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Review Article

Comparing Carbon Dioxide Injection in Enhanced Oil Recovery with other Methods

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Abstract

There are several methods for enhanced oil recovery that used in the oil fields. But selection good method is important key for increasing recovery. In this review we are going to analyze and introduce all of EOR methods. In the end we want to compare CO_2 process with other methods and consider advantage and disadvantage of this method against other methods. We want to open new window in comparing EOR methods. We get into the two problems: the one is deficiency of fossil fuel and another one is weather pollution. We want to consider these two problems in this article and find the best method for solving them. Note to lack of knowledge in these field we want to inform Scientists of both filed for more interaction together.

Keywords: Carbon dioxide injection; Enhanced oil recovery; Comparing methods

Introduction

Most of the current world oil production comes from old fields. Increasing oil recovery from these fields is a major problem for oil companies and governments. In addition, the rate of replacement of the produced reserves by new discoveries has been declining steadily in the last years. Therefore, the increase of the recovery factors from old fields under primary and secondary production will be critical to discover the growing energy demand in the coming years [1]. There are several methods in EOR. It is well known that EOR projects have been strongly influenced by two factors contain economics and crude oil prices. The initiation of EOR projects depends on the readiness and willingness of institutional investors to manage EOR risk and economic disposal and the availability of more attractive investment options [2]. It is important to indicate that statistics on EOR activity is often masked because it goes unreported and their responsible don't publish them. EOR gas injection project statistics remained constant since mid-1908's and exhibited a growing trend since year 2000, especially with the increase of CO_2 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 some increase since 2004 due to the increase of High Pressure Air Injection (HPAI) projects in light oil reservoirs. Chemical EOR methods have not captured the attachment of oil companies with only two projects reported in 2008 [1]. In this article we want to analyze the methods of EOR and compare CO_2 project with other methods according to articles and publications, also in this article we try to introduce all of the methods which used in the world and fields that this method used in them.

Oil Recovery Methods

Enhanced Oil Recovery (EOR) is a term practical to methods used for recovering oil from a petroleum reservoir beyond that recoverable by primary and secondary methods [3]. Oil recovery methods can be divided into three major groups: primary, secondary and tertiary methods (enhanced oil recovery), as show in Figure 1. In the primary process, the oil is forced out of the petroleum reservoir by existing natural pressure of the trapped fluids in the reservoir [4]. Primary oil recovery methods include solution-gas drive, gas-cap expansion, gravity drainage, rock expansion, water drive processes or their composition [5]. With declining reservoir pressure, it becomes more difficult to get the hydrocarbons to the round. Often, artificial lift is required for extraction of these materials [6]. On average, just 5-10% of original oil in place can be recovered by primary techniques and others remain. Over a period of oil production, the repository energy will fall, and at some point, there will be insufficient underground pressure to force the oil to the surface [7]. When a large part of the crude oil in a reservoir cannot be recovered by primary methods, a method for recovering more of the oil left behind must be chosen. Often, secondary recovery is accomplished by injecting gas or water into the reservoir to replace produced fluids and maintain or increase the reservoir pressure for more extraction [8]. Conversion of some production wells to injection wells and subsequent injection of gas or water for pressure maintenance in the reservoir has been designated as secondary oil recovery [9]. The oil recovered by both primary and secondary processes changes about 20 to 50% depending on the oil and reservoir properties (Speight, J. G. 2009) [10]. The biggest portion of oil left behind after conventional oil recovery exhausted. Therefore,

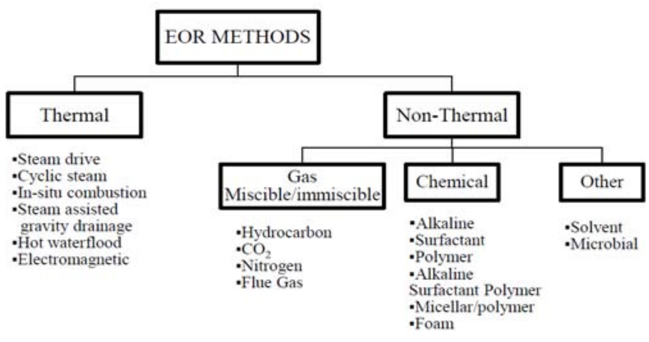

Figure 1: Enhanced oil recovery methods.

