CO_2-ASSISTED GRAVITY DRAINAGE EOR: NUMERICAL SIMULATION AND SCALING MODELS STUDY

A thesis

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By

Prashant Jadhawar
B. Eng. in Petroleum Eng., University of Pune, India
M. Eng. in Petroleum Eng., University of Pune, India
M. Phil. in Petroleum Eng., Heriot-Watt University, UK

THE UNIVERSITY OF ADELAIDE AUSTRALIA

ASP Australian School of Petroleum

Australian School of Petroleum
Faculty of Engineering, Chemical and Mathematical Sciences (ECMS)
The University of Adelaide, Australia

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1. INTRODUCTION

1.1 Background

A recent estimate puts the global conventional and unconventional oil resources at about 4.8 trillion barrels (Jackson, 2007). However the production of natural oil resources has not been increased at pace in accordance with its increased consumption due to the rapid industrial development taking place in the developing nations like India and China (requirement of 84 million barrels per day). This demand has potential to outstrip the energy production in future considering the present level of the world energy supply (Max *et al.*, 2006). The energy supply-demand gap is projected to further widen by more than two fold. One of the options to minimise this gap is to recover more oil by employing enhanced oil recovery techniques.

Recovery of oil from producing zones in the early life of hydrocarbon reservoir is achieved by virtue of natural pressure (drive) existing within itself through the mechanisms of natural water (bottom-water/edge-water) drive, solution gas drive, gas cap drive and gravity drainage. Once the pressure differential between the producing well and the oil bearing formation diminishes to an uneconomical level or ceases to exist, external fluids or materials for enhancing the recovery of oil from the petroleum reservoir are injected in the form of fluids (gas or water)/ chemicals/heat. Water injection (secondary recovery method) is the traditional choice for the recovery of oil remaining at the end of primary recovery methods. In general, primary and secondary recovery methods of EOR produce only one-third of the original oil in place (OOIP), leaving behind two-thirds, trapped in the interstitial pore network of hydrocarbon reservoirs (Lake *et al.*, 1992). It is estimated that the volume of the residual oil beyond primary and secondary methods is about 2 trillion barrels in the world’s hydrocarbon reservoirs (Kulkarni, 2005; Moritis, 2006). This oil resource is enormous and its exploitation by employing novel technologies would be critical in mitigating future energy needs.

Amongst the major contending processes for recovery of this huge trapped resource, gas injection is one of the key competing enhanced oil recovery (EOR) processes. Common gas injectants used for this purpose are hydrocarbon gas, carbon dioxide, nitrogen, air and flue gas. Although enhanced oil recovery methods by gas injection have been practised since the turn of twentieth century; its field applications are on the rise following the success of the CO_2 injection project in the SACROC unit of Permian basin, US. Gas injection is the most widely practiced process amongst all the enhanced oil recovery processes in US and their worldwide application is growing (Moritis, 2006; Moritis, 2008).

Gas injection EOR methods can be broadly classified into two types: Continuous Gas Injection (CGI) and Water-Alternating-Gas (WAG) Injection. Continuous Gas injection (CGI) EOR method offers good microscopic displacement efficiencies in the gas-swept region by lowering interfacial tension developed between the injected gas and reservoir oil, leading to an increase in reservoir displacement efficiency. Reservoir fluids are nearly ten times more viscous than the common gas injectants (carbon dioxide, hydrocarbon gases, nitrogen) thus making gas injection susceptible to generating unfavourable mobility ratios and severe gas-oil gravity segregation in the reservoir, resulting in early gas breakthrough at producing well. In order to overcome the concerns about poor volumetric sweep efficiencies, Caudle and Dyes in 1958 proposed the water-alternating-gas (WAG) process (Christensen *et al.*, 1998). Alternating slugs of water and gas are injected in the producing reservoir wherein counteracting natural tendencies of gas to rise and water to fall horizontal mode gas injection floods was hypothesised to give more uniform flooding patterns.

WAG can be carried out in two modes either in miscible mode (injected fluid/gas completely mixed/miscible with the reservoir fluid) and immiscible mode (injected fluid/gas is not miscible with the reservoir fluid). Miscible WAG process contributes nearly 83% of the total EOR projects over the continuous gas injection (CGI) field projects that are commonly employed to improve oil recovery performance in the field (Christensen *et al.*, 1998). However, the literature review of 59 WAG field projects indicated that WAG Floods yield poor incremental oil recoveries in the range of 5 - 10% OOIP for immiscible WAG projects with an average incremental recovery of 9.7% for miscible WAG projects and 6.4% (Christensen *et al.*, 1998)). Water injection during the WAG process increases water saturation in the reservoir, thereby diminishing gas injectivity and reducing oil mobility, leading to severe injectivity problems and difficulties in establishing gas-oil contact and miscibility in the reservoir. Modified WAG methods such as Hybrid-WAG, Denver Unit WAG (DUWAG), Simultaneous WAG (SWAG), gas thickeners and foam injection have been field employed for improvising volumetric sweep efficiencies which yielded little success (Moritis, 1995) and are not part of the commercial technology.

1.2 Motivation

All of the suggested modifications in methods and their field implementations were aimed at reducing the impacts arising from severe gravity segregation of the injected gas and the reservoir fluid (oil) thereby improving volumetric sweep efficiencies. A method that makes use of the natural tendency of the density based gravity segregation of the fluids (injected gas and the in-situ reservoir fluid) as an advantage to recover the bypassed oil from unswept regions in non-dipping (horizontal type) as well as dipping / pinnacle reef reservoirs looks to be promising alternative.

Gravity forces are recognized to play an important role at nearly every stage of the producing life of the reservoir, whether it is primary depletion, secondary water or gas injection schemes or tertiary enhanced or improved oil recovery methods (Dake, 2001). They always compete with the viscous (flow rate per unit area) forces and the capillary (ratio of the fluid/fluid forces to the grain size) forces acting in porous media in addition to the vertical barriers in the form of heterogeneity. Gas injection at higher rates causes viscous forces to dominate leading to early injection gas breakthrough, thus lowering the oil production rates. On the other hand, capillary pressure effects arising from the rock-fluid and fluid-fluid interfacial tension existing in the porous media prevent the oil from pores to flow into the oil bank. Because of these factors oil is trapped in the porous media adversely affecting the overall oil recovery performance.

In view of these EOR impeding factors, a method that uses gravity forces as an advantage for improving the oil recovery performance is considered in this study. Gravity drainage of the reservoir oil during the controlled gas injection in the EOR process maximizes oil recovery from the oil bearing zone under investigation. Number of the laboratory and field studies (Backmeyer *et al.*, 1984; Bangla *et al.*, 1991; Cardenas *et al.*, 1981; Chatzis *et al.*, 1988; Da Sle and Guo, 1990; DesBrisay *et al.*, 1981; Gunawan and Caie, 1999; Kulkarni and Rao, 2006b) epitomizes the significance of gas-oil gravity drainage process in view of the higher oil recoveries obtained in contrast to other gas injection EOR methods. Recoveries as high as 87-95% have been reported in field tests in dipping and pinnacle reef type reservoir and nearly 100% recovery efficiency has been observed in laboratory coreflood studies (Kulkarni and Rao, 2006b; Ren *et al.*, 2003).

Recent laboratory investigations conducted by Kulkarni (2005) have demonstrated that the characteristic gravity segregation of fluids can be advantageously used for enhancing oil recovery even in gas floods to horizontal type reservoirs. His experiments in miscible gas injection in gravity drainage mode yielded nearly 100% of oil recovery. Although the oil recovery rates from the gas-assisted gravity drainage (GAGD) EOR process is slow, the gravity stable Crestal or downward displacement type injection, either through gas cap expansion or by gas injection at the crest of the reservoir is expected to yield high incremental oil volumes from the producing formations. Detailed discussion of the previous work with respect to the enhanced oil recovery by gas GAGD mechanism is presented in the Chapter 2.

1.3 Knowledge Gap

Critical review of the field studies presented in Chapter 2 indicated that the majority of the studies used immiscible and / or miscible hydrocarbon, lean gas, nitrogen, air injection for achieving the enhanced oil recovery on 22 to 45 ^{o}API gravity oil through gravity-stable displacement in dipping or reef type reservoir. These were oriented towards studying the operational multiphase process mechanisms while maximising the oil recovery. Systematic compositional modelling of CO_2-EOR through gravity drainage mechanism in immiscible and miscible mode is still lacking. Moreover, the effect of orientation of the injection and production wells (well pattern) and the horizontal well instead of vertical gas injection wells on the mechanics of gravity drainage oil recovery process and the final oil production performance has not been investigated specifically for the CO_2-assisted gravity drainage EOR process. Mechanisms with which the CO_2-assisted gravity drainage EOR process proceeds are not clearly understood. This is exploited in this study.

Scaling and the sensitivity analysis of the CO_2-assisted gravity drainage EOR process has not been carried out so far. Moreover, a single scaled model combining the major process affecting multiphase parameters is yet to be presented and is still a major challenge. With the limited CO_2-gas injection studies for gravity drainage EOR process (except by Bangla and his co-workers (1991), present research aims to address those lacunas via numerical reservoir simulations and scaling and sensitivity studies.

1.4 Scope of the Study

In this investigation, CO_2-assisted gravity drainage EOR method is subjected to the numerical simulation (black oil and compositional) and scaled model studies in a non-dipping (horizontal type) reservoir in both the immiscible and miscible mode. In this first ever investigation, the 50 ^{o}API gravity oil from the Australian reservoir is subjected to CO_2-assisted gravity drainage mechanism through the numerical sensitivity studies. This study uniquely investigates the effects of well patterns and horizontal gas injection wells in the secondary immiscible and miscible CO_2 flooding. Mechanisms with which the CO_2-assisted gravity drainage EOR process proceeds in very light reservoir oil, such as of 50 ^{o}API gravity are investigated through the numerical simulations. It includes the effects of grid size, mode of the gas injection, miscibility development, heterogeneity in permeability and porosity and molecular diffusion.

New concept of the critical voidage replacement ratio is introduced in this research. Furthermore, applicability of the reservoir simulation results to the full field scale is studied through the scaling and sensitivity analysis. A new combination model representing the most important multiphase parameters operational in CO_2-assisted gravity drainage EOR process is proposed and validated using the data from field projects. New additional dimensionless groups are developed through dimensional analysis. Dimensionless groups presented in this study through the scaling and sensitivity analysis presents a set of scaled models that are sufficient to completely scale the CO_2-assisted gravity drainage EOR process to map their effect on the final gravity drainage oil recovery. Economical aspects are outside the scope of the research study investigated in this dissertation.

1.5 Research Objectives

The major objectives are to investigate the multiphase mechanisms operational in the CO_2 assisted gravity drainage EOR process through sensitivity analysis using the numerical reservoir simulation and the developed scaled model tools.

1.5.1 Numerical Simulation Studies:

Main objectives in the evaluation of CO_2-Assisted Gravity Drainage EOR process through reservoir simulations are to:

a) Develop an effective production strategy to evaluate the effect of well patterns, oil zone thickness and vertical versus horizontal CO_2 injection wells on the CO_2-assisted gravity drainage oil recovery performance

b) Study the effects of rates of gas injection and corresponding oil production on the final gravity drainage oil recovery
c) Study the effect of connate water saturation on the CO_2-assisted gravity drainage oil recovery
d) Study the effect of grid size (x and y dimensions) and grid thickness on immiscible CO_2-assisted gravity drainage oil recovery
e) Identify the mechanisms that contributes the immiscible and miscible CO_2-assisted gravity drainage oil recovery
f) Develop a general selection map to characterize the choice of CO_2-assisted gravity drainage EOR process between the immiscible and miscible one
g) Investigate the effect and role of miscibility development in the optimization of CO_2-assisted gravity drainage oil recovery
h) Verify the existence of oil film flow using 3D reservoir simulation tool in the immiscible CO_2-assisted gravity drainage EOR process
i) Study the effect of secondary and tertiary mode of CO_2 injection in both the immiscible and miscible CO_2-Assisted Gravity Drainage EOR process
j) Investigate the effect of reservoir heterogeneity in porosity and permeability on oil recovery performance in the CO_2-assisted gravity drainage EOR process
k) Investigate the role of molecular diffusion in both the immiscible and miscible CO_2-Assisted Gravity Drainage EOR process for the homogeneous and heterogeneous porous media
l) Study the methods to optimize the gravity drainage oil production by possible variation between the viscous forces/capillary forces/gravity forces
m) Investigate the conditions to the displacement instabilities and critical injection rates for CO_2 flood profile control during the gravity drainage oil recovery: Introduction of new concept of critical voidage replacement ratio with specific application in the CO_2-assisted gravity drainage EOR process

1.5.2 Scaling and Sensitivity Studies:

Main objectives of this research in scaling and sensitivity studies are:

a) To identify the key multiphase operational parameters and their relative dominance during CO_2-assisted gravity drainage oil recovery process
b) To develop a set of scaled models that captures most of the mechanistic multiphase parameters influencing the CO_2-assisted gravity drainage oil recovery.

c) To scale, for the first time, the CO_2-assisted gravity drainage EOR process through the verification and validation of the developed scaled models using process data from the reservoir simulations in this study and data from the gravity drainage field projects in USA and Norway.

1.6 Outline of the Thesis

Based on the above objectives the thesis has been organized in the Chapter-1 through Chapter-9. Significant contribution of various authors in relation to the EOR methods (especially CO_2 EOR) including the CO_2-assisted gravity drainage EOR process and the relevant topics have been reviewed in **Chapter-2**. CO_2-assisted gravity drainage EOR method is described in the later section with the supporting literature review oriented towards the reservoir simulation studies. Operational parameters controlling the CO_2-assisted gravity drainage EOR method are then discussed to support the results presented in the later sections of this thesis. In the end, theoretical background and literature review of the scaling and sensitivity issues of the CO_2-assisted gravity EOR method are presented.

In the **Chapter-3**, methodologies of the each of the investigations conducted in this research are described in detail.

The **Chapter-4** presents the details of reservoir fluid models used in the reservoir models for studying the parametric sensitivity analysis. Oil composition and the related PVT properties are presented for the two reservoir fluids of 35 and 50 ^{o}API gravity used for this purpose were subjected to the pseudo-miscible and compositional studies. Later section discusses the reservoir fluid characterization procedures employed during the EOS matching of laboratory PVT properties. Finally, the tuned EOS model of Australian reservoir oil having 50 ^{o}API gravity is presented

Investigation of the methods employed to develop a better production strategy for the investigation of CO_2-assisted gravity drainage EOR process is presented in the **Chapter-5.** Results of the simulations conducted to choose between the injection or production well rate constraints, to study the effect of irregular and regular well patterns, type of CO_2 injection wells, capillary pressure and connate water saturation are presented.

In the **Chapter-6**, results of the black oil and compositional simulations over 35 and 50 ^{o}API gravity reservoir fluids for the oil recovery optimization are presented. Results of the sensitivity analysis are presented to outline the effect of various operational mechanisms contributing the enhance oil recovery, grid size, the molecular diffusion, mode of CO_2 injection and reservoir heterogeneity on the final oil recovery in both the immiscible and miscible CO_2-assisted gravity drainage EOR process.

The **Chapter-7** presents the scaling and sensitivity analysis of the CO_2-assisted gravity drainage EOR method. Newly developed correlation that combines the important multiphase operational parameters is presented. Moreover, various dimensionless groups are developed further to investigate a set of dimensionless groups sufficient to scale the CO_2-assisted gravity drainage EOR process. Results of their validity and verification are presented in this Chapter.

The **Chapter-8** discusses the results obtained in this PhD research from the production strategy development, oil recovery optimization and the scaling and sensitivity studies. Based on the results obtained in this PhD study, conclusions were drawn which are finally presented in the **Chapter-9.** Recommendations for the further research are also outlined in this Chapter.

2. LITERATURE REVIEW

Considerable volumes of the reservoir oil are left-behind at the end of primary depletion and later oil recovery methods. Employing the proper EOR methods can maximise oil recovery from the target reservoir. Each of the recovery process is associated with the various fundamental theories and operational multiphase mechanisms. These are therefore addressed in this chapter.

This chapter begins with the overview of EOR methods followed by the gas injection EOR methods including the CO_2 EOR process mechanisms and its potential in Australian reservoirs. Fundamental gas-oil gravity drainage concepts are then discussed before the introduction of the CO_2-assisted gravity drainage EOR method. Literature review of the respective reservoir simulation studies are presented followed by the discussion of the multiphase operational controlling parameters with the focus on the research undertaken in this study. Later section describes the literature review on the scaling and sensitivity studies under investigation.

2.1 Enhanced Oil Recovery (EOR)

Enhanced oil recovery methods are all the techniques of recovering crude oil, condensate or natural gas liquids that requires the utilization of energy and/or materials which are extrinsic to the reservoir and which are not in conventional use by all segments of the crude oil producing industry (Sharp, 1975). The external materials / fluids such as water, steam, nitrogen, carbon dioxide, surfactants or polymers are injected in the reservoirs to recover the left behind oil, when oil flow from oil bearing section of the reservoir drops to an uneconomical level or ceases to flow from its own natural drive. These materials interact with oil through the number of mechanisms to mobilize it to a producing well.

Certain volumes of oil (residual oil) always remain “stranded” in the pore network of a hydrocarbon reservoir after primary recovery and secondary waterfloods. Any EOR method for the recovery of this left-behind oil proceeds by achieving the goal of either reducing mobility ratio (M) or increasing the capillary number (Ali Farouq and Thomas, 1996). These are discussed later in the section 2.3.4.2.

Oil from hydrocarbon bearing zones is initially produced by the "primary" methods that utilise natural drive (high fluid pressures) within the formation to drive reservoir oil into the wellbore and then to the surface production facilities. Solution gas drive, water drive (bottom-water or edge-water), gas cap drive, and gravity segregation constitutes the natural drive mechanisms. The primary recovery stage is completed either when the reservoir pressure is too low to maintain economical production rates, or when the ratio of gas (or water) to oil recovery is too high. The primary recovery factor (the ratio of oil produced to Original-Oil-In-Place -OOIP) typically ranges between 5 to 15% of OOIP (Green and Willhite, 1998a).

As production from oil-bearing reservoir matures after the primary production, oil recovery rate from the matured/depleted reservoir is enhanced by supplying external energy in the form of water (water flooding) or gases like hydrocarbon gas, Air/flue gas and CO_2 (gas flooding). These secondary pressure maintenance recovery methods yield recovery factor ranging from 30 to 50%.

Once an oil field exploited by primary and secondary recovery techniques, the left-behind oil could be produced by the application of tertiary recovery methods. These include chemical flooding, thermal stimulation, immiscible/miscible gas flooding and other recovery methods that use microbial, electrical heating, chemical leaching, mechanical (vibrating, horizontal drilling) means for enhancing oil production. These alter flow properties of crude oil and rock-fluid interactions in the reservoir to improve oil flow. Injection of surfactants, polymers or caustics is practised in the chemical recovery methods. Thermal methods comprise in-situ combustion and steam injection (cyclic huff 'n' puff injection, steam assisted gravity drainage-SAGD) mainly applied for the heavy. Non-thermal methods primarily involve the displacement of the oil by injecting a fluid into the reservoir by the mechanisms of solvent drive to achieve or approach miscibility, interfacial tension (IFT) reduction, and the viscosity change of the oil. These processes include the injection of CO_2, N_2, flue gas, hydrocarbon miscible methods. Tertiary recovery methods yield an additional recovery of 5 to 15% OOIP (Farouq Ali and Thomas, 1996; Lake *et al.*, 1992; Taber *et al.*, 1996).

2.2 Gas Injection EOR Methods

Gas injection is one of the oldest methods of enhanced oil recovery (early 1920's - CO_2 injection EOR in 1916) and remained a laboratory curiosity for the number of decades. Later in the early 1950s industry started first contact miscible projects by injecting propane, LPG, and natural gas. Low viscosity of these gases caused the problems of viscous fingering and solvent channelling aggravated by reservoir heterogeneity, resulting into low volumetric efficiencies. CO_2 again emerged in 1964 when CO_2 was injected in the Ritchie field on relatively smaller scale. Large CO_2 injection EOR project of SACROC Unit in the Permian Basin, Scurry County was started in 1972 as an immiscible secondary recovery. Since then numbers of CO_2 projects have been implemented in different basins all over the US, especially in the Permian basin. To increase the reservoir volume swept by the solvent bank, new methods like Water-Alternating-Gas (WAG), application of foaming agents and polymers were developed. CO_2 projects have been implemented in Canada (Weyburn project), Hungary, Turkey, Trinidad, and Brazil (Mathiassen, 2003; Moritis, 1995; Moritis, 2006; Moritis, 2008; Rao, 2001b). In the recent years, gas injection is increasingly being employed as a secondary or tertiary oil recovery process (Moritis, 2006; Moritis, 2008). Types of gases that can be injected for this purpose includes carbon dioxide (CO_2), hydrocarbon gas (Natural gas dry, sweet, mostly methane), air (nitrogen and oxygen), flue gas (exhaust from power plants, gas turbines, gas engines or heaters), nitrogen (N_2) and the associated gas (wet, sour, produced gas). The specific gas to be injected depends on the type of application (immiscible or miscible), depth of the injection, pressure and temperature at the target depth, oil composition, local availability and the transportation costs.

2.2.1 Classification of Gas Injection EOR Methods

Gas Injection EOR can be categorised based on the type of gas injected and the mode of gas injection in the hydrocarbon reservoirs (see **Table 2-1**). CO_2 injection is preferred over other types of gas injectants because of comparatively lower compression cost and lower minimum miscibility pressure (MMP) apart from the associated governmental tax benefits (such as Norway). Mode of gas injection (secondary or tertiary) depends on the particular field requirement (such as highly dipping reservoirs). Miscible or immiscible gas injection is function of depth of gas injection, oil composition, wettability characteristics of the formation matrix, heterogeneity and other parameters. Details of each of the EOR process are available elsewhere in the literature (Babadagli, 2005; Christensen et al., 1998; Green and Willhite, 1998b; Hunedi et al., 2005; Klins, 1984; Manrique et al., 2006; Mathiassen, 2003).

Table 2-1: Classification of gas injection EOR methods

Gas Injection EOR Methods		
Type of Gas Injected	***Mode of Gas Injection (****Secondary or Tertiary****)***	
1. Carbon Dioxide 2. Hydrocarbon gas (Natural Gas, Naphtha etc.) 3. Flue Gas 4. Air 5. Inert Gas (Nitrogen)	1. Continuous Gas Injection (CGI) 2. Water-Alternating-Gas (WAG) (Christensen et al., 1998) 3. Hybrid-WAG (Moritis, 1995) 4. Denver Unit WAG (DUWAG) (Moritis, 1995) 5. Simultaneous WAG (SWAG) (Moritis, 1995) 6. Crestal (gas cap) injection (Jayasekera and Goodyear, 2002) 7. Crestal gas recycle mode (Jayasekera and Goodyear, 2002) 8. Down-dip injection (with or without WAG) (Jayasekera and Goodyear, 2002) 9. Gas Assisted Gravity Drainage (GAGD) (Kulkarni and Rao, 2004; Rao, 2001a).	1. Horizontal injection 2. Vertical injection a. Reef type b. Dipping reservoirs

2.2.2 Choice of the Injection Gas

EOR surveys by Moritis (2006; 2008) indicated that hydrocarbon and CO_2 gases together constitute majors of the injection gases for gas injection EOR. However, the choice of injection gas is influenced by the location and the gas availability. In offshore fields, the availability of hydrocarbon (HC) gas directly from production wells, and wherever there doesn't exist the enough CO_2 storage and transportation facilities, the option of hydrocarbon gas injection becomes an inevitable and a feasible operation. In the recent years, CO_2 injection EOR method emerged as the most practised process in US (Moritis, 2006; Moritis, 2008), which could be attributed the increasing natural gas prices, availability of natural or manmade CO_2 sources and the increased need for reduction in greenhouse gas emissions in the 21^{st} century. CO_2 injection is a lucrative option for the revitalization of depleted reservoirs and hence recovering enormous trapped resource base.

The injection of CO_2 for the enhanced oil recovery causes lower injectivity problems due to its higher viscosity, compared to other common injectants. Also, the lower formation volume factor (FVF) of CO_2 and lower mobility ratio make the volumetric efficiency higher for CO_2 than other solvents and solvent mixtures. The CO_2 density is much closer to typical light oil density (under miscible conditions) than most of the other solvent injectants at the reservoir conditions, making CO_2 less prone to gravity segregation compared to N_2 and CH_4 under similar pressures. Another beneficial effect of CO_2 is the likelihood of higher gravity segregation in the high water saturation zones of the reservoir than in the higher oil saturation zones. This effect is also useful to target pockets and bypassed areas of oil and drain them effectively.

Moreover, CO_2 incurs lower compression costs for injection compared to the nitrogen, air and flue gas injection. It is cheaper than hydrocarbons, easy to handle and thus lowers the greenhouse gases upon subsurface injection. Choice between the immiscible or miscible flood is highly dependent on number of factors such as gas availability, depth of injection, density and viscosity constraints, extent and cost of reservoir repressurization required for field applications, operational and economic constraints, design factors etc. (Green and Willhite, 1998b; Kuo and Elliot, 2001).

With the obligations of *Kyoto protocol*, and worldwide echoes over the *global climatic changes*, it is imperative for the developed and developing signatory nations to mitigate atmospheric emissions. Flue gases and carbon dioxide are the major contributors to the greenhouse gas emission effects on the environment. Increasing price of natural gas, higher incremental oil recoveries using CO_2 and the additional benefit of permanent carbon sequestration favours CO_2 as injection gas while enhancing oil and gas recovery.

2.2.3 CO_2 EOR: Mechanisms and Processes

Considering high solubility, about 700-800 scf/bbl, (Holm and Josendal, 1974) and the wide range of suitability in the hydrocarbon reservoirs compared to other gas injectants, CO_2 has potential to replace the expensive and greener hydrocarbon (C_2-C_3) injection gases (Novosad, 1996). Once injected in the target reservoir zone, CO_2 develops mutual solubility to form a single, homogeneous phase, leading to the swelling of the reservoir oil, so the expansion in the volume of the oil. Swelling factor is inversely proportional to the residual oil saturation and can be as high as 1.3 to 1.4. This results in the oil viscosity reduction and the water viscosity rise. This favourably improves the mobility ratio of the EOR process.

Whether any process is immiscible or miscible is decided by a parameter called minimum miscibility pressure (MMP). It is the lowest pressure at which the CO_2-containing injection fluid can develop miscibility with the reservoir crude oil at reservoir temperature (Mungan, 1981). It can be determined by either experimental slim tube apparatus Yellig and Metcalfe (1980) or using correlations (Alston et al., 1985; Emera and Sarma, 2005a; Glasø, 1985; Holm and Josendal, 1974; Sebastian et al., 1985). Above MMP, CO_2 develops miscibility with the reservoir oil. Miscibility is defined as the ability of two or more substances to form a single homogeneous phase when mixed in all proportions (Holm and Josendal, 1974). In other words, miscibility is the development of a zero interfacial tension system (Thomas *et al.*, 1995a).

In the intermediate pressure range below MMP, CO_2 can extract or vaporize, even intermediate and heavier hydrocarbon fractions, from reservoir oil, thus improving sweep efficiency, so the oil recovery. Hydrocarbon extraction mechanism is evidenced by the oil shrinkage, mainly in the intermediate pressure range below thermodynamic MMP. Even if it does not sufficiently extract components from the reservoir oil to develop miscibility, an immiscible CO_2 flooding proceeds with the mechanism of the swelling and viscosity reduction (Holm and Josendal, 1974).

Miscible CO_2 flooding works towards the elimination of capillary forces (that inhibit oil flow through the interconnected pores of formation matrix) between the reservoir fluid and CO_2 which may further reduce the oil saturation below the residual oil saturation, thus yielding more recoverable oil. CO_2 achieve miscibility at pressures in the range of only 1450 to 4351 psia (10 to 30 MPa), which is lower than the ones required for N_2 and hydrocarbon gases (Green and Willhite, 1998a).

Miscibility between fluids can be achieved through the development of either the *first contact miscibility* or *multi-contact miscibility*. If carbon dioxide is first contact miscible with a reservoir fluid then it will mix in all proportions as soon as the two fluids are in contact one another, no matter what amounts of each component is used for the mixture (Stalkup Jr., 1983). Multi-contact miscibility can be achieved through two techniques; the vaporising gas drive and condensing gas-drive (Bradley, 1987; Holm and Josendal, 1982). During vaporising-gas drive, when a lean gas is injected, the lighter components of the reservoir fluid (methane through to hexane) from the leading edge of the injection gas are first vaporised, which is continued until it is enriched so as to be miscible with the virgin reservoir fluid. In a condensing-gas drive, an enriched gas with

C2+ components is injected and the heavier components are condensed into the oil. When the oil becomes sufficiently enriched with these light hydrocarbon components it becomes miscible with the injection gas. In the condensing gas drive miscibility is achieved at the trailing edge. The enriched reservoir fluid becomes miscible with fresh injection gas.

2.2.4 Summary of the Worldwide CO_2-EOR Projects

Out of the world's existing left-behind oil (2 trillion barrels) in the matured reservoirs, 592 billion barrels of the oil from the matured reservoirs could be recovered by employing Enhanced Oil Recovery (EOR) methods (Kuuskraa, 2006). All over the world 352 EOR projects are operational producing currently amounts to 2.3 MM BOPD (Moritis, 2008). It represents 3.3% of the total oil production. Projections indicate that it will reach 30 MM BOPD by year 2020.

World EOR scene is dominated by China followed by Venezuela with thermal injection as most practised EOR method. Polymer EOR is the next preferred method. CO_2 injection (mostly miscible) is major EOR process in US contributing to 98% of the total EOR projects (see **Table 2-2**). CO_2 EOR is still not favourable outside US, could be because of lack of the CO2 availability and necessary infrastructure (Moritis, 2008).

Table 2-2: Status of World CO_2-EOR projects

Location	Number	Project BOPD	EOR BOPD
World	125	373,500	285,100
U.S.	105	323,100	249,700
Canada	8	43,000	28,000

US is leading in gas injection projects, mainly CO_2 injection, for enhancing oil recovery with the well developed infrastructure of transportation pipeline and the available CO_2 resources. Out of the present 88 CO_2 EOR projects in the world, 82 CO_2 EOR projects are currently operational in US alone (Moritis, 2008). CO_2 flooding is among the most widely used EOR methods, especially in US because of its availability from either natural resources or man-made industrial resource. Carbon dioxide needed for oil recovery purposes is directly available from either the naturally occurring CO_2 reservoirs in the eastern Rocky Mountains and Mississippi (Martin and Taber, 1992), the McElmo Dome (world's largest known accumulation of nearly pure CO_2, almost 30 million m^3/day), the Sheep Mountain in south central Colorado, the Bravo Dome of the New Mexico (Holtz *et al.*, 1999), the Jackson Dome; or the industrial source comprising Val Verde gas plants, the LeBarge gas plant, the Dakota coal gasification plant, the Antrim gas plant and the Enid fertilizer plant (**Figure 2-1**).

North Sea projects review indicates that the Sleipner, Ekofisk, Forties, Brage and Gullfaks fields are being subjected to the miscible CO_2 EOR studies and CO_2 EOR application would continue to grow in future (Mathiassen, 2003).

2.2.5 Australian CO_2-EOR Potential

Australia's commercial oil and condensate reserves are estimated at 2.0 billion barrels while estimated gas reserves are 49.5 trillion cubic feet of gas (Freij-Ayoub *et al.*, 2006). Currently twelve sedimentary basins of Australia (**Figure 2-1**) produce 500,000 barrels per day of crude oil. It is expected to maintain the current production level until 2009 and decline thereafter. On the other hand, the demand is expected to increase from more than 800,000 barrels per day in 2009-10 to 1,200,000 in 2029-30 (**Figure 2-2**).

NOTE:
These figures are included on page 16 of the print copy of the thesis held in the University of Adelaide Library.

Figure 2-1: CO_2 EOR resources in US (left) depicting current active projects (Moritis, 2008); and in Australia outlining the potential for CO_2 EOR (Bradshaw *et al.*, 2004)

Oil producing fields of Gippsland sedimentary basin and Western Australian margin are expected to be depleted in the next 10-20 years time (Cook, 2006). These are the potential sites of CO_2 EOR projects in addition to the Cooper basin and Dongara and Gorgon field in conjunction with the huge permanent CO_2 sequestration possibilities. Bradshaw (2006) indicated that the enhanced oil recovery methods, if employed, have potential to recover 1.131 billion barrels of oil while safely sequestering 600 MT of carbon dioxide. Enhanced oil recovery while sequestering CO_2 holds good promise to mitigate the increasing oil demand.

NOTE:
This figure is included on page 17 of the print copy of the thesis held in the University of Adelaide Library.

Figure 2-2: Oil demand and Supply in Australia (Lund, 2006)

Enormous CO_2 EOR potential exists in Australia with the availability of huge CO_2 resources in the form of coal fired plant, power generation plants and most important the natural reservoir with high CO_2 content. Incremental oil from nearly 17 eligible onshore and 20 offshore reservoirs can be recovered from Gippsland, Carnarvon, Cooper, Eromanga, Surat, Perth and Bonaparte basins of Australia, through application of miscible and immiscible CO_2 EOR floods with the disposal potential of about 19.3 trillion cubic feet from nearby CO_2 source points (Burrup gas plant - northern basins, Gorgon CO_2 via Barrow island. etc). Dongara field estimated to have 100 million barrels of oil-in-place in a depleted reservoir.

Sequestration of CO_2 in Australia currently yields no economic benefit in jurisdictions without carbon emission restrictions, future regulations of CO_2 emission in the context of climate-change policies may generate such benefits if EOR projects are allowed to earn credits for the units of CO_2 sequestered. This would then maximise the combined revenue streams from both oil production and CO_2 sequestration, net of CO_2 purchase and recycling costs.

2.3 CO_2-Assisted Gravity Drainage EOR Process

In the horizontal mode continuous gas injection (CGI) and water-alternating-gas (WAG) EOR processes, the severe gravity segregation (arising from the density differences between the injection and reservoir fluids) leading the viscous instabilities, so the viscous fingering, water coning often results in the poor volumetric sweep efficiency (Christensen *et al.*, 1998). CO_2-assisted gravity drainage EOR process offers promise to overcome these mechanistic problems thereby taking into advantage of the density dependent gravity separation of the fluids in the reservoir. The gas-cap gas injection and downdip oil production in a controlled manner suppresses the fingers of solvent and sweep-out is improved. In spite of the slow oil-recovery rate, the oil production of 87% (King and Stiles, 1970) to 95% OOIP in gas injection field projects and 100% in inert gas injection laboratory corefloods are observed (Ren *et al.*, 2003). Although the most common application of gravity drainage EOR process is in the dipping or reef type reservoirs, the current study focuses on the non-dipping (horizontal type) reservoir.

2.3.1 Gravity Drainage: Process Definition and Classification

Primarily gravity drainage processes can be classified as the free-fall or pure, the forced gravity drainage process and the simulated gravity drainage by centrifuging, which exists only in laboratories (Schechter and Guo, 1996) (**Table 2-3**). First two are the only considerations in this part of the discussion.

Oil recovery through gravity drainage especially by CO_2 injection is a process wherein the gas zone pressure behind CO_2 floodfront is maintained constant. In other words, there exists no pressure differential in the gas cap (Cardwell and Parsons, 1949a). It is categorised as a ‘free-fall gravity drainage process’ (Cardwell and Parsons, 1949b; Dumore, 1964a; Dumore and Schols, 1974; Dykstra, 1978; Hagoort, 1980; Luan, 1994; Nenniger and Storrow, 1958; Pavone et al., 1989). Gravity head is not opposed by the pressure gradients. During EOR process, the only driving force is the gravity without any external force. According to Hagoort (1980), gravity drainage is a process in which gravity acts as a main driving force and where gas replaces voidage volume.

Table 2-3: Classification of gravity drainage processes

Gravity Drainage process

Mechanism	**Mode of gas injection**	**Gas injection stage**
- Free-fall	- Immiscible	- Secondary
- Forced	- Miscible	- Tertiary

Ideal system would be the one where oil is produced under free-fall (pure) gravity drainage, giving highest possible recovery at the most efficient rate as compared to the forced gravity drainage performance (Dastyari *et al.*, 2005; Muskat, 1949; Saputelli *et al.*, 1998). Gas breakthrough is not desired in free gravity drainage process (Kulkarni, 2005; Mahmoud, 2006).

There seems to be no clear and straightforward definition of the forced gravity drainage in the literature. This is due to the conceptual difference of the mechanisms amongst various authors.

When there is a finite but small (close to zero) pressure differential across the gas-oil interface, average reservoir pressure remains constant. This could further imply that the pressure in gas zone would be constant. This, in turn, would satisfy the Cardwell and Parsons criteria of free fall gravity drainage. Understandably the injection gas breakthrough is not desired in vertically downward gravity based drainage because of the balance of the viscous and gravity forces. Even after injection gas floodfront arrival in the drainage area of the producing wells and injection gas breakthrough in the producing wells, the reservoir pressure should remain constant.

It has been proven that oil-film flow is characterised by the occurrence of the gravity drainage mechanism after CO_2-breakthrough. When reservoir pressure remains constant in this case, it would suffice to the Cardwell Parson's free gravity drainage mechanism. In this situation, the statement "CO_2 breakthrough is not desired in free gravity drainage process" should not be attached to CO_2-assisted gravity drainage EOR process.

On the other hand, forced gravity drainage is a process wherein the injection gas breakthrough is desired before gas-floodfront reaching the drainage area of the producing wells. When this happens the oil recovery mechanism until gas flood-front arrival (GOC) would be viscous displacement, typifying the Buckley-Leverett (B-L) type of displacement. Even the existence of small pressure gradient across the gas-oil contact (or injection gas flood-front) would make B-L theory applicable (See section 2.3.3). Conversely this hypothesis implies the forced gravity drainage exists only before arrival of the injection gas flood-front in the drainage area of producing wells and its breakthrough. After CO_2 (injection gas) breakthrough, if the reservoir pressure remains nearly constant or the difference of pressure across gas-oil contact is very close to zero, Cardwell and Parson's gravity drainage criteria would be satisfied to prevail the free gravity drainage mechanism.

