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Water Management for EOR Applications - Sourcing, Treating, Reuse and Recycle

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Abstract

The growing popularity of water-based Enhanced Oil Recovery (EOR) techniques, such as Low Salinity Injection (LSI), Chemical EOR (CEOR), and steam-flooding, impacts the water footprint of the oil and gas industry. It also affects the water treatment industry by creating new opportunities as a function of the requirements of equipment and systems in EOR projects. In some cases, the needed technologies have little to no history of application in the upstream oil and gas industry, therefore impacting EOR project budgets and schedules. These issues become particularly acute in offshore applications that are generally limited by footprint and weight, thereby further reducing suitable water treatment options. The issues are further confounded by the lack of communication between oil companies on equipment successes and failures in these new applications. EOR projects are often kept as low profile, particularly by smaller oil companies, to strengthen competitive advantages in the marketplace.

One of the best treatment options for the environment is the reuse of produced water for re-injection in EOR applications. This is particularly attractive in CEOR where residual polymer and surfactant may deem the produced water unacceptable for discharge. But injection additives may stabilize emulsions and render the produced water and oil mixture challenging to separate. Ideally, water treatment technologies are used that both enable good separation and maximize potential reuse of produced water.

As a first step in disseminating the current body of knowledge of water usage and treatment in EOR applications, a survey was conducted in 2012 of water-based EOR projects to ascertain their water source and background information on the water treatment technologies employed. The survey was co-sponsored by the Produced Water Society. Specific information on the source water salinity and temperature was obtained, in addition to the type of EOR used, the project location, and details of the existing treatment system(s). The survey results were then augmented with exhaustive literature searches of both full-scale EOR applications and emerging technology solutions currently being piloted.

This paper describes the survey results which detail water-based data from more than fifty EOR projects around the world, along with a critique of the emerging technologies being piloted in global EOR field sites.

Introduction

There is a general trend in the oil and gas industry toward increased application of Improved and Enhanced Oil Recovery (IOR/EOR) techniques [1-6]. Many of these technologies involve extensive water treatment such as Low Salinity Injection (LSI), Chemical EOR (CEOR), and steam-flooding (including conventional pattern-flood and Steam Assisted Gravity Drainage – SAGD). The water treatment industry (consultants, chemical and equipment suppliers, and EPC contractors) looks upon these activities with interest to understand the technology needs and the business opportunities.

A significant fraction of world oil production comes from mature fields. In addition to mature fields, there are a number of fields with moderate to high viscosity oils that have become viable by IOR/EOR techniques with recent sustained oil prices. While there will continue to be oil price fluctuations, over the long run, price of oil is expected to continue to increase. Current estimated cost for CEOR is $10-30 per incremental barrel of oil with polymer flooding at the lower end of the scale and surfactant flooding being the higher end [6]. At these costs, and with current price of oil, this technology is viable now for a large number of fields. If current oil prices are sustained, then the application of IOR/EOR will continue to increase.

Besides the purely economic factor, there are other factors influencing growth as well. Much of the IOR/EOR activity has been driven by the National Oil Companies (NOCs). This is particularly true in the Middle East, China and Venezuela where large-scale activity in EOR has occurred. An NOC views the higher ultimate recovery of EOR as politically attractive since it demonstrates a commitment to prudent and long-term management of oil resources. Economic viability is of course taken into account but on a relatively long term horizon.

For each of the other EOR techniques, there are particular factors that both drive the growth of the technique and shape the character of that growth. For example, the cost of chemicals required for CEOR has steadily and significantly fallen in the past several years. As will be discussed herein, this has reduced the economic uncertainty in CEOR and is a major factor driving its growth. In the case of low salinity flooding, growth is being driven by greater understanding of the range of reservoirs where the technique will increase ultimate recovery. As discussed presently, each EOR technique has its own drivers, challenges and opportunities. Each of these EOR techniques will be discussed from the standpoint of the water treating industry.

As presented in the table below, it is estimated that roughly 3.6 % of current worldwide oil production is from fields that utilize some form of EOR technique. Of the three major EOR techniques (thermal, miscible gas, and CEOR), miscible gas is dominant with 47 % of all EOR production. In the US, the current recovery rate from oil reservoirs is roughly 33 %. If this value were to increase to 43 %, through the application of EOR techniques, it is estimated that an additional 45 billion bbl of oil could be produced from currently known oilfields.

