DESALINATION IN THE OIL INDUSTRY - PERFECTING ENHANCED OIL RECOVERY USING OPTIMIZED WATER QUALITY

Authors: *Lisa Henthorne, Meghan Hartman and Andrea Hayden*

Presenter: *Lisa Henthorne*
Chief Technology Officer – Water Standard – USA

Abstract

Since Marathon Oil used their patented technology on the Brae Platform in 1988 twenty years ago, specialized nanofiltration technology has been used to produce low sulfate seawater for waterflooding in offshore oil fields. Sulfate in seawater is problematic due to its low solubility when coupled with barium and strontium salts in some oil reservoirs and due to the potential for bacteria to reduce sulfate to hydrogen sulfide within the reservoir. Since the Brae installation, more than 44 sulfate removal process (SRP) systems have been installed on offshore platforms, producing over 2,000,000 barrels of water per day (318,000 m^3/day). Today, oil companies are stretching further to produce more oil from existing fields, and considering that globally the rate of average recovery of oil in place hovers around 35% from existing fields, there is plenty of room for improvement.

Historically, other than sulfate levels, the ion composition of water used in waterflooding of oil reservoirs has received little attention. But recently, water quality has emerged as an influential method to increase oil recovery. By targeting injection water composition, a number of benefits have been demonstrated, particularly in chemical enhanced oil recovery (CEOR) and low salinity waterflooding. This paper will present case studies representing three offshore projects to demonstrate the impact and benefits of customized water quality on project economics and potential incremental oil recovery, based on modeling the water treatment systems. These cases include:

a. Low salinity and sulfate, medium ratio divalent/total cations
b. Medium salinity, low hardness
c. Low salinity and hardness, high ratio divalent/total cations

In CEOR applications, customized water quality can improve conformance, reduce polymer costs and reduce alkalinity-related scaling. In low salinity waterflooding, specific ion compositions can be created from seawater or brackish water to alter the wettability of the reservoir resulting in higher oil recovery. Attention to the divalent ion concentration is critical in low salinity floods to prevent clay deflocculation in sensitive reservoirs. Combining low salinity injection with CEOR may offer a two-fold benefit. It should be noted that each oilfield is unique and not all fields are suitable candidates for improving recovery by altering the injection water composition.

Achieving optimum blends of ions to realize maximum recovery is a function of carefully choosing membrane and polishing technologies, and marrying them with adaptable pressure centers for power efficiency. While the offshore industry is familiar with SR membranes, innovative membranes and ion selective systems can be designed to customize water quality cost-effectively, thereby expanding the operator's ability to enhance recovery.

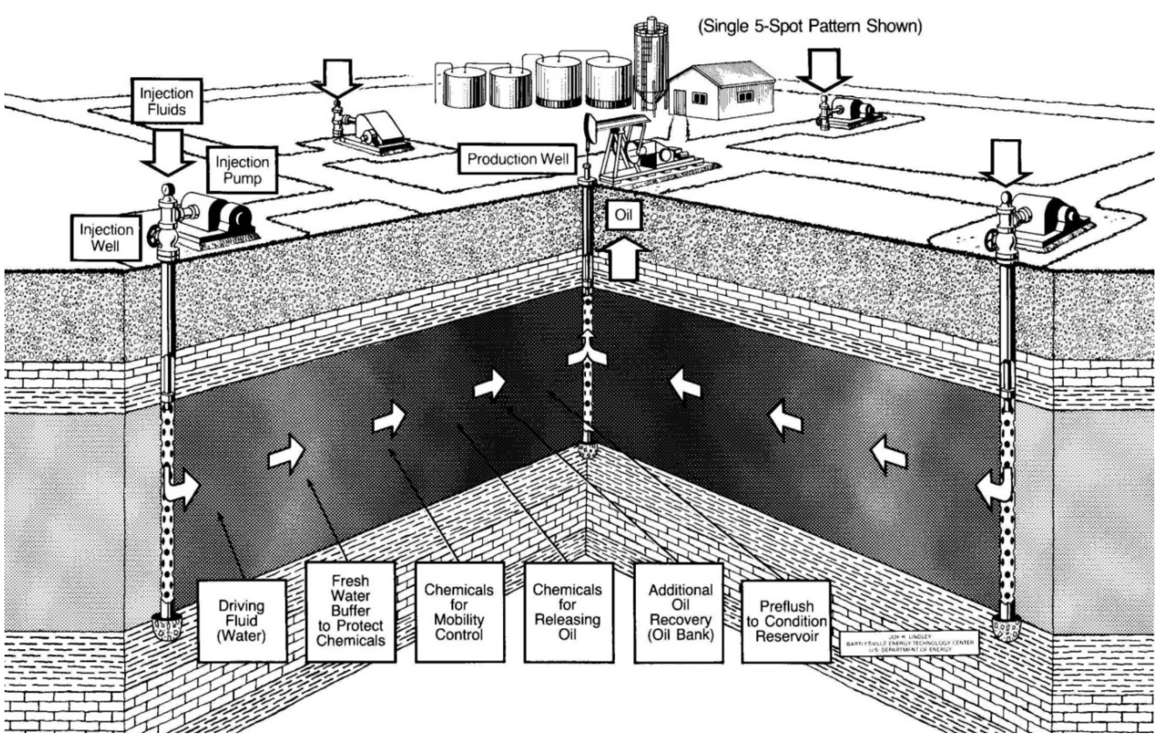
I. INTRODUCTION

As the price of oil and the cost of exploration and production have increased with discoveries moving farther offshore, there is heightened focus in the oil and gas sector on increasing production from existing reservoirs. With large volumes of water used in the production process, water is increasingly moving from an operations issue to one of strategic significance. The oil and gas industry also faces increasing pressure to manage its environmental footprint – including offshore water management. This is even more critical in deeper offshore waters, where water treatment can be extremely expensive – due to footprint and platform weight requirements – and logistically difficult, with limited options and flexibility. Onshore operations can also be limited in remote areas where delivery of equipment and logistics of material can be challenging. As a non-core capability for oil producers, water treatment is often considered the weak link in oil production, in both upstream and downstream operations.

