

Corrosion Mitigation of Deepwater, 143-km Long Multiphase Pipelines

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ABSTRACT

The Laggan-Tormore gas field is a deepwater development located 125 km off the West Coast of the UK Shetland Islands, in the North Atlantic. The field consists of five subsea production wells tied back to subsea manifolds that are connected to two 18-in multiphase pipelines. In addition, two other subsea templates consisting of three subsea wells are connected to the field via a 35-km tieback. The gas field development is unique for the UK Offshore Northern Sector in that produced fluids and gas are not processed offshore. Instead, the fluids and gas are transported via the two 18-in diameter, 143-km multiphase pipelines from the offshore fields to an onshore gas plant on Shetland for processing. The multiphase pipelines are constructed from carbon steel, and therefore, to prevent corrosion an inhibitor was required. Monoethylene glycol is injected in the field at the subsea manifolds for hydrate control, and to facilitate the delivery of the corrosion inhibitor, chemical is injected in combination with the glycol.

Mitigation of corrosion in the Laggan-Tormore multiphase pipelines presented several challenges. The glycol used in the field is recycled via a regeneration unit. Consequently, the corrosion inhibitor would have to withstand the high temperatures within the unit and not suffer physical degradation or a decrease in efficacy when exposed to the unit. Considering there is only one corrosion inhibitor injection location for each multiphase pipeline, the inhibitor is required to be transported the whole length of the multiphase pipeline and provide protection of its entirety. Finally, there is no corrosion monitoring in place in the subsea pipelines. Therefore, to determine if the pipelines are under corrosion control, analysis of the

produced fluids to provide an indirect measurement of the corrosion rate was required, including iron counts, corrosivity measurements of the produced fluids, and corrosion inhibitor residual analysis.

This paper discusses the laboratory work carried out to develop a corrosion inhibitor for this application, details its deployment and provides an overview of the ongoing monitoring performed to ensure the integrity of the multiphase pipelines.

Key words: corrosion inhibitor, multiphase, deepwater, subsea, glycol regeneration and desalination

INTRODUCTION

Oil and gas fields located in water depths greater than 500 m have traditionally been classified as deepwater developments.¹ The production of oil and gas from deepwater fields presents several challenges for corrosion inhibitors to overcome to retain their efficacy and assure pipeline integrity. The production temperature of deepwater fields is generally higher compared with shallow water or onshore developments. Deepwater production chemicals are injected via chemical umbilicals and the pressures within these umbilicals can be >10,000 psi. [69 MPa]. This exposure to high pressure can have a negative effect on chemical efficiency and significantly increase product viscosity so that it cannot be pumped. Finally, the extended reach of the subsea umbilicals leads to longer residence times for chemicals within the umbilicals, equating to longer exposure to the subsea environment.² Stability of the corrosion inhibitors under these conditions is vital to maintain the integrity of the injection system and the performance of the product. Therefore, when applied in deepwater oil and gas fields, corrosion inhibitors need to have prolonged stability at high pressure over a range of temperatures and should ideally conform with appropriate subsea chemical standards.³

However, for deepwater fields that use injection of monoethylene glycol (MEG) for hydrate control, coinjection of corrosion inhibitor with glycol is recommended and this approach has several advantages. As the concentration of the inhibitor in MEG will be relatively low (2,000–5,000 ppm), some of the challenges associated with injection of deepwater corrosion inhibitors are reduced or negated. As the injection rate of glycol is much greater compared to neat corrosion inhibitor, the residence time of the MEG and inhibitor mixture in the umbilical will be greatly reduced compared to the residence time for neat inhibitor injection. Therefore, the risk of product instability is decreased. Additionally, products injected in MEG are not required to have low viscosity under high-pressure conditions as the viscosity of the MEG component will dominate the overall viscosity of the glycol and inhibitor mixture. Another advantage of coinjecting corrosion inhibitor with MEG is that the number of deepwater umbilicals required will be less as a separate corrosion inhibitor injection umbilical is not required. Therefore, coinjecting corrosion inhibitor with MEG will also offer cost savings to the operator.

This paper details the approach taken to select and implement a corrosion inhibitor to mitigate corrosion in deepwater multiphase pipelines that are treated with MEG to prevent hydrate formation. The paper also summarizes the corrosion monitoring work conducted to verify the efficacy of the corrosion inhibitor in the field.

