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Fundamentals of Carbon Dioxide-Enhanced Oil Recovery (CO_2-EOR)—A Supporting Document of the Assessment Methodology for Hydrocarbon Recovery Using CO_2-EOR Associated with Carbon Sequestration

By Mahendra K. Verma

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Conversion Factors

Inch/Pound to SI

Multiply	By	To obtain
	Length	
foot (ft)	0.3048	meter (m)
mile (mi)	1.609	kilometer (km)
	Area	
acre	4,047	square meter (m^2)
acre	0.4047	hectare (ha)
acre	0.4047	square hectometer (hm^2)
acre	0.004047	square kilometer (km^2)
square inch (in^2)	6.452	square centimeter (cm^2)
	Volume	
barrel (bbl), (petroleum, 1 barrel=42 gal)	0.1590	cubic meter (m^3)
acre-foot (acre-ft)	1,233	cubic meter (m^3)
acre-foot (acre-ft)	0.001233	cubic hectometer (hm^3)
	Flow rate	
gallon per day (gal/d)	0.003785	cubic meter per day (m^3/d)
	Mass	
pound, avoirdupois (lb)	0.4536	kilogram (kg)
	Pressure	
pound per square inch (lb/in^2)	6.895	kilopascal (kPa)

Temperature in degrees Celsius (°C) may be converted to degrees Fahrenheit (°F) as follows:

°F=(1.8×°C)+32

Temperature in degrees Fahrenheit (°F) may be converted to degrees Celsius (°C) as follows:

°C=(°F-32)/1.8

Abbreviations

API	American Petroleum Institute
CO_2	carbon dioxide
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EISA	U.S. Energy Independence and Security Act of 2007
HCPV	hydrocarbon pore volume
MMP	minimum miscibility pressure
OOIP	original oil-in-place
ROZ	residual oil zone
TDS	total dissolved solids
TZ	transition zone
USGS	U.S. Geological Survey
WAG	water-alternating-gas

Fundamentals of Carbon Dioxide-Enhanced Oil Recovery (CO_2-EOR)—A Supporting Document of the Assessment Methodology for Hydrocarbon Recovery Using CO_2-EOR Associated with Carbon Sequestration

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Introduction

Background

Under the U.S. Energy Independence and Security Act of 2007 (EISA; U.S. Congress, 2007, Public Law 110–140) legislation, the U.S. Geological Survey (USGS) developed a probability-based methodology to assess the Nation's technically accessible geologic storage resources available for sequestration of carbon dioxide (CO_2) (Brennan and others, 2010; Blondes and others, 2013), independent of economic constraints. With the completion of the assessment of CO_2 geologic storage resources using the above methodology (U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013a,b,c), the first part of the USGS's commitment of the EISA legislation was fulfilled. The second part of the USGS commitment under the EISA legislation is to assess the hydrocarbon recovery potential in oil and gas fields within the sedimentary basins of the United States using CO_2-enhanced oil recovery (CO_2-EOR) methods. Higher primary recoveries in excess of 70 percent in gas reservoirs (Comelson, 1974; Alejandro and Lopez, 2000) and the cost of additional facilities required for CO_2 injection make the CO_2-EOR process economically unattractive, and as a result, there has been no reported attempt to consider application of tertiary recovery in gas reservoirs. Therefore, only oil reservoirs will be included in the assessment, and gas reservoirs will not be discussed here. Equivalent to the recoverable oil volume or the total oil produced is the reservoir pore space available for sequestration (storage) of industrial carbon dioxide.

Objective

The objective of this report is to provide basic technical information regarding the CO_2-EOR process, which is at the core of the assessment methodology, to estimate the technically recoverable oil within the fields of the identified sedimentary basins of the United States. Emphasis is on CO_2-EOR because this is currently one technology being considered as an ultimate long-term geologic storage solution for CO_2 owing to its economic profitability from incremental oil production offsetting the cost of carbon sequestration.

CO_2-Enhanced Oil Recovery (EOR) Process

General

After discovery, an oilfield is initially developed and produced using primary recovery mechanisms in which natural reservoir energy—expansion of dissolved gases, change in rock volume, gravity, and aquifer influx—drive the hydrocarbon fluids from the reservoir to the wellbores as pressure declines with fluid (oil, water, or gas) production. Primary oil recoveries range between 5 and 20 percent (Stalkup, 1984) of the original oil-in-place (OOIP). These low recoveries prompt field operators to find ways to improve recovery through the application of secondary recovery methods, which provide additional energy to the reservoir. Secondary recovery methods entail injecting either water and (or) natural gas into the reservoir for repressurizing and (or) pressure maintenance and to potentially act as a water and (or) gas drive to displace oil. This helps to sustain higher production rates and extends the productive life of the reservoir. Normal practice has been to inject natural gas into the gas cap or at the top of reservoir and inject water below the oil-water contact. The oil recoveries at the end of both the primary and secondary recovery phases are generally in the range of 20–40 percent of the OOIP, although in some cases, recoveries could be lower or higher (Stalkup, 1984). Tzimas and others (2005) have reported a slightly higher recovery range of 35–45 percent of OOIP at the end of secondary recovery in their study of North Sea oil reservoirs.

A substantial amount of residual oil remains in the reservoir at the end of secondary recovery and becomes the target for additional recovery using *tertiary recovery or enhanced oil recovery (EOR)* methods. For the purpose of this paper, tertiary recovery or EOR methods refer to those methods used to recover oil not recovered from the secondary processes. The terminology *improved oil recovery (IOR)* is also used in the petroleum industry and is loosely defined as having a wider scope of practices to increase oil recovery as compared to tertiary recovery or EOR. In addition to what is classified as EOR, the IOR includes secondary recovery processes, such as waterflooding and gas pressure maintenance, and improvements for better sweep efficiency and conformance such as increasing mobility control, infill drilling, and horizontal wells (Taber and others, 1997; Stosur and others, 2003).

A classification by van Poollen and Associates (1981) of EOR methods has the following three categories:

1. Thermal methods, which include steam stimulation (also known as "huff and puff"), steam flood (including hot water injection), and in situ combustion;
2. Chemical methods, which include surfactant-polymer injection, polymer flooding, and caustic flooding; and,
3. Miscible displacement methods, which include injection of hydrocarbon gas, CO_2, or inert gas under high pressure.

The immiscible displacement method with CO_2 injection, although not mentioned in the above classification, is also used for EOR and is briefly described in the section *Fundamentals of the CO_2-EOR Process.*

CO_2-EOR has two major advantages: (1) additional hydrocarbon recovery that promotes energy independence and (2) CO_2 storage to reduce atmospheric emissions of CO_2. The focus in this report is only on additional oil recovery using CO_2-EOR.