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enhanced oil recovery methods must be applied if further oil is to be recovered [11]. Enhanced oil recovery (Tertiary recovery) methods have focused on recovering the remaining oil from a reservoir that has been depleted of energy during the usage of primary and secondary recovery methods. Fluids interact with the reservoir rock and oil system to create conditions favorable for oil recovery. Improved Oil Recovery (IOR) refers to any process or practice that improves oil recovery. IOR includes EOR processes and other practices such as water flooding, pressure maintenance, infill drilling, and horizontal wells [3,12,13].

Enhanced Oil Recovery Methods

Processes for EOR are very sensitive to oil prices. The price of oil on a sustainable basis must exceed the cost of the injecting plus operating costs by a sizeable margin for an EOR process to be considered economical [11]. For this reason, an EOR process must be effective in factors of cost per barrel of oil recovered and also effective in substantially increasing the volume of oil recovered beyond the current recovery process. Economic factor is the key important step in the selection of an EOR process and is emphasized throughout the selection process [14,15]. In general, EOR methods can be classified into two important groups: thermal and non-thermal processes [11], as show in Figure 1. Each main group has a different EOR processes. Each technique has different concepts but similar objective which is to recover remaining oil and improving the recovery rate (Green and Willhite, 1998) [16,17]. EOR processes are very important as technologies that could help meet the growing demand for oil in the world. It is estimated that roughly 65% of the Original Oil In Place (OOIP) remains in the reservoir after primary and secondary recoveries [18]. This remaining oil can be recovered by using suitable EOR processes. The potential for EOR processes is clearly substantial and is responsible for the growth of EOR projects in all oil producing regions of the world (Ezekwe, 2011) [15].

EOR in sandstone formations

It is well known that EOR methods have been greatly implemented in sandstone formations. In general, sandstone reservoirs show the best possible to implement EOR projects because most of the technologies have been tested at pilot and commercial scale in this type of litho logy. Additionally, there are some fields where different EOR technologies have been evaluated successfully at pilot scale demonstrating technical pertinence of different EOR methods in the same field. Buracica and Carmopolis (Brazil), and Karazhanbas (Kazakhstan) are good field examples that have been topic to several EOR technologies at pilot scale in sandstone formations:

Buracica is an onshore light oil (35 °API) reservoir with reported air injection (1978–1980), immiscible CO_2 injection (1991) and polymer flooding (1997) pilot projects. Immiscible CO_2 injection was expanded in the field using CO_2 captured from an ammonia plan [19-23].

Carmopolis is an onshore heavy oil (22 °API) reservoir with reported insitu-combustion (1978–1989), polymer flooding (1969–1972 and 1997), steam injection (1978) and microbial EOR or MEOR (2002) pilot projects. The field has been developed mainly by water flooding [22,24-26].

Karazhanbas is an onshore heavy oil (19 °API) reservoir with documented polymer flooding [27], steam injection [28], in-situcombustion and in-situcombustion with foam injection as conformance strategy [15,29]). Karazhanbas Field was developed by water flooding, Cold Heavy Oil Production with Sand and steam injection [30]. Thermal and chemical methods have been the EOR processes more widely used in sandstone formations compared to EOR gas injection. The following section provides an overview of different EOR methods implemented in sandstone formations [31].

Thermal EOR Methods (Processes)

