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Wettability Alteration in Reservoirs: How it Applies to Alaskan Oil Production.

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Abstract

The natural decline in oil production in Alaskan reservoirs is challenging producers to find methods to extend production. The current stage of reservoir development has reached the point where consideration of enhanced oil recovery methods is appropriate. Such methods could include CO_2, chemical, microbial or thermal recovery. However, these methods require significant capital and/or operational investment. This paper evaluates the application of wettability alteration for Alaskan reservoirs by changing injection water chemistry also known as advanced water flooding. We use empirically-based screening and scoping methodologies to evaluate the suitability, cost and benefits of advanced water flooding for Alaskan reservoirs using public domain data.

First, laboratory and field examples of successes and failures are considered. Using this basis, a theory is developed that directly links water chemistry and reservoir wettability. The theory also illuminates the key characteristics of the reservoir that control wettability. We use empirically-based screening and scoping methodologies to evaluate the suitability, cost and benefits of advanced water flooding for Alaskan reservoirs with sufficient public domain data. The screening tool is built on empirical data from laboratory and field tests that identify the critical factors contributing to incremental production. The scoping tool uses a modified Kinder Morgan approach (dimensionless recovery curve) to evaluate the economic case for each reservoir.

The first field-scale tests of this technique were conducted by BP in the Endicott reservoir on the North Slope and produced good results by lowering the salinity of injection water. Those tests showed that alteration to injection water chemistry can increase recovery significantly. These results have been duplicated in laboratory and field tests in other locations. The tests were conducted without an understanding of the fundamental mechanisms nor optimization of the injected water chemistry, and thus represent minimum recovery. We find the increased recovery is profitable for several fields depending on assumptions about water sources, water treatment costs and rates of injection.

The successful approach to advanced waterflooding requires several key steps: screening the formation to evaluate the applicability of the technique, simple laboratory tests to determine the optimal water chemistry and quantify the increased recovery, economic evaluations to estimate costs and benefits, and finally, comprehensive geochemical models to design the wettability-modifying fluids. The technique has several advantages compared to current methodologies for wettability alteration including substantially lower costs, no environmental impacts and ease of application.

Introduction

The purpose of this paper is to conduct a high-level screen using publically-available data for Alaskan oil fields to evaluate the likely success of low salinity waterflooding. Alaskan oil fields have contributed more than 17 billion barrels of oil to US production since the first fields were discovered. Russian explorers first reported oil seeps in 1853 on the west side of the Cook Inlet (Miller et al. 1959). Cook Inlet was Alaska's first basin with commercial oil and production. The discovery of the Swanson River oil field in 1957 and development of innovative technologies for Alaskan operations provided the knowledge to expand exploration to the North Slope (Hite and Stone 2013). Table 1 summarizes the Cook Inlet fields, type, date discovered and operator at discovery.

Following the Swanson River discovery in Cook Inlet, the Bureau of Land Management opened the North Slope for competitive bidding though simultaneous oil and gas applications—though it was 16,000 acres initially (Banet 1991). In the early 1960s, the North Slope experienced its first seismic exploration program. The Department of the Interior aided oil industry exploration through development contracts, which gave financial incentives for companies to explore in the central Arctic. However, only subeconomic gas fields were discovered, and industry interest was waning. Then in January 1968, the discovery of Prudhoe Bay opened the way for North Slope development.

The discoveries on the North Slope were much larger and today about 90% of all produced hydrocarbons have come from the North Slope (Bird, 2001). The North Slope stretches approximately 500 miles from Cape Lisburne to the Canadian border. The area was not mapped until the 1900s (Banet 1991) with oil and gas seeps being reported by Brooks and Leffingwell. The Naval Petroleum Reserve #4 was established in 1923 and later became the National Petroleum Reserve-Alaska (NPRA). The area showed anticlines and oil and gas seeps that appeared prospective for exploration purely from the surface maps. However, the entire North Slope was "withdrawn from mineral entry" (Banet 1991) because of World War II. The Navy started its exploration program in 1944 and discovered the Umiat, Fish Creek, Simpson, Barrow, Gubik, Wolf Creek, Square Lake and Meade accumulations. The first three fields are oil-bearing, whereas the rest are gas-bearing, with the only sustained production to date stemming from local use of the Barrow gas fields. Most commercial oil production has been between the Colville and Canning Rivers, to the adjacent offshore state and federal waters, until first production from Colville River Unit CD5, which also marks the first commercial oil development from within the boundaries of the NPRA on Alaska Native lands (OGJ 2015). Table 3 summarizes many of the North Slope field discoveries by name, type of hydrocarbon, discovery date and discovery operator.

Decline curve analysis was used to estimate ultimate recovery (EUR) for the oil fields. For offshore Cook Inlet reservoirs, a platform-by-platform basis was used. The abandonment limit was determined by platform facilities limits of 300 BOPD. Analogue data from platform shutdowns or platforms placed in "lighthouse mode" was used to determine the platform abandonment rate limit. For instance, the Baker platform went into "lighthouse mode" when oil production from the platform declined to approximately 515 BOPD in 2003 (Petroleum News 2010), and production halted. The Spark and Spurr platforms averaged approximately 360 and 270 BOPD, respectively, during their last year of production before being placed in "lighthouse mode". Additionally, the Osprey platform operated at a low rate of approximately 226 BOPD in 2013 (Bradner 2014). For the onshore fields of Beaver Creek, Swanson River, and West McArthur River, an abandonment rate of 50 BOPD per well for fields on a pool-by-pool basis was chosen. To determine the pool abandonment limit, the abandonment rate limit was multipled by the number of producing wells as of December 31 2015. Table 2 shows these limits and the associated estimated ultimate recovery.

The EUR for North Slope fields was calculated using decline curve analysis as well. The EUR values assume production ceases at the technical limit of the Trans-Alaska Pipeline System or TAPs, which the pipeline owners have estimated to be as high as 350,000 BOPD, (Alyeska Low Flow Impact Study Final Report 2011). This is a hotly debated issue, and there are numerous other sources that estimate much lower TAPS limits, potentially as low as 50,000 to 70,000 BOPD (Bailey 2012), but we chose the most conservative limit. Decline curve analysis was used to predict estimated ultimate recovery (EUR) on a pool-by-pool basis for all oil-producing pools on the North Slope, but only for only pools with sustained production. These pools were summed on a monthly basis, and then truncated based on a low-flow rate of TAPS at 350,000 BOPD. The results are summarized in Table 4**.**

By the end of 2007, the North Slope fields had produced about 15.7 billion barrels of oil with remaining technically recoverable reserves of 6.1 billion barrels (Thomas et al. 2009). Thomas et al (2009) used optimistic assumptions about the recovery factors for the heavy oil in the Ugnu, West Sak and Schrader Bluff pools and TAPS low flow rates. The EUR's based on decline curve analysis of exising fields using the conservative end-of-pipeline assumptions predict 17.7 billion barrels of oil with an additional 796 million barrels of natural gas liquids. Reported production at the end of 2015 was 16.7 billion barrels of oil leaving about 1 billion barrels to go, less than the projected recoverable oil by Thomas et al. (2009).