As a result, innovative, environmentally-focused and reliable methods of meeting water treatment demands capable of operating in a highly challenging environment must be developed to meet the growing demand. The goal: minimize operating costs, maximize footprint and energy efficiency, while maintaining production and/or increasing oil recovery rates.

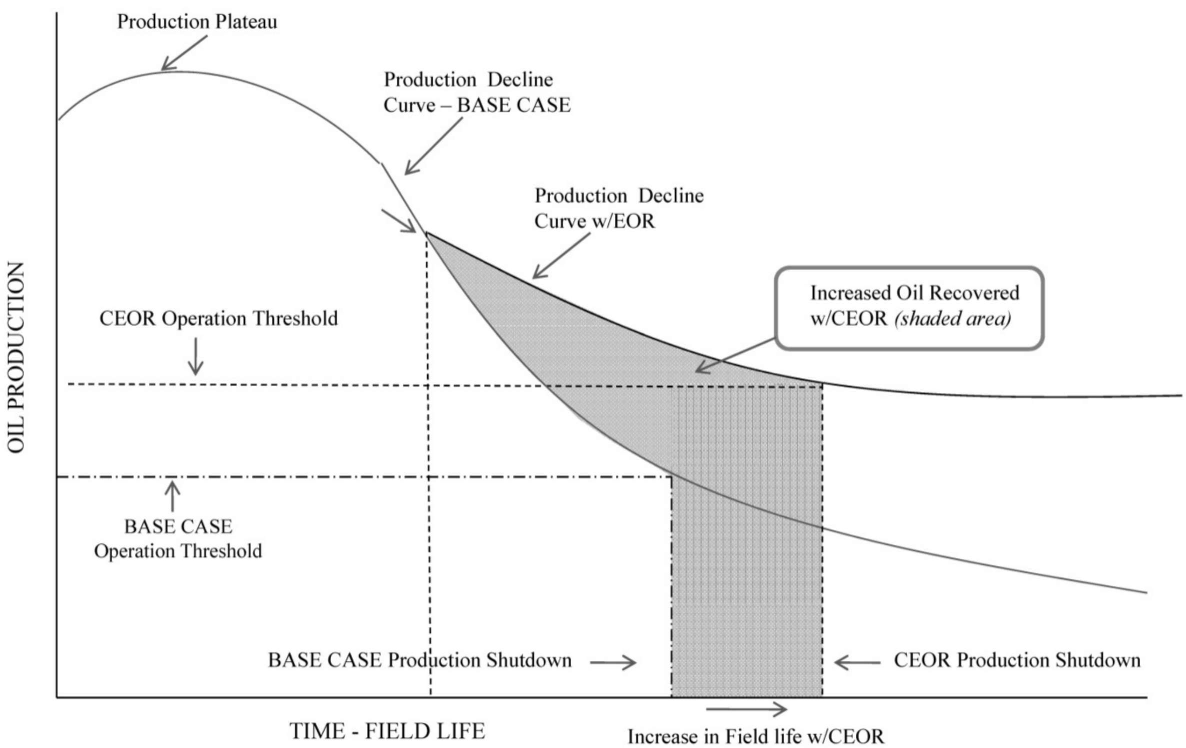
Reservoirs can vary in below ground surface depth, which can impact the cost of drilling and recovery. Typically oil reservoirs are adjacent or mixed with saline water reservoirs. Once a viable reservoir is developed, oil is removed from the subsurface using either natural reservoir pressure or displacement by an injected fluid. A schematic of an indicative reservoir along with displacement by water and chemicals is shown in Figure 1.

Figure 1: Reservoir subsurface and indicative recovery methods (Department of Energy)



Over the course of the reservoir life, production will increase for a period of time until it reaches a peak production plateau and then begin to decline. Once pressures begin to drop within the reservoir, waterflooding activities will commence to maintain oil production. Figure 2 demonstrates an indicative life of an oil field where after reaching peak production, reservoir decline increases and enhanced oil recovery (EOR) programs become beneficial, in this case chemical EOR. Also, as shown in Figure 2, the earlier an EOR program is identified and implemented in a field; the total volume of recoverable oil is also higher.

Figure 2: Life of an oil field with an EOR program implementation



The various phases of a field's life begins with primary recovery where oil is abstracted through the natural pressure or displacement of oil from the reservoir, many times the pressure within the reservoir is enough to force oil to the surface. Since reservoir pressure will fall over time, secondary recovery methods are used to force oil to the surface. The general term Improved Oil Recovery (IOR) is used to describe waterflood management and any more sophisticated methods aimed at improving recovery, and is inclusive of both secondary and tertiary (enhanced) recovery. The purpose of IOR is not only to restore formation pressure, but also to improve oil displacement or fluid flow in the reservoir. Dependent on reservoir characteristics various methods are applied to maintain pressure which can include water or gas injection and result in recoveries from 20-30% of the original oil in place (OOIP). There are a number of benefits and issues that result from water quality, which will be discussed in later sections.

Enhanced oil recovery (EOR) or tertiary methods are used to improve the mobility of oil in the reservoir. The term Enhanced Oil Recovery (EOR) is a subset of IOR, and includes tertiary methods to increase recovery ranging from thermal methods, waterflood based chemical, and microbial addition and gas injection. Typically tertiary programs improve recovery by an additional 5-20% of OOIP.

The various phases of oil recovery in a reservoir are shown in Figure 3. This also includes indicative methods used for recovery or enhancement along with the amount of oil extracted from these methods. Original oil in place (OOIP) refers to the total volumetric quantity of oil present at the beginning of the field's life. The reservoir's capacity is often referred to as pore volume (PV), which is the total volume of the reservoir, inclusive of oil and water. Therefore, at the beginning of a field's life, the PV will include both the OOIP and the volume of original formation water.

