THE IMPACT OF OFFSHORE PIPELINE INSTALLATION AND PRE-COMMISSIONING ON FUTURE SYSTEM INTEGRITY

J. L. Grover

BJ Process and Pipeline Services, Dubai

ABSTRACT

Operators of offshore pipelines focus on the integrity of the system once commissioned, normally using internal corrosion rates as the key measure of remaining life.

Such operators, who focus on pipeline integrity management and intelligent pigging throughout the life of the asset, pay less attention to the asset during the installation and pre-commissioning of offshore pipelines, often entrusting this activity to the installation contractor.

In this paper we draw on over 30 years of experience in pre-commissioning offshore pipelines to examine some of the common mistakes and oversights in the areas of:

- Pipe spool storage and preservation
- Prevention of seawater ingress during lay
- Wet buckle impact and possible contingencies
- Pre-operational cleaning
- Source and treatment of hydrotest water
- Dewatering and drying

For each of the above we assess how the activity can affect the overall integrity of the pipeline and what steps can be taken to minimize any adverse risk.

The objective of the paper is to raise the awareness amongst offshore pipeline operators of the impact installation and pre-commissioning can have on operational pipeline integrity.

INTRODUCTION

Offshore pipelines are designed with an internal corrosion allowance based on the proposed design life of the pipeline and associated field. This may be anywhere between 10 and 30 years. The pipeline design contractor will consider a variety of factors in predicting the likely pipeline internal corrosion rate including product composition and likely composition during the field life, presence of CO_2, H_2S, or water in the product to be transported, whether the product will be treated with a corrosion inhibitor and whether the pipeline will be pigged on a regular basis.

What will not be considered in the corrosion allowance will be corrosion occurring during the storage, installation, and commissioning of the pipeline. In part 1 of this paper examples of newly laid pipelines are illustrated where internal metal loss of 30%WT has been recorded prior to start up.

Furthermore the facilities downstream of the pipeline will be designed to accept the product in the pipeline generally without consideration for the entrainment of any materials remaining in the pipeline.

There are many occurances where debris remains in the line after construction, or fine particles slough off the pipeline wall during service, often referred to as “black powder”.

In part 2 of this paper we will see examples of pipelines which have been cleaned during pre-commissioning to an agreed specification, and yet have produced up to 50 tonnes of powder on start up, damaging filters, shutting down the receiving facilities, and eroding internal components such as control valves.

PART 1 – CORROSION CAUSED DURING INSTALLATION & PRE-COMMISSIONING

Cause

From leaving the pipe mill to commencing service each pipeline joint will be exposed to many situations where corrosion can occur including:

1. End protectors not fitted, or removed during the pipe coating process
2. Pipe joints stored close to the sea, or on the lay barge without end protectors fitted
3. Pipeline suffers a wet buckle or rupture during installation allowing raw dewater to enter the pipeline
4. Water used to flood and hydrotest the pipeline is not correctly filtered or dosed with the correct chemicals to prevent corrosion
5. Pipeline hydrotest water remains in the pipeline beyond the life of the corrosion inhibition chemicals
6. Hydrotest water is not adequately removed from the pipeline by dewatering

Effect

Each of the above, or a combination thereof, can cause internal corrosion (fig. 1) to occur on the pipe wall. This effect is greatly mitigated by internally coating the pipe joints prior to installation. The resulting corrosion adversely impacts the time required to dry the pipeline – in the line detailed in the first case study, drying time increased 100% due to trapped water from poor surface condition. Once the line is in service, this fine corrosion sloughs off causing operational difficulties as detailed in the second case study.

Figure 1 – Internal corrosion

Measurement

Many pipeline operators have recognised the benefit of performing a baseline corrosion, or metal loss survey on newly installed pipelines. Such a survey can either be run during one of the pre-commissioning pigging trains, or in the pipeline product immediately after the line is put into production. Both USWM and MFL tools can be used for this purpose, however MFL tools are generally used due to cost, and future data matching requirements.

It is generally accepted that such a baseline survey should be performed as early as possible if the cause of any internal corrosion (fig. 2) is to be accurately attributed – there have been examples of newly installed pipelines having 50%WT internal wall loss within 18 months of start up which are then attributed to product related corrosion. Obtaining such data during, or immediately after pre-commissioning, may allow for claims to be made, or potential losses recovered from the project insurance.

