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Low-Salinity Waterflooding to Improve Oil Recovery – Historical Field Evidence

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Low-Salinity Waterflooding to Improve Oil Recovery—Historical Field Evidence

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Abstract

Waterflooding is by far the most widely applied method of improved oil recovery. Crude oil/water/rock interactions can lead to large variations in the displacement efficiency of waterfloods. Laboratory waterflood tests and single-well tracer tests in the field have shown that injection of low-salinity water can increase oil recovery, but work designed to test the method on a multi-well field scale has not yet been undertaken. Historical waterflood records could unintentionally provide some evidence of improved recovery from waterflooding with lower salinity water. Numerous fields in the Powder River basin of Wyoming have been waterflooded using low salinity water (about 1000 ppm) obtained from the Madison limestone or Fox Hills sandstone. Three Minnelusa formation fields in the basin were identified as candidates for waterflood comparisons based on the salinity of the formation and injection water and reservoir characteristics. Historical production and injection data for these fields were obtained from public records. Field waterflood data were manipulated to display oil recovery in the same format as laboratory coreflood results. Recovery from fields using lower salinity injection water was greater than that using higher salinity injection water—matching recovery trends for laboratory and single-well tests.

Introduction

Almost without exception, at the start of a waterflood, water from the cheapest source (usually different in composition than the initial formation water) is used as the injection water, provided injectivity is not adversely affected by formation damage. Historically, little consideration has been given in reservoir engineering practice to the effect of the composition of the salt in the injection water on waterflood displacement efficiency or to the possibility of increased oil recovery through manipulation of the injection water composition. Most laboratory relative permeability tests and displacement tests are done using synthetic formation water as both the formation and injected water rather than using formation water and the actual field injection water for these tests.

It has been shown that different wetting states of crude oil, water, and rock ensembles can yield widely different oil recoveries during laboratory waterflood tests. The wetting state, or wettability, of a rock and fluids system can be altered in a number of ways. For example, wettability can be altered in the laboratory by changing the crude oil composition, changing the temperature while aging the rock and crude oil, or by changing the temperature during water displacement.[1] It has also been observed that the composition of the water can have a significant impact on wettability and oil recovery.[1,2,3,4] It follows that there may be cases where attention to injection water composition could lead to increased oil recovery and a likely increase in the economic profitability of a waterflood.

There may be an optimal composition of the dissolved solids in the injection water that would yield the highest oil recovery. The composition could involve many variables with respect to ionic composition and concentration but current knowledge of how and when water composition can be manipulated to increase oil recovery is limited. Several examples of improved recovery by injection of low ionic strength brine have been reported for both outcrop and field core samples by Tang and Morrow.[4,5] Of the many possibilities that need to be further explored, laboratory results showing increased recovery resulting from injection of dilute brine appear the most promising with respect to near term field application. Tang and Morrow showed that oil recovery increased markedly with injection-brine dilution for recovery of several types of crude oil and sandstones. **Fig. 1** is an example of the potential for increased oil recovery from low-salinity waterflooding.[6] The corefloods depicted in this figure were done using two different cores from the CS reservoir under identical conditions with the exception of the composition of the injected water.

Robertson et al. have also discussed examples of laboratory work showing increased recovery from low salinity waterfloods.[7] Average recovery curves from seven corefloods are plotted in **Fig. 2** and show a clear increase in recovery from low-salinity waterfloods under simulated reservoir conditions.

The conditions necessary for improved recovery, such as the type of crude oil and rock, composition of the formation and injected water, and initial water saturation are still far from understood. The crude oil/water/rock interactions that determine displacement efficiency are highly complex. Nevertheless, laboratory observations such as those discussed above were sufficiently encouraging to justify further studies aimed at field application.

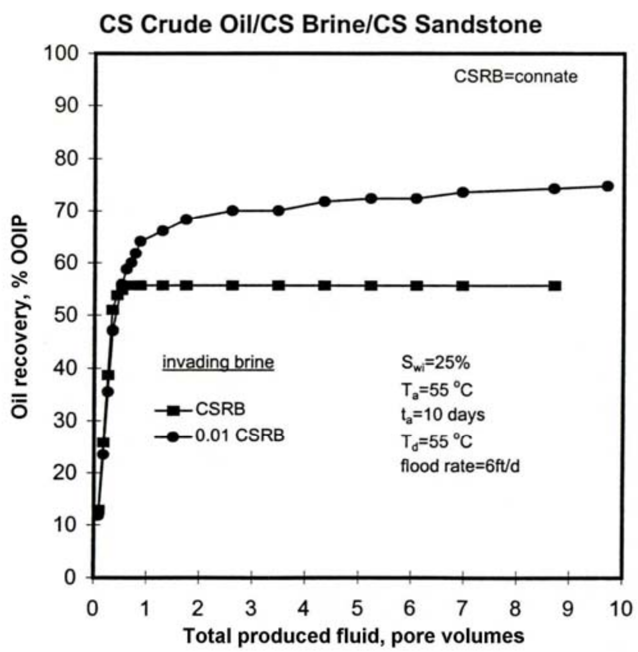

Fig. 1—Example of improved recovery resulting from flooding with diluted formation water (after Tang [6] Fig 3-12). CSRB = CS reservoir brine.

