FEASIBILITY ANALYSIS OF ETHANE AND FLUE GAS INJECTION FOR ENHANCED OIL RECOVERY WITH A NIGER DELTA CASE STUDY

A thesis submitted to the faculty at African University of Science and Technology
in partial fulfillment of the requirements for the degree of Master of Science
in the Department of Petroleum Engineering

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CERTIFICATION

This is to certify that the thesis titled “FEASIBILITY ANALYSIS OF ETHANE AND FLUE GAS INJECTION FOR ENHANCED OIL RECOVERY WITH A NIGER DELTA CASE STUDY” submitted to the school of postgraduate studies, African University of Science and Technology (AUST), Abuja, Nigeria for the award of the Master's degree is a record of original research carried out by DJOSSOU FELICIENNE KANFOUI-CLEMENTINE in the Department of Petroleum Engineering.

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ABSTRACT

DJOSSOU Felicienne Kanfoui C.: Feasibility analysis of ethane and flue gas injection for enhanced oil recovery with a Niger Delta case study
Under the direction of Prof. David Ogbe.

Enhanced oil recovery (EOR) using ethane gas or flue gas has proven to be successful in some regions of the world, but these methods have not been implemented in the Niger Delta. This work investigates the technical and economic prospects of using ethane gas and flue gas injection for EOR in the Niger Delta. The motivation for this work is to find ways to monetize stranded gas reserves. The data from the Niger Delta case study was collected to screen for a candidate reservoir suitable for the application of ethane and flue gas injection. Firstly, the fluid was characterized using commercial PVT software. Secondly, the minimum miscibility pressure which is an important parameter in every miscible gas EOR was obtained using published correlations and simulation of slimtube experiment. Peripheral drive simulation model was developed using the data from the Niger Delta to investigate the techno-economic feasibility of applying ethane and flue gas EOR in the candidate reservoir.

To determine the technical feasibility of gas injection, three production scenarios were evaluated during the numerical simulation of the reservoir performance. The first scenario is a 20-year simulation of the continuous production from the reservoir under natural depletion to serve as the reference case. The second scenario involves the injection of pure ethane gas, and the third scenario is ethane water- alternating-gas (WAG) injection whereby a slug of ethane gas is injected into the reservoir followed by water injection. The ethane gas-water injection cycle was repeated for a total period of 20 years. The three production scenarios (natural depletion, gas injection, and WAG process) were repeated using flue gas instead of ethane gas as the injectant in the second set of simulations of the case study. The injection rate of pure ethane and flue gas was 4MMscf/day. This same gas injection rate was used for the ethane WAG and Flue gas WAG followed by 3000 stb/day rate of water injection per WAG cycle.

The results showed significant improvement in cumulative oil recovery from the EOR application compared to the natural depletion. A cumulative recovery of 46.7% of the stock tank oil initially in place (STOIIP) was obtained from ethane injection. The flue gas injection, ethane WAG and flue gas WAG yielded a cumulative recovery of about 48% of the STOOIIP compared to the reference case of natural depletion with a cumulative oil recovery of 34.3% of the STOIIP.

The annual oil production was used as input in an economic analysis of the Niger Delta case study to evaluate the economic feasibility of ethane and flue gas injection in the region. The results showed that both ethane gas and flue gas EOR are technically feasible because they yielded a higher cumulative oil recovery compared to the natural depletion. It was also observed that both ethane and flue gas EOR processes are economically feasible; but flue gas EOR is more economically viable than ethane injection EOR. The economic advantage of the flue gas over the ethane gas EOR can be attributed to the high cost of the gas plant required to process the ethane gas needed for the injection. The methods and results of this study form the basis and can be considered a starting point for detailed investigation to the application of ethane and flue gas EOR as an option for utilization of gas injection in the Niger Delta.

***Keywords**: Enhanced oil recovery (EOR), ethane gas injection, flue gas injection, water-alternating-gas injection, minimum miscibility pressure, economic analysis, EOR technical feasibility, EOR economic feasibility.*

DEDICATION

I dedicate this thesis to God Almighty who gave me the strength and the knowledge needed for this course. I also dedicated it to my parents and my siblings who have been my pillar and have always encourage me to be educated and be what I am academically today.

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CHAPTER 1: INTRODUCTION

1.0 INTRODUCTION AND NEED FOR ENHANCED OIL RECOVERY

The world-wide production statistics indicate that the ultimate recovery from light and medium gravity oils by conventional (primary /secondary) methods is around 25-35% of the original oil in place (OOIP), while from heavy oil deposits on the average, only 10% OOIP is recoverable. Hence, substantial volume of oil is left unrecoverable by the conventional methods. These remaining reserves are the target of the enhanced oil recovery (EOR) methods so as to increase the recovery percentage (Zekri *et al.,* 2000).

For many years, gas injection has become one of the most favorable enhanced oil recovery methods in the world. Considering the continuous collapse of the international oil price since 2014, the practical application of enhance oil recovery (EOR) becomes more obvious. All the major oil producing countries in the world actively carry out research to support the application of EOR according to the characteristics of their oil reservoirs. This study attempts to evaluate EOR application to the Niger Delta, Nigeria.

At Nigeria's current average oil production rate of 2.5 million barrels per day, the country's proven reserves of 37.5 billion barrels are expected to last about forty-six years (Diezani, 2013). In 2013, Nigeria had set for itself ambitious targets of producing 4 million barrels per day and increasing reserves to 40 billion barrels of crude oil by the year 2016 (Diezani, 2013). In 2017, it was reported that Nigeria could not meet the target of producing 4 million barrels per day because the country's daily oil production had dropped by 280,000 barrels per day from 2013 to 2016 (BP Global, 2017) amounting to a production of about 1.75 million barrels per day. This daily production rate is far below the proposed target of 4 million barrels per day in 2013 (Trading Economics, 2017).

According to Lake (1989), increasing any country's reserves can be done in four categories; discovering new fields, discovering new reservoirs, extending reservoirs in known fields, and redefining reserves because of changes in extraction technology (i.e., enhanced oil recovery). To attain this proposed production rate of 4 million barrels per day, there is a need to increase the recovery factor of producing fields, a reason for Nigeria to apply enhanced oil recovery techniques.

Enhanced oil recovery (EOR) processes are implemented to increase the ability of oil to flow to a well by injecting water, chemicals, or gases into the reservoir or by changing the physical properties of the oil (Lake, 1989). The ultimate objective is to produce additional amounts of oil left behind after primary and secondary recoveries by improving oil displacement efficiency and volumetric sweep efficiency. Field tested EOR processes include thermal, chemical, and miscible methods (Lake, 1989).

Gas injection or miscible flooding method is presently one of the commonly used techniques in enhanced oil recovery. Miscible flooding is a general term for injection processes that introduce miscible gases into the reservoir. A miscible displacement process maintains reservoir pressure and improves oil displacement because the interfacial tension between oil and water is reduced. This refers to removing the interface between the two interacting fluids leading to improved total displacement efficiency. Gases used as injectants include CO_2, natural gas, nitrogen, and flue gas.

1.1 BACKGROUND OF THE STUDY

Nigeria is a country that is rich in oil reserves and its current production averages 2.5 million barrels per day with proven reserves of 37.5 billion barrels expected to last about forty-six years (Diezani, 2013). The recovery factor of Nigeria fields as they mature daily approaches 20-35% of the STOIIP obtainable by conventional methods, hence leaving substantial volume of oil in place unrecoverable by the conventional methods (Zekri *et al*, 2000). In 2020, Anuka *et al.* reported that Nigeria as a nation has had its fair share of the global dilemma of decreased oil production caused by unrecovered oil from oil reserves, resulting in adverse effects on its economy status (Anuka *et al.*, 2020). Optimizing oil field development strategies, though necessary; has become ineffective in adding significant reserves and increasing production rates. A more robust approach such enhanced oil recovery needs to be considered to fully exploit the vast quantities of hydrocarbons still trapped in these matured Nigerian fields (Sinanan and Budri, 2012).

Among the many EOR methods, the use of flue gas and ethane gas injection to enhance oil recovery has been used successfully world-wide since the mid 1960's, and their use is becoming increasingly popular due to their lower production costs and availability when compared to conventional hydrocarbons gases (Clancy *et al*, 1985). This study aims at investigating the technical and economic feasibility of using flue gas and ethane gas injection for enhanced oil recovery in the Niger Delta. The motivation is to commercialize stranded gas in remote fields without pipelines through EOR application.

1.2 JUSTIFICATION OF STUDY

1.2.1 Ethane gas

Decades of research and field experience have confirmed the opportunities, engineering and economic issues affecting the application of hydrocarbon gas EOR in major petroleum provinces. The conventional wisdom has been that hydrocarbon gas is too expensive as natural gas prices are too high (McGuire *et al*., 2016). This is no longer the case in Nigeria where approximately 261 billion cubic feet of natural gas is being flared as of 2018. The US Energy Information Agency (EIA) reported that a 2018 World Bank study indicated that Nigeria was the seventh–largest natural gas flaring country in terms of the global annual natural gas flaring volume (US EIA, accessed May 2020). Ethane, being the second-largest component of natural gas after methane is in abundance and therefore represents the low-cost available gas for deploying EOR in Nigeria. Some work and experiments have been done on the current state and opportunity of ethane for EOR processes. McGuire *et al.*, (2016) summarized the current state of the Ethane industry in the U.S and explored the opportunity of using ethane for EOR process. Simulated data and field examples were used to demonstrate ethane as an excellent EOR injectant considering its availability. According to McGuire *et al*., (2016), the limited supply of low-cost CO_2, its significant drawbacks in terms of corrosion, solubility and high MMP value deters its use in shallow and low-pressure reservoirs. Ethane has maintained superiority over CO_2 as EOR injectant in terms of solubility, swelling, viscosity reduction, and in developing multi-contact miscibility owing to its low MMP values. Ethane based EOR can supplement the remarkably successful CO_2 based EOR industry in the U.S. according to McGuire *et al*., (2016), the current abundance of low-cost ethane presents a significant opportunity to add new gas EOR projects. Ethane is operationally simpler than CO_2 for EOR, it is now inexpensive and will likely stay inexpensive. The perception of hydrocarbon gas being expensive for decades is no longer true as shale revolution in the U.S has created a major EOR opportunity for low-cost ethane used for miscible/immiscible WAG projects (McGuire *et al*., 2016). In Nigeria, the use of ethane as an injectant for EOR will reduce gas flaring especially in oil fields with limited infrastructure for gas transportation.

1.2.2 Flue gas

Utilization of non-hydrocarbon gases as the main sources for gas injection projects has been demonstrated in different countries. The main advantages of the flue gas injection are inexpensive, readily available flue gas sources (which consists mainly of N_2 and CO_2), low compressibility in comparison with other gases like CO_2 or CH_4 (for a given volume at the same conditions). Flue gas occupies more space in the reservoir, and it is an appropriate way for CO_2 sequestering and consequently reducing greenhouse gases. As an EOR method, N_2 and/or CO_2 are/is injected into the oil reservoir for miscible and/or immiscible displacement of the remaining oil (Ahmadi *et al*., 2015).

According to Shokoya *et al* (2004), the potential for cost-effective oil recovery by flue gas injection from currently producing light oil reservoirs as well as depleted and mature waterflooded reservoirs is most important, especially for reservoirs with little or no water production as well as those with low porosity and low permeability where water injection is not feasible. The flue gas could be injected directly into the reservoir from some surface source such as power plants or generated in situ from the spontaneous ignition of oil when air is injected into a relatively hot reservoir (Shokoya *et al*., 2004). Flue gas displacement is more efficient than immiscible gas flood and it is also lucrative gas displacement method for enhanced oil recovery and an environmentally friendly gas injection process.

1.3 PROBLEM STATEMENT

In Nigeria, about 261 billion cubic feet of natural gas is being flared as at 2018 (US EIA: https://www.eia.gov/international/analysis/country/NGA). Ethane, being the second-largest component of natural gas after methane is in abundance and therefore represents the low-cost available gas for deploying EOR in Nigeria. Therefore, the research questions posed in this study are:

- Is ethane a suitable gas injectant for EOR application in Nigeria?
- Instead of ethane, can flue gas be applied since nitrogen is available in the air and CO_2 can be burnt from natural gas?

- Are these two EOR (ethane and flue gas) methods technically and economically feasible in the Niger Delta?

1.4 AIM AND OBJECTIVES OF STUDY

Ethane-based and flue gas-based injection have been verified as promising EOR methods outside Nigeria with good results of oil recovery. This study aims at showcasing the opportunity for ethane-based and flue gas-based enhanced oil recovery application in the Niger Delta. It is proposed to run detailed reservoir simulations of a case study with an economic analysis to demonstrate that ethane and flue gas are good both technically and economically viable EOR injectants in the Niger Delta area of Nigeria.

The objectives of this study include:

i. to collect and screen the reservoir, rock and fluid data for a case study and assess its suitability for ethane and flue-gas injection EOR
ii. to characterize the phase behavior (PVT) of the reservoir fluid
iii. to determine the minimum miscibility pressure (MMP) of the injectants - ethane gas and flue gas.
iv. to build reservoir models for simulating ethane and flue gas flooding using a compositional simulator
v. to study the impact of flue gas and ethane injection on oil recovery, changes in the composition and saturation distribution of flue gas and ethane in the reservoir during injection into the reservoir and
vi. to conduct an economic evaluation and comparative analysis of the technical and economic feasibility of improving oil recovery by injection of ethane and flue gases in the reservoir used in the Niger Delta case study.

1.5 SCOPE OF STUDY

This study is designed to cover the collection of data from various certified sources and screening the reservoir, rock, and fluid data to assess its suitability for ethane and flue-gas injection EOR. Furthermore, the scope of study is to characterize the phase behavior (PVT) of the reservoir fluids and determine the minimum miscibility pressure (MMP) of the injectants--ethane gas and flue gas.

The scope of work also includes building reservoir models for simulating ethane flooding and flue gas flooding using compositional simulator. More importantly, a detailed economic evaluation and comparative analysis shall be carried out to assess the technical and economic feasibility of improving oil recovery by injection of ethane and flue gases in the Niger Delta case study. This study does not involve any wellsite field work.

1.6 ORGANIZATION OF THE STUDY

This research is presented in five (05) Chapters. The background and Introduction to the study is presented in Chapter 1. A literature review to improve our understanding of EOR processes, ethane gas, and flue gas injection is presented in Chapter 2. Chapter 3 covers the study methodology while Chapter 4 presents the results obtained from the simulation, observations, and discussion of results. Chapter 5 covers the conclusions and recommendations proposed for future research to improve the present study.

CHAPTER 2: LITERATURE REVIEW

In this chapter, detailed literature review of major related publications will be presented to create a nexus between this study and those published by many scholars across the globe. It is intended to improve our understanding of the major concepts introduced in this study.

2.0 INTRODUCTION

Most petroleum reservoirs produce through natural drive mechanisms which include solution gas, natural water drive, fluid and rock expansion, gravity drainage, water influx and gas cap drive. These natural drives are known as primary recovery mechanisms. Primary recovery mechanisms utilize the reservoir natural energy without external support or injection into the reservoir (Green and Willhite, 1988).

As pointed out by Zekri *et al.,* (2000) most reservoirs are known for low-efficiency recovery (i.e., 25-35% recovery factor) by natural mechanisms, thereby retaining huge volumes of hydrocarbons in place after the natural energy has been depleted. The reservoir pressure depletes from its initial state till it can no longer produce naturally on its own; at this point there is need for additional recovery methods which could be either to maintain the reservoir pressure or provide external displacement energy (Zekri *et al*., 2000).

To augment the natural energy of the reservoir, a secondary recovery method can be initiated by injecting gas or water into the reservoir. The secondary recovery method of gas injection is usually an immiscible process where gas is injected into the gas cap for pressure maintenance (Green and Willhite, 1988). According to Green and Willhite (1988), the immiscible gas injection process is not as efficient as water flooding where water is injected into the reservoir for pressure maintenance. After secondary recovery, approximately 30-35% of the oil originally in place can be produced by the displacement methods of Enhanced Oil Recovery, EOR.

2.1 ENHANCED OIL RECOVERY TECHNIQUES

The term enhanced oil recovery (EOR) basically refers to the recovery of oil by any method beyond the primary stage of oil production. It is defined as the production of crude oil from reservoirs through processes taken to increase the primary reservoir drive. These processes may include pressure maintenance, injection of displacing fluids, or other methods such as thermal techniques. Therefore, by definition, EOR techniques include all methods that are used to increase the cumulative oil produced (oil recovery) as much as possible. Enhanced oil recovery can be divided into three major types of techniques: chemical, thermal, and miscible process (Bandar D., 2007). Figure 2.1 shows the classification of EOR methods. It is observed that there are different types of EOR methods which are classified under thermal and non-thermal methods.

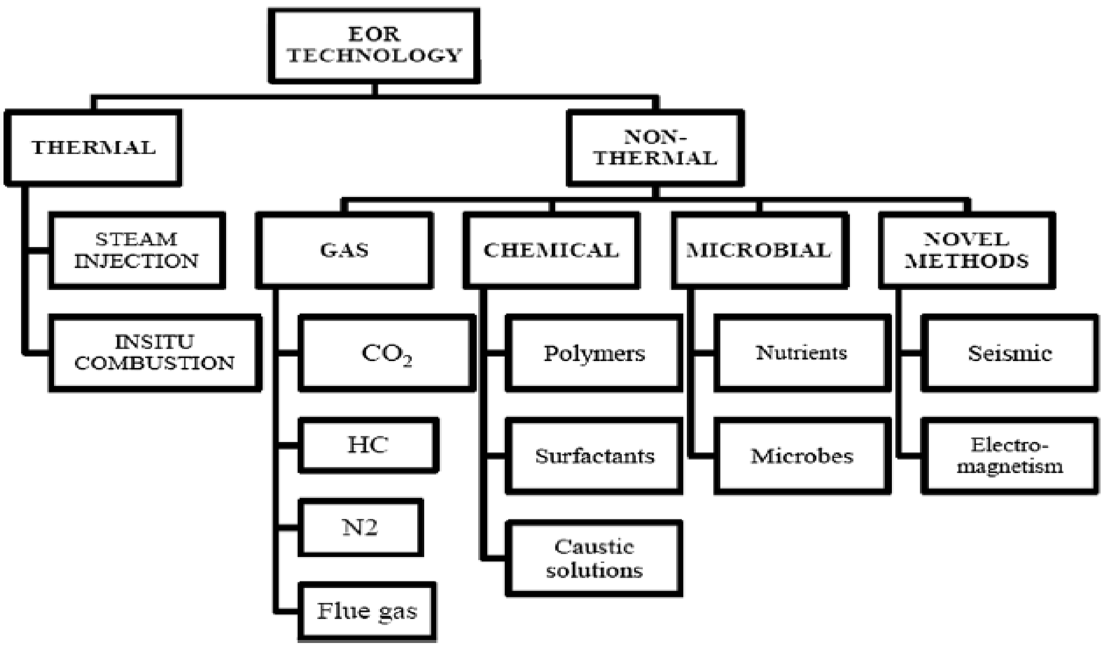

Figure 2.1: Classification of EOR methods (Gbadamosi *et al*, 2018)

2.1.1 Chemical Processes

Chemical flooding is an EOR technique designed to increase the mobility of oil by adding additives or chemicals to the displacing fluid or to the residual oil to control viscosity and interfacial tension (Bandar, 2007). In chemical flooding EOR, a combination of chemicals ranging from alkaline, surfactants agent and polymers are injected into the reservoir to displace the reservoir oil by increasing the displacement efficiency. The specific chemicals injected effectively displace the reservoir oil because of their phase-behavior properties which result in decreasing the interfacial tension between the displacing liquid and reservoir oil. Green and Willhite (1988) reported that chemical (surfactant/polymer) processes have the most potential in terms of ultimate oil recovery among the EOR methods. They also pointed out that the injection fluids used for chemical process are susceptible to loss through rock–fluid interactions, therefore maintaining adequate injectivity is one of the challenges with this process (Green and Willhite, 1988). Chemical processes include micellar polymer flooding, caustic flooding, and polymer flooding.

