

GUAP3 SCALE DISSOLVER AND SCALE SQUEEZE APPLICATION USING KINETIC HYDRATE INHIBITOR (KHI)

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ABSTRACT

The use of Kinetic Hydrate Inhibitors (KHI) is one of the optimum methods employed to control gas hydrate formation issues and provide flow assurance in oil and gas production systems. The application of this technology has several advantages to operators, including significant cost savings and extended life of oil and gas systems. This paper will highlight a specific case where a Major operator in the North Sea (UK sector) significantly reduced the cost of well intervention operations by applying a KHI in a subsea gas lift line. Considerable cost savings were realized by reducing volume of chemical required and this enabled the application to be performed from the FPSO eliminating the need for a dedicated Diving Support Vessel (DSV). Furthermore, the application of KHI also reduced manual handling and chemical logistics usually associated with this particular treatment. In order to prevent mineral scale deposition occurring in downhole tubing and near well bore and in the formation; scale inhibitor squeeze applications are standard practice. For subsea wells the fluids can be pumped down in to the well via gas lift lines. However, upon completion of previous scale squeeze operations at this particular location, hydrate formation was observed when a mixture of MEG and water was used following interventions via the gas lift line. By applying 1% KHI with a mixture of MEG and Water, the well was brought back into production following scale squeeze operations without hydrate formation occurring.

Keywords: Kinetic Hydrate Inhibitors; Flow Assurance cost savings

NOMENCLATURE

The following abbreviations and acronyms are used throughout the text:

AA	Anti-Agglomerant hydrate inhibitor
Bbl	Barrel (42 US Gallons = 0.159 m ³)
CAPEX	Capital Expenditure
DSV	Diving Support Vessel
FPSO	Floating Production Storage and Offloading vessel
GOR	Gas to Oil Ratio
HSE	Health, Safety and Environmental
K	Thousand
Km	Kilometers = Approx. 0.62 Miles
KHI	Kinetic Hydrate Inhibitor
LDHI	Low Dosage Hydrate Inhibitor
m ³	cubic meter = Approx. 6.29 Bbl
MEG	Mono Ethylene Glycol
MeOH	Methanol
MIC	Minimum Inhibitor Concentration
MM	Million

OPEX	Operational Expenditure
ppm	Parts per Million
Scf	standard cubic feet
THI	Thermodynamic Hydrate Inhibitor

INTRODUCTION

Flow Assurance Issues involving Scale Control; and Hydrate Inhibition. Flow Assurance is critical during the efficient production of hydrocarbons from offshore and subsea assets. This can include such challenges as scale prevention; with scale removal by chemical or mechanical means following scale deposition being very difficult in such environments. Other flow assurance issues can include wax deposition; asphaltene issues and the formation of gas hydrates. These issues can lead to blockages and restrictions which can lead to the impairment of flow and the associated loss of revenue from delayed production.

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The following is a discussion of important flow assurance issues focusing on gas hydrate formation; leading to the possible formation of gas hydrate plugs and blockages. It is demonstrated how these issues can be successfully overcome in the field; through technology developments which have been appropriately transferred to producing assets. From the beginning of their life cycle, offshore gas fields can require continuous gas hydrate protection. This is required as the produced hot gas cools, as it flows from the well, typically via an uninsulated subsea flowline, leading to the formation of condensate and water. In contrast, oil wells may only start producing water a couple of years into their life cycle. From the point of water production onwards, however, they may require protection from hydrate formation.

In the discussion below we illustrate a specific case where a Major operator in the North Sea (UK sector) was preventing mineral scale deposition occurring in downhole tubing and near well bore and in the formation areas via scale inhibitor squeeze applications. These are considered standard practice and when applied appropriately - a good flow assurance safeguard. For subsea wells; the fluids can be pumped down into the well via gas lift lines. However, it had been observed that upon completion of previous scale squeeze operations at this particular location, hydrate formation still occurred on the restart of the gas lift lines; even when a mixture of MEG and water was used to try to control hydrate formation; following the scale inhibitor squeeze interventions via the gas lift line.

