CHAPTER ONE

1.1   **INTRODUCTION**

Oil recovery methods have been grouped into three categories, based on when they are likely to be implemented in a typical oilfield. The oil recovery methods are: primary, secondary and tertiary recovery methods.

Primary recovery methods are typically applied during the initial production phase of an oilfield, exploiting the pressure within the reservoir and using pumps to drive the oil to the surface of the reservoir. The pressure difference developed between the reservoir and the bottom oil producing wells forces oil to flow towards the well. This is called reservoir drive. When production by primary recovery method is no longer viable, secondary recovery methods are applied. They rely on the supply of external energy into the reservoir in the form of injecting fluids to increase reservoir pressure, hence replacing or increasing the natural reservoir drive with an artificial drive. This is typically achieved by injecting water (water flooding) in the reservoir using a number of injection wells. Natural gas can also be injected into the reservoir in a secondary recovery process. The gas is injected, either in the gas-cap to increase the volume of gas within the reservoir, hence increasing reservoir pressure and displaying oil downward

to the production wells or into the oil bank to display oil, however without mixing with it (a process called immiscible displacement).

Tertiary oil recovery methods are typically done towards the end of life of an oilfield, to maintain oil production. This is achieved by altering the flow properties of crude oil and the rock-fluid interactions in the reservoir to improve oil flow. Tertiary recovery techniques are: miscible displacement (Co_2 injection), Thermal enhanced oil recovery method and chemical flooding. Fig 1.1 shows an expected sequence of oil recovery methods in a typical oil field.
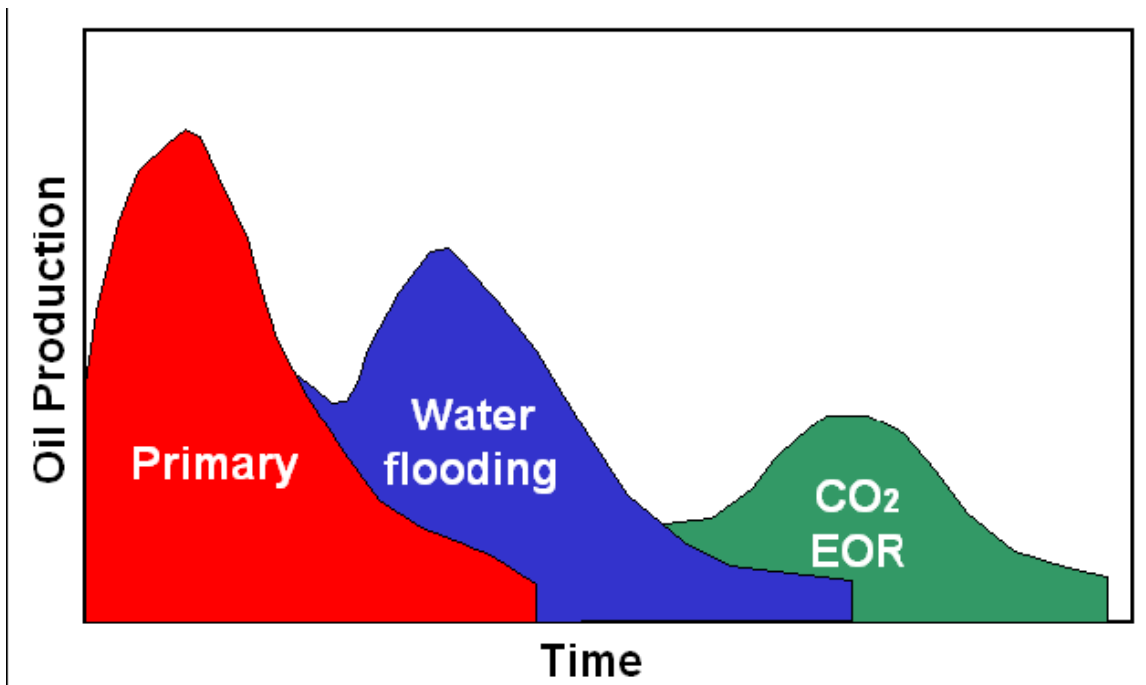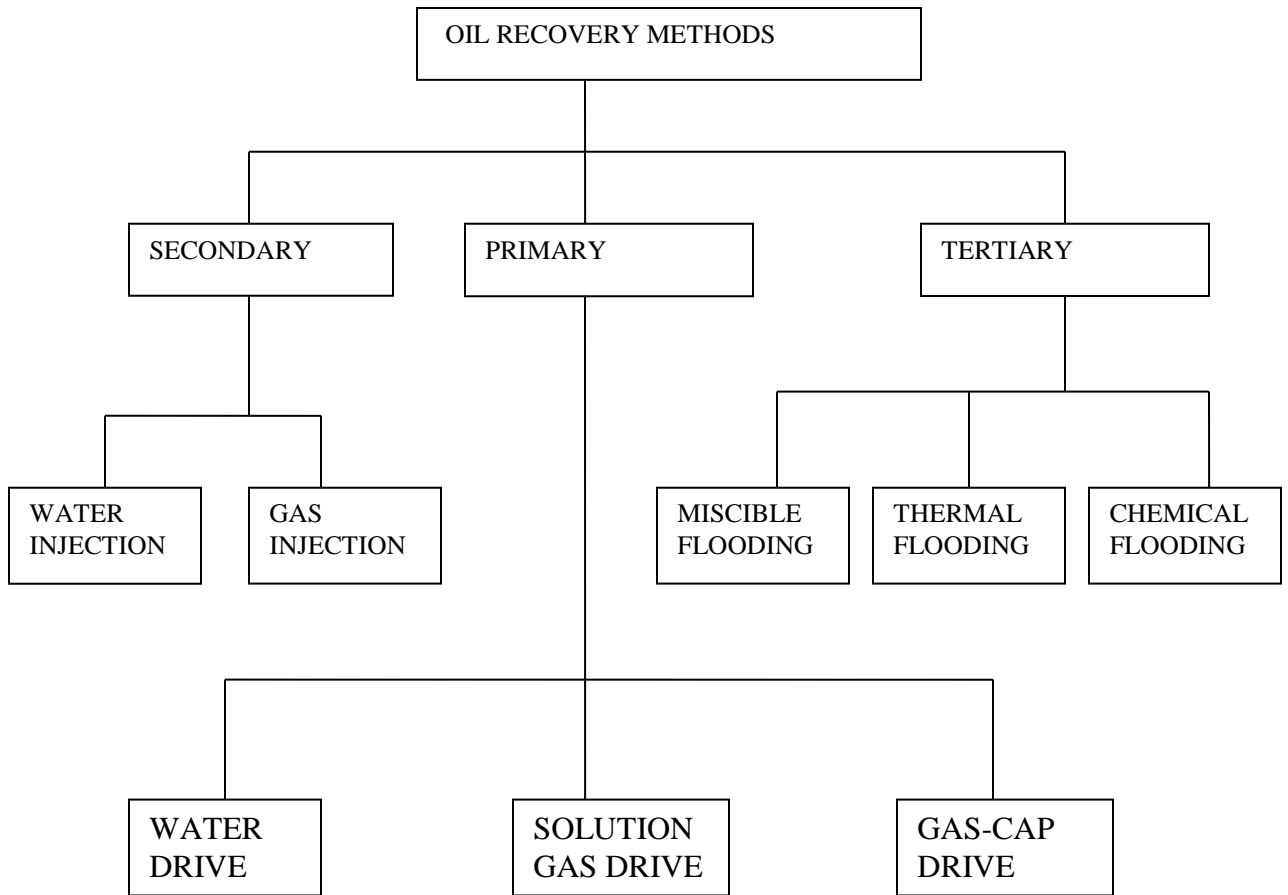

Fig. 1.1 Expected sequence of oil recovery method in a typical oil field.

However, Secondary and tertiary recovery methods are enhanced oil recovery processes. Enhanced oil recovery is not only to restore Formation pressure but also to improve oil displacement or fluid flow in the reservoir. Enhanced oil recovery processes involve the injection of a fluid or fluids of some type into a reservoir. The injected fluids and injection processes supplement the natural energy present in the reservoir to displace oil to a production well. In addition, the injected fluids interact with the reservoir rock/oil system to create conditions favorable for oil recovery. These interactions might for example result in lower interfacial tension (IFT), oil swelling, oil viscosity reduction, wettability modification, or favorable phase behavior. The interactions are attributable to physical and chemical mechanism.

The optimal application of each type of enhanced oil recovery process depends on reservoir temperature, pressure, depth, net pay, permeability, residual oil, water saturation, porosity, and fluid properties such as oil API gravity and viscosity. Figure 1.2 shows the different recovery methods.

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                        │   OIL RECOVERY METHODS   │
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 │INJECTION│ │INJECTION│           │         │FLOODING │ │FLOODING│ │FLOODING │
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              │  WATER   │   │ SOLUTION │   │ GAS-CAP  │
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Fig. 1.2 Oil recovery methods

Miscible displacements have been developed as a successful means of

obtaining greater oil recovery in many reservoirs. However several forms of

miscible displacement operations currently in use or under consideration are:

miscible-slug drive for first contact miscibility, condensing gas drive for

dynamic miscibility, vaporizing-gas drive for dynamic miscibility and

extracting liquid or supercritical fluid drive for dynamic miscibility. The

fourth involves the injection of CO_2 into the reservoir whereupon it expands and thereby pushes additional oil to a production well bore and moreover dissolves in the oil to lower its viscosity and improves the flow rate of the oil. The prospects of using CO_2 has gathered much interest as this would allow storing it away from the atmosphere and hence a tool to combat global warming. However the extra oil extracted would when combusted add additional CO_2 to the atmosphere partially or completely offsetting the benefits of the removed CO_2. Oil displacement by CO_2 injection relies on the phase behavior of CO_2 and crude oil mixtures that are strongly dependent on reservoir temperature, pressure and composition.

Thermal enhanced oil recovery is defined as a process in which heat is introduced intentionally into a subsurface accumulation of organic compounds for the purpose of recovering fuels. The reduction in crude oil viscosity that accompanies a temperature increase not only allows the oil to flow more freely but also results in a more favorable mobility ratio. Thermal recovery processes have been the only practical means of improving the oil recovery performance of reservoirs containing viscous crude's. The use of heat in well bores to decrease the crude viscosity and increases crude production rates has been accepted as viable for many decades. However the most common processes of thermal recovery are:

steam injection and in-situ combustion. Two forms of steam injection are: cyclic steam (steam stimulation) and steam flood (steam displacement) both work on the dual principle that heat can reduce the viscosity of heavy oil thus improving its mobility and recovery.

However cyclic steam injection is a less efficient oil recovery method than steam flooding because the steam penetrates only a limited radius around the production well. However in-situ combustion usually is referred to as fire flood, there are three forms of in-situ combustion processes they are: Dry forward combustion, Reverse combustion and wet combustion. Hot water, hot gas, steam have gained varying degree of acceptance because of its success, relative simplicity and low cost.

However chemical flooding is another enhanced oil recovery method whose primary goal is to recover oil by reducing the mobility of displacing agent (mobility control process) and/or lowering the oil/water interfacial tension (low ITF process). Mobility control process involves injecting a low-mobility displacing agent to increase volumetric and displacement sweep efficiency. The two main techniques of mobility control process are: polymer flooding whereby a small amount of polymer is added to thicken the brine and foam flooding through which low mobility's are attained by injecting a stabilized dispersion of gas in water. Low –IFT methods rely on

injecting a surface active agent (surfactant) which lowers oil/water IFT and ultimately residual oil saturation. Processes that inject the surfactant are called "MP" micellar/polymer floods because of the tendency for surfactants to form micelles in aqueous solutions and the inevitable need to drive the micellar solution with polymer. High PH or alkaline processes produce a surfactant in-situ since these processes rely on reactions with acidic components of the crude to generate the surfactant.

