CHAPTER II
LITERATURE REVIEW

This chapter discussed about fundamental of reservoir fluid behaviour and basic knowledge of improved oil recovery. The introducing of this chapter focuses on secondary oil recovery and then following with the discussion on programs in computer modelling group (CMG) that had been used in this work. Finally, detail about the reservoir simulation which was builtand run by using IMEX module will be presented.

2.1 Classification of Reservoirs and Reservoir Fluids

Petroleum fluids are usually classifiedinto three board categories containing aqueous solutions, liquid hydrocarbon and gases (hydrocarbon and non-hydrocarbon). In all categories depend on their composition, initial reservoir pressure and temperature and pressure and temperature of the surface production.Normally, reservoir fluids are classified by using multicomponent pressure-temperature diagrams as shown in Figure 2.1.

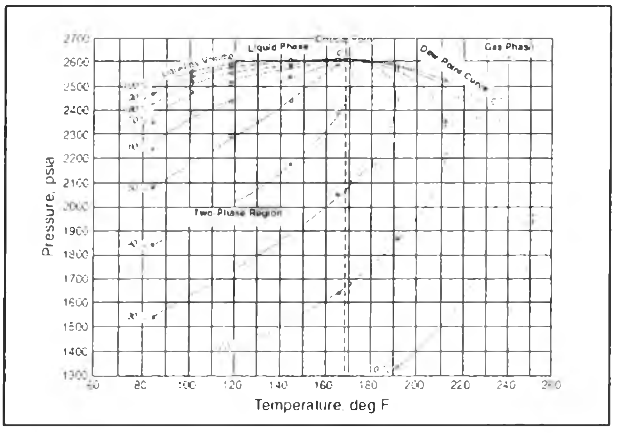

Figure 2.1 Typical P-T diagram for multi-component system (Ahmed, 2012).

As shown in the above figure, the reservoir which has a temperature higher than the critical temperatureis classified as gas reservoir. On the contrast, the reservoir which has a temperature less than the critical temperature is classified as oil reservoir.

2.1.1 Oil Reservoirs

The classification of oil reservoirs depend on reservoir pressure (p_i), oil reservoirs can be classified into two categories.

2.1.1.1 Undersaturated Oil Reservoir

If the initial reservoir pressure (p_i) is greater than bubble-point pressure (p_b), the reservoir is classified as undersaturated oil reservoir. This reservoir has no free gas until the reservoir pressure reduces below the bubble-point pressure (p_b).

2.1.1.2 Saturated Oil Reservoir

If the initial reservoir pressure (p_i) equals to or less than to bubble-point pressure (p_b), the reservoir is called saturated oil reservoir. The oil is completely saturated with dissolved gas. Thus, the gas cap probably exists at the initally pressure and temperature.

The classified oil reservoir described above could not appropriately identify all types of oil because crude oils have various physical properties and chemical compositions. Thus, crude oils commonly classified into three types which are ordinary black oil, volatile oil and heavy oil.

1) Ordinary Black Oil

Figure 2.2 is shown a typical pressure-temperature diagram for ordinary black oil. Following the pressure reduction shows as the vertical line E-F on figure1. The quality lines are proximately equally spaced. When produced, ordinary oil gravities usually between 15° and 40°API. The stock tank of this crude oil is normally dark green to brown in color.

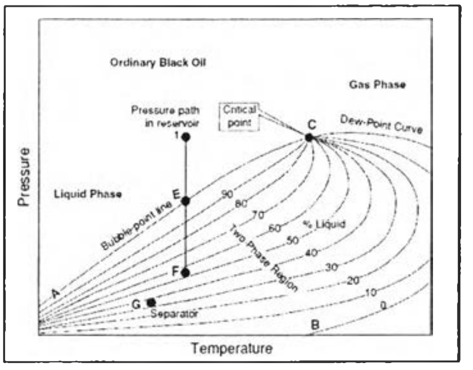

Figure 2.2 A typical P-T diagram for ordinary black oil (Ahmed, 2012).

2) Volatile Oil

Figure 2.3 is shown the typical pressure-temperature diagram for volatile crude oil (high-shrinkage oil. The quality lines are closely near the bubble-point curve and widely spaced at low pressures. The separator conditions indicate as the G point which is lower than 15% quality line. When produced, the volatile crude oil gravities usually between 45° and 55° API. The stock tank of this crude oil is normally greenish to orange in color.

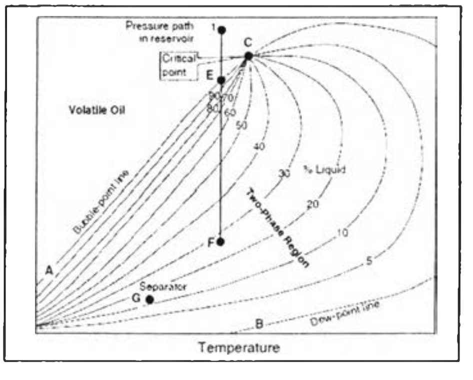

Figure 2.3 A typical P-T diagram for volatile crude oil(Ahmed, 2012).

3) Heavy Oil

The composition of heavy crude and extra-heavy crude oil is low hydrogen/carbon ratios and high asphaltene content. Figure 2.4 is shown the P-T diagram of heavy oil. The heavy crude oil gravities are usually less than 22.3° API.Heavy oil is hard to flow through the porous media and hard to produce by natural force. Heavy crude oil cannot normally be produced by conventional production. Thus, it is necessary to improve oil recovery method.

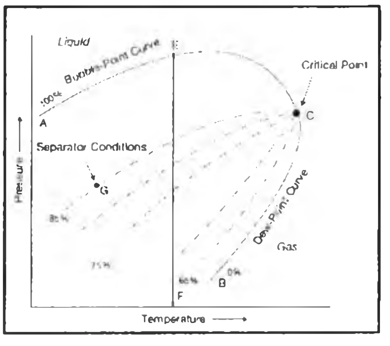

Figure 2.4 Phase diagram of heavy oil reservoir (Ahmed, 2012).

2.1.2 <u>Gas Reservoirs</u>

The reservoir which has temperature above the critical temperature is classified as a natural gas reservoir. In general, natural gas can be classified into four categories which are Dry gas, Wet gas and Retrograde gas condensate.

2.1.2.1 Dry gas

In general, a dry gas reservoir is found with hydrocarbon component in gas phase alone. During production of the reservoir, reservoir gas and produced gas exist in single phase. The liquid associate with the gas from dry gas reservoir is only water. Gas-oil ratio of dry gas is typically greater than 100,000 scf/STB. Tight formation is also source of commercially producible gas and considered as conventional resource. Figure 2.5 is shown the typical diagram of dry gas reservoir.

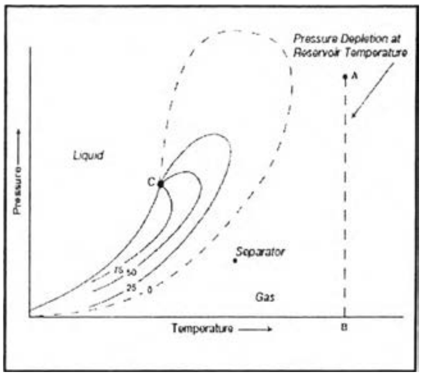

Figure 2.5 A typical P-T diagram of dry-gas (Ahmed, 2012).

