APPROVAL CERTIFICATE

This final year project paper entitled

'Comparative Study of the Performance of CO2 and Water Injection for Improving Production of Depleted Reservoirs by Enhanced Oil Recovery Techniques using "ECLIPSE Reservoir Simulator Software'

was prepared by the following students as partial fulfilment of the requirements for the degree of Bachelor of Science Petroleum Engineering at Al-Ayen University.

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Comparative Study of the Performance of CO_2 and Water Injection for Improving Production of Depleted Reservoirs by Enhanced Oil Recovery Techniques using "ECLIPSE Reservoir Simulator Software

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*Abstract_* **The present renewed interest on CO2 EOR/EGR is led by an environmental concern. The consequence is that, today, we are urgently asked for considering the new CO2 EOR projects in association with CO2 storage. This implies an appropriate production well management allowing for delaying the CO2 breakthrough, while one has to keep a great concern on the safety issues related to the social acceptance, and to ensure a full economic viability of the CO2 injection projects. The picture becomes even more complex when it is planned to link various CO2 emission sites to various remote CO2 injection sites (typically already produced hydrocarbon reservoirs) through a large CO2 transportation infrastructure. In such situation, it will be needed to harmonize in real time the rate fluctuations of the CO2 sources and the evolution of the CO2 sink injectivities (closely related to the reservoir pressure), while avoiding to meet the surface/transportation equipment limitations. A developing concern in using this process is result in raising value of gas in the global market. Therefore, the performance of gas injection might not always be relatively profitable despite of production improvement. The best way to address this is by creating performance predictions to improve production of gas condensate reservoirs and economically evaluate ascertain the profit viability of gas injection. The purpose of this project is to show results of hypothetical oil reservoir model by applying CO2 and water injections by using ECLIPSE 300 V reservoir simulator to improve pressure and sweep efficiency in order to increase productivity. the model 1D included a single well producer and injector with 100x1x1 cells (DX= 10 cm, DY=DZ= 2.0 cm), the model 2D consisted of single well producer and injector with 100x1x30 cells (DX= 10 cm, DY=DZ= 2.0 cm) and The model consisted of four injectors and single producer wells with 20x20x6 cells, There are two separate injection scenarios which were generated. Initially, the scenarios were applied for 1D, 2D and 3D models at different time steps. It can be noticed that the field oil efficiency increased significantly during miscible CO2 injection for a short period of time, and the water flood injection for long period time.**

***Keywords-** CO2 Flooding; Water flooding;Miscible Displacement;Enhanced Oil Recovery (EOR) Processes; ECLIPS.*

I. INTRODUCTION

After Exploration , an oilfield is initially developed and produced using primary recovery mechanisms in which natural reservoir energy expansion of dissolved gases, change in rock volume, gravity, and aquifer influx drive the hydrocarbon fluids from the reservoir to the wellbores as pressure declines with fluid (oil, water, or gas) production. Primary oil recoveries range between 5 and 20 percent Stalkup [1] of the original oil-in-place (OOIP). These low recoveries prompt field operators to find ways to improve recovery through the application of secondary recovery methods, which provide additional energy to the reservoir. Secondary recovery methods entail injecting either water and (or) natural gas into the reservoir for depressurizing and (or) pressure maintenance and to potentially act as a water and (or) gas drive to displace oil. This helps to sustain higher production rates and extends the productive life of the reservoir. Normal practice has been to inject natural gas into the gas cap or at the top of reservoir and inject water below the oil-water contact. The oil recoveries at the end of both the primary and secondary recovery phases are generally in the range of 20-40 percent of the OOIP, although in some cases, recoveries could be lower or higher **Stalkup** [1]

After primary and secondary (water flooding) phases of production, 65% or more of the original oil in place may remain in the rock. EOR processes change the physical characteristics of the oil to enable greater production. The CO2 EOR process is primarily a function of how CO2 interacts with oil which is determined by the property of miscibility, when multiple liquids can mix together completely becoming one homogenous liquid. For example, water and vinegar are completely miscible. By contrast, water and oil are immiscible; they do not combine at any proportion. CO2 at a supercritical pressure and temperature is completely miscible with oil; it will combine completely. In CO2 EOR, the CO2 combines with the oil and helps move it through the rock pore spaces, enabling greater recovery of the oil in place. One of the first CO2 EOR projects was initiated in 1972 in the KellySnider oil field in Texas **Ahmed** [2].

Thirty states in the U.S. produce oil. Many of the historic oil-producing areas of the U.S. are potential candidates for CO2 EOR. DOE began looking at the potential for widespread CO2 EOR in 2006 and conducted a study of CO2 EOR potential in 10 basins, looking at the primary oil-producing regions of the U.S.8 This study was updated in 2009. Ahmadi, K. and Johns [3], Key findings in this assessment include the following:

1) Next Generation CO2 EOR can provide 137 billion barrels of additional technically recoverable domestic oil.

2) Of these 137 billion barrels, 67 billion barrels are economically recoverable at an oil price of $85 per barrel.

3) Sixty-seven billion barrels of oil represent nearly 4 million barrels a day of production for 50 years, which would reduce oil imports by one third.

4) Advances in technology or higher oil prices would add to these reserves.

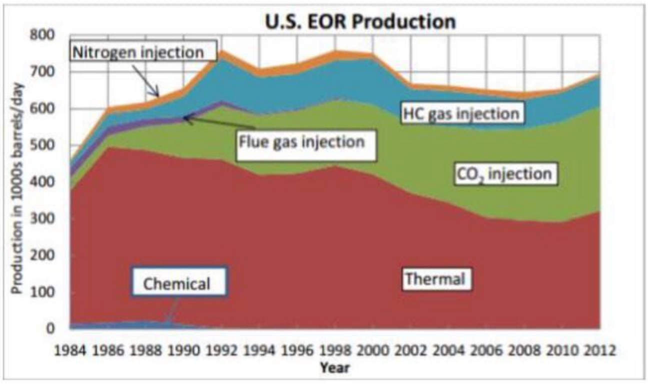

Figure 1: Plot showing U.S. oil production in barrels per day associated with various enhanced oil recovery (EOR) methods HC, hydrocarbon; CO2, carbon dioxide.

Objective :

The principal purpose of this research work is to represent the applicability and the effectiveness of CO2 and water injections by ID, 2D geomodelling to optimize productivity of oil reservoirs by making accurate prediction for correct decision. In addition, monitoring and prediction of sweep and pressure support for an oil reservoir.

II. Enhanced Oil Recovery (EOR)

Enhanced oil recovery (EOR) is oil recovery by the injection of materials not normally present in the reservoir. This definition covers all modes of oil recovery processes (drive, push-pull, and well treatments) and most oil recovery agents. Enhanced oil recovery technologies are also being used for insitu extraction of organic pollutants from permeable media. In these applications, the extraction is referred to as cleanup or remediation, and the hydrocarbon as product. Various sections of this text will discuss remediation technologies specifically, although we will mainly discuss petroleum reservoirs. The text will also describe the application of EOR technology to carbon dioxide storage where appropriate.

The definition does not restrict EOR to a particular phase (primary, secondary, or tertiary) in the producing life of a reservoir. Primary recovery is oil recovery by natural drive mechanisms: solution gas, water influx, and gas cap drives, or gravity drainage(Stosur [9]). Secondary recovery refers to techniques, such as gas or water injection, whose purpose is mainly to raise or maintain reservoir pressure. Tertiary recovery is any technique applied after secondary recovery. Nearly all EOR processes have been at least field tested as secondary displacements. Many thermal methods are commercial in both primary and secondary modes.