Gravity drainage EOR process can further be classified on the basis of the mode of gas injection (secondary or tertiary), type of the geological structures (pinnacle reef type, dipping and horizontal reservoirs) in which it is being implemented, miscible and immiscible (below or above minimum miscibility pressure).

Gravity drainage oil recovery involves various theories, fundamental concepts and the number of the operational interacting parameters. These will be discussed in detail after introduction of the CO_2-assisted gravity drainage EOR process.

2.3.2 Process Description

CO_2-Assisted Gravity drainage EOR process is a top-down process in which gas is injected in the gas-cap through vertical or horizontal wells at a rate lower than the critical rate (**Figure 2-3**). Critical rate is the rate at which injection gas fingers through oil zone (viscous instabilities) leading to its premature breakthrough at the production wells. Injected gas segregates and creates a gas-oil interface. Controlled oil production is started through horizontal wells placed at the bottom of the oil zone such that the voidage created by oil withdrawal (in addition to minor dissolved volumes) is replaced by the equivalent CO_2 injection volume. When this happens, pressure differential across the gas-cap and oil zone (that is GOC) stay at or close to zero implying that the pressure in gas zone behind the CO_2 floodfront would be constant (Cardwell and Parsons, 1949b). This helps to maintain the reservoir pressure nearly constant. Under these conditions, the solution gas saturation is kept at sufficiently lower values due to its minimum liberation from oil. Thus oil viscosity remains at lower values minimizing the oil shrinkage. Moreover, CO_2 injection recompresses some of the dispersed gas in oil zone. Overall effect is that the oil gets dispersed and begins to fall under gravity. On the other hand, gas, due to lower density, begins to flow upward countercurrent to the downward oil drainage. Higher the density difference between the gas and the reservoir oil, more effective will be the gravity drainage. Oil is drained from upstructure high pressure zone under gravity downward towards low pressure horizontal wells, resulting into lowering of the gas-oil-contact, GOC (**Figure 2-3**). If GOC is maintained as horizontal as possible, CO_2-assisted gravity drainage mechanism yields optimum oil recovery.

NOTE:
This figure is included on page 21 of the print copy of the thesis held in the University of Adelaide Library.

Figure 2-3: Conceptual CO_2-Assisted Gravity Drainage process (Jadhawar and Sarma, 2008)

During the occurrence of this process, oil displacement comes from two steps. First, gas invades the originally oil-saturated oil bearing zone as the GOC moves downdip because of oil production farther downdip. Second, oil drains vertically downward through the gas-invaded region (behind GOC) and forms a thin layer with high oil saturation (between the gas and water phases) that drains vertically downward to the oil column. In this process, larger and larger portions of the reservoir are swept by the advancing front without any increase in water saturation in the reservoir, thus maximizing the volumetric sweep efficiency. The interface between the advancing gas (injected) phase and the withdrawing oil phase is kept as close to horizontal as possible (stabilized by gravity forces) thereby balancing the gas injection volumes and producing oil volumes. Gravity segregation delays or even eliminate CO_2 breakthrough at producer as well as prevents gas phase from competing for flow with oil.

Precise control of the gas injection rate and the oil production rate is essential for the success of the CO_2-assisted gravity drainage EOR process. A gas velocity at which this counter current gas-oil flow occurs to segregate the oil and gas, and gravity drainage to begin, largely depends on the oil and gas density, and the rates of gas injection and oil production, the balance of the gravity-capillary-viscous forces, relative saturations of the oil, water and gas, vertical permeability, heterogeneities, amount of the dip (if exists) and number of other operational parameters. Apart from this, application of this process in the immiscible and miscible mode during the secondary and tertiary producing life of the reservoirs is associated with various mechanistic considerations.

2.3.3 Gravity Drainage: Fundamental Concepts and Models

Gravity forces exists during every stage of the producing life of the reservoir whether it is the primary phase of the oil production through gas cap expansion or secondary or tertiary stage of gas injection or during stripper stage of the gas injection in the volumetric reservoirs. Idealised and the most efficient gravity drainage oil production would be the one wherein no free gas is allowed to liberate out of the oil thereby maintaining the reservoir pressure above its bubble point or maintaining the GOR at the current levels or through the partial repressurization of the saturated reservoir (Muskat, 1949). Field and laboratory investigations have shown that the gravity drainage, under certain conditions, can yield very high oil recoveries. It is also recognized that gravity drainage is one of the most important mechanisms of the developing oil field.

Many authors used Buckley-Leverett's (B-L) classical theory (1942), Darcy's law, relative permeability, continuity equation, and decline curve analysis (material balance equation) to study the gravity drainage process and suggested it to be a displacement mechanism (Hagoort, 1980; Li *et al.*, 2000; Terwillinger *et al.*, 1951). Buckley-Leverett theory suggests that after the displacing phase breakthrough, the oil production rate changes (generally decreases) in proportional to its saturation. Since the oil saturation decreases continuously after breakthrough the oil production rate drops with time. If capillary pressure effects are included, then the size of the oil bank increases with the decrease in oil saturation with the proportional decrease of the oil saturation from leading edge to the trailing edge. Buckley-Leverett also acknowledged that slow rate gravity drainage phenomenon is the 'mechanism in which no other forces in the reservoir, except gravity, are available to expel the residual oil'.

However, according to Muskat (1949), although the classical theories of Darcy and Buckley-Leverett are relevant, the decline curve equation, that is applicable to most displacements, represent only the thermodynamic equilibrium between the net liquid and gas phases. It does not itself provide any information about the gravity drainage phenomena, therefore cannot characterise gravity drainage process. Instead, gravity drainage can be modelled by conservation equation, Darcy law and the capillary pressure relationship (Cardwell and Parsons, 1949b; Li et al., 2000; Pedrera et al., 2002; Richardson et al., 1989). Two assumptions of the Buckley-Leverett theory, mainly no mass transfer between the phases and the phases to be incompressible, hypothesized to be limiting factor in its application to CO_2-assisted gravity drainage floods (Kulkarni and Rao, 2006a). Unlike forced gravity drainage, free-fall gravity drainage cannot modelled using a Buckley-Leverett approach because flow rate is not specified (Schechter and Guo, 1996).

Gravity drainage analytical theory put forward by Cardwell and Parsons (1949b) is based on the assumption of the pressure equilibrium within the vertical sand pack column draining a single liquid phase. The combined effects of capillary retention and low relative permeability at lower saturations were indirectly accounted with the inclusion of the saturation-permeability relationship. Their Analytical treatment concluded that the rate of liquid drainage recovery is equal to the percentage of the total area above the height versus the saturation curve, implying that the free gas zone do not act to provide downward force on the gas-liquid interface. Cardwell and Parsons (1949b) could not solve the non-linear equation obtained upon the exclusion of the capillary effects with respect to saturation and the permeability, which made the analysis tractable and uncertain quantitative significance of the theory (Muskat, 1949). A Similar gravity drainage model was proposed by Terwillinger *et al.* (1951) that was based on the immiscible B-L displacement theory and the 'shock-front' technique (using fractional flow equations (Welge, 1952)) to match the gravity drainage laboratory experimental performance (production and fluid saturation distribution as functions of time and distance) under controlled flow rates (constant rate gas injection) and static capillary pressure distribution. They showed that the shock front was smeared out into a capillary transition zone whose shape remains stationary as the front progresses.

Nenniger and Storrow (1958) derived an approximate series solutions based on the oil film flow theory to match the gravity drainage rates obtained in his experiments in highly permeable pack of glass beads. Experimental gravity drainage oil recovery studies of Dumore and Schols (1974) lead to the development of a drainage capillary function. Dykstra (1978) included capillary pressure in the equation, that was lacking in the Cardwell and Parsons (1949b) theory, and derived a mathematical model to match some of the experimental data at the assumed permeability values. Hagoort (1980) theoretically analyzed the efficiencies of the vertical gravity drainage process using both the Buckley-Leverett theory (1942) and Cardwell and Parsons (1949b) theories and derived a mathematical model using Leverett J function for the inclusion of the capillary pressure. Due to the non-linearity of the governing saturation equation, its analytical solution again was not feasible.

Using the theories of Cardwell and Parsons (1949b) and Welge (1952) along with the Dietz (1953) frontal stability criterion, Richardson and Blackwell (1971) proposed mathematical approach to predict the ultimate gravity drainage oil recoveries when the injection rate is less than one-half of the Dietz's (1953) critical rate. They simulated variety of the variety of conditions for this purpose such as vertical flow conditions, water under running viscous oils, gravity segregation of water banks in gas caps, and for control of coning by oil injection. Pavone *et al.* (1989) and Luan (1994) revisited the 'demarcator' concept introduced by Cardwell and Parsons (1948) to generate analytical models for gravity drainage in low IFT conditions and fractured reservoir systems, respectively. They assumed the 'demarcator' (region of minimum gas saturation) (Cardwell and Parsons, 1948) at the bottom (or outlet) of the reservoir systems and showed that it improves the model prediction.

Through the wide range of laboratory experimentations (molecular level to glass bead packs) in water-wet system, Blunt *et al.* (1994) suggested that optimum gravity drainage oil recovery efficiency is obtained in three phase tertiary flood when oil spontaneously spreads as a layer between water and gas under positive spreading coefficient conditions. Li and Horne (2003) presented an empirical model to match and predict ultimate gravity drainage (free-fall) oil recovery obtained through the laboratory experiments, numerical and field data.

Acknowledgement of Cardwell and Parsons (1949b) that the Buckley-Leverett theory could be applicable with an existence of only a slight pressure gradient in the gas zone leads to the non-distinction between the displacement and drainage (Kulkarni and Rao, 2006a). In spite of this, it is possible to achieve a zero pressure gradient in the reservoir thereby maintaining the low rate constant gas injection rate and controlled well pressure. Based on the experimental results on the secondary mode gas injection, Kulkarni and Rao (2006a) further hypothesized that the B-L theory could only be applicable to model gravity until gas breakthrough. They used Richardson and Blackwell (1971) model and Li and Horne (2003) model to predict ultimate recoveries and the gravity drainage oil production rates respectively. Further modification in Li and Horne (2003) model was carried out to account for the average system injection pressure. A fully compositional simulation results on the laboratory experimental based fractured reservoir model by Darvish *et al.* (2004) also shown the presence of the two mechanisms of gravity drainage and extraction in the forced miscible gravity drainage process.

Since gravity drainage is a gravity-dominated process and the only resistance is the capillary pressure force, the oil production depends significantly on the properties of the porous media, fluids, and their interactions. These include relative permeability of the porous media, pore structure, matrix sizes, fluid viscosities, initial water saturation, the wettability of the rock-fluid systems, and the interfacial tension. It is worthwhile to mention here that the gas injection, operations (so the reservoir pressure maintenance operations) in real gas-oil-water systems always results in finite pressure gradient across the gas-liquid flood-front.

2.3.4 Operational Parameters affecting CO_2-Assisted Gravity Drainage EOR Processes

A permeable rock within the porous media requires that the pore throats be interconnected and when there exists a pressure differential across the pore structure, reservoir fluids will flow through them. Various characteristic properties of the rock-system (porosity, permeability, geometry and heterogeneity-anisotropy), interacting fluids (density contrast, viscosity ratio, interfacial tensions-spreading coefficients) and the rock-fluids (wettability, adsorption and fluid configurations) with the applied external conditions (like initial gas, water and oil distribution, gas injection and oil production rates) leads to the generation and interplay of viscous, capillary and gravity forces. These forces greatly influence the relative permeability, capillary pressure, residual saturations and the fluid distributions during the entire EOR operations. It is therefore necessary to discuss the phenomena occurring as a result of the above mentioned factors during the CO_2-assisted gravity drainage EOR process under investigation. A brief literature review of the most important process controlling parameters is presented in this section.

2.3.4.1 Gas injection and oil production rates

At a given production rate, the higher gas injection rates may result in the development of the viscous fingers in the oil phase leading to unstable food-front and the premature gas breakthrough. Unfavorable mobility ratio during gas injection process always leads to the problems of density-based gravity segregation and viscous fingering, especially in the horizontal mode continuous gas injection and the water-alternating-gas (WAG) methods of enhanced oil recovery(Green and Willhite, 1998b). During top-down gravity drainage process, upward gravity forces tend to suppress the downward developed viscous fingers arising from the gas-cap gas injection at a specific rate. Oil can propel in any direction by gas injection at high velocity (rate). At lower gas velocity, oil can flow downward under the effect of gravity displacing the gas and gas to flow upwards. A gas velocity at which the counter-current flow of gas and oil occur is called ‘critical gas velocity or injection rate’. Above this rate, the gas-drive conditions prevail and below exists the gravity drainage wherein the gas and oil will segregate under the prevalent restricted viscous forces. Downward flow of oil will be greater at slower upward flow of gas (Dumore, 1964b; Lewis, 1944).

Critical gas injection rate: Models

Muskat (1949) pointed out that the material-balance based thermodynamic equilibrium methods do not provide any information about the action of gravity drainage. He emphasized that the force of gravity itself is a dynamical phenomenon capable of yielding downward oil gravity drainage at the maximum rate (critical velocity, u_c) given by equation 2.1 (**Table 2-4**).

Terwillinger *et al.* (1951) presented the results of the experimental investigations of constant pressure gravity drainage in a vertical linear homogeneous sand pack and showed that recovery to gas breakthrough by gravity drainage is inversely proportional to the production (or injection) rate. They termed “maximum theoretical rate of gravity drainage” as a criterion of efficiency in gravity drainage reservoirs and defined as “the rate of production from a 100 percent liquid saturated system under a flow gradient equal to the gravity gradient or static pressure gradient differential between oil and gas due to density difference”. This is represented by the gravity drainage reference rate (GRR) as equation 2.2 (**Table 2-4**). In other words the critical rate of gravity drainage if exceeds the maximum rate of gravity drainage, the oil drained by its own weight will be relatively small and gas drive will dominate. Conversely this equation doesn't account for the displacing fluid viscosity (gas) apart from the relative permeability and the displacing fluid viscosity while estimating the critical rate. However, literature review indicated that this equation formed a theoretical basis for the later researchers.

Terwillinger *et al.* (1951) also put forward a model based on the Buckley-Leverett theory and 'Shock front' theory of Welge (1952) to match the steady state gravity drainage experiments in homogeneous porous medium. An accurate prediction of gravity drainage for the system under consideration was provided.

Hill (1952) presented very interesting and noteworthy experiments for both gravity-stabilized viscous fingering in vertical downflow and viscous stabilization of a gravitationally unstable interface (for velocities above critical velocity) when light, less viscous fluid is displaced in vertical downward direction by a heavy, more viscous fluid. In case of the gravity drainage oil recovery assisted by the injected gas, previous phenomenon is applicable in this study. His model based on the experiments accounted for the viscosity of the displacing fluid (injection gas) and showed that the difference of viscosity between the displacing and the displaced fluid tends to cause instability at the interface. This viscosity difference shown to be inversely affecting the critical velocity (u_c) as depicted by the equation 2.3 (**Table 2-4**).

With the assumptions of the homogeneous porous medium, vertical equilibrium of oil and water, piston displacement of oil by water, no oil-water capillary pressures, and that the compressibility effects of rock and fluid may be neglected, Dietz (1953)proposed an equation based on the calculation of the pressures along the gas-water interface in vertical and along the direction of the flow in a dipping reservoir. His stability criteria relating the angle of the oil-water interface to the angle of the layer (β being greater than zero) is represented by equation 2.4 (**Table 2-4**). This criterion can also be applied to the gas-oil displacement. A tilted plane interface occurs between the solvent and oil occurs when the displacement velocity is less than the maximum rate of the allowable oil displacement, called "critical rate" ($u_c = q_c/A$), that can be estimated by equations in **Table 2-4**.

Dumore (1964a) considered the molecular diffusion and mixing in the transition zone to outline the stability criteria of the gas-oil flood-front. His criterion of stable displacement for a horizontal interface was based on the pressure gradient in the injection solvent part of the reservoir being less than that of the existing in oil zone. In a vertical downward miscible displacement, the rate of gas injection at which injected gas will not finger through the producing zone can be given by a critical rate equation 2.5 (**Table 2-4**).

Table 2-4: Summary of the gas injection rate (critical and stable) equations

Eq. No.	Author	Correlation	Parameters
2.1	Muskat (1949)	$u_c = \frac{k_o \Delta\rho g \sin\theta}{\mu_o}$	k_o: Relative permeability to oil (Darcy), $\Delta\rho$: Density difference between the oil and gas, θ: Dip angle, μ_o: viscosity of oil.
2.2	Terwillinger et al. (1951)	$GRR = \frac{k_L A}{\mu_L} g\Delta\rho \sin\alpha$	k_L: permeability to the liquid to 100% liquid saturation, A: Cross sectional area of the reservoir, g: Gravitational constant, $\Delta\rho$: Density difference between oil and gas, α: Dip angle
2.3	Hill (1952)	$u_c = \frac{g}{k}\left(\frac{\rho_o - \rho_s}{\mu_o - \mu_s}\right)$	K: Effective permeability to the liquid to 100% liquid saturation, g: Gravitational constant, μ_o: viscosity of oil, μ_o: viscosity of solvent
2.4	Dietz (1953)	$\tan\beta = \frac{1-M_e}{M_e.N_{ge}\text{Cos}\alpha} + \tan\alpha$ $u_c = 0.0439\frac{k(\rho_o - \rho_s)}{\left(\frac{\mu_o}{k_{ro}} - \frac{\mu_s}{k_{rg}}\right)}\sin\alpha$ $u_c = 0.0439\frac{k_o(\rho_o - \rho_s)}{\mu_o\left(1-\frac{1}{M}\right)}\sin\alpha$	M: Mobility Ratio, N_{ge}: Gravitational force, u_c: Darcy velocity, ft/day, k_o: oil permeability, Darcy, ρ_o & ρ_g = oil and gas density , lb/cu ft, μo, μg = oil and viscosities, cP
2.5	Dumore (1964a)	$u_c = 0.0439\left(\frac{\rho_o - \rho_s}{\mu_o - \mu_s}\right)kg$ $u_{st} = 0.0439\frac{(\rho_o - \rho_s)}{\mu_o(\ln\mu_o - \ln\mu_s)}k\sin\alpha$ $\frac{u_{st}}{u_c} = \frac{\left(1-\frac{\mu_s}{\mu_o}\right)}{\ln(\frac{\mu_o}{\mu_g})} = \frac{\left(1-\frac{1}{M}\right)}{\ln(M)}$	u_c: Critical volumetric velocity (cm3/cm3.sec) of the gas injection, cm/sec, ρ_o & ρ_s : oil and solvent density , lb/cu ft, μ_o & μ_s: oil and solvent viscosities, cP, k: absolute permeability, Darcy, g: gravitational constant, $M = \frac{\mu_o}{\mu_s}$
2.6	Slobod and Howlett (1964)	$u_c = \frac{kg}{j}\left(\frac{\rho_o - \rho_s}{\mu_o - \mu_s}\right)$	j_m: Porosity of the medium
2.7	Cardenas et al. (1981).	$Vc = 8.473\times10^{-4}\frac{k_m \sin\alpha(\rho_2 - \rho_1)}{j_m(\mu_2 - \mu_1)}$	u_c: Critical volumetric velocity of gas injection, cm/sec, ρ_2, ρ_1: oil & solvent density, lb/cu ft, μ_2, μ_1: oil & solvent viscosities, cP, k_m: absolute permeability, mD

At the oil recovery rates lower than the stable rates, each layer of the transition zone will be completely stable with respect to each successive layer. The transition zone may not be stable if the displacement rates fall between the stable and critical velocity, leading to the growing unstable gravity tongue being superimposed on the tilted plane interface. Stable velocity of the gas-oil interface is estimated by equation

Slobod and Howlett (1964) conducted the experimental investigations to study the variables impacting the length of the mixing zone developed between the displaced and the displacing zone in a gravity dominated process. Their work concluded that length of the transition zone is a function of the relative magnitude of the viscous to gravity forces. Porosity (ϕ) term was introduced in the critical rate estimation equation 2.6 (**Table 2-4**).

Miscible coreflood experiments of Brigham (1974) to investigate mixing in the short cores estimated the stability of the coreflood-front. Length of mixing zone leading to the effective mixing coefficient (α_e) is used as a parameter to estimate floodfront stability.

For the estimation of critical velocity under the tertiary multi-contact miscible flooding in the Bay St Elaine project, a modified Dumore equation was presented by Cardenas *et al.* (1981). For a dipping reservoir, the critical velocity (m/day) is given by equation 2.7 (**Table 2-4**).

Review of all the above models suggests that the model by Muskat (1949) forms basis for the next generation of the frontal stability criteria through the variation of the some of the parameters including viscosity, porosity, and the effective cross sectional area. The equation proposed by Dumore (1964a) is the most widely used model even if new models are available (Kulkarni and Rao, 2006a; Muggeridge *et al.*, 2005; Pedrera *et al.*, 2002; Piper and Morse, 1982; Skauge and Paulsen, 2000).

Other Considerations

As hypothesized by Dumore (1952), stable gas injection rates would result in the no viscous fingers so the stable flood-front, thus providing stable gravity drainage system. During the occurrence of EOR process, simultaneous oil production also leads to the destabilization of the system owing to three phase movements. In turn, it results in the reduction or increase in the reservoir pressure. If the volumes of the oil production are replaced by the volume of the gas injection, then the reservoir pressure variation can be minimized or can be maintained constant. Moreover, this voidage balance if followed would also provide stable and horizontal gas-oil front optimizing gravity drainage oil recovery. At what rate this balance should be achieved is the matter of choice based on the process and operational requirements. Investigations carried out in this study are based on the principle of voidage balance.

2.3.4.2 Gravity vs. viscous vs. capillary force effects

Gravity forces are recognized to play an important role at nearly every stage of the producing life of the reservoir, whether it is primary depletion, secondary water or gas injection schemes or tertiary enhanced or improved oil recovery methods. They always compete with the viscous (flow rate per unit area) forces and the capillary (ratio of the fluid/fluid forces to the grain size) forces occurring in porous media (Muskat, 1949).

Injection gases at the reservoir conditions have densities generally one-third or less than that of oil. On the other hand, gases have viscosities about 0.02 cP, whereas oil viscosities generally range from the 0.5 to tens of centipoises. During gas injection operations for enhancing the oil recovery, gases are generally one to two orders of magnitude less viscous than the oil (Stalkup Jr., 1983). Because of these two factors gas when flowing tends to segregate to the top of the reservoir while oil exhibits tendency to segregate downwards to the bottom of the reservoir. Gases being considerably lighter than the reservoir oil, buoyancy forces arising from these density differences greatly influence the outcome of gas flooding processes. Less dense fluid gets trapped in the producing zone, further diminishing the oil recovery performance.

Relative mobility (ratio of effective permeability and the viscosity) of the displacing gases and reservoir fluids being displaced, define viscous force effects on the proceeding EOR operations. Fluids mobility is related to its flow resistance in a reservoir rock at a given saturation of that fluid. CO_2 have very low viscosity compared to the reservoir fluids at the reservoir conditions; so exhibits very high mobility characteristics (Ho and Webb, 2006). When CO_2 is injected at irreducible water saturations, mobility ratio becomes simply the ratio of the oil and solvent viscosities in a homogeneous porous medium and is always greater than unity ($M>1$). When this happens, mobility ratio becomes unfavourable leading to the formation of the viscous fingers, unstable flood front, bypassing the reservoir oil, hence further reducing the efficiency of the gas-oil displacement. Displacement efficiency approaches to unity when mobility ratio is less than one ($M<1$) and is deemed as favourable. In real reservoir situations, the reservoir heterogeneity and the gas-oil density difference further enhance the viscous fingering phenomenon leading to the perturbation growth.

At pore level, capillary forces oppose the gravity forces during gas floods, further reducing the displacement efficiency. Pore scale capillary force effects are generally accounted by capillary number, N_C, which exhibits the ratio of the viscous to capillary forces. In gravity drainage processes, higher N_C works towards achieving the optimum gravity drainage oil recovery (Grattoni *et al.*, 2001).

Gravity can be used as an advantage to overcome these impeding factors to improve the sweep and displacement efficiency in a gravity stable gas injection process (Rao, 2006a). In this process, the gas-oil displacements are occurring vertically with the gas displacing oil downward, the gravity works to stabilize the gas-oil floodfront. Gravity segregation is further aided by the low viscosity of oil, high permeability to oil, high formation dips, and high density gradients favouring the drainage of oil by gas in the reservoir rock. In gravity stable injections, the beneficial gravity segregation effects aid the gravity forces to increase reservoir sweep and oil recoveries. Furthermore, the capillary imbibitions into low permeability zones (in water-wet reservoirs) and miscibility development would be beneficial to oil recovery. The effect of the viscous forces, which result in bypassing of the low permeability regions in the reservoir, would be minimized due to the countercurrent gas-liquid and concurrent oil-water displacement tendencies in gravity stable gas injections. Performance prediction in highly heterogeneous reservoirs is extremely difficult since different forces may be active in different parts and length scales within the same reservoir.

In summary, viscous, gravity and capillary forces in addition to diffusion at the gas-oil and water interfaces do play an important role in any recovery process. In EOR process proceeding with the gravity drainage mechanism, balance of these forces is critical for achieving the optimum oil recovery.

2.3.4.3 Type of injection and production wells, well patterns and grid block size

Commonly vertical wells (injection and production) are employed during the development of oilfield whether it is primary or later enhanced production stages like continuous gas injection (CGI) and water-alternating-gas (WAG) injection methods. Vertical oil production wells are associated with the problems of poor sweep efficiency, gas/water coning issues, sand problems and higher pressure drawdown. Conversely, Horizontal wells can improve sweep efficiency delivering to higher oil productivity (or injectivity in case of injection well) and delayed displacing fluid breakthrough, provide larger surface area and contact length with a greater residence time especially in vertical-downward displacement process, reduce the water (less WOR) or gas coning (less GOR), yield less severe sand production through lower pressure drawdown, lower the well cost thereby reducing the requirement of the number of wells against vertical wells. These multi-dimensional aspect of horizontal wells seems to provide a ‘control tool’ and incremental oil recovery benefits over the vertical wells (Sarma, 1994).

Top-down gas-assisted gravity drainage process (wherein gas injection is in perpendicular to horizontal well orientation), if oil production is carried out with the closely spaced horizontal wells, well productivity index can be improved significantly. At a well spacing of about twice the height of the reservoir, horizontal well provide maximum oil production (Butler, 1992). Dykstra and Dickinson (1992) compared the performance of the vertical vs. Horizontal wells using a parameters called ‘constriction coefficient’ in both the dipping and horizontal reservoir types. Various combinations of vertical injection and/or horizontal oil production wells in different patterns were used in this study. They conclude that at formation thickness less than 0.85 times the distance between wells, a horizontal will produce better than a vertical well in a flat or horizontal type reservoir, whereas at formation thickness greater than this, a vertical well will produce better.

Fassihi and Gillham (1993) studied the effect of number of gridblocks in vertical direction. They decreased the number of gird-blocks from 10 to 3 in vertical direction. Their study concluded that the number of grid-blocks do not significant impact on the oil recovery provided that the bottom layer is kept thin enough to allow for the flow of the drained oil down the structure. Similar studies by Ypma (1985) concluded that a fine grid is needed at the model to avoid the oil being help up in the lowest layer after-drainage.

All of the studies were aimed towards the identifying the relative significance of using vertical gas injection and horizontal oil production wells and the distance between them. Literature review indicates that the relative significance of the horizontal gas injection wells, so the well patterns and grid-size, has not been investigated with regards to its effect on the ultimate gravity drainage oil recovery in top-down gravity drainage process.

2.3.4.4 Grid size and thickness (layers)

Literature suggested only one investigation for studying the effect of grid size on the oil recovery by Fassihi and Gillham (1993). They used air as gas injectant in the double displacement process in the West Hackberry field, Louisiana. Moreover, reservoir simulations were performed using thermal simulator, SSI. When X-direction length was increased from 24 ft to 48 ft, the oil recovery at gas breakthrough matched. On the other when number of gridblocks reduced in the vertical direction from 10 to 3, oil recovery did not changed significantly, provided that the bottom layer was kept thin enough to allow for the flow of the drained-oil down the structure. Similar studies by Ypma (1985) concluded that a fine grid is needed at the bottom of the model to avoid the oil from after-drainage being help up in the lowest layer.

Effect of the grid size (that is the variation in both the X and Y-dimensions) and the layer thickness (in vertical downward direction) in the gas-assisted gravity drainage oil recovery has not been investigated. Moreover, compositional simulations using CO_2 as the injection gas are still needed to be investigated in the gravity drainage process.

2.3.4.5 Wettability and spreading coefficient

These two properties represent the rock-fluid and fluid-fluid interactions (interfacial tensions) in porous media. Any change in these interactions can modify the trapping and movement of gas/oil/water. Wettability is a ‘preferential adherence of one fluid to a solid surface in presence of other immiscible fluids’. The fluid attracted to the rock surface is the wetting phase while other fluids are non-wetting phases. In the prevailing three phase fluid system containing water, oil and gas, rock-surface can be called water-wet and oil-wet if they wet that particular surface. When none of the fluids preferentially wets the rock-surface the system is the neutral-wet system. If both the water and oil wets the rock-surface, then it is mixed-wet system.

Oil recoveries in gravity drainage immiscible and miscible gas floods found to be dependent on wettability characteristics of the porous medium (Rao et al., 1992; Wylie and Mohanty, 1999b). Their experiments in the water-wet system yielded highest recovery in immiscible flood followed by the mixed-wet and oil-wet media. Poor performance in water-wet system was observed in miscible flood. Strong capillary retention forces acting on the wetting phase films and the inability of the oil to spread even under positive spreading coefficient lead to the poor recoveries.

Wettability is an important factor for the continuity of the phases as wetting films on solid, whose stable nature and hydraulic continuity throughout the pore network even in a low saturations leads to very high volumetric recovery of the non-wetting film (oil) in gravity drainage processes. Fluid-fluid interaction at the interface is attributed to the interfacial tension property, and in turn, spreading coefficients.

For gas-oil-water system, the oil spreading coefficient acting on a water-gas interface can be defined as:

$$S_o = \sigma_{wg} - \sigma_{go} - \sigma_{ow} \qquad (2.8)$$

where

σ_{wg} - water-gas interfacial tension

σ_{go} - gas-oil interfacial tension

σ_{ow} - oil-water interfacial tension

When S_o is positive, oil forms a film on water in presence of gas. Film is maintained because the sum of σ_{go} and σ_{ow} is always less than σ_{wg}. Thus, thin film configuration is thermodynamically stable, and allows the oil to drain to values lower than the residual oil saturation value. Gas and water can never form interface under positive S_o. Laboratory and theoretical studies suggest that a positive spreading coefficient under strongly water-wet systems would experience significantly high recoveries through film drainage and minimal losses of the injected gas to the reservoir water (Kalaydjian, 1992; Oren and Pinczewski, 1994). 2-D micromodel experiments of Chatzis *et al.* (1988) and Kantzas *et al.* (1988) concluded that in the strongly water-wet consolidated and unconsolidated porous media, oil forms a continuous film over water yielding high tertiary recovery. Similar results were obtained in the secondary gravity drainage experiments and fractal models presented by Vizika (1993). During vertical downward gas injection process, oil films promote the gravity drainage phenomena thereby providing interconnected pathways for the isolated oil blobs for their drainage towards production well. Negative value of S_o means the formation of the discontinuous distribution of oil between water and gas. Water and gas forms interface at a finite contact angle lowering oil recoveries. Negative spreading coefficients in real reservoir are rare and seldom found.

Blunt *et al.* (1994) showed that both the spreading and non-spreading oils can form films, which is only a few molecules thick. It is determined by the capillary pressure and by whether or not the film was formed from thinning a thicker layer or by encroaching over a surface. Drainage through this film would be far too slow to account for the recoveries seen experimentally. Their drainage experiments in capillary tubes with a square cross-section had water-wet corners and contained oil ganglia separated by air bubbles along its length. The gravitational driving force in the experiments allowed oil ganglia to drain by swelling the oil film and eventually all the oil was recovered. Experiments of (Soroush and Saidi, 1999) in a vertical gas-oil displacements carried over series of a low permeability oil-wet core at high-pressures (below MMP) yielded oil recoveries as high as 75%. It was attributed partly due to the thinning of the adsorbed films and thus the shrinkage of pendular rings as well as the possibility that the displacing phase starts wetting the rock surface. Dong *et al.* (1995) in their theoretical treatment showed that the a non-spreading oil can form a film over a water film in the edges of the pores in a water-wet porous medium. For the negative spreading coefficient systems simulated in the 2D glass micromodel showed that film is formed through the capillary oil imbibition.

Physical model experiments by Paidin (2006) in water-wet and oil-wet porous media in both secondary and tertiary resulted in higher oil recoveries on GAGD oil-wet model compared to water-wet reservoirs. He further reported that the constant injection pressure experiments provide higher oil recoveries than constant injection rate ones.

Review of above experimental studies suggested that very high recoveries in both the water-wet and oil-wet porous media is achievable. No experimental study that outlines the effect of the spreading coefficient is available to date. Nevertheless, by virtue of the water-wet characteristic of the most of the reservoirs, EOR processes can yield higher recovery leaving very low residual oil through IFT reduction and film flow enhancement.

2.3.4.6 Immiscible vs. miscible displacement

More than half of the crude oil is left behind at the end of the primary and enhanced oil recovery process due to the rock-fluid interactions mainly arising from interfacial tensions. For a particular spreading system, interfacial tensions of the existing gas-oil-water phases control the capillary forces, so the equilibrium configurations of the fluids. Capillary forces (capillary pressure) tend to prevent from flowing within the pores of the reservoir rock, trapping huge amount of the residual oil in the reservoirs. This microscopic property plays important role in both the immiscible and miscible CO_2 floods.

According to well-known Young-Laplace equation, the capillary pressure (P_c) is directly proportional to the interfacial tension (σ, IFT) and inversely proportional to the pore throat radius (*R*). During any injection operation one is operating at a certain IFT. If it is lowered for the same imposed pressure differential (which is possible in gravity drainage oil recovery), smaller pore throat radii will be accessed by the injection fluid. This implies that if a lower IFT is obtained using gas than water, then smaller pore throats will be accessed (Thomas *et al.*, 1995a). This further indicates that a long as the gas-oil IFT is lower than water-oil IFT and when oil spreads over the water and forms thin film, gas injection even in immiscible mode would be beneficial. The formation of this continuous oil film is key to the success of gravity drainage process (Vizika, 1993).

CO_2 injection causes oil to swell, causing its expansion. This swelling has number of favourable effects. Oil swelling can apply more favourable set of relative permeabilities if miscibility is achieved. Even if the miscibility is not achieved, the swollen oil droplets force water out of the pore space and create a *drainage process* within the water-wet system (Mungan, 1981). Very low interfacial tension can be obtained due to vaporization and solubility effects. In water-wet systems, drainage oil relative permeabilities are higher than imbibitions curves. This makes more favourable oil flow environment during oil recovery process at any given saturation pressure environment. Moreover, if a system is strongly water-wet, water adheres closely to the smaller pores, it may not be necessary to enter smaller pore throats to recover all of the oil (Thomas *et al.*, 1995b).

Immiscible gravity drainage gas injection in the single-matrix block of a 2D glass micromodels carried out by Dastyari *et al.* (2005) resulted in the faster recovery initially in the free gravity drainage process which slows down at longer times. This observation is reminiscent to the original gravity drainage theories by Cardwell and Parsons (1949b) and Terwillinger *et al.* (1951) and the macroscopic experimentation by Meszaros *et al.* (1990). They further reported the oil recovery in non-fractured reservoir to be higher than the fractured reservoir. This contradicts the conclusions of Catalan *et al.* (1994) and Li *et al.* (2000) who indicated that the presence of fractures in the direction of flow enhances the oil production rates. However, second observation by Dastyari *et al.* (2005) that the residual oil saturation increases to more than twice of the natural gravity drainage is in contrast with the observations of Thomas *et al.* (1990) and Karim *et al.* (1992). Moreover, conclusion that the gas injection in both un-fractured and fractured models results in higher residual oil saturations is again contradictory to almost all the other experimental studies (suggest that gravity stabilized gas injection can result in very low residual oil saturations).

On the other hand, miscible CO_2 injection process works towards achieving the zero interfacial tension (no interface between CO_2 and reservoir fluid). Capillary number results in infinity implying that 100% microscopic displacement efficiency is theoretically possible. Higher residual oil saturations in the reservoir can be obtained thereby increasing capillary number (Klins, 1984). Biennial survey by Moritis (Manrique *et al.*, 2006; 2006; 2008) indicates that almost all of the floods in the United States and Canada are miscible (CO_2 miscible in US and hydrocarbon miscible in Canada). Review of the horizontal CGI and WAG floods also suggests that higher recoveries were achieved in the miscible floods than the immiscible floods (Christensen *et al.*, 1998).

Overlapping values of interfacial tension for immiscible, near-miscible and miscible floods for similar fluid system have been reported (Christensen et al., 1998; Rao, 2001b; Taber et al., 1996). Review of literature studied indicates that there is a disagreement over the need for miscibility development for achieving higher recoveries from the hydrocarbon reservoirs (Mungan, 1981; Schramm *et al.*, 2000; Thomas *et al.*, 1995b).

