GAS CONDENSATE RESERVOIR: A NEW APPROACH TO ENHANCE CONDENSATE RECOVERY AND IMPROVE WELL PRODUCTIVITY

by

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14678

A project dissertation submitted to the

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CERTIFICATION OF APPROVAL

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CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

(MUHAMMAD ZUHAILI BIN KASHIM)

ABSTRACT

Condensate accumulation is a major problem encountered in most of the gas condensate reservoir. During production, the pressure decline causes the formation of condensate that reduces well productivity. Therefore, this study aims to improve well productivity by using various type of gas injection. At the same time, different injection scheme such as distance between injector and producer and injection rate also have been analyzed. Compositional simulator is employed to simulate the studies on hypothetical gas condensate reservoir model. By injecting rarely used propane, it manages to increase the recovery up to 19.8% compared to other conventional injectants. Considering the availability of propane, the efficiency of gas-gas flooding (propane+nitrogen) and gas-solvent flooding (propane+methanol) flooding has been studied where gas-solvent flooding shows 21% of recovery which is higher than pure propane and conventional gas injection. Well distance of the factor of 6 with the injection rate of 8000 MSCF/d shows 19.5% of condensate recovery increment which is the highest compared to other injection scheme studied. Based on the results, propane gas should be considered heavily in condensate removal application as it improves condensate recovery and well productivity at the same time. In general, this study confirmed that the injection component and injection scheme plays an important role in enhancing condensate recovery in the reservoir.

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ABBREVIATIONS AND NOMENCLATURES

$\boldsymbol{\mu}$ - Fluid viscosity (cp)

$\boldsymbol{\mu}*$ - Viscosity at atmospheric pressure (cp)

$\int_{\boldsymbol{m}}^{-\mathbf{1}}$ - Mixture viscosity parameter (cp^{-1})

$\boldsymbol{\rho_r}$ - Reduced liquid density (dimensionless)

$\boldsymbol{M}$ - Mobility

$\boldsymbol{k}$ - Effective permeability

$\boldsymbol{S_{cond}}$ - Condensate blockage skin factor

$\boldsymbol{k_{rg,d}}$ - Gas relative permeability of the condensate blockage zone

$\boldsymbol{r_d}$ **-** Condensate blockage radius (ft)

$\boldsymbol{r_w}$ - Wellbore radius (ft)

CHAPTER 1

INTRODUCTION

1.1 Project Background

Exploration and production for gas reserves has been increasing lately. This is due to high demand of gas which is just behind oil in term of its consumption. Based on Economides, Oligney, and Demarchos (2001), around 22% of world energy demand is accounted for natural gas in general. Based on Figure 1, the natural gas consumption tends to increase two times higher than 2010 in 2040 as forecasted by Briefing (2013). The spike increase of the natural gas is driven by its vast usage especially in energy and industry sector. This is supported by its lower cost and environmental friendly characteristics that attract many oil and gas companies to develop their gas industry in production, transportation or processing field.

Aside from that, most of the heavier component is contained in the form of condensate. This component also provides many uses to the industry and daily application as the processing of the gas condensate will extract the components that are useful in production of fuel, plastics and fibre. Leaving this component behind will leads to major economical concern to the oil and gas industry as well as other manufacturing industry as the demands keep increasing parallel to the world rapid development.

Owing to increasing demand of natural gas and condensate, gas condensate reservoirs could become highly viable sources of gas condensate supply in coming years. Thus, it is shows the importance for the engineers and researches to understand the gas condensate reservoir behaviour and take a big step in order to optimize the gas production to meet spiking demand of gas in current global development era.

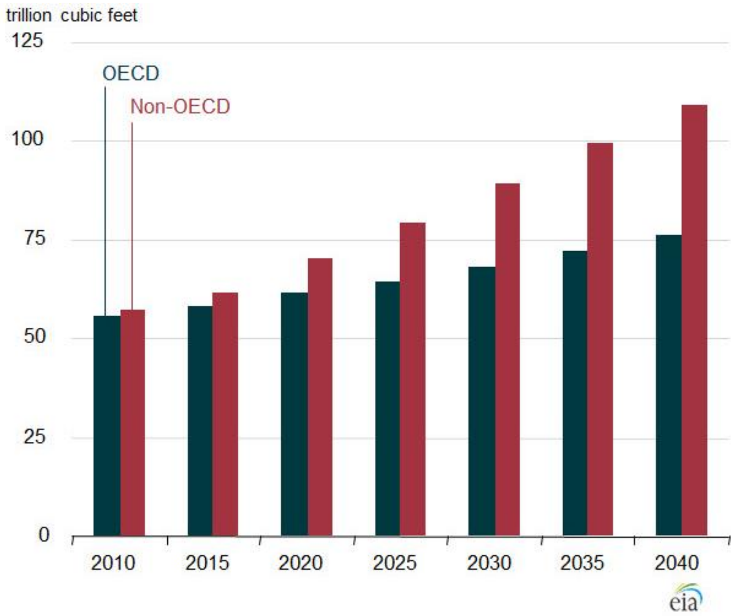

Figure 1: World Natural Gas Consumption, 2010 -2014 (Briefing, 2013)

