Abstract

A considerable portion of current world oil production comes from mature fields and the rate of replacement of the produced reserves by new discoveries has been declining steadily over the last few decades. To meet the growing need for economical energy throughout the world, the recoverable oil resources in known reservoirs that can be produced economically by applying advanced IOR and EOR technologies will play a key role in meeting the energy demand in years to come.

This paper presents a comprehensive review of EOR projects. Specifically, the paper presents an overview of EOR field projects by reservoir lithology (sandstone, carbonate, and turbidite formations) and offshore versus onshore fields. More than 1,500 field projects are reviewed and summarized to evaluate feasibility of EOR technologies. Another area of growing interest is the combination of near-well-bore and in-depth conformance technologies with chemical EOR technologies such as SP and ASP. However, these are in early stages of evaluation. Examples of numerical simulations combining chemical conformance and EOR technologies are presented showing the potential of this recovery strategy in waterflooded reservoirs. Impacts of carbon capture cost and volatility of oil and carbon-credit markets on CO₂-EOR projects based on anthropogenic sources is also addressed.

Based on this review, it is evident that thermal and chemical EOR projects dominate in sandstone formations while gas and water-based recovery methods dominate carbonate, turbidite, and offshore fields. The review also shows the growing trend of CO₂ (from natural sources), high-pressure air injection (HPAI), and chemical flooding including in-depth conformance field projects in the U.S. and abroad.

CO₂-EOR / sequestration in offshore fields and chemical EOR processes offshore (e.g., polymer-based methods) and onshore, including heavy crude oil reservoirs, are some of the opportunities identified for the next decade based on preliminary evaluations and proposed or ongoing pilot projects. The critical review will help to identify the next challenges and opportunities in EOR. Hybrid schemes combining IOR/EOR as well as CO₂-EOR/sequestration can be ranked on the basis of adequate simulation procedures.

Introduction

EOR activity has experienced an increasing interest in recent years in spite of crude oil price decline since 2008. CO₂-EOR in the Permian Basin and thermal methods, especially in Canada, continue to be the most dominant EOR field applications documented in the literature. However, chemical EOR methods have shown an increase in pilot tests and a few large field implementations including the combination of chemical EOR methods with conformance technologies.

In the U.S., chemical and thermal EOR projects have been in constant decline from the mid 1980s to 2005 (Figure 1). However, EOR gas injection projects have shown a steady trend since the mid 1980s and a growing trend since year 2000, especially with the increase of CO₂ projects. Indeed, since 2002 EOR gas injection projects outnumber thermal projects for the first time in the last three decades. However, thermal projects have shown a slight increase since 2004 due to the increase of High Pressure Air Injection (HPAI) projects in light oil reservoirs. Chemical EOR methods still have not captured a high level of interest from operating oil companies with only two projects reported in 2008 (Aalund, 1988; Bleakley, 1974, Leonard, 1982, 1984 and 1986; Matheny, 1980, Moritis, 1990, 1992, 1994, 1996, 1998, 2000, 2002, 2004, 2006 and 2008; Noran, 1976 and 1978). However, there is an increase in EOR chemical projects in the U.S. and abroad that have not been documented in the literature for different reasons that will be summarized later in the paper.

One of the reasons for the increase in U.S. EOR gas injection methods is the vast cheap sources of CO₂ from natural sources ($US 1 to 2/Mscf) and a readily available CO₂ pipeline system making CO₂ EOR projects economically attractive at
oil prices around $US 20/bbl (Manrique et al. 2007; Moritis, 2001). However, it is important to remark that the CO₂ pipeline system in the U.S. was built in a 30-yr time span (1975 to 2005) when tax incentives were in place to ensure security of supply as main drivers as reported by Hustad (2009). Figure 2 shows the evolution of CO₂ projects in the U.S. and average crude oil prices for the last 28 years. Oil prices used are the refiner average domestic crude oil acquisition cost reported by the Energy Information Administration (U.S. EIA, 2009). For reference purposes, the crude oil price used in Figure 2 was arbitrarily selected as the month of June price for each year. Although it can be concluded that CO₂-EOR (from natural sources) is a proven technology with oil prices > $20/bbl, this EOR method represents a specific opportunity in the U.S. but cannot necessarily be extrapolated to all producing basins in the world.

Figure 1. Trend of U.S. EOR projects (From Oil & Gas Journal EOR Surveys 1976 – 2008)

Figure 2. Evolution of CO₂ projects and oil prices in the U.S. (From Oil & Gas Journal EOR Surveys 1980-2008 and U.S EIA, 2009)

This paper summarizes a comprehensive review of EOR projects as part of a larger effort to evaluate actual status of field applications and potential opportunities in the near future. EOR field projects are summarized by reservoir lithology and offshore vs. onshore applications. Additionally, examples of numerical simulations combining chemical conformance and EOR technologies are also presented showing the potential of this recovery strategy based on a successful field experience reported in Argentina.
EOR by Lithology

Reservoir lithology is one of the screening variables for EOR methods limiting the applicability of specific EOR methods (Taber et al., 1997a and 1997b). Figure 3 shows that most EOR applications have been in sandstone reservoirs based on an international EOR project database containing 1,507 projects consolidated by the lead author during the last decade.

Figure 3. EOR field projects by lithology (Based on a total 1,507 international projects)

EOR in Sandstone Formations

From Figure 3, it is clear that EOR thermal and chemical methods are most frequently used in sandstone reservoirs compared to other lithologies such as carbonate and turbiditic formations. In general, sandstone reservoirs show the highest potential to implement EOR projects because most of the technologies have been tested at pilot and commercial scale in this type of lithology. Additionally, there are some fields where different EOR technologies have been evaluated successfully at pilot scale demonstrating technical applicability of different EOR methods in the same field. Carmópolis (Brazil) and Karazhanbas (Kazakhstan) are two good examples of fields with different EOR methods tested at pilot scale in sandstone formations:

- Carmópolis is an onshore heavy oil (22°API) reservoir with reported in situ-combustion (1978 to 1989), polymer flooding (1969 to 1972 and 1997), steam injection (1978), and microbial EOR or MEOR (2002) pilot projects. The field has been developed mainly by waterflooding (de Melo et al., 2005; da Silva et al., 2007; de Souza et al., 2005; Mezzomo et al., 2001; Pinto et al., 2006).
- Karazhanbas is an onshore heavy oil (19°API) reservoir with documented polymer flooding (Chakabaev et al., 1978), steam injection (Antoniadi et al., 1993; Mamedov and Bokserman, 1992), in-situ combustion and in-situ combustion with foam injection as conformance strategy (Antoniadi et al., 1993; Zhdanov et al., 1996). Karazhanbas field was developed by waterflooding, CHOPS or Cold Heavy Oil Production with Sand (Collins et al., 2008) and steam injection.

