PGE 551.1
LECTURE NOTES

BY

ENGR. ESTHER ODIKI

OUTLINE

- Review of Current Recovery Methods
- Recovery Mechanism
- Water Flood performance Prediction
- Sweep Efficiency

REVIEW OF CURRENT RECOVERY METHODS

There are different recovery methods that can be used in the oil and gas industry to produce oil and gas from the reservoir. These recovery methods can be divided into three groups, namely

- Primary recovery methods
- Improved or secondary recovery methods
- Tertiary or enhanced recovery methods

The terms primary recovery, secondary recovery, and tertiary (enhanced) recovery are traditionally used to describe hydrocarbons recovered according to the method of production or the time at which they are obtained.

PRIMARY RECOVERY METHODS

Primary recovery methods also known as primary oil recovery describes the production of hydrocarbons under natural driving mechanisms present in the reservoir without additional help from injected fluids. The energy needed to produce the fluids in the reservoir is supplied by the reservoir rock and fluids. Examples of primary oil recovery methods/mechanisms are;

- Rock and fluid expansion drive
- Depletion drive
- Gas cap drive
- Water drive
- Gravity drainage drive
- Combination drive

IMPROVED /SECONDARY RECOVERY METHODS

Improved or secondary oil recovery (IOR) is used to produce hydrocarbons that cannot be produced with conventional/primary recovery methods. Improved oil recovery methods are

- Water injection
- Immiscible gas injection

The secondary recovery process follows the primary recovery but it can also be conducted concurrently with the primary recovery.

It should be clearly proven that the natural recovery processes are insufficient before undertaking a secondary recovery project to avoid the risk of wasting substantial capital investment on such project.

ENHANCED / TERTIARY RECOVERY METHODS

Enhanced oil recovery (EOR) methods are methods essentially designed to recover oil, commonly described as residual oil, left in the reservoir after both primary and secondary recovery methods have been exploited to their respective economic limits. There are three main types of enhanced oil recovery methods namely

- Thermal recovery (e.g. steam flooding, cyclic steam injection, hot water flooding, in-situ combustion etc.)
- Gas injection (e.g. Natural gas, Nitrogen or CO_2 etc.)
- Chemical injection (e.g. polymer flooding, surfactant flooding, alkaline or caustic flooding etc.)

RECOVERY MECHANISM

PRIMARY RECOVERY MECHANISM

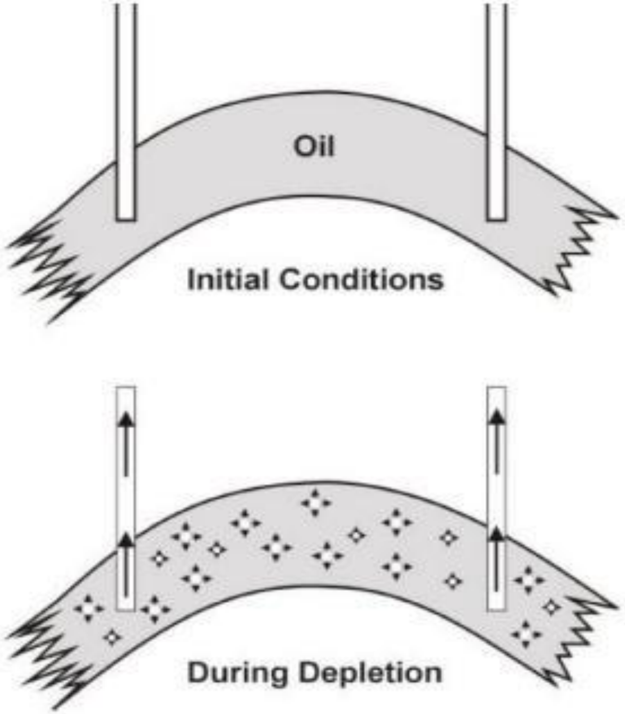
The primary recovery of oil from a reservoir is powered by the reservoir drive mechanism. Recovery mechanism is a function of a unique combination of geometrical form, rock properties, fluid characteristics and the primary drive mechanism of the reservoir. There are basically six (6) primary driving mechanisms that provide the natural energy necessary for oil recovery.

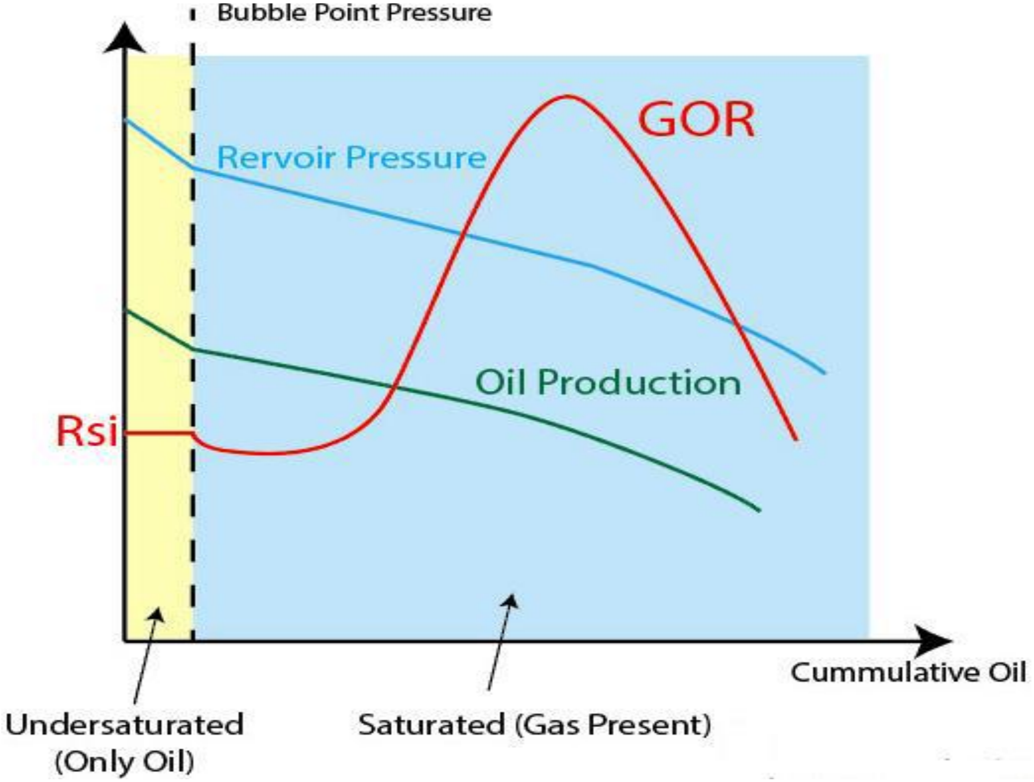
They are;

- Rock and liquid expansion drive mechanism
- Depletion drive mechanism
- Gas cap drive mechanism
- Water drive mechanism
- Gravity drainage drive mechanism
- Combination drive mechanism