As part of the development work for a better understanding of the CO_2-EOR process, several researchers have reported higher oil recoveries with carbonated water based on their experimental work as early as 1951 (Martin, 1951; Johnson and others, 1952; Holm, 1959).The first field-wide application took place in 1972 at the SACROC (Scurry Area Canyon Reef Operators Committee) Unit in the

Permian Basin where the CO_2 was transported via a 200-mile-long pipeline from the Delaware-Val Verde Basin. The process proved to be a technical success but required optimization of the CO_2 slug size or the amount of CO_2 injected for its economic viability (Kane, 1979). Because of the availability of CO_2 in adequate quantities from both natural and industrial sources in the region, there were more field-wide successful applications of the CO_2-EOR process in the Permian Basin than any other region in the United States, and the area continued to show an increasing number of reservoirs with CO_2-EOR as a preferred option.

Geologic Framework

All reservoir lithologies, including siliciclastic, carbonate, and others, are suitable for CO_2-EOR application as long as they have interconnected pore space for fluid accumulation and flow and also have an adequate seal to entrap hydrocarbons. Geology is a critical element in reservoir development and exploitation, particularly when CO_2-EOR is considered. The oil recovery is influenced by geologic features such as rock and fluid characteristics, porosity, permeability, and structural or stratigraphic features such as faults and other barriers to oil or gas movement. A good reservoir characterization leads to improved estimates of OOIP values as well as to a better understanding of reservoir behavior.

Significance of Variables

The technically recoverable volumes of oil will depend on the OOIP values and respective recovery factors. The OOIP value is calculated volumetrically, using the equation below:

$$OOIP = \frac{(7758 * \mathrm{A} * \mathrm{h} * \text{Ø} * \mathrm{Soi})}{Boi} \quad (1)$$

7758 = multiplying factor, barrels/acre-feet
A = reservoir area, acres
h = average net reservoir thickness, feet
Ø = average porosity of formation, dimensionless
Soi = initial oil saturation in pore space, fraction
Boi = oil formation volume factor at initial reservoir pressure, reservoir barrel/stock tank barrel

Recovery factors are a function of the fluid displacement and areal and vertical sweep efficiencies. Probabilistic estimates will be affected by the accuracies of the individual variables used in the calculations; therefore, accurate parameter estimates are important.

Reservoir Engineering Aspect

The CO_2 from a natural or industrial source is injected into a selected oil reservoir either as continuous gas or as water-alternating-gas injection also known as WAG, as described in the section *CO_2 Flood Injection/Designs*. Not all reservoirs are suitable for CO_2-EOR and are screened based on factors such as reservoir geology, minimum miscibility pressure (MMP), oil gravity, and viscosity to help identify the most likely candidates for miscible CO_2. In preliminary screening, reservoirs having a minimum mid-point reservoir depth of 3,000 feet or deeper were selected because the temperature and pressure at that depth foster miscibility of CO_2 with the reservoir oil and also helps to accommodate high-pressure CO_2 injection. Any deviation from the above criteria for choosing a reservoir would depend on the size of the reservoir and potential hydrocarbon recovery. The U.S Environmental Protection Agency (EPA) (2009, 2010) regulations for the protection of underground sources of drinking water (USDW) state that formations containing water with less than 10,000 mg/L (milligrams per liter) total dissolved solids (TDS) are to be avoided for CO_2 storage; however, exemptions may be obtained from the EPA for CO_2-EOR projects.

Most of the CO_2-EOR applications have historically been in reservoirs with medium to light gravity oils, as can be seen from the 123 CO_2-EOR projects (Koottungal, 2012; Kuuskraa, 2012) currently active in the United States in Colorado, Louisiana, Mississippi, New Mexico, Michigan, Oklahoma, Texas, Utah, and Wyoming. Of these projects, 114, including two unreported (Kuuskraa, 2012), are miscible projects in reservoirs with light to ultra-light oils (gravity in excess of 28 ^{o}API [American Petroleum Institute, an oil gravity measure, in degrees] and viscosity of less than 3 centipoise [cp]) except for two reservoirs and nine immiscible projects in reservoirs with heavy to light oils (gravity ranging from 11 to 35 ^{o}API). A summary of all the CO_2-EOR projects within the United States is presented in table 1 (Koottungal, 2012). Based on the records from active EOR projects within the United States, oil production from CO_2-EOR has continued to increase compared to other EOR methods (fig. 1).

Table 1. Summary of carbon dioxide projects within the United States (Koottungal, 2012).

[Perm., permeability; Temp., temperature; NA, not available; md, millidarcy; °API, American Petroleum Institute, an oil gravity measure, in degrees; cp, centipoise, a measure of oil viscosity; °F, degrees Fahrenheit; ss., sandstone; ls., limestone; dol., dolomite; trip., tripolite]

Number of projects	Lithology	Porosity (percent)	Perm. (md)	Depth (feet)	Gravity (°API)	Viscosity (cp)	Temp. (°F)
Miscible							
42	ss.	7–26	16–280	1,600–11,950	30–45	0.6–3.0	82–257
2	ss./ls.-dol.	10	4–5	5,400–6,400	35	1	170–181
41	dol.	7–5	2–28	4,000–11,100	28–42	0.6–6.0	86–232
12	dol./ls.	3–12	2–5	4,900–6,700	31–44	0.4–1.8	100–139
6	ls.	4–20	5–70	5,600–6,800	39–43	0.4–1.5	125–135
1	dol./trip. chert	13.5	9	8,000	40	NA	122
7	tripolite	18–24	2–5	5,200–7,500	40–44	0.4–1.0	101–123
1	inadequate data						
Immiscible							
8	ss.	17–30	30–1,000	1,500–8,500	11–35	0.6–45	99–198
1	dol.	17	175	1,400	30	6	82

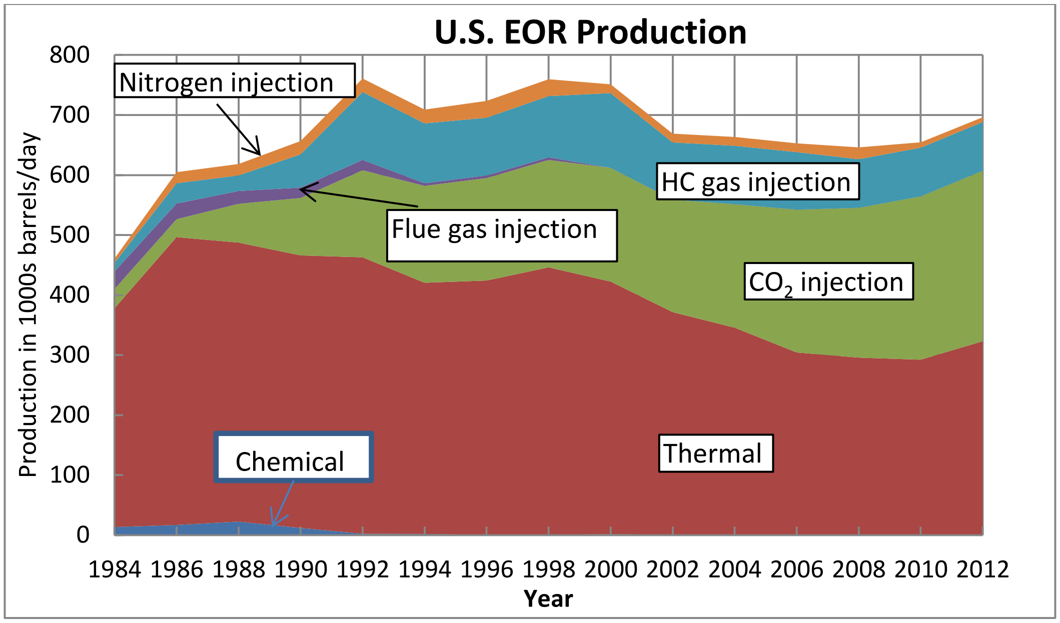

Figure 1. Plot showing U.S. oil production in barrels per day associated with various enhanced oil recovery (EOR) methods (Koottungal, 2012, and Kuuskraa, 2012). HC, hydrocarbon; CO_2, carbon dioxide.