The following section provides an overview of different EOR methods implemented in sandstone formations.

Thermal Methods

Cyclic steam injection (Steam stimulation or Huff & Puff), steamflooding, and most recently Steam-Assisted Gravity Drainage (SAGD) have been the most widely used recovery methods of heavy and extra heavy oil production in sandstone reservoirs during last decades. Thermal EOR projects have been concentrated mostly in Canada, Former Soviet Union (FSU), U.S., and Venezuela. Brazil and China have also reported several EOR thermal projects but in a lesser extent.

Some examples of recent steam injection projects reported in the literature are the steamfloods in the Crude E Field in Trinidad (Ramlal, 2004), Schoonebeek oil field in Netherlands (Jelgersma, 2007), and Alto do Rodrigues in Brazil (Lacerda et al., 2008). Although some attempts have been tried to optimize steam injection processes by using solvents (Rivero and Mamora, 2007), gases (Bagci and Gumrah, 2004), chemical additives (Ovalles et al., 2001) and foams (Mendez et al., 1992) among others, few of these proposed methods have been tested in the field (Mbaba, and Caballero, 1983; Mendez et al., 1992; and Zhdanov et al., 1996). One example is the LASER (for Liquid Addition to Steam for Enhancing Recovery) process that consists of injection of C₅⁺ liquids as a steam additive in cyclic steam injection processes. Although the LASER process was tested at pilot scale in Cold Lake (Leaute, 2002) the process has not been expanded at a commercial scale. Steam injection has also been tested in medium and light oil reservoirs where crude oil distillation and thermal expansion are the main recovery mechanisms in these types of reservoirs (Perez-Perez et al., 2001). However, steam injection in medium and light oil reservoirs has not contributed with EOR production worldwide.
SAGD represents another important EOR thermal method to increase oil production in oil sands. Due to SAGD applicability in unconsolidated reservoirs with high vertical permeability (Manrique and Pereira, 2007), this EOR method has received attention in countries with heavy and extra-heavy oil resources, especially Canada and Venezuela with vast oil sands resources. However, despite SAGD pilot tests reported in China (Li-qiang et al., 2006), U.S. (Grills et al., 2002) and Venezuela (Mendoza et al., 1999), commercial applications of this EOR process have been reported in Canada only and more specifically those implemented in the McMurray Formation, Athabasca (i.e. Hangistone, Foster Creek, Christina Lake and Firebag, among others). Commercial SAGD projects in the McMurray formation validate the importance of the geology and reservoir characteristics in this EOR method as reported by Rottenfusser and Ranger (2004), Putnam and Christensen (2004) and Jimenez (2008), among others. Therefore, at the present level of understanding of the SAGD process, field experiences strongly suggest that this technology will continue to expand mainly in Athabasca’s McMurray formation, depending of course on oil prices.

Alternatives to SAGD have been proposed (i.e., Cross or X-SAGD, Fast SAGD, and single well SAGD or SW-SAGD) or using additives (i.e., ES-SAGD) as reported by Stalder (2008), Shin and Polikar (2005), Elliot and Kovscek (2001) and Govind et al. (2008), respectively. However, all the proposed methods are at early stage of evaluation and are not expected to have an impact on oil production in the near future.

In-situ combustion (ISC) projects have been the second most important recovery method for heavy crude oils in the past decades. Although there are a few ongoing ISC projects in heavy oil reservoirs such as Battrum Field in Canada (Moritis, 2008), Suplacu de Barcu, Romania (Machedon et al., 1995; Panait-Paticaf et al., 2006); Balol, Bechraji, Lanwa, and Santhal in India (Chattopadhyay et al., 2004; Doriaith et al., 2007; Moritis, 2008; Roychaudhury et al., 1997; Sharma et al., 2003); and Bellevue in the U.S. (Long and Nuar, 1982; Moritis, 2008), air injection in light oil reservoirs (referred as High Pressure Air Injection or HPAI) has gained greater attention during the last decade. Since year 2000 the number of ISC projects reported by Moritis (2008) has been steady with 10 projects in sandstone formations. At the same time the number of HPAI projects in U.S. light oil reservoir has shown an important increase during the same period. However, all these HPAI projects have been implemented in carbonate formations and will be briefly addressed in the section of Carbonate Formations.

In addition to ISC and HPAI increasing trends reported by Moritis (2008) during this decade, Duiveman et al. (2005) and Hongmin et al. (2008) documented air injection projects in Handil Field, Indonesia and Hu 12 Block, Zhong Yuan field in China, respectively. Although Handil Field HPAI pilot reported injectivity problems due to lack of reservoir communication in the pilot area, the results were reported as encouraging (Duiveman et al., 2005). On the other hand, the air injection pilot reported in Zhong Yuan field consisted of a Foam Assisted Water-Alternating-Air Injection pilot also reported encouraging results (Hongmin et al., 2008). Further examples of the increased interest in air injection is the planned ISC in Rio Preto West onshore Brazil reported by Moritis (2008) and studies reported by Hughes and Sarma (2006), Sarma and Das (2009), Teramoto et al. (2005), Onishi et al. (2007) evaluating technical feasibilities and potential of HPAI in Australia and Asia, respectively. Based on recent trends we suggest that air injection, especially in light oil reservoirs (HPAI), will continue to grow in the next decade.

Alternatives to ISC such as the “Toe-to-Heel Air Injection” or THAI” (Greaves et al., 2005; Xia et al., 2002) and CAPRI (In-situ catalytic version of THAI) (Xia et al., 2002) processes have been proposed. Both processes are at early stages of evaluation as reported by Petrobank Energy and Resources Ltd. (PETROBANK 2010a and 2010b). Results of this project might be available this or next year to confirm its EOR potential in oil sands and its potential applicability in other type of heavy oil reservoirs. Therefore, THAI is not expected to have an impact on EOR production in the near future. As usual, crude oil price volatility will continue to play a key role in justification of further THAI pilot tests. With regard to CAPRI processes, current competing surface upgrading technologies (i.e., Long Lake Canada) may not justify the use of hydro-treating catalyst or costly hydrogen donors without having operational experiences with THAI.