Much interest has been focused on tertiary EOR, but the definition given here is not so restricted. The definition does exclude water flooding but is intended to exclude all pressure maintenance processes. The distinction between pressure maintenance and displacement is not clear, since some displacement occurs in all pressure maintenance processes. Moreover, agents such as methane in a highpressure gas drive, or carbon dioxide in a reservoir with substantial native CO2, do not satisfy the definition, yet both are clearly EOR processes. The same can be said of CO2 storage. Usually the EOR cases that fall outside the definition are clearly classified by the intent of the process. In the last decade, improved oil recovery (IOR) has been used interchangeably with EOR or even in place of it. Although there is no formal definition, IOR typically refers to any process or practice that improves oil recovery **(Stosur**,).[9]. IOR therefore includes EOR processes but can also include other practices such as waterflooding, pressure maintenance, infill drilling, and horizontal wells. As shown in fig.2:

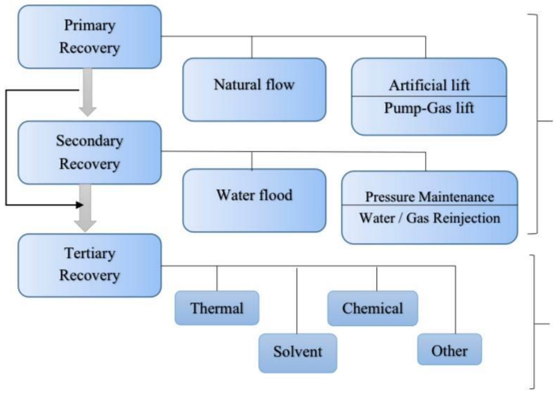

Figure 2: Oil recovery classifications (adapted from the Oil and Gas Journal biennial surveys).

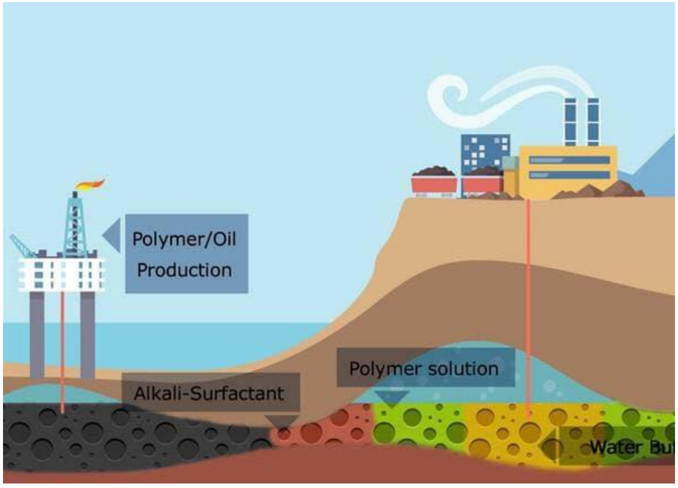

Figure 3 Enhanced oil recovery (EOR)

1. Primary Production Phase

The first producing phase of a reservoir is known as the primary production phase where a new field discovery is found and well penetrations are drilled into the formation. Oil or gas is produced using

the pent-up energy of the fluids in the reservoir rock (generally a sandstone or carbonate (limestone, dolomite) formation. As long as you are good at finding new oil or gas and avoiding the ―dry holes, ‖ the returns come quickly while the reservoir fluid pressures are high. Eventually, however, the energy (usually thought of as reservoir pressure) is depleted and the wells cease to flow their fluids. This requires a stage called ―artificial lift‖ wherein fluids are pushed or lifted to the surface and production can be prolonged. Eventually, the pore pressures are so thoroughly depleted and move so slowly within the formation to the wellbore that the wells produce uneconomic volumes. At this point, as in the case of oil reservoirs, considerable amounts of the oil are left in place, with sometimes as much as 80-90% still ―trapped‖ in the pore spaces of the roc .
(Malzer).[11]

2. Secondary Phase of Production

The field may be abandoned after depleting the fluid pressures or it can be converted to what is called a secondary phase of production wherein a substance (usually water) is injected to repressure the formation. New injection wells are drilled or converted from producing wells and the injected fluid sweeps oil to the remaining producing wells. This secondary phase is often very efficient and can produce an equal or greater volume of oil than was produced in the primary phase of production. As mentioned, water is the common injection in the secondary phase of production since water is relatively inexpensive. Normally fresh water is not used during the waterflood and this is especially true today. The water produced from the formation is recycled back into the ground again and again. Ultimately, in most reservoirs, 50-70% of the oil that was present in the field at discovery remains in the reservoir after the waterflood since it was bypassed by the water that does not mix with the oil. (Malzer).[11]

3. Tertiary Production Phase

If a company desires to produce (access) more of the remaining oil in the reservoir, they can choose to enter a third phase (tertiary phase) of production. This will require the use of some injectant that reacts with the oil to change its properties and allow it to flow more freely within the reservoir. Heat or hot water can do that; chemicals can accomplish that as well. These techniques are commonly lumped into a category called enhanced oil recovery or EOR. One of the most proven of these methods is carbon dioxide (CO2) flooding. Almost pure CO2 (>95% of the overall composition) has the property of mixing with the oil to swell it, make it lighter, detach it from the rock surfaces, and causing the oil to flow more freely within the reservoir so that it can be ―swept up‖ in the flow from injector to producer well. This technique was first tested at large scale in the 1970’s in the Permian Basin of West Texas and southeastern New Mexico. The first two large- scale projects consisted of the SACROC flood in Scurry County, TX, implemented in January of 1972, and the North Crossett flood in Crane and Upton Counties, TX initiated in April, 1972. It is interesting to note that installation of these two floods was encouraged by daily production allowable 2 relief offered by the Texas Railroad Commission and special tax treatment of oil income from experimental procedures.(AIR,).[12]

Factors Affecting Recovery

The two major factors that affect the performance of a miscible flood are oil displacement efficiency at the pore level and sweep efficiency on the field scale. Oil displacement can be explained using the schematic on the left side of Fig. 4, which shows solvent flowing from left to right through a pore space. The displacement process involves several mechanisms. One is direct miscible displacement of oil by solvent along higher-permeability pore paths. Additionally, part of the oil initially bypassed (on the pore level) by solvent can later be recovered through oil swelling that occurs as solvent dissolves in the oil, or by extraction of oil into solvent. Swelling and extraction take place as solvent continues to flow past the initially bypassed oil.(Gao and Towler [13]) These can be significant mechanisms in field processes and together may account for as much as 20 to 30% of the total incremental recovery. Oil displacement efficiency is affected by solvent composition and pressure. Solvents can be designed that give very high displacement efficiencies at the pore level. Chapter Two Literature Revie
The right side of Fig.4 shows that, on a field scale, sweep efficiency is affected by viscous fingering and solvent channeling through high-permeability streaks. Gravity override can sometimes occur because solvent is usually less dense than the oil it is displacing. When vertical communication is high, solvent tends to gravity segregate to the top of a reservoir unit and sweep only the upper part of that zone. Although gravity override can be a problem in reservoirs having good vertical communication (such as Judy Creek and Prudhoe Bay), it is not usually a serious problem for west Texas carbonates, which tend to be more stratified and have poor vertical communication .(Ayirala, S. C., Rao,2003 [8]) Sweep efficiency on the field scale is usually the single most important factor affecting performance of a miscible flood. Sweep efficiency can be increased to some extent by reducing well spacing, increasing injection rate, reconfiguring well patterns, increasing solventbank sizes, and modifying the ratio of injected water to injected solvent (WAG ratio). Fig.(4) presents part of a considerable body of laboratory evidence that solvent effectively displaces oil from contacted regions of the reservoir. The graph of oil recovery as a function of total pore volumes of fluid injected shows the results of a laboratory core flood conducted at conditions corresponding to the Sharon Ridge reservoir in west Texas. The water flood recovered approximately 40% OOIP. A CO2 flood that followed increased oil recovery to approximately 80% OOIP, demonstrating that CO2 can displace a large portion of the residual oil remaining after a water flood. Sorm was 10%; the WAG ratio for the miscible flood was 1.