As the oil production in Alaska declines enhanced oil recovery (EOR) could extend production. The traditional methods of EOR include chemical, thermal, and carbon dioxide options. These methods can generate additional recovery on the order of 10-20% of OOIP, which could mean an additional 5 to 10 billion barrels assuming total OOIP of 56 billion barrels for the North Slope, however the application of those methods will not be not appropriate for all projects, particularly those on the North Slope given the logistical challenges of that location. For instance, thermal recovery would be most useful for heavy oils such as Ugnu, West Sak and Schrader Bluff oil, but not the other pools. Chemical recovery is expensive with reported costs of \$10-12 per incremental barrel and can be ineffective due to mineralogy, temperature and salinity. Carbon dioxide has the logistical challenges of obtaining sufficient amounts of carbon dioxide over the life of the project. These limitations make low salinity waterflooding an attractive option. Low salinity waterflooding is relatively inexpensive, environmentally-friendly, easy to implement during normal waterflood operations and has similar incremental recovery to other EOR methods.

Reservoir wettability has long been recognized as a critical parameter in oil recovery (Jadhunandanand Morrow, 1995, Ogunberu and Ayub, 2005), but attempts to improve wettability normally involve the use of surfactants (chemical flooding), which can be expensive and problematic for many reservoirs due to temperatures and salinity. Low-salinity waterflooding is widely studied today as one of the most inexpensive methods of enhanced oil recovery in clastic and carbonate reservoirs (EOR). The technique has several advantages including ease of application, low cost, increased injectivity and reduction of scaling, souring and corrison damage (Reddick et al 2012). Major petroleum companies have or plan to implement field-scale projects in the next few years (Robbana et al. 2012).

Increases in recovery of up to 30% original-oil-in-place have been observed in laboratory and field studies of low salinity waterflooding (Zhang and Morrow, 2006, Jerauld et al. 2008). McGuire et al. (2005) reported that single well chemical tracer tests performed in Alaska produced favorable results in Kuparuk reservoirs with increases between 6 to 17% OOIP. This project was expanded to interwell field experiments in the same interval with low-salinity injection yielding similar levels of improved recovery (Lager et al. 2008, Seccombe et al. 2010). In addition, Vledder et al. (2010) observed increased production (10-15% OOIP) in response to lowering injection salinity in a Syria sandstone reservoir. They attributed the response to changes in wettability. They reported a dual-step watercut during production which matched the log-inject-log test.

However, there are laboratory cases where increased recovery was not been observed (Sharma and Filoco 2000, Pu et al. 2008, Rivet et al 2010). Skrettingland et al. (2010) reported lab and single well tracer tests in the North Sea that showed no appreciable increase in recovery with low-salinity injection. Thyne and Gamage (2011) used data from 51 Minnelusa sandstone fields under waterflood and found no change in breakthrough time or increase in production, even for salinity reductions of 10 to 100-fold. Zeinijahromi et al. (2015) studied low salinity waterflooding at Zichebashskoe field in Rusia and saw only 4% incremental recovery after reducing waterflood salinity 20-fold. These results show that the application of low salinity waterflooding will not always be successful.

The fundamental observations of increased recovery from low-salinity flooding in the laboratory were made by Martin (1959) and Bernard (1967). This work was extended and brought to wider attention by various workers over the last 15 years (Jadhunanadan and Morrow 1995, Zhou et al. 1996a, Zhou et al. 1996b, Tang and Morrow 1997, Yildiz et al. 1999, Morrow et al. 1998, Tang and Morrow 1999a, Tang and Morrow 1999b, Maas et al. 2001). The work on low salinity waterflooding has led to several variants (LoSal™, Smart Water, Designer Water, Advanced Ion Management, Engineered Salinity™), but all use the same approach of modifying injection water chemistry to increase production without reduced injectivity or increased scaling. While more research has increased the number of proposed mechanisms (Buckley and Morrow, 2010, Kumar et al. 2010, Sheng, 2014), wettability alteration/surface reactions are the dominant causes cited. Table 5 shows the current list of proposed mechanisms and references.

Screening

Currently, the normal procedure for screening candidate fields for low salininty waterflooding includes preliminary assessment, economic studies and extensive laboratory tests, followed by single well tracer tests and field pilots. This procedure is used by the major oil companies (Dixon et al. 2010, Callegaro et al. 2013, Sorop et al. 2013, Suijkerbuijk et al. 2013, Rotondi et al. 2014). While some authors argue that the lack of a known mechanism does not allow screening (Suijkerbuijk et al. 2013), alternative screening strategies are available. Those alternatives are based on observations of the key factors required for success such as reservoir architexture, production history, rock and fluid properties, pressure and temperature.

Some screening protocols are basically qualitative in nature relying on the presence or absence of key factors to generate results (Taber and Martin, 1983, Taber et al. 1997a, b, Aladasani and Bai, 2010, Bourdarot and Ghedan, 2011). This approach analyzes successful and failed projects to compile and identify the factors and conditions such as temperature, permeability, net thickness, depth, oil gravity and oil saturation that are successful. These factors can be incorporated with an understanding of mechanisms in the screening scheme. Other approaches are more quantitative such as Henson et al. (2002) who showed successful IOR projects could be related to macro-scale heterogeneity, Alvarado et al. (2008) who used fuzzy-logic and data clustering algorithims, Graf et al. (2010) who used stochastic methods to speed screening of fields for waterflooding, Veerabhadrappa et al. (2011) who used rheological properties to screen polymers for chemical flooding, or Surguchev et al. (2011) who used a multistep approach that combined qualitative screening with additional steps of analytical modeling of the EOR processes and economic evaluations.

All the Alaskan reservoirs are clastic with the exception of the Lisburne (Bird, 2001), so we first focus on the information for clastic reservoirs. Table 6 shows several of the important factors from experimental and field application of low salinity waterflooding in Alaskan reservoirs. This data forms the fundamental basis for screening and has the advantage that most data are from field studies rather than laboratory work.

The low salinity effect (LSE) in sandstones requires several factors including presence of formation water with divalents, clay minerals and polar components in the oil (Austad et al. 2010, Morrow and Buckley, 2011, Emadi and Sohrabi, 2013, Sheng, 2014). We incorporate these factors (lithology, water chemistry, oil composition and temperature) as well as other components by summing numerical values for each factor to produce an overall score for each candidate field. Our screening algorithum weights each factor according to assigned rank of importance. The screening tool is executed in MS Excel allowing rapid screening of multiple candidates and refinement of weighting as knowledge is gained.