2.1.1.1Caustic Flooding

In caustic flooding, an in-situ emulsification process is employed by caustic or alkaline injection. The added chemicals to the injection water are caustic soda, sodium silicate, sodium carbonate, or sodium hydroxide. These chemicals are mixed with the residual oil in the reservoir. The crude oil must contain natural organic acids; most common are the naphthenic acids. When the alkaline injected water and acidic crude react, soaps are produced at the oil water interface. These soaps cause oil to be movable through the reservoir to a production well (Bandar, 2007).

2.1.1.2Polymer Flooding

Polymer foods are improved waterfloods by increasing the viscosity of the displacing fluid to increase the displacement efficiency. In addition, increasing the displacing fluid's viscosity and lowering its relative permeability through plugging will improve the mobility ratio and this will make an improvement in areal and vertical sweep efficiency (Bandar, 2007).

2.1.1.3 Micellar Polymer Flooding

Micellar solutions are mixtures of surfactants, cosurfactants, electrolytes, hydrocarbon, and water. Surfactants are substances known as surface active agents, such as soap. Cosurfactants are used for stability such as alcohols. Electrolytes are salts used to control viscosity and interfacial tension such as sodium chloride or ammonium sulphate. These solutions, which are designed to be used from one field to the other, are proposed to displace reservoir oil and miscible water (Bandar, 2007).

As rightly pointed out by Green and Willhite (1998), chemical processes are complex technologically and can be justified only when oil prices are relatively high and when residual oil after waterflooding is substantial. The chemical solutions which contain surfactant, cosurfactant, and sometimes oil, are expensive. Chemical losses resulting from adsorption, phase partitioning and trapping, bypassing owing to fingering if mobility control is not maintained can be severe. These losses can be compensated for by increasing the volume of the chemical solutions injected. The stability of surfactant systems in general is known to be sensitive to high temperatures and salinity. Systems that can withstand these conditions must be developed if the process must have wide applicability (Green and Willhite, 1998).

2.1.2 Thermal Recovery

Thermal recovery refers to oil recovery processes in which heat plays the principal role. It is the use of thermal energy (hot water, steam injection or in-situ combustion in the reservoir rock resulting from air or oxygen injection) to improve oil recovery by alteration of oil viscosity (lightening of reservoir oil), favorable phase behavior, and some other possible physical process (Naqvi, 2012). The application of thermal energy to increase heavy oil recovery has become more popular as conventional reserves have declined. Steam injection accounts for the majority of the thermal recovery projects currently in operation. The most widely used thermal techniques are in situ combustion, continuous injection of hot fluids such as steam, water or gases, and cyclic operations such as steam soaking (Bandar, 2007).

In-situ combustion, process of generating heat within the reservoir, applies to the reservoirs that contain low gravity oil, which is heated with the help of air injection and the burning part of the crude oil. The oil is then driven out of the reservoir with the help of steam, hot water, or gas drive, as it becomes less viscous. Either dry or moist air can be injected. The fire propagates from the air injection well to the producing well, moving oil and the combustion gases to the front. The coke left behind the displaced oil works as a fuel. The temperature reaches hundreds of degrees which is enough to crack heavy oil into low boiling products. The displacement of oil is the result of the combination of hot water, steam and gas drive, vaporization, and light hydrocarbons (Naqvi, 2012). In-situ combustion offers many theoretical advantages if the operational characteristics of the process are incorporated in the design and operation of the field project. The in-situ combustion process has the potential of partial upgrading of the oil in the reservoir, which restrains the undesirable constituents of oil from moving along with the oil. Also, there is no need to generate energy on the surface. There are several variants of the in-situ combustion process, namely, forward dry in-situ combustion, and wet and partially quenched combustion, also known by the acronym COFCAW (combination of forward combustion and water flooding) (Naqvi, 2012).

2.1.2.1 Steam Injection

Heat is injected into a reservoir to reduce the oil viscosity and, consequently, to improve the displacement efficiency. As a result of improved mobilization efficiency crude oil is expanded and flows easily through the porous media toward the wellbore. The process may involve steam soak that is sometimes called steam stimulation or “huff and puff”. In this process, steam is injected down a producing well at a high injection rate, after which the well is shut in. The injected steam heats up the area around the well bore and increases recovery of the oil immediately adjacent to the well. After a short period of injection, the well is placed back on production until the producing oil rate declines to economic limits. The cycle is then repeated several times until no additional response to steam injection is observed (Bandar, 2007).

2.1.2.2 Other Thermal Recovery Methods

2.1.2.2.1 Steam-Assisted Gravity Drainage Process (SAGD)

SAGD was firstly developed by Roger Butler and his colleagues in Imperial Oil in the late 1970s. SAGD is a thermal oil recovery process which consists of pair of two parallel horizontal wells drilled near the bottom of the pay. Typically, the length of the wells is between 500 and 1000m, the inter-well distance of the two parallel wells is between 5 and 10m and inter-well pair spacing is between 90 and 120m. The top horizontal well is used to inject steam, while the bottom horizontal well is used to produce reservoir fluids. The heat from steam is transferred by thermal conduction into the surrounding reservoir. The steam condensate and heated oil flow to the production well located below by gravity. The success of SAGD project depends on some key factors such as, accurate reservoir description, efficient utilization of heat injected into the reservoir, understanding displacement mechanism, understanding of geomechanics and overcoming various constrains (Doan et al., 1999). Successful field tests have proven that SAGD is a viable technology for in-situ recovery of heavy oil and bitumen (Butler, 2001; Boyle *et al.*, 2003).

SAGD technique can enjoy many advantages over other thermal methods, especially the conventional steam flooding methods. SAGD overcomes the shortcomings of steam override by using only gravity as the driving mechanism, which leads to stable displacement and a potentially high oil recovery. In addition, the heated oil remains hot and movable as it flows toward the production well, whereas, in conventional steam flooding, the oil displaced from the steam chamber cools, and consequently the oil-phase viscosity increases, as the oil flows to the production well (Chen *et al*. 2008). SAGD process is made more thermally efficient by maintaining a liquid pool that surrounds the bottom production well and prevents escape of steam from the steam chamber(Dang *et al*., 2010).

However, Doan *et al*., (1999) pointed out some limitations of SAGD such as: (1) The theory pertains to the flow of single fluid; (2) Only steam flows in the steam chamber, oil saturation being residual; (3) Heat transfer ahead of the steam chamber to cold oil is by conduction only; (4) Sand control; (5) Hot effluent/high water cut production; (6) Frequent changes in operating regime and high operating costs; (7) Deterioration of production at late stages.

2.1.3 Gas Injection

Gas injection, a widely used enhanced oil recovery method, will probably play a more important role in the future due to several reasons:

1. Gas injection is effective to recover residual oils and its application is likely to be promoted by higher oil prices.
2. For deeper reservoirs and particularly offshore deeper reservoirs, gas injection, a means to achieve a higher oil recovery can be crucial to the viability of a project.
3. When combined with CO_2 capture, gas injection can be used to mitigate CO_2 emission.

During gas injection, the injected gas will swell the oil, reduce oil viscosity, and most importantly, achieve miscibility by exchanging components with the oil (Yan, *et al*., 2012).

There are two major types of gas injection, miscible gas injection and immiscible gas injection. In miscible gas injection, the gas is injected at or above minimum miscibility pressure (MMP) which causes the gas to be miscible in the oil. In immiscible gas injection, flooding by the gas is conducted below MMP. This low-pressure injection of gas is used to maintain reservoir pressure to prevent production cut-off and thereby increase the rate of production (Bandar, 2007).

In a typical gas flooding project, one of the most important design parameters is the Minimum Miscibility Pressure, MMP (Li and Luo, 2017). The extent of miscibility increases with pressure, and the threshold pressure above which the injected gas becomes completely miscible with the oil is known as the minimum miscibility pressure, MMP. Above the MMP, 100% displacement efficiency can be expected on the microscopic scale (Yan *et al*., 2012). Hawthorne *et al*., 2017 stated that hydrocarbon in the very fine pores can be mobilized by CO2 if miscibility was reached. A dramatic mass transfer between oil and CO2 in a high-pressure view cell was observed when pressure was near or above MMP (Li and Luo, 2017). Of all the enhanced oil recovery methods, miscible gas injection has been effective primarily because of the miscibility attained between the injecting gas and the reservoir oil. When two fluids become completely miscible, they form a single phase; one fluid can completely displace the other fluid, leaving no residual saturation. A minimum pressure is required for two fluids to attain miscibility (Wijaya, 2006). This is so as the injected gas molecules dissolved in the oil, reduce its viscosity, and make it mobile which increases the well output. After the crude oil is pumped out, the natural gas is once again recovered (Naqvi, 2012). There are two major variations in the miscible gas injection process: First-Contact Miscibility (FCM) and Multiple-Contact Miscibility (MCM).

a) First-Contact Miscibility

FCM means that the injected fluid can immediately, at first contact, mix with the reservoir oil in all proportions and produce a single-phase fluid. The process involves the injection of relatively small slug of hydrocarbon fluid such as liquefied petroleum gas, LPG, to displace the reservoir oil; the LPG slug is in turn displaced by a larger volume of inexpensive gas that is high in methane concentration. In some cases, water can be used as the secondary displacing fluid. Primary slugs/oil interfaces are eliminated, oil drops are mobilized and moved ahead of the primary slug. Miscibility between primary slug and secondary displacing fluid is also desirable, otherwise the primary slug would be trapped as residual phase as the process progresses (Green and Willhite, 1988). Butane and crude oil also are first-contact miscible, and butane might make an ideal solvent for oil (Wijaya, 2006).

A ternary composition diagram can be used to determine whether two mixtures are first-contact miscible or if they can develop miscibility after several contacts. Two fluids are first-contact miscible if the line connecting the compositions of these two fluids is not crossing the region within phase envelope on the ternary composition diagram. Typical ternary composition diagram of system at 280°F and 2000 psia shown in Figure 2.1 is an example where G1 and G2, O1 and O2, G2 and O2 are first-contact miscible fluids (Shpak, 2013).

b) Multiple-Contact Miscibility

In the MCM process, the injected fluid is not miscible with the reservoir oil at first contact. The process rather depends on modification of the composition of the injected fluid phase, or oil phase through multiple contacts between the phases in the reservoir and mass transfer of components between them. Under proper conditions of pressure, temperature, and composition, this composition modification will generate miscibility between the displacing and displaced phases in-situ (Green and Willhite, 1988).

The critical tie-line on the ternary composition diagram determines whether two fluids can develop miscibility by multiple-contact process. Two fluids can develop multiple-contact miscibility if their compositions lie on the different sides of the critical tie-line (Shpak, 2013).

MCM could either be by vaporizing gas drive, condensing gas drive or both condensing and vaporizing gas drive depending on the mechanism with which the injected gas develops miscibility with the reservoir oil.

The ternary diagram in Figure 2.2 shows that C1 and O2 fluids can develop miscibility through vaporizing-gas drive mechanism. Intermediate and heavy components from the oil O2 vaporize into the gas phase, making the original lean gas C1 richer, which later contact oil again and becomes even richer until it gets to the critical composition C, which is miscible with oil O2. The gas and oil are mixed in the proportions that the overall composition of the mixture falls into the two-phase region. The equilibrium gas G2 is now enriched with intermediate and heavy components, and then again is mixed with the original oil O2 at proportions to form two phase conditions. The more enriched gas G3 is obtained. The process goes on until critical composition C is reached, when miscibility is developed (Shpak, 2013).

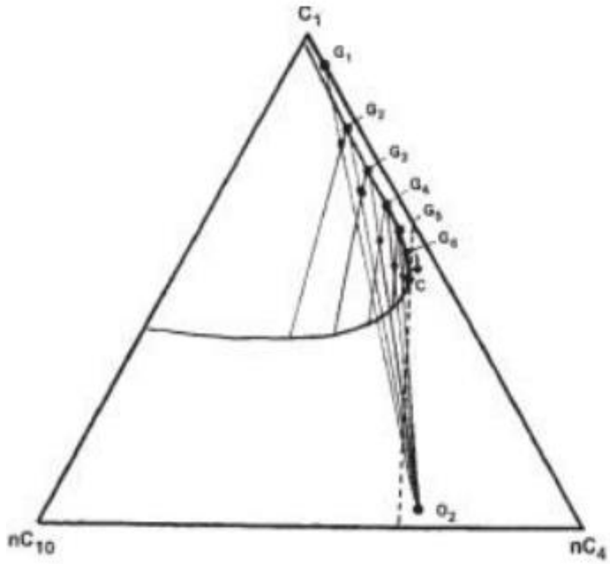

Figure 2.2: Path of developed miscibility by vaporizing-gas miscible drive process for C1/n-C4/nC10 system (Shpak, 2013)

For a three-component hydrocarbon system, like in a ternary diagram, when a rich injection gas displaces oil that is relatively lean in the intermediate component, it is by a mechanism that is called a condensing-gas drive. In this process, the oil near the injection point is enriched by repeated contacts with the injection gas. The intermediate component in the gas condenses into the oil, moving its composition toward the critical point on the phase envelope. Eventually, if the gas is rich enough, i.e., if its composition lies on the single-phase side of the extended critical tie line, the oil becomes so enriched with the intermediate component that it becomes miscible with the gas. Since the miscible zone moves with the velocity of the injection gas, the oil is completely displaced. This process can be easily visualized with the aid of a ternary diagram (Zick *et al*, 1986).

Gas injection processes can be broken down into the following techniques:

2.1.3.1 Liquefied Petroleum Gas Miscible Slug

Displacement by miscible slug usually refers to the injection of some liquid solvent that is miscible upon first contact with the resident crude oil. This process uses a slug of propane or other liquefied petroleum gas (2 to 5% PV [pore volume]) trailed by natural gas, inert gas, and/or water. Thus, the solvent will bank oil and water ahead of it and fully displace all contacted oil (Bandar, 2007).

2.1.3.2 Enriched Gas Miscible Process

In the enriched gas process, a slug of methane enriched with ethane, propane, or butane (10 to 20% PV) and tailed by lean gas and/or water is injected into the reservoir. When the injected gas contacts virgin reservoir oil, the enriching components are slaked from the injected gas and absorbed into the oil (Bandar, 2007).

2.1.3.3 High Pressure Lean Gas Miscible Process

This process involves the continuous injection of high-pressure methane, ethane, nitrogen, or flue gas into the reservoir. The lean gas process, similar to enriched gas, involves multiple contacts between reservoir oil and lean gas before forming a miscible bank. But there is a difference in the enriched gas process where light components condense out of the injected gas and into the oil, then intermediate hydrocarbon fractions (C2 to C6) are stripped from the oil into the lean gas phase (Bandar, 2007).

2.1.3.4 Carbon Dioxide Process

Oil displacement may be initiated by several mechanisms due to injection of CO_2 into oil reservoirs. Carbon dioxide is not usually miscible with reservoir oil upon initial contact; however, it may create a miscible front like the lean gas process. So, there are two major types of CO_2 floods; miscible flood in which the gas is injected at or above the MMP, and immiscible CO_2flood in which flooding by the gas is conducted below the MMP. Miscibility is initiated by the extraction of large amounts of the heavier hydrocarbons (C5 to C30) by CO_2 (Bandar, 2007).

2.1.3.5 Overview of nitrogen gas Injection

According to Bandar Duraya Al-Anazi, (2007), in miscible gas injection, the gas is injected at or above the minimum miscibility pressure (MMP) which causes the gas to be miscible in oil. When flooding by the gas is conducted below MMP it is known as immiscible gas injection. Primary conditions affecting miscibility are composition, fluid characteristics, pressure, and temperature. One gas employed for these gas injection techniques is nitrogen. Nitrogen has long been successfully used as the injection fluid for EOR and widely used in oil field operations for gas cycling, reservoir pressure maintenance, and gas lift. The costs and limitations of the availability of natural gas and CO_2 have made nitrogen an economic alternative for oil recovery by miscible gas displacement. Nitrogen is usually cheaper than CO_2 or a hydrocarbon derived gas for displacement in EOR applications and has the added benefit of being non-corrosive. There are few known correlations to determine the MMP of nitrogen since the available literature data on the MMP of nitrogen with crude oils and synthetic oil are scarce. Nitrogen MMP of different oils is a function of the temperature, reservoir fluid composition, and pressure on miscibility.

Other well-known and applied enhanced oil recovery methods are pressure maintenance and water flooding. These are discussed in the following section.

2.1.4 Pressure Maintenance

A common EOR method employed today is artificial maintenance of formation pressure. This traditional step for increasing oil recovery involves the injection of fluid into (or near) an oil reservoir for the purpose of delaying the pressure decline during oil production. Pressure maintenance can significantly increase the amount of economically recoverable oil over that to be expected with no pressure maintenance (Bandar, 2007).

The level of pressure maintenance in oil production is usually just above bubble-point pressure such that injection costs are minimized. Since production rate is also dependent on reservoir pressure gradients, then the choice of pressure maintenance level will also include rate consideration. To provide the capability for natural flow to surface under high water cut, the selection of pressure maintenance level might be determined. When the reservoir condition volumetric rate of fluid replacement is equal to the reservoir condition volumetric rate of production, the technique is known as complete voidage replacement. In practice, any fraction of voidage could be replaced if it provides an optimum recovery scheme. Proper design of a secondary recovery scheme is best performed after a period of primary recovery, to observe the dynamic response of the reservoir (Archer and Wall, 1986).

2.1.5 Waterflooding

Production from a reservoir can be increased after a decline in pressure from the water drive or pressure maintenance by a technique called waterflooding. This involves the injection of water through injection wells to push crude oil toward the producing wells. Water is pumped into the productive layer at injection pressure through bore holes in a volume equal to (or greater than) the volume of oil extracted. So, the reservoir pressure, the drive energy in the subsurface formation is kept at the optimum level. The original lifetime of the well is prolonged, which greatly reduces the amount of drilling operations and consequently reduces the cost of producing the oil (Bandar, 2007).

2.2 FLUID CHARACTERIZATION

Fluid characterization is an essential tool that forms the basis of any reservoir simulation, recovery estimates, well completion and facility design decisions, pipeline flow assurance choices, and production optimization strategies. It aims at reducing the number of pseudo-components of the fluid to a practical minimum and matches fluid properties in simulated flashes with the properties of the real flashed fluids in the Pressure-Volume Temperature (PVT) reports (Farry, 1998). According to Adeeyo and Marhoun, 2013, PVT analysis is the study of the changes in volume of a fluid(s) as function of pressure and temperature. The essence of PVT analysis is to simulate what takes place in the reservoir and at the surface during production and injection, and to provide vital information about physical and thermodynamic behavior of the reservoir fluids. Laboratory measurements of PVT properties are the primary source of PVT data determined from laboratory studies on samples collected from the bottom of the wellbore or from the surface. Such experimental data are however not always available because of one or more of such reasons:

1) Samples collected are not reliable.
2) Samples have not been taken because of cost saving.
3) PVT analyses are not available when data are needed, this situation often occurs in production-test interpretation in exploration wells.

However, in the absence of such tests the use of correlations provides the only viable option for prediction of PVT properties. Correlations are useful as a check against laboratory results, when these results are neither available nor reliable; the PVT software in the simulator is used to characterize the fluid (Adeeyo and Marhoun, 2013).

PVT software for characterization of the reservoir oil sample is used in this study to characterize the fluid samples. According to Hashemi, Fath and Pouranfard, 2014, insufficient description of heavier hydrocarbons can reduce the accuracy of PVT predictions. PVT matching generally starts with splitting the plus components into two or three pseudo components, specifically when there are many of them compared with the other components. The heavy C6+ component can be split into two pseudo-components; the critical properties correlation and acentric properties correlation can also be selected to describe the newly defined components. This is followed by grouping of components; components with similar molecular weight must be put in the one group. The main reason for grouping components is to speed-up the compositional simulation. In a compositional simulation, the number of grouped components depends on the process that is modeled. For miscibility, more than 10 components may sometimes be needed. In general, 4 – 10 components should be enough to describe the phase behavior. In the PVT software, the main criterion for a successful grouping is whether the new grouped components can predict observed experimental results at least as well as the original ungrouped components; therefore, care is to be taken when grouping the components. Shapes of phase diagrams for grouped and ungrouped components can be compared, if close shapes are obtained then good grouping is achieved.