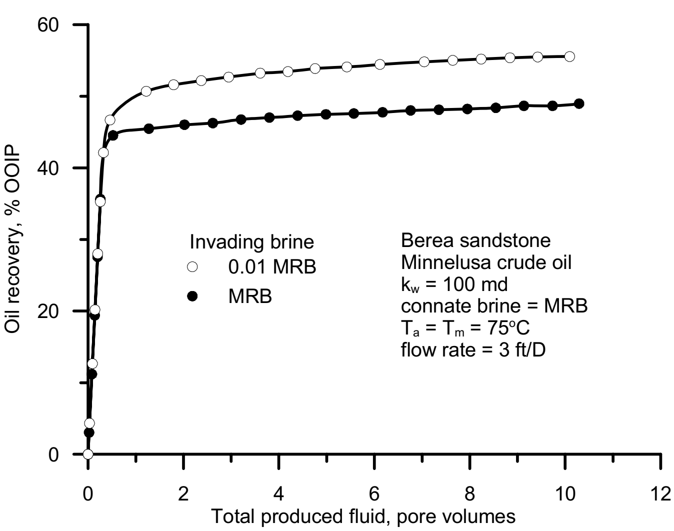

Fig. 2—Example of improved recovery from laboratory cores mimicing Minnelusa reservoir conditions (after Robertson et. al[7]). MRB = synthetic Minnelusa reservoir brine.

A field pilot designed to understand and evaluate the effectiveness of a low salinity injection process was described by McGuire et. al.[8] They concluded, among other things, that there were a number of fields and reservoirs on the Alaska North Slope that appear to be viable targets for low salinity waterflooding and suggested that incremental field recoveries ranging from 6% to 12% are possible.

Idaho National Laboratory (INL) through funding from the U.S. DOE has expanded on the work cited above by searching historical waterflood records for anecdotal evidence of increased oil recovery resulting from the injection of lower-salinity water to displace oil in reservoirs with higher-salinity initial formation water. The objective of this paper is to detail INL's efforts to research and compare such historical field data and to compare field waterflood responses from low- and high-salinity injection waters.

Selection of Fields for Waterflood Comparison

Work focused on field-scale historical data from the Powder River Basin, which is a major petroleum-producing basin in Wyoming that is conveniently close to INL (Idaho Falls, Idaho). Waterfloods, both large and small, have been applied extensively within the basin. A brief study of the waterflooding practices in the basin revealed that the vast majority of waterfloods used fresh water either exclusively throughout the life of the waterflood or at least initially but later re-injected produced water as it broke through in the producing wells. The Fox Hills sandstone and the Madison limestone (both sources of fresh water) were the two major sources of injection water for waterfloods in the basin. Historical records of field operations in this basin, stored by the Wyoming Oil and Gas Conservation Commission (WOGCC), were searched to find waterfloods using relatively fresh injection water and others using more saline injection water. Once adequate field analogues were found, waterflood results were compared to determine if the historical record substantiated the laboratory observation that low-salinity waterfloods can yield higher recovery than that obtained by injecting higher-salinity waters.

The Powder River basin of the United States is located largely in northeastern Wyoming with a small portion extending into southeastern Montana (see **Fig. 3**). The basin is a deep, northerly trending, asymmetric, mildly deformed trough, approximately 250 miles long and 100 miles wide. Its axis is close to its western margin, which is defined by the Bighorn Mountains uplift and the Casper arch. It is bordered on the south by the Laramie and Hartville uplifts and on the east by the Black Hills uplift. The northern margin is defined by the subtle northwest-trending Miles City arch.

The basin is one of the richest petroleum provinces in the Rocky Mountains. More than 2.5×10^9 barrels of recoverable oil have been discovered in reservoirs ranging in age from Late Paleozoic to Upper Cretaceous.[9]

The Muddy-Newcastle is the most prolific oil-producing formation in the basin, but the sand is often poorly sorted with substantial clays present. Clays within the pores are sensitive to fresh water and can migrate and cause plugging of rock pores. Historically, waterfloods in the Muddy-Newcastle formation used injection waters modified by the addition of potassium chloride and/or potassium hydroxide for clay stabilization. The effect of these additives on waterflood displacement efficiency has not been studied in laboratory corefloods. Therefore, fields in this formation were excluded as candidates for comparison of low-salinity-water versus higher-salinity-water oil recovery.

