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COLD HEAVY OIL PRODUCTION USING CO_2-EOR TECHNIQUE

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ABSTRACT

This thesis presents results of a successful simulation study using CO_2-EOR technique to enable production from an offshore heavy oil field, named here as Omega, which is located offshore West Africa at a water depth around 2000 m.

The findings and contributions to knowledge are outlined below:

1. **Long distance CO_2 transportation offshore –** The solution to the space and weight constraints offshore with respect to CO_2-EOR, is a tie-back via long distance CO_2 dense phase transportation from onshore to offshore.
2. **Cold heavy oil production (CHOP) using CO_2-EOR technique** - Based on conditions investigated, Miscible Displacement was found to be more efficient for deepwater production. However, Immiscible Displacement can offer greater reliability with regards to CO_2 sequestration.
3. **CO_2 sequestration during CHOP using CO_2-EOR technique** – Lower CO_2 may be released post start-up operation, followed by gradual decline of CO_2 retention after the production peak. CO_2 retention increases with increasing reservoir pressure, starting with 17.7 % retention at 800 psig to 32.8 % at 5000 psig, based on peak production analysis.
4. **Techno-economic Evaluation** – Miscible displacement is asssociated with higher cash flow stream that extend throughout the lifetime of the asset due to continuous production while Immiscible Displacement has a longer payback period (in order of 22 years) due to the time lag between the CO_2 injection and the incremental heavy oil production.
5. **Mathematical Modelling** – Improved mathematical models based on existing theories are proposed, to estimate the CO_2 requirement and heavy oil production during CHOP using CO_2-EOR technique, and to provide an operating envelope for a wide range of operating conditions.

As part of further work, the proposed models will require more refinement and validation across a broad range of operating conditions, could be adapted and modified to increase its predictive capability over time.

Keywords: CO_2-EOR, Heavy Oil, Recovery, Cold Process, Miscible, Immiscible, Displacement, System Modelling, CO_2 Sequestration.

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I would like to dedicate this thesis to my parents, whom I owe tremendous amount of gratitude and respect.

Above all, All Gratitude to the Most High !

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NOMENCLATURE

A	= Cross sectional area of the pipe	in^2
Bo	= formation volume factor	(rb/stb)
C_E	= EOR Constant	-
Cd	= Drag coefficient,	-
D	= Pipe inside diameter	in
E	= Panhandle/Weymouth efficiency factor	-
Eo	= Eotvos number	-
f	= Moody friction factor	-
g	= Gravitational acceleration	(32.2 ft/ s^2)
g_c	= Conversion factor (32.2 (lb_m ft) / (lb_f s^2))	
GLR	= Gas Liquid Ratio	scf/bbl
GOR	= Gas Oil Ratio	scf/bbl
H_1	= Upstream elevation	ft
H_2	= Downstream elevation	ft
k	= Effective horizontal permeability	md
L	= Length	mile
Mr	= Morton number	
Mw	= Molecular weight	lbm/Ibmol
P_b	= Bubble point pressure	psi
p_{hf}	= Flowing tubing head pressure	psi
P	= Pressure	psi
P_1	= uUpstream pressure	psi
P_2	= Downstream pressure	psi
ΔP_{HH}	= Pressure change due to hydrostatic head	psi
PI	= Productivity index	stb/d/psi
Q_G	= Gas flow rate	ft^3/d
Q	= Volumetric flowrate	ft^3/d
S	= Elevation adjustment parameter, dimensionless	
Re or NRe	= Reynolds Number	
R	= Ideal gas constant	j/mol K
r_e	= Radius of drainage	ft
r_w	= Radius of wellbore	ft

$S^{\#}$	= Total skin	
T	= Temperature	(°F)
v_{sl}	= Terminal settling velocity	ft/s
W_e	= Weber Number	
z_a	= Average compressibility factor	
Δz	= Elevation change	ft
WC	= Water cut	
$\overline{T}$	= Average temperature	°F
u	= Flow velocity	ft/s
γ_{CO2}	= Specific gravity of CO_2	
$\bar{z}$	= Gas deviation factor at $\overline{T}$ and $\overline{P}$	

Greek Symbols

σ	= Interfacial tension	
β	= Angle of inclination	
μ	= Dynanic Viscosity	cP
ρ	= Density	lb/ft^3

Subscript

G, g	= Gas
CO_2	= Carbon Dioxide

SI Metric Conversion Factors

cP x 1.0*E-03 = Pa·s

dyne x 1.0*E-02 = mN

ft x 3.048* E-01 = m

°F (°F-32) /1.8 =°C

gal x 3.785 412 E-03 = m^3

in. x 2.54 = cm

psi x 6.895 = kPa

°API 141.5/(131.5 + °API) = g/cm^3

psi x 6.895 = kPa

ACRONYMS

API	American Petroleum Institute
BHP	Bottom-Hole Pressure
BOPD	Barrel of Oil per Day
CDM	Clean Development Mechanism
CHOP	Cold Heavy Oil Production
CMG	Computer Modelling Group
CSI	Cyclic Solvent Injection
CSS	Cyclic Steam Stimulation
DOE	Department of Energy
EIA	Energy Information Administration
EOR	Enhanced Oil Recovery
EOS	Equation-of-State
FCM	First Contact Miscible
FPSO	Floating Processing, Storage, and Offloading
FVF	Formation Volume Factor
GOR	Gas Oil Ratio
GSGI	Gravity Stable Gas Injection
HCPV	Hydrocarbon Pore Volume
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
IRR	internal Rate of Return
MEOR	Microbial injection for Enhanced Oil Recovery
MMP	Minimum Miscibility Pressure
Mt	Million Metric Tons
NFA	No Further Activity
NETL	National Energy Technology Laboratory
NGL	Natural Gas Liquids
OOIP	Original Oil In Place
PE	Petroleum Experts
PI	Productivity Index
PBG	Prudhoe Bay natural gas
RMG	Reservoir Management Group

ROI	Return on Investment
SAGD	Steam Assisted Gravity Drainage
SSU	Subsea Separation Unit
THAI	Toe-to-Heel-Air-Injection
U.S	United States (of America)
VLP	Vertical Lift Performance
WAG	Water Alternating Gas injection
VAPEX	Vapour Extraction
3LPE	3 layer polyethylene coatings

1. INTRODUCTION

With heavier hydrocarbons accounting for almost triple the combined world reserves of conventional oil and gas, it sounds rational to think that the answer to the challenges of our future energy supply resides in heavy oil exploitation.

Heavy oil deposits are present worldwide both onshore and offshore. Offshore heavy oil development poses significant challenges, which may be associated with low reservoir deliverability (i.e. low pressure, low API gravity and very high crude viscosity); cold and difficult environment (water depth). These challenges require fit for purpose techniques for converting these resources into easily recoverable production and a reliable mathematical model to predict pressure drop and the gas requirements during Enhanced Oil Recovery (EOR).

Heavy oil, owing to its physical properties, requires more than just the known conventional oil (light or medium crude oil) extraction techniques to facilitate its mobility and production to the surface.

This chapter provides a brief statement on the technology employed to date for heavy oil production, the gap in the current technology, and the proposed methodology, which leads to the objectives of this research study.

A brief description of the strategy for meeting these objectives is also outlined, and finally a succinct summary of each chapter is presented.

1.1 Background

As the oil and gas fields mature and the existing reservoirs are becoming incapable to flow naturally, producers / operators are forced to look for alternatives, either new production wells or means to maintain production from existing wells, in order to ensure continuous cash flow and positive return on investment (ROI).

Nevertheless, new technology development and progress in artificial lift have made feasible exploration into challenging environments, such as deepwater development, and have allowed more oil fields to be discovered and better understood. Despite the growing concern on the continuing decline in oil reserves worldwide, the U.S Department of Energy/Energy Information Administration (U.S. DOE/EIA), the Society of Petroleum Engineers (SPE) and other pioneers anticipate significant expansion of world oil production in the future due to the application of advanced oil production technology **[1, 2, 3]**.

1.2 Well / Reservoir Unloading Issues and Mitigation

Improved Oil Recovery (IOR) is known to be the solution for liquid loading problem in the well. The IOR includes a series of technologies such as infill drilling, hydraulic fracturing, horizontal drilling, advanced reservoir characterisation, enhanced oil recovery (EOR), and numerous other methods that can be used to increase the volume of recoverable oil from reservoirs.

EOR, known as tertiary recovery and usually initiated after primary and secondary recovery, has been practiced since the 1950s in various conventional oil reservoirs, particularly in the United States. One of the EOR processes that will likely have the largest worldwide potential is Miscible flooding wherein carbon dioxide (CO_2), nitrogen or light hydrocarbons are injected into oil reservoirs where they act as solvents to move residual oil. Amongst the three options, CO_2 flooding has proven to be the most frequently useful technique given the potential environmental benefit. In the USA, geologically sourced CO_2 has been produced in Colorado and shipped via pipeline to West Texas and New Mexico for decades for EOR **[4]**.

1.3 Behaviour of CO_2 in the Reservoir

The difficulties posed by deepwater oilfield production require that the characteristics of CO_2 as a mean for recovering more oil be fully understood. The literature reports that the miscibility of a reservoir's oil with the injected CO_2 is a function of pressure, temperature and the composition of the reservoir's oil. Laboratory results have demonstrated that the injection of CO_2 would result in swelling of the oil by over 20%, a significant reduction in oil viscosity, and a 95% reduction in interfacial tension **[5]**.

"At sufficiently high pressures, CO_2 is Miscible with oil, and, once dissolved, it has two effects. First, it causes the oil to swell, thereby lowering the oil's viscosity significantly and making it flow more easily in response to pressure gradients. Second, under Miscible conditions, it reduces the interfacial (capillary) forces that cause oil to stick to the reservoir rock. An additional effect occurs in carbonate reservoirs, whereby injected CO_2 mixes with water to form an acid solution that dissolves some of the rock, thereby enhancing the permeability and possibly changing the rock fabric in other ways" **[6]**.

The substantial recovery improvement would result from excluding the water from the fracture flow system within the reservoir structure as the carbon dioxide replaces the water. The carbon dioxide would then process oil in the exposed blocks of matrix pores. The oil would swell, reduce in both viscosity and interfacial tension, and then drain into the fracture system for production at completions lower within the reservoir structure **[7]**.

1.4 Gaps in Current Technology

<u>Tie-back to Offshore Platform for EOR</u> - Long distance CO_2 pipeline transportation from onshore to offshore for EOR application has not been investigated to a great extent in the past. Most offshore platforms have serious limitations with regards to space and weight in order to accommodate additional equipments / facility such as the separation unit needed for CO_2 capture which itself is usually significant in weight. In addition, the requirement of CO_2 in continuous process and in large scale to suit the EOR application; makes it very challenging if not almost impossible at this stage to look for solution of CO_2 supplies within the subsea environment. Hence, long distance tie-back for

supplying CO_2 offshore looks very promising as emerging solution for CO_2-EOR offshore.

<u>CO_2-EOR for Heavy Oil Recovery Offshore</u> - CO_2-EOR technology may be in an advanced stage as far as the onshore development is concerned, but is yet to be adapted offshore and particularly for heavy oil reservoirs.

As the conventional crude is in decline worldwide, the heavy crude exploration is being given more attention as means to mitigate the increasing demand in global energy. Advances in research to close the knowledge gap will play a fundamental role on any future CO_2-EOR in heavy oil development offshore.

<u>CO_2 Sequestration during EOR</u> - There is currently an ambiguity in the published literature on whether storing CO_2 is possible with EOR and some analysts think that this method is powerless to reduce CO_2 emissions. International Energy Agency (IEA) Report titled "Carbon Dioxide Capture and Storage in the Clean Development Mechanism (CDM)" claims that CO_2-EOR projects will result in increased carbon emissions from incremental oil production above a No Further Activity (NFA) baseline **[8, 9]**. The above statement is in disagreement with the NETL Report released on 7 Feb 2008, which clearly states that "CO_2 enhanced oil recovery (CO_2-EOR) offers the potential for storing significant volumes of carbon dioxide emissions while increasing oil production" **[9]**.

"The IPCC Special Report on Carbon Dioxide Capture and Storage", recognize that depleted oil fields could provide an attractive, early option for storing CO_2 (particularly with CO_2-EOR), but concluded that the oil fields would provide only a relatively small volume of CO_2 storage capacity. A report titled "EOR in Wyoming, Prospects and Challenges", prepared by the department of geology and geophysics of the University of Wyoming (15 June 2003) re-assures the state of Wyoming that "Most of the injected CO_2 stays in the reservoir, although some may break through at production wells. Even after CO_2 breakthrough, oil production can continue for some time, and the produced CO_2 can be separated, recovered and re-injected".

This uncertainty or misconception of the CO_2-EOR subject relies on the lack of thorough investigation in order to provide a better understanding. This study will attempt to provide a better understanding on the application of CO_2 for EOR, in addition to the points discussed below, by investigating the possibility of CO_2 storage using EOR. This study will emphasize on the CO_2-EOR significance to increase production and as a possible solution to reduce the greenhouse gas emissions.

Similar to conventional oil, heavy oil is a vital resource with a substantial global reserve. Heavy oil, with its dense and highly viscous nature, wax, carbon and asphaltene content, does not offer the option for primary recovery but requires some advance techniques to facilitate production. Currently there are two types of heavy oil recovery processes known as Cold Flow and Hot Flow. The difference between the two processes is the thermal medium involved in the hot flow to assist the movement of the heavy oil to the production facility. The hot flow techniques include: steam injection, where steam is injected into a nearby well to heat the heavy oil reservoir; and the steam assisted gravity drainage (SAGD) which is similar to VAPEX (Vapour Extraction), where two horizontal wells are drilled and steam is injected into the upper one to heat the reservoir and the warm oil flow by gravity through the lower well. However, these techniques are known to be extremely costly and very energy demanding.

The cold production of heavy oil is a non-thermal process of heavy oil recovery which has been economically successful in several heavy oil fields in Alberta and Saskatchewan **[10]**. The cold flow technique includes methods such as: water alternating with gas (WAG) where the gas acts as solvent to reduce the oil viscosity and the water pushes the oil out of the reservoir. Other cold flow techniques include the use of Electrical Submersible Pump (ESP) and Hydraulic Submersible Pump (HSP). Waterflood is also used but is known to offer a much lower recovery factor than other methods. Although these techniques may be beneficial in term of productivity, they are known to produce large amount of wastes that have no commercial value and that represent a substantial environmental liability if improperly disposed **[11]**.

1.5 Problem Statement

The application of CO_2-EOR has never been performed for heavy oil production in an offshore environment. At the time this research proposal was initiated there was yet no published work or literature on these subjects.

Although injection of CO_2 for EOR could be technically feasible and the potential for increased recovery substantial, there are several challenges surrounding the business particularly in the offshore environment. Despite challenges such as CO_2 sources, CO_2 Capture and CO_2 Storage, there are other likely challenges that could be encountered during the development or implementation of such project. Transporting CO_2 in a subsea environment could potentially pose significant challenges both from a Flow Assurance and Operation perspectives, and will require appropriate hydrodynamic models for pressure and temperature predictions / management along the gathering system network and suitable monitoring planning in place to maintain the integrity of the pipeline. The heat transfer predictions and pipeline integrity management are outside the scope of this thesis.

In addition, applying CO_2-EOR in a subsea development for heavy oil production may involve other challenges related to process boundary conditions, battery limits and the design requirements of the transportation systems. These issues are broken down into three (3) categories as:

1) Process characteristics at the onshore source, i.e. knowing what are the conditions and quality of the CO_2 required at the onshore source. In this study, CO_2 is assumed to be pure and the conditions (e.g. pressure, dry / dense CO_2) required at the onshore source to achieve Miscible and Immiscible displacement is investigated. The complexity of a typical injection-production system for EOR, added to a long tie-back transporting CO_2 from onshore to offshore, will require the use of suitable software and development of fit for purpose predictive models.
2) Design requirements of the pipeline system and the well completions, i.e. determining the characteristics of the flowline system and identify the type of well completion suitable for the operation. The production architectural design and integrity management is outside the scope of this study. However, the influence of horizontal and vertical well completion during CO_2-EOR have been explored.
3) Process requirements at the reservoir, i.e. the pre-requisites of the heavy oil reservoir to accommodate CO_2 EOR; the reservoir fluid composition;

Miscible or Immiscible condition. As the water depth increases, the bottomhole pressure plays an important part in the dynamic of oil from the reservoir to the surface.

Companies have already captured most of the benefits of earlier breakthrough technologies in mature areas, and are now required to increase their maintenance capital just to maintain production levels from their established production base **[12]**. Most cost effective solution for the production of heavy oil is to use technology to maintain recovery, and today, CO_2-EOR comes as a renewal in the world of cold production of heavy oil. A such, knowledge based research is needed to help reduce the challenges faced by the operators and to explore how possible CO_2-EOR can optimize the productivity of the heavy oil reservoir through effective assuring flow. Effective assuring flow will result from a comprehensive analysis and prediction of the production system performance during CO_2-EOR, which this research work was looking into. Therefore, another challenge of this research project was to develop a comprehensive methodology of injection and to provide a better understanding of the pipeline systems behaviour during CO_2 transportation and injection.

In spite of more than 30 years' experience in injection of CO_2 for increased oil recovery on land in the USA and more than decades of research work in the area of artificial lift for EOR, CO_2 injection in offshore oil fields with the possible implication and related Flow Assurance issues still remains a major challenge to the operators and researchers. CO_2-EOR within an offshore environment has never been used or investigated for heavy oil production. This research work mirrors into a real offshore situation and conduct a detailed investigation of flow characteristics within a long subsea tie-back transporting CO_2.

In one way or another, it is very apparent from the above arguments that CO_2-EOR, whether used for conventional oil recovery or Cold Heavy Oil Production (CHOP), will be beneficial in the short or long term both from economic and environmental perspectives.

1.6 Research Aim

The aim of this research was therefore to investigate the use of CO_2-EOR technique for Cold Heavy Oil Production (CHOP) in a subsea environment.

CO_2 capture and subsea separation are outside the scope of this thesis.

1.7 Key Research Objectives

The research objectives were to:

- Explore the feasibility of CO_2-EOR for Cold Heavy Oil Production (CHOP) offshore. Establishing the Source-Sink interaction and the influence on the reservoir productivity. Generally, the availability of natural (geologic) CO_2 supplies from a subsea production environment is very limited. Hence, the use of CO_2-EOR in offshore would have to rely on CO_2 captured from an onshore coal and natural gas-fired power plants, as well as industrial plants (e.g. refineries, ethanol, ammonia, hydrogen and natural gas processing plants and other). A typical example is the Shell and SSE Peterhead Carbon Capture and Storage Project, where up to 10 million tonnes of CO_2 emissions could be captured from the Peterhead Power Station (Aberdeenshire, Scotland), and transported by pipeline, approximately 100 km offshore in the depleted Goldeneye gas reservoir, at a depth of more than 2 km for long-term storage under the floor of the North Sea **[13]**.
- Using appropriate Oil and Gas computer simulation tools to investigate the influence of CO_2 injection in the productivity of the reservoir and CO_2 sequestration during CHOP.
- Establish the process requirements at the onshore facility and at the reservoir.
- Assess the cost benefit of a typical CHOP using CO_2-EOR technique through a techno-economic evaluation.
- Investigate CO_2 sequestration during heavy oil recovery using CO_2-EOR technique.
- Develop a predictive model, using mathematical representations of the injection-production system during CO_2-EOR for CHOP, based on exiting theories.

1.8 Anticipated Contribution to Knowledge

- ✓ Enhanced understanding of the CO_2 transportation offshore -

The study will investigate long distance CO_2 transportation in harsh "low temperature" environment offshore for enhanced heavy oil recovery, and will establish suiable process and design conditions.

- ✓ Increased knowledge for CHOP using CO_2-EOR -

  Smaller and economical topside rig / platform, with weight reduction and smaller footprints are generally the requirements offshore. Consequently, additional needs such as the CO_2-EOR injection system and associated equipments may pose 'unnecessary' space constraints and perhaps be a 'show-stopper' in the project development. Using an integrated surface and sub-surface facility modelling, the study will investigate the recovery of heavy oil using a remote onshore CO_2 injection without the needs for recompression at the offshore platform.

- ✓ Establish a research based evidence, CO_2 sequestration during CHOP using CO_2-EOR technique -

  The results of this investigation will bring more emphasis on the subject of CO_2 storage during CO_2-EOR, which have a direct impact in our daily life through less polluted environment.

- ✓ An improved mathematical representation of CHOP using CO_2-EOR technique -

  fit for purpose improved models, consistent with existing theories, and suitable for heavy oil recovery using CO_2-EOR application, will be proposed.

1.9 Research Strategy

This research explores a subsea development system consisting of a long distance subsea pipeline transporting CO_2 from an onshore source to be injected into a deepwater reservoir for Cold Heavy Oil Production. This is a new and challenging concept, not previously investigated, particularly in a remote and exigent environment as that of deepwater. A schematic representation of the concept is shown in **Figure 1.1**.

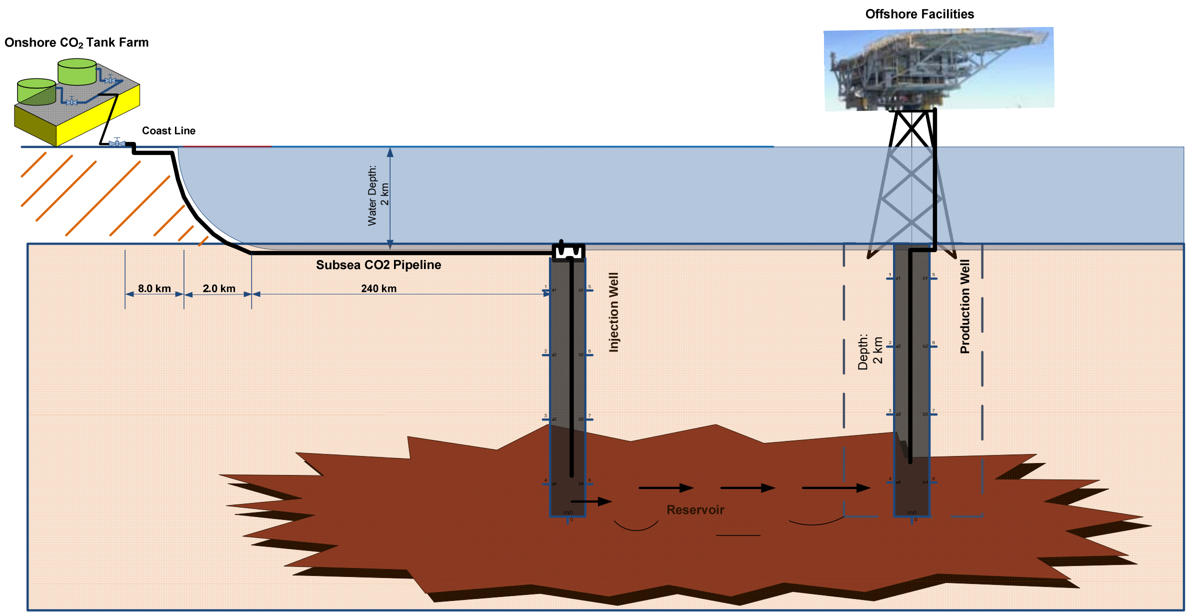


Figure 1.1: Diagrammatic Representation of the Integrated System

The exigency of this novel concept requires that the research be broken into three different campaigns as described below. Each campaign seeks to provide the necessary theory, design and process requirements needed to satisfy the delivery of CO_2 from the source to the sink while achieving the production of heavy oil.

- Source

  This study did not cover the capture process of CO_2, but assume sufficient availability of CO_2 onshore, ready for transportation offshore. An investigation was carried out to determine the required conditions of CO_2 at the onshore facilities. The required pressure onshore will be investigated taking account of the volume of CO_2 and the total length of the pipeline.

- Pipeline System and Well Completion

  The pipe size, material, configuration and the characteristics of the well completion will influence the production profile as well as the process requirements at the onshore terminal. A suitable computer program was used to establish the optimum size of the pipeline on the basis of the capacity of the transported CO_2 and the required arrival pressure in the reservoir.

The type of well completion will influence the overall production cost and will play an essential part in the accessibility of the reservoir. Different completions were explored and the suitability of the selected type of completion and its characteristics was justified against deliverability.

- Sink (Reservoir)

It is known that CO_2-EOR can have a positive impact in some of the conventional oil reservoirs which is caused by the reduction in oil viscosity to facilitate the displacement of oil. Effective CO_2-EOR for heavy oil production will also depend on the reservoir characteristics and fluid properties. CO_2-EOR can be achieved using two processes known as Miscible or Immiscible displacement. The two processes are fundamentally temperature, pressure and reservoir composition dependant. Complete miscibility of the injected CO_2 with the reservoir fluid will be achieved under the minimum miscibility pressure (MMP), i.e. under the right reservoir temperature and pressure. The Immiscible process occurs either when the reservoir fluid is heavier (i.e. less favorable) or when the reservoir pressure is below the required MMP to enable reduction in oil viscosity which in turn will facilitate the sweeping effect. As a mean to remediate to the reservoir immiscibility issue, the Immiscible process is generally supplemented by another oil displacement mechanism to contribute to the heavy oil recovery by blending the CO_2 with solvent such as water, methane, butane and propane to reduce the CO_2 MMP for the reservoir fluid where CO_2 is injected into **[14, 15, 16, 17]**. In another word, if the reservoir pressure is lower than the CO_2 MMP, the MMP of the CO_2 and reservoir fluid mixture can be reduced by blending the CO_2 with adequate solvent. Alternating water injection or foam with CO_2 could also be optional to increase the reservoir sweeping efficiency **[18]**. Hence, another challenge in this study will be to identify the suitability of either Miscible or Immiscible displacement for heavy oil reservoirs.

1.10 Structure of the Thesis

Chapter 1 presents background information on heavy oil recovery with a general discussion on the gaps in the current technology, which thus lead to the principal aim and the framework of this research study.

Chapter 2, provides a comprehensive technical review of previous works done on the heavy oil production, the application and limitations of each of the techniques, highliting the gap in technology.

Chapter 3 gives a description of the methodology adopted for this research work and the breakdown of the studies (simulation cases) performed.

Chapter 4 presents the simulation results of the long distance CO_2 transportation, the CO_2-EOR for CHOP and the CO_2 sequestration during CO_2-EOR for CHOP, and the techno-economical evaluation of a typical CO_2-EOR for CHOP.

Chapter 5 presents the improved mathematical modelling of the integrated injection and production system for CHOP using CO_2-EOR.

Chapter 6 summarises the main findings and contribution to knowledge, and support the claim that there is greater certainty about the accuracy of the simulation results and established models.

Chapter 7 highlights the areas deemed necessary for further work, derived from the outcome of this research works.

2. HEAVY OIL RECOVERY-TECHNICAL REVIEW

2.1 Introduction

The importance of oil since its discovery has raised the curiosity and awareness of industries on the true nature and understanding of this resource.

Conventional oil production goes through three distinct recovery stages namely: Primary, Secondary and Tertiary Recovery where various techniques are employed to maintain production of crude oil at maximum levels.

Heavy oil (non-conventional oil), owing to its physical properties, requires more than just the known conventional oil extraction techniques to facilitate its mobility and production to the surface.

This chapter presents a review of literature relevant to this research area with particular emphasis on the heavy oil production, the current applicable recovery techniques and their limitations.

Enhanced oil recovery (EOR) using carbon dioxide (CO_2) can increase oil production beyond what is typically achievable using conventional recovery methods. A fraction of the injected CO_2 can remain stored underground during the EOR process, which will contribute to a safer environment by reducing pollution to the atmosphere. The state of play, covering Investigation (simulation and laboratory works) and Field Application, of heavy oil recovery using CO_2-EOR technique, the possible environmental impact caused by heavy oil extraction and the likelihood of CO_2 storage during EOR are also discussed in this chapter.

2.2 World Oil Reserves

Based on year 2013 data, the Central Intelligence Agency (CIA) estimates the world proven oil reserves to be approximately 1.6 trillion barrels of crude **[19]**. The total world oil reserves are shown in **Figure 2.1,** the world oil reserves by country is shown in **Figure 2.2** and full details are provided in **appendix 1**.

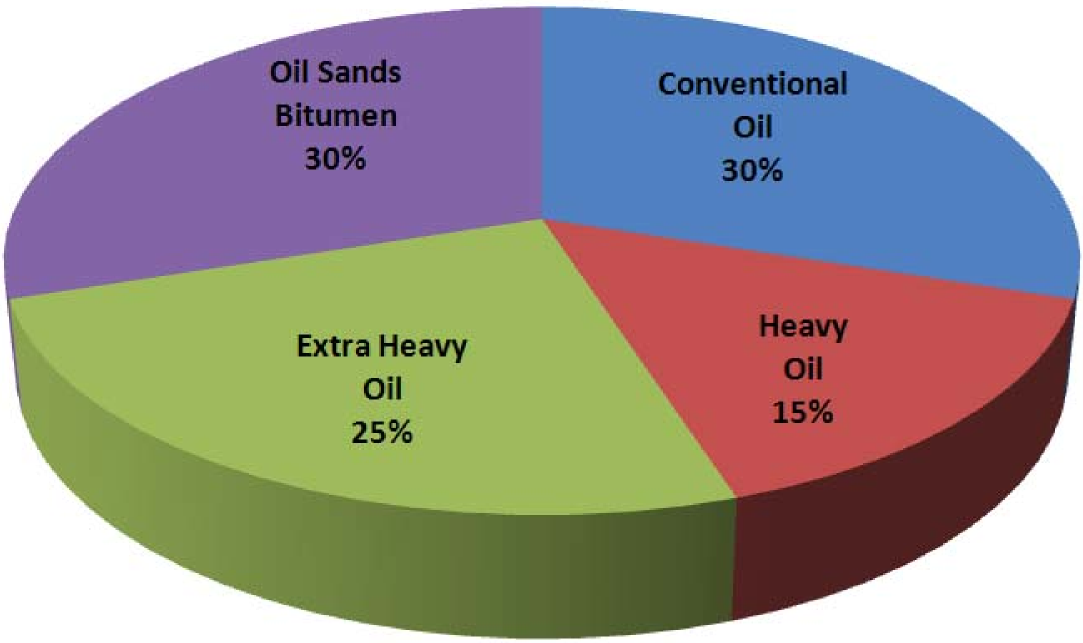


Figure 2.1: Total World's Oil Reserves [19]

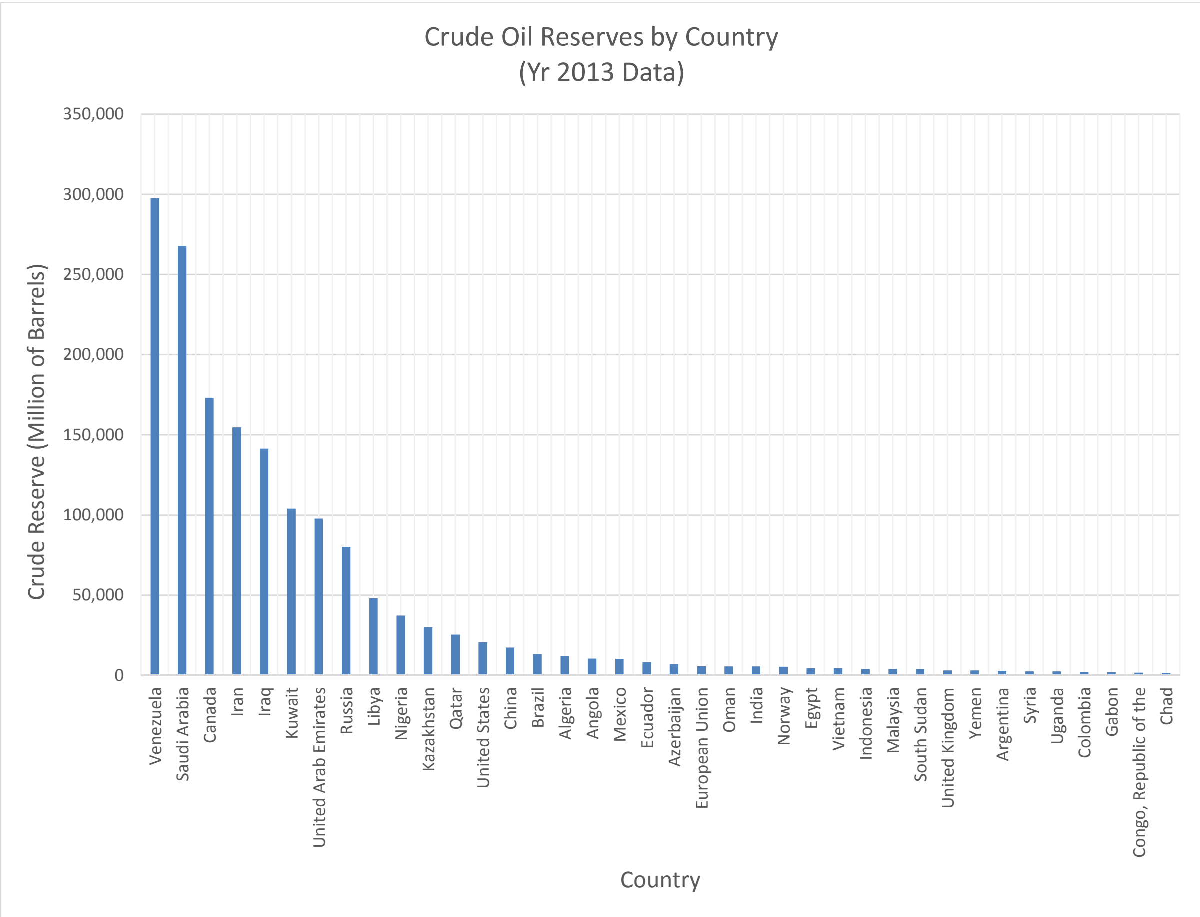


Figure 2.2:World Oil Reserves by Region [19]

Most world oil reserves are non-conventional; and it is reported that the heavier hydrocarbons (which may include heavy oil, extra heavy oil, Bitumen) account for more than six trillion barrels (one trillion m^3) of the oil in place worldwide, triple the combined world reserves of conventional oil and gas **[20]**. Canada and Venezuela are known to possess an estimated 3.6 trillion barrels (570×10^9 m^3) of bitumen and extra heavy oil, about twice the volume of the world's reserves of conventional oil **[21]**. These resources represent the key to easing energy supply concerns in the near term and the future **[22]**.

It is widely believed that heavy oil is underestimated in comparison to conventional oil because of poorer quality data.

The U.S. Geological Survey estimates approximately three trillion barrels of heavy oil in the world as illustrated in **Figure 2.3** below **[23]**.

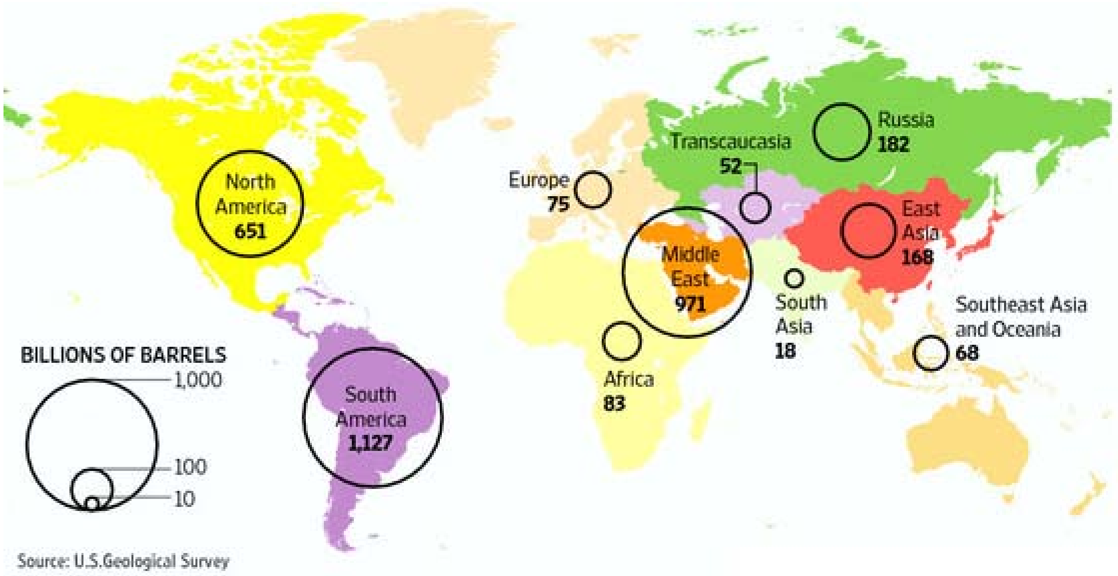


Figure 2.3: Estimated World's Heavy Oil Reserves by Region [23]

Although the climate change idea is making a global call for a reduction in energy demand and minimize carbon fuel supply, it is believed that this transition will not happen that soon. The literature reports that the energy consumption is significantly on the rise and is projected that it will increase by 36% above 2008 levels by 2035 **[24].** The rise in oil demand will inevitably open the door for heavy oil exploitation (due to the decline in conventional oil) and signal its importance in the international market.

Furthermore, more than half of the oil discovered since 2000 is in deepwater oil fields, and the production of oil from these reservoirs is expected to grow **[25]**. Deepwater discoveries and activities / development are worldwide, i.e. Gulf of Mexico, Brazil, West Africa and South East Asia.

Generally, conventional (light) oil is defined as oil with API gravity greater than 25°. Heavy Oil, with API gravity between 10°API and 20°API and a viscosity greater than 100 cP. Natural Bitumen (oil) has an API gravity less than 10° with viscosity greater than 10,000 cP.

The challenges of heavy oil production include, but are not limited to the followings:

- Low deliverability due to low reservoir energy (low pressure, low API gravity and very high viscosity).
- Complex thermodynamic phase behaviour during transportation (e.g. emulsion, foaming, wax deposition due to high content of Asphaltenes and resin).
- Water handling issues due to the early breakthrough of produced water.

2.3 Heavy Oil – Characteristics, Geological Origin and Recovery Process

2.3.1 Characteristics

Heavy oils are defined as asphaltic, dense (low API gravity), and viscous oils that are typically composed of relatively low proportions of volatile compounds with low molecular weight such as benzene, toluene, ethylbenzene, and xylene (BTEX). They also typically contain some two ring naphthalenes and high proportions of high molecular weight compounds. The high molecular weight compounds can be paraffins (straight chain alkanes), asphaltenes (aromatic-type hydrocarbon), resins and other compounds with high melting points and high pour points **[26]**. Heavy oil with high pour point and high viscosity will have less of a tendency to spread which will make recovery process difficult, especially in deep and ultra deepwater.

The American Petroleum Institute (API) categorizes crude oil into four groups on the basis of their heaviness and viscosity, and a typical representation is presented in Table 2.1.

Table 2.1: Crude Oil Categorization and the Physical Properties

Crude Oil Type	Description & Characteristics	API Gravity (°)	Viscosity (cP)
Light Oil	Conventional oil – Can be produced using primary recovery method	≥ 20	< 100
Heavy Oil	Dense, viscous with some impurities (waxes and carbon) – Require advance production technology & diluents at regular distances along the pipeline	10 - 20	100 - 10000
Extra Heavy Oil	Similar to heavy oil	< 10	100 - 10000
Natural Bitumen	Oil sands, denser than heavy oil	< 10	> 10000

2.3.2 Geological Origin

Most scientists believe that crude oil is not heavy at the origin, and that almost all crude oils originate with API gravity between 30° and 40°. Oil becomes heavy only after substantial degradation during migration and after entrapment **[27]**. A variety of biological, physical, and chemical processes have been implicated in degradation. Bacteria borne by surface water metabolize paraffinic, aromatic, and naphthenic hydrocarbons into heavier molecules **[28]**. Formation water washes away some of the lighter, highly water-soluble hydrocarbon molecules. In a process called devolatilization, a poor-quality seal allows lighter molecules to separate and escape.

Heavy oils are typically produced from geologically young reservoirs: Pleistocene, Pliocene, and Miocene **[20]**. Because these reservoirs are shallow, they have less effective seals and are thus exposed to conditions conducive to the formation of heavy oils. Collecting oil from seeps and digging by hand were the earliest and most primitive means of recovery, followed by mining and tunnelling **[20]**.

The literature reports that heavy oil reservoir temperatures and pressures are unlikely to be high due to low gas content caused by the absence of lighter components **[29]**, and high crude viscosity and low permeability usually constraint the reservoir productivity, and consequently strategy to boost production is generally required from an early stage.

2.3.2.1 Heavy Oil Offshore Development

Heavy and extra heavy oil deposits are occurring in 127 basins according to the United State Geological Survey (USGS), and around 4800 billion barrels of bitumen and 'heavy oil' have been identified worldwide **[30]**.

Around 500 billion barrels of recoverable heavy oil are located offshore **[31]**.

A global illustration of offshore heavy oil deposits worldwide is shown in **Figure 2.4** below (in violet).

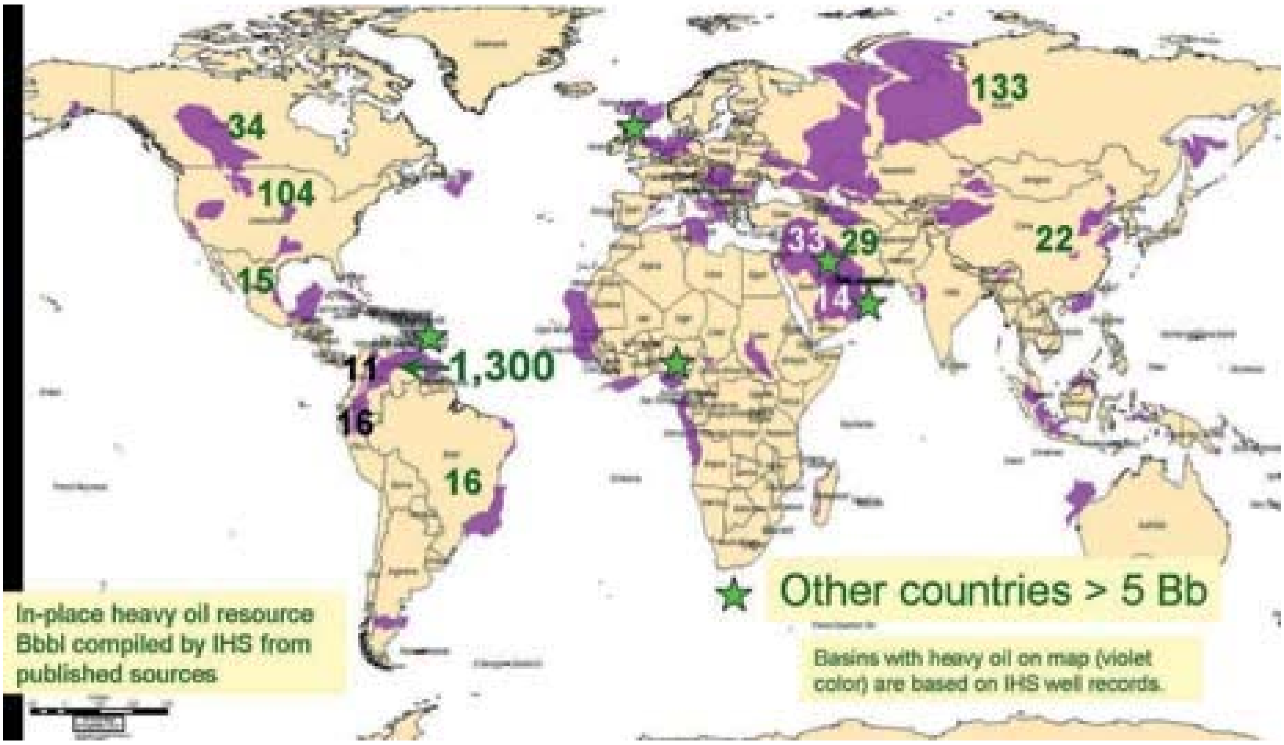


Figure 2.4: Heavy Oil Deposits Word Map [30]

UK (North Sea) & Offshore Brazil

There are several reported offshore heavy oil fields under development, and beside the Gryphon, Harding, and Alba fields (North Sea), there are some well known fields such as those being operated by Statoil known as Peregrino, Grane, Mariner and Bressay.

Peregrino is an heavy oil, with 13 °API and with high viscosity. The field is located in block BM-C-7 operated by Statoil with Sinochem, offshore of Brazil, east of Rio de Janeiro, in the southwest part of the Campos Basin area. The heavy oil in place is estimated to be approximately 2.3 billion barrels **[32]**.

Peregrino reservoir is 53 miles (85 km) off the coast, 328 to 390 feet (100 to 120 m) of water depth, and is 2,300 m (7,546 ft) beneath the seabed offshore Brazil.

Grane is an offshore heavy oil field (19° API) in the North Sea, in Block 25/11, located on the western coast of Norway 185 km off coast, west of the city of Haugesund), with about 755 million barrels in 405 ft (123.4 m) water depth. It is known to be Norway's first heavy oil production and Statoil's largest heavy oil field.

Mariner field is located in the UK North Sea, Block 9/11a and 9/11b, at water depths between 97 m and 112 m, approximately 130 km off the nearest British coast, and is reported to be the largest new offshore development in the UK in more than a decade. The Mariner Field consists of two shallow reservoirs, the Maureen Formation and the Heimdal Sandstones of the Lista Formation, with nearly 2 billion barrels of oil in place and expected reserves of more than 250 million barrels of oil. Both formations yield heavy oil of around 12° to 14° API **[33]**.

The Bressay heavy oil field is located within Blocks 3/27b, 3/28a, 3/28b, 9/2a and 9/3a of the UK Continental Shelf (North Sea), approximately 135 km east of Shetland, in water depth varying from 91 to 118 m, and the expected recoverable heavy oil (11° API) volume is 200-300 million barrels.

There are other known heavy oil fields such as the Captain and Jubarte:

Captain heavy oil Field is located in Block 13/22a of the UK North Sea, approximately 130 km northeast of Aberdeen. The heavy oil (19° API) reserves estimated at 956 million barrels, in 340 ft (104 m) water depth.

Jubarte heavy oil field is located 70 km offshore from the state of Espírito Santo in Brazil, in Campos Basin, block BC-60, at a water depth of 1,300 m. The project is owned and operated by Petrobras, with heavy oil reserves estimated at 600 million barrels (17° API).

Africa (Offshore)

The Dome Flore block is located in West Africa, offshore Senegal and Guinea Bissau, in the area administered by the Agence de Gestion et de Cooperation (AGC) and contains an estimated 800 million barrels of heavy oil in place. Thirteen wells have been drilled into the block, and several have penetrated 10-13° API heavy oil deposits, in shallow Oligocene reservoirs, which lies in 50 m of water, approximately 70 km offshore **[34]**.

Pazflor is located in deepwater offshore Angola block 17, 150 km off the coast of Angola and 40 km north-east of Dalia, which lies in 600 m-1,200m water depths, and is operated by Total Exploration and Production (E&P) Angola, a wholly owned subsidiary of Total, with a 40% interest. The Oligocene reservoirs are located in water depths from 1,000 m to 1,200 m, contain light oil of around 35°-38° API oil and will be developed using a production loop including riser bottom gas lift. The Miocene reservoirs, in 600 m to 900 m waters, contain heavy oil of around 17°-22° API, which will be recovered using subsea gas / liquid separation and liquid boosting **[35, 36]**.

Cegonha heavy oil field is located in the northern area of Kwanza Basin offshore Angola, Block 6, which lies in the water depth from 50 m to 500 m, is operated by Petrobras, and contains around 135 million barrels of heavy oil **[37]**.

The Emeraude Field is a major heavy oil accumulation, lying offshore Pointe-Noire (Republic of Congo) at a water depth of 60 m **[38]**. Further discovery was recently made, known as the Elephant discovery, in the Haute Mer A license area in offshore Congo (Brazzaville), 550 m of water depth, 80 km offshore Congo (Brazzaville), containing heavy oil around 14° API gravity **[39]**.

The West Tano is a heavy oil field offshore Ghana, with estimated reserves around 23.4 million barrels of 15° API heavy oil, operated by Tullow Oil.

The Morondava basin is located along the west coast of Madagascar and is a proven petroleum province with onshore discoveries of oil sands and subsurface heavy oil deposits exceeding 20 billion barrels. The offshore Morondava basin is largely underdeveloped and is considered to retain the same petroleum system that produced the onshore accumulations **[40]**.

2.3.3 Recovery Process

By its nature, heavy oil in most cases necessitates dissimilar production techniques to conventional oil; poses significant transportation challenges and requires generally heavy CAPEX and long payback times. Although some heavy oil production can be accomplished via conventional methods, such as vertical wells, pumps, and pressure maintenance, these methods are considered highly inefficient.

Owing to different reasons including advances in oil production technology, heavy oil production is progressively becoming a potential business for many operators.

Heavy oil recovery methods may fall under primary, secondary or tertiary recovery depeding on the reservoir charaeristics. The tertiary recovery includes thermal or hot production, non-thermal production known as cold production or production using gas injection (although water injection is sometime involved), chemical injection and microbial injection. An illustrative representation is shown in **Figure 2.5** below.

The selection of any of these methods depends on many factors, including the stage of reservoir production, formation and fluid properties, reservoir geology, and the economics.

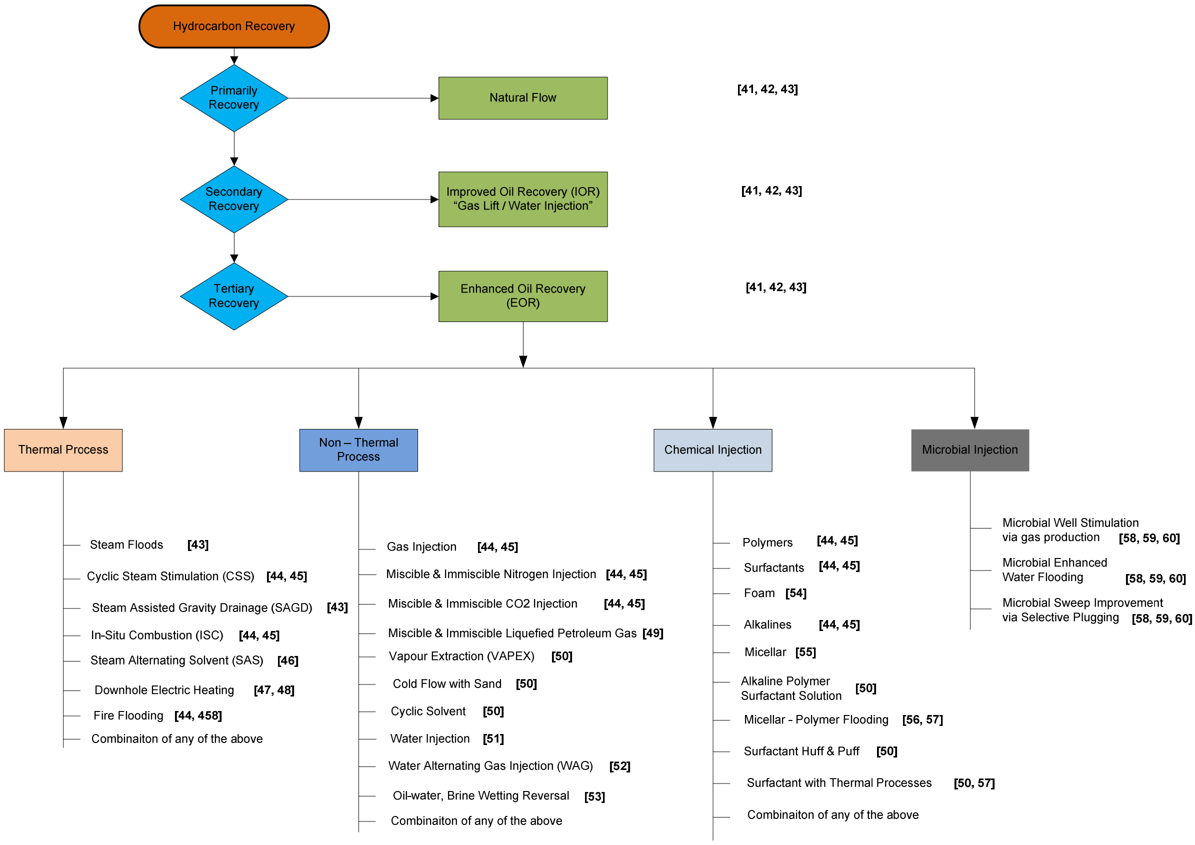


Figure 2.5: Hydrocarbon Recovery Processes

A typical trend of a timeline of hydrocarbon (heavy and light oil) recovery methods in the USA is shown in **Figure 2.6, Figure 2.7** and Figure **2.8** for Termal, Non Thermal (Gas) and Chemical recovery process respectively. Data gathered from literatures **[44, 45]**), and indicate a constant decline in projects using thermal methods from 1980 to 2005 which may be attributed to a considerable growth in CO_2-EOR projects. The growth in CO_2-EOR projects is basically sustained by the economics surrounding the business, with cheap available sources of CO_2 and transportation system (pipeline).

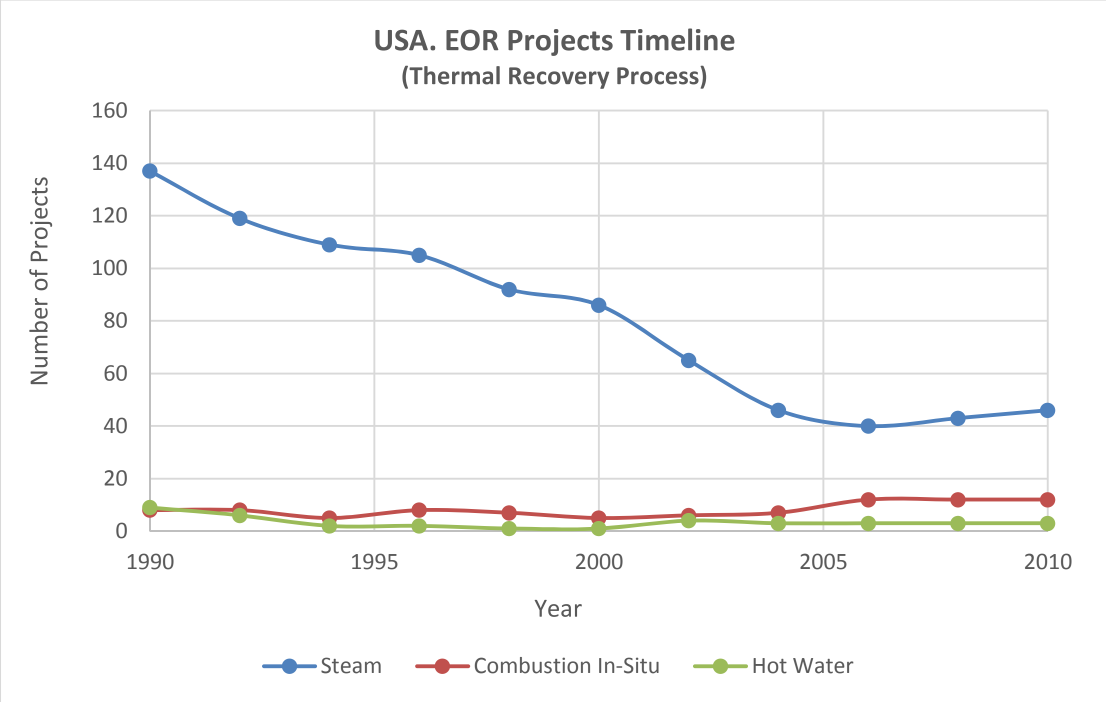


Figure 2.6: Thermal Recovery Methods Timeline in USA

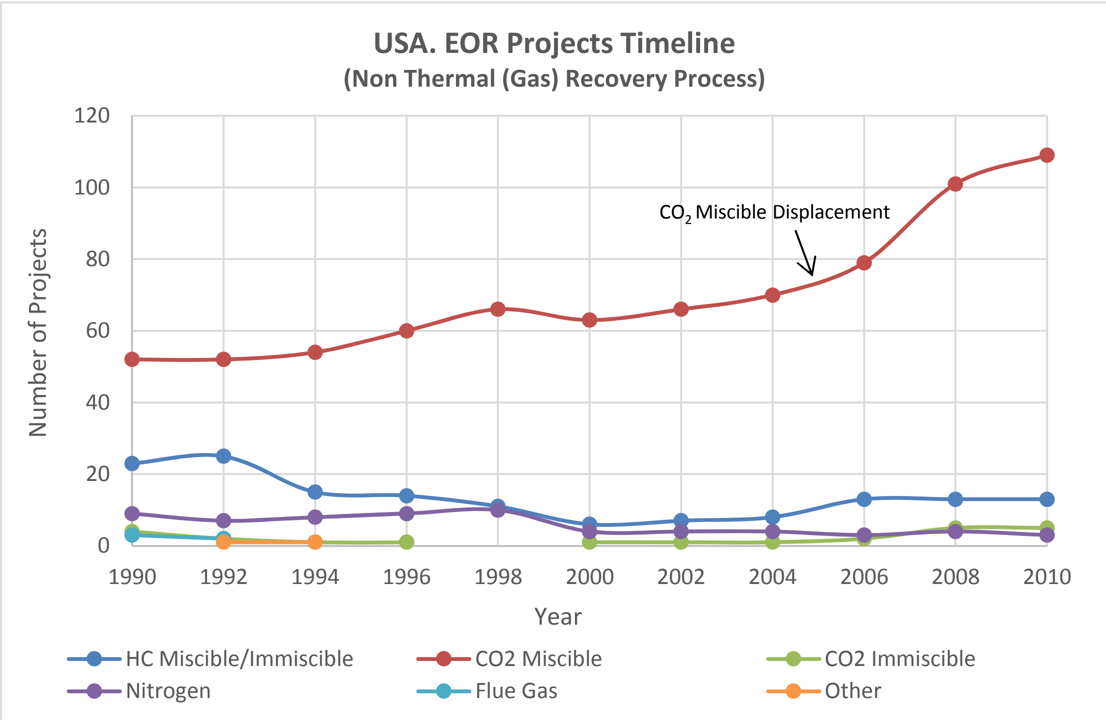


Figure 2.7: Non Thermal (using Gas) Recovery Methods Timeline in USA

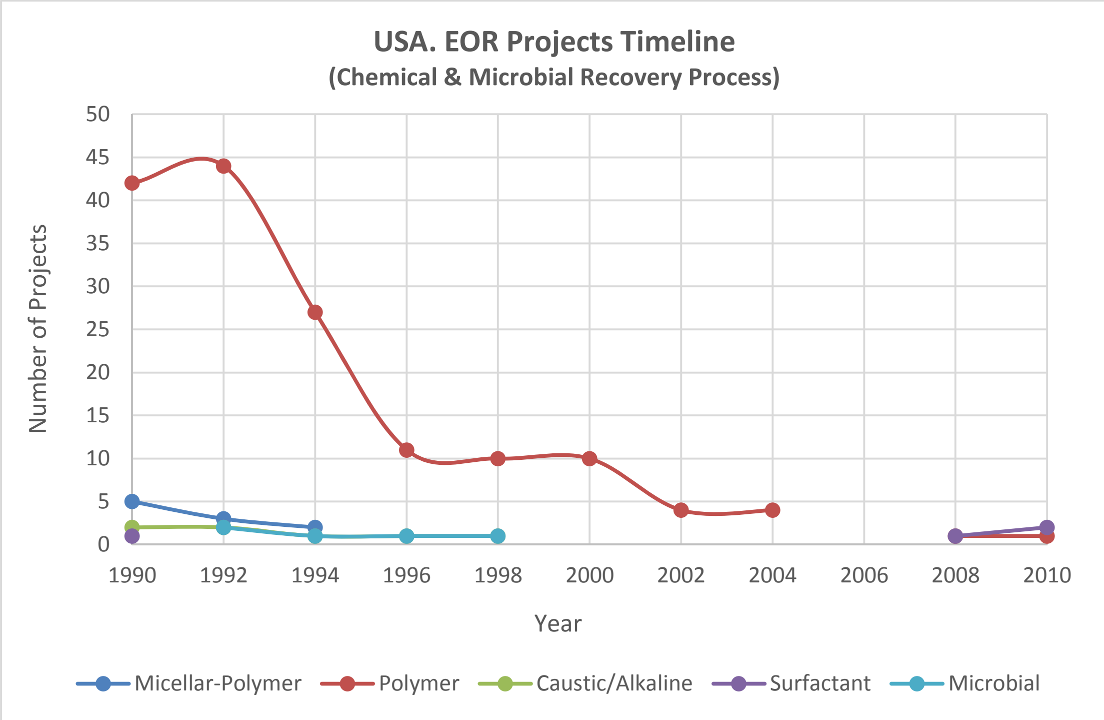


Figure 2.8: Chemical & Microbial Recovery Methods Timeline in USA

2.3.3.1 Primary Recovery

It is the first stage of heavy oil production in which natural reservoir energy, such as gravity drainage, displaces hydrocarbons from the reservoir into the wellbore and up to the surface. However, as the reservoir pressure declines, it becomes necessary to implement an artificial lift system to continue production. Cold heavy oil production with sand (CHOPS) is an example of primary recovery technique involving the continuous production of sand to improve the recovery of heavy oil from the reservoir.

2.3.3.2 Secondary Recovery – Improved Oil Recovery

This stage of recovery involves the injection of pressurized gas or water, or a combination of gas and water to drive to the surface some of the fluids remaining after the first stage (primary recovery). These methods also fall within the non-thermal EOR.

In conventional oil reservoirs, it is reported that additional 25% to 30% of the oil in place may be recovered via secondary methods **[61]**.

In conventional oil and heavy oil reservoirs, a significant portion of the original oil or heavy oil in place remains in the reservoir after primary and secondary recovery because of geological factors (e.g. no contact between the reservoir crude and the injected water or gas, i.e. crude bypassed) and characteristics of heavy oil (interfacial and viscous effects). By means of enhanced oil recovery (EOR) methods, additional heavy oil can be mobilized.

The EOR technology can be grouped into four main categories as shown in **Figure 2.5** above: Thermal recovery, Non thermal recovery, Chemical and Microbial injection.

2.3.3.3 Tertiary Recovery – Enhanced Oil Recovery

2.3.3.3.1 Thermal Recovery Process

It is a thermal stimulation process used to reduce the heavy oil viscosity, hence facilitate heavy oil mobilization.

Steam processes are generally applied to shallow heavy oil reservoirs that due to their extremely high viscosity cannot be economically recovered by primary recovery methods.

The thermal recovery method is generally grouped under two categories known as in situ combustion and injection of heated fluids.

With the in situ combustion, heat is generated inside the reservoir, e.g. Toe-to-Heel-Air-Injection (THAI), where air is injected into the vertical well (injector) to generate combustion, which reduces the oil viscosity and enable heavy oil to flow from the end of the horizontal producer (toe) up to the heel.

The injection of heated fluid, include methods such as steam floods, cyclic steam stimulation (also known as huff and puff, whereby steam is injected under high pressure and temperature in different stages (cycles)).