Thermal EOR processes are defined to include all processes that product heat energy to the reservoir and increasing the ability of oil to flow by reducing its viscosity [32,33]. Thermal recovery processes are globally the most advanced EOR processes. The key of thermal recovery is the use of heat to lower the viscosity of oil and reduces mobility ratio, then, increases the productivity and recovery [34-36]. The oil caused to flow by cater of thermal energy is produced through production wells. When heated, oil becomes less viscous and flows more quickly. Because this is an important property of oil, considerable effort has been devoted to the development of techniques that involve the introduction of heat into a reservoir to improve recovery of the heavier, more viscous crude oils. The viscosity of oils decreases as temperature increases, and the purpose of all thermal oil recovery processes are therefore to heat the oil to make it flow faster. The sensitivity of viscosity to temperature for several grades of oil and water shows [37]. The sharp decreasing of crude oils viscosity with temperature, especially for the heavier crude, largely explains why thermal EOR has been so popular [15,38,39]. Thermal EOR projects have been concentrated mostly in Canada, Former Soviet Union (FSU), U.S. and Venezuela, and Brazil and China to a lesser extent. Steam injection began approximately 5 decades ago. Mene Grande and Tia Juana field in Venezuela [29] and Yorba Linda and Kern River fields in California [40] are good examples of steam injection projects over four decades. Some examples of recent steam injection projects reported in the literature are the steam floods in the Crude Field in Trinidad [1], Schoonebeek oil field in Netherlands [41] and Alto do Rodrigues in Brazil [15]. However attempts to optimize steam injection processes by using solvents [42], gases [43], chemical additives [44] and foams [45] have been proposed, few of these methods have been tested in the field and more of them were only in Laboratory [46]). One example is the LASER (for Liquid Addition to Steam for Enhancing Recovery) process, which consist in the injection of C_5+ liquids as a steam additive in cyclic steam injection processes. Although the LASER process was tested at pilot scale in Cold Lake [47] the process has not been expanded at a commercial scale. Steam injection has also been tested in medium and light oil reservoirs being crude oil distillation and thermal expansion the main recovery mechanisms in these types of reservoirs [48]. However, steam injection in medium and light oil reservoirs has not contributed to EOR production global. Steam Assisted Gravity Drainage (SAGD) represents another main EOR thermal method to increase oil production in oil sands. Due to SAGD applicability in unconsolidated reservoirs with high vertical permeability [12], this EOR method has grown attention in countries with heavy and extra-heavy oil resources, such as Canada and Venezuela, owning vast oil sands resources. However and despite SAGD Laboratory tests reported in China [49], U.S. [50] and Venezuela [51], commercial applications of this EOR process have been reported in Canada only and more specifically those implemented in McMurray Formation, Athabasca (e.g., Hanginstone, Foster Creek, Christina Lake and Fire bag, among others). Among projects, only those developed in McMurray Formation operate commercially. SAGD projects tested in Clearwater formation in Cold Lake, Canada have proved to be uneconomic [52]. Commercial SAGD projects in McMurray formation validate the importance of the geology and reservoir characteristics for this EOR method, findings that have been reported by Rotten fusser and Ranger [53], Putnam and Christensen [54], and Jimenez [55], among others. Therefore, the present level of understanding of the SAGD process and field experiences strongly suggest that this technology will continue to expand, depending on oil prices, mainly in Athabasca's McMurray formation. Alternatives to SAGD have been proposed. Those techniques include modified versions of SAGD through different well configurations or numbers of wells (e.g., Cross or X-SAGD, Fast SAGD and single well SAGD or SW-SAGD) or using additives (e.g., ES-SAGD) to steam [56-59]), respectively. All of the proposed methods are at early step of evaluation and are not expected to have an impact on oil production in the near future.