Gas hydrate formation occurs when natural gas molecules are surrounded by water molecules to form 'cage'-like structures. Gas hydrates are similar in appearance to ice. Both materials have crystalline structures that exhibit similar characteristics – with the important difference that the natural gas hydrate has a natural gas guest molecule as an integral part of its structure [1-4]. Examples of typical hydrate forming gases include Nitrogen, Carbon Dioxide (CO₂), Hydrogen Sulfide (H₂S) and light hydrocarbons (such as methane through to heptanes). Gas hydrates typically form at lower temperatures and higher pressures. The temperature at which hydrate formation occurs is not necessarily very low. Depending on the gas composition and the

pressure, gas hydrates can form at temperatures of up to 30°C where gas co-exists with water [5-6].

If hydrates form; as occurred during the restart of the gas lift lines following the initial scale inhibitor squeeze procedures; then hydrate plug remediation is required as explained below.

Hydrate Plug Remediation - Options and Costs.

Hydrate plug formation (as in Figure 1 below) and subsequent remediation can be a costly occurrence. Hydrate plugs may take days to months to dissociate depending on the system conditions and the remediation actions taken. This is costly in terms of deferred production. The action of trying to locate a blockage, particularly in an offshore production system, is also difficult. An important part of the design and operation of both onshore and offshore production systems concerns hydrate inhibition and control of hydrate formation, in order to prevent the formation of hydrate blockages [7-8].

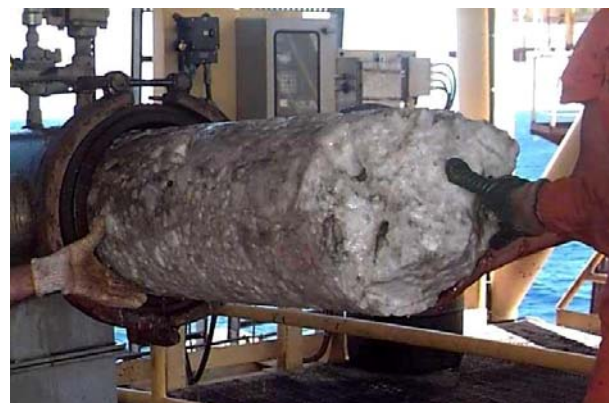


Figure 1: Hydrate plug (courtesy of Petrobras).

Remediation options include the application of Methanol (MeOH) or MonoEthyleneGlycol (MEG) and/or depressurization [9] to help melt a hydrate plug. Other options include trying to apply heat to help speed up the melting of a hydrate plug [9]. All options need to be carefully considered to minimize the risks involved, such as the liberation of significant quantities of gas in a short time frame from a hydrate plug if heat is applied to the hydrate blockage. As 1 scf of methane hydrate releases 170 scf of gas [9] the potential for pipeline rupture during the melting of the gas hydrate plug is significant and this option needs to

be approached with caution. If depressurization is used, it is better if the pressure is reduced on both sides of the plug, leading to no pressure differential; otherwise the plug may loosen and be projected along the pipeline at high velocity.

Control and Inhibition of Natural Gas Hydrate Formation. When considering the control and prevention of natural gas hydrates, operating companies have several potential options available to them. One possibility is that production could be reduced, leading to lower production pressures under these constrained conditions. This would reduce the likelihood of hydrate formation. However, this option incurs costs in the form of deferred production.

Another option is to remove the water from offshore production fluids before transportation – this would require the use of offshore dehydration process units. In this particular case, however, this is not an option as water is introduced as part of the scale inhibitor squeeze procedure. An alternative possibility is to reduce heat losses to the typically colder surroundings. The use of thermal insulation to coat subsea pipelines may lead to a reduction in heat loss from the pipelines and lead to operating conditions which are both warmer and less likely to lead to hydrate formation. The disadvantage of both of these options is that they both require significant additional capital expenditure (CAPEX).

One further option that is discussed in detail below; and was actually used successfully in the field in the current scenario; is the use of chemical additives. This may include the use of more traditional chemical additives such as MeOH or MEG. Alternatively it may entail the use of more recently developed Low Dosage Hydrate Inhibitors (LDHI). The option selected depends on the system conditions and typically takes into account the most appropriate economically viable solution.

Low Dosage Hydrate Inhibitors (LDHI). The categorization of hydrate inhibitors is typically achieved via three different groups depending on the mechanism of hydrate inhibition; these are as follows; (i) Thermodynamic Hydrate Inhibitors (THI); (ii) Kinetic Hydrate Inhibitors (KHI); and (iii) Anti-Agglomerants (AA). Thermodynamic Hydrate Inhibitors differ from LDHIs; as

Thermodynamic Hydrate Inhibitors shift the thermodynamic equilibrium of hydrate formation; whereas LDHIs do not. LDHIs operate by different mechanisms, as they become involved in the mechanism of hydrate formation in such a way as to interfere with and modify the formation of hydrate crystals. Further details concerning this are given below.