Theoretically gas condensate system may present at pressure below 2000 psi and temperature below 100 F^o (Moses & Donohoe, 1987). However, in most of the cases, the retrograde condensate reservoirs exist in pressure between the range of 3000 psi to 8000 psi and for temperature are in the range of 200 F^o to 400 F^o. Besides, there is a rule of thumb that indicates gas condensate system exists when the gas/liquid ratio exceeds 5000 cuft/bbl and the liquid is lighter than 50 API^o (Eilerts, 1957). But, as time goes by, new research and exploration causes the theory to be arguable as stated by Moses and Donohoe (1987).

Gas condensate mixtures comprise of large amount of methane and small portion of intermediate and heavy component (Kamath, 2007). These divergent types of conditions cause the research and application on the gas condensate reservoirs to be very much tricky and puzzling. This complicated nature of fluid flow and phase behaviour exhibited by gas condensate mixtures causes the production to be much challenging compared to production in black oil and dry gas system (Al-Abri, 2011).

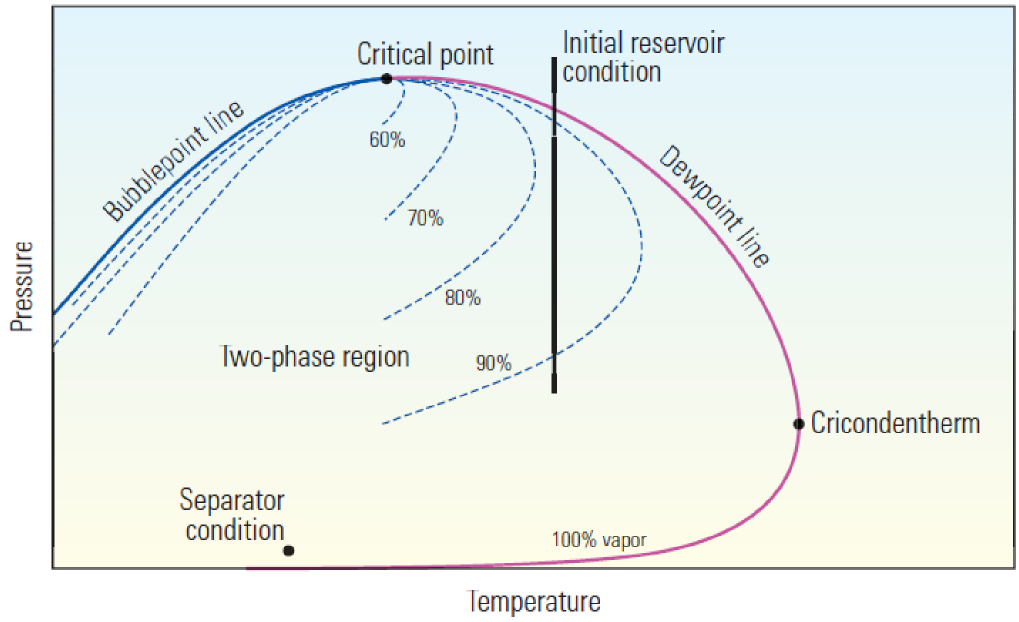

Figure 2 : Typical Gas Condensate System Phase Diagram (Fan et al., 1998)

Gas condensate reservoirs are initially in single phase upon discovery. Due to dynamic characterization of gas condensate system, the composition and saturation of fluid constantly adapts according to changes in isothermal condition. As observed in Figure 2, the single phase fluid remains the same during original reservoir condition. As production continuously takes place, the pressure tends to decline in constant temperature until it reaches the dewpoint pressure where the liquid hydrocarbon is formed. In other word, it is also termed as retrograde condensate because of its nature where the gas phase condenses to liquid under certain conditions of pressure and temperature (Fan et al., 1998). The author also stated that the amount of condensate produced depends on pressure, temperature and fluid phase behaviour. Approximately maximum of 2% of condensate can be yielded by lean-gas system and 20% of condensate can be generated by rich-gas condensate system (Kamath, 2007).

Condensate banking or condensate blockage has been a major headache especially for reservoir engineers since many years for the impairment caused in productivity (Fussell (1973); Hinchman and Barree (1985); Vo, Jones, and Raghavan (1989) ; Zhang and Wheaton (2000) ; Giamminonni, Fanello, Kfoury, Colombo, and Bonzani (2010); Mohamed et al. (2014)). This phenomenon occur due to decrease in bottom hole pressure below the dew point which cause the formation of condensate near the wellbore. The formation of condensate in the reservoir is the highest near to the producing well due to high gas-liquid mobility ratio and capillary forces. As the time increases, the condensate saturation will tend to rise until it restricts the flow of other phase(s).