The degree of dilution required to achieve the LSE has been a subject of debate. There are practical considerations; reducing injection salinity significantly may require water treatment rather than blending with local sources. Early experiments routinely used 10 to 100-fold dilutions to cause incremental production (Bernard, 1967, Yildiz et al. 1999, Tang and Morrow, 1999), but later experiments showed that the degree of dilution could be as little as four times and still see increased recovery (Jerauld et al. 2008). Cissokho et al. (2009) noted that there was a dilution threshold in their experiments that had to be reached to initiate additional production. Figure 1 shows the dilution factor versus incremental recovery in percent original-oil-in-place (OOIP) for experimental and field cases from the Alaska North Slope (ANS), together with some field values from other locations. While there is a general trend of increasing recovery with increasing dilution, the optimum degree of dilution appears to be about 20-fold with greater dilution not significantly increasing recovery.

Oil composition is cited as playing a role in the degree of response to low salinity flooding (Fjelde et al. 2014). Sandstone interactions with the polar components of crude oil play an essential role in altering wettability (Buckley et al. 1998). Oils without polar components have little or no interaction with mineral surfaces (Smith et al. 1989, Tang and Morrow, 1999). Dubey and Doe (1993) showed that acid and base portions of crude oil played an essential role in reservoir wetting through their electrostatic interactions with mineral surfaces and suggested that the acid/base value determines the isoelectric point of crude oil. Fjelde et al. (2014) found that adhesion of oil to glauconite was dependent on pH and brine content. The adhesion of acidic groups was particularly sensitive to the presence of calcium in the brine, while the adhesion of basic groups was insensitive to brine composition or salinity. However, systematic study of oil composition on recovery is rare. One study performed by Suijkbuijk et al. (2012) show there is a positive relationship between incremental production and polar components. Figure 2 shows the results from imbibtion experiments that used Berea sandstone and varied only oil composition.

Rock composition is the most important parameter in predicting the response to low salinity waterflooding (van Winden et al. 2013, Shehata and Nasr-El-Din, 2014). The presence of clay has been noted by many researchers as a requirement for additional recovery (Seccombe et al. 2010, Morrow and Buckley, 2011, Suijkerbuijk et al. 2012). Tang and Morrow (1999) first noted that the amount of incremental production was directly related to clay content. Early papers proposed that kaolinite was required and even recent publications have used kaolinite content to predict recovery (Law et al. 2015). However, the data in Figure 3 shows the recovery is directly proportional to clay content regardless of clay type. The clays in the sandstones tested include kaolinite, chlorite, illite and muscovite. For instance, the sandstone used by Cissokho et al. (2009) had no kaolinite but instead chlorite and illite. Hadia et al. (2011) used samples from the Fray field in the North Sea that had kaolinite clay, but Thyne and Gamage (2011) tested sandstone with illite. Ligthelm (2009) argued that the clay habitat (e.g., grain-rimming versus pore-filling) was an important factor, but most studies lack clay habitat data.

The impact of temperature on recovey in sandstones has been investigated by several researchers (Cissokho et al, 2009, RezaeiDoust et al. 2010, Gamage and Thyne, 2011). Figure 4 shows the effect of temperature on recovery for several sandstones. This data shows a decline in incremental production with temperature with no LSE at 260°F. This may represent a limitation in the application of the technique.

Based on the data, the amount of clay minerals is the dominant factor in predicting the response to low salinity waterflooding. This is followed by the connate water salinity and how practical it will be to obtain enough dilution to maximize production. The impact of oil chemistry is not easily quantified. It is apparent that the crude oil has to have some polar content, and more polar components will increase the LSE.

Presentation of Data and Results

Table 7 shows the estimated original oil in place (OOIP), current production, calculated current recovery factor and the calculated recovery factor at EUR for the oil fields. The fields selected were limited to those with sufficient data to derive EUR values. The first step in screening is evaluating the fields for recovery potential. We compare pool size and recovery factor to assess the current water performance and target size. The second step is to screen the fields for low salinity waterflooding potential using the screening strategy and algorithum discussed above.

The North Slope data show that 89% of total OOIP is found in six fields; PBU-Prudhoe, KRU-Kuparuk, MPU-Kuparuk, KRU-West Sak, PBU-Orion and PBU-Lisburne. The increase in recovery between now and recovery at EUR averages 1% for the six fields, typical for fields reaching the end of secondary recovery. The Cook Inlet data show that 96% of total OOIP is found in five fields; McAuthur Point, Granite Point, Middle Shoal, Trading Bay, and Swanson River. Again the average increase between current conditions and EUR recovery is small, 2.6%.

Figure 5 shows the histogram for recovery at EUR for all screened fields. Alaskan fields show the typical distribution of recovery in global fields. The mean recovery in Alaska is about 30%, near the global average of 32%. On the North Slope, the good recovery factors for the two biggest pools, Prudhoe and KRU-Kuparuk (51 and 43%, respectively), have produced 70% of the total production from 43% of the OOIP. The next four largest pools, KRU-West Sak, MPU-Kuparuk, PBU-Orion, and PBU-Lisburne that represent 36% of the North Slope OOIP, averaged only 3% recovery (3.2% of cumulative oil production).

Figure 6 shows the OOIP and recovery at EUR for the North Slope fields excluding Prudhoe. Prudhoe field has an OOIP of 24 billion barrels with recovery of 51% at calculated EUR. The plot shows that some fields including CRU-Alpine, CRU-Fiord Kuparuk, KRU-Kuparuk, KRU-Tarn, NU-Northstar and PBU-Point Mcintyre have excellent recovery, well above global average. The good recovery factors suggest the current waterfloods are efficient and good targets for enhanced waterflooding with low salinity water. The plot also shows the poor recovery for fields that include large potential reserves such as KRU-West Sak, MPU-Kuparuk, PBU-Lisburne and PBU-Orion highlighting the significant oil in place that has not been recovered.

Figure 7 shows the plot of OOIP and recovery factor at calculated EUR for the Cook Inlet fields. In general, the data show that recovery in the Cook Inlet fields is good, in many cases above the global average. McAuthur River has the largest OOIP followed by Granite Point, Swanson and Middle Shoal. McAuthur River, Middle Shoal, Trading Bay and Swanson River have recovery well above the global average, while Beaver Creek, Granite Point and Redoubt Shoal have under-performed. The good current recovery suggests waterflooding is efficient in these fields and makes them good potential candidates for low salinity waterflooding.

In general, there are several key factors including rock and fluid composition that effect recovery (Coskun et al. 1993). A portion of the low recovery has been attributed to viscous oils (17-22 degree API), but as Figure 8 shows the relationship between oil gravity and recovery factor is not strong. Low recovery is also attributed to reservoir heterogeneity (Thomas et al, 2009). Clastic reservoirs can be hydraulically complex due to heterogeneity and result in low recovery. The Sag River, Badami and Schrader Bluff Formations show recovery under 5% even at EUR and have been recognized as having siginificant heterogeneity. In that case while additional recovery is possible with low salinity waterflooding, the fields may require simultaneous application of polymer to better control breakthrough and increase sweep efficiency.

Another low performing reservoir, the Lisburne carbonate, has high porosity but low, fractured-dominated permeability (Thomas et al. 2009). The Lisburne field is the only carbonate field in the screened fields. The screening tool was tuned for sandstones and does not correctly rate the low salinity waterflooding potential for Lisburne, but low salinity waterflooding in carbonate fields has been shown to be very successful with recovery of an additional 31% OOIP in the fracture, low permeability Ekofisk field in the North Sea (Sohal et al. 2016).