Both KHIs and AAs fall into the category of Low Dosage Hydrate Inhibitors (LDHI). These LDHI are typically applied at levels of between 0.25 to 5 vol. % of the system's produced water and in that respect the acronym LDHI can lead to some confusion when compared to other oilfield chemical dosages, such as scale inhibitors, which may be applied at parts per million (ppm) levels. However, LDHIs are so called as they can be successfully applied at lower dosages when compared to Thermodynamic Hydrate Inhibitors, such as MeOH or MEG.

Anti-Agglomerants (AA) were not used in this particular field application and a more extensive description of their characteristics can be found in the literature [10-15].

Thermodynamic Hydrate Inhibitors (THI). The formation temperature of hydrates is lowered by Thermodynamic Hydrate Inhibitors by approximately the same amount as they lower the freezing point of ice [13]. This effect is not entirely surprising because gas hydrate structures consist of hydrogen bonded water molecules as is also found in ice. In essence, the Thermodynamic Hydrate Inhibitors compete with the water molecules (in terms of hydrogen bonding) making the formation of hydrates thermodynamically less likely. Salts, MeOH and glycols such as MEG are all classified as Thermodynamic Hydrate Inhibitors.

Thermodynamic Hydrate Inhibitors do have the disadvantage that significant quantities of Thermodynamic Hydrate Inhibitor material may be required to prevent hydrate formation, for example; typically 10 to 40-vol. % of methanol may be required to be added to the produced water of a system. The dosage of Thermodynamic Hydrate Inhibitor required for successfully inhibiting hydrates depends on the 'subcooling' in the system. The subcooling is related to the driving force for hydrate formation experienced in the

system, which is typically represented by a numeric value. Subcooling can be defined as the difference between the hydrate dissociation temperature and the cooler system operating temperature at a given pressure. If the subcooling is high, this represents a situation where the system is experiencing severe conditions and a greater driving force for hydrate formation. It has been observed that the effective dosage of a Thermodynamic Hydrate Inhibitor, required to be used to prevent hydrate formation in a system, increases as the subcooling increases. Other issues that need to be taken into account when considering the potential use of large quantities of Thermodynamic Hydrate Inhibitor include the storage, transportation and handling of such large quantities of substances such as methanol, which include significant safety issues.

This has implications for systems which operate under moderate to severe subcooling conditions; such as offshore systems; as it may lead to significant OPEX costs and logistical challenges; such as those described below. This becomes even more significant if the subcooling experienced in a system increases, for example in an offshore gas production system during seasonal cold weather. It was due to the disadvantages of Thermodynamic Hydrate Inhibitors that the development of Low Dosage Hydrate Inhibitors (LDHI) has occurred over the last 18-years [16-17].

As mentioned above; LDHIs can be classified according to the way in which they modify the hydrate crystal formation mechanism. The main two categories of LDHI are the Kinetic Hydrate Inhibitors (KHI) and the Anti-Agglomerants (AA). However, there are other surfactants which act as hydrate inhibitors by dispersing hydrate crystals as they form [18].

In the field application described below, KHIs were used to achieve a successful outcome; they are described in further detail below.

Kinetic Hydrate Inhibitors (KHI). KHIs act via an analogous mechanism to scale inhibitors, in that they inhibit the formation of small crystals by their interaction with crystal growth sites. KHIs usually consist of water soluble polymers which interfere with and delay hydrate crystal nucleation and initial crystal growth processes [19]. The initial indicators to the optimum chemical structures for

use as KHIs came from the observation in nature that certain fish had the ability not to freeze in sub-zero seawater temperatures. The fish had the ability to produce a protein that (like a KHI with a hydrate crystal) interacted with an ice crystal and inhibited the further growth of the ice crystal [20]. In a similar way, the KHI has the ability to decrease the rate of hydrate crystal formation and in effect increase the induction time for hydrate formation. So called 'First generation KHIs' were based on polymers of pyrrolidone or caprolactam ring based structures [21]. However, these materials also had their limitations. The KHI limitations included subcooling limits and also the time limits of the KHI effectiveness. The effectiveness of first generation KHIs at controlling hydrates (at up to 8°C subcooling) was limited to approximately 24-hours. The 'first generation KHIs' had upper limits on the subcooling that they could effectively control (of 10°C) as noted by Kelland et al.[22].

