will not improve significantly, even if the vehicle were to have an 'infinite' number of 'infinitely small' sensors.

In other words, the inherent physics in the amplitude responses and signal-to-noise thresholds of any real system **do not provide a beneficial improvement of the signal detection or signal characterization with radically improved sensor spacing**.

The physics of MFL signal spatial distributions, the local magnetization levels and signal interpretation, ultimately within the cross-analysis/synthesis process steps, were key considerations resulting as an overall system to maximize feature (e.g. pinholes, slots, pits, etc) detection and sizing entitlement.

FACTOR 2: SOFTWARE & FEATURE RECOGNITION

Specialised software and algorithms are essential to the analysis of pipeline inspection data; they support the analysis process by enabling manual analysis to focus decision making on the regions and features which are most critical and where manual expertise adds the most value (Figure F2.1).

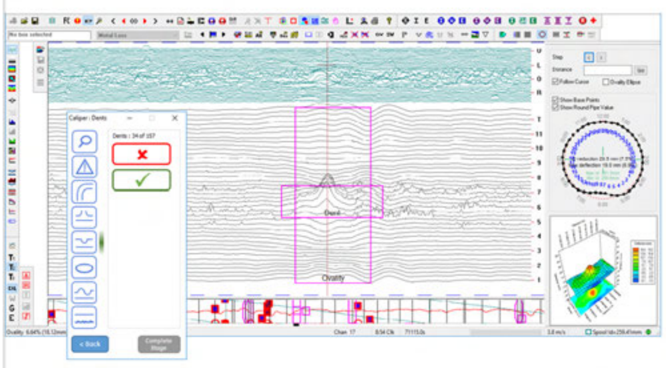


Figure F2.1 The caliper decision support workflow user interface

The signal data collected during an ILI run can be represented as a grid that covers the whole pipeline wall surface and, by analogy, can be thought of as an image of the pipe. For a 100km pipeline section, this image may be 1000 pixels high and 50 million pixels wide (number of sensors x number of data scans), and the task of ILI data analysis is to identify, classify and quantify the size and severity of any injurious features in this massive data set. The number of individual corrosion pits in a pipeline this size may run into millions, and although all of these are visually inspected, algorithms are required to locate and pre-assess this volume of features.

For features meeting the system POD specification to be reported the ILI analysis process must be able to correctly identify and classify them (POI). Achieving a high POI has two components: reliably detecting and labelling areas of data as a region of interest, and then accurately classifying the cause of the signal detected for each area (Figures F2.2 and F2.3).

As MFL technologies do not provide a direct measure of defect depth, Baker Hughes feature detection algorithms ensure that all features meeting the POD specification are detected, from the largest area of general corrosion down to 5mm diameter pinholes. Advanced pre-processing is used on the raw ILI data to normalise, improve signal-to-noise, and ensure consistent detection across all wall thicknesses and pipe types. POD and POI detection specifications are verified for every ILI system by including features into pull tests which are at and below the expected detection thresholds.

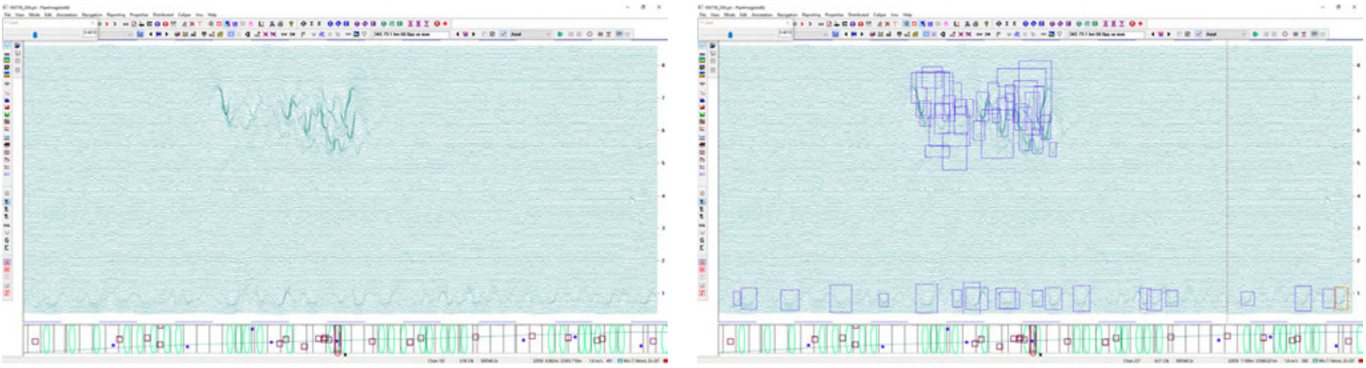


Figure F2.2: ILI signal data showing an area of corrosion above and a seam weld below. On the right we can see potential features detected on both areas by the 'boxing' algorithm.

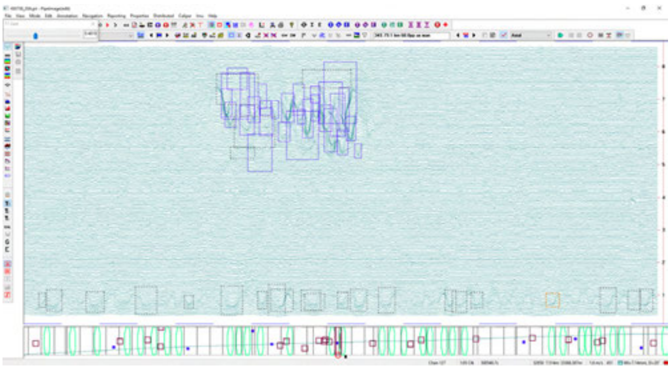


Figure F2.3 After classification the seam weld and non-corrosion areas have been removed

The nature of an accurate MFL inspection system is such that it can be very sensitive to variations that are often seen in different pipelines, even if they are considered the 'same' (WT, steel grade, corrosion levels etc) on paper. This 'pipe-to-pipe' variation is one of the biggest challenges to accurate classification. To overcome this, and meet the accuracy and reliability needed, the latest generation of Baker Hughes classification algorithms are trained and tested on a data set consisting of hundreds of individual pipelines which total around 40,000 Km, contain over 250 million detected metal loss features, and have 100 Tera-bytes of recorded ILI data.

Development does not stop once the algorithm is being used live in production. Performance metrics built in to the analysis software continue to be gathered with each inspection to measure performance and capture unusual line conditions that are used to update and improve the algorithm over time. The example on figure F2.4 shows the area above the blue line is reducing. A reduction in area above the line represents an increase in accuracy through algorithm refinement.

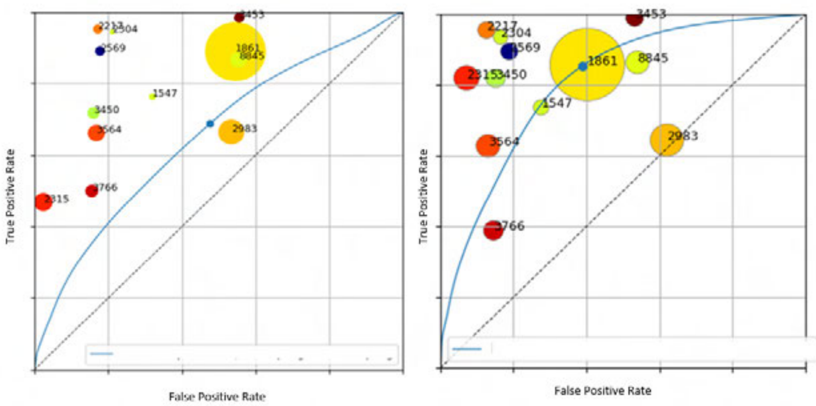


Figure F2.4 Example of iterative performance improvements during algorithm development Each circle represents features from individual pipeline sections with varying attributes.

FACTOR 3: ALGORITHMS & SIZING MODELS

It is not enough to detect an area of corrosion and report it as such, an ILI inspection also needs to report the depth and extent of that corrosion accurately. The level of sizing accuracy that can be achieved (POS) is usually stated as a tolerance +/- a given percentage of the pipe wall thickness, and calculated to an 80% or 90% confidence level, meaning 80% or 90% of all corrosion features will be expected to meet the given tolerance.

The task of predicting the depth profile of an area of corrosion is not straightforward. The relationship between the recorded magnetic flux leakage and defect depth is complex and highly nonlinear; even for simple isolated pits sources of variation include the ILI vehicle build, magnet strength, wall thickness, pipe material, vehicle speed, and of course, the shape of the pit itself.

The Baker Hughes process of sizing consists of two aspects; first characterising an area of corrosion using several descriptors, and then using those descriptors to predict the corrosion dimensions using a statistical method called a 'sizing model'.

Sizing models start with a carefully chosen population of artificial defects machined to replicate real corrosion. 'Pull Through' tests are carried with every ILI vehicle on these defects to give comprehensive coverage over all defect shapes, wall thicknesses and speeds; the sizing model is built using this data.

Figure F3.1 Pull through pipe spools with machined defects

The introduction of the latest generation MagneScan fleet in 2008 saw a step change in the defect population size and variation, resulting in an improved POS across all defect morphologies. Sizing models are now typically derived on an extensive range and number of individual defect signals, and crucially incorporate the expertise and knowledge accumulated across decades of experience in ILI inspection to create a model that is robust and accurate across the whole population.

Although they share the same form, each sizing model is uniquely tailored to an ILI system configuration to ensure the best performance. This means that Baker Hughes has created over 500 models to date.

The POS performance is measured across all defect shape categories in the pull through data set, and due to the variation and extreme defects in this population it is often found that the model performance in operational data, where the natural corrosion is more typical, will exceed the stated POS.

FACTOR 4: DATA ANALYSTS & DATA ANALYSIS PROCESS

Data analysis is where the bulk of the 'time' is spent during any pipeline ILI service. Although there is no direct correlation between the time spent analyzing the data and the typical contractual reporting timescales, it is still a good indication of the levels of 'effort' required. A typical MFL inspection report timescale is 60 days from receipt of the data to deliver of the report (this time will increase for longer pipelines e.g. 100 days for pipelines >150km). Although there are sophisticated feature recognition algorithms and software techniques applied to the ILI data before detailed analysis starts, every inch of the ILI data is reviewed by a data analyst. As this stage is so critical to report quality and resulting end-product accuracy (Figure F4.1) Baker Hughes invests in ensuring the **right people** are selected and governed by **robust processes**.

Figure F4.1. Holistic view of factors influencing ILI report quality

Data analysis essentially consists of spending many hours a day, often for weeks at a time, looking at a busy computer screen of lines and colours for patterns and 'stand out' features. It's often a case of making sure the software got it right – and it doesn't always! This challenging work takes a certain type of individual, hence, Baker Hughes strive to recruit and retain engineering degree level candidates that go through 'psychometric' screening to ensure they have the right 'minds' for the job. This screening is designed to make sure the candidates have both the necessary attention to detail and the ability to commit to the role for a number of years. The latter is clearly important when you consider the time it takes (Figures F4.2, F4.3) to gain the experience and qualifications necessary to comply with the internationally recognized standards ANSI/ANST ILI-PQ-2017. The full details of how Baker Hughes complies with ILI-PQ-2017 are documented in formal document reference Global-E-M003.

The data analysis teams work to, and are governed by, a range of processes and procedures. These are controlled within the ISO 29001 Quality Management Certification system which exists at every one of the Baker Hughes operational sites. Notable elements contributing to robust processes and procedures include:

- On the job training (OJT)
- Report Audits
- Continuous Improvement & Feedback system
- Data analysis quality metrics

These, and other elements, are covered in more detail in recent publications (reference 4), but it is worth exploring report audits in more detail.

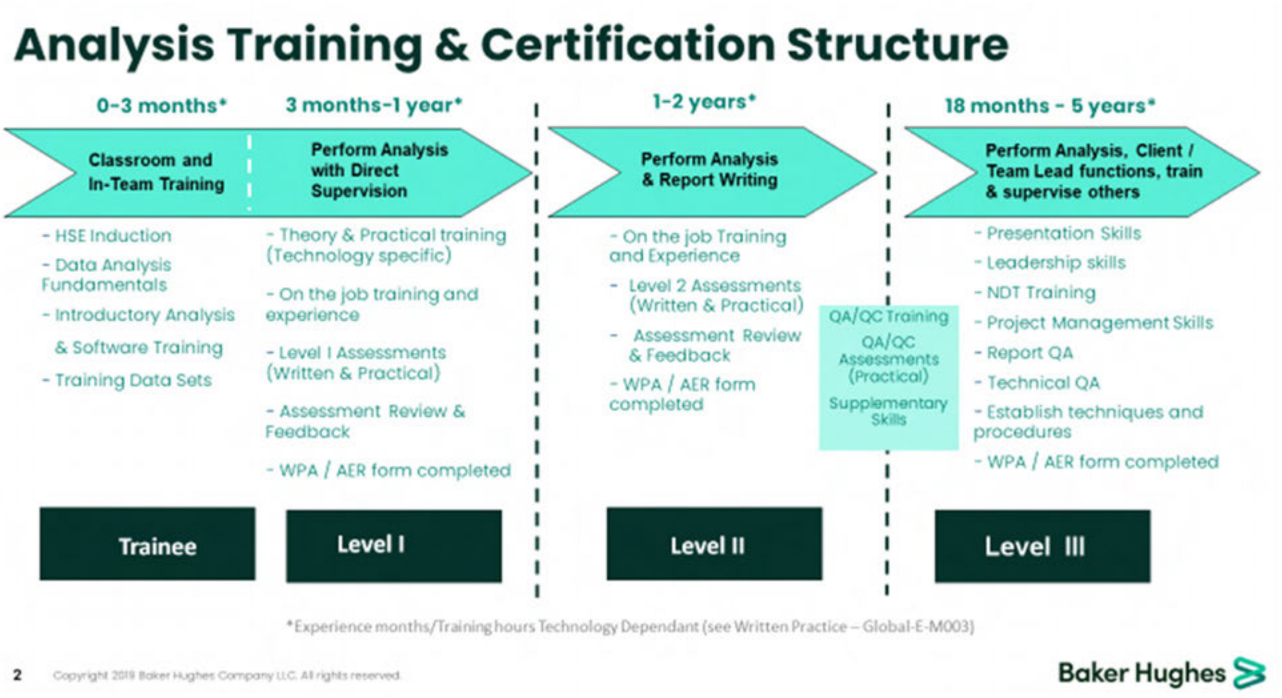


Figure F4.2: Baker Hughes Analysis Training & Certification Structure

Level	Experience (Months)	Training (Hours)	Educational (Formal)
Level I	6	80	*
Level II	18	160	*
Level III	36	500	**

Notes:

* High School graduate or equivalent
** Completion with a passing grade of at least 2 years of engineering or science study at a university, college or technical school.

Figure F4.3: ILI-PQ-2017 magnetic technology qualification & certification requirements

Internal post-delivery report audits are an important best practice. These provide a means of making sure analysis and reporting standards continue to meet the stringent high-quality requirements expected by customers and that significantly impact report accuracy. All audits should be planned, documented and scored to provide the foundation for generating ongoing analysis quality metrics. This proactive approach should seek out potential errors and highlight any process issues that have the potential to introduce future error. Should an error be found, it is documented, which initiates a formal Root Cause Analysis (RCA) and corrective action is taken.

FACTOR 5: PERFORMANCE VALIDATION, VERIFICATION & IMPROVEMENT

The first part of the 'proof' of performance of an MFL inspection system is validation using 'pull-through' data. This compares the recorded, analyzed and sized signals vs the known actual defect dimensions in the pull through spools. Each new MFL vehicle design in the Baker Hughes fleet goes through this validation prior to its release into operations. As mentioned earlier in this paper the first of the latest generation MagneScan fleet was the 6" vehicle - its performance validation can be seen in figure F5.1. In this case the results proved that the vehicle exceeded the depth sizing accuracy target of +/-10% WT with 90% certainty.

Following the system validation and operational release, it is then critical to operator confidence that this can be followed up in the field. Below, figure F5.2 shows how sizing performance of the MagneScan system was verified from multiple sets of dig data provided by operators in Asia, Europe and North America. The system is consistently performing at greater than 90% certainty.

As the volume of 'truth data' grows, confidence in the accuracy of the system does also. In parallel, opportunities for improvement are also presented. In the case of the MagneScan system, a significant improvement opportunity arose to expand the range of features that could be detected, identified and sized accurately. This improvement is covered in detail in an earlier publication (reference 3) but it led to the release of the MagneScan Super High Resolution Plus (SHRP) specification which added detection and sizing accuracy for pinholes and slots. Figure F5.3 shows the performance of the MagneScan SHRP with respect to pinholes within areas of general corrosion.

Since laser scanners have become the norm when verifying ILI performance, the Baker Hughes dig verification data base has grown exponentially from a few thousand defects prior to 2015 to hundreds of thousands today, across all 7 POF categories. Matching of laser scan excavation data is carried out using the DigCom software introduced in 2013, this software allows matching of each individual pit even in complex corrosion (Figure F5.4).

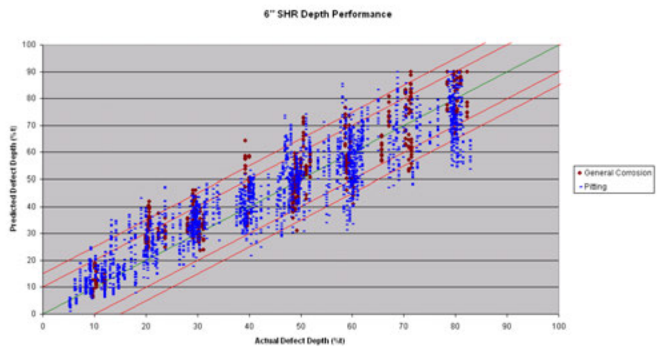


Figure F5.1 Validation of the 6" MagneScan system

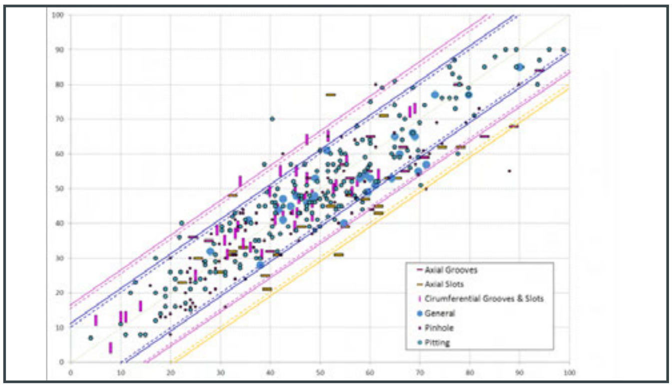


Figure F5.2 MagneScan dig verification data unity plot

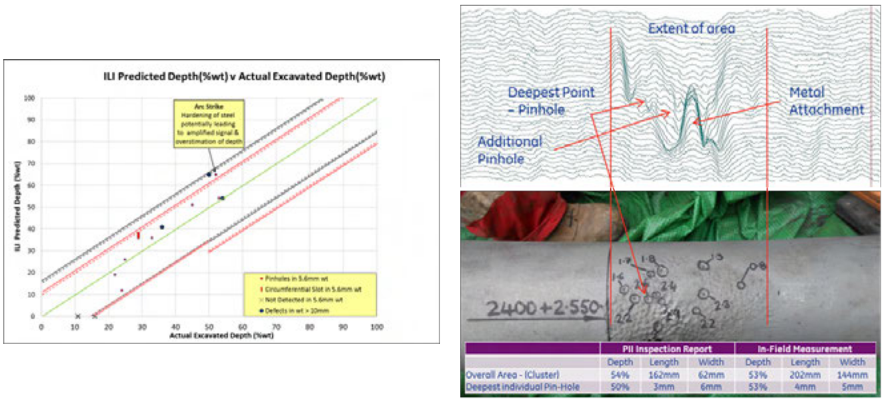
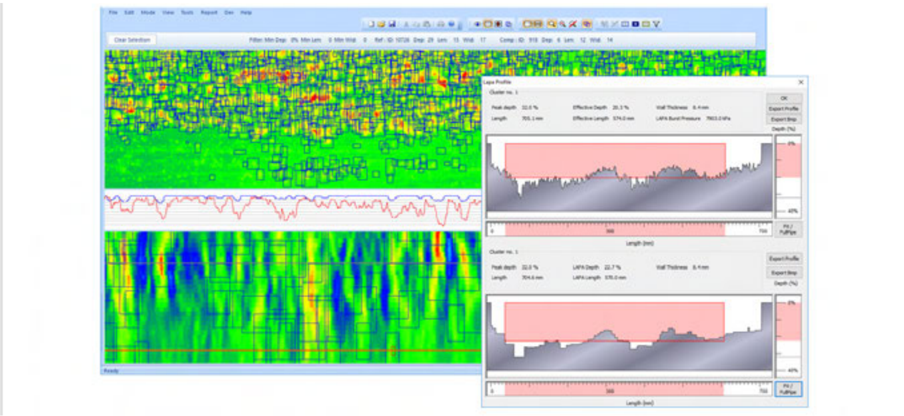


Figure F5.3 MagneScan pinhole verification



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The significant growth in truth data has led to Baker Hughes introducing regular accuracy performance reviews. Held quarterly within our organization and annually with many key customers, these reviews allow us to consider results in detail with the aim of continually improving our accuracy and overall offering to operators. The current truth database for the latest generation of the MagneScan fleet contains in excess of 60,000 features reported at the most accurate (SHR/SHRP) specifications. Actual performance is proven to significantly exceed stated specifications of POD, POI & POS @ 90%.

Since the introduction of these regular reviews, trends and early indicators are being used to drive multiple improvement and enhancement initiatives such as (but not limited to):

- Defect outlier elimination
- Girth weld crack detection & sizing (reference 5)
- Automatic prediction enhancement
- Training and processes

CONCLUSIONS

As noted in the introduction (and discussed in greater detail by Bluck, Sutherland, Dawson [ref 6]) ILI accuracy plays a significant role in achieving critical assessments of pipelines. This accuracy has a direct influence on both:

- material cost saving of reduced digs; and
- improved pipeline safety.

This paper has identified the main protagonists that contribute to the delivery of reliable & accurate data supplied by an MFL, or indeed any ILI, inspection service.

Whilst the ILI vehicle often takes center stage it is supported in equal measure by several other factors. It has been shown that as far as the vehicle is concerned 'more' doesn't necessarily mean 'better' or specifically 'better accuracy'.

At Baker Hughes there is a belief that, based on current industry hardware, accuracy improvements that can directly influence critical assessments of pipelines are just as likely to come from what we do with the data we have today as they are from improvements on the vehicle itself.

ACKNOWLEDGEMENTS

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Surge protection for insulating joints – suitable spark gaps and evaluation of the installation

Manfred Kienlein > DEHN SE + Co KG

Abstract

Insulating joints are used for the electrical separation of pipeline systems or for dividing pipelines that are affected by high voltages into sections. The electrical isolation of cathodically protected systems is maintained until the dielectric strength/ flashover strength of the insulating joint is reached. Overvoltages which occur as a result of lightning striking exposed parts of a pipeline system can exceed the dielectric strength of insulating joints. This can result in open sparks or destruction of the insulating joint.

Ex isolating spark gaps (ExFS) with suitable connection technology have the task of protecting the insulating joint (insulation) against lightning-induced overvoltages and discharging the lightning energy without sparking when dealing with dangerous explosive atmospheres (d.e.A.) at the same time. During normal operation and after the discharge process, the ExFS should disconnect safely electrically. In addition to checking ExFS, GW 24 [1] also provides information on the selection of ExFS including the suitable connection technology, which is described in more detail below.

1. SCOPE OF APPLICATION OF GW 24 [1]

This document deals with measures to avoid ignition hazards on insulating joints and to ensure cathodic corrosion protection in potentially explosive atmospheres. The recommendation is applicable to stations of natural gas pipeline systems and - under consideration of the respectively valid national regulations (e.g. TRbF, TRGS, TRBS, BetrSichV) - analogously also for other product pipelines.

Insulating joints of these systems can be realised as insulating couplings or as insulating flanges.

In the area of ports or waterways, other protective measures may also be applied during the transport or handling of hazardous liquids.

Protective measures against other hazards such as the discharge of coupled technical alternating currents or protective measures against electric shock are described in recommendations GW 22 [2] and AfK Recommendation No. 6 [3].

2. NEED TO USE EXFS

In potentially explosive atmospheres, the primary protection objective is to avoid sources of ignition (e.g. uncontrolled open sparkovers) at insulating joints.

Outside hazardous areas (e.g. with buried insulating joints) there is no need to use ExFS for explosion protection reasons, but defective insulating joints usually impair the cathodic corrosion protection. In the case of pipelines affected by external voltage, it is also possible that the contact protection criterion is no longer met. This makes it necessity to replace defective insulating joints which, besides entailing high repair costs, has a strong influence on plant availability. For these reasons it may also be advantageous to install ExFS with suitable connection technology in areas which are not classified as hazardous.

3. SELECTION, ASSEMBLY AND TESTING OF EXFS

The selection of suitable ExFS incl. connection technology must depend on

- the determined lightning protection level (LPL) or a partial lightning current calculation
- the dielectric strength of the insulating joint,
- the distance between connection points (cable length),
- the technical data of the ExFS
- the installation location (Ex-zone) and
- the insulation coordination (insulating joint to connected ExFS).

3.1. DETERMINATION OF THE LIGHTNING PROTECTION LEVEL (LPL)

The hazard level (LPL) is determined with a risk assessment according to DIN EN 62305-2 [4]. On the basis of this parameter, the maximum lightning current (lightning current distribution according to DIN EN 62305-1 [4]) is determined by the ExFS through various impact scenarios (S1 - S4). For example, in the case of pipelines located above ground (see Figure 1), the maximum lightning current (LPL I) through the ExFS would be 100 kA (10/350 µs) in the event of an S3 strike to the pipeline.

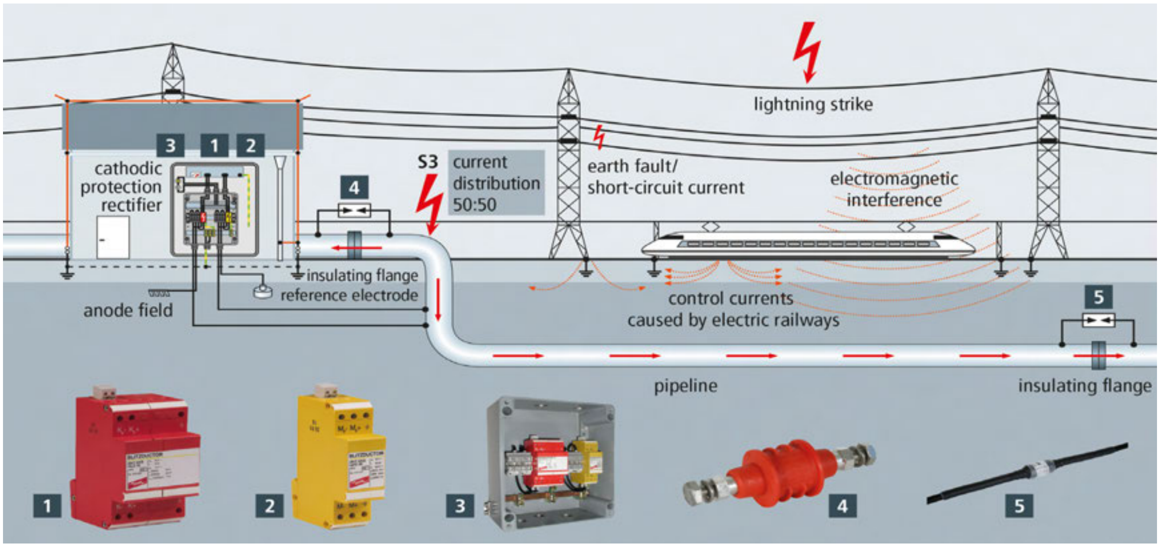

Figure 1 Lightning current distribution at impact S3

Table 2 of GW 24 [1] describes the maximum parameters of the first flash depending on the LPL for the ExFS with connection technology. The maximum values for the negative subsequent flash have not been considered. It is possible to deviate from these maximum values if a detailed consideration according to DIN EN 62305-1, appendix E [4] or comparable is carried out.

3.2. DIELECTRIC STRENGTH OF THE INSULATING JOINT

The insulating joints used in each case are tested after production with a test alternating voltage UPW of 50 Hz corresponding to the classification. There are two test classes:

Class 1: UPW $\geq$ 5 kVrms
Class 2: UPW $\geq$ 2.5 kVrms

The test classes for the insulating joints can be obtained from the respective manufacturer. Higher test voltages (e.g. 10 kV) can also be tested on customer request.

3.3. DISTANCE BETWEEN THE CONNECTION POINTS (LENGTH OF THE CONNECTION CABLE)

Depending on the max. current steepness of the partial lightning current determined under point 3.1 and the length of the connecting cable, the dielectric strength of the insulating joint may be exceeded on account of the voltage drop (during the discharge process) via the connecting cable.

This can be the case with cable length from just 300 mm upwards (based on a class I insulating joint and lightning protection class I). If the length of the connection system (SL+ 2*H according to Figure 2) can be limited to $\leq$400 mm (length ExFS + cable length, with a Class I insulating joint), no further hazard assessment (coordination ExFS with insulating joint) is required.

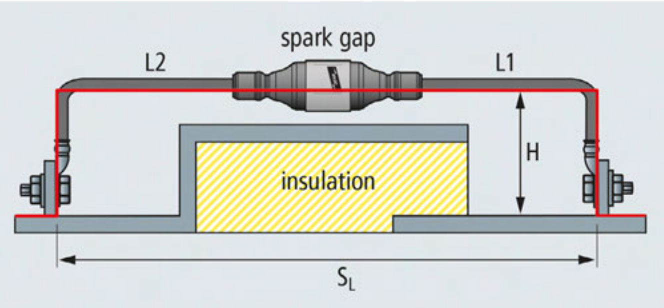

Figure 2 Length of the connection system

In addition, the entire connection technology must be:

- capable of carrying lightning current,
- spark-free (in case of simultaneous occurrence of a potentially explosive atmosphere),
- arranged directly parallel and close to the insulating joint,
- connected by the shortest route,
- secured against accidental bridging (e.g. by tools).

Suitable connection points on pipelines are

- welded on lugs, bolts
- Tapped holes in the flanges to accommodate bolts.

Note: Connection by means of a clamp is only permissible if tests have shown that there are no sparks in case of lightning currents. All screw connections must be secured against self-loosening. Protection against self-loosening can be ensured, for example, by inserting a spring washer. Toothed lock washers have not proven effective in such applications (sparking with lightning currents)

3.4. MINIMUM REQUIREMENTS FOR EXFS

Suitable ExFS should have the following technical data and approvals:

- Tested according to IEC/EN 62561-3 [6].
- Lightning current carrying capacity class: H or N
- DC sparkover voltage: > 600 V 1)
- 100 % lightning impulse sparkover voltage (1.2/50 µs): ≤ 1.25 kV
- Nominal discharge current (8/20 µs): 100 kA
- Lightning impulse current Iimp (10/350 µs): 100 kA (H), 50 kA (N)
- Rated withstand voltage (50 Hz): 250 V 1)
- Rated alternating discharge current (50 Hz): 500 A / 0.2s 2)
- ATEX certification according to directive 2014/34 EU [8] according to the Ex-zone at the place of use
  1) Normally > Û at the installation location
  2) Max. discharge current with external voltage interference at installation site

3.5. COORDINATION EXFS WITH INSULATING JOINT

Coordination between the insulating section of the insulating joint and the spark gap bridging this section should ensure that the equalisation process following a lightning discharge is carried out via the ExFS and not via the insulating section of the insulating joint. The ExFS thus represents a " preset flashover point" which prevents the occurrence of a discharge process with uncontrolled sparking. At the same time the ignition of an explosive atmosphere is avoided.