Experimental investigation by Rao *et al.* (1992) and Wylie *et al.* (1999b) in water-wet media resulted in the very low oil recoveries during gravity stable miscible flood. CO_2 miscible gravity-assisted vertical core experiments by Tiffin and Kremesec (1986) concluded that downward displacement recoveries, even at injection rates significantly higher than the critical rates, are more efficient than horizontal floods at similar rates. The miscibility length was considerably shorter than the horizontal counterparts; wherein the component mass transfer strongly (negatively) affected flood front stability and that displacement efficiency increases at lower fluid cross flow and mixing conditions. On the other side, miscible GAGD flood by Kulkarni (2005) resulted in 100% oil recoveries irrespective of the core properties or the experimental conditions. He, however, went on acknowledging that immiscible GAGD-EOR process yield higher incremental recoveries (47.27% to 88.56% ROIP), nearly 5 to 8 times higher than the miscible WAG recoveries. His coreflood experiments on fractured cores yielded higher oil recovery indicating that fractures aids in the improving GAGD performance. Furthermore, experimental and numerical simulation studies by Muggeridge *et al.* (2005) to investigate the effects of presence of discontinuous shale barriers in the reservoir on miscible gas gravity drainage indicate that all the oil in the vicinity of the shales will ultimately be recovered; and that "regardless of the miscible displacement conditions" it is "surprisingly difficult" to bypass oil in the vicinity of shales over significant times.

2.3.4.7 Relative permeability

The relative permeability, an important petrophysical parameter, is the connecting link between the phase behavioural and transport properties of the system. The relative permeability influences the flow mechanics of the displacement process. It is also a critical input parameter in predictive simulation of gas injection floods. Connate water and mobile water saturation are the important parameters that influence the residual oil saturation at the end of any gas injection process, and in turn, relative permeability.

Connate water saturation is generally considered immobile, which does not always hold true because of the saturation redistribution and/or connate water re-mobilization (coming from gravity -capillary force balances) during gravity drainage process (Sajadian and Tehrani, 1998). Experimental investigations to study its effect on the gravity drainage oil recovery yielded contradictory outcomes. Very low residual oil saturations were obtained for both the high and low interfacial tension values (affecting the gas-oil relative permeabilities) by Dumore and Schols (1974) during gravity drainage experiments. Kantzas (1988) reported higher recoveries when test conducted at the residual water saturation than the residual oil saturation. Centrifugal gas-oil displacements reported that gas-oil relative permeabilities are unaffected (Narhara *et al.*, 1990) in presence of the immobile water. Free gravity drainage experiments by Pavone *et al.* (1989) at low interfacial tension in fractured reservoirs resulted in the reduction of the relative permeability, so the oil production. Their results are in contrast to the observations in other experimentations. Skauge (1994) found that connate water (about 30%) presence increases the oil recovery compared to when no water present thereby increasing the oil relative permeability and the hydrocarbon pore volume (HCPV) oil recovery (maximum) during gravity drainage process. During CO_2 injection, oil recovery rates and the recovery efficiency is found to be directly related to the free water saturation in the reservoir (Kulkarni and Rao, 2005).

Presence of mobile water saturation in the reservoir strongly influences gas-oil displacement process. Under water-wet conditions the residual oil saturation is shielded from the injected solvent (CO_2) by mobile water. These results in delayed oil delayed oil productions, decreased gas injectivity and lower oil relative permeabilities. If gas injection is carried out in the tertiary mode, significant quantities of water need to be displaced and also the injected solvent (especially CO_2) is lost into the reservoir brine (Farouq Ali, 2003).

The water-shielding phenomenon is a strong function of wettability and is more strongly exhibited in water-wet media than oil-wet media (Wylie and Mohanty, 1999a). Similar oil trapping effects are seen for HC and CO_2 injectants in both multiple contact miscibility (MCM) and first contact miscibility (FCM) displacements (Tiffin *et al.*, 1991). On the other hand, oil is continuous phase in oil-wet sand, thus can be easily reached by the injection solvent. The overall displacement efficiency is unaffected by the oil-wet sand. When mobile water is present, the accessibility of the oil by the solvent is governed by immiscible displacement mechanisms, which must be considered parallel to the miscible displacement mechanisms (Mattax and Kyte, 1962).

2.3.4.8 Secondary vs. tertiary gravity drainage EOR process

Gravity drainage process has been implemented in both the secondary as well as tertiary modes. Secondary gas injection generally assumes connate water saturation to be immobile. On the other hand, oil recovery in tertiary gas injection is attributed to the presence of mobile water. Secondary gravity drainage oil recovery proceeds with the initial single-phase oil displacement followed by the secondary gravity drainage behind the gas-oil floodfront (mainly in undersaturated reservoir). This process is controlled by the spreading coefficient and wetting characteristics of the governing porous medium. Under positive spreading coefficient, especially in water-wet and mixed-wet porous media, is mainly responsible for the higher oil recovery through the formation of the continuous oil film. Extent of the gas invasion is controlled by the threshold or entry capillary pressure of the pores in the secondary immiscible gravity drainage process, which can be diminished by the lowering of the interfacial tension or increasing the viscous forces. It is important to note that capillary retention is absent for the miscible process because of the zero interfacial tension between the injection gas and the reservoir oil. On the contrary, the micromodel investigations by Sajadian and Tehrani (1998) concluded that the dominance of gravity forces over the viscous forces do not allow the horizontal movement of the gas-oil contact in the initial stages of oil production, hypothesizing that the oil film flow becomes a critical production mechanism before and after gas breakthrough, for the gravity drainage oil production.

In post-secondary (that is waterflooding) gravity-assisted gas injection operations, transmissibility of the oil films determines the extent of the residual oil saturation (Ren, 2002). Oil flow rates though these oil films were found to be dependent on both the weight of the ganglia as well as the incremental volume of the gas injected till breakthrough. Low film flow rates were primarily gravity driven tertiary coming from the intermittent gas out-flow. Another slug of water injection in the process called 'second contact water displacement (SCWD)' provided incremental recoveries and saturation redistributions (micromodel studies). Effect of water shielding due to water injection after tertiary gas injection (in SCWD) process and other process parameters are yet to be investigated include oil relative permeability, water saturations and surface water handling costs.

2.3.4.9 Diffusion and Dispersion

Dispersion is an important mechanism in miscible displacement. It causes the mixing or dissipation of the miscible slug resulting from variations in the velocity within each flow channel and from one channel to another as they move through porous media. It damps-out the viscous fingers which channel through the miscible zone. It is believed to be the result of variations in the permeability and / or porosity, arising from reservoir heterogeneities (Warren and Skiba, 1964). Three mechanisms contribute to the mixing of miscible fluids: molecular diffusion, macroscopic and microscopic convective dispersion (Perkins and Johnston, 1963; Stalkup Jr., 1983). Molecular diffusion is the transport of mass as a result of spatial concentration difference resulting from random thermal molecular motion. Mixing of fluids in the direction transverse to flow results from diffusion and dispersion. If the injected gas is miscible or partially miscible with the oil to be displaced, both dispersion and dispersion may play important role in the displacement process where channelling and fingering of displacing fluid occurs (Burger and Mohanty, 1997; Cinar *et al.*, 2006; Mohanty and Johnson, 1993; Tchelepi, 1994). Dispersion in the immiscible displacement is governed by local heterogeneity at large scale and capillary/viscous forces at the small scale. In general, four factors contribute to crossflow/mass transfer: dispersion-drive, capillary-drive, gravity-drive, pressure-drive (Burger and Mohanty, 1997).

Graham's experiments were put into mathematical form by Fick, whose law states that the 1D steady state flux (J) is proportional to the concentration difference (c) across the phase interface with the proportionality constant being called 'Diffusion Coefficient (D)'. It is generally not constant and varies with pressure, temperature and to some degree concentration and interfacial tension. In majority of the reservoir engineering applications, diffusion coefficient can be considered to be constant. Diffusion in porous media is described by the general diffusion equation with the introduction of an effective diffusion coefficient D_{eff}, which depends on the texture of the porous medium. The presence of porous media essentially reduces the diffusion coefficient, due to the variable area of contact between two fluids, while the mechanism of diffusion remains the same. This is because the diffusing molecules have to travel through a longer path as well as through the throats and the wider areas of the pores. It takes a longer time for the molecules to travel an apparent distance in porous media than in a conduit without a porous medium conduit.

Reservoir oil is mixture of many heavy and light hydrocarbon and non-hydrocarbon components. Depending on the state of the reservoir these components may be all in the liquid phase or in the gas phase or in a two- phase condition at equilibrium. For any compositional analysis in gas-liquid interface component exchange including diffusion, the value of the diffusion coefficients for all components in the gas and liquid phases is the key parameter in such analysis. The diffusion coefficients of the components in the gas and liquid phases can be calculated by using the correlations to calculate the binary diffusion coefficients as well as the properties of the components. Correlations for the calculation of the binary diffusion coefficients which have been introduced by different authors are different to each other because they have been derived based on different measurements and variety models. In other words, even if different models are applied for a similar measurement set up experiment, the correlations are not the same. The most commonly used equations in gas and oil systems are Sigmund correlation (1976), Chapman and Cowling correlation (1970) and Renner correlation (1988).

2.3.4.10 Porosity heterogeneity

Heterogeneities in porosity and permeability impact vertical sweep efficiency, gas injectivity, vertical communication between layers, gravity crossflow, fluid channeling; hence the overall oil recovery performance of the reservoir. Injectivity and sweep patterns are strongly influenced by stratification and reservoir heterogeneities (Pizarro and Lake, 1998). Heterogeneity delays breakthrough in vertical gravity stable floods because of physical dispersion and reduced gas channelling through high permeability layer. In horizontal floods, K_v/K_h (vertical to horizontal permeabilities) ratio is mainly influenced by viscous, capillary, gravity and dispersive forces. Therefore, heterogeneities in top-down gravity drainage EOR methods may help to improve injectivity and reservoir sweeps.

2.3.5 Screening Criteria: Gravity Drainage Oil Recovery Process

Selection of most appropriate process for the specific field conditions is primarily worked out from the empirical screening criteria thereby by matching reservoir and the fluid properties. Such a screening criteria for the gas injection EOR process is developed by Taber *et. al.* (1996), and Lepski *et. al.* (1998), that can be used as a preliminary screening tool for candidate reservoir to identify its applicability to pilot and field studies. Evaluation of the applicability of the gravity assisted gas injection EOR process to a particular candidate reservoir can be made by using the screening criteria provided by Lepski *et. al.* (1998) and Rao *(2006b)*. Ranges of the values for the specific parameters are summarized in **Table 2-5**.

Table 2-5: Screening Criteria for gas assisted gravity segregation processes

Parameter	**Preferable Range / Value**
Waterflood Residual Oil Saturation	Substantial (range not specified) (Lepski *et al.*, 1996)
Reservoir Permeability (Vertical)	> 300 mD (Lepski *et al.*, 1996)
Bed Dip Angle	> 10^o (Lepski *et al.*, 1996)
Spreading coefficient	Positive (Lepski *et al.*, 1996)
Oil API Gravity	Miscible: > 22^o (Rao, 2006b); Immiscible: > 12^o (Rao, 2006b)
Oil Viscosity	Free Flow (Lepski *et al.*, 1996)
Pay Zone Thickness	> 10 ft sand without isolating shale breaks (Rao, 2006b)
Lateral Continuity	More than 1000-1500 ft for horizontal well placement (Rao, 2006b)
Overburden / Underburden	Well sealed to prevent loss of injected CO_2 (Rao, 2006b)

2.3.6 Field Projects through Reservoir Simulation Studies

Review presented by Howes (1988) and Kulkarni (2006b) summarizing the gravity stable/gravity drainage EOR projects suggested that gravity drainage process has widely been investigated in US and Canada field projects through the laboratory studies or black oil simulations. Following literature is restricted to the field projects (US, Canada, Norway, Libya and Indonesia) wherein the reservoir simulations have been carried out to evaluate them. Peculiar characteristics of each of these projects obtained through this review helped to understand controlling multiphase operational parameters as well as to identify the potential research roadmap. In this section, review is presented under the heading based on type of gas injected either in miscible or immiscible mode in the respective reservoirs.

Miscible CO_2 injection: Black oil model (Wolfcamp Reef reservoir, Texas US)

In a vertical miscible gravity-stable flood, *tertiary* CO_2 was injected just below the Gas-oil-Contact in the Wolfcamp Reef reservoir of Wellman unit, Texas (Bangla *et al.*, 1991). This limestone reservoir has average porosity of 8.5% and permeability ranging from 500 to 1000 mD. Reservoir oil was 43.5 API with 0.43 cP. Waterflood residual oil saturation at the start of tertiary CO_2 injection was 35%. CO_2 injection was supplemented by simultaneous water injection (just above the original OWC) to maintain reservoir pressure above MMP. Full field history matched numerical model studies were performed to optimize the oil production rate, hence the oil recovery, using a *black oil model simulator N-HANCE*. Vertical injection and production wells were used in this study. Results predicted ultimate sweep efficiency from CO_2 flood to be 78% (84% in the field) with incremental tertiary recovery of 16.7% OOIP while leaving behind the 10.5% of residual oil saturation.

Immiscible air injection: Black oil model (West Hackberry field, Louisiana)

West Hackberry field located in Cameron Parish, South-western Louisiana is a faulted salt dome dipping (23-35 degrees) reservoir with average pay thickness of 30 ft having 24 to 30% porosity, 300 to 1000 mD permeability and 19% connate water saturation (Fassihi and Gillham, 1993). The oil is of 33 ^{o}API gravity with 0.9 cP viscosity at a reservoir temperature of 200 ^{o}F and original bubble point pressure of 3295 psi. *Tertiary* air is injected through vertical gas injection wells to displace liquids (oil and water) from previously watered out oil column for their downward gravity drainage (Double displacement Process-DDP) towards the vertical production wells. Fieldwide reservoir simulation of GOR and WOR history matched models (using SSI numerical *thermal model*, *THERM*) was carried out using rectangular grid for the sensitivity analysis. The results on the vertical permeability sensitivity studies concluded that the higher permeability at the bottom layer and lower at the top layer improves the oil recovery performance by delaying gas breakthrough; higher air injection rates destabilize the gas-oil interface; and number of the gridblocks in vertical direction did not significantly impacted gravity drainage oil recovery. Laboratory and the field studies exhibited the recoveries of nearly 90% OOIP against the 50-60% water drive recoveries.

Immiscible produced gas injection: Black oil model (Oseberg Field, North Sea, Norway)

The Oseberg Field in the Norwegian sector of the North Sea in block 30/6 and 30/9 is a low dipping (6^o-10^o east-northeast) sandstone reservoir having 1-5000 mD permeability and 20-25% porosity (Hagen and Kvalheim, 1990; Sognesand, 1997). Reservoir is of 82×23 square feet area with maximum oil and gas column of 705 feet and 1246ft respectively, accumulating about 3.54 billion bbls oil. Field was discovered in 1979. Saturated reservoir having oil of 33.6 ^{o}API gravity was initially at reservoir pressure of 4119 psia and temperature 215.6 ^{o}F. History matched simulation model studies concluded that the produced gas re-injection would provide an oil recovery more than water-flooding (Sognesand, 1992). *Secondary* immiscible gas injection in the gas cap yielded oil recovery factor more than 60% since its start in 1988, with an average oil production rate of 465000 STB/D. For controlling the gas front evolution and avoid premature gas breakthrough, Norsk Hydro used combinations of vertical gas injection wells (gas cap) and horizontal oil production wells (close to oil-water contact) were employed in the Oseberg A, B and C platforms. This resulted in stable- horizontal floodfront leading to the downward oil gravity drainage rate of 0.164 to 1.64 ft/day towards horizontal producers. By end of 2005 about 85% of OOIP was recovered. Field oil production is expected to continue until 2020.

Immiscible methane gas injection: Black oil model (Paluxy formation, East Texas)

Full field 3-D geocellular and flow pilot simulations was conducted on the complex clastic fluvial channel sands in Paluxy formation of East Texas to investigate the commercial viability of the gravity drainage process (Hyatt and Hutchison, 2005). The reservoir pressure of this highly undersaturated low-dipping (2^o) reservoir (original pressure of 1900 psig and a solution GOR of 10 SCF/BBL) was maintained by a moderately strong aquifer. High production water cut was observed since the start of the production of this field in 1930. After the waterflooding of about 70 years, immiscible *tertiary* methane gas was injected in the matured 300 ft reservoir interval having 25% porosity, 2.2 Darcy permeability, 23 ^{o}API gravity oil of 23 cP viscosity (at reservoir condition). Combinations of the vertical gas injection and vertical or horizontal oil production wells were employed during 13 year studies of gravity drainage oil recovery.

Carbon-oxygen production logs indicated the progressive downward movement and drainage of oil behind the advancing gas front to yield more than 15% incremental OOIP recoveries after 13 years. Application of horizontal production wells increased oil recovery rates and sweep efficiency.

Immiscible lean gas injection: compositional model (Handil Field, Indonesia)

The giant oil field, “Handil” is located in the Mahakam Delta of the island of Borneo in Indonesia (Gunawan and Caie, 1999). It comprises more than 500 hydrocarbon accumulations (300 oil in shallow and main zones and 200 gas in deep zones) in structurally stacked and compartmentalized fluvial sands between 984.25 ft (300m) to 1312.34 ft (4000 m) (ss). The reservoir is simple anticline, 4 km long and 3 km wide, with a main east-west fault dividing between the north and south areas. Reservoir structural dip ranges from 5 to 12 degrees connecting to a weak bottom aquifer. Permeability, porosity and connate water saturation are 10 to 2000 mD, 25% and about 22% respectively. Reservoir oil is of 31 to 34 ^{o}API gravity with oil viscosity range between 0.6 to 1.0 cP. Oil accumulations consist of initial oil column between 328.83 ft (100 m) to 606 ft (185 m) underlying a gas cap. TotalFina group’s laboratory and full field 3D numerical simulations for the immiscible and *tertiary* lean hydrocarbon gas injection (gravity drainage of oil) in the five reservoirs yielded additional oil recovery of 1.2% of OOIP during September 1995 to December 1998 (3 years). Reservoir pressures have declined by 300 psi (in 3 years) since the start of the gas injection due to gas cap expansion (114.82 to 246.06 ft) and simultaneous oil withdrawal. With the positive results, 11 more reservoirs (among 30 possible) will be subjected to gas injection EOR process to recover additional 470 MMSTB OOIP during next 15 years.

Miscible hydrocarbon gas injection: Black oil model (Sirte Basin, Libya)

The Intisar “D” reservoir is a carbonate pinnacle reef type oil field lying in the Sirte basin over 3325 acres in concession 103 of Libya. Reef is mostly homogeneous formation with original hydrocarbon column of 888 ft having 22% average porosity and 200 mD average permeability. The highly undersaturated reservoir oil is 40 ^{o}API with initial properties as 0.46 cP viscosity, solution GOR of 509 SCF/STB; and minimum miscibility pressure of 4000 psi lower than the reservoir pressure of 4257 psi (DesBrisay *et al.*, 1981). Reservoir contains the OOIP of 1.830 billion STB. Field began production in 1970 with vertical water injection (water zone) and hydrocarbon gas injection (gas cap) wells under "sandwich scheme" of oil production through vertical wells. In 1981 water injection was stopped and gas injection continued until today (Vilela *et al.*, 2007). This study showed that the Occidental Libya's hydrocarbon gas injection since 1981 mostly remained secondary immiscible EOR process in the vertical gravity drainage mode. Reservoir performance and simulations using the full field history matched (37 years of injection and production) black oil model evaluated the recovery factor as 81% until the Dec 2002. *Tertiary* miscible hydrocarbon gas injection began in 2003 and expected to sustain the oil production until 2024.

Immiscible produced/inert gas injection: Black oil model (Hawkins Woodbine field, East Texas)

Hawkins (woodbine) field was subjected to an immiscible and *tertiary* (DDP) produced/inert gas injection in the 1000 ft hydrocarbon column for enhancing the oil recovery through gas-drive/gravity drainage processes (Carlson, 1988). This extensively faulted and communicating reservoir is divided into the upper, more thicker and permeable Dexter sands; and the lower, Lewisville sands spread over 10000 acres. Dipping (6^o) reservoir has a strong bottom aquifer support and originally contained 1.3 billion barrels of oil having 12-30 ^{o}API gravity and 2-80 cP viscosity. Hand calculations, laboratory results and computer model studies predicted 80% oil recovery efficiency through gravity drainage compared to 60% water drive efficiency. Immiscible gasflood under laboratory conditions could reduce residual oil saturation in water invaded oil column from 35% to about 12% while predictive numerical models showed it to reach near the minimum oil saturation and less than 10% in "drag zones". This study concluded that the gas-drive/gravity drainage combination process would recover 33% more oil than that of water-drive oil recovery.

Immiscible CO_2/hydrocarbon gas injection: Compositional model (Weeks Island, Louisiana)

Immiscible injection of CO_2 plus hydrocarbon-gas (gravity stable mode) in Weeks Island S-RB reservoir of Louisiana was initiated in 1978 by Shell (Johnston, 1988). Highly permeable and steeply dipping (26^o) reservoir is of 26% porosity and 1200 mD. Pilot gas injection studies to predict the field performance of oil recovery (3 MSTB in the 186 ft net pay zone) was carried out through the 2-D radial grid and 3-D Cartesian grid built using Shell's compositional reservoir simulator MULTISIM. Tertiary displacement greater than

90% of the waterflood residual oil saturation was achieved while recovering about 262 MSTB of oil through the vertical downward gravity displacement of oil. Final recovery volumes would be 66% of the starting oil volume with the tertiary recovery about 205 MSTB or 60% of the oil unrecoverable by water displacement.

Immiscible dry gas injection: Black oil model (Elk Hills, California)

26R reservoir is a highly layered (stratified), massive sandstone Stevens reservoir located in the Naval Petroleum reservoir No.1 (NPR-1) in Elk Hills, Kern County, California (Wei *et. al.*, 1992). It is a steeply dipping (23^o to 62^o) anticline reservoir with an initial oil column of 1800 ft (net productive thickness of 1150 ft) amounting 424 MMSTB oil of 36 ^{o}API gravity and 0.42 cP initial viscosity. Permeability and porosity are 2 to 100 mD and 23.6% respectively. *Secondary* crestal dry gas injection in NPR-1 began Oct 1976 as a part of pressure maintenance operation. By Sept 1991, gravity drainage through voidage balance recovered nearly 43% OOIP. Simulation studies projected additional oil recovery about 15.5% of OOIP in remaining producing life of the reservoir. Numerical simulations (Eclipse) over the history matched (reservoir pressure, gas production and the horizontal well performance) reservoir model were performed for the 50 year production forecasting at different levels of gas injection volumes (Echols and Ezekwe, 1998). This study predicted maximum of 70% OOIP starting from Oct 2000 with reservoir pressure decline of 900 psia due to its communication with the 31S N/A reservoir. Vertical gas injection wells and vertical/horizontal production wells were employed in this EOR process.

Immiscible nitrogen injection: Black oil model (Hypothetical)

Ren (2004) conducted the reservoir simulations on 3-D homogeneous anisotropic model using the black oil adaptive-implicit numerical simulator CMG's IMEX. Sensitivity runs were carried to investigate the macroscopic mechanisms of DDP and SCWD (Second Contact Water Displacement process which involves a second waterflood after the tertiary gasflood) processes. 9000 gridblock model was subjected to the sensitivity analysis of immiscible nitrogen injection and oil production rates (through vertical wells), reservoir dip angle, oil relative permeability and Capillary pressure. They further investigated the microscopic mechanisms related to oil film flow in both the processes using visual glass micromodels. Pore level studies concluded that the oil flowing through oil films or layers during gravity assisted tertiary gas injection are driven by its own weight as well as the incremental volume of gas injected.

Table 2-6: Summary of 11 commercial gravity drainage field projects

Location / *Property*	Oseberg Field	West Hackberry	Hawkins Dexter Sand	Weeks Island SRB	Elk Hills	Wizard Lake D3A	Westpem Nisku D	Wolfcamp Reef	Intisar D	Handil Main Zone	Paluxy Formation
	North Sea	**Louisiana, USA**	**Texas**	**Louisiana, USA**	**California, USA**	**Alberta, Canada**	**Alberta, Canada**	**Texas, USA**	**Libya**	**Borneo, Indonesia**	**East Texas, USA**
GEOLOGY and GEOPHYSICS (Formation Properties)											
Lithology	SST	SST	SST	SST	SST	Dolomite	Carbonate	LST	B/D	SST	F/D
Res. Type	6^o-10^o Dip	23^o - 35^o	8^o Dip	26^o Dip	23^o - 62^o	Reef	Reef	Reef	Reef	5^o-12^o Dip	CS, Thk
Pay Thk, ft	66 - 706	31 - 30	230	186	1150	648	292	824	950	15 - 25, m	300
Res. Temp., ^{o}F	215.6	205 - 195	168	225	210	167	218	151	226	197.6	N/A
Porosity, %	20 - 27	27.6 - 23.9	27	26	23.6	10.94	12	8.5	22	25	25
S_{wc} (%)	N/A	19 - 23	13	10	16	5.64	11	20	N/A	22	N/A
k, mD	10-6000	300 - 1000	3400	1200	2 - 100	1375	1050	110	200	10 - 2000	10 - 6000
K_v/K_h Ratio	1.0	1.0	~ 1.0	1.0	1.0	0.1	0.033 - 0.2	N/A	0.75	1.0	1.0
RESERVOIR FLUID PROPERTIES											
Oil API Gravity	33.6	33	25	32.7	36	38	45	43.5	40	31 – 34	23
Oil Visco, cp	0.43	0.9	3.7	0.45	0.42	0.535 (Pb)	0.19	0.43	0.46	0.6 – 1.0	23
Pr at P_b, psi	4061	2920.304	1985	6013	N/A	2154	3966	1375	2224	2800-3200	N/A
Oil FVF at P_b	1.466	1.285	1.225	1.62	1.283	1.313	2.45	1.284	1.315	1.1 - 1.4	N/A
GOR, SCF/STB	158	500	900	1386	584	567	1800	450	509	2000	10
MMP, psi	4713.726	N/A	N/A	N/A	3334	2131	4640	1900	4257	N/A	N/A
SPECIFIC DATA on GAS INJECTION EOR											
Application	Field	Field	Field	Pilot/Fld	Field	Field	Field	Field	Field	Field	Pilot
Area, acres	43243	381	2800	8	9	2725	320	1400	3325	1500	~ 640
Start Date	Dec'88	Nov-94	Aug-87	Jan-79	Jan-81	Jan-69	May-81	Jul-83	Jan-69	Jan-94	Jan-01
Injectant Fluid	**HC**	**Air**	**N_2**	**CO_2/HC**	**HC**	**HC**	**HC**	**CO_2**	**HC**	**HC**	**HC (?)**
Inj Method	Immisc	Immisc	Immisc	Immisc	Immisc	Misc	Misc	Misc	***Immisc***	Immisc	Immisc
Injection Mode	Secondary	Secondary	Tertiary	Tertiary	Secondary	Secondary	Secondary	Tertiary	Secondary	Tertiary	Tertiary
Displ rate, ft/D	0.1749	0.095 - 0.198	N/A	0.04 - 1.2	N/A	0.021 - 0.084	0.020 - 0.203	0.116	0.06	N/A	N/A
Status Date	ongoing	C (2002)	NC (2002)	NC (1986)	ongoing	NC (2002)	HF (1992)	HF (1998)	NC (2002)	N/A	NC (2005)
OVERALL GRAVITY DRAINAGE EOR PERFORMANCE											
WF S_{or}, %	27	26	35	22	N/A	35	N/A	35	N/A	27	N/A
WF Rec, % OOIP	-	60	60	60 - 70	N/A	N/A	N/A	N/A	48	58	35
GF S_{or} (%)	0.1	8	12	1.9	N/A	24.5	5	10	N/A	N/A	N/A
S_o at start (%)	-	N/A	N/A	22	N/A	93	90	35	80	28	N/A
S_o at end (%)	2 - 5	N/A	N/A	2	N/A	12	5	10	18	N/A	N/A
GF Prod, BPD	-	150-400	1000	160	-	1300	2300	1400	40,000	2383	175
GF Rec, %OOIP	62 - 88	90	> 80.0	60	70	86.6	84	74.8	69.2	N/A	N/A
Result	Successful	Successful	Successful	Successful	successful	Successful	Successful	Successful	Successful	Successful	Successful
Reference	Sognesand, 1997; Bu 1992	Karim et al., 1992	Carlson, 1988	Johnston, 1988	Echols et al., 1998	Backmeyer et al. 1984; Cook, 2005	Da Sle et al., 1990	Bangla et al., 1991	Vilela et al., 2007	Gunawan & Caie, 1999	Hyatt & Hutchinson, 2005

2.4 Scaling and Sensitivity Analysis

Scaled model studies provide an accurate way of predicting the reservoir performance and the effect of different parameters on oil recovery. Scaling is a procedure in which the results obtained at one scale size (small scale laboratory experiments) are extrapolated to another scale size (a large scale process) (Buckingham, 1914 ; Gharbi Ridha, 2002; Johnson, 1998; Lozada and Farouq Ali 1987; Novakovic, 2002; Shook et al., 1992). In spite of recent advances in the area of numerical simulation processes, scaled physical models are now preferred because of their capability to capture all the physical phenomena occurring in a particular process.

Scaling generally leads to the definition of the dimensionless numbers known as dimensionless groups, forming a basis for comparison between various scales. There are two distinct approaches to derive a scaling law or model for a particular fluid flow system.

Dimensional numbers making up the scaling laws can be derived by the Dimensional Analysis (Buckingham, 1914) for fluid mechanics modelling and inspectional analysis (Geertsma *et al.*, 1956; Greenkorn, 1964; Ruark, 1935; Shook *et al.*, 1992) for fluid flow through porous media. Present study is focused on the dimensional analysis. Therefore literature review in this section restricted to only dimensional analysis.

2.4.1 Dimensional Analysis

Dimensionless analysis is based on the knowledge of appropriate variables influencing oil displacement. Equations that describe the process are not needed in dimensionless analysis. It is an effective scaling tool simulating analogous field scale multiphase processes into laboratory, to represent an experiment or numerical model incorporating number of the operative spatial and/or physical mechanisms. Number of parameters affecting the performance of oil reservoirs (reservoir heterogeneity, gravity/ capillary/viscous forces, interfacial tension, fluid viscosities, wettability, spreading coefficient, rock porosity, absolute and relative permeability, physical and numerical dispersions, and the initial water saturation, residual oil saturation, Dip angle, Mass transfer) are so combined that their dimensions (composing the dimensionless groups) cancel each other out to form a final group with no dimensions. The effect on certain variables is then studied in terms of the group instead of individual variables in the group. In case of similar geometric scales, if the ratio of the dimensionless group on a larger geometric scale to a dimensionless group on a smaller geometric scale is kept equal to one, then mechanisms occurring on both the scales would be similar (Rappaport and Leas, 1953). Dimensional analysis reduces the number of experimental variables for scaling of simulation parameters to field scale and vice versa.

2.4.2 Scaled Models in Porous Media

Coreflood experiments on the core sample of a particular reservoir are traditionally carried out to test the most suitable oil displacement method for that reservoir. The results so obtained may not be directly applicable and reliable on the field scale. However these results if presented in the form of scaling groups, it is possible to relate them to field scale for the direct implementation. Scaling is a procedure in which the results obtained at one scale size (small scale laboratory experiments) are applicable to another scale size (a large scale process). It leads to the definition of the dimensionless numbers known as dimensionless groups, forming a basis for comparison between various scales

(Buckingham, 1914; Lozada and Farouq Ali, 1987; Shook *et al.*, 1992; Gharbi, 2002). Any scaling law or model comprising dimensionless scaling groups derived through the dimensional analysis is a more realistic way of predicting the reservoir performance through the analysis of individual parameter influence on ultimate oil recovery. Number of parameters involved in the problem statement thus gets reduced thereby eliminating the need of conversion between the units.

Buckingham Pi theorem states that any equation, that completely describes a relation among number of physical quantities, is reducible to form as:

$$f\,(\Pi_1, \Pi_2, \Pi_3 \ldots\ldots) = 0 \qquad (2.9)$$

where,

$\Pi_1, \Pi_2, \Pi_3, \ldots\ldots$ are the independent dimensionless groups.

In other words, it can be simply stated as ‘the physical laws are independent of form of units’. He put forward the rule that the number of dimensionless groups in a complete set is equal to the total number of variables minus the number of fundamental dimensions. Dimensional analysis generates complete and independent dimensionless groups for a process. The generalised stepwise procedure to obtain the dimensionless groups using Buckingham Pi theorem is available in literature (Geertsma *et al.*, 1956; Greenkorn, 1964; Langhaar, 1951) and is not detailed here.

Dimensionless analysis is based on the knowledge of appropriate variables influencing oil displacement. Equations that describe the process are not needed in dimensionless analysis. It is an effective scaling tool simulating analogous field scale multiphase processes into laboratory, to represent an experiment or numerical model incorporating number of the operative spatial and/or physical mechanisms. Number of parameters affecting the performance of oil reservoirs (absolute and relative permeability, fluid viscosities, initial water and oil saturations, residual oil saturation, relative oil, gas and water permeability, rock porosity, gravity/capillary/viscous forces, dip angle, reservoir heterogeneity, interfacial tension, wettability, spreading coefficient, physical and numerical dispersions, and the mass transfer) are so combined that their dimensions (composing the dimensionless groups) cancel each other out to form a final group with no dimensions. The effect on certain variables is then studied in terms of the group instead of individual variables in the group. In case of similar geometric scales, if the ratio of the dimensionless group on a larger geometric scale to a dimensionless group on a smaller geometric scale is kept equal to one, then mechanisms occurring on both the scales would be similar (Greenkorn, 1964; Rappaport and Leas, 1953).

Application of scaling to multiphase flow in porous medium has been studied earlier for miscible and immiscible EOR processes. Immiscible water induced oil displacement was first studied by Leverett *et al.* (1942) through the dimensionless scaling groups. Later Croes and Scwarz (1955) presented the influence of the oil/water viscosity ratio on immiscible displacements through a diagram representing the cumulative oil recovery for the various water-oil viscosity ratios ranging from 1 to 500. They assumed linear displacement of oil by water in homogeneous reservoir. Scaling relationship of immiscible displacement of oil by cold water derived through inspectional analysis was presented for the first time by Rapoport (1955). This was further extended by Geertsma *et al.* (1956) cold-water, hot water displacement and solvent displacement processes using the combined inspectional and dimensional analysis. Carpenter *et al.* (1962) developed scaled model for the homogeneous media having different permeability in the communicating strata. Effects of gravity segregation in miscible and immiscible displacements in five spot models were presented by Craig *et al.* (1957) through two correlations. First one accounted the ratio of vertical to horizontal pressure gradient and the oil recovery at breakthrough for various mobility ratios. Second correlation was the representation of experimental oil recovery and a dimensionless gravity number.

Scaling criteria presented by Perkins and Collins (1960) accounted the relative permeability and capillary pressure curves through the representation of reservoir heterogeneity. Geostatistical and generic characterization generated heterogeneity scaling groups were derived through image representation technique by Li and Lake (1995) to scale the immiscible oil displacement by waterflooding in heterogeneous reservoirs. Gharbi *et al.* (1995) used an artificial neural network technique to scale the immiscible displacements in homogeneous reservoir by using vertical wells through fine mesh simulation data. Flow through heterogeneous 2D anisotropic reservoir was scaled by Gharbi (2002) using inspectional analysis to match 13 dimensionless scaling groups for miscible solvent flooding.

Shook *et al.* (2002) presented dimensionless scaling groups for the waterflood applicable to represent the two phase flow through homogeneous 2-dimensional Cartesian dipping reservoir. The continuous CO_2 flooding in a dipping waterflooded reservoir was scaled by Wood *et al.* (2006, 2008) through ten dimensionless groups (obtained through inspectional analysis) to develop a screening model based on Box-Behnken experiments. The results obtained from CMG's GEM simulator are then used to predict the oil recovery and CO_2 storage potential. Trivedi and Babadagli (2008) proposed new group incorporating the matrix-fracture diffusion transfer to scale the miscible displacement in fractured porous media based on the laboratory experiments.

Literature review suggests that although there are the dimensionless groups available for gas flooding in porous media; the studies regarding the application of the scaled models to the CO_2-assisted gravity drainage EOR process are very limited. Following section attempts to review them.

2.4.3 Scaled Models: Gravity Drainage Process

Gravity, viscous and capillary forces play important role in the to-down gravity drainage EOR process. Their interaction and balance during the process can be captured by the scaled models obtained through dimensional analysis.

It is generally expressed through three numbers, viz. Capillary number, N_C; Bond number, N_B and Gravity number, N_G (Edwards *et al.*, 1998; Grattoni *et al.*, 2001) denoted by equations 2.10, 2.11 and 2.12 respectively in **Table 2-7**. N_C is the ratio of capillary to viscous forces; N_B expresses the ratio of the gravity and capillary number, while N_G defines the relative strength of the gravity and viscous effects.

Gravity drainage studies by Edwards *et al.*(1998) showed that at least two dimensionless groups can be examined to display the importance of capillary forces on the gravity drainage process. They are the Dombrowski-Brownell or microscopic bond number, N_{DB} (Equation 2.13, **Table 2-7**) and macroscopic bond number, N_B (Equation 2.11; **Table 2-7**).

Gas-invasion effect under gravity drainage conditions was studied by Grattoni *et al.* (2001) to investigate the influence of wettability and water saturation on three phase flow. They defined a new dimensionless group that altogether includes the effects of the gravity, viscous and capillary forces. They developed a linear relationship between this new group and the total recovery based on the experimental investigations to include the pore scale effects. Their study concluded that the gravity number, in addition to the Bond and Capillary numbers play a major role in the characterisation of the gravity drainage flow.