Figure 3: Indicative Reservoir Recovery (Delshad, 2010)

Primary Recovery	Natural Reservoir Pressure	10-20% of OOIP
Secondary Recovery	Waterflooding, Gas Cycling	20-30% OOIP
Enhanced Recovery		
	Polymer Flooding	5-15% OOIP (additional)
	Gas Flooding	5-15% OOIP (additional)
	Surfactant Flooding	15-30% OOIP (additional)
Heavy Oil Primary Recovery		0-10% OOIP
Heavy Oil Enhanced Recovery	Thermal EOR	> 50% OOIP

Throughout the life of an oilfield, water plays a critical role in the design and management of operations. In some cases, operators do not take into account the significant impact water will have on the cost of production or the benefits that can result from appropriate management. This paper will discuss the various methods of water-based EOR alternatives and the economic considerations associated with designing specific water qualities for injection.

II. WATER BASED IOR AND EOR METHODS

The majority of water use in oil recovery is related to waterflooding into reservoir formations to either maintain pressure and to force oil out of the production wells. 'Produced water' results during the field production cycle, when the waterflood or natural formation water breaks through into the production wells, and is addressed in Section III. Of all the IOR methods currently in use in oil and gas operations, the most common is waterflooding. Waterflooding is applicable in light to medium density oil fields where petroleum can be mobilized without the use of thermal methods. Historically, there have been three key areas where water treatment has been critically important in waterflooding: flood filtration, sulfate reduced flooding, and produced water treatment. Recent developments in water injection have also explored further improvement to recovery through desalination for low salinity injection.

Water injection can vary depending on whether it's onshore or offshore. In both cases, operators have to be aware of the ions present in the source water, where sulfate is one the target constituents for removal. In the case of onshore applications, water resources can be limited and often operators are forced to use produced water for reinjection. In addition, it can be difficult to transport equipment to the project location, so water treatment needs to be compact and mobile. For offshore applications, seawater is the primary water resource but space and weight is the largest constraint in implementing water-based IOR or EOR. In addition, many times offshore operators have not accounted for platform space requirements of enhanced recovery projects, which may require additional marine facilities adjacent to the platform.

2.1 EOR Programs Goals

One of the fundamental elements in understanding oil recovery is noting the relationship of the oil, the water and the rock within the reservoir. The 'wettability' of reservoir rock is defined as the portion of the rock surface coated with adsorbed hydrocarbons. For increasing oil wetness, the oil prefers to stick to the rock and to flow less easily, relative to water. One of the goals in oil recovery is to shift the reservoir toward more water wetness.

2.2 Sulphate Removal Process (SRP)

Seawater is widely used as an offshore injection fluid for pressure maintenance despite being recognized as having potentially value-eroding properties. The most widely recognized problem is scale formation from chemical incompatibility of the injected seawater (high sulfate) and the original formation brine (barium, strontium). In reservoirs which contain a substantial barium or strontium content, seawater injection will cause the naturally-occurring sulfate contained in the seawater to precipitate with the barium and/or strontium, and can eventually diminish the output of the production wells. Also, sulfate-reducing bacteria in some reservoirs can feed on sulfate in seawater, thereby producing hydrogen sulfite and 'souring' the well or reservoir.

Due to the issues resulting from seawater injection, a mitigating trend in waterflooding is the removal of sulfates from seawater to prevent souring and scaling, referred to as the sulfate removal process (SRP). This process involves desulfating the seawater using specialized nanofiltration (NF) membranes, while maintaining a high salinity. DOW Filmtec and Marathon first introduced this membrane system in 1991. Historically, Dow has been the only manufacturer of SRP membranes, but recently other manufacturers such as Hydranautics and Koch Membrane Systems have been developing SRP-type elements. By the end of 2008, over 44 SRP systems were brought online on offshore production facilities around the world.

A major challenge with offshore SRP systems is the significant capital investment for platform space and weight which are required for installation. Retrofitting a platform to include SRP is extremely expensive and may be impossible.

2.3 Low Salinity Waterflooding

Since the late 1990s, there have been numerous laboratory tests and field studies where injection of low salinity water has resulted in increased oil recovery. This was demonstrated by BP on core samples and in the Alaskan North Slope fields. BP has since trademarked the process, LoSal™. Shell Oil Company has also progressed the concept under the trademark Designer Water™. Further testing and reviews are being undertaken by a number of other national and international oil companies.

Seawater used in offshore applications must be desalinated prior to utilization in EOR. Two general families of technologies are available for seawater desalination: thermal distillation and membrane processes. Thermal technologies are more power intensive and are used successfully in the Middle East in power/water cogeneration facilities where fuel is cheap and abundant. Thermal based processes may be applicable for onshore applications where energy or heat is available for treatment. Membrane processes are more energy efficient, have a smaller footprint, and are less capital intensive than thermal processes, for the purposes of this paper, membrane desalination is only considered.

Research and demonstrations using core flow and single well chemical tracer (SWCT) tests have indicated oil recovery improvements of 5-10% OOIP with low-salinity water injection (Austad et al, 2010, Ayirala et al 2010, Seccombe et al, 2010, Sorbie et al, 2010, Vledder et al, 2010, Ligthelm et al, 2009, Webb et al 2008, Lager et al, 2008). Care must be taken in implementing low-salinity flooding where the reverse effect can occur when injecting into lower salinity formation water and changing the wettability towards oil-wet, and thereby reducing oil recovery.