Gas-injection also can be use to stimulate recovery from an oil reservoir. Gas injection has been used to maintain reservoir pressure at some selected level or to supplement natural reservoir energy to a lesser degree by re-injection of a portion of the produced gas. Complete or partial pressure maintenance operations can result in increased hydrocarbon recovery and improved oil reservoir production characteristics. The quantity of additional liquid hydrocarbons that can be recovered from a reservoir is influenced by several characteristics of the particular reservoir including reservoir rock properties, reservoir temperature, pressure, physical and compositional properties of the reservoir fluids, type of reservoir drive mechanism, reservoir geometry, sand continuity, structural relief, rate of production and fluid saturation conditions. The conservation aspect of gas injection pressure maintenance operations can be particularly important with reservoirs

containing volatile high-shrinkage crude oils and with gas-cap reservoirs containing large quantities of condensate gas. Gas injection has also been employed frequently to prevent migration of oil into a gas-cap in oil reservoirs with natural water drives with down dip water injection or both. Other uses of gas injection in high relief reservoirs have been to enhance gravity drainage process and to recover so called attic oil residing above the uppermost oil-zone perforations. However there are two types of gas injection operation they are: Dispersed gas injection and External gas injection.

Water flooding is another enhanced oil recovery method. The practice of water injection expanded rapidly after 1921, the circle-flood; the first flooding pattern consisted of injecting water into a well until surrounding producing wells water out. The watered out production wells were converted to injection wells to create an expanding "circular" water front. The circle – flood method was replace by a "line" flood in which two rows of producing wells were staggered on both sides of an equally spaced row or line of water intake wells. By 1928 the line flood was replaced by a new method termed the "five-spot" because of the resemblance of the pattern to the five-spots on dice.

CHAPTER TWO

2.1   LITERATURE REVIEW

Ching et al (1989) studied extensively the effects of well spacing on water-flooding recovery method. In Ching's study, a correlation of water flooding from Railroad Commission of Texas shows that as well spacing decreases oil recovery increases.

Kyte et al (1992) found oil recovery by water flooding was increased as the free gas saturation at water-flood initiation was increased to above 15%. The desired gas saturation was obtained by injecting helium into the formation/core.

Shervin (1941) did a comprehensive work on performance of "the Jones Sand Pool" under gas injection in down-dip location of the reservoir. This resulted in the recovery of 65 percent of estimated 70 percent of STO11P at abandonment.

MeGraw (1949) also carried out a gas injection project on the Picktons Field. In his project, a critical review revealed that gas injection was the most economic method of recovering substantial hydrocarbons in place. Out of the original 34MMSTB (amounting to 30 percent of STOIIP) was recovered.

Mettzer et al (1960) carried out an efficient gas displacement project in Raleigh Field, Mississippi. At the end of the programme, a review of the production behavior of the reservoir under gas injection proved beyond reasonable doubt, the success of gas injection. In the early production performance history, the field was found to be producing about 1708 BOPD with eleven wells. Thereafter, production dropped to 1081 BOPD and loss of 2271psi in reservoir pressure caused large drop in the tubing pressures and well productivities.

Hence, this was followed by a further production drop to 208 BOPD before gas injection commenced. Following the gas injection project, a recovery of 833,926 STB of oil more than the estimated ultimate recovery under primary depletion was achieved. Finally, by the completion of the project the Raleigh Field produced 2,900,500 STB of oil equivalent to 71 percent of the original oil in place, was extracted from the productive sand.

Usikalu (1990) of Nigeria Agip Oil Company did a review work on the injection and production performance of one field being produced by gas injection. Using field and laboratory data extensively, different methods of monitoring the gas front advancement and gas break-through in the reservoir were evaluated and concluded that the project yield incremental oil of

economic value in the field and also minimized gas flaring in the Niger – Delta.

Dunn (1911) successfully demonstrated that repressuring a reservoir by injecting gas increased oil production. Dunn based his experiments on an idea he and gained in Ohio in 1903 when gas, at a pressure of 45psi was force into an oil well producing from a 500-ft (152-m) deep sand. According to Dunn, after ten days the gas pressure was released the well began to pump much oil which continued until the gas had worked out again.

Beckman (1926) suggested the concept of using microorganism to recover oil when he analyzed the action of bacteria on mineral oil and proposed that bacterial enzymes could be used in oil recovery.

Zobell (1947) conducted a series of field test and discovered that bacteria can release oil from sedimentary materials. From those tests Zobell found that the mechanism by which bacteria oil release could occur are: production of gaseous CO_2, production of organic acids and detergents, dissolution of carbonates in the rock and physical dislodgement of the oil.

CHAPTER THREE

METHODOLOGY

Enhanced oil recovery processes supplement the natural energy present in the reservoir to displace oil to a production well. There are several enhanced oil recovery methods.

3.1 WATERFLOODING

Water flooding, an enhanced oil recovery method involves injecting water into a reservoir to obtain additional oil recovery through movement of reservoir oil to a producing well after the reservoir has approached its economically productive limit by primary recovery methods.

3.1.1 Development of equations describing multiphase

Flow in porous media

Solution of equations describing multiphase flow in porous media is developed by the continuity equation, which is the partial differential equation describing the law of conservation of mass at every point in the porous medium.

Continuity equation for porous media with fluid flow

Consider a small element of a porous medium shown in Fig. 3.1.1.1 that has dimensions ΔX, ΔY, & ΔZ. Considering the flow of two fluids oil and water Darcy flow is assumed.

The law of conservation of mass, written in terms of rates, is described as follows:

$$\left(\begin{array}{l}\text{Mass of oil entering the}\\\text{differential element in}\\\text{the time increment } \Delta t\end{array}\right) - \left(\begin{array}{l}\text{Mass of oil leaving the}\\\text{differential element in}\\\text{the time increment } \Delta t\end{array}\right)$$

$$= \left(\begin{array}{l}\text{Mass of oil that}\\\text{accumulates within the}\\\text{differential element in}\\\text{the time increment } \Delta t\end{array}\right) \quad \dots\dots\dots\dots\dots \quad (3.1.1.1)$$

Referring to Fig. 3.1.1.1, the mass of oil entering ΔX, ΔY, & ΔZ in the time increment Δt is defined as

$$[(\rho_o u_{o_x}\big|_x \Delta y\Delta z\Delta t] + [(\rho_o u_{o_y}\big|_y \Delta x\Delta z\Delta t] + [(\rho_o u_{o_z}\big|_z \Delta x\Delta y\Delta t] \quad \dots\dots\dots\dots\dots\dots 3.1.1.2$$

Where the first quantity is the mass of oil flowing through plane x in Δt, the

second quantity is the mass of oil flowing through plane y in Δt and the third

quantity is the mass of oil flowing through plane z in Δt.

The mass of oil leaving ΔXΔYΔZ in the time increment Δt is

$$[(\rho_o u_{o_x}\big|_{x+\Delta x}\ \Delta y\Delta z\Delta t] + [(\rho_o u_{o_y}\big|_{y+\Delta y}\ \Delta x\Delta z\Delta t] + [(\rho_o u_{o_z}\big|_{z+\Delta z}\ \Delta x\Delta y\Delta t] \quad \dots\dots\dots \quad 3.1.1.3$$
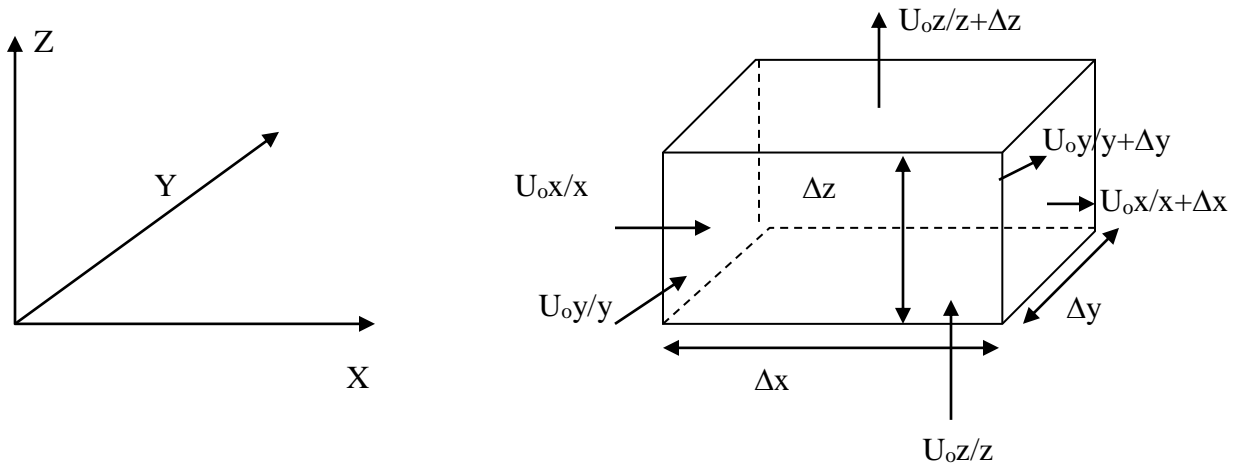
Fig. 3.1.1.1 Differential element of porous rocks

Oil accumulates within the differential element by change of oil saturation,

variation of density with pressure and temperature, and the change in the

porosity of the differential element caused by large change in net confining

pressure.

The mass of oil that accumulates in $\Delta X \Delta Y \Delta Z$ during the time increment Δt is

$$(\rho_o s_o \phi \Delta x \Delta y \Delta z|_{t+\Delta t} - (\rho_o s_o \phi \Delta x \Delta y \Delta z|_{t} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad 3.1.1.4$$

Where:

$\phi \Delta X \Delta Y \Delta Z$ is the incremental (PV). Substituting equ 3.1.1.2, 3.1.1.3 and 3.1.1.4 into equ. 3.1.1.1 And re-arranging gives equ 3.1.1.5

$$-[(\rho_o u_{o_x}\big|_{x+\Delta x} \Delta y \Delta z \Delta t - (\rho_o u_{o_x}\big|_{x} \Delta y \Delta z \Delta t$$

$$-[(\rho_o u_{o_y}\big|_{y+\Delta y} \Delta x \Delta z \Delta t - (\rho_o u_{oy}\big|_{y} \Delta x \Delta z \Delta t]$$

$$-[(\rho_o u_{o_z}\big|_{z+\Delta z} \Delta x \Delta y \Delta t - (\rho_o u_{oz}\big|_{z} \Delta x \Delta y \Delta t]$$

$$= (\rho_o s_o \phi)\big|_{t+\Delta t} \Delta x \Delta y \Delta z - (\rho_o s \phi)\big|_{t} \Delta x \Delta y \Delta z] \qquad \ldots\ldots\ldots.3.1.1.5$$

Equ 3.1.1.5 can be expressed as a partial differential equation by recalling the definition of a derivative from differential calculus.

$$\frac{\partial g}{\partial x_{y,z,t}} = \lim_{\Delta x \to 0} \frac{g(x+\Delta x, y, z, t) - g(x, y, z, t)}{\Delta x} \qquad \ldots\ldots\ldots\ldots\ldots.3.1.1.6$$

Dividing both sides of Equ (3.1.1.5) by $\Delta x \Delta y \Delta z \Delta t$, gives

$$-\frac{(\rho_o u_{o_x})\big|_{x+\Delta x} - (\rho_o u_{o_x})\big|_{x}}{\Delta x} - \frac{(\rho_o u_{o_y})\big|_{y+\Delta y} - (\rho_o u_{o_y})\big|y}{\Delta y}$$

$$-\frac{(\rho_o u_{o_z}\big|_{z+\Delta z} - (\rho_o u_{o_z}\big|_{z}}{\Delta z} = (\rho_o s_o \phi\big|_{t+\Delta t} - (\rho_o s\phi\big|_{t}]/\Delta t \qquad \ldots \ldots \ldots \ldots \ldots 3.1.1.7$$

The limit of equ 3.1.1.7 as $\Delta X \Delta Y \Delta Z$ and Δt tend to zero is equ 3.1.1.8 the continuity equation for the oil phase. The limit $\Delta X \Delta Y \Delta Z \to 0$ means an infinitesimally small portion of a porous medium through which fluid flow.

$$- \frac{\partial}{\partial x}(\rho_o u_{o_x}) - \frac{\partial}{\partial y}(\rho_o u_{o_y}) - \frac{\partial}{\partial z}(\rho_o u_{o_z}) = \frac{\partial}{\partial t}(\rho_o s_o \phi) \dots\dots\dots\dots\dots 3.1.1.8$$

Similarly for the water phase

$$- \frac{\partial}{\partial x}(\rho_\omega \mu_{wx}) - \frac{\partial}{\partial Y}(\rho_\omega u_{\omega_Y} - \frac{\partial}{\partial z}(\rho_\omega u_{w_z}) = \frac{\partial}{\partial t}(\rho_\omega s_\omega \phi) \dots\dots\dots\dots\dots 3.1.1.9$$

These equations assume that there is no dissolution of oil in the water phase. Frequently referring to this assumption by stating that there is no mass transfer between the phases.