There are many techniques that has been carried out ever since this problem has been encountered which include gas cycling, hydraulic fracturing, acidizing, alcohol flooding and drilling horizontal wells. Those methods are targeted to retain the reservoir pressure above dew point pressure as well as to displace the condensate blockage from the near wellbore region. However, those techniques does not promise 100% success rate despite some improvement and enhancement in production rate (Al Ghamdi, Al-Malki, Al-Kanaan, Rahim, & Al-Anazi, 2013). Understanding of gas condensate system is really important especially on implying the treatment as different retrograde gas system possessed different behaviour of condensate as fluid flow and isothermal condition plays a big role in this issue.

1.2 Problem Statement

Condensate banking is a common problem in gas condensate reservoir. The decline in pressure will promotes the forming of condensate near the well bore and cause impairment to well productivity.

In most of the treatment, injectant/solvent plays an important part as their properties and thermodynamics are really sensitive in altering the retrograde gas condensate system. Most of the commonly used injectant/solvent which includes carbon dioxide, nitrogen and methanol has been studied thoroughly in lab and field scale. Although the effect of propane injection in condensate recovery has been validated by some researches, the feasibility of propane in retarding condensate blockage phenomenon still remains ambiguous. However, owing to current world demand for gas in energy and industry sector, detailed study of propane should be done in order to measure its effectiveness in optimizing the productivity. On top of that, there are very less study done on the combination of different injectant/solvent which is gas-gas and gas-solvent flooding.

Besides, different injection scheme also plays a big role in improving condensate recovery. Most of the study on different injector and producer distance is only done to Steam-Assited-Gravity-Drainage (SAGD) technique. Based on SGAD technique, it shows that well distance effects well deliverables. Most of the studies rarely touched the effect on well distance and injection rate on gas condensate reservoir.

As the issue is concerned, selecting the best treatment is a major problem due to the risk and complexity involve in solving this well impairment. There are several studies which show that drilling technique is really significant in improving productivity index in gas condensate reservoir. The commonly used drilling technique is vertical technique. However, many research depicts that horizontal drilling technique is more efficient than the vertical one.

1.3 Objectives of Study

The research main goal is stated as follows:

1) To assess the effectiveness of different gas injection techniques which are pure gas injection, gas-gas flooding and gas-solvent flooding from the combination between propane(C_3), carbon dioxide(CO_2), Nitrogen (N_2), and methanol (CH_4O)
2) To study the effect of different injection schemes (injection rate and distance between injector and producer) in improving condensate recovery

1.4 Scope of Study

This study focuses on four different injectant which is carbon dioxide (CO_2), nitrogen (N_2) and propane (C_3), and methanol (CH_4O). The scope of study for this project was limited to purely simulation studies by using a compositional numerical simulator known as the ECLIPSE (E300). The type of reservoir focused in this study was a gas condensate reservoir as the condensate banking problem only occurs in this kind of reservoir. The input data of the fluid and reservoir model was acquired from the literatures reviewed.

CHAPTER 2

LITERATURE REVIEW

Condensate banking has been a major problem in gas condensate reservoir ever since the first production of this kind of field take place. The main factor that drags into condensate banking or in other word condensate blockage is pressure depletion especially in bottom hole. Drop of pressure below dewpoint in the bottom hole will cause formation of condensate which will eventually leads flow path friction due to flowing of gas and condensate in the same time (Fan et al., 1998).

One of the reservoirs that experience with this condensate blockage problem is Santa Barbara Field which is the largest gas condensate field in Venezuela (Briones, Zambrano, & Zerpa, 2002). The dew point pressure of the field is around 8500 psi. From the well test analysis done on the wells in the field, there is significant permeability impairment where most of the wells undergo at least 50% to 90% of permeability reduction. Besides, there is also decline of gas mobility which is mostly detected near the wellbore. This brings negative impact to the well deliverability.

Another field that heavily affected with the same complex problem is Arun Field located in Acheh, Indonesia (Risan, Abdullah, & Hidayat, 1998). Some of the wells in the reservoir experience significant productivity loss due to condensate banking. As stated by Afidick, Kaczorowski, and Bette (1994), the dew point of the reservoir is approximately 4400 psi. Based on reports by ExxonMobil, some of the well faced more than 50% of gas productivity losses although laboratory PVT data shows that the reservoir has less than 2% of liquid condensation (Barnum, Brinkman, Richardson, & Spillette, 1995).

