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Three-Phase Wet Sour Gas Transmission in a Pipeline

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ABSTRACT
The basis of a wet process scheme involves minimum offshore processing. The reservoir fluid is collected on a wellhead platform and routed without treatment via a three-phase subsea pipeline to the shore where it is processed to deliver gas and condensates at specifications. The concept and design will be applied to produce wet sour gas transmission from offshore to shore via a subsea pipeline, resulting in a lower capital investment. As a consequence two highly undesirable situations can exist at the same time, severe corrosion and hydrate blockage, leading to system failure and the complete shutdown of production. Therefore, both corrosion and hydrate inhibitors can be required to effectively treat these phenomena. A solution of monoethylene glycol (MEG) is used for hydrate prevention and an amine (methyldiethanolamine [MDEA]) will be added as a buffering agent to maintain pH at a neutralizing value to managed corrosion. This requires proper quality assurance of topside and subsea pipelines but will result in lower capital costs as well as lower operational costs. In the proposed "Three-Phase Wet Sour Gas Transmission in a Pipeline", excellent engineering team will focus on the application of a pH control system for carbonate reservoirs in order to prevent scaling.
Keywords: Multi-Phase flow, Carbonate reservoirs, Hydrate Formation, pH Stabilization, Scaling

INTRODUCTION

The concept and design will be applied to produce wet sour gas transmission from offshore to shore via a subsea pipeline, resulting in a lower capital investment. Design elements mainly consist of no water-phase separation on the offshore platform and therefore a three-phase transmission in the pipeline.

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Mild steel is extensively used for pipeline material in the production of wet gas. This material has an inherent low resistance to corrosion but due to economic reasons is the preferred material of choice. However, gas production is accompanied by a number of impurities, including various amounts of water, $CO2$ and $H2S$ [1].

As a consequence two highly undesirable situations can exist at the same time, severe corrosion and hydrate blockage, leading to system failure and the complete shutdown of production. Therefore, both corrosion and hydrate inhibitors can be required to effectively treat these phenomena.

Hydrate formation is prevented by monoethylene glycol (MEG) injection, and corrosion is managed by pH control. This requires proper quality assurance of topside and subsea pipelines but will result in lower capital costs as well as lower operational costs [2].

In view of the high impact on operating costs and production losses, application of a pH control system for carbonate reservoirs should be well engineered during the design stage in order to eliminate deposition of calcium carbonate on the internal surface of valves, riser, and subsea pipelines [3].

WET SCHEME DESCRIPTION

The basis of a wet process scheme involves minimum offshore processing. The reservoir fluid is collected on a “not normally manned” wellhead platform and routed without treatment via a three-phase subsea pipeline to the shore where it is processed to deliver gas and condensates at specifications. The wellhead fluid is assumed to be water saturated at reservoir conditions and may also include produced water.

MEG is injected at the platform departure to prevent both hydrate formation and corrosion in the subsea pipeline. The lean MEG is returned from the onshore plant to the platform through a piggyback line for re-injection into the export line offshore.

The selected offshore process scheme involves the following main process operations:

- Production and testing on the wellhead platform
- Transport of raw production by a subsea pipeline from the wellhead platform to the onshore facility
- MEG piggyback line to transfer MEG from onshore to offshore
- MEG injection as a back-up for the MEG piggyback line
- pH control injection as a back-up for the MEG piggyback line
- Corrosion inhibitor injection as a back-up for MEG injection
- Low dose hydrate inhibitor (LDHI) injection as a back-up for MEG injection