**Chemical Methods**

EOR chemical methods were at their historic peak in the 1980s, most of them in sandstone reservoirs (Needham and Doe, 1987). Total active projects peaked in 1986 with polymer flooding being the most important chemical method of EOR (Figure 1). However, since the 1990s oil production from EOR chemical methods has been negligible around the world except for China (Chang et al., 2006a; Delamaide et al., 1994; Han et al., 1999; Li et al., 2009a and 2009b; Wang et al., 2002; Wang et al., 2009a and 2009b; Xiaoqin et al., 2009). Nevertheless, chemical flooding has been shown to be sensitive to volatility of oil markets despite recent advances (i.e., low surfactant concentrations) and lower costs of chemical additives.

Polymer flooding needs to be considered as a mature technology and still the most important EOR chemical method in sandstone reservoirs based on the review of full field case histories. It is important to remark that this paper does not consider near well bore treatments (i.e., gels and polymer-gels) as EOR processes because these types of treatments are out of the scope of this review. Based on the EOR survey presented by Moritis (2008) there are ongoing pilots or large scale polymer floods in Argentina (El Tordillo Field), Canada (Pelican Lake), China with approximately 20 projects (i.e., Daqing, Gudao, Gudong and Karamay Fields, among others), India (Jhalora Field), and the U.S. (North Burbank). It is important to mention that a commercial polymer flood was developed in North Burbank during the 1980s (Moffitt and Mitchell, 1983) demonstrating that this EOR method may still have potential to increase oil recovery in mature basins. North Burbank reinitiated polymer flooding on a 19 well pattern in December 2007 (Chaparral Energy Inc., 2009). Other countries with reported polymer flooding projects include Brazilian Carmopolis, Buracica, and Canto do Amaro Fields (Shecaira et al.,...
Colloidal Dispersion Gels (CDGs) and BrightWater® also represent novel polymer based technologies that are currently under evaluation at field scale. Although these technologies are quite different from the technical standpoint both are meant to improve volumetric sweep efficiency in a mature waterflood, especially in reservoirs with high permeability contrast and presence of thief zones. Documented CDG’s projects include Daqing Field in China (Chang et al., 2006a; Chang et al., 2006b; Mack, 2005), and the El Tordillo (Diaz et al., 2008) and Loma Alta Sur (Muruaga et al., 2008) Fields in Argentina, among others (Fielding et al., 1994; Mack and Smith et al., 1994). Regarding BrightWater® (Frampton et al., 2004) at the present time Milne Point in Alaska is the only field application discussed or documented in the public domain (Ohms et al., 2009; Puckett, 2009). However, it is expected that the number of CDGs and BrightWater® field applications will increase in the near future based on recent field and laboratory studies underway opening a new window of opportunities for EOR chemical methods (Frampton et al., 2009; Mustoni et al., 2010; Pritchett et al., 2003; Spildo et al., 2009).

While polymer flooding has been the most applied EOR chemical method in sandstone reservoirs (Manning et al., 1983), the injection of alkali, surfactant, alkali-polymer (AP), surfactant-polymer (SP) and Alkali-Surfactant-Polymer (ASP) have been tested in a limited number of fields (Figure 1). Micellar polymer flooding had been the second most used EOR chemical method in light and medium crude oil reservoirs until the early 1990s (Lowry et al., 1986). Although this recovery method was considered as a promising EOR process during the 1970s, the high concentrations and cost of surfactants and co-surfactants, combined with the low oil prices during mid 1980s limited its use. The development of ASP technology since mid 1980s and the development of surfactant chemistry have brought a renewed attention for chemical floods in recent years, especially to boost oil production in mature and waterflooded fields.

Several EOR chemical floods, other than polymer floods, have been widely documented in the literature during the last two decades. However, at the present time Daqing field represents one of the largest, if not the largest, ASP flood implemented as of today. ASP flooding has been studied and tested in Daqing for more than 15 years though several pilots of different scales (Chang et al., 2006a; Demin et al., 1999; Hongfu et al., 2003; Pu and Xu, 2009). Gudong (Qu et al., 1998), Karamay (Gu et al., 1998; Qiao et al., 2000), Liaohoe, and Shengli (Chang et al., 2006) fields are other examples of Chinese ASP projects documented in the literature. Additional EOR chemical flooding reported during the last decade includes:

- ASP flooding in Viraj field, India (Pratap and Gauma, 2004) and West Kielh (Meyers et al., 1992), Sho-Vel-Tum (French, 1999), Cambridge Minnelusa Field (Vargo et al., 2000), and Tanner (Pitts et al., 2006) fields in the U.S.
- AP flooding in Xing Long Tai Oil Field (Zhang et al., 1999), China and David Pool, Canada (Pitts et al., 2004).

Based on the EOR survey presented by Moritis (2008) there are ongoing ASP pilots in Delaware Childers field (Oklahoma) as well in Lawrence field (Illinois) and also refers to planned ASP floods in Lawrence field, Midland Farm Unit (Texas), Nowata field (Oklahoma), and an SP flood in Minas Field, Indonesia (Bou-Mikael et al., 2000). However, the number of ASP and SP floods is much higher than the ones reported in the literature as well the EOR survey presented by Moritis (2008) because operators do not necessarily respond to this survey. Authors of this paper are aware of ongoing projects in the U.S. and Canada not published in the literature (ZARGON, 2009). Additionally, there are several projects in Argentina, Canada, India, and the U.S. under reservoir and lab evaluations with pilot projects scheduled between 2010 and 2011. Therefore, despite the volatility of oil prices, it is fair to conclude that operators are showing a growing interest on EOR chemical flooding. This trend is also supported by the increase of screening studies to evaluate or re-estimate EOR potential of chemical flooding in different basins (Alvarado et al., 2008; Costa et al., 2008; Fletcher and Morrison, 2008; Pandey et al., 2008).

**Gas Methods**

EOR gas flooding has been commonly used as recovery method for light, condensate, and volatile oil reservoirs. Although nitrogen (N₂) injection has been proposed to increase oil recoveries under miscible conditions favoring the vaporization of light fractions of light oils and condensates, today few N₂ floods are ongoing in sandstone reservoirs. Immiscible N₂ floods are reported in Hawkins Field (Texas) and Elk Hills (California) based on the Moritis EOR survey (2008). No new N₂ floods in sandstone reservoirs have been documented in the literature during the last few years and we do not foresee an increment in the number of projects implementing this EOR gas flooding method.