Chemical methods

Chemical EOR methods grown their best times in the 1980's, most of them in sandstone reservoirs [60]. The total active projects improve in 1986 with polymer flooding as the most important chemical EOR method. However, since 1990's, oil production from chemical EOR methods has been poor around the world except for China [61-64]. Nevertheless, chemical flooding has been shown to be sensitive to volatility of oil markets despite recent advances (e.g., low surfactant concentrations) and lower costs of chemical additives. Polymer flooding needs to be considered a senior 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 footnote that this paper does not consider near wellbore treatments (e.g., gels and polymer-gels) as EOR processes, leaving them out of the scope of this review. According to the EOR survey introduced by Moritis in 2008 [18] there are ongoing pilots or large-scale polymer floods in Argentina (El Tordillo Field), Canada (Pelican Lake), China with nearly 20 projects (e.g., Daqing, Gudao, Gudong and Karamay fields, among others), India (Jhalora Field) and the U.S. (North Burbank, Oklahoma). It is important to mention that a commercial polymer flood was developed in North Burbank during the 1980 [65], demonstrating that this EOR method may still have potential to increase oil recovery in mature basins (i.e. mature floods with movable and/or by passed oil). North Burbank reinitiated polymer flooding on a 19-well pattern in December [12]. Other reported polymer flooding projects include Brazilian Carmopolis, Buracica and Canto doAmaro fields [26]. Indiaian companies also report a polymer flood in San and Field [66]. Oman also documented a polymer flood pilot developed in Marmul Field [67] and almost twenty years later a large-scale using is under way [18]. Additionally, Argentina (El Tordillo Field), Brazil (Voador offshore Field), Canada (Horsefly Lake Field) and Germany (Bochstedt Field) announced plans to implement polymer flood projects [18]. Listed ongoing and planned polymer floods provide an indicative sample of field experiences that validates EOR potential of this recovery process. Colloidal Dispersion Gels (CDG's) and Bright Water also represent novel polymer-based technologies that are currently under evaluation at field scale. Although these technologies are exactly different from a technical standpoint, both are meant to improve volumetric sweep efficiency in mature water floods, especially in reservoirs with high permeability contrast and presence of thief zones. Documented CDG's projects include Daqing Field in China [61,68], El Tordillo [69] and Loma Alta Sur [70] fields in Argentina and in multiple U.S. oilfields [71,72]. Regarding Bright Water [73], at the present time Milne Point in Alaska is the judt field application discussed or documented 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 [74-77]. While polymer flooding has been the most applied EOR chemical method in sandstone reservoirs [78], the injection of alkali, surfactant, Alkali-Polymer (AP), Surfactant-Polymer (SP) and Alkali-Surfactant-Polymer (ASP) has been examined in a limited number of fields. Micellarpolymer flooding had been the second most used EOR chemical method in light and medium crude oil reservoirs until the early 1990's [79]. Although this recovery method was considered a undertaking EOR process since the 1970's, the high concentrations and cost of surfactants and co-surfactants, combined with the low oil prices during mid 1980's limited its using. The development of the ASP technology since mid-1980's and the development of the surfactant chemistry have brought up a renewed attention for chemical floods in recent years, especially to boost oil production in mature and water flooded fields. Several EOR chemical methods, other than polymer flood, have been extensively documented in the literature during the last years. However, at the present time Daqing Field reports one of the biggest, if not the biggest, ASP flood implemented as of today. ASP flooding has been studied and testedin Daqing for more than 15 years though several pilots of different scales [1,80]. Gudong, Karamay [81], Liahoe and Shengli [61] 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 [82] and West Kiehl [83], Sho-Vel-Tum [84], Cambridge Minnelusa [85] and Tanner [86] fields in the U.S.AP flooding in Xing Long Tai Oil Field [87] in China and David Pool in Canada [88]. According to the EOR survey presented by Moritis in 2008 [18] there are ongoing ASP pilots in Delaware Childers Field (Oklahoma) and also refers to planned ASP floods in Lawrence Field (Illinois) and Nowata Field (Oklahoma), and SP floods in Midland Farm Unit, Texas (Grayburg Carbonate Fm.) and in Minas Field, Indonesia [89]. However, the number of ASP and SP floods is more than the ones reported in the literature as well the EOR survey presented by Moritis [18] because operators 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. 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 and despite the volatility of oil prices, it is fair to conclude that operators and surfactant manufacturers are showing a growing interest in EOR chemical flooding [90]. This tendency is also noticed with an increase of screening and lab studies to evaluate or re-estimate EOR potential of chemical flooding in different basins [91-96].

Microbial-Enhanced oil recovery (MEOR)

MEOR is an important tertiary recovery technology utilizing microorganisms or their metabolic end products for recovery of residual oil [97]. It is generally accepted that approximately 30% of the oil present in a reservoir can be recovered using current EOR technology (Singer &Finnerty, 1984) [98]. Poor oil recovery in existing producing wells may be due to several factors. The main factor is the low permeability of some reservoirs or the high viscosity of the oil which results in poor mobility [99]. High tensions between the water and oil may also result in high capillary forces retaining the oil in the reservoir rock (Bubela, 1987) [100]. Since most of the oil remains in the reservoir following primary and secondary recovery techniques, attachment has evolved in tertiary recovery techniques (Morkes, 1993) [101]. Techniques consist the using of chemical or physical processes such as pressurization, water flooding or steaming, however, are generally inapplicable to most oil reservoirs. The use of chemical surfactants for cleaning-up oil reservoirs is an unpleasant practice that is hazardous, costly and will leave undesirable residues which are difficult to dispose of without adversely affecting the environment [102].

Polymer flooding

In this enhanced water flooding method, high molecular weight water-soluble polymers are added to the injection water to improve its mobility ratio, reducing oil "bypassing" and raising yields [103]. Permeability profile modification treatments with polymer solutions are becoming increasingly common. In general, polymer is increasingly used in chemical Enhanced Oil Recovery (EOR) after the secondary recovery in two conventional ways, either as an in-depth profile modification agent in conformity control or as an oil displacement agent in polymer flooding [104]. Some recent studies, however, show that a weak gel system consisting of polymer and cross linker can widen the application of polymer in chemical EOR [105-110]. For example, a weak gel can function both as an in-depth profile modification agent and as an oil displacement compound at the same time. Thus, injection of this weak gel system combines the advantages of both conformance control operation and polymer flooding operation. It's not only substantially extends the effective radius in comparison with a conventional conformity control operation but also significantly increases the viscosity of polymer solution.