Because of its special properties, CO_2 improves oil recovery by lowering interfacial tension, swelling the oil, reducing oil viscosity, and by mobilizing the lighter components of the oil. In order to fully understand CO_2-EOR, it is important to look at the properties of CO_2 and the fundamentals of the CO_2-EOR process.

Properties of CO_2

At atmospheric temperature and pressure, CO_2 is a colorless, odorless gas and about 1.5 times heavier than air. The critical pressure and temperature of CO_2 are 1,070.6 psia (pounds per square inch absolute) (73.82 kPa [kilopascals]) and 87.9 °F (31.1 °C [degrees Celsius]), respectively, and at this point, CO_2 gas and liquid coexist. At higher than critical pressures and temperatures, CO_2 is in the supercritical state and forms a phase whose density is close to that of a liquid, even though its viscosity remains quite low (0.05–0.08 cp). This dense phase CO_2 can extract hydrocarbon components from oil more easily than gaseous CO_2 (Jarrell and others, 2002) and is in this supercritical state for CO_2-EOR. Although the low CO_2 viscosity is detrimental to oil sweep, with the CO_2 dissolution in oil, the oil viscosity is also lowered, which in turn helps improve oil recoveries. Liquid CO_2 exists between its critical temperature and pressure and its triple-point temperature (–69.9 °F [–56.6 °C]) and pressure (75.1 psia [517.8 kPa]) and is normally transported as a liquid for economic and operational considerations. The properties of CO_2 are available from various sources including online at http://www.uigi.com/carbondioxide.html#Properties.

Fundamentals of the CO_2-EOR Process

The CO_2-EOR process recovers oil that remains in the reservoir after primary and secondary recovery by contacting and mobilizing stranded oil through improving the volumetric sweep (Ev) and displacement efficiencies (Ed), which are further discussed in the section *Oil Recovery Factor or Efficiency*. The injected CO_2 may become miscible or remain immiscible with oil, depending on reservoir pressure, temperature, and oil properties. The miscible CO_2-EOR process typically achieves higher recoveries than the immiscible process, and therefore, it is a preferred option.

Miscible Mode. The pressure at which miscibility occurs is defined as the minimum miscibility pressure (MMP). Holm and Josendal (1974) defined the MMP as the pressure at which more than 80 percent of oil-in-place (OIP) is recovered at CO_2 breakthrough. Although more recently, an oil recovery of at least 90 percent at 1.2 HCPV (hydrocarbon pore volume) of CO_2 injected is often used as a rule-of-thumb for estimating MMP (Yellig and Metcalfe, 1980). Oil recovery increases rapidly with increasing pressure then flattens out when MMP is reached, as shown in figure 2.

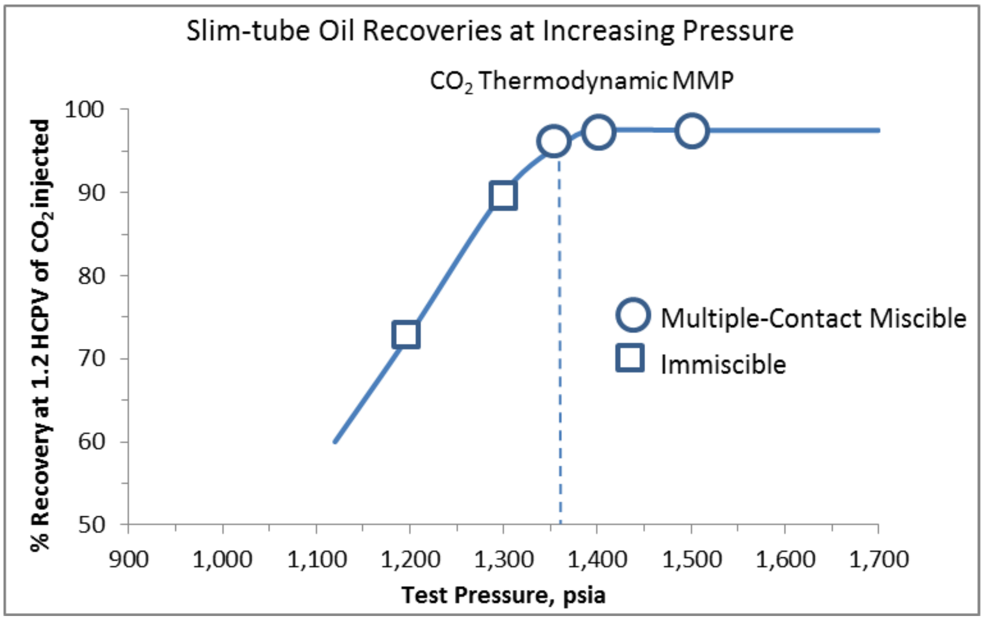

Figure 2. Slim-tube oil recoveries at increasing pressures for fixed oil composition and temperatures (from Yellig and Metcalfe, 1980). CO_2, carbon dioxide; psia, pounds per square inch absolute; %, percent.

There are three types of hydrocarbon miscible mechanisms: (1) first contact; (2) vaporizing gas drive, also known as high-pressure gas drive; and (3) the condensing gas drive, sometimes called enriched gas drive (Stalkup, 1983).

A. First-contact miscible solvents mix with reservoir oil in all proportions, and the mixture remains in one phase. Other solvents, like CO_2, are not miscible on the first contact, but they do develop miscibility on multiple contacts, known as dynamic miscibility, resulting in much improved oil recovery.
B. The vaporizing gas-drive process achieves dynamic miscibility by in situ vaporization of the intermediate-molecular-weight hydrocarbons from the reservoir oil into the injected gas or CO_2.
C. The condensing gas-drive process achieves dynamic miscibility by in situ transfer of intermediate-molecular-weight hydrocarbons (or CO_2 in case of CO_2-EOR) into the reservoir oil.