Similarly than N₂ injection, hydrocarbon gas injection projects onshore sandstone reservoirs have made a relatively marginal contribution in terms of total oil recovered in Canada and the U.S other than on the North Slope of Alaska where large natural gas resources are available for use that do not have a transportation system to markets. It is important to mention that in this paper we refer to EOR hydrocarbon gas methods as those using hydrocarbon gases in Water-Alternating-Gas (WAG) injection schemes, including enriched hydrocarbon gases, or solvents, and combinations. Therefore, hydrocarbon gas injection as pressure maintenance or double displacement strategies are not considered as EOR methods for purposes of this review. Most of immiscible and miscible EOR hydrocarbon gas floods in the U.S. are on the North Slope of
Alaska (Moritis, 2008; Panda et al., 2009; Rathman et al., 2006; Redman, 2002; Shi et al., 2008) while in Canada a miscible gas flood is reported in Brassey field (Moritis, 2008). The situation of hydrocarbon gas injection projects is different in offshore sandstone reservoirs (Christensen et al., 2001). However, this will be addressed later in the paper. In general, if there is no other way to monetize natural gas, then a more practical use of natural gas would be to use it in pressure maintenance projects or in WAG processes. However, and if available, the substitution of hydrocarbon gases by non-hydrocarbon gases (N₂, CO₂, acid gas, air) oil recovery will make more natural gas available for domestic use or export while still maintaining reservoir pressure and increasing oil recoveries. Despite actual low natural gas prices the continuous increase in energy demand will likely affect the viability of new large-scale hydrocarbon gas projects.

On the other hands, CO₂ flooding has been the most widely used EOR recovery method of medium and light oil production in sandstone reservoirs during recent decades, especially in the U.S., due to the availability of cheap and readily available CO₂ from natural sources. Figure 2 clearly show an increasing trend of CO₂ flood projects in the U.S during the last decade in both, sandstone and carbonate reservoirs. The number of CO₂ floods is expected to continue to growth in U.S. sandstone reservoirs. Some examples of planned CO₂ EOR projects in the U.S. include Cranfield, Heidelberg West and Lazy Creek fields in Mississippi, and Sussex field in Wyoming (Moritis, 2008). The number of CO₂ floods in Wyoming sandstone reservoirs are also expected to increase based on a recent evaluation presented by Wo et al. (2009). Additionally, Holtz (2008) recently reported an overview of sandstone U.S. Gulf Coast and Louisiana CO₂ EOR projects to estimate EOR reserve growth potential in the area including sandstone reservoirs in the Gulf of Mexico. CO₂-EOR in the U.S. has shown a vast potential to increase oil recoveries and has been widely documented in the literature. Therefore, the present review will address briefly activities reported outside the U.S.

Some examples of CO₂-EOR field projects in sandstone formations presented in various conferences and/or documented in the literature are summarized below:

- Brazil reports CO₂ floods in Buracica and Rio Pijuca fields (Dino et al., 2007; Moritis, 2008) and announced a CO₂ flood in Miranga field from anthropogenic sources as an EOR and carbon storage strategy (Dino et al., 2007; Guedes, 2008).
- Canada reports CO₂ floods in Joffre and Pembina fields (Moritis, 2008; Stephenson et al., 1993). Operators and government institutions of Canada have been very actively evaluating EOR CO₂ potential during the last decade (Bachu et al., 2000; PTAC, 2003). Recently PTAC (Petroleum Technology Alliance of Canada) estimated an up-side potential for CO₂-EOR in Alberta of 3.6 billion barrels over the next two decades at oil prices of $45/bbl (Byfield, 2009).
- Croatia reported CO₂ pilot injection at Ivančić field injecting CO₂ transported by trucks. Pilot results (2001 to 2006) contributed to define larger application of CO₂ EOR in the country considering the use of CO₂ from anthropogenic sources (Domitrović et al., 2004; Novosel, 2005 and 2009).
- Hungary also reports more than four decades experience in CO₂-EOR floods. CO₂ projects at Budafá and Lovvaszi fields are two cases well documented in the literature (Doleschall et al., 1992). Szank oil field represents a more recent CO₂ EOR flood in Hungary using CO₂ from a sweetening plant (Remenyi et al., 1995).
- Trinidad also has more than three decades experience operating CO₂-EOR projects using CO₂ from an ammonia plant nearby the fields (Mohammed-Singh and Singhal, 2004). Moritis EOR survey (2008) reports up to nine (9) active immiscible CO₂ floods operating since mid 1970s.

As can be seen, CO₂-EOR has become one of the preferred EOR processes globally using CO₂ from natural and industrial sources. Mexico (Bauer, 2006; Muro et al., 2007) and the U.S. (Kulkarni et al., 2008; Wo et al., 2009) are just tow of the countries evaluating CO₂ sources and EOR potential in mature fields and mature CO₂ floods (Senocak et al., 2008). However, this will be further discussed in the section of EOR gas methods in carbonate formations.

**EOR in Carbonate Formations**

It is well known that a considerable portion of the world’s hydrocarbon endowment is in carbonate reservoirs. Carbonate reservoirs usually exhibit low porosity and may be fractured. These two characteristics along with oil wet-to-mixed wet rock properties usually result in lower hydrocarbon recovery rates when compared to sandstone reservoirs. When EOR strategies are pursued, the injected fluids will likely flow through the fracture network and bypass the oil in the rock matrix. The high permeability in the fracture network and the low equivalent porous volume frequently results in early breakthrough of the injected fluids.

A large number of EOR field projects in carbonate reservoirs have been referenced in the literature during the last decades. Although these field projects demonstrate the technical feasibility of various EOR methods in carbonate reservoirs, gas injection (continuous or in a WAG mode) are still the most common EOR process implemented in this type of lithology (Figure 3). Polymer flooding is the only proven EOR chemical method in carbonate formations while EOR thermal methods have made a relatively small contribution in world’s oil production from carbonate reservoirs. However, High Pressure Air Injection (HPAI) projects have been steadily increasing in recent years, especially in light oil carbonate reservoirs in the U.S. (Manrique, 2009).
Manrique et al. (2007) presented a comprehensive review of EOR field experiences in U.S. carbonate reservoirs. Although this review was specific for U.S. carbonate formations, it can be considered representative to estimate technical feasibility and potential of EOR processes in this type of reservoirs based on valuable field experiences documented in the literature. Alvarez et al. (2008) recently documented a literature review of field experiences specifically in heavy oil carbonate reservoirs including several pilot tests carried out in the Grosmont formation in Canada during 1970s and 1980s (i.e., Chipewyan River, Buffalo Creek, McLean, Orchid, Saleski and Algar). Therefore, following section will provide a general overview of different EOR methods implemented in carbonate formations around the world complimenting recent review’s documented in the literature.