2.1.2.2 Wet gas

Figure 2.6 is shown the typical diagram of wet gas. In typically, reservoir is found initially with all the hydrocarbon components in gas phase, same as in dry gas reservoir. The gas existing in the reservoir would be completely in a single phase without condensation in subsurface formation when reservoir pressure declines upon production. When the pressure and temperature reduce at the surface, a portion of gas will condense out through the wells. This occurs due to the presence of certain hydrocarbons in reservoir gas that condense under surface conditions. Wet gas reservoir compound are heavier than dry gas reservoir. The stock-tank oil gravity is above 60°API. The stock tank of this condensate is water-white in color.

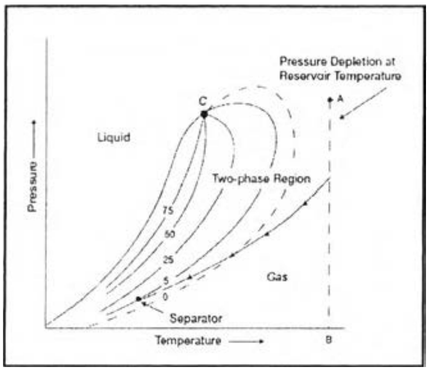

Figure 2.6 A typical P-T diagram of wet-gas (Ahmed, 2012).

2.1.2.3 Retrograde gas condensate

When the reservoir temperature and pressure reduce, a portion of gas occupies by heavier hydrocarbons condenses out and deposit in the subsurface. This effect will occur as a reservoir pressure declines below the dew point of reservoir fluid. Condensation mainly occurs near the wellbore because of the relatively large drop in pressure. The opposite effects of retrograde condensation only occur in lean gas production. Thus, The reservoir pressure maintains above the dew point by reinjecting dry gas in order to improve recovery of relatively rich components. Figure 2.7 is shown the typical diagram of retrograde gas condensate. The retrograde gas condensate gravity is above 50°API. The stock-tank liquid is usually water-white or slightly colour.

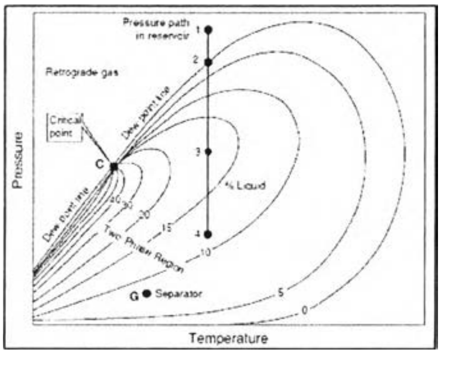

Figure 2.7 A typical P-T diagram of Retrograde gas-condensate (Ahmed, 2012).

2.2 Reservoir Drive

Recovery of hydrocarbon from oil reservoir is generally classified to occur in different recover stages. There are:

(i) Primary Recovery
(ii) Secondary Recovery
(iii) Tertiary Recovery (Enhanced Oil Recovery, EOR)

2.2.1 Primary Recovery Drive Mechanism

During the primary recovery the natural driving force of reservoir is used to force hydrocarbons into the production wells. The different types of drive mechanism depend on the original characteristics of reservoir. There are five important drive mechanisms which are solution gas driving, gas cap drive, water drive, gravity drainage and combination or mixed drive. The following table 2.1 shows the recovery ranges of individual primary recovery drive mechanism.

Table 2.1 Recovery ranges of individual primary recovery drive mechanism (http://www2.ggl.ulaval.ca/personnel/paglover/CD%20Contents/Formation%20Evaluation%20English/Chapter%203.PDF).

Drive Mechanism	Energy Source	Recovery, % OOIP
Solution gas drive	Evolved solution gas and expansion	20-30
Evolved gas		18-25
Gas expansion		2-5
Gas cap drive	Gas cap expansion	20-40
Water drive	Aquifer expansion	20-60
Edge		35-60
Bottom		20-40
Drive Mechanism	**Energy Source**	**Recovery, % OOIP**
Gravity drainage	Gravity	50-70

2.2.1.1 Solution Gas Drive

The reservoir rock which completely surrounded by impermeable barriers is required in this drive mechanism. The reservoir pressure decreases as production goes on and the exsolution and expansion of the dissolved gases into the oil and water provides most of the reservoirs drive energy. Small amount of energy are obtained from the expansion of rock and water, and gas exsolving and expanding from water phase. A solution gas drive reservoir can be considered to be undersaturated or saturated depending on its pressure. Oil recover on this type of reservoir is typically between 2-30% OOIP. Recovery is low, because the oil is less mobility and has more viscosity than gas phase in reservoir. There is usually no water production during oil recovery unless the reservoir pressure drops sufficiently for the connate water to expand to be mobile.

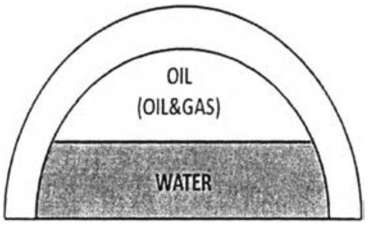

Figure 2.8 Unsaturated oil reservoirs.

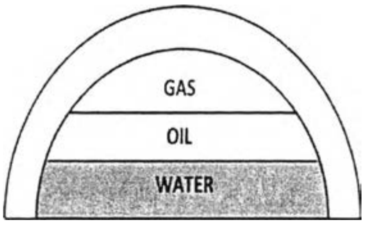

Figure 2.9 Saturated oil reservoirs.

2.2.1.2 Gas Cap Drive

In gas cap drive mechanism, the main source of driving energy comes from gas expansion which already existing above oil zone in the reservoir. The expanding gas cap limits the pressure decrease and pushed the oil out of the reservoir. The actual rate of pressure decrease is related to size of the gas cap in the reservoir. The larger gas cap, the small pressure drop in the reservoir required for the gas cap to expand. The recovery of gas cap reservoir is 20-40% OOIP which is better than the solution gas reservoir.

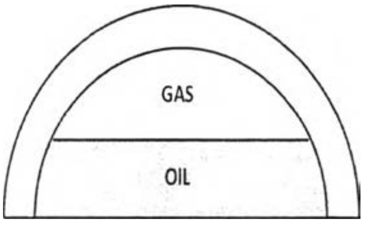

Figure 2.10 Gas cap drive reservoirs.

2.2.1.3 Water Drive

Most of oil and gas reservoirs have aquifer. The driving energy comes from an aquifer that interfaces with the oil- water contact (OWC). The active aquifer is continuously fed by incoming aquifer, and then this bottom water will expand into the reservoir displacing oil. For mostly reservoirs, solution gas drive mechanism is also taken place, and there may also be a gas cap drive mechanism in primary recovery. Two type of water drive are generally classified which are bottom water drive and edge water drive. The recovery from water driven reservoir is typically between 20-60% OOIP, depend on the strength of the aquifer and the efficiency which water displaces the oil in the reservoir, which depends on production oil displacement, reservoir structure, oil viscosity, and production rate.