Coordination under the conditions of lightning discharge is basically given if the voltage across the insulation of the insulating joint caused by the discharge process does not reach the value of the dielectric strength or flashover strength.

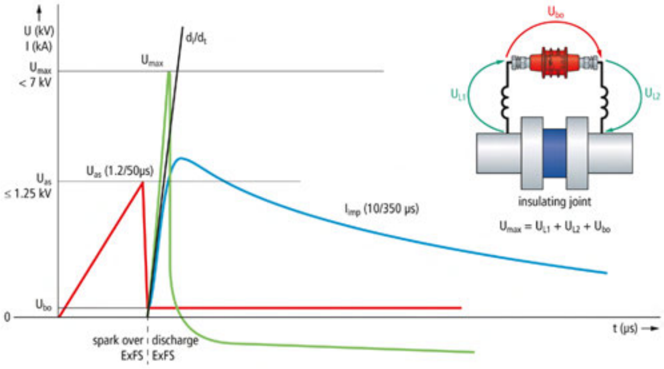

Figure 3 Schematic voltage curve at the insulating joint under lightning influence

As can be seen in Figure 3, during coordination, first of all the sparkover performance of the ExFS and, after sparkover, the voltage drop across the connecting cable must be compared with the insulation strength of the insulating joint.

3.5.1. SPARKOVER OF THE EXFS

The impulse sparkover voltage Uas (1.2 / 50 µs) of an ExFS must be 50 % lower than the rms value of the test AC voltage UPW of the insulating joint (determined according to GW24).

Condition: Uas <= UPW / 2

e.g. Class 2 insulation joint: UPW = 2.5 kV
Impulse sparkover voltage of the spark gap: Uas ≤ 1.25 kV.
Note: When using ExFS with Uas ≤ 1.25 kV, all (class 1 and 2) insulating joints can be protected by the sparkover.

3.5.2. DISCHARGE OF THE EXFS

The electrical voltage stress of an insulating joint is not only determined by the impulse sparkover voltage of a spark gap connected in parallel to the insulating joint. After ignition of the spark gap, an impulse current flows, which causes a voltage drop across the entire connection system. The voltage drop is significantly influenced by the impedance of the connection technology. This voltage drop can reach values which can exceed the electrical flashover resistance of the insulating joint (greater than the sparkover voltage Uas).

The maximum voltage drop across the entire connection system (Umax) of a spark gap arrangement at maximum current steepness must be smaller than the peak value of the test voltage of the insulating joint ÛPW (practical comparison according to GW24).

Condition: Umax < ÛPW

z. B. Class 1 insulating joint: UPW = 5 kV
Peak value of UPW: ÛPW = UPW * √2 = 5 kV * √2 => ÛPW = 7 kV.

The maximum voltage drop Umax can be determined with the following formula:

Umax = Ubo + Iimp * RL + L * di / dt

Ubo: arc voltage of the ExFS, depending on type

Determination based on data sheets [5] specific to the manufacturer is also possible.

3.5.3. CASE STUDY

What should be evaluated here is a spark gap installation via an insulating joint buried in the ground (according to Fig. 4) with the objective of "protecting the insulating joint" in all phases of the lightning-induced discharge process. To facilitate regular inspection, the ExFS should be con-

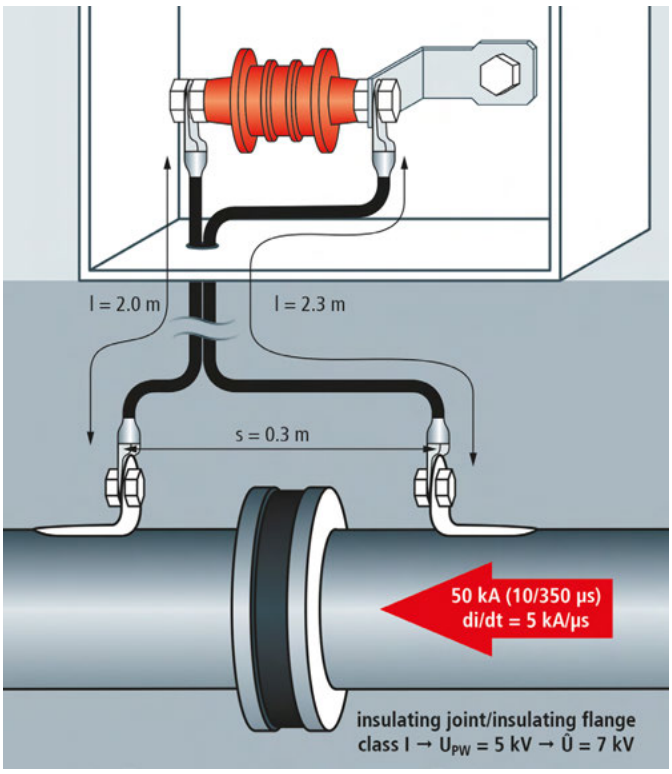

Figure 4: Round conductor connection above ground

nected underground but installed above ground:
Connection cable length (outgoing and return line) of the ExFS: 4.30 m Distance between the connection points S: 0.3 m
ExFS: Ubo = 30 V; Uas <= 1.25 kV
Connection cable: 25 mm², Cu, round;
ρ = 0.0178 Ωmm² / m
RL = 0.712 mΩ / m
L = 1 µH / m
Insulating joint: Class I (UPW >= 5 kV; ÛPW = 7 kV)
Max. lightning current limp : 50 kA (10/350 µs) according to estimation of the max. partial lightning current according to DIN EN 62305-1
=> max. steepness: 5 kA/µs

	Distance between terminals s [mm]	Connecting cable length l [m] 1.0	1.5	2.0	3.0	4.0	5.0
Voltage drop (U_{MAX}) in kV at 5 kA/µs	300	6.6	9.1	11.6	16.6	21.7	26.7
	500	7.6	10.1	12.6	17.6	22.7	27.7
	1000	10.1	12.6	15.1	20.2	25.2	30.2
	1500	12.6	15.1	17.6	22.7	27.7	32.8
	2000	15.1	17.6	20.2	25.2	30.2	35.3

Table 1: Voltage drops of round conductors 25 mm² calculated according to GW24 [1]

Evaluation of the round conductor connection technology according to GW24:
a) Sparkover
Condition: Uas <= UPW / 2;
=> 1.25 kV <= 5 kV / 2
1.25 kV <= 2.5 kV (condition fulfilled)
b) Discharge
Condition: Umax < ÛPW

Umax = 21.7 kV (value according to Table 1)

<u>21.7 kV > 7 kV (condition according to GW24 not fulfilled !)</u>

Further measures are necessary because the goal of "protecting the insulation" cannot be fulfilled in all phases of the discharge process.

Other possible measures would be:
- Parallel connection of a further ExFS (type test recommended)
- Increase the dielectric strength of the insulating joint (e.g. 20 kVrms tested)
- Reduction of the inductance L of the connecting cable, e.g. using coaxial connection solutions (see Figure 5)

Figure: 5 Coaxial connection technology of ExFS [6]

3.5.4 CASE STUDY WITH COAX BOX SN

The round conductor connection technology of the spark gap installation is now replaced by lightning-current-tested coaxial connection technology (Figures 5 and 6):

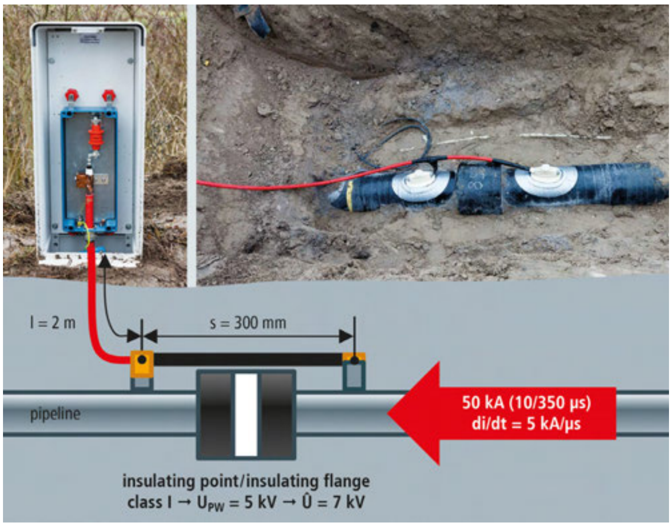

Figure 6: Coaxial connection technology

Length of the coaxial cable L: 2 m
Distance between the connection points s: 0.30 m
ExFS: Ubo = 30 V; Uas <= 1.25 kV
Connection cable type N2XSY 01X35/16 6/10 kV RT
Inner conductor: 35 mm², copper, round;
Outer conductor: 16 mm² Cu, braiding

Insulating joint: Class I (UPW >= 5 kV; ÛPW = 7 kV)
Max. lightning current limp: 50 kA (10/350 µs) based on estimation of the max. partial lightning current according to DIN EN 62305-1.
=> max. steepness: 5 kA/µs

	Distance between terminals s [mm]	Connecting cable length l [m] 1.0	1.5	2.0	3.0	4.0	5.0
Voltage drop (U_{MAX}) in kV at 5 kA/µs	300	3.8	4.4	4.9	5.7	7.9	8.6
	500	6.0	6.6	7.1	8.1	10.2	10.9
	1000	8.9	9.7	10.5	11.5	13.2	14.1
	1500	11.1	11.6	12.1	13.2	14.3	15.5
	2000	17.3	17.6	18.6	20.3	20.5	20.6

Table 2: Extract from the DEHN installation instructions for determining the voltage drop of the coaxial connection box

Evaluation of the coaxial connection technology according to GW24:
a) Sparkover
Condition: Uas <= UPW / 2;
=> 1.25 kV <= 5 kV / 2
1.25 kV <= 2.5 kV (condition fulfilled)
=> same result as for round conductor connection because the same ExFS type was used.

b) Discharge

Condition: Umax < ÛPW
Umax = 4.9 kV (value according to table 2)

4.9 kV < 7 kV (condition according to GW24 fulfilled !)

RESULT:

The specially tested new connection technology of the coaxial connection box with ExFS spark gap presents a technically simple method of positioning the ExFS above ground for testing.

3.6. EXFS INSPECTION

If the ExFS are used in hazardous areas, they must be tested according to DIN EN 60079-17 [7] after three years at the latest. An inspection of the ExFS with connection technology always consists of a visual inspection and a metrological test. The visual inspection includes checking the ExFS with connection technology for the following:

- Damage to the enclosure of the ExFS
- Correct mounting position according to installation instructions of the manufacturer
- Insulation of the connecting cables
- Any loosening of the connecting cable
- Contact stability
- corrosion of the ExFS installation
- Suitability for installation in hazardous areas
- Length of connecting cable > 300 mm ->Proof of coordination ExFS with insulating joint
- For further test criteria see 3.3

A metrological test of the ExFS to check the short circuiting and adequate insulation capacity must be carried out in accordance with the respective manufacturer's specifications and test instructions. Electrical tests must be carried out in the dismantled state and outside hazardous areas. If an electrical test in the Ex-area is necessary, this may only be carried out in close cooperation with the operator.

4. SUMMARY

With the new GW 24 [1], it is possible to evaluate the installation of ExFS in such a way that the goal of "protecting the insulating joint" can be guaranteed in all phases of the lightning-related discharge process in a way that is universally comprehensible. The user has a variety of possible technical measures at his disposal (spark-free or coaxial connection technology), which can be applied to suit the installation environment.

ABBREVIATIONS:

TRbF: technical regulation for flammable liquids, german standard
TRGS: technical regulation for hazaradous substances, german standard
TRBS: technical regulation for operational safety, german standard
GefStoffV: ordinance on hazardous substances
BetrSichV: Ordinance on Industrial Safety, german standard

FORMULAIC CHARACTER

UPW: AC test voltage 50 Hz rms
Û PW: AC test voltage 50 Hz peak value
Umax : maximum voltage drop
Iimp : impulse lightning current (wave shape 10/350 μs)
RL : ohmic resistance of the connection cable
L : inductance of the connection cable
di / dt: average steepness of impuse lightning current Iimp
Ubo: arc voltage of the ExFS, depending on type
Uas: impulse sparkover voltage (see data sheet of the manufacturer)

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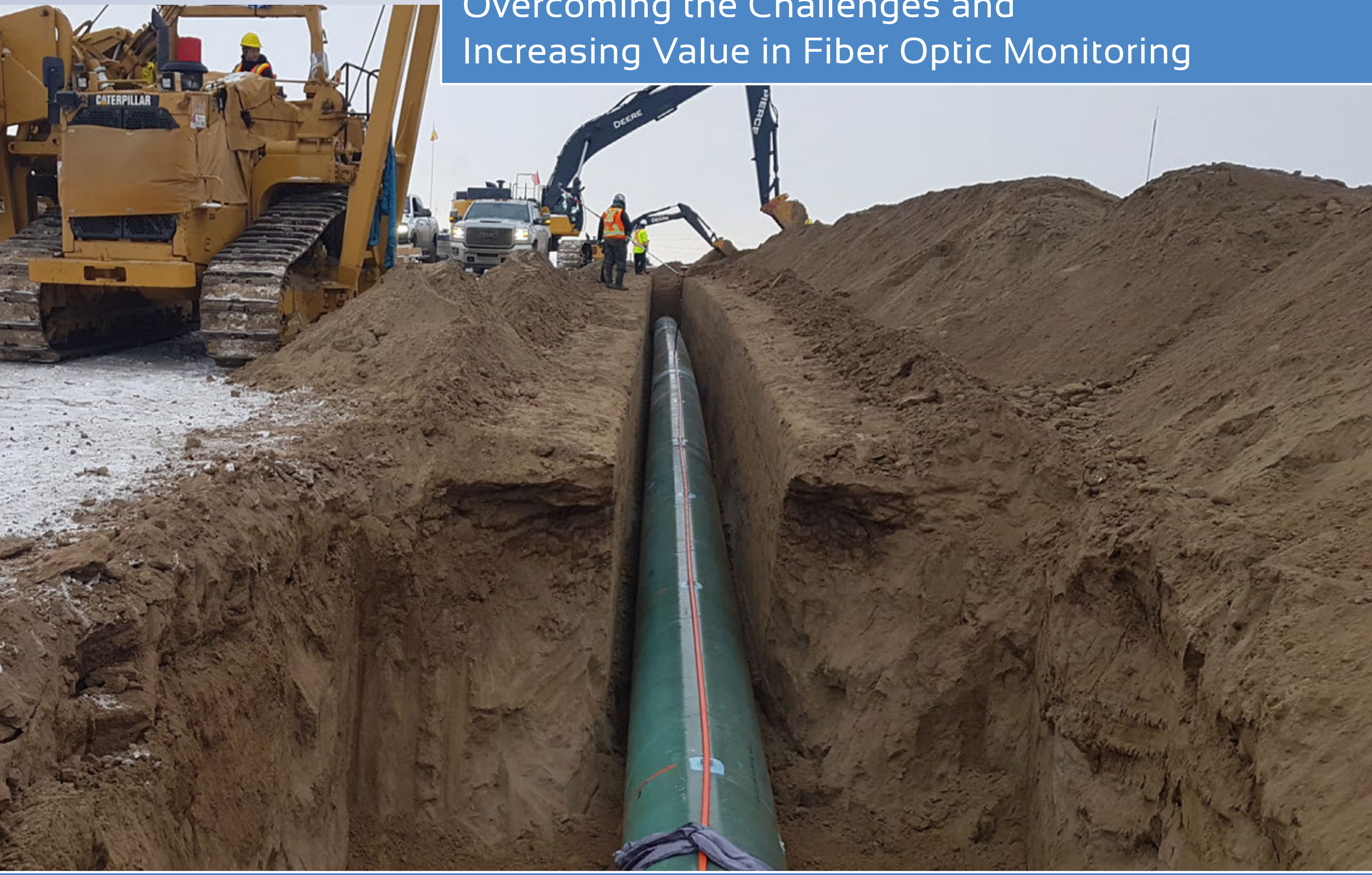
Overcoming the Challenges and Increasing Value in Fiber Optic Monitoring



Steven Koles, Ehsan Jalilian, John Hull > Hifi Engineering

Abstract

Distributed fiber optic sensing has been gaining significant momentum in pipeline industry adoption. The primary application of this technology has been in preventative leak detection, but intelligent new applications such as pipeline flow rate monitoring are now emerging and promise to deliver extra value to the pipeline operators.

We present a high fidelity dynamic sensing system (HDS), which is capable of sensing acoustics, temperature, strain, and vibration over long distances in, on, or near a pipeline. We will discuss the practical considerations and challenges of deploying this technology in the field, including long distance fiber jetting, on and off the pipe placement, deployment in existing conduits, placement underneath riverbeds and roads, internal deployment, and micro-trenching. An overview of conduit sizing and thickness design tradeoffs and their impact on sensitivity will also be provided.

Case studies will be provided to showcase the value of using artificial intelligence and machine learning to explore new frontiers in pipeline monitoring. A variety of "value added" applications such as flow anomaly detection, flow rate, pressure, and density estimation will be discussed in detail. Other applications such as pig, vehicle, and train detection and tracking will also be presented.

A discussion of the critical design criteria for the creation of scalable client notification and data delivery platforms will also be provided. Design considerations include the diversity of customer personas and the associated requirement of interface customizability, the need for scalability to accommodate the always-growing volume of data, future-proof design to permit on-the-fly addition of new events and data streams with minimal core platform modifications, and intuitive user interface design requirements.

1. INTRODUCTION

Pipeline safety is a top concern for the general public, governments, and energy companies. Leaks can be caused by integrity failures due to sudden ruptures, accumulated strain, ground movement, etc. Pipeline companies rely on a number of technologies such as mass balance systems, aerial surveillance, and inline inspection tools to monitor the integrity of their pipelines on a regular basis.

Fiber optic pipeline monitoring has the advantage of continuous monitoring in both time and space. Deploying the fiber optic cable on, near, or inside the pipe effectively transforms it into a powerful suite of distributed sensors. Hifi Engineering's HDS technology utilizes the power of high fidelity fiber optic dynamic sensing to detect small changes in the optical path length between two adjacent fiber bragg gratings (FBGs), which are used as low angle wavelength reflectors. These perturbations are representative of the strain, vibration, acoustic, and thermal energy which is applied to the fiber optic sensor.

A variety of independent event identification algorithms are applied to the data acquired from the fiber optic sensors to detect the occurrence of pipeline integrity related events such a leaks, flow anomalies, or excessive strain. Further algorithms are also used to track pigs in the pipeline, estimate flow rate and pressure, etc.

2. DEPLOYMENT CONSIDERATIONS AND CHALLENGES

Fiber optic deployment methods may be divided into three categories of on the pipe external placement, off the pipe external placement, and internal placement. On the pipe placement (see Figure 1) is ideal for new constructions as it maximizes acoustic and strain sensitivity, though in some cases the client may prefer to place the fiber a short distance away from the pipe due to deployment considerations, or in an effort to monitor multiple parallel pipes. It is best practice to keep the fiber optic cable no more than one meter away from the pipe.

Due to the fragile nature of fiber optics, it is imperative that the sensors be deployed inside a protective housing such as stainless steel tubing or HDPE conduits. From a practical perspective, deploying in multi-duct HPDE conduits provides the greatest level of flexibility during the deployment while allowing the operator to deploy extra fiber optics, control cables, etc. in the future if needed.

Conduit based deployments generally involve the placement of an empty or pre-loaded conduit on or near the pipe during construction, and using splice enclosures to connect the conduit segments. Depending on the specific deployment, the splice enclosure can be anywhere from a few hundred meters to a few kilometers apart. For on the pipe placement, pipeline tape, special clamps, pipeline grade adhesives, or sandbags can be used to secure the conduit to the pipe prior to backfilling the trench. A placement in the 11 o'clock to 1 o'clock range is optimal as it provides high sensitivity while reducing the chances of the conduit getting crushed by the pipe during the backfill process. Sufficient slack allowances must be made to prevent excessive strain on the conduit in case of thermal expansion of the pipe.

Figure 1 - On the pipe fiber installation

Burying pre-loaded conduit during the construction phase is a possibility. In some cases the operator may prefer to simply deploy an empty conduit during the construction phase and use specialized fiber injection equipment (see Figure 2) to jet the fiber into the conduit after the completion of this phase and the backfilling of the trench. This option has the added advantage of minimizing the number of required fiber splices.

Figure 2 - Fiber injection at into buried conduit at a hand-hole site

In some deployment cases such as placement underneath riverbeds and roads, sections of the pipe must be placed using horizontal directional drilling (HDD). Using redundant conduits minimizes the chances of all conduits being damaged throughout the drilling and pull back process. In such cases, multiple conduits (see Figure 3) can be attached to the pipe near the pull-head and then pulled alongside the pipe in the bore (see Figure 4). It is recommended that the conduit not be taped to the pipe to allow it to rotate and move around freely while being pulled inside the bore, otherwise the conduit may experience excessive strain and be damaged during the process of boring.

Figure 3 - A multi-duct HDPE conduit

Figure 4 - HDD pull

Practical considerations regarding conduit sizing include crush rating, the number of fiber optic strands to be fitted inside, and the transportability of the conduit spool. Of great importance is the thickness of the conduit as it directly bears on crush rating and preventing compromising the conduit (see Figure 5), however the increased thickness also results in higher levels of acoustic signal attenuation. Mechanical models have been developed to calculate the optimal inner and outer diameters of the conduit to strike the proper balance between sensitivity and robustness.

Figure 5 - A compromised conduit

Figures 6 and 7 below show the relationship between conduit thickness and crush rating and acoustic attenuation.

Existing pipelines pose a challenge to the deployment of fiber optic sensors. Generally, two approaches are possible. The first involves micro-trenching near the pipe to allow the conduit placement. This approach works in some cases, but can pose a safety risk to the pipeline. In some cases, hydro-vacuuming may be used to expose short pipe segments in order to deploy the fiber optic sensor. In some cases of existing pipelines such as river crossings, internal deployment may be the most suitable choice.

Internal deployment is often accomplished by inserting the fiber optic conduit into the pipe at a valve or other ingress location (see Figure 8) and using a tow pig (see Figure 9) to pull the fiber along with the flow inside the pipe. A dislodgement mechanism such as using mechanical sheer force will need to be used to separate the fiber from the pig once the cable is laid inside the pipe. It's also possible to use degradable pigs that dissolve over time with the pipeline flow.

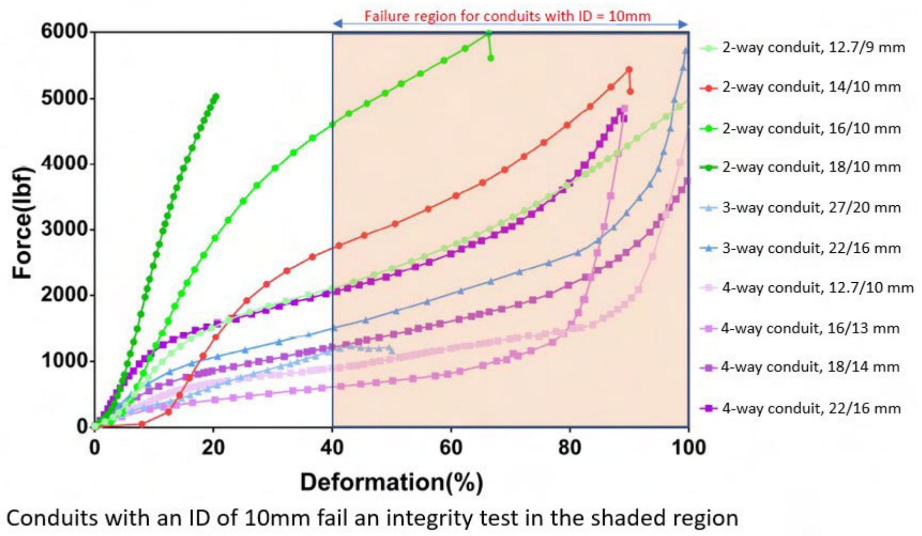
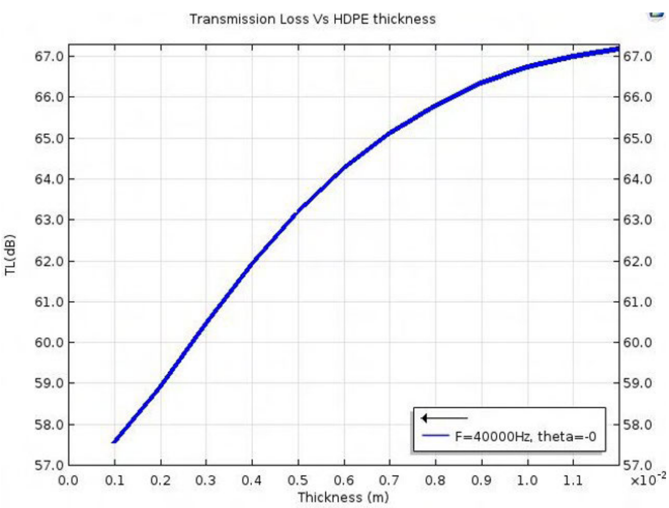


Figure 6 - Conduit sizing impact on crush rating



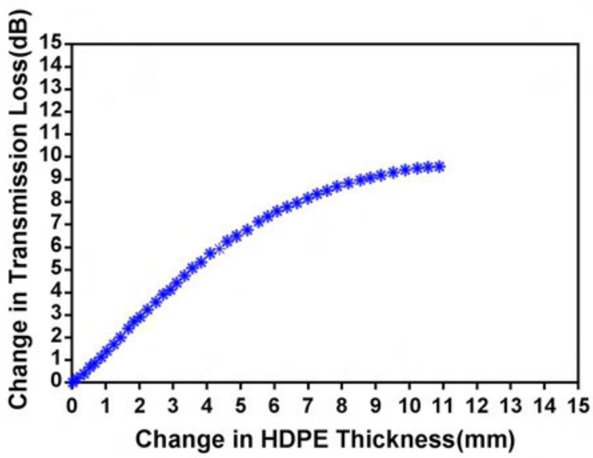


Figure 7 - Conduit sizing impact on acoustic attenuation

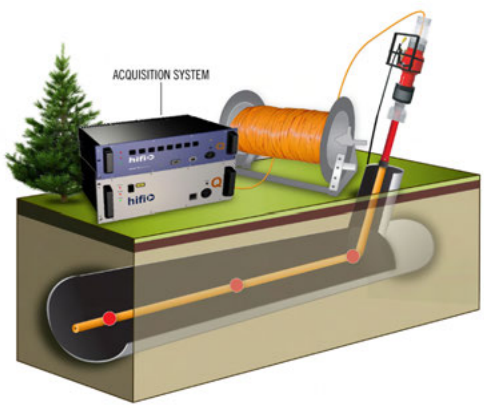


Figure 8 - Internal deployment schematics

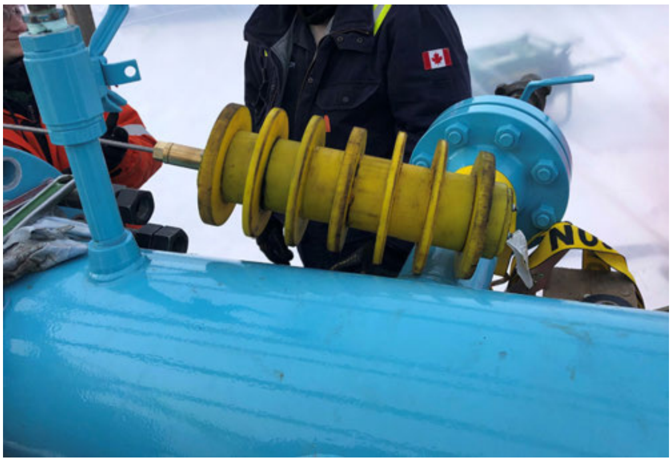


Figure 9 - Fiber optic cable attached to tow pig for internal deployment

3. DATA PROCESSING AND EVENT IDENTIFICATION

Machine Learning and Artificial Intelligence are rapidly gaining prominence as the preferred methods of choice for event detection. Supervised learning approaches such as classification algorithms are powerful tools that can utilize a large database of known events, for instance simulated leaks, to train a monitoring system to detect events such as pipeline leaks, pig runs, and flow anomalies. Decision Tree and Support Vector classifiers are particularly useful for event detection, however the classification outcomes may be impacted if adequate data conditioning, feature extraction, and labeling is not performed. The risk of overtraining the data must be taken seriously and appropriately mitigated by dividing the data into training, test, and validation datasets. It's also good practice to train and test the event detection algorithms using data from various different deployments to ensure robustness and avoid overtraining.

nsupervised learning methods such as cluster analysis are useful in cases where sufficient training data for the event of interest is unavailable, or the available training data, e.g. simulated leaks, is not relevant to the specific deployment environment. Algorithms can be trained to analyze the data to 'learn' baseline activity such as the ambient acoustics or frequent events, e.g. train crossings. The extracted features are divided into various clusters of previously observed events, without a need for the clusters to be labeled. If the features of a future event fall outside these known clusters, they will be flagged as anomalies which need to be further processed.

Among the value added applications of pipeline fiber optic monitoring are pig tracking and flow, pressure, and density estimation. Pig tracking enables pipeline companies to know the exact location of the pig, along with its speed and arrival time at the next pig catching station.