Some rocks are compressible, in a rigorous development of the continuity equation for porous media; the rock also satisfies the continuity equation relative to the fixed x, y, z coordinate system. That is

$$- \frac{\partial}{\partial x}(\rho_f \mu_{fx}) - \frac{\partial}{\partial y}(\rho_f u_{f_Y}) - \frac{\partial}{\partial z}(\rho_z u_{fz_z}) = \frac{\partial}{\partial t}(\rho_f (1-\phi)] \quad \dots\dots\dots\dots 3.1.1.10$$

The above equations represent the law of conservation of mass applied to an infinitesimal volume of porous medium through which fluids are flowing.

Fortunately, the velocity of reservoir rock is negligible and Equ 3.1.1.10 can be approximated by Equ 3.1.1.11 for most petroleum engineering application.

$$\frac{\partial}{\partial t}(\rho_f(1-\phi)]=0 \qquad \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots 3.1.1.11$$

The frontal advance equation for unsteady 1D displacement

The displacement of one fluid by another fluid is an unsteady state process because the saturations of fluid change with time, this causes changes in relative perm abilities and either pressure or phase velocities.

Fig. 3.1.1.2 shows four representative stages of a linear water-flood at interstitial water saturation. Initial water and oil saturations are uniform as shown in Fig. 3.1.1.2a.

Injection of water at flow rate q_t causes oil to be displaced from the reservoir. A sharp water saturation gradient develops, as in fig. 3.1.1.2b. Water and oil flow simultaneously in the region behind the saturation change. There is no flow of water ahead of the saturation change because the permeability to water is essentially zero. Eventually, water arrives at the end of the reservoir as shown in fig. 3.1.1.2c. This point is called breakthrough. After breakthrough the fraction of water in the effluent increases as the

remaining oil is displaced. Fig. 3.1.1.2d depicts the water saturation in a linear system late in the displacement.

A method to predict displacement performance will be presented. This method is the Buckley Leveret or frontal advanced model which can be solved easily with graphical techniques.

(a) Initial conditions

(b) Midpoint in flood

(c) Breakthrough

(d) Late in flood
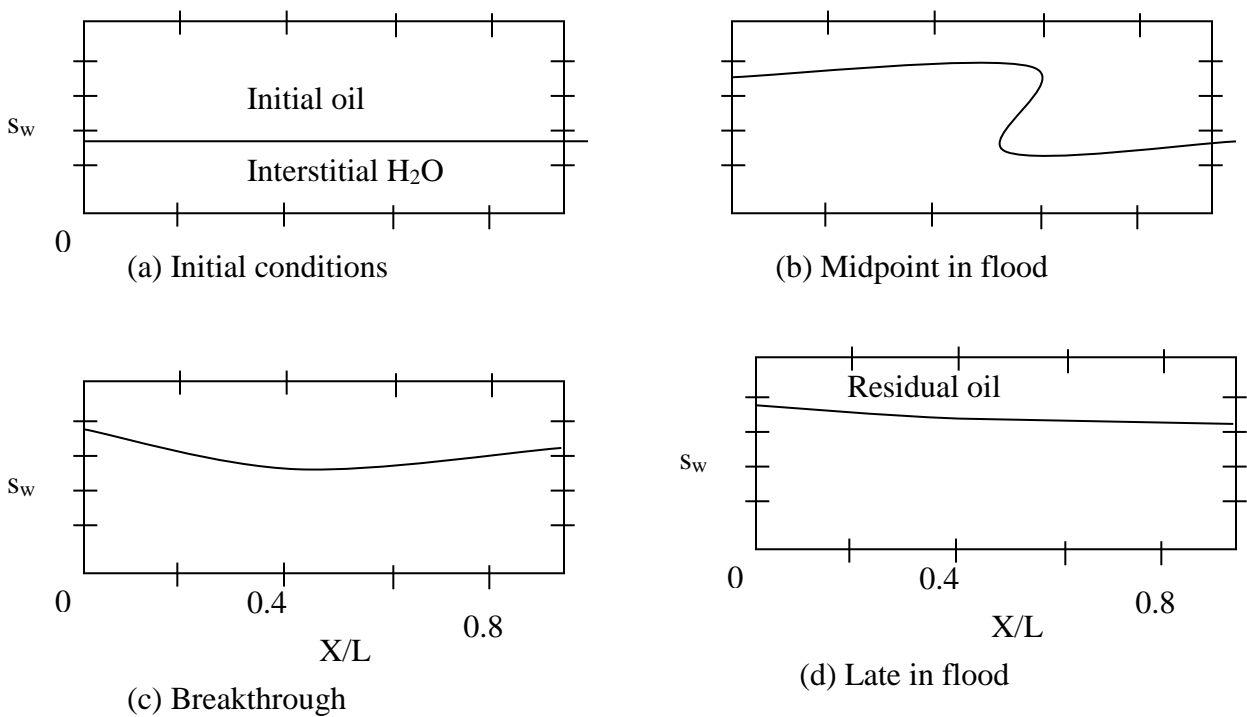
Fig. 3.1.1.2: Saturation distribution during different stages

of a water flood

Buckley-Leverett model

Buckley–Leverett equation also called frontal advance equation which states that in a linear displacement process, each water saturation moves through the porous rock at a velocity that can be computed from the derivative of the fractional flow with respect to water saturation.

Assumption

1.   Incompressible flow

2.   That the fractional flow of water is a function only of water saturation

3.   No mass transfer between phases

The Buckley-Leverett model was developed by application of the law of conservation of mass to the flow of two fluids (oil and water) in one direction (x).

When oil is displaced by water from a linear system

Equ 3.1.1.8 and 3.1.1.9 becomes Equ 3.1.1.12 and 3.1.1.13

$$\frac{\partial}{\partial x}(\rho_o u_{o_x}) = \frac{\partial}{\partial t}(\rho_o s_o \phi) \quad \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots 3.1.1.12$$

And

$$\frac{\partial}{\partial x}(\rho_\omega \mu_{wx}) = \frac{\partial}{\partial t}(\rho_\omega s_\omega \phi) \quad \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots 3.1.1.13$$

Equation 3.1.1.12 and 3.1.1.13 may also be written in terms of volumetric flow rates q_o and q_w by multiplying both sides of the equations by cross-sectional area available for flow (A). Thus

$$-\frac{\partial}{\partial x}(\rho_o q_o) = A\frac{\partial}{\partial t}(\rho_o s_o \phi) \qquad\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 3.1.1.14$$

And

$$\frac{\partial}{\partial x}(\rho_\omega q_w) = A\frac{\partial}{\partial t}(\rho_\omega s_\omega \phi) \qquad\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 3.1.1.15$$

In the Buckley–Leverett model, water and oil are considered incompressible and thus ρ_o and ρ_w are constant. Porosity is also constant so equation 3.1.1.14 and 3.1.1.15 becomes

$$-\frac{\partial q_o}{\partial x} = A\phi\frac{\partial s_o}{\partial t} \qquad\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 3.1.1.16$$

And

$$-\frac{\partial q_w}{\partial x} = A\phi\frac{\partial s_w}{\partial t} \qquad\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 3.1.1.17$$

The sum of Equ 3.2.1.16 and 3.1.1.17 is Equ 3.1.1.18

$$-\frac{\partial(q_o + q_w)}{\partial x} = A\phi\frac{\partial}{\partial t}(s_o + s_w) \qquad\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 3.1.1.18 \text{ But}$$

$s_w + s_o = 1.0$

$$\frac{\partial(q_o + q_w)}{\partial x} = 0 \qquad\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 3.1.1.19$$

or: $q_o + q_w = q_t = $ constant

The fractional flow of a phase, f, is defined as the volume fraction of the phase that is flowing at x, t.

For oil and water phases

$$f_o = \frac{q_o}{qt} = \frac{q_o}{q_w + q_o} \qquad \text{..3.1.1.20}$$

And

$$f_w = \frac{q_w}{qt} = \frac{q_w}{q_w + q_o} \qquad \text{..3.1.1.21}$$

Because the fractional flow is a volume balance.

$$f_o + f_w = 1.0 \qquad \text{..3.1.1.22}$$

Substituting equation 3.1.1.21 into equation 3.1.1.17 we obtain:

$$-\frac{\partial f_w}{\partial x} = \frac{\phi A}{qt}\frac{\partial s_w}{\partial t} \qquad \text{..3.1.1.23}$$

The water saturation in a porous rock is a function of two independent variables; x and t. Thus we can write

$$s_w = s_w(x,\ t) \qquad \text{..3.1.1.24}$$

Or

$$ds_w = \left(\frac{\partial s_w}{\partial x}\right)_t dx + \left(\frac{\partial s_w}{\partial t}\right)_x dt \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots3.1.1.25$$

If there is interest in what happens in a particular saturation, s_w, it is possible to set $ds_w = 0$ in equ 3.2.1.25 thus we then obtain:

$$\left(\frac{dx}{dt}\right)_{sw} = -\frac{\left(\dfrac{\partial s_w}{\partial t}\right)_x}{\left(\dfrac{\partial s_w}{\partial x}\right)_t} \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots3.1.1.26$$

$$\left(\frac{dx}{dt}\right)_{sw} = \frac{qt}{\varphi A}\left(\frac{\partial f_w}{\partial s_w}\right)_t \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots3.1.1.27$$

3.1.2 Water flood design

The design of a water flood involves both technical and economic considerations. Economic analyses are based on estimates of water flood performance. These estimates may be rough or sophisticated depending on the requirements of a particular project and the philosophy of the operator.

Factors constituting a design

The five steps in the design of a water flood are as follows:

1. Evaluation of the reservoir, including primary production performance.

2. Selection of potential flooding plan

3. Estimation of injection and production rates

4. Projection of oil recovery over the anticipated life of the project for each flooding plan.

5. Identification of variables that may cause uncertainty in the technical analysis.

Reservoir description

The purposes of a reservoir description in water flood design are:

1. To define the area and vertical extent of the reservoir.

2. To describe quantitatively the variation in rock properties such as permeability and porosity within the reservoir.

3. To determine the primary production mechanism, including estimates of the oil remaining to be produced under primary operation.

4. To estimate the distribution of the oil resource in the reservoir.

5. To evaluate fluid properties required for predicting water performance.

The data and interpretations that are obtained in development a reservoir description make up many of the input data for the water flood design. The following information is usually available from a reservoir description.

Reservoir characteristics

1. Area and vertical extent of producing formation

2. Isopach maps of gross and net sand

3. Correlation of layers and the zones.

Reservoir Rock properties

1. Area variation of average permeability, including directional trends derived from geological interpretations.

2. Areal variation of porosity.

3. Reservoir heterogeneity – particularly the variation of permeability with thickness and zone.

Reservoir fluid properties

1. Gravity, Formation volume factor, and viscosity as a function of reservoir pressure.

Primary producing mechanism

1. Identification of producing mechanism such as fluid expansion, solution gas drive or water drive.

2. Existence of gas caps or aquifers

3. Estimation of oil remaining to be produced under primary operations.

4. Pressure distribution in the reservoir.

Distribution of oil resources in the reservoir at beginning

of water flood

1. Trapped – gas saturation from solution gas drive.

2. Vertical variation of saturation as a result of gravity segregation.

3. Presence of mobile connate water.

4. Areas already water flooded by natural water drive.

3.1.3 Estimation of water flood performance

Water flood design involves both technical and economic considerations. To make an economic evaluation, it is necessary to estimate fluid injection and

production rates and to make a projection of oil production (or recovery) for the anticipated life of the project for each flooding plan. These estimates, along with the well layout for the water flood provide sufficient technical data to estimate investment requirements, operating costs, and income for a proposed water flood.