**Thermal Methods**

Thermal EOR projects have not been popular in carbonate formations. Neither cyclic nor continuous steam injection have been widely use in carbonate reservoirs. The Garland Field in Wyoming and Yates Field in Texas represent two of the few steam drive projects in carbonate formations documented in the U.S (Dehghani and Ehrlich, 1998; Manrique et al., 2007).

Steam injection in carbonates has been mostly tested at small scale. Few examples include Lacq Supérieur, France,(Perez-Perez et al., 2001; Sahuquet and Ferrier, 1982; Sahuquet et al., 1990), Ikiztepe Field, Turkey, (Nakamura et al., 1995), Cao-32 Field, China, (Zhou et al., 1998), Issaran Field, Egypt, (Buza, 2008; Waheed et al., 2001) and Wafra Field, Partitioned Neutral Zone in Saudi Arabia and Kuwait (Buza, 2008; Barge et al., 2009). The only full field steam flooding operations announced in the near future is at Qarn Alam Field in Oman (Macaulay et al., 1995; Moritis, 2008; Penney et al., 2005 and 2007). Oman also announced steam injection project in limestone Fahud field among other steam pilots (Moritis, 2008). Therefore, steam injection in Oman fields may contribute to define future of steam injection in carbonate formations.

On the other hand, air injection projects in carbonate formations have shown a steady increase since 2000, especially HPAI projects in U.S. light oil reservoirs (Figure 4). To date, eleven (11) HPAI projects in light oil (> 30°API) in U.S. carbonate reservoirs in Montana and in North and South Dakota (Moritis, 2008). South and West Buffalo, and Medicine Pole Hill in North and South Dakota are good examples of combustion projects in light crude oil dolomitic formations (Manrique et al., 2007). The Buffalo field (North Dakota) started air injection approximately three decades ago and projects are still in operation (Gutiérrez et al., 2008; Kumar et al., 2008). The success and expansion of Buffalo and Medicine Pole Hill have contributed to the increase of HPAI projects in the area. Although all HPAI reported by Moritis (2008) in Montana, North and South Dakota have been developed in the same low permeability dolomitic formation (Red River A, B and/or C), air injection has proven to have high potential to improve oil recovery and revitalize both mature and waterflooded carbonate reservoirs (Gutiérrez et al., 2008; Moore et al., 2002). This will be especially true in fields located in remote locations with no access to CO$_2$ sources.

![Figure 4. Trend of air injection projects (From Oil & Gas Journal EOR Surveys 2008)](image)

There is no doubt risk perception of air injection processes is still part of our industry. However, actual HPAI projects in U.S. carbonate reservoirs are demonstrating that risks can be controlled and are economically attractive. Mexico is one example of countries evaluating air injection processes in naturally fractured carbonates given that most of its production and reserves are coming from this reservoir type. Mexico announced a potential HPAI project in The Cárdenas field, onshore light oil (40 °API) fractured carbonate reservoir located in the South Region of the Chiapas-Tabasco basin (Rodriguez and Christopher, 2004). Therefore, production results from recent air injection projects in the U.S. (Williston Basin) and potentially the pilot project in Cardenas Field (Mexico) are likely to dictate the future of this recovery method in carbonate reservoirs in the U.S. and abroad.
**Chemical Methods**

Polymer flooding is the only proven chemical EOR technology and has been conducted mostly at early stages of waterflooding, in carbonate reservoirs (Figure 3). However, carbonate reservoirs have made a relatively small contribution to polymer flooding in terms of total oil recovered in the U.S. (Manrique et al., 2007). With today’s technology Alkali-Polymer (AP), Surfactant-Polymer (SP) and Alkali-Surfactant-Polymer (ASP) floods are applicable to sandstone reservoirs only. As of date, no chemical flooding (other than polymer flooding) in carbonate reservoirs have been reported in the literature reviewed. However, ASP has been tested in carbonate formations at a lab level in Arab-D (Al-Hashim et al., 1996), Upper Edward’s (Manrique et al., 2007) and elsewhere (Bortolotti et al., 2009) core samples. Alkali-Surfactant single well test has been reported in the Mauddud carbonate reservoir in Bahrain as part of ASP feasibility studies in oil-wet limestone reservoirs (Zubari and Sivakumar, 2003).

Surfactant injection in the only chemical method used recently as a wells stimulation and wettability modification of carbonate reservoirs. In fractured reservoirs, spontaneous water imbibitions can occur from the rock matrix into fractures. Subsequently, this mechanism leads to oil drainage from the matrix towards the fracture network, making surfactants attractive to improve oil recovery in oil-wet carbonate reservoirs by changing rock wettability (to mixed / water wet) and promoting the imbibition process. Given the vast quantity of the world's oil reserves contained in carbonate reservoirs, chemically-assisted methods (i.e., spontaneous imbibition, wettability modifiers, and ITF reductions) based on surfactant injection represents an active research area as a strategy to improve oil recovery in carbonate formation (Adibhatia and Mohanty, 2007; Delshad et al., 2009; Haugen et al., 2008; Mohanty, 2006; Najafabadi et al., 2008; Tabary et al., 2009; Webb et al., 2005). However, as of today no large field application has been documented in the literature.

Based on present status of the technology, EOR chemical methods are not expected to make an important contribution in oil production from carbonate reservoirs during the next one or two decades. However, chemically based gas and water shut-off strategies (i.e., gels and foams) will continue to contribute optimizing water, gas, or WAG projects in carbonate reservoirs in the near future (Al-Dhaffaeri et al., 2008; Al-Taq et al., 2008; Hirasaki et al., 2006; Kumar et al., 2007; Portwood, 2005; Sengupta et al., 2001; Smith et al., 2006).

**Gas Methods**

EOR gas flooding have been the most widely used recovery methods of light, condensate, and volatile oil carbonate reservoirs. Figure 3 clearly shows that gas injection have been the EOR method mostly applied in carbonate formations compared to EOR chemical and thermal methods.