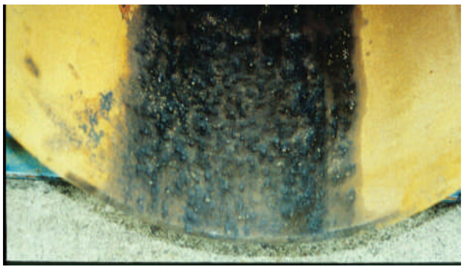


Figure 2 – Pitting corrosion @ 6 o'clock

In addition to ILI tools it is possible to measure riser and topside corrosion using video inspection and external UT inspection techniques. External UT can be applied subsea but applications are limited on buried lines or those that have a concrete weight coat fitted.

Mitigation

The following table summarises possible steps to mitigate the corrosion risks detailed above:

CORROSION RISK	MITIGATION MEASURE
Corrosion during storage, shipping and coating process	Fit end protectors, and use vapour phase corrosion inhibitor or nitrogen blanket to preserve a non-corrosive atmosphere in each spool. Thoroughly clean each spool using a mechanical brush system immediately prior to welding.
Free flooding with raw seawater due to wet buckle	Ensure an emergency dewatering spread is available to quickly dewater the line should a wet buckle occur causing the line to free flood
Water used to flood the line not correctly filtered or chemically treated	At the planning stage have a pre-commissioning specialist review the project specifications for applicability. Take samples of seawater at the filling point to assess suspended solids. Seek advice from the production chemical companies on the best treatment chemicals and dosing rates. Many projects specify a filtration level of 50µ but without any acceptance criteria on suspended solids per unit volume. Some projects are now specifying a maximum allowable level of suspended solids of 20g/m^3. At the execution phase employ an independent representative to check the size and efficacy of the fill water filtration used, and also the actual chemical dosing rates. In addition analyse regular samples of the flooding water to check for quantity and size distribution of suspended solids.
Pipeline hydrotest water remains in the line beyond the effective life of the chemicals	Often a pipeline may be “laid up” for a fixed period between the completion of hydrotesting and the commencement of dewatering / commissioning. Where this period extends beyond theoriginal planned duration, the chemical protection may not be adequate. Such an event needs to be recorded and the hydrotest water displaced with a fresh batch of water, suitably treated for the revised lay up period.
Hydrotest water is not adequately removed from the pipeline by dewatering	A thorough pipeline dewatering operation should leave a water film in the pipe of approx. 0.1mm for uncoated pipe and 0.07mm for internally coated pipe. In some applications it is possible to measure the volume of water removed from the line using flow meters. A desalination slug forms part of the pig train suitably sized to dilute the residual seawater – typically this is 4% of the line volume with acceptance criteria of a final chloride content of below 200ppm. If there is a delay between dewatering and subsequent swabbing / drying / commissioning, the remaining water film will drain down to the bottom of the line and collect at any low points. If this residual water has not been suitably desalinated it can pose an additional corrosion risk.

Table 1 – Corrosion causes and mitigation measures

Case Study 1 – Wet Buckle

Due to confidentiality, the pipeline details below are fictitious, however the engineering calculations and outcomes are factual.

A 36" x 350km offshore gas transmission line suffered a wet buckle during pipelay causing the line to free flood with raw seawater at the buckle point when approx. 160km of the line had been laid. The main section of the line was 14.3mm WT. The pipe was free flooded with seawater for 3 months. When fully immersed in seawater, steel will corrode at a remarkably steady rate to produce the oxide Fe_2O_3 (haematite) or Fe_3O_4 (magnetite). The corrosion is very rapid initially, but falls off gradually over several months to a fairly steady rate (Table 2).

Exposure Time (months)	Average corrosion rate (mm/year)
1	0.33
2	0.25
3	0.19
6	0.15
12	0.13
24	0.11
48	0.11

Table 2 – General corrosion rates for steel in tropical seawater.

It should be noted that these rates are for general corrosion and not pitting corrosion. Pitting corrosion rates are generally quoted as several orders of magnitude higher than the average rate.