Current World-Wide Production Supported by EOR:			
EOR total	3 MM BOPD	3.6 % of total world-wide prod	
Thermal (incl Steam):	1.2 MMBOPD	1.4 %	40 % EOR
Miscible Gas (incl CO2):	1.4	1.7 %	47 %
CEOR:	0.4	0.5 %	13 %

Current US EOR Potential:	
Total oil discovered	450 b bbls
Total oil produced	150 b bbls
Oil remaining in discovered fields	300 b bbls
Current recovery rate:	33 %
Incremental UR (EOR IUR 10 %):	45 b bbls

[1]

One of the water treatment options in EOR applications is the reuse of produced water for re-injection. This is particularly attractive in CEOR where residual polymer and surfactant may deem the produced water unacceptable for discharge. But injection additives may stabilize emulsions and render the produced water and oil mixture challenging to separate. Ideally, water treatment technologies are used that both enable good separation and maximize potential reuse of produced water.

[1] Ultimate Recovery (UR)

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Steam Flood

Steam generation for steam flood (including SAGD) is important in some parts of the world such as Alberta, Bakersfield, Venezuela, and more recently Oman. According to the Oil and Gas Journal Survey of EOR projects, there are roughly 110 steam flood projects in the world producing roughly 1.2 MM BOPD (million barrels of oil per day). Only about 20 of these projects produce greater than 20 M BOPD (thousand barrels of oil per day). These 20 largest projects account for roughly 80 % of the total steam flooding capacity in the world, with a combined capacity of approximately 1 MM BOPD.

One of the important metrics in steam flooding is the ratio of water barrels required for injection versus oil barrels produced (or equivalently m^3 water/m^3 oil). This ratio is referred to as the Steam to Oil Ratio (SOR). In calculating an SOR, the cold water equivalents of steam volume are used. Typical SOR values in Alberta are in the range of 3.5. For various reasons, the Alberta average SOR tends to be lower than that in other parts of the world. Using an estimated global SOR value of 5, gives an estimated 6 MM BWPD (1 MM m^3/day) of the total water being injected in steam floods around the world. This is a relatively small volume compared to the total produced water volume of some 260 MM BWPD. Nevertheless, it does represent a reasonably large opportunity for water treating consultants and equipment suppliers, and several companies are operating in this area.

Thus, steam flood involves a relatively small total oil production volume, and a relatively small water treating volume. Furthermore, a typical steam flood project requires years of pilot study followed by an extended drilling campaign. Consequently, the number of new steam flood projects that are sanctioned every year is relatively small.

Nevertheless, typical steam flood projects garner interest in the oil and gas water treating community. This is due to a number of factors. First, for each major steam flood project, the water treating volumes are fairly high. Also, most projects require some form of desalination. These requirements translate into a relatively high CAPEX cost for a steam flood water treating system. The cost of water treating can make or break a project. In some cases, the CAPEX for water treating equipment can be as high as 200 to 300 million USD, or 20 to 25 % of total project CAPEX. In terms of oilfield water treating equipment, these are relatively large numbers. Thus, the owner/operators (oil companies) drive the water treating industry to deliver knowledge, competence, expertise and technology. Because of this, there is demand for consulting services. In order to reduce project risk, on a relative basis, greater effort goes into concept selection and front end engineering for each project.

Second, the technology is specialized, and there is a willingness on the part of the oil companies to look to the water treating industry for support. The water treating technologies required for steam flooding include the conventional deoiling technologies plus precipitation softening, silica removal, ion exchange, evaporation, crystallization, and of course steam generation. Within the water treating industry, these technologies are well established. Within the oil field, they are unknown to many and well known to the few who operate steam floods. This is not to say that all of the technical and economic problems have been solved. There is still a need to reduce scaling and fouling, and the cost of evaporation and crystallization. However, the problems are at least well known if not yet solved and incremental improvements continue to be made in both the chemistry and in the equipment. Knowledge transfer to regions like Oman is still a problem. But the knowledge is available for those who are willing to cooperate with international business partners.

Third, once a project is running, the chemical and media consumption cost is moderately high. Thus, service providers and consultants provide value in supporting this technology and reducing operating cost.

Considering all of these factors, the steam flooding segment of the Exploration and Production (E&P) water treating business is characterized by steady but slow growth, important in the heavy oil regions of the world, and intensely challenging from a water treating and water management standpoint. To avoid delays and implementation problems faced by some E&P operators, it is critical to follow the proven methods of technology transfer (workshops, consultants, and flexible contracts that include technology support).

Chemical Enhanced Oil Recovery

CEOR is staging a comeback. As shown in the figure below, it is estimated that roughly 400 M BOPD are currently being produced from polymer and Alkali Surfactant Polymer (ASP) fields [8]. This volume is likely to double in the next four years.