When the reservoir pressure is above the MMP, miscibility between CO_2 and reservoir oil is achieved with time as displacement occurs in what is classified as multiple-contact or dynamic miscibility. The intermediate and higher molecular weight hydrocarbons from the reservoir oil vaporize into the CO_2 (vaporization gas-drive process) and part of the injected CO_2 dissolves into the oil (condensation gas-drive process) (Merchant, 2010). This mass transfer between the oil and CO_2 allows the two phases to become completely miscible without any interface and helps to develop a transition zone (Jarrell and others, 2002) that is miscible with oil in the front and with CO_2 in the back (fig. 3).

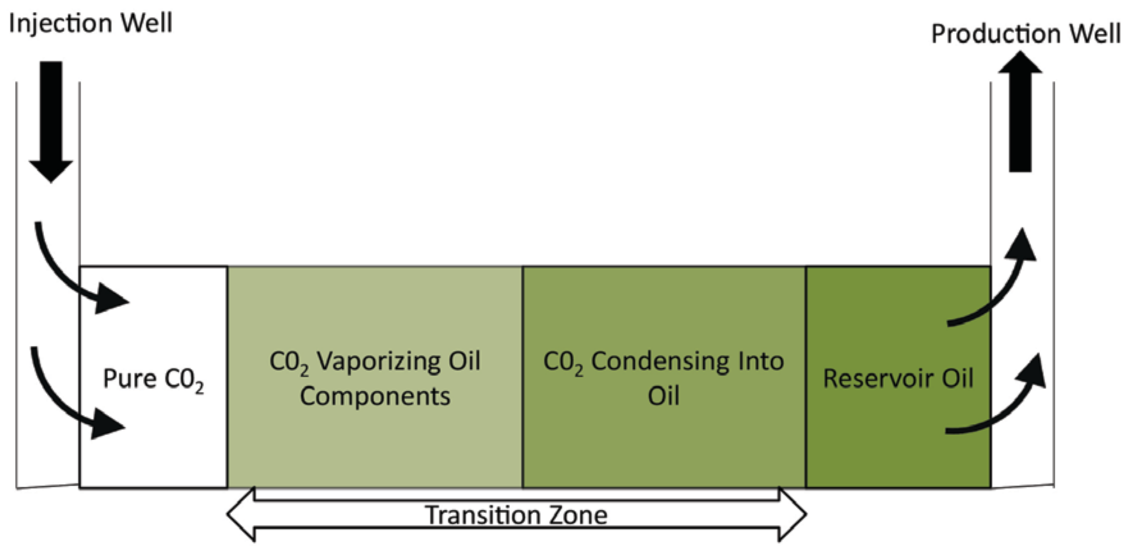

Figure 3. The schematic of the CO_2 (carbon dioxide) miscible process showing the transition zone between the injection and production well. (Modified from Jarrell and others, 2002.)

Slim-tube tests are conducted in a laboratory to determine the MMP and are considered more reliable than the mathematical models or correlations. Because slim-tube tests are expensive, mathematical models and correlations are two additional options available to estimate MMP. Mathematical models provide better results and use equilibrium data and an equation-of-state (EOS) and have a more rigorous procedure for calculating MMP than do correlations. Correlations are easy to use, although they have limitations and are only recommended to use in the absence of slim-tube test or mathematical models. The Holm and Josendal (1974) correlation in combination with Mungan's (1981) extensions takes into account the molecular weight of the C_{5+} components of the reservoir oil and the reservoir temperature (fig. 4), and for a correlation, provides good estimates of MMP. The Lasater (1958) correlation does not estimate MMP but rather is used to estimate the molecular weight of the C_{5+} components of the reservoir oil as a function of oil gravity in degree API (fig. 5) and can be used in conjunction with the Holm and Josendal (1974) correlation for MMP.

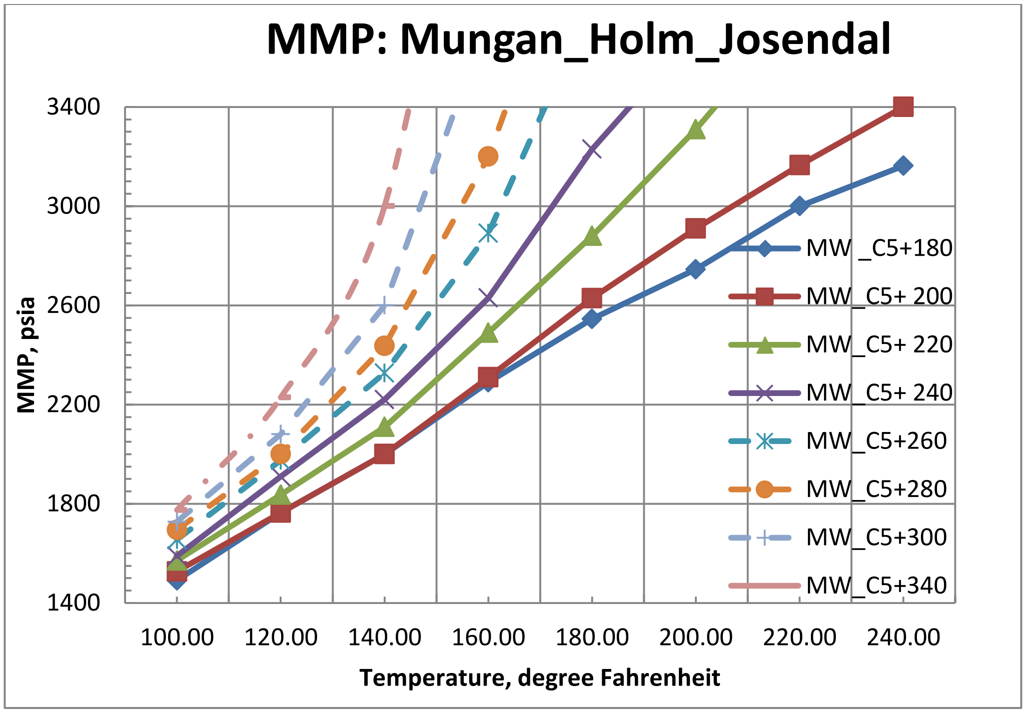

Figure 4. Minimum miscibility pressure (MMP) correlation with molecular weight (MW) of C_{5+} components and reservoir temperature (Mungan, 1981). psia, pounds per square inch absolute.