In this corrosion event, it is has been assumed that the seawater is not stagnant and that there is a continuous supply of fresh corrodant to the steel surface. In addition, it has been assumed that the mill scale, and the corrosion product from the first corrosion event have formed a semi-protective coating on the steel surface. Therefore a corrosion rate of 0.13mm/year has been selected as representative of the average corrosion rate during this event (see references below). No pitting corrosion has been considered.

Therefore, assuming a corrosion rate of 0.13mm/yr over a three month period the wall thickness loss for the 150km pipeline will be d=0.00325cm. The volume of metal loss is given by:

Volume = Area x Length

$$Volume = 2.\Pi.r.d \times L$$

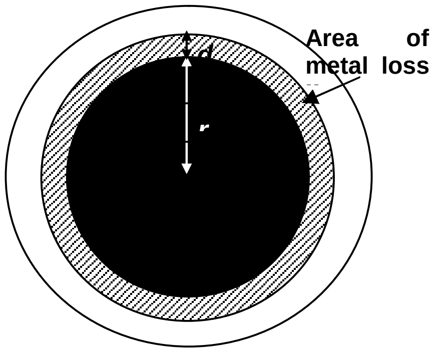
In this equation r is the internal radius of the pipe = 44.3cm, taking the diameter of the pipe to be 91.4cm and the wall thickness to be 1.43 cm. The total volume of metal loss is:

Volume = 2 x 3.14 x 44.3 x 0.00325 x 161000 x 100 = $\underline{1.5 \times 10^7\ cm^3}$

The mass of iron lost is therefore:

$$Mass = \rho_{Fe} \times Volume$$

If the density of iron (ρ_{Fe}) = 7.8 g/cm^3 then the total mass of iron lost = 1.1 x 10^8g. The total number of moles of iron consumed in the reaction is given by the equation:



$$Moles = \frac{Mass}{RAM}$$

Where RAM = Relative Atomic Mass and RAM_{Fe} = 56 g/mol therefore $Moles_{Fe}$= 2.0 x 10^6 moles.

The equation for the reaction of iron in seawater is:

$$3\,Fe + 2\,O_2 \rightarrow Fe_3O_4$$

Therefore the total amount to oxide formed from 2.0 x 10^6 moles of iron is $\underline{6.8 \times 10^5 \text{ moles}}$. The total weight of oxide is given by

Mass = Moles x RMM

Where the Relative Molecular Mass (RMM) of Fe_3O_4 = 232 g/mol. Therefore the total mass of iron oxide formed in this reaction is approximately **<u>157,000 kg (157 tonnes).</u>**

This pipeline was then subject to a baseline MFL survey where the impact of this corrosion was noted in a number of ways.

- Hard bed of debris at 6 o'clock position masking pipe wall
- Internal corrosion measured up to 35% WT
- Blockage of filters from excessive debris removed during the pigging operation

Prior to the MFL survey being performed, a number of standard cleaning pigs were run through the line by the MFL vendor to remove debris from the pipeline. Due to the internal corrosion caused by the wet buckle, and the large amount of dust formed on the pipe wall, these pigs suffered severe wear (fig. 3) and recovered very little debris from the line. It can be seen that the front of the pig is more heavily worn than the rear caused by the pig "nose diving"

Figure 3 – Worn cleaning pig

Subsequently an MFL tool was run in the line (fig. 4). Such tools are fitted with high powered magnets and strong brushes to magnetise the pipe wall – as such these tools make highly effective pipeline cleaners. During this first run nearly 20,000kg of fine powder was recovered from the pig receiver, and all external components of the MFL tool were badly worn or damaged.

Figure 4 – MFL tool

After repeated cleaning runs over 80 tonnes of ferrous debris was removed from the pipeline before a successful MFL run could be performed. This was in addition to the estimated 40 tonnes removed during pre-commissioning, and 20 to 30 tonnes removed from filters downstream of the pig receiver. The results of the MFL run endorsed the calculated corrosion rates shown previously – the deepest internal defects were greater than 35% WT with a large population of > 20% WT shown in the area immediately downstream of the wet buckle area. In total over 100,000 metal loss defects were identified.