Nitrogen (N2) flooding has been an effective recovery process for deep, high-pressure, and light oil reservoirs. Generally for these types of reservoirs, nitrogen flooding can reach miscible conditions. However, immiscible N2 injection also has been used for pressure maintenance, cycling of condensate reservoirs, and as a drive gas for miscible slugs (Manrique et al., 2007). Although over the last four decades several N2 injection projects have been reported in carbonate reservoir in the U.S., Moritis (2008) reports only one miscible WAG-N2 in Jay LEC (Lawrence et al., 2002). However, more recently the operator announced a temporary suspension of production at the Jay Field (SEC, 2009). Outside the U.S., Cantarell is the only representative N2 injection project ongoing in an offshore carbonate field well documented in the literature (Sánchez et al., 2005). No new N2 floods in carbonate reservoirs have been documented in the literature during the last few years and we do not foresee an increment in the number of projects implementing this EOR gas flooding method but in Campeche Bay Area in the Gulf of Mexico (GOM) in Mexico. The number of projects in this area (i.e., KMZ) is expected to grow in the near future given the availability of N2 generation capabilities in the region. High capital (i.e., Air Separation Units) and operational (i.e., N2 Rejection Units, if required) cost associated to N2 injection has reduced the interest of this recovery process in recent years. Additionally, with recent successes and field expansions reported in Montana, North Dakota and South Dakota, HPAI (High Pressure Air Injection) has surged as a potential option with lower capital and operational costs than miscible N2 floods. However, N2 injection still represents an option that can be justified for high pressure and high temperature (HP/HT) light oil reservoirs if there is no access to other gas sources (Mungan, 2000).

Similar to N2 injection, hydrocarbon gas injection projects in onshore carbonate reservoirs have made a relatively marginal contribution in terms of total oil recovered in Canada and the U.S. (Manrique et al., 2007; Moritis, 2008). Some examples of the hydrocarbon miscible flooding (continuous injection or in WAG mode) ongoing or under evaluation in carbonate formations that have been documented are reported in Canada, the Middle East, and offshore carbonate formations (Al-Bahar et al., 2004; Christensen et al., 2001; Edwards, 2002; El Mahdi et al., 2007; Gomes et al., 2002; Mijnssen et al., 2003; Moritis, 2008; Schneider and Shi, 2005). If there is no other way to monetize natural gas, then a more practical use of natural gas would be to use it in pressure maintenance projects or in WAG processes while new business opportunities becomes available. This development strategy will contribute preserving reservoir energy maximizing oil recovery with an upside potential of monetize natural gas through reservoir depressurization strategies late in reservoir life (i.e., reservoir blowdown or depressurization).

CO2-EOR has been successfully implemented in both mature and waterflooded carbonate reservoirs (Manrique et al., 2007; Moritis, 2008). CO2 flooding from natural sources has been the most important EOR process in the U.S. and particularly in carbonate reservoirs of the Permian Basin. Moritis (2008) reported 105 active CO2 floods in the U.S. with 63 of the projects in carbonate formations, mainly in the Permian basin of Texas. The popularity of CO2 projects is closely related to the abundant availability of natural sources of CO2 and associated CO2 transporting pipelines that are generally
located close to the oilfields (Hustad, 2009; Manrique et al., 2007). CO₂-EOR in U.S. carbonate reservoirs is expected to continue to grow (Figure 2) based on natural sources of CO₂. If CO₂ flooding is to increase, non-natural sources will need to be incorporated at competitive costs. In simple terms, if CO₂ is available it will remain the most sound recovery choice for carbonate reservoirs unless more viable EOR strategies are developed. Canada (i.e., Enchant Midale, Judy Creek, Swan Hills and Weyburn) and Turkey (i.e., Bati Raman) also reports CO₂-EOR projects in carbonate formations well documented in the literature (Asghari et al., 2007; Karaoguz et al., 2007; Louie, 2009; Moritis, 2008; Sahin et al., 2008).

On the other hand, climate change has been an issue of intense discussion over the last decade. Despite strong debate within the scientific community as to whether or not global warming is linked to population growth and industrial development, the international community is proactively trying to secure resources to meet future energy demands while simultaneously restricting emissions of CO₂ and other greenhouse gases generated by current energy production (Hamilton, 2009). This topic has been overwhelmingly documented in the literature. Thus, this review will not try to provide an extensive list of references related to this topic. The objective is to highlight that CO₂-EOR has become as an attractive CO₂ storage method within the options currently available. However, it is important to note that storage capability of CO₂ in oil and gas reservoirs is limited (Manrique and Araya, 2008). Additionally, actual capture, compression and transportation costs combined with the lack of proper regulatory framework among other issues (i.e., public perception), we do not foresee an important increase in the number of projects implementing CO₂-EOR from anthropogenic sources in the near future.

Finally, acid gas (mixture of H₂S and CO₂) injection has been also reported as an injectant for EOR applications in carbonate formations. Zama field (Canada), Tengiz field (Kazakhstan), and Harweel (Oman) are a few examples of carbonate reservoirs with ongoing or planned sour or acid gas injection as EOR strategies (Abou-Sayed et al., 2005; Longworth et al., 1996; Moritis, 2008; O’Dell et al., 2006).

EOR: Offshore vs. Onshore

EOR in offshore fields are not only constrained by reservoir lithology, as was described earlier in the paper, but also by surface facilities and environmental regulations, among other factors (Bondor et al., 2005; Manrique, 2009; ORME, 2009). Therefore, EOR applicability in offshore fields is limited compared to onshore fields. Main drainage strategy of offshore fields has been pressure maintenance by gas and water injection. Figure 5 shows the distribution of oil recovery projects in the North Sea (Awan et al., 2008; Jayasekera and Goodyear, 2002; Jethwa et al., 2000; Talukdar and Instefjord, 2008) as well as EOR opportunities in offshore Malaysia (Hamdan et al., 2005; Nadeson et al., 2004; Samsudin et al., 2005; Selamat et al., 2005; Sudirman et al., 2007).

On the other hand, oil production in the U.S. Gulf of Mexico (GOM) is mainly supported by water and/or gas injection (Harun et al., 2008; Liu et al., 2008; MMS, 2005). Despite environmental conditions in the area (e. g., hurricane seasons) oil production from deep waters in GOM is expected to continue to increase in the future but based on conventional recovery methods rather than EOR projects (Close et al., 2008; Iledare, 2008; Poll et al., 2009; Watson and Johnson, 2006). Mexico is another location where offshore reservoirs are supported by gas injection, bottom water drive, and/or water injection. Regarding gas injection it is important to note that Cantarell/Akal represents the largest N₂ injection project in the world (Cruz et al., 2009; Daltaban et al., 2008; Sánchez et al., 2005).