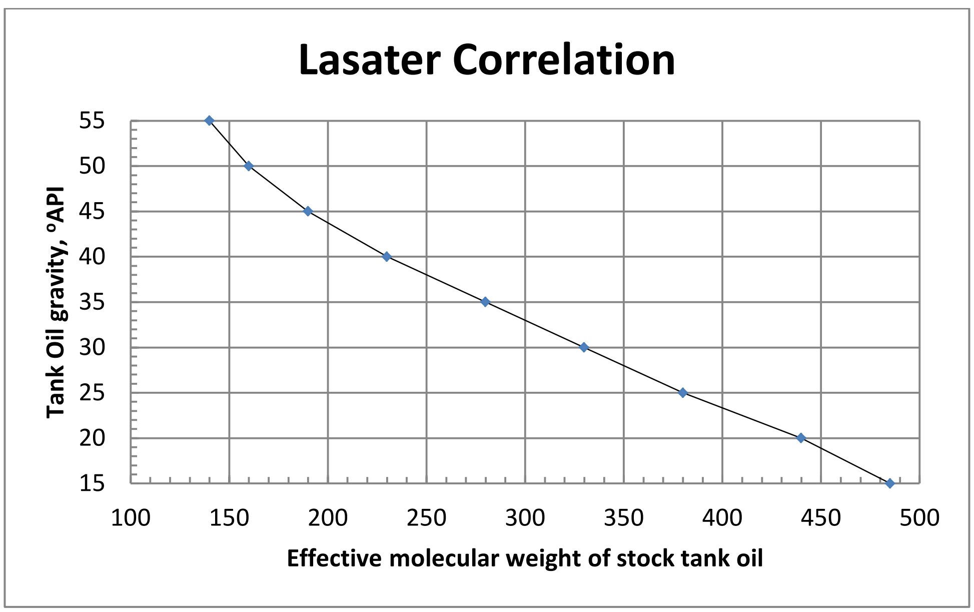

Figure 5. Lasater (1958) correlation relating the molecular weight of C_{5+} components with oil gravity. °API, American Petroleum Institute, an oil gravity measure, in degrees.

As long as the reservoir pressure is above MMP but below fracture pressure, theoretically the oil recoveries could be as high as 90 percent of the original OOIP in the CO_2-swept region (Taber and others, 1997). However, recoveries in most fields are generally lower because of reservoir complexity in terms of lithology, structure, fractures, capillary pressure, rock wettability, oil viscosity and gravity, and permeability contrast between various zones in the reservoir.

Although the lithology (sandstone and carbonate) does not have a direct effect on the CO_2-EOR process, it does come into play due to the reaction of CO_2 with the porous medium of some rocks, for example, limestone and dolomite, and results in higher permeability (Holm, 1959, 1963) and also can improve recovery.

Immiscible Mode. When the reservoir pressure is below the MMP or the reservoir oil composition is not favorable, the CO_2 and oil will not form a single phase and will not be miscible. However, CO_2 will dissolve in the oil causing oil swelling and viscosity reduction that both help to improve sweep efficiency and will facilitate additional oil recovery (Martin and Taber, 1992). Like hydrocarbon gases, CO_2 solubility in oil increases with pressure and decreases with temperature, as can be seen from figure 6 (Simon and Graue, 1965; Welker and Dunlop, 1963).

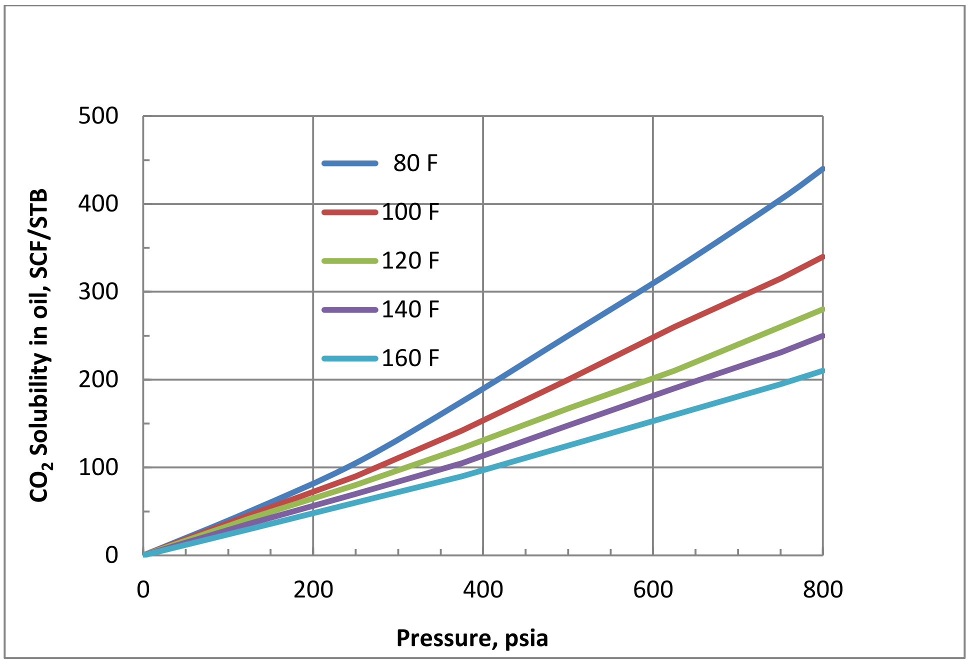

Figure 6. Solubility of carbon dioxide (CO_2) in a crude oil from Moran field in Kansas as a function of pressure and temperature (from Welker and Dunlop, 1963). psia, pounds per square inch absolute; SCF/STB, standard cubic feet per stock tank barrel; F, degrees Fahrenheit.

The role of various reservoir and geologic parameters on the mechanism and displacement behavior of the CO_2-EOR process as well as injection design are described in the following sections.

CO_2 Flood/Injection Designs

After screening the oil reservoirs for the CO_2-EOR candidates comes the task of developing a design for optimal recovery efficiency of the flooding process. Depending on the reservoir geology, fluid and rock properties, timing relative to waterflooding, and well-pattern configuration, the CO_2-EOR flood may use one of several recovery methods as described below (Jarrell and others, 2002) and shown in figure 7.

I. **Continuous CO_2 injection:** This process requires continuous injection of a predetermined volume of CO_2 with no other fluid. Sometimes a lighter gas, such as nitrogen, follows CO_2 injection to maximize gravity segregation. This approach is implemented after primary recovery and is generally suitable for gravity drainage of reservoirs with medium to light oil as well as reservoirs that are strongly water-wet or are sensitive to waterflooding**.**

II. **Continuous CO_2 injection followed with water:** This process is the same as the continuous CO_2 injection process except for chase water that follows the total injected CO_2 slug volume. This process works well in reservoirs of low permeability or moderately homogenous reservoirs.

III. **Conventional water-alternating-gas (WAG) followed with water:** In this process, a predetermined volume of CO_2 is injected in cycles alternating with equal volumes of water. The water alternating with CO_2 injection helps overcome the gas override and reduces the CO_2 channeling thereby improving overall CO_2 sweep efficiency. This process is suitable for most of the reservoirs with permeability contrasts among various layers.

IV. **Tapered WAG:** This design is similar in concept to the conventional WAG but with gradual reduction in the injected CO_2 volume relative to the water volume. With an objective to improve CO_2 utilization, tapered WAG is the method most widely used today because this design improves the efficiency of the flood and prevents early breakthrough of the CO_2, thus less recycled CO_2 and better oil recoveries. The CO_2 utilization is the volume of CO_2 used to produce a barrel of oil and is reported either as a gross volume, including the recycled CO_2, or a net volume.