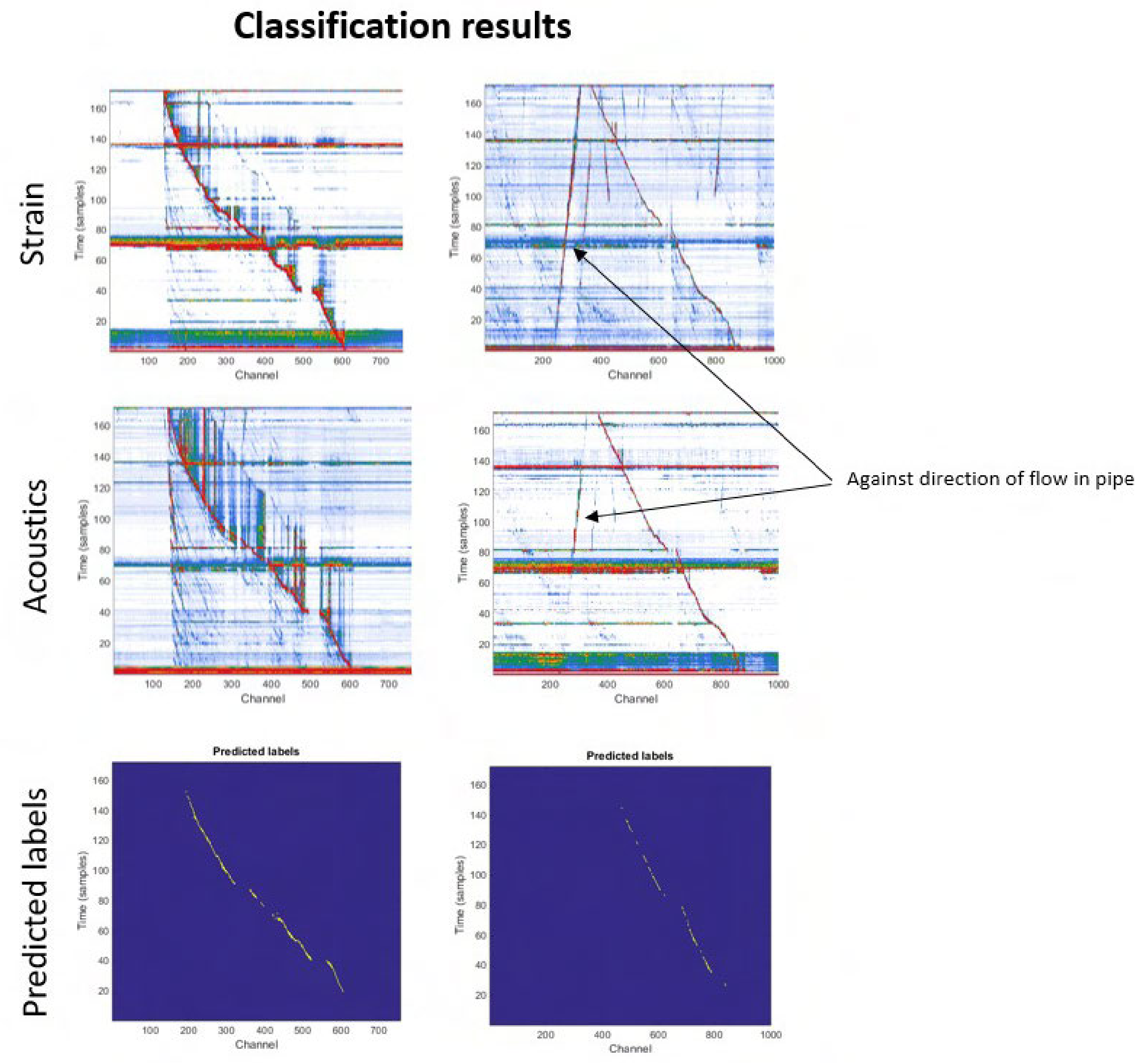


Figure 10 - Pig tracking data

Strain and acoustic data collected from previous pig runs (see Figure 10) can be used to train classification algorithms. Imposing post-classification selection criteria such as acceptable direction and speed bounds can be used to reject events such as cars traveling on roads parallel to the pipeline right of way.

The flow of fluids in pipelines creates an acoustic signature which varies with changes in operational parameters such as flow rate, pressure, and density. The estimation of these operational parameters may be accomplished using regression analysis. Independently measured operational parameters (for example data recorded from flow and pressure meters), can be correlated to the acoustic data collected using fiber optic sensors (see Figure 11). The regression equation can subsequently be used to predict future operational parameters from the acquired acoustic data.

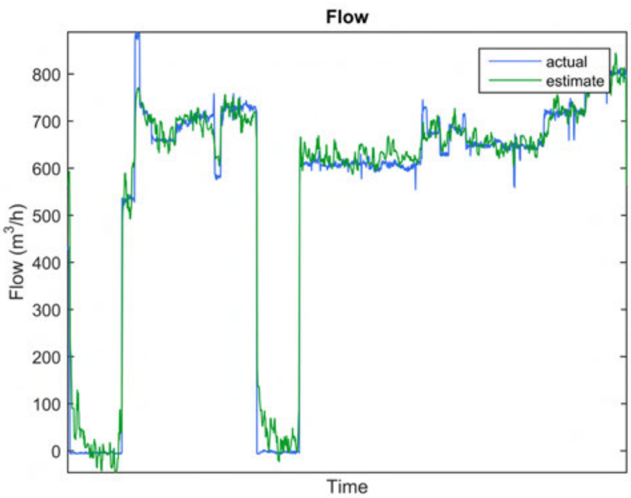


Figure 11 - Flow estimation using fiber optic data

4. USER INTERFACE

A well designed and intuitive user interface is an important component of all critical asset monitoring systems. As the majority of pipeline control room operators are preconditioned to SCADA-based alarm interfaces, it's imperative that the fiber optic monitoring system's user interface be designed in such a way that feels intuitive and familiar to the users. While there are many benefits to making a feature rich UI, it's best to create layered designs with different features targeted to the different client personas. For instance, UI features targeted to control room operators must minimize the usage of bright colors unless they're used to indicate alarms. Similarly, due to the fast paced nature of control room operations, informational and non-actionable notifications must be suppressed.

For non-control room operators such as integrity managers, the UI design can incorporate more long term information that may be of a preventative nature. For example, an integrity dashboard summarizing the number of events (real or simulated) detected to date, the calibration status of the system, etc. can be an effective way to provide insights into the readiness of the monitoring system.

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Digitalization Projects for the Oil and Gas Industry

Michael Barth > ILF Consulting Engineers

Abstract

A new wave of digitalization is made possible by the combination of exhaustive internet access, computing power and storage capacity, artificial intelligence, big data, algorithmic autonomous decision making and robotics. This ever accelerating digitalization is changing our life and the way we make business more than any other (r)evolution before. As such, it requires a change of mindset rather than just deploying new technologies.

Digitalization and the subsequent processing of the data obtained has the potential to reduce downtimes and operation costs, increase efficiency, and to create new ways of working as well as new business models. However, digitalization projects also pose some specific challenges and risks.

Digitalization projects shall be implemented following an overall strategy, which needs to be reviewed, adopted and improved regularly to account for a rapidly changing environment. In order to successfully implement a digitalization project, sufficient knowledge about the new technologies, business models, as well as safety and cyber security issues related to extended data communication and the "digital twin" are required, to name just a few.

Once the objectives of the digitalization project are defined, for each individual project the required (additional) data, computing and networking resources, required service providers and contracts, organizational changes and processes have to be adapted as well as their potential impact on operation, safety and security need to be identified. These changes shall be implemented following a proven change management process for all internal processes of the company, once they have successfully passed the cost benefit analysis.

The very different aspects of developing and implementing digitalization projects and a possible methodology are subject of this paper and the respective presentation.

1. INTRODUCTION

Digitalization is nothing new for the oil and gas industry. However, in recent years we saw a number of developments / trends that impact the O&G sector:

- Rapid advances in technology
- Climate change and changing customer needs and expectations
- Shorter product life cycle and aging workforce
- Increasing concerns for cyber security
- Changing communication patterns

RAPID ADVANCES IN TECHNOLOGY

Especially the ever increasing computing power (from wearables to data centers), combined with the capability to collect and store huge amounts of data which are then processed using advanced algorithms as well as new networking technologies provide the basis for further digitalization, automation and business process improvements. Latest developments like retrofit sets that add machine learning capabilities to the installed base and new machine learning techniques that enable systems to learn from a few examples make these new technologies even more attractive for the O&G industry with its large amount of legacy systems.

Networking technologies like Industrial Ethernet (Ethernet as a "Field Bus"), TSN, MPLS-TP and 5G provide the potential for implementing consistent data networking technologies meeting modern requirements for higher data rates, low latencies and high reliability from the field level up to the enterprise level while ensuring data consistency.

Virtual and augmented reality technologies provide the basis for redesigning and enhancing work flows. Robotics will change the way works will be done in harsh and challenging environments.

CLIMATE CHANGE AND CHANGING CUSTOMER NEEDS AND EXPECTATIONS

The climate change forces our society to act. Renewable energies and consequently a changing mix of energy sources, energy storage, green chemistry, advanced oil and gas exploration and recovery technologies as well as customers engaging in a sharing economy will all impact the demand and supply of oil and gas.

Especially in segments closer to retail / consumer related businesses we may even see new business models emerging and new players entering markets.

SHORTER PRODUCT LIFE CYCLE (AND AGING WORKFORCE)

Manufacturers have long since moved away from pure / simple hardware products. More and more functionality is implemented in software and increasingly will be only available if the devices are inter- connected. Today manufacturers provide end- to- end (IoT) solutions, which aim at providing business insight based on advanced data analytics.

The implementation of features in software provides on one hand for short innovation cycles and a high degree of flexibility. On the other hand this leads to a number of new challenges for operators like the need for continuous training for their employees and for continuous patching and introduces new dependencies on manufacturers and service provides.

Features that are only available when the device or system is connected to other devices or cloud services, provide added value that otherwise would be impossible while at the same time raising questions about ownership of data / information and the responsibility for any advices given by AI our automated responses initiated. Not only for operators rated as "critical infrastructure" the consequences of a certain functionality not being available may also call for an "analogue" backup or the possibility for manual intervention in case the network connectivity is lost.

Especially the short innovation cycles and emerging new technologies require a more agile approach to digitalization projects compared to what was used for traditional projects.

INCREASING CONCERNS FOR CYBER SECURITY

While in the past availability was considered the most important characteristic of OT systems, today the integrity of hardware, firmware, software, device configuration, data and communication links shall be considered as the prerequisite for the availability and proper functioning of control and safety systems. This recently again became apparent in the Triton / Trisis case, where the firmware / operating system of a safety controller was attacked by a special malware and a backdoor was implemented.

Integrity is a prerequisite for a trustworthy cooperation with suppliers, partners, service providers and customers along the entire value chain.

CHANGING COMMUNICATION PATTERNS

Technologies like interconnected devices, digital twins, autonomous vehicles etc. will also lead to an increase in machine- to- machine communication bypassing traditional hierarchies and rendering traditional business and decision- making processes ineffective. As a consequence work procedures will need to be adapted and responsibilities may need to be shifted to field staff.

2. DIGITIZATION, DIGITALIZATION AND DIGITAL TRANSFORMATION

Digitization means the conversion of data from analogue to digital for automating processes that have so far been done manually and make the digitized data easily accessible to downstream applications. It is a prerequisite for the digitalization.

Gartner defines digitalization as "the use of digital technologies to change a business model and provide new revenue and value- producing opportunities; it is the process of moving to a digital business" (Gartner, 2020).

Digitalization allows us to do things that are impossible without the data and the capability to enhance our understanding of the reality using advanced analytical algorithms, simulation and augmented / virtual reality, to name a few. An example is a safety relay of Phoenix Contact, that feeds sensor data about the performed switching operations and the environmental conditions into its digital twin. A sophisticated simulation allows then to assess the current status and the remaining life time of the relay – something no sensor could measure, enabling predictive maintenance.

This type of new capabilities and features and their impact on business processes and organizational structures is what the digital transformation is all about and what will change the way we work.

3. DIGITALIZATION PROJECTS

DIGITALIZATION AS PART OF THE OVERALL BUSINESS STRATEGY

Rapid advances in technology, accompanied by fast changing communication patterns and new cyber threats, require a more agile and flat organization. This seems to be at odds with a culture that is focused on safety and reliability.

Companies shall evaluate at least the following questions:

- Why to change / transform?
- What to change / transform? And what not?
- What are the targets?
- How to get there?
- How to measure success?

and shall integrate digitalization into their overall business strategy.

SO, WHY CHANGE?

Reasons for change include the changing oil and gas consumption, the replacement of legacy technologies with new, networked ones, the increased number of communication partners, regulatory requirements, or simply the need to reduce cost / increase efficiency, to name just a few.

WHAT TO CHANGE? AND WHAT NOT?

Digitalization can be seen as the next round in (business) process optimization based on the improved understanding of plants, their condition and performance, which in turn is fueled by additional digital data and the subsequent processing.

As there is no point in digitalizing poorly designed and inefficient processes, companies shall evaluate the current processes and performance for pain points and improvement potentials.

Process control and dispatching are only a small part of the activities an operator performs as indicated in figure 1. Increasingly the efficiency of these core processes depends on automated asset and maintenance management systems, GIS systems, and electronic document management systems, to name a few.

For example, an integration of a work permit system with the access control system and the (host- based) intrusion detection system could help to quickly verify that the works a person is performing are scheduled for the systems in question.

Such a project would require cooperation across several units, potentially breaking with traditional organizational silos. Some organizations assign the tasks related to the coordination and prioritization of such a project to a Chief Digitalization Officer.

WHERE TO START?

In a first step it shall be ensured that all required data / information is (or can be made) available either in digitized or native digital form and in the right format. The transparent integration of field devices into higher level of the automation pyramid is the foundation of many digitalization projects. In order to ensure interoperability with

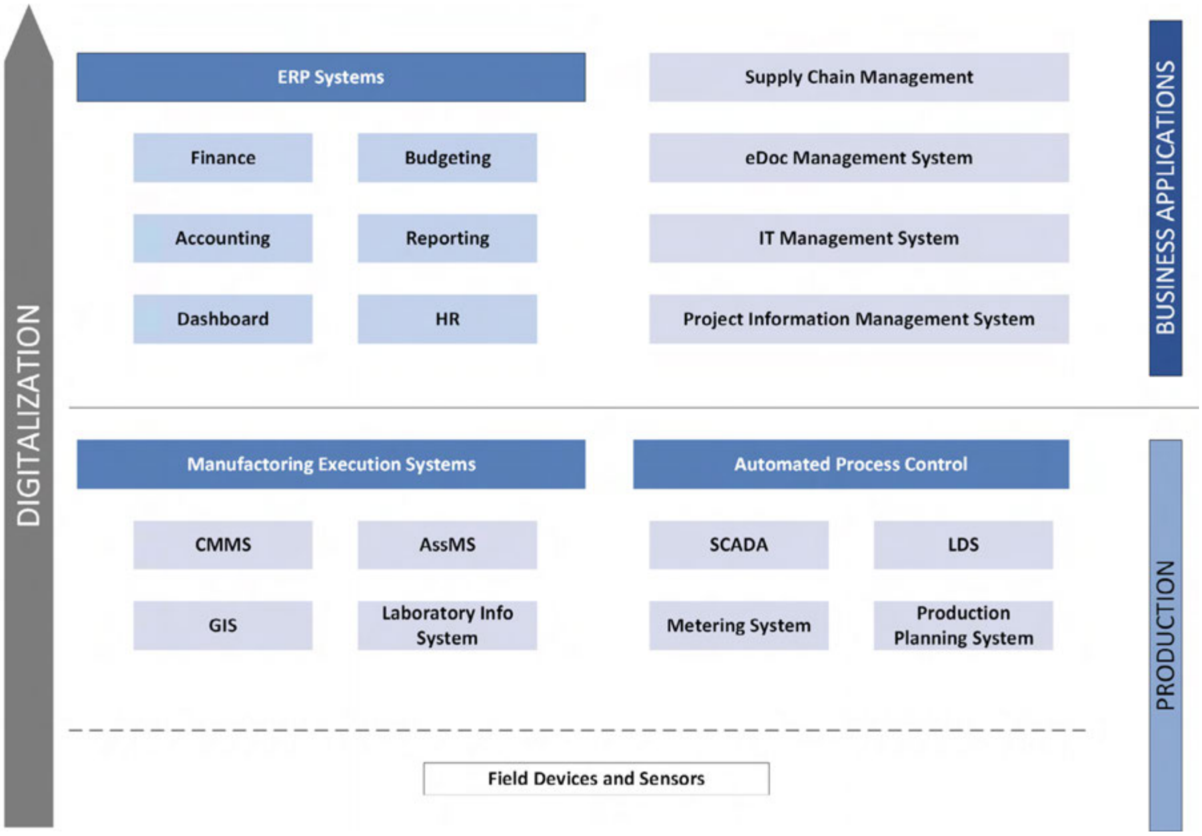

Figure 1: Typical O&G Application Landscape for Digitalization

downstream applications that will process and analyze the data and visualize the information, standardized and open communication protocols and data formats are a must.

While these requirements can be taken into consideration when (re-) designing a plant, brownfield installation typically do not have the required communication system architecture and do not provide a consistent way for integrating field devices into any higher level system.

Consequently, for digitalization projects with a focus on asset inventory, data collection for predictive maintenance, augmented reality for maintenance support etc. in a first step the capabilities of the field devices and other data sources need to be evaluated, a suitable communication system architecture needs to be developed and standard interfaces to downstream applications needs to be defined. Once these new systems have successfully passed the tests, they shall be deployed in a way that does not impact the existing process control and safety systems. The NAMUR Open Architecture provides a model for the integration of such innovative systems into new and existing plants.

Digitalization projects utilizing autonomous logistics systems, drones, robots, and providing lone worker detection, equipment tracking, mobile alarm and hazard warning systems require a complete coverage of the plant area by wireless technologies for connection to the respective high availability networks with the necessary prioritization of communication and security zoning.

LoRa and 5G networks may provide the required coverage, bandwidth, response time / latency and machine- to- machine communication capabilities.

WHAT ARE THE TARGETS?

Typical targets for operators include:

- Support workers with key information when, where and how they need it;
- Predict unexpected outages / plant shut downs;
- Integrate information from field into business processes for enhanced decision
- making; and
- Improved supply chain reliability.

HOW TO GET THERE?

Due to the ever shorter innovation cycles, emerging new products and new business models digitalization is more like a journey than a one- time project. It requires an agile project approach (like Scrum) that allows for the development of new solutions in fast(er) iterations with regular verifications of the outcome and adjustments as required.

Using some of the new technologies either requires the cooperation with new partners (e.g. cloud services providers) or developing the required skills and processes inhouse and may even require implementing / using business models that are referred to as "coopetition" – entering in selected fields of activities into cooperation or even strategic alliances with competitors to be able to leverage the potential of the new technologies.

WHAT ARE THE MAJOR CHALLENGES?

Many companies focus merely on technical challenges like implementing and securing new technologies and network topologies, and granting the required access rights to employees, partners and contractors. However, experience shows that there are three aspects that are easily overlooked: people, organizations and legal aspects.

Many (if not most) people fear fast and radical changes. At best they may simply not use the new technologies. Worst case they actively resist change, potentially rendering all the digitalization efforts in the long run useless. As a consequence it is of utmost importance to listen to employees, partners and customers and address their concerns.

The introduction of new technologies requires corresponding adjustments of organizational structures as well as inter- and intra- company processes and procedures. Production and administration will be much more closely interlinked. IT and OT are converging.

Legal aspects also play an important role in many digitalization projects. Legislation differs from country to country, services may be provided under the legislation of one country, but be used in another one. Furthermore legislation does often not keep pace with fast evolving technology.

4. ILF APPROACH

The following figure shows a high- level view of the major steps in an digitalization project and the aspects to be considered.

IDENTIFY POTENTIAL PROJECTS

Once the targets have been defined and business drivers have been identified, potential projects to address pain points, improvement potentials and new opportunities shall be evaluated.

Typical pain points include manual and error- prone processes, missing or inconsistent data preventing from further (business) process automation, inefficient business processes and organizational structures as well as the fulfillment of regulatory requirements.

At the other end of the spectrum new opportunities, e.g. for increased safety, may be identified. Increased plant coverage with wireless technologies may provide for better detection of lone workers and provisioning of real- time data to field personnel.

EVALUATE PROJECT IDEAS

In a first step requirements regarding functionality, performance, scalability, interfaces, safety & security as well as regulatory requirements shall be compiled. Based on these requirements the necessary skills, resources, partners, and suitable technologies shall be identified and legal aspects be evaluated.

VALIDATE THE BUSINESS CASE

In this step a Cost- Benefit Analysis and a risk assessment shall be performed, covering also aspects like increased system complexity, dependencies on external partners and service providers, cyber security, etc. to assign a budget and agree on a time line.

SET UP AND EXECUTE THE PROJECT

An interdisciplinary team representing all potential stakeholders and users shall be assigned to the project. Suitable solutions shall be developed and tested in a lab environment. Special attention shall be paid to O&M processes and procedures, training and documentation.

DEPLOY TESTED SOLUTION

Once the solution has successfully passed all tests, it shall be deployed in a way that ensures the integrity of the entire process control and safety systems including field devices and communication channels. This may include the use of data diodes for extracting data / information for process control and safety systems in a secure way, and the avoidance of wireless communication systems and technologies in safety loops.

5. CONCLUSIONS

The ongoing digitalization provides new possibilities to improve operation and safety, but also creates a need to closely monitor market and technology trends. To reap the benefits of the new technologies, companies need to build up new skills, use a more agile approach than in the past for the process control and safety systems, and adapt processes and even the organizational structure.

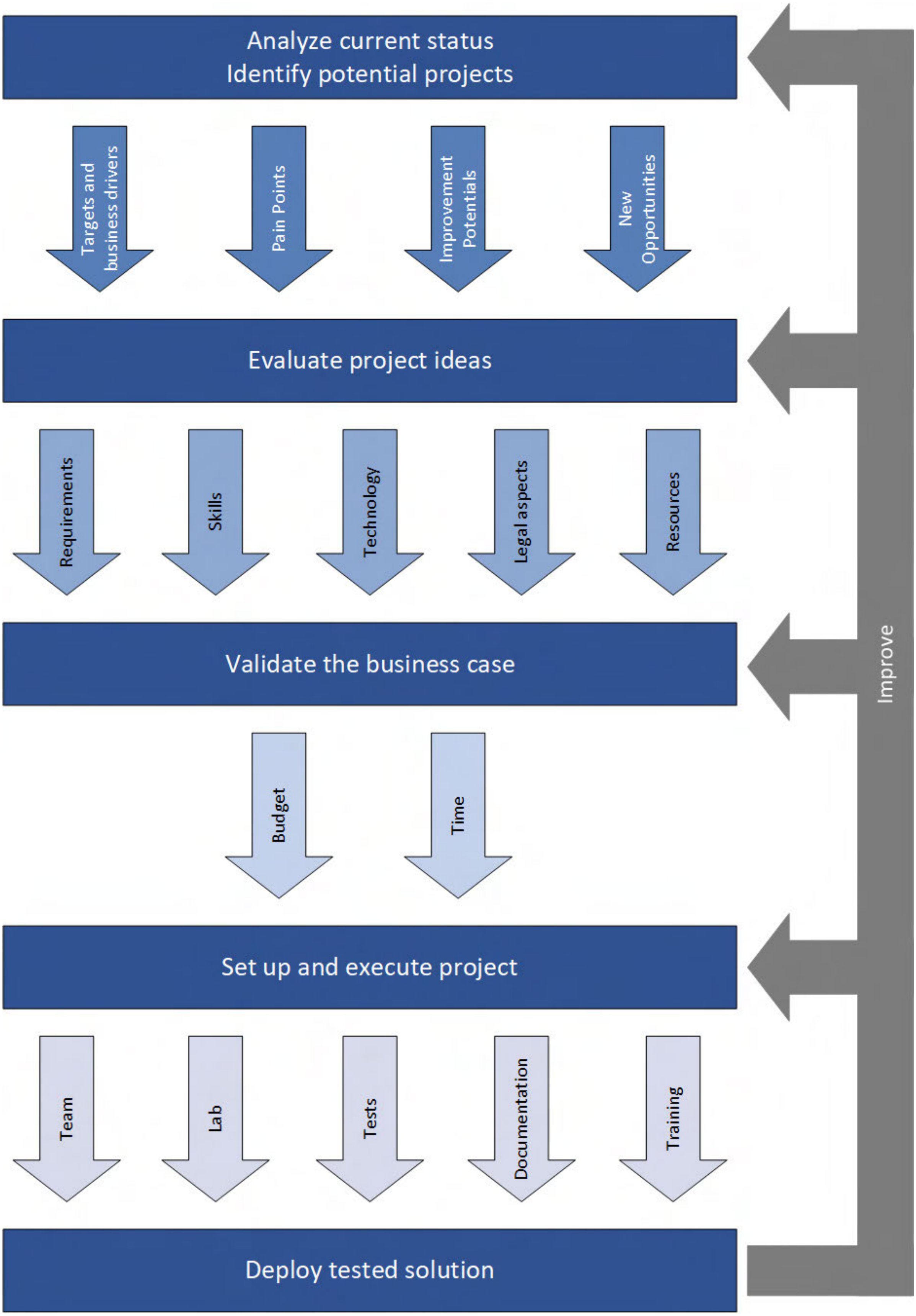

Figure 2: ILF Approach to Digitalization Projects

6. ABBREVIATIONS

5G	Fifth generation mobile network
AI	Artificial Intelligence
IoT	Internet of Things
LoRa	Long range wireless RF technology
MPLS- TP	Multi- Protocol Label Switching – Trans port Profile
OPEX	Operational Expenditure
OT	Operational Technology
TSN	Time Sensitive Networking

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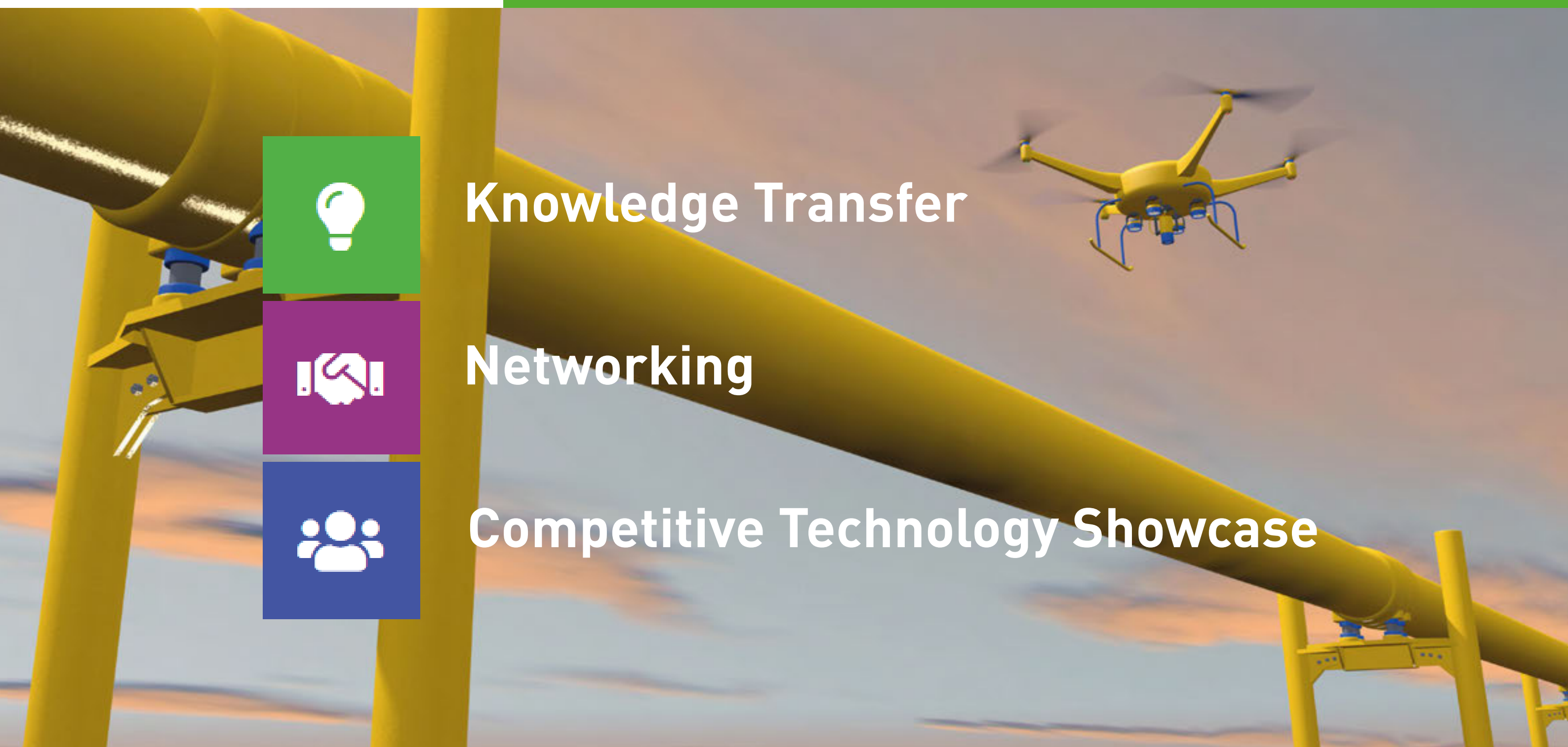

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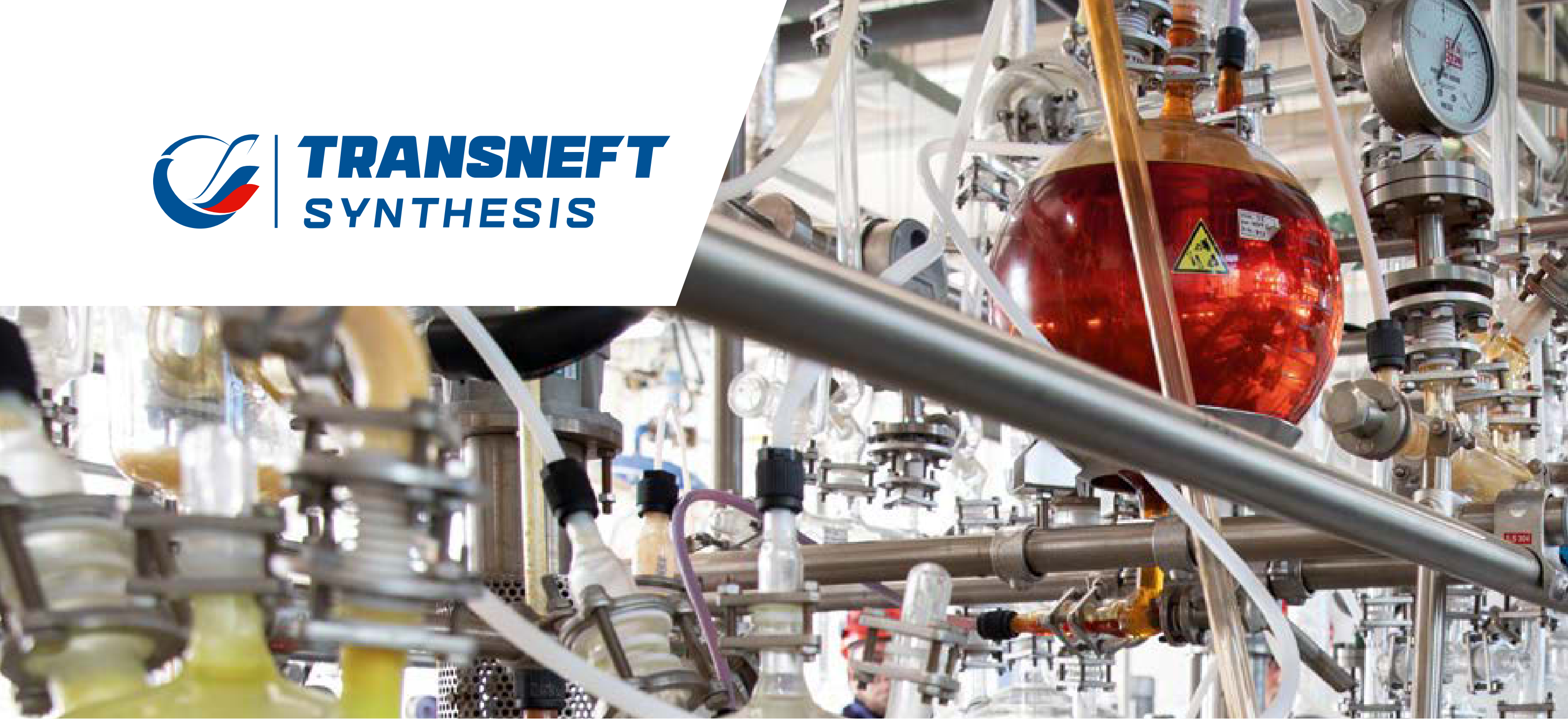

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Design of tanks’ foundation and onshore pipeline against earthquakerelated geohazards in a coastal area in Northern Greece

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National Technical University of Athens; Geoserton Hellas SA; Pipeserv LtD; Korros-E

Abstract

The design of coastal oil and gasoline tanks along with interconnected onshore and offshore pipeline in an area that is characterized by very loose to loose granular and very soft to soft clayey soils, high water table and moderate or high seismicity will be much more demanding and challenging, since various issues are directly or indirectly associated to (a) settlements over time and (b) a potential earthquake. The current paper aims to illustrate the following main topics: (a) estimation-calculation of settlements and their consolidation time and (b) earthquake-related geohazard and soilstructure interaction that have to be coped with for the proper design of tanks’ foundation as well as pipelines in a coastal area at Northern Greece. As a consequence, the main earthquake-related geohazards that are present in the study area are briefly presented, such as seismic wave loading, active-fault rupture, and soil liquefaction phenomena. Emphasis is also given to the numerical simulation of the static and dynamic interaction between the pipeline and the surrounding soil as well as the foundation type and the soil underneath. Since foundation soil will lose its shear strength during an earthquake, specific mitigation measures are proposed. These measures may also be adopted in the case of excessive pipeline distress.

