

Implementation of an Innovative Subsea Corrosion Monitoring Device To Manage Corrosion in a New Subsea Development

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ABSTRACT

A high-pressure gas condensate development located offshore consists of a subsea production system comprising a series of subsea manifolds located on the north, west, and east flanks of the development area. The well clusters and manifolds are tied back via looped 14" carbon steel flowlines to a new platform. In order to manage corrosion, the project corrosion monitoring objective was to flag any short fall in corrosion inhibitor injection rates to minimise internal corrosion in the ten subsea infield flowlines and to confirm the corrosion inhibitor is working. The timeline to deliver the initial device chosen for corrosion monitoring spools (based on electrical resistance) had already been factored into the project plan in 2012. The first batch of corrosion monitoring devices (4) had to all be delivered to the new development by the first quarter of 2016 to ensure installation of the flowline termination assemblies (FTAs) so that the flowlines were not affected.

The device chosen initially was unable to meet the scheduled dates; thus, there was a real possibility that the FTAs and flowlines would be installed without adequate corrosion monitoring. Thus, a new subsea corrosion monitoring device based on ultrasonic technology was designed, fabricated, installed and commissioned. The data to date demonstrates that the corrosion inhibitor has been injected at the required rate by and large and the wall thickness data/corrosion rate data from the corrosion monitoring clamps also confirm negligible corrosion below design requirement (0.1 mm/yr). Should the corrosion inhibitor injection concentration be maintained at or above the target (75 ppm) and the corrosion monitoring data continues to be indicative of negligible corrosion rates, this will be a useful input into determining when in line inspection should be carried out in future. Credible corrosion rates relayed by monitoring device were determined using real time linear regression. A long-term service agreement is in place to enable periodical processing of the raw data, assessment of sensor performance and also continually improving algorithms to realise the full potential of the device.

Keywords: corrosion monitoring, electrical resistance, corrosion rate, wall thickness, flowlines, project, corrosion inhibitor, ultrasonic

INTRODUCTION

Carbon steel flowlines (120 km) installed for a subsea development rely on the effectiveness of protective chemical (corrosion inhibitor) continuously injected into the produced fluid stream to mitigate CO₂ corrosion. The field is a high-pressure gas-condensate development located offshore in water depth ranging from 70 to 580 m. The development is a subsea production system comprising a series of subsea manifolds located on the north, west and east flanks of the field development area. The well clusters and manifolds are tied back via looped carbon steel flowlines to a new fixed process and riser platform. Each production flowline incorporates a Direct Electrical Heating (DEH) system for hydrate management. The well production fluids are exported from the platform to the onshore terminal via separate gas and liquid pipelines and monoethylene glycol (MEG) is imported from the terminal to the platform via a dedicated import pipeline. The export and import pipelines are not discussed further in this paper.

Integrity management (IM) is fundamental to design during the Project phase and throughout Operations. The Company Engineering Standard⁽¹⁾ provides requirements for designing, constructing, operating and maintaining plant, assets, facilities and floating structures throughout their lifecycle to prevent injury to people or damage to the environment. The intent is to prevent loss of containment, structural failure or unintended release of stored energy. Safe and reliable operations was the Projects first priority. Thus, the installation of a subsea corrosion monitoring device was an essential component of ensuring the threat is identified and managed appropriately as required by Company Engineering Standard⁽²⁾.

To deploy a subsea corrosion monitoring device, the challenge the team was facing was threefold; fit-for-purpose design for wall thickness measurements / determination of corrosion rates which could be delivered on a timely basis and at an appropriate cost. The project corrosion monitoring philosophy in 2012 was initially reliant on electrical resistance (ER) technology using rings fabricated from the same flowlines per guidance in Company Engineering Standard⁽³⁾, i.e. *“if corrosion is a credible threat in an area of difficult access e.g. subsea, then corrosion monitoring spools (using electrical resistance) or ultrasonic wall thickness sensing devices can be valuable”*. Thus, the cost of the corrosion monitoring spool to be supplied by the vendor was used as basis of the budget for planning the manufacture and delivery of 10 devices. Early in the project, due to the proposed location of the monitoring spool it became apparent that due to the project requirements a number of issues had to be addressed; primarily, 66 mm (2.6 in) forging thickness that required non-destructive examination (NDE), sensitivity and temperature effects.