V. **WAG followed with gas:** This process is a conventional WAG process followed by a chase of less expensive gas (for example air or nitrogen) after the full CO_2 slug volume has been injected.

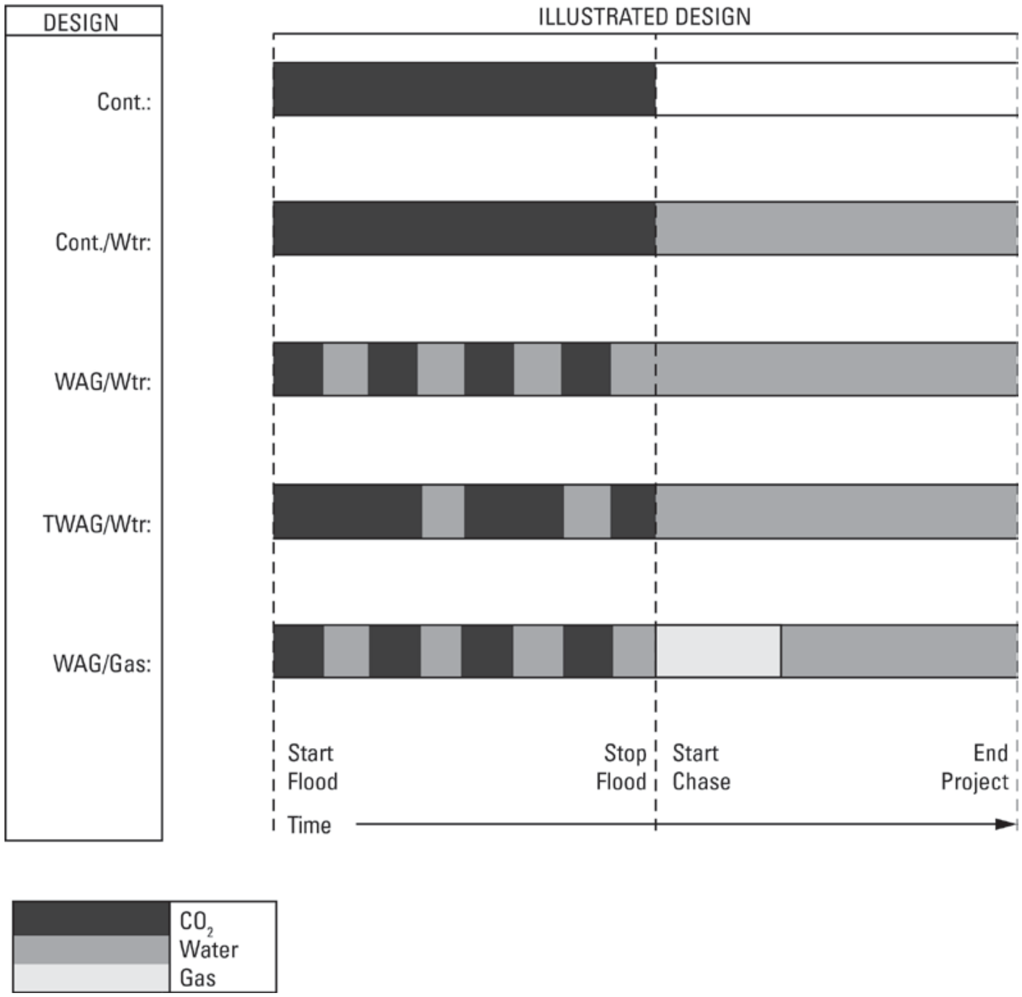

Figure 7. Schematic of various carbon dioxide (CO_2) flood-injectant designs in oil reservoirs (from Jarrell and others, 2002). Cont.= continuous; Cont./Wtr = continuous CO_2 chased with water; WAG/Wtr = conventional water-alternating-gas (WAG) CO_2 flood-chased with water; TWAG/Wtr = tapered water-alternating-gas CO_2 flood-chased with water; WAG/Gas = conventional WAG chased with gas.

Also, injection pattern improves sweep efficiency, and one of the widely used patterns is a normal five-spot (four injection wells at the corners and a production well at the center) or an inverted five-spot (four production wells at the corners with an injection well at the center), and in some cases, seven- or nine-spot patterns. The well pattern could even be a line drive, where the injection wells are located in a straight line parallel to the production wells, if the permeability distribution and other geologic features favor it. The selection of pattern is based on reservoir and fluid properties as well as on reservoir response to fluid injection, which is evaluated through analysis of reservoir performance manually but often using reservoir simulation as a tool; a brief description is given in the section *CO_2-EOR Process—Performance Evaluation and Simulation.*

Oil Recovery Factor or Efficiency

Oil recovery efficiency (E_R) is a measure of the effectiveness of enhanced oil recovery process and has two components: volumetric sweep efficiency (E_V) and displacement efficiency (E_D) (Ghedan, 2009).

$$E_R = E_v * E_D \tag{2}$$

Volumetric sweep efficiency (Ev) is a measure of the volume of a reservoir contacted by the injected fluid and depends on the injection pattern selected, fractures in the reservoir, position of gas-oil and oil-water contacts, reservoir thickness, permeability and areal and vertical heterogeneity, mobility ratio, density difference between the displacing and the displaced fluid, and flow rate. The displacement efficiency (E_D) relates to the displacement or mobilization of oil at the pore level and is defined as the fraction of oil that has been recovered from a zone swept by a waterflood or other displacement process. Displacement efficiency is a function of reservoir pressure and temperature, oil composition, fluid behavior and properties, saturation history of rock-fluid system, slug size, mobility ratio, rock wettability, rock-pore geometry, and structure (Ghedan, 2009; Schlumberger, 1998). Displacement efficiency is equal to $(1–S_{wi}–S_{or})/(1–S_{wi})$, where S_{wi} is the initial or connate water saturation and S_{or} is the residual oil saturation.

Volumetric efficiency (E_V) is a product of both areal efficiency (E_A) and vertical efficiency (E_I), as shown by the following equation (Ghedan, 2009).

$$E_v = E_A * E_I \tag{3}$$

The areal sweep efficiency (E_A) is defined as the fraction of the pattern area from which reservoir fluid is displaced by the injected phase at the time of breakthrough, and it is affected by parameters such as formation dip angle and dip azimuth, presence of fractures, mobility ratio, injection pattern, and directional permeability. The vertical displacement efficiency (E_I) is defined as the ratio of the cumulative height of the vertical sections of the pay zone that are contacted by injection fluid to the total vertical pay-zone height, and it depends on parameters such as mobility ratio, total volume of fluid injected, and the permeability contrast between different pay zones (Ghedan, 2009; Schlumberger, 1998).