FIELD OVERVIEW

The Laggan-Tormore field is a deepwater gas project located in 600m water depth, 125 km off the northwest coast of the Shetland Islands (Figure 1). The Laggan play was discovered in 1986 while Tormore was discovered in 2007 with production commencing from both developments in 2016. Currently, the Laggan-Tormore field has five subsea wells in production that are tied back to subsea manifolds. Two other subsea developments (Glenlivet and Edradour) consisting of three subsea wells located in water depths ranging from 300 to 435 m came on stream in 2017. These fields are connected to the Laggan-Tormore system via a 35-km tieback. The produced fluids and gas from all fields are not

processed offshore but are transported via two carbon steel, 143-km multiphase pipelines to an onshore gas plant on Shetland for processing. At the gas plant the condensate is removed and piped to the Sullom Voe Oil Terminal. Consequently, corrosion inhibitor is required to provide protection of the carbon steel pipelines. Table 1 provides an overview of the production rates for the Laggan-Tormore field and summarizes the pipeline conditions.

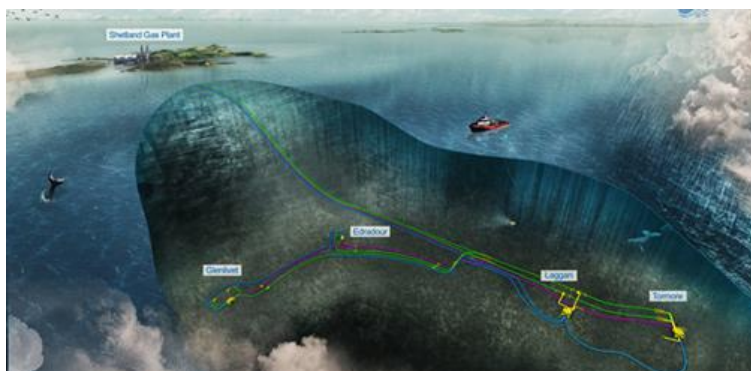


Figure 1. Laggan-Tormore Field Location

**Table 1.
Summary of Multiphase Pipeline Conditions**

Parameter	Units	Value	
		Flowline 1	Flowline 2
Gas production	kSm ³ /day	4,300	4,200
Condensate production	Sm ³ /day	288	288
MEG/produced water production	Sm ³ /day	276	192
MEG:water ratio	N/A	50:50	65:35
CO ₂ concentration	mol%	2.3	0.1
Design pressure	Bar	38	38
Temperature	degC	86	86
Flowline diameter	In	18	18
Flowline length	Km	143	143
Flowline metallurgy	N/A	Carbon steel	Carbon steel
Flow regime	N/A	Stratified wavy	Stratified wavy

The Laggan-Tormore field has the longest subsea-to-shore system ever developed in the North Sea.⁴ A similar North Sea development is the Ormen Lange deepwater gas field that started production in 2007. However, the multiphase flowlines from the platform to the shore are slightly shorter at 120-km long and corrosion is mitigated by means of pH stabilization as opposed to using corrosion inhibitor.⁵

To prevent hydrate blockages in the subsea pipelines, MEG, a thermodynamic hydrate inhibitor, is continually injected. The MEG is injected into the production streams via a dedicated 143-km long umbilical from the onshore gas terminal to the subsea manifolds. The MEG also acts as a carrier fluid for the corrosion inhibitor that is injected into the MEG. The MEG and corrosion inhibitor mixture is then transported with the production streams back to the terminal for separation and processing.

Corrosion and Production Chemistry Challenges

The multiphase pipelines in the Laggan-Tormore field are constructed of carbon steel, and to mitigate corrosion of the pipelines, the operator required an inhibitor for injection at the subsea manifold. However, mitigation of corrosion in these pipelines presented several challenges as follows:

1. The main corrosive species in the pipelines are chlorides and CO₂. The combination of CO₂, chlorides (22,000 ppm) and pipe temperature (86 degC) will result in high general and localized corrosion rates in the system. Corrosion modelling gave a maximum predicted general corrosion rate of 2.7 mm/yr (106 mpy) for the subsea pipelines. However, it is expected that the localized or pitting corrosion rate (which is the most common form of failure in multiphase pipelines) will be an order of magnitude higher.
2. Corrosion inhibitor is injected into the MEG prior to being pumped down the 8" MEG umbilical that is routed to each of the subsea wellheads where it is injected downstream of the subsea choke. Consequently, the corrosion inhibitor is required to be transported the entire length of the multiphase pipelines and provide protection of their entirety.
3. Due to the topography of the pipelines, there are localized areas of high velocity flow and varying flow regimes that will impact corrosion inhibitor efficiency. High gas or liquid velocity has the potential to remove protective inhibitor films from the metal surface and makes it more difficult for inhibitors to adsorb on the pipeline.
4. The length and depth of the flowlines mean that gas hydrate formation is likely as the process fluids and gas cool to seabed temperature along the pipelines. Accumulation of solid gas hydrate blockages within the flowline can significantly disrupt production and can lead to catastrophic equipment failure and health and safety hazards. MEG is injected at the wellheads via dedicated 143-km long umbilicals from the onshore gas terminal to prevent formation of gas hydrates by suppression of the hydrate formation temperature.