Lastly, an Equation of State, EOS, is fitted into the PVT data to have an agreement between the observed data and the results calculated with the EOS. The 3-parameter, Peng–Robinson or Soave Kwong-Redlich EOS can be used. Peng–Robinson EOS, a cubic EOS that was developed by Peng and Robinson in 1976, has been shown to accurately model hydrocarbons and is the most widely used EOS in compositional reservoir simulators (Hashemi and Pouranfard, 2014).

2.3 MISCIBILILTY MECHANISM

2.3.1 Minimum Miscibility Pressure (MMP)

Minimum miscibility pressure can be defined generally as the pressure above which a further increase in pressure causes only a minimal increase in the oil recovery. Several authors have defined minimum miscibility pressure more specifically in various ways. Most of the widely used definitions set the recovery level at a given amount of gas injection. For example, a commonly used standard injection pore volume is 1.2. Some authors use ultimate recovery or breakthrough to define minimum miscibility. Still others defined the minimum miscibility pressure as the pressure above which oil recovery did not increase more than 1% per 100 psi pressure increase (Elsharkawy *et al*., 1992). Fixed recovery levels that range from 90 to 94 or 95 have been also used to define minimum miscibility (Emanuel *et al*, 1986). Yellig and Metcalfe (1980) employed a definition based on maximum or near maximum recovery at 1.2 pore volume injected (PV).

Holm and Josendal (1974) used a definition based on 94% recovery at gas breakthrough and at a gas oil ratio of 40,000 SCF/stb.

To obtain MMP, different experimental and computational methods are available. Experimental methods include slim tube test, multi-contact mixing-cell experiment and rising bubble apparatus. Computation methods contain two main groups: (1) Equation of State (EOS), (2) empirical correlations.

2.3.2 Experimental Methods

2.3.2.1 Rising Bubble Experiment

The rising bubble apparatus was developed in the late 1980s to determine the minimum miscibility pressure for oil with pure gases and a blend of gases (Christiansen and Heimi, 1987). The apparatus shown in figure 2.3consists of a flat glass tube, approximately 8 inches (20 cm) long, mounted vertically in a high-pressure sight gauge in a temperature-controlled bath. The sight gauge is backlighted for visual observation and photography of the bubbles rising in the oil. A hollow needle is connected to the glass tube at the bottom of the sight gauge for injecting gas bubbles. For minimum miscibility pressure measurement, the sight gauge and glass tube are filled with distilled water. Oil is then injected into the glass tube to displace all but a short volume of water in the tube's lower end. Then a small bubble of any gas is injected into the water. The bubble will eventually rise through the column of water, through the oil/water interface, and through the oil itself because of the buoyancy forces. The shape and motion of the bubble are observed and photographed as it rises through the oil column. The rising bubble experiments are repeated over a range of pressures at a constant temperature to measure the minimum miscibility pressure.

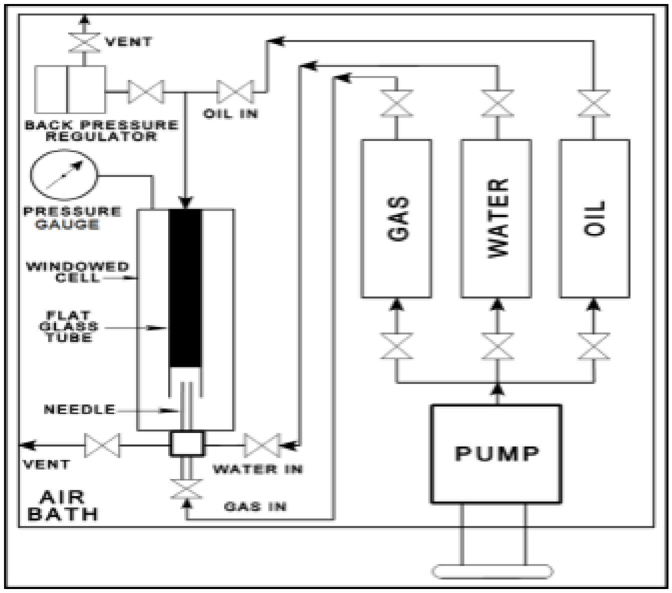

Figure 2.3: Schematic of Rising Bubble apparatus

2.3.2.2 Slimtube Experiment

The most common standard technique for determining minimum miscibility conditions experimentally is using the slimtube experiment. A typical slimtube apparatus consists of a 6.3 mm OD stainless steel tube 40ft long and packed with 160-200 mesh sand as shown is figure 2.4 (Yelling and Metcalfe, 1980). One end of the slimtube is connected to a fluid transfer cylinder and the other end is connected to a visual cell and a back-pressure regulator. At each displacement test, the slimtube is saturated with reservoir oil at reservoir temperature. Then gas is injected at a constant rate using a positive displacement pump to displace the oil. The back-pressure regulator maintains a fixed pressure at the outlet of the slimtube. In some experiments, gas is injected at a low rate to establish a mixing zone, and then the rate is increased to complete the experiment in a shorter time (Elsharkawy *et al*., 1992). To determine the minimum miscibility pressure for a given oil composition at a fixed temperature, the displacement is conducted at various (typically five) pressures (Yellig and Metcalfe, 1980). For minimum miscibility enrichment, the experiment is repeated for several enrichment levels at a constant pressure and temperature. The percent recoveries at 1.2 PVs of injected gas are then plotted as a function of the operating pressure or enrichment level. The minimum miscibility enrichment is the enrichment level or pressure in the case of MMP at which the oil recovery is 90% or more or the pressure/concentration above which no significant recovery is achieved. The slimtube method is a valuable technique for determining minimum miscibility condition and offers the advantage of using real reservoir fluid. But the method can be expensive and time-consuming. Thus, many researchers over the years have developed other non-experimental methods that can be used to approximate the miscibility conditions.

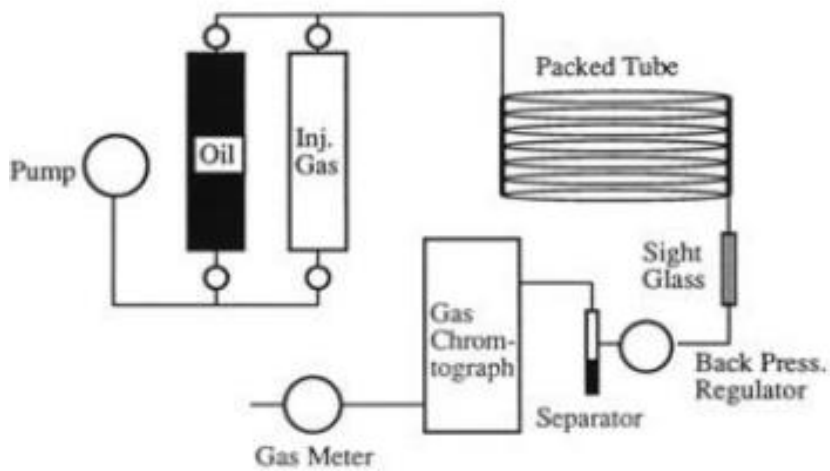

Figure 2.4: Schematic of Slimtube apparatus (Kossack, 2013)

2.3.3 Empirical Correlations

Different well-established empirical correlations for estimating the MMP have been in use for decades, and they have shown a substantial degree of accuracy as most of them were derived from experimental data. Empirical correlations are sets of equations generated from MMP data measured by experimental methods and/or MMP data calculated from compositional simulations. Empirical correlations are used to predict the MMPs for reservoir oils with various types of injected gas. These correlations provide quick estimates of MMPs which can be useful during screening of various gas injection processes for the reservoir. The MMPs calculated from empirical correlations can have large errors and should not replace MMPs obtained from experimental or compositional simulation methods. Empirical correlations should be used to predict MMP value during the early stages of screening the reservoir for various types of miscible gas injection processes. Empirical correlations for prediction of MMPs have been developed based on type and composition of the injection gas (Class and Objectives, 2013).

Some of the widely applied correlations for MMP are presented in the following section.

2.3.3.1 Yellig and Metcalfe MMP correlation

Yellig and Metcafe (1980) presented an empirical correlation for predicting (MMP) at different reservoir temperatures. This correlation is based on reservoir condition only and does not account for oil composition. The (MMP) empirical correlation is valid from 15 to 19 MPa approximately (Yellig and Metcalf, 1980).

$$\boldsymbol{MMP = 12.6472 + 0.015531 \times (T) + 1.24192 \times 10^{-4} \times (T)^2 - \frac{716.9427}{(T+32)}}$$ --*Equation (2.1)*

Where MMP is the Minimum Miscibility Pressure (MPa) and T= $1.8T_R + 32$ is the reservoir Temperature (℃).

2.3.3.2 Firoozabadi and Aziz correlation

This correlation was proposed by Firoozabadi and Aziz (1986) to determine the MMP for leans gas, nitrogen, and flue gas.

$$\boldsymbol{MMP = 9433 - 188 \times 10^3 \left(\frac{P_{C2-C5}}{MO_{C7+}T^{0.25}}\right) + 10^3 \left(\frac{P_{C2-C5}}{MO_{C7+}T^{0.25}}\right)^2}$$ ------------- *Equation(2.2)*

where MMP is the Minimum Miscibility Pressure (psi); MO_{C7+} is the molecular weight of heptane plus in the oil; PC2–C5 is the molecular percentage of intermediates defined by C2–C5, CO_2, and H_2S (mol%); and T is the reservoir temperature (^{0}F).

2.3.3.3 Glaso correlation

Glaso (1985) developed the following equations to predict MMP of hydrocarbon gas/oil system based on the Benham *et al*.'s (1960) data.

$$\boldsymbol{MMP_{x=34} = 0.145 \times \left[43636.9 - 175.196y - (322.296 - 1.276y)C1 + \left(7.77 \times 10^{-12} {MO_{C7+}}^{5.258} e^{319.8C1y^{-1.703}}\right)T\right]}$$ ------------------------------------ *Equation (2.3)*

$$\boldsymbol{MMP_{x=44} = 0.145 \times \left[37941.8 - 132.641y - (557.876 - 1.882y)C1 + \left(11.72 \times 10^{-9} {MO_{C7+}}^{3.73} e^{13.567C1y^{-1.058}}\right)T\right]}$$ ------------------------------------*Equation (2.4)*

$$\boldsymbol{MMP_{x=54} = 0.145 \times \left[51276.2 - 177.216y - (506.868 - 1.475y)C1 + \left(33.922 \times 10^{-14} y^{5.52} e^{21.706 C1 y^{-1.109}}\right)\right]}$$ -- *Equation (2.5)*

Where MMP is the minimum miscibility pressure (psi); x is the molecular weight of C2–C6 in injection gas (g/mol); C1 is the molecular percentage of methane in injection gas (mol%); T is the temperature (F); and y is the corrected molecular weight of heptane plus in the oil, which can be obtained by

$$\boldsymbol{y = \left(\frac{2.622}{yo_{C7+}^{0.846}}\right)^{6.588}}$$ --*Equation (2.6)*

Where y_o,C7+ is the specific gravity of C7+ in the oil

CHAPTER 3: METHODOLOGY

3.0 INTRODUCTION

Compositional simulation is the major tool employed in this study. Major steps in the methodology include data collection and EOR process screening to determine the applicability of ethane and flue gas injection in the candidate reservoir, using PVT software tool to characterize the reservoir fluid, building of simple reservoir models to simulate the ethane and flue gas injection processes. Thereafter, an economic model was built based on the deterministic values of the cumulative oil production obtained from the simulations of the injection processes.

3.1 RESERVOIR DATA AND FLUID PROPERTIES

In this work, the reservoir data, rock, and fluid properties were obtained from the published literature describing typical case studies of the Niger Delta reservoirs. First, the two injection processes were screened based on the Taber *et al* (1997) screening criteria listed in Table 3.1. This is to evaluate the applicability of the EOR methods to the candidate reservoir used in the case study.

Table 3.1: Screening criteria for Ethane and Flue gas Based EOR (Taber *et al*., 1997)

Parameters	**Unit**	**Flue gas Injection EOR screening criteria**	**Ethane gas injection EOR Screening criteria**	**Proposed Case study Data**
Viscosity	Cp	<0.4	<3	0.23
API gravity	API	>35	>23	41
Depth	Ft	>6000	>6000	11600
Temperature	F	NC	NC	207
Pressure	Psia	NC	NC	5045
Oil Saturation	%PV	>40	>30	83%
Composition	%	High % light HC	High light HC	96.08
Average Permeability	mD	Not critical	NC	415.94
Type of formation		Sandstone or carbonate	Sandstone or carbonate	Sandstone

The reservoir fluid used in this study meets the screening criteria for both ethane and flue gas; thus, this reservoir is a good candidate of flue gas and ethane based EOR.

Table 3.2 is a summary of the reservoir, rock and fluid properties used for the two injection processes in the candidate reservoir based on the screening criteria described earlier in Table 3.1.

Table 3.2: Reservoir Properties used in the Case Study

Parameters	**Reservoir Fluid Properties**	**Unit**
Viscosity	0.23	Cp
API gravity	41	API
Depth	11600	Ft
Temperature	207	^{0}F
Pressure	5045	Psia
Average Permeability	415.94	mD
Type of formation	Sandstone	

3.2 CHARACTERIZATION OF RESERVOIR FLUID

The first step in numerical simulation is the characterization of the fluid used in the case study. This requires determination of the number of components to use, critical temperature, critical pressure, critical z values, molecular weights, acentric factors, binary interaction coefficients, and the oil composition. Table 3.3 shows the composition of the 11-component reservoir fluid. Using PVT software, the reservoir fluid components were reduced to 6 major components. The input data included original fluid components, weight fractions, molecular weight, and specific gravity of the C7+ component, while the composition (ZI) was generated by the PVT Simulator. The reservoir temperature and pressure were provided to simulate constant Composition Expansion Experiment

(CCE). The Peng-Robinson (PR) EOS and Lohrenz-Bray-Clark viscosity correlation were used in this study to model the reservoir fluid properties required for numerical simulation. The omega values, critical value of temperature and pressure, acentric factor, binary interaction coefficient, BIC, overall composition, and other characteristic properties of the fluid were estimated.

Table 3.3: Reservoir fluid compositions (Joseph and Imoh-Jack, 2013)

Components	Reservoir fluid (mol %)
N2	0.05
CO2	0.16
C1	85.65
C2	5.99
C3	2.49
iC4	0.58
nC4	0.74
iC5	0.36
nC5	0.27
C6	0.49
C7+	3.22
C7+ MW	148
Sp. Gravity	0.79

3.3 DETERMINATION OF MINIMUM MISCIBILITY PRESSURE

Two different methods were used to determine the minimum miscibility pressure (MMP) for ethane and flue gas in this study. These methods include use of correlations and slimtube experiments.

3.3.1 MMP Correlations for Ethane and Flue Gas

The Glaso (1985) correlation and Yellig and Metcalfe (1980) correlations were used to estimate the MMP of the ethane gas, while the Firoozabadi and Aziz (1986) correlation was used to estimate the MMP of flue gas.

3.3.1.1 Glaso MMP correlations

The Glaso correlation shown as equation 2.4 was used to predict the MMP for the ethane gas system studied in this work. That is;

$$\boldsymbol{MMP_{x=34} = 0.145 \times \left[43636.9 - 175.196y - (322.296 - 1.276y)C1 + \left(7.77 \times 10^{-12} MO_{C7+}{}^{5.258} e^{319.8C1y^{-1.703}}\right)T\right]}$$ ------------------------------------ *Equation (2.3)*

$$\boldsymbol{MMP_{x=44} = 0.145 \times \left[37941.8 - 132.641y - (557.876 - 1.882y)C1 + \left(11.72 \times 10^{-9} MO_{C7+}{}^{3.73} e^{13.567C1y^{-1.058}}\right)T\right]}$$ ------------------------------------ *Equation (2.4)*

$$\boldsymbol{MMP_{x=54} = 0.145 \times \left[51276.2 - 177.216y - (506.868 - 1.475y)C1 + \left(33.922 \times 10^{-14} y^{5.52} e^{21.706C1y^{-1.109}}\right)\right]}$$ --- *Equation (2.5)*

Where MMP is the minimum miscibility pressure (psi); C1 is the molecular percentage of methane in injection gas (mol%); x is the molecular weight of C2–C6 in injection gas (g/mol); T is the temperature (F); and y is the corrected molecular weight of heptane plus in the oil, which can be obtained by

$$\boldsymbol{y = \left(\frac{2.622}{yo_{C7+}^{0.846}}\right)^{6.588}}$$ -- *Equation (2.6)*

Where y_{oC7+} is the specific gravity of C7+ in the oil.

3.3.1.2 Yellig and Metcalfe MMP correlation

The Yellig and Metcalfe MMP correlation which was shown earlier as equation 2.1 was also used to estimate the MMP. It was noted that the Yellig and Metcalfe (1980) correlation was specifically designed for Carbon dioxide (CO_2) gas injection, and so it does not accurately predict the MMP for pure ethane gas. In this study the reservoir temperature (T) was the only variable needed. The results obtained from these correlations were not unique to the candidate reservoir fluid as some of the parameters included in the equations were not required for pure ethane gas injection.

$$\boldsymbol{MMP = 12.6472 + 0.015531 \times (T) + 1.24192 \times 10^{-4} \times (T)^2 - \frac{716.9427}{(T+32)}}\text{Equ}\textit{ation (2.1)}$$

3.3.1.3 Firoozabadi and Aziz MMP correlation

The Firoozabadi and Aziz (1986) correlation shown in equation 2.2 was used to determine the MMP of the Flue gas.

$$\boldsymbol{MMP = 9433 - 188 \times 10^3 \left(\frac{P_{C2-C5}}{Mo_{C7+}T^{0.25}}\right) + 10^3 \left(\frac{P_{C2-C5}}{Mo_{C7+}T^{0.25}}\right)^2} \text{------------- } \textit{Equation (2.2)}$$

where MMP is the Minimum Miscibility Pressure (psi); Mo_{C7+} is the molecular weight of heptane plus in the oil; P_{C2-C5} is the molecular percentage of intermediates defined by C2–C5, CO2, and H2S (mol%); and T is the reservoir temperature (^{0}F).

3.3.2 Equation of state PVT

Using the PVT software tool, the equation of state was used to simulate a multiple-contact process of lightening up the reservoir fluid using 100 percent of pure ethane gas and flue gas (75% N2, 15% CO2) gas based on multi-cell condensing gas miscible drive. The Peng-Robinson (PR) three-parameter EOS and Lohrenz-Bray-Clark viscosity correlation were used to estimate the multiple contact minimum pressure for the two injection gases.

3.3.3 Simulation of Slimtube Experiment.

Slimtube experiment is the most accurate method for determining the minimum miscibility pressure, MMP. In the absence of real samples to work with, this experiment can be simulated using a compositional simulator. The PVT data generated with PR 3-parameter EOS was exported into the slimtube model for estimating the MMP.

3.3.3.1 The Slimtube model

One-dimensional slimtube model is gridded to contain 1000 grid blocks with 0.05-ft grid block size in the x-direction. The length of the slimtube used for this simulation was approximately 50ft with an average permeability of 1600mD, oil gravity of 41°API, and a constant reservoir temperature of 207^{0}F. The injection into the slimtube model was controlled by reservoir pore volumes injected, while the reservoir pressure was varied from 1000psia to 8000psia.

3.4 RESERVOIR MODEL DESCRIPTION

A peripheral drive reservoir simulation model was developed in this study using a compositional simulator. The model consists of two wells--one "Producer" and one "injector". The PVT properties obtained from the PVT software were exported to the compositional simulation model. The reservoir properties used for the reservoir modelling are summarized in the Table 3.4.