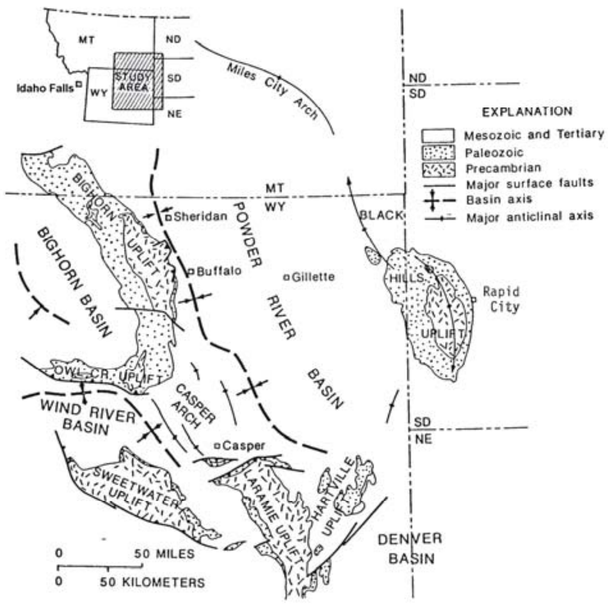

Fig. 3—Map of Powder River basin showing geographic location to INL and surrounding basin borders.

Although Robertson et. al[7] (Fig. 2) did not use Minnelusa reservoir core in their experimentation set, they did show that a potential increase in oil recovery could be achieved by using diluted (lower salinity) injection water with Minnelusa oil and water and Berea sandstone.

Reservoirs in the Minnelusa formation within the Powder River basin are generally small, but lend themselves to waterfloods because of the typically clean, well-sorted sand. The Minnelusa formation is of Pennsylvanian and Lower Permian age. Sandstones of the Minnelusa formation are major oil-producing reservoirs within the basin and are productive in both structural and stratigraphic settings. The productive portion of the Minnelusa formation lies in the northeastern portion of the Powder River basin east of the city of Gillette, Wyoming. The formation outcrops in the Black Hills above Rapid City, South Dakota. Waterflooding with fresh water was a common practice in this formation providing the opportunity for appropriate field comparisons.

The first well in the Minnelusa having commercial significance was completed in 1957. Exploration for additional Minnelusa discoveries has continued with an extremely high increase in exploration activities with the higher oil prices of the early 1980's. Most of the larger Minnelusa reservoirs were discovered in the earlier phase of Minnelusa exploration, during the 1960's, but numerous smaller discoveries have continued into the present. The original oil-in-place for the Minnelusa in the Powder River basin has been estimated at 629×10^6 barrels.[10]

The Minnelusa formation is comprised predominantly of white crystalline sandstone loosely cemented by carbonate and anhydrite. The formation appears to have been deposited in a marine environment, but an eolian origin, in part is not excluded. The upper portion of the Minnelusa formation (Upper Minnelusa) usually contains three sands: the two upper sands ("A" and "B") are usually productive and the lower sand ("C") that is usually nonproductive.[11] Initial pressures of Minnelusa reservoirs are typically above the bubble point resulting in zero initial gas saturation. In a study of thirty-five Minnelusa reservoirs, average values were determined for the reservoir characteristics of these fields and are listed in **TABLE 1**.[12]

TABLE 1—AVERAGE RESERVOIR CHARACTERISTICS OF THIRTY-FIVE MINNELUSA RESERVOIRS.

Average reservoir permeability, md	50 to 657
Porosity, %	16.2
Dykstra-Parsons permeability coefficient, dimensionless	0.75
Formation water saturation, %	25.5
Pay thickness, ft	29.3
API gravity, °API	18 to 40
Initial formation volume factor, res bbl/STB	1.087
Solution GOR, scf/STB	61.5
Oil viscosity at reservoir temperature, cp	15.2
Produced water chloride content, ppm	2000 to 200,000

Although many field records were perused in an effort to select appropriate waterflood comparisons, three fields were ultimately selected as good candidates for waterflood comparisons due to their proximity to each other and waterflood and reservoir characteristics. These fields are described in the following sections.

West Semlek Reservoir Description

The West Semlek unit was formed in 1973 and water injection began in June the same year. The engineering study for the proposed West Semlek unit was submitted in 1971.[13] Production is from the Upper Minnelusa "B" sand of Pennsylvanian age. The reservoir is a stratigraphic trap with truncation of the sand defining the reservoir limits except in the west, where an oil-water contact limits the oil reservoir. The Upper "B" sand is an anhydritic, well-developed, and fine-to-medium grained sandstone, with occasional interbedding of dense shaly dolomite. The reservoir characteristics for the West Semlek field are tabulated in **TABLE 2**.

North Semlek Reservoir Description

The waterflood feasibility study for the small North Semlek field was prepared in 1987.[14] Wells in this field produce from the Lower "B" sand member of the Minnelusa formation. The field was discovered in 1963 with the completion of the Heath Government 21-1. The next well to be completed in the field was the Terra State No. 1 twelve years later in 1975. In 1983, the Semlek Federal No. 1 was completed and the unit development was finished in 1984 with the completion of the Heath Government 21-5. TABLE 2 shows the reservoir characteristics for the North Semlek field.