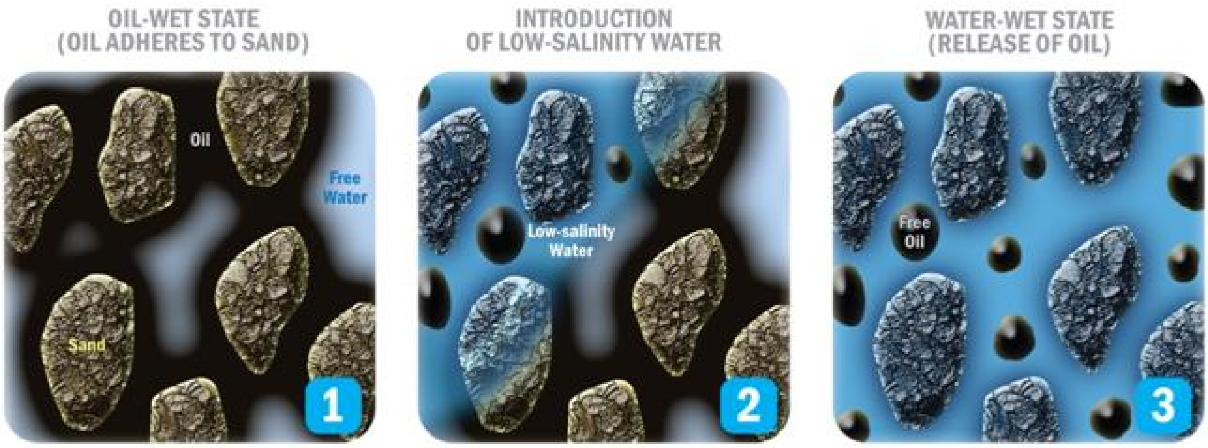
Clay stability of the reservoir must also be studied; injecting fresh water or water with a salinity that is too low can destabilize clays based on the clay composition in the reservoir. Research has been undertaken to describe the suitability of injection water composition for various clay types (Ayirala et al, 2010, Ligthelm et al, 2009, Scheurerman and Bergersen, 1990), indicating smectite and montmorillonite clays to be the most sensitive. The relationship between total cations and percent divalent cations, on an equivalence basis, provides guidance to the degree of clay sensitivity and the suitability of various water compositions for injection.

In concept, low salinity injection changes the wettability characteristics of the reservoir rock. In reservoirs with high salinity formation water, injection of low salinity water will generally shift the properties of the reservoirs to a state of water wetness, increasing the microscopic sweep efficiency, and thereby increasing the potential oil recovery. Also, limestone (carbonate) reservoirs differ in response to low salinity floods compared to sandstone reservoirs, and are more dependent on the ionic make-up of the injection water.

This interfacial chemistry is shown in Figure 4. The process depicted in the figure can be described as follows:

1. Polar molecules in reservoir oil are attracted to the negatively charged clay surface. Divalent cations (calcium, magnesium) act as bridges between the negatively charged molecules in the oil and the negatively charged clay surface.
2. Low-salinity water breaks the oil-wet bond resulting in the release of oil from the rock surface.
3. When low salinity water is injected, the ion exchange equilibrium changes and bound oil becomes mobile and oil recovery increases.

Figure 4: Water-oil-rock interfacial characteristics



Currently, there are no offshore low salinity systems online but the market is moving rapidly to embrace this technology because of the economic impact of the potential additional recovery that can be achieved.

2.4 Chemical Enhanced Water Injection

Chemical EOR (CEOR) is used in partnership with water injection programs in order to mobilize and increase oil extraction. CEOR programs were the most popular in the 1980s, but installations decreased as the price of oil fell in the 1990s. Recently the number of projects has grown exponentially as the price of oil increases, program designs improve, and the cost of chemicals decreases.

Typically sandstone reservoirs are most frequently utilized for CEOR due to the higher permeability of sandstone compared to limestone reservoirs. The majority of the CEOR technologies have been tested at pilot and commercial scale on sandstone lithology (Alvardo, V. and Manrique, E. 2010). CEOR programs can utilize alkali, surfactant, or polymer, or some combination of those such as alkali-polymer (AP), surfactant-polymer (SP), and alkali-surfactant-polymer (ASP).

Alkalis react with organic acids in oil in a saponification reaction to create natural surfactants. Although the degree of saponification is a function of the relative level of organic acids in the oil, alkali is relatively inexpensive compared to manmade surfactants. Alkalis are also beneficial in CEOR programs using manufactured surfactants, as the alkali reduces adsorption of the manufactured surfactant to the reservoir rock.

Water chemistry is critical when using alkali as a CEOR additive. Any hardness in the injectant water will quickly precipitate with the alkali, thereby plugging the reservoir and wells. Therefore, at a minimum, the source water of the CEOR flood must be softened prior to injection.

Surfactants reduce the interfacial tension between oil and water, which mobilizes the oil in the reservoir. Many of the newer surfactants have the ability to handle a range of salinity and hardness, and almost all surfactants are able to handle higher reservoir temperatures. The reduction in interfacial tension produced from a surfactant will depend upon the injected surfactant concentration, the type of oil in the reservoir, the salinity of the injectant, the reservoir temperature, and if polymer is used.