Steam Assisted Gravity Drainage (SAGD) is another example of injection of heated fluid **[62]**, and involves a pair of horizontal wells drilled from a central wellpad and separated by a short distance. In a plant nearby, steam generators powered by natural gas heat water and transform it into steam. The steam then travels through aboveground pipelines to the wells. It enters the ground via the steam injection (top) well. The steam heats the heavy oil to a temperature at which it can flow by gravity into the producing (bottom) well. The steam injection and oil production happen continuously and simultaneously. The resulting oil and condensed steam emulsion is then piped from the producing well to the plant, where it is separated and treated. The water is recycled for generating new steam.

Eighteen thermal recovery or hot flow projects are active in the Lloydminster, using either steam stimulation, in-situ combustion, huff and puff (cyclic-steam-thermal), oxygen or air fed fireflood to heat the reservoir, or a combination of steam stimulation and in-situ combustion **[63]**. A summary is presented in **Table 2.2** below **[63, 64]**.

Table 2.2: Thermal Recovery in Lloydminster [64]

Project Name	Short Description	Technology Applied	Project Name	Short Description	Technology Applied
Mobil-GC Kitscoty 51-2W4	95 wells on 640 acres and taps the Lloydminster Sparky Sandstone K-pool	Wet Combustion Thermal Fireflood	**Dome Lindberg 18-55-5W4**	56 well project uses an oxygen fed fireflood to heat the reservoir.	Oxygen Fireflood
Mobil-GC Silverdale 491W4	Located in township 49-1W4, the 82 well project begun in l975 and comprises 640 acres, tapping the Lloydminster Sparky Sandstone Q-pool.	Wet Combustion Thermal Fireflood - Fire in the formation is kept ignited by injecting an air/water mixture	**Dome Chauvin 26-42-3W4**	Using Cyclic steam stimulation, Dome Chauvin is a 4 well thermal pilot with a total estimated cost to date of $360,000.	CSS
Westmin Lindberg 3-13-6W4	Well was completed with high stress, high temperature materials and works on a one month steam injection, four month production cycle	CSS	**Dome Morgan 35-51-4W4**	43 well project using a combination of steam stimulation and in-situ combustion and Dome has invested $28 million	CSS & In Situ Combustion
Husky Aberfeldy 20-49-26W3	36 producing wells, 12 observation wells and 7 wells for steam injection.	Steam Drive	**Mobil Celtic ¼ -10-23-52W3**	Using a combination of wet combustion and steam stimulation, this 25 well EOR project has 5 injector wells and 20 producers, drilled in an inverted nine spot pattern.	Wet Combustion & CSS
Husky Aberfeldy 1, 12, 50-27W3	610 acre project using six active injection wells and 38 producers. This reservoir has been depleted on primary and waterflood, but twenty producing wells are presently averaging 50 cubic meters of oil per day.	Fireflood (North of Steam Flood	**Husky Golden Lake 11-48-23W3**	7 producing wells and 1 injector in an inverted 7 spot pattern. It will operate on air to start and be converted to oxygen at a later date.	Oxygen Fireflood
Husky Pikes Peak 1-50-24W3	Husky Pikes Peak is an eleven well huff and puff thermal project and consists of 11 new and thermally completed wells.	CSS	**Husky Golden Lake Waseka 14-48-23W3**	17 producing wells, 2 injectors and 2 observation wells.	Fireflood
Murphy Lindberg 6-13-58-54	7 well huff and puff project, begun in 1974 and converted to steam drive in 1981 after producing for six years.	CSS	**Norcen Bodo**	EOR project 3 km. northwest of Bodo began on 20 acres, and expanded to 105 acres later. Has 9 producing wells and one injector, being expanded to 24 producers and 7 air injectors;	Fireflood Expansion
Petro-Can Kinsella 14-30-48-8W4	Four producing wells, 1 injector and three observation wells.	Fireflood	**Murphy Eyehill 16-40-28W3**	25 wells, 9 injectors and 16 producers.	Fireflood
Texas Gulf N. Battleford 23-46-18W3	20 well EOR project, started in the mid 1970's and uses both steam drive and cyclic stream as the thermal process. There are four, five spot patterns drilled, and one, nine spot.	Steam Drive and Fireflood	**Home Kitscoty 51-2W4**	three wells, 2 of which have been drilled and the third was planned for later stage.	CSS

Thermal recovery accounts for about 393,000 BOPD which is about 7% of the US production, while oil recovered using CO_2-EOR is about 196,000 BOPD which is about 3% of U.S. production. The amount of oil recovered by hydrocarbon Miscible EOR (mostly natural gas injection) accounts for about 86,000 BOPD, which is about 1.5 % of U.S. production and nitrogen Miscible/Immiscible EOR accounts for about 32,000 BOPD, which approximately 0.5% of U.S. production. These methods account for well over 99% of all U.S. EOR production with considerably less than 1% coming from chemical EOR and microbial EOR which is still in the research stage" **[65]**.

Overall, most thermal processes are generally linked with high equipment, and facility costs (e.g. steam generation) and considerable safety concerns, hence are progressively been overtaken by the non-thermal processes.

2.3.3.3.2 Non Thermal Recovery Process

Water flooding is a non-thermal method which involves the injection of water to displace the heavy oil.

However, gas injection (i.e. CO_2, natural gas or nitrogen, or any combination) is known to be the most-commonly used method of EOR, which may be due to the cheap and ready availability of the gas sources. The application of nitrogen EOR is generally not cost effective. CO_2-EOR is gaining attention as it is considered to boost recovery significantly and be environmentally friendly due to the sequestration aspect of the process.

Other non-thermal methods include cold flow with sand, Cyclic Solvent Injection (CSI), and Vapour Extraction (VAPEX).

Cold flow with sand, also known as Cold Heavy Oil Production with Sand (CHOPS), is a process that involves the pumping of the heavy oil from the reservoir with no heat involved. It is reported that pumping out sand, release permeable sand tubes of very high porosity (wormholes) in the sand formation, allowing more heavy oil to move within the reservoir and to be recovered. Although, additional recovery may be achieved, disposing the large quantity of sand produced has always proved very challenging in this method.

Cyclic Solvent Injection (CSI) involves a mixture of solvent to be injected into the reservoir to facilitate recovery of heavy oil. Cyclic Solvent Injection (CSI) method is usually compared to Cyclic Steam Stimulation (CSS) in a sense that the method also goes through different cycles, i.e. after the injection of mixture solvent (injection period), the solvent mixture is allowed to mix with the reservoir crude (soak period), and then followed by the production (production period). The solvent mixtures used in the Cyclic Solvent Injection (CSI) process is generally gaseous (to easily fill up the voidage created during primary recovery; generally, it is methane or carbon dioxide, with propane or butane), high solubility with the reservoir heavy oil, and be readily available (inexpensive).

Vapour extraction (VAPEX) involves the injection of a solvent vapour to reduce the viscosity and improve the mobility of the heavy oil. The method (VAPEX) is comparable to SAGD, but instead of steam used in SAGD, VAPEX uses hydrocarbon solvents to mix with the heavy oil, hence enable it to flow more easily.

A number of heavy oil reservoirs under solution gas drive (cold production) have obtained anomalous primary performance results: low production gas–oil ratios, high oil production rates, and recovery of unexpectedly large amounts of oil **[66]**. This unusual behaviour has been attributed to two production mechanisms named: Foamy Oil Process and Wormholes formation.

During the foaming process, gas bubbles expand, giving the oil a foamy character as the bubbles are trapped by the oil; recovery is then enhanced by solution gas drive. Oil recovery with primary techniques can be as high as 20% for some heavy foamy oil reservoirs. The wormholes mechanism is internal erosion in unconsolidated sand reservoirs, which can create a network of high-permeability channels, termed "wormholes." This mechanism can enhance drainage by a factor of ten (10) or more. Wormhole formation and localization apparently are still not completely well understood, which makes it difficult to optimise production **[66]**.

2.3.3.3.3 Chemical Injection for Enhanced Oil Recovery

Chemical EOR involves the addition of chemical agent such as polymers, surfactants, alkaline to the heavy oil reservoir, which will modify the fluid properties to make it more easily recoverable. The chemical EOR is known to improve sweep efficiency by the decrease in mobility ratio, lowering of oil-water interfacial tensions with a reduction in oil viscosity (emulsification) and increase in capillary number. The total number of chemical EOR projects worldwide is reported to be approximately 27 **[55]**.

Coupled with the unavailability of chemical in large quantities, considerable delay in response and reduced well spacing required; the chemical EOR has always been known to be very costly; as the oil or heavy oil price rises so does the price of chemical, hence chemical EOR never gained widespread acceptance.

2.3.3.3.4 Microbial Injection for Enhanced Oil Recovery

The microbial injection for EOR (MEOR) is a technology that requires the injection of bacteria or micro-organisms into the heavy oil reservoir to improve the movement of fluids. It is reported that the micro-organisms injected into the reservoir will create an in-situ microbial growth that will directly influence the structure and properties of the reservoir fluids through various processes including: Biodegradation of crude (i.e. low oil-water interfacial tension and reduced oil viscosity); well stimulation via gas production (bacteria produced gases such as CO_2, N_2, H_2, and CH_4 that can improve oil recovery through gas dissolution into oil and oil viscosity reduction); permeability modification (also known as selective plugging whereby bacteria are used to produce polymers, biomass, to reduce the permeability of highly permeable zones); production of chemicals (organic acids, alcohols, solvents, surfactants and polymers that can improve oil recovery can be produced by a range of micro-organisms) **[67, 59, 68]**.

MEOR depends on the physical-chemical properties of the reservoir, i.e. salinity, pH, temperature, and pressure. With the exception of bacteria that can bear the high salinity and temperature within most reservoirs, some micro-organisms such as moulds, yeasts, algae, might be incapable to grow under most reservoirs conditions **[58]**.

Although the use MEOR might be independent of the crude price, and may also have the advantage of using some bacteria that can prevent the production of unwanted component such as hydrogen sulphide; the MEOR is at a very early stage, i.e. research stage, with a lack of understanding of microbial activities within the reservoir and the impact on the life cycle operation; no published field experience, neither in conventional or heavy oil field.

Likewise, as in the chemical EOR, the MEOR can pose serious safety, health and environmental risks. Perhaps MEOR might be suitable for marginal and shallow oil fields; the envisaged large quantities of microbes required with the likely risk of plugging the well will make this technique very restrictive and very challenging for deepwater, coupled with environmental impact in the event of any unpleasant incident.

2.4 CO_2-EOR for Heavy Oil Recovery

2.4.1 Mechanism

CO_2 injection is one of the EOR techniques that consists of injecting CO_2 at high pressure into an oil reservoir to mobilize oil that has not been extracted using traditional methods.

CO_2 injection into the reservoir, interacts with the reservoir rock and the crude, to create appropriate conditions, as listed below, that facilitate recovery **[69]**:

(i) Reduction of the capillary forces that hold back oil flow through the pores of the reservoir. This is achieved by a reduction in the interfacial tension between oil and the reservoir rock;

(ii) Oil swelling (oil volume expansion), and viscosity reduction;

(iii) Reservoir crude phase change that increase its fluidity;

(iv) Improvement in volume sweep efficiency via favorable mobility characteristics of oil and CO_2.

During CO_2 EOR, 40% of the injected CO_2 is being produced and can be re-injected **[70, 71]**.

The method for calculating the mass CO_2 storage capacity (MCO_2) in the reservoir during EOR operations, which is a function of the recovery factor, original oil in place (OOIP), and oil shrinkage has been proposed by Shaw and Bachu **[70]** as:

At Breakthrough (BT):

$$M_{CO2} = \rho_{CO2res} \times RF_{BT} \times OOIP / S_h \qquad (2.1)$$

At any Hydrocarbon Pore Volume:

$$M_{CO2} = \rho_{CO2res} \times [RF_{BT} + 0.6\,(RF_{\%HCPV} - RF_{BT})] \times OOIP / S_h \qquad (2.2)$$

Where:

ρ_{CO2res} = Density of CO_2 at reservoir conditions;

RF_{BT} = Recovery Factor at CO_2 Breakthrough;

$RF_{\%HCPV}$ = Recovery Factor at the assumed Percentage Hydrocarbon Pore Volume (HCPV) of injected CO_2;

OOIP = Original Oil in Place;

S_h = Oil shrinkage factor ($1/B_o$, where B_o is the Oil formation volume factor).

For Water Alternating Gas injection (WAG), the net CO_2 stored in the reservoir was proposed by Bachu et al **[72]** as:

$$\text{Net } CO_{2\ retained} = WAG_{IOR\ efficiency} \times WAG_{score\ efficiency} \times OOIP \times WAG_{CO2\ factor\ alpha} \times B_o / B_g \quad (2.3)$$

Where:

$WAG_{IOR\ efficiency}$ = Targeted incremental oil recovery factor by CO_2 WAG operations;

$WAG_{score\ efficiency}$ = Factor between 1 and 2, which is related to the net CO_2 utilisation efficiency when expressed in reservoir volumes

With regard to Gravity Stable Gas Injection (GSGI):

$$\text{Net } CO_2 = GSGI_{CO2\ factor} \times GSGI_{score\ CO2\ factor} \times OOIP \times 0.7\ B_o / B_g \quad (2.4)$$

Where:

$GSGI_{CO2\ factor}$ = Incremental oil recovery factor by GSGI operations;

$GSGI_{score\ CO2\ factor}$ = May be equal to 1 depending on project implementation.

0.7 OOIP = 0.7 was identified by the authors to account for a fraction of OOIP and water left in the formation post GSGI operations **[72]**.

However, better predictions could be achieved by appropriate numerical reservoir simulations, which may consider the effect of water invasion, gravity segregation, reservoir heterogeneity and CO_2 dissolution in the formation water **[73]**.

CO_2 is known to be highly soluble in oil and this solubility leads to the swelling of oil, reduce its viscosity and decrease its density, which in turn facilitates mobility. It is reported that the swelling mechanism becomes a prevailing factor in low pressure applications (i.e. P<1000psia) of CO_2 in reservoir systems with low API such as heavy oil.

CO_2-EOR can be achieved under two displacement processes known as Miscible or Immiscible displacement. These two processes are very much dependent on temperature, pressure and reservoir composition.

2.4.1.1 Miscibility

Miscibility is described as: the ability of two or more substances to form a single homogeneous phase when mixed in all proportions **[73]**. CO_2 miscible displacement implies the injection of CO_2 into the reservoir at the required miscible temperature and pressure to facilitate movement of the hydrocarbon out of the reservoir to the surface. As a result of this miscibility, there is a reduction in the crude viscosity, an increase in relative permeability and the elimination of interfacial tension between the oil and injected CO_2, hence no capillary forces to prevent the mobility of the oil. Under these conditions, the literature reports that all reservoir crude oil (100%) being contacted by the injected CO_2 can be displaced **[74]**. However, additional oil recovery is usually limited to around 5-20% of OOIP **[75]**, due to viscous fingering (CO_2 flowing more easily within the reservoir than oil) and an early breakthrough of CO_2.

Miscible CO_2 displacement may not be achieved instantaneously, but progressively through a process generally called Multiple Contact Miscibility (MCM), where a complex phase interaction between the injected CO_2 and the reservoir oil occurs. This interaction also leads to a complex phase behaviour of the CO_2 – oil mixture, which in turn is influenced by the reservoir temperature, reservoir pressure, injected CO_2 composition, and oil composition **[76]**.

The pressure at which miscibility can be achieved is known as minimum miscibility pressure (MMP) and can be predicted experimentally or using empirical equations with a reasonable accuracy.

The Slim Tube Experiment is generally used to establish conditions at which miscibility can occur. Miscible displacement is achieved at the flooding pressure or minimum miscibility pressure (MMP) where about 95% of the oil in the tube is recovered after about 1.3 pore volumes of fluid have been injected. Below this pressure, oil recovery decreases dramatically **[77]**.

The minimum miscibility pressure (MMP) depends on the composition of crude oil, the purity of CO_2 and the reservoir conditions (pressure and temperature); and a miscible CO_2 displacement technique is achievable when CO_2 is injected at a pressure higher than that of MMP, which in turn must be lower than the reservoir pressure **[69]**.

At the MMP, the density of CO_2 is similar to that of the crude oil, i.e. CO_2 is in a dense phase, and becomes fully miscible with oil.

2.4.1.2 Immiscibility

Immiscible displacement occurs when the reservoir pressure is below the minimum miscible pressure (MMP) of the oil, and there is an identifiable separation of the injected CO_2 and the reservoir oil.

CO_2 immiscible process can improve the sweeping efficiency as well as the recovery of conventional or heavy oil through a vaporisation process **[78]**. The hydrocarbon fractions may get vaporized into the gaseous CO_2 phase and the decrease or shrinkage in the oil indicates the extraction. So, even with the MMP not reached, the injected CO_2 can partially dissolve in the reservoir crude, hence causing some swelling (i.e. expansion of the crude). Moreover, the addition of CO_2 in heavy oil may reduce its viscosity by a factor of 10 **[73]**.

Some typical CO_2 Immiscible pilot studies include the Putaohua reservoir in Sanan area of Daqing oilfield **[79]**, and Forest Reserves & Oropouche Projects in Trinidad **[80]**. The incremental oil recovery ranged from 4 to 9%. In Daqing, it is reported that CO_2 injection was carried out after waterflood while in Trinidad CO_2 injection was conducted post water and gas injection.

2.4.1.3 Miscible vs. Immiscibility

The critical pressure (1073 psia or 73.77 Bar) and temperature (87.8 ^oF, or 31 ^oC) of CO_2 are very important to determining the miscibility and immiscibility of oil reservoirs. For miscibility to occur, CO_2 must exist as a critical fluid (i.e. Dense phase, liquid-like, supercritical CO_2). A supercritical CO_2 occurs when CO_2 is at or above its critical point (critical temperature and pressure).

At atmospheric condition, i.e. 1.01 Bar and 15.56 ^oC, the density of pure CO_2 is 1.87 kg/m^3. At critical point, the density of pure CO_2 is 388.3 kg/m^3. As the pressure and temperature increase gradually above the critical point, CO_2 will remain within the supercritical state, at which condition, its density can increase up to 750 kg/m^3.

A typical pressure-temperature phase diagram of CO_2 is shown in **Figure 2.9** below for illustration.

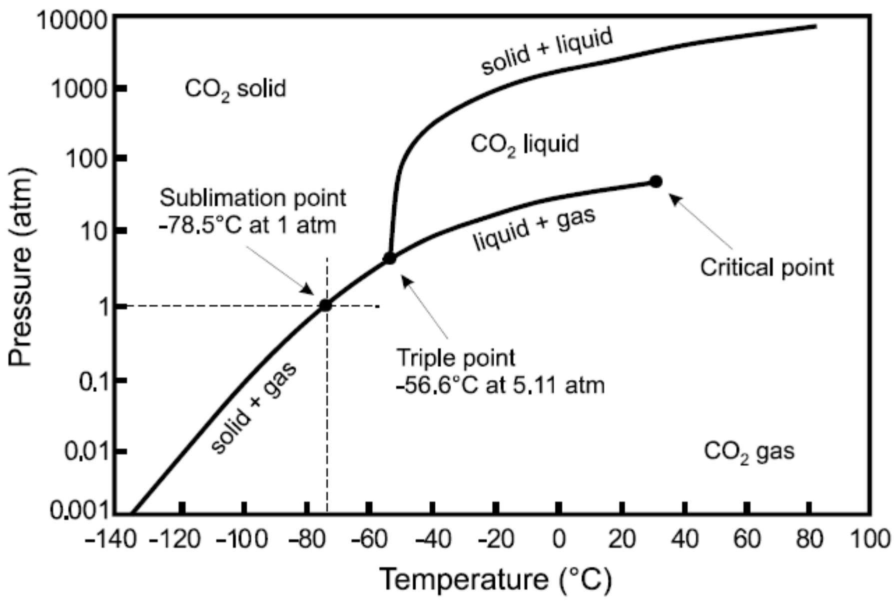


Figure 2.9: Phase Diagram of CO_2

Miscible CO_2 is only possible for the reservoir temperature exceeding the critical temperature of CO_2 and reservoir minimum miscibility pressure (MMP; which increases with temperature and is at least equal to the critical pressure of CO_2) **[81]**.

Immiscible conditions exist at reservoir temperature and pressure generally less than the critical temperature of CO_2 and temperatures above the critical temperature when reservoir pressure is less than the MMP pressure. Under Immiscible conditions, liquid or gas-like phases of CO_2 are possible. The miscibility and immiscibility criteria as provided **[81]**, are shown in **Table 2.3.**

Table 2.3: Miscibility and Immiscibility Conditions Based on CO_2 Critical Temperature & Pressure

Criteria	Conditions	Comments
T_{res} < 86°F	Immiscibility	-
86°F < T_{res} < 90°F	Miscibility / Immiscibility	Either Possible T_{CO2} = 87.8°F
T_{res} > 90°F	Miscible Possible	-
		-
P_{res} < 1000 psia	Immiscible	-
1000 psia < P_{res} < 1200 psia	Miscible / Immiscible	Either Possible P_{CO2} = 1073 psia
P_{res} > 1200 psia	Miscible Possible	-

2.4.1.4 CO_2-EOR Screening Criteria

It has been acknowledged by previous investigators that not all oil or heavy oil reservoirs are suitable for CO_2-EOR and storage for various reasons ranging from technical challenges to the cost surrounding such a project. Preliminary screening criteria for selecting oil or heavy oil reservoir suitable for CO_2-EOR and storage were proposed by Shaw and Bachu **[70]**. Standardized CO_2 sequestration screening criteria are provided by Nelms and Burke **[82]**, but sounds more theoretical, less explicit and less adaptable as the technical screening guideline proposed by Taber et al **[83, 84] (**see **Table 2.2)**.

Criteria recommended by various authors for the technical screening of Miscible CO_2-EOR are presented in **Table 2.4.**

Table 2.4: Screening Criteria for Miscible CO_2-EOR (Light Oil)

Reservoir Parameter	[85]	[84]	[86]	[83]
Depth (m)	< 3000	>700	>914	i) > 1219; ii) > 1006 iii) > 853; iv) > 762
Temperature (°C)	< 90	-	-	-
Pressure (MPa)	>83	-	>103	
Permeability (mD)	>1	-	-	-
Oil Gravity (°API)	>40	>26	>30	i) 22-27.9; ii) 28-31.9 iii) 32-39.9; iv) > 40
Viscosity	< 2	< 15	< 12	< 10
Fraction of Oil Remaining	>0.30	>0.30	>0.25	>0.20

Investigation of the influence of some reservoir parameters on the CO_2-EOR was carried out by Rivas et al **[87]**, through a series of reservoir simulations, and an optimum value for reservoir and oil properties suitable for CO_2-EOR was established. The results of the findings are presented in **Table 2.5** below**.** The suitability of such criteria for heavy oil certainly needs more investigations.

Table 2.5: Optimum Value for Reservoir Parameters for CO_2-EOR Suitability

Reservoir Parameters	Optimum Values	Parametric Weight
API Gravity (°API)	37	0.24
Remaining Oil Saturation	60%	0.2
Pressure over MMP (MPa)	1.4	0.19
Temperature (°C)	71	0.14
Net Oil Thickness (m)	15	0.11
Permeability (mD)	300	0.07
Porosity	20%	0.02

2.5 CO_2-EOR Technique – State of Play

2.5.1 A Worldwide Overview

USA remain the leader in the implementation of the CO_2-EOR technique, since starting the first miscible displacement project in 1972 in the Permian basin (SACROC field).

A worldwide snapshot is presented in **Table 2.6** below

Table 2.6: Active CO_2-EOR Projects Worldwide [45]

Country	Process	No. of Project	Production rate (b/d)
USA	Miscible	70	205775
	Immiscible	1	102
Canada	Miscible	2	7200
Turkey	Immiscible	1	6000
Trinidad	Immiscible	5	313

However, year a 2010 survey indicates that the number of miscible projects in the USA has increased to 103, and the immiscible to 5 **[88]**.

2.5.2 Investigation and Field Application

Technical and economical evaluation of EOR for two heavy oil (18-24° API) fields (four reservoirs in total) in Africa based on 13 established and emerging methods including chemical processes, gas injection, thermal and microbial EOR, are reported by Hon Vai Yee et al **[89]**. Data required for the study include:

- Fluids rock properties;
- Driving mechanism;
- Production data;
- OOIP and recoverable reserves;

- Relative permeability curves.

The Miscible CO_2 injection was found not suitable for any reservoir due to higher calculated MMP (Minimum Miscible Pressure) while the Immiscible gas injection was a viable solution.

The methods used were not really spelled out in the literature, no reservoir simulation were carried out. Although the study showed that the In-Situ Combustion and steam flooding EOR processes could be the most technical and economical EOR, it might not be appropriate to conclude that these are the most effective EOR for heavy oil reservoir in Africa, bearing in mind that the EOR techniques are also reservoir dependant, and two fields out of many that exist in Africa might not necessarily typify or characterize all the African heavy oil reservoirs.

A laboratory investigation, including pressure/volume/temperature (PVT) studies and core-flood experiments have been carried out by Raj et al **[90]**, for assessing the suitability and effectiveness of three injection gases (flue gas containing 15 mole% CO_2 in N_2, a produced gas containing 15 mole% CO_2 in CH4, and pure CO_2) for heavy oil recovery (~14° API gravity collected from Senlac reservoir located in the Lloydminster area, Saskatchewan, Canada). As reported by the author, pure CO_2 appeared to be the best recovery agent, followed by the produced gas.

With a sensitivity of water alternating CO_2, a reduction in either waterflood or CO_2 injection rate resulted in an increased in oil recovery and showed the interference of viscous, capillary and diffusive forces **[91]**.

Hydrocarbon extraction can be easily enhanced at pressures above 1200 psig, **[92]**. A slim tube displacement experiment test indicated that at pressures as high as 3800 psig, CO_2 might reach miscibility with viscous oil **[92]**. This suggests why the author concluded that in the recovery of heavy oil by CO_2 flooding at high pressure, oil displacement efficiency can be as high as that of Miscible displacement. Following the coreflooding test, the author concludes that there is no significant improvement in oil displacement efficiency by using the CO2-WAG injection method, which appears to be different from the results obtained by Srivastava et al **[91]**. The author suggests a CO_2 alternating brine injection will reduce the CO_2 utilisation factor.

For the purpose of investigating the feasibility of CO_2 flooding process under Immiscible conditions for stock tank oil of 22^o API, the following conventional flooding methods were tested:

1) CO_2 flood (secondary oil recovery);

2) Waterflood with reservoir brine;

a) CO_2 continuously injected after waterflood;

3) CO_2-alternate-brine (1:1 WAG ratio) flood after waterflood;

4) CO_2-alternate-brine (2:1 WAG ratio) flood after waterflood;

5) CO_2 huff'n'puff stimulation (cyclic injection mode).

The results indicate that CO_2 immiscible flooding is an effective method for high pressure viscous oil recovery.

Using the steam version of the in-situ combustion numerical model by Coats **[92]**, the Immiscible Displacement mechanism of CO_2 in a simultaneous injection of CO_2 and steam in a heavy oil reservoir was evaluated and it was concluded that the viscosity reduction effect of CO_2 in heavy oil, in a steam stimulation process is the major contributor that increased recovery in a high compressibility reservoir **[93]**. In a normal compressibility reservoir, the major benefit is derived from the solution gas effect of injected CO_2. The author noticed little improvement in the final recovery of the steam and CO_2 drive in comparison to the steam drive case, which is certainly controversial to the results reported by Shubao and Shunli **[94]** and Hornbrook **[95]**. This probably suggests the importance of reservoir conditions in the recovery performance.

The displacement mechanisms were investigated using four recovery methods, steam, steam injection with CO_2, steam injection with surfactant, steam injection with CO_2 and surfactant, using a laboratory physical mode and a (CMG suite of software (e.g. GEM, IMEX)) numerical simulation model **[96]**. The author concluded that the oil recovery of the simultaneous injection of steam; CO_2 and surfactant is higher than that of steam injection; steam with CO_2 and steam with surfactant. CO_2 dissolution in oil helps to improve flow performance of heavy oil.

CO_2 decreases the temperature of steam during the CO_2 alternating steam injection process, which impact on the expansion of steam chamber.

High pressure displacement on the recovery of West Sak crude oil (19.2^o API, hence heavy oil) using steam and CO_2 was also investigated by Hornbrook **[95]** in a laboratory experimental test conducted in an unconsolidated sandpack (2" diameter and 4ft long). The authors claimed that the simultaneous injection of CO_2 and steam increased recovery, reduced injection temperatures, and reduced the heat input required. It was also reported that the optimum CO_2 and steam molar ratio of maximizing recovery is 1:3. This will depend on parameters such as recovery rate, injection rates, pressure, API and other, considering that the authors only focused on the influence of CO_2 addition during the steam drive.

Slim Test Displacement (STD) tests supported by Equation-of-State (EOS) predictions were used to evaluate the ability of various solvents such as CO_2, n-butane and various mixtures of Prudhoe Bay natural gas (PBG) and natural gas liquids (NGL), to miscibly displace heavy, asphaltic West Sak crude **[96]**. Results indicate that for enriched gas drives, the development of dynamic miscibility occurs via simultaneous vaporizing and condensing mechanisms.

STD test results indicate that the ultimate oil recoveries, even for first contact miscible (FCM) solvent were considerably lower due to asphaltene precipitation. Asphaltene tests were conducted for various solvent-West Sak crude mixtures to determine the amount of precipitation and its effect on oil composition. STD results and EOS predictions indicate that CO_2 was unable to develop dynamic miscibility with West Sak crude at reservoir pressure (6650 psia) and temperature (80 ^oF) conditions.

A series of experiments were conducted using a cylindrical tube (1D) and rectangular box (3D) to investigate the effects of simultaneous injection of CO_2 and CH_4 together with steam on the recovery of heavy oil (12.4^o API) mixed with unconsolidated limestone **[98]**. The gases together with steam resulted in higher incremental heavy oil recoveries compared to steam injection alone.

Investigation using ECLIPSE (By Schlumberger) was carried out, considering the West Sak reservoir, to explore the effect of CO_2 and water injection (individually or simultaneously) for the purposes of EOR and CO_2 storage **[98]**. A 3D black oil simulator was constructed accounting for the oil swelling and viscosity reduction, and the results showed higher recovery when a combination of water and CO_2 injection was carried out in early production life. The authors also claimed that CO_2 storage is at its maximum if depletion precedes CO_2 injection and large quantity of CO_2 storage was very likely. Recovery using liquid CO_2 injection was almost identical to that of waterflood due to its reduced mobility compared to that of dry CO_2. Significant improvement with water alternating CO_2 injection and simultaneous water-CO_2 injection was noticed compared to water or CO_2 injection alone. Water-CO_2 ratio played an important factor in the CO_2 retention, with a ratio below one lower CO_2 was required and higher CO_2 storage was noticed at high injection pressure. Water-CO_2 ratio above one favored lower CO_2 retention factor.

Correlations were developed for the prediction of CO_2 solubility, oil swelling factor and viscosity change for CO_2-saturated heavy oils, based on experimentally measured data (physical properties of heavy oil before and after CO_2 saturation) **[99]**. Temperature, pressure and specific gravity are required within the CO_2-solubility and swelling factor correlations, while the crude viscosity is required for predicting the mixture viscosity. The author claims that the correlations can be applied in the context of heavy oils and can also be used to estimate the quantity of CO_2 required to reduce the oil viscosity, hence to facilitate mobility.

Reservoir simulation was carried out to **[100]**:

1) Investigate the possible formation of a second liquid during CO_2 injection and its influence on oil recovery;
2) Assessing the Immiscible and Miscible oil recovery using solvent injection (continuous injection, slug and WAG injection) for the Schrader Bluff which is a shallow water heavy oil reservoir located in the Alaskan North slope.

The results indicated the existence of a second liquid phase which did not have any impact on the oil recovery process. It was justified that the second liquid phase was mainly CO_2 content and only had about 0.05% of the heavier hydrocarbon (C_{11+}). Miscible WAG was more effective than the Immiscible process.

Simulation using a modified EOS to match laboratory saturation pressure and swelling was carried out to investigate the Immiscible CO_2 process in heavy oil reservoirs and Immiscible gas injection alternated with water resulted in higher recovery compared to the slug injection **[101]**.

Schrader Bluff is a heavy oil reservoir in Alaska (USA) with almost 1.5 billion of recoverable heavy oil. The lack of potential primary recovery technique and the abundance of CO_2 in the region triggered off the need to investigate the CO_2 for enhanced recovery of heavy oil. A study was conducted with the objective to establish a suitable solvent (CO_2 / Propane) that will develop miscibility with the Schrader Bluff reservoir heavy oil **[102]**. The investigation was experimentally based and involved carrying out slim tube tests to assess the miscibility of CO_2 with the Schrader Bluff reservoir heavy oil. Unfortunately, the results of the slim tube test indicated that the two fluids were Immiscible at reservoir conditions. The effect of slug size and WAG ratio were assessed using 50% of Prudhoe Bay Gas (PBG) with 50% NGL (as solvent) injected on 4ft core-flood (long sandpacks). The core-flood experiments showed that large size slug (>0.2PV, Pore Volume) of 50%PBG/50%NLG had no significant improvement in the Schrader Bluff heavy oil recovery, while a single small size of 50%PBG/50%NLG mixture or CO_2 slug had higher improvement per unit slug size. These results indicated that CO_2 was more effective than the PBG in IOR for the Schrader Bluff case, although not Miscible with the Schrader Bluff heavy oil. The authors also concluded that the simulation of CO_2 injection into the Schrader Bluff heavy oil reservoir indicated strong possibility of the formation of a second liquid phase.

Sensitivity and the importance of physical effects in the modelling of Miscible or Immiscible CO_2 injection in sandstone and carbonate reservoirs is discussed thoroughly based on fields case study **[103]**. It was concluded that CO_2 is an effective displacing agent, but the physical effects occurring at CO_2 flood need accurate modelling and further research, e.g. CO_2-rich liquid phase and thermodynamic aspect of its formation need to be modelled properly to account for fingering effects and diffusive CO_2 transfer mechanisms. Fingering effect is referred to the hydrodynamic instability, when a more mobile fluid displaces a less mobile one. Evaluation of CO_2 or CO_2-WAG processes were performed on many of the Norwegian Continental shelf reservoirs, and most of the studies proved the technical feasibility of the EOR technology; however, the following points were raised as being the major blockage of the non continuity or implementation of the project:

- ❖ Insufficient quantities of low cost CO_2 in the area;
- ❖ Transport and storage of CO_2 on the offshore platforms;
- ❖ Surface facilities not fit for potential corrosion associated with carbonated water;
- ❖ Inadequate handling capacity on the platform;
- ❖ Contamination of producing gas;
- ❖ Low EOR potential and un-attractive project economics.

Measures that can increase the EOR potential of CO_2 injection in heterogeneous reservoirs were also proposed as:

- ✓ Re-injection of the produced gas;
- ✓ Reallocation of injected CO_2 volume between existing and optimised well patterns;
- ✓ Continuous well control, isolation of offending perforation intervals, well re-perforation programs;
- ✓ Methods of fluid mobility control and sweep improvement;
- ✓ Optimisation of injection scenario.

Results of laboratory investigation of CO_2 immiscible displacement using both continuous injection and WAG for Trinidad crude oil is presented by Mangalsingh **[104]**. The results indicated that CO_2 continuous or WAG Immiscible displacement was more efficient than waterflood. However, the WAG process resulted in higher recoveries than continuous CO_2.

Findings of modelling of CO_2 sequestration within an aquifer that CO_2 can only occupy 1% of the pore volume storability factor and likely as much as 100 times less **[105]**, which currently challenges the 1-4% reported in the literature. The authors related their approaches to a commercial power plant and established that CO_2 storage in aquifer was probably not a viable option due to the size of the aquifer or number of wells required for a given CO_2 to be stored. This conclusion is very equivocal as current thinking favors the aquifer as one the potential CO_2 geological storages.

The concluding remarks by **[105]**, that underground CO_2 sequestration is not feasible at any cost, was based on the two following assumptions:

- Effective CO_2 storage requires the presence of a hydrological isolated, and completely closed geologic structure.
- Any other storage system, except as described above, is guaranteed to leak.

The above assumptions have been heavily criticized on the basis of various literature reviews and decades of CO_2 injection experience **[106]**.

Approaches (pressure-limited storage capacity estimation) employed by **[105]** to estimate CO_2 storage capacity have been rejected in favour of methodologies that reflect more realistic assumptions (i.e. storage efficiency approach, representing the amount of CO_2 that can be stored in a given volume of pore space), and based in part upon knowledge gained from ongoing CO_2 storage projects **[106]**. Moreover, CO_2 sequestration in deep geological formation field projects such as the Statoil Sleipner project (North Sea) with approximately 1 $MtCO_2$/year being injected and rigorously monitored for more than a decade. Three are other large commercial carbon capture and storage projects, Snohvit, In Salah and Weyburn, which further substantiate that underground CO_2 sequestration is feasible, and prove that the assertion by **[105]** that underground storage of large volumes of CO_2 is impossible is unfounded.

2.6 CO_2 Transportation Offshore

CO_2 can be transported in gaseous, liquid or solid form and transportation can either be by road tankers, pipelines or ships for gaseous and liquid CO_2. Pipelines are known to be the most common method for transporting long distance of large quantities of CO_2. Compressed CO_2, liquefaction and solidification are processes use to reduce the volume of CO_2 to facilitate transportation. Gaseous

CO_2 is generally compressed above 8MPa pressure to avoid phase change (two phase flow).

CO_2 transportation is already a proven concept onshore and predominantly in the USA. A list of the well known 47 high-pressure pipelines in the USA, with approximately 6600 km length in total is shown in **Table 2.7** below **[107]**. The services are generally for EOR, food and beverage, and other uses.

Table 2.7: Major High Pressure (Onshore) CO_2 Transportation in USA [107]

Pipelines	Owner / Operator	Length (km)	Diameter (inch)	Estimated Max Capacity (MMCF/D)	Estimated Max Capacity (Million ton/yr)	Location (USA)
Adair	Apache	24	4	47	1.0	Texas
Anton Irish	Oxy	64	8	77	1.6	Texas
Beaver Creek	Devon	137	-	-	-	Wyoming
Borger, TX to Camrick, OK	Chaparral Energy	138	4	47	1.0	Texas, Oklahoma
Bravo	Oxy Permian	351	20	331	7.0	New Mexico, Texas
Centerline	Kinder Morgan	182	16	204	4.3	Texas
Central Basin	Kinder Morgan	230	16	204	4.3	Texas
Chaparral	Chapparral Energy	37	6	60	1.3	Oklahoma
Choctaw (aka NEJD)	Denbury Onshore, LLC	294	20	331	7.0	Mississippi, Louisiana
Comanche Creek (currently inactive)	PetroSource	193	6	60	1.3	Texas
Cordona Lake	XTO	11	6	60	1.3	Texas
Cortez	Kinder Morgan	808	30	1117	23.6	Texas
Delta	Denbury Onshore, LLC	174	24	538	11.4	Mississippi, Louisiana
Dollarhide	Chevron	37	8	77	1.6	Texas
El Mar	Kinder Morgan	56	6	60	1.3	Texas
Enid-Purdy (Central Oklahoma)	Merit	188	8	77	1.6	Oklahoma
Este I to Welch, TX	ExxonMobil, et al	64	14	160	3.4	Texas
Este II to Salt Creek Field	ExxonMobil	72	12	125	2.6	Texas
Ford	Kinder Morgan	19	4	47	1.0	Texas
Free State	Denbury Onshore, LLC	138	20	331	7.0	Mississippi
Green Line I	Denbury Green Pipeline, LLC	441	24	850	18.0	Louisiana
Jo□re Viking	Penn West Petroleum, Ltd	13	6	60	1.3	Alberta
Llaro	Trinity CO_2	85	12-8	77	1.6	New Mexico
Lost Soldier/Werrz	Merit	47	-	-	-	Wyoming
Mabee Lateral	Chevron	29	10	98	2.1	Texas
McElmo Creek	Kinder Morgan	64	8	77	1.6	Colorado, Utah
Means	ExxonMobil	56	12	125	2.6	Texas
Monell	Anadarko	-	8	77	1.6	Wyoming
North Ward Estes	Whitting	42	12	125	2.6	Texas
North Cowden	Oxy Permian	13	8	77	1.6	Texas
Pecos County	Kinder Morgan	42	8	77	1.6	Texas
Powder River Basin CO2 , PL	Anadarko	201	16	204	4.3	Wyoming
Raven Ridge	Chevron	257	16	204	4.3	Wyoming, Colorado
Rosebud	Hess	-	-	-	-	New Mexico
Sheep Mountain	Oxy Permian	656	24	538	11.4	Texas
Shute Creek	ExxonMobil	48	30	1117	23.6	Wyoming
Slaughter	Oxy Permian	56	12	125	2.6	Texas
Sonat (reconditioned natural gas)	Denbury Onshore, LLC	80	18	150	3.2	Mississippi
TransPetco	TransPetco	177	8	77	1.6	Texas, Oklahoma
W. Texas	Trinity CO2	97	12-8	77	1.6	Texas, NM
Wellman	PetroSource	42	6	60	1.3	Texas
White Frost	Core Energy, LLC	18	6	60	1.3	Michigan
Wyoming CO2	ExxonMobil	180	20-16	204	4.3	Wyoming
Canyon Reef Carriers	Kinder Morgan	224	16	204	4.3	Texas
Dakota Gasification (Souris Valley)	Dakota Gasification	328	14-13	125	2.6	North Dakota, Sask
Pikes Peak	SandRidge	64	8	77	1.6	Texas
Val Verde	SandRidge	134	10	98	2.1	Texas
	Totals:	**6,611**				

However, there are no published literatures on CO_2 transportation offshore and similarly there have been no offshore CO_2-EOR field projects reported to date, although there are several proposed and implemented hydrocarbon gas injection (WAG) projects in the North Sea; the Gullfaks and Brage field projects are ongoing WAG injection for EOR **[108, 109]**.

As far design and operation are concerned, CO_2 pipelines may be similar to natural gas pipelines; however, the fundamental difference lies in the fact that CO_2 is normally transported as a supercritical fluid. The supercritical pressure is higher than the operating pressure used in most natural gas pipelines, which typically range from 200 to 1,500 psi **[110]**. Generally, there are booster stations (pumps rather than compressor, due to the liquid behavior of the supercritical CO_2) along the pipeline route to maintain the necessary pressure for the CO_2 pipelines.

It is believed that, significant progress in research and technology is required to make CO_2 transportation offshore feasible to the extent needed to achieve successful EOR offshore.

The application of CO_2-EOR in deepwater will require that the challenge to preserve the long distance CO_2 pipeline to meet the compatibility requirements between the source (onshore) and the sink (reservoir) in harsh (cold) offshore environment be overcomed.

Pure CO_2, i.e. no water, oxygen, nitrogen and methane concentrations, is a pre-requisite, but this specification on its own does not warrant dense phase operation, particularly in a very long distance pipeline exposed to cold ambient fluid. One of the objectives of this study is to ensure that the condition at which the compressed CO_2 leaves onshore is maintained throughout the 250 km distance offshore, and reaches the reservoir in the same phase. In such condition, the pipeline has to operate almost in an adiabatic process, with negligible heat loss due to environmental impact.

Despite that deepwater is generally associated with colossal investments in capital, long-term commitment and great rewards, the challenges surrounding such development are also very huge, from the exploration, drilling to the completion and production stage. Success in these challenging environments requires detailed understanding, advanced and established technology.

2.7 CO_2 Storage / Sequestration

CO_2 sequestration relates to the techniques used for the long term CO_2 storage for the purpose of global warming mitigation.

There are two main storage options known as: Ocean Storage and Geological Storage. Due to substantial uncertainties, Legal and HSE issues surrounding the Ocean Storage, this storage option lacgs behind and faces enormous hurdles to be attractive.

As for geological storage, three main types of geological environments are being considered for carbon sequestration:

1) Oil and gas reservoirs;
2) Deep saline reservoirs / aquifers;
3) Un-mineable coal seams.

In each case, CO_2 would be injected, in a dense form, below ground into a porous rock formation that holds or previously held fluids. CO_2 is injected around 1000 meters or more below sea-bed (reservoir), the pressure allows CO_2 to become and remain supercritical, a dense phase (relative liquid), and thus less likely to migrate out of the geologic formation.

The storage capacity for CO_2 storage in geological formations is potentially huge if all the sedimentary basins in the world are considered. The USA is estimated to have 3.7 trillions metric tons of CO_2 storage capacity and the world capacity for geologic storage is estimated to be potentially as large as 10 trillions metric tons of CO_2 **[111]**.

Oil and Gas Reservoirs. Pumping CO_2 into oil and gas reservoirs to boost production (EOR) is practiced in the petroleum industry today. The United States is a world leader in this technology and uses approximately 32 Mt CO_2 annually for EOR, according to DOE **[112]**. In an EOR application, the integrity of the CO_2 that remains in the reservoir is well understood and very high, as long as the original pressure of the reservoir is not exceeded **[112]**.

The advantage of using this technique for long term CO_2 storage is that sequestration costs can be partially offset by revenues from oil and gas production. CO_2 can also be injected into oil and gas reservoirs that are completely depleted, which would serve the purpose of long term sequestration, but without any offsetting benefit from oil and gas production. CO_2 can be stored onshore or offshore; to date, most CO_2 projects associated with EOR are onshore, with the bulk of U.S. activities in West Texas.

In-Salah CO_2 capture and sequestration (by BP & Sonatrach) in Algeria started in 2004 and the injection was suspended in 2011 due to concerns about the integrity of the seal (i.e. possible vertical leakage into the caprock). During the project lifetime, 3.8 Mt of CO_2 was successfully stored in the Krechba Formation and no leakage of CO_2 was reported **[113]**.

CO_2 sequestration in an old oil field at Weyburn (by Petroleum Technology Research Centre (PTRC) & EnCana Corp) in Canada and the CO_2 escape has been estimated to be less than 1% per 1000 years.

Coal Bed Methane (CBM). Coal beds contain large amounts of methane-rich gas that is adsorbed onto the surface of the coal. The typical CBM recovery process consists of depressurizing the bed, usually by pumping water out of the reservoir. However, another technique is to inject CO_2 into the bed. Tests have shown that the adsorption rate for CO_2 to be approximately twice that of methane, giving it the potential to efficiently displace methane and remain sequestered in the bed **[112]**. CO_2 recovery of CBM has been demonstrated in limited field tests, but more investigation is needed to understand and optimize the process.

One of the advantages of CO_2 sequestration in coal beds is that many of the large un-mineable coal seams are near electricity generating facilities that can be a large point of CO_2 sources; hence, reducing the transportation cost as limited pipeline would be needed.

Saline Formations / Aquifier. Saline formations can be defined as sedimentary rocks saturated with formation water containing high concentrations of dissolved salts. Although sequestration of CO_2 in deep saline formations may not have any added value by-products, it may have a viable long term solution as far as storage capacity and access to a CO_2 source for injection purposes are concerned. In USA alone, deep saline formations could potentially store up to 500 billion tons of CO_2 **[114]**. CO_2 sequestration is being performed offshore in saline aquifers at Sleipner (Statoil) in Norway, and similar project is also ongoing at Snohvit in the Barents Sea. At both sites the CO_2 is judged to be permanently stored.

Saline and other types of reservoirs also have two additional trapping mechanisms that help trapping / storage of the CO_2 known as: Solubility and Mineral trapping. Solubility trapping is basically the dissolution of CO_2 into the reservoir fluids; Mineral trapping is the reaction of CO_2 with minerals in the host formation to form carbonates. As the CO_2 moves through the deposit, it comes into contact with un-carbonated formation water and reactive minerals. A portion of the CO_2 dissolves in the formation water and becomes permanently fixed by reactions with minerals in the host rock. Over long periods of time, the CO_2 might all dissolve and some be fixed by mineral reactions, essentially becoming permanently sequestered **[115]**.

The CO_2 storage projects known to date, with the type of storage and current capacity are presented in **Table 2.8**.

Table 2.8. Existing / Planned CO_2 Sequestration

Project name	Country	Injection start (year)	Approximate average daily injection rate (tCO_2 day)	Total (planned) storage (tCO_2)	Storage reservoir type
Weyburn	Canada	2000	3,000-5,000	20,000,000	**EOR**
In-Salah	Algeria	2004 (suspended in 2011)	3,000-4,000	17,000,000	**Gas field**
Sleipner	Norway	1996	3,000	20,000,000	**Saline formation**
K12B	Netherlands	2004	100	8,000,000	**Enhanced Gas Recovery**
Frio	USA	2004	(1000 planned for 2006+)	1600	**Saline Formation**
Fenn Big Valley	Canada	1998	50	200	**ECBM**
Qinshui Basin	China	2003	30	150	**ECBM**
Yubari	Japan	2004	10	200	**ECBM**
Recopol	Poland	2003	1	10	**ECBM**
Snohvit	Norway	2008	2,000	31 – 40 Mt	**Saline Formation**

2.8 Environmental Challenges

The environmental impact caused by oil sand / heavy oil extraction is heavily criticized by environmental groups such as Greenpeace **[116]**.

Just like all mining and non-renewable resource projects, it is without doubt that heavy oil / oil sands development will leave footprints on the environment. Concerns have been raised due to possible contamination with the land, water and the air, which will occur as described below:

I. Land - large deposits of toxic chemicals during the extraction;

II. Water - During the separation process and through the drainage of rivers;

III. Air - Release of CO_2 and other emissions.

Production of bitumen and synthetic crude oil (Synthetic crude is the by-product of bitumen/extra heavy oil) emits higher greenhouse gas (GHG) than the production of conventional crude oil, hence to offset GHG from the heavy oil / oil sands and other, sequestering the captured CO_2 must be very crucial.

Other HSE issues may well be related to CO_2 transportation. Therefore, just as there are standards for natural gas admitted to pipelines, standards for 'pipeline quality' CO_2 should emerge as the CO_2 pipeline infrastructure develops further **[116]**.

2.9 Summary

The literature survey on CO_2-EOR, CO_2-EOR for heavy oil and CO_2 sequestration, discussed above has demonstrated that neither of these topics have a complete solution or is free of ambiguities, despite the enormous efforts made by previous workers.

CO_2-EOR is a well developed technology that has been used for decades for conventional oil reservoir and can be adapted for heavy oil reservoirs. About 79 CO_2-EOR operations were active in 2004 Worldwide, amongst which 70 Miscible CO_2-EOR and one Immiscible were in the USA **[69]**. Two active Miscible CO_2-EOR exist in Canada, five Immiscible Displacement pilot fields in Trinidad and one commercial Immiscible operation in Turkey.

The experiences gained on CO_2 onshore transportation, CO_2-EOR for conventional oil recovery, heavy oil production using other means and the lessons learnt from earlier involvement in USA (California, Alaska) and Canada might be useful to some extent for future heavy oil development offshore using CO_2-EOR technique.

Below are the key points gathered from this review:

1) Although some literatures report that heavy oil is mainly found in shallow water **[117]**, this study will focus on potential CHOP in deepwater environments.

2) As growth continues, it may become more difficult to secure rights-of-way for the pipelines, particularly in highly populated zones that produce large amounts of CO_2 (IPCC Report). This perhaps suggests that subsea development with regards to CO_2 transportation (for EOR or Storage) may well be the future focus and deployment for Oil & Gas Operators, in which case the knowledge gathered through dedicated investigations will be vital.

3) With regard to heavy oil recovery, the ESPs (Electrical Submersible Pumps) and HSPs (Hydraulic Submersible Pumps) have never been found attractive due to the maintenance and replacement costs that could significantly exceed the expectations. The thermal-aided recovery mechanism or hot flow process such as conventional steam-flood or SAGD may well be attractive onshore but seem doubtful offshore for several reasons:

   - ✓ Large surface facilities required, which is very unlikely to be available offshore,
   - ✓ Known to be energy inefficient,
   - ✓ Exorbitant in term of cost. Although waterflood could possibly be seen as a viable option, it has the disadvantage of a lower recovery factor than some of the Cold Flow processes.

4) Although, concerns over CO_2-EOR are progressively being shifted from the doubts of being a potential CO_2 sequestration technique to the quantity of CO_2 that can be stored underground during the EOR process, more deployment, research and incentive from the government and industries are still needed to improve the existing technologies and remove the ambiguities with better understandings. One of the objectives of this research work is to remove the ambiguities over CO_2 sequestration during heavy oil recovery using CO_2-EOR.

5) Design of CO_2 Miscible flood needs to take into consideration parameters such as:

   a) Reservoir conditions;

   b) Solvent and crude oil properties;

   c) Solvent slug size (Laboratory Core-flood studies have shown that this varies between 2-10% of pore volume **[118]**;

   d) Miscibility;

   e) Displacement stability (Displacement instabilities during Immiscible CO_2 flooding are functionally of Rock-fluid properties, Fluid Saturation Distribution, Viscous forces, Rock Wetability, Miscibility);

6) Factors contributing to the EOR during Immiscible CO_2 are:

   a) Injection rate / Increased Injectivity;

   b) Swelling of oil – (Compositional effect);

   c) Oil viscosity (Viscous effect);

   d) Chemical interaction between CO_2, formation / injection water and reservoir rock;

   e) Transfer of CO_2 from Fractures to matrix involving diffusive, gravitational and capillary forces.

7) Reservoir Permeability is not critical if sufficient rates can be injected **[83]**. The author also claimed using the API Gravity vs Reservoir Depth that below API 22, CO_2 Miscible process is not longer possible, and between API 13 – 21.9 in Depth 1800ft, CO_2 Immiscible is possible, but below API 13 CO_2 immiscible is not possible.

8) Immiscible displacement projects can store larger volumes of CO_2 than Miscible Displacement projects **[98]**.

3. METHODOLOGY & BENCHMARKING

Introduction: This chapter describes the means and methodology used to accomplish individual task and identify the ordering of simulation cases performed.

The intention was to identify and lay down those principles and methods that govern the modelling process so that the key objectives of this research can be attained. As such, in this chapter, the modelling approach and methodology for analysing the results are defined, the number, type and stage of simulation model performed is outlined as well as the tools used to accomplish the modelling.

The modelling activities were broken down into three different categories:

1- Long distance CO_2 transportation offshore (deepwater);

2- Integrated injection-Production Modelling for heavy oil production using CO_2 – EOR technique;

3- CO_2 sequestration during heavy oil production using CO_2-EOR technique.

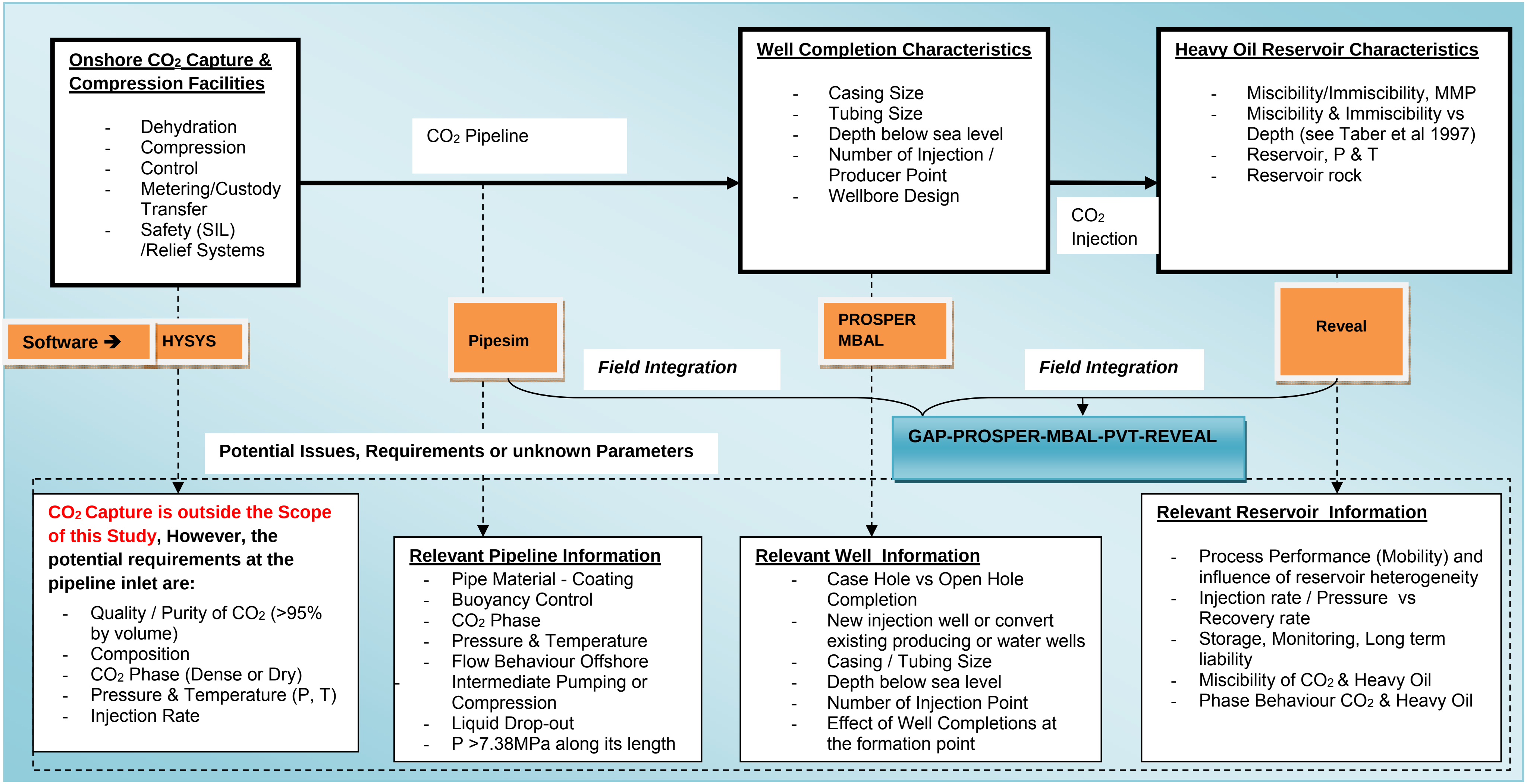
3.1 Overall Concept

A block flow diagram mapping the research project is shown in **Figure 3.1**. The diagram is designed to provide a clear overview of the research concept, and graphically outlining the exact nature of the investigations, summarising the proposed methods and the potential issues or challenges surrounding the investigation. The boxes are connected to other boxes by lines and arrows to represent the sequence and dependency relationships.

CO_2 injection for EOR is interlinked with three other processes, each having different technologies and issues which need to be assessed and properly understood. The three (3) processes are:

- CO_2 Capture
- CO_2 Transportation
- CO_2 Monitoring during storage

CO_2 Capture and monitoring processes do not form part of this study, but only covered in this document partially for information purposes.


Onshore CO_2 Capture & Compression Facilities
- Dehydration
- Compression
- Control
- Metering/Custody Transfer
- Safety (SIL) /Relief Systems
CO_2 Pipeline
Well Completion Characteristics
- Casing Size
- Tubing Size
- Depth below sea level
- Number of Injection / Producer Point
- Wellbore Design
CO_2 Injection
Heavy Oil Reservoir Characteristics
- Miscibility/Immiscibility, MMP
- Miscibility & Immiscibility vs Depth (see Taber et al 1997)
- Reservoir, P & T
- Reservoir rock
Software ➔
HYSYS
Pipesim
PROSPER MBAL
Reveal
Field Integration
Field Integration
GAP-PROSPER-MBAL-PVT-REVEAL
Potential Issues, Requirements or unknown Parameters
CO_2 Capture is outside the Scope of this Study, However, the potential requirements at the pipeline inlet are:
- Quality / Purity of CO_2 (>95% by volume)
- Composition
- CO_2 Phase (Dense or Dry)
- Pressure & Temperature (P, T)
- Injection Rate
Relevant Pipeline Information
- Pipe Material - Coating
- Buoyancy Control
- CO_2 Phase
- Pressure & Temperature
- Flow Behaviour Offshore Intermediate Pumping or Compression
- Liquid Drop-out
- P >7.38MPa along its length
Relevant Well Information
- Case Hole vs Open Hole Completion
- New injection well or convert existing producing or water wells
- Casing / Tubing Size
- Depth below sea level
- Number of Injection Point
- Effect of Well Completions at the formation point
Relevant Reservoir Information
- Process Performance (Mobility) and influence of reservoir heterogeneity
- Injection rate / Pressure vs Recovery rate
- Storage, Monitoring, Long term liability
- Miscibility of CO_2 & Heavy Oil
- Phase Behaviour CO_2 & Heavy Oil

3.2 Field Description

The field name, graphics or layout and explicit description will not be provided for confidentiality reasons. However, this is a field development offshore Africa that may push the technology frontier to another level.

The field to some extend is comparable to other offshore developments, with the particularity that the study in this case is intended to explore other future avenues not previously done, and this includes:

- Deeper water (ultra deepwater) heavy oil production with total depth of 4000 m.
- Long distance CO_2 pipeline tie-back to offshore platform, i.e. CO_2 injection from an onshore plant, 250 km away from the injection pad.
- Very low reservoir deliverability, i.e. low reservoir pressure, low API gravity and very high viscosity, hence requiring some form of mitigations at a very early stage.

The development is intended to bring several wells into production, which were all drilled around the 90s. The heavy oil field, named here as Omega, is located offshore West Africa. Although the water depth is such that it can be considered as deepwater, the analysis has extended its depth to that of ultra-deepwater to mirror a nearby field that has recently been successfully appraised but future development has been suspended for many reasons. The reservoir conditions are 2500 psig and approximately 150° F (65.6° C), but this study has looked into different conditions, with reservoir pressure varying from 1000 psig to 4000 psig to cover the life of the field and other nearby reservoir pressures. An average peak daily production from one of the highest producing wells is anticipated to be around 16700 STB/D production, and could significantly be more if all the wells are online.

The Omega heavy oil field is located approximately 150 km away to the nearby coast, however, this distance has been extended to 250 km for the purpose of this study.

Similar to nearby fields, Omega heavy oil is planned to be produced by means of a floating processing, storage, and offloading (FPSO) unit. The technical challenge of producing Omega is that the oil is heavy crude (15–19° API) produced from the Miocene reservoirs of that region. 10° and 20° API oil gravity was considered for the study.

There is a plan for subsea separation units (SSU) made up of typical separators and suitable dedicated pumps for spanning the heavy fluids up to the topside, to be located at each field near the wellhead.

The Omega heavy oil will be flowing from the subsea separation units (SSU) to the FPSO through 10 inch / 12 inch flexible riser, using the dedicated integrated production system.

However, enormous operational challenges related to the subsea production unit and the complexity of the heavy oil hydrodynamic behaviour are foreseen throughout the life of field, hence alternatives production methods are considered.

Artificial lift is required at an early stage of production due to the lower reservoir pressure, low API and high viscosity. CO_2-EOR technique for producing the heavy oil of the Omega field is being considered.

Heavy oil is generally known to be an onshore business, however, this study has surveyed few shallow and deepwater developments worldwide.

Shallow water (less than 400 m) and deepwater (greater than 400 m, but less than 1500 m) heavy oil developments are happening in the UK Continental Shelf and offshore Brazil respectively, but any development at water depth above 1500 m has not being reported yet in the literature and probably does not exist as far as current heavy oil production record is concerned, which is a fundamental challenge of this investigation, coupled with the use of CO_2 injected in-situ or remotely to enhance the heavy oil recovery. Most offshore heavy oil production is via water or steam flooding, or water alternate gas injection.