The results of the low salinity waterflood screening are displayed in Figure 9. The results show that all fields received scores greater than forty, indicating no critically negative issues. Fields with scores greater than 65 are considered good candidates, and a few fields have scores greater than 80. For instance, KRU-West Sak and MPU-Kuparuk received screening scores of 92 and 87, however when combined with the very low current recovery factors, those fields are not good candidates. These criteria rule out some additional North Slope fields such as KRU-West Sak, PRU-Orion and MPU-Kuparuk unless further research identifies the reasons and suggests methods to overcome the current poor recovery. The exception is PBU-Lisburne which could not be properly screened since it is a carbonate reservoir. The North Slope fields that are the best candidates include PBU-Prudhoe, KRU-Kuparuk, CRU-Alpine and EU-Endicott and are shown in capital letters on Figure 9.

The combined OOIP of these fields is 37.6 billion barrels. If the method were applied to all North Slope fields, assuming

10% incremental production overall based on North Slope field tests, it could potentially realize 3.76 billion barrels of incremental production. This number is probably conservative since there was no systematic investigation of optimum salinity during early testing and knowledge gained during enhanced waterflooding would probably further improve performance. In contrast to the North Slope, all the Cook Inlet fields appear to be attractive candidates for low salinity waterflooding. The fields all received good low salinity screening scores and have good waterflood performance. The total OOIP of the best fields is 3.6 billion barrels. If we assume that low salinity waterflooding would produce an additional 10% of OOIP, this translates to potential incremental recovery of 360 million barrels from the existing Cook Inlet fields.

The potential for an additional 10-15% of OOIP during enhanced waterflooding is attractive, but more detailed evaluation including economic analysis is warranted. More detailed screening should include more detailed reservoir characteristics, evaluation of potential water sources and economic evaluations of cost and benefits. The benefits of increased production and booked reserves would be dependent on information specific to the producing company and is beyond the scope of this work.

There are some limitations with the current screening. Average values were used for clay content, formation water salinity and oil composition in each field. Some fields did not have this information available so values based on the closest analog were used and we could not explicitly account for reservoir heterogeneity. The screening tool does not include cost of enhanced waterflooding. The major cost is the injection water. The highest cost for injection water is the case where produced water is treated onsite before re-injection. Those costs are variable with the most expensive example being water treatment using membrane technology on an offshore platform estimated at $3 per incremental barrel (BP, 2012). Alternatively, in Alaska the injected water source can be local brackish water blended with produced water, which can be very low cost. Careful consideration of all these factors together would be included in an economic evaluation before proceeding. However, the possibility of adding production and reserves (with a successful pilot project) could be a strong incentice for many producers.

Conclusions

Low salinity waterflooding represents an attractive option for extending production from Alaskan oilfields. The evaluation of recovery factors together with the low salinity screening tool (conditioned with data from laboratory and field tests of low salinity waterflooding on North Slope reservoirs) were used to select the best candidates. The most important factors for incremental recovery were clay content of the rock followed by oil composition and temperature for the reservoirs in Alaska. Not all fields had data for all these parameters, so data was drawn from analogous fields to allow screening. In addition, we used average values for these parameters so there is some uncertainty in the screening results.

The best candidates were fields with good current recovery, indicating successful waterflood conditions, and high OOIP. That information combined with the scores from the low salinity screening procedure identified Prudhoe, KRU-Kuparuk, CRU-Alpine, EU-Endicott and PBU-Lisburne on the North Slope. All the fields in the Cook Inlet appear to be attractive candidates and the potential incremental production would be 360 million barrels. On the North Slope the potential incremental oil recovery may exceed 3.7 billion additional barrels.

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Table 1. Cook Inlet field discoveries by name, type of hydrocarbon, discovery date and discovery operator.

FIELD NAME	TYPE OF FIELD	DATE DISCOVERED	OPERATOR DISCOVERY
ALBERT KALOA	GAS	1/4/1968	PAN AM
BEAVER CREEK	OIL & GAS	12/17/1972	MARATHON
BELUGA RIVER	GAS	12/1/1962	CHEVRON
BIRCH HILL	GAS	6/9/1965	CHEVRON
CANNERY LOOP	GAS	6/24/1979	UNOCAL
CANNERY LOOP BELUGA	GAS	6/24/1979	UNOCAL
CANNERY LOOP STERLING	GAS	10/23/2000	Marathon
FALLS CREEK	GAS	4/10/1961	CHEVRON
GRANITE POINT	OIL & GAS	5/16/1965	MOBIL
GRANITE POINT TYONEK	GAS	8/5/1965	MOBIL
IVAN RIVER	GAS	10/8/1966	CHEVRON
KENAI	GAS	10/11/1959	UNOCAL
LEWIS RIVER	GAS	10/1/1975	CITIES
LONE CREEK	GAS	10/12/1998	ANADARKO
MCARTHUR RIVER	OIL & GAS	9/29/1965	UNOCAL
MIDDLE GROUND SHOAL	OIL	6/10/1962	PAN AM
MOQUAWKIE	GAS	11/28/1965	MOBIL
N MID GROUND SH (MGS)	GAS	6/10/1962	PAN AM
N MIDDLE GROUND SHOAL	GAS	11/15/1964	PAN AM
NICOLAI CREEK	GAS	4/28/1966	TEXACO
NORTH COOK INLET	GAS	8/21/1962	PAN AM
NORTH FORK	GAS	12/20/1965	CHEVRON
PRETTY CREEK	GAS	2/20/1979	CHEVRON
REDOUBT SHOAL	OIL	9/21/1968	PAN AM
STARICHKOF	OIL	4/1/1967	PENZOIL
STERLING	GAS	7/11/1961	UNOCAL
STUMP LAKE	GAS	5/14/1978	CHEVRON
SWANSON RIVER	OIL & GAS	7/19/1957	RICHFIELD
TRADING BAY	OIL	6/17/1965	CHEVRON
TYONEK DEEP	OIL	11/5/1991	ARCO
WEST FORELAND	GAS	3/29/1962	AMOCO
WEST FORK	GAS	9/26/1960	HALBOUTY
WEST MCARTHUR RIVER	OIL & GAS	12/2/1991	STEWART
WOLF LAKE	GAS	11/12/1983	ARCO/CIRI

Table 2: Estimated ultimate recovery for Cook Inlet oil fields.