1. INTRODUCTION

The soil improvement of soft clayey soils with preloading is a very efficient method in order to reduce settlements and to safely transfer loads from various projects to foundation soil. On the other hand, in the case of a moderate to strong earthquake in areas where the water table is very close to the ground surface and the subsoil consists of very loose granular soil, earthquake-triggered liquefaction phenomena potentially could occur.

At the present paper a methodology is developed taking into consideration the previously adverse geotechnical conditions that were encountered at an oil and gas storage site in a coastal area at Northern Greece. The site consists of several tanks and onshore pipelines as well as a part of an offshore pipeline, and it was decided to upgrade the site, by constructing two additional tanks with diameter D = 34.50m and D = 26.50m respectively and upgrading the truck loading and the onshore part of the pipeline (Figures 1 and 2).

Figure 1: Satellite image of the study area

2. GEOMORPHOLOGY, TECTONICS AND SEISMICITY

The broader study area presents very low to low inclination and is a part of a big plain terrain. As a consequence many rivers are crossing the area, while at the vicinity of the site there is a river delta, while there are many lagoons which denote recent sedimentation activity (Figure 1).

At the wider area and during Neocene, the basins of Anthemounta, Axios and Mygdonia have been formed, due to tensile stresses that were prevailing in that time. Therefore, many faults have been formed during geological ages with E-W and NW-SE direction (Figure 3). Some of them are characterized as seismic active, such as Anthemounta and Pylaia faults etc. Close to the study area a normal fault with ESE-WNW direction, B1100 strike and transition to the SSE has been recognized through geophysical investigations (Figure 3).

Although this fault can't be documented through satellite images, its length is estimated at six kilometers. It is regarded as active since (a) it is oriented to the contemporary stress field and (b) it is affecting Quaternary sediments. Moreover, Zervopoulou (2010) estimated through empirical equations that a potential fault rupture could lead to earthquake with magnitude of 6R, while its mean vertical displacement could be 28cm and the mean displacement could be 21 cm.

Figure 2: Closer view of the study area

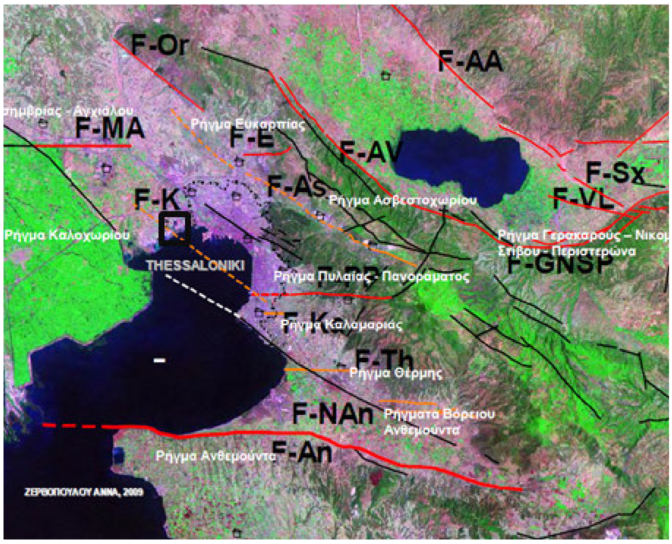

Figure 3: Satellite map of the wider area (red lines represent active faults, dashed lines represent probable fault extension)

Regarding seismicity Zervopoulou (2010) refers that there are three main periods with earthquake events during 20th century (Figure 4).:

The first period from 1902 to 1905 started with an earthquake with magnitude of 6.6R in 1902 at Assiros and ended at 1905 with an earthquake of 7.5R at Athos peninsula. The second period from 1931 to 1933 started with an earthquake with magnitude of 6.6R in 1931 at Northern Macedonia and ended at 1933 with an earthquake of 7.0R at Ierissos.

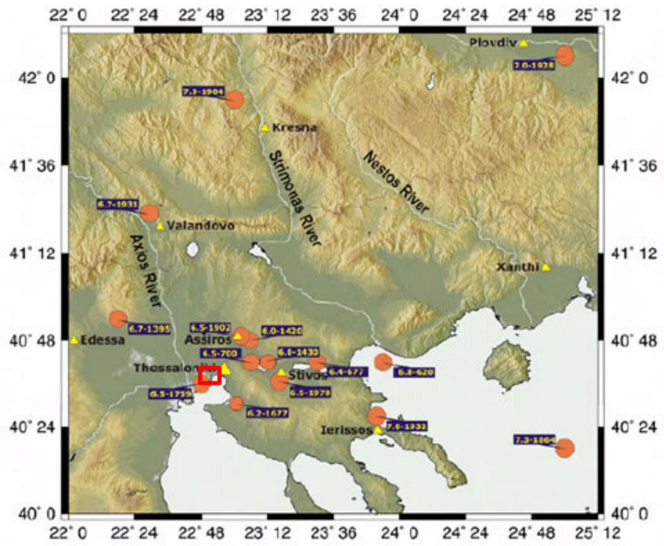

Figure 4: Epicenters for main earthquakes for the three periods of seismicity (close to study area).

The last period at 1978 had an earthquake with magnitude of 6.5R and epicenter at Stivos village and close to Lagada and Volvi lakes (Figure 4).
Finally Figure 5 presents the earthquakes with various magnitudes recorded from ancient time to now days.

3. GEOTECHNICAL AND GEOPHYSICAL DATA

Sampling boreholes with 40m depth were executed underneath the foundation level of the tanks, while geophysical investigation was also executed in order to identify the geotechnical conditions in a wider area. The main geotechnical units are presenting hereinafter, while Figure 6 presents the typical geotechnical profile and Figure 7 presents the results from geophysical investigation.

Geotechnical Unit I: Backfill materials consisting of sand and gravels, with low plasticity.
Geotechnical Unit II: Light brown to greyish sand, poorly graded, with sub-angular
gravel and silt, loose to medium dense (SP-SM)
Geotechnical Unit III: Light brown to greyish clay of low to high plasticity, very soft to
soft (CL, CH)
Geotechnical Unit IV: Light brown to greyish sand with gravel and locally shells (SC)
Geotechnical Unit V: Light brown to greyish to bluish clay of high plasticity, stiff to very
stiff with low portion of sand and gravel.

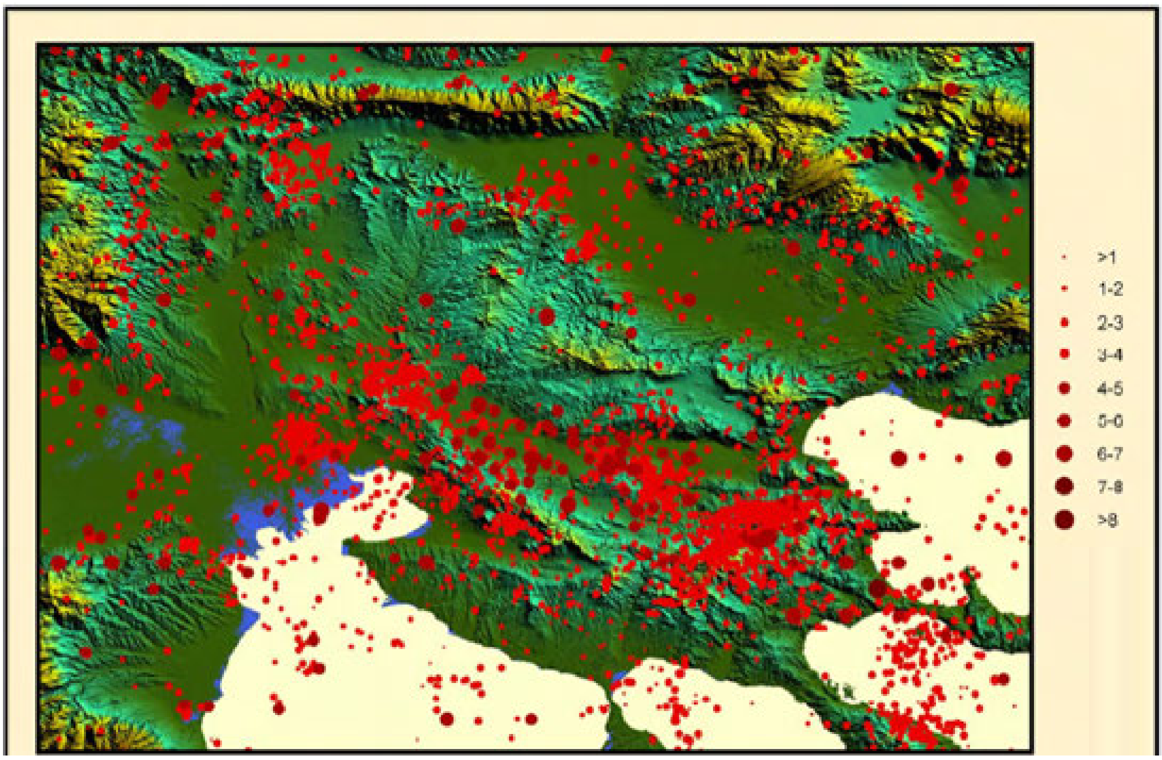

Figure 5: Epicenters of earthquakes recorded from ancient time to now days (data derived from Geophysical Laboratory of Aristotle University of Thessalonikii).


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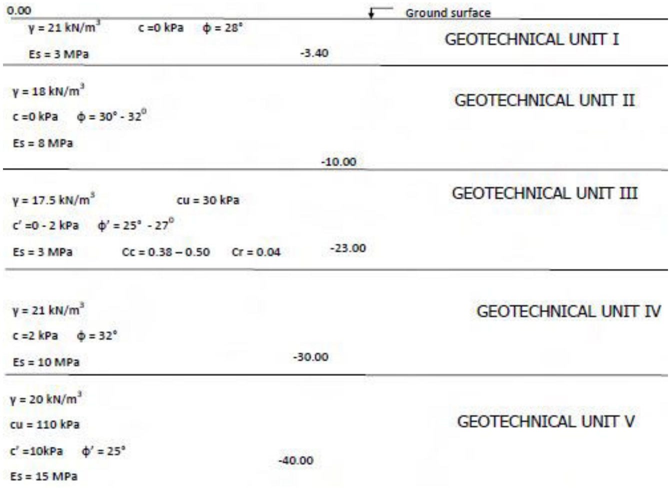

Figure 6: Typical geotechnical profile

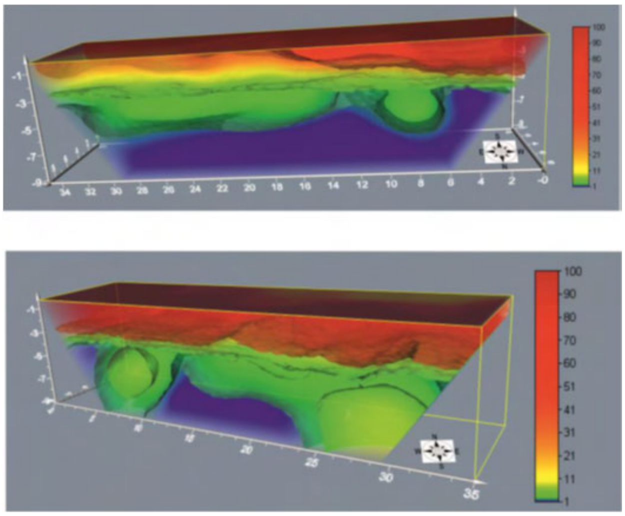

Figure 7: 3D geophysical profile for the distribution of soil resistivity

At Figure 7 the warm colors represent soil formations with high values of soil resistivity while cold colors represent soil formations with low values. The depth of geophysical investigation was ended at ten meters depth and in general is in good agreement with the findings from sampling boreholes.

According to EN1998-1 the foundation soil is characterized as soil category "D": Deposits of loose-to-medium cohesionless soil (with or without some soft cohesive layers), or of predominantly soft-to-firm cohesive soil".

4. STATIC AND EARTHQUAKE-RELATED GEOHAZARD AND THEIR IMPACT TO FOUNDATION SOIL

Taking into consideration the results from Figure 6 and that the site is located to an area which presents medium seismicity, specific studies should be executed for the structures in order to withstand (a) excessive settlements that will occur after the loading of the tanks and (b) the devastating consequences of an earthquake. The earthquake-related geohazards that could affect the site are fault rupture propagation path and soil liquefaction.

(a) Excessive settlements
The estimated stresses from the tanks at the foundation level were estimated to almost 150kPa (operational phase), while the stresses from the initial loading (hydraulic phase) were estimated to almost 170kPa. The foundation soil consists of very loose sandy and clayey formations, thus calculations for raft foundation led to settlements equal to 0.90m. The application of deep foundation could lead to reduced settlements, but their depth should be more than 35m and this foundation type might not respond appropriately during earthquake, as will be seen to the next paragraph. The use of preloading with stress equal to 170kPa is the optimum option in order to reduce settlements, but preloading doesn't affect the completion timing of settlements. This could be achieved by using vertical drains or even better stone columns. Moreover the imposing stress of 170 kPa could led to soil failure.

(b) Fault rupture propagation path and soil liquefaction.
Although a seismic potential active fault exists at the wider area of the site, as mentioned at the previous paragraphs, this was not found inside sampling boreholes, thus it was decided that the fault doesn't affect the site. During a seismic event two variables are necessary in order to evaluate the potential for liquefaction:

a. the level of cyclic stress induced by the earthquake on a sediment layer, expressed in terms of cyclic stress ratio (CSR), and
b. the capacity of a sediment layer to resist liquefaction, expressed in terms of cyclic resistance ratio (CRR).

Then the potential for liquefaction is easily evaluated by comparing the earthquake loading (CSR) with the liquefaction resistance (CRR) in terms of factor of safety (FS) against liquefaction. Values of FS (= CRR/CSR) greater than unit indicate that the liquefaction resistance exceeds the earthquake loading, and therefore, that liquefaction would not be expected. Seed & Idriss (1971) formulated the following equation for calculating CSR:

$$CSR = \frac{\tau_{av}}{\sigma'_{vo}} \approx 0.65 \left(\frac{a_{max}}{g}\right)\left(\frac{\sigma_{vo}}{\sigma'_{vo}}\right) r_d \qquad (1)$$

where
a_{max} : peak horizontal acceleration at the surface of the sediment deposit, i.e 0.16 in our case
g : gravitational acceleration,
σ_{v0} and σ'_{v0} : total and effective overburden stress, respectively;
r_d : stress reduction factor (Seed et al., 2001).

Evaluation of the cyclic resistance ratio (CRR) has been developed either using methods based on the results of laboratory tests, or methods based on in situ tests and field observations of liquefaction behavior in past earthquakes. In order to define the soil liquefaction potential, Figure 8 was used. Taking into consideration the geotechnical properties, as well as the shear strength parameters, it was concluded that the foundation soil presented liquefaction potential.

As a final result and taking into consideration the conclusions and remarks of two previous paragraphs, it was decided to use preloading along with stone columns for tanks' foundation, while for the onshore part of pipeline, the soil improvement by using stone columns along routing was selected. The diameter of stone columns were D = 0.80m, while their spacing was 1.50m in equilateral square pattern.
At the improved soil new calculations were executed and there was adequate safety factor against soil failure (Figure 9), while settlements of the improved soil were in the order of 0.40m. Finally the estimated time for the completion of settlements due to preloading was 5 months, while the remaining to their completion settlements was in the order of 0.07m.

5. PIPELINE VERIFICATIONS

The pipeline behavior should be analyzed as a typical soil-structure interaction (SSI) problem. The finite element method should be used to model the effects of ground-induced actions on a buried pipeline. Typically, the soil compliance around the pipeline is usually represented by four translational bilinear soil springs at all directions (see Figures 10 and 11).

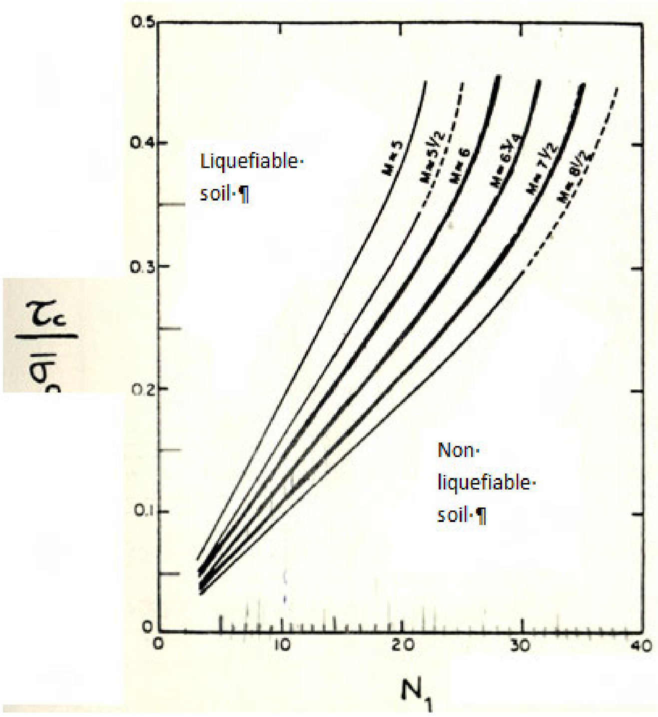

Figure 8: Chart for soil liquefaction potential.

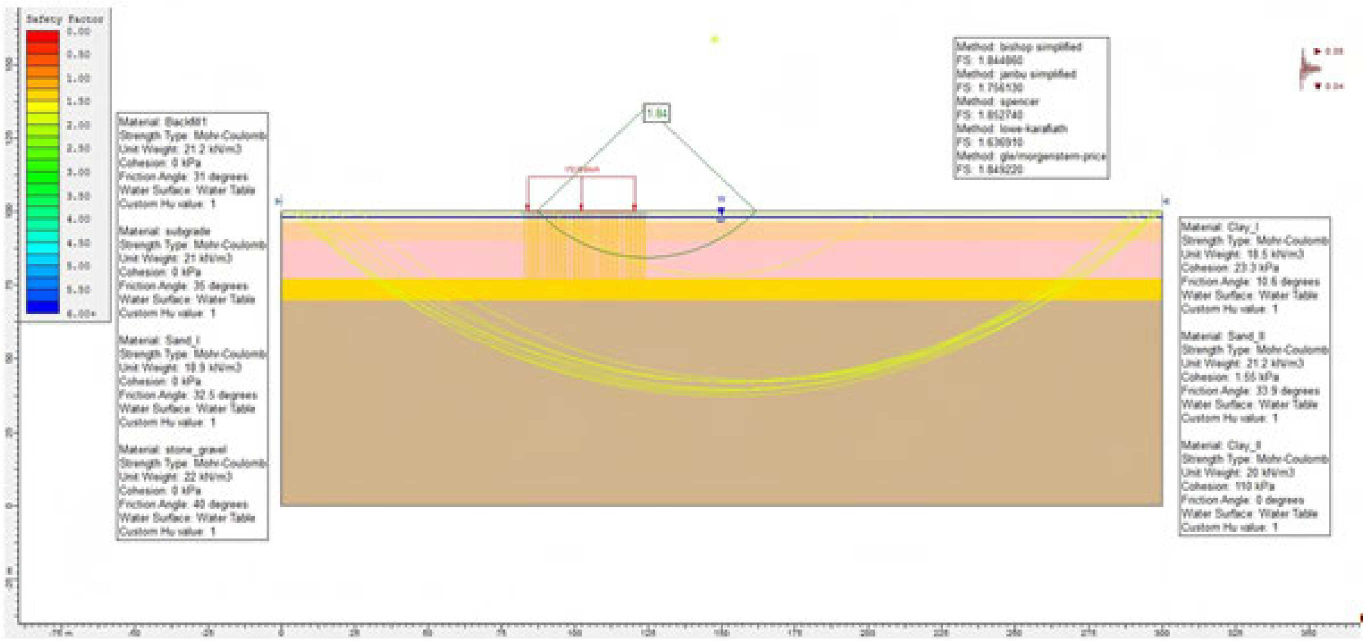

Figure 9: Overall stability of improved foundation soil (seismic conditions).

Soil spring forces F and the corresponding mobilizing soil displacements δ can be calculated according to ALA (2002) for the four soil springs. It is evident that during an earthquake some of these springs present forces F almost equal to zero, in case of soil liquefaction, thus the results of the analyses should met the limit states of the pipeline that refer to two (2) main failure modes and specified in EN 1998-4 standard, namely:

1. Pipe wall fracture due to excessive tensile strain (both base material and weld material in butt-welded joints)
2. Pipe wall local buckling due to excessive compressive strain Those failure modes are quantified in EN 1998-4 standard in terms of axial strain (i.e. strain in the longitudinal direction of the pipe).

6. CONCLUSIONS

Undoubtedly, southeastern Europe and especially Greece is located in a complex geological environment. As a result many geohazards under static and seismic conditions are present. In this paper, we present a case study for tanks' foundation in Northern Greece. The study area is located in deltaic formations and the water table was found only 1m below ground surface. Additionally, the wider area presents low to medium seismicity as a result of seismic fault action. A geotechnical along with geophysical investigation was executed which reveal that the foundation soil consists of very loose granular to very soft clayey material. The bedrock (i.e. marly Neogene formations) was encountered at least 35 m below ground surface. Since the main geohazards were: (a) excessive settlements – almost 0.90m - under operation loading and (b) potential liquefaction for almost 15 m depth below ground surface, it was decided to increase the shear strength of foundation soil, by using stone columns along with preloading. The diameter of stone columns were D = 0.80m, while their spacing was 1.50m in equilateral square pattern. The improved soil is expected to present less settlements, almost 0.40m, while their completion is expected in less than 5 months.

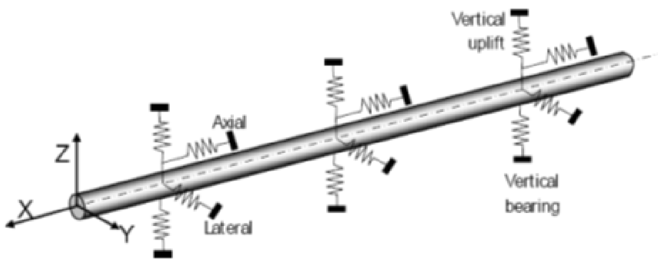

Figure 10: The four springs around the pipeline representing the soil compliance

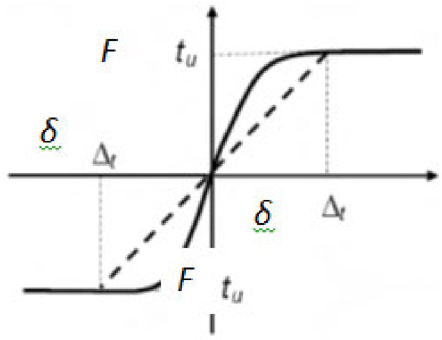

Figure 11: Idealized representation of the bi-linear soil springs

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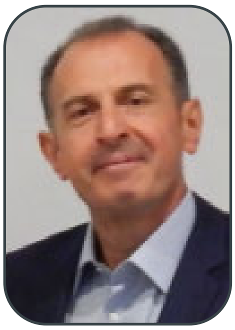

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Multidisciplinary landslide assessment – a systematic and practicable approach for pipeline projects

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Abstract

Ground movements, with the clear majority being landslides, have caused several pipeline incidents worldwide in recent years. This, and experiences obtained from major engineering projects, shows that a systematic approach for the assessment of landslides is essential. A best-practice multidisciplinary workflow, based on detailed terrain analyses, has been applied in recent projects, each comprising a large variety of landslide assessments. The suggested approach is based on detailed landslide inventory databases and maps, susceptibility analyses, as well as landslide hazard assessments and risk classifications. The outcome of this workflow is a project-specific landslide priority register, which provides a sound basis for decision-making, for planning hazard management and for assessing the potential costs and losses caused by landslide-related pipeline damages.

1. INTRODUCTION

Due to their large spatial extents, pipeline corridors often cross areas characterised by adverse geotechnical conditions and by a variety of natural hazards. The assessment and management of geological hazards, such as earthquakes (ground shaking, fault ruptures and secondary phenomena such as liquefaction, subsidence and landslides) as well as gravitational hazards (landslides) are thus of major importance for the successful design, construction, operation and maintenance of pipeline systems (see Sweeney 2005, Baum et al. 2008, and references therein).

According to the 10th Report of the European Gas Pipeline Incident Data Group, different types of ground movements have been responsible for approximately 15% of pipeline incidents observed during the last 10 years. Among these, the clear majority of incidents were related to landslides (depending on the period considered, approximately 65-90% of ground movement incidents related to landslides, EGIG 2018). Pipeline exposures, ruptures and shutdowns resulting from landslide events are global phenomenona since they occur in different geological settings (see e.g. Geertsema et al. 2009, Hählen 2010, Lee et al. 2016, and references therein).

The term "landslide" may be briefly defined as "a movement of a mass of rock, earth or debris down a slope" (Cruden 1991) but comprises a large variety of different gravitational slope processes characterized by different types of materials, movements, geometries and status of activities. In view of this complexity, several international publications and guidelines for landslide hazard/risk assessment and management have been established (see Section 7 References). However, putting clear numbers to landslide hazard and risks still remains challenging because of the heterogeneity of site-specific geological settings, often poorly known to unknown geotechnical and hydrogeological landslide parameters (such as slope deformation activities, residual shear strength and pore pressures) and behaviour under varying external conditions (e.g. site-specific groundwater conditions and seismic events) as well as often poor information concerning potential first-time slope failures.

This and experiences obtained from major engineering projects show that multidisciplinary approaches are essential for successful landslide assessments and for the design of appropriate mitigation measures. A best-practice workflow to deal with landslides along pipeline corridors, which has been applied in recent projects (each comprising a large quantity and variety of landslide assessments), is presented here. The suggested workflow is based on systematic terrain analyses comprising of i) compilations of landslide inventories, ii) susceptibility analyses of terrain units, and iii) landslide hazard assessments and risk classifications. The outcome is a project-specific landslide priority register, which provides a sound basis for decision-making when defining hazard management, monitoring and maintenance plans.

2. LANDSLIDE INVENTORIES

2.1. GENERAL

Landslide inventory databases and maps document the landslide features and different descriptive landslide parameters in a project region. A comprehensive inventory dataset is a fundamental input for route optimisations (for example to avoid landslides to best possible extent) and for further landslide investigations (susceptibility, hazard and risk analyses). Most commonly, qualitative (heuristic) approaches are used for landslide analyses, since quantitative (probabilistic) approaches require an increased amount and higher quality of input data (e.g. multi-temporal assessments and monitoring of landslide features, as well as hydrogeological and hydrological parameters). Empirical heuristic inventory maps depict the actual status of existing landslides, and thus enable identification of critical pipeline sections where further steps such as rerouting (to avoid certain landslide features), technical measures (removal and/or stabilisation of instable materials) or acceptance/monitoring may be required. However, these inventories do not provide information on future landslide activities or potential first-time failures (triggered e.g. by earthquakes, rainstorms or construction works). In this regard, susceptibility maps based on weighted statistical parameters are helpful indicators for landslide-prone pipeline sections (see Section 3).

For a comprehensive landslide inventory (and subsequent hazard/risk analyses), the following characteristics (attributes), at least, should be documented systematically:

- Location (from pipeline KP - to KP, and location relative to the pipeline e.g. above, below, left/right lateral or atop centreline);
- Morphological setting (e.g. ridge geometries, longitudinal or side slopes, gully features, etc.);
- Types of landslide features (scarps, tension and shear cracks, gully head instabilities, toe bulges, source, transit and/or accumulation areas, etc.); important differentiation shall be made between displaced materials with potential for reactivations and "stable" features (e.g. ancient debris fans, rock fall deposits);
- Engineering geological classifications of materials (soils, rocks, rock masses incl. major discontinuities) according to international standards;

- Type of movements (fall, topple, slide, flow, spread, or complex), classification according to terminology by Cruden & Varnes 1996 and Hungr et al. 2012;
- Landslide depth (shallow, medium, deep seated; using different categories of depth classifications provided in literature), based on subsurface investigation/monitoring data and/or subjective ratings based on field observations;
- Status of activity (active, inactive, reactivated, stabilised, etc.) according to terminology given in Turner & Schuster 1996, based on monitoring data and/or subjective ratings based on field observations; plus information on whether first-time failures or reactivated features, date/time of historic events, and whether constantly (e.g. creeping some mm/cm per year) or episodically active with increased displacements (e.g. some cm/dm per months, accelerated/triggered for example by snowmelt, intense rainfall and/or earthquakes);
- Hydrogeological setting (qualitative and/or quantitative information concerning groundwater observed and/or inferred, seepage, sinks, etc.);
- Distance/proximity of landslide features to pipeline centreline, including information on whether features (cracks, displaced ground) are observed atop and/or behind pipelines (i.e. potentially retrogressing landslides which may affect pipe integrity);
- Pipeline depth of cover (relevant regarding depth/thickness of landslide materials, potential failures of loose fill materials, etc.);
- Information on geotechnical surveys and tests (trial pits, boreholes, field and laboratory tests, landslide monitoring points etc.).

Further information for example volume estimations and potential triggering factors (rainfalls, earthquakes, man-made etc.) should be considered at least for the construction works, operation and maintenance (as part of a multi-temporal landslide inventory, i.e. living database covering the considered project lifetime). In order to provide an improved inventory mapping and classification, for regions characterised by complex landslides or landslide clusters it is often not reasonable to map "simple" boundaries of the overall landslide bodies (i.e. the enveloped area representing a spatially "homogeneous" hazard class polygon), but rather to differentiate between individual sub-features characterised by spatially and/or temporally variable deformation behaviour and individual hazard potentials (see e.g. Zangerl et al. 2019).

Comprehensive and high-quality landslide inventories may be obtained from various sources and by using different methods (e.g. Baum et al. 2008, Highland & Bobrowsky 2008, AGS 2007, Guzzetti et al. 2012, and others), mainly from analyses of various archive data and from geological field mapping campaigns (see below).

2.2. DESK STUDIES AND DATA ANALYSES

Comprehensive compilations and analyses of available archive data (desk studies) are essential for high-quality landslide inventories. Alongside existing engineering geological and landslide maps, visual geomorphological analyses of various remote sensing data are a major source of information for identifying and mapping landslides. Especially in early project stages, aerial photographs and ortho-corrected optical satellite imagery are fundamental for landslide inventories. However, quality of the outcome of such desk studies strongly depends on image and terrain characteristics, such as spatial resolution, illumination, clear ground view, whether open land or covered by ice, snow and/or vegetation. In advanced project stages and for photogrammetric monitoring purposes, high-quality imagery, acquired specifically for the project, is required. Multispectral imagery (e.g. Landsat data) can further contribute to the mapping and classification of terrain units including landslide features, but are often not available in adequate high spatial resolution.