Table 2-7: Dimensionless numbers in gravity drainage process

Eq. No.	Number	Correlation	Reference
2.10	Capillary Number	$N_C = \frac{V.\mu}{\sigma}$ $N_C = \frac{v.\mu}{P_C.R_A}.2.Cos.\theta$	Grattoni *et al.*(2001)
2.11	Bond Number	$N_B = \frac{\Delta\rho.g.l^2}{\sigma}$ $N_B = \frac{\Delta\rho.g.l^2}{\sigma.\sqrt{\phi/k}}$	Edwards *et al.* (1998)
2.12	Gravity Number	$N_G = \frac{\Delta\rho.g.k}{\Delta\mu.u}$	Grattoni *et al.*, (2001)
2.13	Dombrowski-Brownell Number	$N_{DB} = \frac{\Delta\rho.g.k}{\sigma}$	Edwards *et al.*, (1998
2.14	New Group of Grattoni *et al.*, (2001)	$N = N_B + A\left(\frac{\mu_D}{\mu_g}\right)N_C$	Grattoni *et al.*, (2001)
2.15	New Group of Kulkarni	$N_K = N_G + \left(\frac{\rho_G}{\rho_O}(N_C + N_B)\right)$	Kulkarni (2005)
2.16	New Group of Rostami *et al.* (2009)	$N_{rostami} = \frac{N_B(\mu_r)^A}{(N_C)^B}$	Rostami *et al.*, (2009)

Parameters: Δρ: Density difference between the oil and gas, g: the gravity, l: characteristic length (represented by the grain diameter), v: Darcy velocity, µ: viscosity of the displacing phase, σ: interfacial tension, θ: contact angle and R_A the average pore throat radius, ø: porosity and k: reservoir permeability

Sharma (2004) developed a water-wet physical model to study the effect of dimensionless numbers viz. Capillary number (N_C), Bond number (N_B), and Gravity number (N_G) on GAGD performance (Sharma, 2005). He found that the type of gas injected (N_2 and CO_2 in this case) at constant pressure in the immiscible mode has no effect on GAGD performance. Gas injection at constant rate to control N_C and N_B resulted into higher oil recovery with increase in N_B.

Kulkarni (2005) conducted coreflood experiments based on the scaled model developed to match the field data from West Hackberry gas injection project (Kulkarni, 2005). Kulkarni (2005) factored the ratio of the gas density to the oil density, along with the N_C, N_B and N_G, into a new suggested dimensionless number, $N_{kulkarni}$. He presented the effect of this newly formed dimensionless group on the final recovery based on 2-D physical model, 1-D coreflood and 3-D filed data in immiscible and miscible gas assisted gravity drainage EOR process. Good accuracy of the match was obtained using this correlation for all the laboratory and field data. He reported that the higher the gravity number, the higher was the oil recovery.

2.5 Summary

Variety of mechanisms of the gravity drainage process has been suggested in literature. However, the exact distinguishable mechanisms by which the different forms of gravity drainage processes (pure or free and forced i.e. the gravity stable) operates has not been specifically identified. Characterization of the gravity drainage process and its modelling using numerical and empirical techniques is still a challenge. Literature point out that the positive spreading coefficient in water-wet and mixed-wet yielded higher oil recoveries through the beneficial effect oil spreading and film flow. However, studies of the gravity drainage recoveries in oil-wet systems resulted in the contradictory outcomes. Investigations of the miscible and immiscible gravity drainage process do not seem to agree on the need of miscibility development to achieve maximum gravity drainage oil recovery in both the non-fractured and fractured reservoirs.

Review of the reservoir simulation studies indicate that the gravity drainage process for enhancing the oil recovery has been or being practically employed in all parts of the world (United States, Norway, Indonesia, Libya and the Middle East) in both the non-fractured and fractured reservoirs. Reservoir simulation studies are quite few with most of them carried out in the immiscible mode using black oil models. Only two reservoir simulation studies were conducted in miscible mode, out of which only one used CO_2 as injection gas (Bangla *et al.*, 1991) in the tertiary mode of gas injeciton. Other injection gases used were hydrocarbon or produced gas, air or nitrogen in either miscible or immiscible mode. Maximum gravity drainage oil recovery ranged from 60 to 90% OOIP. Reservoir oil gravity ranged from 12 to 45 ^{o}API gravity while reservoirs were either dipping (2^{o} to 62^{o}) or reef type homogeneous or fractured reservoirs. Gravity drainage process was implemented in low as well as high permeability reservoirs with moderate to high vertical permeability reservoirs. It is implemented in reservoirs ranging from extremely geo-complex reservoirs like Biomicrite / Dolomite to high quality turbidite (sandstone) reservoirs and not greatly affected by the variation of common reservoir - fluid parameters like reservoir heterogeneity, bubble point pressure, GOR, reservoir temperature & oil FVF.

For gravity drainage EOR floods, only one tertiary CO_2 miscible floods in 43.5 API gravity reservoir-oil by Bangla *et al.* (1991) have been reported so far in field applications. An incremental recovery of mere 16.7% OOIP was achieved while leaving behind 10.5% residual oil saturation in this study on the 43.5 ^{o}API gravity oil. Based on the literature review conducted in this study, it is concluded that the numerical compositional simulation of the secondary and tertiary CO_2 immiscible and miscible flood for the investigation of gravity drainage oil recovery process has not been reported so far. Beneficial mechanistic effects of CO_2 as a gas injectant, as discussed in the literature review, are needed to be investigated with regards to the gravity drainage EOR process. Through the compositional simulations, investigations being conducted in the current studies target this research opportunity.

Review of the scaled model studies showed that the very few studies have been reported for the gravity drainage EOR process. Those were based on the capillary, bond and gravity numbers or oriented towards the inclusion of them to account for the gravity, viscous and capillary force effect predominantly existing during the gravity drainage oil recovery. Based on this literature survey, a new combination dimensionless scaled model is proposed and validated for both the immiscible and miscible CO_2-assisted gravity drainage EOR process. Furthermore, additional scaling groups are also proposed to completely scale the CO_2-assisted gravity drainage EOR process.

3 METHODOLOGY

In this Chapter, the methods followed to achieve the objectives set out in this research are briefly enumerated. Numerical simulation part of this research involves the construction of the reservoir model, production strategy development and the oil recovery optimization studies. Scaling and sensitivity studies comprises identification and evaluation of the mechanistic operational multiphase parameters and development of a set of scaled models that would capture interaction of these multiphase parameters affecting the CO_2-assisted gravity drainage oil recovery. The objectives set in this research are achieved through a systematic parametric work plan shown in **Table 3-1**.

3.1 Reservoir Model Construction

Reservoir model development comprises the construction of reservoir grid, reservoir fluid characterization, rock-fluid properties, well placement, model initialization and the prediction of miscibility development pressure.

A conventional Cartesian grid without corner point geometry or local grid refinement is constructed using the CMG's commercial implicit explicit black oil simulator IMEX as well as CMG's equation-of-state (EOS) compositional simulator GEM. A three dimensional hypothetical system with the base model dimensions (50 × 30 × 10: 600 ft × 400 ft × 150 ft) is then subjected to numerical numerical black-oil and compositional simulations of both the 35 and 50 ^{o}API gravity reservoir-oils. Detailed properties and the developed reservoir models are presented in section 4.1 of the Chapter-4.

Table 3-1: Summary of the parametric research plan

1	**RESERVOIR SIMULATIONS: Sensitivity Analysis**			
1.1	**Reservoir Models:** Two, varied L/W			
	Base model -	(50 × 30 × 10: 600 ft × 400 ft × 150 ft)		
	Effect of grid dimensions; Oil zone thickness	(50 × 30 × 10: 300 ft × 200 ft × 150 ft); (50 × 30 × 30: 120 ft × 80 ft × 50 ft)		
	Fluid model	Pseudomiscible	35 ^oAPI gravity	
		Compositional	50 ^oAPI gravity	
1.2	**Sensitivity Parameters**			
(a)	Rates of CO_2 injection (I_g) & oil production (q_o)	35 ^oAPI gravity	50 ^oAPI gravity	
(b)	Effect of type of the horizontal wells: secondary/tertiary immiscible	35 ^oAPI gravity	50 ^oAPI gravity	
(c)	Well patterns: Irregular vs. regular, Secondary Immiscible and miscible, k_v/k_h ratio = 1.0	50 ^oAPI gravity oil-reservoir		
(d)	Miscibility effects: No Diffusion, homogeneous reservoir (k_v/k_h = 1), 50 ^oAPI gravity oil	immiscible	Secondary	Tertiary
		miscible	Secondary	Tertiary
(e)	**Heterogeneity** in Permeability	Varying k_v = 1200 mD and 1.2 mD; k_v/k_h ratio = 1.0 and 0.001	Secondary miscible - comparison of diffusion and no diffusion case, 50 ^oAPI gravity oil, optimized grid	
	Heterogeneity in Porosity: overturned faults	k_v = 1200 mD, k_v/k_h ratio = 1.0, 3 sets of values	Tertiary immiscible - No diffusion, 35 ^oAPI gravity oil, Base grid	
(e)	**Molecular Diffusion**: 50 ^oAPI gravity oil-reservoir, optimized grid, k_v/k_h ratio = 1.0 and 0.001	Secondary	Immiscible	Miscible
		Tertiary	Immiscible	Miscible
(e)	**Mode of gas injection:** 50 ^oAPI gravity oil-reservoir, optimized grid, k_v/k_h ratio = 1.0 and 0.001, comparison between no-diffusion and diffusion	immiscible	Secondary	Tertiary
		miscible	Secondary	Tertiary
(f)	**Capillary effects**: 50 ^oAPI oil, k_v/k_h ratio = 1.0, base grid	Secondary immiscible		
(g)	**Oil film flow** evaluation through the analysis of immiscible process oil recovery performance			
Comparison parameters:	Oil production rate (q_o, BOPD), gas-oil ratio (GOR, MMSCF/BBL), cumulative oil production (N_P, BBL), water cut (%), average reservoir pressure (psi), field oil recovery (% OOIP), incremental oil recovery (%), oil viscosity, gas and oil saturation, two-dimensional representation of the gas and oil saturation			
2	**SCALING & SENSITIVITY ANALYSIS**			
2.1	**Development of new combination dimensionless group, $N_{Jadhawar\ and\ Sarma}$** based on evaluation of N_C, N_B, N_G, viscosity and density ratio,			
2.2	**Development of additional scaling groups through Dimensional Analysis**			
(a)	Injection and producing pressure Group, Gravity number: Superficial/Darcy velocity based, Pressure based gravity number, water-oil and gas-oil mobility ratio group, residual oil saturation to gas and oil	Tertiary, 35 ^oAPI gravity oil-reservoir, k_v/k_h ratio = 1.0, base grid model		
2.3	**Validation of scaling groups:**			
(a)	New dimensionless group, $N_{Jadhawar\ and\ Sarma}$ **:** Secondary and tertiary CO_2 immiscible and miscible (GEM based), 50 ^oAPI gravity oil	Reservoir simulation results in this study and the data from the gravity drainage field projects including Oseberg field, Norway		
(b)	Additional dimensionless groups, CO_2 Immiscible (IMEX based), 35 ^oAPI gravity oil	Validated using uncertainty analysis		

Note: Values of the rows in right hand columns have no relation with respect to their study. These values/properties in the same column are given for the purpose of the summarising the parametric studies undertaken.

In black-oil simulations, the four component pseudomiscible option without chase gas was used to generate the pseudo-miscible black oil reservoir model using CMG'S equation of state multiphase equilibrium properties determination program, WINPROP. Reservoir oil of 35 ^{o}API gravity with the properties modified from Barrufet (2007) is used in this purpose. With all the detailed properties assigned including the well placement, in the pseudo-miscible reservoir model the model (**Table A-I** in Appendix-A) was initialized using WinProp program for use in the reservoir simulations. WinProp predicted minimum miscibility pressure of 35 ^{o}API reservoir oil as 5300 psia. Nevertheless, only immiscible CO_2 injection is conducted in 35 ^{o}API reservoir-oil simulations.

Australian reservoir oil of 50 ^{o}API gravity with the fluid composition and laboratory based PVT properties (Bon and Sarma, 2004) are used to obtain Peng-Robinson Equation-Of-State (PR-EOS) matched compositional fluid model. Rigorous fluid characterization procedures are performed using the CMG's WinProp program. With all properties assigned including the well placement, in the compositional reservoir model, it was initialized using CMG's WinProp program to yield the initial reservoir conditions and ready for use in the compositional reservoir simulations. Minimum miscibility pressure predicted in the laboratory was 2690 psia while CMG's WinProp predicted it to be 3237 psia.

3.2 Production Strategy Development

The developed reservoir model (either of the pseudo-miscible and compositional model; mentioned at the respective sections) is then subjected to investigate effects of the of CO_2 injection (i_g) and/or oil production rates (q_o), well patterns, injection well type, connate water saturation and capillary pressure to develop a better production strategy that would provide optimum oil recovery in the CO_2-assisted gravity drainage EOR process.

In all of the reservoir simulation studies, the floodfront stability criterion of Dumore (1964a) was employed. Based on his equation, the calculations regarding the rates of critical and stable gas injection rates are performed as reported in the Appendix-B. So the CO_2 injection rates are kept lower than the critical and stable gas injection rates to satisfy the criterion of Dumore (1964a) in all the reservoir simulations runs in this research.

In *rate-constraint* studies, either of i_g or q_o is varied while keeping another value constant. Findings from this study are then used in the subsequent comparative reservoir simulation studies. Investigation of the *effect of injection well type* viz. vertical well versus horizontal well on the gravity drainage oil recovery performance is carried out using irregular well pattern (direct line drive) in immiscible 35 ^oAPI oil-reservoir and the regular well pattern (direct line drive) in the miscible 50 ^oAPI oil-reservoir. 12 vertical CO_2 injection wells were then replaced by 6 horizontal CO_2 injection wells. Oil recovery performance between them is assessed using oil production rates (q_o), gas-oil ratio (GOR), water cut (%), cumulative oil recovery (Np), HC pore volumes injected (%) and the average reservoir pressure. Simulation results were then compared to observe any improvement in the oil recovery over 132 years of gravity drainage oil recovery performance. Outcomes from these two studies are then included in investigating the effect of well patterns on the immiscible and miscible CO_2-assisted gravity drainage EOR performance.

In well pattern study, irregular and regular well pattern of the vertical gas injection wells and horizontal oil production wells are applied in studying their effect on the CO_2-assisted gravity drainage oil recovery (see section 5.4). Four combinations of the CO_2 injection rates (i_g) and oil production rates (q_o) under the reservoir voidage rate ratio of about 1.0. Pressure of the production wells was maintained at 200 psi lower than the injection well pressure. Reservoir simulation results over 132 years in this study are evaluated using oil production rate ($q_{o,}$ BOPD), gas-oil ratio (GOR, SCF/BBL), cumulative oil production (N_P, BBL), water cut (%), average reservoir pressure (psi), field oil recovery (% OOIP), incremental oil recovery (%), oil viscosity, and gas and oil saturation. Moreover two-dimensional gas saturation and oil viscosity changes were also included in the analysis.

A new hypothesis of *stable floodfront without the occurrence of viscous fingering* is presented and verified based on the inferences of abrupt vertical q_o drop, respective rise in GOR and gas saturation profiles in the regular well pattern in both the immiscible and miscible process. Analysis of the corresponding higher incremental oil recovery and reservoir pressure response further signified the gravity drainage oil recovery to identify preliminary mechanisms. Additional parameters viz. oil viscosity, gas and oil saturation further revealed the supporting micro-mechanisms. Based on these findings, the regular well pattern (of vertical gas injection well and horizontal production well), that helps to promote the CO_2-assisted gravity drainage mechanism, is selected for the oil recovery optimization studies through reservoir simulations (**Chapter-6**).

Effect of connate water saturation on the gravity drainage oil recovery performance is investigated by varying its value in three settings in 35 ^{o}API reservoir using irregular well pattern. Pseudomiscible black-oil simulations are conducted using CMG's IMEX simulator in irregular well patterns. Studies regarding the capillary pressure are important to investigate the interplay of capillary pressure with the other operational parameters in the CO_2-assisted gravity drainage EOR process.

Results obtained in this Chapter helped to identify and final the production strategy comprising the i_g and q_o constraint-combination, vertical gas injection wells and horizontal production wells, regular well pattern, capillary pressure and connate water, for implementation in the oil recovery optimization studies.

3.3 Oil Recovery Optimization Studies

Oil recovery optimization studies are conducted to (1) identify the process mechanisms and develop a general process selection map to choose between the immiscible and miscible recovery process; (2) study the effects of grid size through grid-refinement studies, miscibility generation, heterogeneity in permeability and porosity, molecular diffusion and mode of gas injection in the CO_2-assisted gravity drainage EOR process. These objectives are achieved through the numerical simulations using CMG's black-oil simulator IMEX and the compositional simulator, GEM. Both the 35 and 50 ^{o}API gravity reservoir-oils have been used and are specifically mentioned at the relevant sections. In all of the reservoir simulation studies, the CO_2 injection rates are kept lower than the critical and stable gas injection rates to satisfy the Dumore criteria (1964a).

3.3.1 Mechanisms Identification and the General Process Selection Map Development

Main objectives are to identify the operational oil recovery mechanisms in CO_2-assisted gravity drainage EOR process and to develop the respective general selection map for immiscible versus miscible process. They are achieved through the reservoir simulations by CO_2 injection in seven successively higher well rate-constraint combinations (see **Table 6-1**) using the base-model (50 × 30 × 10: 600 ft × 400 ft × 150 ft) in homogeneous porous media (equal vertical and horizontal permeability). Regular well pattern of the vertical CO_2 injection and horizontal oil production wells is used in 132 year immiscible and miscible CO_2-flooding operations. Diffusion effects are neglected. Oil recovery performance is investigated through the comparative analysis of incremental oil recovered in all the immiscible and miscible rate-constraints for the respective pore volumes of CO_2 injected. Incremental recovery is the volume of oil recovered out of the volume that was present in oil zone at the start of secondary mode CO_2 injection (the incremental) for the respective incremental pore volumes injected. This lead to the development of general process selection map based on the final incremental oil recoveries.

Results are further evaluated through analysis of the oil production rate ($q_{o,}$ BOPD), gas-oil ratio (GOR, SCF/BBL), cumulative oil production (N_P, BBL) and average reservoir pressure (psi) to identify the overall oil recovery mechanism. To identify other micro-mechanisms, the oil saturation (S_o) profiles in the blocks (21, 20, 7) in addition to these properties are analysed in both the immiscible and the miscible process. Moreover, the oil viscosity, and gas and oil saturation profiles in other blocks (25, 14, 6), (25, 14, 7) and (25, 14, 8) confirmed the other micro-mechanisms. Moreover two-dimensional gas saturation, oil viscosity and oil saturation changes were also included in the analysis to support the earlier observations.

3.3.2 Effect of Grid Size through Grid Refinement Studies

Literature review presented in Chapter-2 suggests that the effect of grid-size (varying x and y dimensions) and grid-thickness on the CO_2-assisted gravity drainage oil recovery has not been so far investigated. This research opportunity is exploited by reducing the x and y dimensions of grid by half (300 ft × 200 ft) in Case-IV and Case-VII well rate-constraint combinations from the base-model dimensions (600 ft × 400 ft). Identical incremental oil recovery performance is compared between the base model and the reduced size model (300 ft × 200 ft × 150 ft) at the same pore volumes of CO_2 injected. Further evaluation of the grid thickness effect is carried out by reducing the grid thickness to 50 ft from the base case model thickness of 150 ft. Comparative evaluation showed that the reduced model yield the maximum of 16% (case-IV) higher incremental oil recovery. Moreover, the oil held up in these grid-blocks is prevented. This matters most especially in the layer in which the horizontal well is completed. In contrast, the results of Fassihi and

Gillham (1993) and Ypma (1985) suggested that the bottom most layers should be thinner for optimizing the oil recovery. Investigations in the current study concluded that thin layers facilitate the optimum gravity drainage oil recovery even in the upper layers. Furthermore, this grid provided maximum of 98.4% incremental oil recovery in the miscible process at the one-fifth lower oil production rate constraint, which lead to term it as the optimized grid (50 × 30 × 30: 120 ft × 80 ft × 50 ft) for use in the reservoir simulations in the remaining part of thesis. These simulation studies neglected the diffusion effect.

3.3.3 Effect of Miscibility Development

The optimized grid (50 × 30 × 30: 120 ft × 80 ft × 50 ft) is used to analyse the effect of the miscible development by comparing the EOR performance in immiscible and miscible process. These analyses are conducted to answer the following research questions:

- Does miscibility development improve the incremental oil recovery?
- If yes, what are those mechanisms with which it progress?
- How effective are they in comparison with the mechanisms prevailing in the immiscible process

Case-IV well rate-constraint combination is used for the 132 years reservoir simulation of the CO_2 flooding. Incremental oil recoveries (%) obtained in all of the no-diffusion sensitivity runs versus the respective pore volumes of CO_2 injected are plotted for the comparative analysis of secondary and tertiary immiscible processes as well as miscible methods at the respective pore volumes of the CO_2 injected (PV_{CO2inj}). Both the analysis scales of the time (years) taken to achieve the incremental recovery and the pore volumes of the CO_2 injected (PV_{CO2inj}) are taken into account while analysing the oil recovery performance before and after the CO_2 floodfront arrival. All of the four cases are then subjected to the comparative analysis of the incremental oil recoveries at 2.5 PV_{CO2inj}.

Other concurrent parameters that are used in the analysis are the GOR (MMSCF/STB) and water cut (%). Further analysis of average reservoir pressure (psi) identified the overall recovery mechanisms in both the immiscible and miscible process. Other oil recovery supporting-mechanisms are investigated by observing the changes in the profiles of the gas saturation, oil viscosity (cP) and the oil saturation from the representative blocks (21, 20, 7), (25, 14, 23) in the optimized model and the blocks (25,14, 6), (25,14, 7) and (25,14, 8) in the base model, that depicts the various sections of the producing oil zone. All of these analyses are particularly studied in the very light oil of 50 ^{o}API gravity with respect to their effectiveness and comparative ability in optimizing the oil recovery.

3.3.4 Effect of Molecular Diffusion

Investigations in this study are conducted to find out whether the molecular diffusion further enhances the oil recovery in both the homogeneous (vertical permeability of 1200 mD; k_v/k_h= 1.00) and the heterogeneous reservoir (vertical permeability of 1.2 mD; k_v/k_h=0.001). To achieve those, incremental oil recoveries in all the immiscible and miscible CO_2-assisted gravity drainage EOR methods are obtained in presence of the active diffusion phenomena. Diffusion case incremental recoveries (%) are compared with the no-diffusion case recoveries. Final incremental oil recoveries are obtained with the active cross-phase diffusion at 1.45 and 3.53 PV_{CO2inj} in the secondary miscible and immiscible process respectively. On the other hand, tertiary miscible and immiscible CO_2 injection process is obtained at 2.6 and 7.89 PV_{CO2inj}. Number of the years required to yield them are also compared between the diffusion and no-diffusion case. Further numerical studies are also conducted in the heterogeneous reservoir (vertical permeability of 1.2 mD; k_v/k_h=0.001) for the comparison of the pore volumes of the CO_2 injected and the time required to attain the respective incremental oil recovery when diffusion effects are activated. Moreover, the observations in these are analysed by the comparative presentation of the oil viscosity, gas saturation and oil saturation changes occurred during the diffusion mode CO_2 flooding before and after gas floodfront arrival.

3.3.5 Effect of Heterogeneity in Permeability and Porosity

Objectives of this study are to investigate the effect of the permeability heterogeneity and heterogeneity in porosity on the oil recovery performance in the CO_2 assisted gravity drainage EOR process. In permeability heterogeneity studies, the vertical permeability is changed to 1.2 mD so that k_v/k_h = 0.001. The optimized grid (50 × 30 × 30: 120 ft × 80 ft × 50 ft) is used to perform the sensitivity of the heterogeneity by CO_2 injection in 50 ^{o}API gravity oil at case-IV well-rate constraint combination. Oil recovery performance in secondary miscible process is comparatively studied in a heterogenic reservoir (k_v/k_h=0.001) with the cross phase diffusion **(**at 3.2 PV_{CO2inj}) and without diffusion (3 PV_{CO2inj}). During comparative analysis both the scales of pore volumes of CO_2 injected and time (years) taken to obtain the oil recovery are considered with GOR (MMSCF/STB), water cut (%) and average reservoir pressure (psi) properties.

Further analysis of the heterogeneity is carried out with respect to the heterogeneity in porosity values (such as in case of the over-turned faults) in the homogeneous permeability medium (k_v = 1200 mD, k_v/k_h = 0.001) of 35 ^{o}API oil-reservoir. CMG's pseudomiscible black oil simulator IMEX is used in simulating the porosity heterogeneity effects in the irregular well pattern of the vertical gas (CO_2) injection and the horizontal production wells. Two sets of porosity-heterogeneity values are used in this study. In one setting the uniform porosities of 0.22 and 0.18 are assigned to the oil and water zone respectively whereas it is assumed decreasing downwards in the gas zone. In second setting, the porosities values increasing downwards from top layer are assigned. Results obtained in these two cases are then compared with the results in the homogeneous porosity setting (0.22). Parameters used in the evaluation are the oil rate (BPD), cumulative oil production (BBL), GOR (MMSCFD/STB), water cut (%), average reservoir pressure (psi) and the two-dimensional representation of the oil saturation in the producing zone at the start and end of the 132 years CO_2 flooding.

3.3.6 Effect of Mode of Gas (CO_2) Injection

Objective of this study is to investigate the effect of the mode of CO_2 injection viz. secondary versus tertiary on both the miscible and immiscible CO_2-assisted gravity drainage oil recovery. Reservoir simulations in 50 API gravity oil-reservoir and homogeneous permeability reservoir are conducted using the optimized grid. Results of the secondary and tertiary mode miscible process are compared between the no-diffusion case and diffusion case. Similar analysis is also carried for the secondary and tertiary immiscible process results. Pore volumes of CO_2 injected and time taken to achieve the incremental oil recovery (%) are used as the comparison scale. Comparative analysis of the incremental oil recoveries in both the secondary and tertiary mode of CO_2 injection is carried out in this study in miscible as well as immiscible CO_2-assisted gravity drainage EOR method for the pore volumes of CO_2 injected at the complete duration of the CO_2

flooding and at the 2.5 and 1.5 of the PV_{CO2inj}. Other comparison parameters used in the evaluation are the GOR (MMSCFD/STB), water cut (%) and average reservoir pressure (psi) for the understanding physics of the involved process. Micro-mechanisms are evaluated using oil viscosity, gas saturation and the oil saturation in the block (25, 14, 23) in both the immiscible and miscible secondary and tertiary model CO_2 injection. Moreover, the effect of the mode of gas injection is evaluated using the oil average saturation of all of the reservoir simulations. This evaluated provide a useful tool to identify the relative speed of the involved processes. Above all, these recoveries are then compared with the incremental recoveries reported in the literature in the gravity drainage field projects as well as the WAG filed projects.

3.4 Scaling and Sensitivity Analysis

The results obtained in the reservoir simulation studies are applicable to the field studies through the scaling approach. The interacting parameters, identified from the reservoir simulation results, if used in this scaling procedures then these results would be applicable to the field studies. Key objectives of this study are to

- Identify the relative dominance of the mechanistic operational multiphase parameters through risk analysis using the PALISADE’s @risk software.
- Develop a new correlation using traditional dimensionless numbers and assess its application to CO_2-assisted gravity drainage EOR process
- Investigate the CO_2-assisted gravity drainage EOR process using the additional dimensionless groups that are not covered by a new correlation, and
- Develop a set of dimensionless groups that would completely be able to scale the CO_2-assisted gravity drainage EOR process

In order to develop a new correlation, the effects of Capillary, viscous and gravity forces on the immiscible and miscible CO_2-assisted gravity drainage oil recovery are first studied through the analysis of respective changes occurring in capillary number, gravity number, bond number, viscosity and the density difference between the injection gas and the reservoir oil. Once the pattern of the changes in these parameters are obtained with respect to the oil recovery performance in the CO_2-assisted gravity drainage EOR process, the combination models in the literature, notable presented by Kulkarni (2005) and

Rostami (2009) are analysed for their applicability to the EOR process under investigation. Logarithmic correlations of these combination numbers are presented with respect to their applicability for CO_2-assisted gravity drainage EOR process. Based on the inferences are obtained, they are used in developing new combination model in this study. Based on the findings from traditional dimensionless numbers and combination models in this study and shortcomings of the published combination numbers, a new combination group is proposed. In all of these studies the parametric data from reservoir simulations and the data from the gravity drainage field projects are used.

New correlation, $N_{\text{Jadhawar and Sarma}}$, is investigated for the data match of both the immiscible and miscible oil recovery in the reservoir simulations in different porous media of 1200 mD, 120 mD and 1.2 mD and in the gravity drainage field projects (see section 7.2.5). Once the desired accuracy of logarithmic correlation of the new combination dimensionless group is achieved with oil recovery, it form an integral part of the scaling the CO_2-assisted gravity drainage EOR process.

Additional dimensionless groups encompassing the parameters that are not covered by a new correlation, $N_{\text{Jadhawar and Sarma}}$ are developed to provide a set of the dimensionless group that can completely scale the CO_2-assisted gravity drainage EOR process. These are the injection rate based gravity number, pressure based gravity number, water-oil and gas-oil mobility ratio group, injection and producing pressure groups and residual oil saturation to gas and oil. Functional relationship between these scaling groups and their effect on the immiscible CO_2-assisted gravity drainage oil recovery is studied using the data of the reservoir simulations in 35 ^{o}API reservoir oil. Oil recovery behaviour for each of these dimensionless groups is represented in the form of dimensionless recovery (R_D) versus dimensionless time (t_D). Each of these scaling groups values are investigated by varying their values in one by one while keeping values of other scaling groups constant.

Furthermore, the dimensionless recovery performance is validated through comparison of their values when parameters making up the dimensionless groups are changed so that the final values of all the scaling groups remain unchanged. Such a comparison presented in three sample reservoirs. Precisely, the dimensionless groups presented in this study are validated in two approaches: (i) oil recovery performance (%OOIP) through the new combination model, $N_{\text{Jadhawar and Sarma}}$, using the reservoir simulation data and the gravity drainage field projects; and then (ii) Dimensionless recovery performance of three sample reservoirs using the additional dimensionless groups, by varying the values of parameters making up the dimensionless groups so that the final values of the scaling groups remain constant. Conclusions are drawn based on how close matching of the CO_2-assisted gravity drainage oil recovery is obtained using the set of dimensionless groups, that can captures all the operational multiphase parameters and completely scale the CO_2-assisted gravity drainage EOR process.

4 RESERVOIR MODEL CONSTRUCTION

Reservoir model development comprises the construction of reservoir grid, reservoir fluid characterization, rock-fluid properties, well placement and the model initialization with assignment of the respective model parameters. These are discussed in detail in this chapter, leading to the complete compositional simulation model for the sensitivity studies envisaged under investigation.

4.1 Reservoir Model Description

First step in reservoir simulation model development is the construction of reservoir grid system. Conventional Cartesian grid without corner point geometry or local grid refinement is used for this purpose. A three dimensional hypothetical system is constructed using the CMG's commercial implicit explicit black oil simulator IMEX as well as CMG's equation-of-state (EOS) compositional simulator GEM. 50 blocks in the X-direction, 30 blocks in the Y-direction and the 10 layers in the Z-direction (depth) constitutes 15000 grid block model with dimensions 600ft, 400ft and 150ft (thickness) in I, J and K-directions respectively. Cell (1,1,1) is at a depth of 8000 feet at the centre of the cell top. Same grid is used for both the numerical black-oil and compositional simulations of 35 and 50 ^{o}API gravity oils (discussed later).

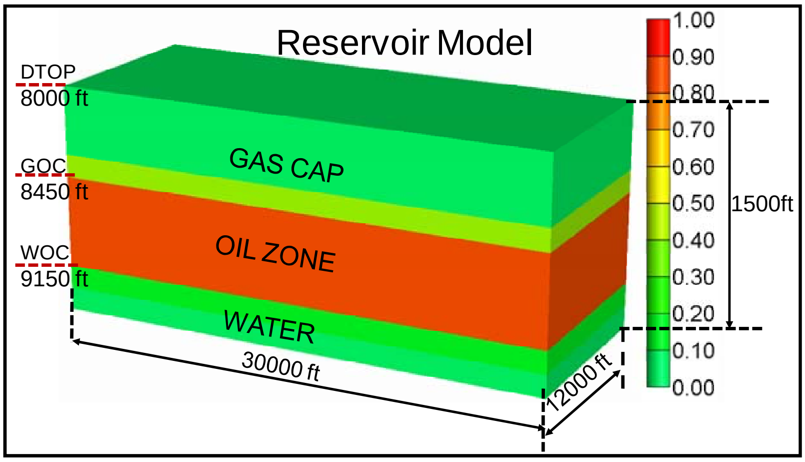

Figure 4-1: Hypothetical 3-D reservoir model representing the gas, oil and water zone thickness

Basic properties during development of the homogeneous anisotropic reservoir model are adapted from review of the field data presented in section 2.3.6 (see **Table 2-6**). Constant reservoir porosity (homogeneous) in all the layers is assumed to be 22%. I and J-direction permeabilities assumed are 1200 mD with the ratio of vertical and horizontal permeabilities (K_v/K_h) of 1.0. Compressibility of the reservoir rock is assumed to be 4 x 10^{-6} $psia^{-1}$. The developed reservoir model is diagrammatically represented in **Figure 4-1**.

4.2 Reservoir Fluid Models

Numerical simulations of CO_2-assisted gravity drainage EOR process are performed on 35 and 50 ^oAPI gravity reservoir oils. Both the black-oil and compositional fluid models were used in the simulations on 35 ^oAPI gravity oil. Peng-Robinson Equation-Of-State (PR-EOS) model was used to tune the PVT properties using CMG's WinProp fluid properties simulator. EOS tuned properties of 35 ^oAPI gravity oil are presented in the appendix-I. Later section enumerates the compositional fluid model of 50 API gravity oil (Australian reservoir fluid) with the detailed fluid characterization procedure followed by the presentation of the history matched properties. As procedure of the reservoir characterization and EOS tuning is same irrespective of the API gravity of the reservoir oil, the history matched properties of only 50 ^oAPI gravity oil are presented in this chapter.

4.2.1 Pseudomiscible Black Oil Model: 35 ^oAPI Oil

The four component (oil, gas, water and chase gas) pseudomiscible option with no chase gas was invoked to simulate three phase flow of fluids. **Figure 4-2** presents the phase envelope of the reservoir fluid depicting its bubble point pressure and the initial reservoir pressure. Also given in the adjoining Table are the compositions of each of the component that constitute the reservoir fluid, mole fraction, molecular weight and specific gravity of the plus components (modified from Barrufet (2007). These typically represent the west hackberry field (Louisiana) composition. Reservoir fluid used is the 35 ^oAPI gravity black oil with the solution gas gravity of 0.65. PVT properties of the oil and gas (**Table I-A** in Appendix-I) were generated using correlations incorporated in the CMG's equation of state multiphase equilibrium properties determination program, WINPROP. The associated formation water properties namely the salinity, formation volume factor, compressibility, viscosity and the density are also simulated using WINPROP at the reference pressure of 4000 psi and the reference depth of 9250 psi. The solvent (CO_2)

properties including solution gas ratio, formation volume factor, the viscosity and the mixing parameter between the oil and solvent responsible for the miscibility were determined using the pseudomiscible option of WINPROP (**Table I-A** in Appendix-I). Minimum miscibility pressure of 35 API oil is simulated predicted as 5100 psi using CMG's WinProp simulator.

Reservoir fluid composition	
Component	Mole%
Carbon Dioxide, CO_2	0.00
Nitrogen, N_2	0.99
Methane, C_1	48.50
Ethane, C_2	3.10
Propane, C_3	3.11
Iso-Butane, iC_4	1.29
N-Butane, nC_4	1.56
Iso-Pentane, iC_5	1.20
N-Pentane, nC_5	0.10
Z (C_{6+})	0.4015
MW (C_{6+})	206.49
SG (C_{6+})	0.8369

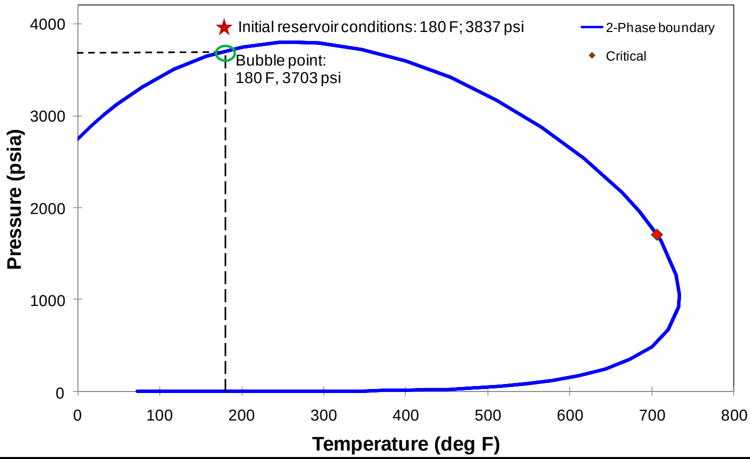

Figure 4-2: Composition and phase diagram of 35 °API gravity reservoir oil depicting the saturation pressure and temperature, and the initial reservoir condition.

4.2.2 Compositional Fluid Model: 50 °API Oil from Australian Reservoir

Australian reservoir oil of 50 °API gravity was selected for investigating the reservoir sensitivity toward the CO_2-assisted gravity drainage oil recovery mechanism. Fluid composition (**Figure 4-3**) and PVT properties are adapted from Bon and Sarma (2004). Phase envelope simulated using CMG's WinProp software is represented in **Figure 4-3**. These properties were used to obtain the EOS matched properties generated through the rigorous fluid characterization procedure, which is enumerated in the next section. Minimum miscibility pressure predicted in the laboratory was 2690 psia while CMG's WinProp predicted it to be 3237 psia.

History matching: EOS characterization

Oil recovery through CO_2 flooding process proceeds with the involvement of the two or more phases along with the interaction of the number of components existing within them. Reservoir fluid encompasses crude oil, having light (C_1-C_5), intermediate (C_5-C_{12}) and heavier fractions (C_{12+}), the formation water and the free gas in gas cap (if exists). The extent of these fractions mainly in the reservoir oil determines the choice of recovery process. Moreover, higher the number of these components (real and pseudo-components), the larger will be the computational time and the storage capacity required during the reservoir simulation. Number and composition of these components constituting the reservoir oil and their interaction with the injection gas, CO_2 in this case, during the EOR process, therefore forms an integral part of any reservoir fluid studies especially in the miscible floods. Compositional simulation of the reservoir fluid is capable of capturing those component interactions through the fluid characterization process.