Production rates

It is necessary to estimate the production rates as a function of time in water flood performance.

The production rate/time relationship is found empirically. The oil rate, $q_o(t)$, is required to produce the estimated water flood reserves (N_{pw}) in the estimated flood life.

Mathematically

$$N_{pw} = \int_o^{t_l} \frac{q_o(t)dt}{B_o}$$

Where: t_l = flood life (Time at which the production rate is at the economic limit).

Injection Rates

Injection rate is a key economic variable in the evaluation of a water flood. When a water flood is conducted in an established area, there may be data or

correlations based on operating experience. Typically, injection rates are correlated in terms of injectivities as barrels per day per acre foot, barrels per day per net foot of sand, or barrels per day per net foot per pounds per square inch. Specific values are dependent on reservoir rock properties, fluid/rock interactions, spacing and available pressure drop. Comparable values would be expected under similar reservoir and operating conditions.

It is often possible to estimate injection rates from relatively simple equations when rates are not known. Two situations are of interest in water flooding operations. If water injection is initiated before a mobile – gas saturation develops, the system may be treated as if it were liquid filled. Another case is the depleted reservoir were a mobile – gas saturation develops during primary production by solution gas drive. In these reservoirs initial injection rates decline rapidly as mobile gas is displaced. Because controlling rates are those for liquid filled system.

3.1.4   Selection of potential flooding plans

Selection of the water flooding plan is determined by factors that are often unique to each reservoir. In some reservoirs, the water flood may be done with edge wells to form a peripheral flood. This is called pressure maintenance, when water injections supplements declining reservoir energy

from solution – gas drive or an aquifer of limited extent. Pressure maintenance often begins while the reservoir is still under primary operation to maintain maximum production rates. Pattern flooding, an alterative to pressure maintenance, may be selected because reservoir properties will not permit water flooding through edge wells, as desired injection rates. In pattern flooding, injection and withdrawal rates are determined by well spacing as well as reservoir properties, pattern size becomes a variable that is considered in economic analyses.

The selection of possible water flooding patterns depends on existing wells that generally must be used because of economics. Patten selection is constrained by the locations of production wells. Many fields are developed for primary production on a uniform well spacing as in fig. 3.1.4.1A. If only existing wells are used, the options are limited to a line drive, five-spot, or nine-spot pattern as shown in figs. 3.1.4.1B through 3.1.4.1D. Infill drilling of injection wells can be used to reduce spacing as in fig. 3.1.4.2 Any of these pattern can be used to water flood a reservoir, but final selection of spacing and pattern type, when there are several possibilities, is determined by comparison of the economics of alternative flooding schemes.
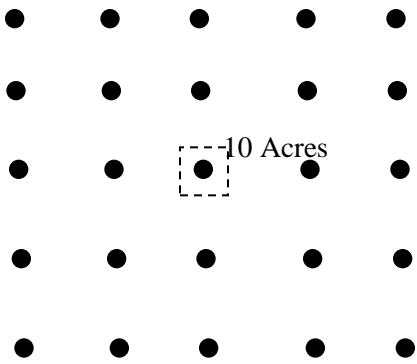
Fig. 3.1.4.1A Regular well spacing
during primary production period-
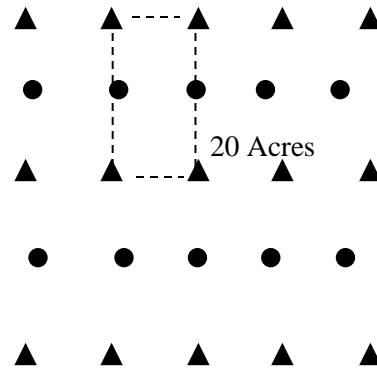10-acre spacing

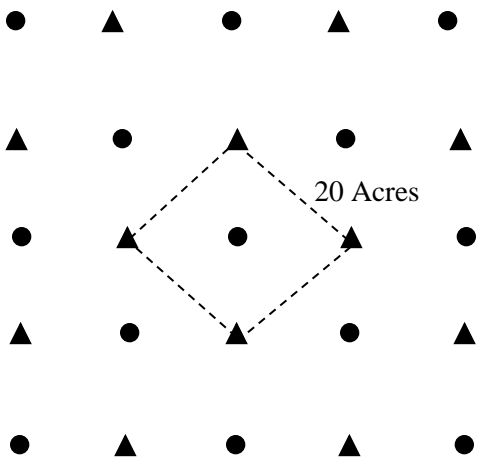Fig. 3.1.4.1B Line drive
spacing on 20-acre spacing

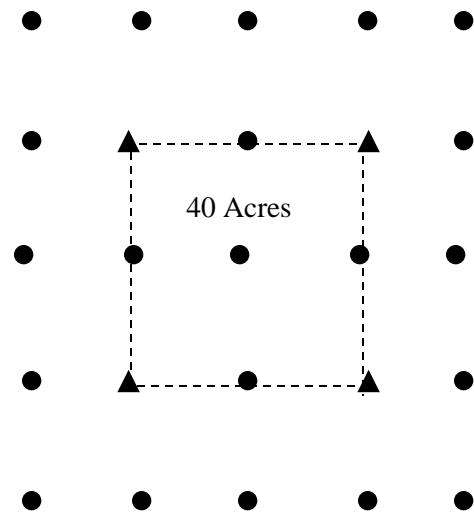
Fig. 3.1.4.1 C-Five-spot pattern on
20-acres spacing

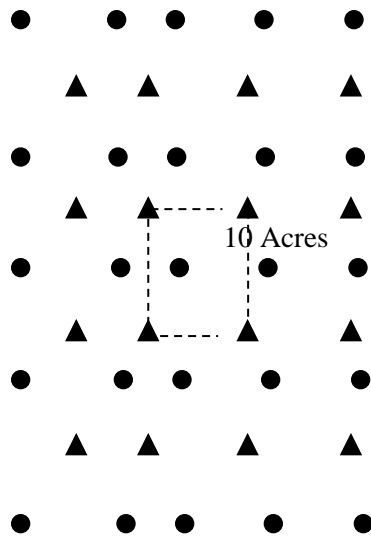Fig. 3.1.4.1d Nine-spot pattern on
40-acre spacing.

Fig. 3.1.4.2 Infill drilling to create
10-acres spacing

3.2 GAS INJECTION OPERATION

Gas injection has been used to maintain reservoir pressure at some selected level or to supplement natural reservoir energy to a lesser degree by reinjection of a portion of the produced gas.

Basically, increased hydrocarbon recovery can be attributed to the oil displacement and vaporization action of the injected gas.

Types of gas – injection operations

Gas-injection operations are generally classified into two distinct types depending on where in the reservoir, relatively to oil zone, the gas is introduced. Basically, the same physical principles of oil displacement apply to either type of operation; however, the analytical procedures. For predicting reservoir performance, the overall objectives and the field applications of each type of operation may vary considerably.

Dispersed Gas Injection

Dispersed gas-injection operations, frequently referred to as internal or pattern injection, normally use some geometric arrangement of injection wells for the purpose of uniformly distributing the injected gas throughout the oil – productive portions of the reservoir. In practice, injection–well/production-well arrays vary from conventionally regular pattern configurations (e.g. five-spot, seven – spot) to patterns seemingly haphazard in arrangement with relatively uniformity over the injection area. The selection of an injection arrangement is usually base on considerations of reservoir configuration with respect to structure, sand continuity, permeability and porosity variations, and the number and relative positions of existing wells.

This method of injections has been found adaptable to reservoirs having low structural relief and to relatively homogenous reservoirs having low specific permeability's. Because of greater injection-well density, dispersed gas injection provides rapid pressure and production response – thereby reducing the time necessary to deplete the reservoir. Dispersed injection can be used where an entire reservoir is not under one ownership, particularly if the reservoir cannot be conveniently unitized.

Some limitations to disperse – type gas injection are:

1. Little or no improvement in recovery efficiency is derived from structural position or gravity drainage.

2. Areal sweep efficiencies are generally lower than for external gas injection operations.

3. Gas 'fingering' caused by high flow velocities generally tend to reduce the recovery efficiency over that which could be expected from external injection.

4. Higher injection well density contributes to greater installation and operating costs.

External Gas Injection

External gas-injection operations frequently referred to as crestal or gas-cap injection uses injection wells in the structurally higher positions of the reservoir – usually in the primary or secondary gas cap. This manner of injection is generally employed in reservoirs having significant structural relief an average to high specific permeability's. Injection wells are positioned to provide good areal distribution of the injected gas and to obtain maximum benefit of gravity drainage, the number of injection wells required for a specific reservoir will generally depend on the injectivity of each well and the number of wells necessary to obtain adequate areal distribution.

External injection is generally considered superior to dispersed – type injection, since full advantage can usually be obtained from gravity drainage benefits. In addition, external injection ordinarily will result in greater areal sweep and conformance efficiencies than dispersed injection operations.

3.3   MISCIBLE DISPLACEMENT

Miscible displacement processes have been developed as a successful means of obtaining greater oil recovery in many reservoirs.

3.3.1 Forms of miscible displacement

Several forms of miscible displacement operations are currently in use, they are: miscible slug-drive for first – contact miscibility, condensing–gas drive for dynamic miscibility, vaporizing-gas drive for dynamic miscibility and extracting liquid or critical fluid drive for dynamic miscibility.

3.3.1.1 Miscible – slug process

In this type of miscible drive, a slug of material such as propane or LPG (Liquefied petroleum gases C_2 to C_4) is injected into the reservoir then followed by a dry gas. The slug miscible displaces oil from the contacted portion of the reservoirs by virtue of a solvent cleaning action.

The basic requirement for miscible displacement by the slug process is that the solvent slug be miscible with both the reservoir oil and dry gas, which is mostly methane. Miscibility between the LPG slug and the displacing gas requires a certain minimum pressure, which can be estimated from published data on the cricondenbars of mixtures of pure components.

3.3.1.2 Condensing–Gas Drive (Or Enriched–Gas Drive)

A condensing–gas drive is that process of oil displacement by gas that makes use of an injected gas containing low molecular weight hydrocarbons

(C_2 to C_6) components, which condense in the oil being displaced. To effect conditions of miscible displacement, sufficient quantities of low molecular weight components must be condensed into the oil to generate a critical mixture at the displacing front.

3.3.1.3 Vaporizing–Gas Drive Process

Another mechanism for achieving dynamic displacement relies on in-situ vaporization of low molecular weight hydrocarbons (C_2 to C_6) from the reservoir oil into the injected gas to create a miscible transition zone. This method for attaining miscibility has been called both the "high-pressure" and the "vaporizing" gas process. Miscibility can be achieved by this mechanism with methane, natural gas, flue gas, or nitrogen as injection gases, provided that the miscibility pressured required is physically attainable in the reservoir. This process requires a higher pressure than normally used in conventional, immiscible gas drives. The increase in oil recovery at the higher pressure is believed to results from:

1. Absorption of injected gas by the oil to cause a volume increase of the oil phase in the reservoir

2. Enrichment of injected gas resulting from vaporization of low-boiling-range hydrocarbons from the oil into the gaseous phase.

3. Reduction in the difference of viscosity and interfacial tension (IFT) between the injected gas and the reservoir oil.

Miscible displacement cannot be achieved by gas injection at realistic pressures unless certain basic requirements are met.

1. Reservoir depths must be sufficient to permit pressures greater than 3000psi, usually 4000psi at reservoir temperatures.

2. The reservoir fluid must contain sufficient quantities of certain (C_1 to C_6) components before the benefits of vaporization can be obtained.

3.3.1.4 Extracting–liquid or supercritical fluid drive (CO_2 miscible process)

Under favorable reservoir pressure and temperature conditions and crude oil composition, supercritical CO_2 can become miscible with petroleum i.e. the crude oil and CO_2 mix in all proportions forming a single-phase liquid. As a result of this interaction the volume of oil swells, Its viscosity is reduced and surface tension effects diminish improving the ability of the oil to flow out of the reservoir.