Table 3.1 below shows a close comparison with other offshore heavy oil reservoir characteristics from different continents **[119, 64, 13]**.

Table 3.1: Typical Offshore Heavy Oil Development

Continent	Europe		South America		Africa	
Country	UK	Norway	Brazil	Trinidad Tobago	Angola	X
Field	Captain	Grane	Jubarte	Soldado	Pazflor	Omega
Operated By	Texaco	Statoil	Petrobras	Trimmar	Total E&P Angola	X
Distance Offshore (km)	130	185	77	35	150	250
API Gravity (°API)	19	19	17	16-20	17-20	10 & 20
Water Depth (m)	104	123.4	1300	30	600 - 900	2000
Depth Below sea bed (m)	884	1500	1900	1200 - 1800	1200 - 2100	2000
Reservoir Pressure (Psi)	-	-	2466	2600	2900	Variable
Estimated Reserves (MMSTB)	956	755	600	-	590	500
Porosity (%)	27 - 30	27 - 33	-	27 - 29	30	20
Permeability (Darcy)	7	7	-	0.7 - 0.8	1.2	0.1
Viscosity at Reservoir Cond (cP)	50 - 150	10	14	-	16 - 64	>100
Reservoir Temperature (°C)	31	77	60	38	60	48.9

3.3 Technical Approach

3.2.1 Omega Field Production - Benchmarking

Calibration of one reservoir performance was carried out, via history matching / parametric study, to ensure a more realistic representation of the reservoir conditions prior to embark on detailed investigation and sensitivity analysis.

Initially, a suitable productivity index was established by benchmarking against the projected heavy oil production rate through one of the Omega wells. During early field life, typical expected heavy oil rate from a low and high producing well was around 8000 STBD to 16700 STBD respectively.

Figure 3.2 illustrates a range of potential rates for different productivity index (PI) between 6 to 20 STB/d/psi.

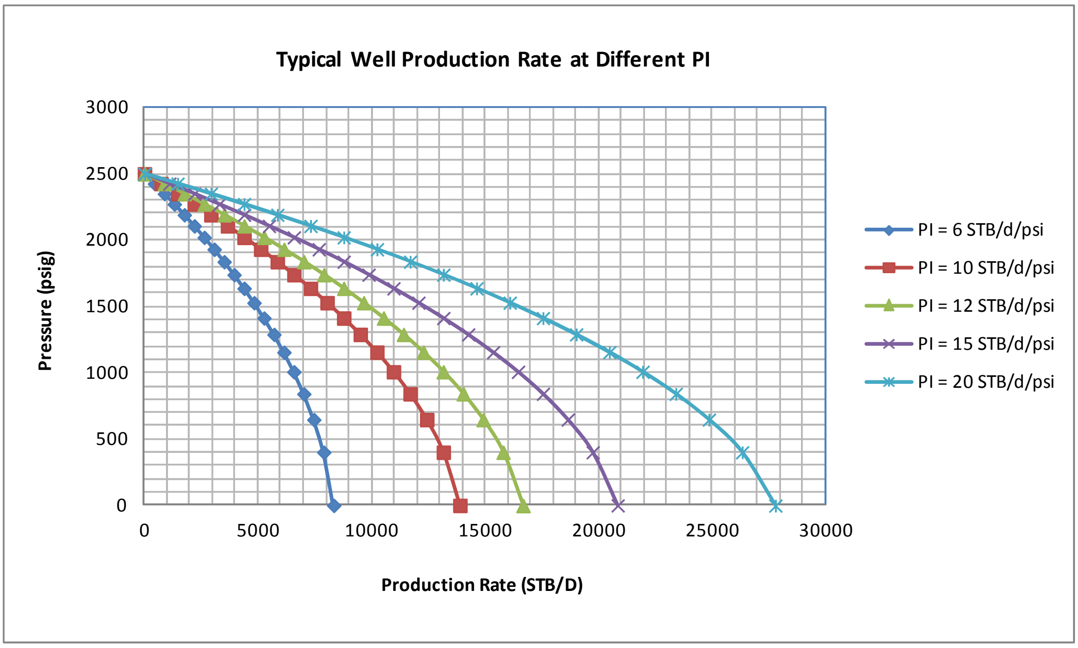


Figure 3.2: Typical Well Production Rate - Benchmarking

The test data used is a combination of limited field data from Reservoir Management Group (RMG) and scaled up data obtained from linear extrapolation to extend the range of data required for validation.

Figure 3.3 illustrates typical predicted reservoir pressure from various correlations for a well producing around 8000 STBD.

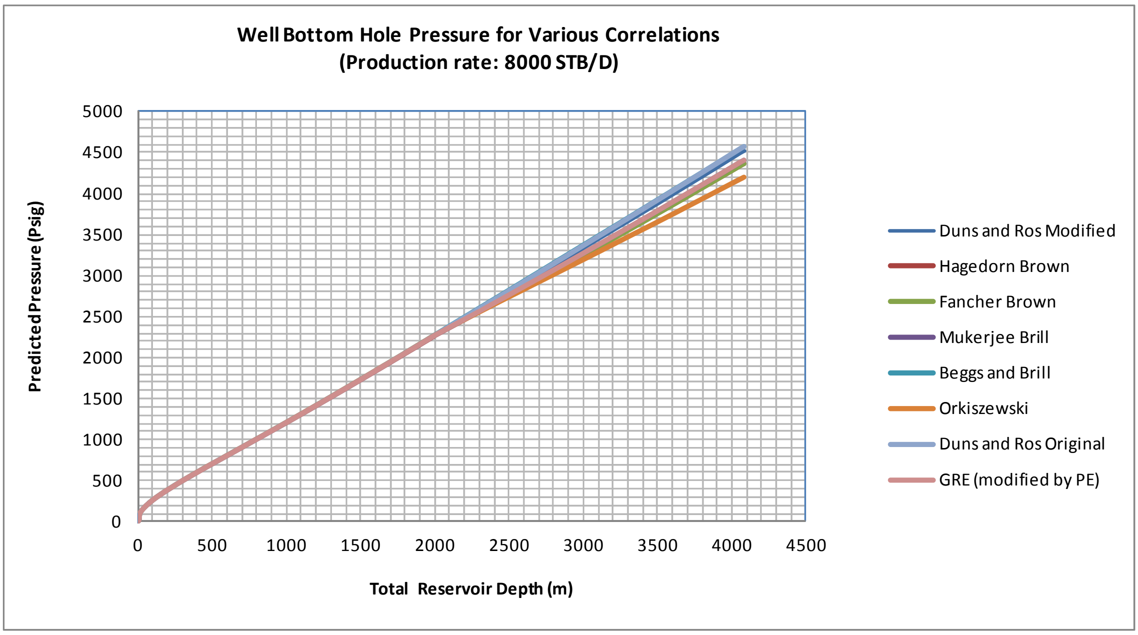


Figure 3.3: Typical Predicted Flowing Pressure – Rate: 8000 STBD

Results indicate consistent prediction from all correlations up to 2000 m depth, and thereafter, each correlation indicates an almost unique trend.

Prediction from different well tubing correlations at various production rates is presented in **Table 3.2** below, and detailed results are included in **Appendix 2**.

The standard deviation from the mean is very high in all cases, which indicates how wide spread the predictions are. Prediction varies from one correlation to another.

The results are summarised in **Table 3.2** below.

Table 3.2: Predicted Flowing Pressure from Various Correlations

Test Data		Predicted Data - Results from Varous Correlation								Statistical Analysis	
Oil Rate (STB/D)	Pressure (Psig)	Pressure (Psig)								Mean	Std Dev.
-	-	Duns & Ros Modified	Hagedorn Brown	Fancher Brown	Mukerjee Brill	Beggs & Brill	Orkiszewski	Duns & Ros Original	GRE (modified by PE)	-	-
2000	2658.6	3101	2759	2668	2879	2893	2606	3069	2844	2853	175
4000	3072.4	3695	3431	3382	3450	3489	3215	3654	3488	3475	151
6000	3486.2	4098	3918	3889	3937	4043	3708	4121	3994	3963	133
8000	3900	4514	4372	4356	4407	4566	4191	4570	4465	4430	127
10000	4313.8	4960	4836	4829	4889	5042	4810	5033	4944	4918	91
12000	4727.6	5391	5274	5272	5341	5524	5252	5476	5397	5366	99
14000	5141.4	5832	5716	5716	5797	6032	5698	5925	5854	5821	116
16700	5700.0	6455	6333	6333	6434	6754	6319	6558	6495	6460	146
18000	5969	6771	6643	6642	6754	7121	6632	6878	6819	6783	164
20000	6382.8	7279	7138	7137	7267	7712	7132	7392	7337	7299	194

A graphical representation of the prediction trend is shown in **Figure 3.4** below.

At lower rates, the error margin with Francher-Brown and Orkisewski correlations is within 0 to -2%, but increase up to 12% at higher production rates.

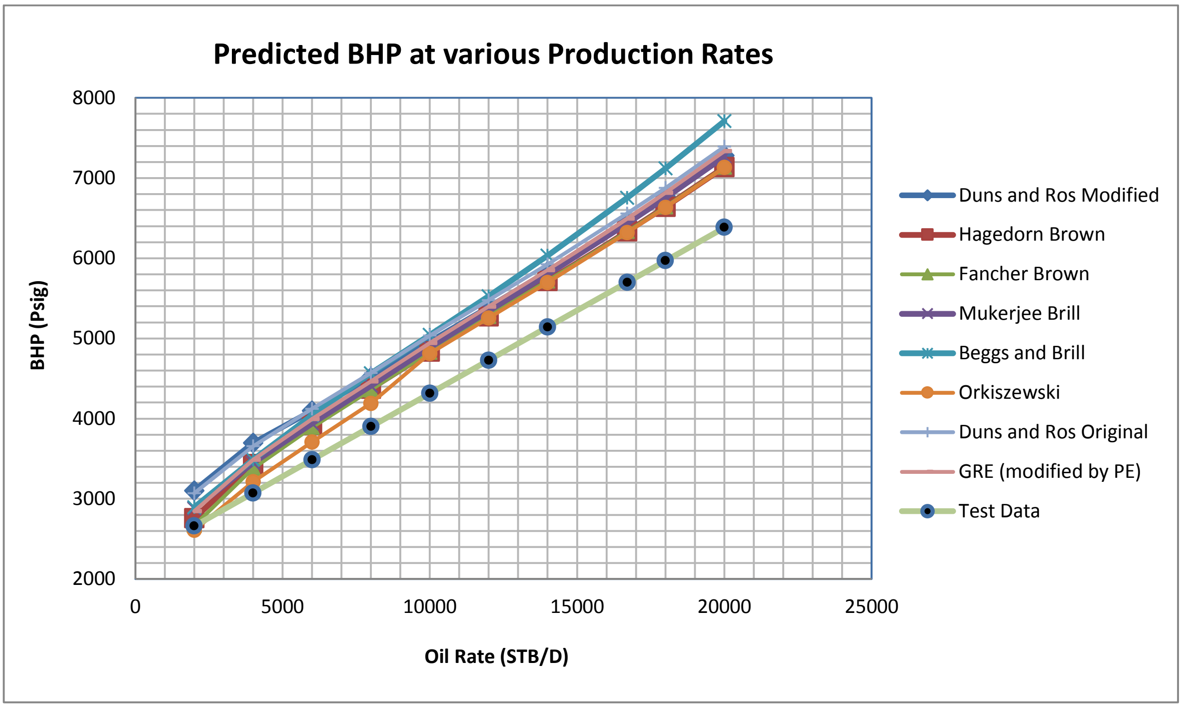


Figure 3.4: Predicted Flowing Pressure against Production Rates

A deviation (percentage error) from the expected reservoir pressure against test data is presented in **Table 3.3** below.

The percentage error is wider at low flowrate, except Francher-Brown and Orkisewski, which are very close to the expected trend.

At higher rate, there is almost a typical trend amongst all the correlations, except Beggs & Brill with overprediction.

Table 3.3: Estimated Error Margin from the Predicted Pressure

Test Data		Predicted Data - Results from Varous Correlation							
Oil Rate (STB/D)	Pressure (Psig)	% Error							
		Duns and Ros Modified	Hagedorn Brown	Fancher Brown	Mukerjee Brill	Beggs & Brill	Orkiszewski	Duns and Ros Original	GRE (modified by PE)
2000	2658.6	17	4	0	8	9	-2	15	7
4000	3072.4	20	12	10	12	14	5	19	14
6000	3486.2	18	12	12	13	16	6	18	15
8000	3900.0	16	12	12	13	17	7	17	14
10000	4313.8	15	12	12	13	17	12	17	15
12000	4727.6	14	12	12	13	17	11	16	14
14000	5141.4	13	11	11	13	17	11	15	14
16700	5700.0	13	11	11	13	18	11	15	14
18000	5969.0	13	11	11	13	19	11	15	14
20000	6382.8	14	12	12	14	21	12	16	15

3.2.2 Omega Field Study – Modelling Approaches

An extended study of the Omega field was considered by scaling some of the field parameters as previously discussed to reflect the possible emerging challenges of the future.

The new concept was based on a 240 km subsea pipeline transporting CO_2 from an onshore compression station. The total pipeline length was 250 km (on and offshore sections), the water depth was 2 km and the depth below the seabed was 2 km. The transported CO_2 was injected into the heavy oil reservoir via a vertical injection well (initial investigation). With regard to the production system, the heavy oil was produced to the topside separator via a subsea wellhead having 4 inch / 6 inch tubing size and 8 inch casing diameter. Single injection and production wells were used. However, more than one well was also possible depending on the capacity requirements. The schematic representation of the integrated injection and production system is shown in **Figure 1.1**.

The reservoir thickness and radius were 300 ft and 2500 ft respectively, the reservoir temperature was 120 °F and the original oil in place (OOIP) was 500 MMSTB. As from the production history, the initial reservoir pressure was variable (2500 psig to 4000 psig) depending on the well. The black oil PVT and Influx Performance data used for the simulation are presented in **Table 3.4**.

Table 3.4: Reservoir Data

Parameters	Reservoir Data	Parameters	Reservoir Data
Separator	Single Stage	Reservoir Pressure	1000 - 4000 psig
Heavy Oil Viscosity	100 & 2000 cP	Reservoir Temperature	120 °F
Oil Gravity	10 & 20 API	Water Cut	0 (Initially)
Gas Gravity	0.7	Total Gas Oil Ratio	100 & 500 scf/STB
Water Salinity	10000 ppm	Productivity Index	20 STB/day/psi

3.2.3 Long Distance CO_2 Transportation Offshore

The objective of this investigation was to assess the behaviour of the CO_2 (pure) along the subsea pipeline, to determine the pressure requirement for various pipeline capacity, pipeline sizes and flow conditions. This exercise was helpful to establish the process and design requirements necessary for the integrated modelling.

The operating conditions for dry and dense CO_2 phase required to perform the steady state simulations were identified on the CO_2 phase diagram which is available on the public domain **[95].** Two separate conditions were evaluated based on the pressure dictated at the pipeline inlet: Dry gas phase and dense phase, in order to assess the flow condition along the pipeline and to establish the exact nature of CO_2 as it reaches the reservoir. The pipeline sizes used for the investigation varied from 6 inch to 14 inch diameter. The inlet pipeline and the seabed temperatures were 70 ^oF and 41 ^oF respectively. The pipeline was assumed coated with 3LPE (3 layer polyethylene coatings) for corrosion protection and 100 mm concrete coating for buoyancy control offshore.

The steady state simulator "Pipesim" by Schlumberger was used to carry out a steady state analysis initially.

3.2.4 Integrated Injection-Production System Modelling

The objective of the integrated injection-production modelling was to bring the injection and production systems together as a single module for the purpose of heavy oil production using CO_2-EOR technique.

The injection system comprised the subsea pipeline transporting CO_2 from the surface facility and connected to the subsea structure ready for injection. The production system was connected to the topside separator via a subsea wellhead having 4 inch/6inch tubing size and 8 inch casing diameter. The schematic representation of the integrated configuration system is shown in **Figure 1.1.**

The integrated system modelling was performed using the Petroleum Experts package "GAP/PROSPER/MBAL" (IPM v6.4).

The advantage of the Petroleum Expert products is that the challenge of modelling the entire systems from the reservoir, gathering lines, including choke valves, pumps and compressors (if applicable), to the risers is remediated in an integrated manner by linking GAP (pipeline models) with PROSPER (well models) and MBAL (reservoir / tank models) together to achieve a full field production forecast.

In order to assess the performance of CO_2-EOR technique for heavy oil production, the following main cases based on different production data (forecast) with varying reservoir pressure, GOR, were investigated:

1) Case 1: Reservoir pressure 4000 psig, GOR 500 scf/STB, heavy oil specific gravity 20 °API, injection pressure 3000 psig;

2) Case 2: Reservoir pressure 1000 psig, GOR 100 scf/STB, heavy oil specific gravity 20 API, injection pressure 3000 psig;

3) Case 3: Reservoir pressure 4000 psig, GOR 500 scf/STB, heavy oil specific gravity 10 API, injection pressure 5000 psig;

4) Case 4: Effect of multiple injection wells on the productivity.

Further cases (sensitivity analysis) were investigated for a wide range of reservoir production history to cover both Miscible and Immiscible conditions. The production forecast performed for different reservoir conditions under both Miscible and Immiscible conditions followed the criteria presented by Ahmed **[120]** which is shown in **Table 3.5** below.

Table 3.5: Miscibility and Immiscibility Criteria

Temperature	Pressure	Condition	Comments
T_{res} < 86 °F	P_{res} < 1000 psia	Immiscible	-
86 °F < T_{res} < 90 °F	1000 psia < P_{res} < 1200 psia	Miscible / Immiscible	Either Possible P_{CO2} = 1073 psia, T_{CO2} = 87.8 °F
T_{res} > 90 °F	P_{res} > 1200 psia	Miscible Possible	-

The sensitivity cases carried out are listed below:

5) Case 5: Miscible Process and the influence on the reservoir production trend;

6) Case 6: Immiscible Process and the influence on the reservoir productivity;

7) Case 7: Varying Reservoir Pressure at Constant GOR for different CO_2 injection Pressure;

8) Case 8: Constant reservoir pressure at various GOR for different CO_2 injection pressure;

9) Case 9: Sensitivity of GOR, viscosity, heavy oil API and injection pressure.

3.2.5 CO_2 Sequestration during Heavy Oil Production using CO_2-EOR

Following successful investigation of heavy oil recovery using CO_2-EOR, the effort was shifted to exploring any occurrence of CO_2 sequestration.

The investigation focussed on the following areas:

- CO_2 sequestration during Miscible and Immiscible conditions;
- CO_2 sequestration using the integrated surface and sub-surface modelling;

REVEAL, the 3D reservoir simulator by Petroleum Experts, was used to model the reservoir in 3D with a grid block of dimension 25, 25, 15 in X, Y and Z directions respectively. A block size of 500 ft x 500 ft x 200 ft, grid depth of 10000 ft and a single porosity was considered. Two wells, one producer and an injector, and both horizontal were investigated. The model was homogenous as shown in **Figure 3.5** below.

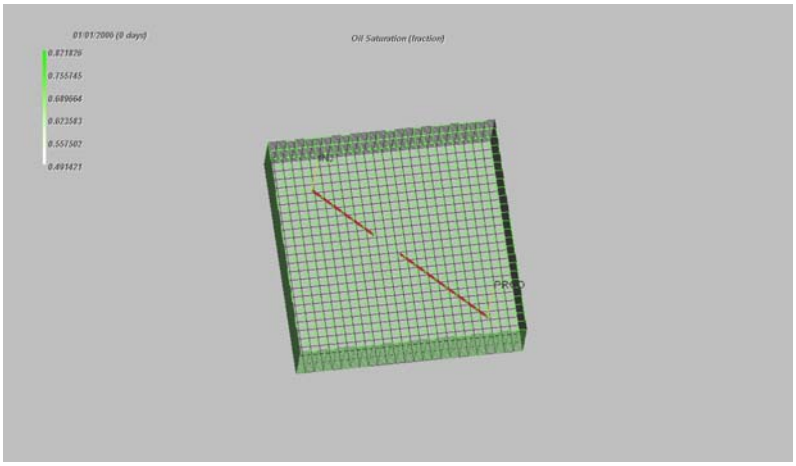


Figure 3.5: Block grid (Horizontal Well) – Illustration Only

Tables 3.6 and **3.7** present the reservoir and fluid properties used in the simulation and the aquifer properties are given in **Table 3.8**.

Table 3.6: Fluids Properties & Rock Properties

	Data	Units
Rock Compressibility	3×10^{-5}	1/psi
Permeability	100	mD
Reservoir Porosity	0.2	Fraction
Well Control: Constant injection Pressure	3000	psig
Water Compressibility	2.9×10^{-6}	1/psi
Heavy Oil Specific Gravity	15	°API
Heavy Oil Viscosity	523 - 2188	cP
Heavy Oil FVF	1.19	RB/STB
Water FVF	0.99	RB/STB
Gas FVF	0.0034	RB/STB
Gas Oil Ratio, GOR	500	scf/STB
Reservoir Temperature	122 - 200	°F
Water gravity	1.068	Sp. gravity
Gas Gravity	0.7	Sp. gravity

Table 3.7: Residual Saturation used for the Simulation

	Data	Units
Critical Oil / Gas Residual Saturation, Sogc	0.05	Fraction
Critical Oil / water Residual Saturation, Sowc	0.2	Fraction
Critical water Residual Saturation, Swc	0.2	Fraction
Critical Gas Residual Saturation, Sgc	0.2	Fraction
End Point Oil / water Relative Permeability, Krow	1	Fraction
End Point Oil / Gas Relative Permeability, Krog	1	Fraction
End Point water Relative Permeability, Krw	1	Fraction
End Point Gas Relative Permeability, Krg	1	Fraction
Corey Exponent for Oil-water	2	-
Corey Exponent for Oil-Gas	2	-

Table 3.8: Aquifer Properties

	Data	Units
Aquifer Model	Infinite Linear	-
Aquifer Porosity	0.2	Fraction
Aquifer Permeability	1000	mD
Aquifer Compressibility	3×10^{-6}	1/psi
Thickness	300	feet
Encroachment Angle	90	degree
Width	300	feet
Region 1	X_West, From (1, 1, 1) to (1, 25, 15)	-
Region 2	X_West, From (25, 1, 1) to (25, 25, 15)	-

The initial pressure used in this analysis was 2500 psig, with the temperature of 200 °F. The CO_2 was injected into the reservoir through a horizontal well, 8 km long and completed over a length of approximately 492.13 ft (150 m). The reservoir gas was modelled as CO_2. With a critical pressure of 1073 psi and critical temperature of 87.8 °F, CO_2 will be in a supercritical state at bottom-hole injection and reservoir conditions; hence CO_2 was defined in the model as gas with the corresponding dense phase density.

Both Black Oil and Compositional Models were used. The Peng-Robinson (PR) EOS was selected to generate the VLP (Vertical Lift Performance) files for the injection and production system using PROSPER. The production system was modelled as a black oil model while the injection system remained compositional to take into account the properties of CO_2.

The following two methods were used to interpret the REVEAL results in order to quantify the CO_2 sequestration during CO_2-EOR:

- Mass conservation of CO_2 around the reservoir loop;
- Production profiles evaluation.

3.2.5.1 Mass Conservation

This approach considered the mass of CO_2 entering ($\dot{m}_{CO2\ inj}$) and leaving ($\dot{m}_{CO2\ out}$) the reservoir and the mass of CO_2 retention ($\dot{m}_{CO2\,Seq}$) within the reservoir, which is conveyed in the following expression:

$$\dot{m}_{CO2\ inj} - \dot{m}_{CO2\ out} = \dot{m}_{CO2\ \ Seq} \qquad (3.1)$$

Where:

$\dot{m}_{CO2\ inj}$: Mass flowrate of CO_2 entering the reservoir;

$\dot{m}_{CO2\ out}$: Mass flowrate of CO_2 exiting the reservoir (CO_2 produced);

$\dot{m}_{CO2\,Seq}$: Mass flowrate of CO_2 retained in the reservoir (CO_2 Sequestration).

The density of CO_2 changes as its pressure (P) changes and using the ideal gas Equation-of-State (EOS), the CO_2 density (ρ_{CO2}) can be calculated at the appropriate pressure, and hence the volumetric flowrate of CO_2 ($Q_{CO2\ Seq}$) can be established using the expression below. "T" stands for temperature and "Mw" for the molecular weight of CO_2 and the other terms have their usual meanings.

$$Q_{CO2\ Seq} = \frac{\dot{m}_{CO2\ Seq}}{\left(\frac{M_W}{R}\right)\left(\frac{P}{T}\right)} \qquad (3.2)$$

Where:

$Q_{CO2\ Seq}$: Volumetric flowrate of CO_2 sequestrated;

ρ_{CO2} : Density of CO_2;

P : Pressure at reference point;

T : Temperature at reference point;

M_W : Molecular weight of CO_2.

3.2.5.2 Production Evaluation

The CO_2 sequestration ($Q_{CO2\ Seq}$) is estimated as the difference between the injected CO_2 ($Q_{CO2\ inj}$) and the produced CO_2 ($Q_{CO2\ out}$), taking into account the rates of CO_2 production during steady or quasi-steady state since the reservoir gas was modelled as CO_2.

The term $Q_{CO2out\ WI}$, represents the produced CO_2 when there is no CO_2 injection.

$$Q_{CO2\ Seq} = Q_{CO2\ inj} - \left(Q_{CO2\ out} - Q_{CO2\ out\ WI}\right) \tag{3.3}$$

Where,

$Q_{CO2out\ WI}$: Produced CO_2 (original gas in place) when there is no CO_2 injection.

In case where the reservoir gas is modelled differently other than CO_2, the $Q_{CO2\ out\ WI}$ in the equation 3.3 may be omitted. $Q_{CO2\ out\ WI}$ was found to be less than 1% of that produced during CO_2 injection, hence the impact on the overall results was negligible, as far the simulations are concerned.

The CO_2 retention as a function of barrel of heavy oil produced (Seq_{co2}) was calculated using the volumetric flow rate of heavy oil produced ($Q_{oil\ prod}$) and the CO_2 sequestration by the following expression:

$$Seq_{CO_2} = \frac{Q_{CO2\ Seq}}{Q_{oil\ prod}} \tag{3.4}$$

Where.

Seq_{CO2} : CO_2 retention / sequestration per barrel of produced heavy oil;

$Q_{oil\ prod}$: Volumetric flowrate of heavy oil produced.

The CO_2 requirement / utilisation per barrel of heavy oil produced (CO_2(Req)) was obtained using the required CO_2 injection as follows:

$$CO_2(\mathrm{Re}\,q) = \frac{Q_{CO2\ inj}}{Q_{oil\ prod}} \tag{3.5}$$

Where,

CO_2(Req) : CO_2 requirement per barrel of produced heavy oil.

4. RESULTS AND DISCUSSION

Introduction: This chapter presents and discusses results of the simulations outlined in chapter 3.

The forecast or output obtained from the simulator was analyzed and interpreted.

Results are presented in four main areas of focus:

1. Long distance CO_2 transportation from onshore to offshore;
2. Cold Heavy Oil Production using CO_2-EOR technique;
3. CO_2 sequestration during heavy oil production using CO_2-EOR technique;
4. Techno-economic evaluation of typical Cold Heavy Oil Production using CO_2-EOR technique.

The final sub-section summarizes the key findings of the investigation.

4.1 Long Distance CO_2 Transportation Offshore

The objective of investigating long distance CO_2 transportation offshore was to establish a relationship between the onshore pressure requirements for various pipeline capacity and the pipeline sizes and flow conditions. Pure CO_2 from the onshore facilities was transported by a 250 km pipeline to the subsea manifold where compression or pumping might be required for injection into the heavy oil reservoir. The results are presented and discussed below for two cases: Dry CO_2 and Dense CO_2.

4.1.1 Dry Gas (CO_2) Phase

The pressure required for different CO_2 flowrate is shown in **Figure 4.1**. The results show that long distance dry CO_2 (gas phase) transportation offshore is possible, but may not be an effective technique or solution for enhanced heavy oil recovery which require high injection pressure just as any EOR. Typical CO_2 injection pressure in the North Sea might vary between 2900–4351 psi (200-300 bar) **[123]**. Recompression will be inevitable in such circumstances (if using dry CO_2 phase) to meet the EOR objectives.

4.1.2 CO_2 Dense Phase

The lowest allowable pressure at the pipeline outlet must be 1073 psig, which is the pressure below which CO_2 may change to the gas phase, hence resulting in low density and high flow velocities. The backpressure was set to be that of reservoir pressure with 4000 psig and the process conditions along the pipeline and at the onshore were determined using PIPESIM software. The required pressure at the pipeline inlet for different CO_2 flowrate and pipe sizes is shown on **Figure 4.2**.

Under the conditions investigated, no differences were experienced between the results obtained using Peng-Robinson (PR) and Soave Redlich Kwong (SRK) Equation of State (EOS). As opposed to the dry CO_2 pipeline simulation results, intermediate recompression for pipeline transporting CO_2 dense phase prior to injection into the reservoir via the well was not necessary provided that the pressure remained significantly high to make an immediate impact into the reservoir. With the high injection pressure required to facilitate mobility of the heavy oil from the reservoir to the topside facilities, it can be stated that CO_2

during EOR application for Cold Heavy Oil Production (CHOP) will behave as supercritical fluid, expanding to fill the heavy oil reservoir as a gas, but with the density identical or greater to that of raw water.

The density variation along the pipeline between 967 kg/m^3 to 1028 kg/m^3 was an essential indication that most part of the pipeline CO_2 was in a dense phase. Keeping a long distance CO_2 pipeline principally in a dense phase without liquid formation in cold environments (i.e. 41 °F as in this case) will be a huge challenge. The temperature along the subsea pipeline dropped rapidly to the ambient seabed temperature, signalling there could be possible corrosion issue (if water condenses) in the long prospect if corrective actions are not taken by means of chemical injection or regular pigging. Alternatives to heating CO_2 at the source in such circumstances are preferable, as the heated CO_2 would barely mitigate against the harsh cooling effect of the sea water.

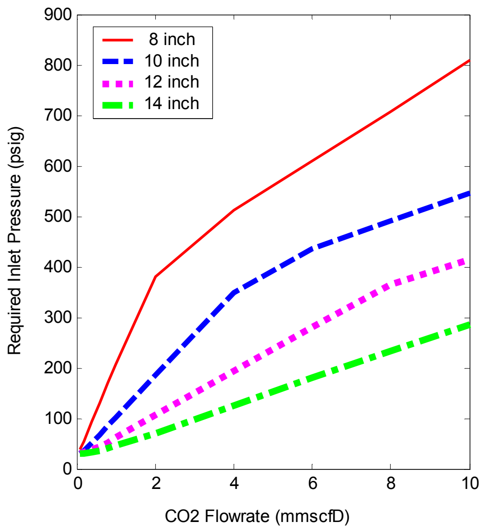


Figure 4.1: Dry CO_2 Pipeline – Pressure Requirement for Various Pipe Sizes

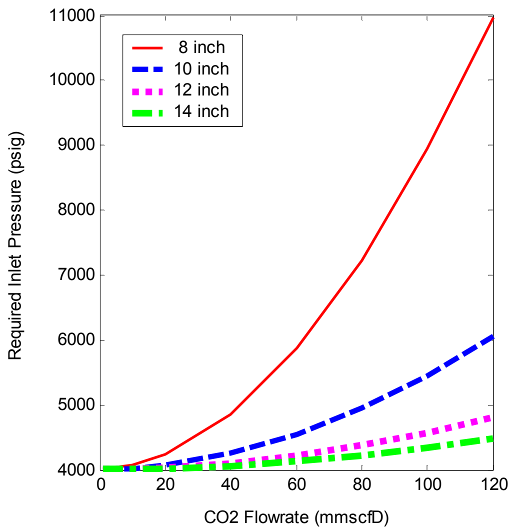


Figure 4.2: CO_2 Dense Phase Pipeline – Pressure Requirement for Various Pipe Sizes

4.2 Cold Heavy Oil Production Using CO_2-EOR Technique

Results of the four preliminary cases investigated are presented and discussed in the sub-sections 4.2.1 to 4.2.4.

4.2.1 Case 1: Reservoir Pressure 4000 Psig, GOR 500 Scf/STB, Heavy Oil Specific Gravity 20 API, Injection Pressure 3000 Psig.

Under the above condition, two sub-conditions were investigated, one under which the production was possible and CO_2 injection was used to boost the recovery (i.e. considering that there will be subsea separation); and another case (considering no subsea separation) where the separator was located at the topside platform, 2km above the seabed making a total depth of 4 km (water depth + depth below sea-bed) and production was primarily not possible under these circumstances due to insufficient reservoir pressure to initiate natural recovery of the resources. The production forecast was performed from year 1997 to 2020 and the results with and without CO_2 injection for both cases are shown from **Figures 4.3** to **4.10**.

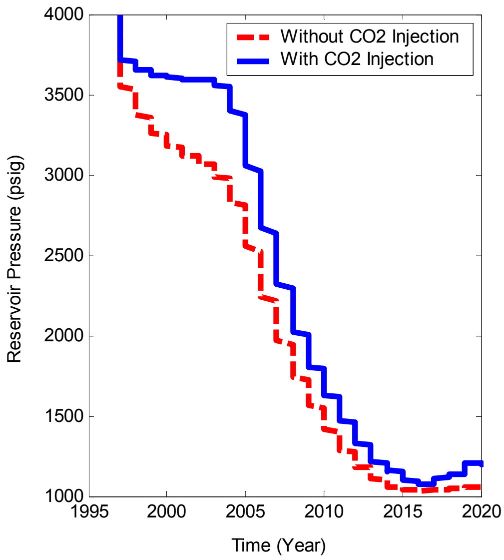


Figure 4.3: Case 1 – Reservoir Pressure Forecast (With / Without CO_2 Injection)

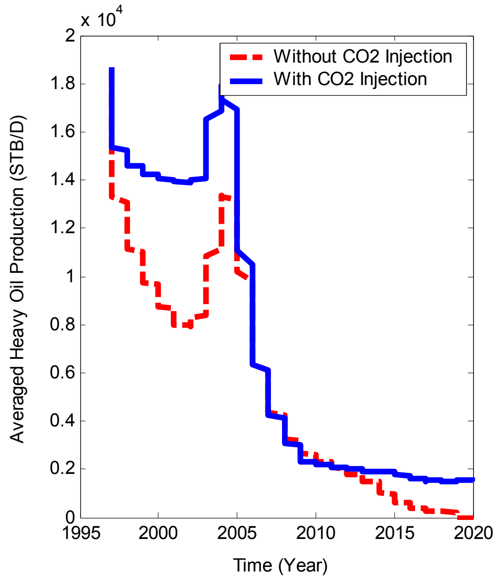


Figure 4.4: Case 1 – Heavy Oil Production Forecast (With / Without CO_2 injection)

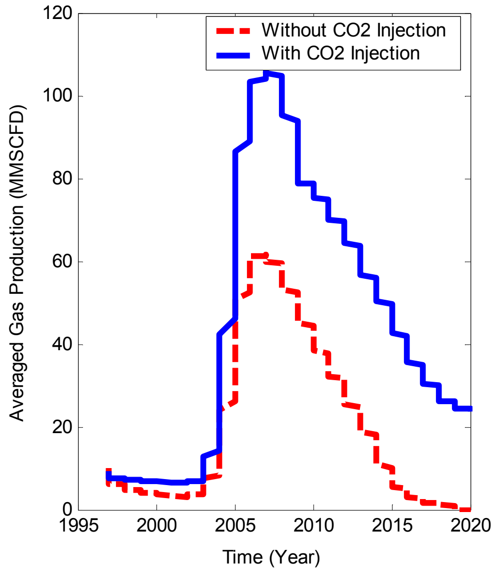


Figure 4.5: Case 1 – Total Gas Production Forecast (With / Without CO_2 Injection)

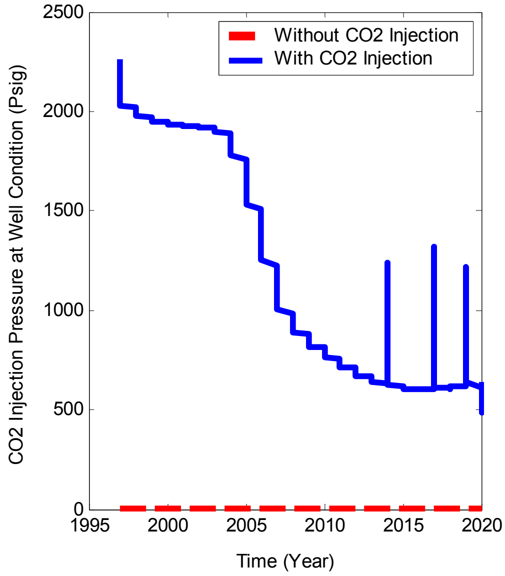


Figure 4.6: Case 1 – injection Pressure (With / Without CO_2 Injection)

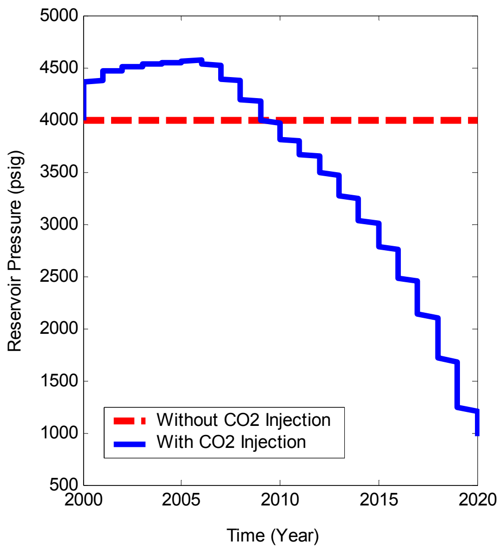


Figure 4.7: Case 1 – Reservoir Pressure Forecast (With / Without CO_2 Injection)

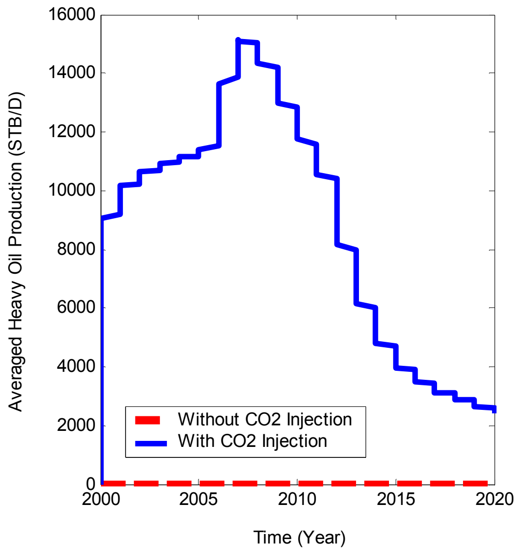


Figure 4.8: Case 1 – Heavy Oil Production Forecast (With / Without CO_2 injection)

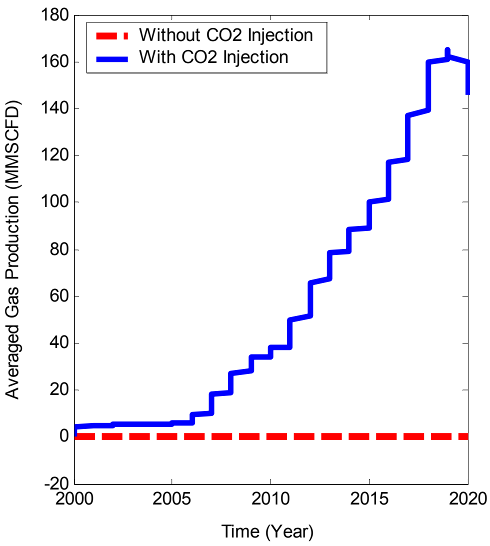


Figure 4.9: Case 1 – Total Gas Production Forecast (With / Without CO_2 Injection)

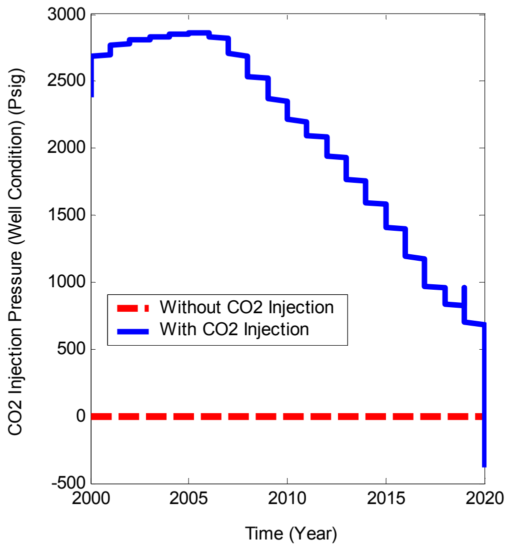


Figure 4.10: Case 1 – Injection Pressure (With / Without CO_2 Injection)

CO_2 injection raised the reservoir pressure as indicated in **Figure 4.3** and **4.6**. As the reservoir pressure increased, so did the rate of recovery, as noticed from the production traces (**Figure 4.4**). The heavy oil recovery doubled in the year 2002, from 7960 STB/D (without CO_2 injection) to 16890 STB/D (with CO_2 injection). Heavy oil recovery in the year 2018 was not possible when the reservoir pressure reached 1000 psig (**Figure 4.4**, without injection), however, the production forecast projected steady production at about 2000 STB/D, with continuous CO_2 injection. The gas production also increased significantly as a result of CO_2 injection as shown in **Figure 4.5**.

The 20 years forecast showed that the heavy oil recovery and gas production (for the case where production was not initially possible due to low energy) was boosted from zero production (without CO_2 injection) to a rapid production as the result of CO_2 injection as shown in **Figure 4.7**. This production trend clearly indicates the positive impact of CO_2 injection for this particular reservoir condition and production system as shown in **Figure 4.8**.

Before the gas breakthrough, the averaged gas production was minimal in proportion of heavy oil production. As the averaged gas production rate began to rise sharply which possibly corresponded at the period of reservoir "gas breakthrough", the gas recovery was boosted causing the peak heavy oil production as shown in **Figure 4.9**. Following this phenomenon (peak heavy oil production), the averaged gas production continued to rise while the heavy oil production was in decline. The heavy oil production was in decline as a result of the injection pressure (at the reservoir) declining as shown in **Figure 4.10**.

4.2.2 Case 2: Reservoir Pressure 1000 Psig, GOR 100 Scf/STB, Heavy Oil Specific Gravity 20 API, Injection Pressure 3000 Psig.

However, under this condition where the initial reservoir pressure was 1000 psig with the GOR at 100 scf/STB, the behavior along the integrated system was completely different and production was only possible after several years of continuous CO_2 injection.

The reservoir pressure with and without CO_2 injection in **Figure 4.11** shows significant increase as the injection of CO_2 starts. The production trend is shown in **Figure 4.12**, and indicates several years of delay prior to initial heavy oil recovery.

This probably suggests that low pressure reservoir with low GOR is most likely not very practical for CO_2-EOR CHOP due to the inefficiency of the process and the long payback time caused by many years of zero production even at significant high injection pressure.

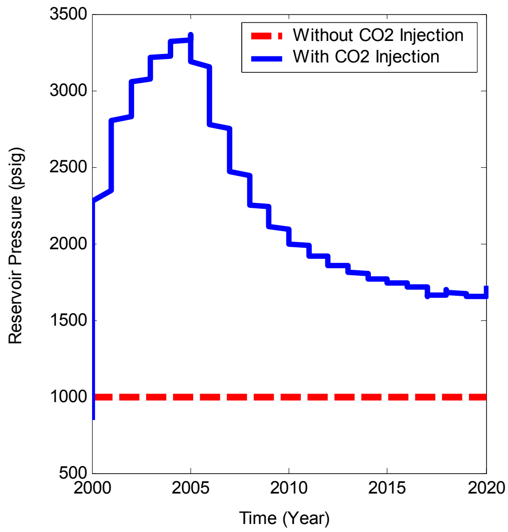


Figure 4.11: Case 2 – Reservoir Pressure Forecast (With / Without CO_2 Injection)

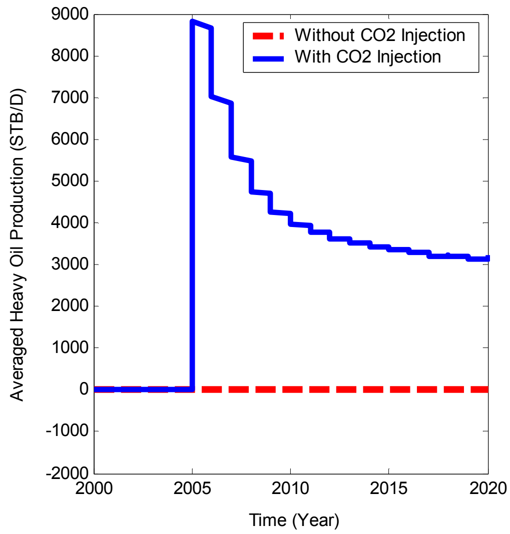


Figure 4.12: Case 2 – Heavy Oil Production Forecast (With / Without CO_2 injection)

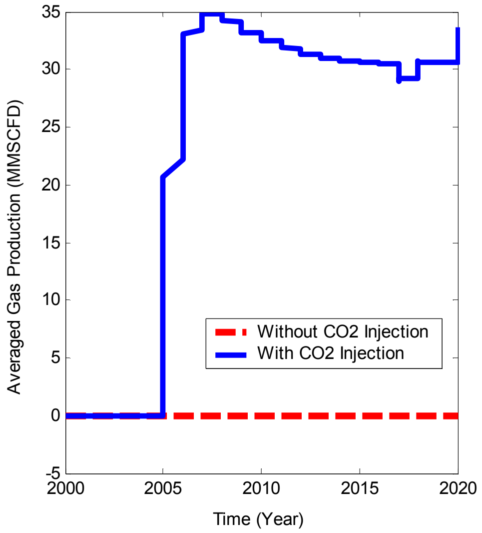


Figure 4.13: Case 2 – Total Gas Production Forecast (With / Without CO_2 Injection)

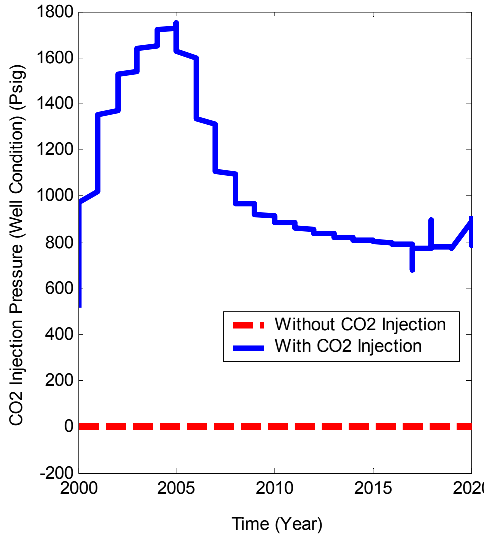


Figure 4.14: Case 2 – Injection Pressure (With / Without CO_2 Injection)

Similar trend is noticed in the gas production profile in **Figure 4.13**, where the gas production starts almost simultaneously with heavy oil, after several years of no production at continuous CO_2 injection.

Figure 4.14 shows that the injection pressure starts to reduce once the production is initiated, due to gas breakthrough. Hence higher sustained injection rate or larger transmission line (with less pressure drop) may be required.

4.2.3 Case 3: Reservoir Pressure 4000 Psig, GOR 500 Scf/STB, Heavy Oil Specific Gravity 10 API, Injection Pressure 5000 Psig.

Despite the high injection pressure used in this case compared to other cases discussed above, it was evident that the production rate was hampered by the non-Newtonian behavior of the reservoir fluid which exhibited high viscous characteristics. The heavy oil viscosity varied from 2010 cP to 1820 cP during the injection process. The production forecast indicated continuous and smooth production from year 2000 to 2020 as shown in **Figures 4.15** to **4.18**.

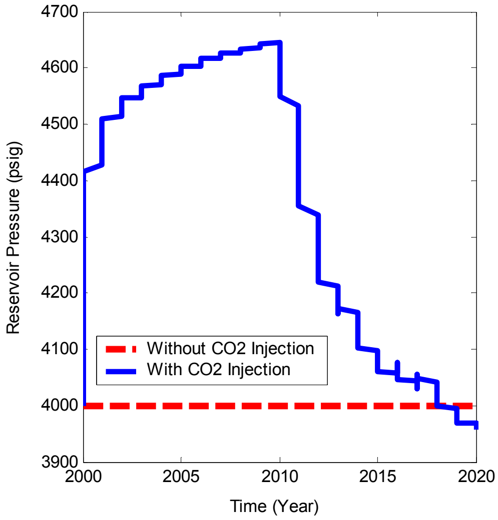


Figure 4.15: Case 3 – Reservoir Pressure Forecast (With / Without CO_2 Injection)

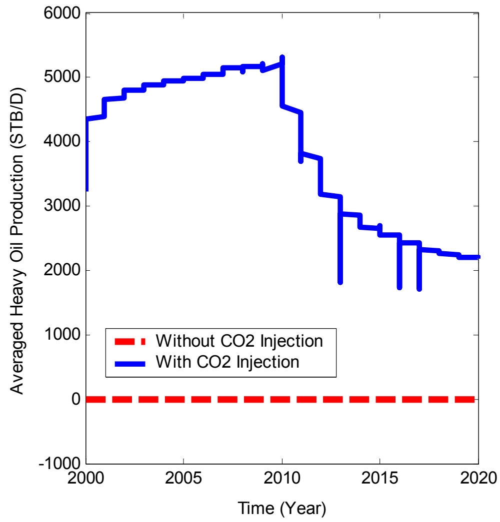


Figure 4.16: Case 3 – Heavy Oil Production Forecast (With / Without CO_2 injection)

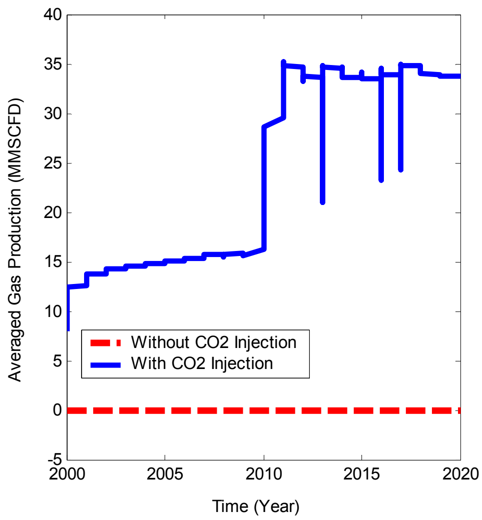


Figure 4.17: Case 3 – Total Gas Production Forecast (With / Without CO_2 Injection)

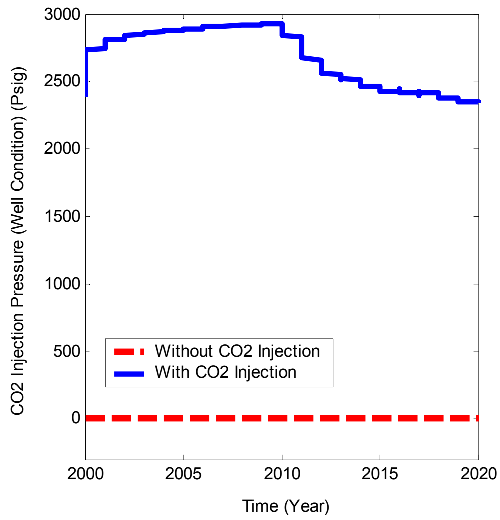


Figure 4.18: Case 3 – Injection Pressure (With / Without CO_2 injection)

4.2.4 Case 4: Effect of Multiple Injection Wells on the Productivity

Multiple vertical injection wells were found to impact on the productivity in accordance with the production system characteristics. The performance of the CO_2-EOR for CHOP was influenced by the injection depth. The efficiency of the injection process increased at deeper injection depth.

The impact of vertical and horizontal well on the well productivity was assessed and the results indicate that the horizontal wells have better enhancement ability than the vertical wells, due to the closeness of the injection and production wells to each other and the contact area provided with the reservoir. The heavy oil production may be increased by several folds with the horizontal wells compared to the vertical wells. The production trends shown below are purely for illustration purposes. This sensitivity analysis was carried out at similar injection pressure (5000 psig), and at high initial reservoir pressure, 5000 psig which will certainly justify the early and appreciable recovery shown in the production trends even without CO_2 injection.

With the vertical wells, the injection well was distanced away, approximately 6151 ft, from the production well. Both wells were perforated within the 15, 14 and 13 layers. In **Figure 4.19** subplots (A, B, C, D) shows the heavy oil (A), gas production (B), water production (C) and CO_2 injection rates (D). The production profiles for the two scenarios, "No CO_2 injection" and "With CO_2 injection", are plotted together, with the heavy oil rate showing almost a steadily decline from year 2006 and the water production ending in 2035, when no CO_2 is injected. With CO_2 injection, the heavy oil and gas trends are sustained and gradually boosted with increasing CO_2 injection rate.

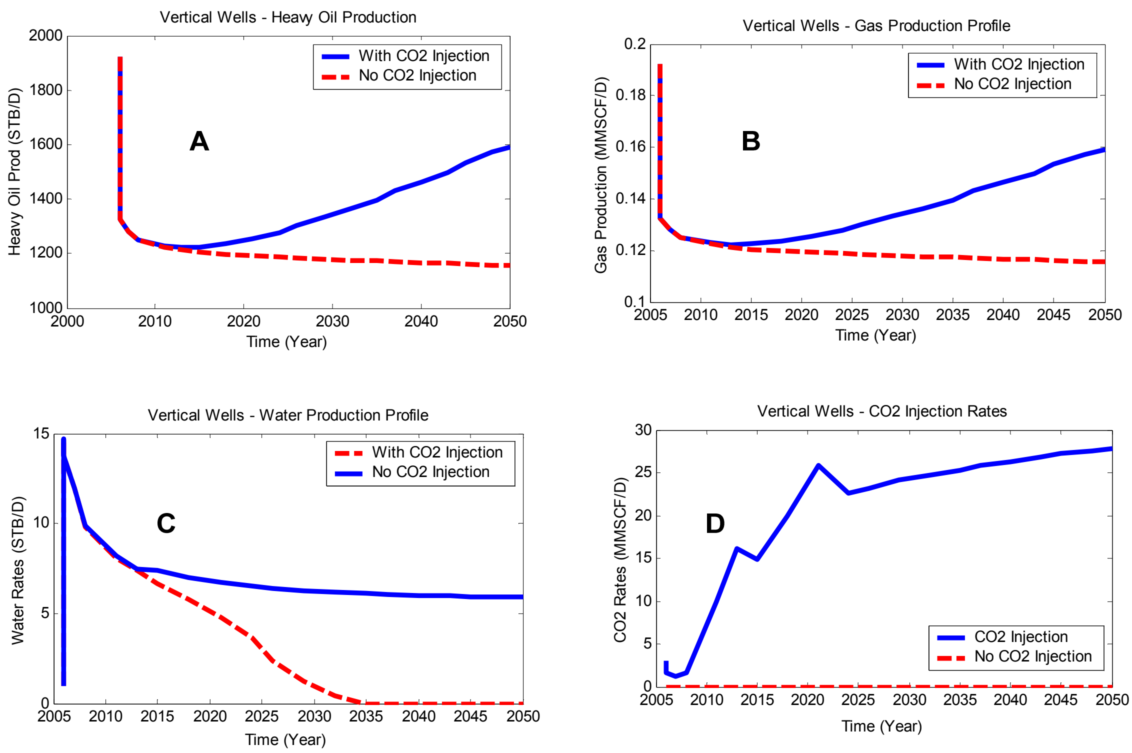


Figure 4.19: Vertical Wells and the Production Trends

In **Figure 4.20** subplots (A, B, C, D) below show heavy oil (A), gas production (B), water production (C) and CO_2 injection rates (D). The production profiles for three different locations of the injection well, with the maximum distance from the injection well to the production well being approximately 6151 ft. The results indicate that the productivity of the well is increased as the injection well gets closer to the production well, showing by the peak heavy oil production occurring earlier when the gap between the well is reduced. There is an increase in gas production, but lower water removal.

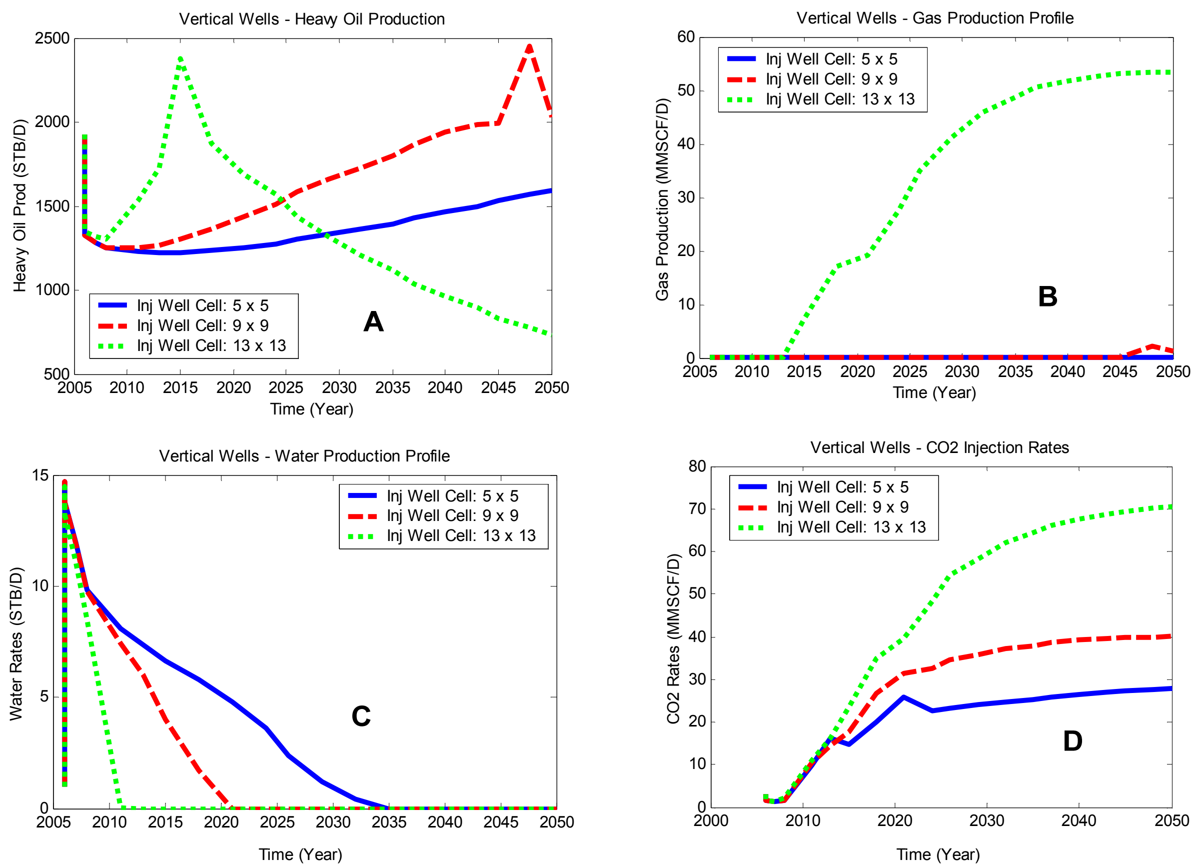


Figure 4.20: Vertical Wells – Effect of Well Location on the Production Trend

With regards to the horizontal well, the distance between the injection outlet and the production inlet was approximately 1993 ft. As the location and position of the wells influence the production trend, the two wells were positioned in opposite directions and lowered at the bottom of the grid.

In **Figure 4.21** subplot (A, B, C, D) below show the heavy oil (A), gas production (B), water production (C) and CO_2 injection rates (D). Results show that high production was maintained steady at around 13350 STB/D from late

2006 to the end of production history (2050) with CO_2 injection, while progressive decline was noticed from 15000 STB/S (2006) ending around 11000 STB/D (2050) when there was no CO_2 injection.

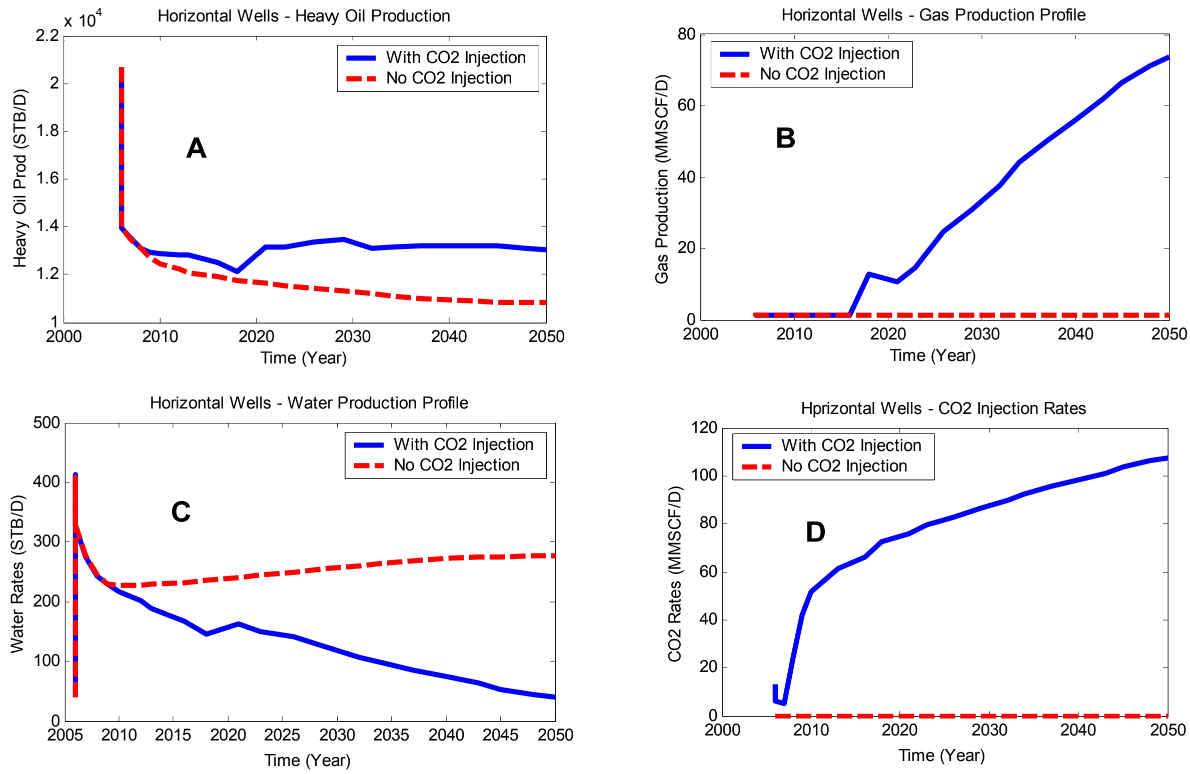


Figure 4.21: Horizontal Wells and the Production Trends

4.2.5 Miscible and Immiscible Process

High pressure reservoir (above 1000 psig) is known to be suitable for CO_2 Miscible process by enhancing the flow performance. However, this study has demonstrated that under certain conditions such as that of non Newtonian heavy crude with high viscosity, the reservoir pressure will probably need to be as high as 4000 psig to create an instantaneous impact on the productivity. Meanwhile, with CO_2 immiscible process occurring at reservoir pressure below 1000 psig, the production forecast has demonstrated that heavy oil recovery was achieved by compensating the low reservoir pressure using high injection pressure to force the heavy oil towards the production well.