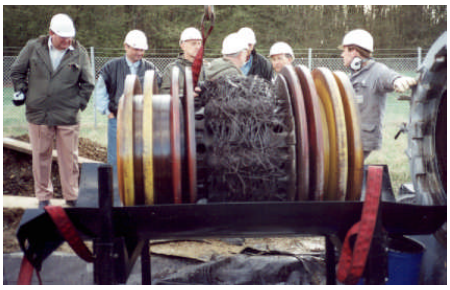


Figure 5 – Welding rods on cleaning pig

PART 2 – DEBRIS FROM INSTALLATION AND PRE-COMMISSIONING

Cause

During the installation of an offshore pipeline it is reasonable to expect that very little debris should enter the pipeline, certainly far less than for an onshore pipeline. Also a prudent installation contactor will employ a system to manually brush the internal surface of each pipe joint as it is welded to the pipe string. However offshore pipelines often feature a landfall section, or short onshore section at each end where there is a greater risk of debris entering the line. Some examples of debris recovered from offshore pipelines during pre-commissioning include:

- Welding rods (fig. 5), welding bladders, hand tools, and shims used to secure bevel protectors to the pipe joint etc.
- Sand and soil introduced into the pipeline either via the onshore / landfall pipelay, or in the water used to flood and test the pipeline
- Naturally occurring seawater borne debris below the project filtration levels such as shell particles

Effect

During the pre-commissioning phase such debris has an adverse effect on pig wear and hence efficacy of the cleaning and filling pigs.

Where debris builds up in one location it can cause damage to a gauge plate and can show as a dent during a calliper inspection. This can then lead to delays and possible expenditure trying to locate a dent or restriction that does not actually exist – if this is post rock dumping it may be impossible to inspect the line to verify the presence of a dent.

Figure 6 – Fine debris removed by cleaning pig

Fine debris, such as particles below 50µ in size tend to settle at the bottom of the pipeline (fig. 6) during hydrotesting, and are very difficult to remove during subsequent dewatering. Once settled this debris can form a crust trapping water, which can adversely affect the drying of the line.

Once the line goes into production (for dry gas lines) this debris slowly dries out and sloughs off into the gas stream as powder (fig. 7) causing downstream problems with valves and filters (fig. 8).

Figure 7 – Dust removed by pigging

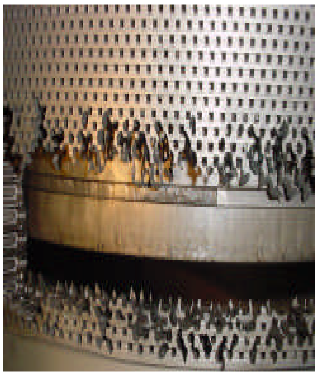


Figure 8 – Control valve cage damage

There are also examples where this debris crust does not slough off and remains at the bottom of the line – affecting the efficacy of MFL inspections by masking part of the pipeline to be inspected and causing the MFL sensors to lift off. Such debris is often referred to as "black powder" however it is actually an oxide and ferrous in nature and may be mixed with fine rust from the pipe wall.

Measurement

The debris removed during initial cleaning can be measured by physically weighing the debris, or analysing the suspended solids in the fill water. The trending of samples taken between pigs in a filling and cleaning pig train gives a good picture of the efficacy of the cleaning process and provides data to demonstrate compliance with the specification or relevant standard. Where a debris pick-up gel is used in the pre-commissioning process it is far easier to measure the trend of debris removed from the pipeline (fig. 9), and hence assert how much debris remains.

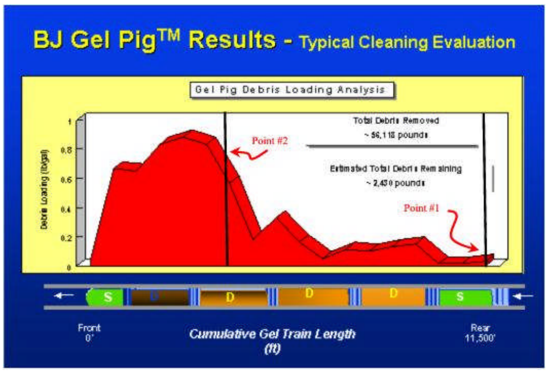


Figure 9 – Debris removed by gel cleaning

Once the pipeline is in service it is very difficult to measure the amount of debris remaining in a pipeline. MFL and calliper pig surveys will show concentrated deposits or restrictions, and downstream product analysis will show the presence of fine debris or powder, however this often generates further debate as to whether such debris is from the pipeline, or the upstream facility feeding the pipeline.