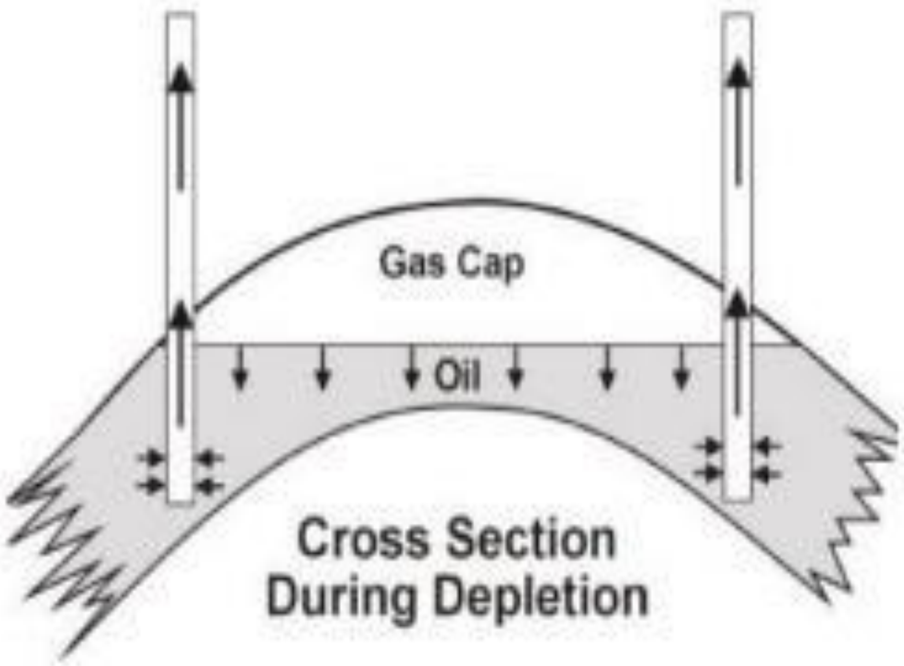
Rock and liquid expansion drive: The oil within the reservoir pore space is compressed by the weight of the overlying sediments and the pressure of the fluid they contain. If fluid is withdrawn from the reservoir, it is possible that the pressure depletion in the pore space attributes to the production of fluid can be compensated for by the sediments compacting lower sediments such as those of the reservoir production zone. This driving mechanism is considered the least efficient driving force and usually results in the recovery of only a small percentage of the total oil-in-place.

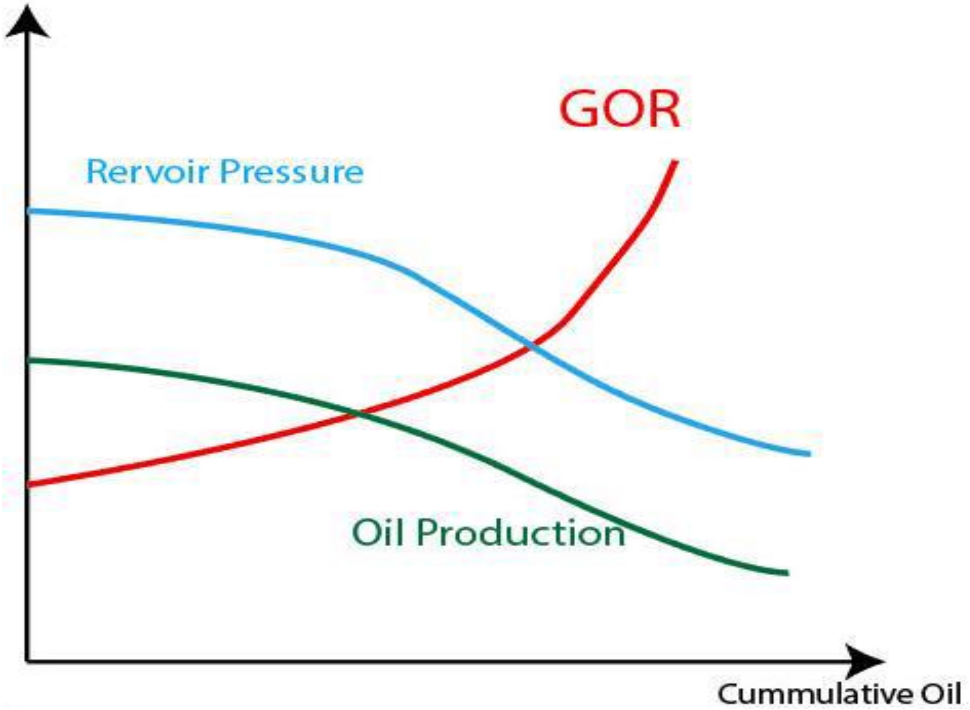
Depletion drive mechanism: In this type of reservoir, the principal source of energy is a result of gas liberation from the crude oil and the subsequent expansion of the solution gas as the reservoir pressure is reduced. As pressure falls below the bubble-point pressure, gas bubbles are liberated within the microscopic pore spaces. These bubbles expand and force the crude oil out of the pore spaces. At the beginning, the produced gas oil ratio will slightly decline because free gas in a reservoir cannot move until it goes over the critical gas saturation. Then gas will begin to flow into a well.



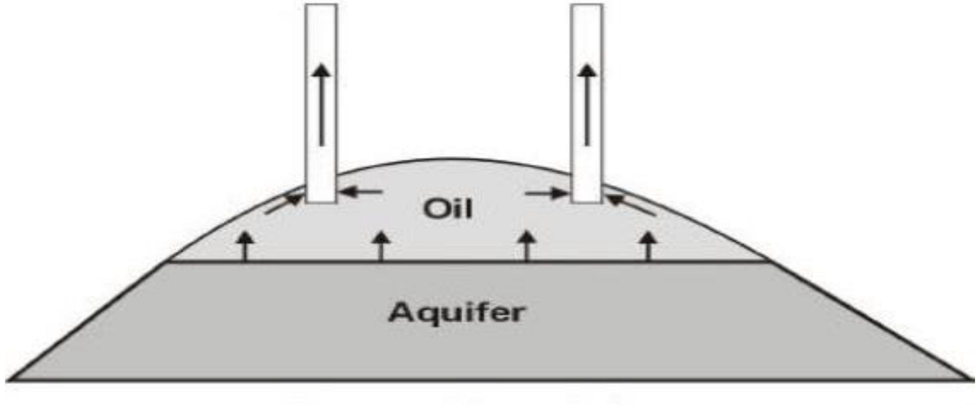


Gas cap drive mechanism: In hydrocarbon reservoirs with gas cap, the gas cap expansion applies a force to the oil column after production and reduction of reservoir pressure. This pressure is the main production mechanism which is called drive by gas cap. During production from this kind of reservoirs, reservoir pressure and oil production reduce with constant rate but the ratio of gas to oil (GOR) increases. This mechanism with recovery factor about 25% to 50%, in sand reservoirs has a weaker role than water drive mechanism.

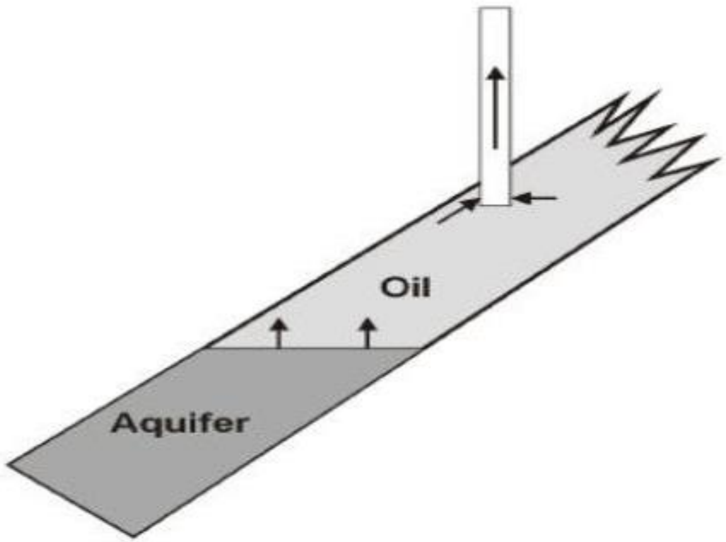




Water drive mechanism: Some reservoirs have communication with a water zone (aquifer) underneath. When reservoir pressure drops due to production, the compressed water in an aquifer expands into a reservoir and it helps pressure maintenance. This mechanism is called “water drive”. Water drive mechanism will be effective if an aquifer contacting reservoir is very large because water compressibility is very low. For example, an anticline structure with extensive water zone (aquifer) will have the most advantage from the use of a water drive mechanism. Water drive mechanism is a very good drive and reservoirs can produce oil over 50% recover factors in many cas