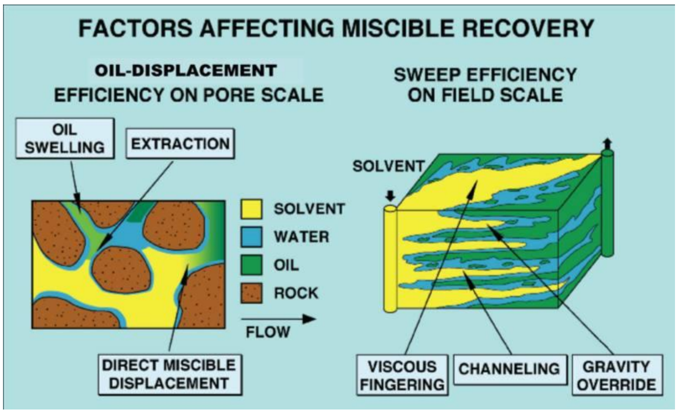

Figure 4: Factors affecting miscible recovery.

The schematics at the bottom of Fig.5 illustrate the pore-level recovery mechanisms discussed earlier (Fig. 5). At the end of the water flood, residual oil is a discontinuous phase that occupies approximately 40% of the pore space. Early in the miscible flood [3.0 to 3.5 total pore volumes (PV) injected], some of this oil has been miscible displaced by solvent from the higher-permeability flow path (on the pore scale). However, some oil also has been initially bypassed by solvent. Note Chapter Two Literature Review 14 that this bypassing at the pore level is much different from solvent bypassing, which can occur at the field scale because of larger scale reservoir heterogeneities. As depicted in the schematic corresponding to late in the flood (to 7.0 total PV injected), part of this locally bypassed oil is subsequently recovered by extraction and swelling that takes place as solvent continues to flow past the bypassed oil. In this case, approximately 30% of the total amount of oil recovered by the CO2 flood was recovered by extraction and swelling .(Ekundayo,., and Ghedan).[14]

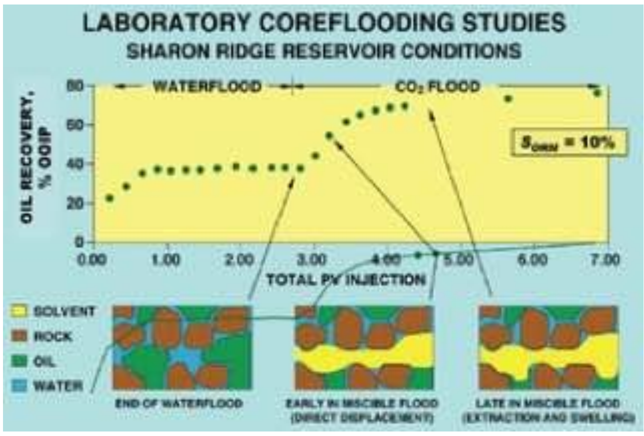

Figure 5: Laboratory core flooding studies.

Enhanced Oil Recovery (EOR) Processes

Enhanced oil recovery (EOR) processes include all methods that use external sources of energy and/or materials to recover oil that cannot be produced, economically by conventional means .(Ayirala, et al [8]

EOR methods :

1- Water flooding : Maintain reservoir Pressure & physically displace oil with water moving through the reservoir from injector to

2- Thermal : Reduce (sorw) by steam distillation and reduce oil viscosity.

3- Chemical : Reduce (sorw) by lowering wateroil interfacial tension and increase volumetric sweep efficiency by reducing the water-oil

4- Miscible gas : Reduce (sorw) by developing miscibility with the oil through a vaporizing or condensing gas

The goal of any enhanced oil recovery process is to mobilize ‖remaining‖ oil. This is achieved by enhancing oil displacement and volumetric sweep efficiencies.

1•Oil displacement efficiency is improved by reducing oil viscosity (e.g., thermal floods) or by reducing capillary forces or interfacial tension (e.g., miscible floods).

2 •Volumetric sweep efficiency is improved by developing a more favorable mobility ratio between the injectant and the remaining oil-in-place (e.g., polymer floods, water alternating-gas processes). (Ayirala, et al).[8]

Thermal Methods :

Thermal EOR processes are defined to include all processes that product heat energy to the reservoir and increasing the ability of oil to flow by reducing its Chapter Two Literature Review 13 viscosity. Thermal recovery processes are globally the most advanced EOR processes. The key of thermal recovery is the use of heat to lower the viscosity of oil and reduces mobility ratio, then, increases the productivity and recovery The oil caused to flow by cater of thermal energy is produced through production wells. When heated, oil becomes less viscous and flows more quickly. Because this is an important property of oil, considerable effort has been devoted to the development of techniques that involve the introduction of heat into a reservoir to improve recovery of the heavier, more viscous crude oils. The viscosity of oils decreases as temperature increases, and the purpose of all thermal oil recovery processes are therefore to heat the oil to make it flow faster. The sensitivity of viscosity to temperature for several grades of oil and water shows The sharp decreasing of crude oils viscosity with temperature, especially for the heavier crude, largely explains why thermal EOR has been so popular Thermal EOR projects have been concentrated mostly in Canada, Former Soviet Union (FSU), U.S. and Venezuela, and Brazil and China to a lesser extent. Steam injection began approximately 5 decades ago (Flock, D.L. and Nouar).[15]

TABLE 1: Steam Flood Process After Initial Cycle

Crude Oil	Recommended
Viscosity	>20 cp (normal range is 100 ± 5000 cp)
Composition	Not critical but some light ends for steam distillation will help
Gravity	10-25 °API
Reservoir	Recommended
Oil Saturation	40% PV
Type of formatin	Sand or Sandstone with high porosity and permeability preferred
Net Thickness	>20 ft
Average Permeability	>200 md
Transmissibility	>100 md ft/cp
Depth	300 _ 5000 ft
Temperature	Not Critical

Limitations

1) Oil saturations must be quite high and the pay zone should be more than 20 ft thick to minimize heat losses to adjacent formations.

2) Lighter, less viscous crude oils can be steam flooded but normally will not be if the reservoir will respond to an ordinary water flood.

3) Steam flooding is primarily applicable to viscous oils in massive, high permeability sandstones or unconsolidated sands.

4) Steam flooding is not normally used in carbonate reservoirs.

5) If sufficient coke is not deposited from the oil being burned, the combustion process will not be sustained. This prevents the application for high-gravity, paraffinic oils.

6) Oil saturation & porosity must be high to minimize heat loss to rock.

7) Process tends to sweep through upper part of reservoir so that sweep efficiency is poor in thick formation.

8) If excessive coke is deposited the rate of advance of the combustion zone will be slow & the quantity of air required to sustain combustion will be high.

Problems:

1. Adverse mobility ratio

2. Complex process, requiring large capital investment, is difficult to control

3. Produced flue gases can present environmental problems

4. Operational problems such as severe corrosion caused by low pH hot water, serious oil water emulsions, increased sand production, deposition of carbon or wax, and pipe failures in the producing wells as a result of the very high temperatures.