Reservoir fluid composition	
Component	Mol%
Hydrogen Sulfide, H_2S	0.00
Carbon Dioxide, CO_2	15.57
Nitrogen, N_2	0.73
Methane, C_1	23.95
Ethane, C_2	8.71
Propane, C_3	8.63
Iso-Butane, iC_4	2.30
N-Butane, nC_4	4.16
Iso-Pentane, iC_5	1.46
N-Pentane, nC_5	1.63
Hexanes, C_6	3.70
Heptane Plus, C_{7+}	35.95
MW (C_{7+})	149.6
SG (C_{7+})	0.7628
Oil FVF (Bo) RB/STB	1.998
GOR, SCF/STB	1263

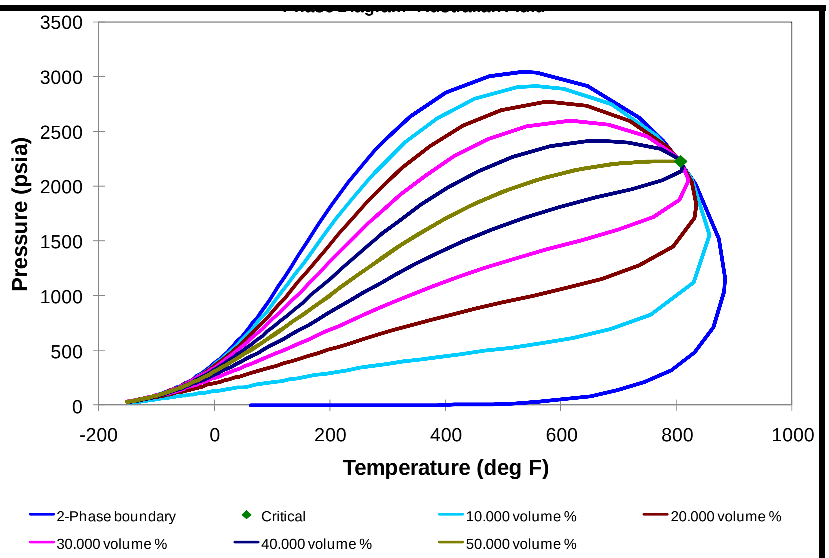

Figure 4-3: Composition and phase diagram of 50 °API gravity reservoir oil

Complex phase equilibria of reservoir fluid during CO_2-assisted gravity drainage oil recovery are studied through the history matching of their PVT properties through the tuning of Peng-Robinson Equation of State (PR-EOS). WinProp™, a CMG's equation of state multiphase equilibrium property software is used to reproduce the observed fluid behaviour and production characteristics, to predict CO_2/Oil phase behaviour and minimum miscibility pressure (MMP). History matched EOS model is obtained through the steps of:

- Data collection
- Input of the compositional and experimental data into WinProp software package
- Tuning of PR-EOS and then match it to the experimental data
- Exporting the history matched EOS model in CMG's GEM™ software for reservoir simulations

Reservoir fluid characterization or EOS tuning for the reproduction of PVT properties is a multi-step process involving

1. *Splitting heavy components (C_{6+} or C_{7+}) into the pseudocomponents*: Since a single heavy fraction lumps thousands of compounds with a carbon number higher than six (or seven), the properties of the heavy component C_{6+} (or C_{7+}) are usually not known precisely, thus represent the main source of error in the EOS reducing its predictive accuracy. Therefore, C_{6+} fractions are split into pseudocomponents to enhance EOS predictions as per the procedure suggested by Whitson (1983). Whitson's method uses a three-parameter gamma probability function to characterize the molar distribution (mole fraction/molecular weight relation) and physical properties (e.g. specific gravity) of petroleum fractions such as hexanes-plus (C_{6+}), preserving the molecular weight of plus fraction.

2. *Lumping or pseudoization of components into a fewer number of pseudo-components*: It is performed primarily to minimize the components and speed up the simulation run time. Similar component properties and molecular weight are the parametric criteria for lumping pseudo-components. Several numbers of regressions are necessary to select the best grouping scheme for the history matched tuning the laboratory experiments.

3. *History matching of PVT properties through regression*: Data from experiments viz. differential liberation (DL), constant composition expansion (CCE) or constant volume depletion (CVD), swelling and separator tests are used in this step. Regression for the viscosity matching is based on the Jossi-Stiel-Thodos (JST) correlation and was carried out in separate regression block. Saturation pressure, DL, CCE and CVD data were excluded in this run. Several regression runs may be necessary to achieve the match of the experimental data. Regression variables are chosen to exclude any regression parameters that, by inspection, cannot significantly affect the calculated value of the regression data. Parameters of plus components were used during regression runs were amongst the following:

   i. Critical pressure (P_c)
   ii. Critical temperature (T_c)
   iii. Critical volume (V_c)
   iv. Accentric factor

v. Volume shifts
vi. Interaction parameters between CO_2 and plus components

EOS tuning process for C_{6+} fractions for an Australian reservoir fluid

Each of the laboratory experiments consisting of the properties obtained was first simulated with the PR-EOS without performing any regression. These simulated model properties are then compared with the laboratory observations (PVT). The obtained comparisons of the preliminary match from the WinProp are given in **Figure 4-4(a) through Figure 4-4(e)**. These preliminary results demonstrate that the behavior of the fluid was being reproduced with a basic (untuned) EOS with reasonable predictions. However, some experiments were not fully matched indicating that the EOS parameters need to be adjusted in order to reproduce the behavior of the reservoir fluid.

Next step was to tune or characterize the EOS so that it is able to reproduce the PVT experiments. This multistep process, that started by splitting the heavy component, is based on the properties of the plus fractions mainly molecular weight (MW), specific gravity (SG) and the mole fraction (Z) as suggested by Whitson. Heavy component (C_{7+}) are split into three pseudocomponents. The pseudocomponents are identified as HYP01, HYP02 and HYP03. By splitting heavy components (C_{7+}), the total number of components of the reservoir fluid then increased from 10 to 13 components. This 13-component mixture is used to tune the EOS by regressions to match the PVT experiments. Several regressions were required to achieve the reasonably accurate match during the process of tuning the EOS. Since a single heptanes-plus (C_{7+}) fraction lumps thousands of compounds with a carbon number higher than seven, the properties of the heavy component C_{7+} are usually not known precisely, and thus represent the main source of error in the EOS and reduce its predictive accuracy. For this reason, regressions are performed against the pseudocomponents to improve the EOS predictions.

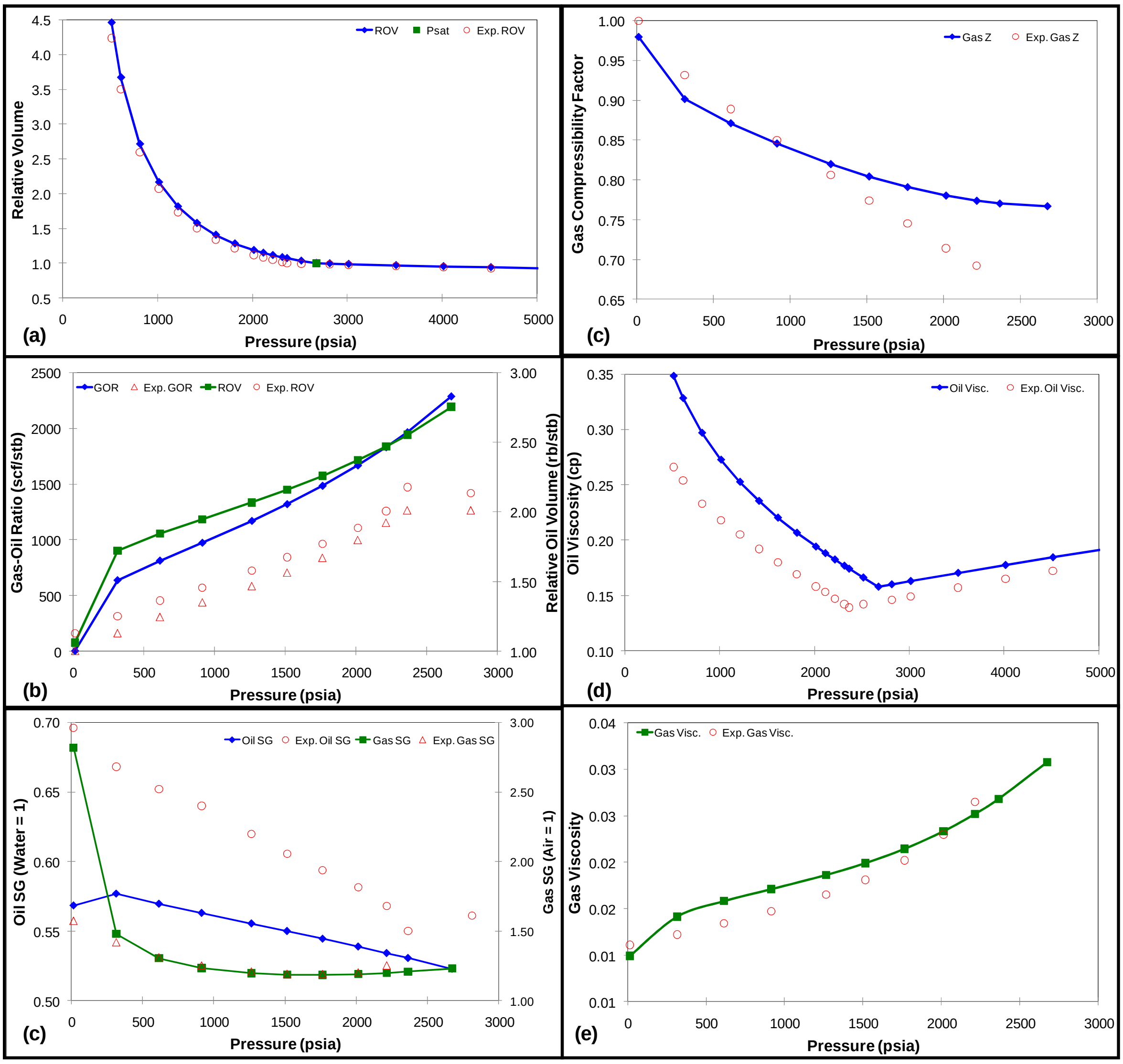

Figure 4-4: Preliminary match of the reservoir oil properties viz. (a) relative volume (b) GOR and Bo (c) Oil and gas specific gravity (d) Gas compressibility factor (e) oil viscosity (f) gas viscosity

Once a satisfactory match of all the experimental data is obtained, 13-component EOS model needs to be grouped into a reduced pseudocomponent EOS model to be acceptable for a compositional reservoir simulation. Performing these steps minimizes the computational time required to solve the numerical equations through iterations, hence the numerical complexity of the simulation.

The methodology for a stepwise regression presented by Fevang (2000) was used for the lumping process from 13 to 10 components. The existing components are lumped to form new pseudocomponents. Using the regression parameters, these newly-formed pseudocomponents were then fine-tuned for the more accurate EOS properties matching.

This process was repeated a number of times to select the best grouping at each stage in the pseudoization process.

A series of grouping exercises are performed. First, C_1+N_2, i-C_4+n-C_4, and i-C_5+n-C_5 were grouped together to obtain a 10-component EOS model leaving the remaining components ungrouped. As mentioned previously, the regression parameters to tune the EOS were the critical properties of the newly formed pseudocomponents and volume shifts. After performing these regressions, very close match of the PVT properties of the 10-component EOS model with the 13-component EOS model was achieved.

In order to reduce the number of components further (10 to 7 component PR-EOS model), another grouping of (C_3+i-C_4+n-C_4+i-C_5+n-C_5) into a pseudocomponent and (HYP02+HYP03) to another pseudocomponent was carried out. It contained the following components: (CO_2); (N_2, C_1); (C_2); (C_3-C_5); (C_6), (HYP01) and (HYP02+HYP03). Another regression was performed in this step. 7-component EOS model predicted PVT properties very similar to the 10-component EOS model. In final step, all of the hypothetical components were grouped into one pseudocomponent. This 6-component model was regressed against the parameters in number of simulation runs to obtain a best possible match of the PVT properties. In all of the above history matching regressions, the viscosity matching regression was excluded.

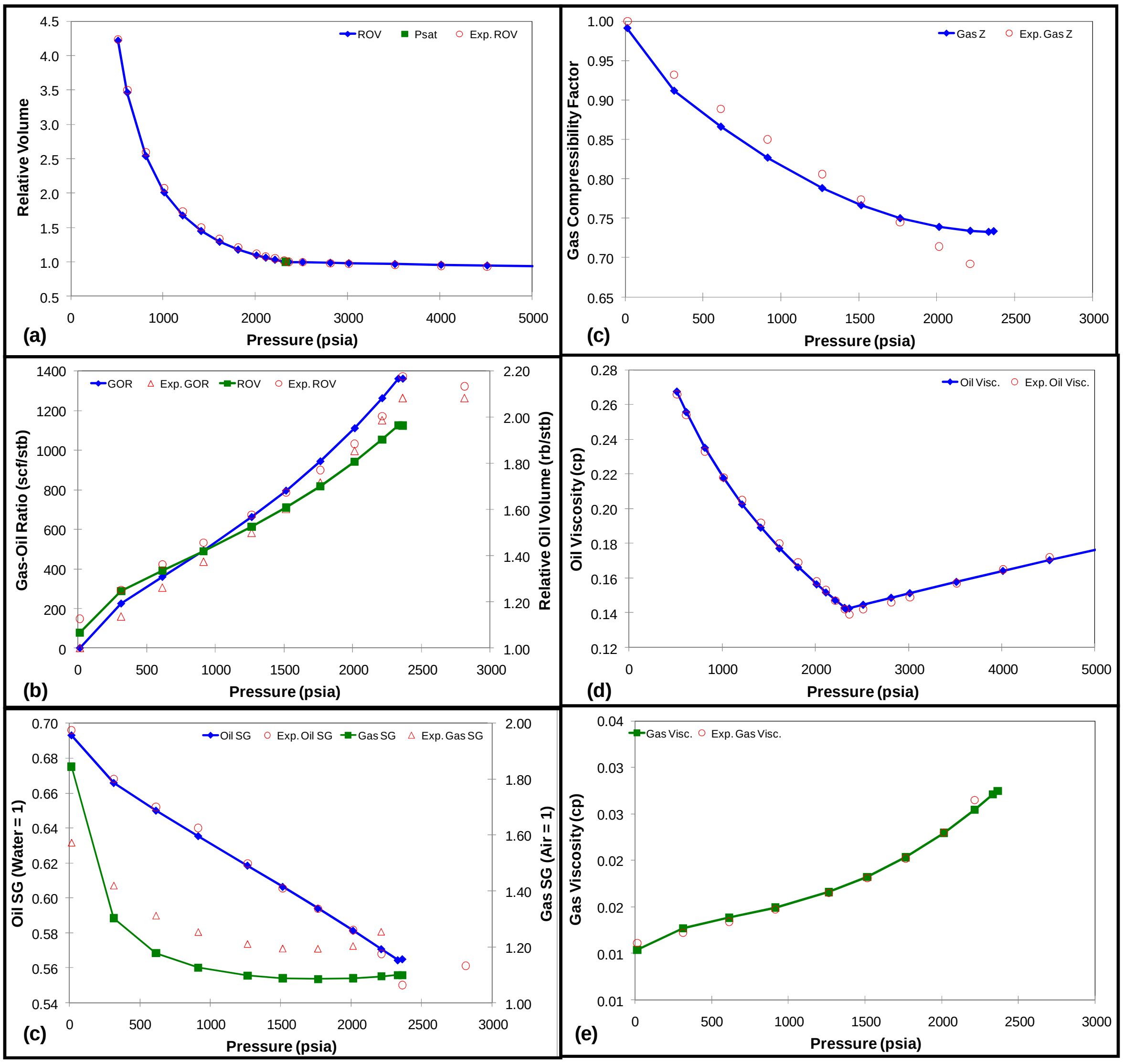

Figure 4-5: EOS predicted match of the reservoir oil properties viz. (a) relative volume (b) GOR and Bo (c) Oil and gas specific gravity (d) Gas compressibility factor (e) oil viscosity (f) gas viscosity

As a final step, regression was performed against both oil and gas viscosity to ensure the correct estimation of reservoir fluid viscosity. The mixing rule exponent parameters, polynomial coefficients and the V_c properties of the plus components and the C_1 of the JST correlation are used in the viscosity regression.

Figure 4-5(a) through Figure 4-5(e) shows that very reasonable and accurate match of the EOS model with the laboratory experimental properties is obtained. They represent the tuned EOS model for use in the compositional reservoir simulation. HC-HC interaction coefficients of the model are as shown in **Table 4-1**. As can be seen, the results provided very good predictions when compared against the observations. This EOS was accepted for use in simulation.

Table 4-2: HC-HC interaction coefficients of 50 ^{o}API gravity oil EOS model

HC-HC interaction coefficients						
component	**CO2**	**N2 toC1**	**C2**	**C3 toIC5**	**FC6**	**HYPtoHYP**
CO2	zero	0.099361831	0.13	0.13152365	0.15	0.1073473
N2 toC1	0.09936	zero	0.004089	0.019254	0.037947	0.075388
C2	0.13	0.004089	zero	0.005701	0.01757	0.046006
C3 toIC5	0.13152	0.019254	0.005701	zero	0.003323	0.019977
FC6	0.15	0.037947	0.01757	0.003323	zero	0.007124
HYPtoHYP	0.10735	0.075388	0.046006	0.019977	0.007124	zero

4.3 Minimum miscibility pressure (MMP)

Whether the CO_2-asssisted gravity drainage EOR process proceeds in immiscible or miscible mode is decided by minimum miscibility pressure (MMP). It is the pressure at which injected CO_2 is completely soluble with reservoir oil in all proportions and interfacial tension between the two fluids reduces to zero. Capillary pressure, thus interface between two fluids is eliminated in the reservoir. MMP is evaluated using various correlations (Bon and Sarma, 2004) and CMG's WinProp software. It is seen that MMP values ranged from 2676 psi (Emera and Sarma, 2005b) to 3237 psi (CMG's WinProp). Experimentally verified value of 2690 psi (*Bon et al.*, 2005) is considered in this study while deciding immiscible or miscible mode CO_2 EOR operations.

4.4 Rock-fluid properties

Three phase relative permeability is obtained using Stone's Second Model thereby assuming the respective values of the end point saturations. The assigned residual oil saturations in water-oil (S_{orw}) and gas-oil (S_{org}) system are 0.20 and 0.10 respectively. Connate water and critical gas saturation are 0.15 and 0.05 respectively. Other end-point saturations are given in **Table A-II** of Appendix-A. All the Corey exponents were set as 2.0. Relative permeability curves shown the **Figure 4-6** were constructed using these values. Reservoir developed is the water-wet system. It is assumed that there is no effect of hysteresis on the relative permeability. No temperature dependence of relative permeability is used in the simulator. Capillary pressure curves in water-oil and oil-gas system adapted from Ren (2002) are as shown in **Figure 4-7**.

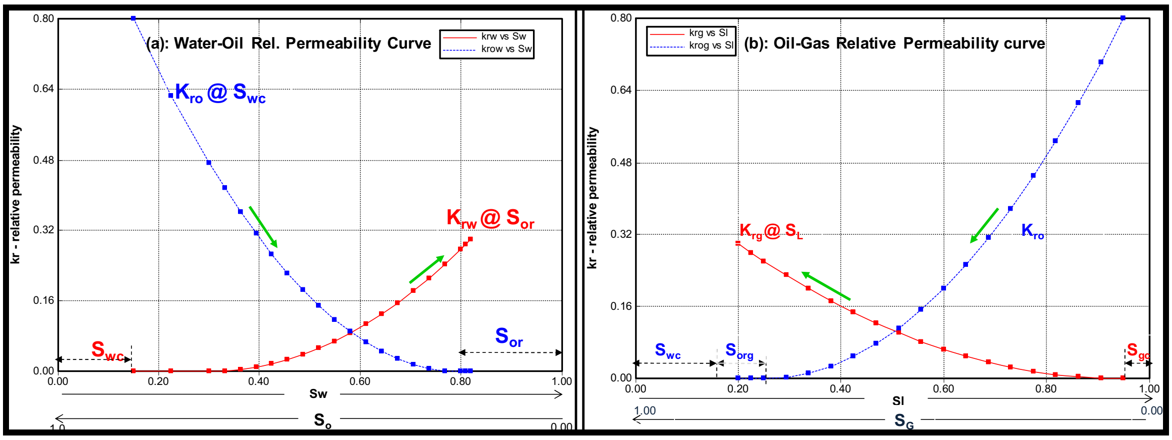

Figure 4-6: Relative permeability curves obtained from Stone-II correlations (a) water-oil (b) gas-oil

NOTE:
This figure is included on page 78 of the print copy of the thesis held in the University of Adelaide Library.

Figure 4-7: Capillary pressure curves adapted from Ren (2002)

4.5 Production Strategy: Well patterns

Reservoir development was undertaken with the drilling of 10 production wells (perforated in the layers 5, 6 and 7) in primary production stage of the reservoir. Entire field was put on production (target of 30000 bpd per well) in January 1970. Primary production was continued up to January 1994. Declining oil production rates lead to the drilling of the three vertical water injection wells (completed in layer 10) at the rate of 40000 barrels per day (bpd) in case of the waterflooding. In secondary or tertiary mode, CO_2 is injected through three vertical injectors perforated in layer-3 (irregular well pattern) while five horizontal producers were drilled in layer-7 to effectively produce the gravity drained oil from the upper layers.

In sensitivity studies, different combinations of vertical and horizontal CO_2 injection and reservoir oil production wells mainly, irregular well pattern and the regular well pattern (**Figure 4-8**) were used. These are discussed in detail at appropriate later sections of this thesis with regards to the effect of the well patterns and horizontal injectors in place of vertical injectors.

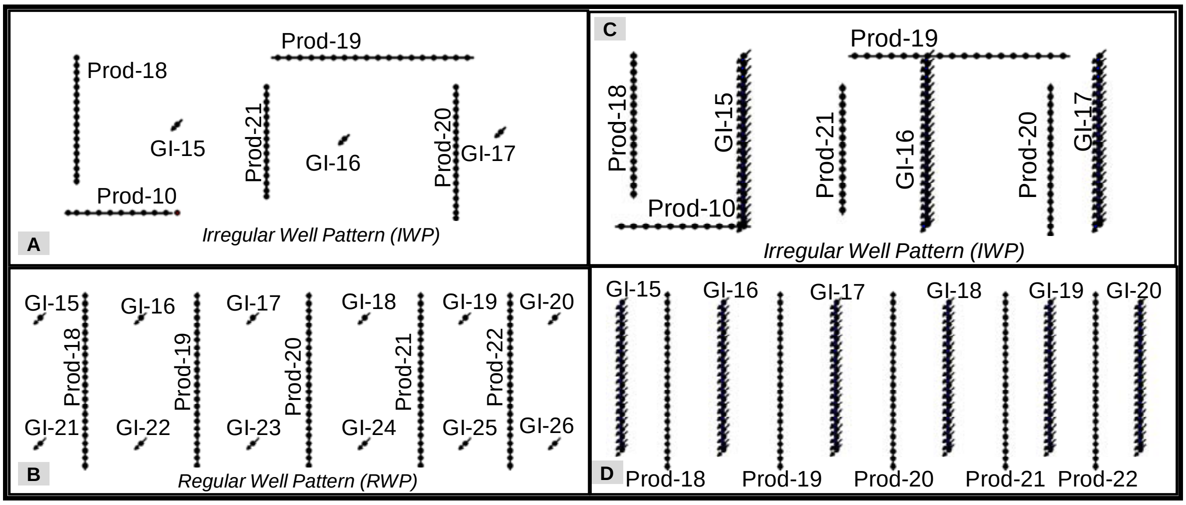

Figure 4-8: (A) and (C) - *Irregular* well patterns; (B) and (D) - Regular Well patterns of vertical /horizontal CO_2 injection wells and horizontal oil production wells

4.6 Model Initialization procedure

Reservoir initial conditions, before production start-up and waterflooding, typical of a homogeneous reservoir, are assumed and used for the initialization of the simulation model. Initial pressure distribution in the reservoir simulation model is initialized according to gravity-capillary equilibrium of a reservoir initially containing water, oil and gas. Reservoir is initially in the gravitational equilibrium.

In case of 35 ^{o}API gravity oil, the initial reservoir temperature is 180 ^{o}F with an average reservoir pressure of 3837 psi. Saturation pressure of the reservoir oil is 3703.327 psi. For 50 ^{o}API gravity oil, the initial reservoir temperature is 279 ^{o}F with an average reservoir pressure of 3274 psi. The saturation pressure of the reservoir oil is 2350 psi. The oil-water-contact (OWC) and the gas-oil-contact (GOC) are at the depths of 8450 ft and the 9150 respectively with the pay zone thickness of 700 ft.

In case of compositional simulation, fluid composition is flashed at reservoir conditions and the respective component proportions in gas and oil phase were assigned in the initialization section at reference pressure of 3200 psia and depth of 8450 psia.

With these data, initialization of reservoir model yields the relative in-place distribution of oil, gas and water as shown in **Table 4-2**.

Table 4-3: Reservoir Volumetrics

Reservoir Volumetrics	**35 ^{o}API oil**	**50 ^{o}API oil**
Original oil in place (OOIP), MMSTB	6138	4150
Original Gas in place (OGIP), MSCF	1296000	1403
Original water in place (OWIP), MMSTB	6316.7	6545
Average saturations		
Oil	39.7%	39.6%
Gas	29.7%	29.3%
Water	30.6%	31.1%

4.7 Summary

Procedures for developing reservoir models using the CMG's IMEX and GEM, the black-oil and compositional simulators, are briefly enumerated in this Chapter. Pseudo-miscible reservoir fluid of 35 ^{o}API gravity and the compositional reservoir fluid of 50 ^{o}API gravity are developed using CMG's WinProp program. Rigorous reservoir fluid characterization procedures that are followed to obtain the final EOS matched compositional reservoir model are described in detail. Minimum miscibility pressures of both the reservoir fluid models are predicted using CMG's WinProp program and presented. Rock-fluid properties, vertical and horizontal well placement scheme and the model initialization procedures are also presented.

5 PRODUCTION STRATEGY DEVELOPMENT

First step in the reservoir simulation is to develop a strategy for the optimum oil recovery performance in the reservoir under construction. This chapter deals with the production strategy development in both the 35 and 50 ^{o}API gravity oil-reservoir with respect to varying the gas injection rates and/or oil production rates, well patterns and the type of vertical vs. horizontal gas injection wells, connate water saturation and the capillary pressure.

5.1 Production History

In this section, brief background of the production (simulation results) during primary depletion and the secondary waterflooding is presented for both the 35 ^{o}API and 50 ^{o}API gravity oil reservoirs.

5.1.1 Production History - 35 ^{o}API oil: Primary Depletion and Waterflooding

When the field was put on production in January 1970 with an initial average reservoir pressure of 3837 psi, the initial production rate was 219864 barrels per day (**Figure 5-1**). With oil withdrawal, the highest energy component, the gas in dissolved state, is also removed. Reservoir pressure continued to decline and then reached below bubble point pressure. Gas-oil ratio (GOR) gradually reduced from 774.252 in Nov 1972 to 728.975 and then declined to critical gas saturation in Jan 1977, during which, oil production sharply dropped. Gas became mobile beyond this stage leading to gradual increase in GOR (**Figure 5-1**), thus mobilizing reservoir oil. Rate of oil production stabilized during nearly constant GOR until July 1991 (160871 bpd and 1108 cu ft/bbl). Oil production rate started to decline in Jan 1991 (168071 bpd). Steep decline in the oil production rate is noticed in later years due to rapidly increasing GOR.

Remarkably no water breakthrough occurred during the first 24 years of oil production during primary production. Grid size effects are further investigated by grid size refinement to half the original model for Case-I. Results presented in **Figure 5-2** show identical GOR and WOR patterns suggesting that grid size do not affect production profile under investigation.

Most of the oil in layer-4 and layer-5 in the vicinity of gas zone is produced. Controlled oil production (30000 bpd) kept solution gas velocity at a lower value thus allowing the gravity force to dominate over the viscous force suggesting that the dominating primary recovery mechanism is gravity drainage. This resulted in 1646 MMSTB of oil and 1611 BCF of gas production from the reservoir.

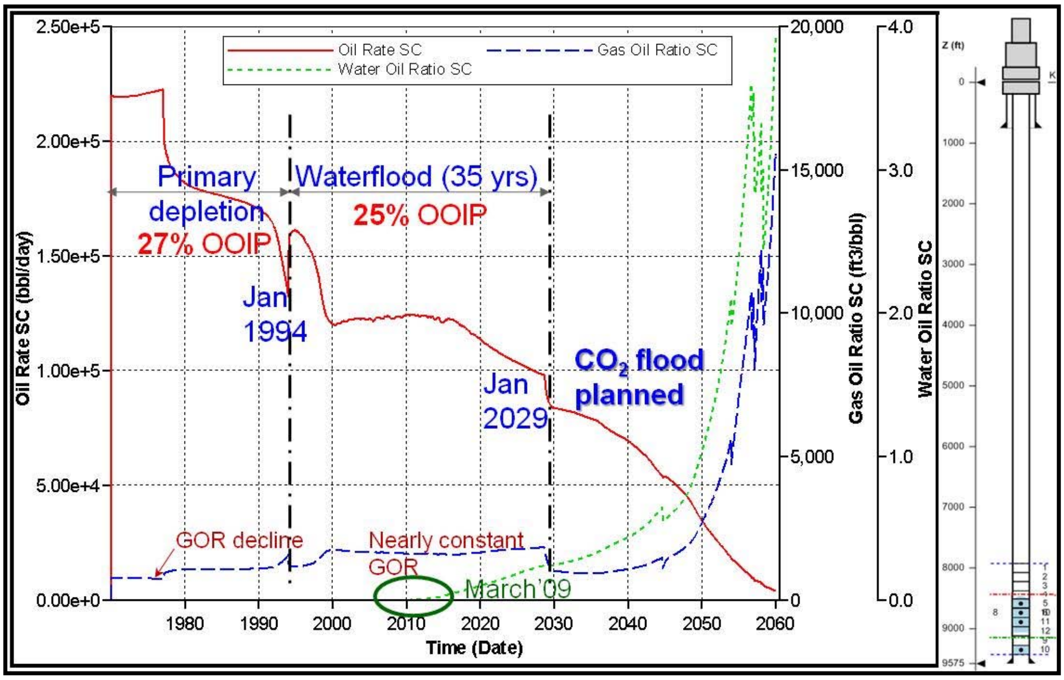

Figure 5-1: Primary depletion and waterflood performance for 35 API reservoir

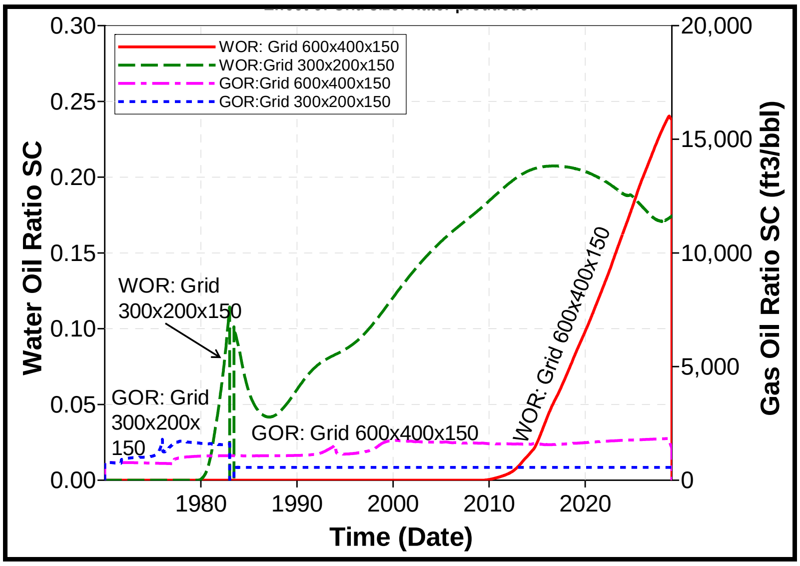

Figure 5-2: Effect of grid size on GOR and WOR

In order to improve the declining oil production, waterflooding was undertaken in January 1994. Water was injected at 40000 bpd while production (through 10 wells) was controlled at 30000 bpd. Oil production peaked at 161298 bpd (November 1994) from initial production rate of 131884 bpd (**Figure 5-1**). During this period, GOR passed through the minimum value and then increased until Jan 2000 (1748) owing to mobilization of the solution gas. Beyond this stage, GOR starts to reduce, gradually providing nearly stable oil production rates, which begins to decline in August 2016 owing to gradual increase in GOR (**Figure 5-1**) and increasing water production. Sharp drop in oil production rate from 98168 bpd in July 2028 to 89687 bpd in January 2029 is observed. Rate of oil production declined in the latter half of waterflooding before remaining steady for about 16 years.

Water did not breakthrough until March 2009 since the start of water injection. Oil saturation in layer-8 just before the start of waterflooding is reduced from 0.8 to 0.12 at the end. After 35 years of waterflooding, oil in layer 8 was mostly produced. It recovered 1554 MMSTB of oil (25% of OOIP), 2486 BCF of gas and 7.4148 MMSTB of water.

5.1.2 Production History - 50 ^{o}API oil: Primary Depletion

Production from the field started in January 1970 with the average initial average reservoir pressure of 3274 psi. Initial production rate was 140534 barrels per day (bpd). With the withdrawal of oil from reservoir, highest energy component gas associated with the reservoir oil in the dissolved state is also removed. Reservoir pressure continues to decline. Oil production continues to rise to reach the peak level of 160287 bpd with the simultaneous decline in GOR (1354) in 1989. Sudden drop in oil production rate is observed owing to rising GOR which then stabilized. Continual decline of oil production rate since then along with the reservoir energy in the form of GOR and reservoir pressure decline lead to the implementation secondary CO_2 injection for the purposes of enhancing oil recovery in 1994.

No water breakthrough was observed during the 24 years of oil production in the primary production stage with the gradual increase in GOR. Further analysis showed that most of the oil in the layer-4 and layer-5, which is in the vicinity of the gas zone, was produced. The overall recovery was 30% of the original oil in place (OOIP). In order to improve the declining oil production rates and to maintain the reservoir flow in gravity dominated regime, the CO_2 flooding was undertaken.

5.2 Production Strategy: Injection Rate or Oil Production Rate Constraint?

Studies to develop a production strategy for CO_2-Assisted Gravity Drainage EOR process are carried out over both the Pseudomiscible black model of 35 ^{o}API reservoir model and the compositional model of 50 ^{o}API Australian reservoir model in this section.

Main focus of this section is to provide a proof of concept of the operational mechanism during CO_2-EOR process through the rate sensitivity studies. To achieve this, tertiary mode immiscible CO_2 flooding is carried in the saturated non-dipping horizontal type reservoir in number of reservoir simulations. In all the simulation runs, reservoir pressure is partially restored through gas-cap CO_2 injection (1200 MMSCF/D) until 2838 psi. Injection rate is then altered to the target rate and maintained constant throughout. Oil saturation distribution at the start of gas injection (January 2032) is as shown in **Figure 5-3**. Production pressure was maintained at 150 psi lower than the injection well pressure. All simulation runs were continued for 98 years.

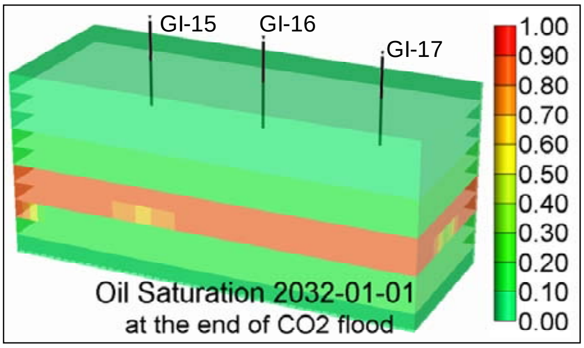

Figure 5-3: Oil saturation at the start CO_2 flood (Case-II)

5.2.1 Critical and Stable Gas Injection Rate

In order to avoid CO_2 fingering through the oil-zone and premature breakthrough to occur at the horizontal production wells placed at the bottom of the oil zone, floodfront stability criteria of Dumore (1964a) is applied. It states that the rate of gas injection in the top-down process should be less than the critical and stable gas injection rates. For the reservoir under investigation in this study, the critical and stable rates are calculated using the multiphase process parameters and presented in **Appendix-B**. To comply with this criterion, the CO_2 injection rates are kept lower than the critical and stable rates in all of the reservoir simulation runs presented in the remaining part of the thesis. Also, the pressure constraints for injection and production wells (difference of 50-80 psi) are used in all the reservoir simulation runs.

5.2.2 Effect of Gas Injection and Oil Production Rates: 35 ^{o}API Reservoir

Two approaches are adopted. In first approach, saturated reservoir response to gas injection (i_g) and oil production rates (q_o) is evaluated in 4 sets of values (Case I to IV). Second approach is based on varying oil production rates at a CO_2 injection rate of 67.5 MMSCFD (see **Table 5-1**).