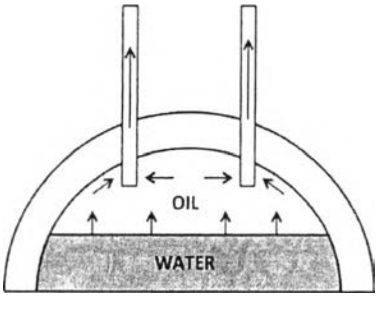

Figure 2.11 Water drive reservoirs.

2.2.1.4 Gravity Drainage

Gravity drainage may be present in primary production mechanism in thick reservoir. The different density between oil and gas and water provide the natural segregation in the reservoir. Gravity drainage is relatively weak drive mechanism, and it is usually used in combination with other drive mechanisms.

The gravity drainage is slow process because gas have to move up to the top of the formation to fill the previously space occupied by oil. The production rate of gravity drainage is very low compared with the other mechanism, but it is extremely efficiency over long periods and give the extremely high recoveries which is between 50-70% OOIP.

The gravity drainage is slow process because gas have to move up to the top of the formation to fill the previously space occupied by oil, but it is extremely efficiency over long periods and give the extremely high recoveries which is between 50-70% OOIP. Therefore, this mechanism is usually used in additional of the other mechanisms.

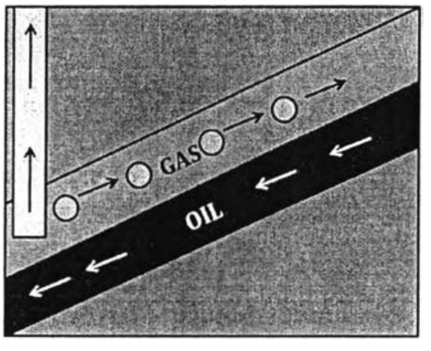

Figure 2.11 Gravity Drainage Reservoirs.

2.2.1.5 Combination or Mixed Drive

In reality, the mostly reservoirs produce oil combines at least two main of drive mechanisms and the efficiency can be increase when the drive mechanisms are incorporated. For example, if low perforation for gas-cap and the high perforation for water drive is occurred in the same reservoir, the ultimate recovery will depend on the strength of each drive present, the size of the gas cap, and the size or permeability of aquifer. The reservoir is managed to identify the strengths of the drives and optimize the performance of reservoir.

2.2.2 <u>*Secondary Recovery Drive Mechanism*</u>

The secondary recovery is normally implemented when the recovery from partially depleted formation of additional quantities of oil present. These secondary recovery techniques generally utilize the principle of augmenting the tendency for oil to flow after the natural drive has been depleted during oil recovery by the primary recovery methods. The secondary recovery processes include water flooding, gas injection under immiscible condition and in some case pressure maintenance. In petroleum industry, secondary recovery normally is water flooding. In case of miscible gas flooding is classified as tertiary recovery or enhanced oil recovery.

Two thirds of crude oil is left behind, due to both microscopic and macroscopic factors. Microscopic factors include effects of wettability and oil-water interfacial tension (IFT). The oil which is in the left after a sweep is called residual oil saturation (S_{or}). Macroscopic factors include reservoir stratification with some strata showing a vary permeabilities. Thus, the displacing fluid is channelling through the high-permeability zoned leaving oil in the low-permeability zones unswept(Bai *et al.*, 2007). Even in the homogeneous and uniformly permeable reservoir, displacement can break down when the displacing fluid has less viscosity than the oil in reservoir, this situation is called adverse mobility ratio. The less viscous fluid penetrates in the oil reservoir; this situation is called viscous fingering.

2.2.2.1 Water Injection

Water is pumped into through an injection well into the reservoir to displace the oil from the zone near the point of the injection toward a point at which fluid is produced. This process is called waterflooding. Waterflooding is the most common method used to enhanced oil recovery because water is relatively inexpensive, and maybe economical despite the low ultimate recoveries predicted(Mai *et al.*, 2010). The efficiency of waterflood project depends on various factors,unfavorable condition could lead to very poor efficiency. The various factors include fixed and inherent properties(Wingen *et al.*, 1961). The properties include oil composition, oil viscosity, porosity, permeability, lenticularity, reservoir temperature, reservoir pressure, depth of reservoir, thickness of reservoir and reservoir fracture. The factors can be classified in two sets of variables. The first set is called “primary variables”. These variables are calculated by using a direct mathematic and the estimation of variables depend on another group of variable, which are secondary variables(Callaway, 1959). The primary variables are:

1) Primary recovery efficiency
2) Connate water saturation
3) Volumetric sweep efficiency
4) Residual oil saturation to waterflooding
5) Crude oil shrinkage
6) Floodable reservoir pore volume

The secondary variables are listed which indicate the primary affect(Callaway, 1959; Singh *et al.*, 1982).

1) Geology considerations (1,3,6)
2) Oil viscosity (1,3,4)
3) Permeability (1,3,4)
4) Uniformity of reservoir rock (3)
5) Flood pattern (3,4)
6) Time of flood (5)
7) Economic factors (1,3,4)

Geology considerations are needed to determine favourable reservoir pore volume. The structures of reservoir control the location of the well and dictate the methods by which a reservoir can be waterflooded.

Oil recovery efficiency can be expressed as two key elements which are displacement efficiency and overall sweep efficiency. The overall sweep efficiency is usually broken as two components which are areal (or pattern) sweep efficiency and vertical sweep efficiency (Shen Pingping, 2005).

Displacement efficiency refers to the fraction of the oil in place that is swept from unit volume to the reservoir. Displacement efficiency is affected by fluid viscosity, mobility ratio, wettability of rock and pore geometry. The displacement efficiency mainly contributes in high permeable zonein highly heterogeneous reservoir(Shen Pingping, 2005).The wettability of rock is tendency of one fluid to spread preferentially onto or adhere to a solid surface in the presence of two immiscible fluids(Craig, 1971). The wettability has strongly affect its waterfloodbehaviour because wettability is a major factor for controlling the location, flow and distribution in porous media(Anderson, 1987). The most studies agree that water flooding performs the best in an intermediate wetting reservoir which is neither strong water-wet nor oil-wet.

The areal sweep efficiency is the fraction of the total flood pattern that contact by displacing fluid. The areal efficiency depends on flood pattern, mobility ratio and fracture. Musket calculated flooding efficiencies for a wide variety of well patterns. (direct-line-drive, staggered-line –drive, 5-spot, 7-spot and 9-spot). The length and orientation of the fracture and the direction of flooding are also affect this efficiency. The vertical fracture was parallel with the direction of flood; the areal sweep efficiency will be reduced(Crawford *et al.*, 1954).

Vertical sweep efficiency is the fraction of the vertical section of the pay zone that is contacted by injected fluid. The vertical sweep efficiency is primarily a function of vertical heterogeneity, mobility ratio, gravity force ratio and total volume of injected. The vertical sweep efficiency will be increased for the homogeneous reservoir and high injected rate. On the other hand, over most of the ranges of gravity force ratio and degree of heterogeneity investigated, channel sand reservoir tended to give increasing oil breakthrough oil recoveries for decreasing rates of injection(Belgrave *et al.*, 1993; Ordonez *et al.*, 2012).