Field (Onshore) or Field and Platform (Offshore)	EUR (MMBBL)	Producing Wells	Abandonment Limit, BOPD
Beaver Creek	6.5	2	100
Granite Point, Anna Platform	61.3	13	300
Granite Point, Granite Point Platform	70.1	12	300
Middle Ground Shoal, A Platform	91.3	16	300
Middle Ground Shoal, C Platform	58.7	14	300
Redoubt Shoal, Osprey Platform	4.1	2	300
Trading Bay Field, Monopod Platform	103.6	58	300
Trading Bay Field, Dolly Varden Platform	221.5	25	300
Trading Bay Field, Grayling Platform	257.2	18	300
Trading Bay Field, King Salmon Platform	155.0	12	300
Trading Bay Field, Steelhead Platform	17.8	7	300
Swanson River	236.8	30	1500
West McArthur River	15.7	5	250

Table 3: Summary of field discoveries by name, type of hydrocarbon, discovery and discovery operator, adapted from (Thomas et al. 2009).

FIELD NAME	TYPE OF FIELD	YEAR DISCOVERED	OPERATOR DISCOVERY
UMIAT	OIL	1946	US NAVY
SOUTH BARROW	GAS	1949	US NAVY
FISH CREEK	OIL	1949	US NAVY
SIMPSON	OIL	1950	US NAVY
MEADE	GAS	1950	US NAVY
WOLF CREEK	GAS	1951	US NAVY
GUBIK	GAS	1951	US NAVY
SQUARE LAKE	GAS	1952	US NAVY
E. UMIAT	GAS	1964	US NAVY
PRUDHOE BAY	OIL	1968	ARCO
LISBURNE	GAS	1968	ARCO
ORION	OIL	1968	MOBIL
PUT RIVER	OIL	1968	ARCO
UGNU	OIL	1968	STANDARD OIL OF CALIFORNIA
KAVIK	GAS	1969	PAN AMERICA PETROLEUM
GWYDYR BAY	OIL	1969	CONOCO
KUPARUK RIVER	OIL	1969	SINCLAIR
WEST SAK	OIL	1969	ARCO
MILNE POINT	OIL	1969	STANDARD OIL OF CALIFORNIA
BOREALIS	OIL	1969	MOBIL
AURORA	OIL	1969	MOBIL
POLARIS	OIL	1969	BP
NORTH PRUDHOE BAY	OIL	1970	ARCO
KEMIK	GAS	1972	STANDARD ALASKA PRODUCTION
EAST BARROW	GAS	1974	US NAVY
FLAXMAN ISLAND	OIL	1975	EXXON
EAST KURUPA	GAS	1976	TEXACO
WEST BEACH	OIL	1976	ARCO
MIKKELSEN	OIL	1978	SHELL
ENDICOTT	OIL AND GAS	1978	SOHIO
WALAKPA	GAS	1980	HUSKY
SAG DELTA NORTH	OIL	1982	SOHIO
LIBERTY (TERN ISLAND)	OIL	1982	SHELL
HEMI SPRINGS	OIL	1984	ARCO
NORTHSTAR	OIL	1984	SHELL
HAMMERHEAD	OIL	1985	UNOCAL
NIAKUK	OIL	1985	SOHIO
COLVILLE DELTA	OIL	1985	TEXACO
SANDPIPER	GAS	1986	MURPHY
TABASCO	OIL	1986	ARCO
POINT MCINTYRE	OIL	1988	ARCO
SIKULIK	GAS	1988	NORTH SLOPE BOROUGH
BADAMI	OIL	1990	CONOCO
STINSON	OIL	1990	ARCO
BURGER	GAS	1990	SHELL
TARN	OIL	1991	ARCO
KALUBIK	OIL (?)	1992	ARCO
FIORD	OIL	1992	ARCO
CASCADE	OIL	1993	BP
KUVLUM	OIL	1993	ARCO
THETIS ISLAND	OIL	1993	EXXON
ALPINE	OIL	1994	ARCO
SOURDOUGH	OIL	1994	BP
RAVEN	OIL	1995	BP
MIDNIGHT SUN	OIL	1997	BP
PETE’S WICKED	OIL	1997	BP
EIDER	OIL	1998	BP
MELTWATER	OIL	2000	ARCO

FIELD NAME	TYPE OF FIELD	YEAR DISCOVERED	OPERATOR DISCOVERY
NANUQ	OIL	2000	ARCO
NANUQ-KUPARUK	OIL	2000	ARCO
SPARK	OIL	2000	ARCO
PALM	OIL	2001	ARCO
ALPINE WEST	OIL	2001	CONOCOPHILLIPS
LOOKOUT	OIL	2002	CONOCOPHILLIPS
OOOGURUK	OIL	2003	PIONEER
NIKAITCHUQ	OIL	2004	KEER-MCGEE
PLACER	OIL	2004	ASRC
TUVAAQ	OIL	2005	KERR-MCGEE
QANNIK	OIL	2006	CONOCOPHILLIPS
NORTH SHORE	OIL	2007	BROOKS RANGE
TOFKAT	OIL	2008	BROOKS RANGE

Table 4: Decline analysis results for North Slope.

Decline Analysis of Producing North Slope Oil Pools		
Oil Pools (or Reservoirs)	EUR (MBBL)*	Phase
Badami, Badami Oil	8,452	oil
Colville River, Alpine Oil	493,900	oil
Colville River, Fiord Oil	75,234	oil
Colville River, Nanuq Oil	5,827	oil
Endicott, Endicott Oil	480,092	oil
Endicott, Ivishak Oil	9,151	oil
Kuparuk River, Kuparuk River Oil	2,560,868	oil
Kuparuk River, Meltwater Oil	21,038	oil
Kuparuk River, Tabasco Oil	22,414	oil
Kuparuk River, Tarn Oil	131,645	oil
Kuparuk River, West Sak Oil	114,296	oil
Milne Point, Kuparuk River Oil	272,960	oil
Milne Point, Sag River Oil	2,944	oil
Milne Point, Schrader Bluff Oil	89,462	oil
Northstar, Northstar Oil	168,010	oil
Prudhoe Bay,, Aurora Oil	50,558	oil
Prudhoe Bay, Borealis Oil	96,942	oil
Prudhoe Bay, Lisburne Oil	188,600	oil
Prudhoe Bay, Midnight Sun Oil	22,837	oil
Prudhoe Bay, Naikuk Oil	98,038	oil
Prudhoe Bay, Polaris Oil	26,199	oil
Prudhoe Bay, Prudhoe Oil	12,167,026	oil
Prudhoe Bay, Point McIntyre Oi	489,640	oil
Prudhoe Bay, Schrader Bluff Oil	41,086	oil
Endicott, Endicott Oil	28,602	NGLs
Northstar, Northstar Oil	9,888	NGLs
Prudhoe Bay, Lisburne Oil	19,028	NGLs
Prudhoe Bay, Naikuk Oil	1,314	NGLs
Prudhoe Bay, Prudhoe Oil	723,007	NGLs
Prudhoe Bay, Point McIntyre Oil	14,891	NGLs
*These estimates are based on the conservative assumption that recovery ends at a TAPS throughput of 350,000 barrels per day.		