The timeline to deliver the corrosion monitoring spools had already been factored into the project plan; not including the issues above. The first batch of corrosion monitoring devices (4) had to all be delivered to the new development by 1Q 2016 to ensure installation of the flowline termination assemblies (FTAs) and flowlines. If the device was unable to meet the scheduled dates there was a real possibility that the FTAs and flowlines would be installed without adequate corrosion monitoring.

The IM strategy of the subsea flowlines was based on robust barrier assurance, i.e. the use of corrosion monitoring device subsea to flag short fall in corrosion inhibitor injected continuously to mitigate internal corrosion. Thus, the following requirements were specified:

¹ Engineering Integrity

² Corrosion Management

³ Corrosion Monitoring

- In situ and integrated into the subsea control module
- Provide real-time wall thickness measurements / corrosion rates that account for temperature changes
- Measure 360-degree coverage of the flowline over a fixed length
- 2.5 μm (98.4 μin) sensitivity to detect underdosing of corrosion inhibitor in the shortest possible time
- Capable of withstanding high-pressure requirements
- The effect of DEH on the flowline corrosion monitoring spools functionality due to impact of current leakage (40 - 180 AC) from the DEH and 35 - 174 μT electromagnetic interference on the electronics
- 30-year design life

To fulfil the above, a revaluation and comparison of corrosion monitoring spools available off the shelf was required. The Projects requirement for continuous high sensitivity measurement of wall loss on subsea pipelines/flowlines represented a challenge to many instrumentation systems.¹ On the market there are a number of companies offering three main methods for corrosion monitoring, of these one offers indirect measurement via the ER method, the second offers guided wave ultrasonic wall thickness measurements and the third offers a system based on classic pulse echo ultrasound measurements. The guided wave measurement method was ruled out, e.g. real time data was not available with one device at the time and both vendors could not deliver the sensitivity required. Another method that also uses ER technology between 2 discrete points in a matrix for data capture was ruled out due to chequered performance history as required by Company Corrosion Monitoring Standard. Nevertheless, there was concern that other devices based on ER have poor tolerance to fluctuations in operating temperature, which interferes significantly with the accuracy of the readings.² Work by Xu et al in the lab on a new kind of ER sensor might offer some promise with regards to better temperature and pressure compensation compared to traditional ER probes.³

Of these three methods, in 2013 only the ER device based on “ring pairs” and Pulse Echo technology had the potential for measuring wall loss with the required sensitivity. The challenge with the ER method is that to achieve the requirement set out by the Project, the “ring pairs” will have to be thin and thus may not sustain a 30-year operation without being replaced. Since the “ring pair” method would require exchange of a spool piece, this was not deemed as a viable operational scenario in addition to aforementioned points. Once the decision was made clear that the NDE qualification (of the “ring pair” device) would not be progressed, a request was made by the Engineering Manager to investigate alternative subsea monitoring devices that would fulfil the Project requirements.

The project team therefore investigated the pulse echo method provided by one of the vendors who had a tool that was designed as a retrofit system installed on existing pipelines. The original methodology and design were developed by the vendor in collaboration with Statoil and Gassco in Norway in the second half of 2000. The system was successfully deployed on three installations in the North Sea between 2008 and 2013 for three different operators [4]. In all deployments the system provided wall loss data to the operators for maintenance and operational decisions. Though, the device had the potential to meet all the project requirements it had the following limitations:

- The sensitivity of the retrofit device did not meet the requirements specified, i.e. 2.5 μm (98.4 μin)
- The retrofit clamp transducers were exposed to seawater thus marine growth will impact performance long term
- The clamp was not designed for 30 years' service as it is battery powered

- The retrofit clamp stored all data over the installation period but can also transmit data to a buoy on the sea which is not a viable proposition long-term
- No data on the effect DEH current and electromagnetic interference would have on the sensors and electronics

In order to meet project requirements a technology qualification program was required to address the points above, particularly the impact of DEH current on the sensors. The device would only be sanctioned if it met the Project requirements, was cost competitive and didn't impact schedule. In order to sustain project and operations corrosion management of the flowlines it was imperative to design the novel subsea corrosion monitoring spool. In addition to fulfilling the hardware and software requirements it was fundamental that credible corrosion rates (factoring temperature compensation) are determined, and real time flowline corrosion rate data was provided to support systematic corrosion management of the subsea flowlines for life of field.