Key findings and differences between the two techniques are summarized in **Table 4.1** below.

Table 4.1: Miscible and Immiscible Recovery – Results Summary

	Miscible Process	Immiscible Process
Recovery Start Time	0 – 1 Year (Immediate Impact)	> 15 Years
Recovery Volume	High	Low
Cost Implication (Qualitative)	Low	High
General Remarks	Pipeline integrity could be an issue due to high pressure demand	Could be used to maintain production

4.2.5.1 Miscible Process

The reservoir pressure was kept constant at 4000 psig and the injection pressure at the pipeline inlet (onshore) ranged from 2000 psig to 7000 psig. Other parameters remained as follows: heavy oil 20° API specific gravity and GOR (500 scf/STB).

The results showed that heavy crude extraction was easily enhanced at injection pressure as high as 3000 psig, provided that the reservoir pressure was around 4000 psig. The production forecast (year 2000 to 2020) presented in **Figure 4.22** showed the variation in maximum heavy oil production and the averaged CO_2 injection rates at different injection pressure.

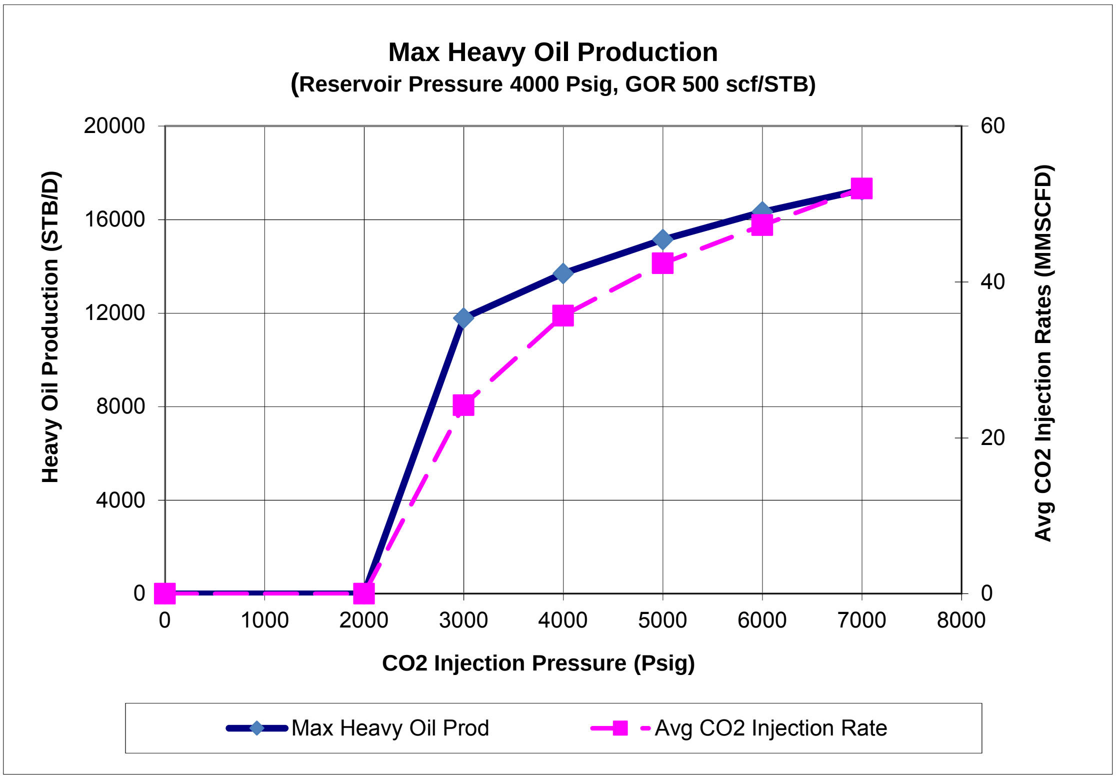


Figure 4.22: Production Rates (Prediction) at various Injection Pressure – Reservoir Pressure 4000 psig, GOR 500 scf/STB

4.2.5.2 Immiscible Process

Immiscible process was investigated using lower reservoir pressure (1000 psig) with the injection pressure at the pipeline inlet varying from 800 psig to 7000 psig. The heavy oil specific gravity was 20^o API. Different production trends compared to the results obtained with a high initial reservoir pressure (4000 psig) were experienced. Even at injection pressure as high as 7000 psig, the production forecast showed no recovery until 01/05/2003 (see Figure 4.23). The production trend shows a rapid production initially, leading to the peak, followed by a curvy decline which gradually lead to a steady state production.

In **Figures 4.23** and **4.24** Subplots (A, B, C, D) illustrate the heavy oil recovery trend (A) and the total gas production rate (B) with varying CO_2 injection pressure from 1000 psig to 7000 psig; and the heavy oil recovery trend (C) and total gas production rate (D) at varying CO_2 injection pressure from 800 psig to 900 psig.

The variation in heavy oil peak production was between 800 to 1000 STB/D as the injection pressure reduced from 7000 psig to 4000 psig in increment of 1000 psig. The difference in maximum production was approximately 2000 STB/D as the injection pressure reduced from 3000 psig to 2000 psig, and much more lower (3000 STB/D) when the injection pressure reduced from 2000 psig to 1000 psig. This indicates that the production was significantly influenced by the injection pressure and that under Immiscible condition significant injection pressure will be required to compensate the low reservoir pressure. Although production was possible at 1000 psig and 900 psig injection pressure, production could only start from year 2016 and 2023 respectively, leading to about 16 and 23 years of continuous CO_2 injection with zero recovery.

Heavy crude displacement by CO_2 injection is known to rely on the phase behaviour of CO_2 and the interaction within the reservoir. The reservoir temperature and pressure can significantly affect the miscibility of the two components (CO_2 and heavy oil). At low reservoir pressure, recovery of the heavy oil to the surface was significantly delayed until mobility of the heavy crude was possible. Due to low pressures hindering the fluids Immiscible or delaying the mobility of the fluids, swelling and the heavy oil viscosity reduction was the pre-requisites prior to the fluid displacement mechanism to be possible. The long period of no production at continuous CO_2 injection was either caused by the lack of sufficient energy (low reservoir and injection pressures) to push the fluids out of the reservoir or the inefficient fluids interaction to create the required swelling and viscosity reduction, or a combination of the two effects.

At 900 psig injection pressure which was below the CO_2 critical pressure, the heavy oil displacement was possible despite more than two decades of zero gas or heavy oil production. The heavy oil production trend in Subplot C was extended beyond year 2020 as shown in other Subplots (A, B, D) to illustrate the time lag during recovery at low injection pressure. A much smaller ROI (Return on Investment) and longer payback time reaffirms that the Immiscible process for heavy oil reservoir in some conditions may not be a viable option.

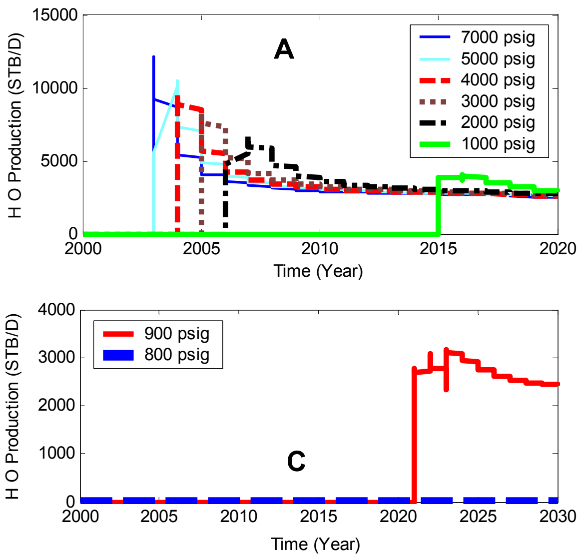


Figure 4.23: Effect of CO_2 Injection Pressure (Reservoir Pressure at 1000 psig – Heavy Oil Production)

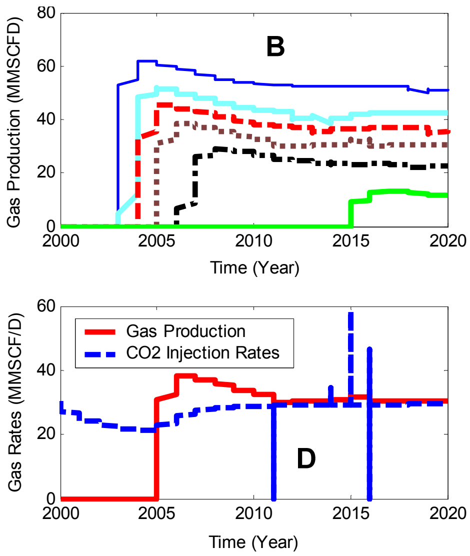


Figure 4.24: Effect of CO_2 injection Pressure (Reservoir Pressure: 1000 psig – Gas Rates)

4.2.5.3 Varying Reservoir Pressure at Constant GOR for Different CO_2 Injection Pressure

The productivity of the reservoir was further investigated by varying the reservoir pressure and the injection pressure while keeping the GOR constant at 100 scf/STB.

With the injection pressure below 4000 psig, the production forecast indicated that the recovery was unlikely when the reservoir pressure varied between 2000 psig and 4000 psig.

However, at 1000 psig (reservoir pressure), the heavy oil recovery was achievable when the injection pressure was below 3000 psig, but with longer period of zero production. The period of zero production was shortened as the reservoir pressure increased; and no heavy crude displacement occurred before the reservoir pressure was sufficient to push the heavy crude toward the production well up to the surface facilities located 4 km above the reservoir.

4.2.5.4 Sensitivity of GOR, Viscosity, Heavy Oil API and Injection Pressure

Figure 4.25 and **4.26** (Subplot A, B, C, D) show, the maximum heavy oil production rate at reservoir pressure varying from 1000 psig to 4000 psig and fixed GOR of 100 scf/STB (Subplot A). The maximum heavy oil production rate at constant reservoir pressure of 4000 psig and varying GOR from 100 to 500 scf/STB is shown in Subplot B. The maximum heavy oil production rate at constant reservoir pressure of 4000 psig, fixed GOR of 500 scf/STB, fixed CO_2 injection pressure of 5000 psig and varying heavy oil viscosity from 10 to 10000 Cp is shown in Subplot C. The maximum heavy oil production rate at constant reservoir pressure of 4000 psig, fixed GOR of 500 scf/STB, fixed CO_2 injection pressure of 5000 psig and varying heavy oil API specific gravity from 10 to 18 ^{o}API is shown in Subplot C.

Initially (early life), the maximum heavy oil production occurred at the lowest GOR (100 scf/STB) potentially because high GOR implies lesser recoverable oil, and progressively the peak heavy oil production decreased as the GOR reduced. This indicates that the heavy oil recovery increased later with higher GOR due to increased CO_2 injection rate. At 3000 psig injection pressure, the heavy oil recovery (although very unstable) was also possible, but only when the GOR was 400 and 500 scf/STB.

By considering different heavy oil specific gravity varying from 10^{o} API to 18^{o} API, a reasonably good range of heavy oil types was taken into account. Heavy oil viscosity is known to vary between 100 cP and 10000 cP. The viscosity effect has been assessed to cover from 10-10000 cP. The results are shown in Subplot C, and reveals that the production was spontaneous as soon as the injection was initiated when the viscosity was 10 cP. Production started two months after the injection was initiated when the viscosity was 100 cP and approximately one year later when the viscosity was 1000 cP and 10000 cP.

As expected, the heavy oil recovery increased and was sustained for longer period for heavy oil with higher API specific gravity.

These results suggest that the heavy oil recovery is considerably influenced by the reservoir properties, the fluid interaction and mixing process, and other thermodynamic effects that effectively enable the dynamic of the fluids within the reservoir up to the surface.

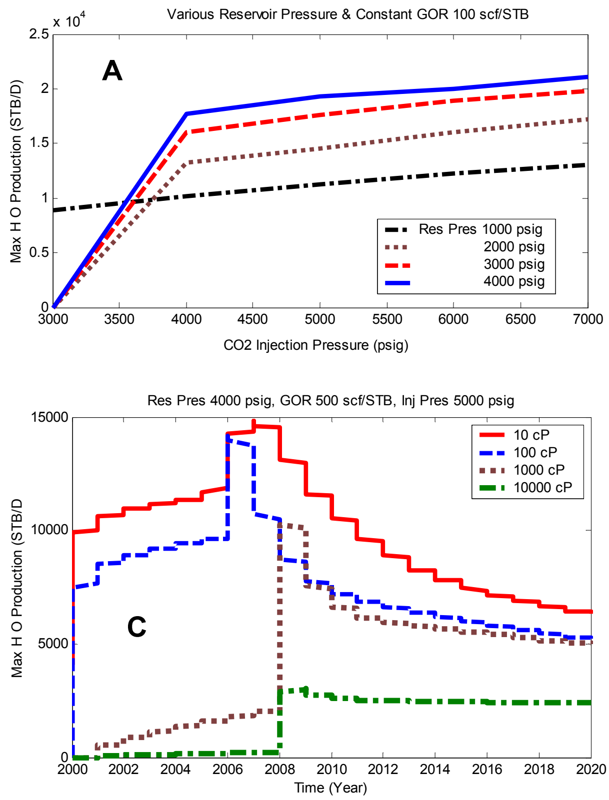


Figure 4.25: Sensitivity Analysis Results (Subplots A, C)

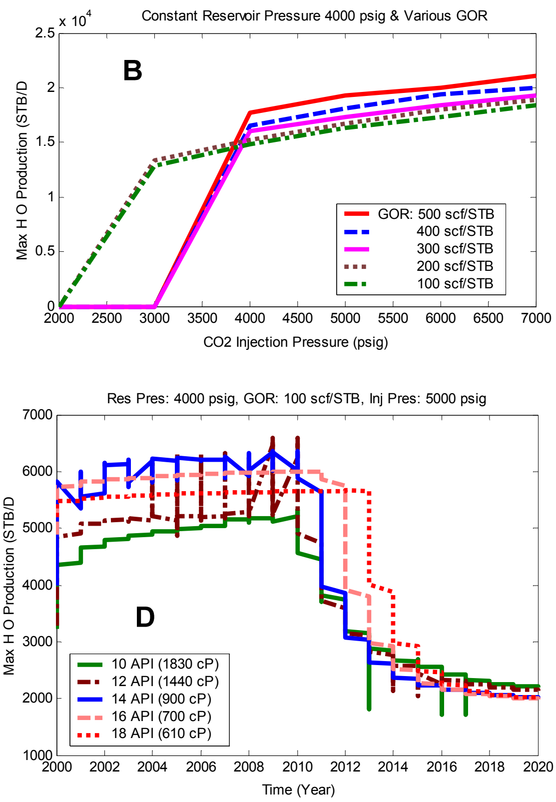


Figure 4.26: Sensitivity Analysis Results (Subplots B, D)

4.2.6 CO_2 Sequestration during Heavy Oil Production Using CO_2-EOR

Carbon dioxide emissions from power plants and stationary industrial sources account for more than 60% of global greenhouse gas emissions. This CO_2 can be captured, stored, transported offshore and injected into heavy oil reservoirs for enhanced oil recovery (EOR). Thus, CO_2 capture and storage and EOR present opportunities for the oil industry to participate in activities that will substantially reduce emissions, and, in the case of EOR, increase the recovery from oil field **[122]**.

During CO_2-EOR, a small amount of the injected CO_2 dissolves in the oil. Laboratory results have demonstrated that the injection of CO_2 would result in swelling of the oil by over 20%, a significant reduction in oil viscosity, and a 95% reduction in interfacial tension **[123]**. This will make oil flow more easily in response to pressure gradients **[124]**. CO_2-EOR is known to allow recovery up to 20 % of the OOIP (Original Oil in Place) **[125]**. Approximately 53 to 82 % more oil could be produced by the CO_2 flood than is produced by water in the best areas of the waterflood, according to the test conducted by **[126**, **127].**

There is variety of speculation with respect to CO_2 storage during EOR, some believe that CO_2-EOR in a conventional oil reservoir will result in increased carbon emissions from incremental oil production **[128]**. Others believe that 40% or up to two-thirds of the injected CO_2 is being produced and can be re-injected **[129**, **130]**.

In the Bati Raman heavy oilfield (9° to 15° API), in southeast Turkey, close to the Turkish-Iraqi border, where Immiscible Displacement using CO_2-EOR, approximately 1700 tonnes of CO_2 is injected daily, 16% to 60% of which is recycled **[131]**.

CO_2-EOR enables chemical and physical interaction of the injected CO_2 with the reservoir rock and fluids, creating favorable conditions that improve oil recovery. These conditions include:

(i) The reduction of the capillary forces that inhibit oil flow through the pores of the reservoir by reducing the interfacial tension between oil and the reservoir rock;

(ii) The expansion of the volume of the oil (oil swelling) and the subsequent reduction of its viscosity;

(iii) The development of favorable complex phase changes in the oil that increase its fluidity;

(iv) The maintenance of favorable mobility characteristics of oil and CO_2 to improve the volume sweep (replacement) efficiency **[69]**.

As such, in this study, the subject of CO_2 sequestration during heavy oil production was investigated and the results are discussed in this section.

In **Figure 4.27** Subplots (A, B, C, D, E, F, G, H) show the effect of temperature varying from 50 ^oF to 200 ^oF on various heavy oil properties such viscosity (A), density (B), heavy oil (FVF) formation volume factor (C), Z-Factor (D); reservoir gas viscosity (E), reservoir CO_2 density (F), gas (FVF) formation volume factor (G), and the (CGR) condensate gas ratio (H).

The temperature range is between 50 ^oF to 200 ^oF (Subplots A, B, C, D) while the pressure vary from 100 psig to 5000 psig. Mobility of heavy oil is known to be much easier at high temperatures. At 200 ^oF, the reservoir heavy oil viscosity was approximately 25 cP, as the temperature reduced the heavy oil viscosity increased. During the injection, as the reservoir heavy oil comes in contact with the injected CO_2 at lower temperature (50 ^oF - 70 ^oF), the heavy oil viscosity will significantly vary as the reservoir temperature will reduce. Hence, the heavy oil viscosity profile showing the heavy oil viscosity variation at different temperatures, and indicating that the heavy oil viscosity could rise up to 7730 cP at 50 ^oF if the reservoir pressure was to reach 5000 psig. The heavy oil density was very close to that of water and varied between 57.5 lb/ft^3 to 60.2 lb/ft^3 at the temperatures and pressures investigated. The heavy oil FVF was almost constant.

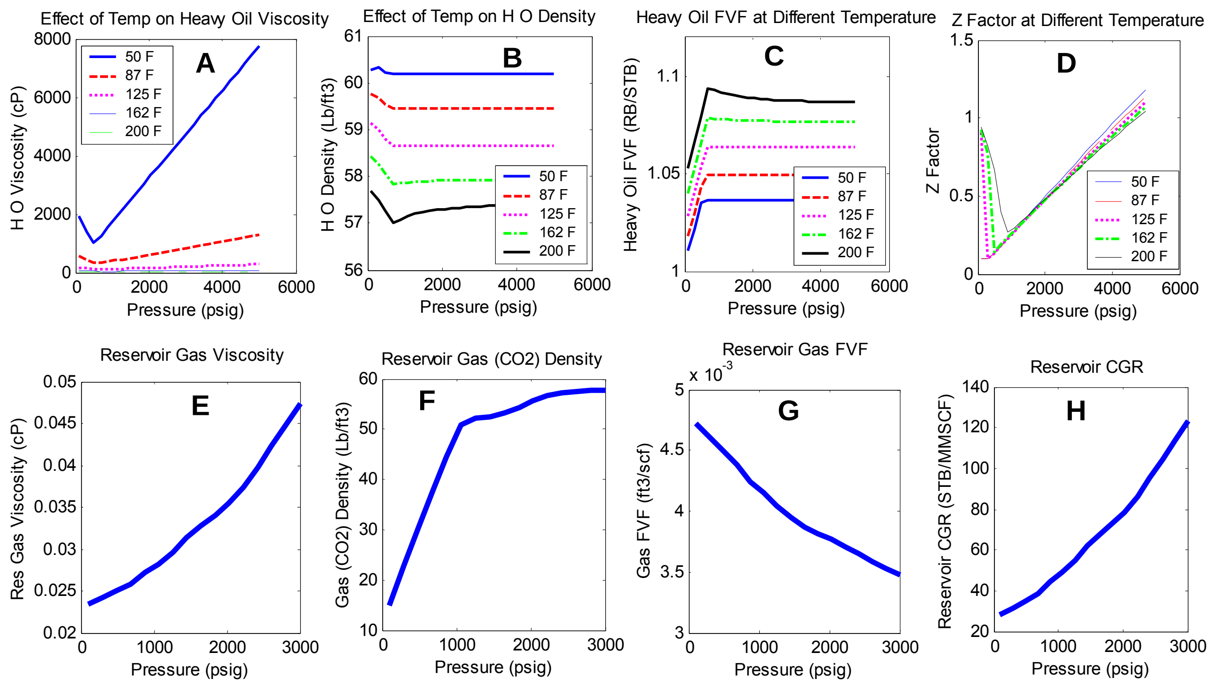


Figure 4.27: Variation of Reservoir Heavy Oil and Gas (CO_2) Properties with temperature and pressure

As shown in **Figure 4.27** Subplots (A, B, C, D, E, F, G, H), the reservoir gas thermodynamic properties were deliberately modelled to reflect those of CO_2. The reservoir gas was modelled as retrograde condensate to take into account the phase change at various temperatures and pressures. CO_2 is expected to reach the reservoir in supercritical state due to the high pressure within the transported line as well as the reservoir. This phenomenon is effectively represented in the modelling by the retrograded condensate process which take into account the condensate CO_2 being lost in the gas stream. The phase behavior of the reservoir gas is adequately illustrated in the density and CGR profiles at various pressures. With regards to the density profile, the gas density sharply rise from 15 lb/ft^3 (dry gas phase) to 52.5 lb/ft^3 (dense phase) when the pressure reaches 1073 psig. Above 1073 psig, the variation in density was very slow and only change from 52.5 lb/ft^3 to 57.8 lb/ft^3 (3000 psig). The high reservoir gas density at 1073 psig was in agreement with conventional knowledge and also ascertained that the properties of the fluid were appropriately modelled. The CGR reflected the phase variation of CO_2 within the reservoir at different pressure as shown in **Figure 4.27** Subplot H.

REVEAL was also used to calculate the reservoir CGR and gas FVF with the dense phase CO_2 density and viscosity for pressure varying from 100 psig to 3000 psig. The CGR increased with increasing pressure, from 28 STB/MMSCF at 100 psig to 123 STB/MMSCF at 3000 psig. There was negligible variation in the reservoir gas (CO_2) viscosity and FVF at different pressures and temperatures. The reservoir FVF was about 0.004 ft^3/scf and the viscosity ranged approximately from 0.023 cP to 0.048 cP.

In **Figure 4.28** Subplots (A, B, C, D) show the variation at different temperature and pressure of the reservoir water viscosity (A), density (B) and (FVF) formation volume factor (C) and Z Factor (D).

The temperature ranged between 50 ^oF to 200 ^oF and the pressure varied from 100 psig to 5000 psig. The viscosity was about 0.34 cP at 200 ^oF and progressively increased with reducing temperature.

The maximum viscosity was 1.4 cP at 50 ^oF. The density varied between 60.5 lb/ft^3 to 63.5 lb/ft^3, and the variation was very minimal. The FVF was approximately 1 RB/STB and the compressibility factor was extremely low.

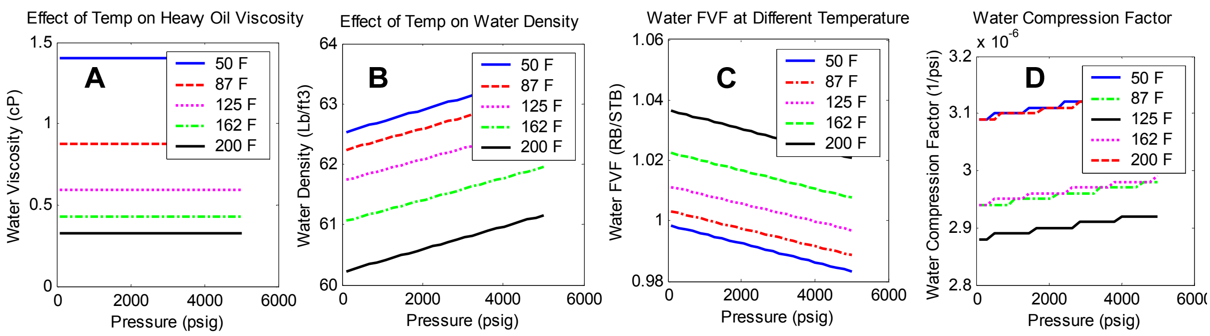


Figure 4.28: Variation of Reservoir Water Properties with temperature and pressure

In **Figure 4.29** Subplots (A, B, C, D, E, F, G, H) show the variation of the reservoir fluids properties: heavy oil viscosity (A), gas viscosity (B), heavy oil FVF (C), gas FVF (D), heavy oil density (E), gas density (F), water density (G) and water FVF (H) at varying temperature from 50 ^oF to 200 ^oF when the reservoir gas is modelled as natural gas as opposed to CO_2.

It is comprehensible that the maximum gas density is 0.0595 lb/ft^3 and the maximum viscosity is 1.3 cP. The heavy oil viscosity increased as the temperature dropped and other fluid behaviors with respect to temperature rise or drop are typical expected trends, which have already been discussed above in this section 4.2.6. The heavy oil viscosity reduces with reduction in pressure, with the highest value (viscosity) occurring at a lower temperature.

The heavy oil FVF increases with increasing temperature and pressure, but the oil density is high at low temperature and low pressure, and reduces as the pressure and temperature increases.

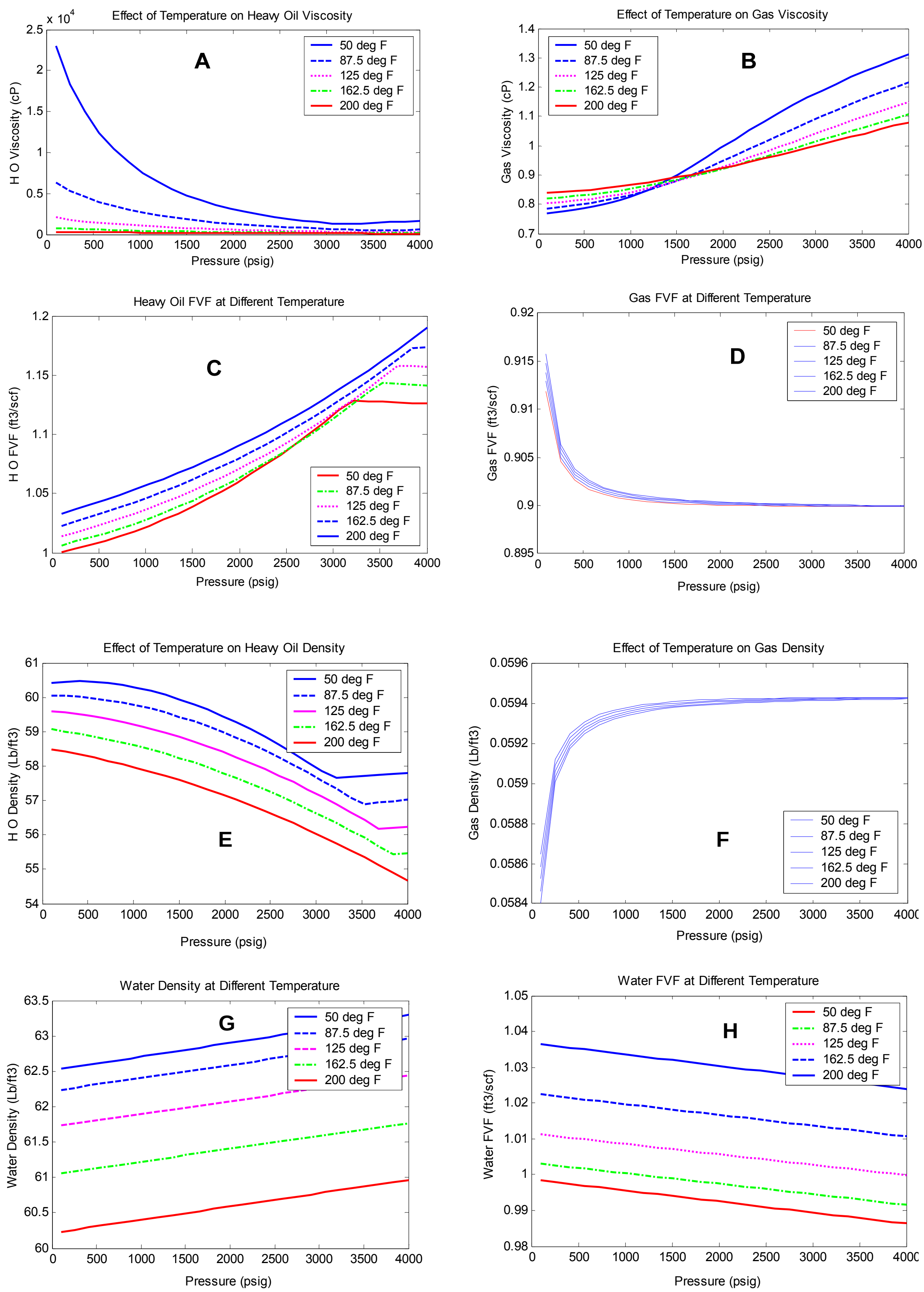


Figure 4.29: Reservoir Fluids Properties and Influence of temperature and pressure

In **Figure 4.30** Subplots (A, B, C, D) show the heavy oil production rates (A) when the injection pressure was 5000 psig, the calculated CO_2 sequestration per barrel of heavy oil produced (B), the percentage retention per barrel of heavy oil produced (C) and the CO_2 requirements per barrel of heavy oil produced (D).

The results reveal that the percentage of CO_2 sequestration was 100% for months post start-up. This may be justified by the theory that the injected CO_2 which is in dense phase expand as it reaches the reservoir. As the CO_2 expands, it reduces the reservoir fluid (heavy oil) viscosity by dissolving into the heavy crude. This process facilitates the mobility of heavy oil within the reservoir and toward the production system. Results also show that the CO_2 sequestration reduced sharply from 100% to 47% when the heavy oil production reached the first peak and reduced further to approximately 22% when the second peak production occurred.

A sharp decline in production was also noticed, which was almost reflected by a continued decline in the percentage of CO_2 retention. In year 2020, a rather slow reduction in the heavy oil production was noticed, at which stage the CO_2 sequestration remained almost stable around 22%.

The CO_2 sequestration per barrel of heavy oil produced remained extremely high at the start-up as no CO_2 was released. But as soon as CO_2 production started, the CO_2 retention per barrel varied between approximately 1500 SCF/STB to 2000 SCF/STB.

The volume of CO_2 utilised per barred of heavy oil produced was significantly higher (11.2 MSCF/STB) at the beginning of the production when there was no CO_2 being produced, sharply reducing to approximately 4 MSCF/STB as the production rose to the peak, stabilised for a couple of years before progressively increasing as the heavy oil production reduced.

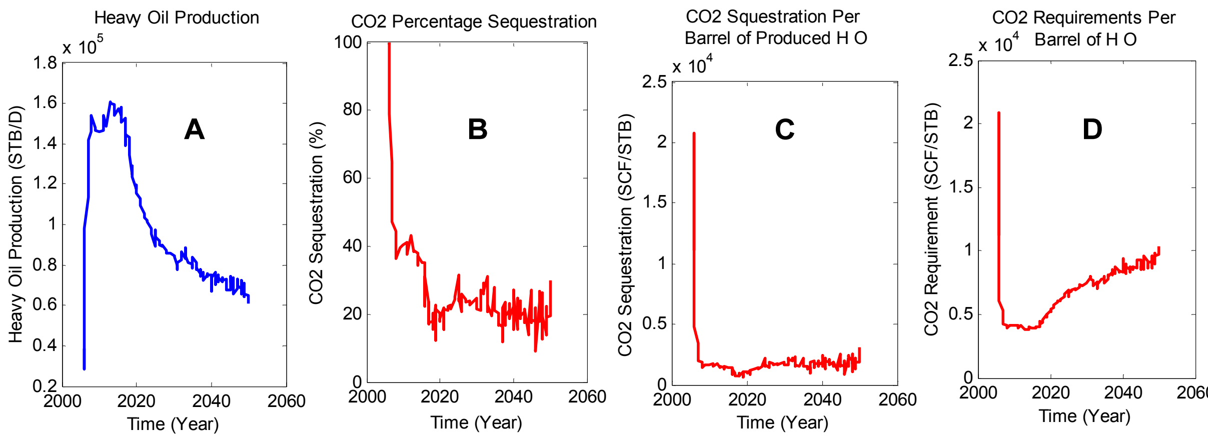


Figure 4.30: CO_2 Sequestration – Reservoir Pressure: 2500 psig, Injection Pressure: 5000 psig

4.2.6.1 Analysis Based on CO_2 Mass Balance

In **Figure 4.31** Subplots (A, B, C, D) show the mass of CO_2 sequestrated (A), the CO_2 retention per barrel of heavy oil (B), the CO_2 requirements per barrel of heavy oil (C), and the percentage of CO_2 retention (D) with the CO_2 injection pressure fixed at 5000 psig.

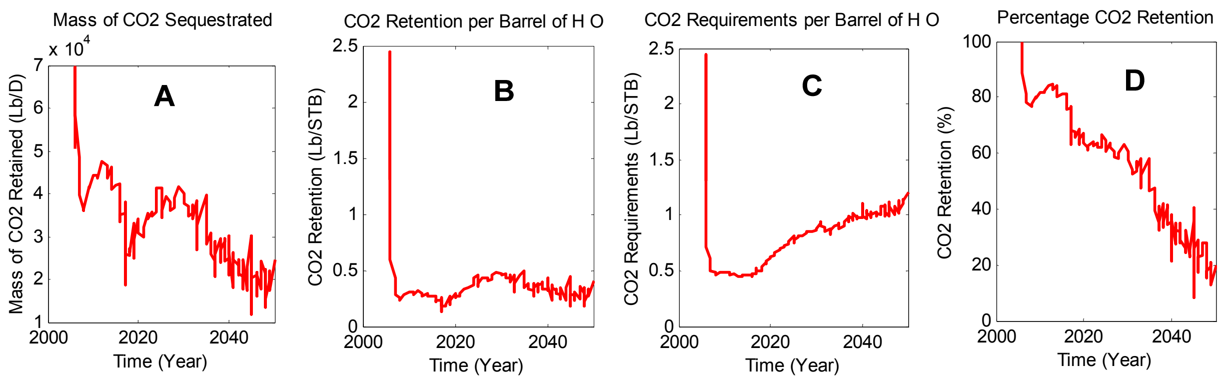


Figure 4.31: CO_2 Sequestration at 5000 psig Injection Pressure – Analysis by Mass Balance

Results show that the CO_2 mass balance around the reservoir inlet and outlet was not consistent, as the CO_2 input was by far greater than the amount released (output). At the beginning (year 2006) of the production, no CO_2 was released as indicated by the mass flowrate of produced CO_2. The calculated percentage of CO_2 retention shows 100 % of CO_2 being retained in the reservoir in the major part of the first year (2006). In the meantime, the heavy oil recovery was spontaneous following the injection of CO_2. The beginning of heavy oil recovery also implied a progressive decline in the percentage retention of CO_2 in the reservoir, reaching approximately 17 % at the end of the prediction period (2050).

The heavy oil and gas production peaked twice as shown on the production profile, firstly at the same time in 2008; then the heavy oil peaked again in 2013 and remained almost steady until the peak gas production occurred in 2017. Following that trend, the heavy oil production began to decline while the gas production remained steady until the end of production in 2050. The difference between the mass of injected CO_2 and the mass of produced CO_2 shows that during that period (peak production), the CO_2 retention dropped sharply as the production peaked, perhaps justifying the momentum required to increase the mobility of the heavy crude. Between year 2020 and 2050, the variation in CO_2 retention was much lower than it was between year 2006 to 2020.

From 2006 to 2008 where the production rose to the peak, the CO_2 retention per barrel of produced heavy oil reduced from 2.4 lb/STB to about 0.4 lb/STB and remained almost constant around that value. The utilised mass of CO_2 for every barrel of heavy oil produced dropped from 2.4 lb/STB to about 0.5 lb/STB, stabilised till 2018 and began to rise again progressively as the heavy oil production gradually was in decline.

4.2.6.2 Analysis Based on Peak Production

In this case, CO_2 sequestration was investigated at various injection pressures. The injection pressure varied from 1000 psig to 7000 psig, in an increment of 1000 psig.

In **Figure 4.32** Subplots (A, B, C, D) show the peak heavy oil production (A), the percentage retention of CO_2 (B), the CO_2 requirements for barrel of heavy oil (C) and the CO_2 retention per barrel of heavy oil produced (D), at different CO_2 injection pressures.

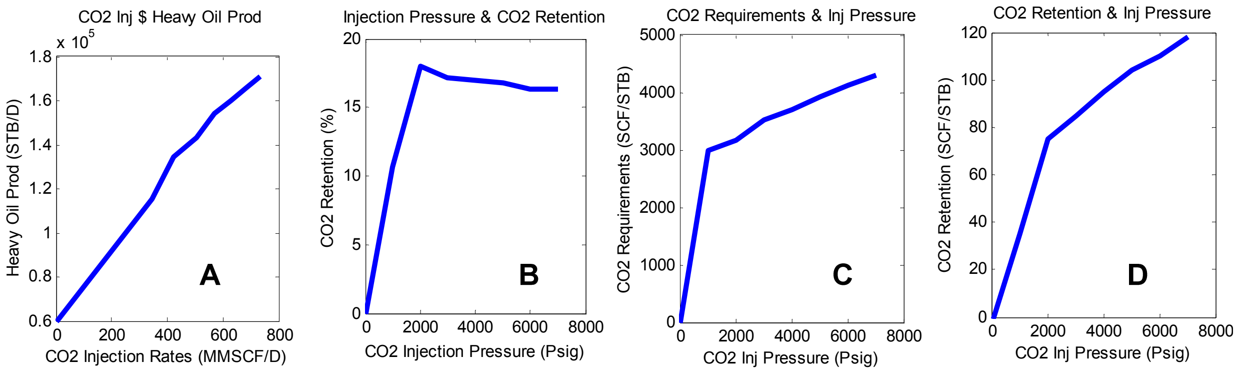


Figure 4.32: CO_2 Sequestration and the Relationship with Injection Pressure and Recovery Rates

The peak production increases with injection pressure. The recovery was about 1.3 % when there was no CO_2 injection; however, the production trend shows appreciable recovery with increasing CO_2 injection pressure. From 0 to 1000 psig injection pressure, there was an increase of 9.7 % recovery. The percentage increase in recovery factor for every increment of injection pressure above 1000 psig was very tiny, although the recovery was significantly higher in the first increment (0 – 1000 psig). The difference between the injected volume of CO_2 and that produced gives an indication of how much CO_2 was retained in the reservoir daily. Although the daily CO_2 retention increased as the CO_2 injection pressure increased, the percentage retention remarkably indicated that a high percentage of CO_2 was retained at the low CO_2 injection (2000 psi). Beyond 3000 psig injection pressure, the percentage CO_2 retention was almost stable.

The analysis shows that when the injection pressure was 7000 psig, for every barrel of heavy oil produced, about 4290 SCF of CO_2 was required and approximately 690 SCF of CO_2 was trapped in the reservoir by various mechanisms. The CO_2 requirement and retention per barrel of heavy oil reduced as the injection pressure reduced or as the peak heavy oil reduced. Nevertheless, further analysis using different data may well predict a diminutive variation or an improved ratio of the amount of CO_2 stored and that required per barrel. Also, ways to improve CO_2 storage during CO_2-EOR have been discussed by Jessen et al **[132]**. One of the methods consisted of re-pressurizing the reservoir after the end of oil production with continuous injection. Meanwhile, well control process, where wells are shut according to a gas-to-oil production ratio limit to avoid excess gas circulation, was claimed as the best way to obtain both maximizing oil recovery and CO_2 storage at the same time **[133]**, opinion that was however rejected by Jayasekera et al **[134]**.

The summary of calculations shown in **Table 4.2** below is based on maximum production, hence illustrate the CO_2 sequestration occurring during a quasi-steady state condition.

Table 4.2: Results Summary for CO_2 Sequestration Based on Evaluation of Production Profiles

CO_2 Injection Pressure (psig)	CO_2 Injection Rate (MMscf/D)	Maximum Heavy Oil Production (STB/day)	Max Gas Production (MMscf/D)	Maximum Recovery Factor (%)	Difference Between Inj & Prod CO_2 (MMscf/D)	CO_2 Retention (SCF/STB)	CO_2 Requirements (SCF/STB)	CO_2 Retention (%)
7000	733	170900	615	13.5	118.00	690.46	4289.06	16.32
6000	685	166056	575	13.3	110.00	662.43	4125.11	16.29
5000	629	160275	525	13.00	104.00	648.88	3924.50	16.79
4000	570	154480	475	12.70	95.00	614.97	3689.80	16.95
3000	505	143280	420	12.20	85.00	593.24	3524.57	17.15
2000	425	134300	350	11.77	75.00	558.45	3164.56	18.03
1000	345	115463	310	11.00	35.00	303.13	2987.97	10.61
0	0	60000	3.9	1.30	-3.90	-65.00	0.00	0.00

4.2.6.3 CO_2 Sequestration During Miscible and Immiscible Process

Immiscible displacement projects can store larger volumes of CO_2 than Miscible Displacement projects **[69]**. This was attributed to the CO_2 breakthrough which is unavoidable in Miscible Displacement operations and avoidable in Immiscible Displacement as the Immiscible projects may be designed to eliminate the breakthrough to enable permanent retention of CO_2.

In **Figure 4.33** Subplots (A, B, C, D) show heavy oil production (A), percentage of CO_2 sequestration (B), CO_2 requirements (C) and retention (D) per barrel of heavy oil produced in subplots, and indicate that considerable amount of heavy oil was achieved at high reservoir pressure, i.e. Miscible conditions. Equally, as the reservoir pressure increases, the influence on the production profile is clearly noticeable.

Despite the constant injection pressure, the volumetric flowrate of CO_2 reaching the reservoir increases as the reservoir pressure reduces. High reservoir pressure enabled high recovery factor. However, in all cases, the mass flowrate of CO_2 show significant delay (period of zero flow) before initial CO_2 production at continuous CO_2 injection. All simulation results were based on 20-30 years production forecast and illustrate that during CO_2-EOR application, the CO_2 requirements varied with time throughout the lifetime of the forecast, which corroborate with the claim reported by Balbinski et al **[135]** and Holt et al **[136]**.

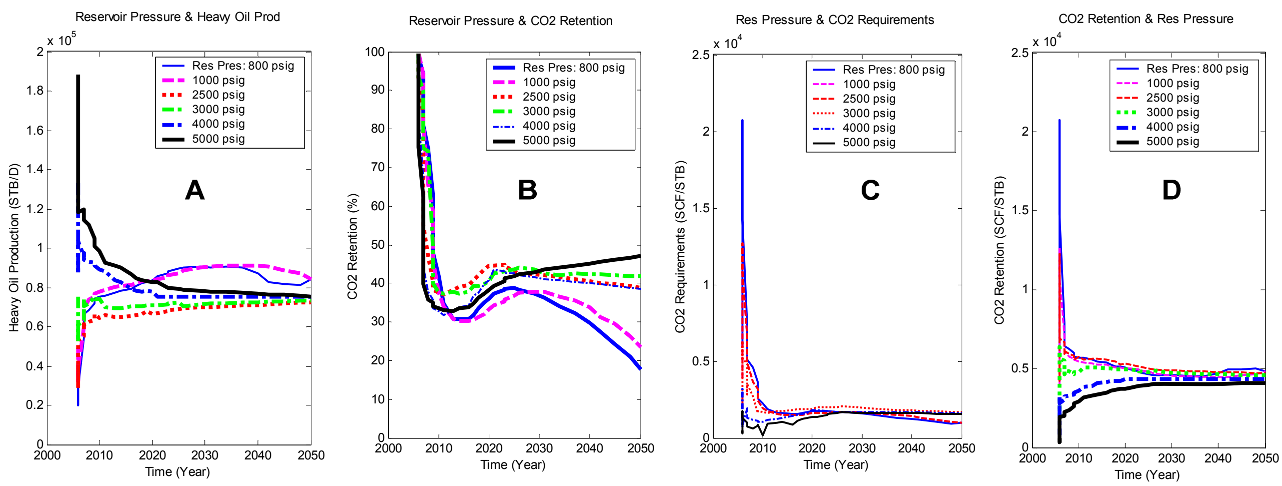


Figure 4.33: CO_2 Sequestration – Influence of Reservoir Pressure – Injection Pressure 5000 psig

While the percentage of CO_2 sequestration was found to be high at high reservoir pressure in this case, the CO_2 utilisation and CO_2 retention per barrel of heavy oil produced was found to be significantly higher during Immiscible conditions compared to Miscible conditions. These findings are in agreement with the theory reported by Tzimas et al **[69]**, that Immiscible Displacement projects would generally require a higher amount of injected CO_2 per incremental barrel of oil produced, typically two to three times more. However, values may vary significantly from field to field. Considering that the "pressure" limit switch between Miscible and Immiscible process is known to be 1073 psig, the simulation results indicate that at low reservoir pressure (800 – 1000 psig) the CO_2 retention and CO_2 requirements per barrel of heavy oil produced was about two times higher than that required at a high reservoir pressure (2500 psig). This factor varies considerably as the reservoir pressure increases.

The percentage of CO_2 retention within the reservoir was influenced by the reservoir pressure, and in this case high sequestration occurred at high reservoir pressure. At start-up (production), the CO_2 retention within the reservoir was maximal for all the reservoir pressures investigated, and for low reservoir pressure (800 & 1000 psig), the sequestration remained high until production reached a quasi-steady state condition, at which stage the decline in CO_2 retention begun progressively as the production continued. At high reservoir pressure (above 1000 psig), the CO_2 retention dropped from 100 % to 35%, rose again approximately to 42 % during transition from start-up and quasi-steady state production; and at quasi-steady state condition, the CO_2 retention within the reservoir continued to rise progressively as the production continued. Results based on peak production show that the minimum percentage of CO_2 retention within the reservoir increases with increasing reservoir pressure, starting with 17.7 % retention at 800 psig to 32.8 % at 5000 psig. The maximum CO_2 retention of 100 % simply reflects that production or release of CO_2 started approximately one year after CO_2 injection commenced. At high reservoir pressure (above 4000 psig), the CO_2 retention and CO_2 requirements / utilisation per barrel remained within the range reported by many authors such as Clarke and Graves **[137]** as being between 6 to 8 Mscf/STB, but at reservoir pressure below 4000 psig the value was in agreement with that presented by Gozalpour et al **[138]** which is 13 Mscf/STB.

4.2.7 Comparative Analysis – CO_2 vs Water Injection for CHOP

The purpose of this analysis is to provide a high level comparative illustration between CO_2 and water injection for enhanced recovery of heavy oil.

The comparison was carried out on similar reservoir conditions and scenario discussed in **Section 4.2.1**, (i.e. with no subsea separation scenario). In addition to 2 km depth from the seabed to the topside, the reservoir pressure is below the bubble point, production via primary recovery method could not be achieved (refer to **Figure 4.8**). The injected fluid is used to provide additional pressure or energy support in order to initiate production.

Initially, the injection pressure was set to be identical in both cases, which resulted in different mass feed rates of injected fluid as shown in **Figure 4.34** below.

The injection mass flowrate of water was between 58 lbm/sec to 60 lbm/sec, higher than the CO_2 injection mass flowrate which was constant around 39 lbm/sec up to year 2007 before gradual increase towards 58 lbm/sec.

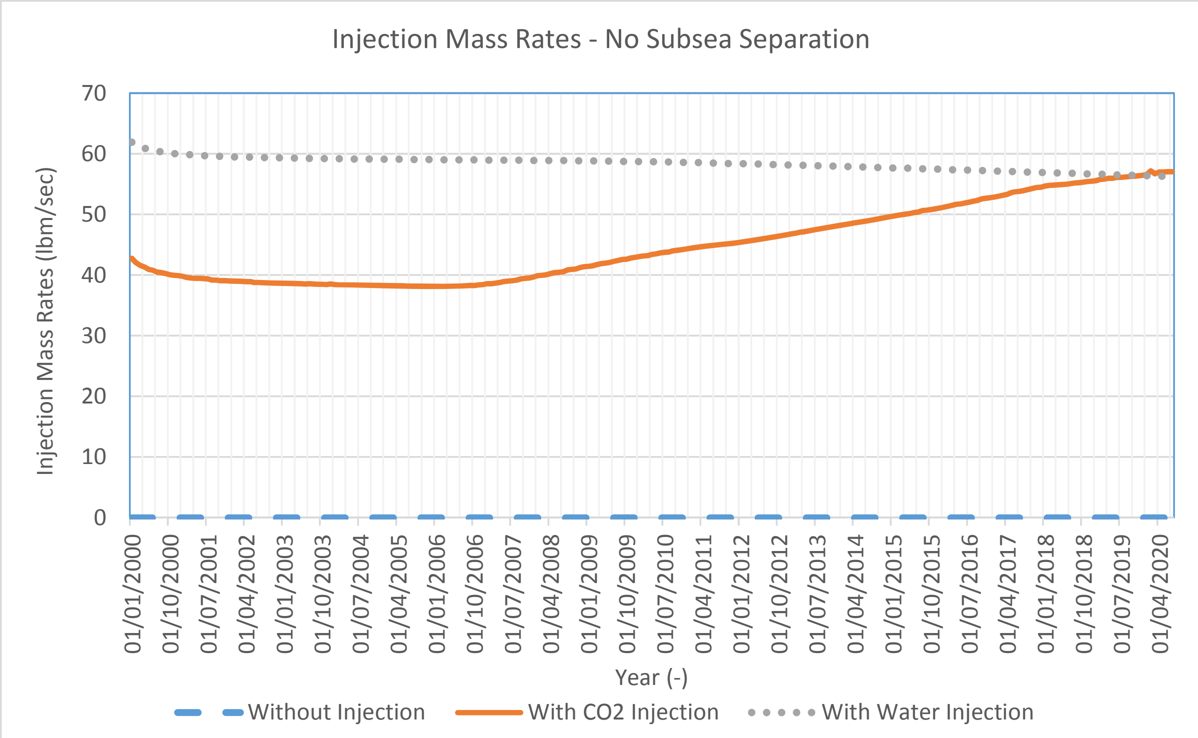


Figure 4.34: Heavy Oil Recovery, Injection Mass Rates – CO_2 vs Water Injection

The corresponding heavy oil production rates without injection and with CO_2 and water injection is shown in **Figure 4.35** below.

Results indicate that CO_2 injeciton provides higher heavy oil recovery rate than water injection for about 13 years, although the water injection mass rate was 40% to 50% higher than the CO_2 injection mass rate.

Towards year 2013 onwards where the CO_2 injection pressure at well conditions was at minimum, the recovery rate with CO_2 injection was in decline while production using water injection was almost stable and higher than that of CO_2 injection. While recovery rate appeared to decrease sharply with CO_2 injection, the decline in production towards the end of forecast was rather slow with water injection.

During early life production, delay in water production may be encountered despite continuous water injection.

The predicted peak heavy oil production is 15122 STB/D and 10151 STB/D for CO_2 and water injection respectively; implying 49% increase in capacity at peak flow with CO_2 injection compared to water injection.

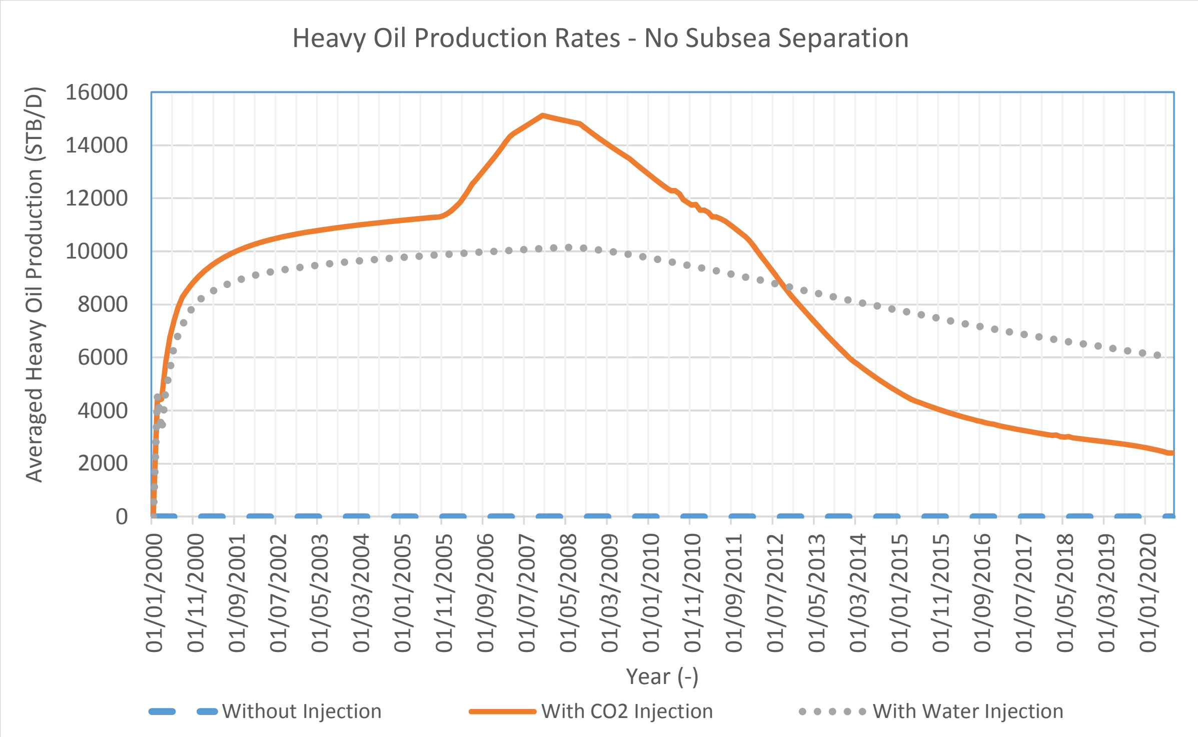


Figure 4.35: Heavy Oil Recovery – CO_2 vs Water Injection

However, in order to provide a representative basis for comparison, the heavy oil recovery using water injection was pro-rated at similar injection mass rate as that of CO_2 shown in **Figure 4.34** above.

Figure 4.36 shows a similar injection mass flowrate for both CO_2 and water injection and the heavy oil recovery rates for the 2 injection fluids. The production trends indicate that the heavy oil recovery rate using water injection is 40% to 55% less than the recovery rate using CO_2 injection. This implies that the recovery factor using CO_2 injection could be higher by the same factor, i.e. almost double compared to water injection, before the decline in recovery rate caused by the sharp reduction in CO_2 injection pressure at reservoir conditions which changes over time.

In this case, the peak heavy oil production is 15122 STB/D and 7154 STB/D for CO_2 and water injection respectively; implying 100% increase in capacity at peak flow with CO_2 injection compared to water injection.

Overall, these findings confirm widespread remarks that water injection for enhanced recovery is associated with low recovery factor.

However, it is very apparent based on these results and worthwhile noting that water injection provides a sustained heavy oil production rates throughout the life of field, despite a lower recovery rate compared to CO_2 injection.

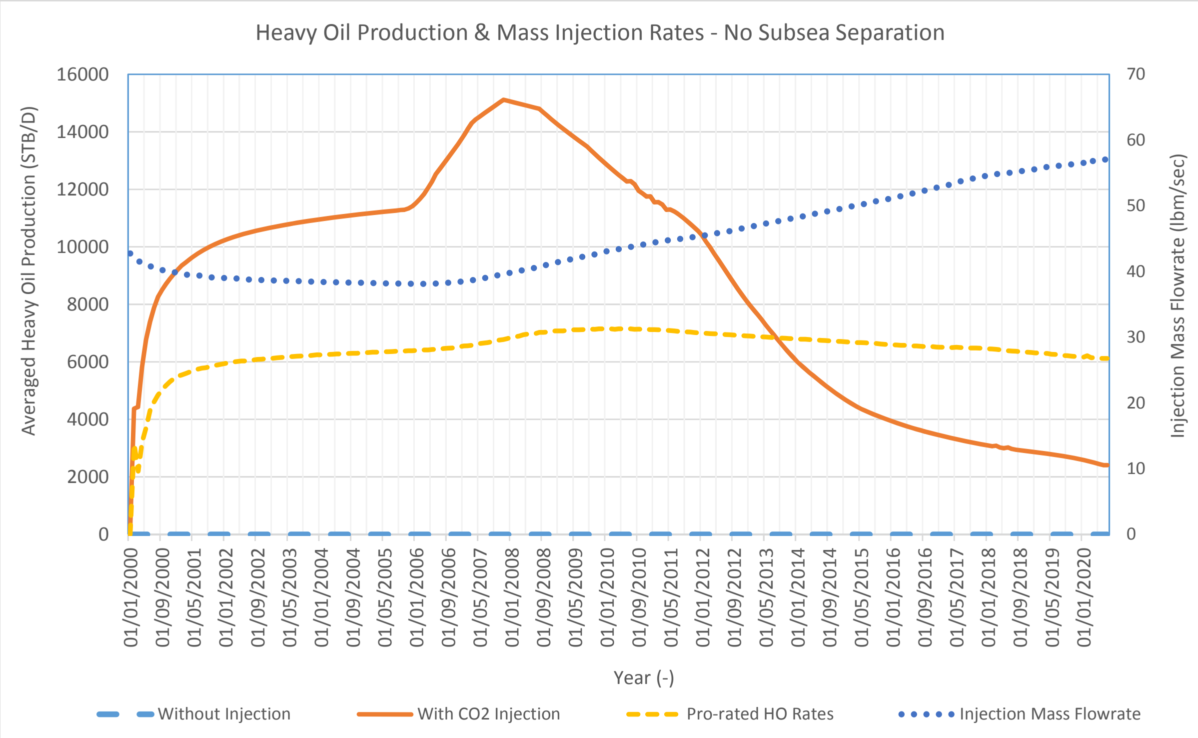


Figure 4.36: Heavy Oil Recovery – CO_2 vs Water Injection (Identical Injection Rates)

4.2.8 Techno-Economic Evaluation of CHOP Using CO_2-EOR

For the purpose of the economic assessment of a typical CHOP using CO_2-EOR, the following two main cases presented below were considered for the investigation:

1. A difficult production start-up due to low reservoir pressure (kept constant at 1000 psig) with GOR 500 scf/STB. CO_2 injection pressure varying between 1000 psig to 7000 psig;
2. A high pressure reservoir (4000 psig) with constant injection pressure (5000 psig).

Using cost data from various sources **[139, 140, 138, 141, 142]** as indicated in **Table 4.3** which summarizes the cost parameters used in this analysis, the economics of a typical heavy oil development using CO_2-EOR was evaluated taking into account the cost of CO_2, the transportation, equipments, construction and operation costs. The profitability of such development was measured by the net present value (NPV) and return on investment (ROI). The NPV and ROI were estimated by performing a discounted cash flow analysis using the oil production and CO_2 consumption rates from the performance model.

The CAPEX was estimated considering typical requirements for field production equipment, CO_2 compression and transportation facilities, new injection and production wells including drilling and completion costs.

Table 4.3: Key Economics Parameters

Process / Operation	Units	Cost	Source
CAPEX			
CO_2 Purchase Price [5]	$/Mscf	1.05	**[139]**
CO_2 Pipeline cost,	$/ton	1600	
Produced Gas Processing (recycle) [1]	$	84613	**[140]**
Injection Well Cost (new) [2]	$/ft	100	**[138]**
Production Well (new) [2]	$/ft	100	**[138]**
Compressor Cost	$million	20	**[141]**
Compressor Installation	$million	6	**[141]**
Pipeline Construction Cost (Onshore)	$/inch.km	50000	**[144]**
Pipeline Construction (Offshore) -	$/inch.km	100000	**[145]**
OPEX			
Injection Well	$/month	1500	**[142]**
Production Well	$/month	1500	**[142]**]
CO_2 Compression	$/Mscf	0.3	**[146]**
Safety & Monitoring	$/injector/year	10000	
Discount Rates [3]	%	12	
Heavy Oil Price			
Heavy Oil Price	$/STB	72.77	**[147]**
Other			
Duration [4]	Year	20 - 30	

Notes:

1. This is the CAPEX of the recycle CO_2 including treatment and compression facilities.
2. Cost is for a vertical well and includes drilling, completion, production equipment and pipes. The cost of horizontal well is estimated to be 1.5 to 2.5 that of vertical wells **[143].**
3. The NPV of the projects is calculated at a discount rate of 12%, despite that the rates used in similar studies range from 7% to 11% **[69]**.
4. The duration is typical and varies between 20 to 30 years, depending on simulation case.
5. Detailed discussions on the economics of CO_2 capture is provided by Holt et al **[136].**

In the estimated CAPEX shown in **Table 4.4**, the purchase price of CO_2 makes the dominant portion of the amount.

The NPV is estimated using the following expression:

$$NPV(i,\ N) = \left[\sum_{t=0}^{N} \frac{(R_t - OPEX_t)}{(1+i)^t} \right] - CAPEX \qquad (4.1)$$

Where:

NPV = Net Present Value of a time series of cash flows, which is defined as the sum of the Present Values (PVs) minus the capital of expenditure (CAPEX).

R = Cash flow estimated as: Net oil price multiply by the production rate. This represents the yearly cash inflow.

OPEX = Operating cost, which represents the yearly cash outflow.

N = Number of periods.

t = Number of years (time of cash flow).

i = Discount rate.