Combining equations 2 and 3, the E_R can be shown as

$$E_R = E_A * E_I * E_D \tag{4}$$

CO_2-EOR Process—Performance Evaluation and Simulation

Before conducting a CO_2-EOR application, its feasibility is evaluated by checking the CO_2 miscibility with reservoir oil using correlations or, if necessary, conducting laboratory tests to determine MMP and viscosity. Once the miscibility is established and all other reservoir parameters are favorable, a pilot test is conducted to check the success of the CO_2-EOR process on a small scale in the field. If all results are positive, reservoir simulation is carried out to (a) scale-up the EOR process to an entire oil field and (b) define the optimum design of the WAG ratio and hydrocarbon pore volume (HCPV) injection volumes for maximum oil recovery. (Note: The HCPV injection is defined as the volume of injectant in terms of the fraction of a reservoir's hydrocarbon pore volume, which is equivalent to OOIP in reservoir barrels or cubic feet.)

The planning phase of a CO_2-EOR process includes **reservoir simulation** for a better understanding of reservoir performance and a **pilot test** to verify the simulation forecast.

Reservoir simulation is essentially a three-step procedure—(1) data input and initialization, whereby all the reservoir parameters input into the simulator are accurate and realistically represent the reservoir; (2) history-matching, where the results of simulation are compared with the historical production and pressure data, and the values of some of the sensitive parameters are adjusted to achieve a good match between the simulation results and historical production and pressure data; and (3) forecast, which includes running several scenarios of various WAG ratios and total HCPV injections to determine the optimum design of the CO_2-EOR flood for maximum oil recovery.

The performance of a CO_2-EOR process is continuously monitored by analyzing all the aspects of process—integrity of the slug of CO_2 and water, performance of oil-production wells, gas-oil ratio and water cut, and the injection wells for fluid distribution among various reservoir layers. Based on the analysis results, necessary corrective or remedial measures are taken to keep up the performance of the individual production and injection wells, thereby helping to improve the recovery factor and the project economics.

Of the various parameters, the injection volume (CO_2 and water) in a WAG flood has the most significant effect on the recovery factor, as can be seen from the statistical study by Azzolina and others (2014) on 31 CO_2-EOR candidates. The study revealed that although recoveries of individual reservoirs differed from each other, they all showed a similar trend of oil recovery increase with injection volume of CO_2 and water (in terms of HCPV) as shown in figure 8. In order to compare the performance of all the reservoirs, it was necessary to extrapolate the recovery to a common injection volume (300-percent HCPV).

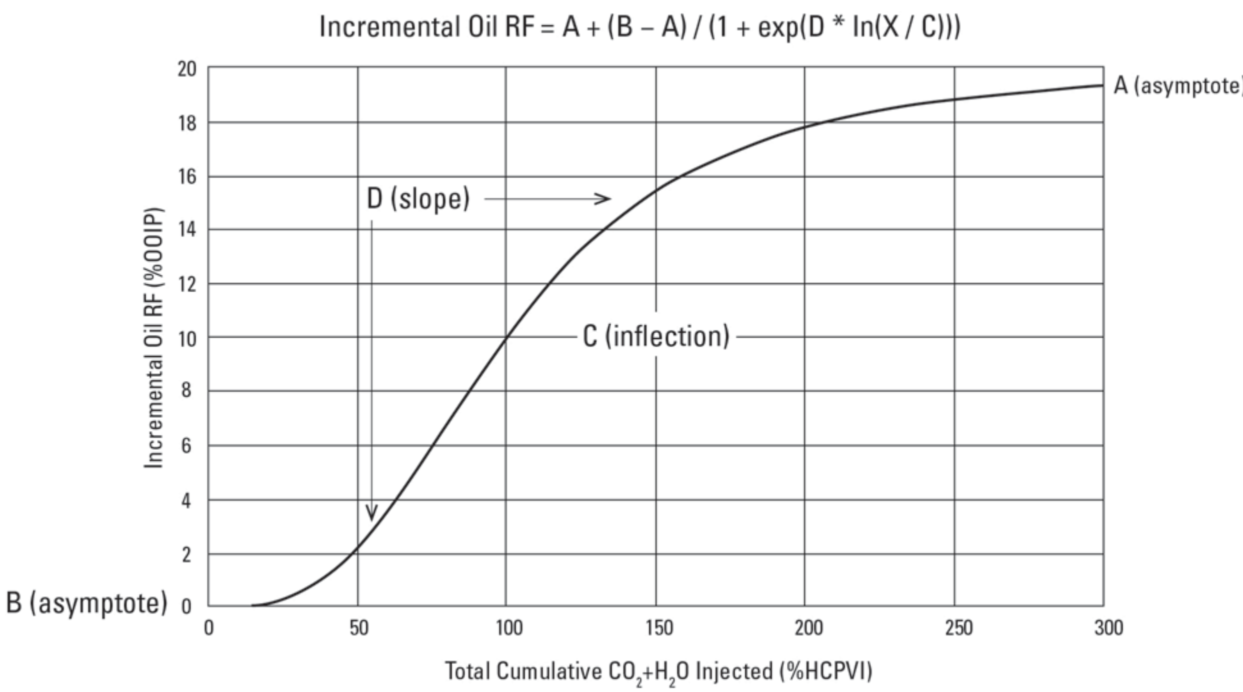

Figure 8. A typical plot of incremental oil recovery with carbon dioxide (CO_2)-enhanced oil recovery and the injection volume (CO_2 + H_2O [water]) (from Azzolina and others, 2014). RF, recovery factor; HCPVI, hydrocarbon pore volume injection.

Operational Aspect

There are several operational aspects that need to be considered before planning to implement the CO_2-EOR in a suitable oil reservoir.

CO_2 Source

There are three possible sources of CO_2: (1) natural hydrocarbon gas reservoirs containing CO_2 as an impurity (generally less than 25 percent), (2) industrial or anthropogenic sources with wide variation of CO_2 percentage in the effluent, and (3) natural CO_2 reservoirs. Depending on the purity, the source gas would require processing in order to bring the CO_2 concentration high enough (90–98 percent) for EOR, especially for a miscible process (Jarrell and others, 2002).

Surface Facilities

The facility requirements for CO_2-EOR are basically similar to what is required for a waterflood with the exception of the CO_2 injection facility, which includes the following three basic elements.

1. Extraction—CO_2 is extracted from the separator gas, which begins to show increasing quantities of CO_2 after its breakthrough in producing wells.
2. Processing—CO_2 is purified to specification after its extraction from the separator gas and is dehydrated before compression.
3. Compression—CO_2 is compressed to raise its pressure for injection.

In addition, gas (natural gas and CO_2) gathering lines, CO_2 distribution lines, and metering are required as a part of the facility design for the CO_2-EOR operation.

As a part of field-wide application, additional injection wells may be required. Well details in terms of their count, locations to comply with well pattern (for example, regular five-spot, inverse five-spot, and so forth), and respective injection rates are usually decided on the basis of simulation results and field experience. Injection-well requirements may be fulfilled by drilling new wells and (or) recompleting older wells. Infill drilling may be useful in some cases to help improve reservoir areal coverage as well as expand pattern flood across the field, whereas step-out drilling may be a better option in other situations.