As shown, CEOR using polymers, surfactants and alkalis is not an entirely new technology. Roughly speaking, there are three technologies involved:

- Water soluble polymer to increase viscosity and sweep
- Surfactant, or alkali plus surfactant, to lower surface tension and improve rock/water interaction (increase capillary number)
- All of the above – ASP

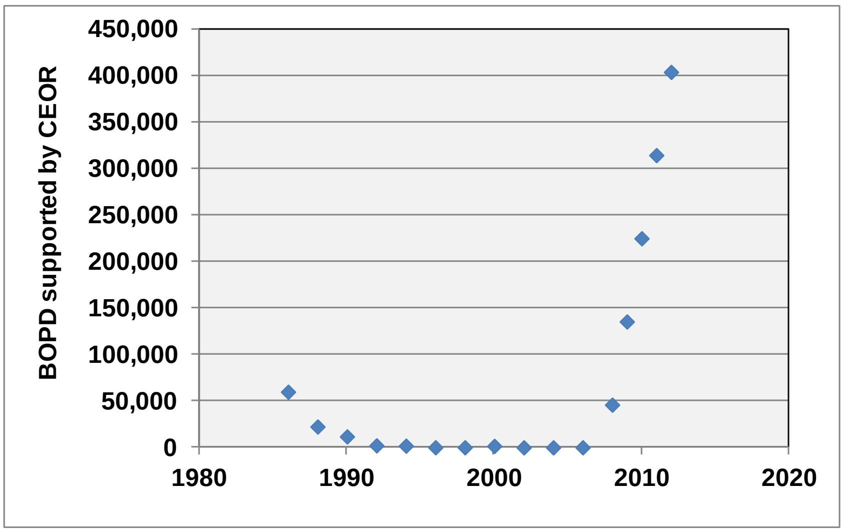

Figure 1. The daily global oil production supported by CEOR. An estimate was made for all CEOR projects around the globe.

Application of CEOR peaked in 1986 [6]. Following the subsequent oil price collapse, the number of significant new CEOR projects and the oil volumes involved has been small but it has been recently increasing. The drivers for this increase are similar to those for the other EOR technologies – maturing oil fields, sustained high oil price.

In addition, the price of polymer has remained constant which means in relative terms that it has significantly dropped in cost:

Hydrolyzed Polyacrylimide (HPAM) (polymer) cost reduction:

1986	16	(USD/kg polymer) / (USD/kg oil)
2011	3	" " " "

While this is a tremendous improvement, the cost of chemicals can still be relatively expensive to the overall project cost. Another factor which has helped overcome this cost is the improvement in predicting the recovery from use of polymer. The literature describes increases in Ultimate Recovery (UR) from 0% to approximately 30% of Original Oil in Place (OOIP) for

CEOR floods in the field [10]. As a result of this uncertainty, for nearly 20 to 25 years, the cost to benefit ratio has been relatively marginal and speculative.

However, with the sustained oil prices of the last six years or so, the cost to benefit ratio has improved to the point where reservoir uncertainty is much less of a deterrent. Also, in the fields where it has been practiced, relatively encouraging results have been obtained and a small but dedicated group of industry practitioners and academic experts have developed a reasonably good understanding of reservoir response. This, together with the incentive of higher ultimate recovery, is driving resource holders to at least consider the option of CEOR.

As with steam flood projects, for the past twenty-five years most CEOR projects have been small, with a few relatively large exceptions. Nevertheless, many small projects, plus the larger projects in China and Oman have contributed significantly to an understanding of water / chemical / reservoir interactions. This has lead to an ability to formulate the chemistry for optimal recovery. It has reduced the uncertainty and risk in reservoir response.

Additionally, CEOR is being readily adopted by a number of regional oil companies, with particular interest being demonstrated by operators in moderately heavy oils of western Canada. In many of these applications, primary or secondary recovery has been underway for years. Without some form of EOR, recovery would be abruptly curtailed. In other cases, CEOR allows very aging fields to continue to be economically productive. Compared to steam flood or Steam Assist Gravity Drainage, a polymer flood requires less capital expenditure, and is therefore an attractive alternative for moderate viscosity (10 to 100 cP) oil.

A number of companies have projects that are making their way through the project maturation funnel. If even half of these projects go forward, there will be a five-fold increase in the number of facilities and in the barrels of oil involved in CEOR in the next five to ten years.

Significant water treating challenges exist for both onshore and offshore projects due to low salinity requirements of the injection water and due to the difficulty of treating the back-produced water containing chemicals as well as oil [8].