Table 3.4: Reservoir properties, grid parameters and production constraints

Parameter	Value	Unit
Surface Properties		
Specific Gravity	41	Deg. API
Viscosity	0.23	Cp
Surface Conditions		
Standard Temperature	60	Deg. F
Separator Temperature	60	Deg. F
Standard Pressure	14.7	Psia
Separator Pressure	14.7	Psia
Reservoir Conditions		
Reservoir Temperature	207	Deg. F
Reservoir Pressure	5045	Psia
Porosity	0.22	Faction
Oil Water contact	11630	ft
Oil Gas contact	11590	ft
Rock Type	Sandstone	

Field Model Dimensions		
No of cells in the X Direction	20	
No of cells in the Y Direction	20	
No of cells in the Z Direction	10	
Grid model	3-Dimension	
Delta X	5000	ft
Delta Y	5000	ft
Delta Z	100	ft
Depth	11550	ft
Rock Properties		
Porosity	0.22	Fraction
Perm X	900	Md
Perm Y	900	Md
Perm Z	90	Md
Compressibility	4e-6	1/psia
Hydrocarbons and Water Properties		
Gas density	0.045	lb/ft^3
Oil density	47.06	lb/ft^3
Solvent density (SDENSITY)	0.063	lb/ft^3
Water density	63	lb/ft^3
Water viscosity	0.31	cp
Water compressibility	3e-06	1/psia
Water formation volume factor	1.0	bbl/stb
Water viscosibility	0	1/psia
Well Data Control Parameters and Constraints		
Oil production rate	250	STB/D
Minimum oil production rate	50	STB/D

Gas injection rate	4000	MSCF/D
Minimum gas production rate	200	MSCF/D
Maximum water cut	0.95	Fraction

Figure 3.1 shows the reservoir model after simulating for 20 years under operating conditions of producer BHP of 800psia, and oil production rate of 250stb/day.

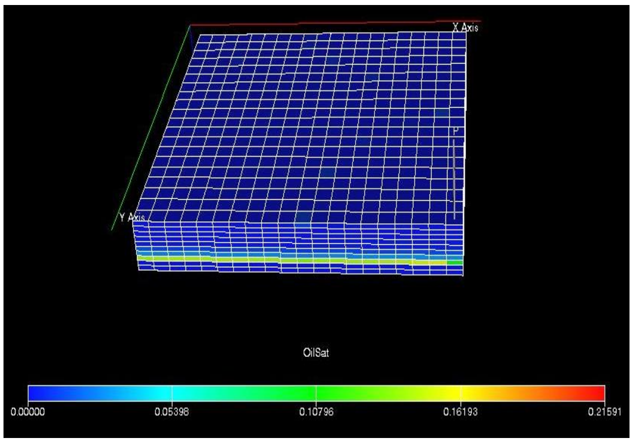

Figure 3.1: Reservoir oil saturation after 20 years of primary depletion

3.5 RESERVOIR SIMULATION

The reservoir model was used to simulate five (05) production schemes for ethane gas and flue gas. The simulations included the base case of natural depletion, the injection of the ethane gas and flue gas, and application of ethane and flue gas water alternating gas injection (WAG) EOR schemes. The constraints used in the simulations are

1. Minimum oil rate of 50 STB/day.
2. Minimum gas injection rate was assumed to be 100 MMSCF/day.
3. The maximum water-cut of 95% was used.
4. Injection pressure above the MMP to simulate miscibility of injection fluid with the in-situ fluid.

3.5.1 Case 1-Natural depletion

Generally, in natural depletion the gas is produced by utilizing the natural reservoir pressure as the driving force for the flow of gas to the surface. The main characteristic of natural depletion is a declining reservoir pressure as gas is being produced.

In this study the base case involves running the model under primary depletion; the model is run without any injection for 20 years with the producer bottom-hole pressure (BHP) set at 800 psia. The base case was used as a template for simulating the other EOR processes. The cumulative oil and gas recovery, average reservoir pressure, and water cut are some of the results obtained from the simulations.

3.5.2 Case 2-Ethane Gas injection

In this case, pure ethane gas was injected into the reservoir for 20 years to displace the oil and recovery of oil and gas from the simulation was recorded.

3.5.3 Case 3-Ethane Water-Alternating-Gas (WAG) injection

Case 3 involves simulating an ethane water-alternating-gas (WAG) injection. This process started with water injection for the first years of production to establish the reservoir injectivity, and this was followed by injection of a slug of ethane gas at 4 MMSCF/D for another five years, and then initiated water injection (3000 STB/D) for the next five years; and followed by ethane injection for the last five years. This WAG EOR process lasted for a total of 20 years.

3.5.4 Case 4-Flue Gas injection

Case 4 is the simulation of flue gas injection; whereby pure flue gas (75% N_2 and 25% CO_2) was injected at 4MMSCF/D for 20 years in the reservoir to displace the oil. The recovery performance during flue gas injection was evaluated.

3.5.5Case 5-Flue Gas Water-Alternating-Gas (WAG) injection

The flue gas water-alternating-gas injection (flue gas WAG) was initiated with water injection for the first five (05) years to establish the reservoir injectivity. This was followed by a slug of flue gas injection at a rate of 4MMSCF/D for another five (05) years; then water was injected at 3000STB/D to complete the WAG cycle. The WAG cycles for flue gas injection are like those used in the ethane WAG EOR process. The flue gas WAG process was simulated for a total of twenty (20) years.

The simulations of the different cases for the natural depletion, ethane gas and flue gas injection were performed by varying some key operating conditions like the BHP at the producers and injector, well injection and production rates to determine the most suitable operating conditions that would yield reasonable volumes of the cumulative oil production.

3.6 SENSITIVITY ANALYSIS

Sensitivity analysis is used to understand the effect of varying each parameter on the objective function (i.e., cumulative recovery in this study) and to reduce the number of control variables in the optimization of the EOR process. The length of the ethane WAG cycles is among the various parameters used in the sensitivity analysis. The length of the WAG cycles was varied from one (1), two (2) and three (3) years of WAG injection. The reservoir injectivity was also studied during the WAG process after the initial water flooding. The reservoir was operated for 4, 5, 6 years of water flooding followed by WAG injection using cycle of 1-, 2-, and 3-year period. These parameters were varied during the reservoir simulations and the cumulative oil and gas production, water cut, and oil production rates were observed.

3.7 ECONOMIC EVALUATION

After completing the technical feasibility aspect of the study, the economic analysis of ethane and flue gas injection was done to determine how economically feasible is ethane and flue gas EOR application in the Niger Delta. In this study the economic analysis was done on the pure ethane and flue gas injections only.

3.7.1 Economic Evaluation and Assumptions for Ethane Gas Injection

One assumption used in the economic analysis of the Ethane gas EOR was that the cost of conditioning the nitrogen and sulphur will not be included in the extraction of ethane from natural gas. This assumption has been corroborated by the findings of Enyi *et al*. (2005). Note, Enyi *et al*. (2005) stated that the low inert gas and sulphur content of Nigerian natural gas makes projects requiring the conditioning process viable, economical, and profitable (Enyi, Appah, and Engineering, 2005). This is an economic advantage for ethane extraction in Nigeria since conditioning of the natural gas is the major stage of ethane extraction, after which it is subjected to low temperature to separate methane, before applying fractional distillation to separate ethane from the heavier hydrocarbon components. The overall costs of conditioning Nigeria's natural gas and extraction of ethane should be economical considering a simple onsite processing equipment without the cost of gas sweetening.

In this study, we will use Jin and Lim (2018) model assumptions in the economic evaluation of ethane recovery process. The following assumptions are defined for the economic analysis of the ethane based EOR project:

1. Ethane gas processing cost of $18 million is required for yearly extraction of 1Bscf of ethane. A yearly price escalating factor of 4% was used to cover the inflation rate from 2018 to date.
2. Operating cost for ethane injection and smooth running of the field per year was assumed to be $6/barrel of oil.
3. A yearly utility cost of $2 million was assumed.
4. The base case oil price is set at $50 per barrel.
5. The royalty charge of 12.5%, petroleum property tax (PPT) of 60%, and income tax of 30% were used.

The Economic analysis was done considering two sources of procuring ethane for injection. First, we considered building a natural gas processing plant with ethane extraction unit in the field. This is probably the most likely option applicable to ethane EOR in Nigeria. Secondly, the ethane can be sourced from the spot market. This is not highly likely in the Nigerian market.

Option 1: Ethane Gas from Local Gas Processing Plant

Constructing a natural gas processing plant with an ethane extraction unit is considered primarily to ensure uninterrupted supply of ethane gas for injection and to evaluate the production of other commercial gases that occur as end products from the plant. This is the option considered to be applicable in the Niger Delta. This option involves estimating the capital investment cost for the daily processing of natural gas required to produce the quantity of ethane to be injected.

Option 2: Sourcing Ethane Gas from the Spot Market

The second option is to buy the required quantity of ethane gas needed for injection at the spot market price. Cost of ethane production (Spot market price) is assumed to $6/MSCF in this case. This is on the high side because EIA (US Energy Information, Administration) reported lower gas spot market prices during 2020 and early 2021. The reason for this assumption is that ethane attracts $1 to $2 premium per MSCF over natural gas price. And we have assumed that the average price of natural gas is $4/MSCF in this study. The assumptions made in the economic analysis using Options 1 and 2 are summarized in the Table 3.5.

Table 3.5: Assumptions for Economic Analysis of Ethane Gas Injection

Item	**Ethane**	**Unit**
Start Year	2021	Year
STOOIP	3.8	MMbbl
Production life	20	Years
OPEX	$6	$/barrel
Depreciation (straight line depreciation)	5 years	Years
Spot Market Price of ethane	$6	$/MSCF
MOD Oil price	50	$/bbl
Royalty rate	12.5%	%
Ethane Gas processing	21	$MM/year

Drilling and Development (2 Wells)	50	$MM
Income tax rate	30	%
PPT	60%	%
Discount rate	10%	%

3.7.2 Economic Evaluation and Assumptions for Flue Gas Injection

Removal of excess nitrogen in natural gas is required to increase the heating value of the gas and reduce the quantity of the gas to be compressed or transported. If the nitrogen content is less than 4%, most pipelines will accept the gas provided the total content of inerts (CO_2 + N_2) does not exceed 4% by volume. However, a typical Nigerian natural gas stream has no traces of nitrogen. For this reason, since nitrogen is readily available in the air, it will be captured by a cryogenic process. Also, carbon dioxide (CO2) will be gotten from burning some of the produced natural gas. Table 3.6 summarizes the assumptions used in the economic analysis of flue gas injection in the Niger Delta case study.

Table 3.6: **Assumptions used in the economic analysis of flue gas injection in the Niger Delta case study.**

Item	**Flue Gas**	**Unit**
Start Year	2021	Year
STOOIP	3.8	MMbbl
Production life	20	Years
OPEX	$6	$/barrel
Depreciation (straight line depreciation)	5 years	Years
MOD Oil price	50	$/bbl

Royalty rate	12.5%	%
Flue gas processing	3	$M/year
ASU Generator	562.4	$MM
Drilling and Development	50	$MM
Income tax rate	30	%
PPT	60%	%
Discount rate	10%	%

3.8 COMPARISON OF APPLICATION OF ETHANE AND FLUE GAS INJECTION EOR

One major objective of this study is to compare the technical and economic feasibility of the application of ethane and flue gas injection as EOR methods in the Niger Delta.

To achieve the comparative assessment of the technical feasibility, we used the results from the simulations of the production performance of ethane vs. flue gas EOR. This involved a comparison of the cumulative oil and gas production, and water cut derived from the simulations of ethane and flue gas based EOR. For a comparative analysis of the economic feasibility, we used the results of the economic analysis of the potential application of ethane and flue gas based EOR in the Niger Delta. The revenues derived from the annual production of oil and gas served as the source of project income. The results of the technical and economic feasibility analyses are presented in the next Chapter.

CHAPTER 4: RESULTS AND DISCUSSION

4.0 INTRODUCTION

This chapter presents the results obtained from this study. The results are discussed to improve our understanding of the technical and economic feasibility of applying ethane and flue gas based enhanced oil recovery processes in the Niger Delta.

4.1 RESULTS OF THE FLUID CHARACTERIZATION

As discussed in chapter 3 the reservoir fluid was reduced to six (06) major components before characterization of the phase behavior. Table 4.1 is a summary of the results obtained from the fluid characterization.

Table 4.1 summary of the results obtained from the fluid characterization.

Cpnt	Cpst	TCRIT	PCRIT	VCRI	ZCRI	ACF	SSHI	MW	OMA	OMB	PA	VCRITVIS	ZCRITVIS
N2	0.0005	227.16	492.31	1.44	0.29	0.04	-0.13	28.01	0.46	0.08	41	1.44	0.29
CO2	0.0016	548.46	1071.3	1.51	0.27	0.23	-0.04	44.01	0.46	0.08	78	1.51	0.27
C1	0.8565	343.08	667.78	1.57	0.28	0.01	-0.14	16.04	0.46	0.08	77	1.57	0.28
C2	0.0599	549.77	708.34	2.37	0.28	0.10	-0.10	30.07	0.46	0.08	108	2.37	0.28
C3-C6	0.0493	735.10	561.96	3.92	0.28	0.19	-0.06	55.40	0.46	0.08	182	3.92	0.28
C7+	0.0322	1154.3	340.11	9.34	0.26	0.48	0.04	148.0	0.46	0.08	415	9.34	0.26

4.2 RESULTS OF MINIMUM MISCIBILITY PRESSURE OF ETHANE AND FLUE GAS.

As mentioned in the previous chapter, the reservoir fluid presented in Table 3.1 and 3.2 was characterized. The PVT analysis produced a fluid phase envelope which is A representative of the reservoir fluid under study. The result of the PVT analysis was used as input to the simulation model of the slimtube experiment to determine the minimum miscibility pressure of ethane and flue gas. Furthermore, published correlations were also used to determine these MMPs. It is well known from the literature that in absence of the slimtube experiments, the simulation of slimtube experiment is the most accurate method for determining MMP. The values of MMPs obtained from the simulation of a slimtube experiment using a 3-parameter Peng-Robinson EOS for ethane and flue gas are 5800 psia and 7350 psia, respectively. Figure 4.1 illustrates the determination of the MMP from the results of the slimtube simulations of ethane and flue gas injection. Table 4.2 depicts the results of MMP obtained from the various methods used in this study.

Table 4.2: Results of Minimum Miscibility Pressure Calculation

METHOD	MINIMUM MISCIBILITY PRESSURE, MMP (PSIA)	
	ETHANE	FLUE GAS
Slimtube Simulation	5800	7350
Glaso Correlation	5742	-
Firoozabadi and Aziz	-	6433
Yelling and Metcalfe	5510	

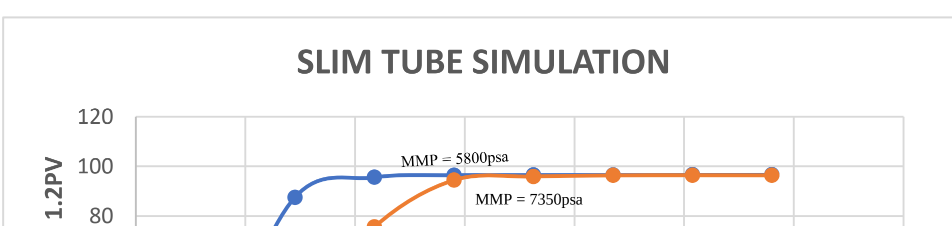

Figure 4.1: Oil recovery vs. pressure plot of slimtube simulations showing MMP

From Figure 4.1 it is observed that the recovery efficiency increases with pressure until a point of deflection is reached after which an increase in pressure gives no additional recovery. The pressure value at this point of deflection is called the minimum miscibility pressure for the ethane and flue gas flooding. The results from Figure 4.1 indicate that the MMP is about 5800 and 7350 psia for ethane and flue gas, respectively. It is observed that the MMP values of flue gas were greater than the MMP obtained for the ethane gas; this is due to the high percentage of nitrogen content in the flue gas. Nitrogen's high MMP is attributed to the presence of impurities.

4.3 RESULTS OF SIMULATION OF NATURAL DEPLETION AND ETHANE EOR PROCESS

In this case study, the data from the Niger Delta was used to estimate the amount of oil recovered from an ethane based EOR process. A simple reservoir model was built with one injector and one producer at each corner. The model was used to simulate the cumulative oil recovery considering different production schemes. The first scheme was the base case (Case 1) in which the simulation model was ran without injection for twenty (20) years. This process is called primary or natural depletion. Pure ethane injection is Case 2 of this study. In the second scheme pure ethane gas was injected at a rate of 4MMSCF/D and oil was produced for 20 years. For the ethane injection, four (4) different injection rates were used to determine the best technically feasible injection rate. The third production scheme, which is Case 3 of this work, an ethane water-alternating-gas (WAG) injection is investigated. For the ethane WAG process, water was first injected for five (5) years to establish the reservoir injectivity, and this was followed by injection of a slug of ethane gas at 4 MMSCD/D into the reservoir for another five (5) years. A second WAG cycle consisting of a 5-year water injection at 3000 STB/D followed by 5-year gas injection was conducted to produce from the reservoir for a total of 20 years. The results from the simulation of the different production scenarios are presented as follow.

Case 1: Natural Depletion

The performance (FOTP, FGTP, FPR and FWCT vs Time) curves under natural depletion of the reservoir after twenty years of simulation are shown in Figure 4.2 to Figure 4.5.