Moran Reservoir Description

The Moran field is located in the northeastern portion of the Powder River Basin, approximately fifteen miles east of the town of Gillette, WY. The field is actually composed of two waterflooding units: the East Moran (Minnelusa) unit and the West Moran Minnelusa unit. ARCO developed the eastern portion of the field and Sun developed the western portion. The original unitization proposal included both the east and west portions of the reservoir, but due to differences between the two operating companies, the east and west portions were allowed to be organized separately.[15,16,17] However, because both units were in fluid and pressure communication and developed concurrently, they were combined in this analysis and treated as one reservoir. TABLE 2 shows the reservoir characteristics for the Moran field.

TABLE 2—RESERVOIR CHARACTERISTICS OF THE WEST SEMLEK, NORTH SEMLEK, AND MORAN MINNELUSA FIELDS.

	West Semlek	North Semlek	Moran
Average reservoir permeability, md	225	—	78
Porosity, %	19.4	15.8	14.4
Water saturation, %	25.0	20	37.1
Initial reservoir pressure, psia	2847	2700	4381
Bubble point pressure, psia	165	300	475
API gravity, °API	23	22.5	22.3
Initial formation volume factor, res bbl/STB	1.049	1.049	1.07
Solution GOR, scf/STB	10	10	50
Reservoir temperature, °F	144	140	200
Depth to productive formation, ft below surface	7240	7270	8715

The relative position of the three Minnelusa fields being analyzed for this study is shown in **Fig. 4**.

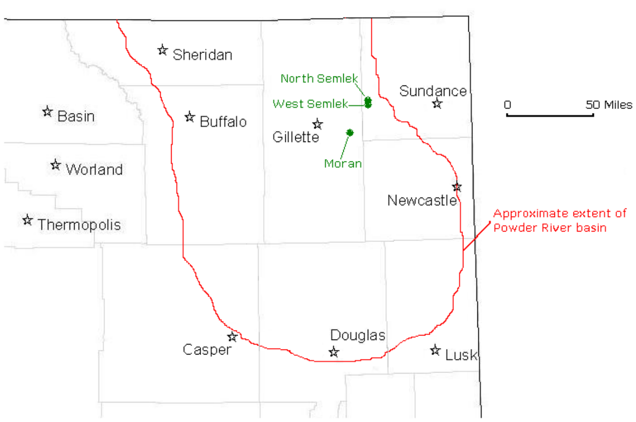

Fig. 4—Northeast corner of Wyoming showing the approximate extent of the Powder River basin and the location of the North Semlek, West Semlek, and Moran waterflooding units.

Injection and Formation Water Analyses

The following sections describe both the formation water of each of the three reservoirs selected for waterflood comparison and the injection water used for secondary recovery.

West Semlek Water Analysis

The engineering study for the West Semlek unit[13] reported that the total dissolved solids (TDS) in the initial formation water produced from the Minnelusa Upper "B" sand averaged 60,000 parts per million (ppm). Injection water for this unit came from two off-unit water wells producing from the Minnelusa Lower "B" sand. Analyses of the water from the two wells were obtained from water analysis records at the WOGCC and are shown in **TABLE 3**. Average concentration of total dissolved solids for the two injection water wells at the onset of the waterflood was 7165 ppm.

TABLE 3—WATER ANALYSES FOR THE TWO OFF-UNIT SOURCE-WATER WELLS (MINNELUSA LOWER "B" FORMATION) FOR THE WEST SEMLEK UNIT WATERFLOOD.

Dissolved components	Concentration, ppm Well 28-1	Well 28-6
Cations		
Potassium	79	122
Sodium	610	2580
Calcium	630	740
Magnesium	133	142
Anions		
Sulfate	2110	2550
Chloride	576	3470
Carbonate	0	0
Bicarbonate	495	688
Total dissolved solids	4380	9950

Very little water was produced during the primary production phase for the West Semlek unit. Water injection began in 1973 and breakthrough occurred a year later. As the waterflood progressed, produced reservoir water was commingled with makeup water from the Minnelusa Lower "B." A subsequent analysis of produced water collected 13 years after waterflood initiation reported that the TDS concentration of the produced reservoir water had decreased from the initial value of 60,000 ppm to 15,500 ppm.

Over time, the TDS concentration of the recycled water decreased and its volume increased, which tended to even out the variability of the salinity of the injection water with time. To simplify the analysis, a value of 10,000 ppm for the salinity of the West Semlek injection water is assumed to be constant throughout the life of the waterflood. This relationship can be described mathematically by:

$$C_r f_r + C_m (1 - f_r) = C_t , \quad (1)$$

where C_r is the salinity of the water recycled from producing wells, f_r is the fraction of the total injected water that is recycled, C_m is the salinity of the makeup water (Minnelusa Lower "B" sand), and C_t is the total salinity of the combined injection water. At the start of the waterflood, C_r was equal to

60,000 ppm, C_m was equal to 7165 ppm, C_t was equal to 10,000 ppm, and f_r, calculated from Eq (1), was 5.4%. This value for f_r, the fraction of injection water that was recycled, will be used to consistently compare results from the other waterfloods.