Mitigation

DEBRIS RISK	MITIGATION MEASURE
Large items such as welding rods, hand tools, bevel protector shims etc.	Stringent training and close supervision of installation personnel should prevent such debris entering the pipeline. Where the presence of larger debris is suspected, running high strength magnetic pigs in the cleaning pig train should remove most metallic objects.
Sand / soil introduced during installation of onshore and landfall sections	Run cleaning pigs through the line propelled by compressed air prior to pre-commissioning. Ensure the main line pre-commissioning standards are enforced for onshore and landfall sections
Sand and naturally occurring sea water material introduced	Take samples of sea water at the filling point to assess suspended solids levels and specify a filtration level that will cover the full range of suspended solids, rather than setting an arbitrary figure of 50µ to 100µ. If removal by filtration is not feasible or practical, specify the use of water based debris pick up gel in the dewatering pig train to remove all debris introduced by sea water filling.

Table 3 – Debris causes and mitigation measures

Case Study 2 – Fine Debris

An offshore gas pipeline laid in the Arabian Gulf took water from the landfall area to fill and test the pipeline. This water was filtered to 50µ in line with good industry practice and multiple cleaning pigs were run. The line was subsequently vacuum dried to a dewpoint of -20°C and left under a nitrogen blanket prior to start up. Internationally accepted pre-commissioning practices were observed at each phase of the operation.

The line was then commissioned and filled with dried and filtered process gas from the offshore location with production feeding an onshore treatment plant. Within 30 days of start up the throughput in the line dropped off and flow had to be shut in causing a full field shutdown. The filters upstream of the slug catcher were found to be completely blocked with fine powder and concerns were raised as to the efficay of the pre-commissioning cleaning process. The fine powder was analysed and results showed that the particle size was typically below 50µ and hence could note have been removed by the seawater filters. Furthermore this debris was found to be fine sand and shell particles that are typical in that geography.

The decision was made that for future lines a water based debris pick-up gel train would be run after hydrotesting on future lines to remove such fine debris – this proved successful with no problems reported on subsequent lines.

CONCLUSIONS

1. When planning a new offshore pipeline it is important to look at the environment in which it will be installed to assess any fundamental problems that could adversely affect the line during pre-commissioning, particularly the source and quality of water to be used to fill and test the line.

2. For gas pipelines, internal coating should be considered not just on the merits of flow efficiency, but also on the corrosion protection and ease of cleaning and drying facilitated by the internal coating.

3. Wet buckles in uncoated pipelines will cause significant internal corrosion if the line is not quickly dewatered – for projects in remote areas a permanent dewatering spread should be considered as mobilisation of such a spread may take many weeks.

4. Corrosion caused by untreated seawater entering uncoated pipelines can cause significant internal corrosion, reducing the effective corrosion allowance and design life of the line.

5. Simply filtering the fill and test water to 50µ will not prevent smaller sized particles from entering and collecting in the line - there are many examples of fine powder being recovered from gas lines immediately after start-up, damaging in-line components and affecting downstream facilities

6. Pipeline debris can build up during pre-commissioning into hard lumps that can resemble dents. This can lead to false data on geometry surveys, adversely affecting a project in both financial and schedule terms.

7. When executing a new pipeline, pre-commissioning should be viewed with equal importance to design, procurement and installation, with the process being overseen by the pipeline end user.

References

1. Shreir, L.L., Jarman, R.A, Burstein, G.T.: *Corrosion - Metal/Environment Reactions*, Vol. 1. Publ.: Butterworth Heinemann, Oxford, 1994.

2. Butler, G.: Ison, H.C.K.: *Corrosion and its prevention in waters*. Publ.: Robert E. Krieger Publishing Company, New York, 1978.

3. John Morgan : *Cathodic Protection*, Publ.: NACE, 1987.

4. Jaime Perez ; *Black Powder in Sales Gas Pipelines*, Pipeline Management for Oil & Gas Conference, Kuala Lumpur, 2005.

Acknowledgements

The author would like to thank his colleagues at BJ Services for sharing their wealth of experience in pipeline pre-commissioning and inspection in the preparation of this paper.