Carbon dioxide is however not instantaneously miscible with oil at first contact. Miscibility conditions develop dynamically in the reservoir via

composition changes when the CO_2 flows through the reservoir and gradually interacts with oil, a process called multiple contact miscibility (MCM). When the CO_2 is injected into the reservoir and is brought in contact with crude oil, initially its composition is enriched with vaporized intermediate components of the oil. This local change in the composition of oil enables the miscibility between the oil and CO_2 (vaporizing process) forming a miscible zone between the oil bank and the injected CO_2. The miscibility for CO_2 in the oil is strongly affected by pressure. A minimum miscibility pressure (MMP) is required so that CO_2 becomes fully miscible with oil. At that pressure, the density of CO_2 is similar to that of the crude oil. The value of the minimum miscibility pressure depends on the composition of crude oil, the purity of CO_2 and the reservoir conditions (pressure and temperature). Hence, a miscible CO_2– displacement technique can only be implemented when CO_2 can be injected at a pressure higher than that of the minimum miscibility pressure, which in-turn must be lowered than the reservoir pressure. A schematic of Co_2 miscible process is shown in Fig. 3.3.1.4.1
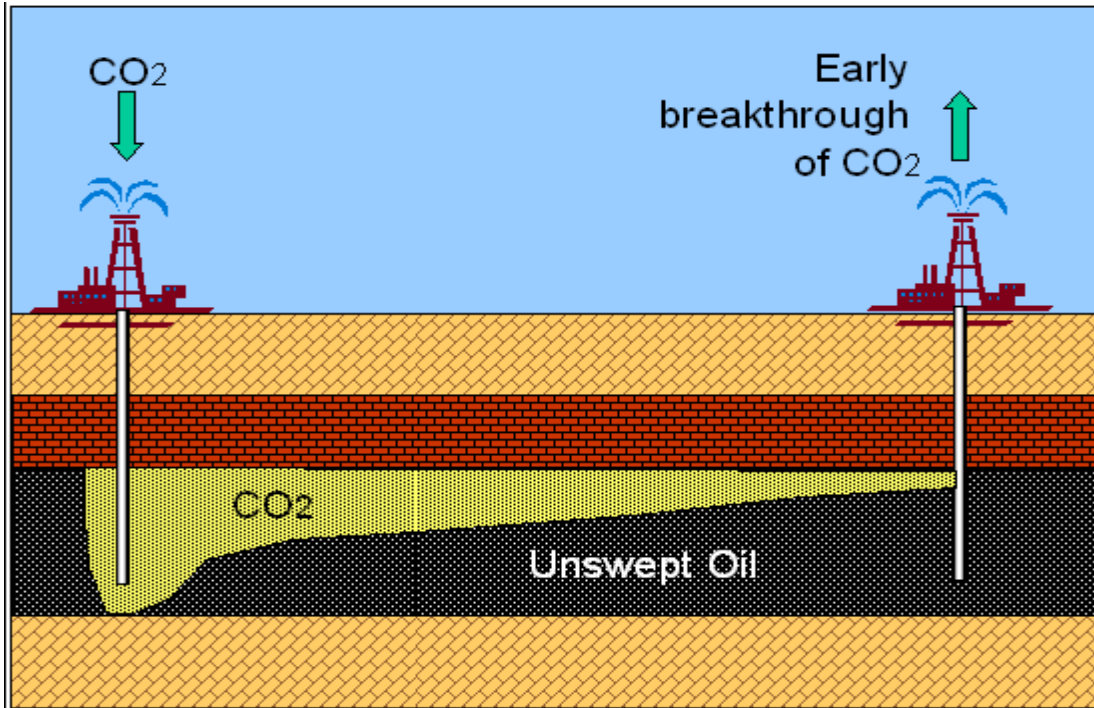
Fig. 3.3.1.4.1 Early breakthrough of Co2 due to non-

Optimal Flow and gravity effects

Design procedures and criteria of CO_2 miscible

Displacement process

A number of factors must be considered in the design of a miscible displacement process. This section discuses those that relate primarily to the laboratory and modeling studies that precede field testing.

Significant reservoir analysis is required. The reservoir analysis should focus on geology, fluid distributions, performance of primary production, analysis of any prior displacement process (such as water flooding), injection rates,

and pattern geometry effects. Gaining an understanding of reservoir heterogeneity is especially critical for the final design. An economic study, including a sensitivity analysis also should be done.

In a miscible displacement process a solvent slug that efficiently displaces the reservoir oil at the microscopic level must be used. Typically, ROS to the solvent should be 10% or less. Depending on reservoir fluids and conditions (Pressure and Temperature) and the solvents available, either a first contact or multiple contact process can be applied. Volumetric sweep out (which is dependent on mobility ratio, gravity effects, reservoir heterogeneities and well pattern) must be such that the overall recovery efficiency is sufficient to yield a satisfactory economic return.

3.4   THERMAL RECOVERY METHODS

All thermal recovery processes tend to reduce the reservoir flow resistance by reducing the viscosity of the crude. The thermal recovery processes used today fall into two classes: those in which a hot fluid is injected into the reservoir and those in which heat is generated within the reservoir itself, the latter are known as in-situ processes an example of which is in-situ combustion or fire flooding. Processes combining injection and in-situ generation of heat have been tested but currently are not practiced to any

great extent. Thermal recovery processes also can be classified as thermal drives or stimulation treatments.

3.4.1   Hot – water drives

In its simplest form, a hot-water drive involves the flow of only two phases: water and oil. Steam and combustion processes,

on the other hand, always involve a third phase: gas. Thus, the elements of hot water flooding are relatively easy to describe, being basically a displacement process in which oil is displaced immiscibly by both hot and cold water.

Because of the pervasive presence of water in all petroleum reservoirs, displacement by hot water must occur to some extent in all thermal recovery processes.

The presence of a gas phase is known to affect the performance of water floods, and the same is thought to be true of hot-water drives. The effects of presence of gas phase in a hot-water drive are: Gases dissolved in the crude this result in an apparent initial expansion of the oil phase wherever gas bubbles form but only until the gas bubble coalesce into a (continuous) gas phase.

Performance prediction

There are three essentially different approaches to estimating the performance of a hot-water drive. One approach proposed by Van Heiningen and Schwarz makes use of the effect of oil viscosity on the isothermal recoveries.

The method calls for shifting from one viscosity ratio curve to another of lower value in a manner corresponding to the changes in the average temperature of the reservoir (which increases with time). In applying this procedure, the oil/water. Viscosity ratio as a function of temperature and the average reservoir temperature as a function of time are the principal items required.

The second approach also is borrowed from water flood technology and is based on the isothermal Bukley-Leverett displacement equations. Modified forms of those equations for application to hot-water drives were first introduced by Willman et al 1961; they have been used frequency as a fairly simple way of estimating the recovery performance of hot-water drives in linear and radial systems. It is emphasized that estimates of recoveries from linear and radial flow systems must be reduced to allow for well-pattern and heterogeneity effects.

The third approach to estimating the performance of a hot-water drive is to use thermal numerical simulators. The simulators are capable of calculating more accurate recovery performances than can be achieved by the two simpler methods just discussed.

Displacement by hot water

The approach proposed by Willman et al consists of discretizing the reservoir into n zones, each at a constant and uniform temperature T_j different from zone to zone. The location and size of these zones vary with time in a manner consistent with energy balance considerations within each constant temperature zone, the isothermal Buckley-Leverett displacement equations apply and the rate of growth of the saturation front is a constant. But the rate of growth of the area encompassed by the saturation fronts change as each new temperature zone is entered. For linear or radial flows, the rate of growth of the saturation fronts at a temperature T_j is given by:

$$\frac{dA}{dt} = (1.289 \times 10^{-4} \, acre-ft \Big/ bbl) \times \frac{1}{\phi h_n} q(Tj) \frac{\partial f_w(s,Tj)}{\partial s} \qquad \ldots\ldots\ldots 3.4.1.1$$

Where:

$\frac{dA}{dt}$ = rate of growth of the area encompassed by the saturation front having a

water saturation S, acres/d,

ϕ = porosity,

h_n = net sand thickness, ft

f_w = fractional flow of water which in hot-water flood depends on both

saturation and temperature.

q = flow rate at ambient reservoir temperature and pressure, b/d

T_j = is the temperature level of the zone, °F.

For conventional water floods where the reservoir temperature is not considered to change with time Equ3.4.1.1 reduces to the form.

$$\frac{dA}{dt} = (1.289 \times 10^{-4} \, acre - \frac{ft}{bbl}) \times \frac{i}{\phi h_n} f'w(s) \quad ....3.4.1.2$$

Where

$$f'_w(s) = \frac{\partial f_w(s,T_i)}{\partial s} \quad .... 3.4.1.3$$

T_i = original reservoir temperature

This is the form of the Buckley/Leverett displacement equation that describes the rate of advance of a saturation front. Since the Buckley-Leverett equation is not Linear, its' results can not be superimposed.

Inherent in any application of the Buckley-Leverett displacement equation is the requirement that the fluids be of constant density i.e. no thermal expansion or change of density is allowed. In thermal applications this condition is applied with each constant temperature zone but the densities are allowed to differ from zone to zone. For constant – density fluids and for negligible gravity and capillary effects, the fractional water flow is given by:

$$f_w(s,T) = \frac{1}{1+[M(s,T)]^{-1}}$$

Where

M(s, T) = mobility ratio of the co flowing fluids.

$$M(s,T) = \frac{krw}{\mu_w} \frac{\mu_o}{kr_o}$$

The viscosity ratio of oil to water has a strong dependence on temperature, especially for viscous crude's. The relative permeability ratio, for convenience usually is taken to be a function only of saturation.

Calculation of the area swept by the saturation fronts from equ 3.4.1.1 requires information about $\partial f_w / \partial s$ over a saturation range at each temperature T_j. Generally these slopes are determined graphically from a plot of the fractional flow f_w against saturation S, in which case one such plot is required for each T_j. A short cut is sometimes available. When the relative

permeability ratio is considered to be independent of temperature, values of

$f_w(s)$ and $\partial f_w / \partial s$ at different temperatures can be generated from those at the

initial reservoir temperature by means of the relations

$$f_w(s,T) = \frac{f_w(s)}{(f_w(s) + F_\mu(1 - f_w(s)))} \qquad \text{......................} \qquad 3.4.1.4$$

and

$$f_w(s,T) = \frac{f_w(s)}{(f_w(s) + F_\mu(1 - f_w(s)))^2} \qquad \text{..................} \qquad 3.4.1.5$$

Where:

$$F_\mu = \left(\frac{\mu_o}{\mu_w}\right)_{Ti} \bigg/ \left(\frac{\mu_o}{\mu w}\right)_T \qquad \text{...................} \qquad 3.4.1.6$$

$$f_w(s) = F_w(s,T_i) \qquad \text{..........................} \qquad 3.4.1.7$$

Production performance

The amount of oil displaced in a hot-water drive is invariably larger than the

amount produced. The oil that is displaced but not produced is stored in

unsewpt portions of the reservoir. In the case of viscous crude's especially,

the mobility ratio between the advancing oil and any gas or water in the

reservoir is very favorable. This means that crude will tend to fill regions of

the reservoir initially filled with mobile gas and water before it is produced.

As is generally done in applying simple methods to predict the performance of water floods, it is assumed that the crude recovery is not sensitive to the well pattern. And it is assumed that the method developed by Dykstra and Parsons for water flood performance predictions can be modified for hot water drives.

Design of Hot-Water drive

The same matters must be considered in designing hot-water floods as in designing any other fluid injection project. some of the principal things to consider are the possibility of using existing wells as they become available or after they have been worked over and recompleted the need for additional wells to reduce the spacing or to improve recovery, the effect of depth and average reservoir injectivity on the project life and economics, the type and location of surface facilities to be used, the availability and treatment of the water, and the environmental constraints on the use of fuel and the disposal effluent. In thermal recovery projects the principal additional consideration include the larger rates of fuel consumption, the need for cooling hot effluent and the effect of temperature on the surface and down hole hardware.