The mobility ratio is an important factor for both vertical sweep and areal sweep efficiency. This factor causes the problems in the waterflooding process and creates limitation on this process, particularly in heavy oil production. Therefore, mobility ratio will be improved to increase oil recovery. The mobility ratio is the mobility of the displacing fluid divided by that of the displaced fluid, i.e. for water flooding, it is the mobility of water divided by the mobility of oil.

$$M = \frac{k_{rw}\mu_o}{k_{ro}\mu_w} \tag{2.1}$$

Where $k_{rw}$is relative permeability of water

k_{ro} is relative permeability of oil

μ_w is viscosity of water

μ_o are viscosity of oil

Ideally, oil is displaced by a "piston-like" mechanism but in reality the viscous fingers are occurred at the frontal displacement, especially in high mobility ratio(Kumar *et al.*, 2001). Impact of reservoir heterogeneity and oil viscosity increase as the mobility ratio is increased and the more severe channelling occurs. This effect gives the limitation of waterflooding on more heavy oil.

Economic factors include many things such as crude oil price, depth of reservoir, operating costs, well spacing, availability of water and other considerations which may affect the economic limit to waterflooding operations may be conducted(Brashear *et al.*, 1978).

2.2.2.2 Gas Injection

Gas injection is another method for secondary recovery. The gas injected could be carbon dioxide, nitrogen, hydrocarbon, or other gases as an injection fluid in order to increase oil production rate and extent the production life of the wells.Carbon dioxide (CO_2) is the most widely studies and is focused in this work.This method is mainly same aswaterfloodingand it is used to maintain gas cap pressure, even though oil displacement is not required. In this work focused on CO_2immiscible flooding.

Carbon dioxide is the second best injected fluid after water. The immiscible gas injection becomes interesting and promising techniques for heavy oil because can solve the problems such as high mobility between CO_2 and heavy oil. The problems will create the channelling and fingering. ImmiscibleCO_2 flooding is a technique which improve properties of the oil in the reservoir. This method has four mechanisms which increase oil recovery. They are (i) viscosity reduction, (ii) oil expansion, (iii) interfacial tension reduction, and (iv) blow down recovery(Jha, 1985; Sobers *et al.*, 2010). The four mechanisms increase oil recovery by reduction of oil viscosity, swelling of oil, vaporization of oil, miscibility effects, reduction of interfacial tension, solution gas drive during blow-down, and increase in injectivity(Mungan, 1991). The blowdown recovery is associated with residual CO_2 in the reservoir which is released when the pressure is reduced below the saturation pressure. The reduction of viscosity by water flooding following the gas injection can be improved oil recovery compared with water flooding(Spivak *et al.*, 1984).

In immiscible CO_2 process, part of CO_2 is absorbed into the reservoir and the excess part of CO_2forms a free-gas phase in the reservoir. Other immiscible mechanisms that CO_2 injection as decompression (dissolved gas drive) and reduction of interfacial tension(Issever *et al.*, 1998). In general, reduction of oil viscosity is not important for light oil but very significant in the recovery of heavy oil. Temperature, pressure and concentration of dissolved $CO_2$is depended on the viscosity of oil saturated with CO_2(Khatib *et al.*, 1981). When the temperature is above 150 °C, the oil viscosity is the lowest because the diffusion and solubility of CO_2in the oil and extraction process that is responsible for viscosity reduction are decrease. A process of dissolution occurs therefore causing oil swelling when CO_2. The oil swelling is function of temperature, pressure and oil composition. The solubility and swelling factor of CO_2 will increase with pressure and decrease with temperature and density above critical temperature. When the energy stored by CO_2 dissolves into the solution with increasing pressure that is released after flooding and continues to drive the oil to the well bore. The immiscible CO_2 flooding method can recover as much as 15% incremental oil over a waterflooding in moderately viscous oils.

2.2.3 Tertiary Recovery Drive Mechanism

Tertiary normally comes after primary and secondary. Tertiary recovery more often called enhanced oil recovery (EOR), which can be misleading, as it is not necessarily the third recovery method used in a reservoir(Howes, 1988). Enhanced oil recovery will be possible when increasing the capable of displacement efficiency. It must be possible to inject the displacing fluid into the reservoir and to have it contact a major portion of reservoir. It must also be possible to do this economically.

Primary and secondary recovery methods normally recover about 35% of the original oil in place. It is really important to increase oil recovery by using other techniques. Many enhanced oil recovery methods have been created to increase oil recovery.

Two thirds of crude oil is left behind, due to both microscopic and macroscopic factors. Microscopic factors include effects of wettability and oil-water interfacial tension (IFT). The oil, which is in the left after a sweep, is called residual oil saturation (S_{or}). Macroscopic factors include reservoir stratification with some strata showing a vary permeabilities. Thus, the displacing fluid is channelling through the high-permeability zoned leaving oil in the low-permeability zones unswept. Even in the homogeneous and uniformly permeable reservoir, displacement can break down when the displacing fluid has less viscosity than the oil in reservoir, this situation is called adverse mobility ratio. The less viscous fluid penetrates in the oil reservoir; this situation is called viscous fingering.

Traditionally, there are three common enhanced oil recovery processes that are miscible, chemical and thermal(Howes, 1988). However, the new technology and more promising process with higher efficiency are developed.Al-adasani *et al.* (2010)has classified the EOR methods into five categories, which are gas-based, water-based, thermal-based, other, and combustion methods. The classifications of EOR are more suitable for heavy oil reservoir including surfactant injection, gel treatment, polymer flooding, low salinity water injection, air injection, microbial enhanced oil recovery (MEOR), modified enzyme, water-alternated-gas (WAG) injection and the combination of alkaline-surfactant (AS) injection.

2.2.3.1 Gas-Based Enhanced Oil Recovery Method.

Gas injection is one of frequent methods to enhanced oil recovery. These methods are mostly applied into the light oil and can be classified into two major types which are miscible and immiscible condition(Jr., 1987). Gases that have been used are carbon dioxide, nitrogen, flue gas and light hydrocarbon. Immiscible gas injection was already explained under secondary recovery, thus miscible gas injection will be mainly applied in this section. In this work focused on miscible CO_2flooding and water-alternating-gas (WAG).

1) Miscible CO_2 flooding

Miscible CO_2 flooding can enhance the oil recovery from porous rock by miscible effects through extraction of hydrocarbon from the oil in the porous rock. Miscibility is defined as the ability of two or more substance to form a single homogeneous phase when mixed all proportion(Holm, 1986). The most important variable in the miscible displacement process is the minimum miscibility pressure (MMP).Holm (1987)explained that MMP is defined as the lowest pressure at which about 95% of the contacted oil is recovered at a given temperature.Miscibility between carbon dioxide and oil will occur when the pressure is high enough to dissolve the CO_2 as a good solvent for the lighter crude oil. Carbon dioxide miscible flooding required minimum miscibility pressure is about 1,200 psi to above 4,500 psi(Yellig *et al.*, 1980).

The miscibility is the function of gas impurity, gas composition, oil composition, depth of reservoir, operation temperature and pressure(Johns *et al.*, 1996; Stalkup, 1978).The fracture pressure increases with depth than the required miscibility pressure, the operating pressure margin usually increases with depth(Heller *et al.*, 1986). Thus, reservoirs depth becomes one of the most important criteria and it must be deep enough to withhold and maintain the high pressure.Depth of reservoir is usually carried out in reservoirs that are more than 800 meter.