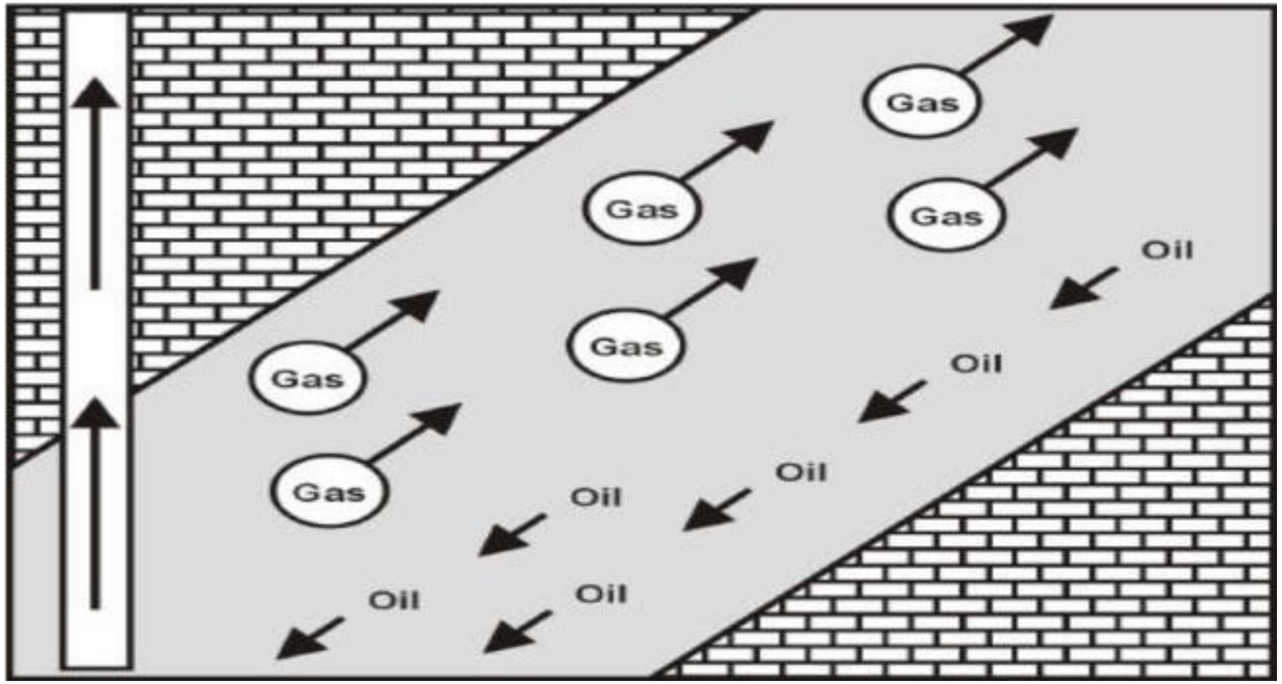


Bottom water drive

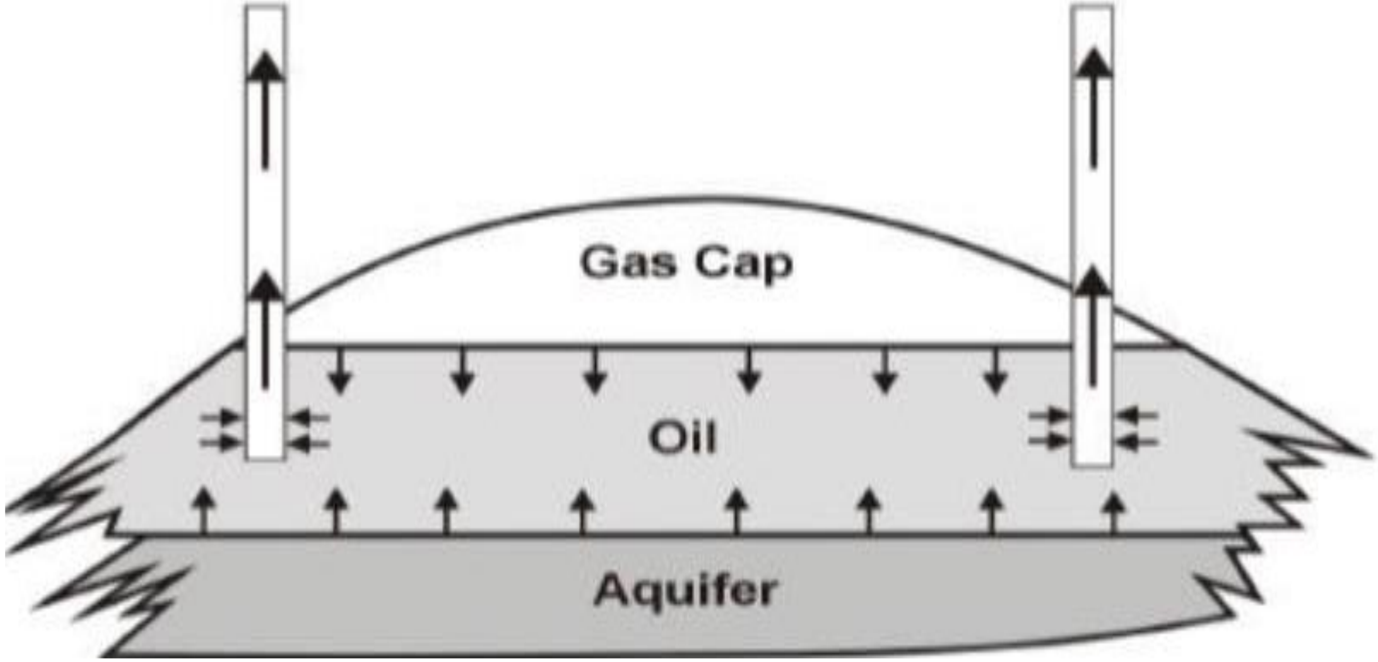


Edge water drive

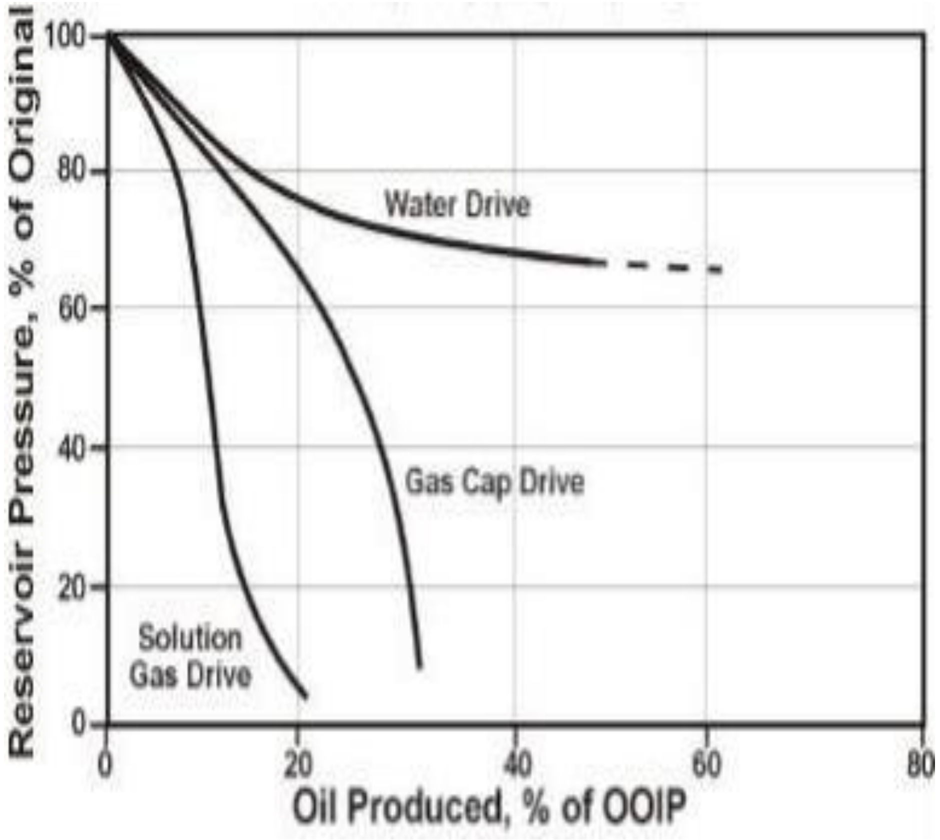
Gravity drainage drive mechanism: The density differences between oil and gas and water result in their natural segregation in the reservoir. This process can be used as a drive mechanism, but is relatively weak, and in practice is only used in combination with other drive mechanisms. The figure below shows production by gravity drainage. However, it is extremely efficient over long periods and can give rise to extremely high recoveries. Consequently, it is often used in addition to the other drive mechanisms.

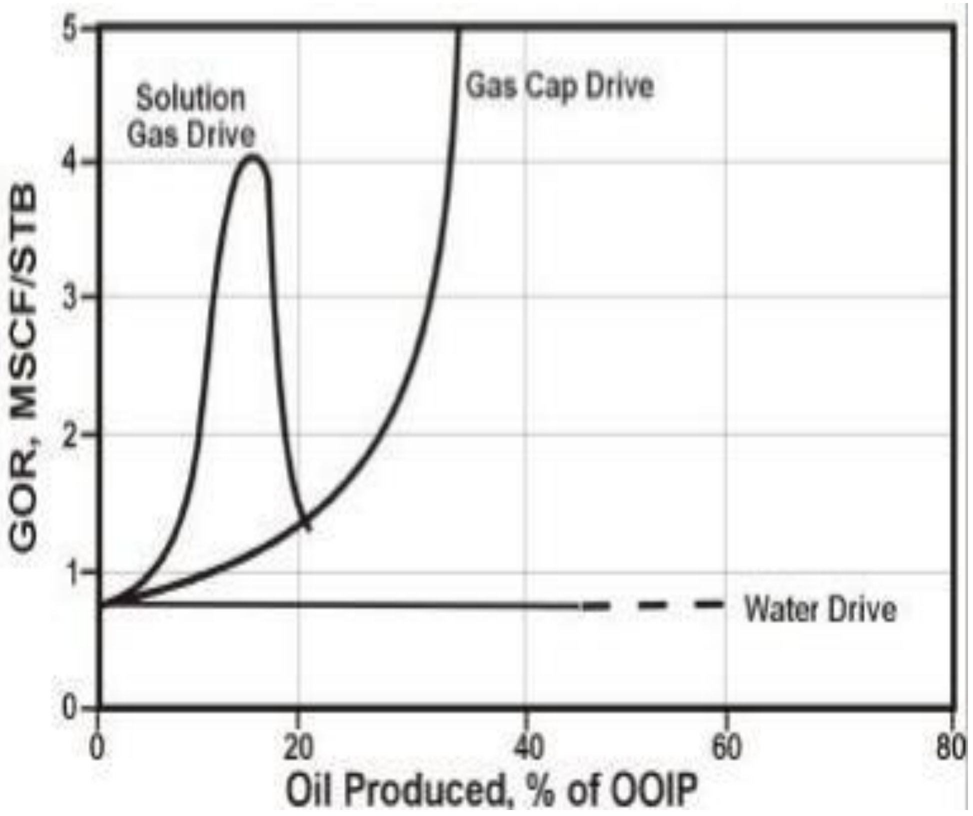


Combination drive mechanism: Most of the fields work with more than one mechanism. The most common combination of drives is solved gas drive (with or without gas free cap) with a weak water drive. When the free gas cap is combined with active water drive, combination drive has more efficiency.



The reservoir pressure and GOR trends for solution/depletion, gas cap and water drive mechanisms is shown in the figures belwo. Note particularly that water drive maintains has the reservoir pressure much higher than the gas drives, and has a uniformly low GOR.





RESERVOIR PRESSURE MAINTENANCE MECHANISM

The second stage of Hydrocarbon production during which an external fluid such as water or gas is injected into the reservoir through injection wells located in rock that has fluid communication with production wells. The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbon toward the wellbore. There are two major techniques.

They are:

- Water injection
- Gas injection

Water injection in order to maintain pressure: In small oil fields which are shown in figure ‘i’ below, pressure preserving by water injection in water layers at edge of reservoir is efficient, But in great field, injection should be done all over the water layer as shown in figure ‘ii’, in this status water zones can be formed in reservoir and advancing of these zones in oil reservoir, help pressure increase and oil drive toward production wells. Water injection has several advantages such as frequency in the ground surface, low price, easy to inject and having the characteristics of a reservoir natural fluid.