3.4.2   Steam Drives

Steam drives differ markedly in performance from hot-water drives the difference in performance being solely due to the presence and effects of the condensing vapor.

The presence of the gas phase causes light components in the crude to be distilled and carried along as hydrocarbon components in the gas phase, where the steam condense, the condensable hydrocarbon components do likewise, thus reducing the viscosity of the crude at the condensation front. Moreover the condensing steam makes the displacement process more efficient and the net effect is that recovery from steam drives is significantly higher than from hot-water drives.

Mechanisms of Displacement

An important phenomenon affecting displacement is changes in surface forces resulting from temperature effects.

An important additional phenomenon affecting in steam drives – a phenomenon first discerned by Willman et al is the steam distillation of the relatively light fractions in the crude. Distillation causes the vapor phase to be composed not only of steam but also of condensable hydrocarbon vapors. Some hydrocarbon vapors will condense along with the steam, mixing with

the original crude and increasing the amount of relatively light fractions in the residual oil trapped by the advancing condensate water ahead of the front.

Prediction of performance

The first step in calculations is to determined the volume of steam zone and the amount of oil displaced from it, where the gross volume of the steam zone is V_s, the amount of oil produced is

$$N_p = (7758 \, bbl/acre - ft)\phi \frac{hn}{h_t}(s_{oi} - s_{or})E_c V_s$$

Where:

h_n = Net reservoir thickness

h_t = Gross reservoir thickness

s_{oi} = Initial oil saturation

s_{or} = Residual oil saturation

E_c = Produced fraction of the oil displaced from the steam zone (sometimes called the capture factor).

V_s = gross volume of the steam zone.

The volume of the steam zone always can be related to the fraction of the injected heat present in the steam zone, $E_{n,s}$, by

$$V_s = \left(\frac{acre - ft/cuft}{43560} \right) \frac{Qi E_n s}{M_R \Delta T}$$

Where:

M_R = Total heat content of the steam zone per unit volume

Q_i = Cumulative heat injected, calculated from heat

Injection rate

$$\dot{Q}_i = W_i (c_w \Delta T + f_{sdu} L_v dh)$$

Where:

W_i = Mass rate of injection into the reservoir

ΔT = Temperature rise of the steam zone above the initial reservoir temperature (assumed to be the same as the temperature rise at down hole conditions ΔT_i).

$(f_{sdh}$ and $L_{vdh})$ = Steam quality and latent heat of vaporization both at down hole conditions.

C_w = Average specific heat over the temperature range corresponding to ΔT

$E_{h,s}$ = Thermal efficiency of the steam zone and vanishes when no steam vapor is injected

Thermal efficiency is given by

$$E_{h,s} = \frac{1}{t_D}\left[G(t_D) + (1-f_w)\frac{u(t_D - t_{cD} = }{\sqrt{\pi}}\; .[2\sqrt{t_D} - 2(1-f_{uv})\sqrt{t_D} - t_{cD} - \int \frac{e^x erf_c\sqrt{x}dx}{\sqrt{t_D - x}} - \sqrt{\pi}G(t_D)]\right]$$

the dimensionless time t_D is given by

$$t_D = 4\left(\frac{Ms}{MR}\right)^2 \frac{\alpha S}{h_t^2} t,$$

The function $G(t_D)$ is given by

$$G = 2\sqrt{\frac{t_D}{\pi}} - 1 + e^{to}erfc\sqrt{t_D}$$

The dimensionless critical time is defined by

$$e^{tcD}erfc\sqrt{t_{cD}} \equiv 1 - f_{uv}$$

$$f_{uv} = (1 + c_w\Delta T/f_{sdh}L_{vdh})^{-1}$$

and the unit function u(x) is zero for x < 0 and one for x > 0.

$E_{h,s}$, the thermal efficiency of the steam zone is plotted as a function of dimensionless time.

Design of steam drives

The design of any Field project requires a correlation of its economics and its requirements for technical success.

The following should be considered in designing steam drives:

1. Is the reservoir description adequate?

2. Is there enough oil in place to justify the effort?

3. Can the old wells be used for thermal operations?

4. Are three adequate sources of fresh water and fuel

5. Is there sufficient information to estimate the likely range of operating variables (such as pressures and rates at injectors and producers) and production performance?

The reservoir description includes not only the vertical and horizontal distribution of porosity, permeability, oil in place, and gas and water saturations, but also the amount of clays sensitive to fresh water, the lateral continuity of the sand and any other factor that may influence the operations of the steam drive.

3.4.2 In-Situ combustion

In Situ is Latin for 'in place'. Thus, in-situ combustion is simply the burning of fuel where it exists in a reservoir. The team is applied to recovery processes in which air, or more generally an oxygen-containing gas, is injected into a reservoir, where it reacts with organic fuels. The heat generated then is used to help recover unburned crude.

There are three forms of in-situ combustion process they are: Dry forward combustion, Wet combustion and Reverse combustion.

3.4.2.1   Dry forward combustion

The most commonly used form of the combustion process is simple air injection. It is called dry combustion to distinguish it from wet combustion in which water and air are injected into the reservoir.

Model of the process

The conceptual model that is used most commonly to describe understand and calculate the recovery by the dry forward combustion process is the frontal advance (FA) model. Within a horizontal reservoir all phenomena and displacements are independent of vertical position. In the frontal advance model, the combustion front fills the entire vertical extent of the reservoir, and all fluid transport is horizontal since temperatures in the oil bank are not too high (the downstream surface of the oil bank moves much faster than the temperature fronts), the growth of the oil bank increases the resistance of flow. In the case of high initial oil saturations of viscous crude's, the resistance to flow can be great enough to reduce the air injection rate to the point that the rate of heat losses exceeds the rate at which heat is

being generated by combustion. The resultant cooling only aggravates the situation. The system becomes plugged. Plugging, It must be remembered, does not always occur in the frontal advance model. But the flow resistance in the frontal advance is higher than in any other model. The frontal advance model is easy to conceptualize and understand; it was proposed in a manner and at a time when other displacement processes (e.g. water flooding) were being investigated similarly; it is very well represented by simple laboratory combustion tube experiments; and it tends itself to the separation of chemical and displacement mechanisms. The frontal advance model is representative of field behavior where there is no tendency for fluids to bypass through high permeability zones or where pressure gradients everywhere are large compared with the gravitational potential gradient $(g\Delta\rho/g_c)$ conditions that often may not prevail. Despite these limitations, the frontal advance model has served as a useful springboard from which much significant information and insight on combustion processes have been obtained and developed.

Dry forward combustion design

Dry combustion displacement processes are alternatives to steam drives conditions that would suggest using combustion rather than steam include:

High reservoir pressure e.g. greater than 2000psi; Excessive heat losses from steam injection wells e.g. in reservoirs deeper than 4000ft, lack of fresh water supply or water treatment costs that make the use of steam too expensive, serious clay swelling problems due to fresh condensate and unattractive or prohibited use of any fuel to fire steam generators. As in any displacement process, sand continuity between injectors and producers is an absolute requirement.

The design of a combustion project like that of any injection operations must consider how the reservoir flow resistance and the injection pressure limitations imposed by prudent operation practices affect the injection rate, since the rate of growth of the burned zone is essentially proportional to the air injection rate, the maximum air injection rate determines the minimum life of the project. if the minimum life is unacceptably long from an investment (or any other) point of view, ways must be considered either to prudently increase the levels of the injection pressure or to reduce the flow resistance to air, or both. Flow resistance to air may be reduced by increasing the gas saturation before ignition, usually by injecting air for weeks or months before ignition, by reducing the well spacing, or through conventional thermal stimulation treatments. If air is injected for a prolonged

period before ignition, there is a risk that ignition will occur before an adequately low resistance to air flow is established.

An additional factor that must be considered in combustion operations is the concept of a minimum air flux. According to this concept, vigorous burning cannot occur for long where the local rate of heat losses exceeds the rate of heat generation.

3.4.2.2   Wet Combustion

Wet combustion is the general name given to the process in which water passes through the combustion front along with the air (or other reaction supporting gas). The process always has been applied to forward combustion. The water entering the combustion zone may be in either the liquid or the vapor phase, or both. Ideally, the water is injected along with the air but is injected intermittently with the air when the flow resistance to two-phase flow near the injection well is too high to achieve the desired injection rates.

Model of the wet combustion process

The most comprehensive description of various situations that may develop in the wet combustion process (and one that is mathematical) is that of

Beckers and Harmsen. The description offered here is highly idealize and emphasizes the recovery aspects of the wet combustion process.

Although the addition of water to a combustion process alters its performance in significant and practical ways, no new mechanisms affecting displacement are brought into play. Control of the wet combustion process (everything else being the same) is attained through the injected water/air ratio, F_{wa}.

Design of the wet combustion process

Wet combustion should be considered an alternative to

dry combustion in all cases, since it could reduce the air requirements and accelerate the production response. However, it should not be used in formations where flow resistance is marginally acceptable for dry combustion, because the addition of water will increase the flow resistance further. Neither should it be used where the injected water would interact adversely with formation clays or other minerals to reduce the reservoir injectivity. The effectiveness of the wet combustion process decreases where gravity override is expected to be important, especially in thick, massive intervals having good vertical continuity and high permeability.

In thin sands, where there is significant heat loss to adjacent formations, wet combustion processes should be considered. The effect of the injected water in recuperating heat from the burned zone and the zones adjacent to it is particularly important where sands are thin. In such cases a high temperature combustion process may be sustainable.

Special attention should be given to the flow capacity of the wells used in the operation. Adding water to the air reduces the relative permeability to the two fluids. Accordingly, the flow resistance is increased in the burned zone especially near the injectors. Similarly, the production will include a larger proportion of water (i.e. the water cut will increase) since adding water can reduce the project life, the average oil production rate tends to increase. The relatively high oil production rates and water cut also tend to increase the pressure gradients near producers. Furthermore, the addition of water lowers temperatures at the producer's one of the advantages of wet combustion. However, this is accompanied by a slight increase in the crude viscosity and, thus, in the flow resistance. This increase in flow resistance is one reason for preferring a higher ratio of producers to injectors, even higher than in dry combustion operations.

The flow resistance may be high enough in some instances to require stimulation of both injectors and producers and even to require the injection

of alternate, slugs of water and air to reduce two-phase flow effects near injection wells.

The hardware in the injectors may be arranged especially to reduce down hole separation of the air and water. Because of lower temperatures at the wells and less acidic waters owing to lower fuel consumption and increased dilution by the injected water, corrosion of producing wells is not so severe in wet combustion projects. This reduce corrosion may allow the use of more existing wells than would be possible if no water were added.

On the other hand, water disposal problems will increase in wet combustion projects.

In reservoirs, where clay/water problems may arise, the injection of water must be considered carefully, if the burned zone is subjected to sufficiently high temperatures (e.g. $1200^{o}F$), the clays often are fired to the point that they no longer will swell when contacted with water. But in a wet combustion process, the resultant temperatures may be so low that clay swelling cannot be avoided unless a compatible formation water is injected.

3.4.2.3   Reverse Combustion

In reverse combustion, the combustion front moves opposite to the direction of air flow. Combustion is initiated at the production well, and the

combustion front moves against the air flow. In a frontal displacement model, the crude that is displaced must pass through the burning combustion zone and through the hot burned zone. In the process the extent of the high-temperature region in the burned zone depends (among other things) on the rate of heat losses to the adjacent formations. As the crude is displaced through the combustion front, it is cracked; the light ends vaporize and the heavy ends contribute a residue. As the vapors approach cooler sections of the burned zones, some condensation occurs, and liquid oil and water may exist near the outlet. The region upstream of the combustion zone is heated by heat conduction, which leads to low temperature oxidation reactions and the generation of considerable heat at significant rates upstream of this zone is the initial zone, unaffected by the process except by the flow of air.

Because no oil bank builds up, the total flow resistance of this process can only decrease with time. For this reason, the process is particularly well suited for very viscous crude's, where the buildup of an oil banks would likely increase the flow resistance significantly.