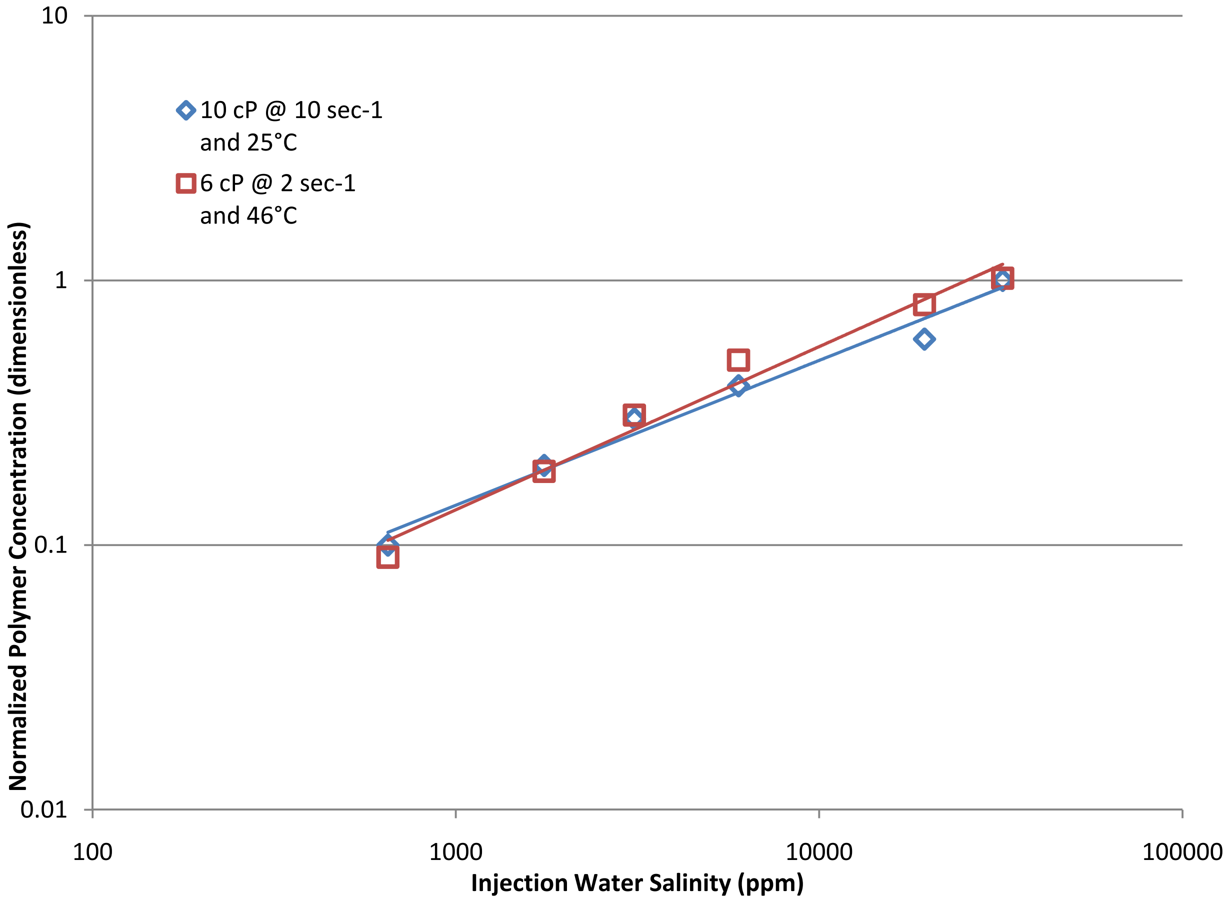
Polymer addition is the most common type of CEOR program and has been used for over forty years in the field. Polymers are most applicable to light and medium gravity oil fields, with utilization designed to increase the viscosity of injected water and as a mobility control agent that provides better displacement efficiencies during a waterflood. The most common form of polymer used in the field is hydrolyzed polyacrylamide (HPAM) which has the ability to be used up to 85^{o} C.

Water quality has a direct impact on the performance and success of CEOR programs. Water salinity of the injection water greatly impacts the viscosity, or thickness, of polymer floods used in CEOR applications. According to recent studies (Ayirala, S., Ernesto, U., Matzakos, A., Chin, R., Doe, P., van Den Hoek, P., 2010), when low salinity water is used instead of seawater, lower polymer concentrations are required to achieve the same enhanced recovery, making polymer CEOR a more cost effective EOR process by reducing the polymer, storage, handling and facilities cost. For other CEOR processes using alkalinity (ASP for example), it is mandatory that the injection water be softened or desalinated to remove any calcium or magnesium content, in order to prevent precipitation of these constituents as a function of the alkalinity addition.

As previously discussed, many operators currently implement some form of waterflooding to maintain reservoir pressure and continue oil production, whether direct seawater or a sulfate reduced process. These processes do not typically target specific ion compositions and therefore do not result in an increase in oil production.

Recent studies have shown that in polymer CEOR projects, by using low salinity feed water, the polymer consumption required to achieve an ideal viscosity can be 5-10 times lower than when compared to seawater (Othman, M. Chong, M.O., Sai, R.M., Zainal, S., Zakaria, M.S., Yaacob, A.A., 2007). Figure 5 demonstrates the required concentration of polymer based on the salinity of the injectant water at varying shear rates. Although there is a slight difference based on shear rate, the salinity is the overriding factor in determining the quantity of polymer required to achieve a desired viscosity.

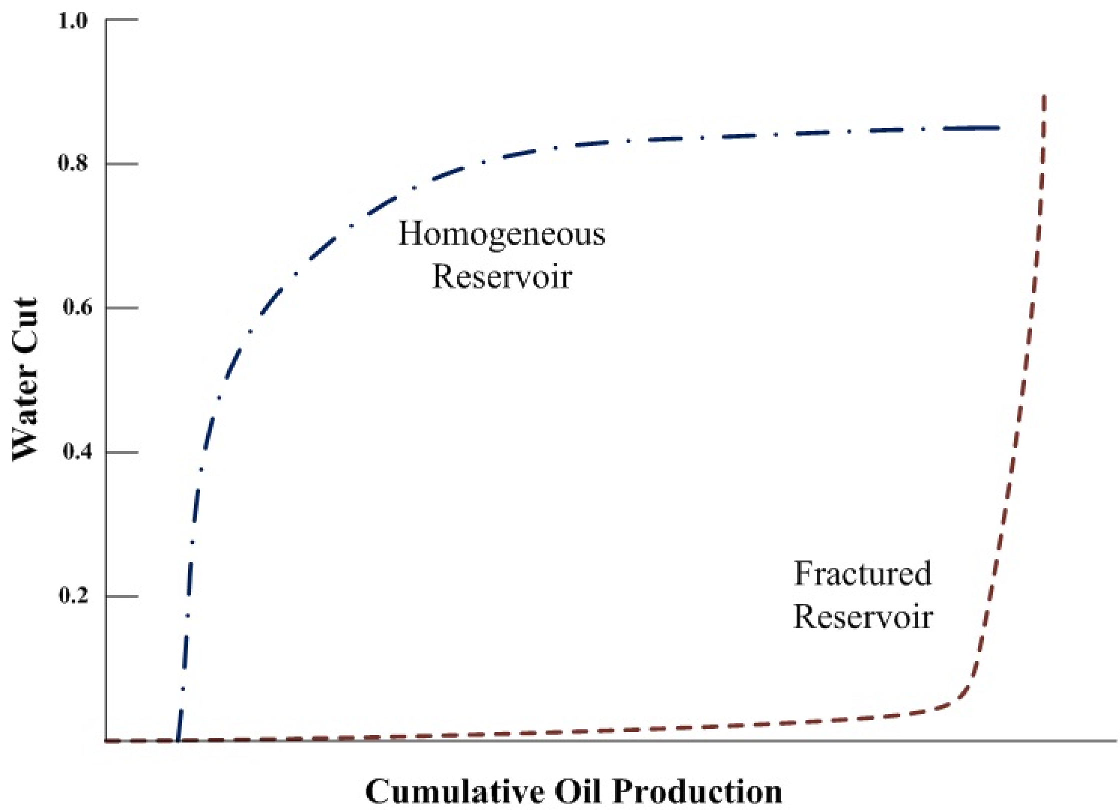
Figure 5: Polymer concentration required to achieve desired viscosity at varying salinity (Ayirala, S., Ernesto, U., Matzakos, A., Chin, R., Doe, P., van Den Hoek, P., 2010)