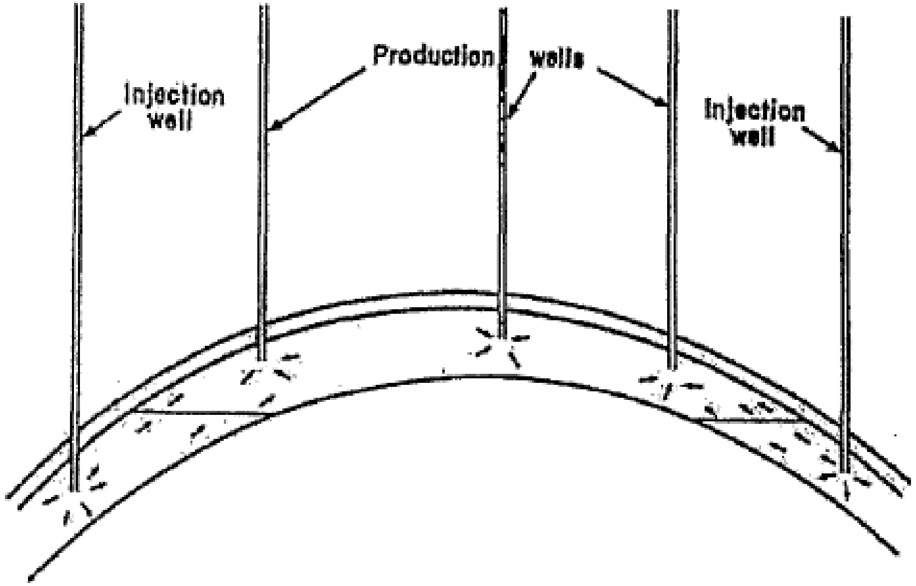


Figure i- Water injection in small field

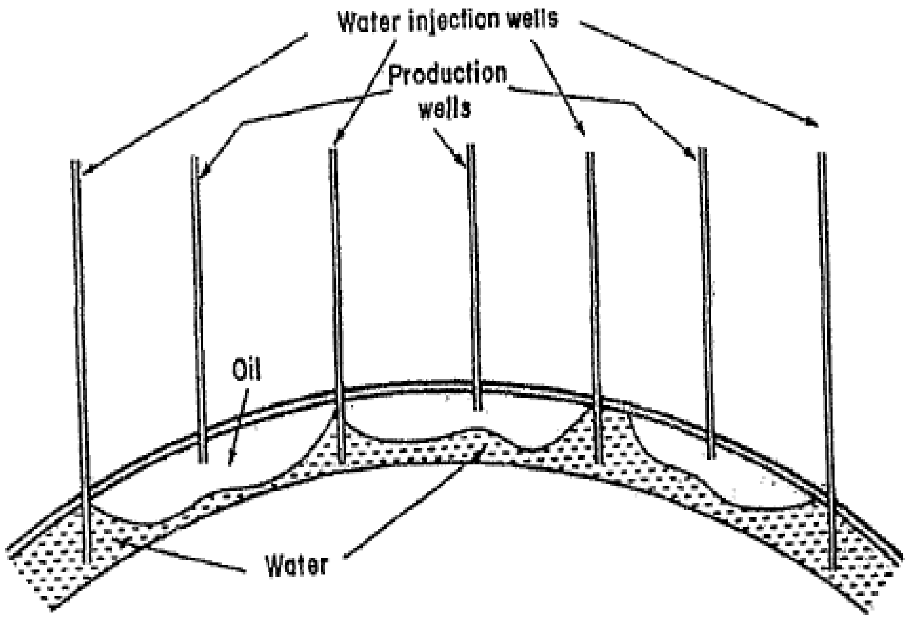
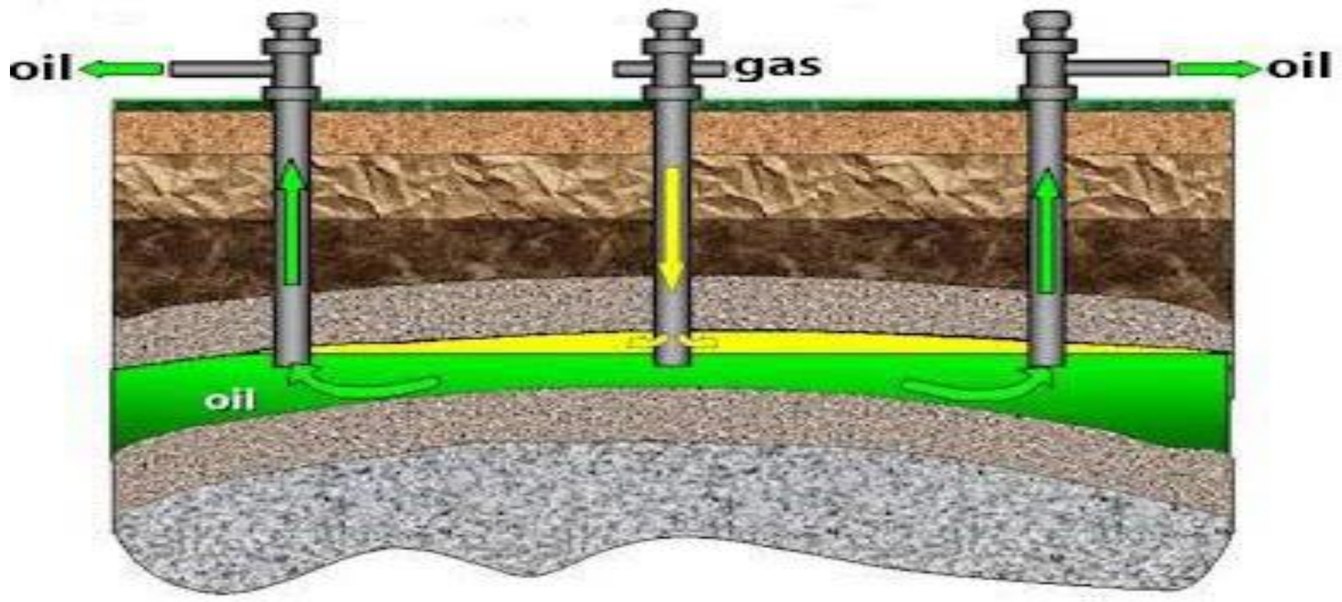


Figure ii-Water injection in large field

Gas injection in order to maintain pressure: As you see in the figure below, gas injection is formed in gas cap center. In this kind of injection, the pressure of injective gas is relatively low and surface tension is fixed between phases. In large field, gas injection should be done in all over the reservoir, as what was said about water injection, it can create gas zones which result in pressure increase and oil drive toward the production well. It should be considered that gas injection is very effective, when the reservoir natural drive mechanism is gravity drainage mechanism. The injection of natural gas has been decreased in all over the world, because of using it as heat and fuel.



WATERFLOOD PERFORMANCE PREDICTION

Waterflooding is a form of oil recovery wherein the energy required to move the oil from the reservoir rock into the producing well is supplied from the surface by means of water injection and the induced pressure from the presence of additional water. It is one of the economically viable techniques for recovery of additional oil from mature fields.

Thomas, Mahoney, and Winter (1989) pointed out that in determining the suitability of a candidate reservoir for waterflooding, the following reservoir characteristics must be considered:

- Reservoir geometry
- Fluid properties
- Reservoir depth
- Lithology and rock properties
- Fluid saturations
- Reservoir uniformity and pay continuity
- Primary reservoir-driving mechanisms

Reservoir geometry: The areal geometry of the reservoir will influence the location of wells and, if offshore, will influence the location and number of platforms required. The reservoir's geometry will essentially dictate the methods by which a reservoir can be produced through water-injection practices. An analysis of reservoir geometry and past reservoir performance is often important when defining the presence and strength of a natural water drive and, thus, when defining the need to supplement the natural injection. If a water-drive reservoir is classified as an active water drive, injection may be unnecessary.

Fluid properties: The physical properties of the reservoir fluids have pronounced effects on the suitability of a given reservoir for further development by waterflooding. The viscosity of the crude oil is considered the most important fluid property that affects the degree of success of a waterflooding project. The oil viscosity has the important effect of determining the mobility ratio that, in turn, controls the sweep efficiency.

Reservoir Depth: Reservoir depth has an important influence on both the technical and economic aspects of a secondary or tertiary recovery project. Maximum injection pressure will increase with depth. The costs of lifting oil from very deep wells will limit the maximum economic water-oil ratios that can be tolerated, thereby reducing the ultimate recovery factor and increasing the total project operating costs. On the other hand, a shallow reservoir imposes a restraint on the injection pressure that can be used, because this must be less than fracture pressure of the formation. In waterflood operations, there is a critical pressure (approximately 1 psi/ft of depth) that, if exceeded, permits the injecting water to expand openings along fractures or to create fractures. This results in the channeling of the injected water or the bypassing of large portions of the reservoir matrix. Consequently, an operational pressure gradient of 0.75 psi/ft of depth normally is allowed to provide a sufficient margin of safety to prevent pressure parting.

Lithology and rock properties: Thomas et al. (1989) pointed out that lithology has a profound influence on the efficiency of water-injection in a particular reservoir. Reservoir lithology and rock properties that affect flood ability and success are: porosity, permeability, clay content and net thickness.

Fluid saturations: In determining the suitability of a reservoir for waterflooding, a high oil saturation that provides a sufficient supply of recoverable oil is the primary criterion for successful flooding operations. Note that higher oil saturation at the beginning of flood operations increases the oil mobility that, in turn, gives higher recovery efficiency.