Water flooding (water injection)

Water flooding consist of injecting water into the reservoir. It is the most postprimary recovery method. Water is injected in patterns or along the periphery of the reservoir (Ekundayo,., and Ghedan). [14]

Mechanisms That Improve Recovery Efficiency :

Water Drive, Increased Pressure

Limitations :

High oil viscosities result in higher mobility ratios.

Some heterogeneity is acceptable, but avoid extensive fractures.

Challenge :

Compatibility between the injected water and the reservoir may cause formation damage.

Screening Parameters :

1. Gravity > 25 API
2. Viscosity < 30cp
3. Composition not critical
4. Oil saturation > 10% mobile oil
5. Formation type sandstone/carbonate
6. Net thickness not critical
7. Average permeability not critical
8. Transmissibility not critical
9. Depth not critical
10. Temperature not critical

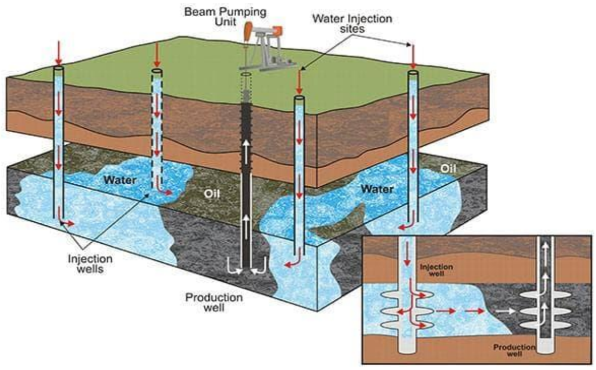

Figure 6: Water injection

Note: Most EOR screening values are approximations based on successful north American project

Chemical Methods :

These methods are increasing capillary number processes (micellar-polymer, caustic/alkaline) or mobility ratio processes (polymer). All are based on injecting one or more chemicals into a reservoir to bring about the aforementioned changes.

Polymer Flooding :

Polymer methods consist of injecting an aqueous phase (water or brine) into which has been dissolved a small amount of a polymeric thickening agent. The thickening agent increases water viscosity and in some cases lowers the permeability to the phase to bring about the lowered mobility ratio. Polymer methods do not increase capillary number. Primarily because of its small cost, there have been more polymer floods done than any other type of EOR process. Unfortunately most of these were take advantage of an artificial taxing policy in the US and not to recover much incremental oil. With the lapsing of the policy and the collapse of the oil price in the mid 80s, these projects virtually disappeared, giving way to a variation of the process based on polymer gels. With the restoration of the oil price, interest has picked up, especially because of the significant reported successes in the Chinese Daqing Field. Polymer processes have historically recovered about 5% of the original oil in place and taken about 1 lbm of polymer to produce an incremental barrel (Baviere,).[10]

Mechanisms That Improve Polymer augment Recovery Efficiency :

Mobility control (improves volumetric sweep efficiency).

Limitations :

1. High oil viscosities require a higher polymer concentration.

2. Results are normally better if the polymer flood is started before the water± oil ratio becomes excessively high.

3. Clays increase polymer adsorption.

4. Some heterogeneity is acceptable, but avoid extensive fractures. if fractures are present, the cross linked or gelled polymer techniques may be applicable.

Challenges:

Lower injectivity than with water can adversely affect oil production rates in the early stages of the polymer flood. Acrylamide-type polymers loose viscosity due to shear degradation, or it increases in salinity and divalent ions.

Screening Parameters :

1-Gravity > 18 API

2-Viscosity < 200cp

3-Composition not critical Oil saturation > 10%

4-PV mobile oil Formation type sandstone /carbonate

5-Net thickness not critical

6- Average permeability > 20md

7- Transmissibility not critical Depth < 9000ft

8- Temperature < 225

Surfactant/Polymer Flooding

Surfactant/polymer flooding consists of injecting a slug that contains water, surfactant, electrolyte (salt), usually a co-solvent (alcohol), and possibly a hydrocarbon (oil), followed by polymer-thickened water (Baviere).[10]

Mechanisms That Improve Recovery :

Interfacial tension reduction (improves displacement sweep efficiency) Mobility control.

Limitations :

1) An areal sweep of more than 50% for water flood is desired.

2) Relatively homogeneous formation.

3) High amounts of anhydrite, gypsum, or clays are undesirable.

4) Available systems provide optimum behavior within a narrow set of conditions.

5) Water chlorides should be<>20000 ppm and divalent ions

Challenges :

1. Complex and expensive system.

2. High adsorption of surfactant.

3. Interactions between surfactant and polymer.

Screening Parameters :

1- Gravity > 25 API

2-Viscosity < 20cp

3- Composition no critical

4-Oil saturation > 10%

5- Pv Formation type sandstone

6-Net thickness > 10 ft

7-Average permeability > 20md

8- Transmissibility not critical Depth < 8000ft

9- Temperature < 225

10- Salinity of formation brine < 150000 ppm TDS.

CO2 Flooding (CO2 injection)

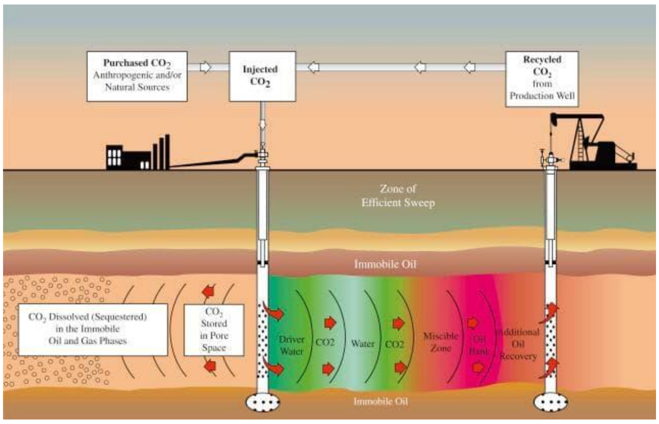

Figure 7: CO2 Enhanced Oil Recovery.

CO2 Properties

The idea of utilizing CO2 to improve the recovery of oil was proposed in the 1950s when Whorton and Brownscombe received a patent for an oil-recovery method with CO2 and it has received considerable attention since then(Holm, [4]). A lot of laboratory and deskwork has been conducted and in the 1970s, widespread field testing took place. Under ambient conditions, carbon dioxide is a colorless, odorless, inert, and noncombustible gas. Its properties under standard conditions (1.01MPa, 0 °C) are:

1. Molecular weight 44.010 g/mole

2. Specific gravity with respect to air 1.529

3. Density 1.95 kg/m3

4. Viscosity 0.0137 MPa/s

Carbon dioxide phase diagram (Chemistrybeta.com) 12 CO2 is a solid at low temperature and pressures. Solid CO2 will evaporate directly to gas at the temperature of -78.5 °C. As the temperature increases, the liquid phase appears for the first time and coexists with the solid and vapor phases at the triple point. With further increasing temperature and pressure, it reaches a critical point, where the CO2 behaves as a vapor. Its critical properties are:

P_c = 7.39 MPa (1073 psia) T_c = 304 K (31.1°C, 37.8 °F)

V_c = 94 cm3/mole

Due to this critical temperature and pressure, CO2 behaves as a supercritical fluid under most reservoir conditions [10]. At the critical conditions of pressure and temperature, the viscosity of CO2 is 0.0335 cp which is higher than other probable injection gases (N2: 0.016 cp; CH4: 0.009 cp). CO2 is (2 to 10 times) more soluble in oil than in the water. Dissolving in water, CO2 increases the water viscosity and forms carbonate acid, which has a beneficial effect on shale and carbonate rocks.