More detailed information on terrain morphology and landslide features can be obtained from high-resolution topographic LiDAR (light detection and ranging, synonym laser-scanning) survey campaigns. For linear pipeline projects, airborne laser-scanning (ALS) is an ideal and powerful tool to survey larger areas. Similar to aerial photographs, ALS surveys can be performed using manned aircraft or unmanned aircraft vehicles (UAV). In contrast, ground-based terrestrial laser-scanning (TLS) is limited to surveying and monitoring selected critical sites. Laserscan technology permits a detailed, area-wide and three-dimensional survey of terrain surfaces.
LiDAR 3D point cloud data and processed derivatives such as digital elevation models (DEMs), contour lines, hillshade images and classified slope inclination maps provide crucial information on terrain characteristics. In contrast to optical imagery, where terrain features may be shielded by vegetation, vegetation features can be extracted from the LiDAR point cloud data, enabling critical features (such as landslides, erosion, sinkholes, etc.) to be clearly identified and mapped.

Multi-temporal differential LiDAR data provide evidence of whether landslide features have been pre-existing, or related to specific events (like earthquakes, rainstorms, etc.) or construction works, and also enable the quantification of landslide mass wastes and accumulation (Figure 1) as well as of construction-related earth works (determination of cut and fill volumes). In addition, multi-temporal point cloud data can provide information on 3D displacement vectors (to as resolution of some dm), meaning that 3D survey can be performed and monitoring data be gathered without direct site access being required (Fey et al. 2015, Pfeiffer et al. 2019).

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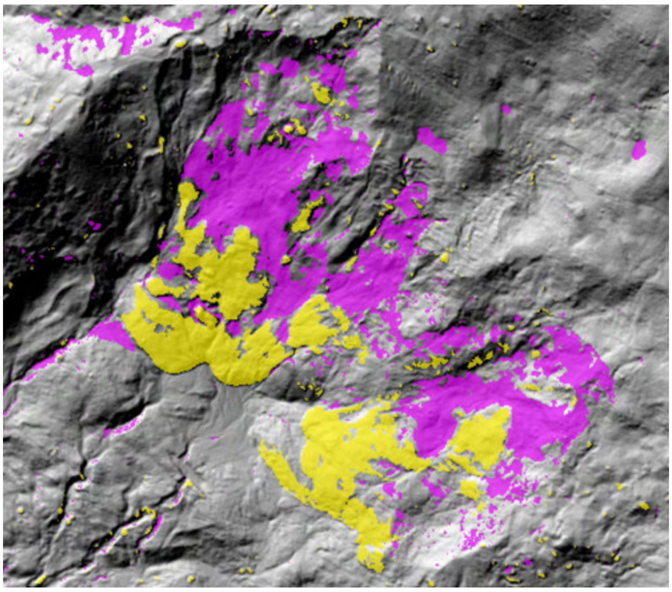

Figure 1: Differential ALS hillshade image depicting quantified landslide mass wastes and accumulations. Magenta: source areas with negative vertical displacements (terrain subsidence -0.5 to -2 m). Yellow: positive vertical displacements (uplift +0.5 to +2 m) due to mass accumulations.

Further information on terrain (in-)stability can be derived from satellite-borne interferometric synthetic aperture radar (InSAR) data (e.g. Rott & Nagler 2006). Multi-temporal radar images cover large areas (up to hundreds of km2) and can provide information on locations and amounts of ground deformations (landslide and earthquake displacement maps; see Figure 2).

Major advantages of InSAR analyses are i) the high resolution of data, which enables detection of very slow landslides with displacements of some mm-cm/year, and ii) the amount of archive data, which now cover several years of earth observation and thus enable retrospective monitoring of large project areas and critical sites (Prager et al. 2009, Intrieri et al. 2018). However, limitations for InSAR techniques are given by topographic settings (slope aspect and steepness, as well as shading effects, etc.) and by snow, ice and/or high vegetation cover.

In addition to analyses of remote sensing data, various other archive data sources including geodetic surface monitoring data, geotechnical subsurface monitoring data, historic chronicles of events, personal information from local residents and others such as radiometric age dating data can contribute to landslide inventories. Age dating data can provide crucial information for differentiating between landslide and non-landslide deposits (e.g. between earthflow or rock avalanche deposits and glacial till) and may form a basis for the establishment of landslide chronologies and time-series for hazard assessments (concerning recurrence intervals, frequencies, and failure probabilities).

2.3. GEOLOGICAL FIELD INVESTIGATIONS

Geological field investigations comprise the assessment of lithological, structural, geotechnical and hydrogeological characteristics of landslide areas. The respective information can be obtained from field mapping campaigns, field measurements and subsurface investigations (trial pits, boreholes including in-situ tests and monitoring). Detailed lithological mapping of landslide source and accumulation areas can enable a correlation of geological units and materials, and thus provide crucial input for process analyses (e.g. of landslide mechanics and deformation/runout behaviour, if single or multiple landslide events, etc.) (e.g. Prager et al. 2009, Dufresne et al. 2016).

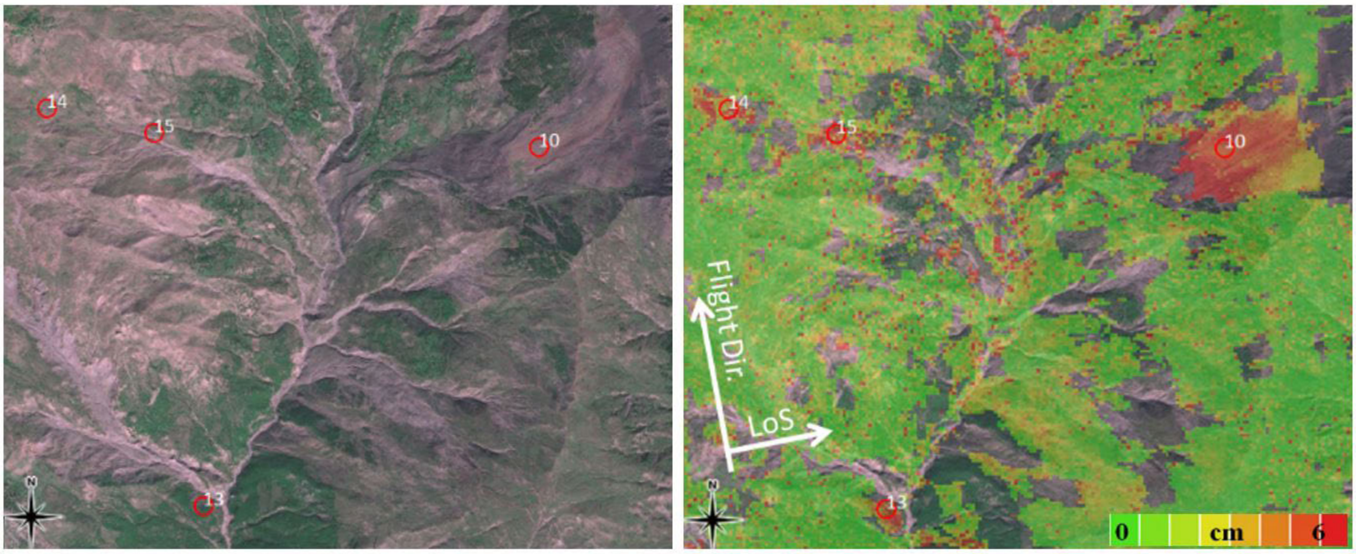

Figure 2: Landslide-prone badland terrain captured as an optical satellite image (left) and InSAR displacement map (right, calculated by Enveo Ltd. from ALOS PalSAR L-band 23cm, dates 2007-2008) showing stable and/or insignificant terrain units (green) and displaced ground (orange to red, i.e. erosion features and active landslides; red circles indicate major displacements of up to 6 cm/year).

Findings from field mapping campaigns should be digitally recorded e.g. by using tablet-borne software applications. This enables offline navigation and waypoint mapping (including relevant site-specific information) using various kinds of project-specific information and maps (such as topographic maps, optical and LiDAR imagery, pre-assessed landslide features, pipeline centrelines, KPs, etc.).

In order to assess structural and geotechnical field parameters for landslide analyses and planning of mitigation measures, geological and geotechnical field measurements (spot measurements) are to be performed at representative outcrops in accordance with international standards and guidelines. This comprises measurements of the spatial orientations of exposed main discontinuities (stratification or bedding planes, major fractures, etc.), the assessment of engineering geological rock mass parameters, and performing geotechnical field measurements in soils and weak rocks.

Based on the findings from geological field surveys, detailed geotechnical subsurface investigations (trial pits, rotary core drillings including in-situ tests, and geotechnical lab analyses) may be required at selected landslide locations. The geological profiles obtained therefrom can provide evidence of displaced materials e.g. varying degrees of weathering/disintegration and/or sheared soils/rocks. Equipped with groundwater standpipes or inclinometer, borehole locations can also yield essential monitoring data concerning time-dependent landslide behaviour and for hazard assessments.

3. LANDSLIDE SUSCEPTIBILITY ANALYSES

Landslide susceptibility analyses (LSA) based on weighted statistical parameters represent a powerful tool for assessing sections of landslide-prone terrain (potential first-time failures) and for subsequent hazard evaluations. The required input data comprise a variety of field information (lithological, geotechnical and geomorphologic terrain units/maps, landslide inventory, man-made deposits, etc.) as well as different high-resolution remote sensing data. The main relevant geo-information includes data derived from digital elevation models (e.g. slope inclination and aspect, altitude or terrain curvature, topographic position index TPI, watersheds and stream networks, etc.), and multispectral imagery (such as land use classifications, normalized density vegetation index NDVI) (van Westen et al. 2008, Corominas et al. 2014, and references therein).

LSA can be performed using qualitative and/or quantitative approaches (Chae et al. 2017). Qualitative or knowledge-driven (empirical) methods are based on weighting of predisposing factors by experts, and therefore may involve a considerable degree of bias (due to the subjectivity of experts' ratings). In contrast, quantitative methods are based on physical process analyses or data-driven analyses (statistical relationships between predisposition factors and landslide occurrences). Physically-based approaches (e.g. infinite slope models, 3D runout analyses) are generally complex and computationally intensive, and thus preferentially applied to individual slopes or rather small areas. Data-driven approaches, on the other hand, can be used to cover large regional extents (pipeline ROWs) and provide a sufficient statistical robustness for the large amount of input datasets. Besides, several data-driven models can be easily implemented in a Geographic Information System for further data processing.

In view of this, data-driven bivariate statistics are commonly applied for large-extent pipeline corridors. Using bivariate methods, statistical relationships between known landslide locations and various terrain factors that potentially contribute to landslides can be analysed (e.g. slope geometries, soil/rock properties, drainage patterns, fault vicinity, man-made cuts or fills, etc.). Thus, a practicable workflow using a combination of two methodologies, namely Frequency Ratio (FR) and Weight of Evidence (WoE), has been established, which provides a satisfactory compromise between computational effort and predictive power of results.

For both approaches (FR and WoE), each input factor is categorised into a set of classes (based on literature reviews and expert knowledge) and tested for its spatial relationship with the landslide inventory. Both approaches allow the calculation of the probability of landslide occurrence, i.e. landslide susceptibility index (LSI) as a measure for identifying landslide-prone locations (see Figure 3) (Bonham-Carter 1994, Bonham-Carter et al. 1989, Lee & Choi 2004). For reasons of comparability, the predictive power of results is verified by computing the receiver operating characteristic (ROC) curves and the area under the curve (AUC) values (Chung & Fabbri 2003). The full model workflow can be implemented in ArcGIS 10.6 by using the spatial analyst extension and the ArcSDM toolbox for WoE.

4. LANDSLIDE HAZARD ASSESSMENTS

Natural hazards may be defined as "the probability of occurrence within a specified period of time and within a given area of a potentially damaging phenomenon" (Varnes & IAEG 1984). Landslide hazards may be defined as the probability of slope failure, which can be statistically assessed based on geotechnical parameters and/or empirically based on expert judgements (Turner & Schuster 1996). This implies the magnitude of landslide events (destructive power) within a given area (geographic locations of landslide occurrences) and given period (temporal frequency of occurrence and recurrence) (Guzzetti 2006, AGU 2007).

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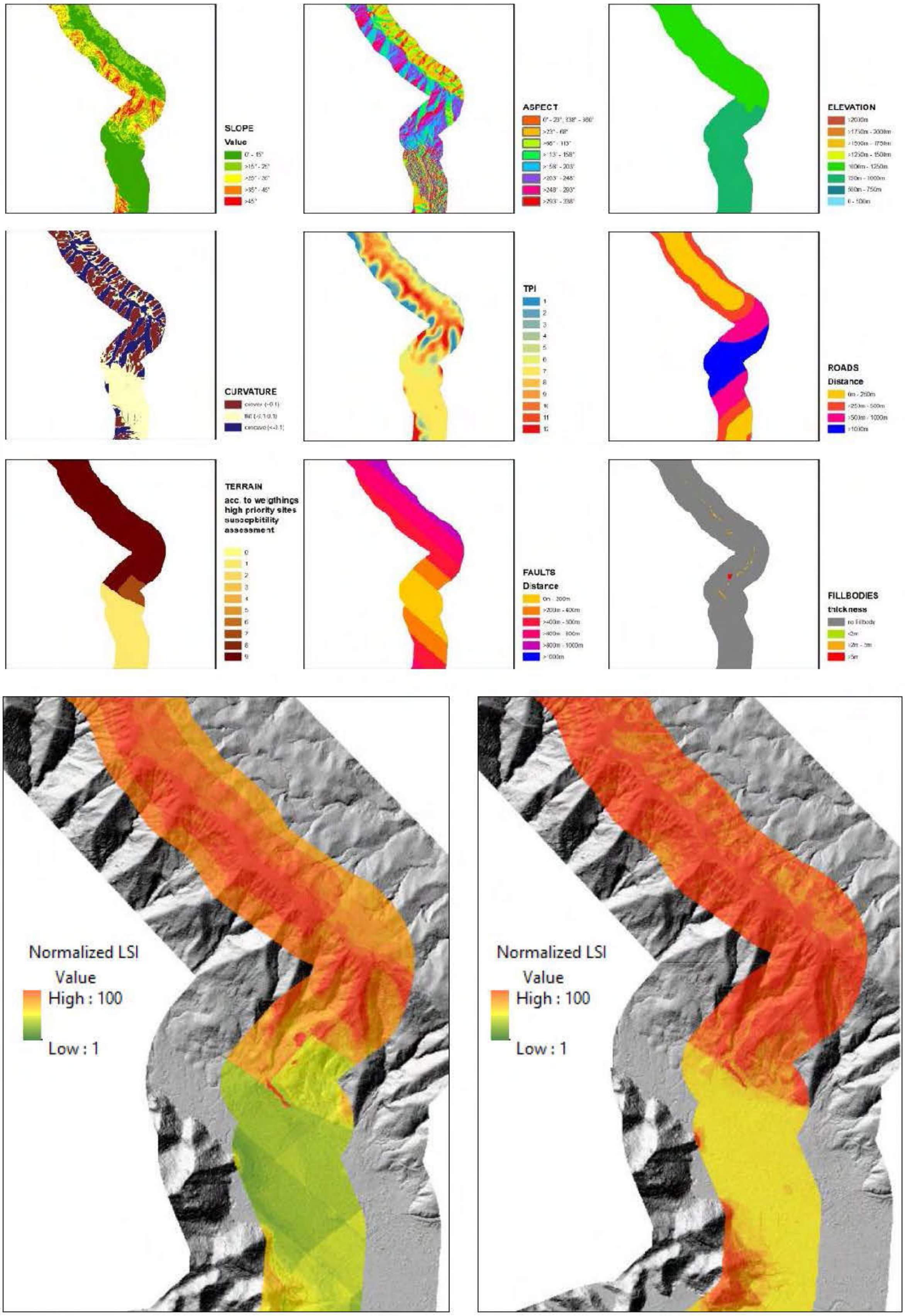

Figure 3: Exemplary landslide susceptibility maps depicting a normalised landslide susceptibility index LSI calculated using the FR (figure lower left) and WoE approaches (figure lower right). Both computed models based on selected input parameters (smaller figures above, e.g. slope characteristics, TPI, buffer distances to road cuts and faults, expert judgements of soil/rock characteristics).

In general, for landslide hazard assessments different approaches may be required: i) site-specific geotechnical slope stability analyses, ii) comprehensive regional (ROW) analyses and iii) runout studies for rapid landslides (on individual local and/or regional scale). The locations, stability conditions and expected magnitudes of landslides can be obtained from detailed inventory data (including geotechnical and geodetic surface and subsurface information) and susceptibility analyses (see above).

Area-wide hazard maps related to the failure (release) of landslides can be assessed using probabilistic and deterministic approaches. Probabilistic landslide hazard maps show the spatio-temporal probabilities of landslide occurrence (in the range 0-1). Deterministic landslide hazard maps delineate between hazard areas and non-hazard areas (showing a factor of safety or landslide depth), and are directly related to trigger events of a defined magnitude or frequency (such as intense rainfalls or earthquakes). In principle, both types of landslide hazard maps can be established using several methodological approaches (see Chapter 7 References):

- Physically-based hazard maps may be based on modelling e.g. rainfall infiltration, pore pressure or seismic accelerations, and deriving a factor of safety. Since specific geotechnical parameters are required, this approach has been preferentially applied to selected critical regions. However, by varying the input parameters also probabilistic slope scenarios can be calculated (sensitivity analyses);
- Statistical methods: the spatial probability of landslides may be derived by relating the landslide inventory to a set of susceptibility layers (e.g. slope inclination, lithology, land cover) by using various approaches. If the inventory implies temporal information, probabilistic hazard maps can be derived. Statistical approaches may also be applied to assess triggering thresholds (or probabilities) of defined rainfall or earthquake scenarios by relating the landslide inventory to meteorological or seismic records (assessment of worst-case landslide scenarios or scenarios with a certain probability of exceedance for defined triggering events, etc.).
- Rule-based methods: a number of well-documented landslide areas are selected to develop a rule-based approach by means of statistical analyses, physically-based modelling and/or morphometric analyses, in combination with expert knowledge. These rules obtained from selected well-documented landslide regions may be transferred to other less documented areas.

The best applicable approach depends on the quality and quantity of the available input data. Physical-based approaches require a certain amount of geotechnical data and may preferentially be applied to some selected areas. Statistical approaches, on the other hand, are applicable for regions with a high-quality landslide inventory. If the quality of the landslide inventory is insufficient, rule-based approaches may be applied (however, this may lead to results which do not represent hazard maps but rather susceptibility or hazard indication maps).

In addition to slope stability and failure assessments, also landslide hazard maps related to the transit and accumulation paths of landslides may be required. Such runout studies can be performed by using specific modelling software (see for example Dorren et al. 2006, Hungr & McDougall 2009, Gruber & Mergili 2013, Hergarten & Robl 2015). On the one hand, landslides with runouts initiating from the ROW can affect third parties below. On the other hand, long-runout landslides such as major rock avalanches and debris flows may have sources far beyond ROWs (see e.g. Geertsema et al. 2009, Dufresne et al. 2016), and therefore sometimes affect pipeline corridors rather unexpectedly if not been considered by extensive regional studies. Therefore, the hazard classification of identified landslides should be based on expert judgments of the observed terrain features. It is also important that differentiation is made between landslides with active movements and/or potential for renewed movements along pre-existing sliding zones (i.e. rock/soil slides and/or flows) and landslide deposits which represent rather "stable" accumulation features (e.g. ancient debris fans, rock fall and rock avalanche deposits, etc.). Another important hazard threat to pipelines, and thus also to be considered, is possible retrogression of steep and high, bare cliff sections.

In complex landslide settings (cf. Section 2.1., p. 3), the hazard rating may locally differ from the general classification scheme, because for example i) slope failures can change slope geometries and stresses, and thus trigger adjacent instabilities, or ii) in landslide clusters, individual failures situated upslope of a certain location may load and thus reactivate older landslides further downslope, or vice versa iii) erosion of landslide toes by torrents and rivers may retrogress and cause failures further upslope. Thus, depending on the local site conditions, also apparently "negligible" to "very low" hazard landslides may be classified as "low" to "medium" hazard features (even if they are a distance away from the centreline), since these landslides may potentially influence landslides closer to the ROW).

The information obtained from inventory, susceptibility and hazard assessments can be summarized in a landslide hazard/risk classification scheme (Figure 4) and applied to indicative hazard maps. This aims to provide data in such a form (decision matrix) that it then can be used for the classification of route corridors, the selection of preferred centrelines and for route optimisations. For construction and long-term pipeline integrity, detailed risk determination (incl. pipe stress analyses), designing mitigation measures, and establishing monitoring concepts and maintenance plans (incl. priority ranking of potential landslide-related repair works) is mandatory.

5. LANDSLIDE RISK ASSESSMENTS

Concerning risk, literature offers a large variety of definitions and assessment procedures, with a conventional risk definition expressed by the product of probability (of a hazard) and consequences. According to Varnes & IAEG 1984, (landslide) risk may be defined as the expected losses, damages or disruption of economic activities due to a particular natural phenomenon. For pipelines, landslide risk may be viewed as the probability of undesirable consequences and expected degree of damage (vulnerability), such as pipeline exposure, freespan, bulging and/or rupture.

As hazard assessments, also risk assessments may be based on quantitative and qualitative approaches (see references, e.g. Guzzetti 2006, AGS 2007).

Quantitative (probabilistic) landslide risk analyses are based on numerical parameters (e.g. landslide frequencies, magnitudes) to estimate objective probabilities of pipeline damage. Concerning the indicative ranges of annual probabilities for different types of landslides (see e.g. AGS 2007), the specific input data on activity and recurrence intervals (radiometric age dating data, chronicles, time series, statistics, mid-/long-term monitoring data, etc.) are often incomplete or not available, especially on a regional scale. Thus, temporal/spatial probabilities related to 25- or 50-year project lifetimes can often hardly or not seriously be quoted as an input for risk calculation.

Description	Hazard Class	Indicative Hazard/Risk to Pipeline
• Landslide boundary (scarp, flank or toe) > 100m distance from centreline.	H0 negligible	General threat (exposure, critical freespan or rupture) not credible to barely credible
• Landslide boundary (scarp, flank or toe) 50-100m distance from centreline; or: • minor and shallow landslide within ROW, but hazard feature entirely removed by construction works.	H1 very low	General threat (exposure, critical freespan or rupture) barely credible to rare.
• Landslide boundary (scarp, flank or toe) 25-50m distance from centreline; or: • minor and/or shallow landslide within ROW, but mitigated by construction works.	H2 low	General threat barely credible to unlikely. Exposure unlikely; Critical freespan (project-specific) rare; Rupture barely credible to rare, only under exceptional circumstances (< 0.1% chance of occurrence during project lifetime).
• Landslide boundary (scarp, flank or toe) 10-25m distance from centreline; or: • minor and/or shallow landslide on centreline, but mitigated by measures (at and beyond ROW); (detailed assessments and measures required, reroute recommended).	H3 medium	General threat rare to possible. Exposure possible; Critical freespan (project-specific) unlikely; Rupture during project lifetime rare to unlikely (0.1% to 1% chance of occurrence during project lifetime).
• medium-/deep-seated landslide 0-10m distance from centreline; (reroute strongly recommended).	H4 high	General threat possible to likely. Exposure likely; Critical freespan (project-specific) possible; Damage or rupture during project lifetime possible (1% to 10% chance of occurrence during project lifetime).
• deep-seated landslide or landslide-cluster 0-10m distance from centreline; (reroute inevitable).	H5 very high	General threat likely to almost certain Pipeline rupture during project lifetime almost certain (> 10% chance of occurrence during project lifetime).

Figure 4: Brief description and hazard classification scheme of identified landslide features (qualitative and semi-quantitative).

A DEEPER INSIGHT

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Instead, qualitative (heuristic) approaches may be more applicable. Qualitative ratings are relative and descriptive, with inferred likelihoods based on geological and morphological site information (i.e. multi-temporal landslide inventories and hazard scenarios) and expert judgements, and may also consider literature data on landslides in comparable settings. In some projects, landslide risk has been simply based on the location and distance of individual landslide features to the RoW (centreline).

For a more detailed risk assessment, landslide parameters such as kinematics (velocities, potential accelerations and stabilisation), geometries (thickness/depths) and potential for landslide expansion should also be considered (see also Chapter 6 Hazard Assessments). Based on experiences, several landslides such as earth flows in cohesive soils or deeply weathered claystone units, in principle have the potential to be re-activated within a specific pipeline lifetime, but also previously stable or marginally stable slopes can be affected by first-time failures (see susceptibility analyses above). Concerning potential impacts on pipelines, several slow to very slow ("creeping") landslides often do not cause pipe exposures and/or freespan but rather mid- to long-term deformations and potentially critical pipe stress and strain. Thus, and because changing boundary conditions like earthquakes and/or intense rainfalls can affect especially such pre-existing landslides (i.e. reactivations or accelerated movements are generally more likely than major first time failures), potentially critical sites should be further assessed by monitoring (concerning direction and rate of movements, potential accelerations) and pipe stress analyses (for quantifying potential stress and strain, and identifying vulnerable sections of a pipeline).

Based on the investigations described above (landslide inventory, susceptibility and hazard assessments), a landslide register depicting the landslide-related risks can be established. This should comprise all landslide features mapped within a defined buffer distance around the pipeline, giving descriptions of and qualitative/quantitative information on:

- setting, landslide features, materials, etc. (as documented in the inventory; see Section 2);
- individual landslide hazard classes (H0 negligible to H5 very high; see above);
- probability/likelihood of pipe exposure, freespan or loading scenarios;
- pipe stress and strain (quantified by specific analyses);
- pipeline integrity (hazard/risk) assessment;
- recommended actions (indicative);
- terms for additional measures (very short- to long-term) and priority ranking of landslide site.

These landslide descriptors can be used for pipeline risk evaluation and defining site-specific mitigation measures (e.g. geotechnical installations, monitoring). Thus, the register provides the fundamental input parameters for a risk matrix, which in turn enables the further assessment of potential costs and losses (due to pipeline repair works or shutdown).

6. CONCLUSIONS

The suggested workflow presented herein aims to contribute to a practicable and effective assessment of critical landslide locations along pipeline ROWs and to an improvement of landslide management during all stages of pipeline projects (from pre-FEED to operation and maintenance). Based on long-term experiences obtained from several major engineering and research projects, the most essential input for landslide hazard and risk analyses is a comprehensive inventory database (since quality and quantity of inventory datasets are fundamental for hazard/risk models).

The inventory and hazard risk models should be planned as a living system, meaning they should be re-interpreted and updated as soon as new survey/monitoring data are available, and/or when terrain changes are observed (new and/or expanded landslide features, man-made activities e.g. construction works or material deposition).

An overview of the main relevant information on landslide hazards and risks can be provided in a landslide hazard register. This indicates the locations at which potential pipeline damages (due to exposures, freespans, bulging and/or ruptures) have to be expected during a project´s lifetime. Based on this, further investigations and site-specific mitigation measures to reduce the landslide hazards and guarantee pipeline integrity can be planned (i.e. close-out, avoidance to the best possible extent, rerouting, monitoring, stabilization measures and maintenance plans); furthermore, risks concerning potential costs and losses (due to pipeline harm) can be assessed.

> *"Using a best-practice multidisciplinary workflow, critical landslide locations along pipeline ROWs can be assessed in a practicable and effective way, contributing to an improvement of landslide management during all stages of pipeline projects (from pre-FEED to operation and maintenance).*
>
> *Christoph Prager*

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A Holistic Approach to Achieve Excellence in Pipeline Security Using „BISMA" & "SOLIDS"

Muhamad Rais > PT Pertamina Gas

Abstract

One of subsidiaries of Pertamina is Pertamina Gas which manage special task in operating crude oil transportation 12,000 BOPD. In the operation still occur illegal tapping activities and risk of pipeline product theft is a major concern to industry. In 2012, oil thieves drills 748 illegal taps or an average 2 times every day. Losses from transportation approximately 40% per day and loss revenue more than $20 million a year. The activities of illegal tapping by cutting into pipelines can cause pipeline ruptures and explosions, leading to human casualties, destruction of property, and damage to the environment.

Pertamina Gas is a company who has focus in midstream and downstream of gas industry in Indonesia. Pertamina Gas implement BISMA (Business Map) and SOLIDS (Security and Oil Lossess management with integrated Detection System) to achieve excellence in pipeline security. About 30 segments have a Medium-High Risk and 22 locations that being illegal tapped.

BISMA is an application that using GIS as tools to differentiate assets by colour/symbol such as transmission pipeline, station and visualize each pipeline segment with risk score. SOLIDS includes liquid management system (LMS), pipeline leak detection system (PLDS), security patrol, emergency response team (ERT), communication network and corporate social responsibility. With BISMA capability in storing risk analysis, it could enhance the AMS operating methods based on rating and periodic maintenance to achieve operational reliability. LMS is a system to control and monitor crude oil distribution and also dispatch data to BISMA.

With PLDS, it could detect the drift in the operating pressure of crude oil transportation and determine location of oil pipeline leaks based on the negative wave pressure data received by transmitter on a particular pipe segment. The main difference between theft event and leak event on a pipeline is the speed of product losses. Illegal tapping points withdraw product very slowly, and no product is split on the ground. Security patrol carries out supervision in the right of way and finding leak location coordinate that detected by PLDS. ERT take a specific actions regarding oil spill response management.

The implementation of BISMA and SOLIDS is an innovative oil loss detection technologies and pipeline security that detect product thefts quickly and accurately locate those illegal tapping points. Pertamina Gas has been succeeded in reducing losses from illegal taps from 2013 until 2018. In 2013 the number of illegal tapping cases as much as 748 points and decreased significantly in 2018 zero case.

1. INTRODUCTION

Pertamina Gas Central Sumatera Area (Pertamina Gas CSA) is one of the operational areas of Pertamina Gas which transporting crude oil through 262 kilometers of pipeline from Tempino to Sei Gerong with pipe diameter of 8". The Crude oil flowed by ± 13,000 BOPD from the oil field located in the working area of Jambi and South Sumatra, Indonesia. Crude oil is then processed at Refinery Unit III Pertamina. Along right of way (ROW) Pertamina Gas Central Sumatera Area has 5 booster station and 2 metering station.

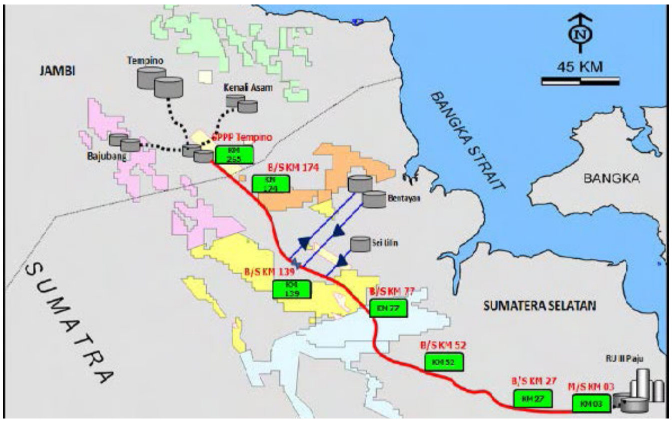

Figure 1. Crude Oil Pipeline Tempino-Sei Gerong

In the operation of crude oil transportation still occur illegal tapping of oil, resulting in oil losses and cause environmental pollution. The effort taken to reduce the frequency of illegal tapping is to create an integrated system that includes supervision and security of assets along the pipeline called oil losses management with integrated detection system (SOLIDS).