The advantage of this method is that it does not need the large quantities of data such as permeability and porosity distribution, fluid and rock properties(Sayyafzadeh *et al.*, 2011). To maximum the ultimate oil recovery it is possible to pick the most economical plan of miscible gas injection.

The miscibility pressures in heavy oil reservoirs are usually higher than reservoir pressure because heavy oil has high molecular weight.As a result, heavy oil required high pressure to achieve the miscibility. It is quite hard to achieve miscibility with heavy oil unless injected light hydrocarbon to reduce the minimum miscibility pressure (MMP)(Mohanty *et al.*, 1995; Orr Jr. *et al.*, 1983; Sobers *et al.*, 2010). Hence, miscible injection is rarely applied to the heavy oil reservoir.

2) Water-Alternating-Gas (WAG)

Injection of gas slugsalterated water slugs or water-alternating-gas (WAG) is usually used for controlling gas mobility. The WAG technique is a combination of two oil recovery methods that are waterflooding and gas injection. In additional, when gas usually acts as a non-wetting phase and because of its higher mobility compared with the oil, gas tends to penetrate in low flow resistant regions and displace oil piston-like. However, gas does not penetrate into whole region and tends to pass through high permeability zones. Consequently, water entry pressure into porous media is increased and continuously injected water is passed to the lower permeability regions. As result, injected water displaces the residual oil and also forced the injected gas inside the pores(Derakhshanfar *et al.*, 2012). Several papers have been published that WAG is very effective in additional oil recovery (Derakhshanfar *et al.*, 2012).

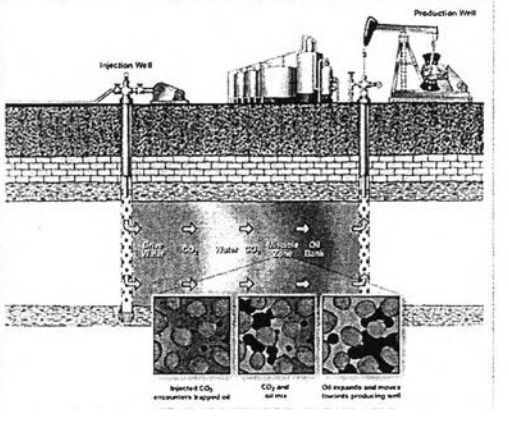

Figure 2.12 Water-Alternating-Carbon Dioxide process.

2.3.3.2 Water-Based enhanced oil recovery method

Water-based enhanced oil recovery methods includes the chemical methods which are polymer flooding, alkaline flooding, surfactant flooding, combination of three methods (alkaline-surfactant (AS), alkaline-surfactant-polymer (ASP)) and the relatively new methods (low salinity water flooding, surfactant imbibition) Nowadays heavy oil becomes more considerable in many cased studies(Doorwar *et al.*, 2011; Feng *et al.*, 2012; Thomas *et al.*, 1999; Zhang *et al.*, 2012).

Thermal methods, which are viscosity reduction, are the most common used in heavy oil recovery. Unfortunately thermal recovery methods for heavy oil have a limit by the reservoir fracture because most of heavy oil reservoirs have thin pay thin pay thickness. The situation can be successful but not economical feasible due to huge heat losses to overburden and underburden formation or active bottom aquifers(M. Dong *et al.*, 2011; Liu *et al.*, 2006; Mai *et al.*, 2009; Pei *et al.*, 2012; Wang *et al.*, 2010).

1) Polymer Flooding

Polymer flooding is included in the chemical methods that have most attention for heavy oil recovery. This method has fewer complexes than other chemical methods such as alkaline flooding and surfactant flooding.

Polymer flooding is considered as an improved waterflooding technique, because it cannot reduce the residual oil saturation and it helps recover additional oil by improving the displacement efficiency and increasing volume of reservoir that is contacted (Du et al., 2004). Water-soluble polymer added into water to increase viscosity of water, thus decrease the mobility and improve the efficiency of oil recovery.

Usually, polymer flooding is applicable for the reservoirs, which have high mobile oil saturation and moderate heterogeneity. Polymer flooding has been recommended for oil viscosity less than 100 cP under reservoir temperature, and sandstone reservoir with oil saturation higher than 30%, reservoir permeability greater than 20 mD, net thickness more than 3 m (10 ft), and reservoir temperature less than 90°C. (Alkafeef et al., 2007) It has not been recommended for the case which oil viscosity is greater than 200 mPa.s(Chang, 1978; Taber et al., 1997a; Taber et al., 1997b).

During a polymer flooding process, brine will be injected into the reservoir followed by the polymer slug. Then, another freshwater slug will be injected before the continuous drive water injection. Basically, polymer is classified into two types, which are hydrolyzed polyacrylamide (HPAM) and polysaccharides biopolymer or xanthan gum. Each of them is sensitive to different degradation mechanism. Table 2.2 is shown a summery.

Table 2.2 Polymer degradation mechanisms (Chang, 1978).

Type of Degradation	Susceptibility		Cause	Remark
	Polyacrylamide	Xanthan Gum		
Chemical*	High	Moderate	The cation Na+, CA++, Mg+++	Divalent ions are more derimental
Chemical	High	High	Transition metal ions	Aggravated by high temperatures and high pH
Chemical	High	High	Oxygen and oxidizing agents	Aggravated by high temperatures
Chemical	High	High	Hydrolysis by acidic or basic chemicals	Aggravated under aerobic conditions or high temperatures
Thermal	High >250°F	High >160°F	High temperature	Aggravated under aerobic conditions or high pH
Microbial	Moderate	High	Yeasts, bacteria and fungi	Aggravated by warm temperature and/or under aerobic conditions
Mechanical/ shear	High	Low	Intense shear stress and high flux such as that occurring with low through values, orifices and low permeability formations	Aggravated by di- and trivalent cations

From the experimental studies indicated that the polymer flooding can recover more than 20% incremental oil, after waterflooding when applied to heavy oil(Wassmuth *et al.*, 2009). There also have positive pilot results from heavy oil in Turkey, China and Canada(Gao, 2011; Kang *et al.*, 2011; Wassmuth *et al.*, 2009). Higher polymer concentration and slower injection could further improve recovery (Asghari*et al.*, 2008).

2) Surfactant/Miceller Polymer Flooding

Microemulsion flooding is another name of micellar polymer flooding. This technique gains the great promise for recovering large quantities of residual oil(Gogarty, 1976; Holm, 1976). The basic components of the surfactant solution are hydrocarbon, surfactant and water. The basic components can also contain a small amount of electrolyte and electrolytes(Gogarty *et al.*, 1968). Generally, the basic process consists injecting of slug preflush (low-salinity water), followed by the miscellar slug proper, and followed by a slug of polymer solution which is grades into waterflood(Thomas *et al.*, 1992). The displacement mechanism of this technique in porous media is a function of composition of the microemulsion which lead to ultra-low IFT and a high viscosity of the microemulsion.Bouabboune *et al.* (2006); Holm (1976)distinguish between different type of surfactant-polymer floods. A micellar solution is a dispersion of a surfactant in an oleic or aqueous solvent. The surfactant encourages a stable micro emulsion phase to from that oil and water are essentially a single phase which displaces and oil bank. The design is based on that composition which provides the most favourable.