Mechanisms That Improve Recovery

CO2 extracts the light _ to-intermediate components from the oil , and if the pressure is high enough, develops miscibility to displace oil from the reservoir(vaporizing gas drive).

Limitations :

Very low viscosity of CO2 results in poor mobility control. Availability of CO2.

Challenges :

1. Early breakthrough of CO_2 causes problems.

2. Corrosion in producing wells.

3. The necessity of separating CO_2 from saleable hydrocarbons. Repressuring of CO_2 for recycling.

4. A large requirement of CO_2 per incremental barrel produced.

Screening Parameters :

1) Gravity > 27 API

2) Viscosity < 10cp

3) Composition C5-C20 (C5-C12)

4) Oil saturation > 30% PV

5) Formation type sandstone/carbonate

6) Net thickness relatively thin

7) Average permeability not critical

8) Transmissibility not critical

9) Depth < 2300 ft

10) Temperature < 250

CO_2 Dissolution in Oil

The dissolution of CO_2 in crude oil results in the main factors that contribute to enhanced oil recovery. The solubility of CO_2 in oil depends on the pressure, temperature and characteristics of the oil as was shown in Figure 3.2 below. ADA crude oil has a gravity of 30.3 °API while West Texas crude is of 39 °API. According to Figure 3.2, CO_2 has a higher solubility in lighter oil; this value is slightly greater when the temperature is 13 increased. When the pressure increases, solubility will increase and is sometimes limited to a saturation value. Figure 3.2. CO_2 solubility in crude oil (Christiansen, and Haines,).[6]

1. Oil Swelling: As a result of CO_2 dissolution into the crude oil, the oil volume will increase from 10 to 60%. This phenomenon is greater for light oil and leads to lower residual oil saturation (Holm, 1987 [5]). Oil swelling increases the recovery factor for a given residual oil saturation increases, the mass of the oil remaining in the reservoir under standard conditions is lower than residual oil that has not had contact with the CO_2.

2. Viscosity Reduction: CO_2 dissolution in crude oil also results in oil viscosity reduction. Calculations indicated that this viscosity reduction is the major mechanism for EOR. 14 Laboratory experiments show that, for any given saturation pressure, the viscosity reduction is relatively greater for oil with higher original viscosity (Flock,. and Nouar,). [15]

Miscible Displacement

The miscible state is described by L.W. Holm as ―the ability of two or more substances to form a single homogeneous phase when mixing in all proportions. For petroleum reservoirs, miscibility is defined as that physical condition between two or more fluids that will permit them to mix in all proportions without the existence of an interface. If two fluid phases form after some amount of one fluid is added to others, the fluids are considered immiscible.‖ There are two processes involved in a miscible gas drive. The two processes are they are identified as the first contact miscibility process and the multiple contact miscibility process. First contact miscibility is achieved when both fluids are completely miscible in all proportions without any multiple behaviors. Other solvents are not directly miscible with reservoir oil, but miscibility can be achieved under certain conditions by in-situ mass transfer between oil and solvent through repeated contacts. This kind of miscibility is called multiple contact or dynamic miscibility. When large amounts of CO_2 are mixed with oil, intense mass transfer between phases occurs. Multiple contact miscibility is subdivided into two processes: condensing gas drive and vaporizing gas drive. 15 Both condensing drive and vaporizing drive are based on component transfer. Components in the injected gas and reservoir oil can be classified into four groups:

- Lean components: CO_2, N_2, and CH_4 injection gas.
- Light components: C1 (methane).
- Intermediate components: C2-C6, these components are present in oil but not Significantly present in the injection gas.
- Heavy components: C7+ (heptane and heavier fractions).

1. Vaporizing Gas Drive: The most important function of CO_2 is that it can extract or vaporize hydrocarbons from crude oil. Vaporizing gas drive mechanism refers to a process where a lean injection gas passes over reservoir oil rich in intermediate components and extracts those fractions from the oil and concentrates at the displacement front where miscibility is achieved. A schematic of CO_2 gas vaporizing and condensing gas drive mechanisms are shown in Figure 3.3 below. One dimensional schematic of CO_2 miscible process (Flock, D.L. and Nouar,).[15]

2. Condensing Gas Drive: Condensing is a process that refers to the transfer through condensation of intermediate components from rich solvent to intermediate-lean reservoir oil through condensation. In CO_2 miscible flooding, the intermediates that were stripped from the oil that are present in the gas condense when the gas encounters fresh oil downstream.

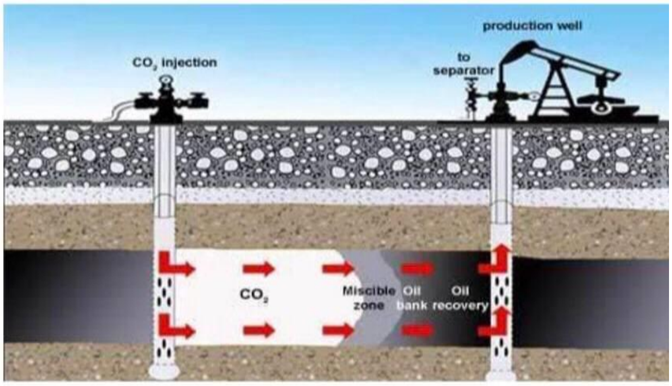

Figure 8 : EOR is identifying sights where CO_2 can be captured from local emission sources and then trucked or pipelined to the oilfield that can benefit from the CO_2 EOR process.

III. METHODOLOGY

A basic homogeneous model was constructed in one and two dimensional compositional ECLIPSE 300 model to simulate the hydrocarbon reservoir and study the resulting data. There are three major scenarios have been done on the model (water injection, CO_2 injection and water injection followed by CO_2 injection) in order to obtain the impact of including the three phases relative permeability and capillary pressures on the displacement process two simple models, 1D and 2D cross sectional simulation model were built and also to investigate the accurate output parameters such as recovery factor, total gas production, pressure etc. Therefore, the simple geometry and grid structure were selected to improve the brightness and understanding of the effect of relative permeability and the recovery mechanisms while the displacement processes are in working. Although, compositional model takes too long time to generate PVT data compare to black oil model and also needs to define the equation of state (EOS), but compositional model is better here for the reservoirs which have high specific gravity (API).

1. Models Description

1.1 1D Model

The simple grid structure of 1D was selected to analyses the sensitivity of sweep efficiency and pressure support to shifts in relative permeability and capillary pressures. The effect of vertical flo was excluded. In addition, the 1D model permits an examination of the growth and construction of the saturation profiles, shock fronts and phase paths along the system during the displacement process. Beides of that the 1D model permits very fine grid quantification, where the impact of numerical dispersion is investigated within a reasonable timeframe. Furthermore, the model included a single well producer and injector with 100x1x1 cells (DX= 10 cm, DY=DZ= 2.0 cm) as shown in Figure (7). The initial porosity is 0.25 with a permeability is 500 mD in all (x, y and z) directions. The initial reservoir pressure was 342.7 atm at temperature of 140°C at zero depth. In addition, there are ten numbers of components have been used in order to improve hydrocarbon recovery (N2, CO2, C1, HC23, HC46, C8, HC13, HC26, and HC43). It is assumed that there are three phase of oil, water and gas in the model. To define good use of three phase simulator, ODD3P keyword has been used to set the primary residual gas saturation, primary residual oil saturation and primary water saturation in gas-oil, gas-water, oil-gas, oil-water, water -gas and water-oil systems, respectively.