The ROI is estimated as the Present Values (accumulated gross benefits less ongoing costs) divided by the CAPEX, and is given by the following expression:

$$ROI(i,\ N) = \frac{\left[\sum_{t=0}^{N} \frac{(R_t - OPEX_t)}{(1+i)^t} \right]}{CAPEX} \quad x \quad 100 \qquad (4.2)$$

The payback time is estimated using the initial investment cost (CAPEX) and the minimum achieved annual revenue throughout the life cycle of the field, as represented in the following expression:

$$Payback\ Time = \frac{CAPEX}{Min\ (Annual\,\mathrm{Re}venue)} \qquad (4.3)$$

Table 4.4: High Level Cost Eavaluation of CHOP using CO_2-EOR

CAPEX (1)	**351,561,369**			
OPEX (2)	**156,000**			
Inj Pres (Psig) (4)	**PV (US. Dollars) Million**	**NPV (US. Dollars) Million**	**ROI (%)**	**Payback Time (Year)**
7000	800	448	227	8
6000	622	270	177	8
5000	487	135	139	9
4000	535	183	152	9
3000	433	81	123	10
2000	301	-50	86	12
1000	33	-318	9	23 (3)
Reservoir Pres (Psig) (5)	**PV (US. Dollars) Million**	**NPV (US. Dollars) Million**	**ROI (%)**	**Payback Time (Year)**
800	429	77	122	6
1000	503	152	143	5
2500	1227	875	349	4
3000	1315	964	374	3
4000	2152	1800	612	3
5000	4161	3810	1184	1

Notes:

1. This CAPEX is a high level estimate for illustration only. Cost includes single pipeline (6-inch) and associated equipments cost, CO_2 purchase and other costs as shown in Table 4.3.
2. Similar to the CAPEX, the OPEX is a high level estimate for illustration only. Cost does not include the supply cost of CO_2 which was accounted separately considering the CO_2 requirements for individual cases.
3. Takes into account period of no production beginning at the start-up.
4. Variation of Injection Pressure at Constant Reservoir Pressure (1000 psig) & GOR (500 scf/STB).
5. Variation of Reservoir Pressure at Constant Injection Pressure (5000 psig) & GOR (500 scf/STB).

At low reservoir pressure, it appears as shown in **Table 4.4** that the operation was profitable, when the injection pressure was above 2000 psig, due to the additional recovery that yielded significant revenue, with payback time reducing as the injection pressure increases, high NPV and ROI. **Table 4.4** equally shows the "beneficial" effect of individual displacement process based on the CO_2 demands and the production profile. Miscible displacement was effectively the most profitable option, identifiable from revenue generated in the form of NPV, while providing a high ROI and an expected smaller project payback time, and a substantial percentage of CO_2 sequestration. The analysis assumed that the project owner / operator will dictate a limiting internal rate of return (IRR) that would decide the feasibility of the project. Similarly, the results also confirm as generally speculated that Immiscible Displacement process has very limited economic values due to significant amounts of CO_2 injection required, the low additional production of heavy oil and consequently longer payback time, which in this case can extend up to 22 years. The results in **Table 4.4** may look very optimistic, but even considering the production cost to be $13 to $16 per barrel of heavy oil **[148]**, Miscible Displacement will still provide appreciable benefit as well as reasonable payback time.

With the breakeven cost of CO_2 being the CO_2 purchase price at which the project net present value (NPV) equals zero, using the economic model as in **Table 4.4**, the analysis show that the breakeven cost of CO_2 will vary approximately between $9.5 to $38.5 per Mscf when the heavy oil price varies between $40 to $150 per bbl.

Re-injection of the produced CO_2 will somehow help towards reducing the high investment costs.

5.3 Summary

The findings resulting from this chapter are summarized below:

- Dry CO_2 transportation offshore is possible at low pressure, but recompression will be required for an effective EOR application. Long distance CO_2 transportation offshore can also be achieved at high pressure with CO_2 remaining in dense phase throughout the entire system.
- CO_2-EOR is an effective technique for heavy oil production based on the conditions investigated and discussed in this chapter. The compressed CO_2 at the onshore facilities can be transported subsea at high pressure and injected straight into the reservoir for heavy oil recovery. Results may vary to some extent under certain conditions, depending on the reservoir characteristics and production history; and production could be delayed until mobility of the crude within the reservoir is possible in some cases.

- The performance of the CHOP using CO_2-EOR is influenced by the production history, initial reservoir pressure, GOR, and fluid properties.
- The integrated modelling systems have demonstrated that the CO_2-EOR CHOP phenomenon can be well understood and appreciated when the injection and production systems are integrated together as a single module. Results indicate that during CO_2-EOR application, the CO_2 requirements vary with time throughout the lifetime of the forecast, which corroborate with the claim reported by Balbinski et al **[135]** and Holt et al **[136]**.
- Both Immiscible and Miscible conditions were evaluated and it was clear under the conditions investigated that Miscible process was more efficient and pragmatic than Immiscible process.
- Low heavy oil reservoir pressure with low GOR can be very costly to optimise due to production ‘hold back’ and the momentous energy (injection pressure) required to initiate recovery. The higher the viscosity, the longer the mixing process within the reservoir, and the higher the required injection pressure to facilitate the movement of the heavy oil within the reservoir to the production platform.
- The investigation of CO_2 sequestration during CHOP using CO_2-EOR technique have revealed that lower CO_2 is released in the first few years of the operation, followed by a gradual decline of CO_2 retention after the production peak. The CO_2 retention per barrel was almost constant post peak production and the CO_2 utilisation per barrel of heavy oil increased as the heavy oil in place reduced. The CO_2 returning with the produced heavy oil could be re-injected into the reservoir to minimize the project CAPEX. The recovery factor varied between 8 % to 12 % of the original heavy oil in place, which was within the range reported by Clarke et al **[137]** who suggested a recovery factor using cold production to be between 6 % to 15% of original oil in place (OOIP).
- A comparative analysis between CO_2 and water injection indicates that the heavy oil recovery factor using CO_2 injection could be as double as that of

water injection at peak flow. However, water injection provides a sustained heavy oil production rates throughout the life of field.

- The techno-economic evaluation has shown that Immiscible Displacement during CO_2-EOR may be considered as a high risk investment, particularly at low injection pressure. Miscible displacement is very pragmatic from an operation point of view and have a higher cash flow stream that extends throughout the lifetime of the asset due to continuous production while Immiscible Displacement have a longer payback period due to the time lag between the CO_2 injection and the incremental heavy oil production.

5. IMPROVED MATHEMATICAL MODELLING FOR COLD HEAVY OIL PRODUCTION USING CO_2-EOR TECHNIQUE

Introduction: The use of CO_2 injection to enhance recovery of heavy oil has been investigated and thorough understanding has been gathered based on the detailed simulation works carried out and discussed in the previous chapter.

Having recognized the limitations of the existing models and the needs for developing fit for purpose predictive models for the CHOP using CO_2-EOR technique, this chapter presents the development of an "improved" mathematical formulation for the heavy oil recovery using CO_2 injection.

The word "improved" in this context is used to emphasize the fact that the proposed models are derived from known and well established theories as outlined in relevant sections below, with importance placed on strengthening the areas of deficiency in the existing algorithms and suggesting the applicable operating envelope for which models are best suited.

The modelling is broken down into two (2) parts:

1- The injection system

2- The production system

The proposed models have proved to be consistent with existing theories and the simulation results discussed in previous chapter. The relevance and specificity of those predictions determine how potentially useful the proposed improved models could be.

5.1 Injection System Modelling

Design of the long distance CO_2 pipeline shall take into account the nature and volume of the CO_2 to be transported, the length of the pipeline and the type of terrain. The size of the pipeline dictates the capacity that pipeline can transport from the source to the destination (sink). Complex equations, such as the Weymouth Equation, the Panhandle Equation, and the Modified Panhandle Equation, have been developed for sizing natural gas pipelines in various flow conditions. These equations were used for the hydraulic analysis of the CO_2 transportation covered in chapter 4. These equations relate the volume of the transported gas to various factors involved, hence helping to evaluate the optimum pressure requirements and pipe size for a given CO_2 rate.

5.1.1 Long Distance CO_2 Transportation – Pressure Requirements

Like natural gas, CO_2 flowing in pipelines will also result in energy losses, i.e. Mechanical energy being converted into heat, resulting from friction losses: internal losses due to viscosity effects and losses due to the roughness of the inner wall of the pipeline.

The Weymouth Equation is generally preferred for smaller-diameter lines ($D < 15$ inch) while the Panhandle Equation and the Modified Panhandle Equation are reported to be better for larger-sized and long transmission lines.

There are two distinct types of correlations for calculating friction pressure loss (ΔPf).

1- The first type, adopted by the AGA (American Gas Association), includes Panhandle, Modified Panhandle and Weymouth. These correlations are for single phase gas only. They incorporate a simplified friction factor and flow efficiency.

2- The second type of correlation is based on the friction factor known as the Moody or Fanning and is given by the Fanning Equation.

The pressure gradient due to viscous shear or frictional losses, i.e. Mechanical energy, is presented by Ikoku **[149]** and Katz and Lee **[150]**, in the following expression:

$$\left(\frac{dp}{dL}\right)_f = \rho\frac{d(lw)}{dL} \tag{5.1}$$

Where,

p = Pressure

ρ = Fluid Density

lw = Mechanical energy (loss of work) converted to heat

L = Pipe length

The authors related the lost work per unit length of pipe and the flow variables as indicated below:

$$\frac{d(lw)}{dL} = \frac{fu^2}{2g_c D} \tag{5.2}$$

Where:

u = Flow velocity

D = Pipe diameter

f = Moody friction factor

g = Gravitational acceleration (32.2 ft/s^2)

g_c = Conversion factor (32.2 (lb_m*ft)/(lb_f*s^2))

Substituting **Equation 5.1** into **5.2**, gives the following expression

$$\left(\frac{dp}{dL}\right)_f = \frac{f\rho u^2}{2g_c D} \tag{5.3}$$

Equation 5.3 is a differential equation governing frictional pressure drop in a pipe. Fluid density and velocity are functions of local pressure.

For a long distance pipeline where the three thermal dynamic components could be represented, the pressure gradient expression becomes:

$$\frac{dp}{dL} = \frac{g}{g_c}\rho\sin\theta + \frac{f\rho u^2}{2g_c D} + \frac{\rho u du}{g_c dL} \tag{5.4}$$

The first term is the elevation or potential energy losses, the second term is the frictional losses and the third term is the kinetic energy change. The elevation component is pipe angle dependent and is zero for horizontal flow. The friction loss component applies to any type of flow at any pipe angle and causes a pressure drop in the direction of flow. The acceleration term is generally considered negligible for incompressible flow, however for compressible flow, causes a pressure drop in any locations where there are velocity changes.

The friction term can also be represented in the following expression:

$$\frac{dP}{dL} = \frac{f\rho U^2}{2g_c D} = \frac{P(MW)}{zRT}\frac{fU^2}{2g_c D} \qquad (5.5)$$

Gas is compressible; its density depends on pressure and temperature. Using the real gas law, in the following expression, the density can be calculated:

$$\rho = \frac{m}{v} = \frac{MW\,p}{zRT} \qquad (5.6)$$

Where, m is mass of gas and ρ is gas density. MW is the molecular weight and other terms have their usual meanings.

Considering the steady state flow of single phase CO_2 in a constant-diameter, horizontal pipeline, and taking into account **Equation 5.5**, the mechanical energy Equation, **Equation (5.1),** becomes:

$$\frac{dp}{dL} = \frac{f\rho u^2}{2g_c D} = \frac{p(MW)}{zRT}\frac{fu^2}{2g_c D} \qquad (5.7)$$

Integrating **Equation 5.7** gives the following expression:

$$\int dp = \frac{(MW)\,fu^2}{2Rg_c D}\int \frac{P}{zT}dL \qquad (5.8)$$

If the temperature is assumed to be constant at an average value in a pipeline, $\bar{T}$, and gas deviation factor, $\bar{z}$, is evaluated at average temperature and average pressure, p , **Equation 5.8** can be evaluated over a distance L between upstream pressure, p_1 and downstream pressure, p_2:

$$p_1^2 - p_2^2 = \frac{25\gamma_{CO2} q^2 \overline{T}\overline{z} f L}{D^5} \tag{5.9}$$

Where:

γ_{CO2} = Specific gravity of CO_2

q = Flowrate

$\overline{T}$ = Average temperature or T_m

$\overline{z}$ = Gas deviation factor at $\overline{T}$ (or T_m) and $\overline{P}$ (or P_{avg}) and as shown below:

$$\overline{P} = \frac{2}{3}\left(\frac{P_1^3 - p_2^3}{p_1^2 - p_2^2}\right), \quad \overline{T} = \frac{T_2 - T_1}{\ln\left(\frac{T_1 - T_g}{T_2 - T_g}\right)} + T_g \tag{5.10}$$

C = Constant with a value depending on the units used in the pipeline Equation. If L is in miles and q is in scfd, C = 77.54.

Equation 5.9 can be written in term of flowrate measured at a referenced condition 'b', as follow:

$$q = \frac{CT_b}{p_b}\sqrt{\frac{(p_1^2 - p_2^2)D^5}{\gamma_{CO2}\overline{T}\overline{z} f L}} \tag{5.11}$$

Where, C is a constant with value depending on the units used. If L is in miles and q is in scfd, C = 77.54.

5.1.1.1 Weymouth Equation

Equation 5.11 above takes the following form when the unit of gas rate is scf/h.

$$q_{scf/h} = \frac{3.23T_b}{p_b}\sqrt{\frac{1}{f}}\sqrt{\frac{(p_1^2 - p_2^2)D^5}{\gamma_{CO2}\overline{T}\overline{z}L}} \tag{5.12}$$

Where:

$\sqrt{\frac{1}{f}}$ is termed the transmission factor. The Moody friction factor may be a function of flow rate and pipe roughness. If flow conditions are in the fully turbulent region, 'f' becomes:

$$f = \frac{1}{\left[1.14 - 2\log(e_D)\right]^2} \tag{5.13}$$

Where 'f' depends only on the relative roughness, e_D. When flow conditions are not completely turbulent, 'f' depends on the Reynolds number:

$$\mathrm{Re} = \frac{0.48\, q_{scf/h}\, \gamma_{CO2}}{\mu D} \tag{5.14}$$

Weymouth proposed that 'f' vary as a function of diameter in inches as shown in **Equation 5.15**, in order to avoid the repeated, varied attempts in solving the equations above (i.e. trial and error):

$$f = \frac{0.032}{D^{1/3}} \tag{5.15}$$

Hence, the Weymouth Equation becomes:

$$q_{scf/h} = \frac{18.062 T_b}{p_b} \sqrt{\frac{(p_1^2 - p_2^2) D^{16/3}}{\gamma_{CO2} \bar{T} \bar{z} L}} \tag{5.16}$$

Or in terms of pressure drop:

$$P_1^2 - P_2^2 = \frac{\gamma_g \bar{T} \bar{z} L_1}{D_1^{16/3}} \left(\frac{q_{scf/h} P_b}{18.062 T_b} \right)^2 \tag{5.17}$$

The use of the Weymouth Equation involves the following assumptions:

- No mechanical work;
- Steady flow;
- Isothermal flow (i.e. Constant temperature);

- Constant compressibility factor;
- Horizontal flow;
- No kinetic energy change.

These assumptions can affect accuracy of the results. For example, Weymouth Equation is generally applied to short on-site (within production facility) lines, where the gas velocity and Reynolds number are generally low. These lines can be high pressures, high flow rates and medium sizes.

Isothermal conditions in very long pipelines may overestimate pressure drop in such lines, or perhaps be over-conservative than actually needed. Large pressure loss especially for large-diameter and low-velocity pipelines, are often predicted with Weymouth Equation. Similarly, the inclusion of compressibility factor within the Equation is very important; unlike liquids where the density can be fairly assumed constant in the pipeline, the density of the gas varies along line with local temperature and pressure, and particularly for very long pipeline with undulated route bathymetry where large temperature drop can be encountered.

5.1.1.2 Panhandle A Equation

The Panhandle A pipeline flow Equation assumes the following Reynolds number dependent friction factor:

$$f = \frac{0.085}{\mathrm{Re}^{0.147}} \tag{5.18}$$

The resultant pipeline flow Equation is thus:

$$q_{scf/d} = 435.87 \frac{D^{2.6182}}{\gamma_g^{0.4604}} \left(\frac{T_b}{P_b}\right)^{1.07881} \left[\frac{(p_1^2 - p_2^2)}{\bar{T}\bar{z}L}\right]^{0.5394} \tag{5.19}$$

Where, ‘q’ is the gas flow rate in cubic feet per day (cfd) measured at T_b and P_b, and other terms are the same as in the Weymouth Equation.

5.1.1.3 Panhandle B Equation - (Modified Panhandle)

The Modified Panhandle correlation is a modified version of the original Panhandle Equation and is sometimes referred to as the Panhandle Eastern Correlation or the Panhandle B correlation.

The Panhandle B equation takes into account the following friction factor:

$$f = \frac{0.015}{\mathrm{Re}^{0.0392}} \tag{5.20}$$

The resultant pipeline flow Equation is thus:

$$q_{scf/d} = 737\, D^{2.530} \left(\frac{T_b}{P_b}\right)^{1.02} \left[\frac{(p_1^2 - p_2^2)}{\bar{T}\bar{z}L\gamma_g^{0.961}}\right]^{0.510} \tag{5.21}$$

A general non-iterative pipeline flow Equation is written as:

$$q = a_1\, E \left(\frac{T_b}{P_b}\right)^{a_2} \left[\frac{(p_1^2 - p_2^2)}{\bar{T}\bar{z}L}\right]^{a_3} \left(\frac{1}{\gamma_g}\right)^{a_4} D^{a_5} \tag{5.22}$$

where the units are q in 'cfd' measured at T_b and P_b, $\bar{T}$ in ^{0}R, P in psia, L in miles, and D in inches. The values of the constants are given in **Tables 5.1** and **5.2** below for specific pipeline flow equations.

Table 5.1: Empirical Flow Equation Constant

Equation	a_1	a_2	a_3	a_4	a_5
Weymouth	433.5	1	0.5	0.5	2.667
Panhandle A	435.87	1.0788	0.5394	0.4604	2.618
Panhandle B	737	1.02	0.51	0.49	2.53

Table 5.2: Transmission Factor for Pipeline Flow Equation

Equation	Transmission Factor
Weymouth	$1.1 \times 5.6\ D^{0.167}$
Panhandle A	$0.92 \times 3.44\ \mathrm{Re}^{0.073}$
Panhandle B	$0.90 \times 8.25\ \mathrm{Re}^{0.0196}$

5.1.1.4 Proposed Modification to Panhandle B "Equation 5.21" and Calculation Procedure for CO_2 Pipeline

CO_2, as dense phase, has considerable pressure / temperature influence on the physical properties such as the density, viscosity ...etc. Dense phase is a highly compressible fluid that exhibit properties of both liquid and gas. The dense phase has a viscosity similar to that of a gas, but a density closer to that of a liquid. The dense phase is a favorable condition for transporting CO_2 for enhanced oil recovery.

In this study, using the established theories discussed above, the procedures below have been developed for estimating the minimum amount of CO_2 required to take into account the physical properties of CO_2. The procedures are:

1) Frictional pressure drop to be estimated using **Equation 5.3**, taking into account CO_2 dense phase properties (i.e. Density of CO_2 in dense phase). The density of CO_2 in dense phase can be estimated using **Equation 5.6**, with 'p' be the pressure of CO_2 at any point along the pipeline and should not be less than that of CO_2 in dense phase, i.e. 1073 psia;
2) Assume a range of velocities;
3) Calculate the Reynolds number using **Equation 5.23** below, which takes into account all the physical quantities such as viscosity, velocity, density and surface tension of CO_2.

$$R_e = (W_e)^{0.5} \ (E_o / M)^{0.25} \tag{5.23}$$

Where;

Weber number We,:

$$W_e = \frac{\Delta\rho U_t^{\ 2} D}{\sigma} = \frac{4E_o}{3C_d} \tag{5.24}$$

with C_d = 8/3 for Eotvos number less or equal to 16, or

$$C_d = \frac{2}{3}\sqrt{E_O} \quad for\ (E_O < 16). \tag{5.25}$$

Eotvos number,

$$E_o = \frac{\Delta\rho\, g\, D^2}{\sigma} \tag{5.26}$$

Morton number,

$$M = \frac{g\, \mu^4_{GasDensePhase}}{\Delta\rho\, \sigma^3} \tag{5.27}$$

4) The friction factor is estimated using the proposed formulation,

$$f = \frac{C}{(W_e)^{0.5}\ (E_o / M)^{0.25}} \tag{5.28}$$

and C should be less than 20. A simple linear relationship is established in the form of $f = 0.003C$

5) The CO_2 gas rates calculated using **Equation 5.22** above should not be less than that calculated using the Equation presented by Turner et al **[151]**, in which case the following expression should result:

$$q_{CO2} = a_1\, E\left(\frac{T_b}{P_b}\right)^{a_2} \left[\frac{(p_1^2 - p_2^2)}{\bar{T}\bar{z}L}\right]^{a_3} \left(\frac{1}{\gamma_g}\right)^{a_4} D^{a_5} \geq \frac{3.06(P_{INJ} - P_R)v}{Tz} \tag{5.29}$$

Taking into account the elevation between the two ends, **Equation 5.29** becomes:

$$q_{CO2} = a_1\, E\left(\frac{T_b}{P_b}\right)^{a_2} \left[\frac{(p_1^2 - e^s\ p_2^2)}{\bar{T}\bar{z}L_e}\right]^{a_3} \left(\frac{1}{\gamma_g}\right)^{a_4} D^{a_5} \geq \frac{3.06(P_{INJ} - P_R)v_{sl}A}{Tz} \tag{5.30}$$

Where

$$L_e = \frac{L(e^s - 1)}{s} \tag{5.31}$$

The equivalent length, Le, and the term e^s take into account the elevation difference between the upstream and downstream ends of the pipe segment. The parameter ‘s’ depends upon the gas gravity, gas compressibility factor, the flowing temperature, and the elevation difference. It is defined as follows in (System International) SI units:

$$s = 0.0684\, G \frac{(H_2 - H_1)}{T_f\, Z} \tag{5.32}$$

where

H_1 = Upstream elevation, m
H_2 = Downstream elevation, m
s = Elevation adjustment parameter, dimensionless
e = Base of natural logarithms (e = 2.718…)
T_f = Average gas flowing temperature

G = Gas gravity (e.g.: air = 1.00)

Z = Gas compressibility factor

6) **Optimising the CO_2 demand** - As it was observed, as shown in **Figure 5.1** below, that the gas rate estimated using **Equation 5.22** (orginal Panhandle B) was significantly overpredicted for EOR application, five dataset were generated using a comparative multiple linear statistical regression approach, in view to optimize the gas estimates using **Equation 5.30**. The dataset effectively denote the impact of each empirical flow constant in **Equation 5.30**, particularly parameter ‘a_1’; and the trends are summarized in **Table 5.3** and illustrated in **Figure 5.1**.

Table 5.3: Empirical Flow Equation Constant

Data	a_1	a_2	a_3	a_4	a_5	Comment
Panhandle B (Original)	737	1.02	0.51	0.49	2.53	Original Equation
1st Set	600	0.605	0.379	0.49	3.48	a1, a2, a3, a5 modified
2nd Set	500	1.02	0.51	0.49	2.53	a1 modified
3rd Set	400	1.02	0.51	0.49	2.53	a1 modified
4th Set	400	1.02	0.51	0.49	2.53	a1 modified
5th Set	330	1.02	0.51	0.49	2.53	a1 modified **(proposed)**
6th Set	300	1.02	0.51	0.49	2.53	a1 modified

Reducing 'a_1' in **Equation 5.30** from 737 to 330 was found to provide identical results as modifying a_1, a_2, a_3, and 'a_5' as shown in **Table 5.3** above, and fit suitably with the CO_2 requirement for EOR. Hence, in addition to other proposed modifications already discussed above, it is recommended as part of optimization of CO_2 requirements during CO_2-EOR that parameter 'a_1' in **Equation 5.30** should be 330.

An illustration of the Panhandle B Equation is shown **in Figure 5.1**, in terms of CO_2 injection requirements at different Bottom-hole pressure dictated by EOR, for the set of data evaluated as shown in **Table 5.3.**

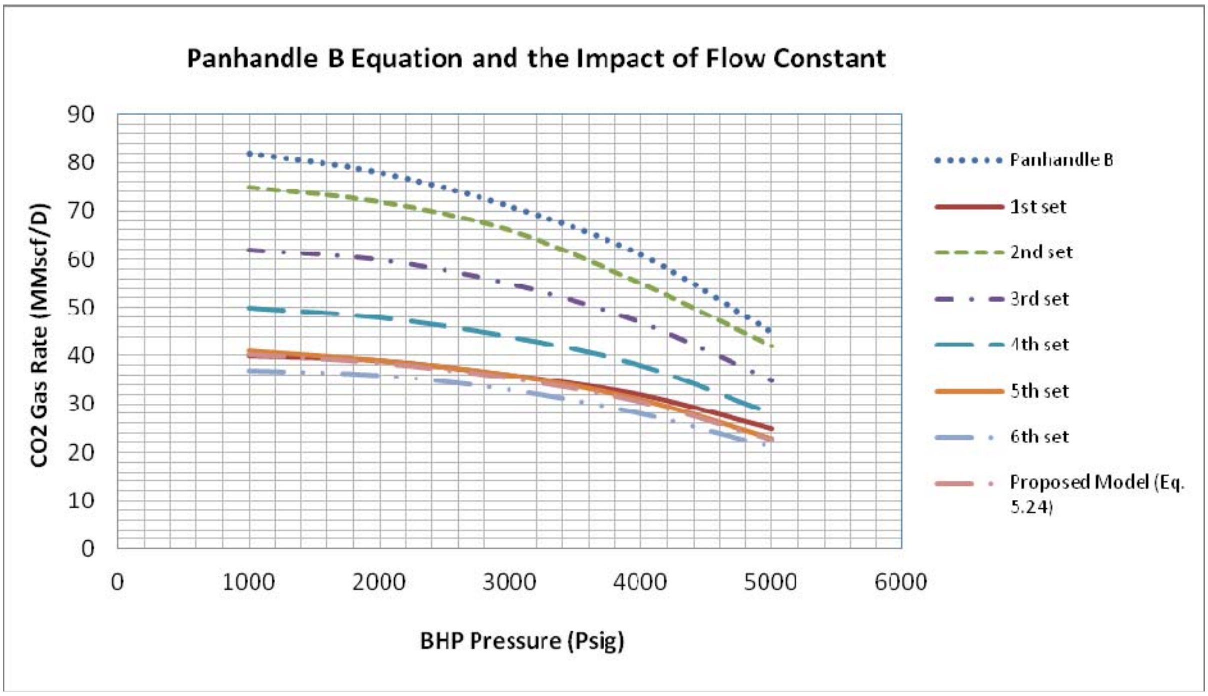


Figure 5.1: CO_2 Injection and the Pressures

5.1.1.5 Minimum CO_2 Rate to Lift Heavy Oil

The minimum gas rate that will allow heavy crude to be lifted continuously and is calculated based on the correlation presented by Turner et al **[151]**.

Considering a heavy oil reservoir in a non-production status as undergoing liquid loading issue, the accumulation of liquids (liquid loading) increases the bottom-hole pressure that reduces the gas production rate.

The pioneer investigators, who analyzed and predicted the minimum gas flow rate capable of removing liquids from the gas production wells, presented two mathematical models to describe the liquid loading problem: the film movement model and entrained drop movement model. Based on field data analysis, they concluded that the film movement model does not represent the controlling liquid transport mechanism **[151]**.

The entrained drop movement model was derived from the terminal free settling velocity of liquid drops and the maximum drop diameter corresponding to the critical Weber number of 30.

The terminal velocity Equation by Turner et al **[151]**, is expressed as:

$$v_{sl} = \frac{k_v \sigma^{1/4} (\rho_L - \rho_g)^{1/4}}{C_d^{1/4} \rho_g^{1/2}} \qquad (5.33)$$

Where:

v_{sl} = Terminal settling velocity

k_v = 1.3 as per Turner et al. (1969), however to account for the CO_2 in dense phase, it was found as part of this research study that k value in the order of 8.4 was more suitable for EOR.

σ = Interfacial tension

ρ_g = Gas density

ρ_L = Liquid density

C_d = Drag coefficient, recommended by the authors **[151]** to be 0.44

According to the authors, gas will continuously remove liquids from the well until its velocity drops below the terminal velocity. The minimum gas flow rate for continuous liquid removal was expressed as follow.

$$Q_{gm} = \frac{3.06 p v_{sl} A}{Tz} \qquad (5.34)$$

Q_{gm} = Minimum required gas flow for liquid removal

p = Pressure at depth of interest

A = Cross sectional area of the pipe

T = Temperature

z = Gas compressibility factor

As part of this research study, **Equation 5.34**, was modified to take into account the pressure difference between the injection and the reservoir pressure, hence **Equation 5.34** becomes:

$$Q_{gm} = \frac{C_E (P_{INJ} - P_R) v_{sl} A}{Tz} \qquad (5.35)$$

Where:

C_E = This parameter is named in this study as the EOR constant, as the original value has been improved to suit the EOR application.

P_{INJ} = Injection Pressure

P_R = Reservoir Pressure

The original Turner et al. constant of 3.06 was amended as it was established that the output from the original formulation demarcates widely from the zone of operability of EOR. A range of value was investigated as shown in **Table 5.4** below.

Table 5.4: Proposed Model and the EOR Constant

Equation / Data-set	**C_E Value**	**Comment**
Turner et al. (Original)	3.06	Original Equation, underpredict the CO_2 requirements for EOR
1st Set	1	Not suitable with the proposed model
2nd Set	2	Not suitable with the proposed model
3rd Set	3	Not suitable with the proposed model
4th Set	4.3	**Proposed value**
5th Set	5	May underestimate the boundary of stability
6th Set	6	May underestimate the boundary of stability

An illustration of Turner et al. with the six dataset presented in **Table 5.4** is shown below in **Figure 5.2**, in terms of the CO_2 injection requirements at different Bottom-hole pressures.

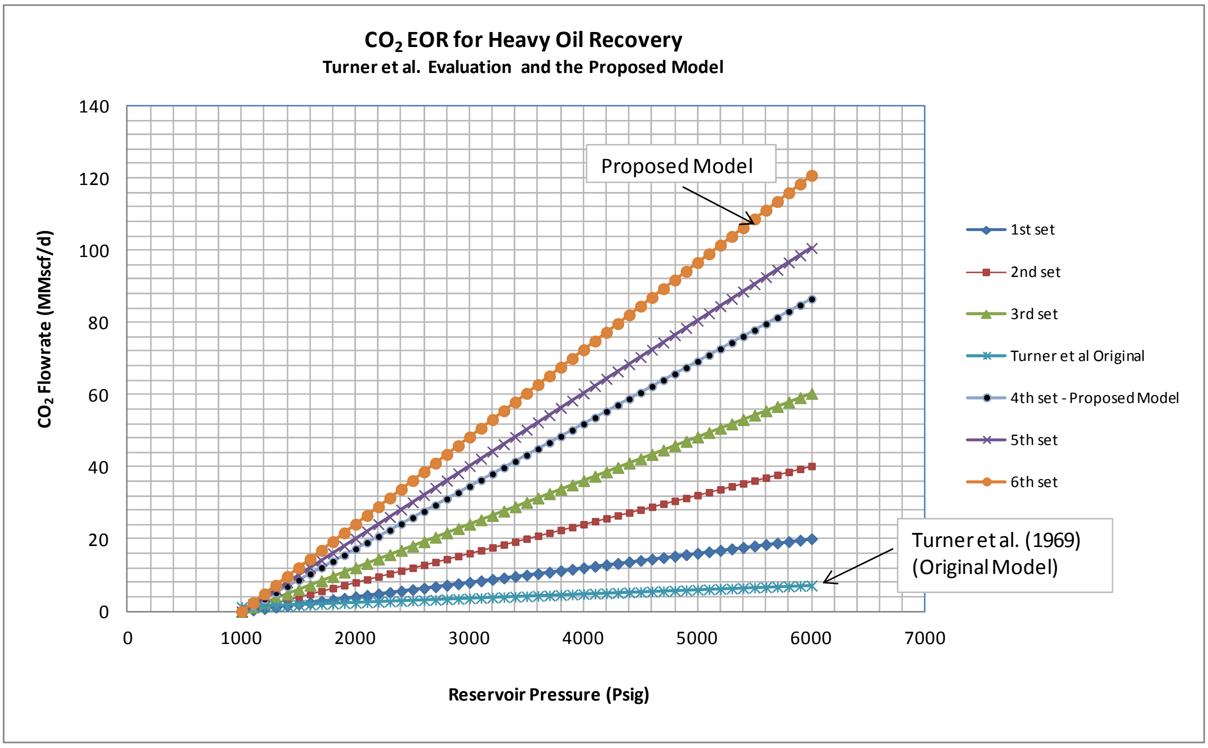


Figure 5.2: Modified Turner et al. with Various C_E Value

Results from the original Panhandle B Equation are plotted against the original Turner et al. (1969); as shown in **Figure 5.3** below, it is apparent that the operating envelope and optimum operating point for CHOP using CO_2 injection cannot be established as the two models fall out of phase.

Effectively, the original Panhandle B equation broadly over-predicts the CO_2 requirements for EOR, while the current Turner et al. model under-predicts the minimum CO_2 required to lift the heavy crude at various bottom-hole pressure.

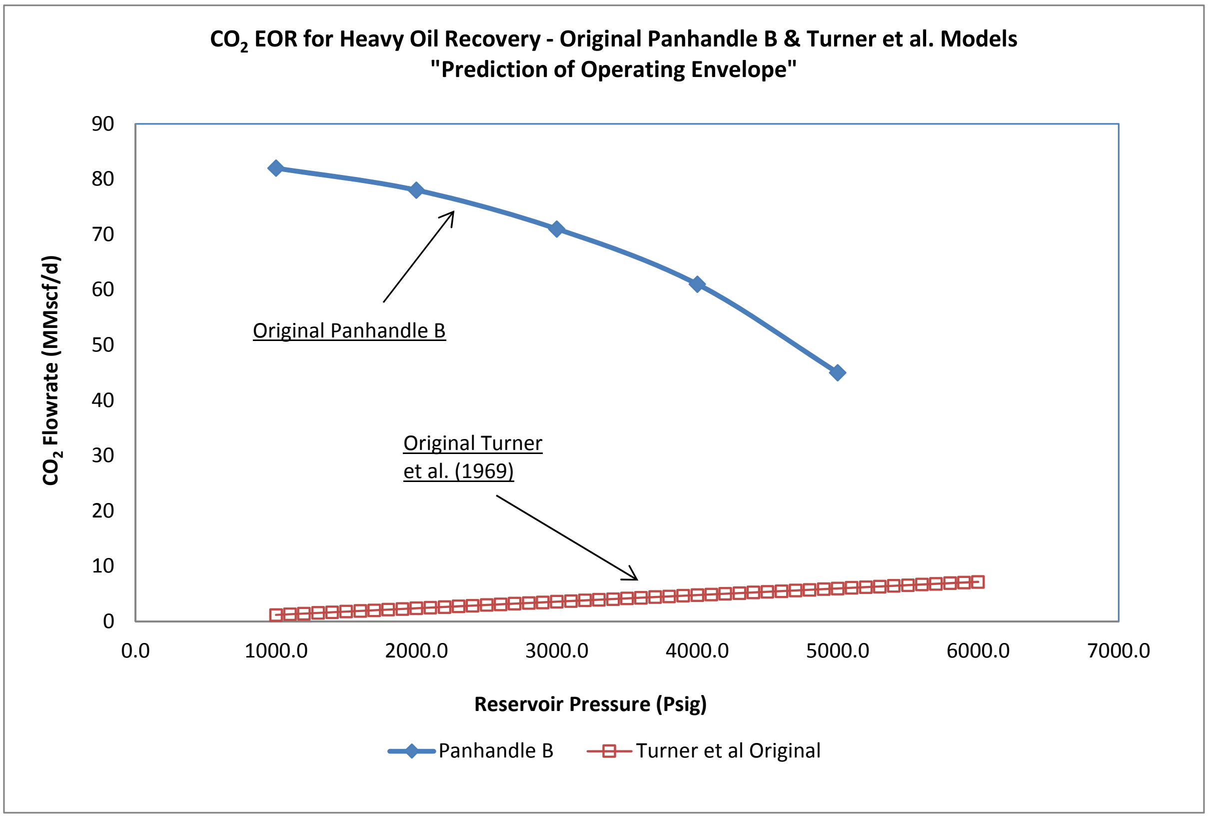


Figure 5.3: CHOP using CO_2-EOR – Original Panhandle B & Turner et al. Models

However, the output from the proposed models (modified Panhandle B and Turner et al.) is presented in **Figure 5.4** below.

Fundamentally, integrating the proposed trends from **Figure 5.1** and **Figure 5.2** gives an operating envelope, with a range of bottom-hole pressure against various CO_2 injection rates.

The proposed correlation, modified from the formulation presented by Turner et al **[151]**, is used to set the criteria for minimum CO_2 requirements for heavy oil recovery and confirm findings from the simulation results discussed in chapter 4 that Immiscible process, i.e. Pressure below 1073 psig is not suitable or advisable for heavy oil recovery using CO_2-EOR.

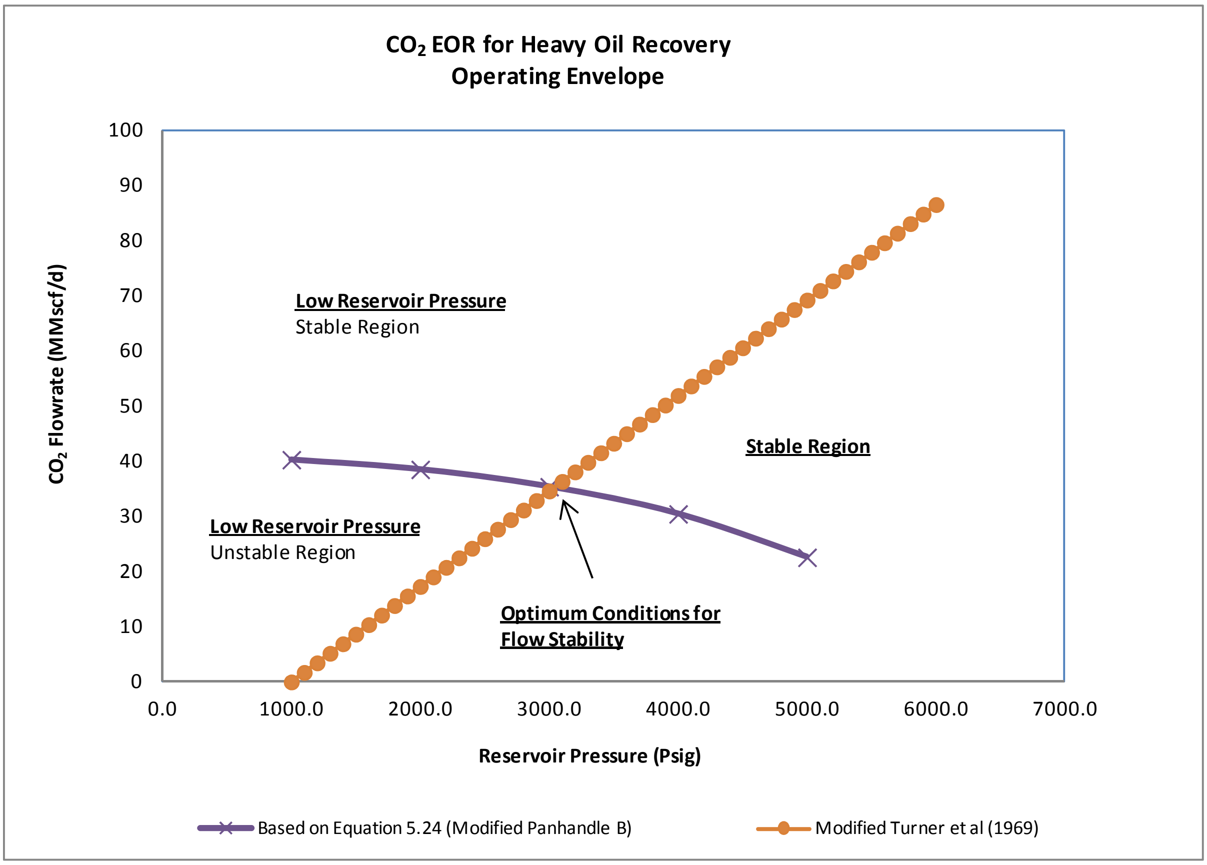


Figure 5.4: CHOP using CO_2-EOR – Operating Envelope of the Injection System

Hence, the final expression taking into account the elevation/depth difference, becomes:

$$Q_{gm} = \frac{4.3\,(P_{INJ} - e^{s}\,P_R)\,v_{sl}\,A}{Tz\,L_e} \qquad (5.36)$$

5.2 Production System Modelling

This section presents the mathematical modelling of the production system and guide through the theories use as a foundation in making feasible predictions.

5.2.1 Pressure Drop Calculation

Flow through a typical production system will be characterized by the following stages or components:

1) Flow through porous medium
2) Flow through vertical or directional wellbore

3) Flow through choke
4) Flow through surface line

A schematic of a simple production system is shown in **Figure 5.5**.

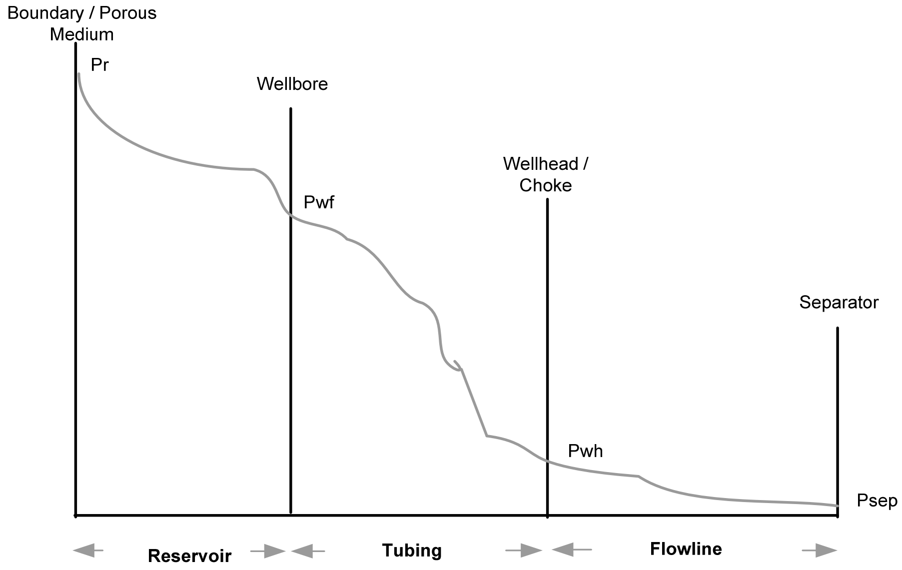


Figure 5.5: Representation of Pressure Losses across a Production System

The production system can be segmented into two main components:

1) Surface component

2) Sub-surface component.

The surface component includes the choke and surface pipeline. The sub-surface component includes the reservoir and tubing.

5.2.1.1 Sub-surface Component

<u>Bottom-hole Pressure</u>

The total pressure at the bottom of the tubing is a function of flowrate and the following pressure elements:

1) Wellhead back pressure;
2) Hydrostatic pressure (i.e. gravity and elevation change across the tubing);
3) Friction losses (i.e. viscous drag and slippage)

For a given production rate, the bottom-hole pressure can be calculated in two ways:

1) Reservoir component - using inflow equations, represented by the following simple expression,

$$P_{wf} = P_r - \Delta P_r \tag{5.37}$$

ΔP_r is the pressure loss across the reservoir which is function of flowrate (Q), hence a plot of P_{wf} vs. Q will be the Inflow Performance Curve or relationship (IPR)

2) Tubing component - using multiphase flow correlations for pipes and chokes and surface lines.

$$P_{wf} = P_{out} + \Delta P_{tubing} + \Delta P_{choke} + \Delta P_{surface\ Line} \tag{5.38}$$

The pressure losses across tubing, choke and surface lines are all function of flowrate (Q), hence a plot of P_{wf} vs. Q will be the Outflow Performance Curve or relationship (OPR)

These two different ways of calculating P_{wf} result in two curves known as the IPR and OPR. The crossed point of these two curves gives the production rate and the corresponding bottom-hole pressure for the production system. Production will be impossible when there is no crossed point between these two curves. This may reflect inadequate reservoir pressure to lift the fluid out of the well, and can be the result of declining reservoir pressure or too much energy loss in the tubing, choke, or surface line. In such conditions, a recompletion where possible or an artificial lift method is required.

Wellhead Pressure

Similarly, the wellhead pressure can be estimated in two different ways, i.e. surface and sub-surface components.

Surface components – This is made of the choke and the surface pipeline. For any production rate, the wellhead pressure can be estimated by adding the pressure loss across the surface line and the choke to the reservoir outlet pressure (P_{out}), as shown in **Equation 5.39** below:

$$P_{wh} = P_{out} + \Delta P_{choke} + \Delta P_{surface\,Line} \tag{5.39}$$

Pressure losses across choke and surface line are function of flowrate (Q). P_{wh} vs. Q using **Equation 5.39** will provide the outflow performance curve or relationship.

Sub-surface component - The wellhead pressure can be estimated by the following expression:

$$P_{wh} = P_r - \Delta P_{reservoir} + \Delta P_{tubing} \tag{5.40}$$

Pressure losses across the reservoir and tubing are function of flowrate (Q). P_{wh} vs. Q using **Equation 5.40** will provide the inflow performance curve / relationship.

Reservoir Inflow Equation

Single phase liquid flow may result when the bottom-hole pressure is higher than the bubble point pressure, due to gas dissolving in the oil. The production can be calculated using Darcy's Equation from a vertical well with closed outer boundary **[152]**. **Equation 5.41** below is the simplest IPR equation that considers a direct linear relationship between the inflow into a well and the pressure differential between the reservoir and the wellbore, and is generally termed 'drawdown, i.e. $(P_r - P_{wf})$

$$q_O = PI\ (P_r - P_{wf}) \tag{5.41}$$

Where;

$$PI = \frac{7.08 \times 10^{-3}\ k_o\ h}{\mu_o\ B_O\ (\ln r_o / r_w - 0.75 + S^{\#} + a'q)} \tag{5.42}$$

PI = Productivity index stb/d/psi

k_o = Effective permeability (md)

h = Effective feet of oil pay (ft)

P_r = Average reservoir pressure (psia)

P_{wf} = Wellbore flowing pressure at centre of perforations (psia)

q_O = Oil flow rate (STB/D)

r_e = Radius of drainage (ft)

r_w = Radius of wellbore (ft)

$S^{\#}$ = Total skin

a'q = Turbulent flow term (The a'q term is normally not significant for low permeability wells and low flow rates)

μ_o = Viscosity (cp) at average pressure of (P, + P_{wf}) / 2

B_o = Formation volume factor at average pressure

For a horizontal well, Joshi's Equation **[153]** below can be used.

$$q_O = PI\ (P_e - P_{wf}) \qquad (5.43)$$

Where:

$$PI = \frac{2\pi k_H h}{B\mu\left[\ln\left[\left[1+\left[\frac{2r_e}{L}\right]^2\right]^{1/2}+\frac{2r_e}{L}\right]+\frac{\beta h}{L}\ln\left[\frac{\beta h}{2\pi r_w}\right]\right]\left[1+\frac{S_H}{\ln\left[\frac{r_e}{r_w}\right]}\right]} \qquad (5.44)$$

And **;**

$$\beta = \sqrt{K_H / K_V} \qquad (5.45)$$

K_V = Vertical Permeability (md)

K_H = Horizontal Permeability (md)

L = Horizontal Well Length (ft)

<u>Vogel's Equation for Oil Reservoirs</u>

A simplified solution to the two phase flow problem was proposed by Vogel

[154], to account for two phase flow in the reservoir (i.e. saturation effects):

$$q_O / q_{\max} = 1 - 0.2 \left[\frac{P_{wf}}{P_r} \right] - 0.8 \left[\frac{P_{wf}}{P_r} \right]^2 \tag{5.46}$$

Where:

q_o = Oil production rate

qmax = Maximum liquid production rate

The straight line IPR, described above, is not applicable for two phase flow (gas and liquid) in the reservoir.

Generally, when the Bottom-hole Flowing Pressure (BHFP or BHP)) is above the bubble point, the normal straight line **Equation 5.43** can be used:

However, when BHP drops below the bubble point, the modified Vogel Equation can be used:

$$q_O / q_{\max} = J \ (P_r - P_{wf}) + \frac{J\,P}{1.8} \left[1 - 0.2 \left[\frac{P_{wf}}{P_b} \right] - 0.8 \left[\frac{P_{wf}}{P_b} \right]^2 \right] \tag{5.47}$$

Where 'J' is the same as 'PI'

Equation 5.48 and **5.49** were provided to take into account water production, and assuming that oil is produced from a different zone to the water:

$$q_w = PI \ (P_r - P_{wf}) \tag{5.48}$$

$$q_O = q_{o\_\max} \left[1 - 0.2 \left[\frac{P_{wf}}{P_b} \right] - 0.8 \left[\frac{P_{wf}}{P_b} \right]^2 \right] \tag{5.49}$$

<u>Fetkovich Method, [155]</u>

Fetkovich **[155]**, proposed the following relationship and expressions:

$$q_O = J_o^{'} \ (P_r^2 - P_{wf}^2)^n \tag{5.50}$$

Where:

n = Exponent of inflow performance curve

For reservoir pressures above bubble point pressures, the inflow performance curves can be derived using the following **Equation 5.51**:

$$q_O = J_o^{'} \, (P_r^2 - P_{wf}^2)^n - J \, (P_r - P_b) \tag{5.51}$$

The maximum flowrate of a well can be determined using the following **Equation 5.52**:

$$q_{\max} = q_o \; / \left[1 - \left[\frac{P_{wf}}{P_r} \right]^2 \right]^n \tag{5.52}$$

<u>Standing's Method, [156]</u>

Standing's Method **[156]**, has been developed based on Vogel's Equation, considering the definition of productivity index and the assumption that fluid saturation should be identical everywhere in the reservoir.

The expressions involved in Standing's Method **[156]**, are presented below:

$$\frac{J *_{future}}{J *_{present}} = \frac{\left[\dfrac{k_{ro}}{\mu_o \, B_o} \right]_{future}}{\left[\dfrac{k_{ro}}{\mu_o \, B_o} \right]_{present}} \tag{5.53}$$

And

$$q_{future} = J *_{future} P_{future} \left[1 - 0.2 \left[\frac{P_{wf}}{P_{future}} \right] - 0.8 \left[\frac{P_{wf}}{P_{future}} \right]^2 \right] \tag{5.54}$$

where:

J* = PI at minimal (zero) drawdown (i.e. where two phase flow effects are negligible)

k_{ro} = Relative permeability to oil,

μ_0 = Oil viscosity

B_o = Oil formation volume factor

Multiphase Correlations For Flow in Wellbore

Nowadays, a large number of correlations are available for modelling the production system; however, none of them can provide satisfactory results across a wide range of conditions.

A concise summary of some of the well known vertical wellbore correlations is provided below:

Beggs and Brill Correlation [157]

Developed using air-water two phase flow experiments, the Beggs and Brill correlation is applicable for a wide range of pipe inclination angles and the terms involved can be estimated using the following procedure:

The mixture superficial velocity is expressed as:

$$U_M = U_{SL} + U_{SG} \tag{5.55}$$

The no-slip holdup is estimated using the following expression:

$$\lambda_{ns} = \frac{U_{SL}}{U_{SL} + U_{SG}} \tag{5.56}$$

Froude number, N_{FR}:

$$N_{FR} = \frac{U_M{}^2}{g\,d} \tag{5.57}$$

Liquid velocity number:

$$N_{Lv} = U_{SL} \left(\frac{\rho_L}{g\,\sigma_L} \right\}^{0.25} \tag{5.58}$$

The following parameters are estimated to establish the corresponding flow regime, L_1, L_2, L_3, and L_4:

$$L_1 = 316\,\lambda_{ns}^{0.302}\,; \quad L_2 = 0.0009252\,\lambda_{ns}^{-2.4684}\,;\; L_3 = 0.10\lambda_{ns}^{-1.4516}\,;\; L_4 = 0.5\lambda_{ns}^{-6.738} \tag{5.59}$$

The flow pattern is then determined using the following limits:

Segregated: $\lambda_{ns} < 0.01 \; and \; N_{FR} < L_1 \quad or \;\; \lambda_{ns} \geq 0.01 \; and \; N_{FR} < L_2$

Transition: $\lambda_{ns} \geq 0.01 \; and \; L_2 < N_{FR} \leq L_2$

Intermittent: $0.01 \leq \lambda_{ns} < 0.4 \, and \;\; L_3 < N_{FR} \leq L_1 \quad or \;\; \lambda_{ns} \geq 0.4 \; and \; L_3 < N_{FR} \leq L_4$

Distributed: $\lambda_{ns} < 0.4 \; and \; N_{FR} \geq L_1 \quad or \;\; \lambda_{ns} \geq 0.4 \; and \; N_{FR} > L_2$

The horizontal liquid holdup parameter, λ_0, is expressed as:

$$\lambda_o = \frac{a\,\lambda_{ns}^{b}}{N_{FR}{}^{c}} \tag{5.60}$$

where a, b, and c are empirical constant, with value expressed for each flow pattern as shown below in **Table 5.5**:

Table 5.5: Beggs & Brill, a, b, c Constant

Flow Pattern	a	b	c
Segregated	**0.98**	**0.4846**	**0.0868**
Intermittent	**0.845**	**0.5351**	**0.0173**
Distributed	**1.065**	**0.5824**	**0.0609**

The inclination correction factor coefficient is presented as:

$$C = (1-\lambda_{ns})\ln(d\,\lambda_{ns}^{e}\,N_{Lv}{}^{f}\,N_{FR}{}^{g}) \tag{5.61}$$

where d, e, f, and g are empirical constant, with value expressed for each flow condition as in **Table 5.6** below:

Table 5.6: Beggs & Brill, d, e, f, g Constant

Flow Pattern	d	e	f	g
Segregated uphill	**0.011**	**-3.768**	**3.539**	**-1.614**
Intermittent uphill	**2.96**	**0.305**	**-0.4473**	**0.0978**
Distributed uphill	No Correction C = O			

The liquid hold up inclination factor is estimated using the following expression:

$$\psi = 1 + c(\sin(1.8\theta) - 0.333\sin^{3}(1.8\theta)) \tag{5.62}$$

Where:

θ is the inclination angle, reflecting a deviation from the horizontal axis.

The liquid holdup is estimated using **Equation 5.63** below

$$\lambda = \lambda_o \psi \tag{5.63}$$

The Palmer correction factor is applicable in the following range:

λ = 0.918 * λ applicable for uphill flow regime

λ = 0.541 . λ applicable for downhill flow regime

The following expression is used during transitional flow regime:

$$\lambda = a\,\lambda_1 + (1-a)\,\lambda_2; \quad a = \frac{L_3 - N_{FR}}{L_3 - L_2} \tag{5.64}$$

Where:

λ_1 is the liquid holdup, applicable for segregated flow,

λ_2 is the liquid holdup, applicable for intermittent flow.

(1) Frictional pressure gradient

The frictional factor ratio is expressed in a following form:

$$\frac{f_{tp}}{f_{ns}} = e^S \tag{5.65}$$

where:

$$S = \frac{\ln(y)}{-0.0523 + 3.182\ln(y) - 0.8725[\ln(y)]^2 + 0.01853\,[\ln(y)]^4} \tag{5.66}$$

Where, "y" is expressed as:

$$y = \frac{\lambda_{ns}}{\lambda^2} \tag{5.67}$$

The no-slip Reynolds number is expressed as follows:

$$(N_{\mathrm{Re}})_{ns} = \frac{\rho_{ns}\,U_M\,D}{\mu_{ns}} \tag{5.68}$$

Equation 5.68 (no-slip Reynolds number) and the Moody's diagram are used to establish the no-slip friction factor, f_{ns}',.

The no-slip friction factor, f_{ns}', can be translated into Fanning friction factor by, $f_{ns} = f_{ns}' / 4$.

A general expression for the two phase friction factor is: $f_{tp} = f_{ns} \dfrac{f_{tp}}{f_{ns}}$

The friction pressure gradient is obtained using the following formula:

$$\left[\frac{dp}{dx}\right]_f = \frac{2 f_{tp}\, \rho_{ns}\, U_M^{\;2}}{D} \quad (5.69)$$

Hagedorn and Brown Correlation [158]

The correlations are made of Hagedorn-Brown correlation for slug flow and Griffith correlation for bubble flow; and are applicable for vertical wells only.

The switching criterion is the flow regime, and the parameters to guide proceeding with either Hagedorn-Brown correlation for slug flow or Griffith correlation for bubble flow are presented below:

$$A = 1.071 - \frac{0.2218(U_{SL} + U_{SG})^2}{D\,(0.3048)^2} \quad (5.70)$$

If A < 0.13, then A = 0.13

$$B = \frac{U_{SG}}{U_{SL} + U_{SG}} \quad (5.71)$$

Hagedorn and Brown Correlation is used for positive B-A, and Griffith correlation for negative B-A.

Griffith correlation, [159]

The key expressions involved in Griffith correlation are presented below:

$$\lambda = 1 - 0.5\left[1 + \frac{U_M}{U_S} - \sqrt{\left[1 + \frac{U_M}{U_S}\right]^2 - 4\left(\frac{U_{SG}}{U_S}\right)}\right] \quad (5.72)$$

$$U_S = 0.8 \;*\; 0.3048 \quad (5.73)$$

Hagedorn-Brown correlation:

The calculation steps are summarized in the following expressions below:

The liquid viscosity number and coefficient can be obtained using the following terms:

$$N_L = \mu_L \left[\frac{g}{\rho_L \, \sigma_L^3} \right]^{1/4} \quad (5.74)$$

$$CN_L = \frac{0.0019 + 0.0322 \, N_L - 0.6642 \, N_L^2 + 4.9951 \, N_L^3}{1 - 10.0147 \, N_L + 33.8696 \, N_L^2 + 277.2817 \, N_L^3} \quad (5.75)$$

If $N_L <= $ **0.002,** then $CN_L =$ **0.0019**

If $N_L >= $ **0.4,** then, $CN_L =$ **0.0115**

The expressions for the liquid, gas velocity number, and pipe diameter dimensionless number are presented below:

$$N_{LV} = U_{SL} \left[\frac{\rho_L}{g \, \sigma_L^3} \right]^{1/4} \quad (5.76)$$

$$N_{GV} = U_{SG} \left[\frac{\rho_L}{g \, \sigma_L^3} \right]^{1/4} \quad (5.77)$$

$$\phi = \frac{N_{LV}}{N_{GV}^{0.575}} \left[\frac{P}{14.7} \right]^{0.1} \left[\frac{CN_L}{N_d} \right] \quad (5.78)$$

$$\frac{\lambda}{\psi} = \left[\frac{0.0047 + 1123.32 \, \phi + 729489.64 \, \phi^2}{1 + 1097.1566 \, \phi + 722153.97 \, \phi^2} \right] \quad (5.79)$$

The secondary correction factor is expressed as:

$$\phi = \frac{N_{GV} \, N_L^{0.380}}{N_d^{.2.14}} \quad (5.80)$$

$$\psi = \frac{1.0886 - 69.9473\,\phi + 2334.3497\,\phi^2 - 12896.683\,\phi^3}{1 - 53.4401\phi + 1517.9369\,\phi^2 - 8419.8115\,\phi^3} \qquad (5.81)$$

The expression for the liquid holdup is:

$$\lambda = \frac{\lambda}{\psi}\,\psi \qquad (5.82)$$

The frictional pressure gradient is estimated using the following expression:

$$\left[\frac{dp}{dx}\right]_f = \frac{2f\ \rho_{ns}\ U_M^2}{D}\,\frac{\rho_{ns}}{\rho_s} \qquad (5.83)$$

Where:

f = Fanning friction factor

ρ_{ns} = no-slip average of densities

ρ_s = slip average of densities

Grav Correlations [160]

Vertical flow correlation for gas condensate wells developed by Gray is summarized within the following expressions below **[160]**.

$$dP' = \frac{g}{g_c}\,(\xi\,\rho_G + (1-\xi)\,\rho_L)\,dh + \frac{f_t\,G^2}{2\,g_c\,D\,P_{mf}\,dh} + \frac{G^2}{g_c}\,d\left[\frac{1}{\rho_{mi}}\right] \qquad (5.84)$$

Where;

ξ is the gas volume fraction and is estimated as follows:

$$\xi = \frac{1 - \exp\left\{-0.2314\left[N_V\left[1 + \frac{202.0}{N_D}\right]\right]^B\right\}}{R+1} \qquad (5.85)$$

$$B = 0.0814\left[1 - 0.0554\,\ln\left[1 + \frac{730\,R}{R+1}\right]\right] \qquad (5.86)$$

$$N_V = \frac{\rho_M^2 \, U_{SM}^2}{g\,\tau(\rho_L - \rho_G)} \tag{5.87}$$

$$N_D = \frac{g\,(\rho_L - \rho_G)\,D^2}{\tau} \tag{5.88}$$

$$R = \frac{U_{SO} + U_{SW}}{U_{SG}} \tag{5.89}$$

The applicable correlations for estimating pressure drop across vertical wellbore are presented in **Table 5.7** below, with their respective characteristics with respect to their relationship to slippage between phases and flow pattern.

Table 5.7: Applicable Pressure Drop Correlations for Wellbore

Correlation By:	Reference	General Considerations (Yes / No)	
		Slippage between Phases	Flow Pattern
Poettmann and Carpenter (1952)	[161]	No	No
Baxendell and Thomas (1961)	[162]	No	No
Fancher and Brown (1963)	[163]	No	No
Hagedorn and Brown (1965)	[158]	Yes	No
Gray (1978)	[160]	Yes	No
Asheim (1986)	[164]	Yes	No
Duns and Ros (1963)	[165]	Yes	Yes
Orkiszewski (1967)	[166]	Yes	Yes
Aziz et al (1972)	[167]	Yes	Yes
Beggs and Brill (1973)	[157]	Yes	Yes
Mukherjee and Brill (1985)	[168]	Yes	Yes

5.2.1.2 Surface Component

Multiphase Flow Through Choke

Choke flow generally operate in "Critical" or "Sonic" flow conditions (i.e., the velocity of the fluids through the choke reaches a level identical to the velocity of sound), with the aim to restrict flow to the desired rate. Flow then becomes independent of downstream disturbance of pressure, temperature, or density because the disturbance cannot travel in the upstream direction.

The rate of multiphase flow through a choke and the upstream pressure are according to Gilbert **[169]**, Baxendell **[170]**, Achong **[171]** and Ros **[172]**, correlated by the following relationship:

$$P_1 = \frac{A q_L R_P^B}{d^C} \tag{5.90}$$

where:

P_I = Upstream pressure which is also known as the Wellhead pressure

q_L = Liquid production rate,

Rp = Producing gas/liquid ratio,

d = Choke diameter

A,B,C = Empirical coefficients given in **Table 5.8** below

Table 5.8: Empirical Constant for Two Phase Critical Flow Correlations

Correlation	Reference	A	B	C
Gilbert (1954)	[169]	10.0	0.546	1.89
Ros (1960)	[172]	17.4	0.5	2.0
Baxendell (1967]	[170]	9.56	0.546	1.93
Achong (1961)	[171]	3.82	0.65	1.88

D = ID of flow conduit

f_t = Two phase flow friction factor

G = Mass velocity

h = Depth

P = Pressure

q = Flow rate

R = Superficial liquid / gas ratio

S = Specific gravity

S_G = Gas gravity

t = Temperature

V, U = Velocity

P = Density

т = Mixture surface tension

Subscripts:

f = Friction effect

G = Gas phase

i = Inertia effect

L = Liquid phase

M = Gas / liquid ratio

o =Hydrocarbon condensate

s = Superficial value

w = Free-water phase

Multiphase Flow Surface Flowline

The Bernoulli expression shown below is a representation of incompressible fluid in motion:

$$\frac{U^2}{2g} + h + \frac{P}{\rho g} = C \tag{5.91}$$

Where:

g = Gravity acceleration constant

U = Velocity of the fluid, and

H = Height above an arbitrary datum

C = Constant along any streamline in the flow, but varies from streamline to streamline.