Table 5. Proposed Low Salinity Mechanisms

Wettability Alteration	Webb et al. 2006, Patil et al. 2008, Berg et al. 2009, Vledder et al. 2010, Ashraf et al. 2010, Chen et al. 2010, Emadi and Sohrabi, 2013, Mahani et al. 2013, Romero et al. 2013, Al-Shalabi et al. 2014, Aghaeifar et al. 2015, Yang et al. 2015
Surface reactions/MIE	Lager et al. 2006, Austad et al. 2010, Sorbie and Collins, 2010, RezaeiDoust et al. 2011, RezaeiDoust et al. 2010, Austad et al. 2013, Brady et al. 2012, Fjelde et al. 2012, Brady et al. 2015
Fines migration	Tang and Morrow 1999, Pu et al. 2010, Fogden et al. 2011, Zeinijahromi et al. 2013, Hamouda and Valderhaug, 2014
IFT	McGwire et al. 2005, Alotaibi and Nasr-El-Din, 2010, Alvarado et al. 2014, Moeini et al. 2014
Double layer expansion	Ligthelm et al. 2009, Lee et al. 2010, Suijkerbuijk et al. 2013
Mineral Dissolution	Hiorth et al. 2010, Pu et al. 2010b
Salting in	RezaeiDoust et al. 2009
Micro-dispersions	Emadi and Sohrabi, 2013
Asperites	Brady et al 2015

Table 6. Results of Alaskan low salinity waterflooding.

Source	Dilution Factor	Recovery %OOIP	T °C	Porosity %	Perm. mD	Initial salinity mg/l
McGuire et al. 2005	10	8	76	22	-	23,000
McGuire et al. 2005	7.3	9	103	-	-	23,000
McGuire et al. 2005	10	13	65.5	16	101	23,000
McGuire et al. 2005	16	21	99.7	24	-	23,000
Seccombe et al. 2010	7	20	114	22	800	28,000
Seccombe et al. 2008	15	9.5	116	22	800	22,000
Seccombe et al. 2008	440	18	116	22	800	22,000
Seccombe et al. 2008	122	11.6	116	22	800	22,000
Webb et al. 2004	37.5	20	-	25	400	220,000
Kulathu et al. 2013*	367	14	25	20	100	22,000
Kulathu et al. 2013	4	7	25	20	100	22,000
Kulathu et al. 2013	2	2	25	20	100	22,000
Patil et al 2008*	2	3	93	19-32	38-97	22,000
Patil et al 2008	4	14	93	19-32	38-97	22,000
Patil et al 2008	367	28	93	19-32	38-97	22,000

* = laboratory studies

Table 7. Alaska Oil Fields OOIP, cumulative oil production, EUR and calculated recovery factors.

Alaska North Slope and Cook Inlet Estimated Ultimate Recovery						
Fields/Pools	Reservoir	OOIP	Cum Oil	RF	EUR*	RF at EUR
		MBBLS	MBBLS	%	MBBLS	%
ANS-Badami	Badami SS	300,000	6,993	2	8,452	3
CRU-Alpine	Alpine SS	1,100,000	426,780	39	493,900	45
CRU-Fiord-Kuparuk	Kuparuk River SS	100,000	62,882	63	75,234	75
CRU-Nanuq	Nanuq SS	127,000	3,187	3	5,827	5
EU-Endicott	Kekiktuk Conglomerate	1,100,000	468,925	43	493,000	45
EU-Ivishak	Ivishak SS	29,000	8,702	30	9,151	32
KRU-Kuparuk	Kuparuk Formation	5,900,000	2,377,982	40	2,560,868	43
KRU-Meltwater	Bermuda/Cairn Sand	100,000	18,894	19	21,038	21
KRU-Tabasco	Tabasco SS	160,000	19,129	12	22,414	14
KRU-Tarn	Bermuda SS	230,000	115,743	50	131645	57
KRU-West Sak	Schrader Bluff West Sak SS	7,700,000	79,327	1	114,296	1
MPU-Kuparuk	Kuparuk River SS	6,649,083	250,970	4	272,960	4
MPU-Sag River	Sag River & Ivishak	168,848	2,796	2	2,944	2
MPU-Schrader Bluff	Schrader Bluff	160,000	27,033	17	62752	39
NU-Northstar	Ivishak SS	247,000	162,739	66	168,010	68
PBU-Aurora	Kuparuk River SS	230,000	40,596	18	50,558	22
PBU-Borealis	Kuparuk River SS	350,000	79,329	23	96,942	28
PBU-Lisburne	Lisburne Group	2,500,000	166,843	7	188,600	8
PBU-Midnight Sun	Kuparuk River SS	60,000	20,581	34	22,837	38
PBU-Niakuk	Kuparuk River SS	400,000	94,386	24	98,038	25
PBU-Orion	Schrader Bluff	3,200,000	33,024	1	41,086	1
PBU-Point McIntyre	Kuparuk River SS	880,000	459,446	52	489,640	56
PBU-Polaris	Schrader Bluff	450,000	19,426	4	26,199	6
PBU-Prudhoe	Sadlerochit Group	24,000,000	11,670,862	49	12,167,026	51
CI-Beaver Creek	Hemlock/Tyonek	30	6.3	21	6.5	22
CI-Granite Point	Hemlock/Tyonek	149	151.459	102	489.6	329
CI-McAuthur River	W.Foreland/Hemlock/ Tyonek	1,500	639	43	26.2	2
CI-Middle Ground Shoal	Tyonek (aka Middle Kenai)	600	202	34	150	25
CI-Redoubt Shoal	Hemlock/Tyonek	20	3.6	18	4.1	21
CI-Swanson River	Hemlock/Tyonek	435	233	54	244	56
CI-Trading Bay	Hemlock/Tyonek	350	106	30	755	216
CI-W. McAuthur River	Hemlock	100	14.3	14	15.7	16
*These estimates are based on the conservative assumption for TAPS throughput of 350,000 bpd.						

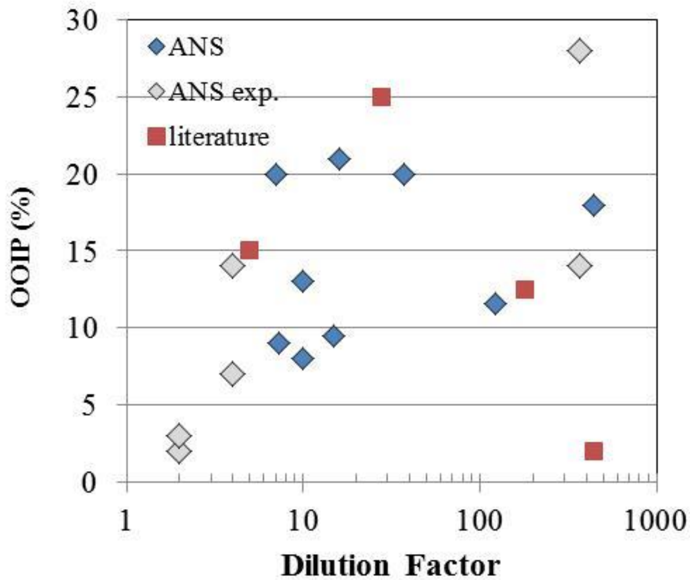

Figure 1. Dilution factor versus incremental oil recovery (%OOIP) for Alaska North Slope cores and field tests.