Similar to previous examples, most offshore environments are under continuous optimization strategies of gas and waterflooding to extend field production life and maximize oil recovery (Awan et al., 2008; Beltrão et al., 2009; Daltaban et al., 2008; Huseby et al., 2008; Lindeloff et al., 2008; Monahan, 2009; Tealdi et al., 2008). There are multiple initiatives or EOR methods tested or that has been proposed for offshore fields; however, only a few examples will be summarized in this review:
- CO₂ EOR / Sequestration have been proposed during the last decade (Awan et al., 2008; Gaspar et al., 2005; Hustad, 2009; Imbus et al., 2006; Xiang et al., 2008). CO₂-EOR, from produced gas, has been tested in Dulang Field, Malaysia (Nadeson et al., 2004).
- High-pressure air injection (HPAI) has been proposed (e.g., Ekofisk, North Sea) but has not yet been tested for technical and economical reasons (Adetunji et al., 2005; Stokka et al., 2005). Mexico has also considered the potential of air injection in offshore fields (Rodriguez and Christopher, 2004).
- Although field applications of chemical EOR methods in offshore fields have not been widely documented in the literature, a few examples are:
  - FAWAG (Foam Assisted WAG) to improve gas mobility control based on a chemical method was successfully tested in Snorre Field, Norwegian North Sea (Awan et al., 2008; Blaker et al., 2002).
  - Single-well Alkali-Surfactant-Polymer (ASP) combined with single-well partitioning tracers before and after the ASP injection was successfully evaluated in Lagomar Field, Maracaibo Lake, Venezuela (Hernandez et al., 2002; Manrique et al., 2000).
  - Single-well Alkali-Surfactant (AS) combined with single-well partitioning tracers before and after the AS injection was successfully evaluated in Angsi Field, offshore Terengganu, Malaysia (Othman et al., 2007).
- Polymer flooding has gained recent interest for offshore EOR applications including the injection of Colloidal Dispersion Gels or CDG (de Melo et al., 2005; Moritis, 2008; Spildo et al., 2009).

Although there are several initiatives to evaluate EOR potential in offshore fields, most of them are at early stages of evaluation or might not be economically attractive with the current technology. Therefore, it is not expected that commercial applications of EOR methods are likely to take place for at least a decade or two. Surface facility constraints and environmental regulations (e.g., chemical additives for EOR) also represent a major hurdle for large EOR applications in offshore fields. Offshore EOR projects are capital-intensive projects, and, coupled with the volatility of energy markets, the probability of EOR implementation in offshore fields in the short term is expected to be low. Therefore, waterflooding and gas injection and its combination (e.g., WAG) processes combined with injection profile modification and/or gas or water shut-off (i.e., foams, gels, and in-depth gel treatments such as BrightWater®) strategies will continue to support offshore production in the near future.

**Combination of Chemical EOR Technologies**

The benefits of injection profile modification, either gas or water shut-off using foams, or gel treatments (Zhdanov et al., 1996) for optimizing recovery processes such as waterflooding (Montoya et al., 2010), WAG (Awan et al., 2008; Hughes, et al., 1999), air injection (Hongmin et al., 2008), and steamflooding (Mendez et al., 1992), and combinations of these processes are well documented. However, the combined use of these conformance technologies with chemical EOR methods is not widely spread in the field. The use of this hybrid approach has gained interest in recent years especially after field pilot results in El Tordillo Field, Argentina (Muruaga, et al., 2008).

Authors of this paper are involved in several field evaluations to solve water-channeling (conformance) issues prior to EOR chemical flooding including CDGs, SP, and ASP as a strategy to optimize sweep efficiency and increase recovery factors. However, these studies are ongoing evaluations not amply documented in the literature, except for the El Tordillo Field case. The El Tordillo Field pilot project combined the injection of gel treatments in injectors to reduce water channeling and modify injection profiles followed by CDG injection in two well patterns at approximately 80 acre well spacing. In November 2005, 15,000 and 12,000 barrels of gels were injected at the injection wells I-1 and I-2, respectively. Gel treatments showed immediate response arresting the oil-decline rate before the treatment. In July 2006, CDG injection started and was sustained for a period of nine months (until April 30, 2007). Oil production rate increased very rapidly and then stabilized for several months. At the time of the pilot project evaluation in 2008, the incremental oil reserves from the project were estimated approximately at 50,000 m³ (> 300,000 bbl of oil) at about $4.00 per incremental barrel (Muruaga, et al., 2008). As of today, the project is performing better than originally predicted and the operator is expanding the project at larger scale combining both technologies gel treatments and CDG.

To show the benefits of the combination of gel treatments with different chemical EOR methods a simple numerical 5-spot model was generated with all wells completed in all layers. The model has a total of 10,206 grid blocks (27x27x14) with a grid block size of 35x35x6 ft. Fluid and reservoir properties and general characteristics of the model are summarized in Figure 6 and Table 1. Average reservoir permeability was set in 100 mD. A thief zone, 6 ft thick (divided in three layers of 2 ft thick each) was created between the injector (I1) and producer P3 with an average permeability of 3,743 mD (Figure 6). Simulation cases presented in this example include:

- Primary production for a period of 7 years followed by water injection.
- Gel treatment completed in injector (I1) after 2.4 years of water injection. Gel treatment was approximately 6,600 bbl.
- Chemical flooding (CDG or SP) 3 months after gel treatment at the injector (I1). To demonstrate the importance of correcting water injection profile in the reservoir conformance one case of SP flooding was run without a gel treatment at the injector.
All chemical EOR processes evaluated consider a total injected slug of 0.2 PV followed by waterflooding. The gel volume injected was assumed 50% (approx. 6,600 bbl) of the total volume of the thief zone in the model. Volume of the thief zone was also estimated from the production history data (WOR vs. Cumulative oil) obtaining similar results (Less than 1% difference). For simplicity, the gel treatment in the simulation was implemented using permeability (transmissibility) reduction in the thief zone. Additionally, conditions used for CDG, and SP injections were also based on average formulations available from previous laboratory experiences. This approach has proven to be very effective when laboratory data are not available and provides valuable information and guidance for decision-making processes before costly and time consuming studies are justified.

The model was initialized at a reservoir pressure of 600 psi. The injector (I1) was controlled at 1,000 bbl/day and bottom hole pressure (BHP) of 1,100 psi, assuming a frac gradient of 0.7 psi/ft. All producers were controlled using a total fluid production of 2,500 bbl/day with a BHP of 100 psi.