Reservoir uniformity and pay continuity: Substantial reservoir uniformity is one of the major physical criteria for successful waterflooding. For example, if the formation contains a stratum of limited thickness with a very high permeability (i.e., thief zone), rapid channeling and bypassing will develop. Unless this zone can be located and shut off, the producing water-oil ratios will soon become too high for the flooding operation to be considered profitable. The lower depletion pressure that may exist in the highly permeable zones will also aggravate the water-channeling tendency due to the high permeability variations. Moreover, these thief zones will contain less residual oil than the other layers, and their flooding will lead to relatively lower oil recoveries than other layers. Areal continuity of the pay zone is also a prerequisite for a successful waterflooding project. Isolated lenses may be effectively depleted by a single well completion, but a flood mechanism requires that both the injector and producer be present in the lens. Breaks in pay continuity and reservoir anisotropy caused by depositional conditions, fractures, or faulting need to be identified and described before determining the proper well spanning and the suitable flood pattern orientation.

Primary reservoir driving mechanism: The primary drive mechanism and anticipated ultimate oil recovery should be considered when reviewing possible waterflood prospects. The approximate oil recovery range is tabulated below for various driving mechanisms. Note that these calculations are approximate and, therefore, oil recovery may fall outside these ranges.

Reservoir Drive Mechanism	**Oil Recovery Range, %**
Rock and liquid expansion drive	3-7
Solution gas/ depletion drive	5-30
Gas cap drive	20-40
Water drive	35-75
Gravity drainage	< 80
Combination drive	30-60

Water-drive reservoirs that are classified as strong water-drive reservoirs are not usually considered to be good candidates for waterflooding because of the natural ongoing water influx. However, in some instances a natural water drive could be supplemented by water-injection in order to: Support a higher withdrawal rate, Better distribute the water volume to different areas of the field to achieve more uniform areal coverage, and Better balance voidage and influx volumes.

Gas-cap reservoirs are not normally good waterflood prospects because the primary mechanism may be quite efficient without waterinjection. In these cases, gas injection may be considered in order to help maintain pressure. Smaller gas-cap drives may be considered as waterflood prospects, but the existence of the gas cap will require greater care to prevent migration of displaced oil into the gas cap. This migration would result in a loss of recoverable oil due to the establishment of residual oil saturation in pore volume, which previously had none. The presence of a gas cap does not always mean that an effective gas-cap drive is functioning. If the vertical communication between the gas cap and the oil zone is considered poor due to low vertical permeability, a waterflood may be appropriate in this case.

Solution-gas or depletion drive mechanisms generally are considered the best candidates for waterfloods. Because the primary recovery will usually be low, the potential exists for substantial additional recovery by water-injection. In effect, we hope to create an artificial water-drive mechanism. The typical range of water-drive recovery is approximately double that of solution gas drive. As a general guideline, waterfloods in solution gas-drive reservoirs frequently will recover an additional amount of oil equal to primary recovery.

OPTIMUM TIME TO START WATER FLOOD

The most common procedure for determining the optimum time to start waterflooding is to calculate:

- Anticipated oil recovery
- Fluid production rates
- Monetary investment
- Availability and quality of the water supply
- Costs of water treatment and pumping equipment
- Costs of maintenance and operation of the water installation facilities
- Costs of drilling new injection wells or converting existing production wells into injectors
- Reservoir oil viscosity
- Free gas saturation
- Productivity of producing wells
- Overall life of the reservoir

The principal requirement for a successful fluid injection project is that sufficient oil must remain in the reservoir after primary operations have ceased to render economic the secondary recovery operations. This high residual oil saturation after primary recovery is essential not only because there must be a sufficient volume of oil left in the reservoir, but also because of relative permeability considerations. A high oil relative permeability, i.e., high oil saturation, means more oil recovery with less production of the displacing fluid. On the other hand, low oil saturation means a low oil relative permeability with more production of the displacing fluid at a given time.

SELECTION OF FLOODING PATTERNS

One of the first steps in designing a waterflooding project is flood pattern selection. The objective is to select the proper pattern that will provide the injection fluid with the maximum possible contact with the crude oil system. The selection of a suitable flooding pattern for the reservoir depends on the number and location of existing wells. This selection can be achieved by converting existing production wells into injectors, and/or drilling infill injection wells. When making the selection, the following factors must be considered:

- Reservoir heterogeneity and directional permeability
- Direction of formation fractures
- Availability of the injection fluid (gas or water)
- Desired and anticipated flood life
- Maximum oil recovery
- Well spacing, productivity, and injectivity

Essentially four types of well arrangements are used in fluid injection projects:

- Irregular injection patterns
- Peripheral injection patterns
- Regular injection patterns
- Crestal and basal injection patterns

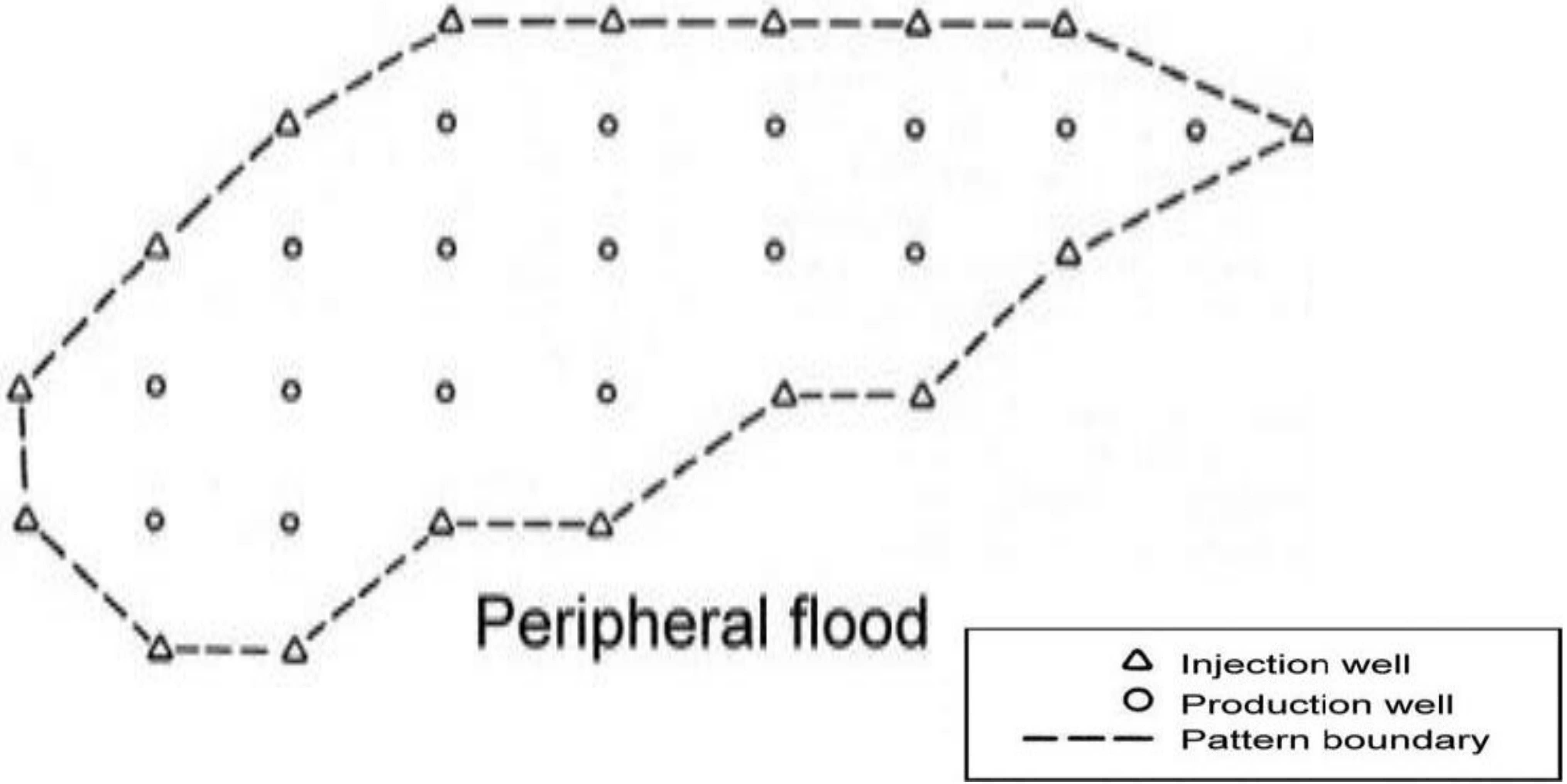
Irregular injection patterns: Willhite (1986) points out that surface or subsurface topology and/or the use of slant-hole drilling techniques may result in production or injection wells that are not uniformly located. In these situations, the region affected by the injection well could be different for every injection well. Some small reservoirs are developed for primary production with a limited number of wells and when the economics are marginal, perhaps only a few production wells are converted into injectors in a non uniform pattern. Faulting and localized variations in porosity or permeability may also lead to irregular patterns.