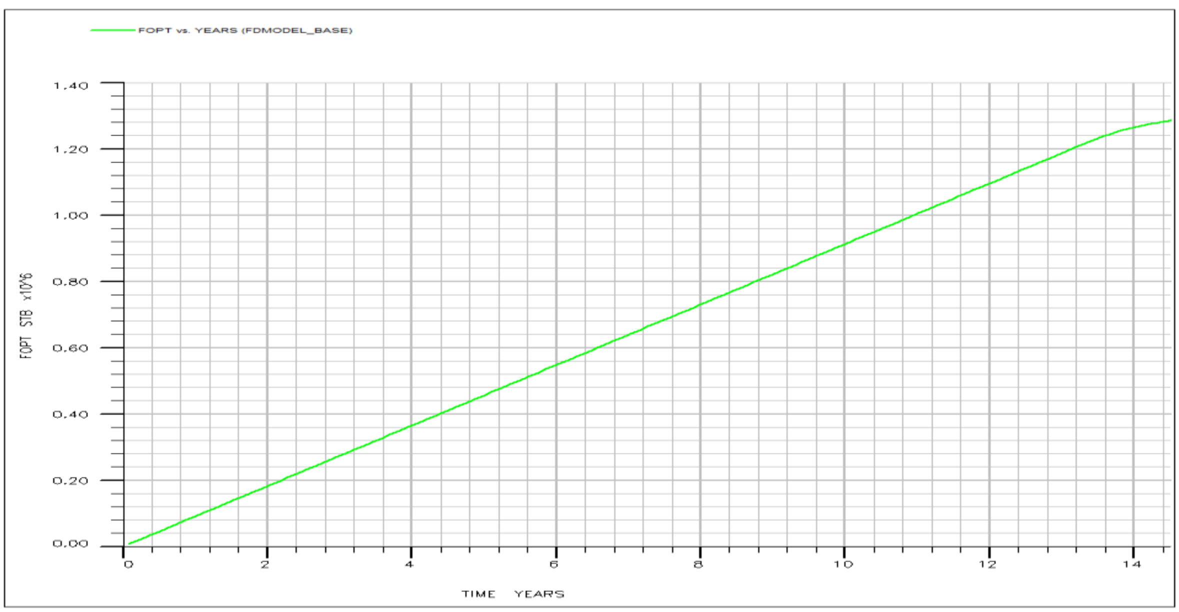

Figure 4.2: Cumulative oil recovery from natural depletion after 20-year simulation

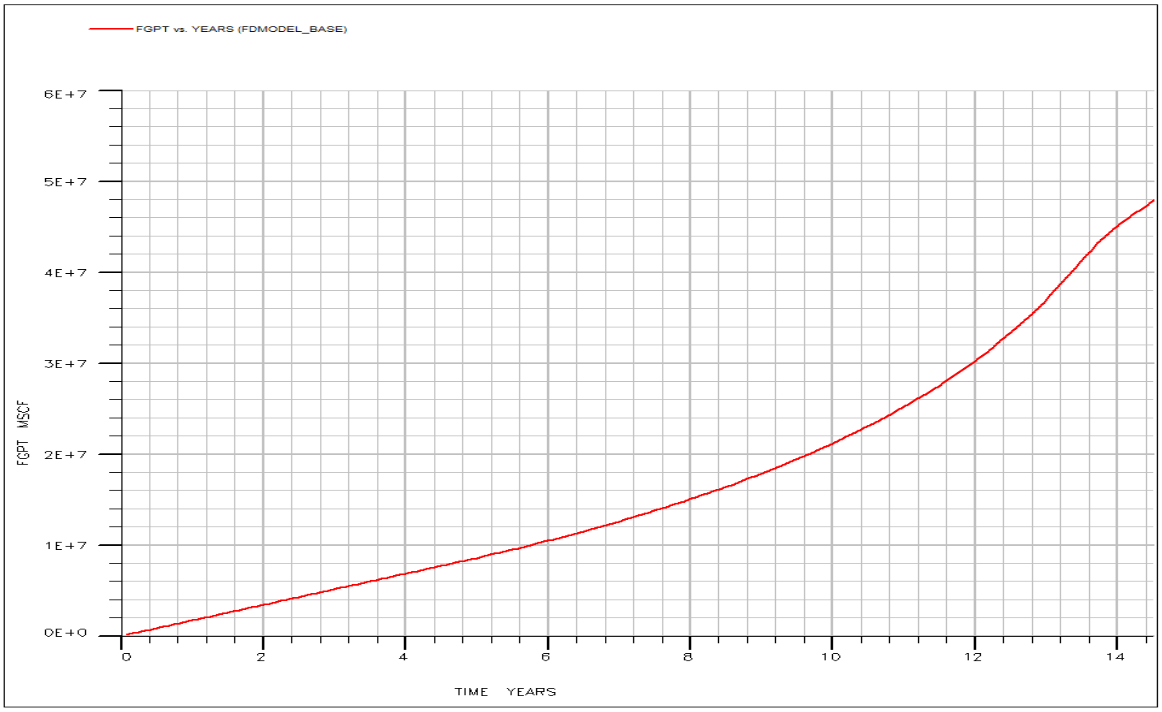

Figure 4.3: Cumulative gas recovery from natural depletion after 20-year simulation

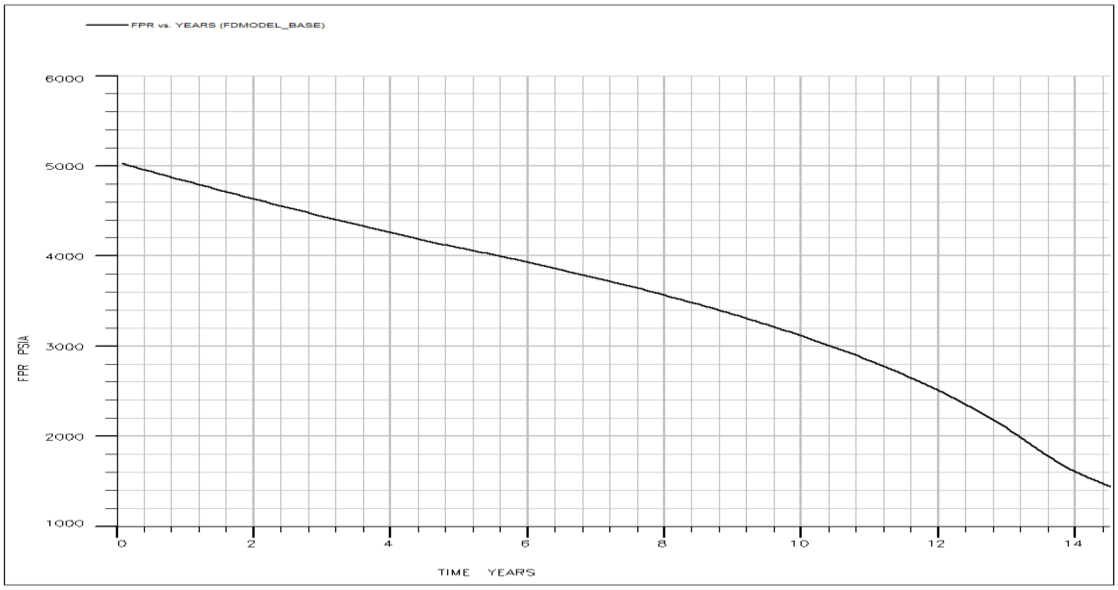

Figure 4.4: Average reservoir pressure vs time from natural depletion after 20-year simulation

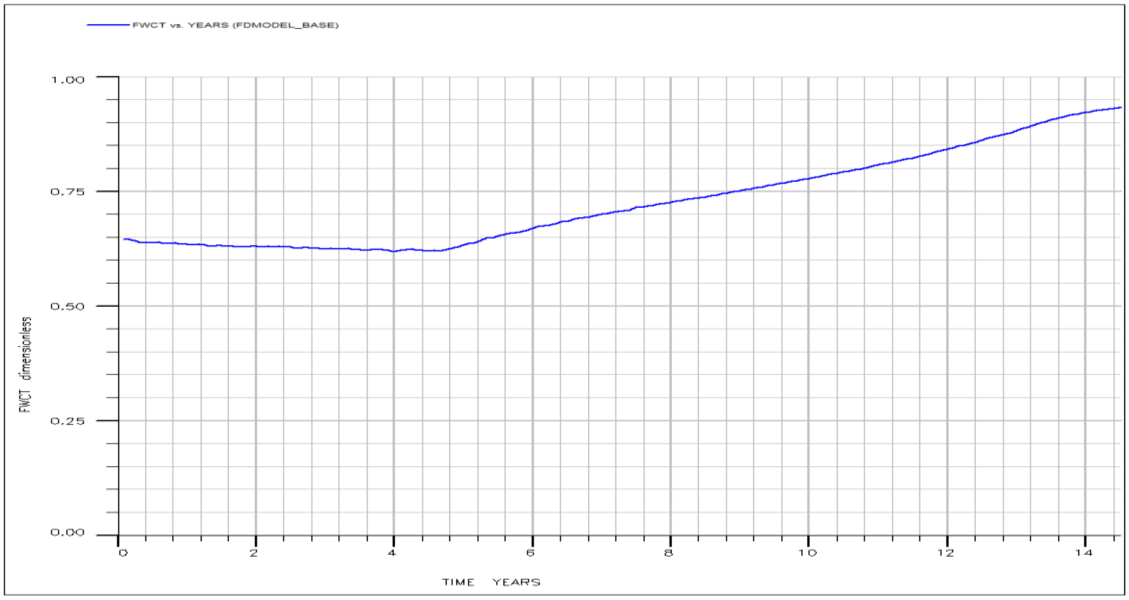

Figure 4.5: Water cut vs. Time from natural depletion after 20-year simulation

Observations: Figure 4.2 shows that during natural depletion the cumulative oil recovery increases gradually from the first year of production to the 16th year where it reached its peak with a cumulative production value of 1.3MMSTB. The results plotted in Figure 4.3 indicate that the gas cumulative recovery also increases gradually from the first year of production to 53BSCF at the fifteenth (15^{th}) year of production.

From Figure 4.4 it is observed that the field pressure decreased rapidly from the initial reservoir pressure 5045 psia to 1200 psia where it became constant till the end of the production. As shown in Figure 4.5, the water production remains constant at 60% from the beginning of production till the fourth year, and then it rose gradually to water cut of about 95% at the 15th year of production.

Discussion: Simulation results were obtained from natural depletion of the reservoir from an initial pressure of 5045 psia to 1200 psia with one production well. During this period, a recovery of 34.2% was obtained with a production plateau of about five (5) years. The low recovery from the reservoir suggests that large quantities of oil remain in the reservoir and, therefore, this reservoir is considered a good candidate for enhanced oil recovery. Furthermore, the rapid and continuous decrease of the reservoir pressure is attributed to the lack of extraneous fluid or gas cap expansion to provide voidage replacement of the gas and oil withdrawals. Also, there was significant water production with the oil during the entire production life of the reservoir. This could be due to the presence of an active water drive.

Case 2: Pure Ethane Gas Injection for 20 years

In this case pure ethane was injected at the rate of 4MMSCF/day in the reservoir for twenty (20) years. Figures 4.6 through 4.9 show the simulation results from the injection of ethane gas in the reservoir for the 20-year period.

Observations: From Figure 4.6 it was observed that the cumulative oil recovery increases gradually with a cumulative production of 1.78MMSTB at the end of production. Results shown in Figure 4.7 indicate that the gas cumulative recovery also increases gradually from the first year of production to the last year of production with a cumulative gas production of 38BSCF.

Figure 4.8 is a plot of the average reservoir pressure vs. time. The average reservoir pressure shows a gradual decreasing trend from the initial reservoir pressure of 5045psia to 3200psia at the end of the 20-year production.

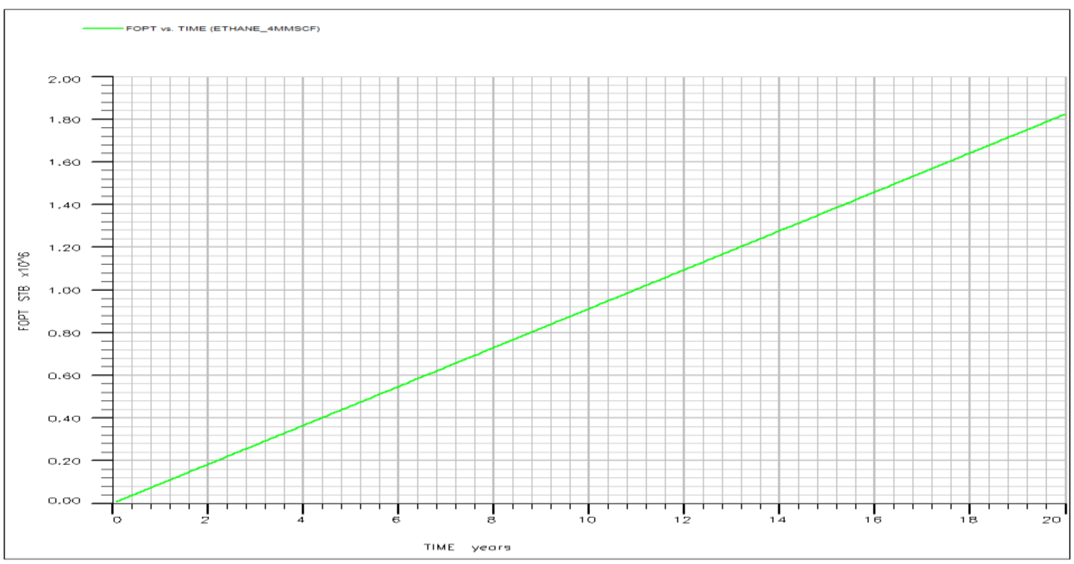

Figure 4.6: Cumulative oil recovery from pure ethane injection after 20-year simulation

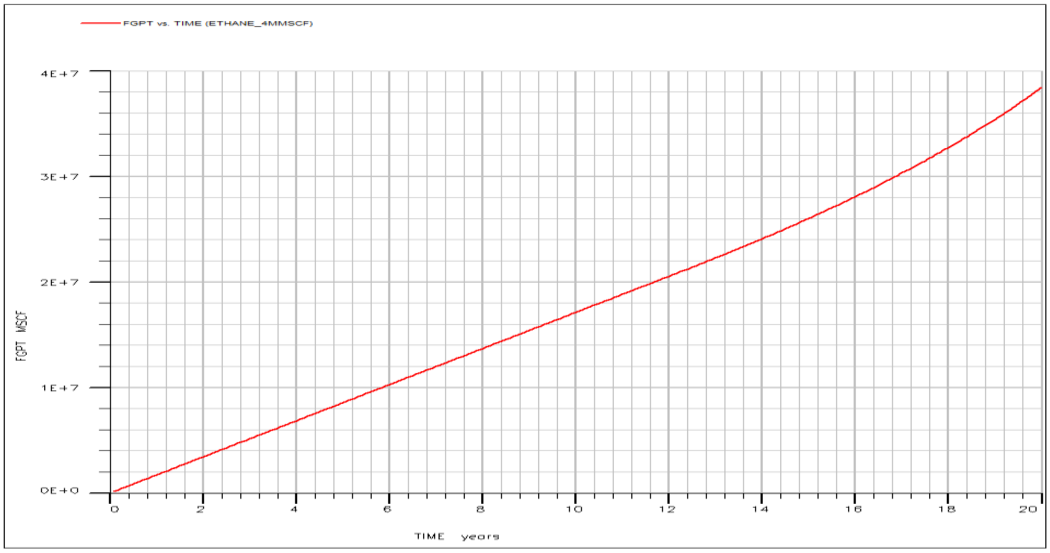

Figure 4.7: Cumulative gas recovery from pure ethane injection after 20-year simulation

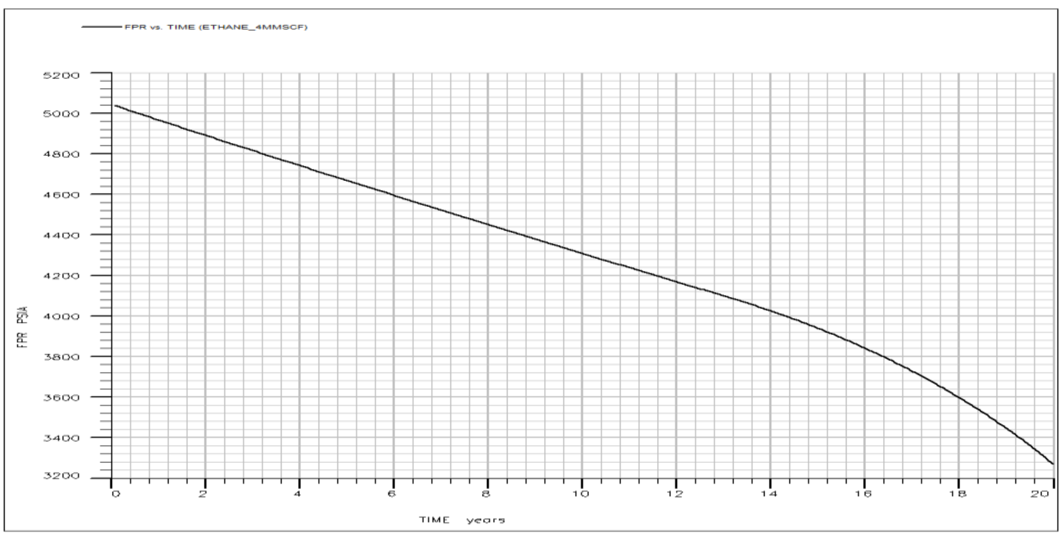

Figure 4.8: Average field pressure vs Time from pure ethane injection after 20-year simulation

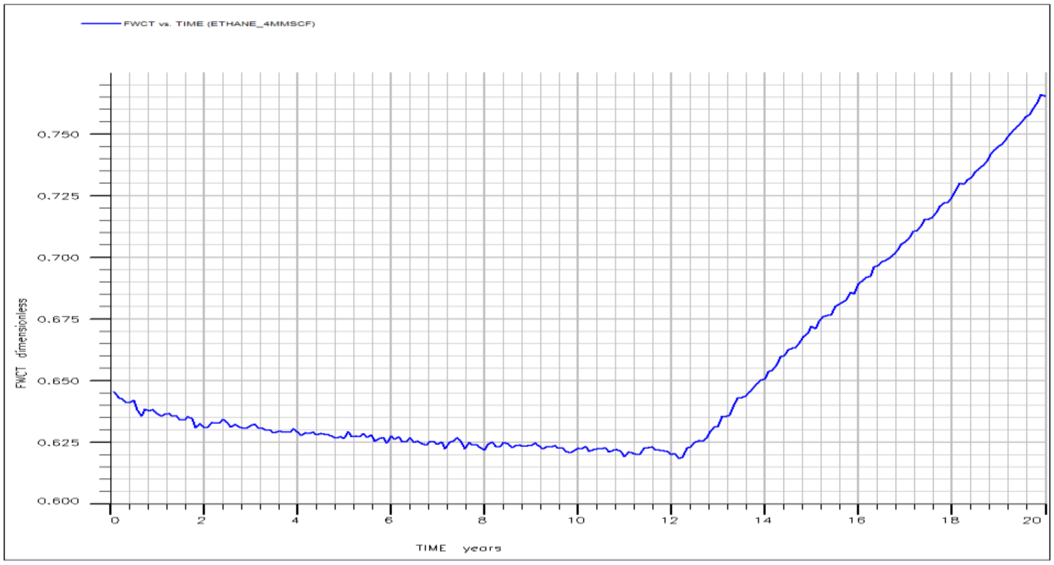

Figure 4.9: Water cut vs Time from pure ethane injection after 20-year simulation

Notice the improvement in pressure maintenance during the pure gas injection compared to the natural depletion where the terminal pressure after 15 years of production was 1200 psia. The trend of water production as shown in Figure 4.9 remains constant at 65% water cut from the beginning of production until the 12th year. Thereafter, the water cut increased to about 75% until the end of the 20-year production.

Discussion: The results of **s**imulation of pure ethane injection yielded an oil recovery factor of 46.8% at the end of production. This recovery factor is higher than the recovery gotten from the natural depletion. Furthermore, it was also observed that ethane injection process showed improved pressure maintenance during the 20-year production compared to the rapid decrease in average reservoir pressure observed during the natural depletion.

Case 3: Ethane WAG Injection for 20 years

In this case of ethane WAG, the gas was injected at the rate of 4MMSCF/day followed by water injection at a rate of 3000 STB/D per WAG cycle for twenty (20) years of cumulative production. Figures 4.10 through 4.13 show the results of the 20-year simulations. The results of the cumulative oil and gas recoveries are shown in Figures 4.10 and 4.11, while the average reservoir pressure and the filed water cut profiles are shown in Figure 4.12 and Figure 4.13, respectively.