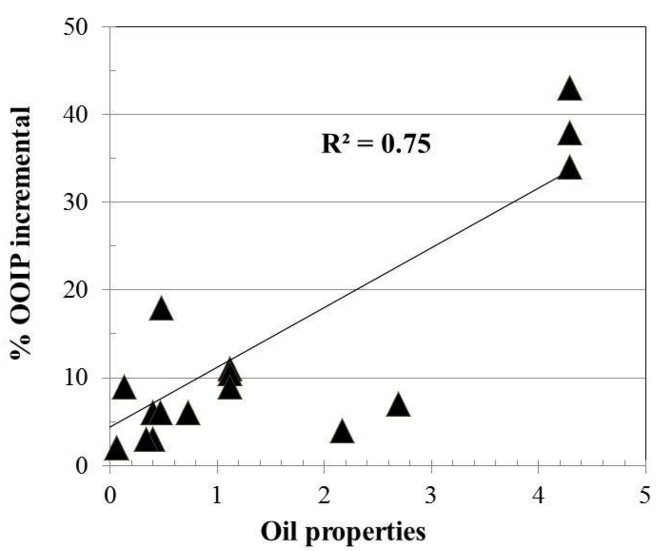

Figure 2. Polar content measure (TAN, TBN and sulfur) versus increased recovery in % OOIP for Berea sandstone imbibition experiments where oil was the only variable (Suijkbuijk et al. 2012).

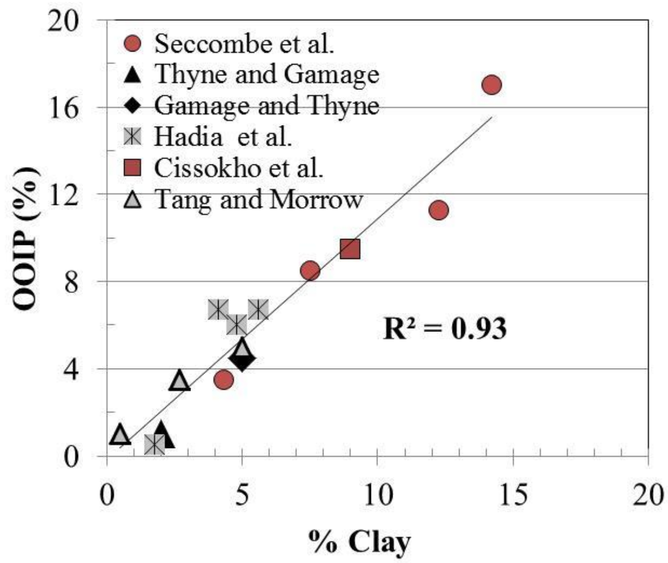

Figure 3. Clay content in sandstone versus incremental oil production (in %OOIP).

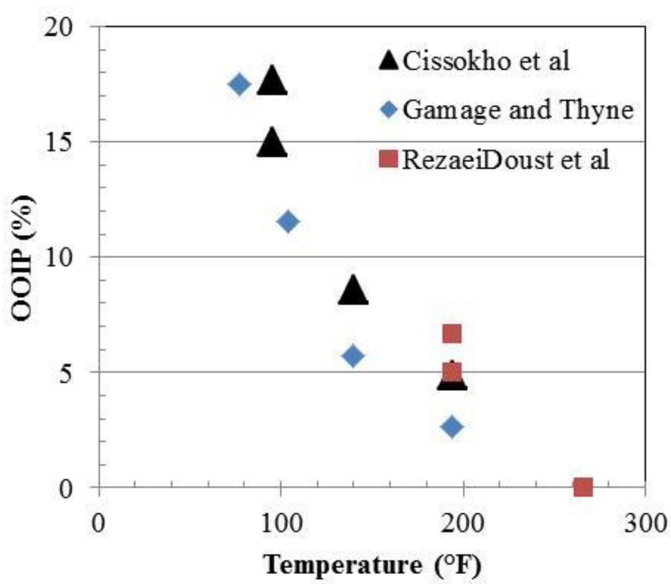

Figure 4. Experimental data for temperature versus increased recovery (%OOIP) for three different sandstones.

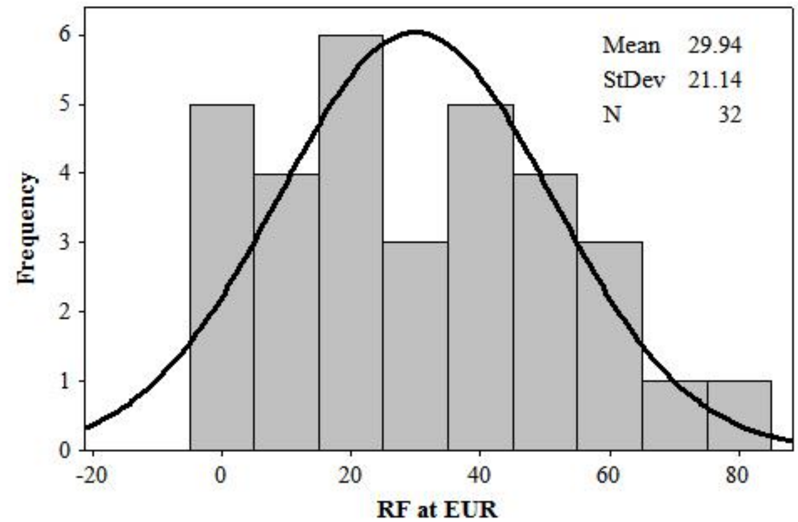

Figure 5. Histogram of recovery factor for Alaskan fields in this study from the North Slope and Cook Inlet.

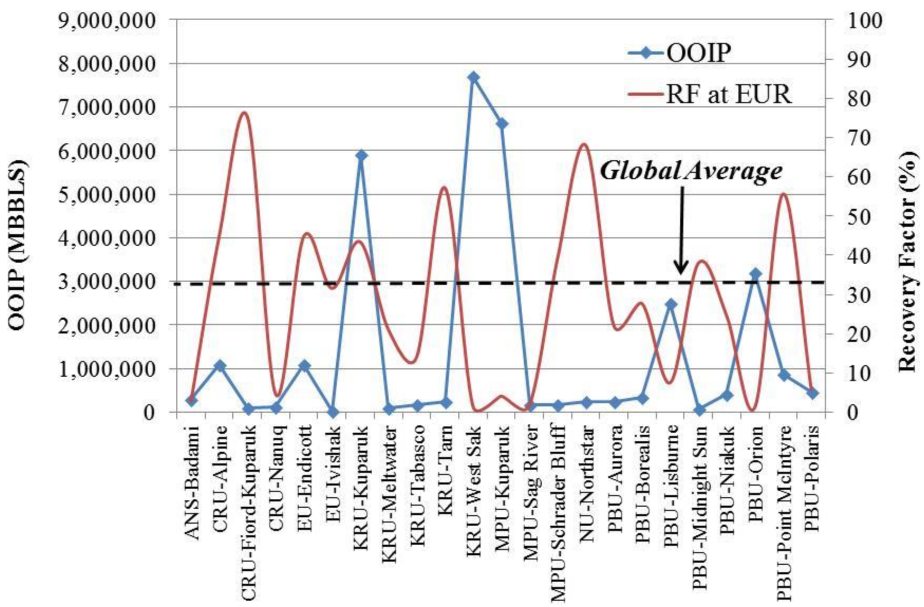

Figure 6. Plot of OOIP and recovery factor (RF) at calculated EUR for North Slope fields.