2. ILLEGAL TAPPING

Illegal tapping is an illegal activity to leak the pipeline with the intention of taking some of the oil flowing through the pipe. Motive of Illegal Tapping like a leak pipe in the hidden location, tapping pipe in the house, sabotage and mass involvement. The occurrence of illegal tapping can have an impact on environmental problem such oil spill and can cause fire.

Figure 2. Illegal Tapping on hidden area

The loss is calculated from the stolen and burned oil. The loss has not included the calculation of losses due to damaged pipes and damage to the environment at the oil spill site. Also due to the termination of oil distribution on that day.

3. DATA AND METHOD

SECURITY & OIL LOSSES MANAGEMENT WITH INTEGRATED DETECTION SYSTEM (SOLIDS)

Pertamina Gas develops integrated systems ranging from asset safeguards to use of technology to detect oil leaks along the Tempino - Sei Gerong pipeline with SOLIDS as can be seen in Figure 3 below:

Figure 3. Security & Oil Losses Management With Integrated Detection System (SOLIDS)

The SOLIDS consists of :

I. LIQUID MANAGEMENT SYSTEM (LMS)

LMS is a system to control and monitor crude oil distribution. This system monitors operational parameters such as pressure, flow rate, temperature, tank level and differential pressure.

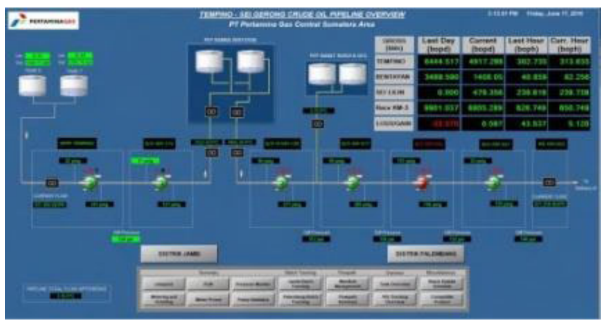

Figure 4. Liquid Management System (LMS)

II. PIPELINE LEAK DETECTION SYSTEM (PLDS)

Is a leak location detection system or theft on the pipeline by pressure wave method. This system detects the cause of the decrease in the operating pressure of the crude oil transportation and determines the location of oil pipeline leaks based on the negative wave pressure data received by the transmitter installed on a particular pipe segment.

Pipeline leak detection methods have many kind like inline inspection, volume balance, negative pressure wave etc. Pertamina Gas choose leak detection system with negative pressure wave method.

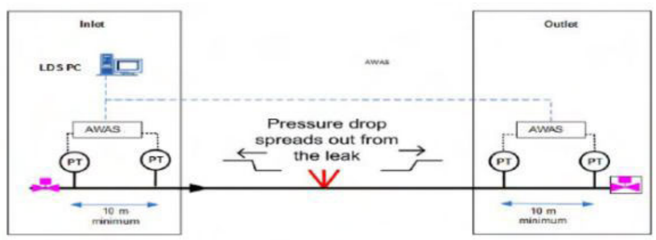

Figure 6. Principle Pipeline Leak Detection System

Leak Detection System can analyze when leak occur in pipeline and give the notification alarm location and time of the leak. Leak detection system use HMI for operation and monitoring real time. Operator can be know situation among pipeline like pigging activity and start-stop shipping pump.

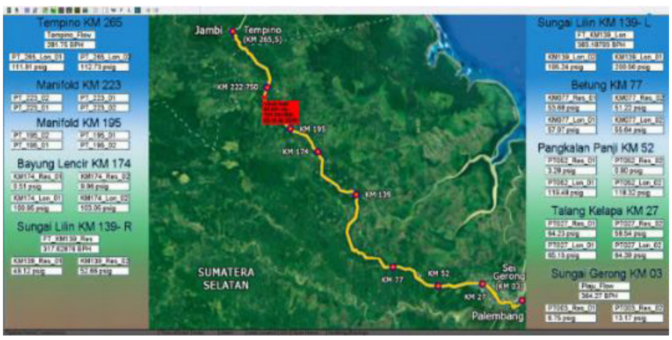

Figure 7. Display LDS Pertamina Gas CSA

Display the pipeline position on a map show the operational parameter such as pressure and flow. When occur illegal tapping or leaking, LDS can give the notification on the map with red alarm (location and time) leak. The alarm is result from pressure drop calculation, and pressure trending from history database as can be seen from figure 8 below:

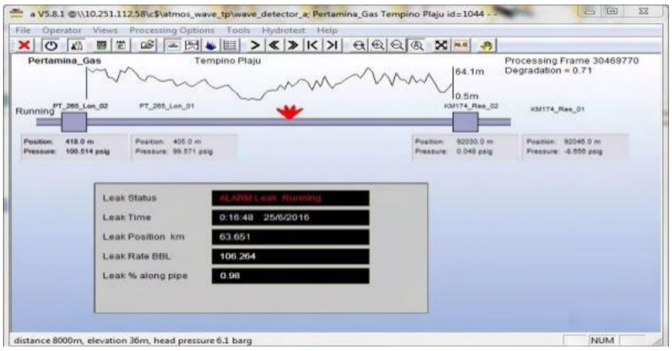

Figure 8. Pressure Trending LDS

LDS system can detect the cause of the decrease in operating pressure and detect the location of pipeline leakage with 98% accuracy and prevent the loss of the company due to oil transportation losses. Pertamina Gas CSA has a limit for performance leak detection system maximum 1% every segment. Every month Pertamina Gas carry out on tuning test to minimize false alarm.

III. SECURITY PATROL

Security patrol is surveillance and security system along the pipeline equipped with GPS Tracker attached to personnel and operational vehicle units. The security patrol carries out supervision on all assets of Pertamina Gas including warning sign, ROW boundary marker, test point and others that are reported periodically. The patrol team is equipped with a GPS Tracker attached to personnel and operational vehicle units.

Figure 9. Security Patrol Team

IV. EMERGENCY RESPONSE TEAM (ERT)

Is a team formed to conduct emergency counter measures along the pipeline. Emergency conditions include risk mitigation due to illegal tapping and leaking. Activities include emergency response team, heavy equipment, work equipment and material procurement.

Figure 10. Emergency Response Team

The activities of ERT are effective in dealing with the effects of illegal tapping quickly and effectively so that loss of oil (losses) and environmental damage can be minimized.

V. COMMUNICATION NETWORK

Communication network is effective for sending information from the field about operational conditions as well as security disturbances in the pipeline, so that countermeasures can run quickly and precisely. CCTV installed in the booster & metering station to be able to monitor and record images in real time as well as to know the activities and activities that are taking place inside the booster & metering station.

Figure 12. Monitoring Station by CCTV

VI. CORPORATE SOCIAL RESPONSIBILITY (CSR)

Pertamina Gas also coordinates and persuasive approaches with local village officials to secure the existence of oil pipelines in our ROW. Corporate social responsibility (CSR) program is also very helpful in conducting activities and approaches to the community based on the social mapping. Pertamina Gas determined five fields that were prioritized in CSR implementation: Education, Health, Environment, Community Development and Donation.

4. RESULT AND DISCUSSION

From consistent implementation of SOLIDS and supported by good coordination with government and CSR program along the ROW. Pertamina Gas succeeded in reducing illegal tapping from 2010 until 2018 which can be seen in Figure 13:

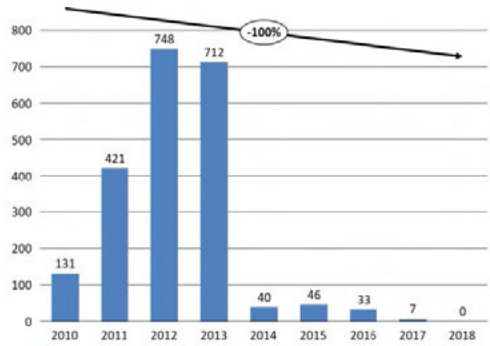

Figure 13. Decrease in Illegal Tapping Event Year 2010 - 2018

In 2010 the frequency of illegal tapping was 131 points and increased dramatically in 2012 by 748 points. With the implementation of SOLIDS, the frequency of illegal tapping from 2010-2018 has been greatly reduced and by 2018 Pertamina Gas has succeeded in reducing the frequency of illegal tapping to zero.

The system will continue and continue to maintain the consistency and security of national vital objects through Pertamina Gas operations.

5. CONCLUSIONS

From the above exposure can be summed up as follows:

1. The case of illegal tapping can be derived from 748 cases in 2012 to 0 case in 2018.
2. Pertamina Gas has successfully conducted various efforts in tackling illegal tapping with BISMA & SOLIDS through optimization:
   a. Liquid Management System (LMS)
   b. Pipeline Leak Detection System (PLDS)
   c. Security Patrol
   d. Emergency Response Team (ERT)
   e. Communication Network
   f. Corporate Social Responsibility (CSR)
3. Implementation of BISMA & SOLIDS, empowerment and improvement of good relations with the community can help tackle the case of illegal tapping.

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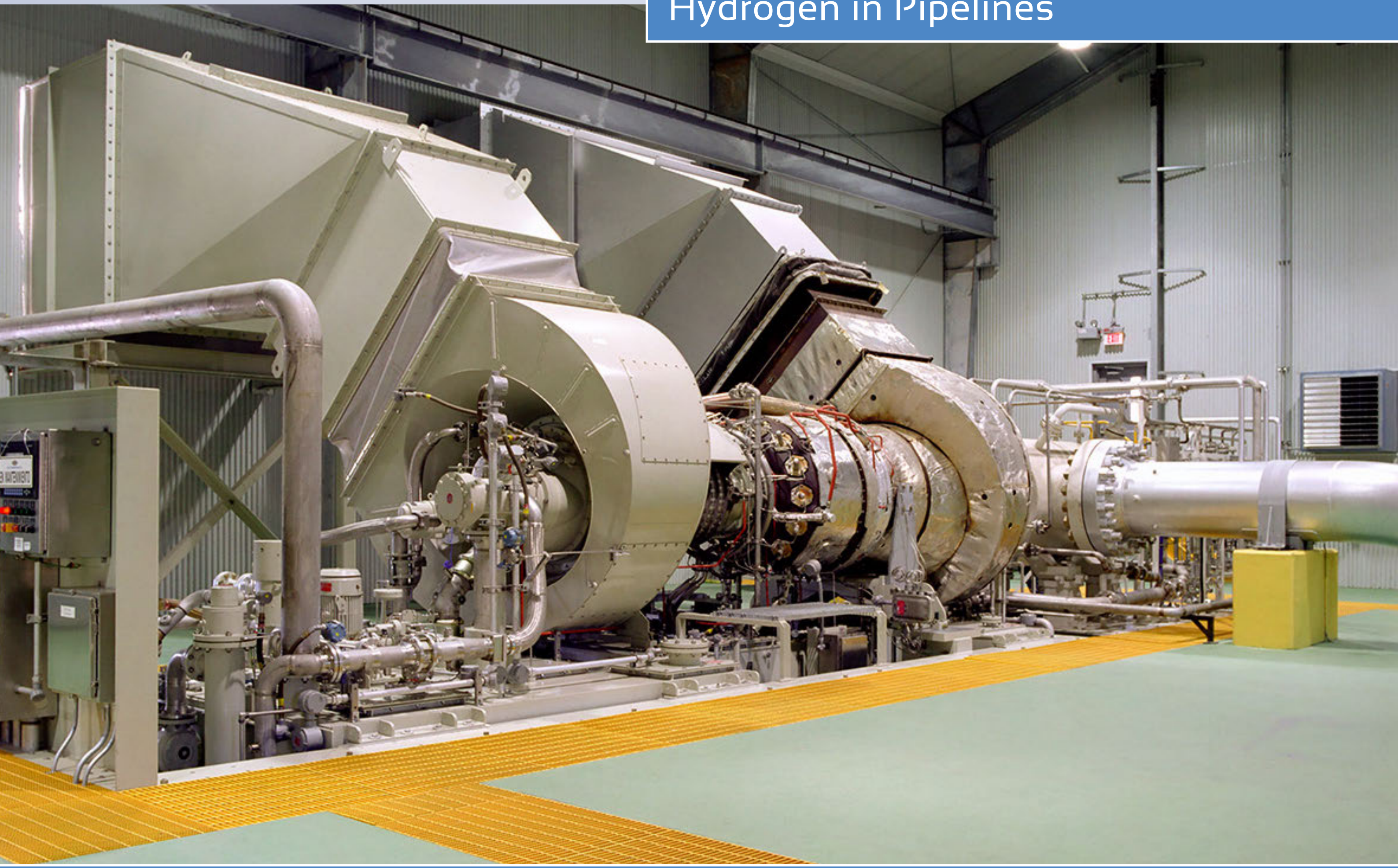
Hydrogen in Pipelines



Rainer Kurz, Luke Cowell, Marc Vignal > Solar Turbines Incorporated

Abstract

Increasing the use of renewable energy requires new approaches to energy storage and energy transport. One of these approaches is to store and transport hydrogen in natural gas pipeline networks. Blending hydrogen into the existing natural gas pipeline network appears to be a strategy for storing and delivering renewable energy to markets. Adding Hydrogen to the natural gas requires considerations regarding combustion systems, as well as the impact on compressors and pipeline hydraulics.

Hydrogen increases the reactivity of natural gas fuels, showing increased flame velocity, flame temperatures, different autoigniton behavior, and a wider range of flammability. The handling of failed starts, where unburned fuel can be present in the exhaust system, and may cause an explosion hazard has to be addressed. Results from analysis and rig testing of the combustion components with hydrogen and natural gas mixtures will be presented and discussed.

Further, the impact of hydrogen addition on pipeline hydraulics and compressor operating are considered. The transport efficiency of the pipeline, safety aspects, and in particular questions about the capability of existing and new infrastructure to use natural gas – hydrogen mixtures as fuel are addressed in this paper.

1. INTRODUCTION

Decarbonization technologies are ramping up to mitigate the build up of GHGs and to minimize Global Warming. In particular, a transition to renewable energy generation technologies are in flight and accelerating. However, fundamental limitations with current forms of renewable energy are

-their variability over time – both short term and seasonally and
- their geographic limitations – cannot be generated everywhere which creates a need for alternate transport.

Mitigation scenarios such as P2G (power-to-gas) scenarios are under evaluation. They include the use of renewable energy created during peak production periods beyond local demand to create hydrogen. The existing natural gas transmission systems would then be used to both store and transport the energy. P2G offers advantages for longer term storage as depicted in IES chart ([1], Figure 1). These scenarios compete with other energy storage solutions, as well as with hybrid compressor systems (Faller and Stollenwerk,[2])

Using the existing natural gas pipeline system as storage and transport vehicle is an elegant solution for the energy storage problem. In these concepts, surplus electricity from renewables (Wind, Solar) is used to create Hydrogen via electrolysis ('Green Hydrogen'). This hydrogen is then injected into natural gas pipelines. Current European plans call for the capability to add up to 20% Hydrogen into the natural gas stream. Similar ideas are discussed in North America (Adolf et al.[3]). A study by Melaina et al. [4] summarizes key issues when blending hydrogen into natural gas pipeline networks. It discusses the benefits of blending, the impact on end-use systems, safety, material durability and integrity management, leakage and downstream extraction. The study finds no significant increase in safety risks, material durability, and integrity for hydrogen concentrations of 20% and less in transmission lines.

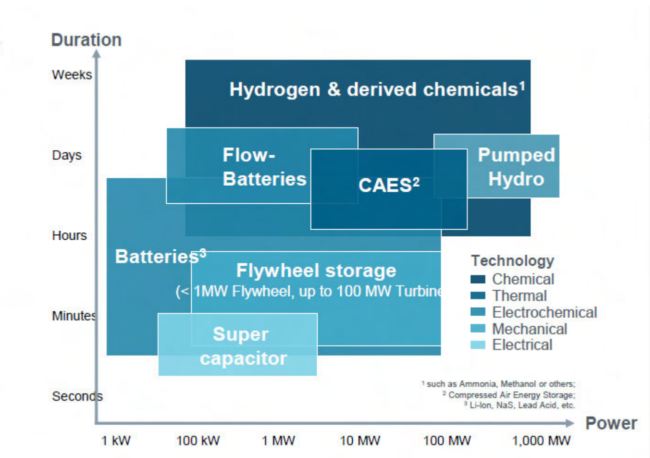


Figure 1: Energy Storage concepts ([1])

Adding hydrogen into natural gas pipelines raises, among others, two additional questions that will be discussed here:

-What is the impact of hydrogen in natural gas on gas turbine combustion and safety?
-What is the impact of Hydrogen on transportation efficiency in a pipeline?

2. GAS TURBINE COMBUSTION SYSTEMS

Generally two different combustion system technologies are used in industrial gas turbines. The conventional or diffusion flame combustion system is characterized by high flame temperatures and is designed for concurrent mixing and burning of the air and fuel within the combustor volume. Conventional combustion gas turbines exhibit excellent turn-down with very broad fuel flexibility.

The other combustion system is a Dry Low Emissions system (SoLONOx) that uses lean premixed combustion to operate with low emissions of NOx and CO. With lean premixed combustion, the fuel and air are premixed before reaching the flame front at a reduced fuel-air ratio and corresponding reduced flame temperature. A detailed description of the SoLONox combustion system and a comparison with the conventional fuel systems can be found in Cowell [5]. Both the conventional and the DLE configurations are available in either a single gas or with dual fuel capability in which both gas and liquid or two gas fuels can be used. Typically, in dual fuel applications a liquid fuel such as #2 Diesel or a second gas fuel is provided to allow continuous operation in the event of an interruption in the gas supply.

3. HYDROGEN AND NATURAL GAS BLENDS AS A GAS TURBINE FUEL – AREAS OF CONCERN

Adding hydrogen to natural gas changes many characteristics of the fuel that need to be considered for gas turbine applications. From a combustion perspective the parameters below are important and the impact these changes introduce are discussed [6]. The laminar flame speed to increase nearly exponentially with hydrogen concentration. In the range of 0 to 30% hydrogen in pipeline gas the methane reactions dominate in the combustion process and the increase is relatively modest. Each combustion system is designed for select range of flame speed variation. Diffusion flame or conventional systems generally do not have an upper level but do have a lower level where the flame speed becomes too slow and they "blow out". This is clearly not an issue with hydrogen addition. For DLE combustion systems there is an upper limit as well. The flame speed must be significantly less than the mixture velocity in the injector in order to prevent the flame from pulling into the injector pre-mixer and causing damage. A flame propagating upstream into the Lean-Premix fuel injector is often called "flashback". For lean premix fuel injectors designed for pipeline natural gas flashback will occur at very high levels of flame speed. Determining this point for already installed lean-premix combustion systems is a key requirement whenever using a fuel different than pipeline gas.

The pollutant emissions (NOx, CO and UHC) from a gas turbine engine are most directly influenced by a fuels flame temperature. The adiabatic flame temperature is the maximum temperature that the products of a given combustion reaction can reach without heat loss. In a gas turbine combustion system the majority of pollutant emissions will vary proportionally with that fuels adiabatic flame temperature. In general, fuels with higher adiabatic flame temperature will create more NOx and less CO and UHC. The flame temperature for H2 and natural gas mixtures in the range of 0 to 30% varies by approximately 17°C which will increase NOx emissions modestly for a conventional combustion system and very slightly for a DLE combustor. The corresponding change in CO or UHC are even less at less than 1 ppm within the typical gas turbine operating range

Combustion Stability is characterized by the presence or lack of significant levels of combustor pressure oscillations or combustor rumble. Extensive analysis and often engine qualification is required to verify that different fuel compositions do not significantly change the combustion stability characteristics.

Hydrogen has a very broad flammability range of 4 to 75% in air. It has a slightly lower autoignition temperature and must be treated more carefully than when using natural gas fuels to manage the risk of fire or explosion. This is clearly a concern if there is a gas leak near or in the gas turbine package but is also a concern for failed gas turbine ignition or flame-outs when unburned fuel will enter the gas turbine exhaust system. The amount of fuel that can enter the exhaust system between the time the control system detects the failure or flame-out and the fuel valve closes is long enough to completely fill the exhaust ducting, and this mixture can ignite. This risk is minimal for most of the P2G hydrogen mixture scenarios where the hydrogen will be less than 20%. However, at 20% to 30% H2 there remains the possibility that an exhaust mixture from a failed start or flame-out may be flammable and additional study is in progress to completely characterize and mitigate this risk.

The gas turbine operator with hydrogen containing fuels needs to properly assess the gas for the appropriate industry Gas Group. Based on the Gas Group the hazardous area and the selection of equipment, such as electrical instrumentation and electrical enclosures, should conform to the appropriate industry code. The gas group does not change until the hydrogen mixtures in natural gas increase over 20%.

As the smallest element in nature, hydrogen is very light and very permeable, thus with a high diffusivity. Common fuel system seals that are leak tight with natural gas fuels may not seal effectively with hydrogen. High hydrogen fuels may require special leak testing of gas systems. Elastomers, including O-rings and diaphragms, are more susceptible to explosive decompression problems.

Absorption of hydrogen into metals can cause a general loss of ductility, which is termed hydrogen embrittlement. High strength martensitic steels are particularly susceptible to embrittlement and should not be used with hydrogen rich fuels. Per NACE MR0175/ISO 15156 2003 carbide-stabilized grades and the 300 series stainless steels should be used for hydrogen fuels. These requirements are applicable for hydrogen mixtures greater than 4%.

Other less measurable changes to the combustion process such as flame shape can have an impact on combustion dynamics and on combustor liner wall temperatures.

4. GAS TURBINE EXPERIENCE AND QUALIFICATION WITH HYDROGEN

Industrial gas turbines are used in many applications that support and use pipeline natural gas that will be impacted with the addition of hydrogen. These include gas transmission applications to drive pipeline compressors to transport the gas and for local power generation, often in CHP configurations, to generate electricity and steam for end users.

Gas turbine applications with high hydrogen fuels are well documented [7]. In general, the majority of existing applications use diffusion flame combustion. More recently experience is increasing with DLE gas turbines with considerable concentrations of hydrogen. The unique requirements and qualifications along with field experiences for both diffusion and DLE gas turbines are discussed in relation to using the expected hydrogen and pipeline natural gas fuel blends.

Gas Turbines with conventional combustion systems are readily capable of using a broad range of hydrogen rich fuels. Historically for applications the amount of hydrogen in fuel has been over 30%. Typical hydrogen rich fuels used in gas turbine applications have been refinery gas (~30% H2), Coke Oven Gas (COG) (~60%), and industrial process gases (30 to 100%). The impact and requirements for the combustion system and gas turbine package are consid-

ered. Solar has experience with many applications with significant concentrations of hydrogen. In the past decade many of these applications have been using coke oven gas (COG) on 23000hp class and 7700hp class generator sets. COG is a process waste gas created in the process to create coke for steel production. The typical gas turbine fuel created with COG has 55 to 60% hydrogen, 25 to 30% methane, 5 to 10% CO, and 5 to 10% diluents (N_2+CO_2)

The NOx emissions increase substantially due to the high temperature flame front. The NOx emissions with conventional combustion can be reduced by as much as 80% through water injection. Clearly, for the expected P2G hydrogen and natural gas blends of 5 to 20% the effect on the conventional combustion system will be minor with less than 5% increase in NOx compared to natural gas alone and no impact on durability.

The ability of gas turbines using lean premixed combustion is an area of active research and development for most OEMs. The initial assessment at this OEM is that using existing DLE gas turbines with the latest combustion system technology with pipeline gas mixed with 5 to 15% hydrogen will not require significant modification. The ability of earlier generations of SoLoNOx combustion systems to use these levels of hydrogen are still being investigated. As in the previous section the impacts on the combustion system and the gas turbine package are considered.

The lean premixed gas turbine are limited by the same fuel and system characteristics that were described earlier for the conventional gas turbines. However, due to nature of the combustion system design several of these characteristics are more restrictive.

As described earlier the lean premixed combustion system NOx emissions are controlled by operating the combustion system at fuel lean conditions that are inherently closer to the lean extinction point. In addition, in order to prevent local hot spots, where NOx formation rates can be considerable, the fuel injector includes a fuel and air pre-mixer section. These design differences present several challenges as natural gas is mixed with hydrogen. First, due to its higher flame speed there is a greater risk for the flame to "flashback" into the injector pre-mixer, which is not designed for high temperature. Secondly, as with conventional systems the flame temperature changes can impact NOx emissions. Finally, lean premixed are sensitive to combustor pressure oscillations that have been "tuned out" for natural gas but as hydrogen is added to the fuel the flame shape may change due to variations in flame speed, flame temperature, and fuel density that may cause an increase in pressure oscillation amplitude levels that need to be addressed.

These design areas of concern of the DLE combustion system are being actively investigated. At this OEM, qualification of its DLE (SoLoNOx) gas turbines has been on-going to allow usage of a broader range of fuels by focusing on these design areas and how they are impacted by the key fuel parameters listed in Table 1. This activity has included analytical and test assessments of how variations in flame speed, flame temperature and fuel density impact the combustion characteristics of emissions, combustion stability and durability (component temperature). A brief overview of this work is presented in the context of natural gas and hydrogen fuel mixes in the range of 5 to 30%.

Extensive combustion rig and gas turbine testing has been completed with a range of fuels with variable flame speed and flame temperature as reported in Cowell [6]. In this study flame speed and temperature were changed by adding propane (C3), butane (C4) and CO_2 into natural gas to simulate "associated gases" (raw gas recovered during oil extraction) and raw natural gas.

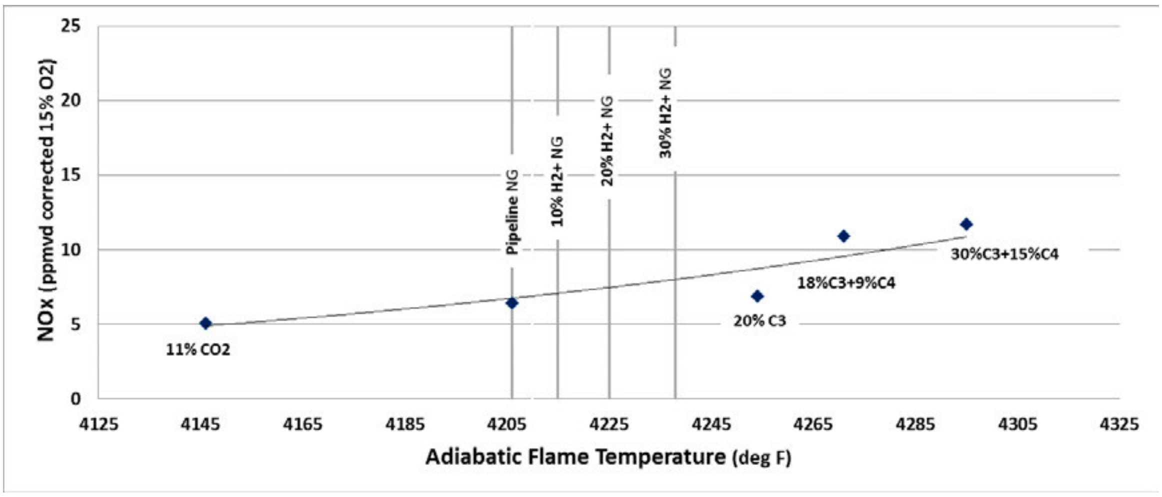


Figure 2: NOx Emissions Variation on a 23000hp class Gas Turbine at Full Load and Standard Pilot with Associated Gas Test Fuels with Different Values of Adiabatic Flame Temperature

Figure 2 is emissions data taken with the associated gas test fuels plotted as a function of flame temperature. The results included were taken on a 23000hp class gas turbine tested in the factory operating at full load. As outlined emissions of NOx and CO are most influenced by flame temperature. Just as in the case for conventional combustion the gas turbine controls keep the overall gas temperature entering the turbine constant regardless of the fuel being used. However, as the adiabatic flame temperature increases the NOx emissions will increase due to the flame becoming more compact and burning hotter locally. For reference, Figure 3 includes the adiabatic flame temperature of different NG and hydrogen blends. Over the range of adiabatic flame temperature typical of these blends of H2 the SoLoNOx gas turbine is expected to show a very slight increase in NOx of 1 to 2 ppm. Data for CO emissions are not included as for all data points the emissions were less than 2 ppm. Similarly, low levels are expected with H2 and natural gas mixtures.

However, it should be noted that with the described DLE configuration an added pilot fuel circuit is used to augment flame stability at low loads and during transients. The pilot control schedule is set experimentally and may need to be adjusted differently with hydrogen mixes as compared to the fuels tested in Figure 3. The data in Figure 3 was taken at a constant pilot level. Due to the enhanced stability generated while burning hydrogen containing fuels, the analysis indicates that lower levels of %pilot may be possible.

The testing completed in the fuel variation study also indicated that with the range of fuels tested in a 23000hp class gas turbine indicated no change in combustion stability characteristics or the component temperature. Hydrogen in the range of 5 to 20% is expected to behave in a similar way. For the component temperature an assessment against the change in flame temperature compared with the test program is entirely adequate. Similarly, in the range of 5 to 10% hydrogen little to no change in combustion stability characteristics are expected. Engine testing will be conducted for hydrogen concentrations of 20% to confirm the analytical assessments.

It should also be noted that the test program described has been completed on the most current SoLoNOx combustor configurations. However, in the P2G scenario with hydrogen addition to the pipeline existing gas turbine packages with legacy SoloNOx combustion system also need to use this gas. Some limited testing with the higher flame speed test fuels described has been completed and with some of these configurations flashback or combustion stability issues have been identified. These configurations will all likelihood need to be upgraded to the latest configuration. A more extensive program is in progress to assess many of the more common configuration in the SoLoNOx fleet for robustness with the subject blends of hydrogen and natural gas.

Direct testing of hydrogen and natural gas fuel blends is also in progress using combustion rigs with a single fuel injector. Figure 3 highlights results taken on a 23000hp class gas turbine with hydrogen blended with natural gas. The rig was operated at simulated full load flow conditions at nominal day temperatures. As expected the NOx emissions do increase slightly as the adiabatic flame temperature of the fuel gas is increased. However, the magnitude is only 3 ppm.