The pressure required to transport a specified volume of fluid from point A to point B will consist of the following components:

1) Frictional component
2) Elevation component

3) Pipe delivery pressure

The pressure drop along the flowline is expressed as:

$$\Delta P = \Delta P_f + \Delta P_{el} + \Delta P_{acc} \tag{5.92}$$

where:

ΔP_f = Pressure drop due to friction

ΔP_{el} = Pressure drop due to elevation pressure (hydrostatic head loss)

ΔP_{acc} = Pressure drop due to acceleration of the fluids (generally insignificant, hence will be ignored)

<u>Pressure Drop due to Friction</u>

$$\Delta P = f_{tp} \frac{L}{D} \rho_m \frac{U_m^2}{2} \tag{5.93}$$

where:

f_{tp} = Two phase friction factor

L = Pipeline length

D = Diameter

U_m = mixture velocity

ρ = Slip mixture density

$$\rho_{slip} = \rho_L H_L + \rho_G H_G \tag{5.94}$$

<u>Pressure Drop due to Elevation</u>

$$\Delta P_{el} = \rho_m g L \sin\theta \tag{5.95}$$

where:

L = segment length

g = acceleration due to gravity

θ = angle of segment to horizontal

ρ_m = in-situ mixture density

The friction factor depends on the Reynolds number *"Re"*, and the relative roughness *e/D* of the pipe wall,

$$f = f\left(\mathrm{Re}, \frac{e}{D}\right) \tag{5.96}$$

Where Laminar flow regime exists, i.e. Re < 2000, 'f' can be estimated using the following expression:

$$f = \frac{64}{\mathrm{Re}} \tag{5.97}$$

Where Turbulent flow regime exists, i.e. Re > 3000, 'f' can be estimated using the popular Colebrook expression:

$$\frac{1}{\sqrt{f}} = -2\log\left(\frac{e/D}{3.7} + \frac{2.51}{\mathrm{Re}\sqrt{f}}\right) \tag{5.98}$$

The Moody diagram, which is known to be a relationship between the Colebrook Equation and the Reynolds number "Re", is shown in **Figure 5.6** below:

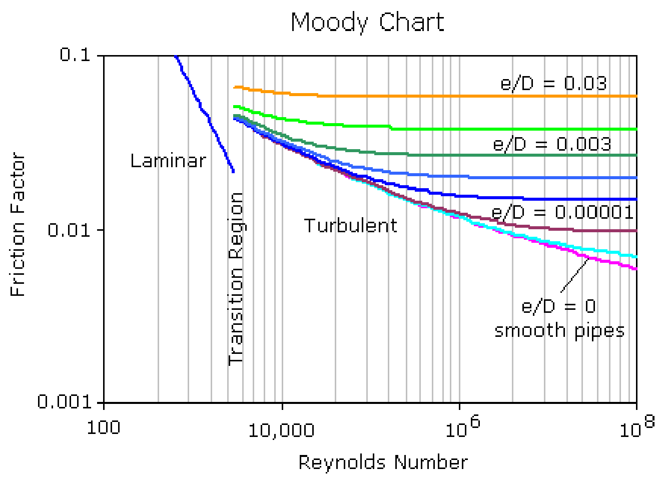


Figure 5.6: Moody Diagram

Pressure Drop or Required Inlet Pressure - Calculation Procedure:

1- Calculate the phase velocity, mixture velocity, mixture density (taken account of phase slippage);
2- Calculate the Reynolds number;
3- Determine the friction factor using the proposed model, Colebrook-White method or using the Moody Chart for single gas phase only;
4- Evaluate the frictional pressure loss term;
5- Evaluate the elevation pressure loss term;
6- Add 4 and 5 above to establish the total pressure drop term per pipe length;
7- For a given pipe length, evaluate the total pressure drop;
8- Knowing the outlet pressure and the total pressure drop, calculate the required inlet pipeline pressure.

Prediction of pressure drop in pipe dated back from 1952 when a predictive approach was published by Poettmann and Carpenter **[161]**. Thereafter, many attempts have been made, giving birth to more complex mathematical models.

The existing pressure drop correlations are generally classified into three categories based on the adopted concept.

1) **Homogeneous Flow Model**: In this case, the multiphase mixture is assumed to behave like a homogeneous single phase fluid, with no-slip or difference between phase in-situ velocities. The work of Poettmann and Carpenter **[161]**, Baxendell and Thomas **[162]**, Tek **[173]**, Fancher and Brown **[163]** and Hagedorn and Brown **[158]** fall within this group.

2) **Separated Flow Model, also known as Slip Model**: This model assumes the phase to be segregated with dissimilar velocities (slip). The slip velocity or the in-situ void fraction of each phase must be established. A large number of correlations based on slip model have been developed and a well known one is that by Lockhart and Martinelli **[174]**.

3) **Flow Pattern Approach**: Previous pioneers have attempted to express pressure drop correlation for each flow regime, however, the difficulty of recognizing each flow regime has prompted different flow pattern maps and correlations. Flow pattern map developed by Ros **[175]** and Duns and

Ros **[165]** were based on dimensionless gas and liquid velocity numbers. Other flow pattern maps published in the early 1960s are those of Griffith and Wallis **[176]** and Govier et al **[177]**. A mechanistic model was proposed by Orkiszewski **[166]** in which bubbly to slug flow transition is according to the criteria developed by Griffith and Wallis **[176]**, while the transition from slug to churn and churn to annular follows the criteria by Duns and Ros **[165]**. The correlation proposed by Beggs and Brill **[157]** is based on extensive laboratory data and the flow pattern map developed for horizontal flow, based largely on empirical data. A multiphase flow model was developed from first principles by Hasan and Kabir **[178]**, to estimate gas void fraction factor, or mixture density leading to pressure gradient; each flow regime, and transition from one flow regime to another were thoroughly taken into account.

5.3 Proposed Generalised Model Based on Asheim [179] Formulation

Two stability criteria were developed by Asheim **[179]**. The first is related to the inflow response and indicates that the well will be stable if the responses of reservoir inflow and gas injection to a decrease of downhole tubing pressure can result in an increase in the average density of the fluid mixture.

This criterion is given by the expression below, which also indicates that high PI's and high injection rates promote stability.

$$F_1 = \frac{\rho_G\, B_G\, q_G^2}{q_L} * \frac{PI}{(E\, A_{INJ})^2} \tag{5.99}$$

where:

F, = Stability criteria, F > 1 for stability

ρ_G = Lift (Injection) gas density at standard surface conditions

B_G = FVF of gas at injection point

Q_G = Flow rate of gas-lift at standard conditions

q_L, = Flow rate of liquids at standard conditions

PI = Productivity index

E = Orifice efficiency factor 0.9

A_{INJ} = Injection port/orifice size

The second criterion is related to the pressure depletion response in both tubing and gas conduit. A decrease in the tubing pressure will cause the gas flow rate to increase more than the liquid flow rate.

The second criterion is expressed as follows:

$$F_2 = \frac{V_t}{V_c} \frac{1}{g\,D} \frac{P_t}{(\rho_{ft} - \rho_{gi})} \frac{q_{ft} + gi}{q_{ft}\ (1 - F_1)} > 1 \qquad (5.100)$$

where

F_2 = Asheim stability criterion 2

V_t = Tubing volume downstream of the gas injection point

V_c = Gas conduit volume

g = Acceleration of gravity

D = Vertical depth to injection point

p_t = Tubing pressure

ρ_{ft} = Reservoir fluid density at the injection point

ρ_{gi} = Lift gas density at the injection point

q_{ft} = Flow rate of reservoir fluids at injection point

5.3.1 Proposed "Generalised" Injection-Production Relationship

The proposed new injection-production relationship is based on the formulation by Asheim **[179]**, to take into account the heavy oil reservoir characteristics as well as the injection system.

Firstly, after modification of Asheim **[179]** formulation to include the simplified two phase flow model suggested by Vogel **[154]** and the heavy oil density, the criteria becomes:

$$F_1 = \frac{\rho_G \, B_G \, q_{G\_INJ}^2}{q_o / q_{max}} * \frac{PI}{(E \, A_{INJ} \, \rho_O)^2} \qquad (5.101)$$

Where;

1- q_o/q_{max} is calculated using the simplified two phase flow model suggested by Vogel **[154]**, **Equation 5.46**.

2- q_{G_INJ} or q_{CO2} is calculated using the proposed methodology presented below in **Equation 5.102**.

$$q_{CO2} = a_1 \, E \left(\frac{T_b}{P_b}\right)^{a_2} \left[\frac{(p_1^2 - e^s \, p_2^2)}{\bar{T}\bar{z}L_e}\right]^{a_3} \left(\frac{1}{\gamma_g}\right)^{a_4} D^{a_5} \geq \frac{3.06(P_{INJ} - e^s \, P_R) v_{sl} A}{Tz \, L_e} \qquad (5.102)$$

Assuming a pseudo-steady state production, the operating regime of a typical production system is established using **Equation 5.46** and **Equation 5.101.**

However, it was established that the original Asheim Equation does not fit into the current concept, and in order to align the output from **Equation 5.101** to the test data, the final expression was amended as presented below following a multiple linear regression analysis:

$$F_1 = 0.07 \; \frac{\rho_G \, B_G \, q_{G\_INJ}^2}{q_o / q_{max}} * \frac{PI}{(E \, A_{INJ} \, \rho_O)^2} \qquad (5.103)$$

Computing **Equation 5.103** gives the relationship between CO_2 injection and the potential heavy oil production rates.

The output trends from the original Asheim **Equation 5.99**, and the final proposed expression (**Equation 5.103**) are illustrated in **Figure 5.7** below.

Figure 5.7 below is based on reservoir with sufficient pressure to ensure deliverability at a given CO_2 rate; and it indicates reasonable match between the test data and results from the proposed model, while the original Asheim results fall widely out of the expected trend.

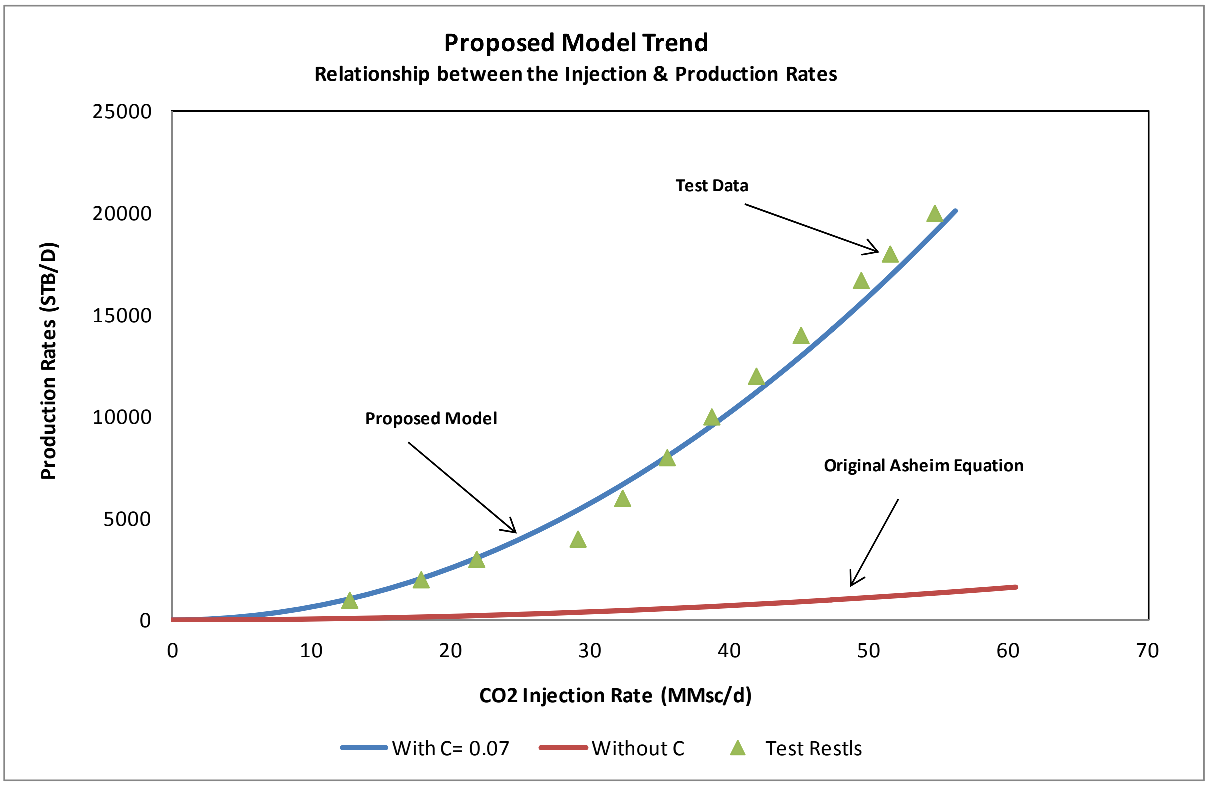


Figure 5.7: Relationship between the Injection and the Production rate based on the proposed generalised Model.

5.3.2 Model Validation against Predicted Results

<u>Reservoir Pressure Requirements</u>

The model trends and predictions have been compared against the simulation results discussed in **chapter 4** above and limited field data from the nearby field to Omega obtained from Reservoir Management Group (RMG). The proposed model shows good agreement with the test data, in general.

At low production rates, i.e. from 4000 STB/D to 8000 STB/D, the percentage error is between 1 to 2.5%, and narrow between 0.2 to 1% as the flowrate increases above 10000 STB/D.

The predicted pressure at various production rates with the corresponding percentage error is presented in **Table 5.9** below.

Table 5.9: Proposed Model Prediction - Pressure vs. Heavy Oil Rate

Test Data		Proposed Model Results	% Error
Oil Rate (STB/D)	Pressure (Psig)	Pressure (Psig)	
4000	3072	3151	- 2.5
6000	3486	3548	- 1.7
8000	3900	3944	-1.1
10000	4314	4341	- 0.6
12000	4728	4737	- 0.2
14000	5141	5133	0.2
16700	5700	5669	0.6
18000	5969	5926	0.7
20000	6383	6323	1.0

CO_2 Injection Requirements

Superimposing the gas requirements (simulation results) from **Figure 4.22** with **Figure 5.4**, gives an optimum condition for CO_2-EOR which is shown in **Figure 5.8** below.

In order to achieve stable flow, a reservoir pressure or bottom-hole pressure of 3000 psig and a minimum CO_2 injection rate of 35 MMscf/d are required, although there may be some achievable recovery at lower pressure than 3000 psig.

The two curves (Figures 4.22 and 5.4) acknowledge that there is no added value operating at low injection or reservoir pressure (i.e. below 1000 psig), which validate the simulation results discussed in chapter 4.

The results of the proposed model indicate that at higher reservoir pressure, lesser CO_2 is required, although higher CO_2 may still be injected for higher productivity as the simulation results illustrate.

The upper boundary in **Figure 5.8** sets the minimum requirement for low pressure operation, up to the point where it crosses the second line. The point where the two lines cross each other represents the optimum favourable condition for the stable flow regime.

In Chaper 4, **Figure 4.22**, the simulation results showed that 2000 psig injection pressure was insufficient to enhance recovery, hence the simulation could not continue under such operating conditions, which justify the zero heavy oil recovery and zero injection rate from a model point of view. However, the corresponding CO_2 rate is estimated to be about 25 MMscf/d.

As far as validating the proposed integrated Injection-Production model is concerned, **Figure 5.8** clearly illustrates that the proposed model depict perfectly the simulation results.

Figure 5.8 shows the range of operability, and indicates that at CO_2 injection rate lower than 40 MMscf/d, with the reservoir pressure below 3000 psig, the system will remain within the unstable region, although some intermittent heavy oil recovery may be observed. This trend was also observed in the simulation results discussed in chapter 4, with **Figure 4.22** showing that recovery was only achievable when the CO_2 arrival pressure was 3000 psig.

The simulation results predict stable flow from 3000 psig, which fit perfectly well within the stable flow region outline from the proposed model results shown in **Figure 5.8**.

A comparative summary is presented in **Table 5.10** below, and outlines broadly how results from the proposed models capture the predictions from the simulation results.

At CO_2 injection rate lower than 24 MMSCF/D, both simulation results and the proposed model predict an unstable operating condition; while at rates greater or equal to 35 MMSCF/D , and provided that the Bottom-hole flowing pressure is at least 3000 psig, the results predict continuous deliverability (i.e. stable condition).

The proposed model predicts lesser productivity at lower injection rates compared to the simulation results and slightly higher production rate at CO_2 injection rate above 50 MMSCF/D.

The proposed model predicts significantly lower heavy oil production rate at 35.7 MMSCF/D compared with the simulation results.

At higher CO_2 injection rate (above 40 MMSCF/D), the margin between the two results reduces from 10% to 3%.

Table 5.10: Comparison of Model Output against Simulation Results

Operating Conditions	Predictions			
Avg. CO_2 Rates	Simulation Results		Poposed Model Results	
	Max Heavy Oil Production	Operating Regime	Max Heavy Oil Production	Operating Regime
(MMSCF/D)	(STB/D)	-	(STB/D)	-
0	0	-	0.0	-
24.2	-	Unstable	-	Unstable
35.7	11790	Stable	5440.8	Stable
42.4	13702	Stable	11860.8	Stable
47.3	15150	Stable	16718.5	Stable
52	16335	Stable	16943.7	Stable

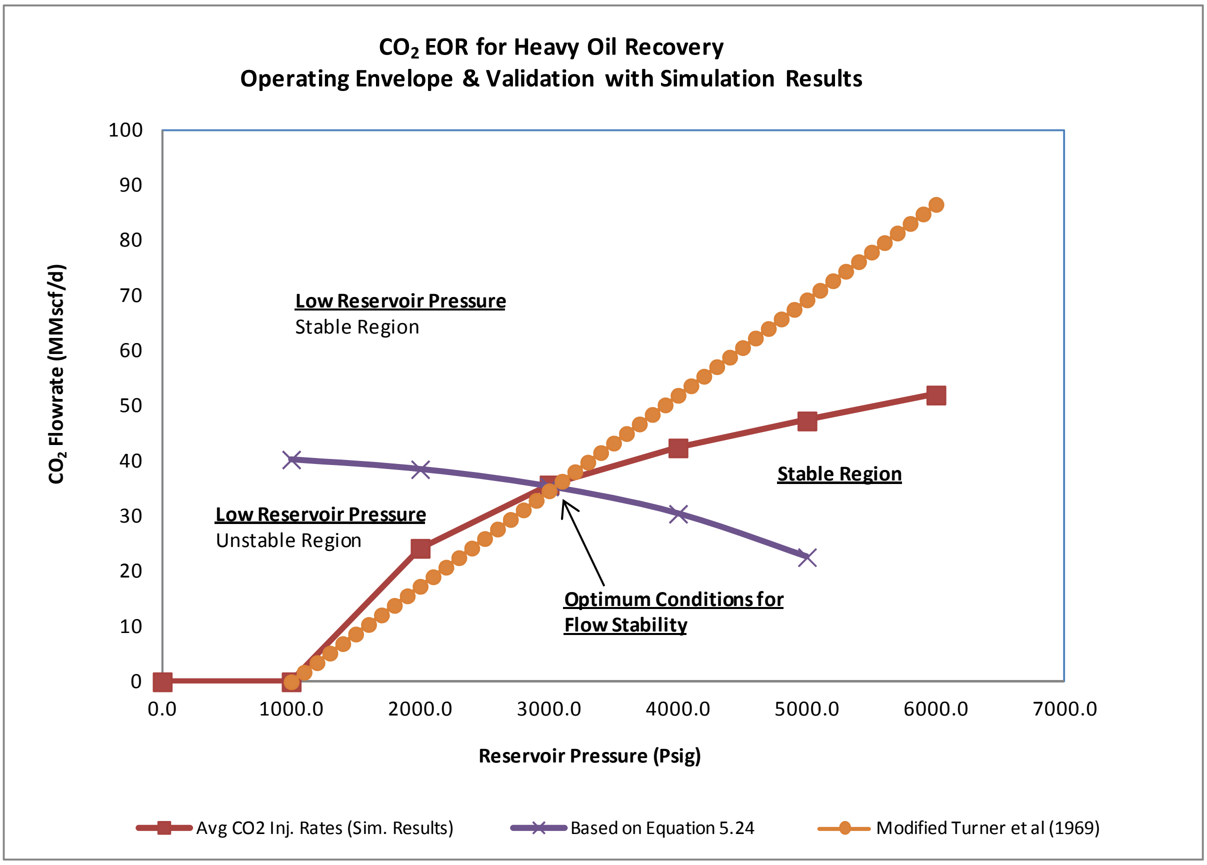


Figure 5.8: Comparison of the Proposed Model against Simulation Results

Heavy Oil Production Trend

The heavy oil forecast from the proposed model output have been compared against the simulation results discussed in **chapter 4**, and the comparative results indicate very close trend up to the optimum operating regime where stable production occurs.

The heavy oil forecast at various injection rates and reservoir pressure for both simulation results and prediction from the proposed model is presented in **Figure 5.9** below. The proposed model is very conservative at low reservoir pressure (3000 psig) and predicts much lower heavy oil rate (5500 STBD compared to approx. 12000 STBD) at the same CO_2 injection rate compared to the simulation results. However, at higher reservoir pressure, i.e. from 4000 psig and above, the variation in heavy oil production between the two predictions is within reasonable difference, i.e. 5% to 10%.

The simulation results under-predict the expected production rate of 16700 STBD by 9.3%, while the proposed model over-predicts by only 0.1%.

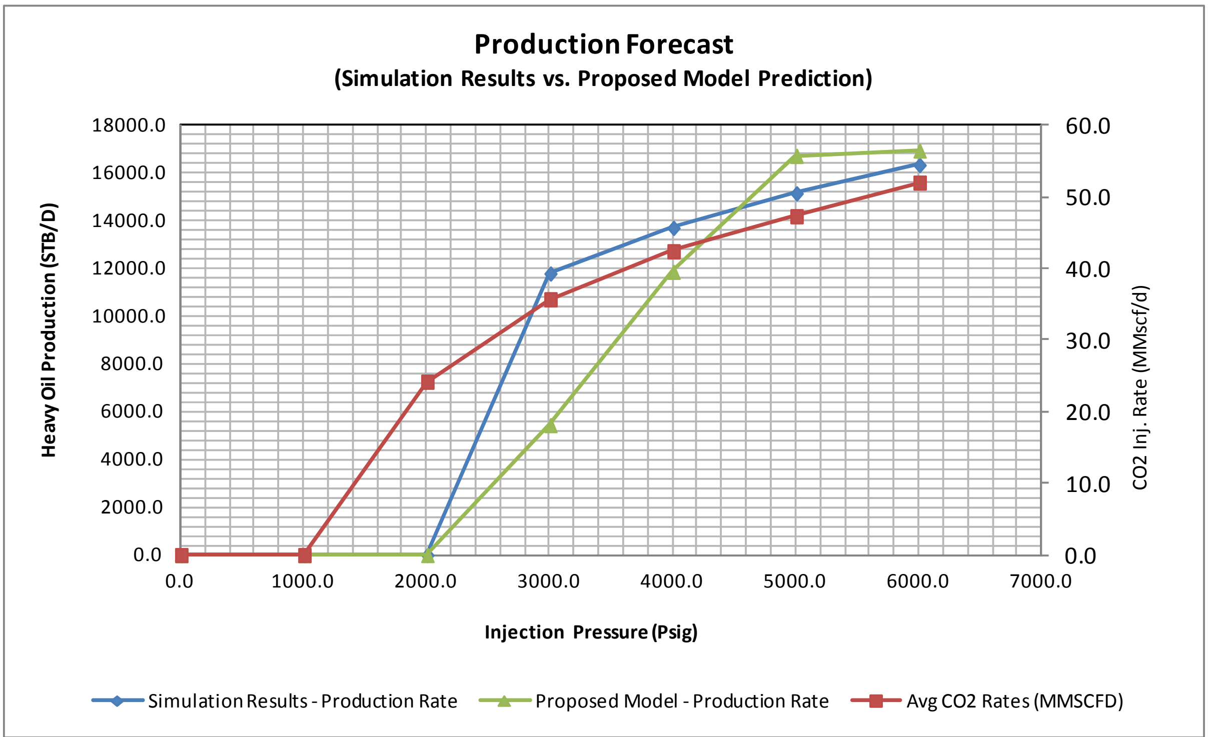


Figure 5.9: Heavy Oil Production Forecast: Proposed Model against Simulation Results

5.4 Summary

Key findings are summarized below

- An improved mathematical model, to estimate the CO_2 requirement during heavy oil recovery using CO_2-EOR, is proposed based on existing Panhandle B formulation.

- An improved mathematical model to establish the minimum CO_2 rate, at sufficient / high bottom-hole pressure, that will allow heavy crude to be lifted continuously, is proposed based on existing correlation by Turner et al **[151]**.
- An operating envelope for the CHOP using CO_2-EOR technique for a wide range of operating conditions was developed using the modified Panhandle B model and the modified Turner et al. equation.
- An improved formulation to outline the relationship between the injection and the production systems is proposed using an existing concept by Asheim **[179]**, to provide an estimated heavy oil production rate at a given CO_2 injection rate.
- The proposed mathematical models make sensible and consistent predictions across the limited range of data used in the investigation.
- The theoretical models substantiate the fact that Miscible CO_2-EOR for heavy oil recovery is more effective, with immediate impact on recovery than Immiscible process. With a low reservoir pressure, and at low CO_2 injection rate, particularly in deepwater where high pressure is required, CO_2-EOR is inefficient, making the recovery miserable, with potentially significant impact on the project return.
- Fine-tuning, scale-up and broader validation, will be required to make the proposed models more representative – Refer to Further Work in Chapter 7.

6. CONCLUSIONS

There are two main heavy oil recovery processes known as non thermal (Cold) recovery and thermal (Hot) recovery. The non thermal recovery process is known to be inexpensive, in which case, the trade-off is the early cash flow and minimal pre-investment.

CO_2-EOR technique, which is one of the non-thermal processes, has been successfully investigated for heavy oil recovery, as part of this research work.

This chapter presents concluding remarks that form part of the contribution to knowledge.

6.1 Key Findings and Contributions to Knowledge

The aim of the research was to investigate the use of CO_2-EOR technique for heavy oil recovery, with the objectives to provide useful guidance as well as better understanding of the entire recovery process. In particular:

- To investigate the hydraulic behaviour of CO_2 transportation offshore.
- To explore the feasibility of heavy oil recovery using CO_2-EOR technique.
- To assess the potential sequestration of CO_2 during heavy oil recovery using CO_2-EOR technique.
- To carry out a techno-economic evaluation of a typical heavy oil recovery using CO2-EOR technique.
- To develop fit for purpose generalised mathematical models to guide in the understanding of heavy oil recovery using CO_2-EOR.

The subsequent sections summarizes the key findings and contribution to knowledge.

6.1.1 CO_2 Transportation Offshore for EOR

Results show that CO_2 can be transported in dry or dense phase. However, dense phase is more preferable and suitable for the purposes of EOR, which by its nature is a high-pressure driven application.

Dry CO_2 transportation offshore is very possible at low pressure, but recompression will be required for an effective EOR application, however, recompression from an offshore topside rig may be problematic due to the space and weight constraints on most offshore platforms (new or existing). These limitations generally pose major challenge on most offshore platforms and enormous difficulties are always foreseen with regard to accommodating additional facilities.

At high pressure, CO_2 remains in dense phase, with the density equivalent to that of a liquid, and can be discharged at high pressure from an onshore plant directly into the reservoir for EOR, via (a tie-back) long distance pipeline transportation offshore.

6.1.2 Cold Heavy Oil Production Using CO_2–EOR Technique

Heavy oil recovery was previously investigated using some of the tertiary recovery techniques such as water alternating gas (WAG), chemical processes, gas injection and microbial EOR, and predominantly onshore. But, this research work have focused on the use of CO_2-EOR for cold heavy oil recovery offshore.

Results show that CO_2-EOR is an effective technique for heavy oil production. The compressed CO_2 at the onshore facilities can be transported subsea at high pressure for heavy oil recovery. The performance of the CO_2-EOR for CHOP can be influenced by the production history, initial reservoir pressure, GOR, and fluid properties.

Immiscible and Miscible processes can enhance recovery, but Miscible process was found to be more efficient due to the swift impact and high deliverability than Immiscible process.

Low heavy oil reservoir pressure with low GOR can be very costly to optimize due to production 'hold back' and the required injection pressure to initiate recovery. The higher the viscosity, the longer the mixing process within the reservoir, and the higher the required injection pressure to enable recovery up to the surface platform.

A comparative analysis between CO_2 and water injection indicates that the heavy oil recovery rate using CO_2 injection could be as double as that of water injection at peak flow. However, water injection provides a sustained heavy oil production rates throughout the life of field.

6.1.3 CO_2 Sequestration during Heavy Oil Recovery Using CO_2-EOR

The simulation results have demonstrated that there is a great opportunity for CO_2 sequestration during CHOP using CO_2-EOR technique. Although some amounts of CO_2 are released with the produced heavy oil, it could be re-injected into the reservoir.

The heavy oil recovery factor varied between 8% to 12% of the original heavy oil in place.

During CO_2-EOR application, the CO_2 requirements vary with time throughout the life of field. At high reservoir pressure (above 4000 psig), the CO_2 retention and CO_2 requirements per barrel of heavy oil was between 6 to 8 Mscf/STB, and at reservoir pressure below 4000 psig the value was 13 Mscf/STB.

Results indicate that Immiscible displacement can store larger volumes of CO_2 than Miscible Displacement.

6.1.4 Techno-economic Evaluation of Typical CHOP Using CO_2-EOR

A good and thorough understanding of the technology as well as the costs involved are always essential and the pre-requisites to help in the decision process and to identify the viability of the project.

It is important to highlight that the cost of CO_2 may not be insignificant and could make a considerable portion of the total costs.

The cost assessment confirms findings from simulation works that Immiscible Displacement during CO_2-EOR may be considered as a high-risk investment, particularly at low injection pressure. Miscible displacement is very pragmatic from an operational point of view and have a higher cash flow stream that may extend throughout the lifetime of the project due to continuous production while Immiscible Displacement have the longer payback period due to the time lag between the CO_2 injection and the incremental heavy oil production.

6.1.5 Generalised Mathematical Model for CO_2-EOR

An improved mathematical model, to estimate the CO_2 requirement during heavy oil recovery using CO_2-EOR, is proposed based on existing “Panhandle B” formulation.

An improved mathematical expression is also proposed to estimate the minimum CO_2 rate, at sufficient / high bottom-hole pressure, that will allow heavy crude to be lifted continuously; and was derived from the Turner et al. (1969) correlation.

An operating envelope for the CHOP using CO_2-EOR technique for a wide range of operating conditions was developed using the modified “Panhandle B” model and the modified Turner et al. (1969) equation.

A generalized expression outlining the relationship between the injection and the production systems was developed using an existing concept by Asheim **[179]**, to provide an estimated heavy oil production rate at a given CO_2 injection rate.

The proposed models were derived from existing theories to cover a wide range of operating envelope during CO_2-EOR, while identifying the best operating regime. Comparative results indicate very close agreement with limited field data from the Omega field and other generated data, with 0.2% to 1% error, while Francher-Brown and Orkiszewski are the closest with 12% error.

The proposed mathematical models make realistic predictions with consistent accuracy across the range of conditions investigated.

The theoretical models are consistent with the simulation results with respect to the most suitable displacement process, and indicate that Miscible CO_2-EOR for heavy oil recovery is preferable than Immiscible process.

7. FURTHER WORK

Future works deemed necessary as a direct result of this research work are summarized below.

7.1 Cold heavy Oil using CO_2-EOR Technique

CO_2-EOR as potential EOR technique for recovering heavy oil in the Omega field offshore West Africa has shown positive results, as far as productivity is concerned. A wide range of investigation, from reservoir parametric study to well completion, was carried out to assess the impact on the reservoir productivity. The performance of the CO_2-EOR was influenced by the injection depth; with higher productivity observed with multiple injection wells. The horizontal wells are undeniably the ideal solution; with the closeness of the injection and production wells to each other increasing the reservoir productivity by several folds. However, there is an optimum closeness that can be allowed for efficiency and safety purposes.

However, the impact of spacing between the producer and injector has not been given enough attention in this research work, but has been recognized that it could play an important part in the deliverability of the reservoir, and hence impacting on the project economics. It is anticipated from preliminary sensitivity cases that a closer spacing will result in faster heavy oil recovery, but could that offset the required investment costs? Therefore, there will be some added values exploring in details, via a techno-economic evaluation, the influence of spacing with different well types (vertical, deviated, horizontal) on the recovery trend.

Similarly, horizontal well was found to be more effective than vertical well, although costly to drill, the impact of deviated well (which provide more access to the heavy oil bearing zone) could be explored for wider operating conditions.

Subsea CO_2 Separation – Results have shown that the CO_2 injected for heavy oil recovery is partially released with the production fluids. As this probably has never been done before, the subsea CO_2 separation and the potential challenges may be investigated in the future, whereby the produced CO_2 is separated using dedicated subsea separation module and re-injected below ground. As large scale CO_2 is required for EOR, CO_2 removal subsea will certainly only be appropriate for sequestration purposes. Subsea heavy oil production is one of the most focused challenges at the present time within the subsea separation applications. Although pilot cases have being implemented in Brazil and Gulf of Mexico, the Pazflor field is proving more challenging due to the nature of the heavy oil, the water depth and other factors. CO_2 separation within an offshore platform has been implemented previously, a typical example is the Sleipner Project (North sea) where offshore CO_2 is separated and injected into a geological formation 1000 m below the seafloor for storage purposes. The challenge and the drawback of the Sleipner project was the cutback in production and highly cost impact. The challenge was to scale down the process plant sufficiently so that the 8200 tonnes miniaturized version of the CO_2 separation unit could be accommodated on an offshore platform.

Subsea separation will have the advantage of continuous recycle of CO_2 whereby the produced CO_2 is separated from the production fluids and re-injected back into the reservoir for EOR or for storage as part of the reduction in greenhouse gas emission.

7.2 CO_2 Sequestration during Cold Heavy Oil Production using CO_2-EOR Technique

Although there has been some evidence of CO_2 sequestration during EOR, the analysis has overlooked the interaction between the reservoir geology and the injected CO_2, and any potential phase change during transportation.

A detailed analysis of the geochemical interaction between the reservoir rock and the injected CO_2 with a close look into the dissolution and the mineralization process during CO_2-EOR may provide improved prediction of CO_2 sequestration. Whether CO_2 will remain "safely stored" within the reservoir in the long term, depends on the interaction of CO_2 with the heavy oil reservoir characteristics and the impact of the reservoir aquifer. CO_2 dissolution into the formation water with the heavy oil reservoir will require a much detailed investigation taken into account aquifer characteristics. CO_2 mineralization is possibly the result of chemical reactions with the reservoir rocks, yielding new carbonate minerals which are known to rely on CO_2 for their existence, hence creating a right condition for CO_2 sequestration. Further assessment is needed to determine the interaction between the reservoir geologic and the operational factors that can lead to improved CO_2 storage during heavy oil recovery.

These investigations will require suitable computer program that can help tracing the movement and dissipation of CO_2 within the reservoir.

For example, Compositional tracking such as the module available in OLGA software by Schlumberger, may be used for tracking and quantify CO_2 retained within the reservoir based on the released rate.

7.3 Proposed Injection–Production Model

The proposed mathematical expressions were derived from established theories, and make reliable predictions for the range of conditions and data investigated.

Refining the proposed models across a broader range of operating conditions for optimum performance will undeniably be an important task.

The proposed models have been tested successfully against limited data, and once extended to cover larger scale of operating conditions and specification; the models could be integrated into a tool that could be used for CO_2 injection and heavy oil production analysis and evaluation.

The proposed models may require further investigation and possible refinement (if necessary) at low pressure (around 3000 psig), as considerable difference from the simulation results, i.e. very low production compared to predictions from other correlations, was observed in some cases.

The proposed injection-production relationship is based on the “lifting” stability criteria by Asheim **[179]**, and has proved to be fit for the conditions investigated. However, Asheim correlation takes into account the slippage between phases but does not consider the flow pattern across the wellbore during production. An extensive evaluation with a large amount of data will be required to develop an optimized flow pattern based model for the heavy oil production using CO_2-EOR.

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LIST OF PUBLICATIONS

List of accepted and published articles are presented below and copy attached thereafter.

Papers accepted for publication in the Journal

1- Tchambak, E., Oyeneyin, B., Oluyemi, G.F., "The Prospect of Deepwater Heavy Oil Production Using CO2 EOR" Peer reviewed/accepted; Energy Sources, Part A: Recovery, Utilization, and Environmental Effects. Accepted for publication on 29 April 2011.

Papers published in the Journal

1- Tchambak, E., Oyeneyin, Babs., and Oluyemi, Gbenga.: "Heavy Oil Recovery-A Cold Process using CO_2-EOR Technique'', Journal of Advanced Materials Research, v.367, pp. 421-429, 2012

2- Tchambak, E., Oyeneyin, Babs., and Oluyemi, Gbenga.: "CO_2 Injection Studied For Deepwater Heavy Oil Reservoir'', Pipeline and Gas Journal, December 2010 Vol. 237 No. 12.

3- Tchambak, E., Oyeneyin, B., Oluyemi, G.F., "Investigation of CO_2 Sequestration during Cold Heavy Oil Production". Energy Sources, Part A: Recovery, Utilization, and Environmental Effects, (2013), 35:12, pp. 1174-1184

The Prospect of Deepwater Heavy Oil Production Using CO_2-EOR

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ABSTRACT

The prospect of unconventional oil development has so long been coming to offset the rapid decline of conventional crude. And looking ahead, the worry is already turning away from the onshore exploitation to the challenging offshore environment, with the question being whether the emerging technology can overcome the challenges of deepwater heavy oil production.

In economics terms, the immiscible process shows a negative return, a longer payback time and a low NPV. With an increased revenue through increased production, there is a degree of strong, dynamic and appealing prospect to any future heavy oil development using miscible process.

Keywords: CO_2-EOR, Cold Heavy Oil, CO_2 Sequestration. CO_2 Utilisation, CAPEX.

INTRODUCTION

Formation of heavy oil and bitumen is reported to be identical to that of conventional oil which is composed of hydrocarbons formed years ago under extreme pressure and high temperatures. This must to some extent justify why most scientists believe that crude oil is not heavy at the origin, and that almost all crude oils originate with API gravity between 30° and 40°. Oil becomes heavy only after substantial degradation during migration and after entrapment (Curtis et al, 2002). Conventional oil production goes through three distinct recovery stages as outlined in Figure 1, named: Primary, Secondary and Tertiary Recovery also known as Enhanced Oil Recovery (EOR), where various techniques are employed to maintain production of crude oil at maximum levels. However, heavy oil recovery generally uses different techniques than those of conventional oil and one of the most exploratory techniques to date is CO_2-EOR.The USA remains the pioneer and leader of CO_2-EOR technique for conventional oil recovery, accounting for 94% of the worldwide CO_2-EOR oil production, (Tzimas et al, 2005). 79 CO_2-EOR operations were active in 2004 worldwide (Drilling Production, Special Report, 2005), amongst which 70 miscible CO_2-EOR projects and 1 immiscible were implemented in the USA, 2 active miscible displacement CO_2-EOR projects in Canada, 5 immiscible displacement pilot fields in Trinidad and 1 commercial immiscible displacement operation in Turkey. There has been a number of CO_2-EOR projects in operation in Hungary between 1980's the mid-1990's (IEA Report Number PH3/22, February 2000**)**. CO_2-EOR technique has also been applied for heavy oil recovery. The Bati Raman oilfield (southeast Turkey), close to the Turkish-Iraqi border, containing heavy oil with very low gravity, 9° to 15° API, CO_2-EOR has been used since 1986 to boost up production to 6000 bbl/D, (IEA Report Number PH3/22, February 2000). The addition of CO_2 in poor quality heavy oil may reduce its viscosity by a factor of 10 (ECL Technology, 2001).

There are two types of CO_2-EOR processes known as miscible and immiscible displacements, which are predominantly dependent on the reservoir conditions. The immiscible displacement process has seen very limited applications to date due to efficiency issues and thus unattractive economics. The miscibility of CO_2 in crude oil or heavy crude oil is strongly influenced by pressure and a minimum miscibility pressure (MMP), which is typically above the critical pressure of the CO_2, is required for CO_2 to become fully miscible with oil. At that pressure, CO_2 exists in supercritical state with its density varying between that of light crude to that of raw water.

Most CO_2 transportation (pipelines) for EOR has been predominantly onshore, with limited experience reported offshore. Most of these pipelines operate in the 'dense phase' regime, and the flow is driven by compressors at the pipeline inlet, although some pipelines have intermediate compressor stations where necessary to boost the flow as required. Similarly, the difficulty in implementing CO_2-EOR offshore, where space and weight are major limitations, is reflected in the higher costs of implementation, compared with onshore deployment. Higher costs will incur for offshore pipelines and for the provision of new topside processing structures, (Tzimas et al, 2005).

While taking account the economics and the CO_2 sequestration, this paper discusses the prospect of CO_2-EOR application for deepwater heavy oil exploitation.

MODELLING APPROACH

Investigation was focus on the following points:

1. CO_2 sequestration during miscible and immiscible conditions
2. CO_2 sequestration using integrated surface and sub-surface modelling
3. Economics of typical project

CO_2 sequestration was investigated during miscible and immiscible displacements. The reservoir was modelled alone without integration with the surface facilities. Using REVEAL, the reservoir was modelled in 3D with a grid block of 500ft x 500ft x 200 ft, with horizontal injection and production wells both placed within grids 5, 5, and 15, 15 respectively. The CO_2 injection pressure used in this analysis was 5000 psig. The reservoir temperature was 200 ^oF. CO_2 was injected into the reservoir through a horizontal well, 8 km long and completed over a length of approximately 150 m. Six different reservoir pressures were investigated: 800, 1000, 2500, 3000, 4000 and 5000 psig.

Following successful reservoir modelling, GAP/RESOLVE/REVEAL by Petroleum Experts, was used to integrate the injection and production systems. The surface facilities were modelled using GAP, the subsurface facilities including reservoir using REVEAL, and the surface and sub-surface facilities were integrated together using RESOLVE. The total pipeline length was 250 km covering both onshore (10 km) and offshore sections (240 km). The 2km water depth was taken into account during steady state simulation to establish the process requirements at the onshore and the behaviour of CO_2 along the long distance pipeline. In estimating the percentage CO_2 sequestration, a conservative approach was used by considering all produced gas as CO_2 which gave a small difference between input and output.

As far as the economics assessment was concerned, two main cases were considered. A difficult production start-up due to low reservoir pressure (kept constant at 1000 psig) with GOR 100 scf/STB was considered with CO_2 injection pressure varying between 1000 psig to 7000 psig; and a high pressure reservoir (4000 psig) with constant injection pressure (5000 psig). Using cost data from various sources such as (McCoy and Rubin, 2008), (Damen et al , 2004), (Gozalpour et al, 2005), (Hernandez 2006, Reeves et al 2005), (www.epa.gov) as indicated in Table 1 which summarise the cost parameters used in this analysis, the economics of a typical heavy oil development using CO_2-EOR was evaluated taking into account the cost of CO_2, the transportation, equipments, construction and operation costs. The profitability of such development was measured by the net present value (NPV) and return on investment (ROI). The NPV and ROI were estimated by performing a discounted cash flow analysis using the oil production rates and CO_2 consumption rates from the performance model. The CAPEX was estimated considering typical requirements for field production equipment, CO_2 compression and transportation facilities, new injection and production wells including drilling and completion costs. The CAPEX was amortized over the project lifetime (in this case, duration of simulation) using a specified discount rate.

RESULTS & DISCUSSION

Reservoir Modelling – CO_2 Sequestration (Miscible Process vs. Immiscible Process)

The emphasis was all around the influence of reservoir pressure, i.e. miscible and immiscible conditions, with regards to the CO_2 retention and utilisation per barrel of heavy oil produced. It is reported in (Tzimas et al, 2005) that immiscible displacement projects can store larger volumes of CO_2 than miscible displacement projects. And this was attributed to the CO_2 breakthrough which is unavoidable in miscible displacement operations and avoidable in immiscible displacement as the immiscible projects may be designed to eliminate the breakthrough to enable permanent retention of CO_2.

In subplot format, the modelling results (heavy oil production, percentage of CO_2 sequestration, CO_2 requirements and retention per barrel of heavy oil produced) shown in Figure 2 indicate that considerable amount of heavy oil was achieved at high reservoir pressure, i.e. miscible conditions. Equally, as the reservoir pressure increased, the influence on the production profile was clearly noticeable.

The recovery factor varied between 8 % to 12 % of the original heavy oil in place, which was within the range reported by (Clarke et al, 2007) who suggested a recovery factor using cold production to be between 6 % to 15% of OOIP. Despite the constant injection pressure, the volumetric flowrate of CO_2 reaching the reservoir increased as the reservoir pressure was reduced. High reservoir pressure enabled high recovery factor. However, in all cases, the production traces of mass flowrate of CO_2 produced showed significant delay (period of zero flow) before initial CO_2 production at continuous CO_2 injection. In another hand, all simulation results were based on 20-30 years production forecast and illustrate that during CO_2-EOR application, the CO_2 requirements varied with time throughout the lifetime of the forecast, which corroborate with the claim reported in (Balbinski, 2003) & (Holt, 2004).

While the percentage of CO_2 sequestration was found to be high at high reservoir pressure in this case, the CO_2 utilisation and CO_2 retention per barrel of heavy oil produced was found to be significantly higher during immiscible conditions compared to miscible conditions. These finding are in agreement with the theory reported in (Tzimas et al, 2005), that immiscible displacement projects would generally require a higher amount of injected CO_2 per incremental barrel of oil produced, typically two to three times more. However, values may vary significantly from field to field. Considering that the "pressure" limit switch between miscible and immiscible process is known to be 1073 psig, the simulation results indicate that at low reservoir pressure (800 – 1000 psig) the CO_2 retention and CO_2 requirements per barrel of heavy oil produced was about two (2) times higher than that required at high reservoir pressure (2500 psig). This factor varies considerably as the reservoir pressure increases.

The percentage of CO_2 retention within the reservoir was influenced by the reservoir pressure, and in this case high sequestration occurred at high reservoir pressure. At the production start-up, the CO_2 retention within the reservoir was maximal for all the reservoir pressures investigated, and for low reservoir pressure (800 & 1000 psig), the sequestration remained high until production reached a quasi steady state condition, at which stage the decline in CO_2 retention begun progressively as the production continued. At high reservoir pressure (above 1000 psig), the CO_2 retention dropped from 100 % to 35%, rose again approximately to 42 % during transition from start-up and quasi-steady state production; and at quasi-steady state condition, the CO_2 retention within the reservoir continued to rise progressive as the production continued. Results based on peak production show that the minimum percentage of CO_2 retention within the reservoir increased with increasing reservoir pressure, starting with 17.7 % retention at 800 psig to 32.8 % at 5000 psig. The maximum CO_2 retention of 100 % simply reflects that production or release of CO_2 started approximately one year after CO_2 injection commenced. At high reservoir pressure (above 4000 psig), the CO_2 retention and CO_2 requirements / utilisation per barrel remained within the range reported by many authors such as (Clarke et al, 2007) as being between 6 to 8 Mscf/STB, but at reservoir pressure below 4000 psig the value was in agreement with that presented by (Gozalpour et al, 2005) which is 13 Mscf/STB.

Integrated Surface & Sub-surface Facilities (Injection-Production System)

The process conditions along the pipeline were established based on the CO_2 phase diagram and steady state simulation (where outlet pressure (reservoir) and maximum velocity was used as criteria). The transported CO_2 was predominantly in dense phase, with possible liquid drop depending on temperature variation. In this case, the same reservoir models built for various reservoir pressures ranging from 800 psig to 5000 psig were linked to the "GAP" pipeline model using RESOLVE to assess the CO_2 sequestration.

Remote CO_2 injection required significant amount of CO_2 capacity, as shown in Figure 3. And in such cases, the higher the reservoir pressure, the lower the volume of CO_2 required to make significant impact on the production trend. Heavy oil production and the CO_2 requirements were significantly influenced by the reservoir pressure. With the reservoir pressure at 800 psig and 1000 psig, the heavy oil production was less than 8000 bbl/d, and the production was increased beyond 10000 bbl/d when the reservoir pressure was above 1000 psig. The total gas production was significantly below the amounts of CO_2 injection for all the reservoir pressures investigated, and particularly when the reservoir pressure was 800 psig, the total gas produced was almost half the volume of CO_2 injected. Despite continuous CO_2 injection, in all cases, the gas production started about a couple of year post start-up and the lower the reservoir pressure, the longer the period of no production. An estimate of percentage of CO_2 retention, CO_2 retention and CO_2 utilisation / requirements per barrel of heavy oil is shown in Figure 4 (subplot format). And remarkably, the high percentage of CO_2 retention in the reservoir was found to occur during immiscible displacement (reservoir pressure lower than critical pressure of CO_2, 1073 psig) as reported in (Tzimas et al, 2005). The minimum percentage of CO_2 sequestration varied from 55 % at low reservoir pressure (800 psig) to 47 % at high reservoir pressure (5000 psig). The CO_2 retention and CO_2 requirements per barrel of heavy oil produced were significantly high at low reservoir pressure and progressively reduced as the reservoir pressure increased.

The high CO_2 retention experienced in this case and particularly during immiscible displacement may well be attributed to the significant variation between the amount of injected CO_2 and the marginal difference in the total gas produced in the two modelling approaches used. High volume of CO_2 injection was required for immiscible displacement, and was almost double the amount that was injected in the previous cases where only the reservoir 3D model was considered (no integration with GAP). With the remote injection (integrated modelling), the amount of CO_2 injection rate reaching the reservoir was much smaller at high reservoir pressure (5000 psig) compared to that when the reservoir pressure was 800 psig or 1000 psig. A slim tube displacement experiment test conducted by (Chung, 1988) has indicated that at pressure as high as 3800 psig, CO_2 might reach miscibility with viscous oil, and the findings discussed in this paper have shown that the amount of CO_2 sequestration increased with increasing CO_2 injection flowrate (i.e. high pressure), particularly during immiscible displacement since the amounts of CO_2 released with the produced heavy oil was minimal.

Economics of the Project

This economic evaluation is purely illustrative, carried out using simplified cost assumptions to reflect typical heavy oil development using CO_2-EOR technology. The economics do not take into account detailed pre-tax cash flows (e.g. Royalty & severance taxes ... etc) or other costs (e.g. "upgrade" of heavy oil), but assumed 12% discount rate.

In the estimated CAPEX shown in Table 2, the purchase price of CO_2 makes the dominant portion of the amount. At low reservoir pressure, it appears as shown in Table 2 that the operation was highly profitable, when the injection pressure was above 2000 psig, due to the additional recovery that yielded significant revenue, with smaller payback time, high NPV and ROI. Table 2 equally show the "beneficial" effect of individual displacement process based on the CO_2 demands and the production profile. Miscible displacement was effectively the most profitable option, identifiable from revenue generated in form of NPV, while providing a high ROI and an expected smaller project payback time, and substantial percentage of CO_2 sequestration. The analysis assumed that the project owner / operator will dictate a limiting internal rate of return (IRR) that would decide the feasibility of the project. Similarly, the results also confirmed as generally speculated that immiscible displacement process has very limited economics values due to significant amounts of CO_2 injection required, the low additional production of heavy oil and consequently the long payback time, which in this case can extent up to 19 years. The payback time will be project specific and will vary significantly according to production performance which will depend on the reservoir and injection characteristics. The results in Table 2 may look very optimistic, but even considering the production cost to be $13 to $16 per barrel of heavy oil (www.cera.com), miscible displacement will still provide appreciable benefit as well as reasonable payback time.

With the breakeven cost of CO_2 being the CO_2 purchase price at which the project net present value (NPV) equals zero, using the economics model as in Table 2, the analysis show that breakeven cost of CO_2 will vary approximately between $9.5 to $38.5 per Mscf when the heavy oil price varies between $40 to $150 per bbl.

As it costs much less to recycle CO_2 than to buy it at market value (Todd and Grand, 1993), re-injection of the produced CO_2 with production maximisation will somehow help towards reducing the high investment costs.

CONCLUSIONS

This techno-economic evaluation carried out has made known that CO_2 sequestration was very likely during heavy oil recovery using CO_2-EOR technique. Nevertheless, the percentage of CO_2 sequestration, the CO_2 retention and CO_2 utilisation per barrel of heavy oil produced were very depending on process conditions at the pipeline inlet and at the reservoir, as well as the injection-production systems configuration. Consequently, in real project the results may vary from one field to another. Moreover, there were substantial grounds on which immiscible displacement during CO_2-EOR may be considered as a high risky investment, particularly at low injection pressure. However, immiscible displacement may be very desirable in some context mainly for CO_2 sequestration or as a mean to maintain reservoir pressure. Although not cost-effective, immiscible displacement at high CO_2 injection pressure may be as operational as miscible displacement, but less imperative. Miscible displacement is very pragmatic from an operation point of view and have a higher cash flow stream that extends throughout the lifetime of the asset due to continuous production while immiscible displacement have the longer payback period due to the time lag between the CO_2 injection and the incremental heavy oil production.

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Process/Operation	Units	Cost	Source
CAPEX			
CO_2 Purchase Price [5]	$/Mscf	1.05	**(McCoy & Rubin 2008)**
CO_2 Pipeline cost,	$/ton	1600	
Produced Gas Processing (recycle) [1]	$	84613	**(Damen et al, 2005)**
Injection Well Cost (new) [2]	$/ft	100	**(Reeves et al, 2004)**
Production Well (new) [2]	$/ft	100	**(Reeves et al, 2004)**
Compressor Cost	$million	20	(Gozalpour, 2005)
Compressor Installation	$million	6	(Gozalpour, 2005)
Pipeline Construction Cost (Onshore)	$/m	500	Assumed
Pipeline (Offshore) - Vessel Day Rate	$/day	87500	Assumed
OPEX			
Injection Well	$/month	1500	(Hernandez,et al 2006)
Production Well	$/month	1500	(Hernandez,et al 2006)
CO_2 Compression	$/Mscf	0.3	**(Joshi, 2003)**
Safety & Monitoring	$/injector/year	10000	
Discount Rates [3]	%	12	
Heavy Oil Price			
Heavy Oil Price	$/STB	50	Assumed
Other			
Duration [4]	Year	20 - 30	

Table 1 – Key Economics Parameters

Notes:

1. This is the CAPEX of the recycle CO_2 including treatment and compression facilities.
2. Cost is for vertical well and includes drilling, completion, production equipment and pipes. The cost of horizontal well is estimated to be 1.5 to 2.5 that of vertical wells **(**http://www.npd.no/).
3. The NPV of the projects is calculated at a discount rate of 12%, despite that the rates used in similar studies range from 7% to 11% **(** Tzimas, and Peteves, 2005).
4. The duration varies between 20 to 30 years, depending on simulation case.
5. Refer to **(**Holt et al, 2004)**]** for detailed discussions on the economics of CO_2 capture**.**

CAPEX ($) [1]	**217,250,000**			
OPEX ($) [2]	**156,000**			
Injection Pressure (Psig) [4]	**PV ($)**	**NPV ($)**	**ROI (%)**	**Payback Time (Year)**
7000	536873287.7	319,649,419	247.2	7.2
6000	415473950.1	106,821,227	191.3	8.0
5000	324045095.3	106,821,227	164.9	8.9
4000	358261159.5	141,037,291	165	8.9
3000	289964448.6	72,740,580	133.5	9.8
2000	201928146.2	-15,295,722	93.0	11.7
1000	20647780.7	-196,576,088	9.5	22.1 [3]
Reservoir Pressure (Psig)	**PV ($)**	**NPV ($)**	**ROI (%)**	**Payback Time (Year)**
4000	1354180605	1,136,956,736	623.4	**3**

Table 2: Economics of CHOP using CO_2-EOR

Notes:

1. Cost includes single pipeline (6-inch) and associated equipments cost, CO_2 purchase and other costs as shown in Table 1.
2. Does not include the supply cost of CO_2 which was accounted separately considering the CO_2 requirements for individual case.
3. Takes into account period of no production beginning at the start-up.
4. Variation of Injection Pressure at Constant Reservoir Pressure (1000 psig) & GOR (100 scf/STB)

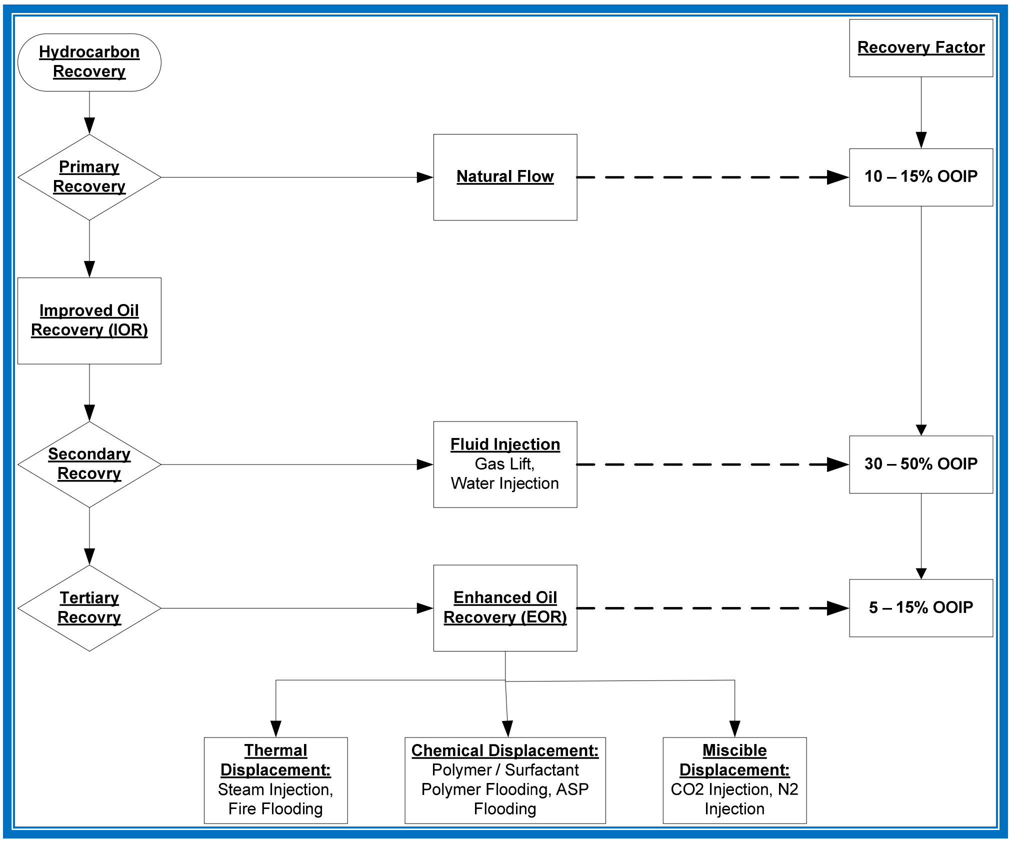

Figure 1: Conventional Oil Recovery Techniques

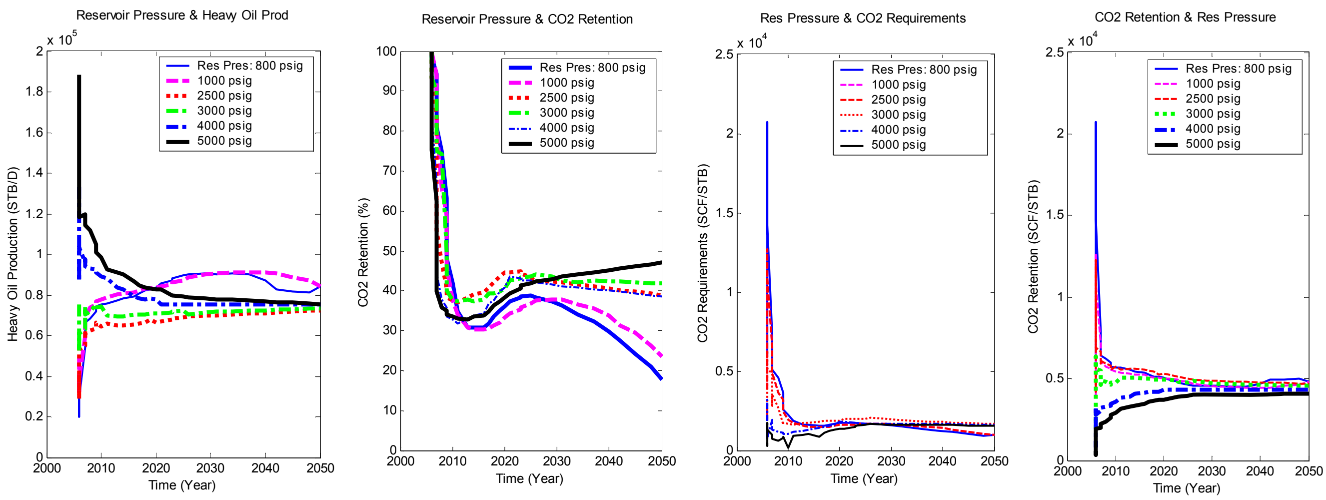

Figure 2: CO_2 Sequestration – Influence of Reservoir Pressure – Injection Pressure 5000 psig

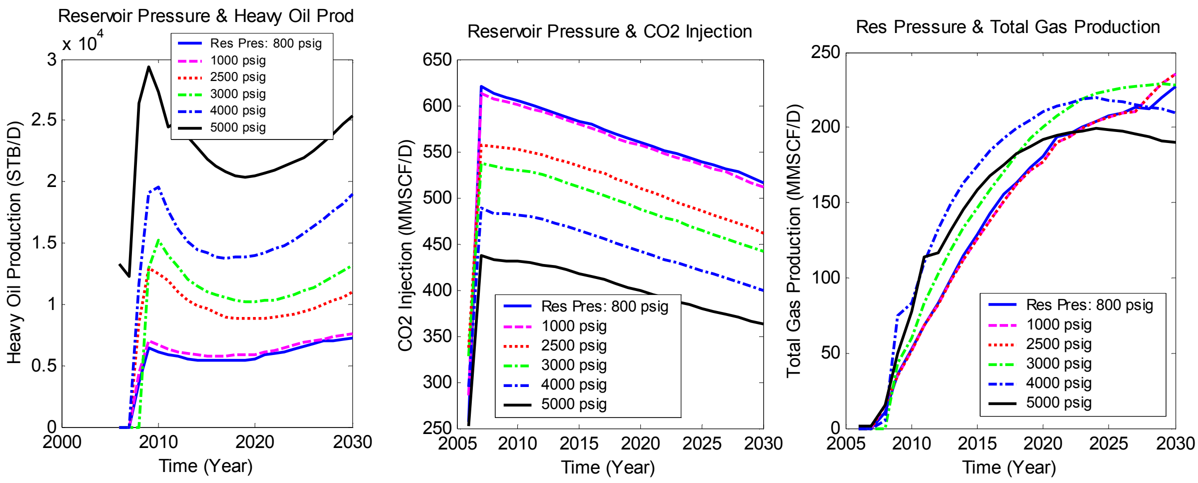

Figure 3: Production Profiles based on GAP / RESOLVE / REVEAL Modelling

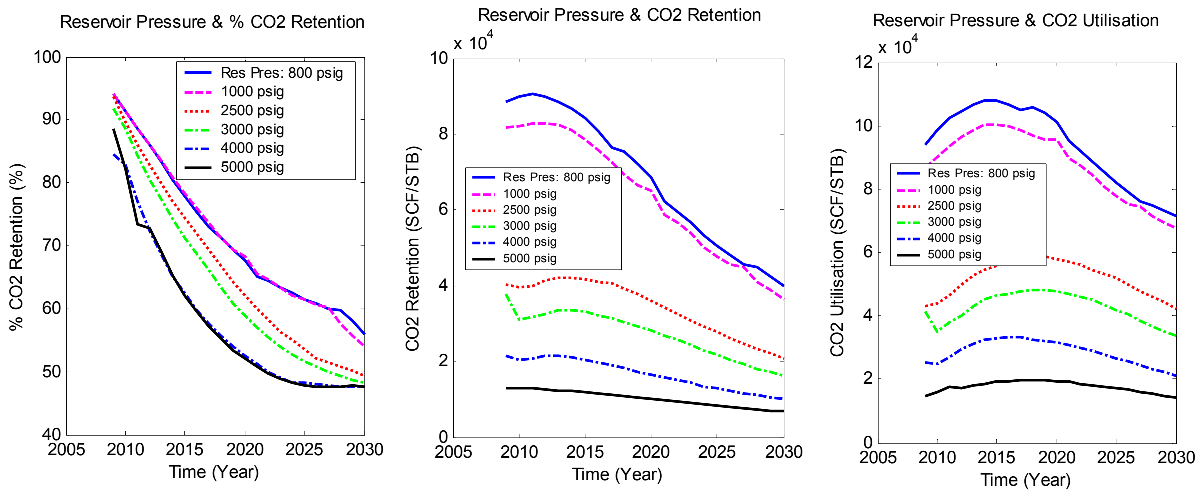

Figure 4: CO_2 Sequestration based on GAP / RESOLVE / REVEAL Modelling

Heavy Oil Recovery: A Cold Process Using CO_2-EOR Technique

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Keywords: CO_2 Injection, CO_2 Transportation Offshore, EOR, Heavy Oil Recovery, Cold Process, Integrated System Modelling.