North Semlek Water Analysis

Total dissolved solids of the initial reservoir (formation) water averaged 42,000 ppm for the North Semlek field with NaCl accounting for approximately 80% of the dissolved solids. The water supply well, completed in the fresh water Fox Hills formation, was the Muñoz Government 28-5 and a water analysis for this well is shown in **TABLE 4**.

TABLE 4—ANALYSIS OF WATER PUMPED FROM THE MUÑOZ GOVERNMENT 28-5 WELL COMPLETED IN A FRESH WATER (FOX HILLS) FORMATION.

Dissolved components	Concentration, ppm
Cations	
Sodium	318
Calcium	5.8
Others	0
Anions	
Sulfate	199
Chloride	5.3
Carbonate	0
Bicarbonate	567
Total dissolved solids	1095

This reservoir produced a negligible amount of water during primary recovery. The same assumption regarding a relative stability of the injection water salinity is applied for the North Semlek field as for the West Semlek field. The average total salinity of the injection water of the life of the project can be calculated using Eq (1) by assuming the same initial value for f_r, the fraction of the total injected water that is recycled (0.054). For this waterflood, C_m was equal to 1095 ppm and C_r was equal to 42,000 ppm. The average injection water salinity, C_t, calculated from Eq (1) was 3304 ppm.

Moran Water Analysis

Water records obtained from the WOGCC for the Czapanskiy A-4 well within the Moran unit analyzed before the initiation of the waterflood showed the salinity of the initial formation water to be 128,000 ppm, which fits within the salinity range estimated in the feasibility study[17] for the unit (between 89,000 ppm to 158,000 ppm). One of the original wells in the unit (E. Moran No. 2) was recompleted as a water source well in the Fox Hills formation. Water injection began in December 1987 into wells E. Moran No. 1 and Czapanskiy A-4. An analysis of the water from the Fox Hills sand can be seen in TABLE 4.

As with the other Minnelusa reservoirs, the Moran unit produced very little water during a short primary production period. The average injection water salinity for the Moran unit over the life of the waterflood was calculated to be 7948 ppm by following the same protocol as outlined for the West Semlek and North Semlek waterfloods.

Plotting of Waterflood Data

There are many ways to plot field waterflood results for analysis; however, being that laboratory corefloods were used to illustrate improved recovery and formed the basis for the field analysis, comparison of field waterflood recoveries were manipulated to render recovery plots in the same style as laboratory results. Field waterflood results are typically plotted as oil production rate versus time, from which decline rates can be calculated and future production estimated. But laboratory corefloods results are normally shown as a plot of oil recovery versus total produced fluid (see Fig. 1 for typical plot of laboratory data). Therefore, historical field waterflood records were converted to plot oil recovery, R_N, versus pore volumes of total produced fluid, V_T.

Oil recovery, R_N, is the ratio of cumulative oil volume produced, N_p, and the volume of oil originally in place, N:

$$R_N = \frac{N_p}{N}. \quad (2)$$

Total volume of produced fluid, V_T, is reported as a multiple of the reservoir's pore volume and is the ratio of the sum of the produced oil, N_p, and water, W_p, (converted to reservoir barrels) and the pore volume of the reservoir, V_p:

$$V_T = \frac{\sum \left(N_p B_o + W_p \right)}{V_p}, \quad (3)$$

where B_o is the oil formation volume factor. Because the formation volume factor for water is essentially unity, the produced water volume is assumed to be equal to the reservoir water volume.

The following sections discuss how field waterflood data from the three Minnelusa fields were manipulated and plotted in order to compare field waterflood results to laboratory corefloods.

West Semlek Waterflood Production Plot

The engineering study for the West Semlek field included an area that was later removed from the unit boundaries due to better reservoir knowledge. Accordingly, values for reservoir pore volume, V_p, and initial oil in place, N, in the engineering study needed to be modified to reflect the change in reservoir boundaries. New values for reservoir pore volume and initial oil in place were subsequently calculated to fit the new understanding of the reservoir's limits. The revised bulk volume, V_b, for the new unit boundary was calculated to be 8764 acre-ft. The pore volume of the modified unit was calculated to be 13,597,736 res bbl using Eq (4) and assuming the original reservoir porosity of 19.4%.

$$V_p = 7758 V_b \phi, \quad (4)$$

where V_p is reservoir pore volume in reservoir barrels, V_b is the bulk volume in acre-ft, and ϕ is porosity.

Initial oil in place, N, is a function of the reservoir pore volume, V_p, initial water saturation, S_{wi}, and initial oil formation volume factor, B_{oi}:

$$N = \frac{V_p\left(1 - S_{wi}\right)}{B_{oi}}, \qquad (5)$$

where N is in stock tank barrels, V_p is in reservoir barrels, S_{wi} is a fraction, and B_{oi} is the initial formation volume factor with units of res bbl/STB. From Eq (5) and using the values for S_{wi} and B_{oi} listed in TABLE 2, the original oil in place was calculated to be 9,721,928 STB or 1109 STB/acre-ft.

Production data from the seven active producers in the West Semlek unit during secondary recovery operations were obtained from historical well records. The data were manipulated using Eqs (2) and (3) to create the desired form of the oil recovery curve for the West Semlek unit shown in **Fig. 5**.