Monoethylene glycol is completely miscible with the produced water and, after removal of gas and condensate, is recovered for re-injection by passing it through a MEG regeneration and desalination system to remove water and salt yielding a lean MEG stream (90wt%MEG). The recycled MEG is then topped up with corrosion inhibitor to the required concentration and pumped offshore once more. Hence, this is a closed loop system and the MEG is constantly recycled and re-injected. The maximum temperature within the MEG regeneration unit is approximately 156 degC. Therefore, any corrosion inhibitor used in this field must be stable after repeated exposure to extremes of temperature and not suffer any performance degradation after passing through the unit.

The MEG regeneration and desalination unit removes salt via a precipitation process. Therefore, as corrosion inhibitors will adsorb on to any surface or solids present, when the salt precipitates some of the inhibitor will adsorb on these salts. Therefore, the overall concentration of inhibitor in the fluids will decrease during the desalination process, which results in a higher treat rate of inhibitor. However, the residual corrosion inhibitor concentration in the injected MEG is required to be >1000 ppm.

5. Within the Laggan-Tormore field, there is no corrosion monitoring in place in the subsea multiphase pipelines. Therefore, it is not possible to directly measure the corrosion rates in the subsea pipelines or assess the efficacy of the corrosion inhibitor in the field. The only way to determine if the pipelines are under corrosion control is by indirect corrosion measurements using

Fe counts, inhibitor residual analysis and measurement of the produced fluid corrosivity onshore in the laboratory.

6. In addition to corrosion and hydrate formation, there is a risk of wax deposition in the pipelines. Therefore, any corrosion inhibitor developed must be fully compatible with the wax inhibitor used and each chemical should not be antagonistic to the other chemicals.

MEG Regeneration and Desalination Unit

MEG is recovered for re-injection in the MEG regeneration and desalination unit where water and dissolved salts are removed in a 3-stage process outlined below.

1. Divalent cations present in the rich MEG (Mg^{2+} , Ca^{2+} , Fe^{2+} , Sr^{2+} , Ba^{2+}) are precipitated by injection of sodium carbonate and sodium hydroxide solutions. The resulting solid particles ($\text{Mg}(\text{OH})_2$, CaCO_3 , FeCO_3 , SrCO_3 , BaCO_3) are removed at the front end of the process in a pre-treatment section using a membrane filter process. This step also removes pipeline corrosion products (typically FeCO_3 , FeS) and other solids carried into the MEG unit along with the rich MEG. If not removed, the divalent cations (as highly soluble chlorides) will accumulate in recycle streams within the MEG unit (particularly in the desalination section) leading to fouling and reduced availability.
2. The calcium-free rich MEG from the pre-treatment section is routed to the two regeneration trains where water is removed using distillation columns with reboiler and reflux to yield a lean MEG stream at 90wt% MEG. The regeneration column operates under a slight positive pressure (0.5barG) with the reboilers operating at 156 degC. At the design condition the water removal rate is 28.2m³/h and the produced water contains approximately 50 to 100-ppm MEG. The hot lean MEG from the regenerators (approximately 156 degC) is cooled against the incoming rich MEG stream.
3. A slipstream of the lean MEG from the regenerators is routed to the desalination section where the MEG and water components are vaporized under partial vacuum (140 degC, 0.2 barA) with simultaneous precipitation of the remaining dissolved salts using proprietary brine displacement technology. The salt-free MEG-water vapor from the desalination section is condensed-cooled and blended into the saline lean MEG that was not routed to the desalination section to yield the lean MEG product. The precipitated salt, predominantly sodium chloride, accumulates as a slurry in a sodium chloride brine and is periodically discharged from the process as a dry cake (<10wt% moisture) using basket-type centrifuges.

A schematic of the MEG regeneration and desalination unit is shown in Figure 2 and the operational parameters are given in Table 2. Hydrocarbon skimming facilities are installed in the pretreatment and regeneration sections to remove any free hydrocarbon carried with the rich MEG into the MEG package from the upstream separators and from the rich MEG storage tanks.

Table 2.
MEG Regeneration and Desalination Design Parameters

Parameter	Value	
	Rich MEG	Lean MEG
% MEG	60	90
% Total dissolved solids (TDS)	2.62	2.93
% Water	40	10
m ³ /h	77.0	50.8