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Rheological evaluation of a sodium silicate gel system for water management in mature, naturally-fractured oilfields

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ABSTRACT

Excess water production is a common problem in mature and hydrocarbon rate declining oil and gas fields. Increased water production rates reduce oil and gas production, increase the cost related with fluid lifting, handling and disposal of produced water, and negatively influence the hydrocarbon production economics. Among the various existing techniques for water control, silicate gel systems are known to be an effective and environmentally friendly method for managing water production. The gel systems usually contain two main components, the liquid silica and activator. The low-viscosity (almost like water) system, which is mixed and pumped from surface in a liquid form, is designed to gel under reservoir conditions, thus allowing sufficient time for the pumped fluids to reach the designated location from the treatment well.

This work focuses on the laboratory qualification of a commercially available sodium silicate system for designing and implementing field water shutoff treatments in mature, naturally-fractured carbonate formations. Lab rheology measurements are carried on sodium silicate gel samples using the Anton Paar Rheometer MCR302. Two test modes are run with the specific purposes: the Dynamic-Mechanical (DMA) mode is employed to determine the onset of gelation (sol–gel transition time or gel point) and the viscosity increase versus time; the Amplitude Sweep (AS) mode is used to assess the formed gel's shear strength at a given viscosity. Gel point and gel strength play an important role in designing successful water shutoff treatments since the first determines the required time for the injected gelant system to gel into reservoir and other determines the forces the formed gel can withstand under shear conditions.

The effects of silicate and activator (NaCl solution) concentrations, presence of divalent ions (e.g., Ca^{2+}, Mg^{2+}), temperature, and gelant dilution on sol–gel transition time are investigated. A general correlation is derived that describes the relation between sol–gel transition times and silicate solution concentration, activator concentration, temperature, degree of water dilution, and concentration of divalent ions. This correlation can be used to design the recipe of the silicate system for applications in fields with treatment region temperatures in the range of 40–60°.

1. Introduction

Excess water production, especially in mature oil fields, has serious implications on field operations and the environment into which produced water may be discharged. The produced water is either separated down-hole and injected into another formation, or brought together with oil/gas to surface and separated there. Operational expenses, including lifting, separation, treatment, pumping and reinjection, and/or disposal add to overall cost of oil production. Once the water is separated from oil, it can be either re-injected into formation or disposed to the environment. As a production well ages, its water-cut and hydrostatic pressure increase. Maintaining the same production rate requires either to increase bottom-hole or reduce wellhead pressure. At some point, when these two pressures reach their limit and can no longer be adjusted, the production rate will decrease sharply and the well may even “die”. Installation of gas-lift or down-hole pumps can help to cure the well but at an additional capital and operating cost. In 2002, produced water was estimated to cost the petroleum industry approximately USD 45 billion annually Veil et al., 2004. These costs include the expense to lift, dispose of or re-inject produced waters, as well as the capital investment in surface-facility construction, and other environmental concerns (Bjørn et al., 2011).

Waterflooding is the easiest and cost-effective mean for maintaining reservoir pressure and increasing oil production efficiency. However, due to normally adverse mobility ratio most of

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the injected water flows through high conductive paths/zones, thus leaving large amounts of upswept oil in the reservoir. Subsequently, oil production rate is reduced while water production is increased over time. Economic concerns are related not only with the large amounts of oil remaining in the reservoir, but also with the large time-increasing costs associated with the produced excessive water. Improved oil recovery factors could be achieved by addressing the problem of excess water production and its effective utilization to displace mobile reservoir oil. This problem is much more pronounced in naturally fractured carbonate formations. According to Portwood (1999), a typical water shutoff treatment could reduce water production by 75% to 90% and increase oil production by 1000%.

There are several mechanical and chemical methods, both near-well and in-depth formation, that can be applied to reduce excess water production. In order for such technologies to be successful, the mechanism(s) that contribute to the occurrence of excess water must be evaluated and effective/proper treatments designed (Hatzignatiou and Olsen, 1999; Bailey et al., 2000). The solution to control water production corresponds to a given problem and can be to (a) prevent early excess water production; (b) reduce excess water production; or (c) isolate water flow pathways/water shut-off.

1.1. Prevention of early excess water production

Solutions/techniques should be considered from the planning/designing stage to prevent unwanted water production before it occurs. Such techniques include (a) well-placement technology to efficiently place a production well within the producing zone, (b) horizontal wells to delay the onset of water coning/cresting, (c) installation of smart/intelligent well completions to manage effectively the oil and water production rates and maximize field oil recovery, and (d) placement of perforation intervals in cased-hole wellbores to delay water coning.