Table 5-1: Gas injection (ig) & oil production (q_o) rate settings

Case	i_g, MMSCFD	q_o, bpd
	3 vertical injectors	5 Horizontal producers
I	18	4000
II	51	10000
III	67.5	13000
IV	90	17600
Varying q_o at constant i_g		
1	67.5	9000
2	67.5	11000
3	67.5	18000

In Case-I rate combination (See **Table 5-1**), oil rate and gas-oil ratio (GOR) remained constant throughout with maximum water-oil ratio (WOR) of 0.5 as shown in **Figure 5-4**. For Case-II, higher oil production is obtained compared to the previous Case. Oil production rate gradually declined until July 2097. During this period, producing GOR remained near its solution GOR values, stabilizing at 590 cu ft/bbl. Controlled injection and production rates supported by strict pressure control of respective wells provided the nearly constant reservoir pressure. This arrested the solution gas velocity in the oil zone such that oil got dispersed and fell freely under gravity. Increased oil saturation (in 2097) in layer-7 beneath the layer-6 (see **Figure 5-4**) is indicative of this gravity drainage mechanism. Beyond this stage, oil production declined more rapidly. Corresponding GOR started to rise indicating that the CO_2 flood-front reached in layer-7 within the drainage area of horizontal wells 10 and 18. First CO_2 breakthrough occurred at this stage. Once it reached the other producing wells, GOR increased rapidly. In spite of rising producing GOR, average reservoir pressure profile remained constant suggesting that the gas-cap pressure could be constant, thus satisfying the Cardwell and Parsons' criteria of free-fall gravity drainage oil recovery. Further increase in oil saturation in layer-7 at the end of CO_2 flood since first CO_2 breakthrough provide the evidence of the existence of free-fall CO_2-assisted gravity drainage mechanism (see **Figure 5-5**). Gravity drainage enhanced oil recovery after CO_2 breakthrough could have come from oil flowing in the form of continuous thin films (Vizika, 1993) between the gas and water phases, and then draining under gravity towards producer.

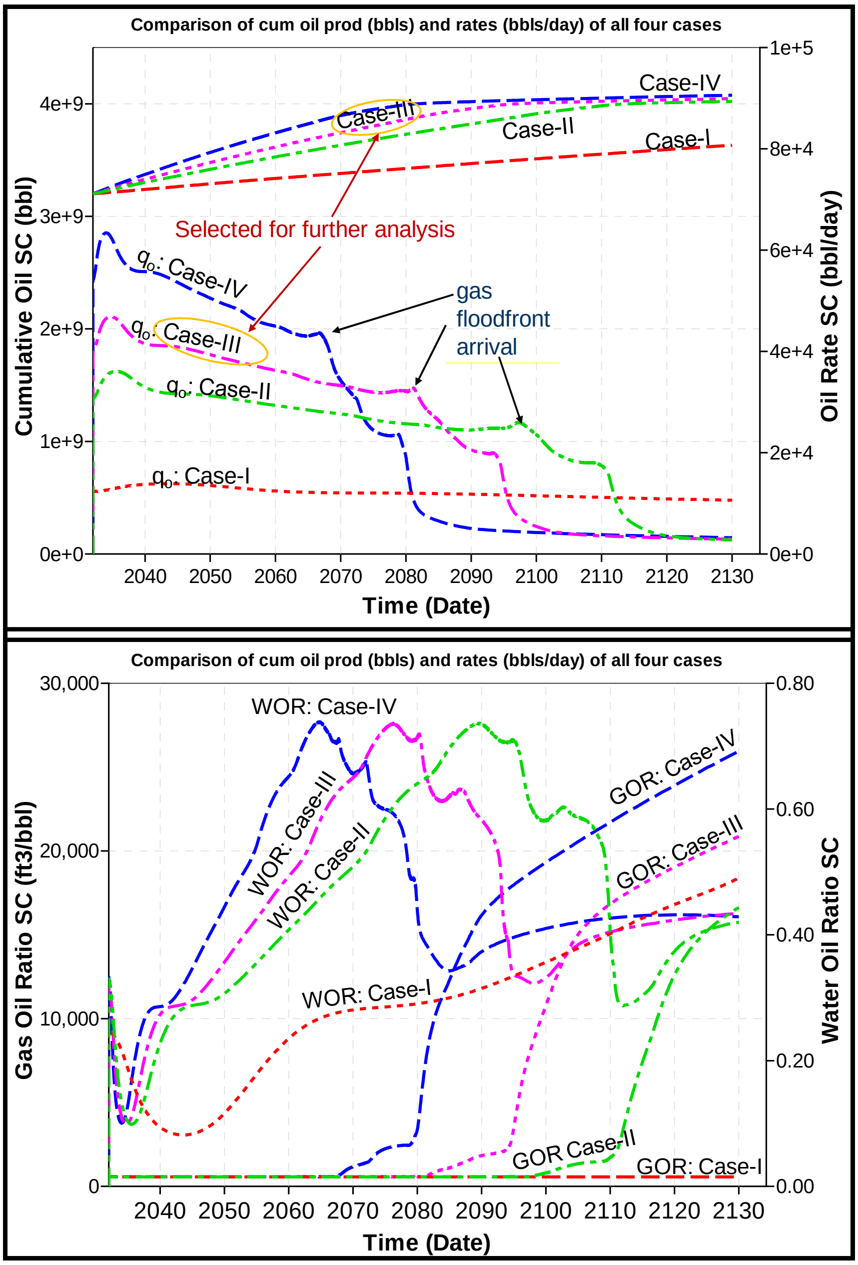

Figure 5-4: CO_2-assisted gravity drainage EOR performance in four gas injection (i_g) and oil production rate (q_o) combinations

Higher rate combination of 67.5 MMSCF/D and 13000 BPD (Case-III) yield better oil recovery performance. Oil production decline is higher compared to Case-II until CO_2 breakthrough. Producing GOR did not change noticeably (about 577 cu ft/bbl) and it remained at the solution GOR values because of the pressure maintenance at near constant values. This minimized the viscosity reduction thereby preventing the oil shrinkage. Countercurrent segregation of oil and gas due to the density difference occurred, leading to the downward oil drainage under gravity. Rise in producing GOR, containing the solution and injection gas, is observed when CO_2 floodfront reached wells 10 and 18 in 2081 (16 years earlier than Case-II). When CO_2 breakthrough occurs in the remaining horizontal producers, producing GOR abruptly increase (January 2094) to maximum of 22000 cu ft/bbl. Producing WOR is also higher in comparison with Case-II (**Figure 5-4**). After CO_2 breakthrough, constant reservoir pressure, similar to case-II, is observed in spite of the increasing GOR. Oil film flow driven by CO_2-assisted gravity drainage mechanism enhances the oil recovery after CO_2 breakthrough. Similar draining of oil in layer-7 from upper layer-6 under gravity effect (as seen in Case-II) is observed before and after CO_2 breakthrough.

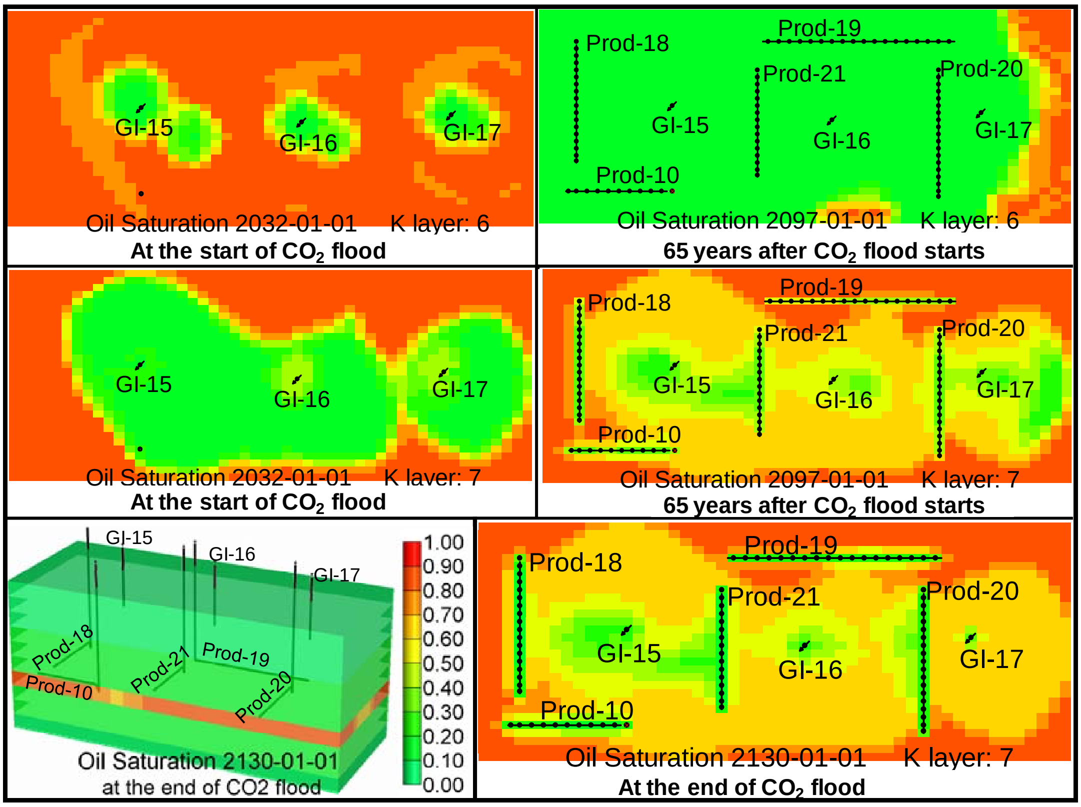

Figure 5-5: Oil saturations in layer-6 and 7 at the start; 65 years later and at the end of CO_2 flood in Case-II

At rate-constraints of 90 MMSCF/D and 17600 BPD (Case-IV), higher oil production is obtained (43430 bpd in January 2032) with its steep decline (17600 bpd in January 2067) in the later years compared to previous cases (**Figure 5-4**). It took only 35 years to sweep out layer-6. GOR sharply increased in January 2079 with the maximum value of 26000 cu ft/bbl when gas-oil contact reached wells while WORs were similar. Oil saturation profiles were similar to shown in Figure except the time taken for oil drainage under gravity effect (35 years in Case-IV) was less. Oil production mechanism before and after CO_2 breakthrough is similar as obtained in Case-I, Case-II and Case-III.

With each higher rate-constraint, higher gas-oil ratio is observed. GOR remained nearly constant until CO_2 breakthrough. It continued to increase, as high as 26000 cu ft/bbl with increasing rates and concurrent oil production in the order of 1000-3000 bpd. Oil recovery decline rate also increased with each higher rate combinations. Similar WOR values were obtained in all cases. However, CO_2 and water-breakthrough occurred early with successive higher rate combination.

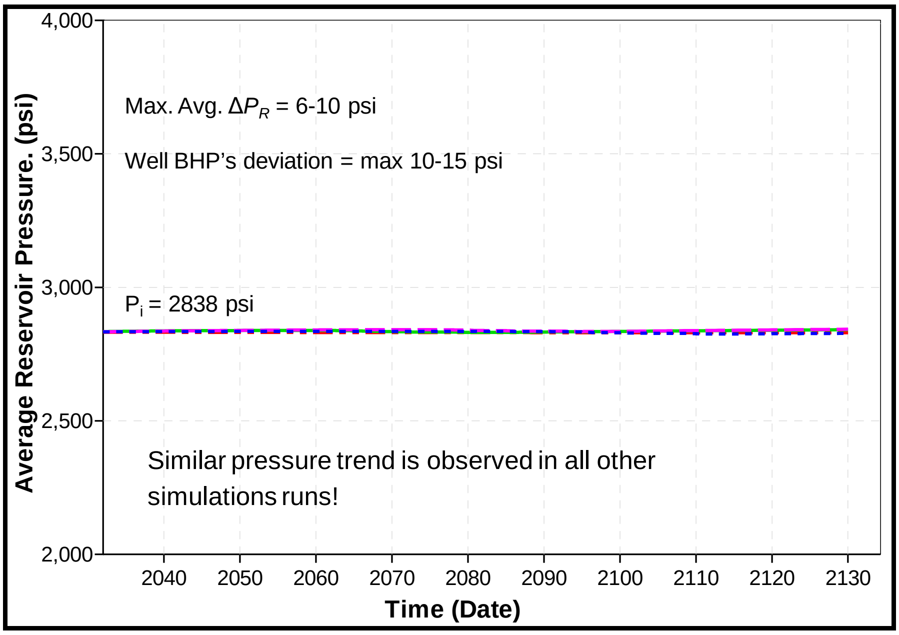

Figure 5-6: Average reservoir pressure during CO_2-assisted gravity drainage EOR process for all the cases.

In all of the above four rate constraints, similar observations were found especially with regards to the EOR mechanism. Controlled rate-constraints maintained a smaller pressure differential across the advancing gas flood front and horizontal wells. Reservoir produced with the GOR equal to the solution GOR until CO_2 breakthrough. In spite of increasing GOR after CO_2 breakthrough, the reservoir pressure remained constant throughout. Respective average reservoir pressure behaviour in all foregoing rate-combinations (Case-I through Case-IV), as depicted in **Figure 5-6**, showed a maximum deviation 10 psi (end of gas flood) from its starting value This implies that the reservoir pressure behind CO_2 floodfront in gas zone could be constant, thereby satisfying Cardwell and Parson's criteria of free fall gravity drainage in all the rate-constraints. After CO_2 breakthrough, oil film drainage under gravity effect contributes the enhanced oil recovery. Increased oil saturations in layer-7 (previously waterflooded zone) in all of the combinations indicate that the operational mechanism is the free fall gravity drainage mechanism.

Incremental oil recoveries obtained include 7% (Case-I), 11.7% (Case-II), 13.76% (Case-III) and 14% (Case-IV) OOIP. Analysis of cumulative volumes of the reservoir oil produced (as depicted in **Figure 5-4**) show that a combination of higher gas injection and oil production rates (Case-IV: 90 MMSCF/D and 17600 BPD) yielded marginal cumulative oil production over previous Case-III (67.5 MMSCF/D, 13000 BPD). This is due to decrease of the sweep efficiency after CO_2 breakthrough coming from the capillary retention as seen in **Figure 5-4**. As Case-III provided more stable oil recovery and lower GOR pattern, it was selected for the subsequent simulation runs. Furthermore, end oil saturations in all cases (layer-6) were reduced to values as low as 0.10 from its starting value 0.84.

Further studies of varying oil production rates (production well constraint) at constant gas injection rates (67.5 MMSCF/D) were carried out in three settings (see **Table 5-1**). At 9000 bpd production rate, oil recovery by gravity drainage is prolonged thereby delaying CO_2 breakthrough by 25 years against the base case of 13000 bpd (**Figure 5-7**). Lower GOR, gradual decline in oil production rates and lower cumulative recoveries were the characteristics of Case-I. For 11000 bpd, it took 9 more years (2090) before the gas front reached the wells. Oil recovery process was shortened (January 2067) when 18000 bpd rate of oil production was used. However, steep decline in oil production rates was observed. With the increasing production rates, higher GORs and WORs were also noticeable. Cumulative recoveries in Case-IV are higher compared to other Cases, but are closer to the base Case-III (at 13000 bpd). This is due to decrease of gravity-viscous ratio and consequent decrease of sweep with gravity-dominant vertical displacement. These results also suggest that higher GOR can be controlled by reduction of the production rates after first gas breakthrough. Oil production can be continued with the typical field rates of about 1000 bpd even after gas breakthrough.

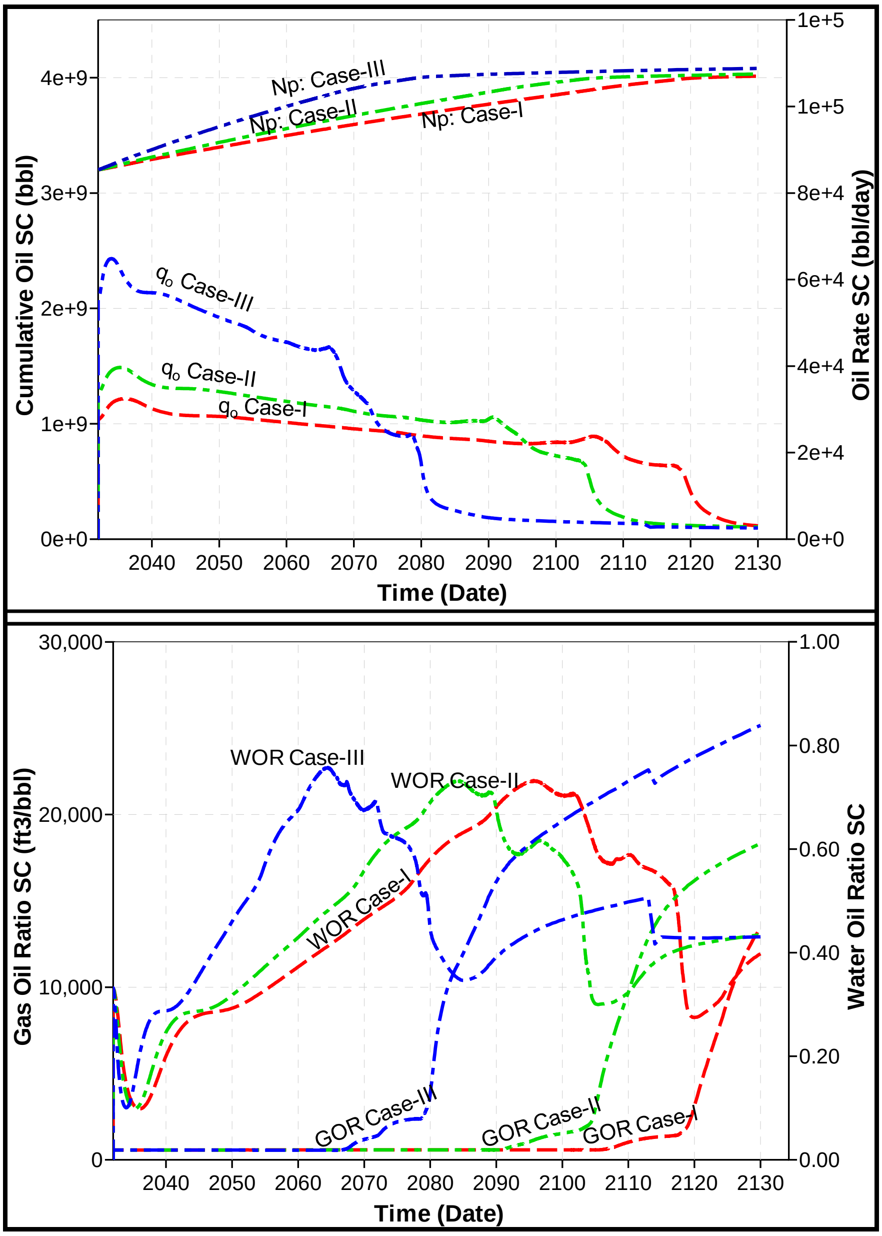

Figure 5-7: Effect of the varying oil production rates at constant gas injection rates on the CO_2-assisted gravity drainage oil recovery.

5.2.3 Effect of gas injection and oil production rates: 50 °API reservoir

Effects of the rate-constraints in miscible GAGD-EOR process are studied by varying either their oil production rate while keeping gas injection rate constant or vice versa in the immiscible process. For 50 °API gravity reservoir, percentage field oil recovery obtained through regular well pattern is as shown in **Figure 5-8**. In immiscible process CO_2 injection rate (i_g) and the oil production rate (q_o) constraint of 2.0 e+07 MMSCFD and 52500 BPD are used. Two simulations were carried out in the miscible process. In the first, i_g was kept same while q_o was adjusted to maintain the voidage balance. In the second simulation, q_o was kept same while i_g was adjusted. The main purpose of this study is to help in finalizing to choose either of these constraints.

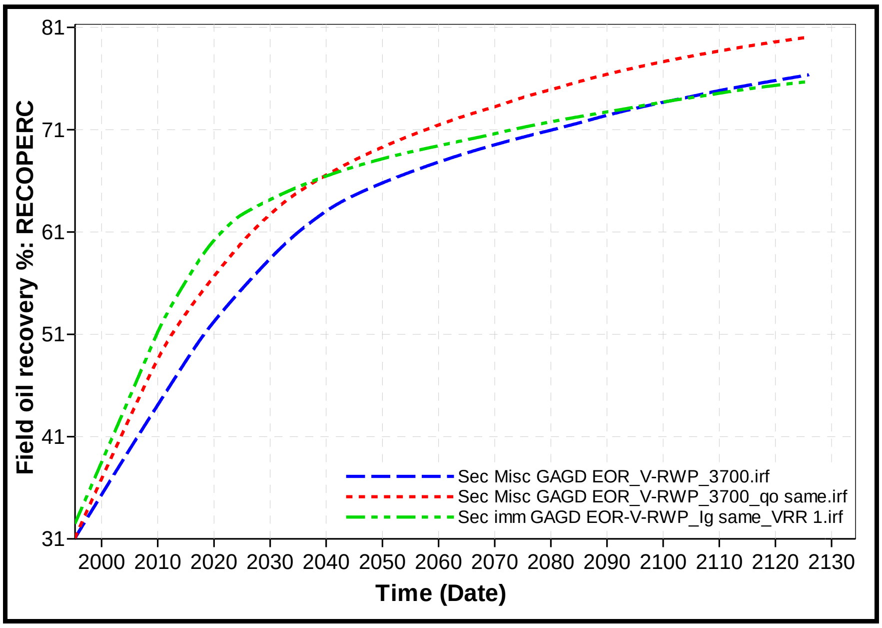

Figure 5-8: Comparison: Effect of the varying gas injection rate vs. oil production rate on the field oil recovery (% OOIP)

When i_g was kept same while q_o was adjusted, the percentage oil recovery for both the immiscible and the miscible oil recovery is nearly identical (76%). On the contrary, 4% higher field recovery was obtained when i_g was adjusted by keeping q_o same as the immiscible process to maintain the voidage balance. As objective is to recover optimum oil from the reservoir, second constraint combination is selected in the next phase of simulations as a part of the production strategy development.

5.3 Type of CO_2 Injection Well - Vertical vs. Horizontal

Reservoir simulations are first conducted using vertical CO_2 injection and then compared with the simulation results obtained using the replaced horizontal CO_2 injection wells. This section presents these results in both the 35 and 50 ^{o}API oil reservoirs. Immiscible and miscible results in 50 ^{o}API reservoir are compared with the discussion of the concurrent operational mechanism.

5.3.1 35 API Reservoir: Irregular Well Pattern

To study the effect of horizontal over vertical gas injection wells, three horizontal wells were drilled and reservoir was put on operation in January 2032. Case-III and Case-IV are used in this study. Oil production rate and its cumulative production, as depicted in **Figure 5-9**, are identical to those obtained in the vertical injection wells. Higher GOR values are obtained in case of horizontal injection wells in comparison with the vertical injection wells. Results indicate that the horizontal wells may not significantly help to improve gravity drainage. This suggests that the oil drainage from upper layers is a mechanism purely operating on the principle of gravity provided the viscous and gravity forces are balanced through gas-assisted reservoir pressure maintenance, irrespective of type of the injection wells used.

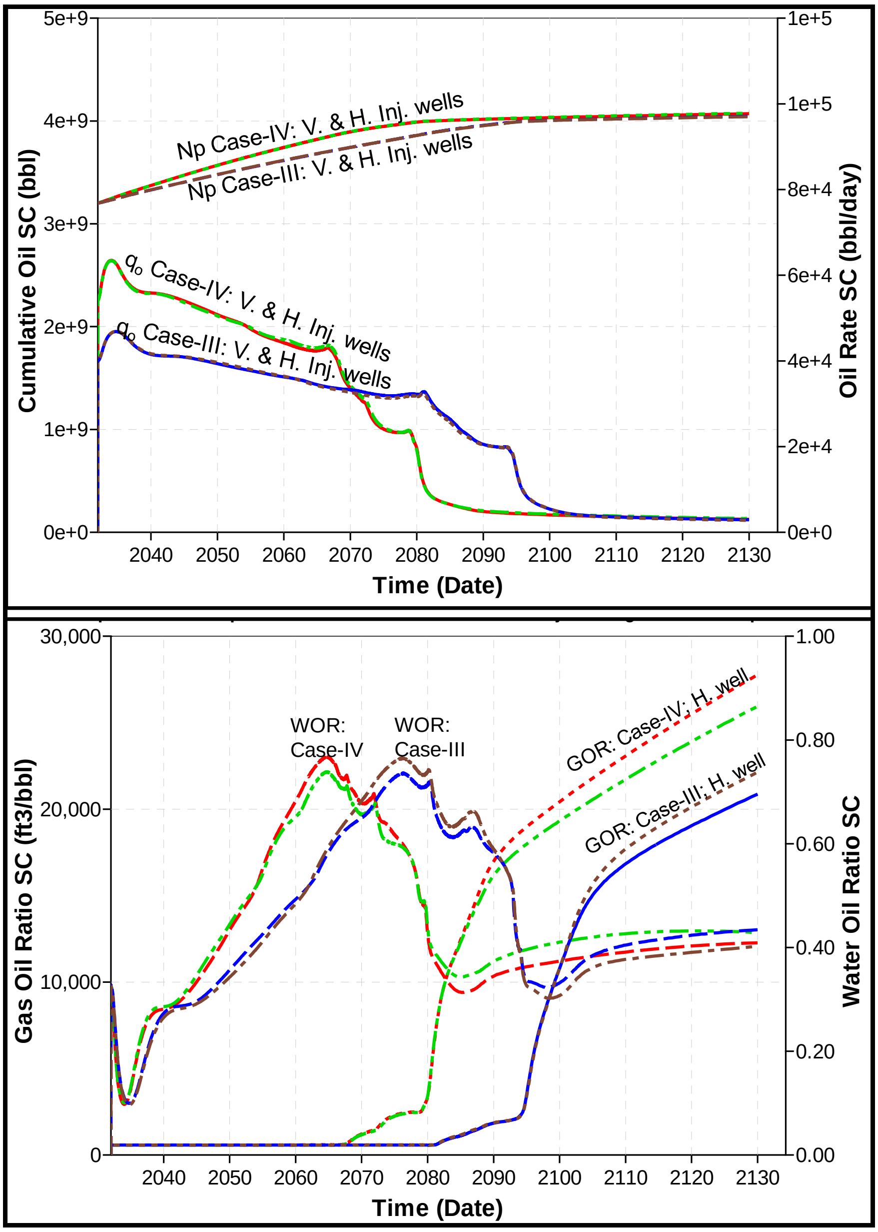

Figure 5-9: Effect of the horizontal versus vertical gas injection wells on CO_2-assisted gravity drainage oil recovery in 35 ^oAPI reservoir oil

5.3.2 50 API Reservoir: Regular Well Pattern (RWP)

Effect of the type of CO_2 injection well, that is vertical and horizontal; on the gravity drainage oil recovery performance is studied in regular direct line drive well pattern (RWP). 12 vertical CO_2 injection wells were then replaced by 6 horizontal CO_2 injection wells (see **Figure 4-8**). Oil recovery performance between them is assessed using oil production rates (q_o), gas-oil ratio (GOR), water cut (WC%), cumulative oil recovery (Np), HC pore volumes injected (HCPVinj%) and the average reservoir pressure.

Simulation results were then compared to observe any improvement in the oil recovery over 132 years of gravity drainage oil recovery performance.

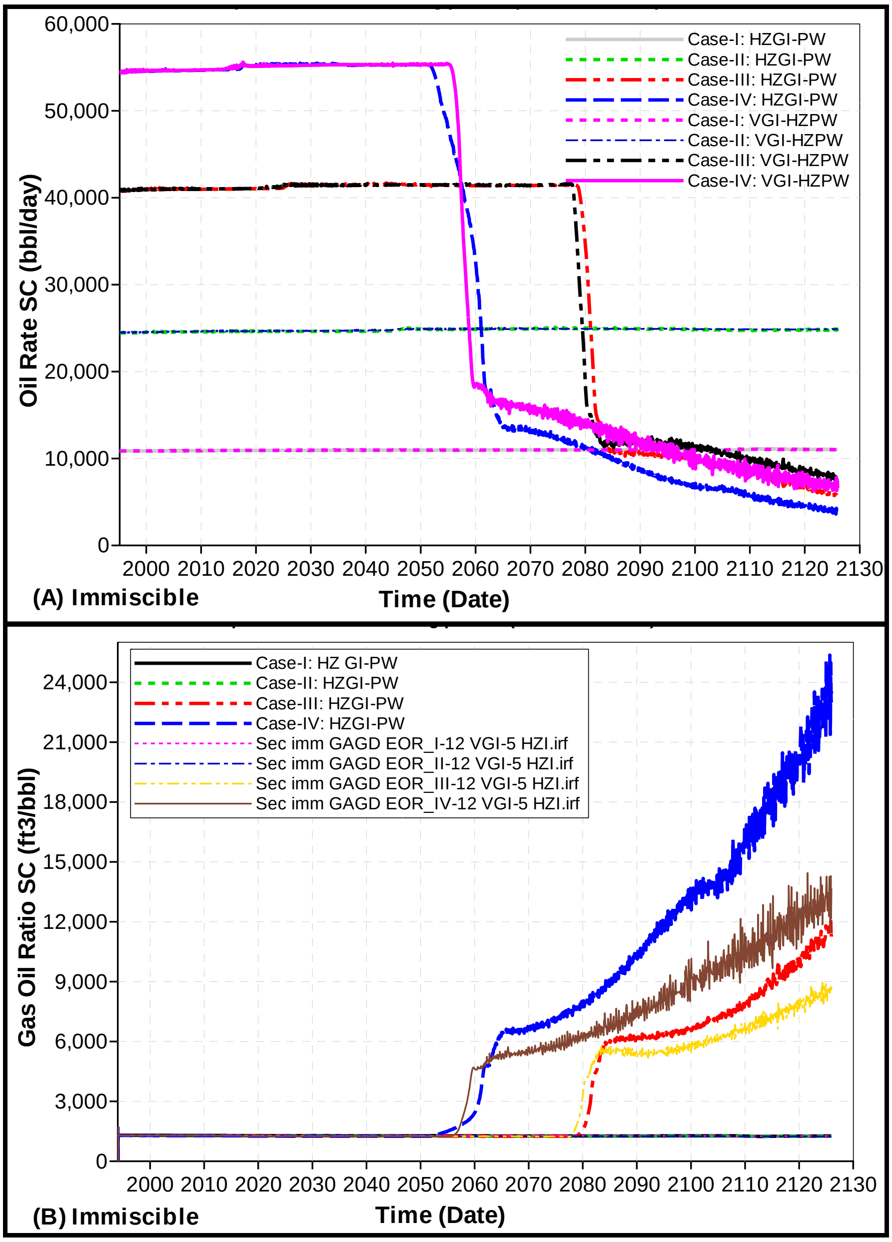

Figure 5-10: Vertical vs. horizontal CO_2 injection well effect (q_o and GOR) on CO_2-assisted gravity drainage oil recovery in the immiscible process

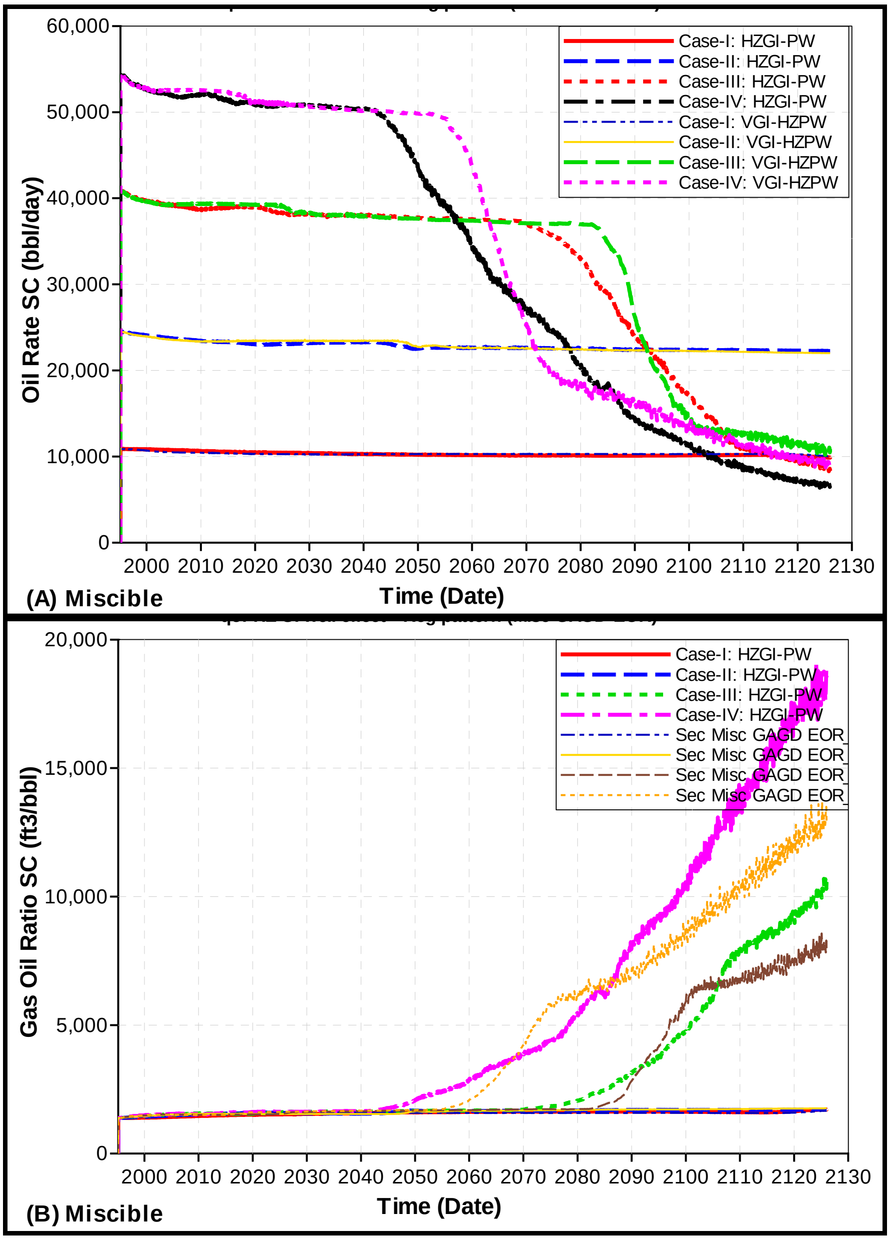

Figure 5-11: Vertical vs. horizontal CO_2 injection well effect (q_o and GOR) on the CO_2-assisted gravity drainage oil recovery in miscible process

Comparative reservoir response to vertical and horizontal CO_2 injection wells in an immiscible and miscible CO_2-assisted gravity drainage EOR process is as shown in **Figure 5-10** and **Figure 5-11** respectively. Analysis shows that the oil production occurred at the maximum rate constraint (**Figure 5-10A** and **Figure 5-11A**) at the producing GOR equal to the solution gas GOR (**Figure 5-10B** and **Figure 5-11B**) with minimal water breakthrough. Moreover, oil production sustained longer for vertical CO_2 injection (VGI) wells as compared to horizontal gas injection wells (HZI) in case-III and case-IV. Once oil in the oil-bearing zone is swept vertically downward by the advancing gas front, CO_2 breakthrough occurs in the production wells. It is delayed in vertical injection well cases by 2 to 3 years in immiscible and 12 years in miscible process compared to the horizontal well cases (see **Figure 5-10B** and **Figure 5-11B**). Oil production rate drops, and then stabilizes at a gravity drainage rate of the oil production. After CO_2 breakthrough GOR continue to rise owing to gas production along with the flow of oil between the gas and water in immiscible process. Interconnected oil-films are drained under gravity towards the horizontal producers.

Sharper decline (nearly vertical) of oil production rate was observed when VGI wells were used in immiscible process. GOR is also lower in vertical CO_2 injection wells compared to the horizontal wells. However water production seen to be lower with the horizontal CO_2 injection wells because of the perforations along the horizontal section of wells. Similar GOR behavior was observed in the miscible process. Decline of oil production rate is not sharp in case of miscible process, as was the case with the immiscible one.

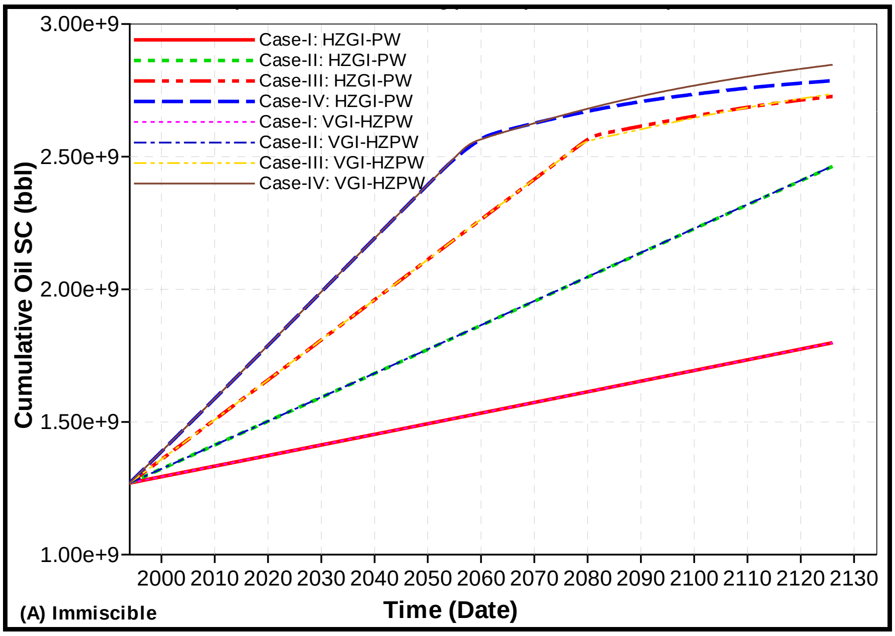

Figure 5-12: Effect of vertical versus horizontal CO_2 injection wells in the *immiscible* CO_2-assisted gravity drainage EOR process: Cumulative oil recovery (N_P)

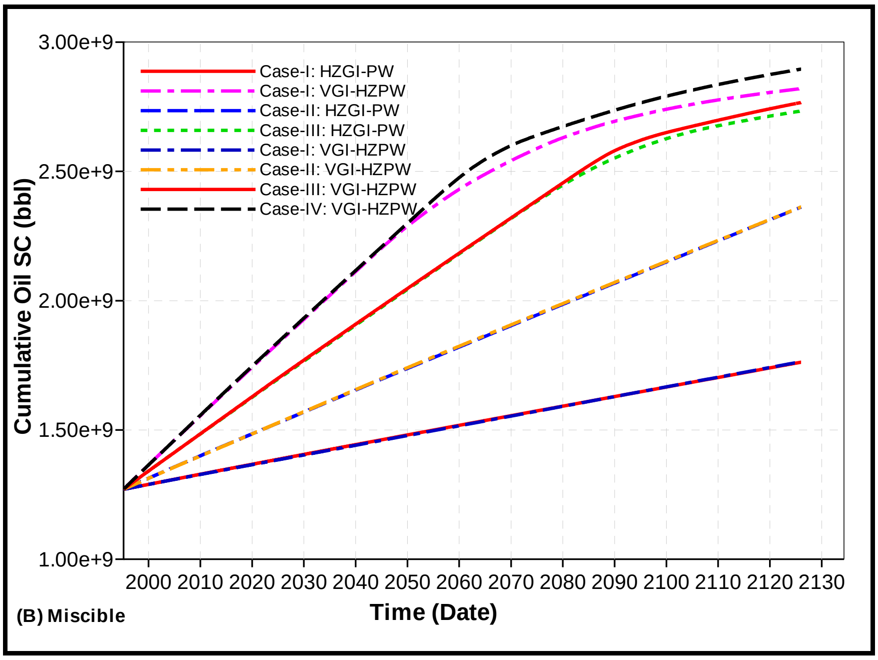

Figure 5-13: Effect of vertical versus horizontal CO_2 injection wells in the *miscible* CO_2-assisted gravity drainage EOR process: Cumulative oil recovery (N_P)

Further assessment of cumulative oil production volumes in both the immiscible and miscible process (**Figure 5-12** and **Figure 5-13**) indicated that the horizontal CO_2 injection wells yield identical recovery relative to the vertical CO_2 injection wells except case-IV. Instead, less cumulative oil was produced with case-IV of the horizontal injection and production well combination. These results suggest that the type of injection well may not significantly affect the overall CO_2-assisted oil gravity drainage EOR performance. Rather, it would adversely diminish oil recovery performance, especially for the reservoir system under consideration. This is because the oil production is predominantly the function of gravity drainage mechanism and not the volume of reservoir contacted by CO_2.