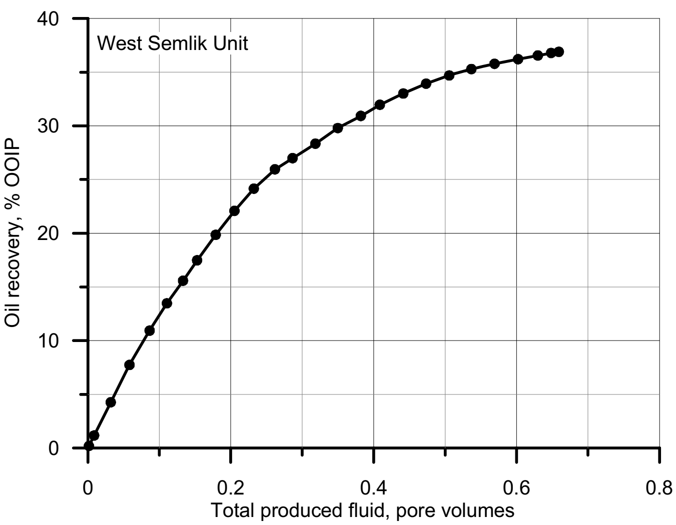

Fig. 5—Oil recovery from West Semlek unit.

North Semlek Waterflood Production Plot

The reservoir pore volume for the North Semlek field was not given in the waterflood feasibility study,[14] but knowing this value is necessary to generate the desired form of the oil recovery plot. The feasibility study, however, did provide enough information to calculate the reservoir pore volume. The feasibility study explains that the North Semlek reservoir is divided into an upper section and a lower section by a fluid transition zone. Above the transition zone, the initial oil saturation was 80%, while below the transition zone the initial oil saturation was 60%. Original oil in place for the whole unit was reported to be 3,620,926 STB; with 3,088,271 STB above the transition zone and the remainder below the transition zone.

Eq (5) can be rearranged to calculate the pore volume for the two zones separately:

$$V_p = \frac{NB_{oi}}{\left(1 - S_{wi}\right)}. \qquad (6)$$

The pore volume of the upper zone was calculated to be 4,049495 res bbl by the above equation and the pore volume of the lower zone was calculated to be 931,258 res bbl; with the sum being 4,980,754 res bbl, which is the pore volume of entire reservoir.

Eqs (2) and (3) were again used to calculate the oil recovery and total produced fluid from this field. **Fig. 6** is a plot showing the oil recovery from the North Semlek unit.

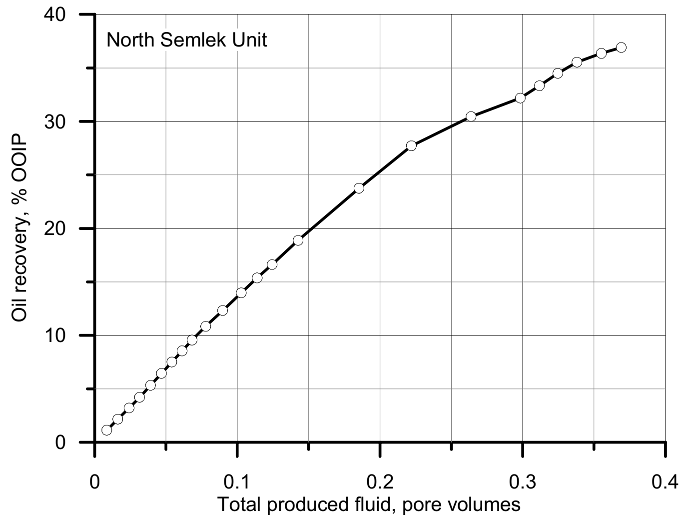

Fig. 6—Oil recovery from North Semlek unit.

Moran Waterflood Production Plot

The original oil in place for the Moran Minnelusa reservoir was estimated to be 1,783,000 STB in the Moran waterflood feasibility studies.[15,16,17] The reservoir pore volume was calculated to be 20,043,941 res bbl using Eq (4). As with the other units discussed earlier, oil recovery for the Moran unit was calculated using Eq (2) and pore volumes of total fluid produced was calculated using Eq (3).

Fig. 7 shows the oil recovery curve for the Moran field as a function of total produced fluid.

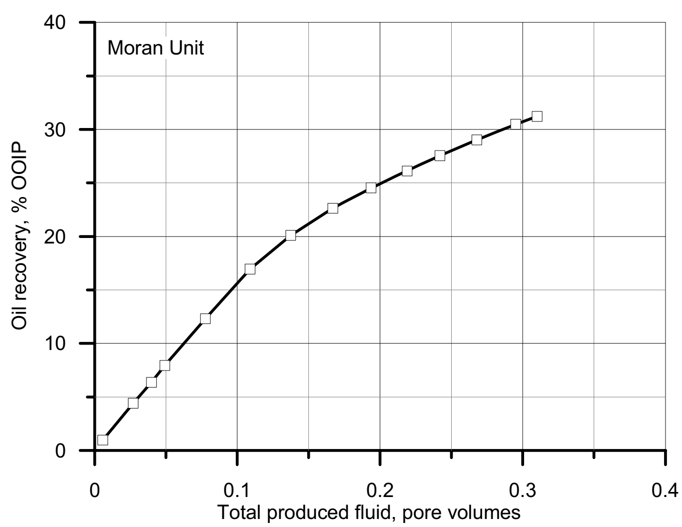

Fig. 7—Oil recovery from the combined Moran units.