Water treating challenges occur on both the injection side and the back-produced side. The ionic composition of the injection water plays a crucial role in CEOR success. Clay swelling is better understood and the water chemistry required to prevent it is now reasonably well established. Generally speaking, there must be sufficient divalent cations to prevent ion exchange and collapse of the clay structure. Therefore, the concentration of divalent cations cannot be below a certain threshold depending on the clay concentration and type. At the other extreme, in a polymer flood the concentration of HPAM required to achieve a target viscosity increases as salinity increases, and it especially increases as the concentration of divalent cations increases. Whereas, the ‘optimal salinity’ of a surfactant flood can vary greatly as a function of the surfactant chemistry and the reservoir dynamics, with an objective of achieving the lowest interfacial tension between the water and oil. Reservoir souring is just as much of an issue with CEOR as it is with conventional water flooding and manipulation of ionic composition offers some hope to minimize souring through injection of nitrate or reduction in sulphate. Finally, there is age-old water compatibility limitation related to sulphate scaling potential if for example the injection water is seawater (high in sulphate) and the formation water contains barium or strontium.

Water treating techniques for achieving the required water ionic chemistry such as sulphate removal, Nanofiltration (NF) for divalent ion removal, Reverse Osmosis (RO), and remineralization are being practiced both onshore and offshore. Sulphate rejection membranes were first installed offshore for the Marathon South Brae field in 1988 in order to mitigate sulphate scaling. Since then, offshore installations were relatively few until about 2004 or so when the total barrels treated passed the 2 MM BWPD mark. Since then, uptake of this technology has been significant with a current capacity of close to 10 MM BWPD [7]. As with other technologies, uptake appears to follow an S-curve which requires a "critical mass" of applications and experience before industry-wide acceptance will occur.

Membrane technologies require reliable pre-treatment to prevent membrane fouling. Fouling is both a design challenge and a challenge for surveillance and operation. When membranes become fouled, the permeate rate decreases. Biological fouling, or biofouling, poses the most significant challenge. Controlling biofouling is a function of biocide dosing – intermittent is far superior to continuous dosing for membrane applications – combined with conservative designs that reduce or eliminate ripe conditions for biogrowth. Good monitoring techniques are also key, combined with effective cleaning agents. Membranes can also function as pre-treatment, in the form of ultrafiltration or microfiltration technology, and these represent one of the fastest growing technologies in the water treating industry. Given the significant uptake curve for this technology, there is wide recognition of its importance and adoption for use on sulphate removal packages is becoming widespread for new systems.

Recently, Total started polymer flooding the Dalia field in deepwater offshore Angola. This is the first offshore polymer flood in the world. On average, 8,000 BWPD are being injected using desulphated seawater (from sulphate rejection membrane system). Polymer concentration is about 900 mg/L. A 750 kg bag of polymer is consumed every 1.5 days. An increase in daily oil production was seen immediately upon polymer injection. It is too early for back-produced fluids. Once the back-produced fluids contain detectable concentrations of polymer, the fluids will be routed to a disposal well. While this project represents only a small volume application, it is significant in that it is the first offshore polymer flood. Other operators have larger offshore polymer flood projects under development.

For many polymer projects, treating back-produced CEOR fluids will be a challenge. One of the early deterrents to CEOR in the 1980’s was the difficulty of separating and metering the oil. Reservoir response was essentially unknown for many applications because accurate oil production rates could not be determined due to inadequately designed separation facilities. Designing the separation facility remains a major challenge.

A polymer flood will produce water with at least twice, up to perhaps five times the viscosity of conventional produced water. This by itself would not be such a big problem. Water viscosity differences are already well known. The produced fluids in the Norwegian sector of the North Sea are hot and have therefore about half the viscosity of produced water in the deepwater Gulf of Mexico. This viscosity difference, from temperature alone (and not polymer) is adequately taken into account in water treating system design.

However, the presence of polymer changes two other key aspects of the produced water. First, polymer at moderate and higher polymer concentrations (> 500 ppm) increases the sensitivity of oil / water mixtures to shear. As a result, the produced water entering the facility will have higher oil concentrations and smaller drops. Second, polymer increases jetting of bubbles in a flotation unit. In other words, it is more difficult to evenly disperse bubbles in the presence of polymer thus significantly reducing the performance of flotation units. Perhaps all of these problems can be overcome by new equipment designs. The literature on the Daqing field suggests this may be the case, including an example of an innovative technology that has recently been installed to separate and recycle the polymer from the back-produced CEOR fluids. However, as discussed below, there is limited incentive currently for equipment suppliers to undertake this challenge.

One of the interesting developments in water treating back-produced fluids is in chemical treating of ASP fluids. In a recent application of Hydrophilic-Lipophilic Deviation (HLD) theory, George Hirasaki and his group at Rice University have identified cationic surfactants that act as strong demulsifiers to break ASP emulsions. Typical ASP back-produced fluids are composed of tight emulsions of small oil drops in water which are stabilized by the ASP chemicals. The chemistry of these demulsifiers is specific in the sense that only one particular compound seems to work with any particular ASP formulation. Nevertheless, when the proper chemistry is selected, settling time is reduced from 12 hours to 12 minutes. Apparently the cationic surfactant pushes the ASP surfactant away from the oil / water interface. From a high-level perspective, it is not a surprise that a chemical strategy is successful in treating such a chemically stabilized emulsion.