Gas methods

EOR gas flooding has been the most widely applied recovery methods of light, condensate and volatile oil reservoirs. Although Nitrogen (N_2) injection has been proposed to increase oil recoveries under miscible conditions favoring the vaporization of light fractions of light oils and condensates, today fewN_2 floods are ongoing in sandstone reservoirs. Immiscible N_2 floods are reported in Hawkins Field (Texas) and Elk Hills (California) based on the Moritis EOR survey in 2008 [1]. No new N_2 floods in sandstone reservoirs have been documented in the literature during the last few years ago and we do not foresee an increment in the number of projects implementing this EOR gas flooding method. Similarly to N_2 injection, hydrocarbon gas injection projects in onshore sandstone reservoirs have made a relatively marginal portion 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 marketplaces. It is important to mention that in this paper we refer to EOR gas methods using hydrocarbon gases such as Water-Alternating-Gas (WAG) injection schemes, enriched gases or solvents and its combinations. Therefore, hydrocarbon gas injection as pressure maintenance or double displacement strategies are not considered EOR methods for purposes of this review. Most of immiscible and miscible EOR hydrocarbon gas floods in the U.S. are on the North incline of Alaska [111-114] while in Canada a miscible gas flood is reported in Brassey Field. The situation of hydrocarbon gas injection projects is different in offshore sandstone reservoirs [115]. 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 (N_2, CO_2, acid gas, air) oil recovery will build more natural gas available for domestic use or export while still maintaining reservoir pressure and increasing oil recoveries. Despite current low natural gas prices, the continued increase in energy demand will likely affect the viability of new large-scale hydrocarbon gas projects. On the other hand, CO_2 flooding has been the most widely used EOR recovery method for medium and light oil production in sandstone reservoirs during last year's, especially in the U.S. due to the availability of cheap and readily available CO_2 from natural sources. The number of CO_2 floods is expected to continue to grow in U.S.s and stone reservoirs. Some examples of planned CO_2-EOR projects in the U.S. include Cranfield, Heidelberg West (from anthropogenic sources) and Lazy Creek Field in Mississippi and Sussex Field in Wyoming. Number of CO2 floods in Wyoming sandstone reservoirs are also expected to enhance based in a recent evaluation presented by Wo et al. [116] (this will be constrained by availability of CO_2 for injection). Additionally, Holtz [117] reported an overview of sandstone gulf coast and Louisiana CO_2-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 major potential to increase oil recovery and has been widely documented in the literature. Therefore, the present review will address briefly activities reported outside the U.S. Some examples of CO_2-EOR field projects in sandstone formations presented in various conferences and/or documented in the literature are summarized below: Brazil reportsCO_2 floods in Buracica and Rio Pojuca fields [118] and announced a CO_2 flood in Miranga Field from anthropogenic sources as an EOR and carbon storage strategy [119]. However, this will be further discusses in the section of EOR gas methods in carbonate formations.

Nitrogen Flooding

Nitrogen flooding can be a permanent EOR method if the following conditions exist in the candidate reservoir:

1. The reservoir oil must be rich in ethane until hexane (C_2-C_6) or lighter hydrocarbons. These crudes are characterized as "light oils" having an API gravity higher than 35 degrees.

2. The oil should have a high formation-volume factor – the capability of absorbing added gas under reservoir conditions.

3. The oil should be under saturated or low in methane (C_1) (methane is less).

4. The reservoir should be at least 5,000 feet deep to sustain the high injection pressure (in excess of 5,000 psi) necessary for the oil to attain miscibility with nitrogen without fracturing the producing

formation. Gaseous Nitrogen (N_2) is attractive for flooding this kind of reservoir because it can be manufactured on site at less cost than other alternatives. Since it can be extracted from air by cryogenic separation, there is an unlimited source, and being completely inert it is noncorrosive. In general, when nitrogen is injected into a reservoir, it forms a miscible front by vaporizing some of the lighter components from the oil. This gas, now enriched to some extent, continues to move away from the injection wells, contacting new oil and vaporizing more components, thereby enriching its still further. As this action continues, the leading edge of this gas front becomes so enriched that it goes into solution, or becomes miscible, with the reservoir oil. At this time, the interface between the oil and gas disappears, and the fluids mixture as one. Continued injection of nitrogen pushes the miscible front (which continually renews itself) through the reservoir, moving a bank of displaced oil toward production wells. Water slugs are injected alternately with the nitrogen to increase the sweep efficiency and oil recovery. At the surface, the produced reservoir fluids may be separated, not only for the oil but also for natural gas liquids and injected nitrogen [120-122].

