Journal of Petroleum Science and Engineering 138 (2016) 1–10

Contents lists available at ScienceDirect

Journal of Petroleum Science and Engineering

journal homepage: www.elsevier.com/locate/petrol

Non-aqueous vs aqueous overflush scale inhibitor squeeze treatment in an oilfield offshore Norway

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ARTICLE INFO

Article history:
Received 15 October 2015
Received in revised form
27 November 2015
Accepted 29 November 2015
Available online 8 December 2015

ABSTRACT

The field under study is located offshore Norway. Due to the need for pressure support, it is anticipated that seawater will be injected and continuous gas lift will be used in a number of wells. Barium sulphate scale deposition is expected as high concentrations of barium have been measured in the formation brine. Scale inhibitor squeeze treatments will form an important part of the scale mitigation plan.

Squeeze treatments entail the injection of an inhibitor chemical to prevent scale deposition, the treatment generally consists of the following stages: preflush, main treatment, overflush and shut-in. The preflush stage is normally injected to condition the formation, with typically a mutual solvent being deployed to improve inhibitor retention and well clean-up times. The chemical slug is injected in the main treatment stage, generally as an aqueous phase. The overflush stage is deployed to displace the chemical slug deeper into the reservoir and thus expose the chemical to a greater surface area of rock to achieve a higher level of retention. Commonly, the overflush is deployed as an aqueous phase; however, it is not always feasible to inject large volumes of water in wells which are water sensitive or which already require artificial lift. Water is denser than hydrocarbons, and therefore more difficult to lift. In these circumstances, a non-aqueous overflush, generally marine diesel, may be preferable. The diesel volumes required are feasible for scale squeezes during the first years, although some additional logistic effort and costs are to be considered.

The objective of this paper is to compare squeeze treatment lifetime achieved by conventional aqueous and non-conventional squeeze treatments, where non-conventional refers to treatments where the overflush is split into aqueous and non-aqueous stages, typically diesel being used for the non-aqueous stage. The simulation and optimisation calculations were performed using a specialised near wellbore model for scale treatments, where a two-phase flow model was used to describe the displacement process during the multi-stage overflush. Splitting the overflush was found to reduce the squeeze lifetime marginally, as the non-aqueous overflush is not as effective as a purely aqueous overflush in propagating scale inhibitor deeper into the formation. However, this is counterbalanced by the fact that a smaller volume of water needs to be injected in the formation, and so reducing the risk of formation damage and most important for this particular case, a smaller volume of water will need to be lifted, so the well may be set back to production with ease.

1. Introduction

The oil field under study is located offshore Norway, it consists of two separated main reservoir formations. Both formations are relatively at shallow depth, characterised by low pressures and temperature. This study will be focused on the shallower formation, as seawater breakthrough is not expected to occur in the deeper formation producing wells. Due to the low reservoir pressure existing, it is anticipated that seawater injection will be injected for pressure support. In addition, a number of the wells in the central and main segment require gas lift. The south segment wells do not require gas lift, because of an existing gascap.

High levels of Barium measured in the formation brine is expected to cause barium sulphate scale deposition. Barium sulphate precipitates due to the mixing of incompatible brines, namely seawater rich in sulphate ions and formation brine rich in Barium ions. The deposition of barium sulphate might occur deep in the reservoir, which is not damaging, and possibly the contrary as

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http://dx.doi.org/10.1016/j.petrol.2015.11.033
0920-4105/

shown in the Gyda field (Mackay et al., 2006), where sulphate is stripped form the injected seawater, as the mixing front travels through the formation. Consequently, the levels of sulphate and barium close to the production wells will not be as high, and although barite-scaling tendency will be still present, it could be significant lower. In addition, carbonate scales may occur when the fluids are heated up before entering the separators however is not considered as a challenge from treatment perspective.

Squeeze treatments is one of the most common techniques for scale mitigation. They are commonly deployed to inhibit sulphate scales and in particular barite, which has extremely low solubility and is very hard. Prevention is key as sulphate scale only dissolves at a reasonable rate in the best dissolvers if given enough time and temperature (Kelland, 2009). Considering the low reservoir temperature, scale dissolvers are not expected to be very effective. Preventive over corrective squeeze treatments are thus the primary plan.