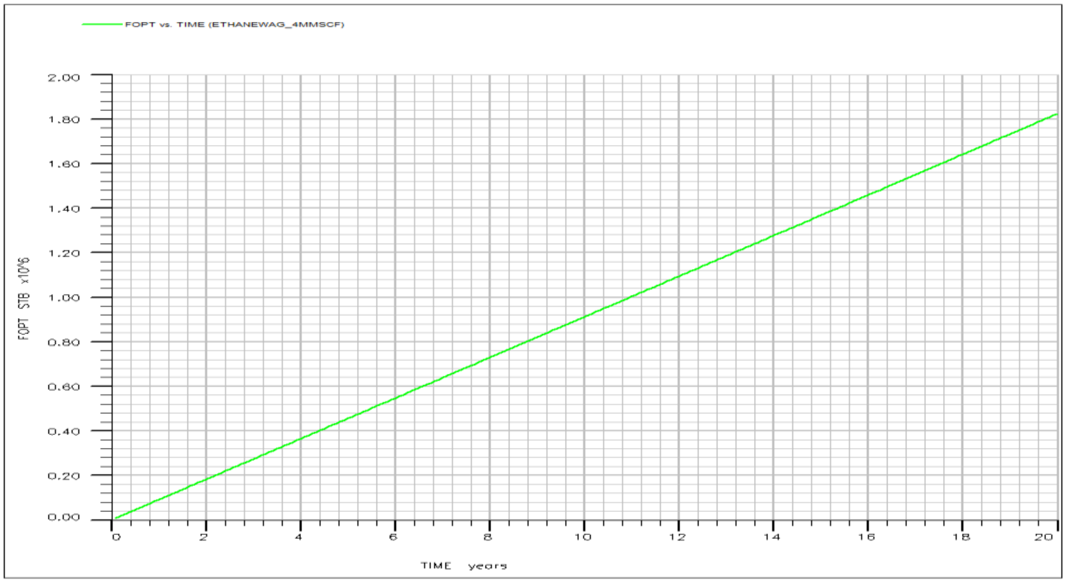

Figure 4.10: Cumulative oil recovery from ethane WAG injection after 20-year simulation

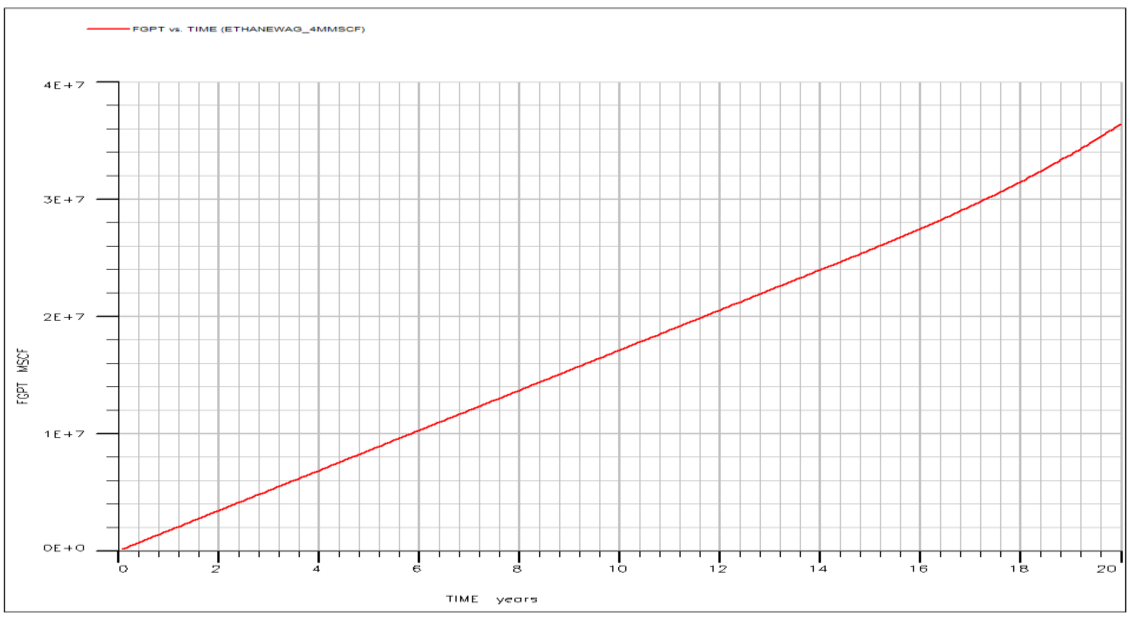

Figure 4.11: Cumulative gas recovery from ethane WAG injection after 20-year simulation

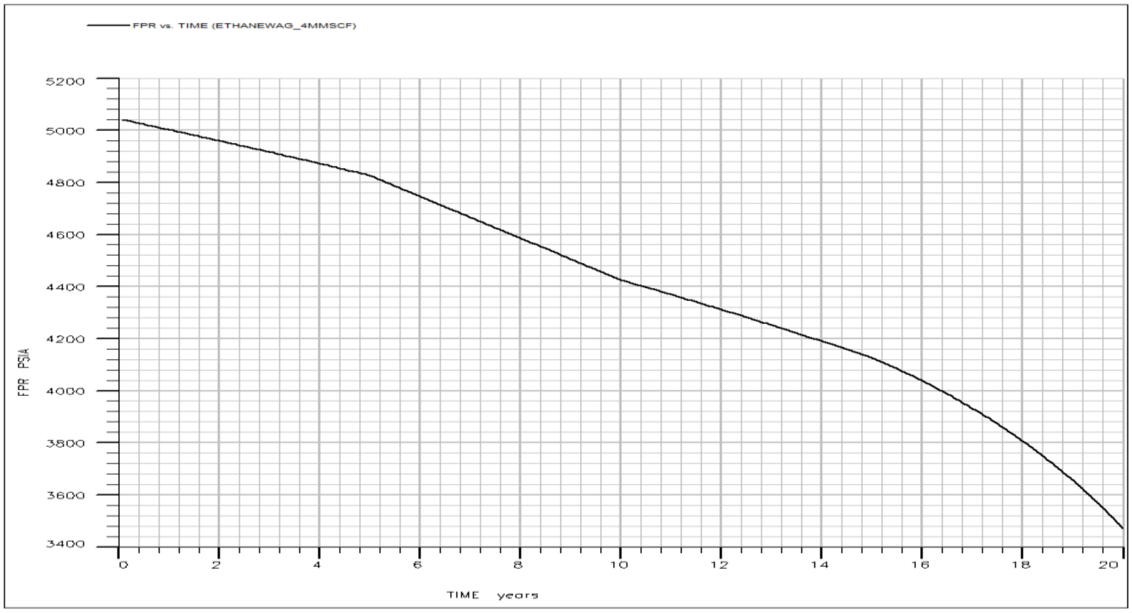

Figure 4.12: Field pressure vs Time from ethane WAG injection after 20-year simulation

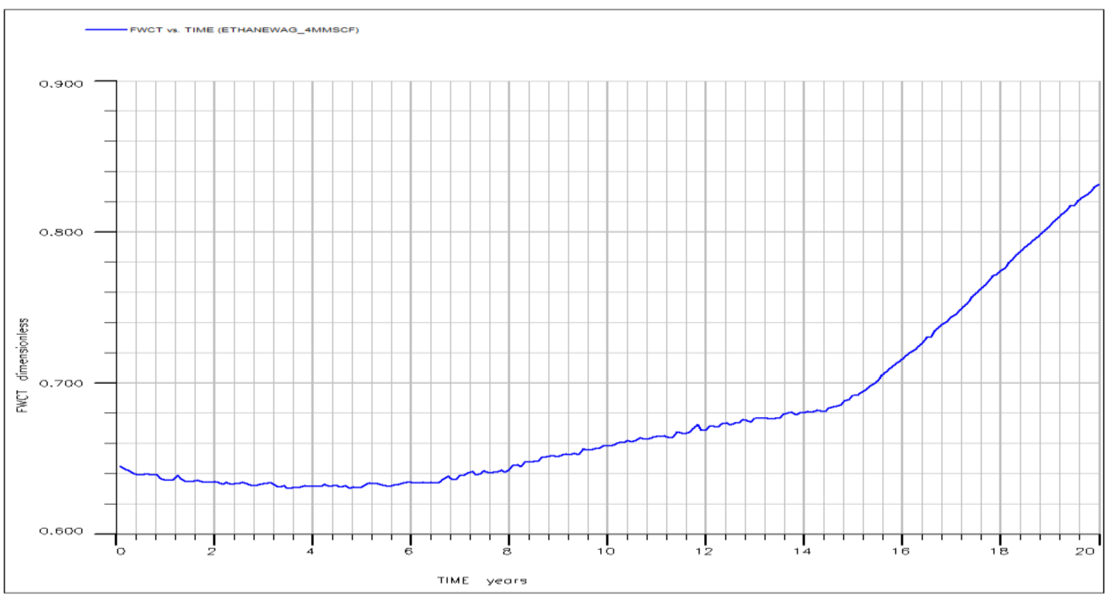

Figure 4.13: Field water cut vs Time from ethane WAG injection after 20-year simulation

Observations: Results of the ethane WAG indicated that the cumulative oil recovery increased from the beginning of production to 1.8MMSTB at the end of production, while the gas cumulative recovery also increased 3.7 BSCF at the end of 20-year production. The field pressure trend shows a gradual decrease from the reservoir pressure 5045psia to 3400 psia at the end of production. The field water cut profile remains relatively constant at 65%from the beginning of production till about the sixth (6^{th}) year of production before it increased gradually to about 85% at the end of production.

Discussion: Simulation results obtained from ethane WAG injection show an oil recovery factor of 47.3% at the end of production. This cumulative recovery is higher than the results from both the natural depletion and pure ethane injection. However, it was observed that the cumulative gas recovery obtained from the ethane WAG process is less than that obtained from the natural depletion and pure ethane injection. It was also observed that the ethane WAG injection provided improvement in pressure maintenance in the reservoir compared to the results obtained from the natural depletion and pure ethane injection. Furthermore, there was significant water production with the oil during the entire production life of the reservoir.

4.4 RESULTS OF SIMULATION OF FLUE GAS EOR

Case 4 of this study was the simulation of flue gas injection. In Case 4 the flue gas (75% N_2 and 25% CO_2) was injected to recover the oil from the production well during 20 years of production. The following graphs (Figures 4.14 to 4.170) show the results of the flue gas injection simulation for the 20-year period.

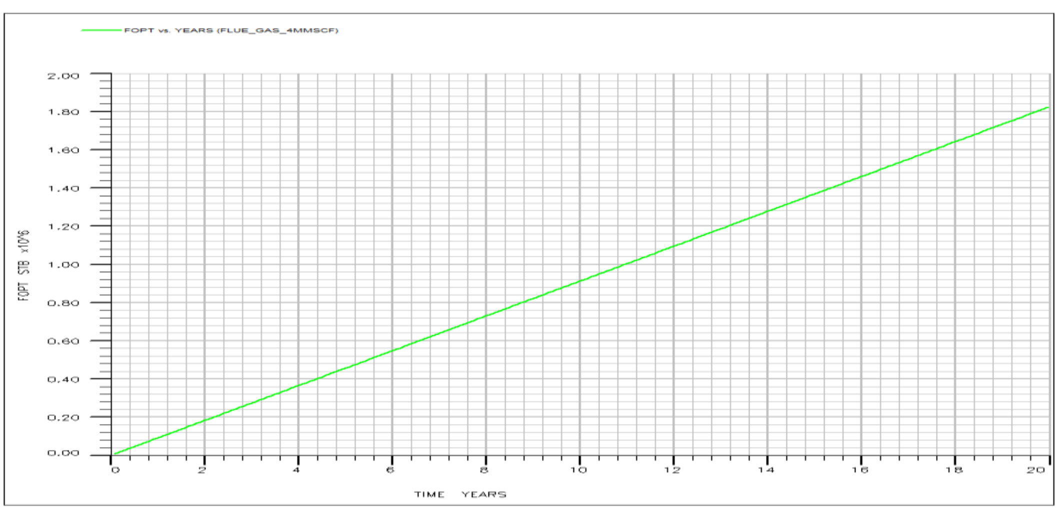

Figure 4.14: Cumulative oil recovery from flue gas injection after 20-year simulation

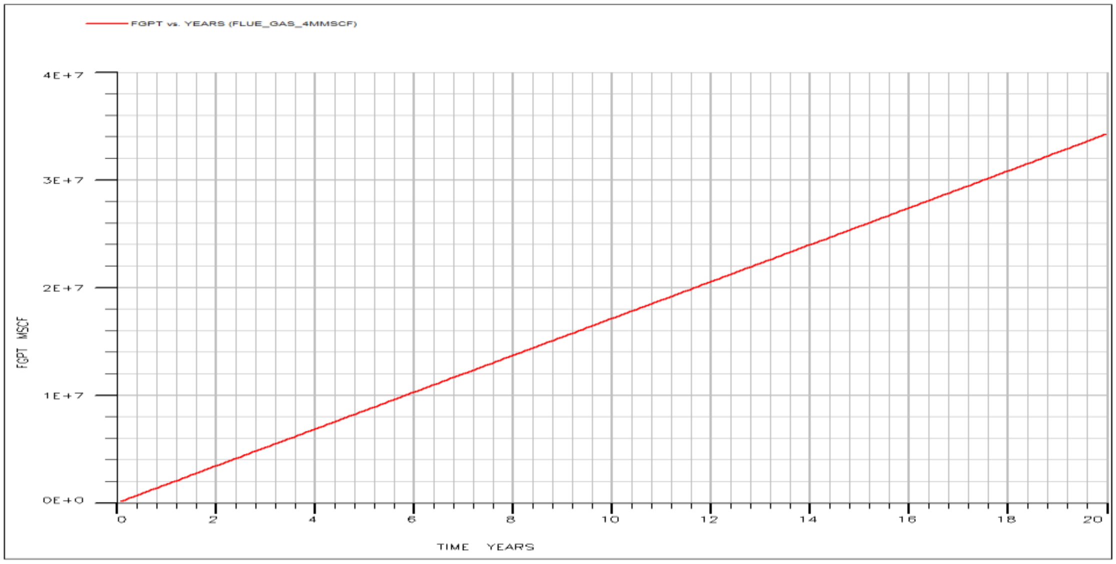

Figure 4.15: Cumulative gas recovery from flue gas injection after 20-year simulation

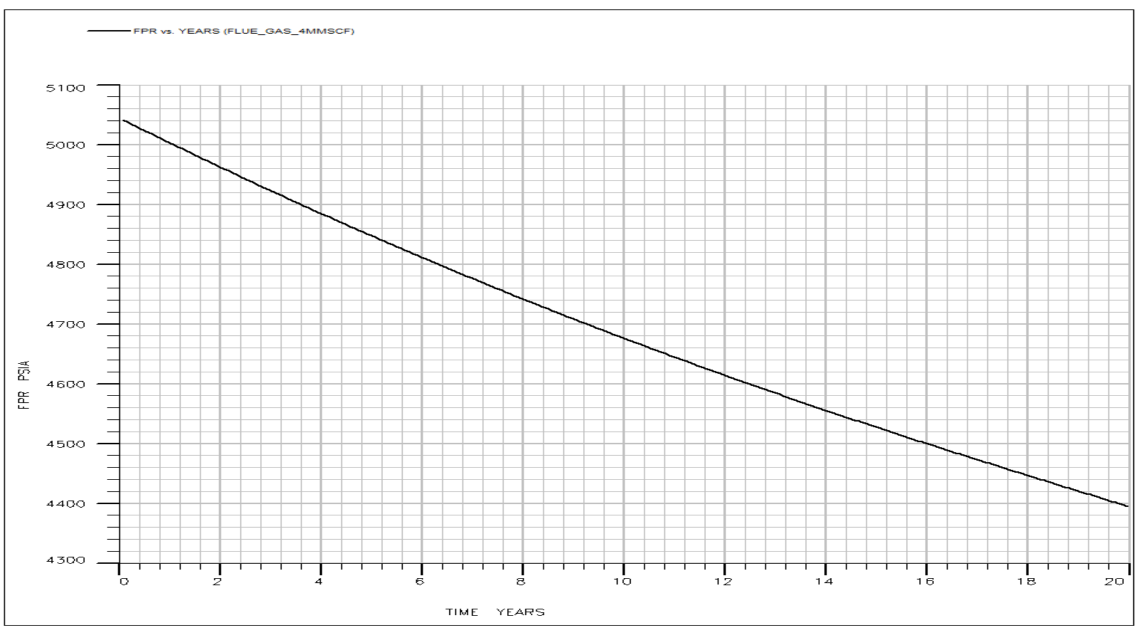

Figure 4.16: Field average pressure profile from flue gas injection after 20-year simulation

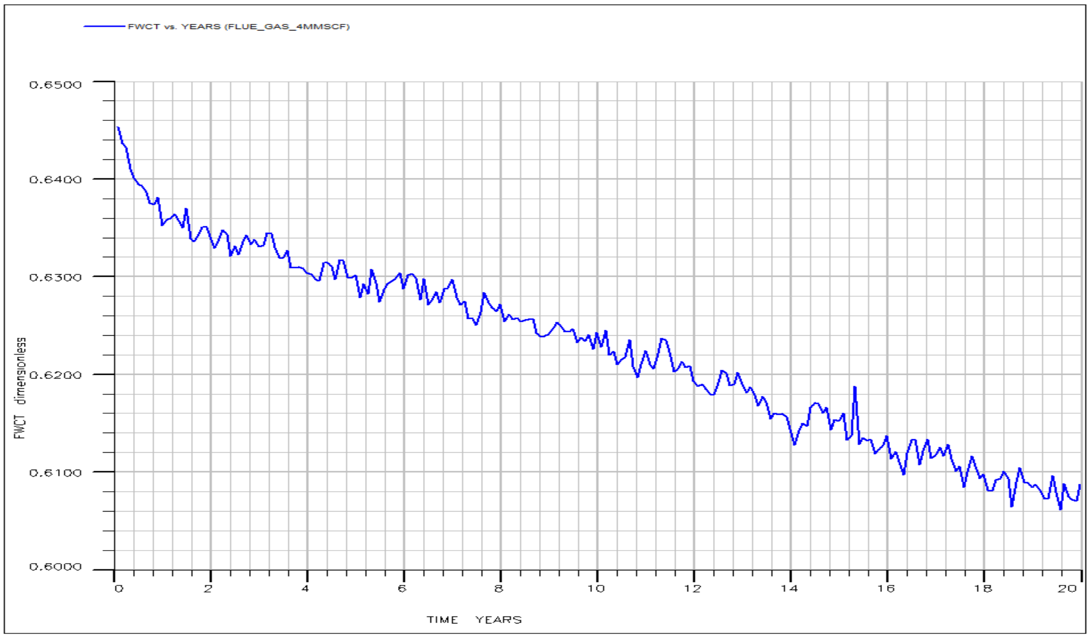

Figure 4.17: Field water cut vs. Time from flue gas injection after 20-year simulation

Observations: From the results shown in the above figures it was observed that the cumulative oil recovery from flue gas injection is about 1.82MMSTB, while the cumulative gas recovery is about 4.5BSCF at the end of production.

Significant improvement in pressure maintenance is observed from the results of the flue gas injection. The field pressure decreased gradually from the initial reservoir pressure of 5045psia to 4400 psia at the end of production. The water cut profile shows a slight decrease from 65% at the beginning of the production to about 60% (water cut) at the end of production.

Discussion: The results of the **s**imulation obtained from the flue gas injection indicated an oil recovery factor of 47.8% at the end of production of 20 years. Obviously, the flue gas injection is more efficient because it yielded a slightly higher oil recovery factor compared to the pure ethane injection EOR (46.8%) and natural depletion. Furthermore, it was observed that the flue gas EOR showed improved pressure maintenance during the 20-year production compared to rapid decrease in pressure during the natural depletion. Also, the flue gas process showed less water production compared to the ethane gas EOR or the natural depletion process. These results show the improved displacement efficiency provided by the flue gas EOR.

4.5 RESULTS OF SIMULATION OF FLUE GAS WAG EOR

Recall, the Case 5 of this study is a flue gas water-alternating-gas (WAG) injection in which water was first injected for five (5) years to establish the reservoir injectivity, and this was followed by a slug of flue gas injected at a rate of 4MMSCF/D for another five (5) years and followed by water injection at a rate of 3000STB/D for five years. The flue gas WAG cycle was repeated until the reservoir was produced for a total of 20 years. Figures 4.18 through 4.21 show the results of the flue gas WAG EOR.