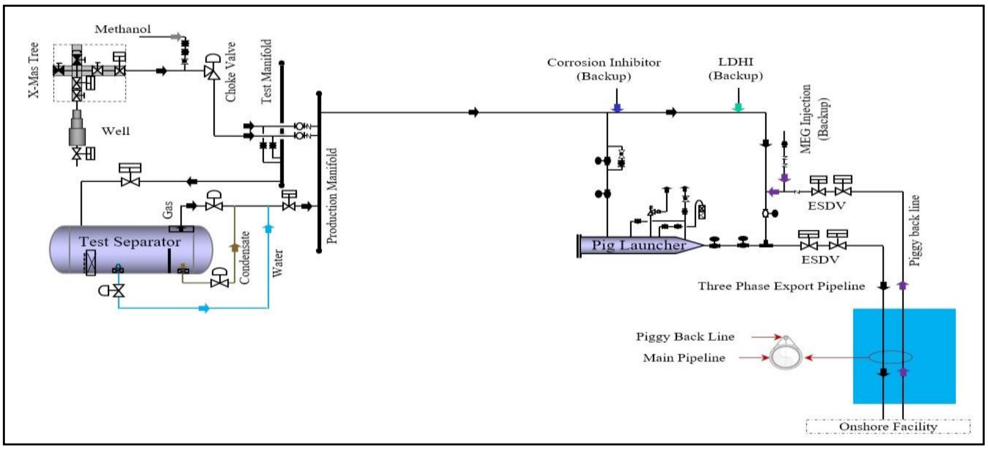

Figure 1: Offshore Process Scheme

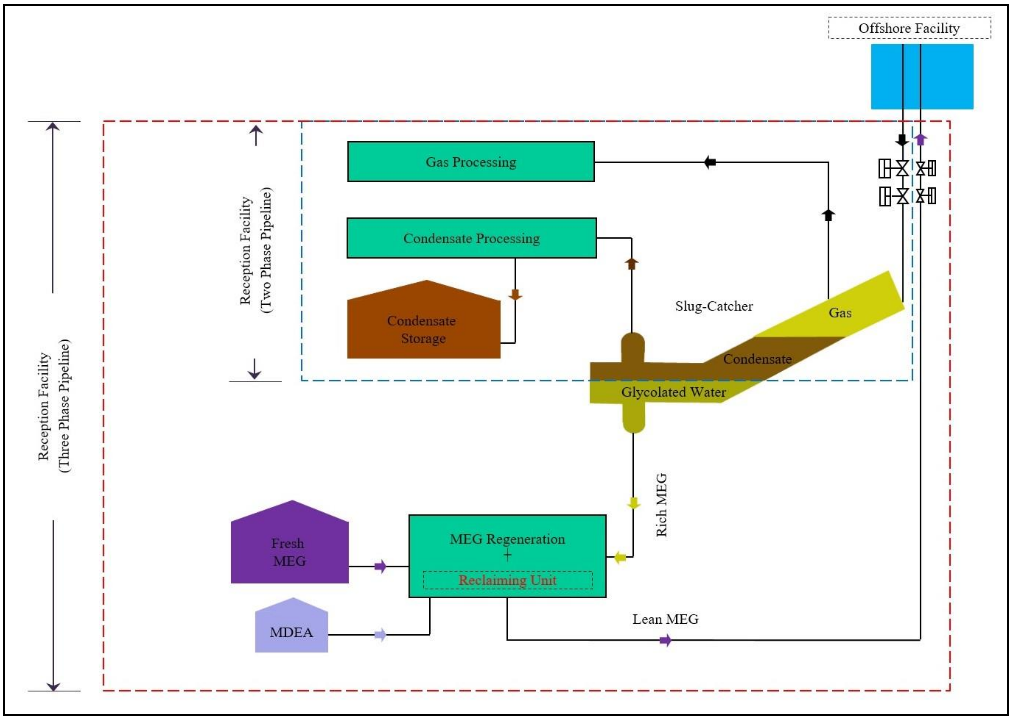

Figure 2: Onshore Process Scheme

MULTI-PHASE FLOW

Multi-phase flow, consisting of gas, condensate and water, is transferred inside the pipeline, so the flow regime needs to be checked and all production planning to be performed based on the flow regime. For most gas condensate systems, two main flow regimes are predicted:

- Slug Flow

This flow pattern is encountered at low gas velocity. It is formed mostly in uphill sections of the pipeline. The gas flows as a long pocket with liquid slugs along the top of the pipeline. The remaining liquids flow as a continuous film along the bottom of the pipe. This flow is highly turbulent, especially at the head of the liquid slugs where gas bubbles are entrained in swirling movements in the core of the slugs [4].

- Stratified Flow

In wet gas production, stratified flow is the most common regime. The gas and liquid phases are segregated from each other by a continuous interface.

The gas flow containing the gaseous phase of hydrocarbons, CO2 and H2S travel in the upper section of the pipeline, and the liquids flow with salt-containing water and hydrocarbons along the bottom.

In multi-phase production, both gas and hydrocarbon phases exist as well as water. As the temperature in the line drops, condensed water can form at the top of the line; these droplets can be highly corrosive because of the gaseous products present. This can lead to corrosion at the top and bottom of the line.

LIQUID HOLD-UP

Liquid hold-up occurs only when a steady state condition is reached. Liquid hold-up of a subsea pipeline is affected by different parameters; the two main parameters are flow rate and pressure.

Liquid hold-up is the combination of both condensate and water hold-up. Under constant pressure and an increasing flow rate, the hold-up decreases as the liquid can be carried out by gas, while at a lower flow rate, the liquid hold-up increases and may cause plugging of the subsea pipeline, leading to a very high differential pressure and producing slug flow [5].

PIGGING OPERATION

To have smooth production, it is necessary to evaluate the flow regime in all cases and to avoid high liquid hold-up, frequent pigging operations need to be predicted. Regular sphere pigging will be required at low flow rates to avoid instabilities in the subsea pipeline and to reduce liquid hold-up.