It should be noted that if the severity of the system (represented by the subcooling) exceeds the effectiveness of the KHI, then a rapid formation of hydrate will occur, which would be a serious flow assurance concern. In essence, KHIs provide a certain amount of time during which hydrate formation is inhibited. During this limited time period of inhibition, the operator should be able to move the produced fluids through and out of the hydrate forming conditions of the production process. The KHI treatment should be designed so that the KHI induction time is greater than the produced fluids' residence time in the hydrate forming region of the production process. This will enable the produced fluids to pass through the production system without forming hydrate blockages even though the system is operating in the hydrate forming region. A good hydrate management strategy needs to assess the probability, and associated risks, of the hydrate inhibition time being exceeded in the system. Adequate contingency plans need to be put in place for such an occurrence; such as possible system depressurization; and the option of obtaining remediation quantities of Thermodynamic Hydrate Inhibitors, as appropriate.

Further generations of KHIs have been developed; such as 'Second generation KHIs' and even 'Third generation KHIs'. These have extended the limits

of subcooling and product effectiveness. KHI effectiveness of up to 11 to 12°C (for days to weeks depending on the subcooling) has now been achieved [23].

KHIs have several advantages when compared to Thermodynamic Hydrate Inhibitors (THI). One of the main advantages of KHIs is that they operate effectively at lower dosages than THIs. The associated operational expenditure (OPEX) savings that this brings about can make the KHI the most cost effective option. KHIs can also reduce the risks due to the storage and transportation of large quantities of Thermodynamic Hydrate Inhibitor – which may be flammable, as in the case of MeOH, for example. KHIs also have the benefit that they are relatively environmentally friendly. KHIs are also not limited by Gas to Oil Ratios (GOR) as AAs are. KHIs also have the advantage that they are not limited by the water cut experienced in the produced fluids, as in the case of Anti-Agglomerants (AA).

KHIs are not, however, a universal panacea for hydrate related issues. There are a significant number of offshore systems that need to operate under higher subcoolings than can be optimally controlled using KHIs alone. In such systems which typically operate under higher pressures and cooler temperatures, subcoolings of higher than 10°C are common. Deepwater systems typically have subcoolings of the order of 20°C and even higher subcoolings can be found in ultra-deepwater systems [24]. Such applications led to the opportunity and drive for the development of Anti-Agglomerant (AA) hydrate inhibitors [25].

The Control of Scale via Scale Inhibitor Products and Squeeze Applications. The control of scale formation is also an important aspect of flow assurance during hydrocarbon production; in addition to hydrate control issues. Under appropriate conditions, scale formation can occur. Scale deposition is a common problem in reservoirs where injected seawater mixes with aquifer brines. The problem is most severe in and around the production well bores, and can cause considerable disruption to hydrocarbon production after water breakthrough. To deal with the problem two general tasks must be performed. Firstly, the quantity and type of scale must be identified, together with the location and timing of

the deposition. Secondly, a suitable removal and/or prevention strategy must be designed and implemented. Both of these tasks require reservoir and laboratory data, and field experience is also a vital component in ensuring successful treatment. Both tasks are routinely assisted by application of appropriate modeling tools. In addition, models are routinely used in chemical scale inhibitor selection studies and to optimize inhibitor squeeze treatments [26].

Central to the down-hole scale management strategy are scale inhibitor “squeeze” treatments. The objective of these treatments is to prevent mineral scale formation by maintaining a sufficient concentration of chemical inhibitor in the produced water. The majority of treatments are adsorption squeezes in which a solution of scale inhibitor is pumped into the formation. There, the chemical is retained on the surface of the reservoir rock by a combination of physical and chemical interactions (adsorption) and provides protection over a period of several months as a result of its gradual depletion. Scale deposition can be prevented if a certain threshold concentration – the so-called “minimum inhibitor concentration”, or MIC – is maintained in the produced water. Once the level of inhibitor has dropped below the MIC it is necessary to repeat the treatment. Squeezes are typically designed to provide protection for anything between 6 months and 2 years. During this time, water samples are regularly taken and analyzed to allow assay of scale inhibitor residuals and monitor trends in levels of scaling ions.