In the foregoing description two phenomena significantly alter the applicability of reverse combustion. One of these is the possibility of spontaneous ignition. Dietz and Weijdema have pointed out that it is seldom feasible to avoid spontaneous ignition for very long unless the reservoir

temperature is unusually low. The natural reactivity of crude's, coupled with the surrounding reservoir temperatures found in most situations would, in most cases, combine to provide Spontaneous ignition in a matter of months. And, of course, once this happens the oxygen would be consumed close to the injection point and no longer would be available to maintain reverse combustion.

The second phenomenon is the inherent instability of reverse combustion. A recent study by Gunn and Krantz concludes that the diameter of the combustion channel would tend to be limited to a few feet, the preferred dimension depending on the reservoir and crude properties and on the operating conditions. It is likely that the preferred dimension of the burned zone is larger than that of the combustion tubes in which the process has been studied experimentally and may be about the same as the thickness of the sand intervals.

The formation of narrow channels in reverse combustion operations does not mean reverse combustion cannot be used successfully. But it means that:

1.   The frontal displacement model is not applicable.

2.   Steps may have to be taken to delay ignition (e.g. inhibiting slow oxidation reaction).

3.   Additional work is required to determine how to use burned channels in a full scale operation.

3.4.3   Cyclic Steam Injection

Cyclic steam injection clearly reduces the flow resistance near the well bore, but it also enhances the depletion mechanism by causing gas dissolved in the crude to become less soluble as the temperature increases and increases the amount of water retained in the reservoir through a combination of temperature – induced wettablility changes and hysteresis in the relative permeability curves in a manner analogous to a countercurrent inhibition displacement process.

Cyclic steam injection mechanisms

The mechanisms involved in the production of oil during cyclic steam injection are diverse and complex.

There is no doubt that a reduction in the viscosity of the crude in the heated zone near the well greatly affects the production response. Changes in surface forces with increasing temperature probably play a role in the preferential retention of the condensed water in the reservoir rather than the

more viscous oil, a fact that has been noted in several studies. Other factors, such as different phase compressibility's and flashing of water to steam (thus reducing the relative permeability to water) may also favor water retention. Another class of mechanism is associated with the generation of a non condensable gas phase. This may result from the fact that the solubility of gases in the formation liquids decreases with increasing temperature but also may result from chemical reactions.

By and large, there must be a driving force present in the reservoir initially if cyclic steam injection is to succeed. In other words, it is not sufficient merely to reduce the flow resistance in the reservoir. Gravity drainage and solution – gas drive are often highly important in providing forces during the production phase. And during soaking and production, condensation of steam tends to reduce the pressure at and near the well, thus promoting flow.

Performance prediction

The performance of a cyclic steam injection operation is sensitive to the acting production mechanisms, to the reservoir and fluid properties near the well and to the operating variables. The applicability of predictive methods depends on the proper representation of the reservoir and crude properties,

even assuming that the total interaction between the operating variables and the reservoir are properly taken into account. One reservoir property that is not known precisely but that significantly affects the production response of cyclic steam injection operations is the relative permeability to the flowing fluids. Coats et al reported that relative permeabilities require hysteresis modifications (i.e. they are different during injection and back flow) in other to match the performance of a multicylce operation. Relative permeabilities, especially with inhibition/drainage/temperature effects, are not available normally. So it is highly questionable if a prediction of performance in an area where there has been no cyclic steam injection to likely to be even moderately accurate. Where cyclic steam injection production is available, likely values of the reservoir and crude properties can be determined through history-matching procedures. These can then be use to predict the performance of nearby wells under different operating conditions.

Cyclic steam injection Design

Because cyclic steam injection is relatively easy and inexpensive to implement, it is customarily tested directly in the field, even where there has been no previous experience of the process where an operator has access to

the results of previous experience, or where it is known that others have had

success, the object is not to prove the process but to optimize it.

Optimizing also generally is done in the field, sometimes aided by

models or more rarely, by numerical thermal reservoir simulators.

3.5   CHEMICAL FLOODING

Chemical flooding involves recovering oil through mobility could process

and low interfacial lesion (ITF) processes.

3.5.1   Mobility control processes

Effect of low mobility on oil recovery

Mobility control processes are most applicable to reservoirs that have

substantial movable oil. The mobility ratio concept illustrates how lowering

the mobility improves oil recovery. The mobility ratio, M between a

displacing agent and a displaced fluid is:

$$M = \lambda_D / \lambda_d$$ ……………….. 3.4.1

Where:

λ_D = mobility of displacing agent

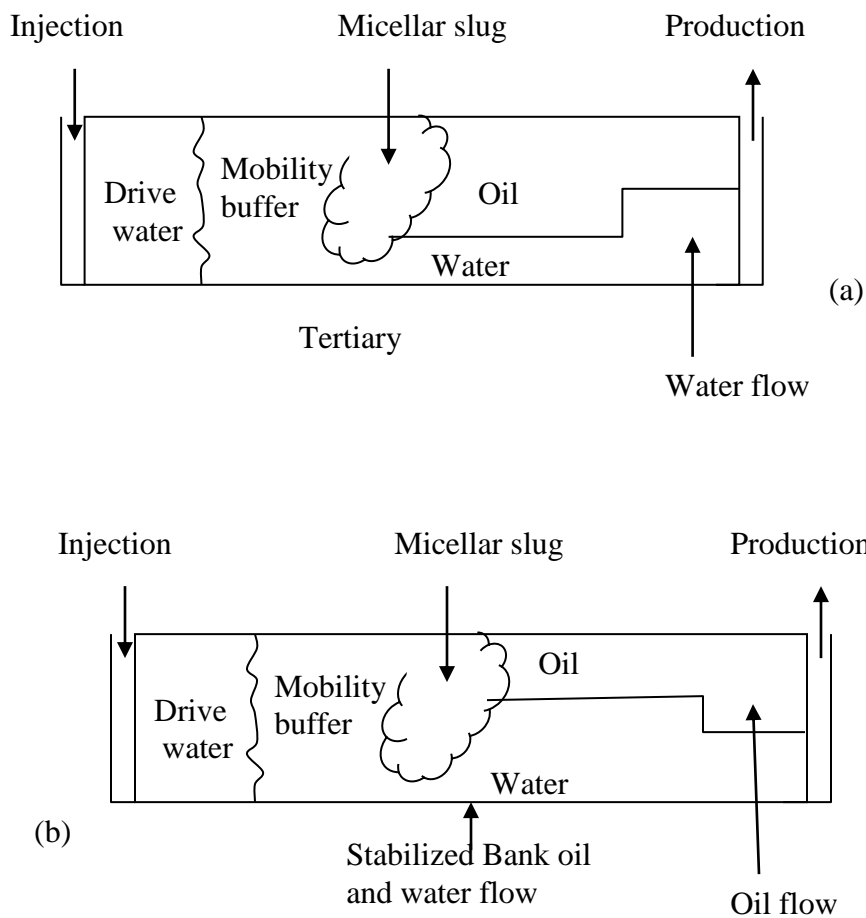λ_d = mobility of displaced fluids

Lowering the mobility ration (M) or mobility of displacing agent (λ_D) results in improved oil recovery through larger displacement efficiency. E_D. The two main methods in mobility control process are: polymer flooding and foam flooding.

3.5.1.1 Description of the Micellar/polymer process

Injection   Micellar slug   Production

Drive water   Mobility buffer   Oil
                               Water
                                                                    (a)

Tertiary

Water flow

Injection   Micellar slug   Production

Drive water   Mobility buffer   Oil
                               Water

(b)

Stabilized Bank oil and water flow

Oil flow

Fig.3.5.1.1.1   Micellar/polymer process

Figure 3.5.1.1.1 above shows the Micellar/Polymer process.

In most situations the Micellar/Polymer process is implemented as a tertiary process where the initial oil saturation is s_{orw}, ROS after water flooding.

A specified volume, or primary slug, of micellar solution is injected. The volume of the slug is one of the process variables; however, typical volumes are about 3% to 30% of the flood pattern. The Micellar solution has a very low interfacial tension (Low-IFT) with the residual crude oil and mobilizes the trapped oil, forming an oil bank ahead of the slug; the micellar slug also has a relatively low interfacial tension (Low-IFT) with brine and thus displaces brine as well as oil. Both oil and water flow in the oil bank.

Because oil is initially at residual saturation in a tertiary flood, no oil production occurs until the oil bank breaks through at the end of the flow system. Fig. 3.5.1.1.1b shows an idealize displacement conducted as a secondary Flood where water is immobile at the initial water saturation. Oil is produced immediately upon injection of the chemical slug because it is initially at a high saturation. Both oil and water flow in the oil bank because some of the interstitial water is displaced by the micellar slug.

Design procedures and criteria

General criteria for an efficient micellar/polymer flood

A number of general criteria must be met for a chemical flood to perform at a high and acceptable efficiency.

1.   Low interfacial tension (Low-IFT) between the primary chemical slug and the oil bank.

2.   Low interfacial tension (Low-IFT) between the mobility buffer and the primary chemical slug.

3.   Favorable mobility ratio between the chemical slug and the oil bank.

4.   Favorable mobility ratio between the buffer and the primary chemical slug.

5.   Maintenance of the integrity of the chemical slug i.e. prevention of surfactant losses that seriously degrade the slug.

Design of a process considering these factors typically involves significant laboratory work with the specific rock/chemical system of interest.

General Approach in the Design

Design of a micellar/polymer flood is a complex process. The process begins with the reservoir crude oil (or an equivalent oil), the composition of the

reservoir brine, and the composition of possible injection waters at reservoir temperature.

Selection of a surfactant and co surfactant (if needed) that will give high solubilization parameters at reservoir salinity is the critical step. This selection is required to obtain ultralow interfacial tensions (ultralow-IFT's) necessary for effective displacement. The composition of the surfactant/co surfactant solution depends on a number of parameters, including, at least, surfactant/co surfactant types, reservoir oil, brine type and composition, polymer compatibility, pH and temperature.

It is also important to understand the behavior of a chemical system as it flows through the reservoir rock. The integrity of the chemical slugs must be maintained for some minimum acceptable flow period. Again in the absence of data, no equations are readily available, and thus it is desirable to conduct laboratory core floods.

3.5.1.2   Foam flooding

Gas/Liquid foams offer an alternative to polymers for providing mobility control in chemical floods.

Foams are dispersions of gas bubbles in liquids. Gas/liquid dispersions are normally unstable and unusually will break in less than one second. If

surfactants are added to the liquid, however, stability is improved greatly so that some foams can persist indefinitely.

To understand foam properties requires some discussion of surfactants and their classifications. Most of the discussion applies to MP surfactants as well.

Surfactant chemistry

A typical surfactant monomer is composed of a nonpolar portion (Lipophile i.e. having strong affinity for oil) and a polar portion (hydrophile i.e. strong affinity for water). The entire monomer is an amphiphile (has affinity for both oil and water). The figure below shows the molecular structure of two common surfactants.

Sodium dodecyl sulfate

Sulfonate
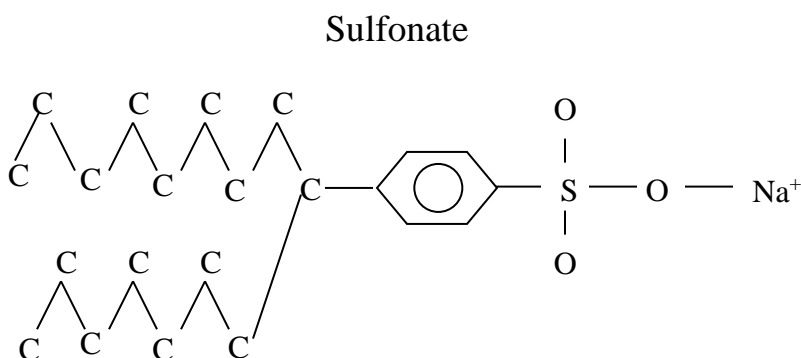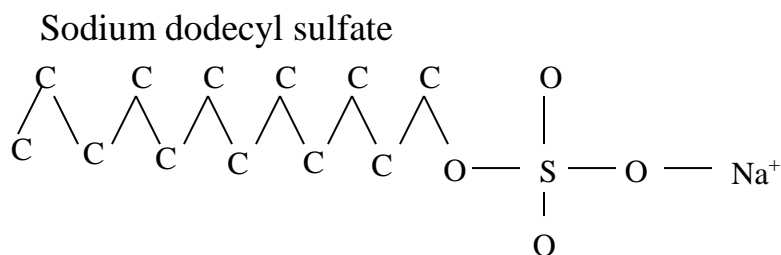
The monomer is represented by a tadpole symbol with the nonpolar portion being the tail and the polar the head.