In all of these water treating challenges, the devil is in the details. Seemingly small decisions can make the difference between a system that performs well with minimum OPEX and high up time, versus a system that is chronically difficult and costly to operate. Operators that suffer water treating problems often do not tally the real cost of those problems. The staff time required to solve water treating problems can be high and can put significant strain on the staff resources of an organization. In many cases, if communication between the reservoir chemist and the water treatment specialists could be in place from the time the CEOR cocktail formulation and water chemistry requirements are developed, it is expected that many of these consequential decisions could be addressed in the early stages of the project.

In addition to the technical challenges mentioned above, there are significant opportunities as the industry implements CEOR projects. While the technology is complex and knowledge in this area is specialized, the commercial barrier to entry is not high. Relatively few patents remain in effect. Little intellectual property barriers exist. The main barrier to entry is expertise. Deep expertise in water treating is required. If history is a guide, the NOCs and International Oil Companies (IOCs) will look for this expertise from the consultants, equipment suppliers, and the engineering consultant companies. However, this will likely not be enough. As the NOCs and IOCs begin to take ownership for water, they are beginning to realize that in-house expertise is required as well.

Knowledge of how to design and operate CEOR systems is certainly specialized but credible expertise is available. The International Service Providers have recognized the opportunities in this area already for several years. The most successful of these companies are those that have specialized in water treating and developed deep expertise in all three critical areas of chemistry, equipment, and process line-up.

As discussed above, some technologies are available to treat water for CEOR. Selecting appropriate technology and designing an integrated process requires expertise. Most of the large major engineering firms do not have the expertise to select and design systems that not only perform well but which are reasonable to operate. On the other hand, some of the moderate size engineering companies have established a niche by providing expertise together with engineering. Such companies are notable in that they send staff to workshops and encourage staff to publish papers. They offer consulting in addition to engineering. Such companies add significant value to a project.

New technology is needed as well. As discussed above, some of the chemical companies are pursuing the opportunities vigorously. This is not a surprise. Obviously, both natural and man-made chemicals are at the root of the water treating problems. There is another reason that is less obvious. Chemical suppliers have a front-row seat at the game. Upstream chemical suppliers typically employ ten times the number of field staff compared to almost every other oilfield services provider, on an equivalent revenue basis. In fact, field services are the main value driver for their business. Thus, the chemical providers see the field problems firsthand. The top-tier upstream chemical suppliers are very efficient at capturing the challenges of water treating and turning them into new products.

Water treating equipment suppliers have a slightly different, but understandable perspective. Roughly four or five years ago the major equipment suppliers saw an opportunity to sell offshore type water treating equipment to onshore CEOR projects. Given the difficulty of treating back-produced fluids, required residence time is high. For large scale projects, the required size of settling tanks becomes impractical. Therefore, it makes sense to use hydrocyclones, flotation and nutshell filters. The former two were typically only seen offshore. Recently though, the equipment suppliers saw a new opportunity. They collaborated with oil companies to test and implement their existing offshore technology for this relatively new application. As a result, a number of CEOR projects in the field use a combination of hydrocyclones, flotation and nutshell filters to treat back-produced fluids, which in many cases, are re-injected after further CEOR-chemical addition.

Unfortunately though, the equipment performed only about half as well as expected. Shear thinning, higher oil concentrations, smaller drops, and bubble jetting makes these fluids more difficult to treat than expected. Overcoming these problems will require new technology and possibly a fundamental understanding of the fluid properties. Not only is this expensive, but there are relatively few laboratories, test sites and people who can do the work. The equipment suppliers feel that there is not a large enough market to justify such a development effort. They may be correct about this. These companies tend to have a keen sense of the cost, and potential market for developing new technology. While CEOR will clearly increase in volume, it will never capture more than a few percent of the total global water treating market.

Low Salinity Water Flood

Among the various EOR techniques, low salinity water flood has generated the most discussion. LoSal™ EOR is part of the BP suite of EOR technologies (which include BrightWater®) that have been developed under the company's "Pushing Reservoir Limits" program. The Clair Ridge project will be the world's first offshore project to use low salinity water to increase oil recovery [9].

Over the 40-year life of the Clair Ridge field, BP expects about 640 million bbl of oil to be recoverable. Of that, about 42 million barrels are expected to be the result of applying LoSal™ EOR. It is expected that the desalination equipment will cost roughly 120 million USD [9]. Thus, like a typical steam flood project, the cost for water treating equipment can be high for offshore water flood where desalination is required.