Lower costs of production are obviously beneficial for operating companies during the production of hydrocarbons. One way that this can be achieved is in the advances that have been made in the formulation, testing and application of speciality chemical products; to give scale inhibitors which can be squeezed to give longer squeeze lives; and also products which enable their detection using residual methods to indicate the appropriate time to repeat the squeeze treatment whilst minimizing scaling risk.

EXPERIMENTAL DETAILS

A hydrate formation curve computer modeling software programme was used to determine the severity of the hydrate problem and design laboratory tests. The software programme predicted that the conditions in the gas lift system

would form type II hydrates with a calculated subcooling of 12°C. Laboratory tests were designed to replicate the conditions experienced in the field in the optimum way possible. Hydrate laboratory tests were carried out using high pressure rocking cells.

KHI Rocking Cell Test Apparatus. Baker Petrolite's gas hydrate rocking cell test apparatus consists of individual pressurized rocking cells (see Figure 2). Each cell is equipped with a sight glass to enable visual observations to be made. Each cell can be used with field fluids at field pressures. In a typical experiment, each cell is charged with brine, oil (or condensate), and an inhibitor chemistry package. Once the liquids are in place, the cells are then pressurized to the target value with a suitable hydrocarbon gas mixture and placed in a temperature controlled bath. The cells are either rocked (to simulate flow conditions) or held static (to simulate a shut-in) during the course of each experiment. The rocking motion, when employed, causes added agitation. The window in each cell allows visual interpretation of the fluid. Computer software monitors and records the pressure of each cell throughout the test. The monitoring of cell pressure is particularly useful for Kinetic Hydrate Inhibitors (KHI) as cell pressure decreases as hydrate formation occurs.



Figure 2: High pressure hydrate rocking cells for KHI evaluation experiments.

Synthetic gas compositions as close as possible to those expected in the field are used. Gas samples from the field are also used where possible.

A series of tests were completed to determine how much Mono Ethylene Glycol (MEG) alone would be required to inhibit hydrate formation for the relevant time period. The results of the laboratory tests showed that 35 vol. % MEG (based on water) would successfully inhibit hydrate formation whereas 30 vol. % MEG (based on water) was insufficient in inhibiting hydrates with obvious signs of hydrate crystals in the cells.

A subcooling of 12°C is a severe test for a KHI to inhibit hydrate formation on its own over a long time period. Preliminary testing showed that the conditions were, in fact, too severe for a KHI alone to control hydrate formation in the system. Test work then concentrated on the use of a KHI in conjunction with MEG. Figure 3 below shows various combinations of KHI and MEG which failed to inhibit hydrate formation. Test failures are noted by the sudden decrease in pressure during the experiment; due to hydrate formation – with gas being converted into solid hydrate.

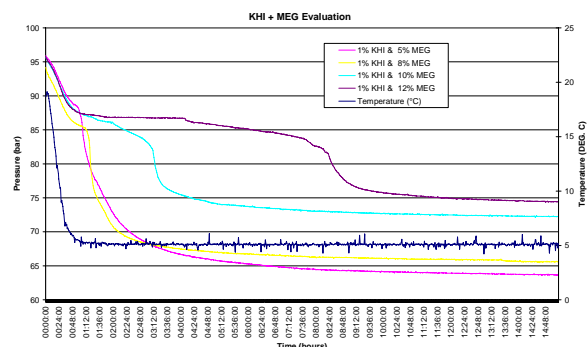


Figure 3: During the KHI evaluation experiments using the rocking cell apparatus; hydrate formation was noted by sudden pressure decreases in the cells.

Further laboratory evaluation showed that an optimum approach was achieved when 1 vol. % KHI was applied with a MEG/water mix. Experiments showed that hydrate formation was successfully inhibited. Figure 4 below indicates this; with no sudden change in pressure; that this combination of KHI and MEG/water controls hydrate formation. This was verified by visual observations.

Once the appropriate levels of KHI and MEG/water had been evaluated in the laboratory experiments; other secondary tests were carried out to confirm that the proposed application would not have a detrimental effect on the system; this included; for example; such tests as material compatibility tests, emulsification tests and corrosion tests.