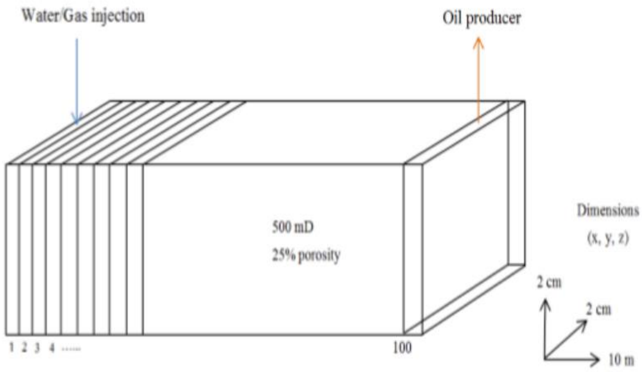

Figure 9:1D Model uniformed porosity and permeability are applied for each cell. Injection well located in cell 1 and Production well in cell 100.

1. 2 2D Model

The basic 2D model was constructed in order to extend the initial simulations and results which were obtained in the 1D model to investigate the impact of sweep efficiency and pressure by using relative permeability and capillary pressures. In addition, the model consisted of single well producer and injector with 100x1x30 cells (DX= 10 cm, DY=DZ= 2.0 cm) as shown in Figure (9). The initial porosity is 0.25 with a permeability is 500 md in all (x, y and z) directions. The initial reservoir pressure was 342.7 atm at temperature of 140°C at zero depth. In addition, there are ten numbers of components have been used in order to improve hydrocarbon recovery (N2, CO2, C1, HC23, HC46, C8, HC13, HC26, and HC43). It is assumed that there are three phase of oil, water and gas in the model. To define good use of three phase simulator, ODD3P keyword has been used to set the primary residual gas saturation, primary residual oil saturation and primary water saturation in gas-oil, gas-water, oil-gas, oil-water, water-gas and water-oil systems, respectively.

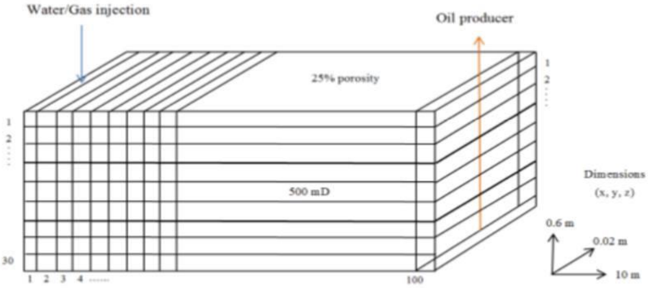

Figure 10: 2D Model uniformed porosity and permeability are applied for each cell. Injection well located in cell 1 and Production in cell 100.

Reservoir Fluids and Rock Properties

Oil PVT

Characteristics The reservoir fluid PVT properties reported in lab unit centimeter. The oil, gas and water viscosities at ambient temperature are 4.1566, 0.06077 and 0.305cp with a molecular weight 600 gm/gm-M, respectively. It is guessed that the oil volume factor is 1 cm3/Scm3 whereas the ambient temperature is140°C. The following table presents the oil PVT properties:

TABLE 2: Oil Properties.

Density (gm/cm3)	Viscosity (cp)	Molecular Weight (gm/gm-M)
0.994	4.1566	600

3.3.2 Gas PVT Characteristics

The gas volume is quantified at reservoir conditions to the volume of gas measured at standard conditions. In general, as the pressure gas rises, the gas volume quantified Bg will reduce while the viscosity of gas will increase. Gas formation Volume Factor (Bg) has been measured using the equation (1) below:

Bg==0.00504 zT/p

Where :

Bg = gas formation volume factor

Z = deviation factor

T = temperature

P = pressure

Reservoir Rock and Water Characteristics

The reservoir rock and water properties, which are used in the compositional one and two dimensional model, are summarized in the Table (3) below:

TABLE 3: Rock and Water Properties characteristics

Water Compressibility (1/atm)	5.06625E-04
Rock Compressibility (1/atm)	7.09275E-05
Water Viscosity (cp)	0.305
Water Formation Volume factor (m3 ⁄cm3)	1.0

Relative Permeability and Saturation

There are three sequence of relative permeability for all phases (oil, gas and water). The residual and saturation parameters including the end point relative permeability are summarized in Table (4). Based on the Corey method, relative permeability was obtained. The data below is shown for relative permeability, gas-oil system. The relative permeability quantified for water saturation (Figure 11), gas saturation (Figure 12) and oil saturation (Figure 13) based on the available data.

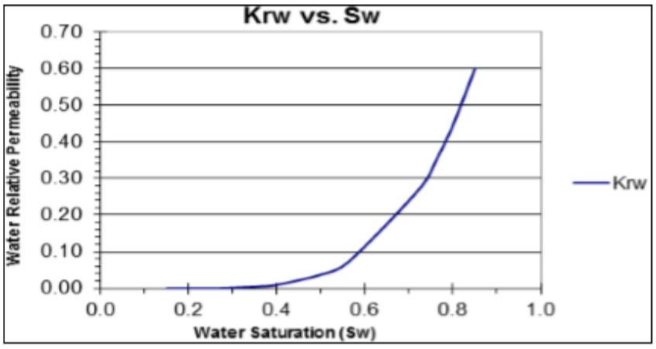

Figure 11: Showing water relative permeability against water saturation.

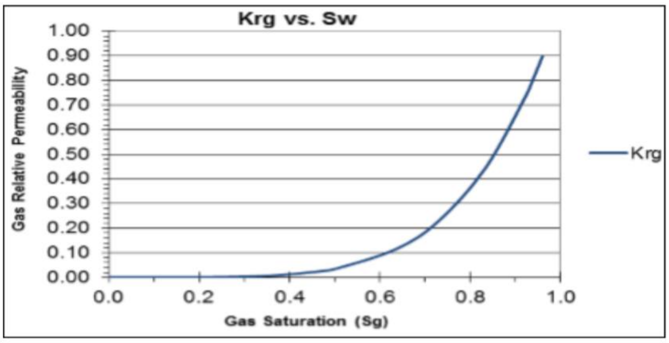

Figure 12: Showing relative permeability against gas saturation.

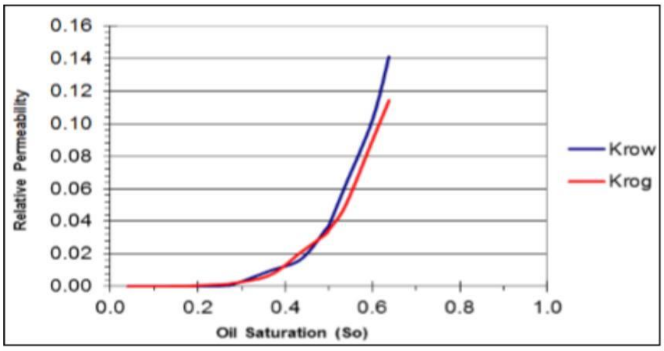

Figure 13: Showing oil saturation relative permeability.

