ASPECTS OF COALBED NATURAL GAS WATER AND OIL RECOVERY[1]

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Abstract. The application of coalbed natural gas (CBNG) water injection to improved oil recovery is being investigated. Such application can be permitted as Class II injection. This is more advantageous economically than Class V injection. Therefore CBNG water injection for improved oil recovery is value-added disposal. Use of CBNG water for oil recovery will also reduce the depletion of fresh water aquifers currently used in Wyoming as a source of injection water. The potential for application of low salinity flooding to a specific reservoir requires tests on cores and crude oil obtained from that reservoir. Information will be presented on the Tensleep reservoir rock from the Teapot Dome field that was selected for laboratory tests of CBNG water injection in Wyoming oil reservoirs.

Additional Key Words: CBNG water, low salinity, low salinity brine injection, improved oil recovery

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Introduction

Co-produced water from coalbed natural gas (CBNG) production presents a serious disposal problem that impacts CBNG development in Wyoming. Production of CBNG water across all Wyoming coal fields could reach about 54.3 billion barrels if all of the recoverable CBNG gas (31.7 tcf) from the projected reserves were produced over the coming decades (Bergman et al., 2005). Environmentally friendly and economically sound management of CBNG water production has become crucial to continuous CBNG development in Wyoming. The salinity of most of the CBNG water in Wyoming ranges from 300 to 2500 ppm. The CBNG water has limited suitability for domestic and animal consumption or for agriculture. For example, 40% of water samples tested in the Powder River basin showed high sodium adsorption ratio, i.e. the ratio of sodium to calcium and magnesium (SAR > 10) (Rice et al., 2000). Subsurface disposal of such brine may have to be categorized under the restrictive Class V injection.

Numerous laboratory tests and field tests show that oil recovery by injection of low salinity brine (up to 4000 ppm) can be increased in both secondary mode (at the outset of development of a reservoir) and tertiary mode (extension of field life at a mature stage of waterflooding) (Tang and Morrow, 1997; Webb et al., 2004; Zhang and Morrow, 2006). Webb et al (2005) reported increased oil recovery ranging from 2 to 18% in tertiary mode. Laboratory tests of secondary mode flooding showed oil recovery increases of up to 60% compared to high salinity flooding (Tang and Morrow, 1997). Results of pilot tests on watered out fields in Alaska were in good agreement with laboratory observations (McGuire et al., 2005). Furthermore, unexpectedly high field wide recoveries have been ascribed to injection of low salinity water. BP has reported that the low salinity process has the potential to add ~ 1 billion barrels to their reserves worldwide over the next 20 years (http://ior.rml.co.uk/issue12/articles/BP). The mechanism of increase in oil recovery by low salinity flooding is not well understood, particularly with respect to why the response of some reservoirs is much better than for others (Tang and Morrow, 1999; McGuire et al., 2005; Lager et al., 2006).

Experimental

To test the effect of CBNG water injection on improved oil recovery, reservoir rock samples from Tensleep formation, Teapot Dome Field of Natrona County, Wyoming were obtained. Thin section analysis indicated that the sandstone rock was composed of quartz, feldspar, cement, with very small amount of clay and small dolomite crystals, the rock had good sorting (Fig.1).

The permeability and porosity of the two core samples were about 40 md and 14% respectively. Crude oil from Minnelusa formation was used as the test oil. Synthetic CBNG water used in the laboratory was based on the water composition of CBNG well Echo 15-19 which represented the average salinity of CBNG water (about 1300 ppm) from the Powder River Basin (Table 1).

The reservoir cores were first cleaned with toluene – methanol – toluene displacement to remove the oil residue and deposited salts, and dried by evaporation at room temperature and then heated at 105°C. The cores were saturated with Minnelusa brine (see Table 1), Minnelusa crude oil was used to establish initial water saturation S_{wi} for both cores was about 19%. After aging for 10 days, the cores were flooded in secondary mode with Minnelusa brine to establish residual oil saturation. The cores were then flooded in tertiary mode with 1300 ppm CBNG brine. The aging and displacement temperature was 75°C. Oil recovery versus volume of brine injected was recorded.

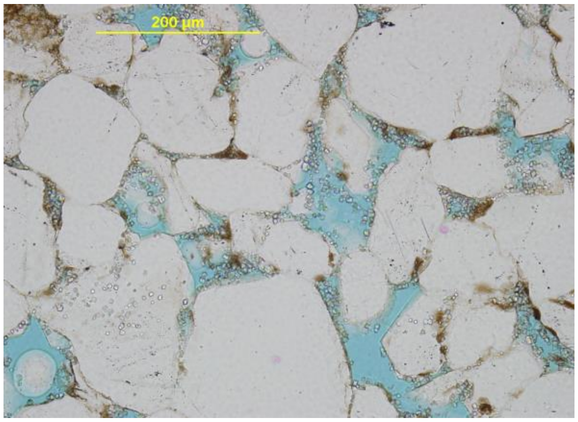

Figure 1 Thin section of the Tensleep rock.

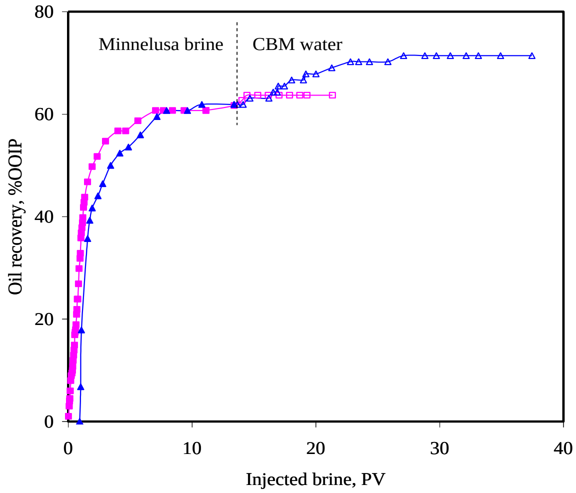

Figure 2 Oil recovery by waterflooding.

Table 1. Formation water composition

Composition	Minnelusa formation water concentration, g/L	CBNG water concentration*, g/L
NaCl	29.803	0.9157
Na_2SO_4	5.903	-
$CaCl_2$	2.104	0.1915
$MgCl_2$	-	0.1804
$MgSO_4$	0.841	-
KCl	-	0.0287
TDS	38.651	1.3163

* Water composition of CBNG Well Echo 15-19 (Rice et al., 2000)

Results and Discussion

Two waterflood tests were performed. Both cores were first flooded with synthetic Minnelusa formation water at a rate of 1 ft/day. The oil recovery was about 60% for both cores. Then the cores were flooded with synthetic CBNG water at the same rate. The oil recovery increased by 4% for one core and 10% for the other (Fig. 2). Injection pressure and effluent pH, were also monitored during the waterflood. The results indicated that CBNG water from the Powder River Basin might be used to improve oil recovery for Tensleep sandstone reservoirs.

Preliminary laboratory results are encouraging. Further tests on the effect of CBNG water on oil recovery for the Tensleep and other candidate reservoirs are in progress. Other factors that impact the viability of using CBNG water to improve oil recovery are the relative locations of CBNG wells and target reservoirs, the compatibility of the rock and fluid properties, and transportation costs.

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