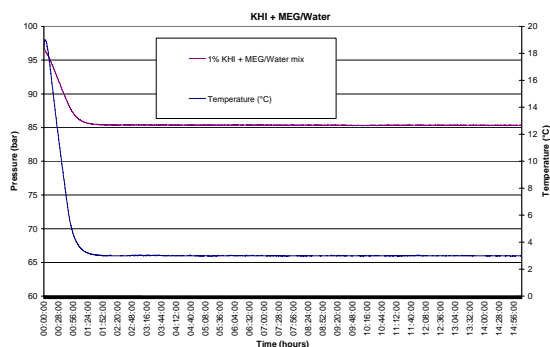


Figure 4: During the KHI evaluation experiments using the rocking cell apparatus; an optimum mix of 1 vol. % KHI with MEG and water successfully prevented hydrate formation - noted visually and via the lack of sudden pressure decreases in the cells.

Once all required laboratory tests had been satisfactorily passed; then the application was ready for field implementation.

FIELD APPLICATION

As noted above, when considering the production of hydrocarbon fluids from offshore gas systems, flow assurance is a significant issue which needs to be taken into account. An important element of flow assurance is the investigation into the possibility of gas hydrate formation and its subsequent control. The inhibition of gas hydrate formation needs to be taken into account as part of the production of oil and gas, especially as hydrates typically form at lower temperatures and higher pressures. Production facilities, particularly offshore wells and offshore transmission lines, may be operating under conditions where hydrate formation is favourable. The following case history illustrates the successful control of gas hydrate formation in an offshore system and the favourable use of KHIs to enable efficient and cost effective hydrocarbon production.

The Guillemot P3 well scale inhibitor squeezes were applied via the gas lift line with the requirement of significant amounts of MEG after the individual treatments in order to dehydrate the gas lift line and to prevent hydrate formation when gas was reintroduced into the line. In a recently applied scale inhibitor squeeze treatment on the Guillemot P3 well; a Kinetic Hydrate Inhibitor (KHI) in combination with a reduced amount of MEG was successfully applied after the treatments resulting in a significant reduction in chemical usage, costs and HSE exposure.

Guillemot P3 is situated in the Guillemot A field in the Central North Sea, located in blocks 21/25 and 21/30, approximately 172-Km East of Aberdeen. The field is produced via a sub sea tie-back to a Floating Production Storage and Offloading (FPSO) vessel, Anasuria, which is situated in 90-metre water depth. The Anasuria FPSO vessel is the centre for control of Teal, Guillemot A, Cook and Teal South fields' production and oil storage and oil and gas export operations. Guillemot A was discovered in 1979 and came on stream in October 1996. The Guillemot A field is being developed with six wells, four producers (P1, P2, P3, and P4) and two water injectors (W1, W2); see Figure 5 and Figure 6 below.

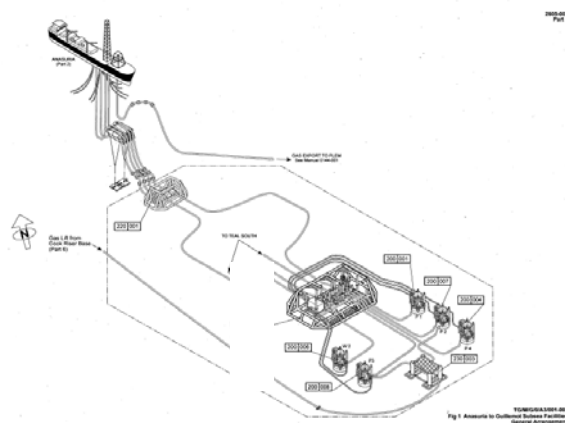


Figure 5: Anasuria to Guillemot subsea facilities.

The Guillemot field was developed by water flood schemes, with pressure support and sweep provided by water injection wells with the exception of Guillemot well P3, which is on natural depletion with gas lift support. The

Guillemot P3 well in the Guillemot A field will experience scale deposition (barium sulphate) due to the incompatibility between the Fulmar and Forties formation water. The scale precipitates and adheres to the tubing, pipelines, valves, etc., restricting flow and preventing equipment operating correctly. Scale removal is costly and particularly difficult in the well bore and would need DSV intervention. Mitigating the impact of scale requires a judicious combination of up-front prediction of the nature of the problem, followed by the formulation of a control strategy based upon prevention/inhibition and removal.