Moreover, two results in case-III and IV points out that the combination of the vertical CO_2 injection and the horizontal production well provides more efficient sweep out of the oil zone. Oil recovery can be optimized when the gas-oil contact or the CO_2-floodfront is maintained as horizontal as possible. Higher cumulative oil production obtained in the combination of the vertical CO_2 injection and the horizontal oil production well than the horizontal wells combination clearly demonstrated this hypothesis, indicating that vertical CO_2 injection well indeed provided more horizontal floodfront than the horizontal CO_2 injection wells. It further delays CO_2 breakthrough.

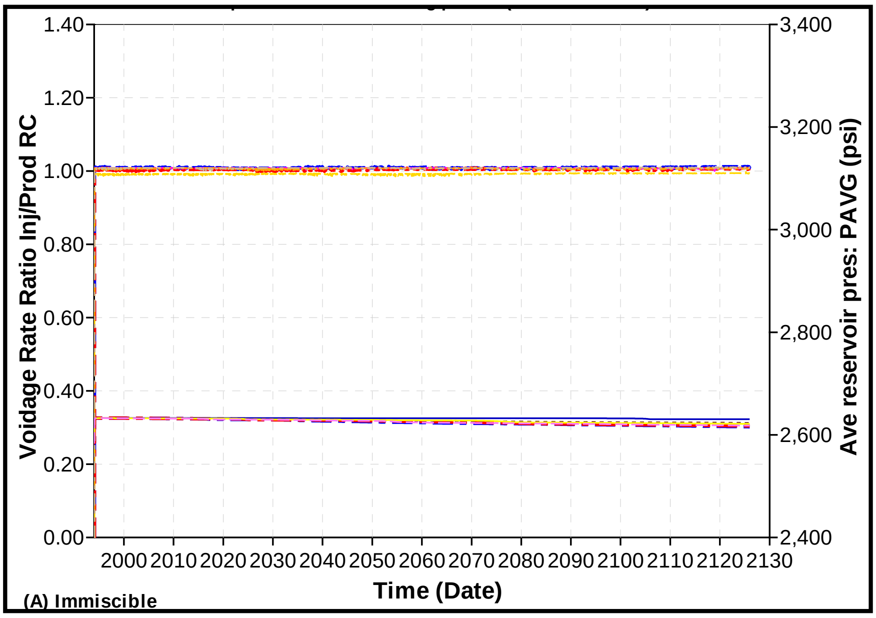

Figure 5-14: Average reservoir pressure in the *immiscible* CO_2-assisted gravity drainage EOR process during injection well type studies

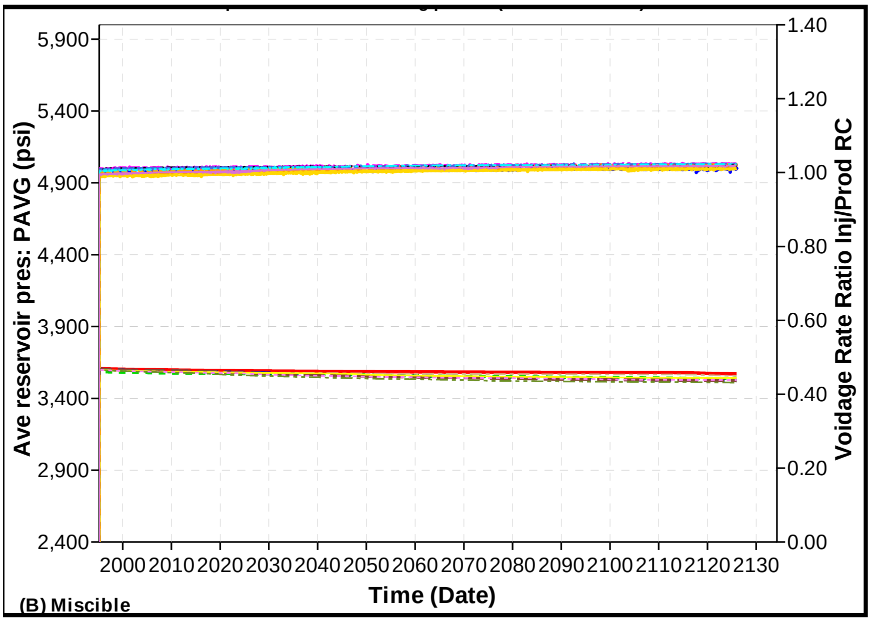

Figure 5-15: Average reservoir pressure in the *miscible* CO_2-assisted gravity drainage EOR process during injection well type studies

Reservoir response to pressure over 132 years of oil production as shown in **Figure 5-14** and **Figure 5-15** indicates that average reservoir pressure drop is maximum 35 psia. Both of these injection well types provide identical reservoir pressure profile. As pressure drop in minimum, it could be implied that both the pressure in the gas zone behind the gas-oil floodfront could be very less than that of the actual average reservoir pressure drop.

This indicates that the reservoir pressure in the gas zone behind CO_2-oil interface could be constant making the process gravity drainage EOR process assisted by the injected gas.

5.4 Well Patterns: Irregular vs. Regular

Reservoir simulations of CO_2-assisted gravity drainage EOR process are carried out using CMG's EOS based compositional simulator GEM. CO_2 is injected in secondary stage after the primary depletion of the reservoir in both the immiscible and miscible modes. Base case runs are obtained through combinations of the vertical CO_2 gas injection (GI) and the horizontal oil production wells in both the immiscible and miscible CO_2-EOR processes and compared with the other runs with which the parameters are to be evaluated. Four combinations of the CO_2 injection rates (i_g) and oil production rates (q_o) under the reservoir voidage rate ratio of about 1.0. Main objective of this study is to evaluate the effect of well patterns both the irregular and regular on the final CO_2-assisted gravity drainage oil recovery. The results would help in identifying the best possible combination between the vertical or horizontal injection and the horizontal production wells.

In all the simulation runs of CO_2-assisted gravity drainage EOR process, the reservoir pressure is partially restored to 2652 psi in immiscible CO_2 injection and 3605 psi from 2584 (Jan 1994) in miscible CO_2 injection by injecting gas in the gas cap. Once the desired reservoir pressure is achieved the gas injection rate is then altered to the target rate and maintained constant throughout the gas injection operations. Pressure of the production wells was maintained at 200 psi lower than the injection well pressure. All the simulation runs were carried out for the 132 years.

Effect of the orientation of the vertical as well as horizontal CO_2 injection wells and the respective horizontal oil producing wells in a particular case is studied in either irregular or regular direct line drive well pattern. Irregular well pattern comprises the vertical gas injection wells and the horizontal production wells as depicted in **Figure 4-8**. Minimum and maximum distance between the injector and producer in this well combination is 2400 ft and 6600 ft respectively. Vertical and horizontal wells are then re-oriented to form the regular direct line drive pattern (**Figure 4-8**). In the later case, minimum and maximum well spacing were 2400 and 3000 ft respectively.

Base cases of reservoir performance for CO_2-assisted gravity drainage EOR process are obtained in four cases (combinations) of CO_2 injection (i_g) and oil production rates (q_o).

In immiscible process, these i_g (MMSCF/D) and q_o (BOPD) are 15.3 to 18 and 4000, 40.5 to 44 and 9000, 67.5 and 15000, and 88.5 and 20000 respectively for three vertical gas injection wells (perforated in layer-3 of the gas zone) and 5 horizontal oil production wells (perforated in layer 8 of oil zone, about 80 feet above WOC). The reservoir was then put on production in 20^{th} January 1994. In miscible flooding, four cases (combinations) of CO_2 injection (i_g - MMSCF/D) and oil production rates (q_o - BOPD) are 25.1 and 4000, 56.4 and 9000, 93.6 and 15000, and 124 and 20000 respectively for three vertical gas injection wells and 5 horizontal oil production wells. Higher i_g values are coming from the requirement of CO_2 compression, so the high pressure injection at a pressure greater than MMP. CO_2 flooding was started in March 1995. The lower rate constraints of the CO_2 injection and oil production wells are specifically chosen to have CO_2 floodfront or gas-oil contact as horizontal as possible without any interference from high pressure gas injection.

Reservoir performance for the irregular pattern well (IWP) placement obtained through the reservoir simulation runs are compared with the regular direct line drive well pattern (RWP) using oil production rate (q_o), gas-oil ratio (GOR), water-oil ratio (WOR), and cumulative oil production (N_p). Results of these sensitivity parameters over 132 years for scoping analysis of the well pattern effects on the gravity drainage oil production assisted by CO_2 injection are presented in this section.

5.4.1 Secondary Immiscible CO_2-Assisted Gravity Drainage EOR

At lower CO_2 injection rate of 1.5E+06 (each of 12 wells), reservoir is produced at a flat oil production rate (12000 BPD) at the maximum rate constraint (**Figure 5-16A**) and producing GOR equal to the solution gas GOR (**Figure 5-16B**). At higher CO_2 injection rate of 3.32E+06 (each of 12 wells), the oil rate with IWP drops near the end of simulation run owing to CO_2 breakthrough indicating that CO_2 floodfront reached the producing wells.

In case-III (5.62 MMSCFD, each of 12 wells) of IWP-CO_2 injection, oil production continues at the maximum rate constraint (see **Figure 5-16A**). During this period, the producing GOR is equal to solution GOR. Oil production rate drops once CO_2 floodfront reaches the producing wells and continue to decline. For the same CO_2 injection rate, oil production rate in RWP observed to provide longer production times compared to IWP-production rates at the maximum production rate constraint. It then passes through an abrupt near-vertical drop owing to CO_2 floodfront arrival and CO_2 breakthrough at the producing wells. It is marked by the shooting up (sharp near-vertical upward rise) of the respective producing GOR (as shown by arrow in **Figure 5-16B**) from the level of the solution GOR. Once the oil production rate drop is arrested and rates are stabilized, GOR shows the gradual increase trend which continue to rise gradually. Moreover, CO_2 floodfront arrival is delayed in RWP and CO_2 breakthrough occurs 10 years later than in IWP- CO_2 injection case. Cumulative oil recovery curve changes its trend from linear to a near-horizontal straightening up once CO_2 breakthrough occurred (**Figure 5-16B**).

For higher CO_2 injection rate in case-IV, oil production rate drop, so the CO_2 floodfront arrival, observed to occur early in both the IWP and RWP compared to case-III because of the higher rate constraint (**Figure 5-16A**). Oil production observed to continue to take place longer at the maximum rate constraint, very similar to case-III, which then near-vertically dropped (in RWP case) indicating the vertical downward sweepout of the oil zone and the CO_2 floodfront arrival (**Figure 5-16A**). Respective GOR behavior was duplicated like case-III with the delayed CO_2 breakthrough by 8 years in RWP case (Figure B). Water production is lower in RWP than IWP (**Figure 5-17A**).

Gas saturation profile for immiscible process in 2059 is as depicted in (**Figure 5-16C**). Gas saturation profile clearly indicated that the gas-cap gas did not finger through to the horizontal production wells before CO_2 floodfront arrival, satisfying the Dumore criterion of the floodfront stability (1964a). This further lead to *a hypothesis that regular well pattern provides more horizontal and stable CO_2 floodfront (gas-oil contact) than the irregular well pattern*.

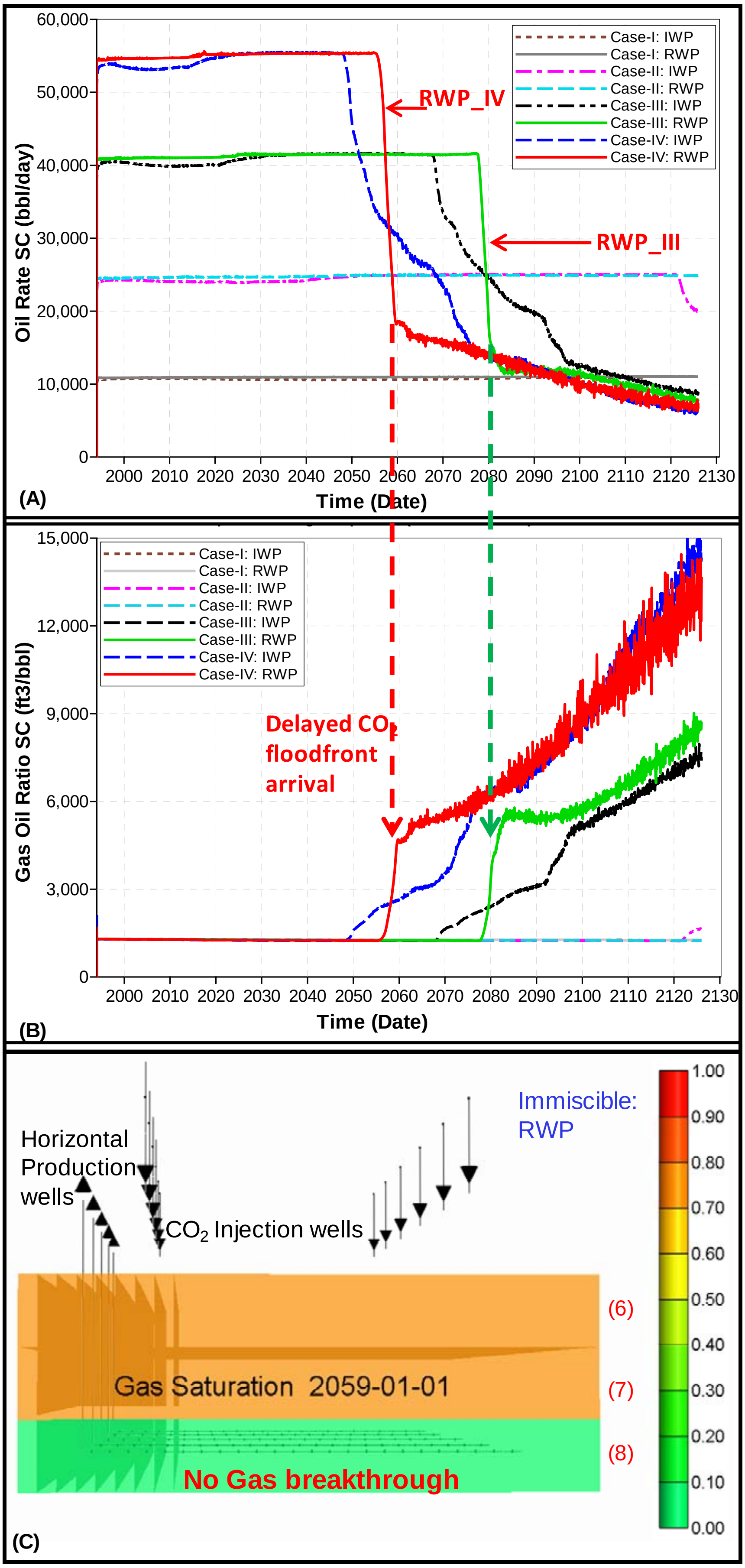

Figure 5-16: Effect of well pattern - irregular vs. regular in immiscible CO_2 flood on q_o and GOR in 4 combinations of Ig and qo

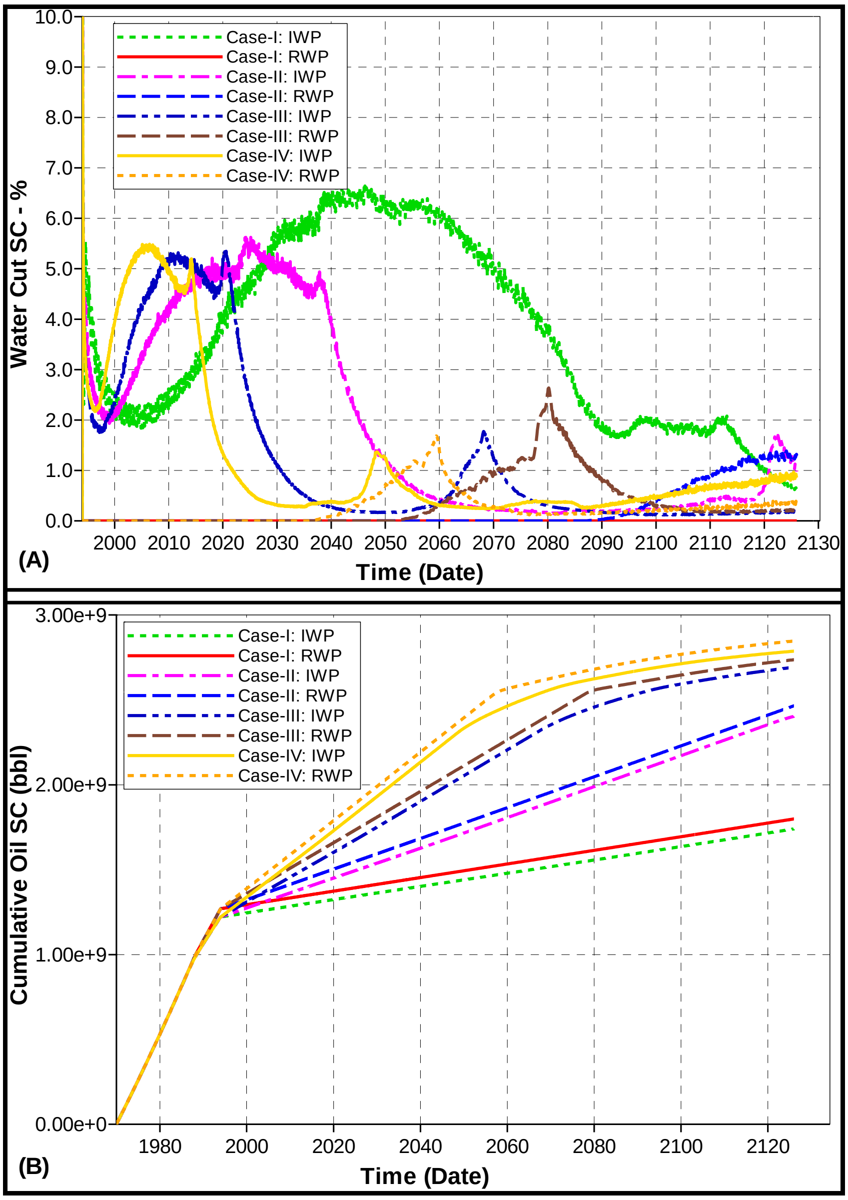

Figure 5-17: Effect of well pattern (irregular vs. regular) in immiscible CO_2 flood on water cut % and Np in 4 combinations of I_g and q_o

Furthermore, abrupt drop of the oil production rate in both the case-III and case-IV in RWP occurs at the same cumulative oil production value (**Figure 5-18A**) before occurrence of the CO_2 breakthrough. This drop-profile is matched during transition of the oil rate profile from the CO_2 breakthrough and the beginning of the oil production rate stabilization at the gravity drainage rates. Oil production rates are prolonged in RWP compared to IWP. Cumulative oil volume is same until CO_2 breakthrough irrespective of the higher rate combination in case-IV. However, the cumulative oil production obtained in case-IV after CO_2 floodfront arrival is higher in comparison with Case-III (see **Figure 5-17B**). Comparison of the overall cumulative oil recoveries in RWP and IWP, suggest that oil production under RWP yield higher Np compared to their IWP counterparts after CO_2 breakthrough.

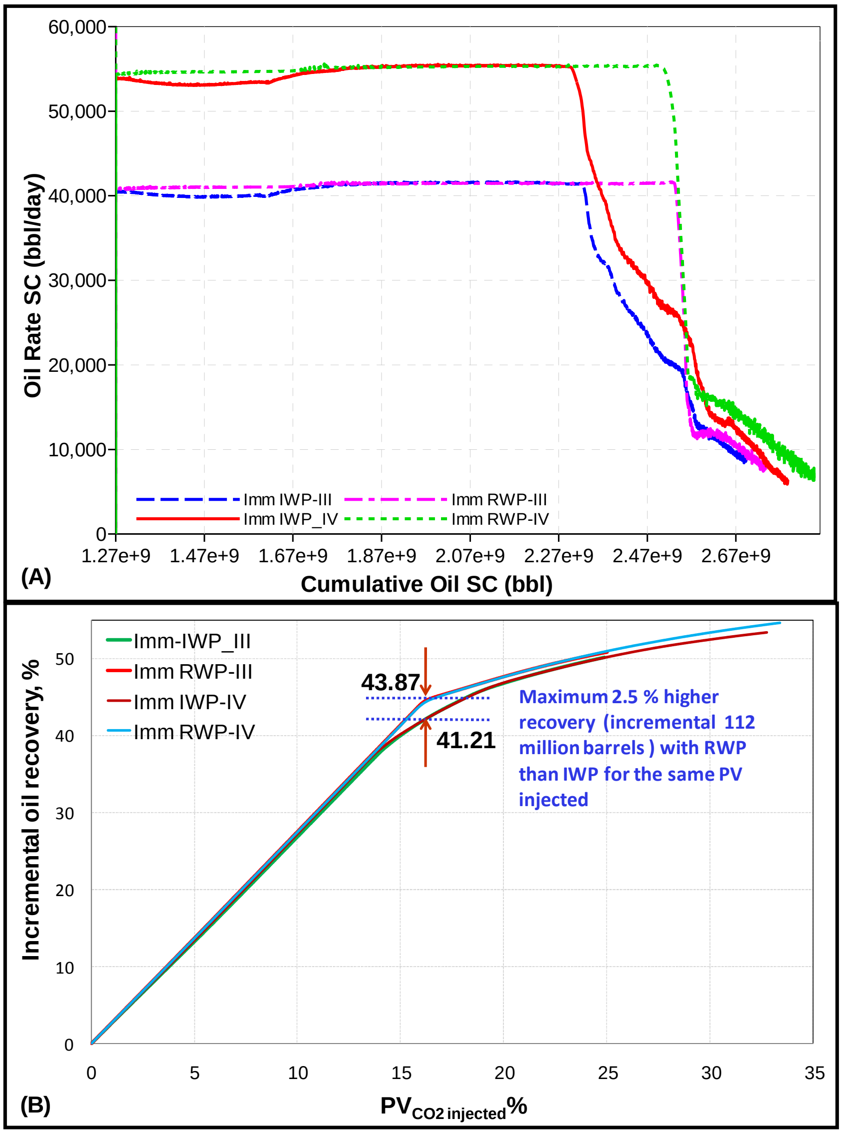

Figure 5-18: Effect of well pattern - irregular vs. regular (immiscible CO_2 flood) on (A) qo vs. Np; and (B) incremental oil recovery vs PV_{CO2inj}.

These two results (case-III and IV) outline an important observation in that the RWP provides more efficient oil-zone sweep-out thereby yielding 2.5% higher oil recovery than the IWP case (**Figure 5-18B)**. Earlier observation of the near-vertical drop of oil production rate and the delay in CO_2 floodfront arrival at the producing wells lead to the hypothesis of the horizontal gas-oil interface in RWP than IWP. These are backed up by the 2.5% higher recovery in RWP. In this context, it can be concluded that the optimum oil production is achieved in a top-down CO_2-assisted gravity drainage EOR process when the gas-oil floodfront is maintained as horizontal as possible. Results obtained in this well pattern study clearly demonstrated this hypothesis.

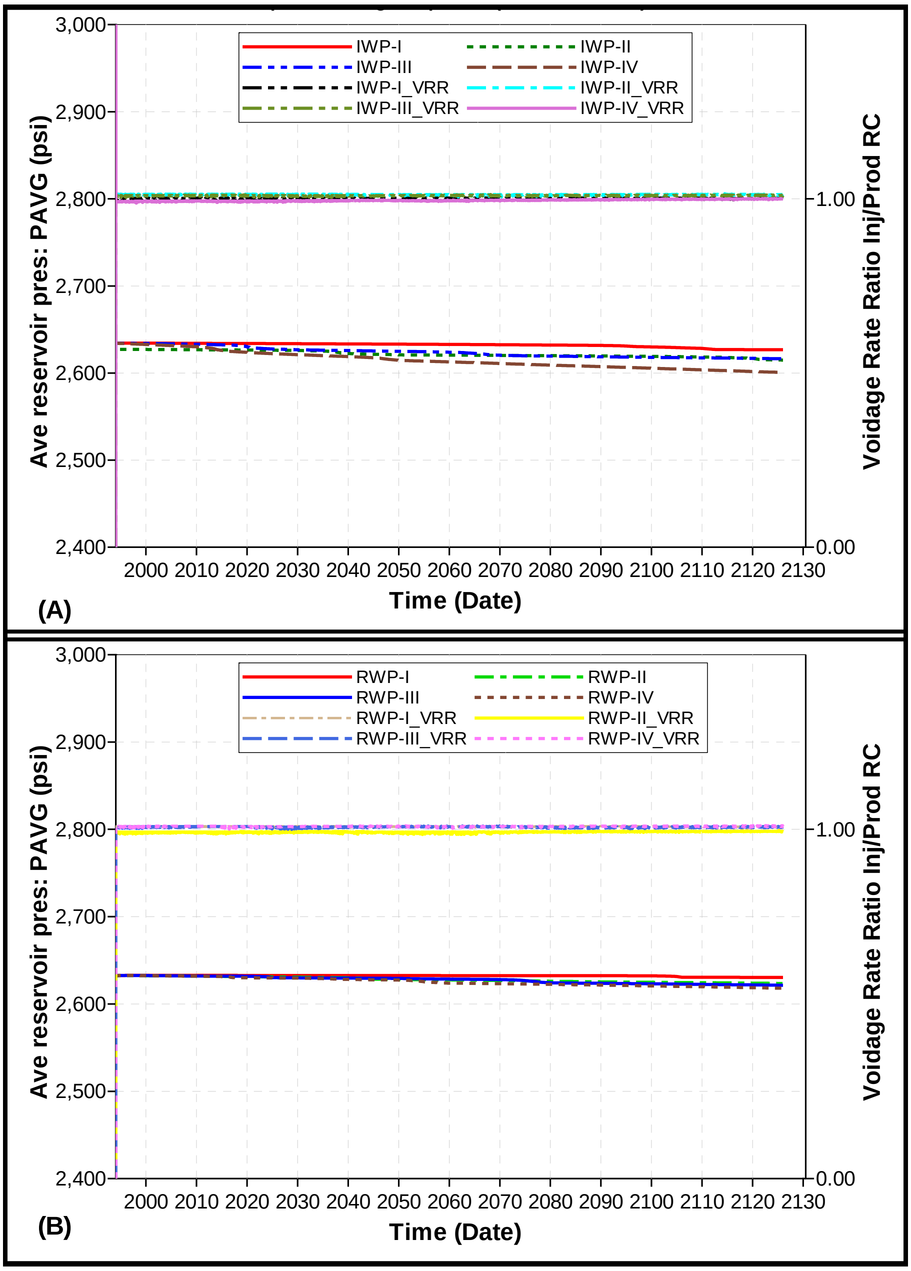

Figure 5-19: Effect of well pattern on the reservoir pressure (P_R) in (C) IWP (D) RWP

Average reservoir pressure distribution during both the IWP and RWP reservoir simulations are as shown in **Figure 5-19**. Maximum reservoir pressure drop in IWP is 35 psia (**Figure 5-19C**) whereas in RWP, it is 4, 11, 13 and 16 psia (**Figure 5-19D**) in Case-I, Case-II, Case-III and Case-IV combinations respectively over 132 years of oil production. It is considerably lower than those observed in IWP. These lower values demonstrate that

RWP would help better in maintaining the reservoir pressure. This further imply that the pressure in the gas zone behind the gas-oil floodfront could be constant, which, in turn, satisfies the Cardwell and Parson's criteria of gravity drainage process mechanism of the enhanced oil recovery.

5.4.2 Secondary Miscible CO_2 -Assisted Gravity Drainage EOR

Effect of well patterns on the gravity drainage oil recovery in miscible CO_2 flooding observed to be similar to that of the immiscible CO_2 flood performance. At lower CO_2 injection and oil production rate in case-I and case-II, reservoir is produced at a flat and maximum oil production rate constraint (**Figure 5-20A**) in both the IWP and RWP. During this period, production occurred at the producing GOR equal to the solution gas GOR (**Figure 5-20B**) without any water breakthrough.

In case-III and IV, oil production continued for longer period in RWP compared to IWP. Gas-cap gas sweeps the oil-bearing zone vertically downward and then reaches in the gravity drainage area of the producing wells. Gas floodfront arrival and CO_2 breakthrough in RWP are delayed by 13 and 6 years in case-III and case-IV respectively compared to IWP cases (**Figure 5-20B**). Oil production rate drops, not as sharp as in immiscible case, and then stabilizes at a gravity drainage rate of the oil production. GOR kept rising after CO_2 floodfront arrival in the drainage area of horizontal production wells. Water breakthrough is suppressed in high pressure CO_2 miscible flooding.

Figure 5-20C represents the gas saturation profile in miscible process in the year 2055. No gas-cap gas breakthrough to the horizontal production wells was observed before the gas floodfront arrival. Moreover, the CO_2 floodfront was maintained horizontal, thus supporting the hypothesis that the regular well pattern indeed provides more stable and horizontal floodfront than the irregular well pattern. Cumulative oil recovery curve (**Figure 5-20B**) changes its trend from linear to a near-horizontal straightening up once CO_2 breakthrough occurred.

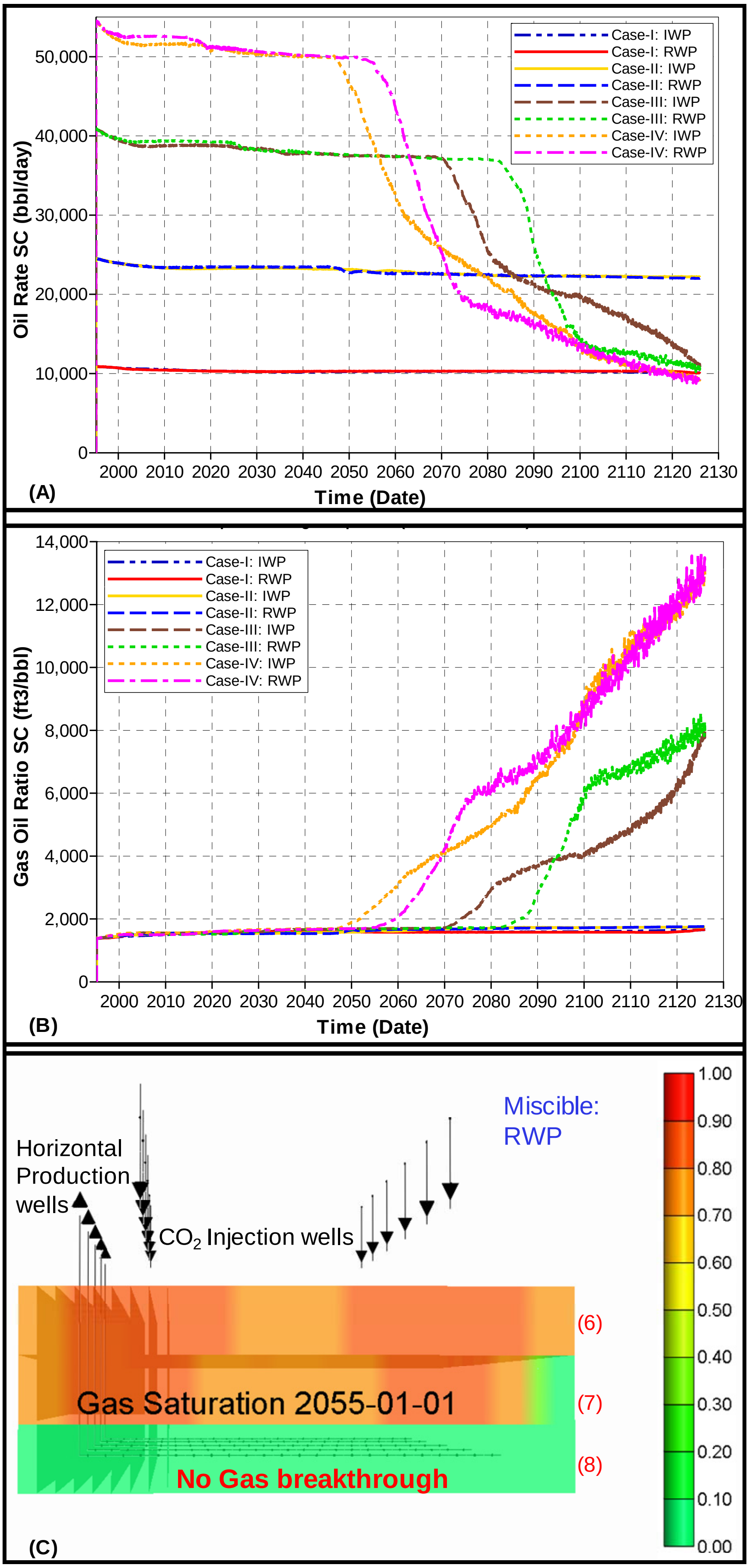

Figure 5-20: Effect of well pattern - irregular vs. regular (miscible CO_2 flood) on (A) qo and (B) GOR in 4 combinations of Ig and qo; and (C) gas saturation front not fingering through the oil zone

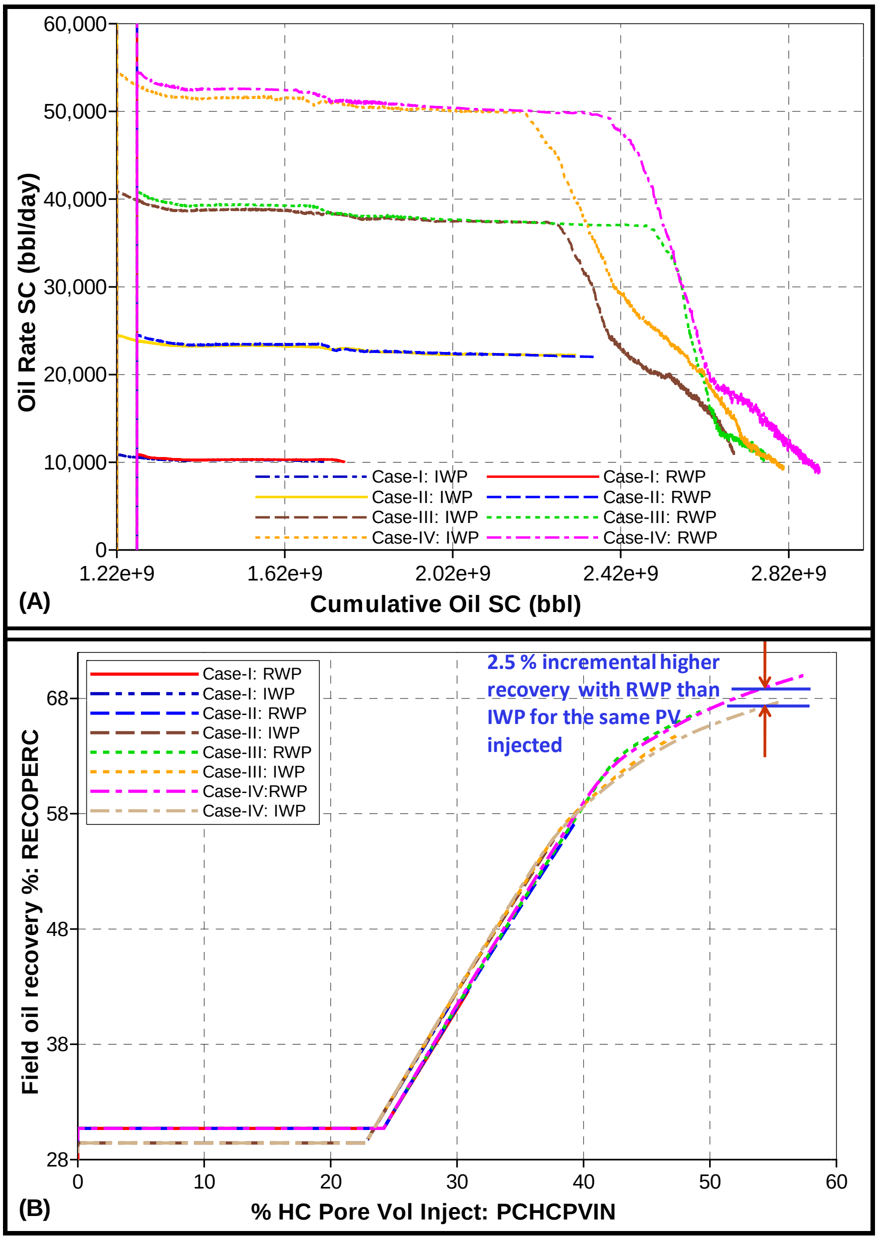

Figure 5-21: Effect of well pattern in miscible CO_2 flood - IWP vs. RWP: (A) q_o vs N_p and (B) Field oil recovery for the respective pore volumes of CO_2 injected in 4 combinations of I_g and q_o

Oil production rate drop in both the case-III and case-IV in RWP occurs at the same cumulative oil production value (**Figure 5-21A**). This drop-profile is identical during transition of the oil rate since the time at which CO_2 floodfront arrived and the oil production rate stabilization at the gravity drainage rates began. Qo is prolonged in RWP compared to IWP oil production rates. Cumulative oil volume is same until CO_2 breakthrough.