Discussion of Results

A comparison of the waterflood recoveries from the three fields analyzed is shown in **Fig. 8**. The North Semlek and Moran waterfloods both show better oil recoveries than the West Semlek waterflood.

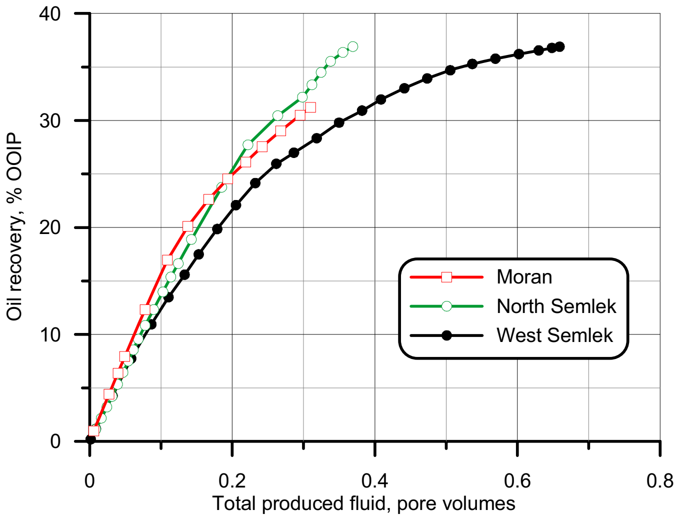

Fig. 8—Comparison of the recoveries from all three waterflooded Minnelusa reservoirs.

Salinity Ratio of Injection to Initial Formation Water

Salinity ratio is defined as the ratio of the salinity of the injection water to the salinity of the initial formation water. A salinity ratio of unity occurs when the salinities of the injection and initial formation waters are equal and a salinity ratio of zero occurs when the salinity of the injection water is zero, regardless of the salinity of the initial formation water. The salinity ratio is calculated for each of the Minnelusa waterfloods examined and can be seen in **TABLE 5**.

TABLE 5—SALINITY OF INITIAL FORMATION AND INJECTION WATERS USED FOR THE THREE WATERFLOODS ANALYZED.

	—— Salinity, ppm ——		
Fields	Initial formation water	Injection water	Salinity ratio
West Semlek	60,000	10,000	0.1667
North Semlek	42,000	3,304	0.0787
Moran	128,000	7,948	0.0621

Salinity Ratio vs. Oil Recovery

Oil recovery for the three waterfloods analyzed appears to be a function of the salinity ratio. **Fig. 9** is a plot of the oil recovery as a function of the waterflood salinity ratio and shows that oil recovery tends to decrease as the salinity ratio increases. This is a significant finding for it agrees with results from laboratory corefloods. This figure represents data taken from only three waterfloods and is not meant to provide quantitative values for improved oil recovery, but provides qualitative field evidence of improved recovery from low-salinity waterfloods from historical records.

Difficulties Associated with Historical Analyses

Searching the historical record for anecdotal evidence to support laboratory findings can be rife with pitfalls. Invariably, the wrong kinds of data would be recorded or not enough of the right kinds of data would be available. Specifically designed field pilots based on laboratory testing need to be undertaken to more accurately quantify the improved oil recovery potential for individual fields.

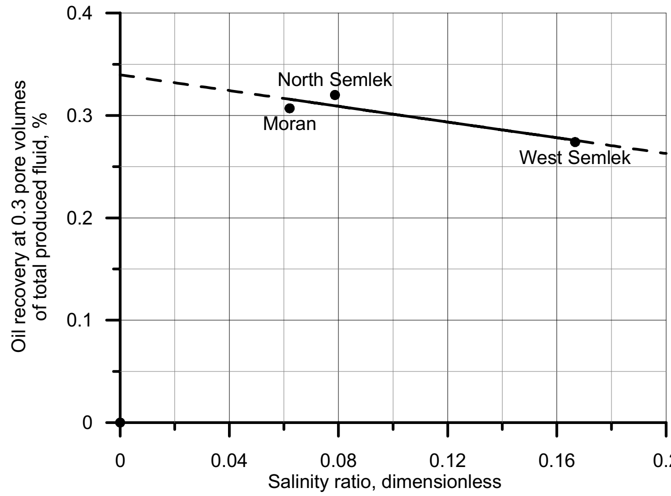

Fig. 9—Relationship between oil recovery and salinity ratio for three Minnelusa waterfloods.