BP is also planning to make the Mad Dog Phase 2 in the Gulf of Mexico the second low salinity water injection project. The final decision on capital expenditure is expected to be taken in 2013, with first oil production projected for 2020. After Clair Ridge, and Mad Dog Phase 2, a further four projects are currently being evaluated by BP. Thunder Horse in the Gulf of Mexico may be among them.

Shell has been reported to be evaluating the Ursa field in the Gulf of Mexico for commercial application of low-sal water technology. The Ursa-Princess water flood has already been in operation for four years using sulphate removal membranes.

In Norway, Statoil has the offshore Heidrun, Snorre and Gullfaks fields under consideration for low-salinity pilots, while Saudi Aramco is currently conducting tests on the effectiveness of low-salinity water ("Smart Water") in carbonate reservoirs, and has reported positive results.

With the current price of oil, and with the number of projects sanctioned or in the early phases of implementation, it would appear that low salinity water flood is heading for significant growth. However, industry experts are quick to point out that the applicability of low-salinity water could be limited by a couple of factors. There is only a small number of oil companies in the world that have reservoir engineering expertise to accurately determine the economic benefit of low-salinity water flood. Some industry opinion holds that targeting appropriate reservoirs for low salinity applications is made problematic by the fact that the mechanism by which low-salinity water works is not entirely understood. Others in the industry see it slightly differently. According to one industry observer, "I think the mechanism is relatively well understood. What isn't so well understood is the range of oil properties, rock composition and water composition where you'll get the benefit. To assess this accurately requires a very strong reservoir engineering capability" [9]. This, together with the associated costs may be limiting factors.

Furthermore, in the deep water, the competent design and operation of water flood facilities are still a challenge. The cost of weight and space for deep water facilities is high which excludes the use of buffer capacity (storage tanks) and which creates significant challenges in terms of fluid dynamics and chemical reaction time. This is particularly true if membranes are to be used for either sulphate reduction (NF), or desalination (NF/RO). Seawater filtration remains a challenging area as well. In the past, owner/operators were faced with the difficult decision whether to install multimedia filtration or not. Offshore multimedia systems are expensive in terms of weight and space, and typically are problematic in terms of operation due to high flux rates which are used to reduce weight and space. If no multimedia filtration is installed, then the risk of membrane fouling is high. Compact ultrafiltration using membranes may address this problem. Several platforms are already in operation and the technology is rapidly improving. While compact ultra-filtration is now in sight, compact deoxygenation of seawater has been a valuable and yet elusive goal of the industry for decades.

Yet, the application of membrane desalination for offshore water flooding has steadily increased in the last eight years or so [7]. The traditional driver for this technology has been to reduce sulphate scaling in the producer wells. Lately, this technology has being applied also for reduced souring risk. The benefits of membrane desalination justify the technical obstacles and risks of implementation. Cumulative sulphate membrane installed capacity is roughly 8 MM BWPD. Altogether, with the addition of low salinity water flood, this figure may double in the next four to five years.

Survey Results

In an effort to assess the current produced water treatment technology methods used in water-based EOR, a survey was conducted in 2012 as part of a joint research project being conducted by Water Standard and in partnership with the Produced Water Society.

The survey targeted a broad scope of audience and was designed to gather data on water treatment methods presently being used in existing and active water-based EOR projects worldwide to address a gap in research related to current technologies. Through literature and industry research, the survey results were then augmented for both full-scale EOR applications and emerging technology solutions currently being piloted.

Approximately more than fifty projects were identified of which over 50% of the projects are located in North America, followed by 20% of the projects located in the Middle East.