To prevent barium sulphate scale formation in the Guillemot P3 well, scale inhibition treatments are carried out, by pumping chemicals into the well bore and displacing them into the formation. Once initiated, the inhibition treatments need to be carried out on a routine basis (typically every 6 months). Up to 2005, these scale inhibitor squeeze treatments were carried out using a Diving Support Vessel (DSV). Due to the high cost of these well interventions a Business Improvement Project was started in 2005 with the incentive to reduce costs. The result of the project was that significant savings could be gained by carrying out the scale inhibitor squeeze treatments via the gas-lift line. This removed the requirement of a DSV for the scale inhibitor squeeze treatments, which was a significant cost saving, OPEX saving of £1.5MM - £1.8MM per year.



Figure 6: Shell Anasuria FPSO.

From 2005 onwards the scale inhibitor squeeze treatments were carried out from the FPSO through the gas lift line. In this operation scale squeeze chemicals were flowing to the well using the gas lift line and the right valve alignments in the subsea tree. The treatment was split into two sections; the chemical squeeze treatment and the MEG-water dehydration of the gas lift line followed by a slow displacement of the gas lift line to gas with methanol injection.

Due to the large quantities of MEG (Mono-Ethylene-Glycol) and accompanying chemical tanks which were required after the scale inhibitor squeeze / scale dissolver treatments it was operationally impossible to conduct a scale inhibitor squeeze on the back of a scale dissolver treatment because of deck space issues. If scale deposition was noticed in the well due to the delay of a scale inhibitor squeeze treatment or wrong placement of the squeeze chemicals, scale dissolver treatments were still carried out from a DSV.

In 2006; a further Business Improvement Project was put in place with the objective to reduce the amount of MEG, normally required to prevent hydrate formation within the gas lift line following scale inhibitor squeeze operations. After exhaustive acceptance testing the outcome of the project was that a smaller amount of MEG in combination with a Kinetic Hydrate Inhibitor could provide the same dehydration and hydrate protection. With the application of a Kinetic Hydrate Inhibitor a reduction of 50-75% in the amount of MEG was realized.

Typically Kinetic Hydrate Inhibitor chemicals are applied in oil and gas production applications. The use of a Kinetic Hydrate Inhibitor in combination with reduced amounts of MEG to dehydrate the gas lift line and to prevent hydrate formation after a scale inhibitor squeeze or scale dissolver treatment is a novel use of this existing technology. Related to the reduction of the amount of MEG are the reductions in OPEX, logistics and HSE exposure. Due to the significant reduction in MEG, scale inhibitor squeeze and scale dissolver treatments can be carried out from the FPSO now without the requirement of a DSV or extra supply vessel for a scale dissolver job.

In June 2007 this novel use of existing technology was successfully carried out on the Guillemot P3 treatment, which through multidisciplinary teamwork, demonstrated the following further improvements:

- Savings of \$550K a year in vessel / chemical costs.
- Savings of DSV costs at some \$1.8 MM.
- Improved Safety Performance, through significant reduction in the number of lifts required.
- Improved Environmental Performance, through significant reduction in the use of chemicals.
- Improved Operational Reliability, through removal of the potential impact of bad weather on the campaign.
- Return of 1000 m³/day production on Guillemot P3 with no gas lift from the dead well as a result of the Scale Dissolver job.

Implementation of this novel technology was achieved by a multidisciplinary team, adopting as its mission "To get it right the first time".

CONCLUSIONS

Kinetic Hydrate Inhibitors (KHI) can have a significant impact on the efficiency of hydrocarbon production; by helping to efficiently provide flow assurance against hydrate formation [27]. Baker Petrolite has considerable experience in developing and applying effective KHI products [28] and this has been demonstrated again here in this discussion. Initial work focused on the selection of suitable effective KHI to be used in the system; via appropriate laboratory test work simulating the system conditions. This development progressed to the successful use of the KHI selected in the actual system; once the KHI had also shown itself to be effective in all related tests in the laboratory.

The KHI application significantly reduced the cost of well intervention operations; by applying the KHI in a subsea gas lift line and reducing the volume of MEG required. Considerable cost savings were realized by reducing volume of chemical required overall and this enabled the application to be performed from the FPSO eliminating the need for a dedicated Diving

Support Vessel (DSV). Resultant savings of \$550K a year in vessel / chemical costs were achieved. Savings of DSV costs were \$1.8 MM. Chemical logistics usually associated with this particular treatment were simplified. Furthermore, the application of KHI also reduced manual handling, leading to improved safety performance through significant reduction in the number of lifts required. Improved Environmental performance was achieved through significant reduction in the use of chemicals.

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