Water-alternating-gas (WAG) injection

WAG injection is an oil recovery method initially purposed to improve sweep efficiency during gas injection. In some recent applications produced hydrocarbon gas has been reinjected in water injection wells with the aim of improving oil recovery and pressure conservation. Oil recovery by WAG injection has been attributed to contact of upswept zones, especially recovery of attic or cellar oil by exploiting the dissociation of gas to the top or the accumulating of water toward the bottom. Because the residual oil after gas flooding is normally lower than the residual oil after water flooding, and three - phase zones may catch lower remaining oil saturation; WAG injection has the potential for increased microscopic shift efficiency. Thus, WAG injection can lead to improved oil recovery by combining better mobility control and contacting upswept zones, and by leading to improved microscopic displacement. Laboratory displacement studies of WAG injection were carried out to evaluate its usage in GS-5C sand of a matured light oil field. It is observed that the number of cycles in the WAG injection process affects the recovery of oil from the circle sample. An incremental displacement efficiency of 19.3 % of Hydrocarbon Pore Volume (HCPV) is observed in the five-cycle WAG injection process as against to about 12.75 % of HCPV in single cycle WAG injection process. The WAG injection process is also verified for increasing and decreasing WAG ratio (tapering). It is observed that the tapering in WAG injection process recovered the displacement efficiency. The gas tapering with increasing and decreasing WAG ratio gives incremental displacement efficiency of 20.73 % and 23.84 % of HCPV in the core pack respectively. The observations on the effect of gases revealed that the CO_2 gas with five cycle WAG process gives an incremental displacement efficiency of 40.18 % of HCPV, which is much higher than displacement efficiency of 19.3 % of HCPV in the five cycle WAG process using hydrocarbon gas [123-128].

CO_2 Injection

The physical properties of co$_2$

Pure CO_2 is a colourless, odourless, inert, and non-combustible gas [129]. The molecular weight at standard conditions is 44.010 g/mol, which is one and a half times higher than air. CO_2 is solid at low temperatures and high pressures, but most dependent on temperature. By increasing the pressure and temperature, the liquid phase appears for the first time and coexists with the solid and vapour phases at the triple point [130]. The liquid and the vapour phase of CO_2 coexist from the triple point and up to the critical point on the curve. Below the critical temperature CO_2 can be either liquid or gas over a wide range of pressures. Above the critical temperature CO_2 will exists as a gas regardless of the pressure. However, at increasingly higher supercritical pressures the vapour becomes and behaves more like a liquid [131].

How carbon dioxide flooding works

Most oil reservoirs are at a pressure in the range 10 to 30 MPa (atmospheric pressure is approximately 0.1 MPa) and at temperatures from 30°C to 110°C [132]. Primary production allows the oil to flee from the reservoir under its own pressure and by the expansion of gas dissolved in the oil. This still leaves a reservoir full of oil and gas. In secondary production, the reservoir pressure is maintained by injecting another fluid, normally water that displaces the oil [133]. In a single reservoir there may be hundreds of particular wells that inject water and hundreds of production wells that collect the displaced oil [134]. Water injection still does not recover all the oil for two reasons. First, the reservoir rock is heterogeneous. The water may find a high permeability pathway from an injection well to a production well, leaving other regions that are not swept by the water. Second, in the small interstices between the rock grains, ganglia of oil surrounded by water are held in place by the water/oil surface tension and do not flow [135]. Water flooding is used wildly in the North Sea and accounts for approximately half of the oil production in the US. Between 40-50% of the original oil in place will be recovered. Primary production, by comparison, typically removes a mere 5-20% of the oil. At reservoir temperatures and pressures, carbon dioxide is above its critical point and has a density between half and three quarters that of water [133,136-138]. Under typical conditions it is miscible with individual, short chain alkanes containing fewer than 13 carbon atoms. The crude oil is a cocktail of hundreds of different hydrocarbon components, many of them containing more than 30 carbon atoms. In thermodynamic equilibrium, a mixture of the reservoir oil and carbon dioxide forms two phases – one is a phase rich in CO_2 and light hydrocarbons, while the other phase contains a preponderance of heavier molecules. As the pressure increases, the carbon dioxide extracts a greater fraction of low molecular weight hydrocarbons from the oil. The carbon dioxide rich phase is the less viscous phase and so flows more readily through the rock, contacting fresh crude oil. This new mixture again may form two phases, but more and more of the oil is dissolved in the CO_2. In laboratory displacements it is possible that eventually an oil/CO_2 mixture is formed that is completely miscible with the reservoir oil. The pressure at which this is first achieved is called the Minimum Miscibility Pressure (MMP) [139]. In the field complete miscibility is rarely, if ever, achieved, because other processes force the inject ant and crude oil to mix in non-ideal, immiscible proportions. However, the MMP does take a guide for the pressure at which the displacement of oil is effectual, since a large fraction of the oil in trapped ganglia will dissolve in the carbon dioxide to form an oil-rich phase that is collected at a production well. Moreover, some carbon dioxide will dissolve in the oil ganglia, causing them to swell. The oil may then occupy a sufficiently large fraction of the void space in the rock (called the saturation) to form a continuous pathway of fluid. In this case it will also flow to a production well. In laboratory experiments of a miscible flood 85-98% of the residual oil to water flooding can be displaced, but in the field about 25-40% of the remaining oil can be recovered. In the field, the overall efficiency is affected by other keys, such as the geology of the reservoir and the density and viscosity differences of the fluids [140-142].