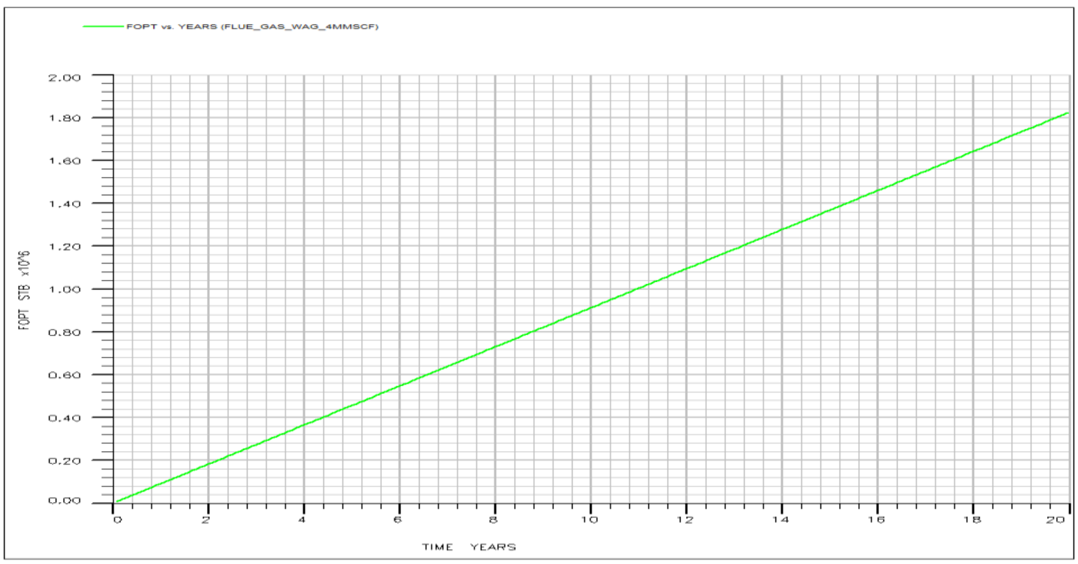

Figure 4.18: Cumulative oil recovery from Flue gas WAG after 20-year Simulation

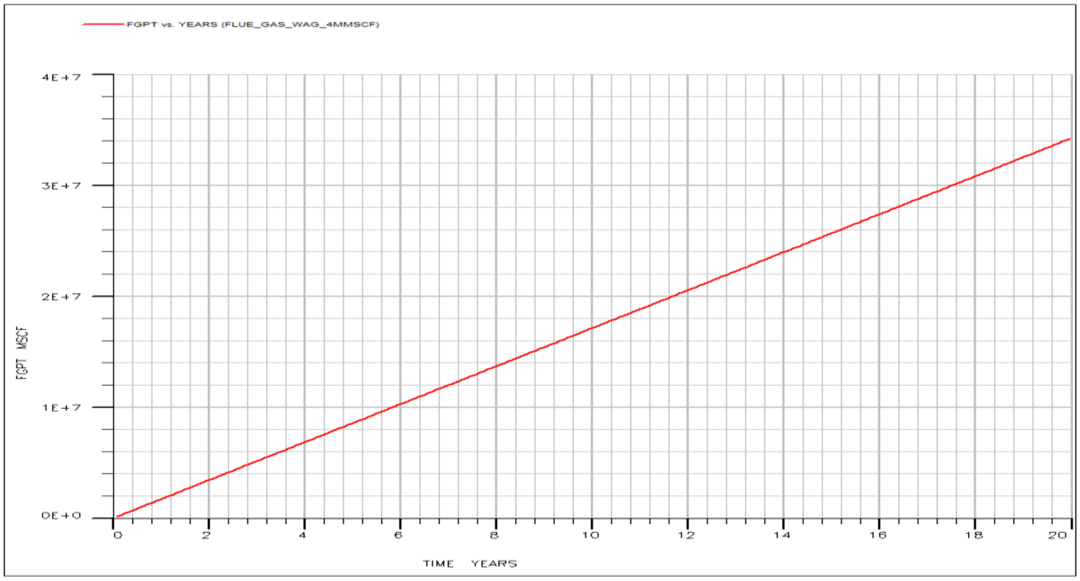

Figure 4.19: Cumulative gas recovery from Flue gas WAG after 20-year Simulation

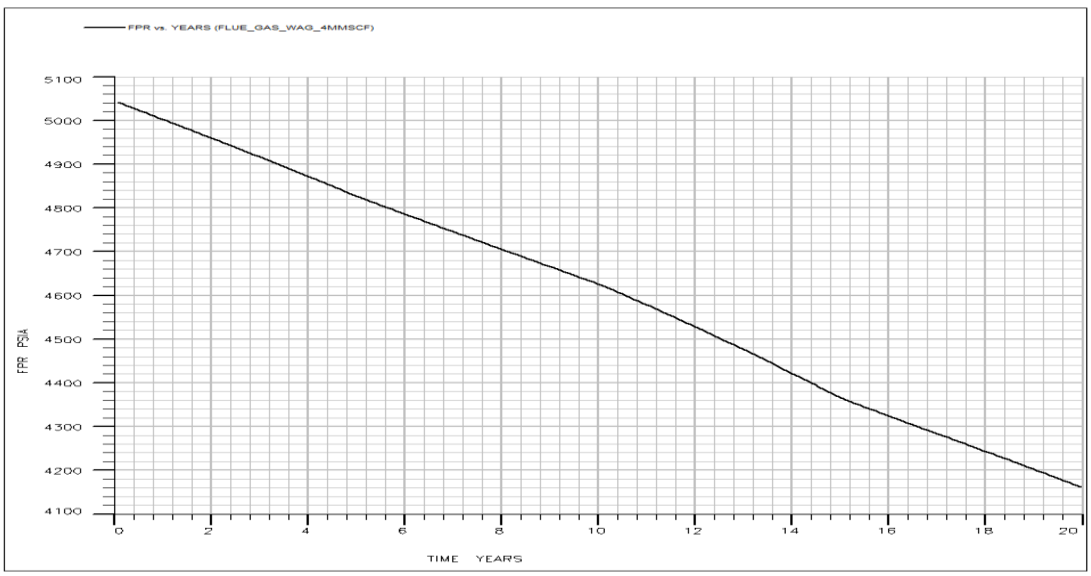

Figure 4.20: Field Pressure profile from Flue gas WAG after 20-year Simulation

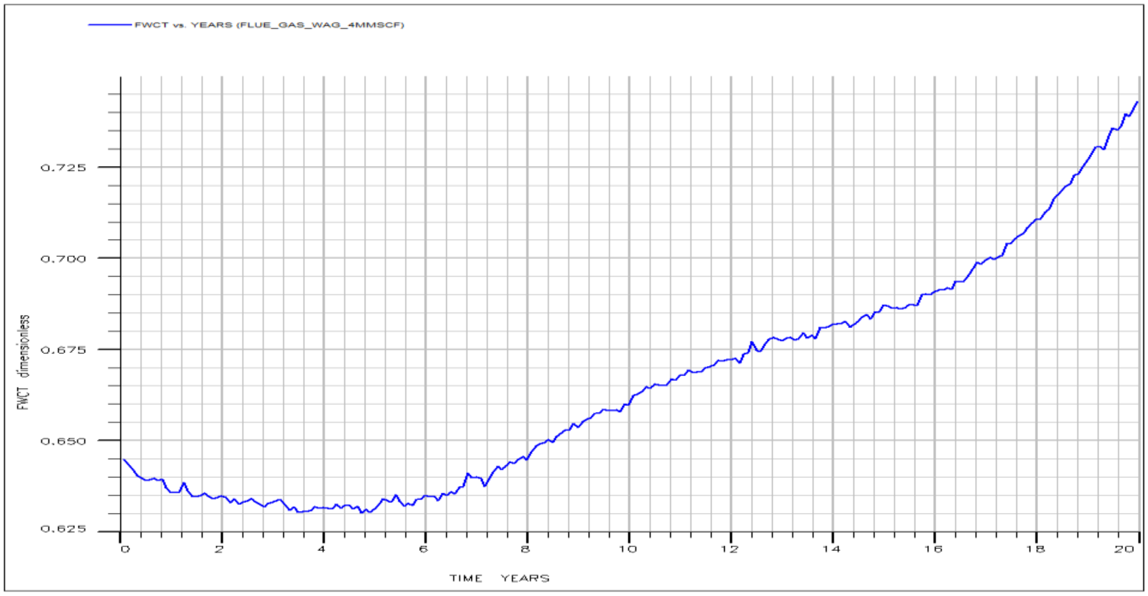

Figure 4.21: Field Water cut Profile from Flue gas WAG after 20-year Simulation

Observations: The cumulative oil recovery from the flue gas WAG increased gradually from the beginning of production to 1.82MMSTB at the end of production, while the cumulative gas recovery is 3.7BSCF at the end of production.

Pressure maintenance from the flue gas WAG was similar to that of the flue gas injection. For the flue gas WAG EOR, the field pressure decreased from the initial reservoir pressure of 5045psia to 4200 psia at the end of production. The water cut profile for the flue gas WAG was different from that obtained from the flue gas EOR. In the case of the flue gas WAG, the water cut increased from 65% to about 75% at the end of production.

Discussion: Simulation results show an oil recovery factor of 47.8% at the end of production from applying the flue gas WAG in the reservoir. This recovery factor is approximately the same as that obtained from the pure flue injection. However, the recovery from flue gas WAG is slightly higher than the cumulative recovery gotten from ethane WAG injection; and it is a significant improvement over the recovery from natural depletion (34.3%). It was observed that the cumulative gas recovery obtained from flue gas WAG EOR is lesser than that obtained from the depletion and pure ethane injection. Notice that there is improvement in pressure maintenance during the WAG injection compared to the pressure maintenance for both the ethane injection and natural depletion. Furthermore, there was significant water production with the oil during the flue gas WAG EOR. This could be due to the presence of an active water drive.

4.6 COMPARISON OF TECHNICAL MERITS OF ETHANE AND FLUE GAS ENHANCED OIL RECOVERY

The cumulative oil recoveries from all the cases presented in this study are summarized in Table 4.3.It is observed that the cumulative oil recovery for the pure flue gas yielded a higher recovery factor compared to the pure ethane and natural depletion. Furthermore, it is observed that about the same recovery factor is obtained from ethane WAG injection and flue gas WAG process.

From the practical application in the field, the flue gas injection is preferred to the ethane gas injection due its slightly higher recovery factor. However, there is a need to consider the cost implications of the two gas injection processes to identify the more technically and economically viable process.

Table 4.3: Cumulative oil Recovery for various Model Operating Conditions

Operating Conditions	**Total cumulative oil production (MMSTB) and recovery percentage**	
Injection rate	**Ethane injection**	**Flue gas injection**
Gas injection rate = 4MMSCF/day	1.78 (46.8%)	1.8 (48%)
WAG 4MMSCF/day	1.8 (48%)	1.81 (48%)
Natural Depletion at 250 STB/DAY	1.3 (34.3 %)	

4.7 RESULTS OF SENSITIVITY ANALYSIS

During the sensitivity analysis the length of the ethane WAG cycles was varied from one, two and three years, and it was observed that the various WAG cycle lengths have practically the same cumulative oil recovery. However, as shown in the Appendix, there were slight differences in observed pressure profiles from the simulations using the various WAG cycle lengths. This observation shows that the time of WAG injectivity does not have an impact on the oil cumulative recovery; thus, a little or no impact on the pressure profile in the case study.

4.8 RESULTS OF ECONOMIC ANALYSIS

The economic analysis considered three cases, i.e., natural depletion, ethane, and flue gas injection EOR processes.

4.8.1 Economic study of natural depletion

The annual oil production for 20 years was used for the economics analysis of natural depletion in this study. The net present value (NPV) from the natural depletion shows that the field generated enough cash flow to sustain the field operations with an internal rate of return (IRR) of 48%.

4.8.2 Economic analysis for ethane gas based EOR.

Figure 4.22 shows the results of net cash flow from the economic analysis for pure ethane injection with an onsite gas processing plant as a source of ethane injection gas. The results indicate that the net cash flow from the annual oil production for the case of pure ethane injection (at a rate of 4MMscf/day) was more than that obtained from the base case of natural depletion (no fluid injection). It is observed that pure ethane gas injection could generate enough revenues needed to run the field operation and pay for the capital needed for capturing the 4MMscf/day of ethane gas injection capacity during the project life of 20 years. Ethane EOR yielded an internal rate of return of 58% and a payout period of about three (3) years. This economic feasibility of ethane injection EOR also applied to the option of buying the ethane gas needed from the Spot market to sustain the 20-year gas injection.

4.8.3 Economic analysis of flue gas based EOR.

Figure 4.22 also shows the results of net cash flow from the economic analysis of pure flue injection considering the onsite burning of the natural gas to capture CO2 and the capture of nitrogen from air through cryogenic process. The results indicate that the net cash flow from the annual oil production by flue gas injection was more than that obtained from the base case (natural depletion with no fluid injection) and pure ethane injection. It was also observed that flue gas injection could generate enough revenue to run the field operations and pay for the capital cost required to generate 4MMscf/day of the flue gas injection capacity during the project life of 20 years. Furthermore, the revenue generated could also cover the cost of burning natural gas to get the CO_2 to be used for gas injection during the 20-year project life. The favorable economic indices from the flue gas injection are an internal rate of return of 60%, and a payout period of about one and a half years (i.e., payout period ≈1.6 years). Therefore, flue gas injection is seen to be technically and economically viable in the case study. This same inference applies to economic analysis of flue gas WAG project with the alternate injection of water at 3000STB/D and 4MMscf/day of flue gas.

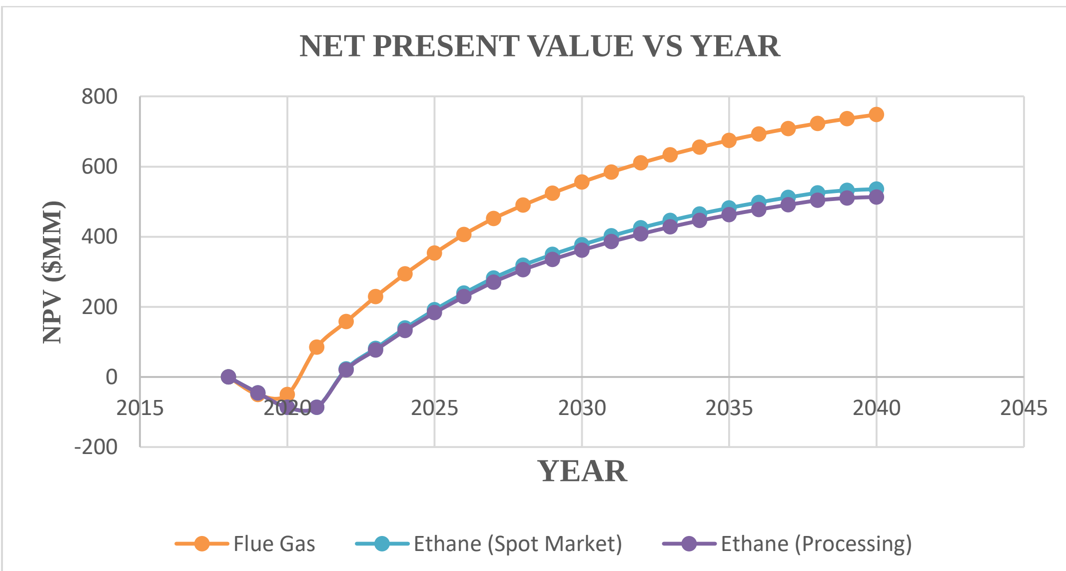

Figure 4.22: Plot of cumulative net cash flow for pure Ethane Gas and flue gas EOR

4.9 SENSITIVITY ANALYSIS OF THE VARIABLES USED IN ECONOMIC STUDY

Results of sensitivity analysis carried out by varying the input parameters used in the economic study are shown in Tables 4.4 and 4.5. It was observed that the price of oil per barrel has significant impact on the net present value (NPV) and the internal rate of return (IRR) of the project. The results imply that this project could be more economically attractive with an increase in the oil price per barrel. The higher the capital expenditure, CAPEX, the lesser is the NPV and the IRR. The CAPEX is dependent on the infrastructure or facilities required for constructing the project. Furthermore, the operating expenses, OPEX, are tied to the oil production. So, the higher the OPEX, the lesser is the project NPV. The discount rate also has some slight impact on the profitability of the project. The higher the discount rate, the lesser is the NPV and the IRR. Depending on the minimum IRR of interest compared to the calculated IRR, the company can decide to either reject or embark on the project.

Table 4.4: Result of sensitivity analysis of the oil price on project profitability

VARIABLE	VALUE	NPV ($MM)		IRR		DPOP (Years)	
OIL PRICE		Flue gas	Ethane	Flue Gas	Ethane	Flue Gas	Ethane
	40	587	386	53%	50%	1 year 4 months	2 years 9 months
	45	667	450	56%	54%	1 year 4 months	2 years 8 months
	50	748	514.7	60%	58%	1 year 3 months	2 years 9 months
	55	828.5	578	63%	61%	1 year 3 months	2 years 7 months
	60	908	643	66%	64%	1 year 3 months	2 years 7 months

Table 4.5: Result of sensitivity analysis of the Operating Expenses (OPEX) on project profitability

VARIABLE	VALUE	NPV ($MM)		IRR		DPOP (Years)	
OPEX		Flue gas	Ethane	Flue Gas	Ethane	Flue Gas	Ethane
	6	748	514.7	60%	58%	1 year 4 months	2 years 9 months
	8	711	485	58%	56%	1 year 4 months	2 years 9 months
	10	647	456	57%	54%	1 year 4 months	3 years
	12	637	426	55%	53%	1 year 5 months	3 years
	15	582	382	52%	50%	1 year 5 months	3 years 1 month

4.10 PERTINENT REMARKS ON RESULTS OF THS STUDY

Summarily, the following important recaps can be drawn from the results and discussion so far.

It was observed that during the natural depletion, the cumulative oil production was 1.3MMSTB within a period of sixteen 16 years of production. Furthermore, the field pressure was observed to decrease rapidly from the initial reservoir pressure 5045 psia to 1200 psia where it became constant till the end of the production.

Also, during pure ethane injection**,** it was observed that the cumulative oil recovery increased gradually with a cumulative production of 1.78MMSTB at the end of production while the average reservoir pressure shows a gradual decreasing trend from the initial reservoir pressure of 5045psia to 3200psia at the end of the 20-year production. However, the ethane WAG injection yielded a cumulative oil recovery of 1.8MMSTB and the field pressure is likely the same as pure ethane injection.

In addition, during the flue gas injection it was observed that the cumulative oil recovery from flue gas injection is about 1.82MMSTB. Significant improvement in pressure maintenance is observed from the results of the flue gas injection. The field pressure decreased gradually from the initial reservoir pressure of 5045psia to 4400 psia at the end of production. However, the cumulative oil recovery and the Pressure maintenance from the flue gas WAG is likely the same the flue gas injection.

After the economic analysis it is observed that both pure ethane injection and flue gas injection could generate enough revenues needed to run the field operation and pay for the capital needed for capturing the 4MMscf/day of gas injection capacity during the project life of 20 years. Finally, it was observed that Ethane EOR yielded an internal rate of return of 58% and a payout period of about three (3) years while Flue gas EOR yielded an internal rate of return of 60%, and a payout period of about one and a half years (i.e., payout period ≈1.6 years).

CHAPTER 5: CONCLUSION AND RECOMMENDATION

The conclusions derived from this thesis are presented in this section. Some recommendations are suggested for future research to improve the methodology and results obtained from this study.

5.1 SUMMARY AND CONCLUSIONS

In this thesis, the technical and economic feasibility of ethane and flue gas based EOR is conducted using a case study to model a reservoir in the Niger Delta. An EOR screening of the reservoir data collected was performed using published screening criteria to establish the applicability of ethane and flue gas injection EOR in the Niger Delta. The reservoir fluid was characterized using PVT software after which the minimum miscibility pressure, MMP, was obtained from the simulation of the one-dimensional model of a slimtube experiment. The MMPs were also computed based on published correlations for comparison with the results obtained from the slimtube simulation method. Many constraints (e.g., minimum oil production rate, maximum water cut, minimum bottom-hole pressure, minimum injection pressure, etc.) were used in building the simulation models to reflect the conditions in the Niger Delta. The simulations were run for twenty (20) years for the cases of natural depletion, ethane, and ethane WAG EOR, and both flue gas injection and flue gas WAG EOR. Using the annual oil production volumes from the simulations, an economic analysis was conducted to determine the economic viability of ethane gas and flue gas based EOR. The results obtained from this case study show that both EOR processes are technically feasible and economically viable in the Niger Delta.

The following conclusions can be derived from the results of this study:

1. The MMP of flue gas is shown to be higher than the MMP of ethane due to the presence of impurities in the nitrogen which has the highest percentage in the flue gas.
2. The cumulative recovery by natural depletion of the reservoir (i.e., no injection to maintain reservoir pressure) was 34.3% of the stock tank volume of the oil originally in place, STOOIP.
3. The cumulative recovery by application of ethane EOR in the reservoir was 46.3% of the stock tank volume of the oil originally in place, STOOIP.
4. The injection of flue gas yielded a higher cumulative oil recovery factor(i.e., 48%) than ethane injection (46.3%) and it is also significantly higher than the recovery by natural depletion (34%).

5. The application of ethane WAG and flue gas WAG injection yielded the same oil recovery factor of 48% of the STOOIP after injecting 4MMscf/day and 3000 STB/D of water per WAG cycle. The recovery by the two WAG processes is significantly higher than the recovery by natural depletion.
6. Sensitivity analysis of the length of the WAG cycles shows that the time of injectivity does not have an impact on the cumulative oil recovery in this case study.
7. The economic analysis indicated that both flue gas and ethane gas EOR are technically and economically feasible in the Niger Delta.
8. Based on the results of this study, it is noted that flue gas EOR seems to be more technically feasible than ethane EOR as it yielded a higher oil recovery than ethane gas EOR; and flue gas EOR is more economically attractive because of its low cost of onsite processing compared to the cost of processing ethane gas for injection.