A preliminary search of historical waterfloods from publications from the WOGCC indicated that there were a number of waterfloods that used Minnelusa formation water as the water source as well as a number of fresh water floods. However, a detailed search and analysis greatly reduced this number down to a few waterflooding units. Some problems were encountered in determining injection water salinities and the evaluation of chemicals added to the injection water for various purposes.

Uncertainty associated with water salinities. In laboratory corefloods, the salinity and composition of the injection water can be tightly controlled and the displacement front is relatively sharp. However, in field waterfloods that were analyzed, the salinity of the injection water was not controlled, nor was it measured and recorded.

Use of polymer. State and public records indicated that some polymer was used in all three field-floods, but not enough information was available to determine how much polymer was used. However, assuming that each waterflood used the same amount of polymer, issues arising from its use were neglected because its affect would be identical for each waterflood leaving the salinity ratio as the only major difference between floods and responsible for the differences in oil recovery.

Comparison of Field vs. Laboratory Recovery Curves

Total displacement efficiency combines several different efficiencies, including macro-displacement efficiency—also called volumetric sweep efficiency, which is the product of horizontal and vertical sweep efficiencies—and micro-displacement efficiency—also called pore-scale displacement efficiency. The intended use of the oil recovery plots used in this analysis, where oil recovery is plotted against total produced fluid normalized with respect to reservoir pore volume, was to compare the changes in micro-displacement efficiency of waterfloods with different injection water salinities. This type of plot is highly effective for analyzing micro-displacement efficiency of laboratory coreflood experiments where small reservoir volumes, linear flow patterns, and carefully bounded reservoirs minimize or eliminate differences in macro- or volumetric sweep.

Some caution must be used when analyzing displacement efficiency from field-scale waterfloods. Selection of field waterfloods for comparison must be made to minimize variances in volumetric sweep efficiencies so that differences in oil recovery can fairly be attributed to differences in micro-displacement efficiency. Each of the reservoirs used in this current study was selected from Minnelusa sands as near each other geographically as possible. In addition, the crude oil and reservoir temperature were very similar for each field. Regardless of the careful selection of the three fields for analysis, the fact that each field is distinct is recognized and results may be influenced by differences in reservoir geometry as well as differences in injection-water salinity.

The results of this analysis tend to corroborate laboratory results of increased recovery from low-salinity waterfloods. Nevertheless, this corroboratory evidence should not be considered proof positive, but may be used to promote further efforts for field application of this potentially effective improved recovery method.

Conclusions

A number of conclusions can be drawn from the work presented in this paper:

1) Specifically designed field pilots based on laboratory testing need to be undertaken to more accurately quantify the improved oil recovery potential from low-salinity waterfloods for specific fields.

2) Results of this analysis tend too corroborate laboratory results of improved recovery from low-salinity floods.

3) A trend in oil recovery from historical field data was identified with respect to injection water salinity.

4) Data showed that oil recovery tended to increase as the salinity ratio of waterfloods decreased, which generally means that lower salinity floods tended to have higher oil recoveries.

Nomenclature

B_o = oil formation volume factor, res bbl/STB
B_{oi} = initial oil formation volume factor, res bbl/STB
f_r = fraction of total injected water that is recycled, fraction
N = volume of oil originally in place, STB
N_p = volume of oil produced, STB
R_N = oil recovery, fraction
C_m = salinity of makeup injection water, ppm
C_r = salinity of recycled injection water, ppm
C_t = total salinity of injection water, ppm
S_{wi} = initial water saturation, fraction
V_T = volume of total produced fluid, fraction of reservoir pore volume
V_p = pore volume of reservoir, res bbl
V_b = bulk volume of reservoir, acre-ft
W_p = volume of produced water, STB
ϕ = porosity, fraction

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Conversion Factors

acre-ft	× 1.233 789	E+03 =	m^3
°API	141.5/(131.5+°API)	=	g/cm
bbl	× 1.589 873	E-01 =	m^3
cp	× 1.0*	E-03 =	Pa·s
ft	× 3.048	E-01 =	m
ft^3	× 2.831 685	E-02 =	m^3
ft^3/bbl	× 1.781 076	E-01 =	m^3/m^3
°F	(°F – 32)/1.8	=	°C
mile	× 1.609 344*	E+00 =	km
psi	× 6.894 757	E+01 =	kPa

*Conversion factor is exact.

Author Biographies

Dr. Eric Robertson is a Research Petroleum Engineer at the U.S. Department of Energy's Idaho National Laboratory (INL) in Idaho Falls, Idaho where he leads work involved with geologic CO_2 sequestration and fossil fuel production. He has led a number of projects at INL including projects on methods to re-use captured CO_2 as fuel, improved oil recovery by manipulating injection water chemistry, Alaskan oil and gas issues, heavy oil production methods, and microbial enhanced oil recovery. He received a PhD degree in Petroleum Engineering from Colorado School of Mines and MS and BS degrees in Petroleum Engineering from University of Wyoming. Eric is a licensed Professional Engineer (petroleum) in the state of Wyoming and eric.robertson@inl.gov is his email address.