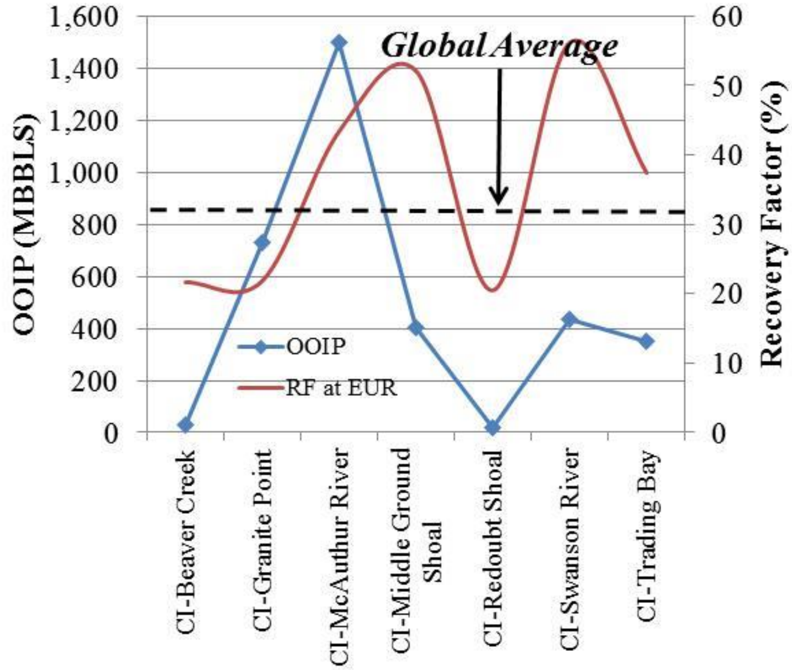

Figure 7 shows the OOIP and recovery at EUR for the Cook Inlet fields.

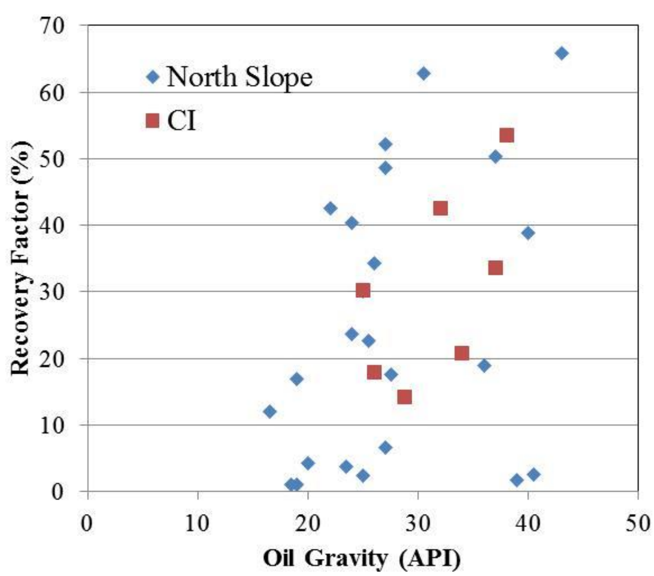

Figure 8. Relation between oil gravity (API) and recovery factor (%) for Cook Inlet and North Slope fields.

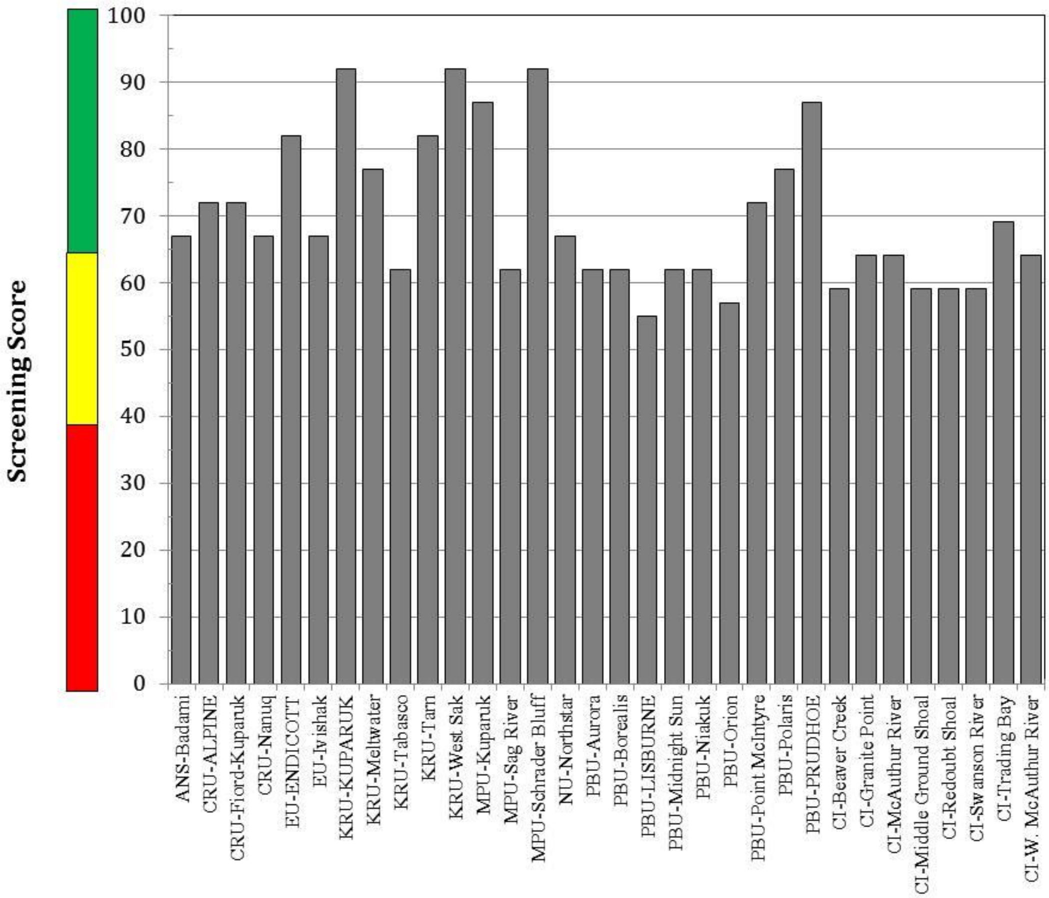

Figure 9. Plot of screening score for low salinity waterflooding for Alaskan Oil Fields.
Best North Slope candidates are labeled in all capital letters.