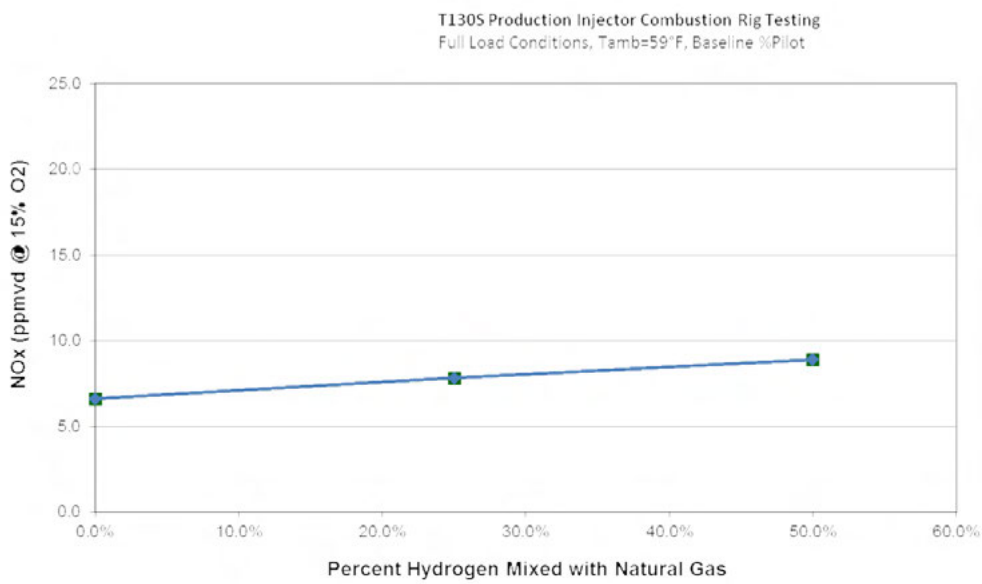


Figure 3: NOx Emissions Variation of a 23000hp class gas turbine fuel injector in Combustion Rig Testing at Simulated Full Load Conditions for a 59°F Day and Constant Pilot Level with Varying Blends of Hydrogen Mixed with Natural Gas.

CO and unburned hydrocarbon emissions were throughout the testing. Component temperature maps were also created, with little variation evident. Testing is in flight to assess the flashback robustness of the SoLoNOx injectors at varying levels of hydrogen content. In test work to date no flashback events were observed under any test conditions with hydrogen content less than 30%. This work is on-going to cover other engine models and different SoLoNOx legacy configurations.

4.1 PACKAGE IMPACTS

As the level of hydrogen (and other more reactive gases) increases additional requirements and limitations are placed on the gas turbine package. For these applications the following list of additional safety requirements are added for gas turbine packages. Solar Turbines has historically required them for any applications with hydrogen greater than 4%. The requirements and limitations for the conventional gas turbine package also apply for the SoLoNOx package

- Configure and equip packages to meet Gas Group B
- Incorporate additional fire and gas detection devices
- For generator packages the risk of flameout is decreased by limiting applications to those that are tied to the power grid. Similarly, duct firing in the exhaust is precluded since it could be a guaranteed ignition source.
- Ignition and start-up on pipeline quality natural gas or diesel fuel is required and then the fuel is transferred at a low load.
- Special exhaust purge sequences are added and used when there is a failed start or after a flame-out before a subsequent attempt to restart.
- The fuel system is configured to prevent leakage in the package by using NACE compliant materials and appropriate fuel system seals. In addition, the fuel system piping goes through an X-ray inspection process to further reduce the risk of leaks.

4.2 SOLONOX GAS TURBINE PACKAGE EXPERIENCE

In contrast to the conventional combustion, experience packages with SoLoNOx gas turbines operating on hydrogen is only recently starting to expand. It is worth noting that SoLoNOx experience with associated and raw natural gases has become very extensive. These gases are quite comparable in the range of flame speed and flame temperature as will result with hydrogen mixed with natural gas in the range of 5 to 20%.

Direct experience on the SoLoNOx platform is limited to a refinery generator set application where a 23000hp class gas turbine has operated with natural gas mixed with up to 9% hydrogen. Qualification and mapping was completed with the unit demonstrating 15 ppm and no operational issues. The unit is started on 100% natural gas and the package was updated to be compliant with the requirements for applications greater than 4% H2. However, due to customer requirements the operating time accumulated with the 9% hydrogen fuel mix has been brief.

Units with high and medium Wobbe Index associated and raw natural gases are much more extensively used and tested, and have few modifications from the standard configurations supporting operation on pipeline gas. The earliest shipments have been in operation for multiple years with many of these shipments reaching the overhaul interval. Operationally, these SoLoNOx engines run on associated gases in much the same was as they operate on pipeline natural gas. As indicated earlier on the applications with fuels with higher adiabatic flame temperatures the NOx emissions are higher by 2 to 5 ppm. As with all DLE gas turbines, fuel quality with adequate fuel treatment is a pre-requisite for trouble free operation.

5. PIPELINE TRANSPORTATION

Hydrogen gas has a higher mass calorific value than methane gas. Because of this property, molecular hydrogen is appreciated for space shuttle engines. However, its volume calorific value lower than methane gas. The dynamic viscosity is also significantly different, and finally, heat capacity, isentropic exponent, and the thermal conductivity are also different [8,9].

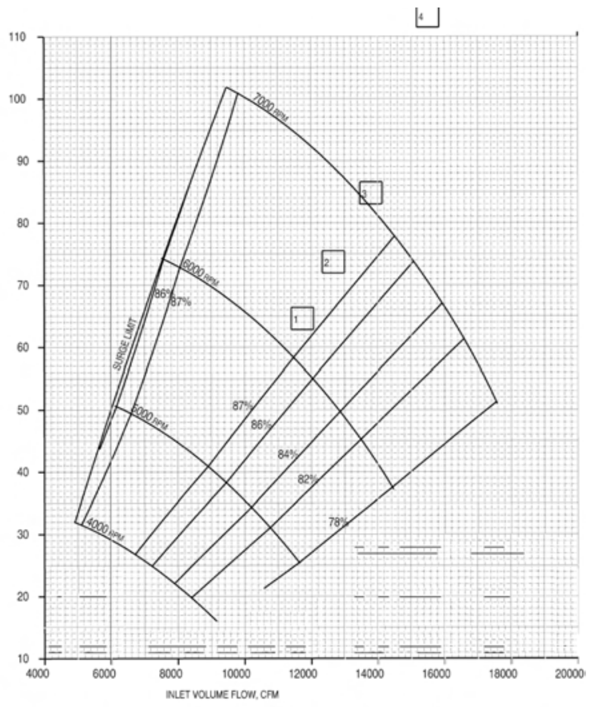


Figure 4: Compressor operating with different levels of H2 mixed into natural gas. Inlet pressure and temperature, and the discharge pressure where kept constant, while the H2 content was increased. The flow through the compressor was adjusted to keep the energy flow constant: 1-0% H2,2-10%H2, 3-20% H2,4-40%H2.

Due to the low molecular weight of Hydrogen, Hydrogen compression is significantly more difficult than Methane compression. Figure 4 shows the operating points of a gas compressor, where the inlet pressure and temperature, and the discharge pressure where kept constant, while the H2 content was increased. The flow through the compressor was adjusted to keep the energy flow constant. For these conditions, compressing 100% hydrogen gas would increase the work by a factor of 10. Bainier et al [8] have studied the impact of hydrogen on the transportation efficiency. Transportation efficiency essentially compared the amount of fuel burned to transport a given amount of energy over a certain distance. Using energy rather than standard flow (or mass flow) allows a direct comparison of the impact of different gas mixtures. A compressor station in the middle of a longer pipeline was modelled- therefore one can assume that the output from the station modelled is the same as the output from the previous station. The power consumption in such a compressor station as a function of H2 concentration is shown in Figure 5.

The power consumption for a situation where, for different H2 concentrations, the same amount of energy is transported is show in Figure 6.
The results of the study shows fundamental relationships for the discussion on mixing hydrogen into natural gas pipelines:

- At the same pressure conditions and the same suction temperature, the compression work increases with the increase of H2 concentration.
- Hydrogen has a negative Joule-Thompson Coefficient, and therefore its temperature increases when the pressure drops. For the gas, flowing into the pipeline downstream of the station cooler, the higher the H2 concentration, the harder it is for the gas temperature to decrease along the pipeline. This characteristic has two consequences:
  - Pressure losses increase with the H2 concentration. The higher the H2 concen tration, the higher the influence of the soil conductivity.
  - For a shorter distance between compressor stations, the compressor inlet temperature and the required compres sion power increase with the H2 concentration.

    Figure 8 shows the required increase power to transport the same quantity of energy. For the given parameters, the power increase reflects a reduction in transport efficiency.

Finding a reduction in transportation efficiency when hydrogen is mixed into the pipeline is a serious drawback in the discussion on usage of hydrogen. Mixing hydrogen into the natural gas stream will also reduce the amount of energy and existing pipeline can transport [9]. One has to take into consideration however, that the yardstick to evaluate the use of hydrogen may not be the transportation efficiency, but rather the fact that pipelines allow for storing hydrogen. In other words, hydrogen injection into pipelines may not have to compete in terms of transportation efficiency, but rather in terms of roundtrip efficiency compared to other storage methods, like compressed air storage or batteries. Obviously, in this discussion, the efficiency of the processes that generate hydrogen, using electricity from renewables, has a big impact.

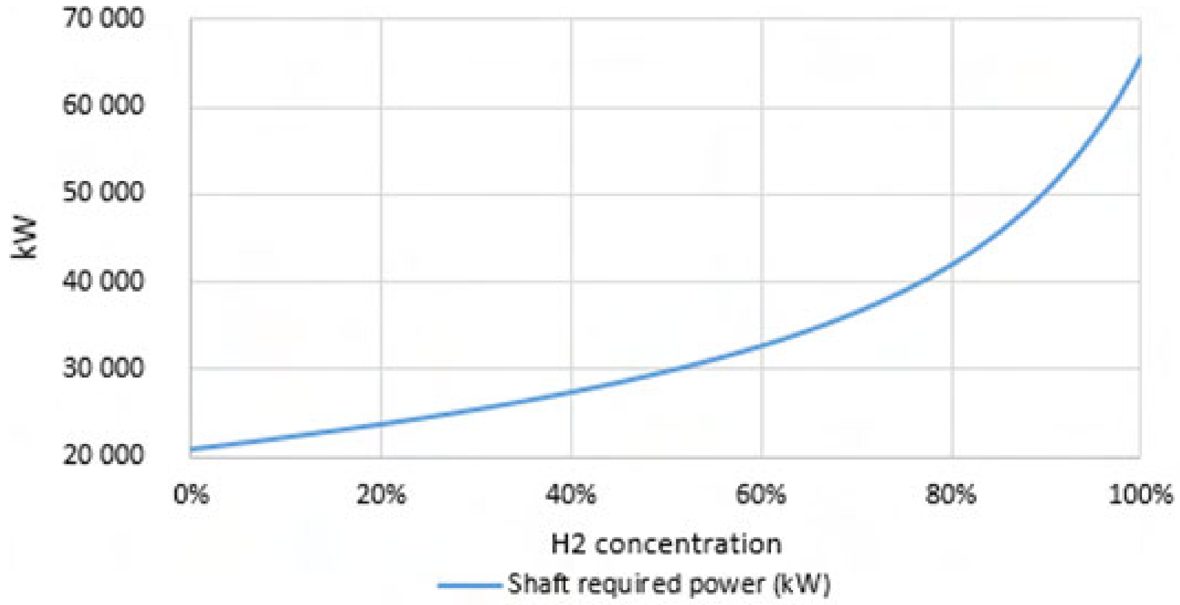


Figure 5: Power Consumption for pipeline compressor station [8]

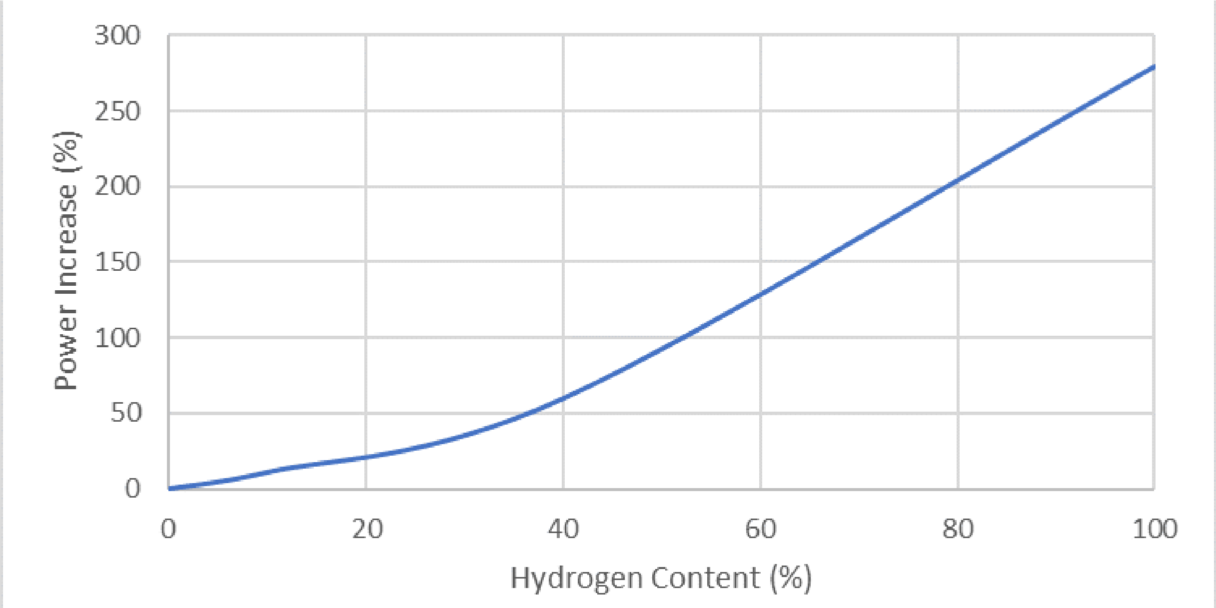


Figure 6: Power increase to transport the same amount of energy in a pipeline [8].

6. CONCLUSIONS

This study indicates injection Hydrogen into a natural gas pipelines in moderate rates is manageable with currently available technology:

- Conventional combustion systems are proven for H2 + NG blends up to 30%. Starting on these fuels is the only risk.
- Even for Lean Premix systems, like SoLoNOx, H2+ NG mixtures of 5 to 10% are not problem today.
- Concerns are related to safety, for example at failed starts. These are manageable with todays technology
- Gas compressors are able to handle hydrogen in natural gas, but they will have to run faster (ie, re-stages may be required on existing units), and will consume more power.
- The transportation efficiency of pipelines will be reduced when hydrogen is added.

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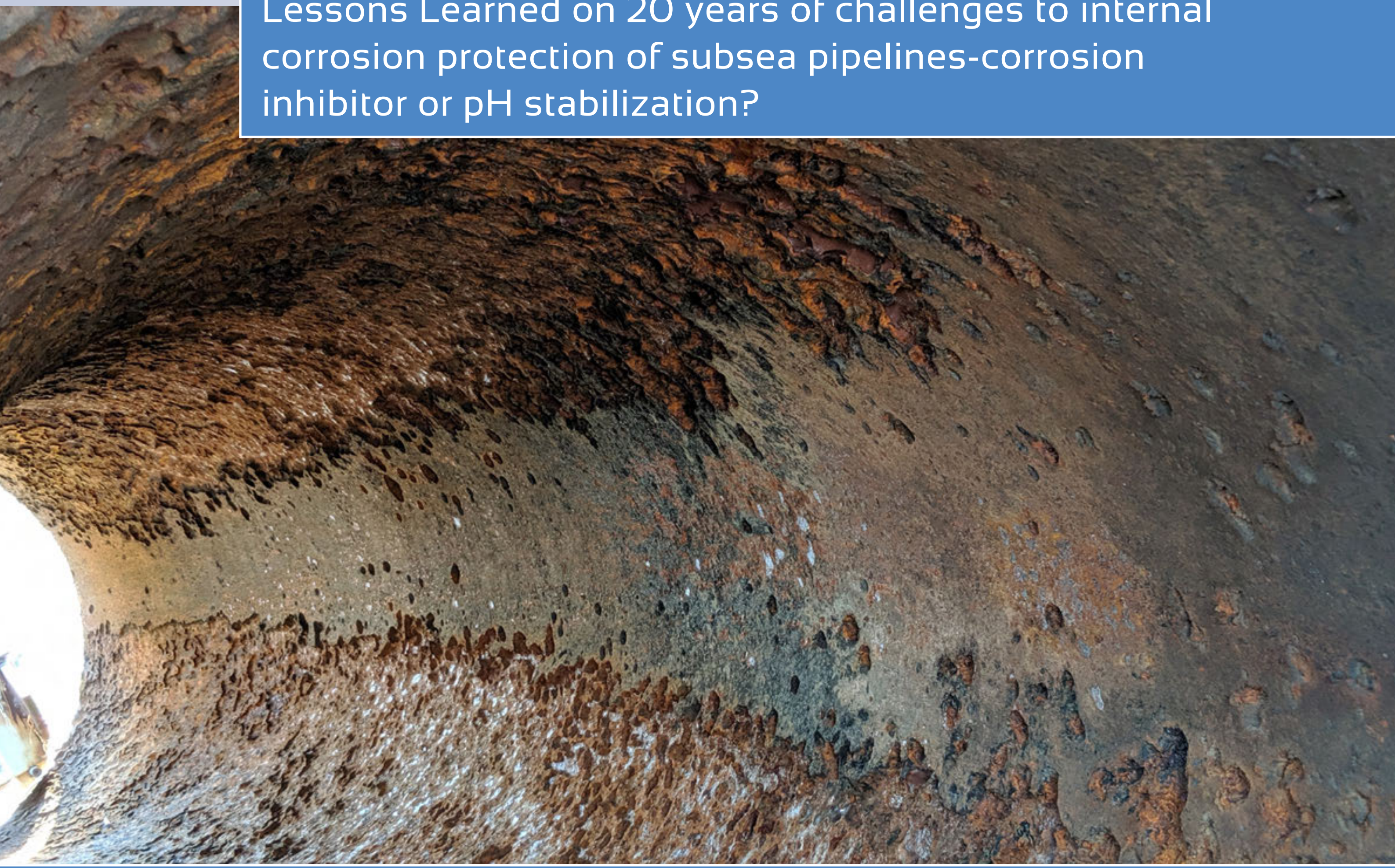
Lessons Learned on 20 years of challenges to internal corrosion protection of subsea pipelines-corrosion inhibitor or pH stabilization?



Reza Ghorbani, Omid Razavi Zadeh > South Pars Gas Complex

Abstract

The three phase fluid of the massive South Pars reservoir under the Persian Gulf, is transmitted 100Km to onshore facilities via numerous 32" API 5L pipelines. The wet sour fluid contains 0.5 mol% of H2S and 1.7 mol% of CO2 which forms a hostile environment to carbon steel. Hence, as per former laboratory researches at design stage in about 20 years ago, two different mitigation methods were concluded to tackle internal corrosion and hydrate formation issues.

pH stabilization technique (PST) was developed during the project conceptual phase and implemented for the first time for Sour system by TOTAL Company in the in oil and gas sector; and the second one was conventional injection of film forming corrosion inhibitor. Since then, PST has been carried out by continuous injection of 70 wt.% Lean Mono Ethylen Glycol and 4 wt.% of Methyl Diethanol Amine, as the main method. In the meantime, film forming inhibitor injection was also deployed as the backup when PST was unavailable.

PST requires a robust MEG regeneration system. when the fluid is enriched with calcium and carbonate ions during water formation influx, it can lead to sever scale deposition and clogging the line. On the other hand, corrosion inhibition by film forming has some ambiguities such as protection of metal beneath the sludge, or the reliability of residual corrosion inhibitor in the presence of low dosages of kinetic hydrate inhibitor.

In this paper, mass spectroscopy and high pressure liquid chromatography on filed and synthetic samples is deployed to pinpoint the actual error value and compensation rate. Consequently, a reasonable degree of certainty for the amount of residual corrosion inhibitor is figured out to increase the reliability in the pipeline integrity management strategies.

1. INTRODUCTION

Pipelines as the prevailing means of crude transportation in the midstream sector of oil and gas industry, has always been one of the main topics in the corrosion field of study. With reference to official statistical organizations, Iranian's pipeline industry is ranked eighth among 120 countries possessing 3.5 million kilometer pipelines in the operation [1]. Asia as the leading oil and gas pipeline length have around 71,000 Km [2], In South Pars field developments 37 sea lines of 3,000 Km (total length) operates which made it as one of the biggest offshore operating activities in world.

Based on available data by united states regulatory and DNV reports, almost half of all pipelines' incidents are caused by internal corrosion [3, 4]. From the corrosion point of view, the acidic water corrosion in the upstream sector, is mainly categorized in two classes. Sweet environment is referred to the formation of carbonic acid by dissolution of carbon dioxide into the water, and likewise there is sour environment when hydrogen sulfide dissolves into the water

At the first stages of sweet corrosion, iron carbonate layer forms as the main corrosion product, which mitigate further corrosion as a diffusion barrier by below electrochemical reaction [8]:

$$Fe + CO2 + H2O \rightarrow FeCO3 + H2$$

The layer shows a good adhesion strength larger than the typical wall-shear stress imposed by turbulent flow[9], after attaining a minimum thickness of 2 microns[10, 11]. Hypothetically this leads to a uniform corrosion with limited penetration (depending on CO2 partial pressure and temperature up to 80 microns), but in the reality the layer thickness in some locations cannot reach the criteria, and so dissociation forms in anodic areas. This can be due to the presence of chloride as a reducing agent or higher flow over rough surfaces forming micro-turbulences. Depend on the fluid dynamics, at low velocities Pitting corrosion, at medium velocities Mesa Attack and at velocities higher than 10 m/s Flow Accelerated Corrosion (FAC) occurs. In any case, all mentioned mechanisms are reliant on fluid chemistry, temperature, partial pressure, and flow[12]. Thus different mathematical models are developed by different companies or universities[13, 14]depending on the operator and national authority as the client[15]. There is another type of corrosion which is involve presence of wet H2S in fluid which is called Sour corrosion . The main reaction mechanism for wet H2S or sour corrosion is as follows:

$$Fe(OH)^+ + H^+ + HS^- + OH^- \rightarrow FeS + 2H_2O \text{ (Basic Solution)}$$

In this reaction, iron sulfide (FeS) as a protective corrosion film forms on surface. This layer has higher adhesion strength with lower thickness than that of iron carbonate. however this is always a risk of FeS destruction by turbulences and also not stoichiometric FeS. Depending on temperature, pH and H2S concentration, it deviates from stoichiometric composition and results in Fe1-xS or Fe1+xS deficient structures which may have lower adhesion strength. In addition, the interaction of H2S and CO2 exacerbate internal corrosion condition. Moreover one of the main issues with pipelines is the simultaneous occurrence of corrosion and hydrate formation. Common solution is the combined injection of corrosion and hydrate inhibitors, but they may have adverse effect on each other's functionality[24].

Further to Mono-Ethylene Glycol (MEG) as a Thermodynamic Hydrate Inhibitor (THI), Low Dosage Hydrate Inhibitors (LDHI) are classified in two categories by their mechanism[25]. Kinetic inhibitors (KHI) hinder hydrate formation by prolonging induction time of hydrate formation more than the residence time of free water in pipeline; whereas anti-agglomerants (AA) emulsify hydrates to prevent pipeline clogging. The most important aspect of a KHI is its effect on the mineral scale deposition in the pipeline. MEG is considered as a conventional KHI around the world, but occasionally another effective KHI may be added to MEG especially during well intervention operations[27].

In any case, a single compound to inhibit: 1) corrosion, 2) hydrate formation and 3) scale deposition at the same time, has not yet been developed. Thus, pipeline operators are dealing with the combined inhibitor injection effect. Specifically, in the case of lengthy pipelines as for South Pars, the temperature gradient between input and output flow causes massive formation of both hydrates and scales on the metal surface. Henceforth, in this article 20 years of pipeline operation experience in South Pars by different inhibition methods, are discussed in detail.

2. PROCESS

2.1. OFFSHORE PROCESS

The South Pars field process facilities are developed in twenty-four identical integrated phases. The platforms are situated in the South Pars Field area approximately 100 km from the Iranian coast. The reservoir production with minimum offshore processing facilities is connected to the shore via 32" multiphase sea lines. A brief schematic illustration of the offshore process flow is represented in figure1.

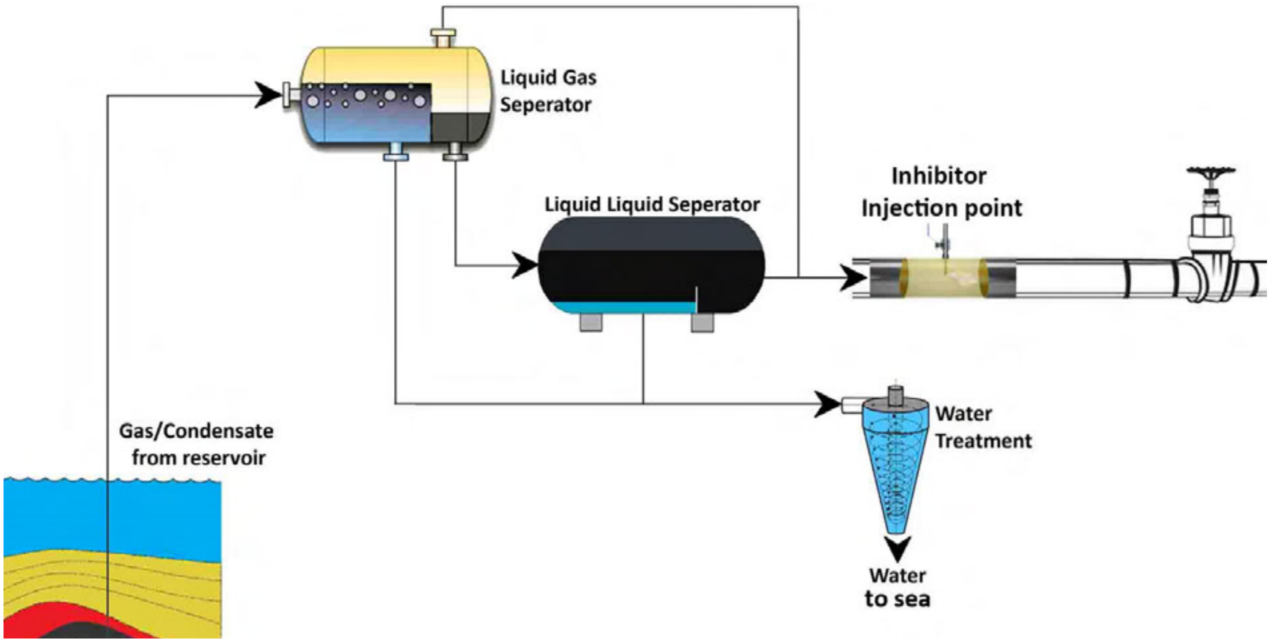


Figure 1: A brief schematic representation of offshore process

Each platforms are connected to the onshore facilities by means of a 32" export pipelines. All pipelines are bearing a 4" MEG piggy back line.

South Pars fluid contains 0.5 % H2S and 1.8% CO2 and When pressure and/or temperature decrease, condensate water provoking corrosion with acid gas and made pH between 3.6 and 3.8.

2.2. ONSHORE PROCESS

The fluid of rich MEG sent to MEG Regeneration Units which is located in onshore including 4 identical packages that in normal operation 3 units are online, alongside 1 unit in stand-by mode. The main purpose of the MEG Regeneration Units is to reduce the water content (approx. 66.5%) of the Rich MEG and maintain the concentration as per specification which is suitable for re-injection into the offshore sea lines. As Fig. 2 shows, this is achieved by simply removing contaminants in filters and evaporating the excess water by passing the fluid through Glycol Reboiler.

2.3 INHIBITION STRATEGIES

MEG which is sent from onshore through a 4" piggy back lines is injected at platform departure to prevent both hydrate formation and corrosion in the sea line. The onshore MEG regeneration unit provide solution of 70% MEG (30% H_2O) which supplied via 4" piggyback line from onshore. This contains 1.5 vol.% Methyl DiEthanolAmine (MDEA) as a pH control additive to prevent corrosion issues within the sea lines. The in situ pH at arriving point shall be kept above 7.04 to ensure effective corrosion mitigation. This technique called pH Stabilization technique (PST) and South Pars is the biggest field in the world implementing corrosion prevention by PST.

In addition, The platform is equipped with corrosion inhibitor(C.I) package to provide protection when PST is out of service. Injection rate is based on 0.5 liter per MMSCF1 of gas. Corrosion Inhibitor is to be injected at 20 ppm wt.% on total fluids. One storage tank with capacity of 6000 liters is dedicated which equivalent of 10 days of Inhibitor injection as per designated rate.

2.4. INSPECTION AND CORROSION MONITORING

ILI considered as the essential and most important technique to detect cracks and metal loss which may formed internal and external of the pipe line which usually shall be carried out in a regular 4 years intervals. Since the interval frequency is almost long, it is strongly required to deploy other corrosion monitoring techniques such as corrosion coupons , Electrical resistance probes and laboratory analysis.

Intrusive Corrosion monitoring points located at departure from the wellhead platforms and at arrival at the onshore facilities. Corrosion coupons installation, preparation, analysis and interpretation carried out according to NACE SP 0775.The coupons and probes are installed through 2" access fittings at both '6 and 12 o'clock' position in order to ensure they will be in contact with vapor saturated gas and the free water.

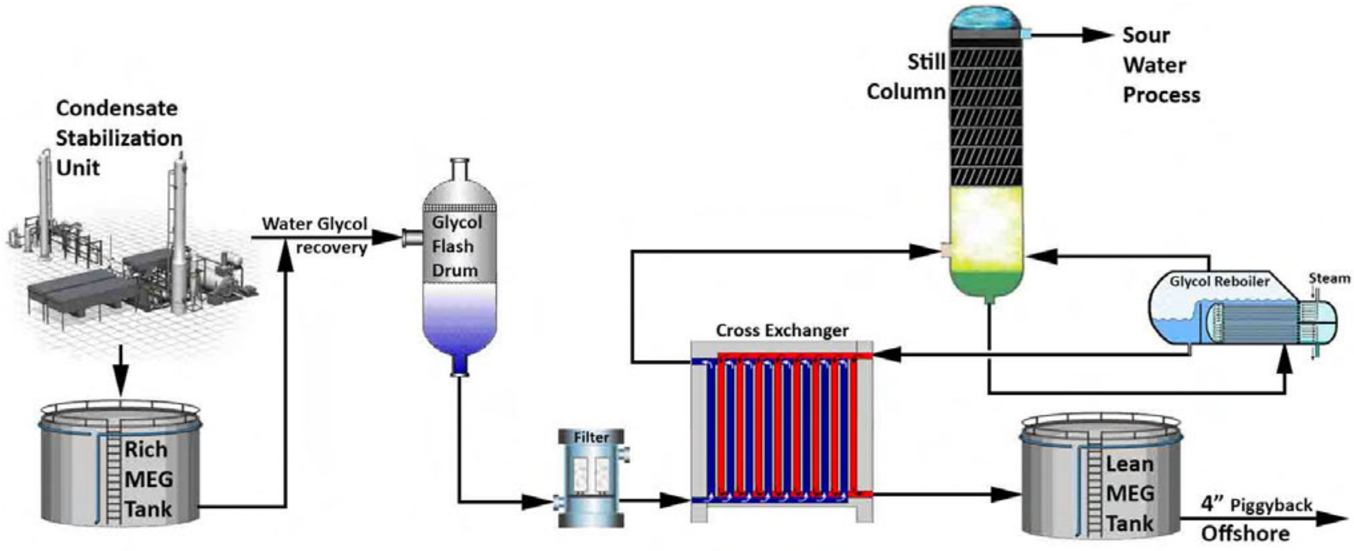


Figure 2: MEG regeneration process flow diagram

Chemical analysis on sample got on corrosive fluid are of prime importance to cross check with intrusive monitoring acquired data and improve the response time.

Adequacy of injected corrosion inhibitor is carried out by measurement of residuals corrosion inhibitor at the end of sea lines using methyl orange which recently superseded by Bromophenol Blue titration technique due to significant erroneous results .