Peripheral injection patterns: In peripheral flooding, the injection wells are located at the external boundary of the reservoir and the oil is displaced toward the interior of the reservoir. The following are some characteristics of peripheral flood:

- The peripheral flood generally yields a maximum oil recovery with a minimum of produced water.
- The production of significant quantities of water can be delayed until only the last row of producers remains.

- Because of the unusually small number of injectors compared with the number of producers, it takes a long time for the injected water to fill up the reservoir gas space. The result is a delay in the field response to the flood.
- For a successful peripheral flood, the formation permeability must be large enough to permit the movement of the injected water at the desired rate over the distance of several well spacing from injection wells to the last line of producers.
- To keep injection wells as close as possible to the waterflood front without bypassing any movable oil, watered-out producers may be converted into injectors. However, moving the location of injection wells frequently requires laying longer surface water lines and adding costs.
- Results from peripheral flooding are more difficult to predict. The displacing fluid tends to displace the oil bank past the inside producers, which are thus difficult to produce.

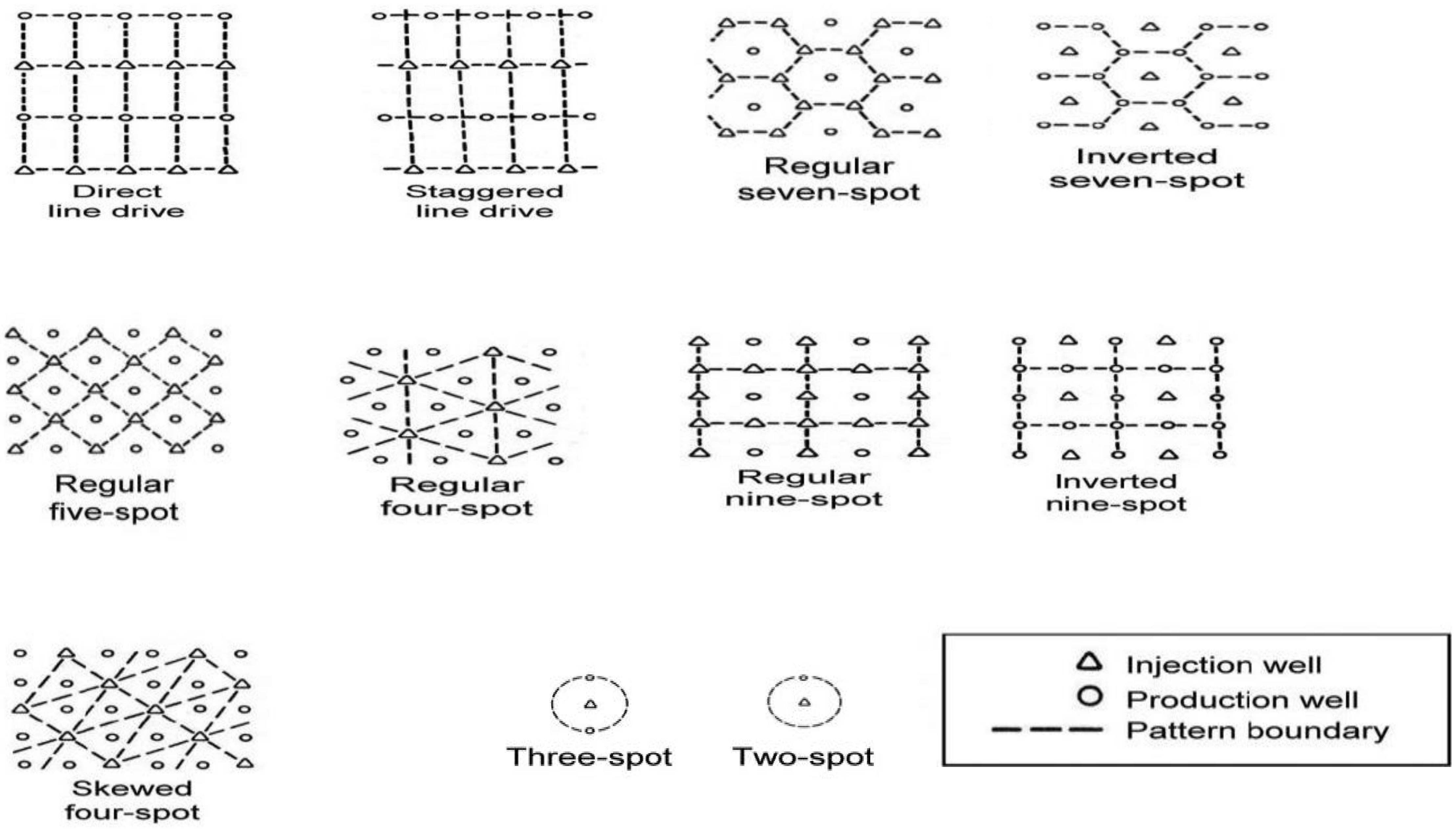
Injection rates are generally a problem because the injection wells continue to push the water greater distances.



Regular injection patterns: Due to the fact that oil leases are divided into square miles and quarter square miles, fields are developed in a very regular pattern. A wide variety of injection-production well arrangements have been used in injection projects. The most common patterns are explained below:

- **Direct line drive**: The lines of injection and production are directly opposed to each other. The pattern is characterized by two parameters: a = distance between wells of the same type, and d = distance between lines of injectors and producers.
- **Staggered line drive**: The wells are in lines as in the direct line, but the injectors and producers are no longer directly opposed but laterally displaced by a distance of a/2.
- **Five spot**: This is a special case of the staggered line drive in which the distance between all like wells is constant, i.e., a = 2d. Any four injection wells thus form a square with a production well at the center.
- **Seven spot**: The injection wells are located at the corner of a hexagon with a production well at its center.
- **Nine spot**: This pattern is similar to that of the five spot but with an extra injection well drilled at the middle of each side of the square. The pattern essentially contains eight injectors surrounding one producer.

The patterns termed inverted have only one injection well per pattern. This is the difference between normal and inverted well arrangements. Note that the four-spot and inverted seven-spot patterns are identical.