CO_2-EOR and the World

As of 2012, there were 15 CO_2-EOR projects outside of the United States—six in Canada, three in Brazil, five in Trinidad, and one in Turkey (Koottungal, 2012). Of the six CO_2-EOR miscible projects in Canada, the Weyburn project is the most significant because it was the first project with the primary objective of injecting CO_2 for additional oil recovery as well as for carbon sequestration to help mitigate climate change. In recent years, there have been some serious efforts by Scottish Carbon Capture & Storage (SCCS), the Scottish Government, and other companies to investigate the possible application of CO_2-EOR in the North Sea. This interest is based on the potential for additional oil recovery from depleted oil fields using CO_2 captured from power plants and industry (BBC News, 2012). The objective is to gain a better understanding of the use of CO_2 in EOR operations with the goal of extending the producing life of North Sea oil fields using CO_2 captured from large emitters, such as power plants and industrial facilities, and permanently store the greenhouse gas in offshore oil reservoirs. It is estimated that there is the potential to recover 24 billion barrels of additional oil in the North Sea using the CO_2-EOR process.

Al-Aryani and others (2011) have reported on the first CO_2-EOR pilot test in the Middle East where pulsed neutron logging was used to monitor the performance of a CO_2 flood in one of the largest oil fields in Abu Dhabi, United Arab Emirates. The results of this test will be viewed with great interest based on the fact that it will have a significant impact on the application of CO_2-EOR in many oil-rich countries in the Middle East with the potential for very large additional oil recoveries. In India, a CO_2-EOR feasibility study was implemented in an oil field on the west coast, but the results are not yet publically available (Srivastava and others, 2012). In China, there is ongoing research and pilot testing of CO_2-EOR and carbon sequestration in the Jilin oil field with plans to expand to other fields (Peng, 2011).

The CO_2-EOR has proven to be an economically viable option for EOR, as can be seen by the number of currently active CO2-EOR projects (Koottungal, 2012). Therefore, it is expected that its scope will be further widened for its application to many more oil fields around the world.

Technological Challenges

Although the CO_2-EOR process has been successfully implemented in many conventional reservoirs in the United States and around the world, there are still technical challenges to address such as its application to oil reservoirs with somewhat unfavorable geologic, reservoir, and operating environments and its application to unconventional reservoirs. This challenge has spurred innovation in research and development and led to advances such as recovery from the residual oil zone (ROZ) and transition zone (TZ), and "next generation" CO_2-EOR technology. These advances are not included in the assessment but have the potential to significantly impact the hydrocarbon resource base in the near future and are briefly discussed below.

Residual Oil Zone (ROZ)/Transition Zone (TZ)

In his report "Stranded Oil in the Residual Oil Zone," Melzer (2006) highlighted the significance of the transition zone (TZ) and residual oil zone (ROZ) in terms of additional oil potential that can be tapped with a successfully tested tertiary oil recovery process, that is, CO_2-EOR. The TZ is defined as the section beneath the traditional oil-water contact, and the ROZ is the zone that is below the TZ and is formed due to capillary, hydrodynamic, or structural forces. The significance of these zones can be determined from the estimate of oil that exists in the TZ and ROZ and the potential to recover additional oil from nine fields in the Permian Basin. A preliminary estimate shows that the TZ and ROZ in the Wasson and Seminole fields hold about 4 billion barrels of oil, and in seven other fields (Adair, Cowden North and South, Fuhrman-Mascho, Means, Reeves, Seminole East, and Yellowhouse) hold 4 billion barrels. It is estimated that of the 8 billion barrels of oil in the TZ and ROZ in the nine fields combined, about 3 billion barrels, is potentially recoverable (Melzer, 2006).

There are currently many active ROZ CO_2-EOR pilots and commercially producing projects in the Permian Basin. As recovery from the ROZ has only recently been researched and implemented, data and industry experience are currently limited.

"Next Generation" CO_2-EOR Technology

The current "best practices" CO_2-EOR technology generally recovers 5–15 percent of the OOIP, still leaving behind a large volume of oil due to (a) insufficient injection of CO_2, (b) poor sweep efficiency, (c) poor displacement efficiency, (d) lack of CO_2 contact with remaining oil resources, and (e) inadequate management control, as described by Remson (2010). The "next generation" CO_2-EOR technology could theoretically recover as much as 20 percent of the OOIP. These recoveries may seem to be lower than what could be expected from CO_2-EOR but that is because of the impact of economics. The National Energy Technology Laboratory (NETL) proposed four specific "next generation" CO_2-EOR technology options with the intent to increase the recoveries from current "best practices" technologies as summarized below (Remson, 2010).

1. Increasing CO_2 injection volumes,
2. Optimizing flood design and well placement for extracting more of the residual oil,
3. Improving the mobility ratio by increasing the viscosity of water by use of polymers, and
4. Extending miscibility by reducing the miscibility pressure through the use of liquefied petroleum gas (LPG).

A few more items could be added to the above list, such as use of advancements in drilling technology to drill long horizontal and multiple lateral wells, monitoring the oil front using the time-lapse three-dimensional (3-D) seismic surveys, also known as four-dimensional (4-D) seismic surveys, and production logging. Some of the technologies such as drilling horizontal lateral wells and increasing the slug size of CO_2 have recently been implemented into active CO_2-EOR floods and have shown positive results. In the Peregrino field in Brazil, Statoil reported an increase in recovery factor from 10 percent to approximately 20 percent, attributing it to a high degree of reservoir exposure, drilling of long horizontal wells, and improved water injection (http://www.ogfj.com/articles/2012/11/horizontal-drilling-enhancing-improved-oil-recovery-in-brazil.html, accessed on January 14, 2015). Carpenter (2014) reported on the overall benefits of drilling horizontal wells in a marginal oil field in China, which included improving the economics of the field.

A statistical analysis of CO2-EOR process by Azzolina and others (2014) reveals that oil recovery improves with an increase in the HCPV injection of CO_2+water in a WAG process.

Conclusions

The combined primary and secondary oil recovery is reported to be in the range of 20–40 percent of the OOIP (Stalkup, 1984). As a result, there is a large volume of potentially recoverable oil left in the reservoir, which becomes the target for a suitable EOR processes. Of the various EOR processes, CO_2-EOR is the most widely used process with the highest potential for additional recovery.

With the goal to maximize recovery, a miscible CO_2-EOR process is preferred over the immiscible one. For the CO_2-EOR process, the CO_2 can be injected either as a continuous stream, water-alternating-gas (CO_2), also known as WAG, or as tapering WAG. Because injection volume of CO_2 and water in a WAG flood has a major influence on the recovery factor, it should be evaluated for maximum recovery. Also, there is room for improvement in recovery with the CO_2-EOR process through the use of next generation processes, which include the use of polymers to adjust the mobility ratio, horizontal well technology, time-lapse 3-D seismic surveys (also known as 4-D seismic surveys) to locate sweet spots, and various improvements in well-completion technology.

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