CORROSION MANAGEMENT

In accordance with Company Corrosion Management Standard, the project identified internal corrosion threats in the 14" carbon steel subsea flowlines and outlined the strategy for management of these threats (primarily CO₂ corrosion), in design and operation. The cornerstone for delivery of the strategy was the design and commissioning of a new subsea corrosion monitoring device. Although the flowlines were fabricated with corrosion allowance due to CO₂ corrosion (and typical corrosion morphology is general corrosion), continuous reliable (> 95% availability) corrosion inhibitor injection (at dose determined by performance test) was required and injected upstream of the flowline at the manifold. The corrosion inhibitor injection at the required availability and dose should allow the rate of CO₂ corrosion at the bottom of line (including at welds) to be controlled to below 0.1 mm/yr (4 mils/yr). To ensure corrosion inhibitor availability requirements are met, the corrosion inhibitor injection system was designed to meet high reliability requirements in-line with Company Engineering Standard⁽⁴⁾. Accordingly, dual redundant pumps are installed, and a spare corrosion inhibitor core is available within each production umbilical. The section upstream of the subsea flowlines are made from corrosion resistant alloy and typical distance to the FTAs, the location of the corrosion monitoring device ranges from 70 - 100 m.

CURRENT DESIGN

The UT sensor consists of two hinged sections with hydraulic actuators for opening and closing the clamp during installation on the pipe.⁵ The UT clamp is based on discrete ultrasonic transducers spread out in a matrix to provide a picture of the wall thickness and corrosion rate distribution around the pipe. In the retrofit design the transducers are of a stand-off type, meaning that they are installed with a small distance from the pipe. This is to account for variations in pipe surface and to ease the alignment of the transducers to the pipe, not being dependent on a perfect mechanical alignment for all transducers. In order for the transducer to operate with stand-off the original design relied on the seawater as a couplant. The transducers are open to the sea. Thus, for non-buried pipes, installation of the device is pretty straightforward. However, the area where the flowlines and perhaps the device was to be installed is prone to soil liquefaction. In addition, to the limitations previously identified another concern was related to the ingress of silt and mud that will reduce the tool's ability to make good measurements, particularly at the 6 o'clock position. Furthermore, there is no evidence the transducers exposed to seawater would last for as long as 30 years. Another concern for the tool is the physical stability of the sensor clamp over 30 years. With an operational requirement of being able to measure wall thickness changes as small as 2.5µm (98.4 µin) only the slightest misalignment of the sensor clamp will affect the wall thickness trend.

⁴ Specification for Chemical Dosing Packages for Oil and Gas Production

Due to the concerns with the original design of the retrofit clamp a process of redesigning the system was started. The redesign focused on reaching a design life of 30 years as the measurements system itself had demonstrated in earlier deployments that the sensitivity performance was obtainable.⁴ The retrofit clamp could in the Project terms be regarded as having a maturity level of TRL7 (Field proven), being deployed, but when redesigning the system only parts of the device would have this level and as a system the design was set back to a TRL2 (Validated concept) level. To be deployable for the new development a TRL4 (Environment tested) level was required. Therefore, the redesign would also require a requalification of several aspects of the device. The most important consideration is the impact of DEH before the full redesign of the tool.

PRELIMINARY TEST

Impact of DEH

Due to flow assurance requirements, a DEH system is installed on each of the subsea flowline. DEH heats the flowlines by forcing a large electric current into the steel pipe through electromagnetic induction. Thus, the impact of the DEH on the corrosion monitoring device needs to be evaluated. Due to the uncertainty of the survivability of the corrosion monitoring system during DEH operation this was set out as a “go” or “no go” decision point. Therefore, the device had to be tested and validated before the main qualification took place.

This meant that a conceptual redesign was needed in order to verify the performance of the device during DEH operation under as realistic conditions as possible using a couplant to facilitate UT measurement. Traditionally water is used as a couplant in the retrofit device but in this case as an enclosed environment was chosen, the plan was to use oil. Water, Glycol, Wacker AK20 and Silicon oil were tested for acoustic properties and the conclusion was that Wacker AK20 and Silicon oil had similar acoustic properties and not differing too much from water, though with some attenuation of the signal. The Silicon oil was chosen for its thermal and preservative capacity. Electronics and sensors will last long in this non-aggressive Silicon oil environment.