Modeling chemical flood displacement

Oil recovery by a chemical flood can be model using/estimated with a simple material – balance calculation. The purpose of the calculation is to provide an order-of-magnitude approximation of recovery that might be expected from a flood.

Beyond a material balance, there are basically two approaches to modeling micellar/polymer floods. The first approach uses the frontal – advanced theory to predict displacement performance. The second approach involves solution of a system of equations describing the transport of each chemical species through the porous rock. This system of equations is solved with finite – difference technique. Such a program is called a chemical flood simulator. But would not be considered here.

Estimating of recovery by material balance

Oil recovery by the surfactant/polymer process can be approximated by application of a simple material balance. Because a favorable mobility ratio is maintained in the process, volumetric sweep efficiency is assumed to be the same as for a water flood preceding the surfactant process. Recovery is then given by

$$N_p = \frac{Ah\iota(s_{orw} - s_{orc})}{B_o 5.615} E_{vw}$$

Where:

N_p = oil recovered in the process (STB)

A = pattern area, (ft^2)

h = reservoir thickness (ft)

ϕ = porosity

s_{orw} = initial oil saturation, Ros at termination of water flood (corresponds to one endpoint saturation of the water flood relative permeability curve).

S_{orc} = oil saturation, Ros left by surfactant slug

B_o = oil formation volume factor, FVF (rb/stb)

E_{vw} = volumetric sweep efficiency of water flood preceding

Chemical flood.

ROS's left by chemical floods, s_{orc} typically range from 0.05 to 0.15 PV in laboratory core floods. These residuals may be considerably higher (0.15 to 0.25 PV) when a chemical system is optimized for economics of field scale operation.

CHAPTER FOUR

4.1   DATA ANALYSES AND PRESENTATION

In this chapter, analysis of the historical data from ELF was tabled and

presented. A case study of reservoirs YB is shown table 4.1.

A GRAPH OF CUMMULATIVE OIL PRODUCTION (bbl) VERSUS CUMMULATIVE WATER INJECTION (bbl)
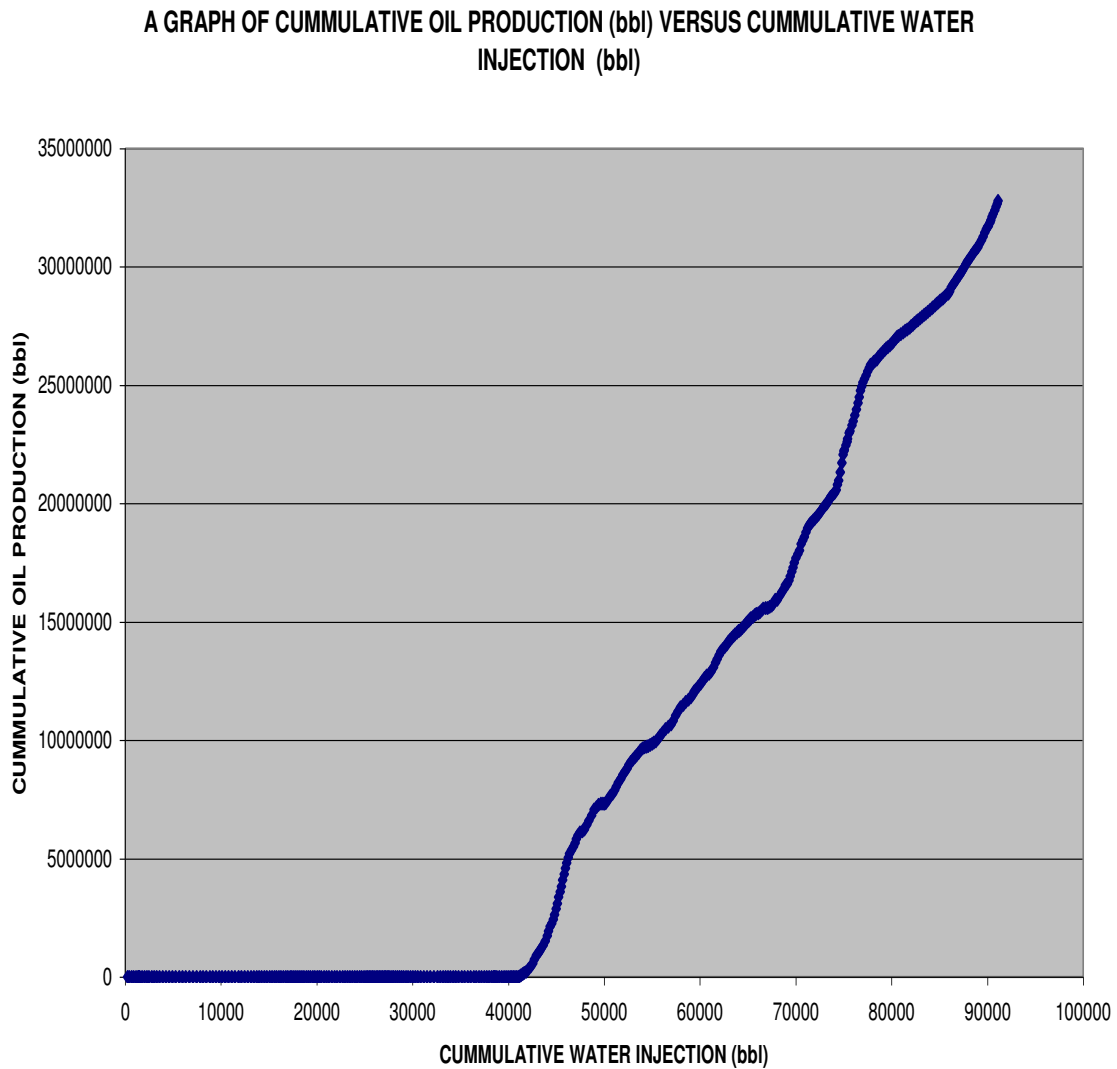

Fig.4.1

From fig. 4.1 it can be seen that there is a rise in cumulative production as the cumulative water injection increases.

Also, the graph clearly states that enhancing the recovery of oil is dependent on how much water is been injected into the reservoir, as this serves as the basis for pressure maintenance in the reservoir.

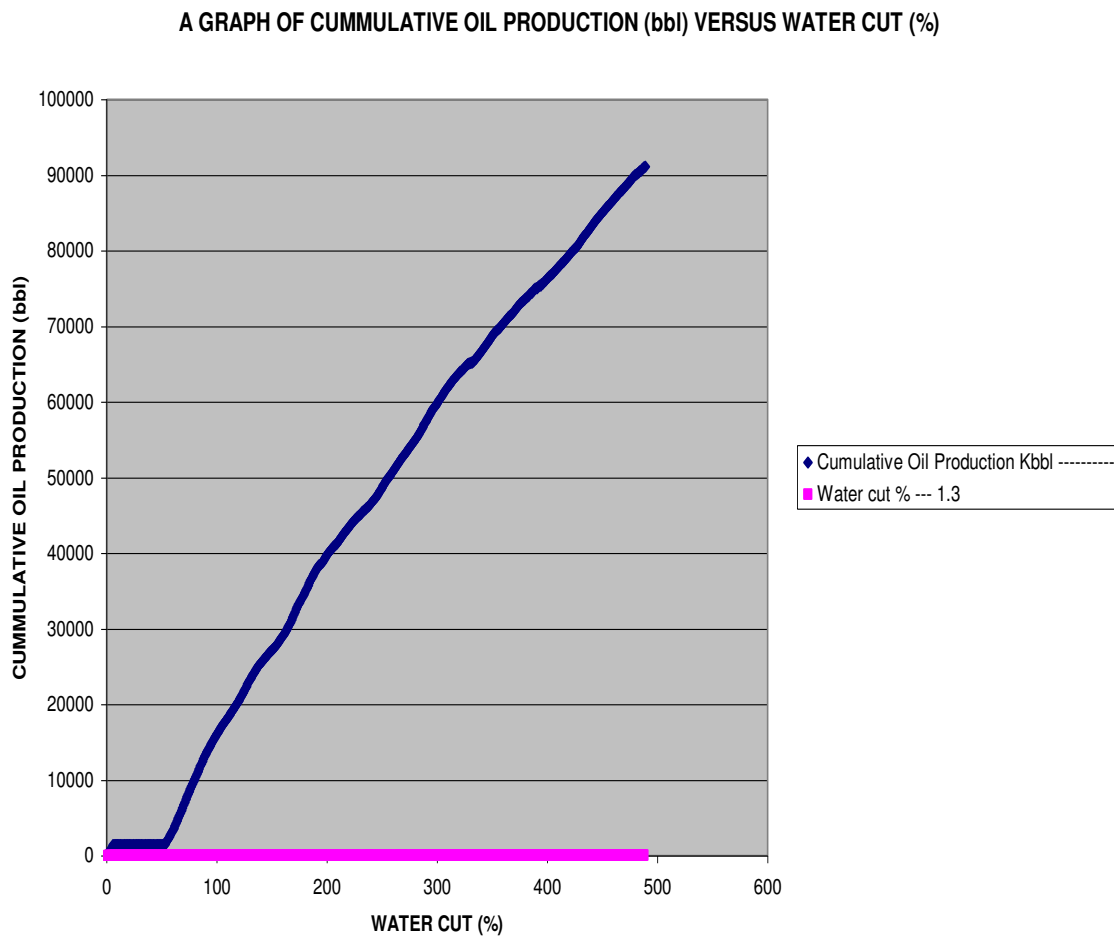**A GRAPH OF CUMMULATIVE OIL PRODUCTION (bbl) VERSUS WATER CUT (%)**

Fig.4.2

Also fig. 4.2 shows a trend of increasing cumulative oil production with water cut. The higher the water cut from the reservoir, the more the production of oil. This is in accordance with the displacement mechanism techniques.

CHAPTER FIVE

CONCLUSION AND RECOMMENDATION

5.1   **CONCLUSION**

Enhanced oil recovery increases the Amount of oil that can be extracted from an oil field. Enhanced oil recovery is achieved by water injection, gas injection, miscible displacement methods, thermal recovery methods and chemical flooding. The optimal application of each type of recovery method depends on reservoir rock and fluid properties.

As can be drawn from the data analysis, the cumulative production is dependent on the volume of injected water. At 237.567kbbl, the cumulative injection was zero and there was no water injection. Also, as the reservoir pressure depletes, water is injected to restore formation pressure at the rate of 3082.013 bbl/d. Thus there is a rise in the cumulative production of oil to 41144.9kbbl and an increase in water injection to 15410bbl.At this point, the reservoir is producing water at the rate of 4.7%.

However, each of these enhanced oil recovery methods is highly energy intensive. Electricity along with its competing alternatives i.e. natural gas, is an important power source for operation in all enhanced oil recovery projects.

5.2   RECOMMENDATION

For an effective enhanced oil recovery operation, the following

recommendations need to be considered:

1. The state of enhanced oil recovery industry in the Niger delta should be

    Examined because of the prospect of deregulation and increased

    Competition in power generation.

2. New enhanced oil recovery technologies that will change power

    Demand should be utilized.

3. The outlook for future enhanced oil recovery development should be

    Consider.

4. With emission restrictions under consideration, enhanced oil

    Recovery projects that will help power generators handle

    And dispose CO_2 emissions in a low cost and safe manner should be

    Employed

5. Innovative technologies that will help to enhance oil recovery should

    Be incorporated.

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