HYDRATE FORMATION

For this offshore design, hydrate will be controlled by using a thermodynamic inhibitor. This treatment is effective by lowering the freezing point of an aqueous solution. MEG is injected into the production line departing the platform.

During the transport of the multi-phase fluid between the offshore facility and the onshore reception facility through the subsea pipeline, there is a risk of hydrate formation in the presence of free water. To protect against hydrate formation, an aqueous glycol solution (70% MEG–30% H_2O [wt/wt]) is injected offshore in the subsea pipeline [6].

The hydrate formation curve of each gas depends on the composition of the fluid. Adding methanol or glycol leads to a depression in the hydrate formation temperature. Simulations shall be performed to calculate the hydrate formation curve for reservoir gas.

When a simulation of the subsea pipeline (Pressure & Temperature) profile is compared with the corresponding hydrate formation curves for a different percentage of MEG content in the glycolated water phase, a risk of hydrate formation can be observed with no MEG. When the MEG concentration is increased, the risk of hydrate formation is completely eliminated.

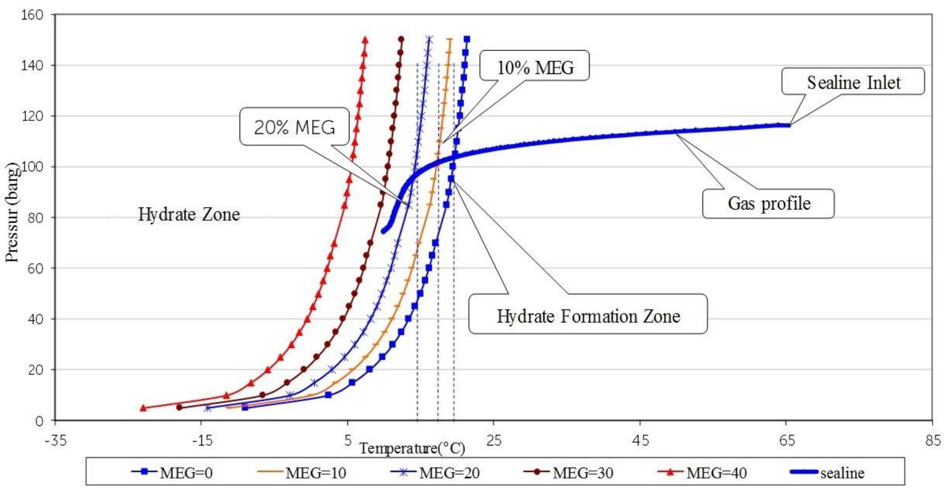

Figure 3: Pipeline Hydrate Formation Curves

PH STABILIZATION METHOD

pH stabilization will be applied to control corrosion in the three-phase fluid (gas, condensate and water). In this technique, a solution of 70% of MEG is used for hydrate prevention on the offshore platforms. With this hydrate prevention, an amine (methyldiethanolamine [MDEA]) will be added as a buffering agent to maintain pH at a neutralizing value (pH ≥7), and corrosion in the subsea pipeline will be maintained at <0.1 mm/year.

MDEA is recirculated with the MEG and since in a steady state regime, there is no addition of consumables. This proven concept is more cost effective than use of a traditional corrosion inhibitor that cannot be recovered. The role of MDEA is to capture H+ ions, thereby increasing the bicarbonate content of the medium and raising the pH, which reduces the corrosive power of the fluid [7].

$CO_2 + H_2O \rightarrow H_2CO_3$, unstable carbonic acid

$H_2CO_3 \rightarrow H^+ + HCO_3^-$

The pH value is one of the essential factors for the pH stabilization technique. Consequently, the most stringent precautions are to be taken in order to determine pH accurately with a reliable pH-measuring method. The technique relies upon increasing the bicarbonate content, and the presence of further calcium produces calcium carbonate, leading to scale formation.

$Ca^{++} + HCO_3^- \rightarrow CaCO_3 + H^+$

Consequently, the most significant impacts of pH stabilization in the presence of calcium due to reservoir and well drilling are:

- The risk of scale formation in the pipeline is drastically increased.
- MEG cannot be regenerated as anticipated because it will contain salt. Lean MEG concentration and efficiency will be reduced, and the risk of scaling in the MEG regeneration unit (reboiler and exchangers) will dramatically increase.

SCALING

One of the problems encountered with the three-phase development is scaling caused by carbonate products from produced water.