III. PRODUCED WATER

The oil and gas sector also has substantial wastewater treatment needs related to the produced water brought to the surface along with the oil or natural gas. Produced water is generated from large volumes of brine and petroleum resources and its management and treatment is a critical component to oil and gas production. Especially as oil fields age, the ratio of water to oil produced can drastically increase over the field's life, as depicted in Figure 6. Therefore the economics are one of diminishing return as less oil revenue is generated and more operating costs are incurred from increased water treatment needs. Due to the large volume of water in production, water management, treatment, and disposal become important to the economic returns and environmental impacts of an oil field.

Figure 6: Reservoir water cut throughout oil production



Growing environmental restrictions in some areas of the world is driving treatment and reinjection of produced water. In many fields, as is the case for onshore North America and offshore in the North Sea, produced water has a zero discharge requirement which forces operators to strategically manage their water resources. These drivers, as well as increased water scarcity, have pushed oil companies to use water more sustainably, driving the concept of water reuse across the industry. At a minimum, produced water has to be separated from the oil, and the oil often has to be further cleaned before it can be offloaded or transferred into a pipeline. The produced water will also undergo several treatment steps before it is discharged to the sea or reinjected.

As important as CEOR is to offshore oil production, treatment of the resulting produced water is just as critical. Chemical emulsions must be broken down in order to treat and discharge the produced water. The chemicals and technologies to accomplish emulsion treatment are sophisticated, requiring a specified level of treatment expertise.

Produced water varies significantly in different oil fields in terms of the dissolved solids, hydrocarbons and contaminants present. The variation of constituents in the produced water results in treatment challenges, as systems must be designed to target specific components along with meeting specifications. There are a number of treatment alternatives available, but prior to treatment, operators can improve the volume of water entering a well through mechanical blocking or in some cases downhole oil/water separators.

Primary methods for separating oil and water include gravity methods such as hydrocyclones. The hydrocyclone uses conical geometry in order to increase the centrifugal force on the liquid. This process

is driven by a differential pressure system and separates liquids by the difference in density, where the water phase is heavier than the light oil, and the water exits the narrow bottom of the hydrocyclone and oil droplets are forced through the top. When using a hydrocyclone, it is important to keep the turbulence at a minimum in order to encourage oil and water separation. One of the main hurdles is that hydrocyclones cannot remove soluble oil from water.
Downstream of the primary separation, a common secondary treatment is gas flotation. In this process gas is bubbled through the liquid where it captures oil and solids that can be removed from the surface.

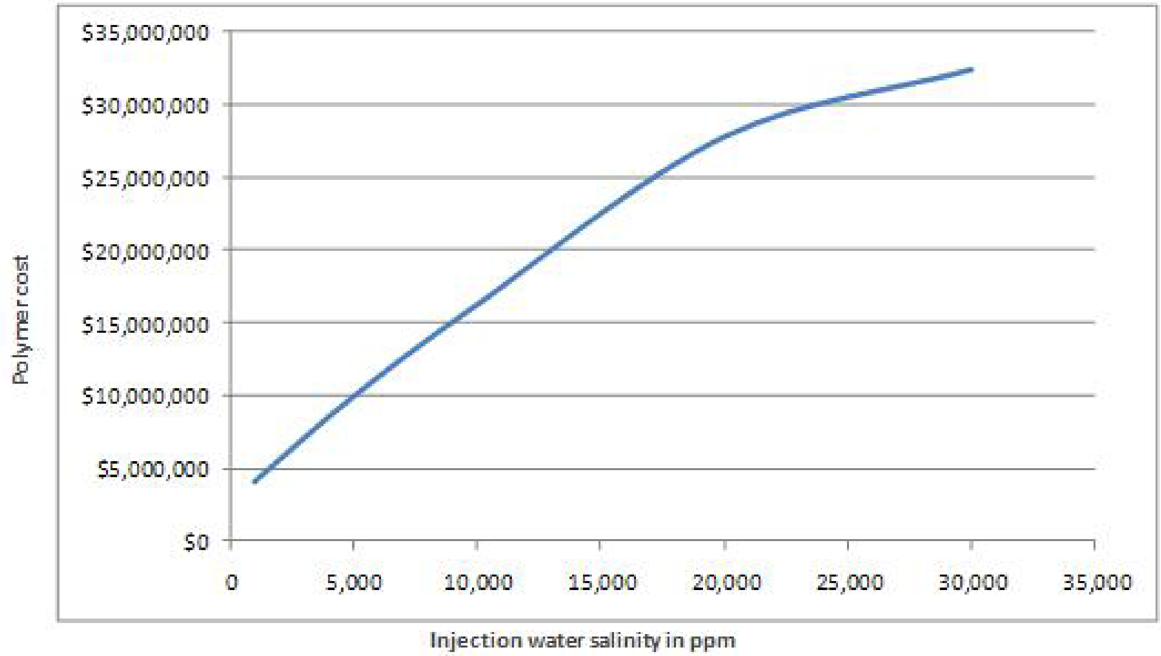
Polishing filtration units are able to further remove hydrocarbons to under 5ppm, using media such as black walnut shells. The shells remove small oil particles due to their large adsorption area and ability of oil to adhere to the nut's surface.