Theoretically, oil is produced under miscible condition and the efficiency should be 100%. However, in practically the efficiency cannot be 100% because the process is very complex and the efficiency is limited by reservoir condition. From the field experiment shown that the process can also be uneconomical if oil-chemical-brine phase behaviour is not appropriate with the reservoir condition(Gogarty, 1978). Figure 2.12 is shown the normally process of micellar flooding.

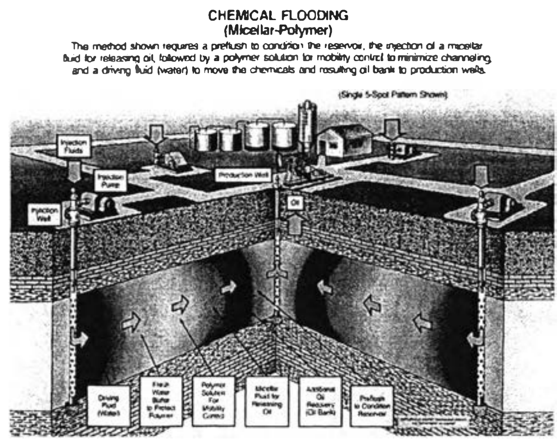

Figure 2.13 Micellar flooding process.

From the theory, micellar polymer flooding is classified into miscible process but the optimize point only occur in a very narrow condition. For example, formation water should not consist more than 500 ppm of divalent cations and 20,000 ppm of chloride(Taber *et al.*, 1997). The appropriate temperature for preventing chemical degradation is limited to less than 80°C. In practically, micellar polymer flooding is very complex and expensive process. Moreover this technique has very limited studies on heavy oil.

3) Alkaling Flooding

Alkaline flooding, also known as caustic flooding is a promising method for enhanced oil reservoir, especially for the thin pay thickness reservoir which other methods can not applied (Arhuoma et al., 2009). During primary production and secondary production, oil may be produced in form of emulsion depending on reservoir condition and fluid properties (M. Dong et al., 2011).

The major mechanisms of this method are (M. Dong et al., 2011; Taber et al., 1997b).:(1) lowering of the interfacial tension (IFT) between oil and water; (2) emulsification of oil and water; (3) wettability alteration; and (4) mobility improvement. The two important mechanisms for improving mobility and oil recovery are formation of water-in-oil emulsion and wettability alter In alkaline flooding have many chemicals such as NaOH or Na2CO3 are used to react with the acid in heavy crude oil to form a detergent which seems like substance (Cooke Jr. et al., 1974; Wang et al., 2010). Some cased studies proposed the formation of oil-in-water emulsion as recovery mechanism (Jennings Jr. et al., 1974). In this situation, oil will emulsion into water phase and oil droplet either plug rock pores which give improved sweep efficiency (Haihua Pei et al., 2012).

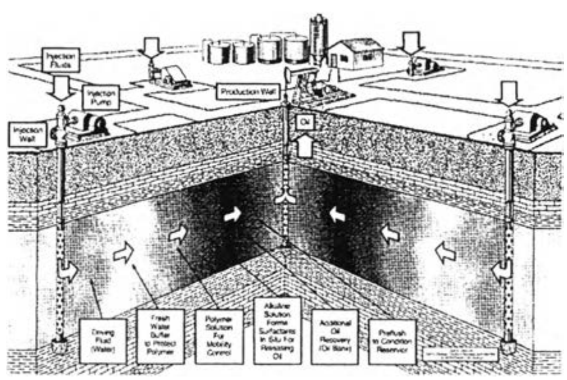

Figure 2.14 Alkaline Flooding process.

4) Alkaline-Surfactant (AS)/ Alkaline-Surfactant-Polymer (ASP)

Actually alkaline is rarely used alone to flood the reservoir, but it normally used with surfactant and/or polymer as a combination for enhanced oil recovery technique. Injectivity can be increase by reducing oil saturation which will increase the effective permeability of water due to change in relative permeability(Wyatt *et al.*, 2002). Reduction of oil saturation can be achieved by adding chemical such as alkali and surfactant. Polymer will be adding into the solution for increasing its viscosity and decreasing the chance of fingering effect, thus increasing the overall efficiency.

The efficiency of the combination between alkaline-surfactant flooding has a high potential in heavy oil recovery(Liu *et al.*, 2006; Pei *et al.*, 2012; Wang *et al.*, 2009). The heavy oil relates in organic acid that could be neutralized by using alkali to form surfactant. The experimental studies have shown that injection of alkaline solution and very dilute concentration of surfactant, the IFT between the viscous oil and water could be reduced to ultralow level and gain more oil recovery(Liu *et al.*, 2006).

5) Low-Salinity Waterflooding

Low-salinity waterflooding is one of relatively new technology that was generated in the 90's. Many experiments study the effect of brine, crude oil and experimental procedure on wettability.Jadhunandan *et al.* (1995); Morrow *et al.* (1986)informed that the wettability of reservoir has a directly influence on oil recovery for the displacement of oil by water. Tang *et al.* (1997)explained that decrease salinity can change reservoir wettability and improved spontaneous imbibitions. Alotaibi*et al.* (2009) studied that lowing brine concentration can decrease the interfacial tension (IFT). Many case studies have evidence that weakly water-wet conditions are the most favorable in waterflooding mechanism(Jadhunandan *et al.*, 1991). They also have evidence that brine composition could have significant impact on oil recovery(Tang *et al.*, 1997; Yildiz *et al.*, 1999). Brine composition could not only lead to increase oil recovery but also increase in the economic profitability of a waterflood(Robertson, 2007).

2.3.3.3 Thermal-Based enhanced oil recovery method.

Thermal-based recovery is used to produce heavy oil and bitumen in high-permeability reservoirs. The main advantages are improved sweep efficiency, enhanced producible reserves, and a decrease in the number of wells required for field development(Joshi, 1991). Hot fluids, such as stream or hot water, are injected into the reservoir to reduce oil viscosity and retaining force responsible for oil entrapment (Alajmi *et al.*, 2009).

Thermal-based recovery methods include cyclic steam injection, steamflooding, Steam-Assisted Gravity Drainage (SAGD) and in-situ combustion. Cyclic steam injection and steamflooding have been widely used in standards recovery metod for heavy oil and extra-heavy oil. Crude oil productions by using thermal recovery methods have two main mechanisms: (1) heat form the steam reduces the oil viscosity and increases its mobility and (2) pressure is supplied by injected stream to push the oil toward the production well.

As mentioned earlier, the application of thermal recovery is limited due to the reservoir geology. In order to minimize heat losses to adjacent formation during thermal recovery methods, they are mainly applied to reservoir less than 1100 m deep with crude oil API gravity less than 20°, and typical well spacing of 2-5 ac (Trigos *et al.*, 2010). Moreover, steamflooding is an expensive process and consumes a lot of energy. The ultimate recovery efficiency is ranging from 9% to 79% OOIP (Lu et al., 2010).