ABSTRACT

Owing to substantial improvement in enhanced oil recovery (EOR) technologies and significant decline in discovery of light and medium crude oil fields, the heavy oil development is progressively receiving considerable attention to fill the supply gap. Cold heavy oil production (CHOP) using captured carbon dioxide (CO_2)-EOR technique was investigated using the state-of-the-art Integrated Product Modelling packages of Petroleum Experts as part of the Well Engineering Research Group unconventional oil reservoir management studies being undertaken at Robert Gordon University. Beyond ascertaining the feasibility of the CHOP using CO_2-EOR, the objectives of the investigation were to establish the process requirements at the onshore facilities based on series of parametric studies and to enhance the understanding of the subsea integrated injection and production systems during the injection process. The injection system consisted of an injection well connected to a 240 km subsea pipeline transporting CO_2 from an onshore compression station. The production system included a topside separator connected to the production well via a 2km riser. A broad range of reservoir production history was used and the simulation results indicate that heavy oil displacement was easily achievable under miscible conditions (i.e. high reservoir pressure), but the production trend was strongly influenced by the reservoir characteristics (i.e. GOR, WC, Pressure).

INTRODUCTION

Large volume of recoverable heavy oil resources remains undeveloped worldwide due to lack of adequate, safe and reliable Enhanced Oil Recovery (EOR) technique. EOR has been practiced since the 1950s in various conventional oil reservoirs, particularly in the USA. One of the EOR processes that likely have the largest worldwide potential is miscible flooding wherein carbon dioxide (CO_2), nitrogen (N_2) or light hydrocarbons are injected into oil reservoirs where they act as solvents to move remaining oil. Amongst the three options, CO_2 flooding is proving to be the most useful technique given the potential environmental benefit. But, can CO_2-EOR technique be seen as potential heavy oil recovery method, and consequently urge on more deployment into heavy oil exploitation?

About 79 CO_2-EOR operations were active in 2004 worldwide [1, 2]. However, these were mainly implemented in onshore environment. And one of the unanswered questions to date has been to know whether CO_2-EOR technique can be adapted offshore. Although, there are several proposed and implemented hydrocarbon gas injection (WAG) projects in the North Sea [3, 4], there are yet no published literatures on long distance CO_2 transportation offshore.

Heavy oil recovery in most cases necessitates dissimilar production techniques to conventional oil. Two main production processes known as Cold Process or non-thermal which include cold flow with sand production, cyclic solvent process, VAPEX; and Hot Process or thermal which include steam floods, cyclic steam stimulation, SAGD are generally employed. In either case, the fraction of OOIP that can be recovered depends on the oil properties, artificial lift method used and the reservoir characteristics.

MODEL DESCRIPTION

This research was carried out to investigate the use of CO_2-EOR technology as a mean to facilitate heavy oil recovery in a typical deepwater environment, despite the literature suggesting that heavy oil was mainly found in shallow water [5]. The concept was based on a 240km subsea pipeline transporting CO_2 from an onshore compression station. The total pipeline length was 250 km (on and off shore sections), the water depth was 2 km and the depth below the sea-bed was 2 km. The transported CO_2 was injected into the heavy oil reservoir via a vertical injection well. With regard to the production system, the heavy oil reservoir was producing to the topside separator via a subsea wellhead having 6" tubing size and 8" casing diameter. Data available on the public domain was used to model and characterise the reservoir. Single injection and production wells were used. However, more than one well was also possible depending on the capacity requirements. The schematic representation of the integrated injection and production system is shown in **Figure 1**.

The reservoir thickness and radius were 300 ft and 2500 ft respectively, the reservoir temperature was 120 ^{o}F and the original oil in place (OOIP) was 500 MMSTB. As from the production history, the initial reservoir pressure was 4000 psig. The black oil PVT and Influx Performance data used for the simulation are presented in **Tables 1 and 2**.

The steady state simulator "Pipesim" by Schlumberger was used to carry out a steady state analysis on the 250 km CO_2 pipeline and the integrated system modelling was performed using the Petroleum Experts package "GAP/PROSPER/MBAL". Regarding the integrated modelling cases, different production history was used with varying reservoir pressure, GOR and viscosity. The main cases of interest were:

1. Reservoir pressure 4000 psig, GOR 500 scf/STB, specific gravity 20 API, Injection pressure 3000 psig;
2. Reservoir pressure 1000 psig, GOR 100 scf/STB, specific gravity 20 API, Injection pressure 3000 psig;
3. Reservoir pressure 4000 psig, GOR 500 scf/STB, specific gravity 10 API, Injection pressure 5000 psig.
4. Effect of multiple injection wells on the productivity.

RESULTS AND DISCUSSION

Long Distance CO_2 Transportation Offshore

The goal of this investigation was to assess the behaviour of the CO_2 along the subsea pipeline, to determine the pressure requirement for various pipeline capacity, pipeline sizes and flow conditions. This exercise was helpful to establish the process and design requirements necessary for the integrated modelling. The simulated pipeline was 250 km long transporting CO_2 from the onshore facilities to the subsea manifold.

The operating conditions for dry and dense CO_2 phase required to perform the steady state simulations were identified on the CO_2 phase diagram which is available on the public domain, such as in [6]. Two separate conditions were evaluated based on the pressure dictated at the pipeline inlet: Dry gas phase and dense phase, in order to assess the flow condition along the pipeline and to establish the exact nature of CO_2 as it reaches the reservoir. The pipeline sizes used for the investigation varied from 6 inch to 14 inch diameter. The inlet pipeline and the sea-bed temperatures were 70 ^{o}F and 41 ^{o}F respectively. The pipeline was assumed coated with 3LPE (3 layer polyethylene coatings) for corrosion protection and 100 mm concrete coating for buoyancy control offshore.

Dry Gas (CO_2) Phase

The pressure requirement for different CO_2 flowrate is shown on **Figure 2**. The results show that long distance dry CO_2 (gas phase) transportation offshore is possible, but may not be an effective technique or solution for heavy oil recovery which require high injection pressure just as any EOR. This argument is supported by [7] that stipulate typical CO_2 injection pressure in the North sea to be between 200-300 bar. Recompression will be inevitable in such circumstances to meet the EOR objectives.

CO_2 Dense / Liquid Phase

The lowest allowable pressure at the pipeline outlet must be 1073 psig, which is the pressure below which CO_2 may change to gas phase, hence resulting in low density and high flow velocities. The backpressure was set to be that of reservoir pressure with 4000 psig and the process conditions along the pipeline and at the onshore were determined. The pressure requirement for different CO_2 flow rate and pipe sizes is shown on **Figure 3**.

Contrary to some public literatures, no differences were experienced between the results obtained using PR and SRK EOS. As opposed to the dry CO_2 pipeline simulation results, intermediate recompression for pipeline transporting CO_2

dense phase prior to injection into the reservoir via the well was not deemed necessary provided that the pressure remained significantly high to make immediate impact into the reservoir. With the high injection pressure required to facilitate mobility of the heavy oil from the reservoir to the topside facilities, it is beyond question to state based on the steady state results that CO_2 during EOR application for CHOP will behave as supercritical fluid, expanding to fill the heavy oil reservoir as a gas, but with the density identical or greater than that of raw water.

The density variation along the pipeline between 967 kg/m^3 to 1028 kg/m^3 was an essential indication that for the most part of the pipeline CO_2 was in dense phase. Keeping a long distance CO_2 pipeline principally in dense phase without liquid formation in cold environment (i.e. 41 ^oF as in this case) is a notorious challenge. The temperature along the subsea pipeline dropped rapidly to the ambient sea-bed temperature, signalling there could be possible corrosion issue in the long prospect. Alternatives to heating CO_2 at the source in such circumstances are preferable, as the heated CO_2 would scarcely mitigate against the harsh cooling effect by the sea water.

<u>Integrated Injection and Production Systems</u>

Simulating the Integrated Injection and Production Systems using black oil models indicated that CO_2 EOR was a practical solution and effectual technique for cold heavy oil recovery. The composition of heavy oil was randomly selected and was used together with the CO_2 PVT properties to build a GAP/PROSPER/MBAL compositional model using "PR EOS". Successful results were obtained as those of black oil models, except that high injection pressure was required for the compositional model.

Case 1: <u>Reservoir pressure 4000 psig, GOR 500 scf/STB, specific gravity 20 API, Injection pressure 3000 psig</u>.

Under the above condition, two sub-conditions were investigated, one under which the production was possible and CO_2 injection was used to boost the recovery; and another case where the separator was located at the topside platform, 2km above the sea-bed making a total depth of 4km (water depth + depth below sea-bed) and production was primarily not possible under these circumstances due to insufficient reservoir pressure to initiate natural recovery of the resources. The production forecast was performed from year 2000 to 2020 and the results with and without CO_2 injection for both cases are shown in **Figures 3 and 4.**

It was noticeable from the production traces (Figure 3b) that the heavy oil recovery doubled in year 2002, from 7960 STB/D (without CO_2 injection) to 16890 STB/D (with CO_2 injection). Remarkably, heavy oil recovery at year 2018 was not possible when the reservoir pressure reached 1000 psig (Figure 3b, without injection), however, the production forecast projected steady production at about 2000 STB/D, with continuous CO_2 injection. The 20 years forecast showed that the heavy oil recovery and gas production (for the case where production was not initially possible due to low energy) was boosted from zero production (without CO_2 injection) to a rapid production as the result of CO_2 injection. This production trend clearly indicates the positive impact of CO_2 injection for this particular reservoir condition and production system.

Before the gas breakthrough the averaged gas production was minimal and almost stable while the heavy oil production was increasing sharply. As the averaged gas production rate began to rise sharply which possibly corresponded at the period of reservoir "gas breakthrough", the gas recovery was boosted causing the peak heavy oil production. Following this phenomenon (peak heavy oil production), the averaged gas production continued to rise while the heavy oil production was in decline.

Case 2: <u>Reservoir pressure 1000 psig, GOR 100 scf/STB, specific gravity 20 API, Injection pressure 3000 psig</u>.

Under this condition where the initial reservoir pressure was 1000 psig, the GOR 100 scf/STB, the behaviour along the integrated system was completely different and production was only possible after several years of continuous CO_2 injection (**Figure 5)**. This probably suggests that low pressure reservoir with low GOR is most likely not very practical for CO_2-EOR CHOP due to the inefficiency of the process and the long payback time caused by many years of zero production even at significant high injection pressure.

Case 3: Reservoir pressure 4000 psig, GOR 500 scf/STB, specific gravity 10 API, Injection pressure 5000 psig.

Despite the high injection pressure used in this case compared to other cases discussed above, it was apparent that the production rate was hampered by the non-Newtonian behaviour of the reservoir fluid which exhibited both high viscous and elastic characteristics under the injection phenomenon. The heavy oil viscosity varied from 2010 cp to 1820 cp during the injection process. The production forecasts indicated continuous and smooth production from year 2000 to 2020 (**Figure 6)**.

Case 4: Effect of multiple injection wells on the productivity

Multiple vertical injection wells were found to impact on the productivity in accordance with the production system characteristics. Injection wells departing from the distribution manifold created identical effects due to the unique dependence of the same injection source. The performance of the CO_2-EOR for CHOP was influenced by the injection depth. The efficiency of the injection process increased at deeper injection depth.

CONCLUSIONS

The findings of the investigation can be summarised as follow:

- Dry CO_2 transportation offshore is possible at low pressure, but re-compression will be required for an effective EOR application. Long distance CO_2 transportation offshore can also be achieved at high pressure with CO_2 remaining in dense phase throughout the entire system.

- CO_2-EOR is an effective technique for heavy oil production based on the conditions investigated and discussed in this paper. The compressed CO_2 at the onshore facilities can be transported subsea at high pressure and injected straight into the reservoir for heavy oil recovery. Results may vary to some extent under certain conditions, depending on the reservoir characteristics and production history; and production could be delayed until mobility of the crude within the reservoir is possible in some cases.

- The performance of the CO_2-EOR CHOP was influenced by the production history, initial reservoir pressure, GOR, and fluid properties.

- Although valuable remarks were drawn by analysing each component individually, the integrated modelling systems have demonstrated that the production optimisation was well understood and appreciated when the injection and production systems were integrated together as a single module.

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Abbreviations

API	American Petroleum Institute
CHOP	Cold Heavy Oil Production
CO_2	Carbon Dioxide
EOR	Enhanced Oil Recovery
IOR	Improved Oil Recovery
OOIP	Original Oil In Place
PR	Peng Robinson
SRK	Soave-Redlich-Kwong
EOS	Equation of State

Table 1: Black Oil PVT Data

	Data
Separator	Single Stage
Heavy oil Viscosity	100 & 2000 cP
Oil Gravity	10 & 20 API
Gas Gravity	0.7
Water Salinity	10000 ppm

Table 2: Inflow Performance Data

	Data
Reservoir Pressure	1000 & 4000 psig
Reservoir Temperature	120 ^{o}F
Water Cut	0
Total Gas Oil Ratio	100 & 500 scf/STB
Productivity Index	20 STB/day/psi

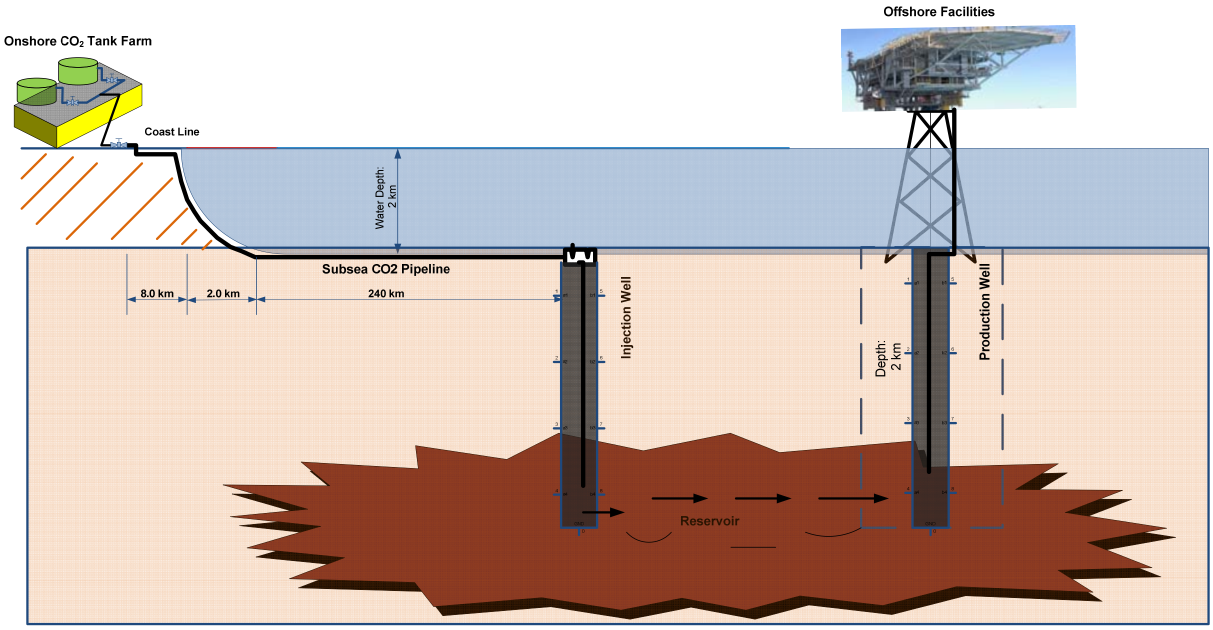

Figure 1: Schematic Representation of the Integrated Injection and Production Systems

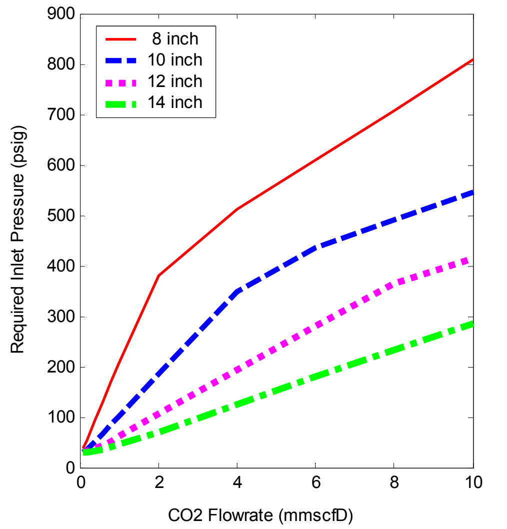

Figure 2: Dry CO_2 Pipeline – Pressure Requirement for Various Pipe Sizes

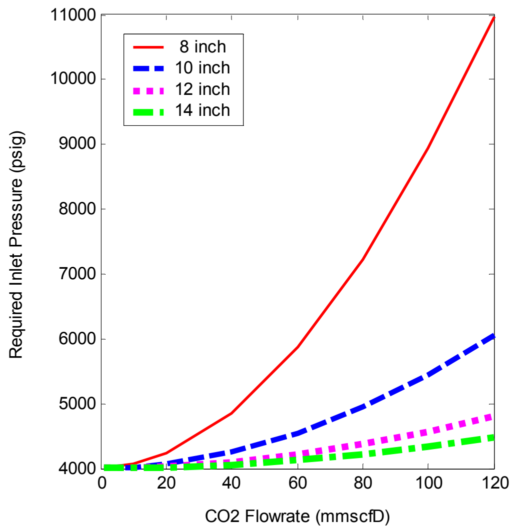

Figure 3: CO_2 Dense Phase Pipeline – Pressure Requirement for Various Pipe Sizes

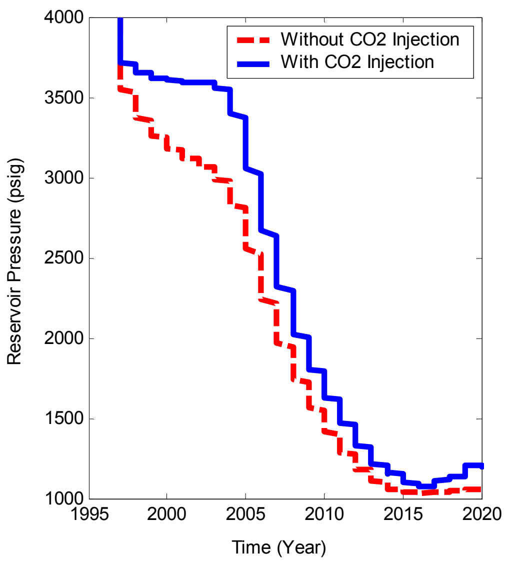

Figure 3a: Case 1 – Reservoir Pressure Forecast – With / Without CO_2 Injection

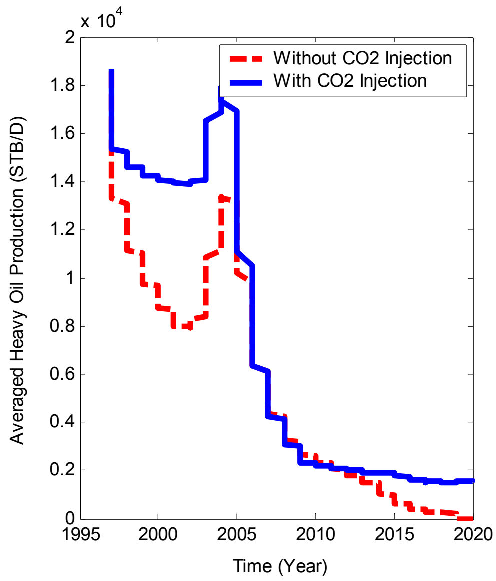

Figure 3b: Case 1 – Heavy Oil Production Forecast – With / Without CO_2 Injection

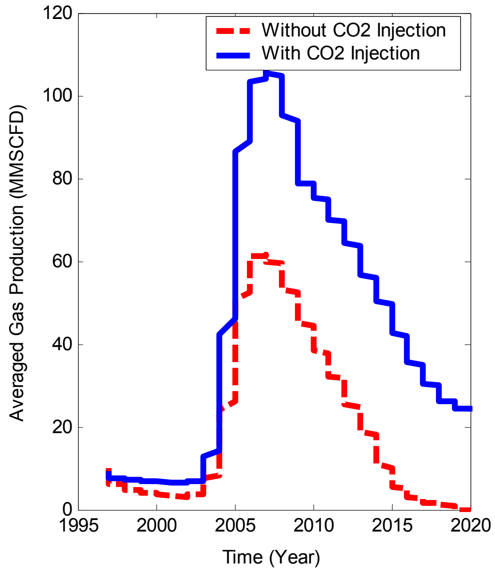

Figure 3c: Case 1 – Total Gas Production Forecast – With / Without CO_2 Injection

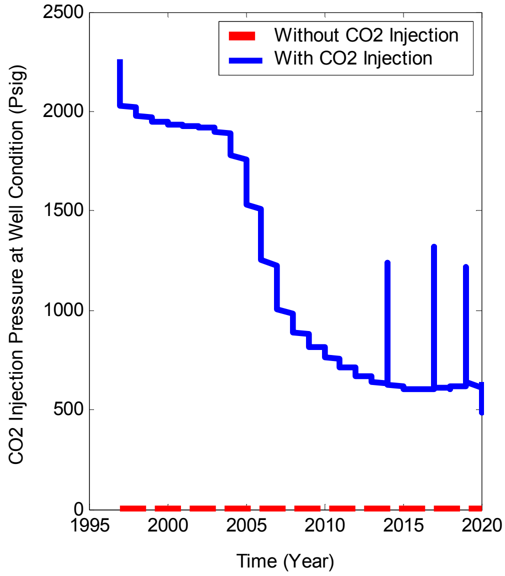

Figure 3d: Case 1 – Injection Pressure

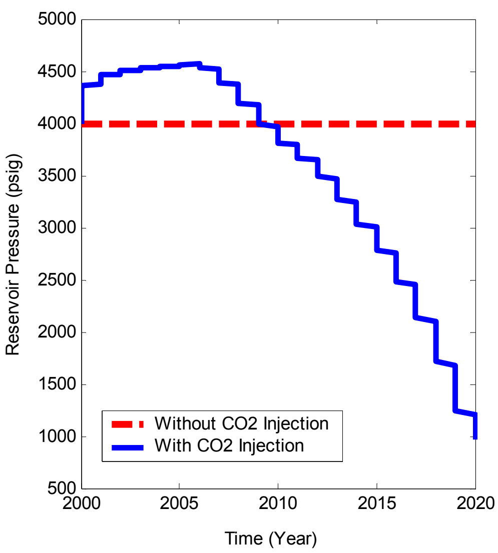

Figure 4a: Case 1 – Reservoir Pressure Forecast – With / Without CO_2 Injection

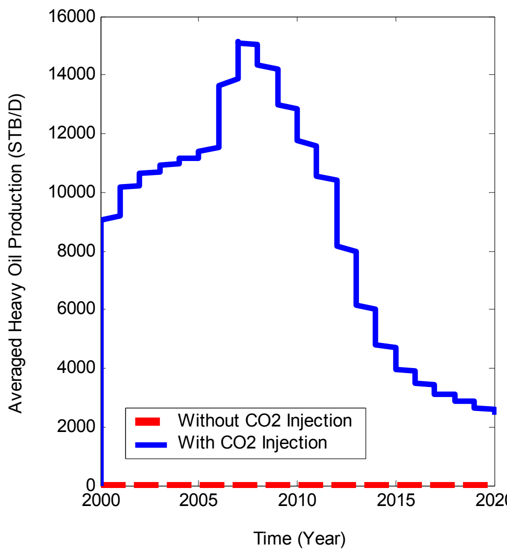

Figure 4b: Case 1 – Heavy Oil Production Forecast – With / Without CO_2 Injection

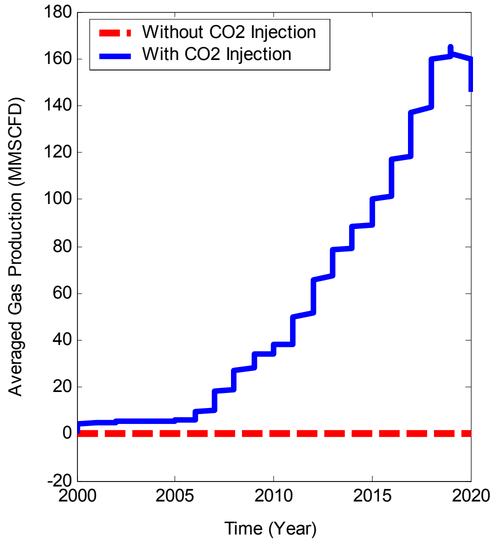

Figure 4c: Case 1 – Total Gas Production Forecast – With / Without CO_2 Injection

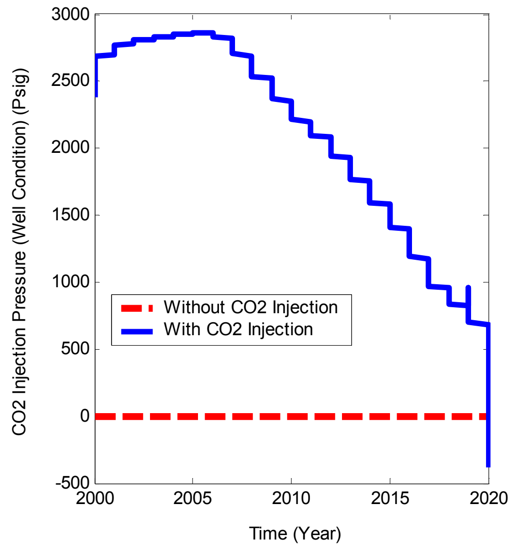

Figure 4d: Case 1 – Injection Pressure

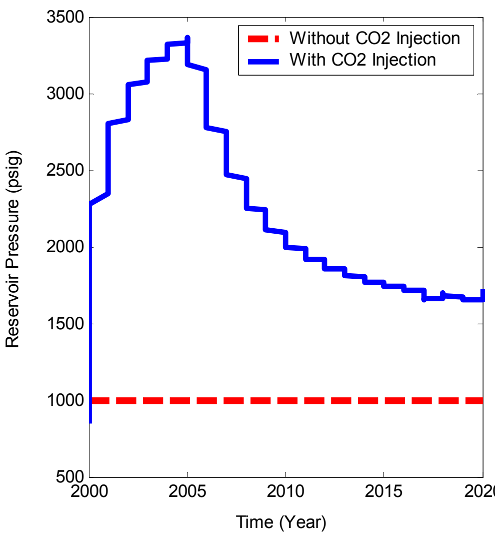

Figure 5a: Case 2 – Reservoir Pressure Forecast – With / Without CO_2 Injection

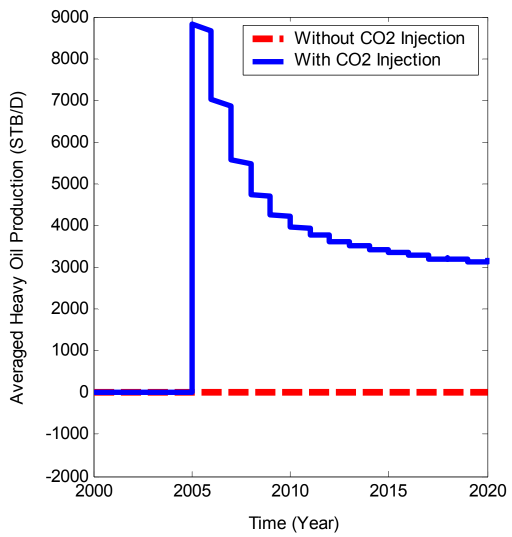

Figure 5b: Case 2 – Heavy Oil Production Forecast – With / Without CO_2 Injection

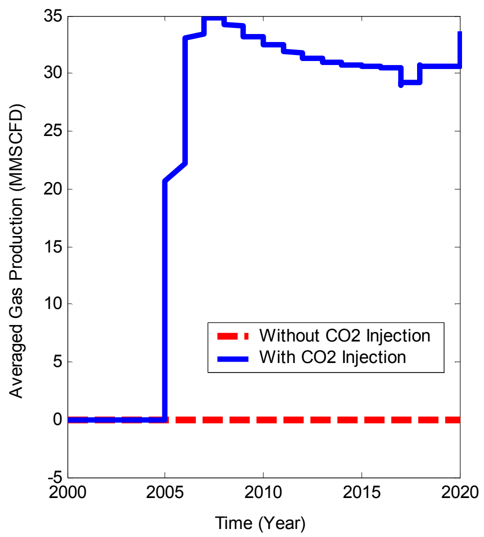

Figure 5c: Case 2 – Total Gas Production Forecast – With / Without CO_2 Injection

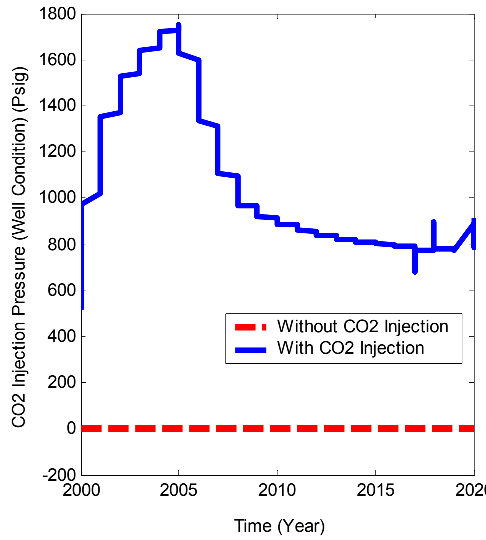

Figure 5d: Case 2 – Injection Pressure

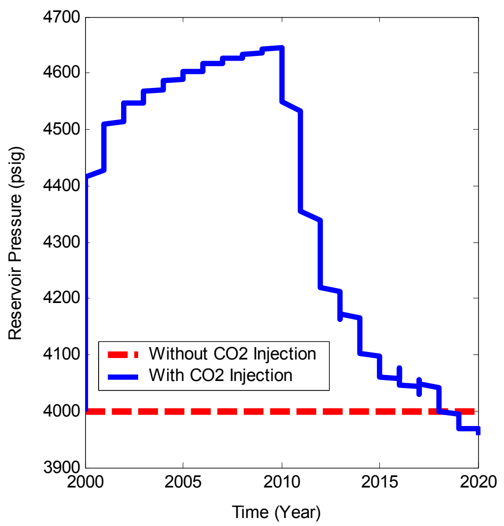

Figure 6a: Case 3 – Reservoir Pressure Forecast – With / Without CO_2 Injection

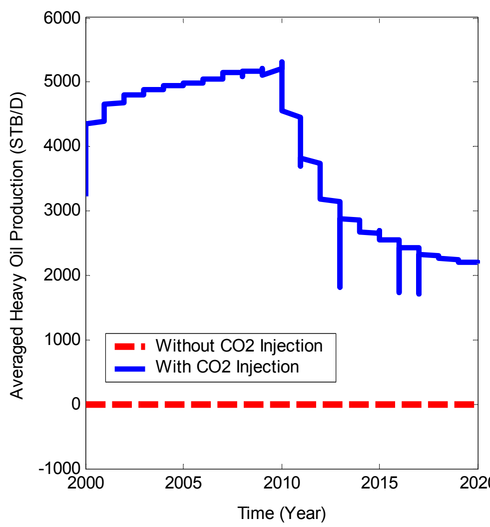

Figure 6b: Case 3 – Heavy Oil Production Forecast – With / Without CO_2 Injection

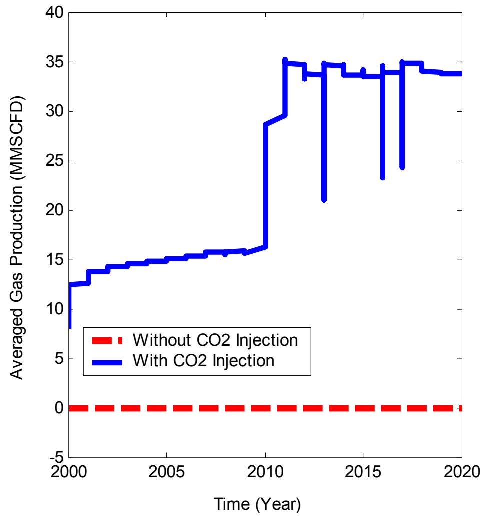

Figure 6c: Case 3 – Total Gas Production Forecast – With / Without CO_2 Injection

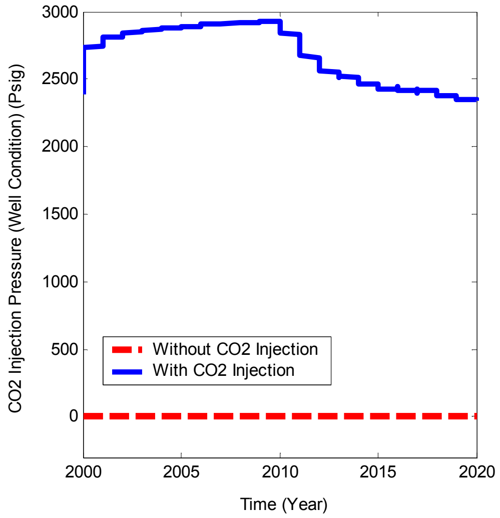

Figure 6d: Case 3 – Injection Pressure

CO_2 Injection Studied In Deepwater Heavy Oil Reservoir

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ABSTRACT

A comprehensive simulation work on cold heavy oil production (CHOP) using captured carbon dioxide (CO_2-EOR) technique was investigated using the state-of-the-art Integrated Product Modelling packages of Petroleum Experts as part of the Well Engineering Research Group unconventional oil reservoir management studies being undertaken at The Robert Gordon University (RGU).

This study enhances the Global interests to explore the beneficial uses of the captured CO_2, with particular application in deepwater development which is seen as emerging solutions from a safety, costs balance and long term perspectives. The modelling work discussed in this paper considered transportation of CO_2 from an onshore compression station using a 240 km subsea pipeline and injected into a heavy oil reservoir (2 km below sea-bed) via a vertical injection well. A production system designed to facilitate the recovery of the heavy crude to the topside separator (2 km water depth) was connected to the reservoir.

The Integrated Injection and Production Systems modelled to operate as a single module have demonstrated interesting results, the realism as well as the challenges of CO_2-EOR for CHOP. Sensitivity analysis showed that the productivity of the reservoir and performance of the CO_2-EOR was significantly influenced by the reservoir characteristics, production history and the injection pressure. Both miscible and immiscible displacements were evaluated based on the reservoir pressure criteria available on the public domain. Despite the supercritical state of the transported CO_2 at high injection pressure, the integrated modelling results showed no specific requirement for intermediate compression or booster pump along the system, particularly for miscible conditions with minimum injection pressure of 3000 psig.

Overall, the results indicated that CO_2-EOR for CHOP will initiate (for unloading reservoir) or boost (loading reservoir) production in miscible conditions. However, at low reservoir pressure, although recovery of the resources was achievable, a severe delay in the production forecast (i.e. years of zero recovery) at continuous CO_2 injection revealed that immiscible condition was perhaps not as viable as miscible process for the conditions investigated.

Keywords: CO_2-EOR, Heavy Oil Recovery, Cold Process, Miscible process, Immiscible Process Integrated System Modelling.

INTRODUCTION

Heavy oil development is progressively becoming a way forward to mitigate the decline in the worldwide conventional crude. Despite the literatures claiming that heavy oil is only found in shallow water [1], recent publication [2] indicates that Petrobras has approved the first offshore heavy oil development project for its Siri field in the Campos Basin. The Siri field is known to have recoverable reserves of 270 million barrels of heavy oil, at around 12.3 API and Petrobras recognizes that the exploitation of the resources will rely on special and emerging technology. This paper focuses on deepwater heavy oil recovery using captured carbon dioxide (CO_2-EOR).

Heavy oil recovery was previously investigated using some of the tertiary recovery techniques such as water alternating gas (WAG) chemical processes, gas injection and microbial EOR. About thirteen (13) methods were theoretically evaluated by [3] on two (2) heavy oil (18-24 API) fields consisting of four (4) reservoirs in total in Africa. Pure CO_2 was reported to be the best recovery agent by [4] following core-flood laboratory investigation using three injection gases (flue gas containing 15 mol% CO_2 in N2, a produced gas containing 15 mol% CO_2 in CH4, and pure CO_2) for heavy oil recovery (~14° API collected from Senlac reservoir located in the Lloydminster area, Saskatchewan, Canada). Similar to [4], but with sensitivity of Water alternating CO_2 carried out, [5] reported that a reduction in either waterflood or CO_2 injection rate resulted in an increased in oil recovery and showed the interference of viscous, capillary and diffusive forces. [6] concluded that the simultaneous injection of CO_2 and steam increased recovery, reduced injection temperatures, and reduced the heat input required, following a high pressure displacement on the recovery of West Sak heavy crude oil (19.2 API,) using Steam / CO_2 in a 1D laboratory experimental test conducted in an unconsolidated sand-pack (2” diameter and 4ft long).

In another hand, space and weight constraint on most offshore platforms (new or existing) is generally a major challenge and enormous difficulties are foreseen with regard to accommodating additional facilities such as those required for CO_2-EOR. Consequently, direct injection from an onshore source could be a good way forward and this study looked into an integrated injection and production system interaction with CO_2 injected from a remote onshore source.

MODEL DESCRIPTION

Deepwater heavy oil recovery using CO_2-EOR technique was investigated using the Petroleum Experts suite of software GAP/PROSPER/MBAL. The investigation was entirely simulation based and the surface and subsurface facilities were integrated together to properly assess the effect of injecting CO_2 from a remote location. The total pipeline length was 250 km covering both onshore (10 km) and offshore sections (240 km). The water depth was 2 km as well as the depth below the sea-bed. The transported CO_2 was injected into the heavy oil reservoir via a vertical injection well. The Injection system comprised the subsea pipeline transporting CO_2 from the surface facility and connected to the subsea structure ready for injection, while the production system was connected to the topside separator via a subsea wellhead having 6” tubing size and 8” casing diameter. The schematic representation of the integrated configuration system is shown in Figure 1.

The reservoir was modelled using typical data. The reservoir thickness and radius were 300 ft and 2500 ft respectively, the reservoir temperature was 120 ^oF and the original oil in place (OOIP) was 500 MMSTB. Different production history with initial pressure varying from 1000 psig to 4000 psig was used. A comprehensive sensitivity analysis was carried out for a wide range of reservoir production history to appreciate the importance of the integrated injection and production systems. Production forecast was performed for different reservoir conditions under both miscible and immiscible conditions using the following criteria presented in [7] which are shown Table 1.

Temperature	Pressure	Condition	Comments
$T_{res} < 86\ ^oF$	$P_{res} < 1000$ psia	Immiscible	
$86\ ^oF < T_{res} < 90\ ^oF$	1000 psia $< P_{res} < 1200$ psia	Miscible / Immiscible	Either Possible $P_{CO2} = 1073$ psia, $T_{CO2} = 87.8\ ^oF$
$T_{res} > 90\ ^oF$	$P_{res} > 1200$ psia	Miscible Possible	

Table 1: Miscibility and Immiscibility Criteria Based on CO_2 Critical Temperature & Pressure

Results of the following cases are discussed in the next section:

1. Miscible Process and the influence on the reservoir production trend;
2. Immiscible Process and the influence on the reservoir productivity;
3. Varying Reservoir Pressure at Constant GOR for different CO_2 Injection Pressure;
4. Constant reservoir pressure at various GOR for different CO_2 injection pressure;
5. Sensitivity of GOR, viscosity, heavy oil API and injection pressure.

RESULTS AND DISCUSSION

High pressure reservoir (> 1000 psig) is known to be suitable for CO_2 miscible process by enhancing the flow performance. However, this study has demonstrated that under certain conditions such as that of non Newtonian heavy crude with high viscosity, the reservoir pressure will probably need to be as high as 4000 psig to create an instantaneous impact on the productivity. Meanwhile, with CO_2 immiscible process occurring at reservoir pressure below 1000 psig, the production forecast has demonstrated that heavy oil recovery was achieved by compensating the low reservoir pressure using high injection pressure to force the heavy oil towards the production well. Table 1 shows the key findings and differences between the two techniques.

	Miscible Process	Immiscible Process
Recovery Start Time	0 – 1 Year (Immediate Impact)	> 15 Years
Recovery Volume / Factor	High	Low
Cost Implication	Low	High
General Remarks	Pipeline integrity could be an issue	Could be used to maintain production

Table 1: Key Features of the Miscible and Immiscible Processes

Miscible Process

The reservoir pressure was kept constant at 4000 psig and the injection pressure at the pipeline inlet (onshore) ranged from 2000 psig to 7000 psig. Other parameters remained as follow: heavy oil 20° API specific gravity, GOR (500 scf/STB). The integrated system results showed that heavy crude extraction was easily enhanced at injection pressure as high as 3000 psig, provided that the reservoir pressure was around 4000 psig. The production forecast (year 2000 to 2020) presented in Figure 2 showed the variation in maximum heavy oil production and the averaged CO_2 injection rates at different injection pressure.

Immiscible Process

Immiscible process was investigated using lower reservoir pressure (1000 psig) with the injection pressure at the pipeline inlet varying from 800 psig to 7000 psig. The heavy oil specific gravity was 20° API. Different production trends compared to the results obtained with high initial reservoir pressure (4000 psig) were experienced. Even at injection pressure as high as 7000 psig, the production forecast showed no recovery until 01/05/2003. The recovery was initiated by a rapid production leading to the peak, followed by a curvy decline which gradually lead to a steady state production.

Figures 3a & 3b illustrates the gas injection and the total gas production trend as well as the heavy oil production when the injection pressure was 3000 psig. The reservoir pressure was 1000 psig and the GOR 100 scf/STB. The variation in heavy oil peak production was between 800 to 1000 STB/D as the injection pressure reduced from 7000 psig to 4000 psig in increment of 1000 psig. The difference in maximum production was approximately 2000 STB/D as the injection reduced from 3000 psig to 2000 psig, and much more lower (3000 STB/D) when the injection pressure reduced from 2000 psig to 1000 psig. This indicates that the production was significantly influenced by the injection pressure and that under immiscible condition significant injection pressure will be required to compensate the low reservoir pressure. Although production was possible at 1000 psig and 900 psig injection pressure, production could only start from year 2016 and 2023 respectively, leading to about 16 and 23 years of continuous CO_2 injection with zero recovery.

Heavy crude displacement by CO_2 injection is known to rely on the phase behaviour of CO_2 and the interaction within the reservoir. The reservoir temperature and pressure can significantly affect the miscibility of the two components (CO_2 and heavy oil). At low reservoir pressure, recovery of the heavy oil to the surface was significantly delayed until mobility of the heavy crude was possible. Due to low pressures hindering the fluids immiscible or delaying the mobility of fluids, swelling and the heavy oil viscosity reduction was the pre-requisites prior to the fluids displacement mechanism to be possible. The long period of no production at continuous CO_2 injection was either caused by the lack of sufficient energy (low reservoir and injection pressures) to push the fluids out of the reservoir or the inefficient fluids interaction to create the required swelling and viscosity reduction, or a combination of the two effects.

In another hand, at 900 psig injection pressure which was below the CO_2 critical pressure, the heavy oil displacement was possible despite more than two (2) decades of zero gas or heavy oil production. A much smaller ROI (Return on Investment) and longer payback time as it appears seem to prove that the immiscible process for heavy oil reservoir in some conditions may not be a viable option.

Sensitivity Analysis

Sensitivity analysis was carried out to assess the influence of the reservoir pressure, GOR, heavy oil viscosity and specific gravity, on the reservoir productivity. The results are show in sub-plot format in Figure 4.

Varying Reservoir Pressure at Constant GOR for different CO_2 Injection Pressure;

The productivity of the reservoir was further investigated by varying the reservoir pressure and the injection pressure while keeping the GOR constant at 100 scf/STB. With the injection pressure below 4000 psig, the production forecast indicated that the recovery was unlikely when the reservoir pressure varied between 2000 psig and 4000 psig.

However, at 1000 psig (reservoir pressure), the heavy oil recover was achievable when the injection pressure was below 3000 psig. The period of zero production was shortened as the reservoir pressure increased; however, no heavy crude displacement occurred before the reservoir pressure was sufficient to push the heavy crude toward the production well up to the surface facilities located 4km above the reservoir.

Sensitivity of GOR, Viscosity, heavy oil API and injection pressure.

In this case, the production forecast is shown in Figure 4 for a constant reservoir pressure (4000 psig) and various GOR. The maximum heavy oil production occurred at the lowest GOR (100 scf/STB), and the peak production decreased as the GOR reduced. At 3000 psig injection pressure, the heavy oil recovery (although very unstable) was also possible, but only when the GOR was 400 and 500 scf/STB.

By considering different heavy oil specific gravity varying from 10^o API to 18^o API, a reasonably good range of most common types of heavy oil were taken into account. Heavy oil viscosity is known to vary between 100 cP and 10000 cP. The viscosity effect has been assessed covering from 10-10000 cP. The results are also shown in Figure 4, and reveals that the production was spontaneous as soon as the injection was initiated for 10 cP. Production started two (2) months after the injection was initiated when the viscosity was 100 cP and approximately one year later when the viscosity was 1000 cP and 10000 cP. This suggests that the heavy oil recovery is appreciably influenced by the reservoir properties, the fluids interaction and mixing process, and other thermodynamic effects that effectively enable the dynamic of the fluids within the reservoir up to the surface.

CONCLUSIONS

On the basis of the results of this investigation, cold heavy oil recovery is certainly achievable using CO_2-EOR technique, with CO_2 injected from a remote onshore source. Under such conditions, CO_2 is transported in dense phase as high injection pressure is required to account for the frictional losses along the transmission line and to create the enhancement required that will move the heavy crude from the reservoir to the topside surface facilities. Both Immiscible and Miscible conditions were evaluated and it was clear under the conditions investigated that Miscible process was more efficient and pragmatic than Immiscible process.

Low heavy oil reservoir pressure with low GOR can be very costly to optimise due to production 'hold back' and the momentous energy (injection pressure) required to initiate recovery. The higher the viscosity, the longer the mixing process within the reservoir, and the higher the required injection pressure to facilitate the movement of the heavy oil within the reservoir to the production platform. When the initial reservoir pressure was as high as 4000 psig with 500 scf/STB (GOR), heavy oil production was instantaneous as soon as CO_2 injection was initiated.

It is believed that during CHOP using CO_2-EOR technique, part of the injected CO_2 must be trapped in the heavy oil reservoir by various means, while considerable volume of the injected CO_2 must undoubtedly return with the produced heavy oil to the topside production facilities. This subject (CO_2 sequestration) is currently being investigated as part of the research interests of the Well Engineering Research Group at the RGU.

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ABBREVIATIONS

API	American Petroleum Institute
CHOP	Cold Heavy Oil Production
CO_2	Carbon Dioxide
EOR	Enhanced Oil Recovery
IOR	Improved Oil Recovery
MMP	Minimum Miscibility Pressure
OOIP	Original Oil In Place
STB	Stock Tank Barrel

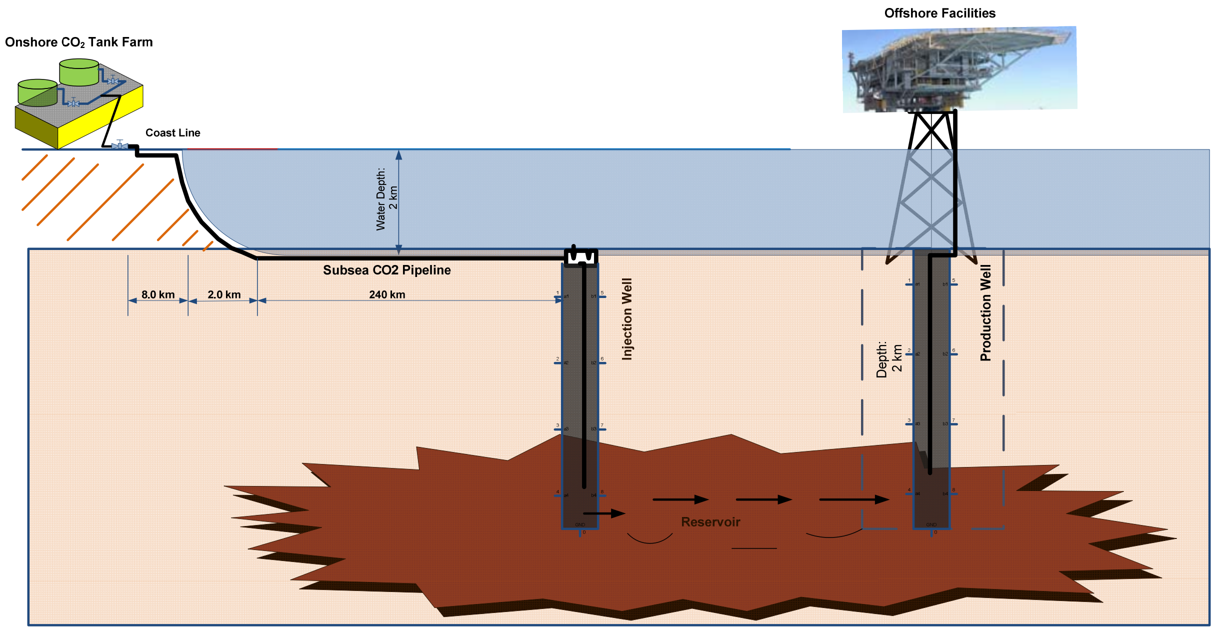

Figure 1: Diagrammatic Representation of the Integrated System

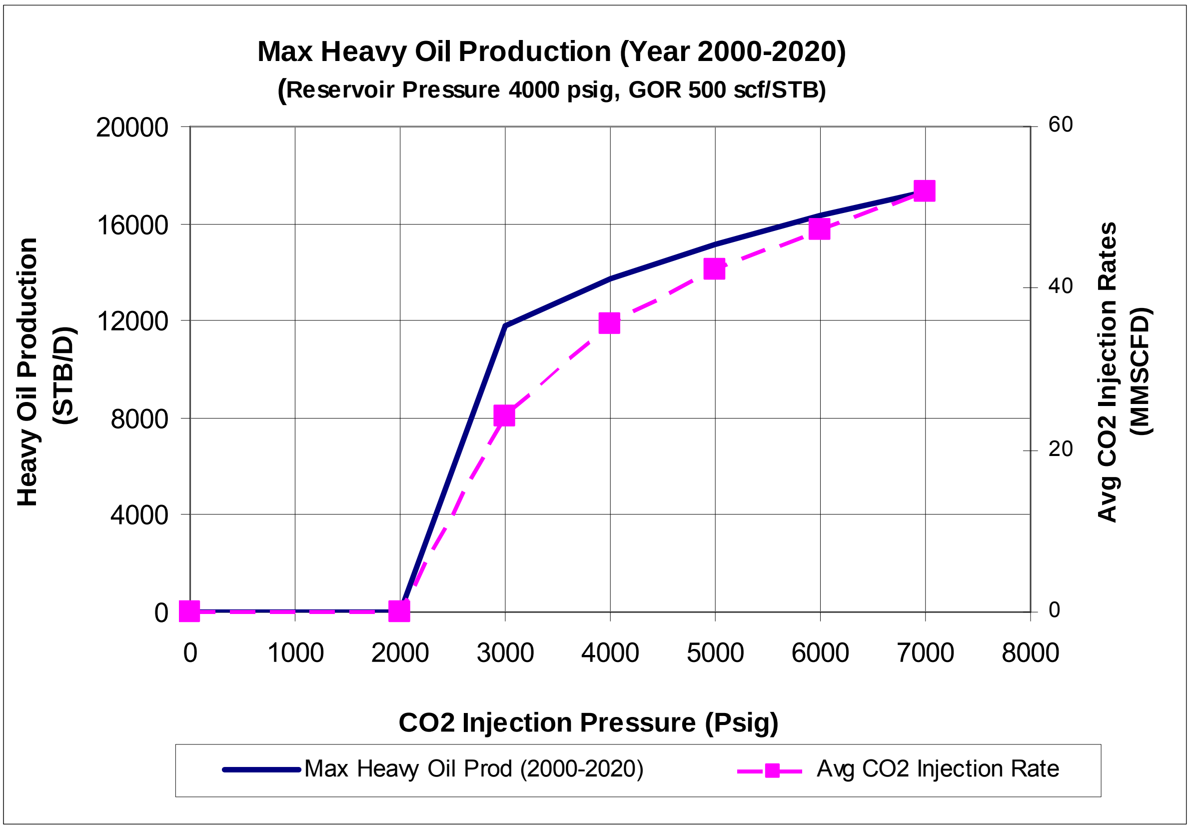

Figure 2: Production Rates (Prediction) at various Injection Pressure – Reservoir Pressure 4000 psig, GOR 500 scf/STB

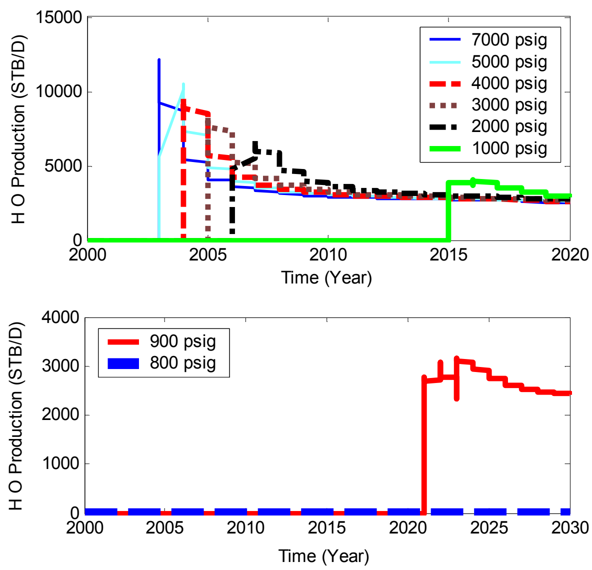

Figure 3a: Effect of CO_2 Injection Pressure –Reservoir Pressure: 1000 psig – Heavy Oil Production

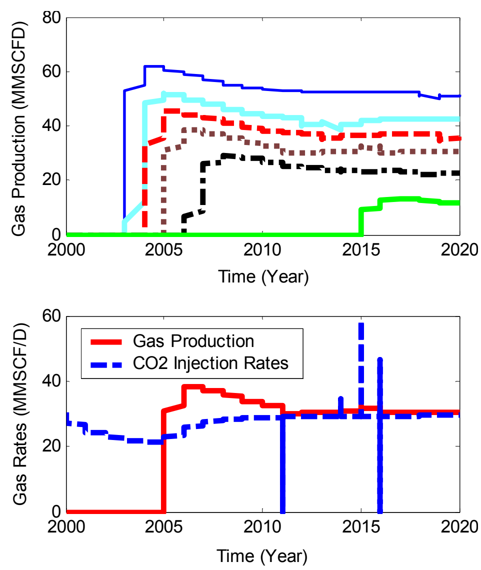

Figure 3b: Effect of CO_2 Injection Pressure – Reservoir Pressure: 1000 psig – Gas Rates

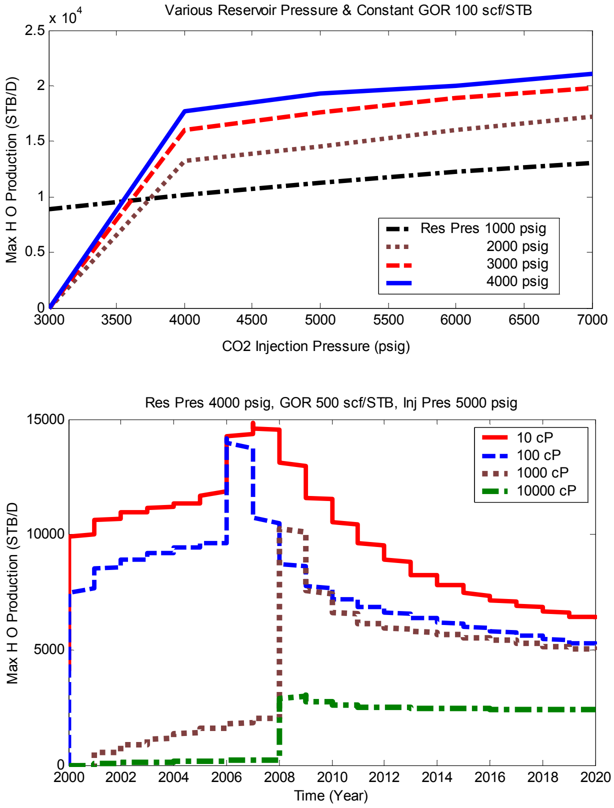

Figure 4a: Sensitivity Analysis Results

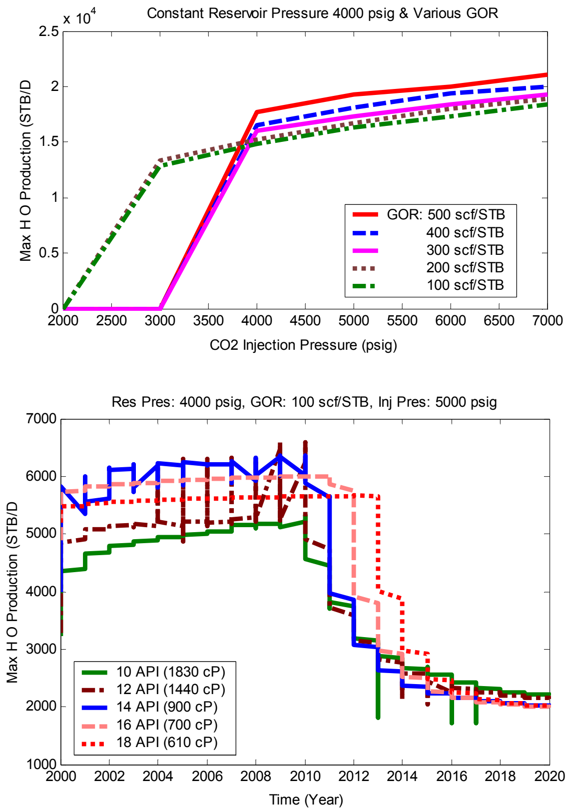

Figure 4b: Sensitivity Analysis Results

Investigation of CO_2 Sequestration during Cold Heavy Oil Production

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ABSTRACT

CO_2 sequestration during cold heavy oil production (CHOP) using captured carbon dioxide (CO_2-EOR) was investigated using REVEAL of Petroleum Experts. The results indicated that the CO_2 release was influenced by the production phases. The prediction showed high CO_2 retention in the first few years post start-up, followed by gradual decline towards 16.5 % post peak production. The recovery rate was strongly influenced by the reservoir characteristics such as fluid properties, permeability, aquifer and well completion. Horizontal wells provided better performance than vertical wells. The CO_2 utilisation and retention per barrel of heavy oil increased as the CO_2 injection pressure increased.

Keywords: CO_2-EOR, Cold Heavy Oil Production, CO_2 Sequestration. CO_2 Utilisation, Well Completion.

INTRODUCTION

Carbon dioxide capture for enhanced oil recovery (CO_2-EOR) is one of the preferred enhanced recovery techniques to date and offers potential economic benefit through additional oil recovery as well as CO_2 storage. There are four (4) main techniques used to capture CO_2 from large-scale industrial facilities or power plants known as: 1) Post-combustion capture, 2) Pre-combustion capture, 3) Oxy-fuel combustion capture, 4) Industrial processes. Description of each process can be found in the IPCC report (IPCC Report, 2005). There are two (2) main storage options known as Ocean Storage and Geological Storage. Due to substantial uncertainties, Legal and HSE issues, the ocean storage lack behind and face enormous hurdles to be attractive. As for geological storage, three (3) main types of geological environments are being considered for carbon sequestration: 1) Oil and gas reservoirs; 2) Deep saline reservoirs / aquifers; 3) Un-mineable coal seams. Under high pressure, CO_2 turns to liquid and can move through a formation as a fluid. Once injected, the liquid CO_2 tends to be buoyant and will flow upward until it encounters a barrier of non-porous rock, which can trap the CO_2 and prevent further upward migration, (www.netl.doe.gov). Saline and other types of reservoirs also have two additional trapping mechanisms that help trapping / storage of the CO_2 known as Solubility and Mineral trapping.

During CO_2-EOR, a small amount of the injected CO_2 dissolves in the oil. Laboratory results have demonstrated that the injection of CO_2 would result in swelling of the oil by over 20%, a significant reduction in oil viscosity, and a 95% reduction in interfacial tension (Hycal, 2004), and making the oil flow more easily in response to pressure gradients (Nummedal et al, 2003). CO_2-EOR is known to allow recovery up to 20 % of the OOIP (Original Oil in Place) (Meyer, 2008). Approximately 53 to 82 % more oil could be produced by the CO_2 flood than is produced by water in the best areas of the waterflood, according to the test conducted by (Holm and O'Brien, 1971) and (Holm, 1987).