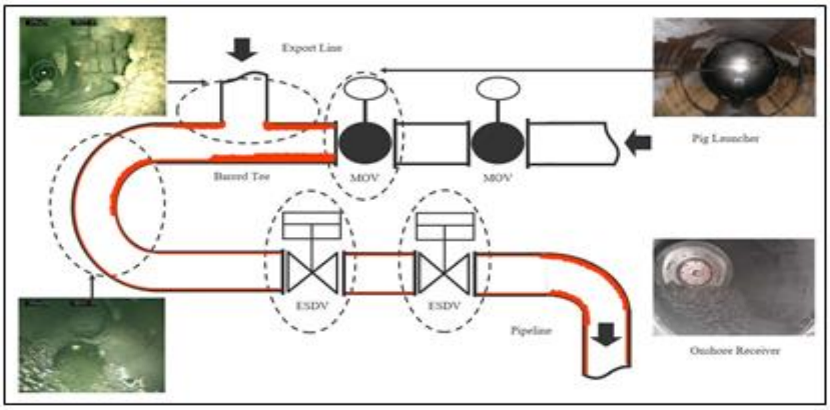

Figure 4: topside and pipeline scaling

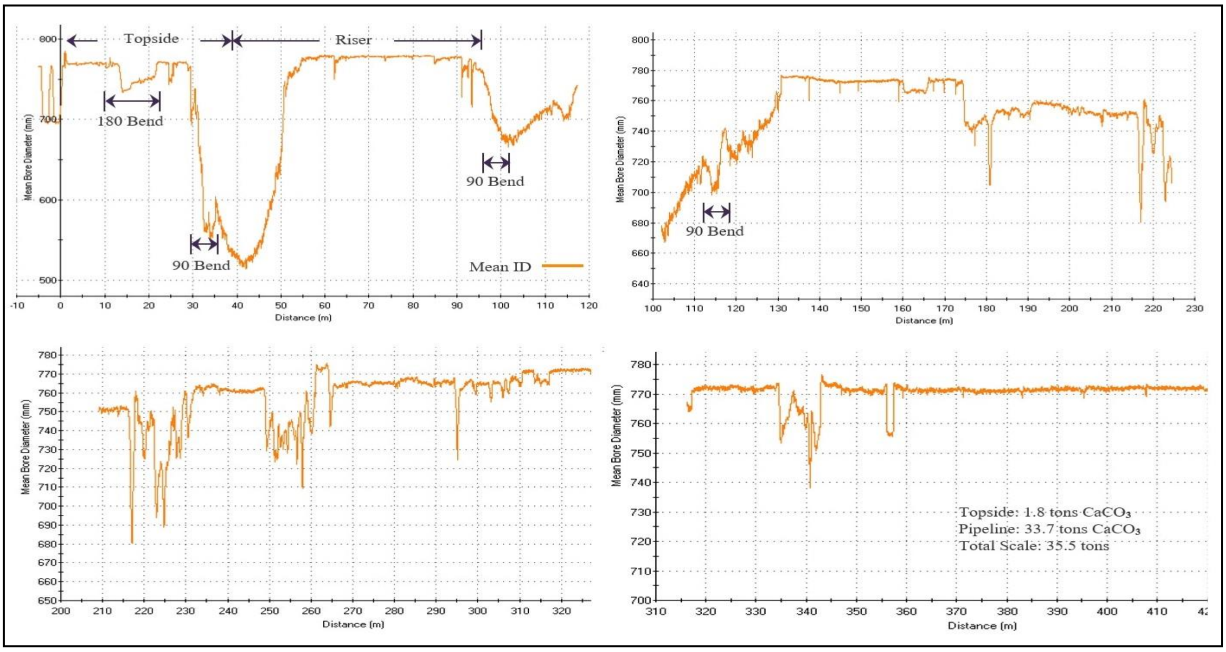

Figure 5: Pipeline Scaling Profile

Figure 6: pipeline inspection and mechanical cleaning

CONCLUSIONS

1.1 Transferring the three-phase flow with a wide range of hydrocarbons and water is a complex operation, and flow assurance is a major concept. Proper quality assurance should be in place to address the issue, which may happen as a result of the three-phase flow operation.

1.2 The long pipeline, which is located on the seabed, causes high differential pressure and temperature decline. Therefore, to have smooth production, a simulation tool is necessary to predict any slug reception, liquid hold-up, pigging campaign and hydrate formation.

1.3 In the proposed "Three-Phase Wet Sour Gas Transmission in a Pipeline", excellent engineering team will focus on the application of a pH control system for carbonate reservoirs. In addition, during the operational phase, the team will address calcium carbonate scaling on the top side valves, riser and pipeline by suitable monitoring. Otherwise the company will be subjected to production loss due to the replacement of damaged valves, pipeline acid cleaning and additional engineering, which have high cost implications.

1.4 In order to prevent scaling and achieve the required outlet glycol purity, the following points are highly recommended:

1.4.1 Adding a reclaiming unit to the MEG regeneration unit to remove the calcium and salt impurities inside the MEG.

1.4.2 Daily quality control and close monitoring of the lean MEG concentration, glycolated water pH, and Ca^{++} in the lean and rich MEG.

Notes on contributors

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