If polymeric membranes are used for desalination following produced water polishing, the feed water cannot have hydrocarbons levels above 1ppm for extended periods of time since it will foul membranes. Various polishing techniques are presently being explored around the world to achieve this goal on a cost-effective and dependable basis.

IV. CASE STUDY ANALYSIS

From field experience, the quantity of chemicals used in a waterflood directly impacts the economics of a CEOR program. Figure 7 shows indicative costs of a polymer injection with varying salinities for a 100,000 barrels per day (bbl/d) injection program. This is based on a polymer cost of $1.20 per pound of polymer and does not take into account the transportation, storage, equipment, or logistics of the program. This figure indicates that chemical costs are one of the largest variable expenditures of a project.

Figure 7: Annual polymer cost of polymer injection with varying salinity at 100,000 bbl/d (Adapted from Ayirala, S., Ernesto, U., Matzakos, A., Chin, R., Doe, P., van Den Hoek, P., 2010)



To demonstrate the effect of salinity on EOR programs case studies were examined based on the cost of their programs and the additional revenue generated from implementation. Three cases were studied that illustrate various injection scenarios; these cases included an SRP system which is used in IOR waterflooding programs, but can be paired with either surfactant or polymer to increase recovery. Low salinity was also selected which is an EOR program with water injection only, but can be significantly enhanced with the addition of chemicals. Finally, water softening, or nanofiltration treatment, was examined and can be used to increase recovery with water injection only, as well as with chemical addition.

The chemical concentrations required for these three processes are shown in Figure 8. As described above, as the salinity of injectant water decreases, as does the polymer requirement to achieve the desired viscosity.

Figure 8: Required chemical concentration by water treatment process

	Resulting Salinity (TDS)	**Alkali Concentration (mg/L)**	**Surfactant Concentration (mg/L)**	**Polymer Concentration (mg/L)**
SRP	23,000	-	1,000	1,200
Low Salinity	1,500	14,000	1,000	250
Softening (Nanofiltration)	20,000	14,000	1,000	1,100

From this required chemical addition, the indicative oil recoveries are shown in Figure 9. This increase in oil recovery is based on general field cases and assumption. Combining low salinity treated water with an ASP flood can increase production beyond that achievable by ASP flooding alone due to the resulting wettability improvements in the reservoir (Ayirala, S., Ernesto, U., Matzakos, A., Chin, R., Doe, P., van Den Hoek, P., 2010).

Figure 9: Indicative incremental oil recovery by treatment process (not cumulative)

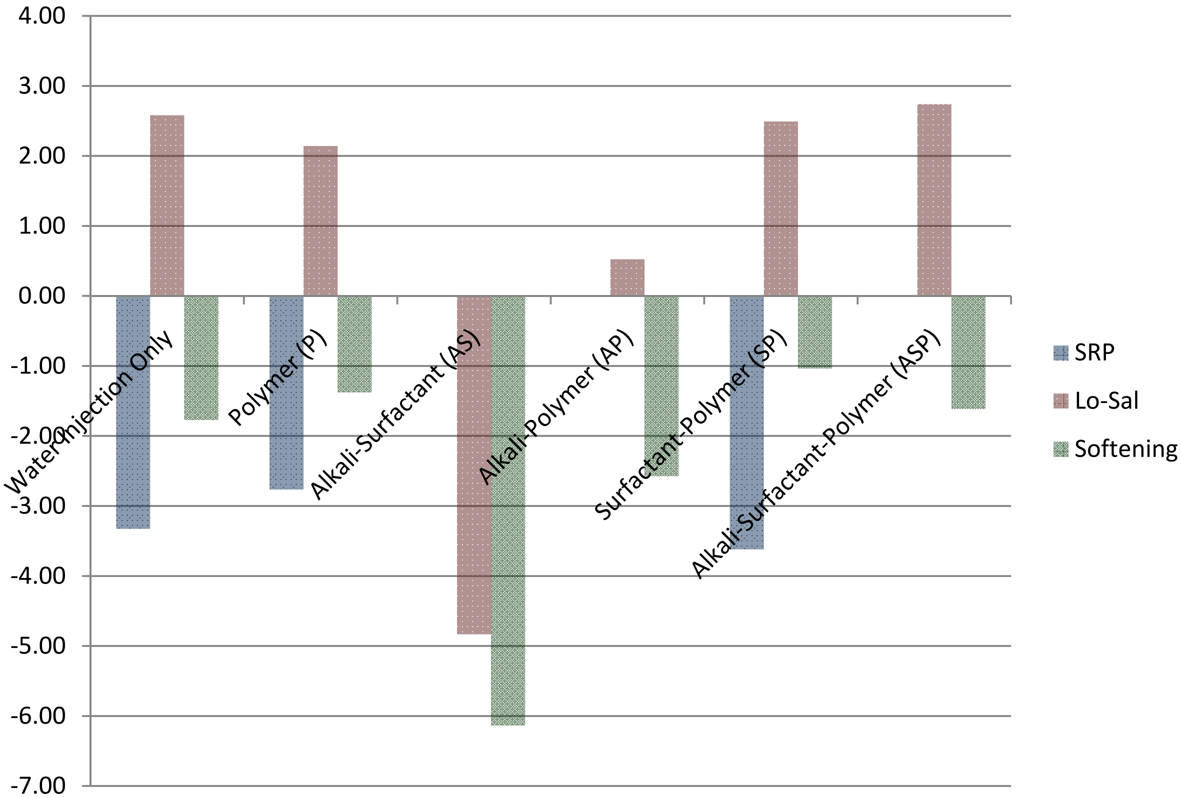
	Water Injection Only (no ASP)	**Polymer (P)**	**Alkali-Surfactant (AS)**	**Alkali-Polymer (AP)**	**Surfactant-Polymer (SP)**	**Alkali-Surfactant-Polymer (ASP)**
SRP	0%	3%	-	-	4%	-
Low Salinity	6%	10%	7%	12%	15%	20%
Softening (Nano-Filtration)	2%	6%	5%	8%	10%	12%