There are variety of speculation with respect to CO_2 storage during EOR, some believe that CO_2-EOR in conventional oil reservoir will result in increased carbon emissions from incremental oil production (IEA GHG, 2007), other believe that 40% (Shaw and Bachu, 2002) & (Hadlow, 1992) or up to two-thirds (wikipedia.org) of the injected CO_2 is being produced and can be re-injected. In the Bati Raman heavy oilfield (9° to 15° API), in southeast Turkey, close to the Turkish-Iraqi border, where immiscible displacement using CO_2-EOR is in operation, approximately 1700 tonnes of CO_2 are injected daily, 16% to 60% of which is recycled, (IEA GHG, 2000). Despite most scientists believing that crude oil is not heavy at the origin (Curtis, 2002), CO_2 storage during heavy oil recovery or in heavy oil reservoir has not been investigated widely and the question is whether the existing theories for conventional oil are by default applicable for heavy oil reservoir.

CO_2-EOR enables chemical and physical interaction of the injected CO_2 with the reservoir rock and fluids, creating favourable conditions that improve oil recovery. These conditions are discussed in detail by (Tzimas et al, 2005).

MODELLING APPROACH

The reservoir was modelled using REVEAL, the reservoir simulator by Petroleum Experts. The grid block was of dimension 25, 25, 15 in I, J and Z directions respectively. A block size of 500 ft x 500 ft x 200 ft, grid depth of 10000 ft and a single porosity. Two wells, one producer and an injector, and both horizontal. The model was homogenous as shown in **Figure 1.** The simulation was performed over 25 years starting from 1 January 2006. **Tables 1 and 2** present the reservoir and fluid properties used in the simulation and the aquifer properties are given in **Table 3**.

The initial pressure used in this analysis was 2500 psig, with the temperature of 200 ^oF. The CO_2 was injected into the reservoir through a horizontal well, 8 km long and completed over a length of approximately 150 m. The reservoir gas was modelled as CO_2. With a critical pressure of 1073 psi and critical temperature of 87.8 °F, CO_2 will be in a supercritical state at bottom-hole injection and reservoir conditions; hence CO_2 was defined in the model as gas with the corresponding dense phase density.

In a subplot format, **Figure 2a** shows the variation at different temperature and pressure of the reservoir heavy oil and gas viscosity, density, formation volume factor (FVF) and condensate gas ratio (CGR). The temperature ranged between 50 ^oF to 200 ^oF while the pressure varied from 100 psig to 5000 psig. Mobility of heavy oil is known to be much easier at high temperature. At 200 ^oF, the reservoir heavy oil viscosity was approximately 25 cP, as the temperature reduced the heavy oil viscosity increased. During the injection, as the reservoir heavy oil comes in contact with the injected CO_2 at lower temperature (50 ^oF - 70 ^oF), the heavy oil viscosity will significantly vary as the reservoir temperature will reduce. Hence, the heavy oil viscosity profile purposely illustrated the heavy oil viscosity variation at different temperatures, and indicated that the heavy oil viscosity could rise up to 7730 cP at 50 °F if the reservoir pressure was to reach 5000 psig. The heavy oil density was very close to that of water and varied between 57.5 lb/ft^3 to 60.2 lb/ft^3 at the temperatures and pressures investigated. The heavy oil FVF was almost constant.

As shown in **Figure 2a**, the reservoir gas thermodynamic properties were deliberately modelled to reflect those of CO_2. The reservoir gas was modelled as retrograde condensate to take into account the phase change at various temperature and pressure. CO_2 is expected to reach the reservoir in supercritical state due to the high pressure within the transported line as well as the reservoir. This phenomenon is effectively represented in the modelling by the retrograded condensate process which take into account the condensate CO_2 being lost in the gas stream. The phase behaviour of the reservoir gas is adequately illustrated in the density and CGR profiles at various pressures. With regards to the density profile, the gas density sharply rose from 15 lb/ft^3 (dry gas phase) to 52.5 lb/ft^3 (dense phase) when the pressure reached 1073 psig. Above 1073 psig, the variation in density was very slow and only changed from 52.5 lb/ft^3 to 57.8 lb/ft3 (3000 psig). The high reservoir gas density at 1073 psig was in agreement with conventional knowledge and also ascertained that the properties of the fluid were appropriately modelled. In another hand, the CGR reflected the phase variation of CO_2 within the reservoir at different pressure as shown in **Figure 2a**. REVEAL was also used to calculate the reservoir CGR and gas FVF with the dense phase CO_2 density and viscosity for pressure varying from 100 psig to 3000 psig. The CGR increased with increasing pressure, from 28 STB/MMSCF at 100 psig to 123 STB/MMSCF at 3000 psig. There was negligible variation in the reservoir gas (CO_2) viscosity and FVF at different pressures and temperatures. The reservoir FVF was about 0.004 ft^3/scf and the viscosity ranged approximately from 0.023 cP to 0.048 cP.

Figure 2b shows the variation at different temperature and pressure of the reservoir water viscosity, density and formation volume factor (FVF) in a sub-plot format. The temperature ranged between 50 °F to 200 °F and the pressure varied from 100 psig to 5000 psig. Once again, the profiles were in accordance with prediction published in the public domain. The viscosity was about 0.34 cP at 200 °F and progressively increased with reducing temperature. The maximum viscosity was 1.4 cP at 50 °F. The density varied between 60.5 lb/ft^3 to 63.5 lb/ft^3, and the variation was very minimal. The formation volume factor was approximately 1 RB/STB and the compressibility factor was extremely low.

The variation of the reservoir fluids (heavy oil, gas and water) properties with temperature when the reservoir gas is modelled as natural gas as opposed to CO_2 is presented in **Figure 3**. And it is comprehensible that the maximum gas density is 0.0595 lb/ft^3 and the maximum viscosity is 1.3 cP. The heavy oil viscosity increased as the temperature dropped and other fluids behaviours with respect to temperature rise / drop were as previously reported.

METHODOLOGY

Both Black Oil and Compositional Models were used. The PR EOS was selected to generate the VLP files for the injection and production system using PROSPER. The production system was modelled as black oil model while the injection system remained compositional, with the properties of CO_2 clearly inputted. However, although the models take into account the fluid composition through the VLP file created using PROSPER, the output from REVEAL provides no information regarding the reservoir fluid composition.

Two methods, mass conservation of CO_2 around the reservoir loop and the production profiles evaluation, were used to interpret the REVEAL results in order to estimate the CO_2 sequestration during CO_2-EOR.

Mass Conservation

This approach considered the mass of CO_2 entering ($\dot{m}_{CO2\ inj}$) and leaving ($\dot{m}_{CO2\ out}$) the reservoir and the mass of CO_2 retention ($\dot{m}_{CO2\,Seq}$) within the reservoir, which is conveyed in the following expression:

$$\dot{m}_{CO2\ inj} - \dot{m}_{CO2\ out} = \dot{m}_{CO2\ Seq} \tag{1}$$

The density of CO_2 changes in a significant way as its pressure (P) changes and using the ideal gas Equation of State (EOS), the CO_2 density (ρ_{CO2}) can be calculated at the appropriate pressure, and hence the volumetric flowrate of CO_2 ($Q_{CO2\ Seq}$) can be established using the expression below. “T” stands for temperature and “Mw” for molecular weight of CO_2.

$$Q_{CO2\ Seq} = \frac{\dot{m}_{CO2\ Seq}}{\left(\frac{M_W}{R}\right)\left(\frac{P}{T}\right)} \tag{2}$$

Production Evaluation

Likewise, the formulation is consistent with the ones described in the mass conservation. The CO_2 sequestration ($Q_{CO2\ Seq}$) is estimated as the difference between the injected and the produced CO_2 ($Q_{CO2\ inj}$), taking into account the rates of CO_2 production during steady or quasi-steady state since the reservoir gas was modelled as CO_2. $Q_{CO2out\ WI}$, produced CO_2 when there is no CO_2 injection.

$$Q_{CO2\ Seq} = Q_{CO2\ inj} - \left(Q_{CO2\ out} - Q_{CO2\ out\ WI}\right) \tag{3}$$

In case where the reservoir gas is modelled differently other than CO_2, the $Q_{CO2\ out\ WI}$ term in the equation shall be omitted. $Q_{CO2\ out\ WI}$ was found to be less than 1% of that produced during CO_2 injection, hindering negligible any influence on the overall results, as far the simulations are concerned.

The CO_2 retention as function of barrel of heavy oil produced (Seq_{co2}) was calculated using the volumetric flowrate of heavy oil produced ($Q_{oil\ prod}$) and the CO_2 sequestration by the following expression:

$$Seq_{CO2} = \frac{Q_{CO2\ Seq}}{Q_{oil\ prod}} \tag{4}$$

The CO_2 requirement / utilisation per barrel of heavy oil produced ($CO2_{Req}$) was obtained using the required CO_2 injection as follow:

$$CO2_{Req} = \frac{Q_{CO2\ inj}}{Q_{oil\ prod}} \tag{5}$$

RESULTS AND DISCUSSIONS

The residual in place estimated by the solver based on the information provided is given below:

Water in place : 3.31093e+009 STB

Heavy Oil in place : 1.27529e+010 STB

Gas in place : 1.27529e+006 MMSCF

Figure 4 shows the heavy oil production rates when the injection pressure was 5000 psig, the calculated CO_2 sequestration per barrel of heavy oil produced, the percentage retention and the CO_2 requirements per barrel of heavy oil produced. The results reveal that the percentage of CO_2 sequestration was 100% for months post start-up. This may be justified by the theory that the injected CO_2 which is in dense phase expand as it reaches the reservoir. As the CO_2 expands, it reduces the reservoir fluid (heavy oil) viscosity by dissolving into the heavy crude. This process facilitates the mobility of heavy oil within the reservoir and toward the production system. Results also show that the CO_2 sequestration reduced sharply from 100% to 47% when the heavy oil production reached the first peak and reduced further to approximately 22% when the second peak production occurred. A sharp decline in production was also noticed, which was almost reflected by a continuous decline in the percentage of CO_2 retention. In year 2020, a rather slow reduction in the heavy oil production was noticed, at which stage the CO_2 sequestration remained almost stable around 22%. The CO_2 sequestration per barrel of heavy oil produced remained extremely high at the start-up as no CO_2 was released. But as soon as CO_2 production started, the CO_2 retention per barrel varied between approximately 1500 SCF/STB to 2000 SCF/STB. In another hand, the volume of CO_2 utilised per barred of heavy oil produced was significantly high (11.2 MSCF/STB) at the beginning of the production when there was no CO_2 being produced, sharply reducing to approximately 4 MSCF/STB as the production rose to the peak, stabilised for a couple of years before progressively increasing as the heavy oil production reduced.

Analysis Based on CO_2 Mass Balance

Figure 5 shows the mass of CO_2 sequestrated, the CO_2 retention per barrel of heavy oil, the CO_2 requirements and the percentage retention for the 25 years prediction. The CO_2 injection pressure was 5000 psig.

During the 25 years prediction, the results show that the CO_2 mass balance around the reservoir inlet and outlet was not consistent, as the CO_2 input was by far greater than the amount released (output). At the beginning (year 2006) of the production, no CO_2 was released as indicated by the mass flowrate of produced CO_2. The calculated percentage of CO_2 retention shows 100 % of CO_2 being retained in the reservoir in the major part of the first year (2006). In the meantime, the heavy oil recovery was spontaneous following the injection of CO_2. The beginning of heavy oil recovery also implied a progressive decline in the percentage retention of CO_2 in the reservoir, reaching approximately 17 % at the end of the prediction period (2050).

The heavy oil and gas production peaked twice as shown on the production profile, firstly at the same time in 2008; then the heavy oil peaked again in 2013 and remained almost steady until the peak gas production occurred in 2017. Following that trend, the heavy oil production began to decline while the gas production remained steady till the end of production in 2050. The difference between the mass of injected CO_2 and the mass of produced CO_2 show that during that period (peak production), the CO_2 retention dropped sharply as the production peaked, perhaps justifying the momentum required to increase the mobility of the heavy crude. Between year 2020 and 2050, the variation in CO_2 retention was much lower than it was between year 2006 to 2020.

From 2006 to 2008 where the production rose to the peak, the CO_2 retention per barrel of produced heavy oil reduced from 2.4 lb/STB to about 0.4 lb/STB and remained almost constant around that value. The utilised mass of CO_2 for every barrel of heavy oil produced dropped from 2.4 lb/STB to about 0.5 lb/STB, stabilised till 2018 and began to rise again progressively as the heavy oil production gradually was in decline.

Analysis Based on Peak Production

In this case, CO_2 sequestration was investigated at various injection pressures. The injection pressure was varied from 1000 psig to 7000 psig, in an increment of 1000 psig.

Figure 6 shows in a sub-plot format the peak heavy oil production, the percentage retention of CO_2, the CO_2 requirements for barrel of heavy oil and the CO_2 retention per barrel of heavy oil produced, at different CO_2 injection pressure. The peak production increases with injection pressure. The recovery was about 1.3 % when there was no CO_2 injection, however, showed appreciable growth as the CO_2 injection pressure was increased. From 0 to 1000 psig injection pressure, there was an increase of 9.7 % recovery. The percentage increase in recovery factor for every increment of injection pressure above 1000 psig was very tiny, although the recovery was significant high in the first increment (0 – 1000 psig). The difference between the injected volume of CO_2 and that produced gives an indication of how much CO_2 was retained in the reservoir daily. Although the daily CO_2 retention increased as the CO_2 injection pressure increased, the percentage retention remarkably indicated that high percentage of CO_2 was retained at low CO_2 injection (2000 psi). Beyond 3000 psig injection pressure, the percentage CO_2 retention was almost stable.

The analysis shows that when the injection pressure was 7000 psig, for every barrel of heavy oil produced, about 4290 SCF of CO_2 was required and approximately 690 SCF of CO_2 was trapped in the reservoir by various mechanisms. The CO_2 requirement and retention per barrel of heavy oil reduced as the injection pressure reduced or as the peak heavy oil reduced. Nevertheless, further analysis using different data may well predict a diminutive variation or an improved ratio on the amount of CO_2 stored and that required per barrel. Also, ways to improve CO_2 storage during CO_2-EOR have been discussed in (Jessen et al, 2005), one of the methods consisted of re-pressurising the reservoir after the end of oil production with continuous injection. In another hand, (Kovscek and Cakici, 2005) claims that a well control process, where wells are shut in according to a gas-to-oil production ratio limit to avoid excess gas circulation, is the best way to obtain both maximum oil recovery and CO_2 storage at the same time, opinion that was however rejected by (Jayasekera, 2005).

The calculations summary show in **Table 4** is based on maximum production, hence illustrate the CO_2 sequestration occurring during a quasi steady state condition.

CONCLUSIONS

On the basis of this investigation, heavy oil recovery was achievable using CO_2-EOR technique, and the volume of CO_2 produced together with heavy oil was appreciably lower than the volume of CO_2 injected. The results revealed lower CO_2 release in the first few years of the operation, followed by a gradual decline of CO_2 retention after the production peaked. The CO_2 retention per barrel was almost constant post peak production and the CO_2 utilisation per barrel of heavy oil increased as the heavy oil in place reduced.

The injected CO_2 was partly trapped in the heavy oil reservoir by various means and the volume of the trapped CO_2 was very much dependent of the production phase / cycle. Despite the low percentage of CO_2 sequestration at quasi-steady state production, the CO_2 returning with the produced heavy oil will have to be re-injected into the reservoir to minimize the project CAPEX. Moreover, a detailed analysis of the geochemical interaction between the reservoir rock and the injected CO_2 with a close look into the dissolution and mineralisation process during CO_2-EOR may provide improved prediction of CO_2 sequestration.

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Table 1: Fluids Properties & Rock Properties

	Data	Units
Rock Compressibility	3 x 10^{-5}	1/psi
Permeability	100	md
Reservoir Porosity	0.2	Fraction
Well Control: Constant Injection Pressure	3000	psig
Water Compressibility	2.9 x 10^{-6}	1/psi
Heavy Oil Specific Gravity	15	API
Heavy Oil Viscosity	523 - 2188	cP
Heavy Oil FVF	1.19	RB/STB
Water FVF	0.99	RB/STB
Gas FVF	0.0034	RB/STB
Gas Oil Ratio, GOR	500	scf/STB
Reservoir Temperature	122 - 200	C
Water gravity	1.068	Sp. gravity
Gas Gravity	0.7	Sp. gravity

Table 2: Residual Saturation used for the Simulation

	Data	
Critical Oil / Gas Residual Saturation, Sogc	0.05	Fraction
Critical Oil / Water Residual Saturation, Sowc	0.2	Fraction
Critical Water Residual Saturation, Swc	0.2	Fraction
Critical Gas Residual Saturation, Sgc	0.2	Fraction
End Point Oil / Water Relative Permeability, Krow	1	Fraction
End Point Oil / Gas Relative Permeability, Krog	1	Fraction
End Point Water Relative Permeability, Krw	1	Fraction
End Point Gas Relative Permeability, Krg	1	Fraction
Corey Exponent for Oil-Water	2	
Corey Exponent for Oil-Gas	2	

Table 3: Aquifer Properties

	Units	Values
Aquifer Model		Infinite Linear
Aquifer Porosity	Fraction	0.2
Aquifer Permeability	md	1000
Aquifer Compressibility	1/psi	3 x 10^{-6}
Thickness	feet	300
Encroachment Angle		90
Width	feet	300
Region 1		X_West, From (1, 1, 1) to (1, 25, 15)
Region 2		X_West, From (25, 1, 1) to (25, 25, 15)

Table 4: Results Summary for CO_2 Sequestration Based on Evaluation of Production Profiles

CO_2 Injection Pressure (psig)	CO_2 Injection (MMscf/D)	Maximum Heavy Oil Production (STB/day)	Max Gas Production (MMscf/D)	Maximum Recovery Factor (%)	Difference Between Inj & Prod CO_2 (MMscf/D)	CO_2 Retention (SCF/STB)	CO_2 Requirements (SCF/STB)	CO_2 Retention (%)
7000	733	170900	615	13.5	118.00	690.46	4289.06	16.32
6000	685	166056	575	13.3	110.00	662.43	4125.11	16.29
5000	629	160275	525	13.00	104.00	648.88	3924.50	16.79
4000	570	154480	475	12.70	95.00	614.97	3689.80	16.95
3000	505	143280	420	12.20	85.00	593.24	3524.57	17.15
2000	425	134300	350	11.77	75.00	558.45	3164.56	18.03
1000	345	115463	310	11.00	35.00	303.13	2987.97	10.61
0	0	60000	3.9	1.30	-3.90	-65.00	0.00	0.00

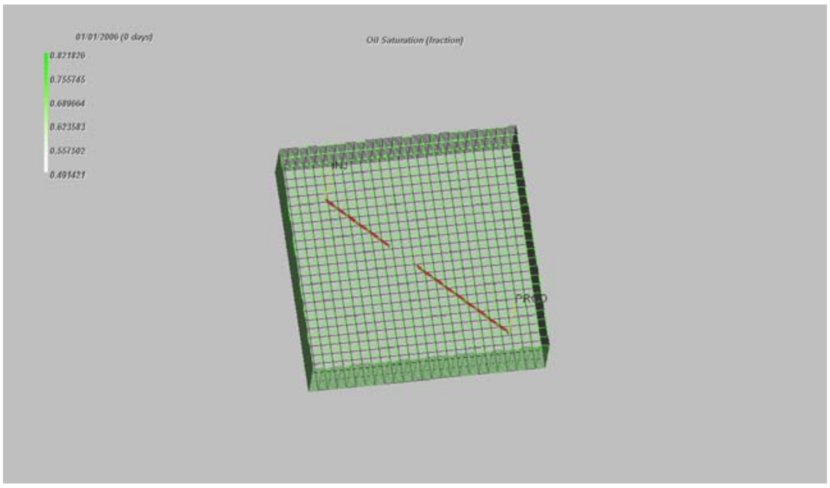

Figure 1: Block Grid and Horizontal Wells

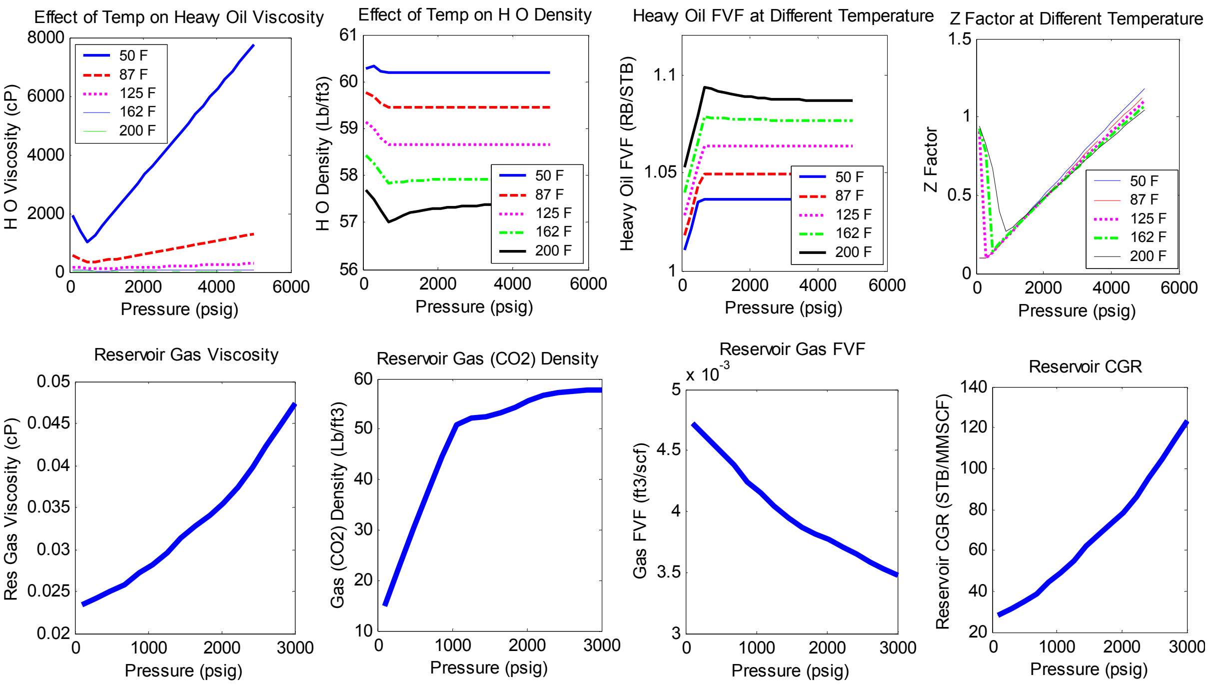

Figure 2a: Variation of Reservoir Heavy oil and Gas (CO_2) Properties with Temperature and Pressure

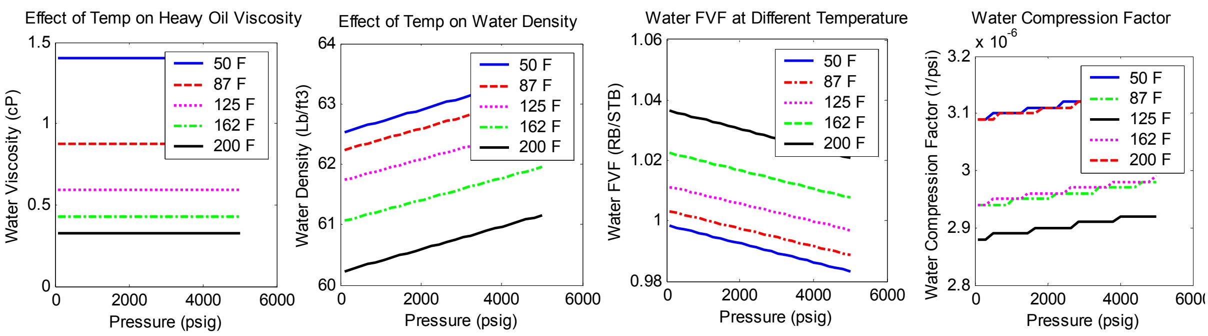

Figure 2b: Variation of Reservoir Water Properties with Temperature and Pressure

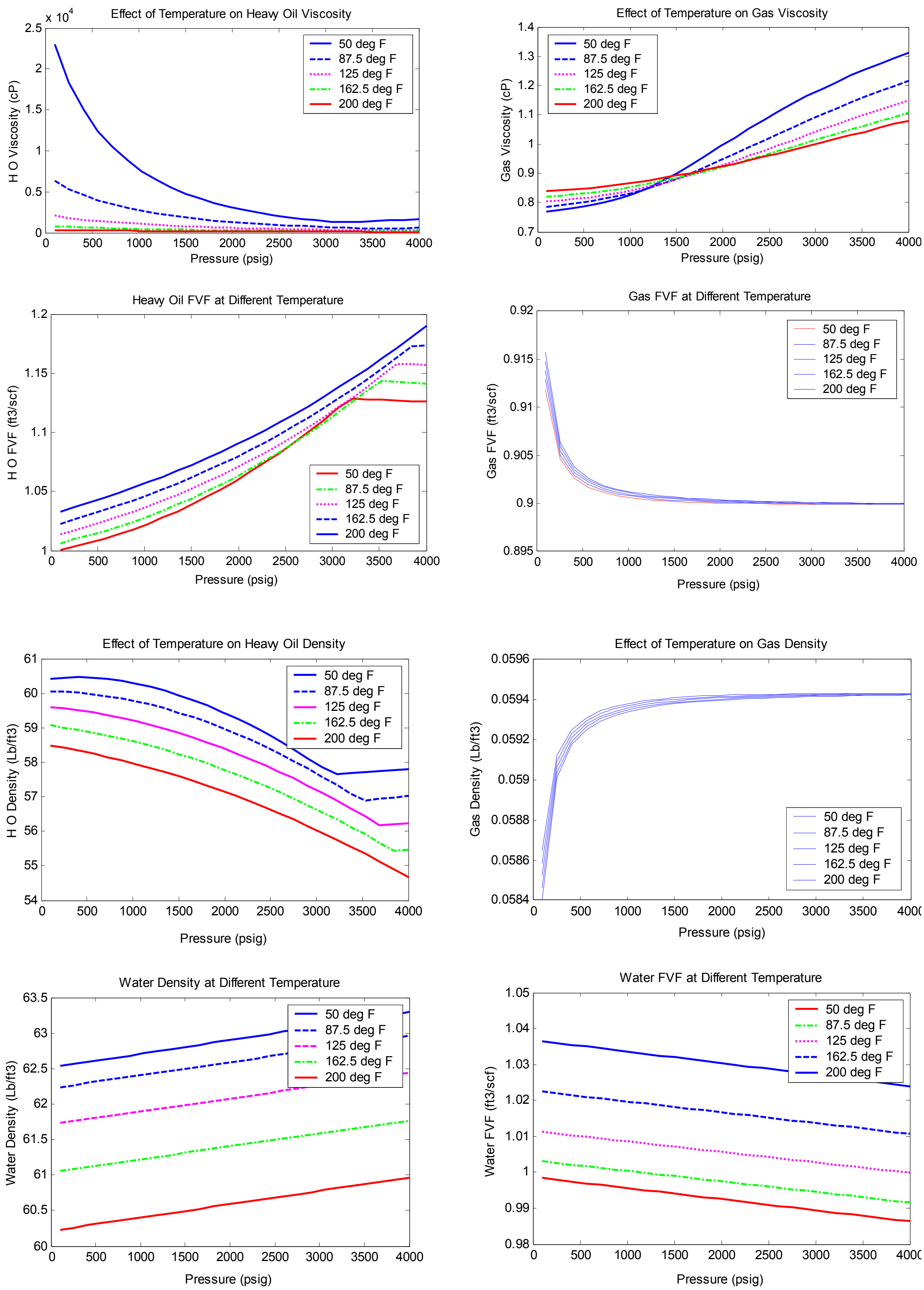

Figure 3: Reservoir Fluids Properties and Influence of Temperature and Pressure

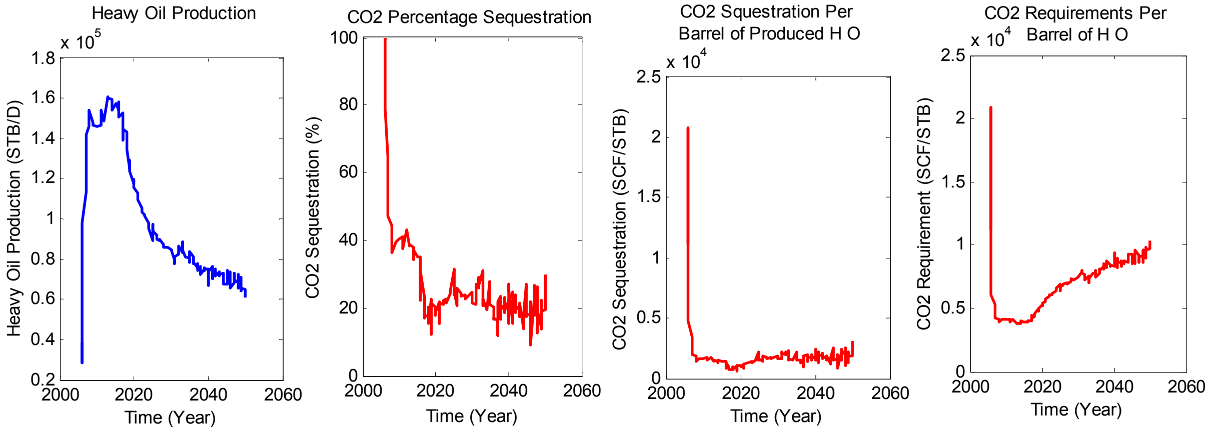

Figure 4: CO_2 Sequestration – Reservoir Pressure: 2500 psig, Injection Pres: 5000 psig

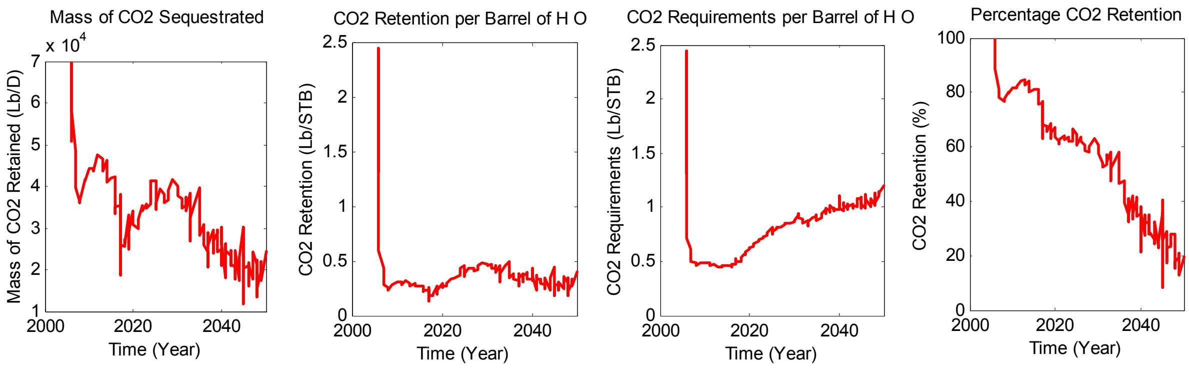

Figure 5: CO_2 Sequestration at 5000 psig Injection Pressure – Analysis by Mass Balance

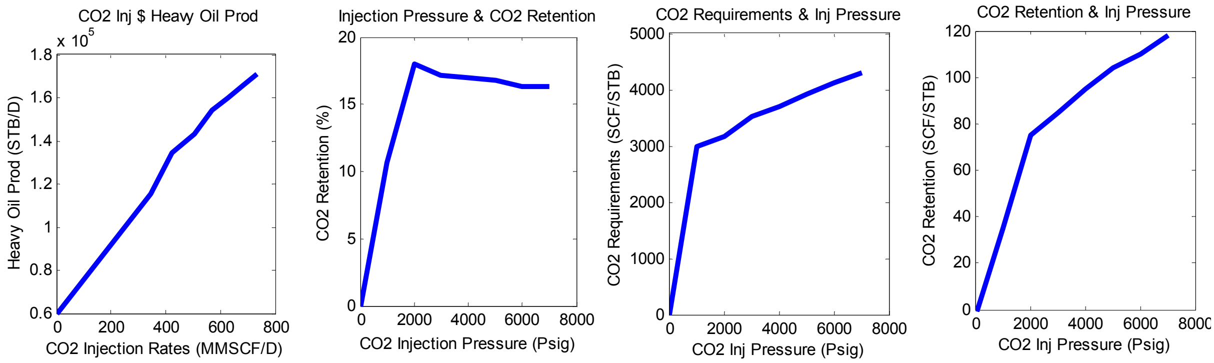

Figure 6: CO_2 Sequestration and the Relationship with Injection Pressure and Recovery Rates

Appendix 1 – World Oil Reserves by Country

Rank	Country	Barrels of Oil	Millions Barrels of Oil
1	Venezuela	297,600,000,000	297,600
2	Saudi Arabia	267,900,000,000	267,900
3	Canada	173,100,000,000	173,100
4	Iran	154,600,000,000	154,600
5	Iraq	141,400,000,000	141,400
6	Kuwait	104,000,000,000	104,000
7	United Arab Emirates	97,800,000,000	97,800
8	Russia	80,000,000,000	80,000
9	Libya	48,010,000,000	48,010
10	Nigeria	37,200,000,000	37,200
11	Kazakhstan	30,000,000,000	30,000
12	Qatar	25,380,000,000	25,380
13	United States	20,680,000,000	20,680
14	China	17,300,000,000	17,300
15	Brazil	13,150,000,000	13,150
16	Algeria	12,200,000,000	12,200
17	Angola	10,470,000,000	10,470
18	Mexico	10,260,000,000	10,260
19	Ecuador	8,240,000,000	8,240
20	Azerbaijan	7,000,000,000	7,000
21	European Union	5,675,000,000	5,675
22	Oman	5,500,000,000	5,500
23	India	5,476,000,000	5,476
24	Norway	5,366,000,000	5,366
25	Egypt	4,400,000,000	4,400
26	Vietnam	4,400,000,000	4,400
27	Indonesia	4,030,000,000	4,030

Rank	Country	Barrels of Oil	Millions Barrels of Oil
28	Malaysia	4,000,000,000	4,000
29	South Sudan	3,750,000,000	3,750
30	United Kingdom	3,122,000,000	3,122
31	Yemen	3,000,000,000	3,000
32	Argentina	2,805,000,000	2,805
33	Syria	2,500,000,000	2,500
34	Uganda	2,500,000,000	2,500
35	Colombia	2,200,000,000	2,200
36	Gabon	2,000,000,000	2,000
37	Congo, Republic of the	1,600,000,000	1,600
38	Chad	1,500,000,000	1,500
39	Australia	1,433,000,000	1,433
40	Sudan	1,250,000,000	1,250
41	Brunei	1,100,000,000	1,100
42	Equatorial Guinea	1,100,000,000	1,100
43	Denmark	805,000,000	805
44	Trinidad and Tobago	728,300,000	728
45	Ghana	660,000,000	660
46	Turkmenistan	600,000,000	600
47	Romania	600,000,000	600
48	Uzbekistan	594,000,000	594
49	Peru	579,200,000	579
50	Italy	521,300,000	521
51	Thailand	453,300,000	453
52	Tunisia	425,000,000	425
53	Ukraine	395,000,000	395
54	Netherlands	352,000,000	352
55	Turkey	270,400,000	270

Rank	Country	Barrels of Oil	Millions Barrels of Oil
56	Germany	254,200,000	254
57	Pakistan	247,500,000	248
58	Bolivia	209,800,000	210
59	Cameroon	200,000,000	200
60	Belarus	198,000,000	198
61	Congo, Democratic Republic of the	180,000,000	180
62	Albania	172,400,000	172
63	Poland	156,500,000	157
64	Papua New Guinea	154,300,000	154
65	Spain	150,000,000	150
66	Chile	150,000,000	150
67	Philippines	138,500,000	139
68	Bahrain	124,600,000	125
69	Cuba	124,000,000	124
70	Cote d'Ivoire	100,000,000	100
71	France	85,180,000	85
72	Austria	85,000,000	85
73	Guatemala	83,070,000	83
74	New Zealand	81,400,000	81
75	Serbia	77,500,000	78
76	Suriname	76,800,000	77
77	Croatia	71,000,000	71
78	Burma	50,000,000	50
79	Japan	44,120,000	44
80	Kyrgyzstan	40,000,000	40
81	Georgia	35,000,000	35
82	Bangladesh	28,000,000	28

Rank	Country	Barrels of Oil	Millions Barrels of Oil
83	Hungary	27,320,000	27
84	Mauritania	20,000,000	20
85	Bulgaria	15,000,000	15
86	South Africa	15,000,000	15
87	Czech Republic	15,000,000	15
88	Tajikistan	12,000,000	12
89	Lithuania	12,000,000	12
90	Israel	11,500,000	12
91	Greece	10,000,000	10
92	Slovakia	9,000,000	9
93	Benin	8,000,000	8
94	Belize	6,700,000	7
95	Taiwan	2,380,000	2
96	Barbados	2,260,000	2
97	Jordan	1,000,000	1
98	Morocco	680,000	1
99	Ethiopia	430,000	0.4
100	Moldova	7,330	0.01
	Total		**1,635,466**

Appendix 2 – Predicted Reservoir Production Trend

Duns and Ros Modified												
Bottom Measured Depth (feet)	True Vertical Depth (feet)	Pressure (psig)	Temperature (Deg F)	Slip Liquid Velocity (m/s)	Slip Gas Velocity (m/s)	Oil Density (kg/m3)	Oil Viscosity (cP)	Gas-Oil Interfacial Tension (dyne/cm)	Total Mass Rate (lbm/day)	Oil Mass rate (lbm/day)	Gas Mass Rate (lbm/day)	Tubing rate (STB/day)
0	0	0	93.85				90.2989	21.091				
50	50	246.33	93.98	23.044	46.06	921.935	72.6754	19.3757	6487745	5502590	985155.56	16700
100	100	312.15	94.11	19.517	36.704	921.393	68.898	18.6582	6487745	5510328	977417.56	16700
200	200	415.18	94.37	16.064	28.12	920.439	63.604	17.5399	6487745	5522080	965665.19	16700
312.4	312.4	510.87	94.67	13.977	23.225	919.435	59.1792	16.4953	6487745	5532877	954868.38	16700
412.4	412.4	586.45	94.93	12.755	20.466	918.563	55.9589	15.6659	6487745	5541400	946344.63	16700
512.4	512.4	656.37	95.2	11.847	18.467	917.694	53.1703	14.8965	6487745	5549309	938435.81	16700
612.4	612.4	722.25	95.46	11.134	16.928	916.821	50.6949	14.1708	6487745	5556797	930948.06	16700
712.3	712.3	785.3	95.73	9.971	16.256	915.939	48.4553	13.4777	6487745	5564002	923743.38	16700
812.3	812.3	846.09	96	9.601	15.143	915.046	46.4068	12.8119	6487745	5570992	916753.31	16700
912.3	912.3	905	96.27	9.283	14.2	914.139	44.5186	12.1709	6487745	5577811	909933.75	16700
1012.3	1012.3	962.38	96.55	9.007	13.387	913.22	42.7661	11.5525	6487745	5584498	903246.81	16700
2012	2012	1489.53	99.38	7.327	8.978	903.152	29.9466	6.5128	6487745	5648345	839399.75	16700
3011.8	3011.8	1983.67	102.37	6.596	7.271	891.334	21.8446	3.5302	6487745	5712710	775035.25	16700
4011.6	4011.6	2465.89	105.56	6.296	6.331	877.905	16.2872	2.0046	6487745	5780189	707556.88	16700
5011.3	5011.4	2941.84	108.93	6.028	6.028	863.111	12.3324	1.2075	6487745	5851611	636134.06	16700
6011.1	6011.1	3414.37	112.51	5.866	5.866	847.193	9.4505	0.75794	6487745	5927541	560203.69	16700
7053.2	7015.6	3869.9	115.55	5.668	6.248	837.197	8.0755	0.53349	6487745	5977440	510305.63	16700
8037.6	7924.8	4265.83	117.31	5.61	6.242	838.341	8.1491	0.42318	6487745	5977440	510305.63	16700
9022	8834	4663.73	118.82	5.563	6.243	839.321	8.2429	0.34141	6487745	5977440	510305.66	16700
10006.3	9743.3	5063.4	120.05	5.523	6.248	840.192	8.3612	0.27903	6487745	5977439	510305.63	16700
11236.8	10879.8	5565.25	121.19	5.481	6.258	841.19	8.5514	0.21974	6487745	5977439	510305.63	16700
12195.9	11770.4	5959.67	121.74	5.451	6.268	841.942	8.7421	0.20607	6487745	5977439	510305.59	16700
13079.1	12605	6328.99	121.98	5.426	6.277	842.629	8.9553	0.20607	6487745	5977439	510305.56	16700
13403	12911	6455.46	122	1.271	2.462	842.934	9.0618	0.20607	6487745	5977440	510305.63	16700

Hagedorn Brown												
Bottom Measured Depth (feet)	True Vertical Depth (feet)	Pressure (psig)	Temperature (Deg F)	Slip Liquid Velocity (m/s)	Slip Gas Velocity (m/s)	Oil Density (kg/m3)	Oil Viscosity (cP)	Gas-Oil Interfacial Tension (dyne/cm)	Total Mass Rate (lbm/day)	Oil Mass rate (lbm/day)	Gas Mass Rate (lbm/day)	Tubing rate (STB/day)
0	0	0	93.85				90.2989	0.20607				
100	100	312.15	94.11	19.517	36.704	921.393	68.898	18.6582	6487745	5510328	977417.56	16700
200	200	415.18	94.37	16.064	28.12	920.439	63.604	17.5399	6487745	5522080	965665.19	16700
212.5	212.5	426.59	94.4	15.773	27.423	920.326	63.0539	17.4157	6487745	5523370	964374.81	16700
312.4	312.4	510.87	94.67	13.977	23.225	919.435	59.1792	16.4953	6487745	5532877	954868.38	16700
412.4	412.4	586.45	94.93	12.755	20.466	918.563	55.9589	15.6659	6487745	5541400	946344.63	16700
512.4	512.4	656.37	95.2	11.847	18.467	917.694	53.1703	14.8965	6487745	5549309	938435.81	16700
612.4	612.4	722.25	95.46	11.134	16.928	916.821	50.6949	14.1708	6487745	5556797	930948.06	16700
712.3	712.3	785.3	95.73	9.971	16.256	915.939	48.4553	13.4777	6487745	5564002	923743.38	16700
812.3	812.3	846.09	96	9.601	15.143	915.046	46.4068	12.8119	6487745	5570992	916753.31	16700
912.3	912.3	905	96.27	9.283	14.2	914.139	44.5186	12.1709	6487745	5577811	909933.75	16700
1012.3	1012.3	962.38	96.55	9.007	13.387	913.22	42.7661	11.5525	6487745	5584498	903246.81	16700
2012	2012	1489.53	99.38	7.327	8.978	903.152	29.9466	6.5128	6487745	5648345	839399.75	16700
3011.8	3011.8	1983.67	102.37	6.596	7.271	891.334	21.8446	3.5302	6487745	5712710	775035.25	16700
4011.6	4011.6	2465.89	105.56	6.296	6.331	877.905	16.2872	2.0046	6487745	5780189	707556.88	16700
5011.3	5011.4	2941.84	108.93	6.028	6.028	863.111	12.3324	1.2075	6487745	5851611	636134.06	16700
6011.1	6011.1	3414.37	112.51	5.866	5.866	847.193	9.4505	0.75794	6487745	5927541	560203.69	16700
7053.2	7015.6	3860.82	115.55	5.782	5.782	837.162	8.0701	0.53591	6487745	5977440	510305.63	16700
8037.6	7924.8	4238.81	117.31	5.732	5.732	838.236	8.1304	0.42959	6487745	5977440	510305.66	16700
9022	8834	4619.01	118.82	5.69	5.69	839.169	8.2117	0.34964	6487745	5977440	510305.63	16700
10006.3	9743.3	5001.14	120.05	5.655	5.655	840.008	8.3184	0.28792	6487745	5977439	510305.59	16700
11236.8	10879.8	5481.24	121.19	5.618	5.618	840.979	8.4945	0.22864	6487745	5977440	510305.66	16700
12195.9	11770.4	5858.75	121.74	5.592	5.592	841.719	8.6741	0.20607	6487745	5977440	510305.63	16700
13079.1	12605	6212.43	121.98	5.57	5.57	842.399	8.8771	0.20607	6487745	5977440	510305.66	16700
13403	12911	6333.26	122	1.39	1.39	842.701	8.9788	0.20607	6487745	5977440	510305.66	16700

Fancher Brown												
Bottom Measured Depth (feet)	True Vertical Depth (feet)	Pressure (psig)	Temperature (Deg F)	Slip Liquid Velocity (m/s)	Slip Gas Velocity (m/s)	Oil Density (kg/m3)	Oil Viscosity (cP)	Gas-Oil Interfacial Tension (dyne/cm)	Total Mass Rate (lbm/day)	Oil Mass rate (lbm/day)	Gas Mass Rate (lbm/day)	Tubing rate (STB/day)
0	0	0	93.85				90.2989	0.20607				
100	100	312.15	94.11	19.517	36.704	921.393	68.898	18.6582	6487745	5510328	977417.56	16700
200	200	415.18	94.37	16.064	28.12	920.439	63.604	17.5399	6487745	5522080	965665.19	16700
212.5	212.5	426.59	94.4	15.773	27.423	920.326	63.0539	17.4157	6487745	5523370	964374.81	16700
312.4	312.4	510.87	94.67	13.977	23.225	919.435	59.1792	16.4953	6487745	5532877	954868.38	16700
412.4	412.4	586.45	94.93	12.755	20.466	918.563	55.9589	15.6659	6487745	5541400	946344.63	16700
512.4	512.4	656.37	95.2	11.847	18.467	917.694	53.1703	14.8965	6487745	5549309	938435.81	16700
612.4	612.4	722.25	95.46	11.134	16.928	916.821	50.6949	14.1708	6487745	5556797	930948.06	16700
712.3	712.3	785.3	95.73	9.971	16.256	915.939	48.4553	13.4777	6487745	5564002	923743.38	16700
812.3	812.3	846.09	96	9.601	15.143	915.046	46.4068	12.8119	6487745	5570992	916753.31	16700
912.3	912.3	905	96.27	9.283	14.2	914.139	44.5186	12.1709	6487745	5577811	909933.75	16700
1012.3	1012.3	962.38	96.55	9.007	13.387	913.22	42.7661	11.5525	6487745	5584498	903246.81	16700
2012	2012	1489.53	99.38	7.327	8.978	903.152	29.9466	6.5128	6487745	5648345	839399.75	16700
3011.8	3011.8	1983.67	102.37	6.596	7.271	891.334	21.8446	3.5302	6487745	5712710	775035.25	16700
4011.6	4011.6	2465.89	105.56	6.296	6.331	877.905	16.2872	2.0046	6487745	5780189	707556.88	16700
5011.3	5011.4	2941.84	108.93	6.028	6.028	863.111	12.3324	1.2075	6487745	5851611	636134.06	16700
6011.1	6011.1	3414.37	112.51	5.866	5.866	847.193	9.4505	0.75794	6487745	5927541	560203.69	16700
7053.2	7015.6	3860.78	115.55	5.782	5.782	837.162	8.0701	0.53593	6487745	5977440	510305.56	16700
8037.6	7924.8	4238.71	117.31	5.732	5.732	838.236	8.1303	0.42962	6487745	5977440	510305.63	16700
9022	8834	4618.85	118.82	5.69	5.69	839.168	8.2116	0.34967	6487745	5977440	510305.63	16700
10006.3	9743.3	5000.93	120.05	5.655	5.655	840.007	8.3182	0.28795	6487745	5977439	510305.53	16700
11236.8	10879.8	5480.98	121.19	5.618	5.618	840.978	8.4943	0.22867	6487745	5977440	510305.63	16700
12195.9	11770.4	5858.44	121.74	5.592	5.592	841.718	8.6739	0.20607	6487745	5977440	510305.59	16700
13079.1	12605	6212.09	121.98	5.57	5.57	842.398	8.8769	0.20607	6487745	5977440	510305.59	16700
13403	12911	6332.9	122	1.39	1.39	842.7	8.9785	0.20607	6487745	5977439	510305.66	16700

Beggs and Brill												
Bottom Measured Depth (feet)	True Vertical Depth (feet)	Pressure (psig)	Temperature (Deg F)	Slip Liquid Velocity (m/s)	Slip Gas Velocity (m/s)	Oil Density (kg/m3)	Oil Viscosity (cP)	Gas-Oil Interfacial Tension (dyne/cm)	Total Mass Rate (lbm/day)	Oil Mass rate (lbm/day)	Gas Mass Rate (lbm/day)	Tubing rate (STB/day)
0	0	0	93.85				90.2989	0.20607				
100	100	312.15	94.11	19.517	36.704	921.393	68.898	18.6582	6487745	5510328	977417.56	16700
200	200	415.18	94.37	16.064	28.12	920.439	63.604	17.5399	6487745	5522080	965665.19	16700
212.5	212.5	426.59	94.4	15.773	27.423	920.326	63.0539	17.4157	6487745	5523370	964374.81	16700
312.4	312.4	510.87	94.67	13.977	23.225	919.435	59.1792	16.4953	6487745	5532877	954868.38	16700
412.4	412.4	586.45	94.93	12.755	20.466	918.563	55.9589	15.6659	6487745	5541400	946344.63	16700
512.4	512.4	656.37	95.2	11.847	18.467	917.694	53.1703	14.8965	6487745	5549309	938435.81	16700
612.4	612.4	722.25	95.46	11.134	16.928	916.821	50.6949	14.1708	6487745	5556797	930948.06	16700
712.3	712.3	785.3	95.73	9.971	16.256	915.939	48.4553	13.4777	6487745	5564002	923743.38	16700
812.3	812.3	846.09	96	9.601	15.143	915.046	46.4068	12.8119	6487745	5570992	916753.31	16700
912.3	912.3	905	96.27	9.283	14.2	914.139	44.5186	12.1709	6487745	5577811	909933.75	16700
1012.3	1012.3	962.38	96.55	9.007	13.387	913.22	42.7661	11.5525	6487745	5584498	903246.81	16700
2012	2012	1489.53	99.38	7.327	8.978	903.152	29.9466	6.5128	6487745	5648345	839399.75	16700
3011.8	3011.8	1983.67	102.37	6.596	7.271	891.334	21.8446	3.5302	6487745	5712710	775035.25	16700
4011.6	4011.6	2465.89	105.56	6.296	6.331	877.905	16.2872	2.0046	6487745	5780189	707556.88	16700
5011.3	5011.4	2941.84	108.93	6.028	6.028	863.111	12.3324	1.2075	6487745	5851611	636134.06	16700
6011.1	6011.1	3414.37	112.51	5.866	5.866	847.193	9.4505	0.75794	6487745	5927541	560203.69	16700
7053.2	7015.6	3891.89	115.55	5.778	5.778	837.279	8.0885	0.52768	6487745	5977440	510305.63	16700
8037.6	7924.8	4331.72	117.31	5.72	5.72	838.589	8.1949	0.40809	6487745	5977439	510305.63	16700
9022	8834	4773.44	118.82	5.674	5.674	839.682	8.3193	0.32232	6487745	5977439	510305.59	16700
10006.3	9743.3	5216.88	120.05	5.636	5.636	840.629	8.4668	0.2586	6487745	5977440	510305.63	16700
11236.8	10879.8	5773.47	121.19	5.596	5.596	841.686	8.6924	0.20607	6487745	5977440	510305.69	16700
12195.9	11770.4	6210.6	121.74	5.569	5.569	842.467	8.9109	0.20607	6487745	5977439	510305.59	16700
13079.1	12605	6619.31	121.98	5.547	5.547	843.168	9.1501	0.20607	6487745	5977440	510305.66	16700
13403	12911	6754.32	122	1.384	1.384	843.47	9.2658	0.20607	6487745	5977440	510305.66	16700

Orkiszewski												
Bottom Measured Depth (feet)	True Vertical Depth (feet)	Pressure (psig)	Temperature (Deg F)	Slip Liquid Velocity (m/s)	Slip Gas Velocity (m/s)	Oil Density (kg/m3)	Oil Viscosity (cP)	Gas-Oil Interfacial Tension (dyne/cm)	Total Mass Rate (lbm/day)	Oil Mass rate (lbm/day)	Gas Mass Rate (lbm/day)	Tubing rate (STB/day)
0	0	0	93.85				90.2989	0.20607				
100	100	312.15	94.11	19.517	36.704	921.393	68.898	18.6582	6487745	5510328	977417.56	16700
200	200	415.18	94.37	16.064	28.12	920.439	63.604	17.5399	6487745	5522080	965665.19	16700
212.5	212.5	426.59	94.4	15.773	27.423	920.326	63.0539	17.4157	6487745	5523370	964374.81	16700
312.4	312.4	510.87	94.67	13.977	23.225	919.435	59.1792	16.4953	6487745	5532877	954868.38	16700
412.4	412.4	586.45	94.93	12.755	20.466	918.563	55.9589	15.6659	6487745	5541400	946344.63	16700
512.4	512.4	656.37	95.2	11.847	18.467	917.694	53.1703	14.8965	6487745	5549309	938435.81	16700
612.4	612.4	722.25	95.46	11.134	16.928	916.821	50.6949	14.1708	6487745	5556797	930948.06	16700
712.3	712.3	785.3	95.73	9.971	16.256	915.939	48.4553	13.4777	6487745	5564002	923743.38	16700
812.3	812.3	846.09	96	9.601	15.143	915.046	46.4068	12.8119	6487745	5570992	916753.31	16700
912.3	912.3	905	96.27	9.283	14.2	914.139	44.5186	12.1709	6487745	5577811	909933.75	16700
1012.3	1012.3	962.38	96.55	9.007	13.387	913.22	42.7661	11.5525	6487745	5584498	903246.81	16700
2012	2012	1489.53	99.38	7.327	8.978	903.152	29.9466	6.5128	6487745	5648345	839399.75	16700
3011.8	3011.8	1983.67	102.37	6.596	7.271	891.334	21.8446	3.5302	6487745	5712710	775035.25	16700
4011.6	4011.6	2465.89	105.56	6.296	6.331	877.905	16.2872	2.0046	6487745	5780189	707556.88	16700
5011.3	5011.4	2941.84	108.93	6.028	6.028	863.111	12.3324	1.2075	6487745	5851611	636134.06	16700
6011.1	6011.1	3414.37	112.51	5.866	5.866	847.193	9.4505	0.75794	6487745	5927541	560203.69	16700
7053.2	7015.6	3860.68	115.55	6.035	4.952	837.162	8.07	0.53595	6487745	5977440	510305.63	16700
8037.6	7924.8	4238.01	117.31	5.986	4.872	838.233	8.1298	0.42977	6487745	5977440	510305.63	16700
9022	8834	4617.15	118.82	5.945	4.806	839.163	8.2104	0.34998	6487745	5977440	510305.56	16700
10006.3	9743.3	4997.92	120.05	5.911	4.75	839.998	8.3162	0.28838	6487745	5977440	510305.63	16700
11236.8	10879.8	5476.04	121.19	5.873	4.692	840.966	8.491	0.22919	6487745	5977439	510305.66	16700
12195.9	11770.4	5851.84	121.74	5.846	4.653	841.703	8.6695	0.20607	6487745	5977440	510305.63	16700
13079.1	12605	6203.79	121.98	5.825	4.615	842.382	8.8713	0.20607	6487745	5977440	510305.59	16700
13403	12911	6319.42	122	1.908	0.60638	842.676	8.9701	0.20607	6487745	5977440	510305.59	16700

Duns and Ros Original												
Bottom Measured Depth (feet)	True Vertical Depth (feet)	Pressure (psig)	Temperature (Deg F)	Slip Liquid Velocity (m/s)	Slip Gas Velocity (m/s)	Oil Density (kg/m3)	Oil Viscosity (cP)	Gas-Oil Interfacial Tension (dyne/cm)	Total Mass Rate (lbm/day)	Oil Mass rate (lbm/day)	Gas Mass Rate (lbm/day)	Tubing rate (STB/day)
0	0	0	93.85				90.2989	0.20607				
100	100	312.15	94.11	19.517	36.704	921.393	68.898	18.6582	6487745	5510328	977417.56	16700
200	200	415.18	94.37	16.064	28.12	920.439	63.604	17.5399	6487745	5522080	965665.19	16700
212.5	212.5	426.59	94.4	15.773	27.423	920.326	63.0539	17.4157	6487745	5523370	964374.81	16700
312.4	312.4	510.87	94.67	13.977	23.225	919.435	59.1792	16.4953	6487745	5532877	954868.38	16700
412.4	412.4	586.45	94.93	12.755	20.466	918.563	55.9589	15.6659	6487745	5541400	946344.63	16700
512.4	512.4	656.37	95.2	11.847	18.467	917.694	53.1703	14.8965	6487745	5549309	938435.81	16700
612.4	612.4	722.25	95.46	11.134	16.928	916.821	50.6949	14.1708	6487745	5556797	930948.06	16700
712.3	712.3	785.3	95.73	9.971	16.256	915.939	48.4553	13.4777	6487745	5564002	923743.38	16700
812.3	812.3	846.09	96	9.601	15.143	915.046	46.4068	12.8119	6487745	5570992	916753.31	16700
912.3	912.3	905	96.27	9.283	14.2	914.139	44.5186	12.1709	6487745	5577811	909933.75	16700
1012.3	1012.3	962.38	96.55	9.007	13.387	913.22	42.7661	11.5525	6487745	5584498	903246.81	16700
2012	2012	1489.53	99.38	7.327	8.978	903.152	29.9466	6.5128	6487745	5648345	839399.75	16700
3011.8	3011.8	1983.67	102.37	6.596	7.271	891.334	21.8446	3.5302	6487745	5712710	775035.25	16700
4011.6	4011.6	2465.89	105.56	6.296	6.331	877.905	16.2872	2.0046	6487745	5780189	707556.88	16700
5011.3	5011.4	2941.84	108.93	6.028	6.028	863.111	12.3324	1.2075	6487745	5851611	636134.06	16700
6011.1	6011.1	3414.37	112.51	5.866	5.866	847.193	9.4505	0.75794	6487745	5927541	560203.69	16700
7053.2	7015.6	3879.44	115.55	5.278	9.336	837.232	8.0811	0.53095	6487745	5977440	510305.63	16700
8037.6	7924.8	4293.41	117.31	5.255	9.142	838.446	8.1684	0.41674	6487745	5977439	510305.66	16700
9022	8834	4707.82	118.82	5.236	8.977	839.469	8.2737	0.33352	6487745	5977439	510305.66	16700
10006.3	9743.3	5122.52	120.05	5.221	8.827	840.365	8.4021	0.27088	6487745	5977440	510305.59	16700
11236.8	10879.8	5641.25	121.19	5.203	8.7	841.376	8.6031	0.21204	6487745	5977440	510305.63	16700
12195.9	11770.4	6048.03	121.74	5.185	8.678	842.132	8.8017	0.20607	6487745	5977439	510305.66	16700
13079.1	12605	6428.66	121.98	5.169	8.66	842.82	9.0224	0.20607	6487745	5977440	510305.63	16700
13403	12911	6557.66	122	1.289	2.194	843.123	9.1315	0.20607	6487745	5977440	510305.59	16700

GRE (modified by Petroleum Expert)												
Bottom Measured Depth (feet)	True Vertical Depth (feet)	Pressure (psig)	Temperature (Deg F)	Slip Liquid Velocity (m/s)	Slip Gas Velocity (m/s)	Oil Density (kg/m3)	Oil Viscosity (cP)	Gas-Oil Interfacial Tension (dyne/cm)	Total Mass Rate (lbm/day)	Oil Mass rate (lbm/day)	Gas Mass Rate (lbm/day)	Tubing rate (STB/day)
0	0	0	93.85				90.2989	0.20607				
100	100	312.15	94.11	19.517	36.704	921.393	68.898	18.6582	6487745	5510328	977417.56	16700
200	200	415.18	94.37	16.064	28.12	920.439	63.604	17.5399	6487745	5522080	965665.19	16700
212.5	212.5	426.59	94.4	15.773	27.423	920.326	63.0539	17.4157	6487745	5523370	964374.81	16700
312.4	312.4	510.87	94.67	13.977	23.225	919.435	59.1792	16.4953	6487745	5532877	954868.38	16700
412.4	412.4	586.45	94.93	12.755	20.466	918.563	55.9589	15.6659	6487745	5541400	946344.63	16700
512.4	512.4	656.37	95.2	11.847	18.467	917.694	53.1703	14.8965	6487745	5549309	938435.81	16700
612.4	612.4	722.25	95.46	11.134	16.928	916.821	50.6949	14.1708	6487745	5556797	930948.06	16700
712.3	712.3	785.3	95.73	9.971	16.256	915.939	48.4553	13.4777	6487745	5564002	923743.38	16700
812.3	812.3	846.09	96	9.601	15.143	915.046	46.4068	12.8119	6487745	5570992	916753.31	16700
912.3	912.3	905	96.27	9.283	14.2	914.139	44.5186	12.1709	6487745	5577811	909933.75	16700
1012.3	1012.3	962.38	96.55	9.007	13.387	913.22	42.7661	11.5525	6487745	5584498	903246.81	16700
2012	2012	1489.53	99.38	7.327	8.978	903.152	29.9466	6.5128	6487745	5648345	839399.75	16700
3011.8	3011.8	1983.67	102.37	6.596	7.271	891.334	21.8446	3.5302	6487745	5712710	775035.25	16700
4011.6	4011.6	2465.89	105.56	6.296	6.331	877.905	16.2872	2.0046	6487745	5780189	707556.88	16700
5011.3	5011.4	2941.84	108.93	6.028	6.028	863.111	12.3324	1.2075	6487745	5851611	636134.06	16700
6011.1	6011.1	3414.37	112.51	5.866	5.866	847.193	9.4505	0.75794	6487745	5927541	560203.69	16700
7053.2	7015.6	3873.4	115.55	5.761	5.86	837.21	8.0775	0.53255	6487745	5977439	510305.63	16700
8037.6	7924.8	4276.02	117.31	5.709	5.804	838.38	8.1563	0.42079	6487745	5977440	510305.59	16700
9022	8834	4680.24	118.82	5.666	5.759	839.376	8.2544	0.33844	6487745	5977439	510305.66	16700
10006.3	9743.3	5085.9	120.05	5.631	5.721	840.258	8.3767	0.27589	6487745	5977440	510305.66	16700
11236.8	10879.8	5594.89	121.19	5.594	5.681	841.263	8.5715	0.2167	6487745	5977439	510305.63	16700
12195.9	11770.4	5994.65	121.74	5.57	5.642	842.018	8.7656	0.20607	6487745	5977440	510305.63	16700
13079.1	12605	6368.8	121.98	5.548	5.62	842.706	8.9821	0.20607	6487745	5977440	510305.66	16700
13403	12911	6495.36	122	1.38	1.425	843.009	9.0892	0.20607	6487745	5977439	510305.59	16700