Direct line drive
Staggered line drive
Regular seven-spot
Inverted seven-spot
Regular five-spot
Regular four-spot
Regular nine-spot
Inverted nine-spot
Skewed four-spot
Three-spot
Two-spot
Injection well
Production well
Pattern boundary

Crestal and Basal Injection Patterns: In crestal injection, as the name implies, the injection is through wells located at the top of the structure. Gas injection projects typically use a crestal injection pattern. In basal injection, the fluid is injected at the bottom of the structure. Many water-injection projects use basal injection patterns with additional benefits being gained from gravity segregation.

OVERALL RECOVERY EFFICIENCY: The overall recovery factor (efficiency) RF of any secondary or tertiary oil recovery method is the product of a combination of three individual efficiency factors as given by the following generalized expression:

$$RF = E_D \, E_A \, E_V$$

In terms of cumulative oil production (N_P), overall recovery efficiency is expressed as

$$N_P = N_S \, E_D \, E_A \, E_V$$

where

RF = overall recovery factor

N_S = initial oil-in-place at the start of the flood, STB

N_P = cumulative oil produced, STB

E_D = displacement efficiency

E_A = areal sweep efficiency

E_V = vertical sweep efficiency

Displacement Efficiency (E_D): Displacement efficiency E_D is the fraction of movable oil that has been displaced from the swept zone at any given time or pore volume injected. Because an immiscible gas injection or waterflood will always leave behind some residual oil, E_D will always be less than 1.0. Mathematically, the displacement efficiency is expressed as:

$$E_D = \frac{Volume\ of\ Oil\ at\ start\ of\ Flood - Remaining\ Oil\ Volume}{Volume\ of\ Oil\ at\ start\ of\ Flood}$$

$$E_D = \frac{(Pore\ Volume)\left(\frac{S_{oi}}{B_{oi}}\right) - (Pore\ volume)(\frac{\bar{S}_o}{B_o})}{(Pore\ Volume)(\frac{S_{oi}}{B_{oi}})}$$

$$E_D = \frac{\left(\frac{S_{oi}}{B_{oi}}\right) - (\frac{\bar{S}_o}{B_o})}{(\frac{S_{oi}}{B_{oi}})}$$

Where

S_{oi} = Initial oil saturation at start of flood

B_{oi} = Oil formation volume factor at start of flood, bbl/STB

$\bar{S}_o$= Average oil saturation in the flood pattern at a particular point during the flood

Assuming a constant formation volume factor during the flood life, ED is expressed as:

$$E_D = \frac{S_{oi} - \bar{S}_o}{S_{oi}}$$

where the initial oil saturation (S_{oi})is given by:

$$S_{oi} = 1 – S_{wi} – S_{gi}$$

However, in the swept area, the gas saturation is considered zero, therefore:

$$\bar{S}_o = 1 - \bar{S}_w$$

In terms of water saturation, displacement efficiency is expressed thus:

$$E_D = \frac{\bar{S}_w - S_{wi} - S_{gi}}{1 - S_{wi} - S_{gi}}$$

If S_{gi} = 0, where S_{gi} = Initial gas saturation at the start of the flood

$$E_D = \frac{\bar{S}_w - S_{wi}}{1 - S_{wi}}$$

Where

S_{wi} = Initial water saturation at the start of the flood

$\bar{S}_w$ = Average water saturation in the swept area

The displacement efficiency E_D will continually increase at different stages of the flood i.e. with increasing average water saturation of the swept area. E_D reaches maximum when the average oil saturation in the area of the flood pattern is reduced to the residual oil saturation S_{or}.

FRONTAL DISPLACEMENT THEORY

Buckley and Leverett (1942) developed a well established theory called frontal displacement theory which provides the basis for establishing the relationship between displacement efficiency and increasing water saturation in the reservoir. The frontal displacement theory consists of equations:

—Fractional flow equation

—Frontal advance equation

Fractional Flow Equation

The development of the fractional flow equation is attributed to Leverett (1941). For two immiscible fluids, oil and water, the fractional flow of water, fw (or any immiscible displacing fluid), is defined as the water flow rate divided by the total flow rate. Mathematically expressed as:

$$f_w = \frac{q_w}{q_t} = \frac{q_w}{q_w + q_o}$$

Where

f_w = fraction of water in the flowing stream i.e. water cut, bbl/bbl

q_w = Water flowrate, bbl/day

q_o = Oil flowrate, bbl/day

q_t = Total flowrate, bbl/day

$$f_D = \frac{1 + \left[\frac{0.001127\,(KK_{ro})A}{\mu_o i_D}\right]\left(\frac{\partial P_c}{\partial x} - 0.433\Delta\rho\ \sin\alpha\right)}{1 + \frac{K_{ro}}{K_{rD}}\frac{\mu_D}{\mu_o}}$$

Where subscript "D" refers to the displacement fluid, therefore $\Delta\rho = \rho_D - \rho_o$

The effect of capillary pressure is neglected hence *dPc* = 0

For water injection,

$$f_w = \frac{1 - \left[\frac{0.001127\,(KK_{ro})A}{\mu_o i_w}\right]\,(0.433\,(\rho_w - \rho_o)\ \sin\alpha)}{1 + \frac{K_{ro}}{K_{rw}}\frac{\mu_w}{\mu_o}}$$

For Gas injection,

$$f_g = \frac{1 - \left[\frac{0.001127\,(KK_{ro})A}{\mu_o i_g}\right]\,\left(0.433\,(\rho_g - \rho_o)\ \sin\alpha\right)}{1 + \frac{K_{ro}}{K_{rg}}\frac{\mu_g}{\mu_o}}$$

Where

f_w = Fraction of water (Water cut), bbl/bbl

f_g = Fraction of gas (gas cut), scf/scf

K = Absolute permeability, md

K_{ro} = Relative permeability to oil

K_{rw} = Relative permeability to water

K_{rg} = Relative permeability to gas

μ_o = Oil viscosity, cp

μ_w = Water viscosity, cp

μ_g = Gas viscosity, cp

i_w = Water injection rate, bbl/day

i_g = Gas injection rate, scf/day

ρ_o = Oil density, g/cm3

ρ_w = Water density, g/cm3

ρ_g = Gas density, g/cm3

A = Cross sectional area, ft2

α = Dip angle (positive for upward dip flow and negative for downward dip flow)

The above equation is used for two immiscible fluids.

From the definition of water cut, i.e., $f_w = q_w/(q_w + q_o)$, the limits of the water cut are 0% and 100%. At the irreducible (connate) water saturation, the water flow rate q_w is zero and, therefore, the water cut is 0%. At the residual oil saturation point, S_{or}, the oil flow rate is zero and the water cut reaches its upper limit of 100%.

The shape of the water cut versus water saturation curve is characteristically S-shaped. The limits of the f_w curve (0 and 1) are defined by the end points of the relative permeability curves. In general, any influences that cause the fractional flow curve to shift upward (i.e., increase in f_w or f_g) will result in a less efficient displacement process.

During the displacement of oil by waterflood, an increase in f_w at any point in the reservoir will cause a proportional decrease in f_o and oil mobility. Therefore, it is very important to select the proper injection scheme that could possibly reduce the water fractional flow. This can be achieved by investigating the effect of the injected water viscosity, formation dip angle, and water-injection rate on the water cut.

ASSIGNMENT

1. Explain the effect of the following on fractional flow/water cut.
   - Dip angle and Injection rate
   - Water and Oil viscosities
2. A linear system is ender consideration for a waterflooding project with injection rate of 1,000bbl/day. The oil viscosity is considered constant at 1.0cp. Using the given relative permeability cure and the given information below, calculate and plot the fractional flow curve for the reservoir dip angles 10^{O}, 20^{O}, and 30^{O}. Assuming
   a. Up-dip displacement
   b. Down-dip displacement