1.2. Reduction of excess water production

Various solutions can be applied to control excess water volumes brought up to surface, thus reducing the (a) total fluids production costs (lifting, produced water treatment, storage and re-injection) and (b) environmental impact of oil and gas operations, and risks associated with re-injection wells. Downhole oil–water separation (DOWS) can be used in wells with low oil production and a high water cut to separate water from oil and inject it into another formation (Bowers et al., 1998). Polymers may be used to increase injected water viscosity to avoid early water breakthrough and improve formation sweep efficiency.

1.3. Water shut-off - isolation of water flow pathways

These solutions involve the use of either mechanical or mainly chemical methods/techniques, that can “shut off” water-bearing channels or fractures in the formation and prevent water from making its way to the well. Packers, plugs setting and cement are traditional mechanical blocking devices addressing near-wellbore water problems, such as casing leaks, flow behind casing, rising of bottom water, and watered-out layers without cross-flow (Bedaiwi et al., 2009). However, if the various layers are in communication within the formation, this method will not affect the fractional flow because of fluid cross-flow (Skrettingland et al., 2012). For this case, chemical in-depth treatments are more advantageous over the mechanical methods.

1.4. Water shut-off chemicals

Chemical solutions have a larger range of application in term of formation depth away from the wellbore and can address several water-type problems. Appropriate chemical systems can be used in either the near-wellbore area to block the most water productive layers (with a higher efficiency compared with mechanical techniques) or in-depth treatments to block high water permeability fractures/zones originated away from a production well. Polymer and sodium silicate gelants are the most popular chemicals for water shut-off. These chemicals (gelants) are injected as solutions to form gels in the reservoir. The gels are designed to be sufficiently strong for long periods at formation temperature, salinity, and pH; in addition, are able to withstand the applied pressure during hydrocarbon production. The resulting profile modification or conformance control diverts injected water to unswept reservoir zones and improves the distribution of fluids in heterogeneous reservoirs (Simjoo et al., 2007). With significant advantages such as high control of setting time, flexibility for pumping without a work-over rig, deeper penetrations into formation, easy removal from wellbore by water recirculation, etc., chemical solutions have been used more often and with higher success rate (Perez et al., 2001).

Polymers have been studied and used more than silicate for water-shutoff operations. However, these robust and effective chemical systems are listed as either black or red according to Norwegian environmental regulations, and therefore cannot used in the Norwegian Continental Shelf (Bjørn et al., 2011). Recent studies and field tests have demonstrated the feasibility and efficiency of silicate gel as water-control chemicals. Moreover, silicates are categorized as green chemicals and are more environmentally friendly than most other chemicals used for fluid diversion. Silicate gels are formed based on the principle of lowering the gelant's pH, which is normally done with the addition of acidic activators to the aqueous solution of sodium silicate. The use of silicate gels for petroleum applications has been documented since 1922; however, their benefits and field potential were not appreciated for a long time. One of the reasons is that the mechanism of silicate gelation, particularly under reservoir conditions, is poorly understood (Lakatos and Lakatos-Szabó (2012); Vinot et al., 1989). In order to bring silicate gel closer to the field application, many studies were undertaken to better understand the systems' behavior and different additives were tested to improve their performance (Vinot et al., 1989; Nasr-El-Din and Taylor, 2005). Several laboratory experiments on silicate systems for deep reservoir placement have been performed (Skrettingland et al., 2012). The possibility to simulate and match silicate-gel treatment laboratory results using a commercial simulator was demonstrated by Hatzignatiou et al. (2014). Recently, a thorough laboratory evaluation of sodium silicate systems in combination with polymer for better conformance control in highly conductive formation has been carried by Hatzignatiou et al. (2015).

As any other system, silicate gel systems have their own advantages and disadvantages. The main advantages of silicate gels are the low viscosity of treating solutions; short to moderate pumping time before gelation onset; flexible chemical mechanism; good chemical stability; excellent thermal and mechanical resistivity; easy gel “breaking” in case of technical failure; simple and cost-effective surface technology; and environmentally “green” chemicals. Various silicate-based technologies have been used in several field applications worldwide, exhibiting a good field experience and providing valuable lessons for future deployments. Until 2012, more than 80 jobs were performed with 60–65% of the treatments deemed technically successful and 40% of the jobs as economic (Lakatos and Lakatos-Szabó, 2012). In June 2011, a single well pilot injection of sodium silicate in the Snorre