Assuming the conditions summarized earlier, primary production was started Jan. 1, 1990 and continued until Dec. 31, 1996. Water injection was started Jan. 1, 1997 and by April 30, 1999 the water cut in producer P3 was approximately 95%, while the water cut in the remaining producers was below 50%. The thief zone generated in the model clearly showed severe water channeling. The injection profile of injector (I1) showed that approximately 83% of the water was flowing through the thief zone. At this time a gel treatment was started to modify water injection profile (May 1999). Three months after the gel treatment different chemical EOR processes were evaluated to evaluate the potential for increment oil recovery factors.

Table 1. Basic model characteristic and properties

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Area</td>
<td>21.3 acres</td>
</tr>
<tr>
<td>Well spacing (Inj. – Prod.)</td>
<td>200 m</td>
</tr>
<tr>
<td>Thickness</td>
<td>61 ft</td>
</tr>
<tr>
<td>Average Permeability</td>
<td>100 mD (30 to 130 mD)</td>
</tr>
<tr>
<td>Kv/Kh</td>
<td>0.1</td>
</tr>
<tr>
<td>Average Porosity</td>
<td>0.19 (0.17 – 0.21)</td>
</tr>
<tr>
<td>Av. Initial water Sat. (Swi)</td>
<td>0.35 (0.26 – 0.45)</td>
</tr>
<tr>
<td>Total Pore Volume</td>
<td>10.99 MMf³</td>
</tr>
<tr>
<td>OOIP</td>
<td>1,238 Mbbl</td>
</tr>
<tr>
<td>Reservoir Temperature</td>
<td>70°F</td>
</tr>
<tr>
<td>Oil Density</td>
<td>53.83 lb/ft³</td>
</tr>
<tr>
<td>Bubble Point Pressure (Pb)</td>
<td>139 psi</td>
</tr>
<tr>
<td>Oil Viscosity @ Pb</td>
<td>9.4 cp</td>
</tr>
<tr>
<td>Dead Oil Viscosity</td>
<td>15 cp</td>
</tr>
<tr>
<td>GOR</td>
<td>50 ft³/bbl</td>
</tr>
</tbody>
</table>

Figure 7 shows incremental oil recovery factors and water-oil-ratios vs. cumulative oil production obtained for different recovery strategies compared to waterflooding. These results assume gel treatment is permanent, while in reality different or additional gel treatments over time might be necessary to keep the diversion in place. However, if preliminary economics does not shows enough potential under this optimistic scenario (permanent gel treatment effects) the proposed recovery strategies can be discarded at early stages of evaluation. If economics looks promising incorporate costs for multiple gel treatments (i.e. one gel treatment every two years) is recommended. Again, this approach has proven to be very effective for IOR/EOR evaluation under budget and time constraints.
Results clearly show the importance of a gel treatment to keep the diversion in place optimizing displacement efficiency and final recoveries of SP flooding (Figure 7a). The combination of gel treatments to modify water injection profile and SP flooding not only increment oil recoveries but also reduce water production (Figure 7b) and most importantly the production and final recoveries of SP flooding (Figure 7a). The combination of gel treatments to modify water injection profile and SP channeling justifying the combination of gel treatments and CDG with successful results.

In this particular example it can be noticed that gel treatments followed by CDG (Polymer flood as well but not shown in the figure) does not generate incremental recovery factors that justify the combination of both technologies. This result shows the importance of assessing the remaining oil saturation to justify the combination of gel treatment with polymer-based chemical flooding such as polymer flooding or CDG injection. This was not the case for El Tordillo Field in Argentina, where detailed reservoir analysis demonstrated the presence of important unswept areas due to severe water channeling justifying the combination of gel treatments and CDG with successful results.

There are other EOR strategies under evaluation in lab and by simulation combining EOR technologies such as CDG and ASP or SP (A/SP) that may lead to a new hybrid EOR schemes in waterflooded reservoirs with high permeability contrast. However, the understanding of chemical interaction of surfactants with microgels is still at early stages of evaluation (Al-Manasir et al., 2009).

Finally, the proposed evaluation methodology has been used for different IOR/EOR evaluations including CO2-EOR/sequestration (not included in this paper) to rank EOR opportunities on the basis of adequate screening and different simulation procedures as described by Manrique et al. (2009).

Conclusions

Thermal methods, specifically steam injection, still dominate as the preferred EOR method for heavy oil reservoirs. As of today, SAGD seems to be a technology only applicable to Canadian Oil Sands and more specifically in the McMurray formation. High-pressure air injection (HPAI) represents one of the thermal recovery processes showing an increased interest in recent years in both carbonate and sandstone formations. However, HPAI field projects are still concentrated in the low permeable dolomitic Red River formation of Montana and North and South Dakota. Lack of understanding and dissemination of information regarding HPAI designs and risk mitigation have been probably responsible for the limited number of cases deployed as full-field projects, despite significant success in ongoing projects.

Hydrocarbon gas injection (continuous or in a WAG mode) continues to be the preferred recovery process in offshore fields, gas condensate reservoirs, or fields in remote locations without access to gas markets. N2 EOR projects seem to be in decline except in the Campeche Bay Area in Mexico because of the availability of vast installed N2 generation capacity. CO2 injection is getting most of the attraction as an EOR method and potentially as a sequestration strategy in recent years. However, CO2-EOR projects in operation are mostly concentrated in the U.S. (especially in the Permian Basin) and associated to natural sources of CO2. CO2-EOR / sequestration projects are not expected to grow in the near future until industrial sources of CO2 are produced at much lower costs and the proper regulatory framework is in place.
Chemical EOR methods have made a relatively small contribution to the world’s oil production during the last decades. China is the country with the largest oil production coming from Chemical EOR projects. However, there are an increasing number of ongoing and planned SP and ASP evaluations at pilot scale, especially in Canada and the U.S. Polymer flooding is gaining interest for heavy crude oil reservoirs (i.e., Canada) and offshore fields. Most recently, the combination of conformance technologies (gel treatments) to improve injection profile and sweep efficiency with chemical EOR flooding such as CDG, SP, or ASP is starting to get more interest from operators in South America and the U.S. based on El Tordillo Field experience.

Simple screening and simulation approaches have contributed to identify technical and economical feasibility of different EOR methods before costly and time-consuming lab and reservoir studies can be justified. In the simulation example shown in this paper we demonstrated that gel treatments as part of waterflooding optimization definitively contributes to maximize incremental recovery factors of EOR chemical floods and hence project economics. The number of ongoing evaluations of combined IOR/EOR technologies (e.g., Gel treatment and CDG or Gel treatments and A/SP) and the successful results and project expansion of El Tordillo field in Argentina suggest a growing trend that may contribute establishing EOR chemical flooding in years to come.

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