Moreover, when protection is under PST mode ,daily analysis of pH, total Fe and salinity as chloride content is take place whilst for C.I injection mode, evaluation of residual C.I and total Fe is a prime importance.

3. CHALLENGES AND ISSUES

Depend on the mode of protection, there are several issues and challenges which threat the pipeline integrity and flow assurance. One of the recent main issues is probable risk on top of line corrosion (TOLC) initiation in segregated flow regimes, where high amounts of acidic gases (CO2 / H2S) are dissolved in the condensed water due to the cooling by external conditions (high heat transfer rate).

On the other side, at the bottom of pipeline there is a risk for Corrosion Under Deposit (CUD) where organic depositions is likely and inhibitor diffusion is minimal. To tackle this issue, compliance to diligent program is in progress to run bi-directional or sphere pigs to mitigate the corrosion risk by removing the sludge , deposit and liquid hold-up from the pipeline.

Considering the typical fluid composition in South Pars multiphase flow pipelines, the CO2/H2S ratio is below 20 indicating the dominance of H2S corrosion. However, formation of protective FeS thin film is vulnerable to reducing agents such as chlorine and organic acids, that incipient localized corrosion at the breakdowns, causes pitting and metal loss.

On following section, issues which is experienced with PST and C.I is explained and evaluated.

3.1. PH STABILIZATION (PST)

PST is very well suited to be used in combination with glycol as hydrate preventer which regenerated in a closed loop which considered cost effective from operational expense point of view. The role of PST is capturing H+ ions and thus increasing bicarbonate concentration and reduce the fluid corrosiveness. However as main limitation and drawback, when the formation water contains high concentrations of calcium cations (above 500 ppm), the potential for calcium carbonate sedimentation increases drastically due to the increment in the insoluble calcium carbonates which experienced in South Pars. Below equation shows the equilibrium reaction for calcium carbonate formation:

$$H_2CO_3 <-> H^+ + HCO_3- \qquad Ca^{++} + HCO_3^- -> CaCO_3 + H^+$$

Following the pressure drop and to flow assurance issues noticed on sea lines on 2003 (just few years after operation) it was decided to run the caliper pig to identify and quantify the amount and distribution of scale inside the pipelines. At the first step, It was attempted to run a gauge pig to obtain a preliminary data on pipeline clearance. A severe damage to the received gauge pig as is shown in Fig. 3 (left), clearly indicated that the thickness of the scale deposits was much greater than anticipated.

Figure 3. Damaged gauge pig and CCTV inspection results

Consequently, it was clearly understood that a special caliper pig tool is required to pass inside the pipeline with regards to the scale significance. The configuration for the 32" caliper pig used had 16 caliper arms and two odometer distance measurement wheels. The 16 caliper arms activated 8 caliper sensors, i.e. two arms to each sensor. The aim of the caliper survey was to report the location, and approximate quantity, of calcium carbonate deposits formed within the pipeline as a unwanted part of PST.

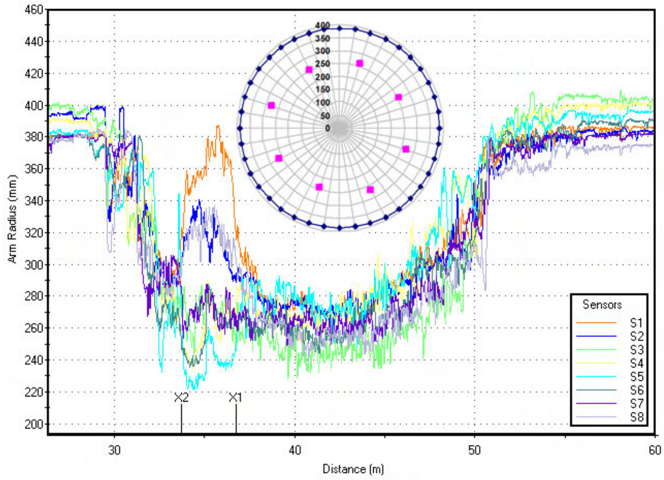


Figure 4. Caliper pigging result showing high amount of deposition right after injection point at the top of riser.

An overview can be determined from the bore plots obtained by caliper pig in Figs. 4 and 5. According to Fig. 4, the topside pipe-work appears to be clear of deposits, with the mean bore staying within a few millimeters of the nominal bore, from the launcher, through the pipeline bend entry to the sea, at the top of the riser. Figure 4 inset is a diameter plot of the data showing the extent and distribution of the scale, where the minimum bore is in the orders of 500mm (i.e. a bore reduction of 270mm or 35%). The total length of the deposits measured over this section was 25.5m (vertical section of riser).

To dissolve the scale, a massive operation of acid cleaning done by injection of inhibited hydrochloric acid between pigs using pistoning technique and acid withdrawal by depressurizing and subsequent neutralization by soda ash.

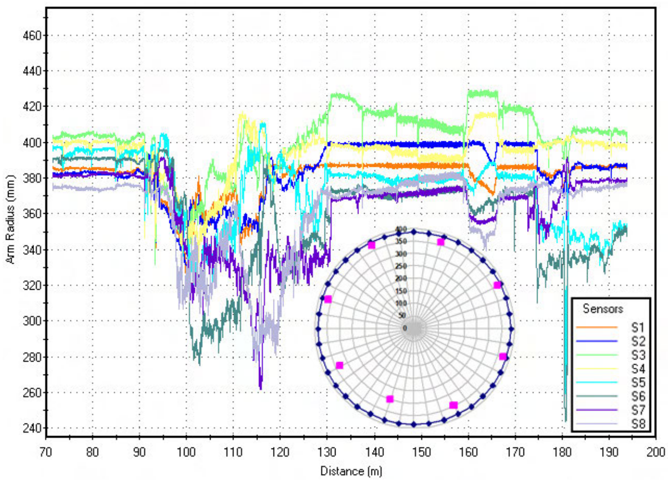


Figure 5. Caliper pigging result showing deposition at the bottom of riser through dog-leg

Another difficulties with PST, is sludge deposition due to contamination of glycol with salt, hydrocarbon, particulate, or corrosion inhibitor. This contingencies increase the cost for replacing glycol filters elements and also maintenance team to struggle to meet the timing compliance. In worst case scenario, if the glycol system is badly contaminated, the system is to be fully drained and recharged with new fresh glycol. In addition, High concentration of calcium ions in MEG can dramatically affected the MEG regeneration

Figure 6.Severe scale build up on lean-rich MEG exchanger tubes

units duty by scale precipitation on external and internal sides of exchangers tubes which hinder the unit to change rich MEG to lean MEG within the specification as shows in Fig.6.Under this circumstances it is strongly required a MEG reclaiming package to be installed as complementary of MEG regeneration unit. There are some cases that PST was stopped due to unavailability of MEG regeneration packages and swing to C.I injection unintentionally.

3.2. CORROSION INHIBITOR

Continues injection of film former inhibitors has been considered as a backup corrosion prevention method of sea lines. Proper corrosion inhibitors selected by a wide range of laboratory and field evaluations. A number of factors such as temperature, pressure, inhibitor water-condensate partitioning, water chemistry and flow regimes [31], influence inhibition in multiphase flow pipelines. In South pars, Imidazoline based film former CI was adopted. In comparison, results of corrosion rate acquired by coupons and ER probe are plotted in Fig.7.

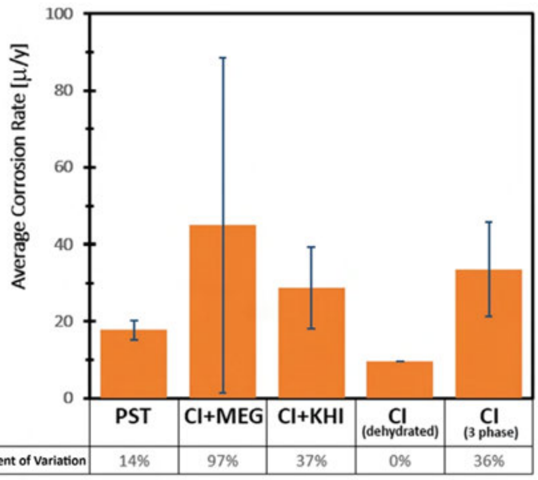


Figure 7. Corrosion rate measurement by coupons and ER probes for both methods of CI injection and PST.

As it has been shown in Fig.7 complete dehydration of three-phase fluid, leads to the lowest general corrosion rate. Accordingly, the next best method experienced was PST with the most reliable data.

Although general corrosion rate acquired by corrosion coupons shows mild metal loss however recent finding proven events of top of line corrosion (TOLC) under specific conditions. In one of lines which after only 2 years of operation a 3 mm localized corrosion was detected. The corrosion mechanisms evaluated as to be TOLC, which was due to the stratified flow and inability of CI diffusion in the gas phase. Severe localized corrosion detected on similar dead leg zones where water saturated gas is trapped as like TOLC. One solutions to this problem, is flow pattern enhancement which enables C.I molecules to attach all pipe wall surface. Unfortunately the only plausible technique to detect metal loss due to TOLC is ILI which is not a frequent application to capture the threat in early stages. Consequently a diligent dynamic test method is required to evaluate inhibitors performance on prevention of TOLC.

Measuring residual of corrosion inhibitor active component is a key performance indicator to ensure adequacy of chemical to optimize the injection rate whilst protection is achieved. Hence, care must be taken in reliance on inhibitor residuals as a sole indicator of inhibitor performance. As stated earlier, methyl orange method was used for several years to determine the residual C.I of samples which collects from pipeline outlet in onshore. However, recently it was found that there is some uncertainly on accuracy of measurement of residual C.I in presence of LDHI. In order to proof the validity of methyl orange method and probable oversights, extensive cross discipline collaboration work was done and variety of samples in different concentration of CI and LDHI was tested. Based on the results which is summarized in table 1, the amount of residual C.I is over-estimated when in conjunction with LDHI compare to real value. For example, when there is 5 ppm of C.I, accompanied by 5 ppm LDHI in the sample, the results show 15 ppm of CI concentration (verified by liquid chromatography mass spectroscopy. Consequently several test methods such as Bromophenol Blue titration and Iodometry has been implemented to assess the reliability when measuring residual C.I in presence of LDHI. Based on the results, highest reliability is acquired when using Bromophenol Blue titration with only 5-10 % present error which is shown in Fig.8. Studies and analysis now is in progress to minimize the error to a level of high degree of certainly

As these data show, the resulted concentration do not follow a distinctive pattern which analytical chemist unable to calibrate devices to eliminate the error. It would even more hectic when sulfur, oxygen or nitrogen constitutes of crude such as mercaptan are present

In addition, corrosion inhibitors and hydrate inhibitors may have adverse effect on each other and produce undesirable polymeric byproduct, such as heavy compounds of paraffin or olefin which leads to a drastic reduction in the heat exchanger efficiency in downstream process. Consequently most stringent precautions is required to perform the compatibility test and the also avoid to inject beyond the recommended dosage to prevent sticky substances in downstream. This leads to a drastic reduction in the heat exchanger efficiency in downstream process, owing to the formation of thick adhesive fouling on the tubes.

Compare to expenses part since C.I injection considered as once through and not going to recycled in system, this will incur extra operational cost compare to PST. The cost includes C.I procurement, shipment to offshore and loading. more over there is always a risk of inhibitor unavailability if the bad weather hinder chemical transportation in to platform. however the cost may be offset compare to PST when capital expense for installation of MEG regeneration packages and energy consumption to run the unit when all parameters comes into the picture.

Finally, since CI are generally not environment friendly and cannot be disposed in the environment, most stringent precautions and care is required for safe disposal of inhibitor solutions due to the prevent any environmental side effect like changing the biochemical oxygen demand and chemical oxygen demand.

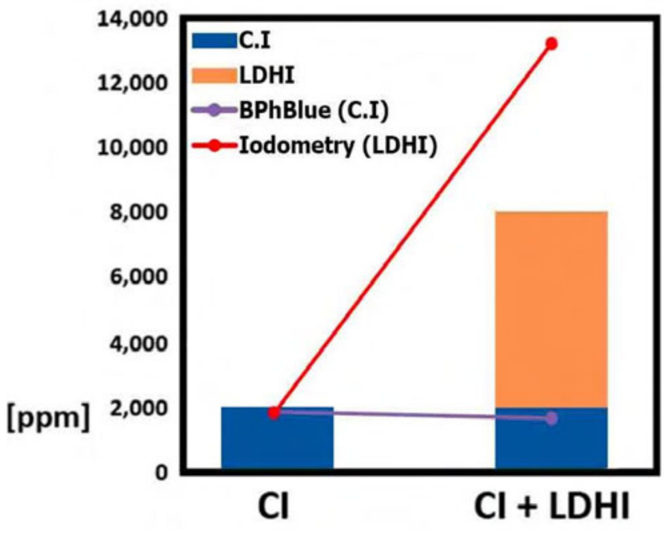


Figure 8. The effect of CI partitioning on the LDHI measurement

Sample No.	CI [ppm]	LDHI [ppm]	Measured CI [ppm]
1	5	15	34.81
2	5	10	24.81
3	5	5	14.63
4	5	0	5.15
5	10	0	9.95
6	20	0	19.96
7	0	10	20.03
8	0	20	38.87
9	10	10	30.37
10	20	20	Over range

Table 1. CI and LDHI partitioning measurement results

4. CONCLUSION

Although PST and C.I has their own pros and cons, successful implementation strongly depends on the condition and system fluctuation. The negative and positive aspects of the both methods are listed briefly below:

- PST results in minimal corrosion rates compare to C.I with average corrosion rate almost below 0.1mpy however both techniques shows low general corrosion rate. In addition, Protection passive layer formed by PST is more adherent and resistive to fluid shear stresses than formed film by CI.
- If reservoir water is produced which is mostly contains high concentration of Ca2+, there is a high risk of sedimentation inside the pipeline which have high impact on flow assurance. Sedimentation also can occur the onshore MEG regeneration package which hinder the unit to re-treat MEG into desired purity.
- In most cases, the calcium content of the wells of a platform is vary. Under this condition, it is strongly recommended to perform robust well management strategy by put wells in service in such a way that Ca2+ maximum concentration of the mixed fluid set below 500 ppm.
- PST requires expensive capital investment whilst CI imposes greater running costs and also offshore logistic expenses. In addition there is always risk of C.I unavailability due to bad weather or other dispatch problems. Mostly, there is no enough space on platforms to keep massive chemical inventory.
- Although both methods are vulnerable to TOLC, the risk is higher when using C.I specially on gas trapped areas. Consequently most stringent precautions requires to select a new corrosion inhibitor to validate effectiveness against TOLC by dynamic set up tests.
- Selecting the method of measuring residual C.I is crucial. The test method shall be fully evaluated and validated to ensure reliability and replicability on analysis and corrosion mitigation.

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Safely repairing subsea flanges on flexible flowlines with a flexible bridging jumper structure

Giuseppe Rizzo > Oceaneering International Services

Abstract

As offshore pipelines age, the oil and gas industry must properly maintain equipment to prevent leaks. In subsea flowlines, leaks sometimes originate from aging flanges. These flanges must be replaced. Historically, replacing the flange has required a lot of time. Different costly approaches are available, from subsea reparations to flowline retrieval topside to carry out repair works Further, such operations have to be carried out in a safe manner to ensure no potential pollutants are released during the repair and that all personnel involved in the activity are safe. A better way to carry out the flange repair subsea was needed.

Oceaneering developed a technology that made it possible to convert and retrofit diver-assisted flexible flowline subsea connections to one that could be made via remotely-operated vehicle (ROV). The method relies on the Flexible Bridging Jumper Structure (FJBS), which connects two jumper ends with the Grayloc® Remotely Operated Clamp Connector. This structure makes it possible to carry out all operations remotely and with less need for support vessels and fewer personnel, which translates directly into safer operations and lower costs. More importantly, the bridging structure combined with the Grayloc® connector minimizes the potential for losing pollutants into the water during the operation.

The FJBS solution has been fully qualified. Factory acceptance testing (FAT) occurred at an Oceaneering facility in Houston, Texas. The FJBS was deployed multiple times following its development in 2016; the second generation of the FJBS was first deployed successfully in South America in 2018.

The system consists of a clamping frame, Z tray assembly, X tray assembly, frame and frame assembly, along with ROV torque buckets to allow for ROV operations. To install the Grayloc® remotely-operable clamp, the FJBS is deployed with a replacement weak link installed. The flowline end fittings are then placed onto the support structure clamp. The pull in cylinders are activated. Following a subsequent seal test on both ends, the alignment skids are retrieved to surface. The FJBS can accommodate different flowline sizes, which reduces the tooling required for each intervention.

1. INTRODUCTION

Due to the environmental and safety risks of subsea intervention operations, many offshore oil and gas companies are actively seeking ways to mitigate and eliminate risks. Companies are increasingly favoring remotely operated vehicle (ROV) operations over diver operations for several reasons. One is that diver operations are limited to certain depths, but many subsea assets are installed well below those limits. Sometimes, metocean conditions, like high currents, are such that diving operations are unsafe or outright impossible. Finally, every person who is working offshore presents a certain amount of health, safety and environment (HSE) risk, and that risk exposure is much higher for divers. ROVs, on the other hand, can safely operate in depths to 3,000 meters, even in challenging metocean conditions. They are operated remotely, so there are no personnel in the water. Additionally, fewer personnel are needed to support ROV operations than diving operations. For all of these reasons, ROVs can help operators reduce risk when executing subsea interventions.

Historically, a flange replacement operation might have involved closing down the flowline, cutting the flowline, replacing the worn equipment, and reconnecting the flowline. This approach carries the risk of potential pollution. Also, because divers have historically had to torque bolts into place when connecting two jumper ends, there was the possibility of an incomplete seal, which could lead to contamination of the subsea environment. Using the FJBS can reduce pollution risk for subsea repairs. The FJBS connects two flexible jumpers using a proprietary subsea connector that allows for future disconnect of the jumpers as needed. The FJBS also relies on a diverless method of repair, relying instead on an ROV which can torque bolts precisely.

Another factor is the time involved for the repair. When the flowline is shut in for the repair, no hydrocarbons are being produced. Repair operations that can decrease the length of the shut-in are preferable because they return the wells they serve to profitability faster. Moving equipment through the water column takes time, and in the past, one common practice was to bring aging flexible flowlines to the topsides to makeup the repair connection, then returning the flowline to the seabed.

The FJBS method is a field-proven way to make a diverless connection between two flexible jumpers subsea in both shallow and deep water. It was used offshore South America in 2018 for a client who needed to retrofit equipment to bring additional production online after several years of inactivity, but the work couldn't be carried out by divers because of high ocean currents and low visibility. This subsea connection had to be carried out by an ROV. Oceaneering successfully connected the wet-stored jumper and a new flexible jumper with a solution that resulted in less environment impact, lower intervention cost, fewer support vessels, fewer personnel, and increased safety.

Figure 1: The Flexible Jumper Bridging Structure (FJBS)

2. USE CASES

In addition to using the FJBS to carry out intervention work on aging flexible jumpers, it is possible to use the structure to help avoid potential leaks and during commissioning activities.

For leak avoidance, for example, the FJBS may be used if an operator is worried about potential leaks or whether an anchor has caused damage. During commissioning, the FJBS may be used to prevent water from entering into a flowline, or it can be used for the blind flange during decommissioning when the line must be closed.

3. THE EQUIPMENT

The FJBS consists of two independent silicone-lined clamp assemblies that secure each end of the flexible's end fitting: one fixed and one designed to provide alignment in the X, Y, and Z axes. Both assemblies share a common structure that supports both flexibles and their end fittings after the connection is made. The connection can be made with the Grayloc® clamp, or another type of connection. The structure also provides the necessary stroke to accommodate flange adaptation and flexible jumper deployment. ROV torque buckets make it possible for ROVs to carry out the repair.

The FJBS was designed to pull a flexible jumper with 10 tonnes of force over a stroke of 30 inches (76.2 cm). It was designed to horizontally and vertically align the flexible jumper end fitting with 2 tonnes of force and over +/- 3 inches (7.62 cm) in either direction.

The Grayloc® remotely operated clamp connector creates a metal-to-metal seal for the jumper connection. The Grayloc® clamp has a gasket to ensure a proper seal.

Length:	34.2 ft/10.4 m
Width:	8.5 ft / 2.6 m
Height:	7.2 ft / 2.2 m
Weight in air:	25,000 lb / 11,340 kg
Weight in water:	21,875 lb / 9,922 kg
Design life:	25 years

Table 1: FJBS specifications

The foundation of the FJBS is the frame. The frame's flexible jumper supports hold the jumper segments in place during the connection operations. The frame can move along the X and Z axes for proper alignment during the connection operations. There are ROV torque buckets in various locations on the frame to allow for ROV operations.

The X and Z tray assemblies can compensate for the linear misalignment on both longitudinal and vertical orientations.

Figure 2: The FJBS during factory acceptance testing in Houston, Texas.

4. STANDARDS

The FJBS solution meets all standards stipulated in API Recommended Practice (RP) 17H for ROV and remotely operated tool interfaces and intervention systems. It also meets the American Welding Society's codes for general structural welding and stainless steel structural welding, the Det Norske Veritas standard for certification of portable offshore units and recommended practice for cathodic protection design, and International Organization for Standardization's standard for cathodic protection design.

5. OPERATIONS

Prior to beginning the subsea repair, preliminary activities like dredging must first occur. That dredging can be carried out by an ROV capable of dredging. Then the bridge structure is deployed over the side of a vessel using a crane and lowered to the seabed. The FJBS, which deploys with a blind clamp and replacement connector installed, is situated on the seabed so the jumper segments that must be connected can be placed onto the flexible jumper supports.

The ROV removes the flexible jumper from the Christmas tree and places the end of the flexible jumper onto the flexible jumper support structure on the FJBS. Next, the ROV pulls the flexible jumper into the spool adapter. The X and Z tray assemblies, which move to ensure proper alignment, can remove linear misalignments of up to ±75 mm (±3 inches).

A clamp secures the flexible jumper in place. The ROV activates the Grayloc® clamp connectors and secures the flange bolts to lock the jumper into place. Once the connection is secure, a pressure test on the API flange is carried out to verify a proper seal.

Figure 3: FJBS on a vessel for a project offshore Canada.

The ROV can open the blind clamp and retract the flexible jumper until the spool clears. A crane removes the blind clamp and installation tool, which clears the way for the second flexible jumper to be connected.

The flexible jumper is deployed with the Grayloc® clamp and pull-head preinstalled. It is lowered into the flexible jumper support. The clamp closes when the jumper is in position. The flexible jumper Grayloc® clamp is opened and the pull-head removed. The ROV pulls the second flexible jumper toward the flexible jumper equipped with the Grayloc® clamp. The X, Y and Z axes are adjusted as needed. The flexible jumper mates with the Grayloc® clamp, which torques into place. The Grayloc® connection is then pressure tested to ensure the connection is successful.

The ROV opens both flexible jumper bridge clamps to free the jumpers from the FJBS. The ROV attaches rigging to the bridge structure for equipment recovery, and a crane pulls it to the surface. The job is now complete.

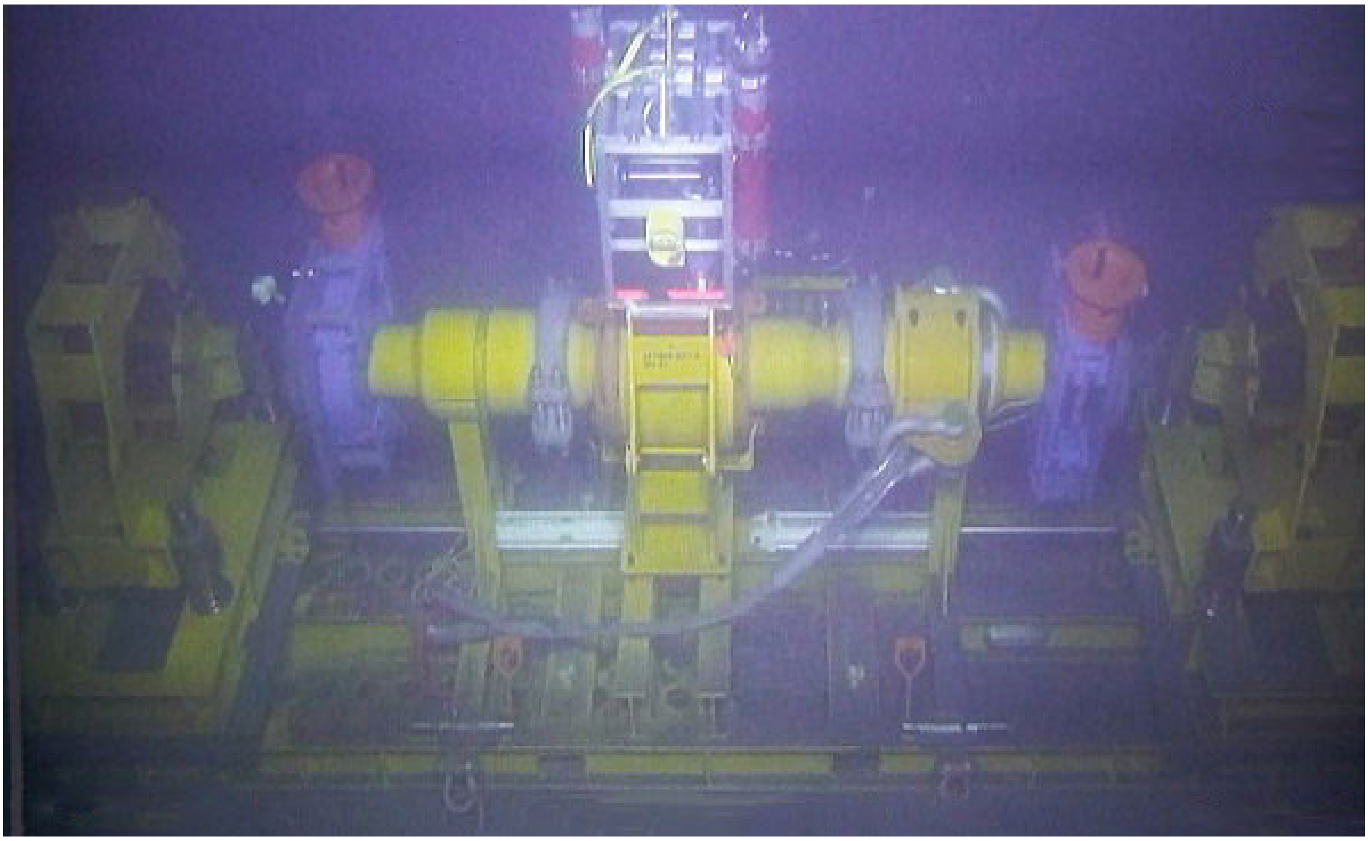

Figure 4: A pressure test shows the connection was successfully set.

6. CONCLUSION

While the traditional method of connecting jumpers has long involved solutions that required divers and could lead to the release of a pollutant, the FJBS is engineered in such a way that removes divers from the process while eliminating the possibility of polluting the subsea environment. The FJBS is a flexible flowline subsea connection that can be made by ROVs rather than divers, which makes the operation safer from a personnel perspective.

Ensuring the integrity of equipment helps improve the profitability of late-life assets.
The FJBS technology represents an important step toward improving the profitability of late-life assets. It eliminates diver-assisted operations, which greatly reduces CAPEX due to the elimination of the vessel support and ancillary equipment required for diving operations.

The deployment of the FJBS has enabled clients to save money while improving human safety and decreasing the threat of environmental pollution. Using this technique, one client saved about $6 million by using the FJBS and avoiding the need for divers to carry out the flexible jumper connection.

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Association

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www.koetter-consulting.com

Inline Inspection

3P Services
Germany
www.3p-services.com

A.Hak Industrial Services
Netherlands
www.a-hak-is.com

Baker Hughes
United States
www.bakerhughes.com

Intero Integrity Services
Netherlands
www.intero-integrity.com/

Kontrolltechnik
Germany
www.kontrolltechnik.com

KTN AS
Norway
www.ktn.no

LIN SCAN
United Arab Emirates
www.linscaninspection.com

NDT Global
Germany
www.ndt-global.com

Pipesurvey International
Netherlands
www.pipesurveyinternational.com

PPSA - Pigging Products and Services Association
United Kingdom
www.ppsa-online.com

Romstar
Malaysia
www.romstargroup.com

Rosen
Switzerland
www.rosen-group.com

Ametek – Division Creaform
Germany
www.creaform3d.com

Applus RTD
Germany
www.applusrtd.com

EMPIT
Germany
www.empit.com

Integrity Management

Metegrity
Canada
www.metegrity.com

Pipeline Innovations
United Kingdom
www.pipeline-innovations.com

Leak Detection

Asel-Tech
Brazil
www.asel-tech.com

Atmos International
United Kingdom
www.atmosi.com

Direct-C
Canada
www.direct-c.ca

Entegra
United States
www.entegrasolutions.com

Fotech Solutions
United Kingdom
www.fotech.com

GOTTSBERG Leak Detection
Germany
www.leak-detection.de

Hifi Engineering
Canada
www.hifieng.com

Liwacom
Germany
www.liwacom.de

MSA
Germany
www.MSAsafety.com/detection

OptaSense
United Kingdom
www.optasense.com

Pergam Suisse
Switzerland
www.pergam-suisse.ch

PSI Software
Germany
www.psioilandgas.com

sebaKMT
Germany
www.sebakmt.com

SolAres (Solgeo / Aresys)
Italy
www.solaresweb.com

Materials

Vallourec
France
www.vallourec.com

Monitoring

Airborne Technologies
Austria
www.airbornetechnologies.at

Krohne Messtechnik
Germany
www.krohne.com

PHOENIX CONTACT
Germany
www.phoenixcontact.de/prozess

SolSpec
United States
www.solspec.solutions

Operators

Transneft
Russia
www.en.transneft.ru/

TRAPIL
France
www.trapil.com/en/

Qualification & Recruitment

YPPE - Young Pipeline Professionals Europe
International

Pump and Compressor Stations

TNO
The Netherlands
www.pulsim.tno.nl

Repair

CITADEL TECHNOLOGIES
United States
www.cittech.com

Clock Spring NRI
United States
www.clockspring.com

T.D. Williamson
United States
www.tdwilliamson.com

Research & Development

Pipeline Transport Institute (PTI LLC)
Russia
www.en.niitn.transneft.ru

Safety

DEHN & SÖHNE
Germany
www.dehn-international.com/en

HIMA
Germany
www.hima.de

Signage

Franken Plastik
Germany
www.frankenplastik.de/en

Surface Preparation

MONTI - Werkzeuge GmbH
Germany
www.monti.de

Trenchless Technologies

Bohrtec
Germany
www.bohrtec.com

GSTT - German Society for Trenchless Technology
Germany
www.gstt.de

Rädlinger Primus Line
Germany
www.primusline.com

Valves & Fittings

AUMA
Germany
www.auma.com

Zwick Armaturen
Germany
www.zwick-armaturen.de

In the next Edition of **ptj:**

SEPTEMBER 2020

4th Special Edition for the ptc

The next issue of Pipeline Technology Journal (ptj) will be the 4th Special Edition for the ptc

This issue will again feature papers from the Pipeline Technology Conference - ptc.

Event Calendar		
UESI Pipelines 2020 Conference	9 - 12 August 2020	San Antonio, USA
IPC - International Pipeline Conference	28 September - 2 October 2020	Online
Virtual Pipeline Summit (VPS)	7 October 2020	Online
16th Pipeline Technology Conference	15 - 18 March 2021	Berlin, Germany

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