1) Steam Injection

Steam injection is applied mainly in injection of two-phase mixture of hot water and steam, although hot water injection and superheated steam injection are included as well. Steam injection is mainly classified into many categories which are Cyclic Steam Stimulation (CSS), continuous steam injection and Steam Assisted Gravity Drainage (SAGD)

Cyclic steam injection (also known as huff-n-puff or steam-soaking), high temperatures steam (200-350°C) is injected at high pressure into reservoirs. In this process, steam is injected under high pressure and temperature(Ghoodjani *et al.*, 2012). The pressure dilates the formation and heat reduces the viscosity of heavy crude oil. Heated crude oil is then pumped into the surface, from the same injection well, after soaking period to allow injected steam and heat more crude oil. This process is repeated in cycles until either the production is too low(Bahlani *et al.*, 2008). The main advantage of this process is quick oil production but oil recovery factor with CSS are generally lower, typically less than 15% OOIP (Morlot*et al.*, 2007).

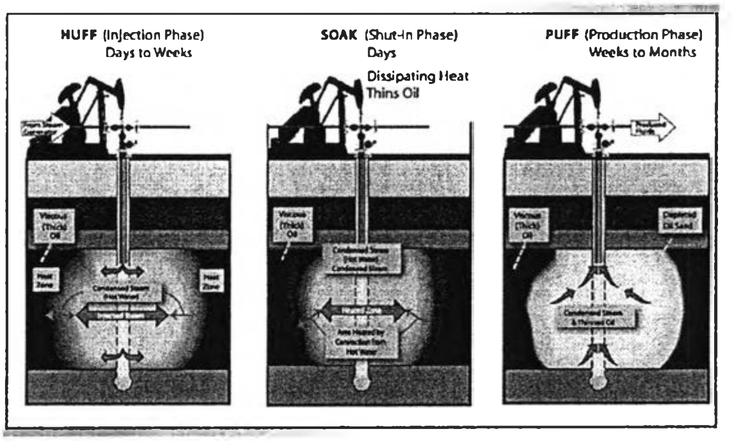

Figure 2.15 Cyclic Steam Injection (Flores, 2004).

Continuous steam injection has been used for about five decades. This process is continuously injected the wet steam into the formation through wells. The main objective of this process generates an average temperature increase within formation that decreases in oil viscosity allowing it to move more easily towards production wells(Trigos *et al.*, 2010). This process requires injection and production well and gains oil recoveries higher than the previous method. Oil recovery can reach up to 50% or more(Ghoodjani *et al.*, 2012). Many case studies have focused on steam injection and its efficiency in oil recovery from heavy oil(Bahonar *et al.*, 2007; Mondragon *et al.*, 2000). The important of effective recovery in heavy oil is viscosity reduction(Haghighi *et al.*, 2012).

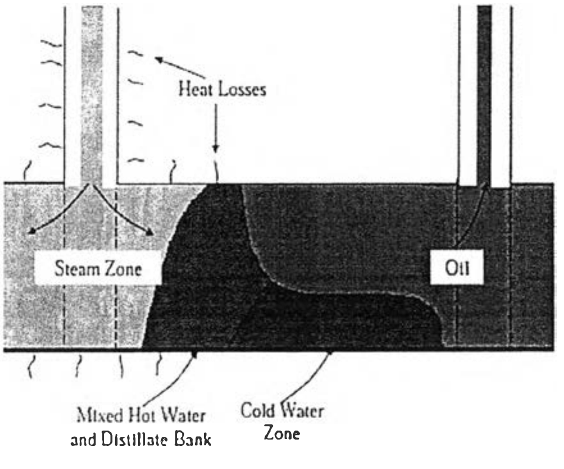

Figure2.16 Steam Injection Process (Ghoodjani *et al.*, 2012).

The main problem which can occur during steam injection process is steam channeling. The steam channeling mainly caused by the heterogeneity of reservoir, which can create not only a quickly increase of water cut but also even in a direct production of steam through high permeability channels. X. Dong *et al.* (2011)concluded that the possibility of steam channeling will high when the reservoir has high permeability, high oil viscosity, depth shallow, stem strength bigger and oil layer looser. The effect of steam channeling leads to poor efficiency of steam flooding.

Various techniques combining thermal-based with water-based or gas-based have been developed to improve the problem of steam channeling. Hunter *et al.* (1992) proposed the technically and economically technique which is polymer gel system treatment containing a polyacrylamide polymer and proprietary organic crosslinking to increase steamflood thermal efficiency. Thermaoreversible gel-forming system (GFS) with lower critical dissolution temperature (LCDT) is other methods that can increase the efficiency of cyclic-steam treatment. GFC solution is converted into gel which blocks the permeable channels. Thus, the conformance of thermal-steam treatment increases (Altunina, 2006).

2) Steam-Assisted Gravity Drainage (SASG)

Steam-assisted gravity drainage (SAGD) process is a recovery method which has been considered as more effective in heavy oil recovery. This method has two horizontal parallel wells vertically separated by short distance (15ft). The top well served as injector well and the bottom well takes water, condensed water and heated oil from reservoir. The steam is continually injected inside the steam chamber for a period of approximately 2-4 months, heating oil and condensed water drain by gravity.

The limitation of Steam assisted gravity drainage (SAGD) is similar to steamflooding and cyclic-steam that depend on the reservoir geology. The performance of SAGD can be significantly affect with high steam injectivity, low mobile water saturation near the producer, absence of continuous shale barriers, high vertical to horizontal ratio and optimum injector-producer vertical spacing (Kamath *et al.*, 1993). In the heterogeneous reservoir, the mobile water-saturations have a negative effect on the thermal efficiency of SAGD(Oskouei *et al.*, 2010).

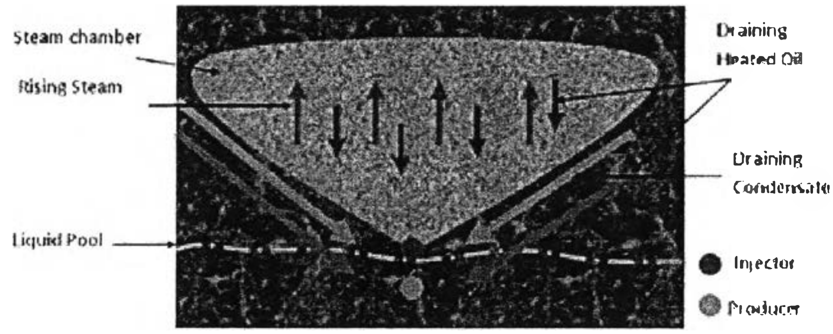

Figure 2.17 Steam-Assisted Gravity Drainageprocess(Ablahlani, 2008).

3) Vapor Extraction (VAPEX)

After development of the Steam-Assisted Gravity (SAGD) process, Butler et al. (1991) introduced an alternative thermal recovery method that used a solvent vapor or solvent mixture to form a vapor-filled chamber within the reservoir. The crude oil becomes dilute by dissolved solvents and drain to the production well by gravity force. The VAPEX process promises for the heavy oil reservoirs which are located in low-permeable fracture carbonated reservoirs and thin reservoirs by using low capital and operating costs(Ghoodjani *et al.*, 2012; James *et al.*, 2007; Nourozieh *et al.*, 2009).Many recent researches have shown that the process is highly energy efficiency, environmental friendly and requires low capital investment and low operating costs(Das, 1998).