Scale inhibitor squeeze treatments are deployed to protect the near wellbore area from scale deposition and formation damage. The inhibitor will, of course, be actively protecting the pipeline to topside, but commonly topside facilities are further dosed. In a squeeze treatment, a scale inhibitor solution is normally bullheaded into the formation and then normally pushed for a few feet deeper in the formation. Then the well is shut-in for few hours to allow the chemical further retain in the formation surface. Finally, the well is put back in production and the chemical is slowly released and returned in the produced water. The produced water contains chemical concentration that prevent scale deposition, as long as the concentration are above a certain threshold, commonly known as MIC (minimum inhibitor concentration), when the chemical level falls below this threshold the well has to be resqueezed. Squeeze treatments normally consist of the following stages: preflush, main treatment, overflush and shut-in. The preflush stage is normally injected to condition the formation; in certain occasions, a mutual solvent is deployed to improve inhibitor retention and well clean-up times. The chemical slug is injected in the main treatment stage, generally in an aqueous phase. The overflush stage is deployed to displace the chemical slug deeper into the reservoir and thus expose the chemical to a greater surface area of rock to achieve a higher level of retention. Generally, the overflush is deployed as an aqueous phase, which normally results in longer squeeze lifetimes, as the chemical will be pushed deeper in the formation. However, in some occasions it is not feasible or recommended to inject large volumes of water. Such as in water sensitive formations, pre-emptive squeezes (wells at low water cuts) or/and where artificial gas lift is required, water is denser than hydrocarbons, and therefore more difficult to lift.

The main goal of this paper is to compare squeeze treatment lifetime achieved between a conventional aqueous treatment and a non-conventional squeeze treatments, which refers to treatments where the overflush stage is split into an aqueous and non-aqueous stage, where typically diesel is injected as the non-aqueous fluid. Splitting the overflush might not be as effective as a purely aqueous stage, as the scale inhibitor propagation may not as effective. However, this might be counterbalanced by the fact that a smaller volume of water will be required to achieve comparable squeeze lifetimes, thus reducing the risk of formation damage, well clean-up (a smaller volume of water needs to be produced back). And finally, a smaller volume of water has to be lifted, easing the process to put the well back in production.

2. Scale management

Reservoir scaling is a serious concern which has to be addressed during all the field life. The same approach adopted by Mackay et al. (2005) will be followed in this study, where an integrated risk analysis of scale management was proposed during the Front End Engineering Design (FEED) stage. The study includes the following steps, identification of maximum scale potential, evaluation of best suited chemistry by laboratory testing, modification of full reservoir simulation model to predict seawater breakthrough and finally, near wellbore squeeze modelling, which is based on the flow profiles derived from the reservoir model simulations.

Table 1
Formation and seawater compositions.

	Formation Brine	*Seawater*
Na (mg/l)	39,600	11,510
K (mg/l)	466	420
Mg (mg/l)	772	1410
Ca (mg/l)	3030	435
Ba (mg/l)	366	0
Sr (mg/l)	626	7
SO_4 (mg/l)	–	2800
Total Alkalinity (mg/l as HCO_3)	2200	150

2.1. Scale potential

To calculate the scale potential a number of flash-type calculations to predict the scaling risk associated to seawater injection in the reservoir formation were performed using PHREEQC, a geochemical model, which accounts for the original acronym-pH-REdox-EQuilibrium (Parkhurst and Appelo, 1999). The calculation considers the mixing of seawater and formation brine at the reservoir conditions, the formation brine and seawater can be found in Table 1. This type of calculation estimates the saturation ratio (SR) of the minerals that might precipitate, and the mass of the deposits, in particular Barite and Celestite are likely to deposit at the formation and topside facilities (separator), see Fig. 1. The results show the highest scaling tendency occurring around 60% seawater fraction, however the saturation ratio for Barite above 200 occurs for almost all the mixing ratios, outlining the strong impact of the problem over the field life. As mention before, carbonate scaling is not considered as major challenge in terms of treatment.

2.2. Evaluation of best suited chemistry

To evaluate the best suited chemistry for the reservoir under study, the amount of scale inhibitor required to control scale deposition has to be performed. In particular for barium sulphate scales static bottle test are be used as screening method (Kelland, 2009). From these tests the minimum inhibitor concentration, commonly known as MIC, is determined. The MIC value is normally based on the worst scaling conditions, which occurs around 60% of seawater percentage where saturation ratio of $BaSO_4$ reaches its maximum, see Fig. 1. However, the chemical supplier suggested that the MIC may vary from 7.5 to 2.5 ppm, which varies as a function of the scaling tendency. The scaling tendency is a function of the produced water composition, which is determined by the seawater fraction and may be lowered by barium stripping.

2.2.1. Barium stripping

Barium reservoir stripping may lead to a reduction in the barite scaling precipitation tendency in near wellbore areas (Mackay et al., 2006), resulting in a lower MIC. To considered barium stripping a reactive transport reservoir model was used to simulate the $BaSO_4$ precipitation reaction to identify the impact of the occurrence of barite deposition in the reservoir on the