Where:

Sw: water saturation, variable Swc: connate water saturation

SO: Oil saturation= 1-Sw Sorw: residual oil saturation to water

Sg: gas saturation= 1- So – Sw Sorg= residual oil saturation to gas

Sgc: critical gas saturation nog= 2; miscible to miscible system

Corey exponent for water, nw= 4 Corey exponent for oil/water, now=2

Corey exponent for oil/gas=1, 2, 4 Corey exponent for gas = 4

Sorg: residual oil saturation to gas Sgc: critical gas saturation

Totally miscible system, nog= 1 totally immiscible system, nog= 4

TABLE 4: End point of relative permeability and residual saturations

Oil residual saturation to water, Sorw	0.64
Oil residual saturation to gas, Sorg	0.64
Connate water saturation, Swc	0.35
Gas residual saturation, Sgr	0.05
End point water relative permeability, Krw	0.6
End point oil relative permeability, Kro	0.14
End point gas relative permeability, Krg	0.115

D Model Description and Input Parameters

This chapter proceeds with the development of a Oil reservoir 3D model using ECLIPSE 300 (compositional model) reservoir simulation simulator. The features of the reservoir were introduced to characterize rock properties (porosity, permeability and compressibility), and fluid properties (viscosity, density and API) of a typical gas condensate reservoir. The compositional model software was applying to simulate gas and condensate production under pressure depletion using single producers and four injector wells for each scenario. In addition, Sensitivity on the model time steps have been applied using input parameters in order to find out an accurate output parameters such as pressure, recovery factor etc. The compositional reservoir simulator (Eclipse 300) model was applying to predict and monitor the effect of CO_2 injection on field oil efficiency and the reservoir behavior using five spot models involve four injectors (A,B,C,D wells) and single producer (Well P) as illustrated in Figure 14 .

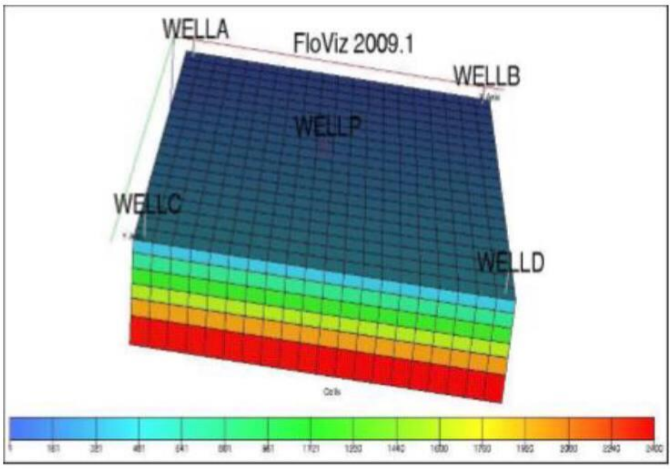

Figure 14: FloViz visualization shows well locations

CO2 gas injection was set up to inject under reservoir condition and the wells were located based on the five spot systems. In addition, WAG flooding was performed on the same system in order to compare their results with the two CO2 flooding processes. The model consisted of four injectors and single producer wells with 20x20x6 cells. The model included several low porous and permeable layers of the hydrocarbon reservoir. The input porosity is ranged about 0.07 to 0.18 with changeable permeability according to X, Y and Z directions. In addition, the model consists of seven numbers of comments (MC1, MC2, MC3, MC4, MC5, CO2, and N2.

IV. Results and Discussions

Oil reservoir can be depleted during production due to condensate blockage impact and it can be repaired by partial or full pressure maintenance process of gas injection (Christiansen, R. L. and Haines, 1984). Gas cycling is recorded historically and experimentally to provide higher recovery of oil in place and indicate better fluid recovery behavior while estimated to other alternatives like carbon dioxide Carcoana [17].

A developing concern in using this process is result in raising value of gas in the global market. Therefore, the performance of gas injection might not always be relatively profitable despite of production improvement. The best way to address this is by creating performance predictions to improve production of gas condensate reservoirs and economically evaluate ascertain the profit viability of gas injection.

The purpose of this chapter is to show results of hypothetical Oil reservoir model by applying CO2, water injections by using ECLIPSE 300 reservoir simulator to improve pressure and sweep efficiency in order to increase productivity. There are two separate injection scenarios which were generated. Initially, three of these scenarios were applied for 1D and 2D models at different time steps. Furthermore, Buckley leveret theory was used to find out recovery factor based on one dimensional model, homogenous formations and PVT data. Subsequently, five scenarios were used for 3D model to demonstrate the effect of injection on the reservoir pressure support and sweep efficiency in order to obtain a relationship between injection and field oil recovery

1. 1 1D Model

The one dimensional model was run with three different case scenarios at different time steps.The following simulation cases were run:

• Simulation case 1
› Water flooding
• Simulation case 2
› CO2 injection

1.2 1D Result

The following results are graphical indications and Table (5) of the pattern of field oil efficiency (FOE), field oil production total (FOPT), field gas production total (FGPT) and field pressure(FPR) generated by ECLIPSE 300 compositional oil simulator for the 3 simulation cases at 60 and 120 hours.

TABLE 5: Summary of 1D simulation results for all cases.

Simulations	60 hours				120 hours			
Cases	FOE (%)	FOPT (SCC)	FGPT (SCC)	FPR (ATM)	FOE (%)	FOPT (SCC)	FGPT (SCC)	FPR (ATM)
Water Injection	76.1	321.7	92762	343.4	78.5	332.2	95772	343.25
CO_2 Injection	82.6	342.4	154447	342.9	90.8	377.7	398891	342.9

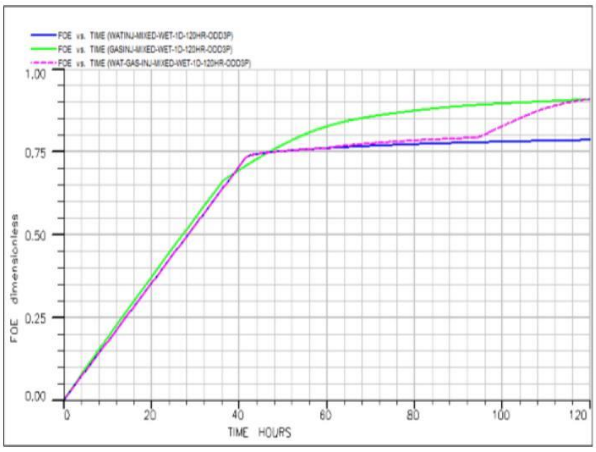

Figure 15: Plot of Field Efficiency (FOE) against Time depicting all 3 cases.

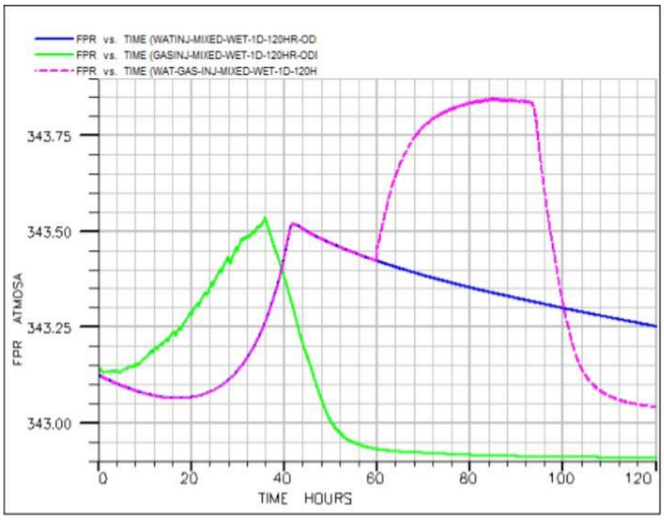

Figure 16: Plot of Field Pressure (FPR) against Time for all 3 cases.