Cumulative oil production obtained in case-IV in the later stage of oil production (after CO_2 breakthrough) is higher as compared to the cumulative oil produced in case-III (see **Figure 5-20A**). Moreover, oil production under RWP yield higher Np compared to their IWP counterparts after CO_2 breakthrough, mainly coming from the gravity drainage oil recovery. These two results points out that the RWP provides more efficient sweepout of the oil zone thereby increasing cumulative oil production by 2.5% as shown in **Figure 5-21B**. These results resemble the cumulative gravity drainage oil recovery obtained in immiscible CO_2 flood (see **Figure 5-20B**).

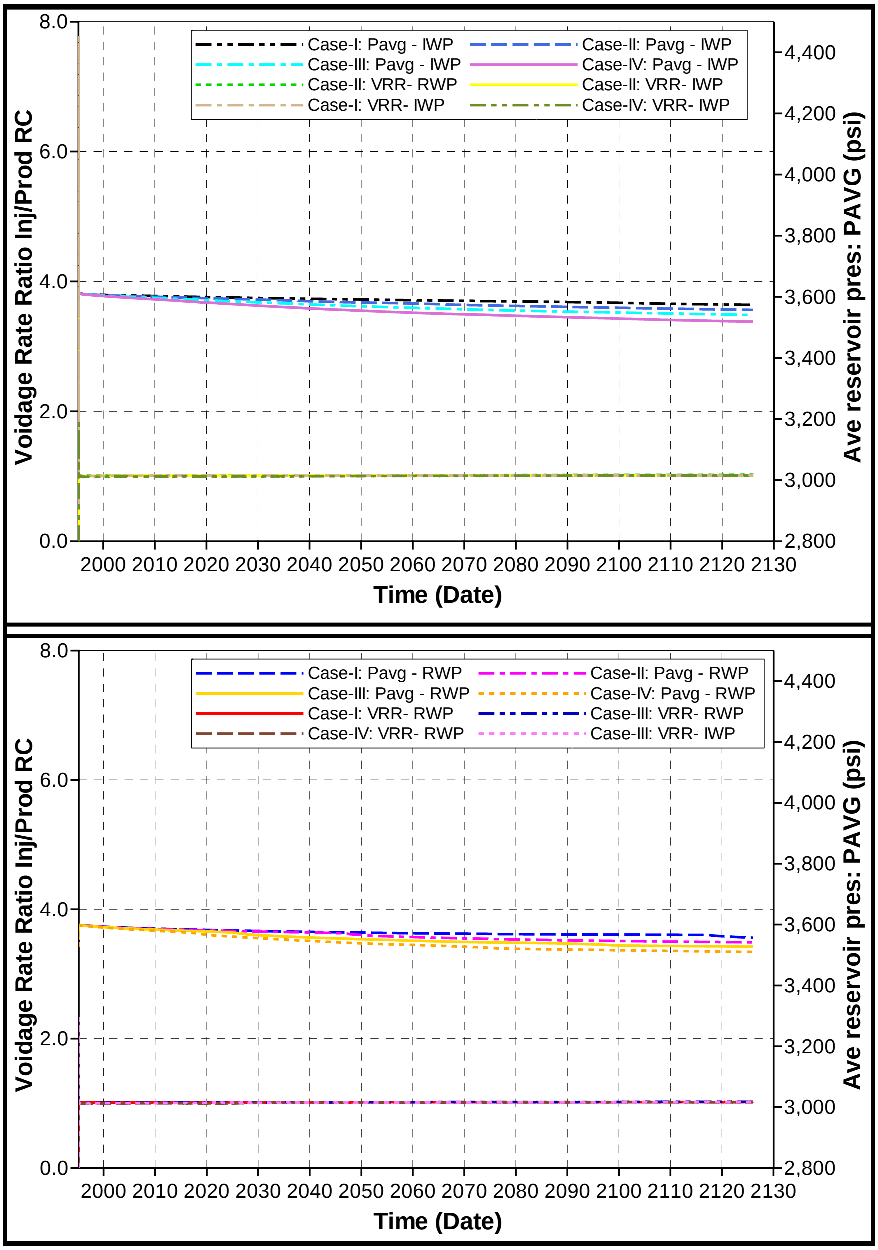

Figure 5-22: Average pressure distribution in (A) irregular well pattern and (B) regular well pattern

Steep decline in oil production rate and the significant delay in CO_2 floodfront arrival in miscible CO_2-assisted gravity drainage EOR process further support the hypothesis of obtaining more horizontal gas-oil interface in RWP than IWP. Moreover, it is backed up by the 2.5% higher incremental recovery in RWP than the IWP. This further signifies the statement that the "optimum oil recovery can be achieved when the gas-oil contact is maintained as horizontal as possible in the vertical-downward process of CO_2-assisted gravity drainage oil recovery". As mentioned earlier similar observation was noticed in the immiscible process. Therefore it can be concluded that the regular well pattern (RWP) would maintain more horizontal and stable gas-oil contact than the irregular well pattern (IWP).

Reservoir response to pressure over 132 years of oil production as shown in **Figure 5-22A** and **Figure 5-22B**, indicates that average reservoir pressure drop in RWP (maximum 80 psia) is lower than those observed in IWP (max 100 psia). This further implies that RWP maintains the reservoir pressure effectively than the IWP, so the pressure in gas zone behind the gas-oil floodfront. Although reservoir pressure drop seems to be higher than the immiscible pressure response before CO_2 breakthrough, results indicated that the reservoir pressure behavior is more flat after CO_2 breakthrough. Reservoir pressure in the gas zone behind CO_2-oil interface could be constant.

5.4.3 Mechanisms Contributing the Enhanced Oil Recovery

Reservoir is produced at the maximum rate constraint thereby vertical downward sweeping of oil zone. Flat GOR profile indicates that oil production occurs at the solution GOR without the injection gas, CO_2, breakthrough at the producing wells. Average reservoir pressure profiles (see **Figure 5-19C** and **Figure 5-19D**; **Figure 5-22A** and **Figure 5-22B**) showed that the reservoir pressure remains constant during this period at the lower CO_2 injection rates (case-I and Case-II). At higher CO_2 injection rates in case-III and case-IV, there are the regions of the reservoir pressure, wherein it drops and then remain constant thereafter for certain period. This, in turn, implies that there could be no pressure differential in the gas zone during those production phases, satisfying the Cardwell and Parson's (1949b) fundamental criteria of free gravity drainage oil recovery mechanism. In addition, the GOR profile results indicated the enhanced oil recovery in this study have come from the free-fall gravity drainage mechanism. Darcy flow and the principle of mass balance plays important role in this recovery.

After CO_2 breakthrough, this reservoir pressure behavior is more pronounced. GOR kept rising gradually while reservoir continues to produce at considerably lower but gradually declining production rate. In these oil swept zone of the reservoir, the continuous phase is gas within which the trapped oil blobs are dispersed. Under gravity they tend to follow downward path. They get inter-connected and flow in the form of thin film between the continuous gas phase and water phase in the water-wet rocks (which is the case in this study). Drainage of these oil films that provide high permeability pathways for their Darcy flow towards the oil bank and oil is produced through the horizontal producers. This oil film flow behind the gas-oil interface in the gas zone (displaced oil zone) is mainly responsible for the stable oil production under the prevailing gravity drainage mechanism.

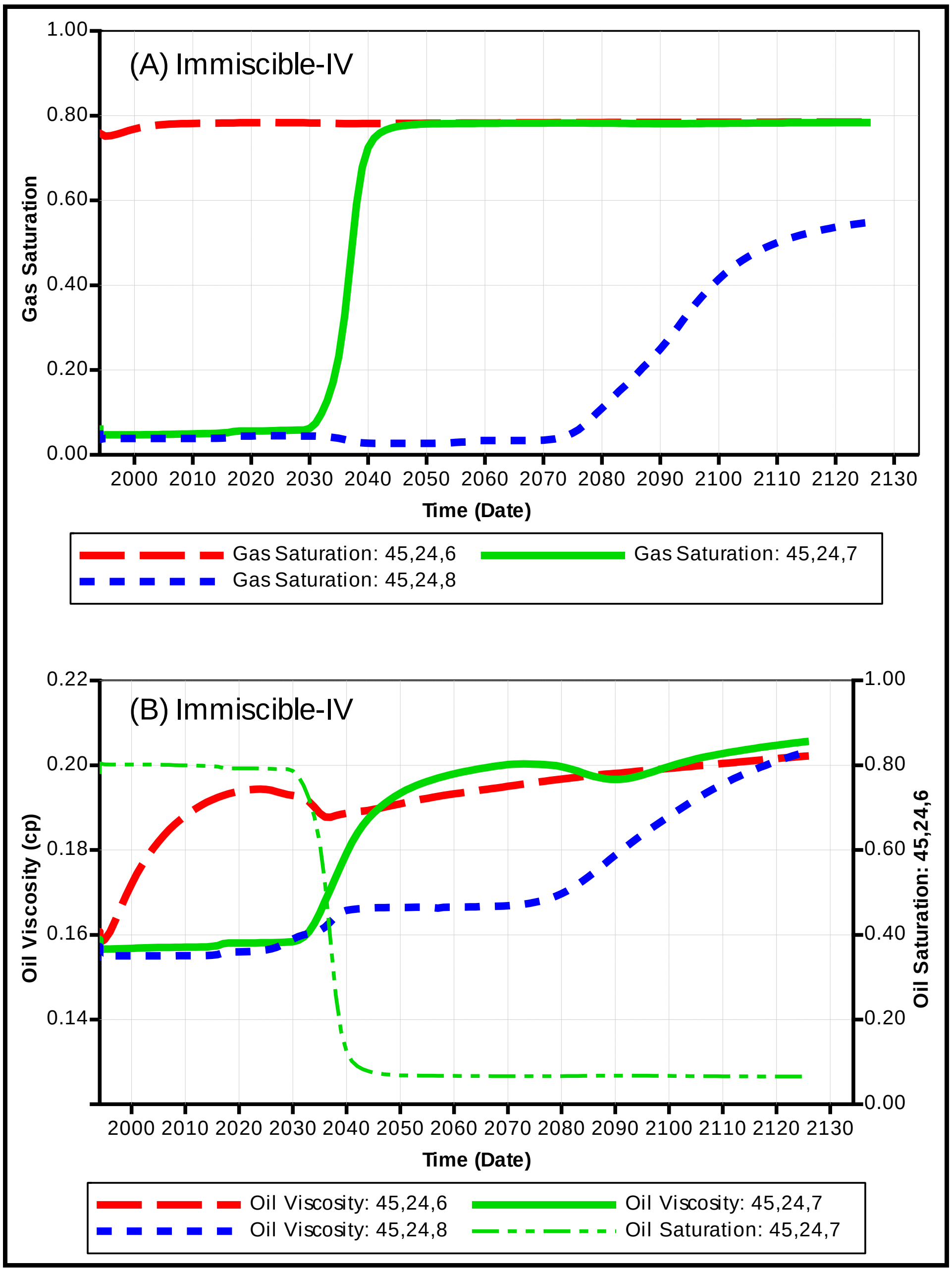

Figure 5-23: Gas saturation and the respective oil saturation and the viscosity profile in the *immiscible* CO_2 flood

In order to understand the other micro-mechanisms occurring concurrently with gravity drainage in both the immiscible and miscible process, the gas saturation (S_g) and oil viscosity (μ_o) profiles along with oil saturations (S_o) in the blocks (45, 24, 6) - first block, (45, 24, 7) - second block and (45, 24, 8) - third block are analyzed. In vertical top-down gravity drainage-EOR process, CO_2 floodfront will first reach the first block and later in other deeper layer-blocks second and third as represented by S_g values at the start of gravity drainage CO_2 injection (**Figure 5-23A** and **Figure 5-23B**).

In case of immiscible CO_2 flood, oil viscosities in the first block (45,24,6) continued to rise in spite of the maximum Sg values (see **Figure 5-23A** and **Figure 5-23B**). In the second beneath block (45,24,7), the Gas-oil contact (GOC) reach 50 years later as indicated by the sharp rise in S_g. During this period, the corresponding oil viscosity also increased sharply. Even after S_g stabilization at the maximum values, oil viscosity continues to rise. Similar trend was seen with the Sg and μ_o values in the third block (45,24,8). These results suggest that the CO_2 continue to extract or vaporize the medium and heavy components of oil from the pores while continuing to flow in the form of the oil films. Careful observation of the sustained S_o values in the Symbolic block (45, 24, 7) indicated the occurrence of the continuing oil-film drainage. Profiles of S_g, μ_o and S_o values obtained in these blocks in the immiscible flood showed that the extraction and vaporization of the medium and heavy components from the reservoir oil, in addition to oil-film flow, contributes the enhanced oil recovery. Similar profiles of S_g, μ_o, and S_o values were obtained in immiscible flood in other blocks during immiscible process.

In miscible gravity drainage CO_2 injection, the first block (45, 24, 6) witnessed complete oil recovery shown by the small oil viscosity reduction and then dropping off to zero values (see **Figure 5-24B**). The leading edge of the CO_2 floodfront reached the second block (45, 24, 7) 30 years later. The reservoir oil swelled to reduce viscosity before minor increase indicating vaporization of heavy components. This process continued until all of the oil is recovered from this block as shown by the oil saturation curve. Variations in the oil viscosity were less pronounced than the immiscible flood. However, oil from the first and second block was completely recovered in miscible flood.

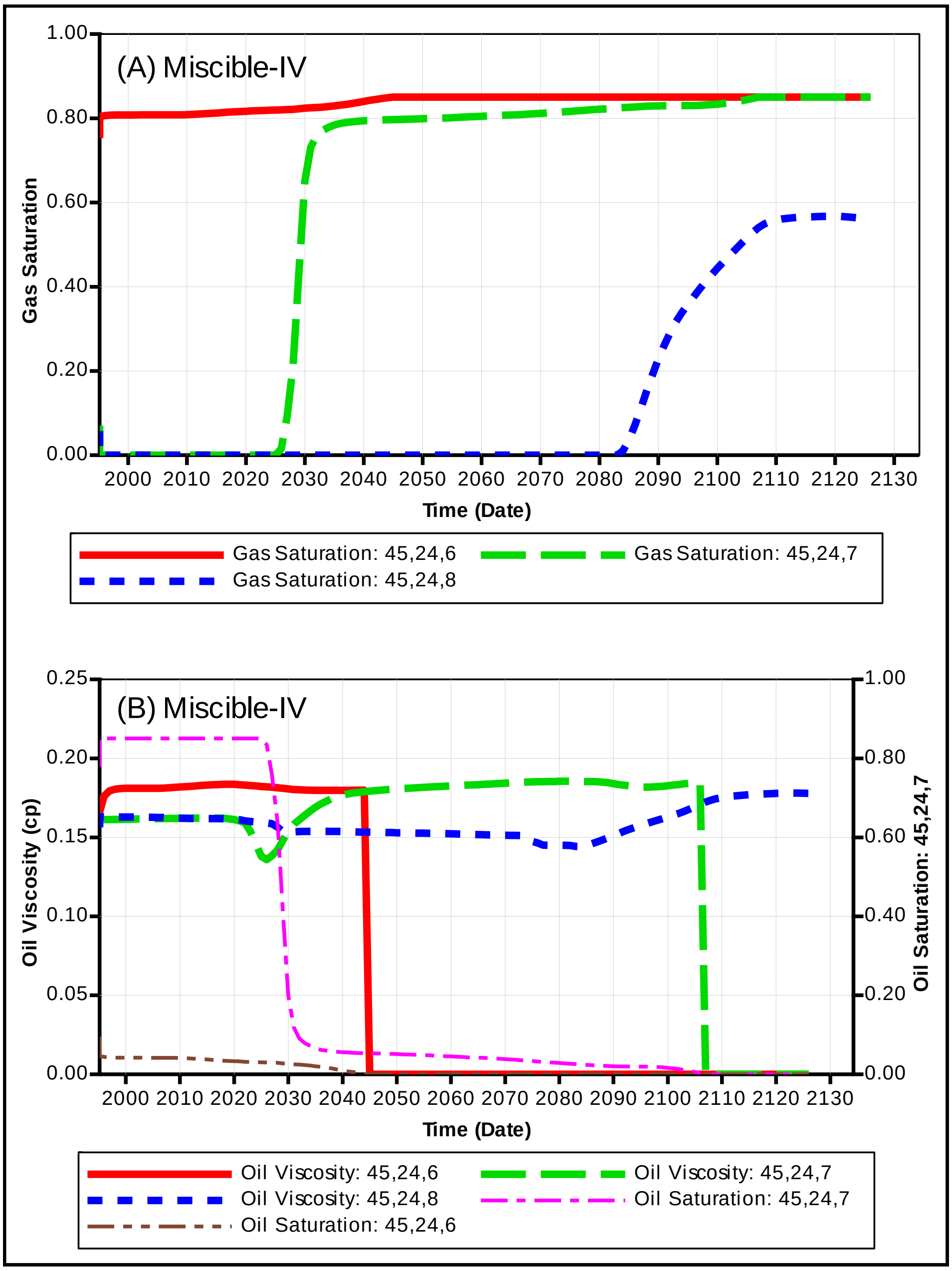

Figure 5-24: Gas saturation and the respective oil saturation and the viscosity profile in the *miscible* CO_2 flood

Figure 5-25 diagrammatically represent the viscosity changes occurred right from start (1996) to the end (2126) of the secondary miscible CO_2 flooding process. Red numbers in on the right of the top-left figure indicates the oil zone layers, the target zone of the production in top-down process. Also shown are the injection and horizontal production wells (layer-8). Oil viscosity in layer-7 observed to be reduced in year 2002, suggesting that the oil swelling has occurred providing more efficient drainage. It is then increased in 2057 following the oil drainage from the upper layer to the down, indicating either the extraction of the lighter components from oil or vaporization of the medium to heavier components during the movement of the miscible zone (as suggested by the green interface of 0.09 cP viscosity and 0.19 cP). Similar observations were seen towards the end of CO_2 flood.

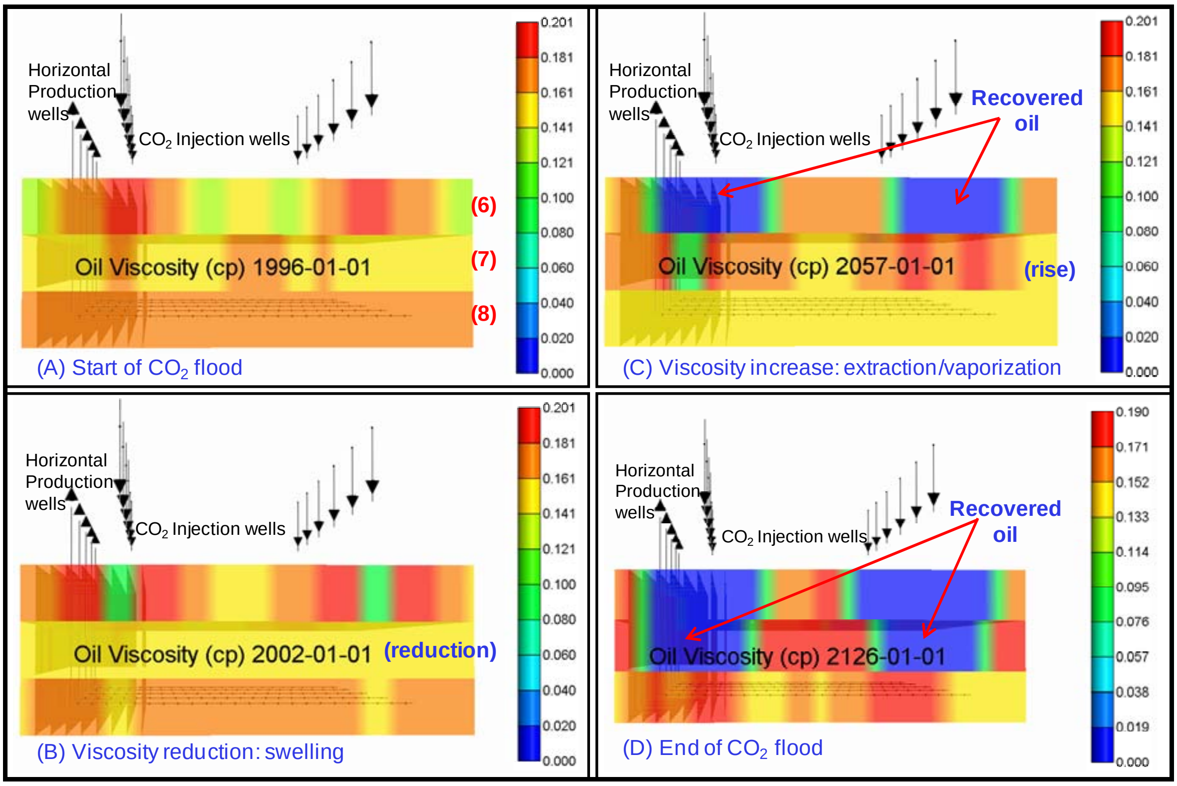

Figure 5-25: Viscosity changes during miscible CO_2 flood (Case-IV)

These results show that the gravity drainage through bulk flow and the oil-film drainage are accompanied by other micro-mechanisms such as the oil swelling (viscosity reduction), extraction and vaporization (viscosity rise) of reservoir oil by CO_2 in both the immiscible and miscible processes.

5.5 Effect of Connate Water Saturation

Connate water saturation effects on the gravity drainage mechanism in 35 ^{o}API reservoir using irregular well pattern are presented in this section. Pseudomiscible black-oil simulations are conducted using CMG's IMEX simulator in irregular well patterns.

Connate water saturation (S_{wc}) is varied as 0.15, 0.22 (base case as used in the rate sensitivity studies) and 0.05 in the Case-III rate constraints of 67.5 MMSCF/D and 13000 bpd. Results are presented in **Figure 5-26**. A S_{wc} of 0.22 resulted in the highest GOR

(27000 cu ft/day) and WOR (1.20) and lowest oil recovery rate. Gas floodfront reached layer-7 in July 2077 that is 10 and 11 years earlier compared to cases with S_{wc} of 0.15 and 0.08, respectively. Oil gravity drainage rate was lowest in S_{wc} of 0.22 compared to the other two cases. Considerably lower cumulative oil production was obtained against the other two S_{wc} values.

At lower S_{wc} = 0.08, higher residual oil saturation was seen after waterflooding because of higher available oil volume. Stable enhanced oil recovery pattern obtained during CO_2 flooding indicated a more effective oil drainage mechanism. GOR increased after CO_2 breakthrough. Lowest GOR (17000 cu ft/day) and WOR (0.35) values were observed. Moreover, cumulative oil production is highest among three settings, especially after CO_2 breakthrough.

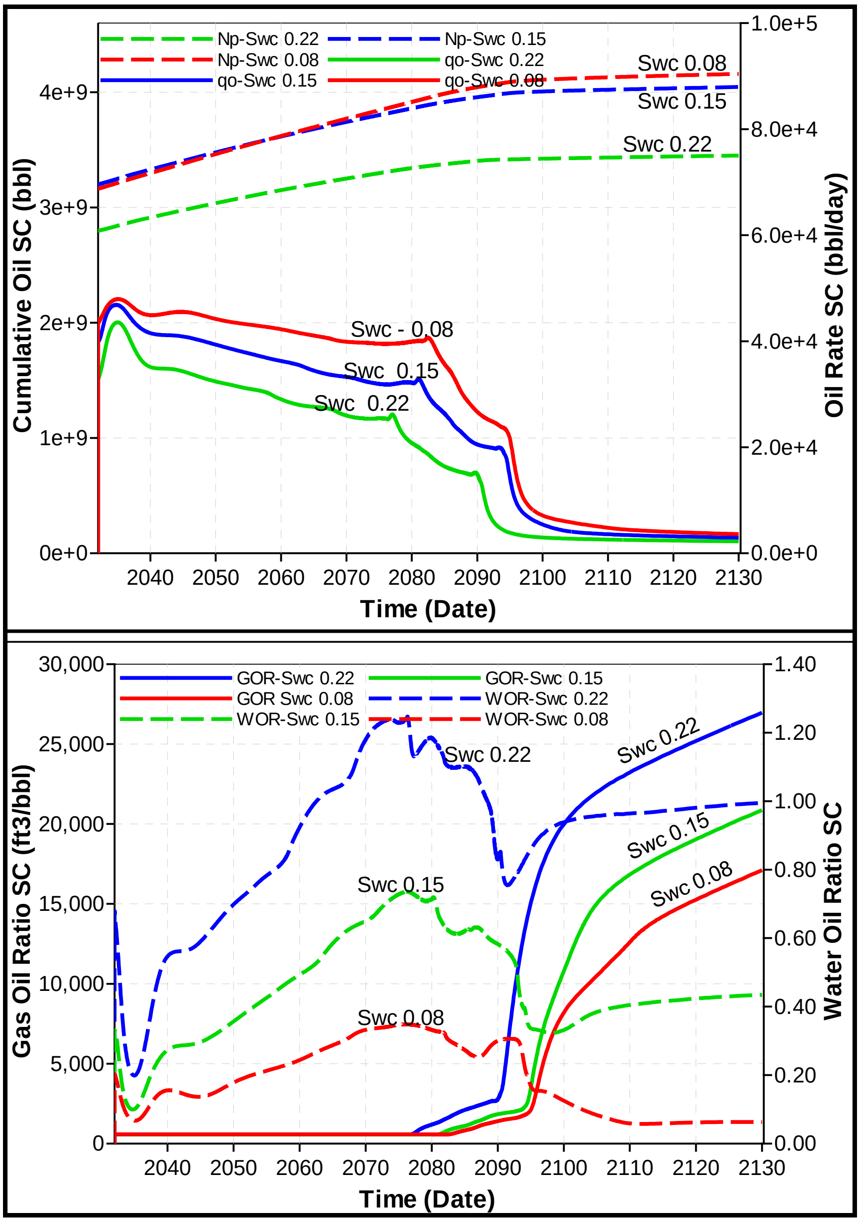

Figure 5-26: Comparison of GAGD-EOR performance at three S_{wc} values: 0.08, 0.15 and 0.22

Minimum drop in reservoir pressure is observed before and after CO_2 breakthrough although producing GOR sharply increased in the later stage. This further helped the CO_2-assisted drainage of the oil from upper to lower under gravity. These results are similar to earlier rate-sensitivity and the porosity heterogeneity studies. Lower the fraction of water initially present in pores in the form of connate water, least will be the hindrance to oil drainage under gravity.

5.6 Effect of Capillary Pressure

Literature review suggests that capillary force acts to oppose the gravity forces in during the operation of the gravity drainage EOR process. Results of the well pattern studies demonstrated that the oil recovery rate drops down after the gas floodfront arrival, which is hypothesized to be due to capillary retention. Interfacial tension between the existing phases leads to the differentiation between the positive and negative spreading coefficient, which in turn is responsible for the film flow drainage in the immiscible process. Oil film drainage is particularly responsible for the oil recovery after the gas floodfront arrival. Therefore, capillary pressure consideration is must while investigating the CO_2-asssited gravity drainage EOR process. Furthermore, this research aims to study the interaction of the multiphase parameters operational in the CO_2-asssited gravity drainage EOR process through the scaling and sensitivity analysis. Therefore the capillary pressure effects in immiscible CO_2-assisted gravity drainage EOR process are studied in this investigation through the analysis of oil production rates, GOR, produced water cut and the cumulative oil recovered. Simulation results obtained for the four combinations of the i_g and q_o are as shown in **Figure 5-27** in the irregular well patterns. The results of these four combinations in the absence and the presence of the capillary pressure effects were then compared to analyze the reservoir performance.

Results in regular well pattern indicate that the oil production rates were sustained longer (by 1.5 years) in no capillary pressure cases than the cases with capillary pressure consideration (case-II to IV), leading to the extended operating time. This is an optimistic oil recovery rather than the actual reservoir representation. Moreover, capillary pressure when considered, more stable and flat oil production rate is yielded. Cumulative oil production is higher and no water breakthrough is occurred with capillary effects. Comparison of the field oil recovery with and without capillary effects shows that the assigning the finite capillary pressure values yield in higher field oil recovery, because of the release of the trapped oil blobs from pores. They join to form thin oil film that flows under gravity drainage. They form high relative permeability pathways to yield higher recovery.

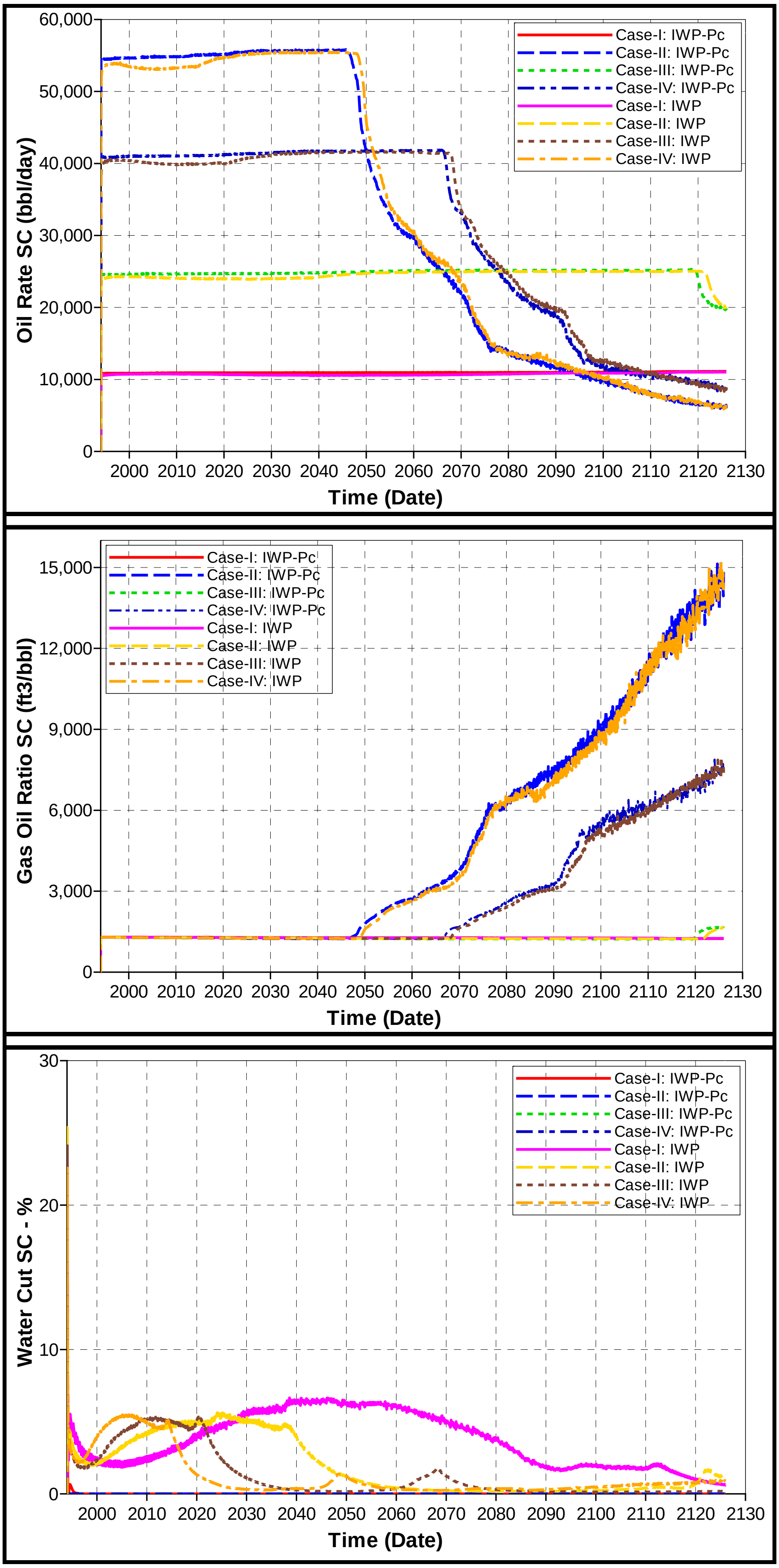

Figure 5-27: Effect of Capillary pressure in (irregular well pattern) on - q_o, GOR and water cut (%)

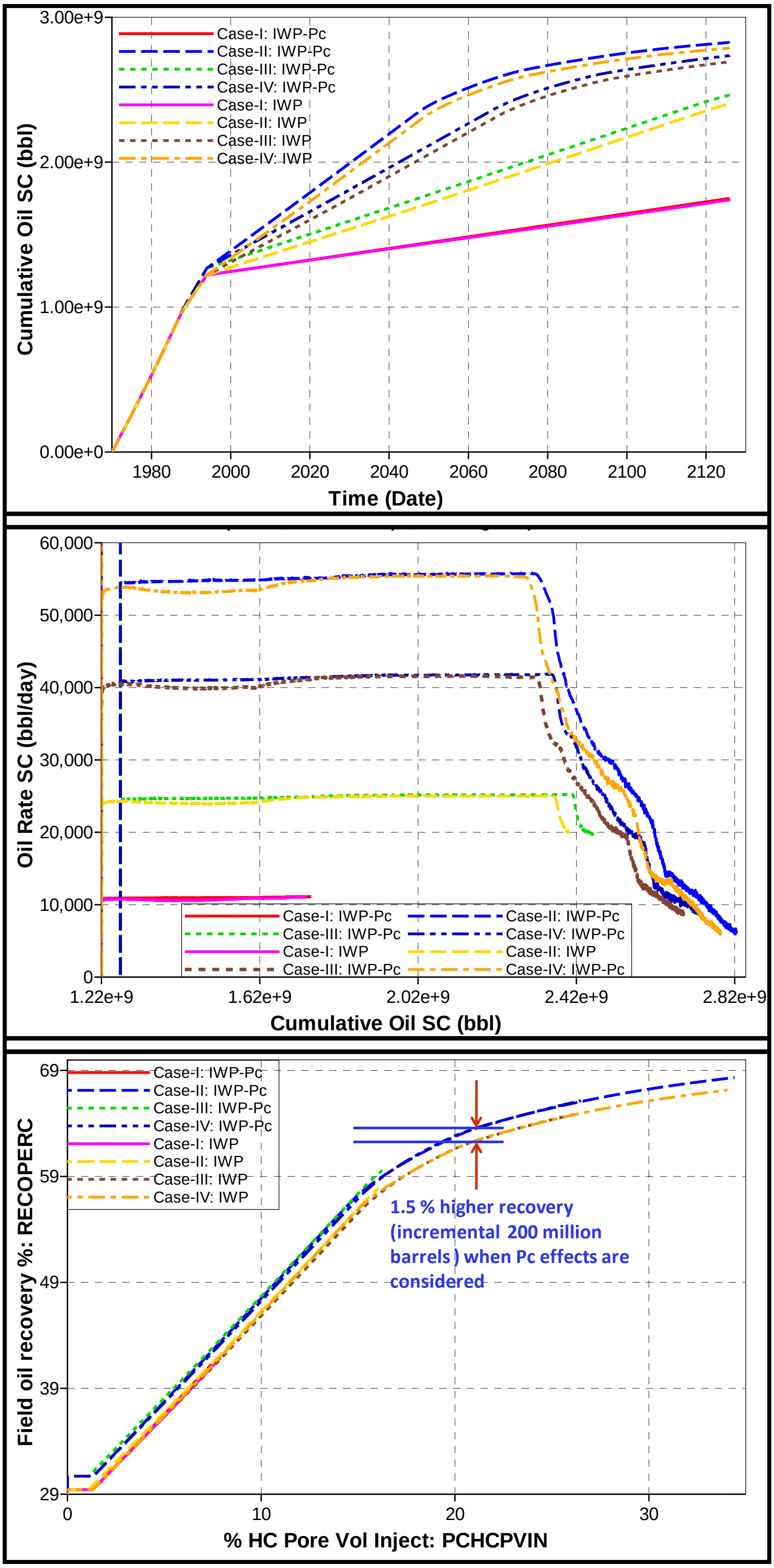

Figure 5-28: Effect of Capillary pressure in (irregular well pattern) - qo vs. Np (top); and Field recovery (%OOIP) vs HCPVinj, % (bottom).

5.7 Summary

This Chapter presented the effects of well rate-constraints, type of the injection well, well patterns, connate water saturation and the capillary pressure on the CO_2-assisted gravity drainage oil recovery performance. Injection well rates are varied in all the following studies. Finding that horizontal injection well might diminish the gravity drainage oil recovery performance, the vertical gas injection wells are used in the irregular vs. regular well pattern studies. Well pattern studies resulted in the development and verification of horizontal gas floodfront hypothesis and understanding of the involved process-mechanisms. Positive outcomes of the well pattern studies are then applied in the investigations regarding the oil recovery optimization. Investigations in this Chapter established that the regular well pattern provides the optimum oil recovery compared to the irregular well pattern. Therefore regular well patterns comprising the vertical gas injection wells and the horizontal oil production wells are used throughout the remaining numerical simulation studies.