Life-cycle: Life-Cycle Assessment (LCA) is a method to evaluate the environmental impacts of product systems, from the cradle to the grave [143]. Emissions and resource use from the resource extraction, production distribution, use and disposal phases are included in the Life-Cycle Inventory (LCI) [144]. The portion of these emissions and resource uses to specific environmental impacts (e.g. global warming, human toxicity, biotic resource extraction) is evaluated in the impact assessment. LCA has been developed independently in a number of applications and disciplines, including chemical engineering and energy analysis. The assessment of alternative energy technologies has been one of the most important application areas, and initial assessments have focused on the cumulative (fossil) energy demand, including embodied or "grey" energy [145]. An important motivation in the 1970s was to consistently compare fossil and renewable energy technologies in terms of the energy services they deliver for a given amount of fossil fuels. LCA has since been extended to label a wide range of environmental concerns [146]. It has been standardized by ISO [147]. CO_2 Capture and Storage (CCS) is an end-of-pipe technology for fossil fuel fired power plants, boilers, and industrial processes which produce big amounts of CO_2 [148]. Many analysts see CCS as a necessary and important element in a strategy to limit global warming and stabilize atmospheric temperature to level below 2°C above the pre-industrial level [149]. There are multiple different technological options for CO_2 capture, including chemical and membrane absorption from the exhaust stream or a synthesis gas, or combustion with pure oxygen. At this point, post-combustion absorption by an amine-based solvent is the most mature technology [150], but other technologies are still permanent contenders. To illustrate the LCA of energy technologies, we investigated a specific CO_2 value chain using a hybrid LCA approach. The value chain consists of a natural gas combined cycle power plant with post-combustion capture, pipeline transport and injection in a North Sea oil field for Enhanced Oil Recovery (EOR). There have been several LCAs of CCS. EOR has been investigated as a reserve option for CO_2. These studies very often are quite general [151]. Due to the CO_2 injection in the oil field, a change in the electricity supply of the platforms is necessary. It is only model global warming and acidification impacts, because there is too little information available on emissions causing human or ecological toxicity [151].

Comparing various EOR methods

In the discussion of the effect of enhanced oil recovery, we must first understand that these technologies are adapted to the specific geological conditions of the area of extraction and these factors are very important to understand which method is suitable. The transformation of the reservoir must be: Layer heterogeneity: reservoir layer thickness (HS ≥ 2.0m), serious (non-uniformity coefficient ≥ 10). It is very difficult to assess the top 10 metres of a reservoir thickness, but with Sino technology they can assess the permeability of every reservoir layer in a previously flooded well. This means that Sino technology can identify remaining oil reserves and effectively retrieve them. Secondly, is to look at the physical conditions of the crude oil reservoir. If it is high density heavy oil (Ǖ0 ≥ 1000mps), then application of this modified tapping technique with thermal recovery technology can be most effective. Comparing the Sino EOR technology to other recovery methods is not simple or straightforward, as other measures are limited in their application range. On the other hand, Sino's technology is adaptable to varying geological conditions. The list below outlines the approximate recovery rates of several of the alternative recovery techniques discussed above:

1. Elastic + dissolved gas drive mining: ultimate recovery ≤ 10%

2. Water flooding: the ultimate oil recovery can be increased to 30 to 35%

3. Other manual techniques including: chemical flooding - polymers, tertiary flooding, carbon dioxide flooding, thermal recovery (physical drive) – in-situ combustion, the injection of high-pressure superheated steam 35-40%

4. Biological drive - bacteria, oil recovery technology. (Mostly indoor experiments, no formal field test results.)

Advantages and Disadvantages by using CO_2 as a Solvent in Miscible Floods

CO_2 is regarded to be affine solvent for miscible CO_2 floods. But still there are both advantages and disadvantages to take into consideration when considering an EOR project [151].