1.3 D Discussions

The field pressure depleted by production in a gas condensate as any other hydrocarbon reservoirs. The pressure will be decreasing continuously till a point where the reservoir cannot produce which is regarded as the abandonment pressure. Production schemes are planned to operate and sometime maintain reservoir pressure to sustain the productivity of the reservoir. Figure (16) represents the pressure decline pattern form three depletion scenarios which are cited earlier. It can be noticed that there is a recovery of pressure as a result of injected of water, CO2 and water/gas scenarios. While CO2 injection, pressure increased significantly for a short period compared to other scenarios. There is an increase of pressure smoothly during water injection. The significant increase pressure is recorded during a simultaneous water/CO2 injection. Furthermore, field oil efficiency increase sharply during CO2 injection, whereas water injection has lower field oil efficiency. Simultaneous water/CO2 injection has better field oil efficiency compared to water and CO2 injection because water provide optimum pressure support and CO2 expand the residual oil significantly as shown in Figure (15). It can be seen that the maximum total gas production was recorded during CO2 injection whereas the minimum gas production was shown during water injection as illustrated in Appendix C, Figure (C-2). The simultaneous water/CO2 injection showed better oil production totally compared to water and CO2 injection as indicated in Appendix C, Figure (C-1).

2.1 2D Model

The two dimensional model was run with three different case scenarios the same as one dimensional model at different time steps to obtain better improvement in oil recovery.

2.2 2D Result

The following results are graphical indications and Table (6) of the pattern of field oil efficiency (FOE),field oil production total (FOPT), field gas production total (FGPT) and field pressure(FPR) generated by using ECLIPSE 300 compositional oil simulator for the 3 simulation cases at 2400 and 4800 hours.

TABLE 6: Summary of 2D simulation results for all cases

Simulations	2400 hours				4800 hours			
Cases	FOE (%)	FOPT (SCC)	FGPT (SCC)	FPR (ATM)	FOE (%)	FOPT (SCC)	FGPT (SCC)	FPR (ATM)
Water Injection	55.2	3055.7	881073	342.8	57	3194	909803	342.79
CO_2 Injection	83.3	4453.1	6978451	342.8	88.2	4718	7388948	342.79

2.3 2D Discussions

There can be noticed that is quite the same field efficiency as the 1D scenario. Field efficiency increased sharply during CO2 injection, whereas, water injection has lower field efficiency. Simultaneous water/CO2 injection has better field oil efficiency compared to water and CO2 injection, separately as shown in Figure (17).Furthermore, the maximum total gas production was recorded during CO2 injection whereas the minimum gas production was shown during water injection as illustrated in Figure (18). There is a smooth increase in pressure during water injection. The significant increase in pressure is recorded during a simultaneous water/CO2 injection as shown in Appendix C; Figure (C-3).The simultaneous water/CO2 injection showed better oil production totally compared to water and CO2 injection, individually as indicated in Appendix C.

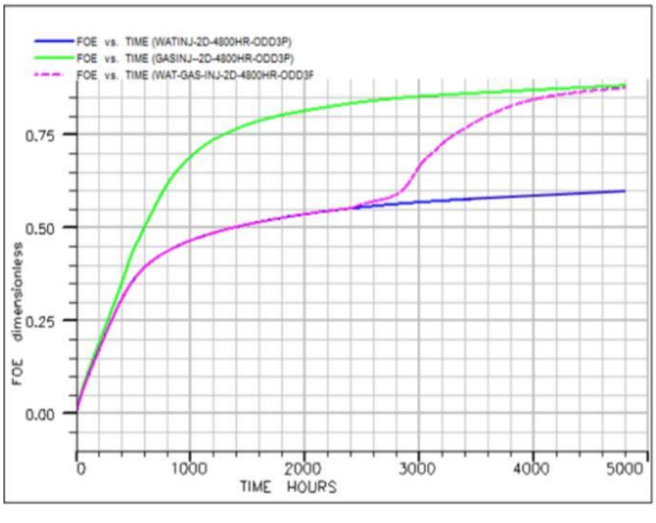

Figure 17: Plot of Field Oil Efficiency (FOE) against Time depicting all 3 cases.

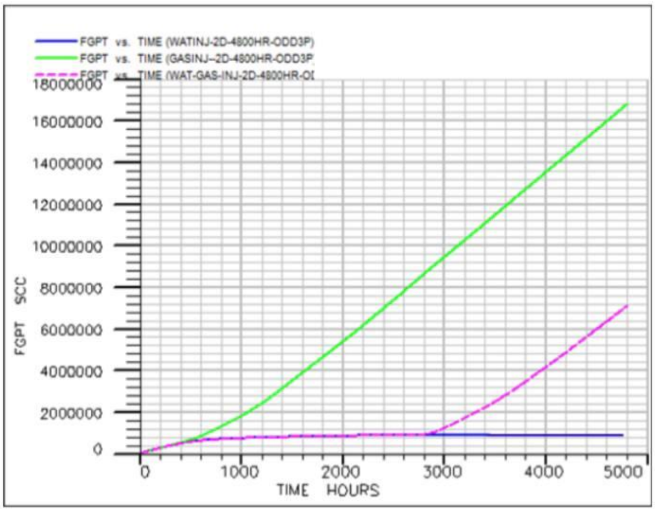

Figure 18: Plot of Field Gas Production Total (FGPT) against Time depicting all 3 cases.

3D Model Discussion

It can be noticed that the field oil efficiency increased significantly during miscible CO2 injection for a short period of time. Whereas, there is a moderated increase during waterflood injection for short period, because miscible CO2 helps the oil as a pressure support to dissolve and expand, and then go through the reservoir matrix and the production well. Figure (19) shows the effect of oil recovery with respect to the amount of CO2 gas injected into the field. It can be clearly seen that as CO2 miscible gas is injected into the reservoir, the efficiency of oil recovery increases significantly.

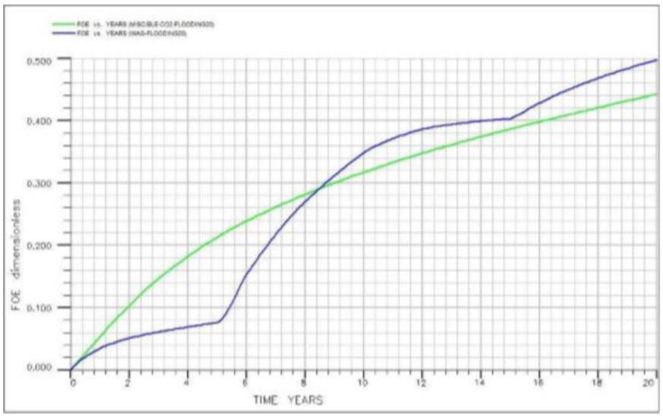

Figure 19: Field oil efficiency versus time (years).

V. Conclusions and Recommendations

Water, CO2, WAG injections have been concluded to predict field oil efficiency and also infer pressure support and sweep efficiency in a 1D, 2D and 3D geometry using ECLIPSE 300 compositional simulator. The following observations have been made:

1. As a result of high mobility ratio and low viscosity for gas condensate reservoir, CO2 injection has slightly higher recovery factor than water injection based on Buckley Leveret theory for 1D model.

2. For a short period of time CO2 injection has great effect on recovery factor. Although, water injection followed by CO2 has better recovery factor based 1D, 2D and also 3D model using Eclipse 300 compositional simulator.

3. The presence of heterogeneity causes the reduction of liquid recovery and the ability of CO2 is compromised to sweep the reservoir liquid.

Recommendations for Further Work :

1. Consider additional simulations and sensitivities which have not discovered here. Examine the impact of distinct product of permeability and net formation thickness (kh) on the condensate recovery.
2. Consider the effect of different gas injection pressure.

3. Consider distinct pattern of permeability variation with depth.

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