Table 1: Worldwide EOR Projects

Project Name	Location	Operator	Type of EOR
Dalia	Africa	Total	P
El Borma Field (Pilot)	Africa		Thermally Activated Particle (TAP)
Future EOR with Cobalt International Energy	Africa & GoM	Cobalt International Energy	SAGD
Endicott Field	Arctic	BP	LSI
ANGSI CEOR	Asia	PETRONAS	ASP, SP
St. Joseph	Asia	Petronas	ASP
Daqing	Asia	Daqing Oilfield	P, trials ASP
Shengli Oilfield	Asia	Shengli Oilfield Corporation	P, SP, ASP, Thermal
Dagang Oilfield	Asia	Petrochina	CEOR
Mangala Field	Asia	Cair Energy India Pty Ltd	ASP
BP Clair Ridge	Europe	BP	LSI
Baku	Europe	BP	non-SAGD Steam
Skarv Development Project	Europe	BP	Unnamed
Unnamed	Europe	Unnamed	LSI
Jasmine Development Project	Europe	ConocoPhillips	Unnamed
VicBilh	Europe	Total	CEOR
Mad Dog	GoM	BP	LSI
Thunderhorse	GoM	BP	LSI
Al Shaheen Low Salinity Project	Middle East	Maersk	LSI
PDO Marmul	Middle East	PDO	CEOR
Unnamed	Middle East	TOTAL	SP
Oman	Middle East	Shell	ASP, P, SP
Polymer flooding Marmul	Middle East	PDO	Polymer (HPAM)
Al Shaheen	Middle East	Maersk Oil	ASP, P, Microbial, LSI
Kuparuk	North America	ConocoPhillips	LSI
Battrum	North America	Hyak Energy	ASP
Trembley Oilfield	North America	Unnamed	ASP
Unnamed	North America	Denbury Resources	non-SAGD Steam
Unnamed	North America	ConocoPhillips	SAGD
Husky Valhalla	North America	Husky Oil Operations Ltd	Microbial, Low Salinity Injection
Silo Field	North America	R360	SAGD
Unnamed	North America	Unnamed	Microbial
Cymric	North America	Chevron	non-SAGD Steam
Unnamed	North America	ACS Medio Abiente	LSI
Unnamed	North America	Unnamed	LSI

Unnamed	North America	Cenovus	SAGD
ASP flooding pilot	North America	OXY	ASP
Lawrence	North America	Rex Energy	ASP
Pelican Lake	North America	CNRL	P
Pelican Lake	North America	Encana	P
Saskatchewan	North America	Talisman	ASP
Viking Kinsella Wainwirght	North America	Harvest Operations Corp.	P
Unnamed	North America	Unnamed	SAGD, non-SAGD Steam
Peregrino Polymer Flooding	South America	Statoil	P
Unnamed	South America	Proprietary	SAGD
Peregrino, Brazil	South America	Statoil	LSI
ASP Colombia	South America	Williams Energy	ASP
Chichimene Field	South America	Ecopetrol	Gravity Stable Air Injection
Meta Providence	South America	Williams Energy	CEOR
Mina	Unnamed	Shell	CEOR
HTHS EOR Project	Unnamed	Total	SP

P: Polymer
SAGD: Steam Assist Gravity Drainage
ASP: Alkali Surfactant Polymer flood
LSI: Low Salinity Injection

Over 30% of the projects indicated ASP as the type of EOR process being implemented, followed by over 25% of projects using LSI.

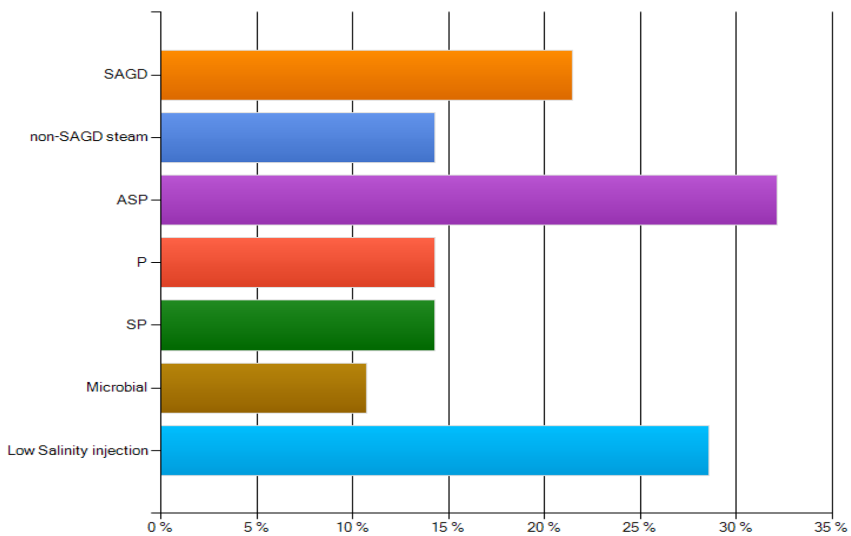

Figure 2: Survey Results - Type of EOR Process

Over 50% of the projects identified are utilizing produced water as source water for water-based EOR, followed by over 40% of the projects using seawater. The survey results indicate a broad array of water treatment unit operations currently being implemented to treat the source water, as represented on Figure 4.