General assumptions were made for initial capital expenditure (CAPEX) of the water treatment system, which for each of the three systems, does not vary significantly. The CAPEX in this example included the water treatment equipment (i.e. pre-treatment, membranes, energy-recovery devises, etc) and chemical injection system, if used. It did not account for intake, discharge, electrical systems, piping, engineering, and integration since these systems would be required for every treatment process. This exercise also assumes that seawater will be used and that produced water does not have to be treated.

For this example, operational expenditure (OPEX) is the largest contribution towards the cost of the program. The majority of this OPEX is the cost of chemicals, which at current costs and concentrations can be upwards of over $40 million annually.

Based on these assumptions, an analysis was conducted to determine the increase in oil production based on EOR program. A 100,000 bbl/day water injection was assumed, with the program spanning over 10 years. From the net present value (NPV) of the systems and revenue along with a price of oil at $50/bbl, the revenue was estimated based on the increase in oil production. Figure 10 shows the relative return of the EOR program based on the initial capital investment required for each system. For example, the low salinity system used as water injection only, produces a relatively large increase in oil without having to factor in chemicals or implementing a chemical injection system. Whereas in the surfactant-polymer cases, annual chemical usage is large and the revenue generated from the additional barrels does not compensate for the water treatment and chemical systems cost.

Figure 10: Relative Return Based on Initial Capital Investment at $50/bbl



This analysis shows that using low salinity water injection with no CEOR chemical addition or with ASP injection produces the highest return from the initial capital investment. The use of CEOR chemicals may produce a higher overall recovery of oil, but the economics are very sensitive to the price of oil and chemicals, so having low salinity water will have a constant return on the investment.

These case studies demonstrate the importance water quality plays in reservoir maintenance and enhanced recovery programs. By planning for water-based programs at the beginning of reservoir life, oil recovery can be significantly improved as the field ages. In addition, attention to water quality and optimization of ions can be critical to reservoir chemistry and EOR programs.

V. CONCLUSION

Water supply for drilling, production, IOR, and treatment of produced water are critical challenges for the oil and gas industry, driven by new demands and environmental stewardship. Water-based EOR programs can be largely improved by customizing water quality and specifying ions. Investment in water treatment systems can increase oil production, with revenues proving the return on the initial capital investment. The oil industry recognizes that it needs to improve handling of water-related issues and minimize operational water footprint by maximizing water recycling and improving water efficiency. Water treatment is quickly emerging as one of the most significant challenges facing the offshore industry.

VI. REFERENCES

Alvardo, V., Manrique, E., "Enhanced Oil Recovery: An Updated Review," Energies 3(9), 1529-1575, August 2010.

Austad, T., RezaeiDoust, A., Puntervold, T., "Chemical Mechanism of Low Salinity Water Flooding in Sandstone Reservoirs," 2010 SPE Improved Oil Recovery Symposium, April 2010.

Ayirala, S., Ernesto, U., Matzakos, A., Chin, R., Doe, P., van Den Hoek, P., "A Designer Water Process for Offshore Low Salinity and Polymer Flooding Applications", 2010 SPE Improved Oil Recovery Symposium, April 2010.

Delshad, M. (2010, November 2-3). Introduction to Chemical Enhanced Recovery. Houston, TX, USA: SPE Enhanced Oil Recovery Seminar.

Department of Energy. (n.d.). Chemical Recovery. Retrieved 2011, from National Energy Technology Laboratory: www.netl.doe.gov/KMD/cds/disk44/A-Introduction/chem_recovery.PDF

Lager, A., Webb, K., Black, C., Singleton, M., Sorbie, K., "Low Salinity Oil Recovery – An Experimental Investigation", Petrophysics Journal, Vol. 29, No. 1, 2008.

Ligthelm, D., Gronsveld, J., Hofman, J., Brussee, N., Marcelis, F., van der Linde, H.A., "Novel Waterflooding Strategy By Manipulation of Injection Brine Composition", 2010 SPE Improved Oil Recovery Symposium, April 2010.

Othman, M. Chong, M.O., Sai, R.M., Zainal, S., Zakaria, M.S., Yaacob, A.A., "Meeting the Challenges in Alkaline Surfactant Pilot Project Implementation at Angsi Field, 2007 Offshore Malaysia," Offshore Europe, September 2007.

Scheuerman, R., Bergersen, B., "Injection-Water Salinity, Formation, Pretreatment, and Well-Operations Fluid-Selection Guidelines", Journal of Petroleum Technology, July 1990.

Seccombe, J., Lager, A., Webb, K., Jerauld, G., Fueg, E., "Improving Waterflood Recovery: LoSal™ EOR Field Evaluation", 2010 SPE Improved Oil Recovery Symposium, April 2010.

Sorbie, K., "A Proposed Pore-Scale Mechanism for How Low Salinity Waterflooding Works", 2010 SPE Improved Oil Recovery Symposium, April 2010.

Vledder, P., Carrera Fonseca, J., Wells, T., Gonzalez, I., Ligthelm, D., "Low Salinity Water Flooding: Proof of Wettability Alteration On A Field Wide Scale", 2010 SPE Improved Oil Recovery Symposium, April 2010.

Webb, K., Lager, A., Black, C., "Comparison of High/Low Salinity Water/Oil Relative Permeability", International Symposium of the Society of Core Analysts, Abu Dhabi, UAE, 2008.