4) In-Situ Combustion (ISC)

The in-situ combustion is another thermal recovery method, which is known as fireflooding. The mechanism starts with injection of heated air into the reservoir. The oil oxidation is generated, and then the temperature increases. Continuing the oxidation until the temperature reaches "the ignition point" when the combustion is generated. Oil is displaced by vaporizing from the thermal front as well as the sweep provided by combustion product gases and hot water. Generally, the fuel in this process is the small fraction of heavy oil which is burned as fuel by the advancing front(Fadaei *et al.*, 2010; Hascakir *et al.*, 2010).

The history of in-situ combustion, as applied to heavy oil recovery, is rarely successful because it is difficult to control the combustion front and premature air breakthrough(Shen, 2002). Therefore, THAI (Toe-to-Heel Air Injection) has been used as the alternative recovery method for heavy oil reservoir(Fatemi *et al.*, 2011). THAI integrates in-situ combustion with advanced horizontal well concepts. In the process, horizontal well served as oil producer locates at the bottom of the reservoir and the vertical well served as air injector locates at the top and near the end of horizontal well. The combustion front from the end of horizontal well leads to recoveries of oil up to 80% (Ghoodjani *et al.*, 2012).

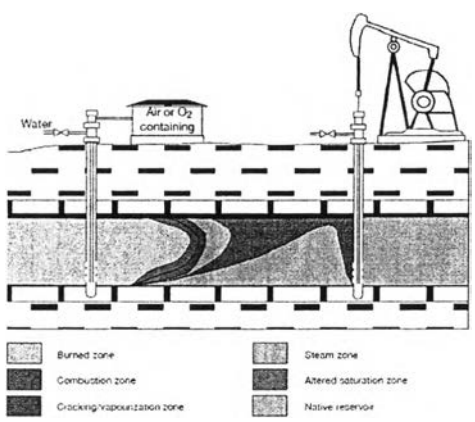

Figure 2.18 In-situ Combustion Process (Ursenbach *et al.*, 2010).

2.3 Saturations

The pore spaces in reservoir rocks are always completely saturated with reservoir fluid. Typically, the pores are completely filled with the combination of the three fluids.

(1) Oil and its associated impurities in the liquid phase.

(2) Natural gas and its associated impurities in the vapor phase.

(3) Connate water or water that flowed or was injected into the reservoir.

When sediments were deposited in an aqueous environment, pore spaces were completely saturated with water. Then, when the burial and compaction was occurred, the water may be forced out by hydrocarbon from the pore spaces and the saturation remained less than 100%.

In the pore spaces of oil and gas reservoirs always have remaining water which was forced by hydrocarbon. At any time during the life of an oil or gas reservoir, the following relationship must be true.

$$S_o + S_w + S_g = 1.0$$

where:

$$S_o = \frac{oil\ volume}{pore\ volume} = \frac{V_o}{V_p}$$

$$S_w = \frac{water\ volume}{pore\ volume} = \frac{V_w}{V_p}$$

$$S_g = \frac{gas\ volume}{pore\ volume} = \frac{V_g}{V_p}$$

Typically, oil saturation or gas saturation are zero, but water saturation is greater than zero.

2.4 Reservoir Simulation

Reservoir simulation has been developed into the most flexible and widely tools in reservoir engineering. The reservoir simulation program is used to predict the future performance of oil and gas reservoirs over wide range of operating condition. Thus, simulation is usually applied for all reservoir types and all reservoir performance studies. As an asset building and maintaining, an oil fields are normally time consuming and expensive. Hence, reservoir models are typically built for identifying the number of wells required, reduction of reservoir pressure predicting and the expected production of oil, gas and water. Normally simulation is faster, cheaper and more reliable than other methods for prediction the performance.

A reservoir models which were divided into a number of grid blocks. Each block is related to a designated location in the reservoir condition that includes porosity, permeability, relative permeability, etc. In simulator, fluid can flow through the neighboring blocks at a rate determined by pressure difference between blocks and fluid properties. In this section will discuss about the popularly reservoir simulation programs that are for simulation the primary depletion and secondary recovery. The simulation program that will be discussed are CMG and ECLIPSE.

2.4.1 IMEX (Implicit-Explicit Black Oil Simulation)

In this study, a compositional simulation model was built by using CMG-IMEX (Version 2009.11, Computer Modelling Group Limited, Canada). IMEX stands for Implicit-Explicit Black Oil Simulation which is full feature three phase and four phase black oil reservoir simulation for modeling primary and secondary recovery process in gas and conventional oil reservoir. IMEX can be also used for modeling miscible and polymer injection in conventional oil reservoirs and primary depletion of gas condensate reservoirs, as well as the behaviour of the naturally or hydraulically fractured reservoir. Therefore, IMEX is used for analysis in heavy oil the influence of secondary recovery.The model includes the effect of capillary, viscous and gravity force.

2.4.1.1 Associated paper with IMEX module

Derakhshanfar *et al.* (2012)used the experimental data to conduct the simulation works of carbon dioxide-assisted waterflooding on heavy oil saturated sand pack. The simulation model of his work was a Cartesian model and assumed to have homogeneous porosity and permeability in all direction. The injector and producer were positioned at the very left and right grid blocks in the horizontal direction, respectively. However, his work does not compare the percent error between the experimental results and simulation result.

Zheng *et al.* (2013)used IMEX module to better understand mechanism of CO_2-WAG process with the purpose of pressure maintenance in heavy oil reservoir. He simulated grid block with Cartesian model to represent the physical model in the experiments. Homogeneous porosity and oil saturation are used in all direction, while the absolute permeability of each layervaries with the depth because the capillary pressure and high absolute permeability is neglected.

2.4.1.2 The simulation package in IMEX module

Figure 3.1 shows the model tree view which are I/O control, Reservoir, Components, Rock-Fluid, Initial Conditions, Numerical, Geomechanics and Well &Recurrent. The model tree view is the application for this program. Each package contains the data sets and options to customize the simulation work.

Figure 2.20 Model tree view.

2.4.2 <u>ECLIPSE Black Oil Simulation</u>

ECLIPSE Black Oil simulation is generally used for 3D black oil reservoir modeling. This simulation software models extensive well controls and supports efficient field operations planning, including water and miscible-solvent gas injection. The black oil model assumed that the reservoir fluids consist of three phases.

2.4.2.1 Associated paper with ECLIPSE

Rafiee *et al.* (2011) investigated the miscibility process of carbon dioxide injection into gas reservoir using compositional and a black oil reservoir simulator. This simulation model was built for this process having injection and production wells. Both simulators and results were compared the effect of gas miscibility in order to find optimum miscibility parameters. The simulation results showed that compositional result was similar to the black oil run, when the miscibility factor in the case is almost half of the complete miscible process.

Al-Harbi *et al.* (2012) built the find grid of tw0 5-spot sector model and then upscaled. The results obtained from the fine model using waterflooding data and utilizing pseudo function data. The results presented that pseudo functions are effective tool to improve history matching. Moreover, pseudo functions can still give predictable water performance when changing the development schemes. However, gas performance was unpredictable.