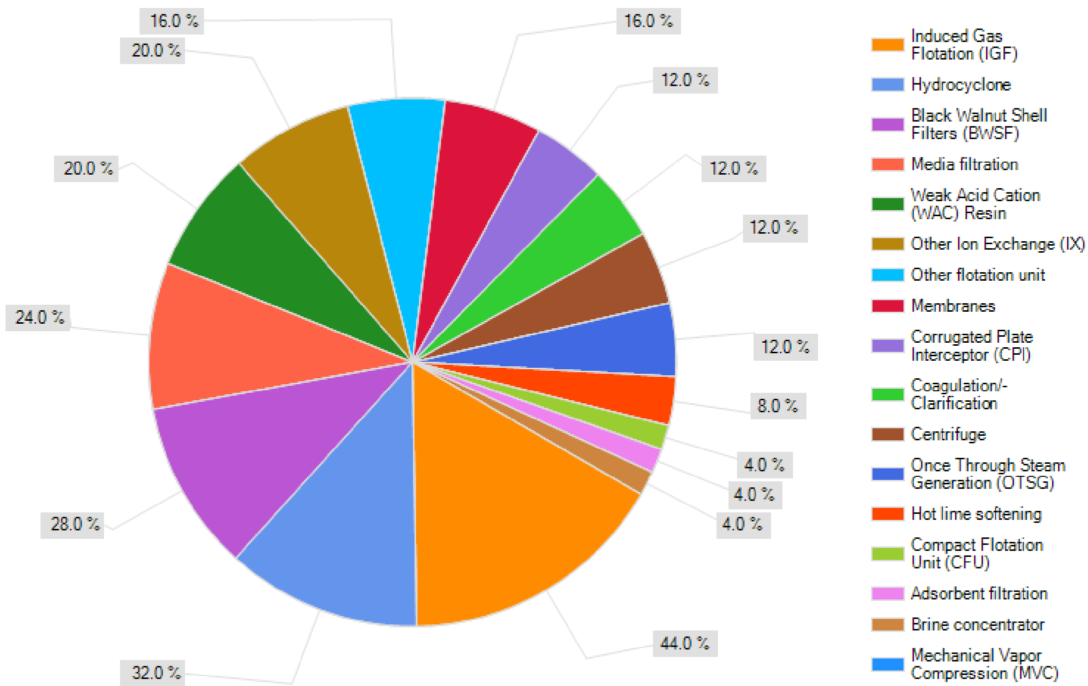

Figure 3: Survey Results – Water Treatment Unit Operations

Ranked as the most commonly used technology for produced water treatment, with over 40% of the project utilizing this technology, Induced Gas Flotation (IGF) consists of separation of oil and fine solid particles using attachment to induced gas bubbles to float contaminants to the surface. Hydrocyclones ranked second with 32% of the survey projects using this technology, which consists of separation of oil or solids from water using hydraulically induced centrifugal force from tangential input of feed. Both IGF and Hydrocyclones are impacted by polymer influences.

Third, with 28% of survey projects using this technology for produced water treatment is Black Walnut Shell Filter (BWSF), an adsorption process which easily strips oil and contaminants from water. Black walnut shell media resists fouling better than other media filters. Its performance is not expected to be impacted by CEOR chemicals.

Conclusion

Water treating in EOR is critical to achieve the desired injection water quality, as well as to ensure the back-produced waters are effectively treated with regard to the environment and the reservoir needs, if recycled. New water treating technologies are emerging but many are unproven in the challenging E&P EOR applications, and all should undergo thorough vetting and risk analysis. NOC's are playing a major role in expediting EOR projects and technology transfer is occurring more quickly than historical industry norms.

The recent survey of water treating in current water-based EOR projects indicates a wide range of technologies are being applied, with interest in newer technologies such as ceramic membranes and polymeric membranes beginning to have a showing. For back-produced water from EOR, traditional hydrocyclones and compact flotation technology is still the most popular, and due to their cost, effectiveness and compactness, their prevalence will continue with the likely addition of more sophisticated polishing technologies on their tail-end.

CEOR applications offer the most significant challenges to the water treating industry, both on the injection and back-produced water fronts. Ongoing pilot studies on numerous CEOR sites around the world will bring new technologies to light in the coming year, which will reduce CEOR risks and therefore likely foster additional growth.

Nomenclature

ASP	Alkali Surfactant Polymer
BOPD	Barrels of Oil Per Day
BWPD	Barrels of Water Per Day
BWSF	Black Walnut Shell Filter
CAPEX	Capital Expenditure
CEOR	Chemical Enhanced Oil Recovery
E&P	Exploration and Production
EOR	Enhanced Oil Recovery
EPC	Engineering, Procurement, and Construction
HLD	Hydrophilic-Lipophilic Deviation
HPAM	Hydrolyzed Polyacrylimide
IGF	Induced Gas Flotation
IOC	International Oil Company
LSI	Low Salinity Injection
MISC	Malaysian
NF	Nanofiltration
NOC	National Oil Company
OOIP	Original Oil In Place
OPEX	Operational Expenditure
RO	Reverse Osmosis
SAGD	Steam Assist Gravity Drainage
SOR	Steam to Oil Ratio

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