Advantages

The largest difference compared to other gases is that CO_2 can extract heavier components up to C_{30}. The solubility of CO_2 in hydrocarbon oil causes the oil to swell [139]. CO_2 expands oil to a greater extent than methane does. The swelling depends on the amount of methane in the oil. Because the CO_2 does not displace all of the methane when it contacts a reservoir fluid, the more methane there is in the oil, the less is the swelling of oil. CO_2 has the following characteristics in a flood process [138]:

• It promotes swelling

• It decreases oil viscosity

• It increases oil density

• It is soluble in water

• It can vaporize and extract portions of the oil

• It achieves miscibility at pressures of only 100 to 300 bars

• It reduces water density

• It reduces the difference between oil and water density, and then reduce the change for gravity segregation

• It reduces the surface tension of oil and water, and result in a more effective displacement

Disadvantages

One of the main problems in achieving profitable CO_2 flooding has been the high mobility of the CO_2 [152]. The relative low density and viscosity of CO_2 compared to reservoir oil are responsible for gravity tonguing and viscous fingering. The effect of CO_2 is more severe than those problem are in a water flood. In order to avoid those negative effects, several attempts have been done to improve the sweep efficiency. Those can be [153]:

- Installation of well packers and perforating techniques
- Shutting in production wells to regulate flow
- Alternating CO_2 and Water injection (WAG)
- Addition of foaming solutions together with CO_2

Conclusion

According to above blog it can be said among all methods for EOR CO2 injection is much better for these reasons:

• CO_2 EOR is considered to be the best option due to high additional oil recovery.

• CO_2 EOR can give up to 47 % by inject 4 million tonnes CO_2/year.

• Miscibility and core flood studies indicates that up to 15 % methane can be tolerated in the injected stream before recovery is adversely affected.

• 40 – 80 million tonnes of CO_2 can be stored in the subsurface over a twenty-year period.

• Some main obstacles to performance were identified:

•high cost of CO_2

•Surface facilities has to be modified

•Fiscal regime (lower marginal tax rate)

In the end it can be said due to the advantages of CO_2 and the great volume production of this gas in the world using this gas in EOR can be useful from two directions. For one thing, we can use this gas for extraction of oil from old field and the other that with this work we can control the volume of this gas in air for decreasing Greenhouse Effect, Compared with other methods this method can be used in the wider range in future.

Based on the studies in this paper can be said Now CO_2 injection as a method old enters a new period. In this time According to the Earth pollution problem as well as greenhouse effect new methods must be found for reduction concentration of greenhouse gases. The growth of the industry is also growing consumption of fossil fuels on the one hand will limit resources on the other hand increases CO_2 concentration with progressive rate. These two phenomena in the same direction are big problem for future of the planet and energy.

Among methods of EOR all of the methods can improve EOR but Except CO_2 injection others cannot reduce the greenhouse gases, And None of these methods are in line with green chemistry.CO_2 injection method is Quite the contrary why so in one hand by injection of CO_2 in source oil can be doing EOR as well as in other hand by reduction of CO_2 concentration in the environment can be help Stylized Earth's climate. According to this point essential looks that Authorities with studies and Responsibility for pollution of whether choice the best methods to control CO_2 concentration and management of Fossil fuels, by CO_2 injection into old source can be get both targets. For this work we have to inform to Related bodies and introduce new methods for saving Logged CO_2 from Factories and Industrial and transferring them into oil extraction places however the cost of transfer from the cities those are far from the oil source to extraction place maybe much but note to public worry about weather pollution of this gas in The not too distant future must spent several times until can be created normal Circumstances for live in the round.

In the end our purpose from writing this article is considering types of methods for EOR also studying greenhouse effect and its Origin and reducing it. Now we want to offer new method by two goals: Suggested method is saving CO_2 from industrial and factories and transfer it to oil source and two goals are: EOR in old source and reduction of pollution weather.

Note to this point that most of the oil source are in Middle East writer hopes this article influences on Attitude of Authorities in this area. We invite readers to more study and understanding problems about weather pollution and trying to find new ethnology for best saving CO_2 and transferring to oil source.

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