In collaboration with SINTEF in Trondheim, the research institute that originally was involved in the development of the DEH concept, a series of tests were designed to verify the interoperability of the device (Figure 1) with DEH operation as follows:

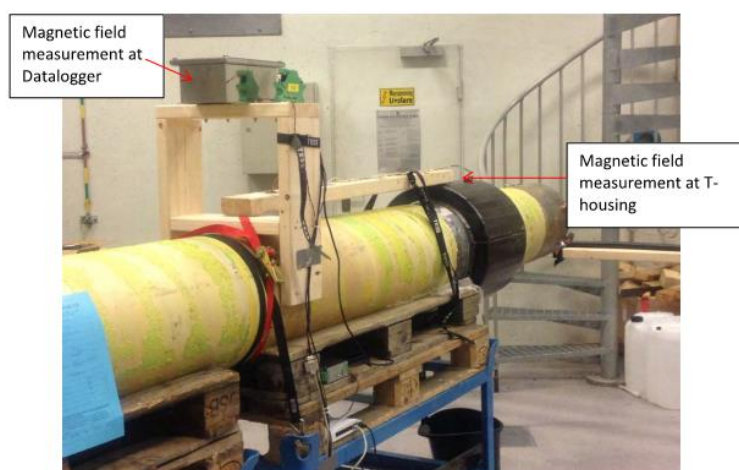


Figure 1: Corrosion monitoring system trial set-up for DEH testing.

1. Baseline testing of the corrosion monitoring system transducer and electronics using Silicon oil as couplant before DEH is activated

2. DEH sweep test, running current in steps of 10 A from 0 - 200 A and 100 A from 200 A to 350 A
3. DEH on/off test, toggling DEH at full current rate on/off
4. DEH durability test, running DEH for an extended period

During the trial wall thickness was measured every 5 minutes. The qualification criteria are:

1. The corrosion monitoring system shall survive the DEH operation
2. The device readings shall not deviate more than the nominal uncertainty ($\pm 2.5 \mu\text{m}$ or $\pm 98.4 \mu\text{in}$) during DEH operation

SINTEF have facilities to replicate full DEH currents and a conceptual design was made where sensors was mounted on a representative spool piece (See Figure 1) and a current was run through the spool during continuous UT measurement. The prototype successfully withstood 350 A and associated 230 uT magnetic field strength with no degradation in performance; these values are in excess of the project requirements. It was a significant achievement and milestone in the qualification program as it had the most uncertainty of all the planned tests. This test verified that the UT measurements and the electronics were not affected by the DEH currents and magnetic fields. Based on these results the conceptual design was enhanced and scheduled for a TRL4 test program to verify that the design would operate in a simulated operational environment, mainly pressure and seawater.

THE DESIGN

The conceptual design was based on some features of the original retrofit design where the system shall provide a number of readings per day and send online data to a control system, numerous times daily for 30 years. As stated before, the design consists of an ultrasound transducer (sensor) clamp, a data logger clamp and a fixture clamp. The power in the retrofit clamp design was provided by a battery with a limited life that also depends on use. Thus, a battery solution will not, nor will the acoustic communication support the data capacity and the requirement to send raw data from the measurements numerous times a day. It was therefore clear that the data logger required a change in design.

The main elements of the design will be described to give a better understanding of the operational principles of the final "In-Situ tool" or what is in the Project terms named UltraMonit⁽⁵⁾ Corrosion Monitoring Clamp (UCMC) in reference to the forerunner. UCMC essentially had to fulfil the following requirements to facilitate the internal corrosion management of the subsea flowlines.

- Minimum data sampling frequency every 4 hours
- Transducers distribution optimised around pipe
- Real time data available through control system
- Direct measurement of wall thickness
- Real time temperature compensation
- Sensitivity required $2.5\mu\text{m}$ ($98.4 \mu\text{in}$)
- Device to monitor across carbon steel weld downstream of clad transition

Transducers distribution

The maximum number of transducers that is physically possible to install is 527 based on a configuration optimising the number of cassettes and transducers i.e. 31 and 17 respectively. The area of coverage⁽⁶⁾ of cubic close packed circular probes produced a coverage of 24% of

⁵ Trade Name

⁶ Coverage is defined as the ratio of area that the transducers measure over the total area covered by the device