5.2 RECOMMENDATION

Based on the methodology and results of this study, the following recommendations are made:

1. Additional research on flue gas based EOR using different reservoirs (different geological parameters, rock and fluid properties) to further validate the technical and economic feasibility of the process application in the Niger Delta.

2. More detailed economic analysis should be done in a future study on the ways to improve the viability of ethane gas EOR process.

NOMENCLATURE

ACF: Acentric factor

BBL: Barrel

BHP: Bottom Hole Pressure

DPOP: Discounted Payout Period

CAPEX: Capital Expenditures

CPNT: Component

CPST: Composition

EOS: Equation of State

EOR: Enhanced Oil Recovery

FMC: First Contact Minimum Miscibility

IRR: Internal Rate of Return

MCM: Minimum Contact Miscibility

MOD: Money of the Day

MMP: Minimum Miscibility Pressure

MMSCF: Million Standard Cubic Feet

MW: Molecular Weight

NPV: Net Present Value

OMA: Omega A

OMB: Omega B

OPEX: Operating Expenses

PCRIT: Critical Pressure

PPT: Petroleum Profit Tax

PV: Pore Volume

PVT: Pressure Volume Temperature

SAGD: Steam Assisted Gravity Drainage

STOIP: Stock Tank Oil in Place

TCRIT: Critical Temperature

WAG: Water Alternative Gas

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APPENDIX A

This Appendix shows additional results obtained from the sensitivity analysis of the impact of the length of the WAG cycle on reservoir performance. The WAG cycle lengths are varied from 1, 2, 3 to 5 years of gas injection followed by the same length of period for water injection.

A.1 Additional Results of Sensitivity analysis of Ethane gas WAG EOR

Figures A.1.1 through A.1.4 show the additional results obtained from the sensitivity analysis of the injectivity time used in the Ethane gas WAG based EOR.

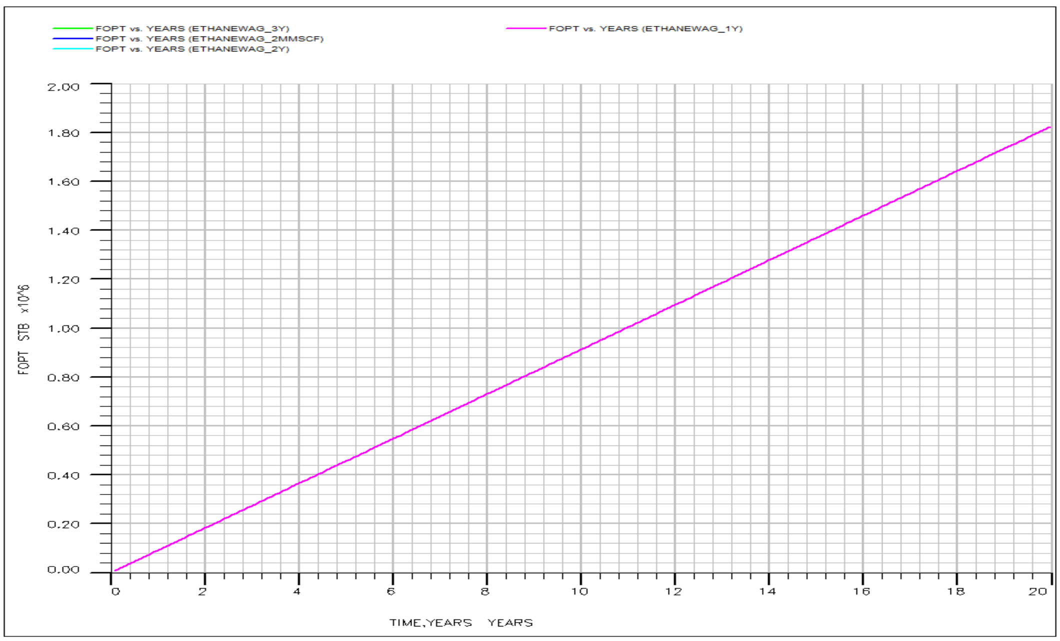

Figure A.1.1: Cumulative oil recovery vs Time using 1, 2, 3, 5 years of ethane WAG injection cycles for the 20-year model simulation

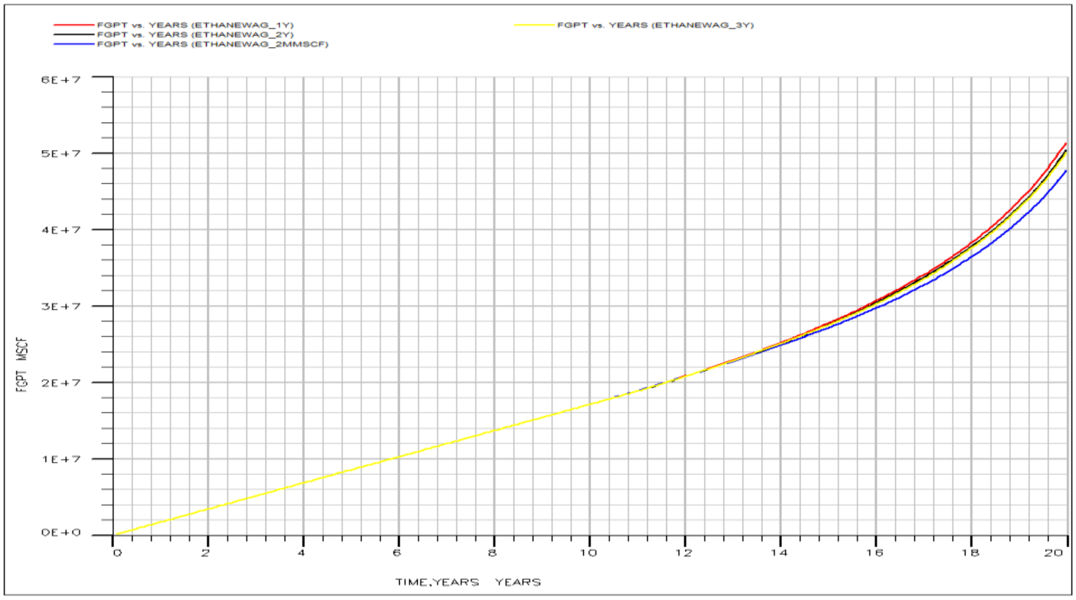

Figure A.1.2: Cumulative gas recovery vs Time using 1, 2, 3, 5 years of ethane WAG injection cycles for the 20-year model simulation

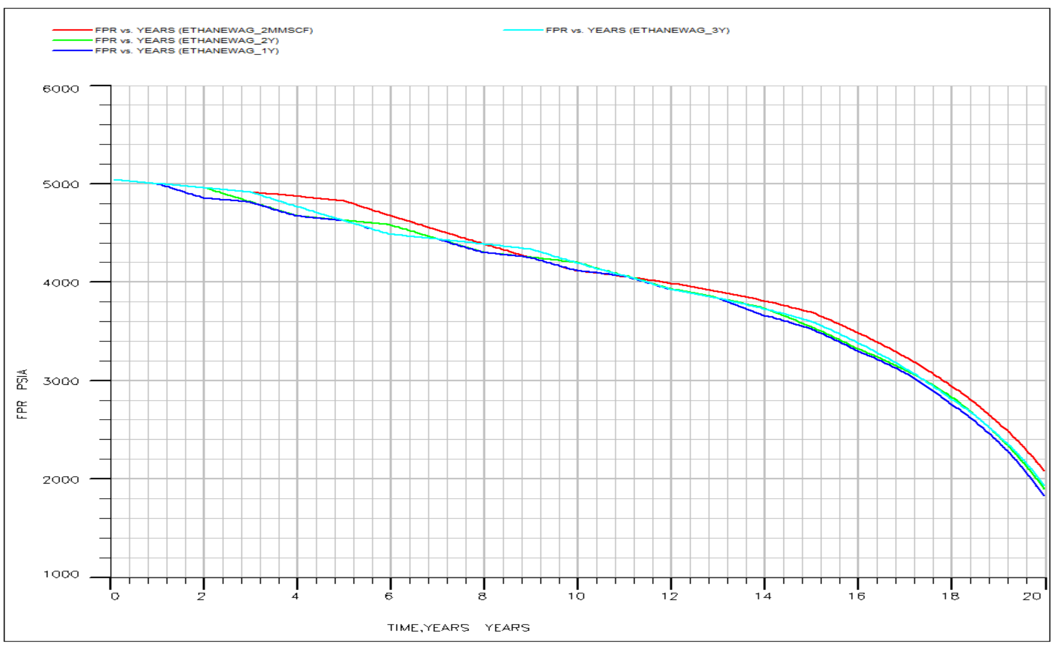

Figure A.1.3: Average Field Pressure vs Time using 1, 2, 3, 5 years of ethane WAG injection cycles for the 20-year model simulation

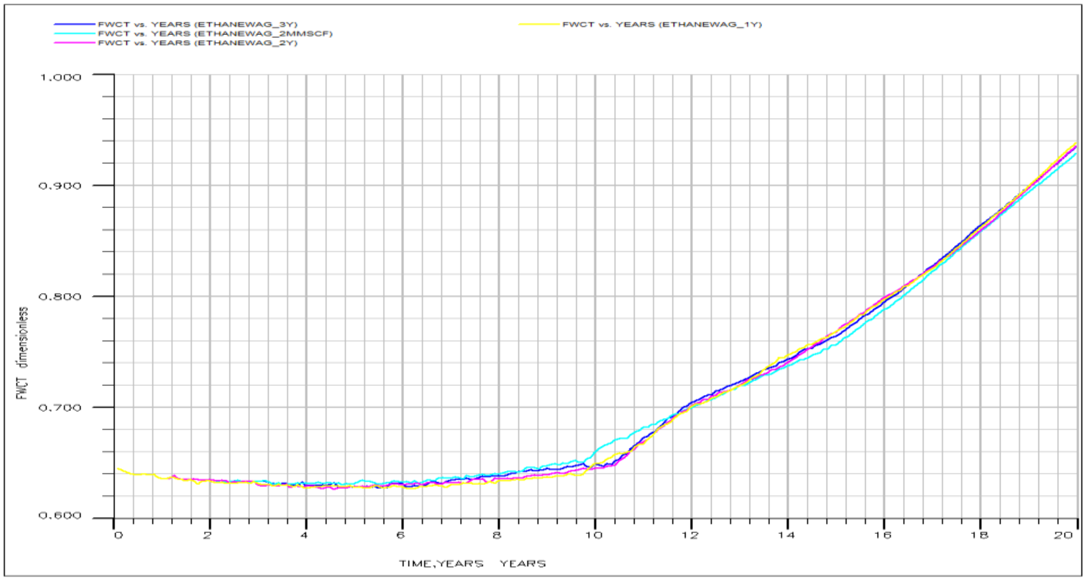

Figure A.1.4: Field Water cut vs. Time using 1, 2, 3, 5 years of ethane WAG injection cycles for the 20-year model simulation

A.2 Additional Results of Sensitivity analysis of Flue gas WAG EOR

Figures A.2.1 through A.2.4 show the additional results obtained from the sensitivity analysis of the injectivity time used in the Flue gas WAG based EOR.

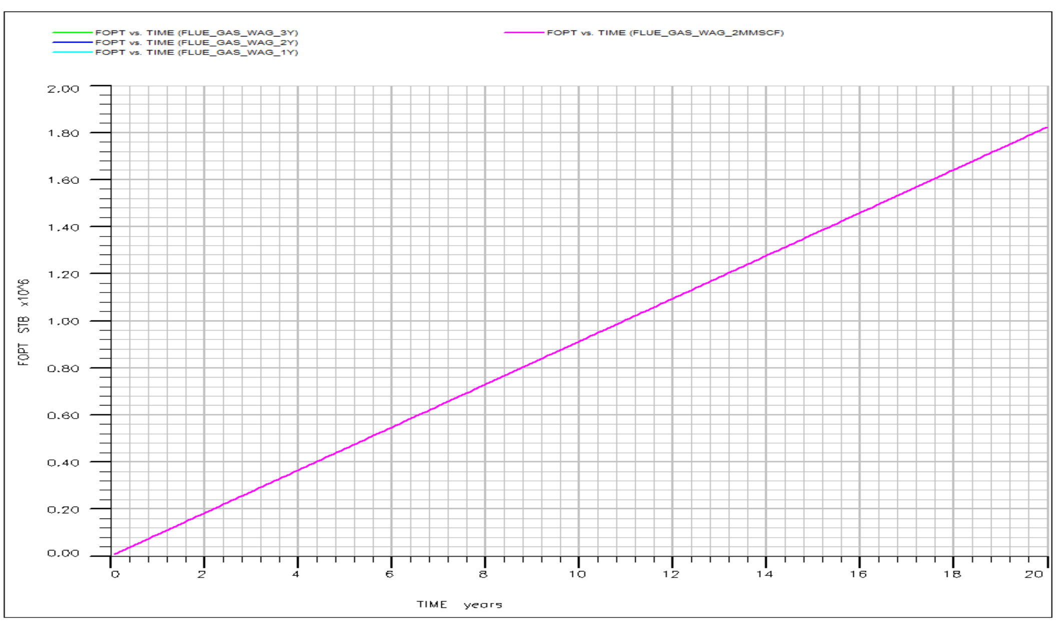

Figure A.2.1: Cumulative oil recovery vs. Time using 1, 2, 3, 5 years of flue WAG injection cycles for the 20-year model simulation

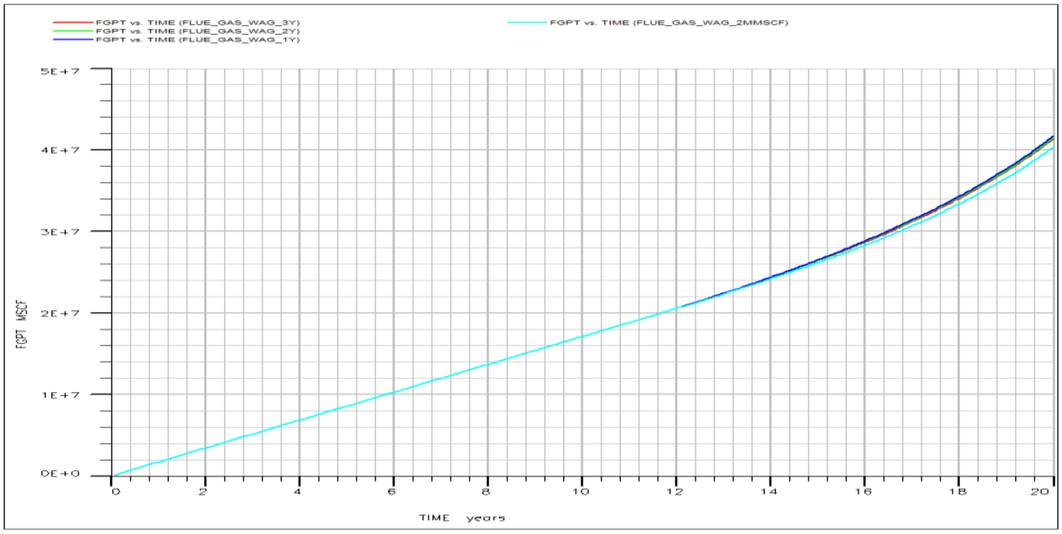

Figure A.2.2:Cumulative gas recovery vs. Time using 1, 2, 3, 5 years of flue WAG injection cycles for the 20-year model simulation

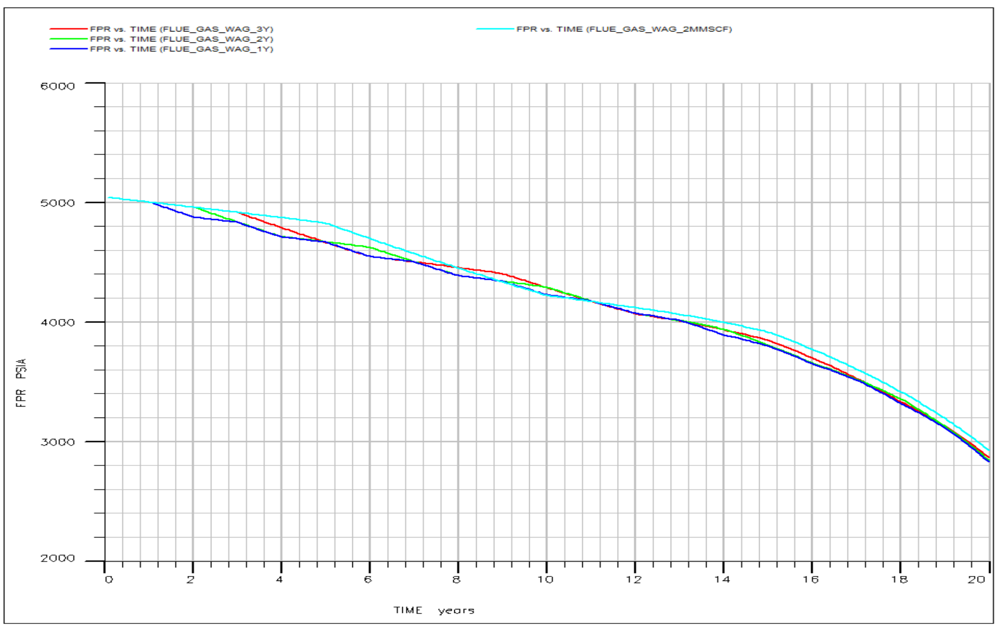

Figure A.2.3: Average Field Pressure vs. Time using 1, 2, 3, 5 years of flue WAG injection cycles for the 20-year model simulation

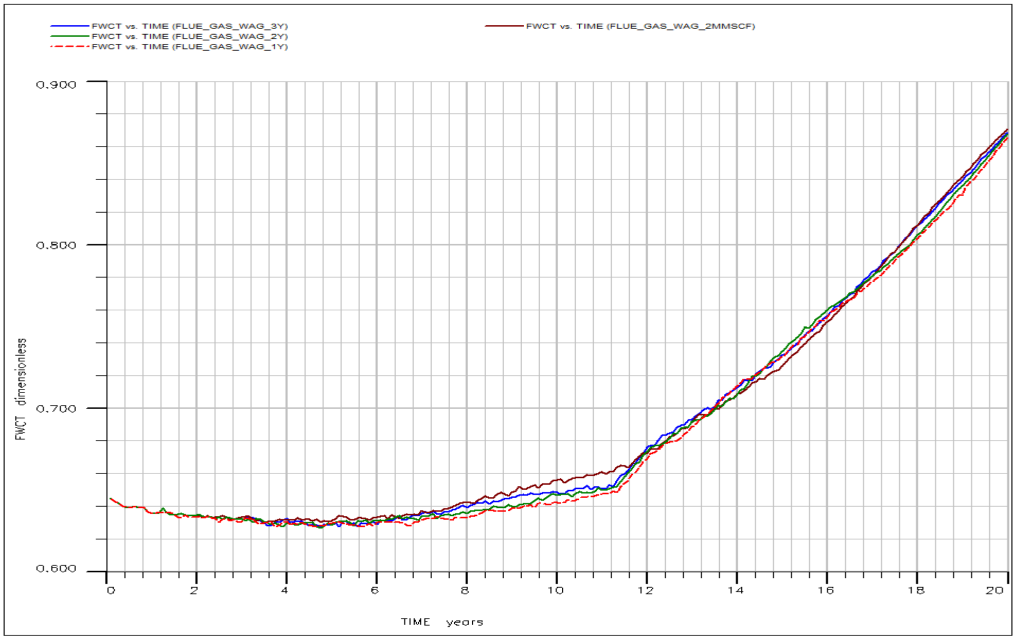

Figure A.2.4:Field Water cut vs. Time using 1, 2, 3, 5 years of flue WAG injection cycles for the 20-year model simulation