More than that, this problem also has been influencing productivity in Baimiao Gas Condensate Field which is located in Henan, China (Miao, McBurney, Wu, Wei, & Zhao, 2014). Baimiao Field is a tight gas condensate reservoir which experience rapid pressure decline. At the early stage of production itself, the author reported that some of the well in the reservoir has undergoes pressure drop below dew point pressure which forms liquid zone near the well bore which restricts gas productivity. Initially, from 30 production wells, it shows a high rate of gas production which is around 0.8 MMscf/d. However after 1 year of production, the gas production rate undergoes rapid declination to 0.3 MMscf/d. This shows that the reservoir has experienced 68.5% reduction in productivity which is critical and serious.

Due to this, many of the condensate banking treatment has been introduced and applied to mitigate the problem. The treatment is usually focused on two aspects which is pressure maintenance above dew point and alteration of reservoir fluid phase behaviour.

2.1 Solvent

Commonly, solvent is used to alter the relative permeability and interfacial tension of the phase. In the gas condensate reservoir, it is used mainly to reduce the gas relative permeability as well as to reduce interfacial tension between the gas and condensate (Sayed & Al-Muntasheri, 2014). The effect produced by solvent will help to enhance gas recovery and well deliverability.

Hamoud A. Al-Anazi, Pope, Sharma, and Metcalfe (2002) had done an experiment to study the treatment of condensate blockage in both high permeability and low permeability reservoirs using methanol. Berea sandstone and Texas Cream limestone cores is studied in this study as they possessed high (246mD – 378mD) and low (2mD – 5mD) permeability respectively. Methanol treatment was done in two separate periods where each period is injected with 20 pore volume (PV) of methanol.

From the experiment, the author reported that methanol treatment managed to delay the condensate accumulation which results in flow period enhancement for both cores which is in high and low permeability condition. Hamoud A. Al-Anazi et al. (2002) also stated that sufficient methanol injection provides the ability to displace both condensate and water by the technique of multi-contact miscible(MCM).

As methanol injection proved to be one of the reliable and effective method in retarding the condensate banking phenomena in lab and simulation scale, the research has been extended to field application (Hamoud A. Al-Anazi et al. (2002); Hamoud A. Al-Anazi, Sharma, and Pope (2004); Hamoud A. Al-Anazi, Walker, Pope, Sharma, and Hackney (2005)). Hamoud A. Al-Anazi et al. (2005) has carried out a field application analysis on Hatters Pond field in Alabama to observe the potential of methane in eliminating condensate accumulation. Smackover dolomite and Norphlet sandstone core plugs were used in the experiment. The cores were saturated with methanol, water sample from Hatter's Pond field and synthetic brines respectively.

Subsequently after methanol treatment, Hamoud A. Al-Anazi et al. (2005) described that there is a large increment in liquid and gas production by the factor of approximately two in the period of 120 days. The laboratory experiment of Hamoud A. Al-Anazi et al. (2002) is proved by this field application study where the methanol is very effective in displacing the water and condensate which accumulated from the near wellbore area.

Assessment on different type of solvent is conducted to measure the productivity of the solvent in inhibiting condensate blockage phenomenon (Hamoud Ali Al-Anazi, Solares, & Al-Faifi, 2005). The coreflood experiment is carried out using four type of solvent which is methanol, Isopropyl alcohol (IPA), methanol-water and methanol-IPA mixtures. The laboratory analysis shows that methanol, Isopropyl alcohol (IPA) and mixtures of both solvent is effective in eliminating condensate accumulation, delaying the condensate banking and increase the gas production. In contrast, methanol-water mixture is ineffective in gas condensate reservoir as the properties altered are not suitable in removing condensate accumulation near well bore region.

2.2 Gas Injection

2.2.1 Nitrogen

Nitrogen gas is an attractive approach as it is safe, environmental friendly, highly abundant and non-corrosive (Sänger, Bjørnstad, & Hagoort, 1994). Nitrogen is among one of the gas that is usually associated in most of the reservoir fluid (Vogel & Yarborough, 1980). Besides, Wu, Ling, and Liu (2013) stated that nitrogen is easy to transport and cheap compared to carbon dioxide as most of the nitrogen extracted from producer and other sources are injected back to the reservoir. Nitrogen is injected into the reservoir in form of condensate in order to retain the reservoir pressure above dew point pressure and displace the condensate accumulation (Kossack and Opdal (1988); Donohoe and Buchanan (1981)). However, the performance of nitrogen in hydrocarbon recovery in most of the field operation has been fluctuating even though nitrogen is one of the widely used injection gas in reservoir pressure maintenance and miscible displacement (Wu et al., 2013).

Aziz (1983) has done a critical analysis on gas cycling operation which mainly focuses nitrogen injection. The author mentioned that the recovery efficiency depends on some factors which include areal sweep, vertical sweep and revaporization of condensate. Nitrogen injection is applicable in the condition of low heterogeneity reservoir where constant injection and production rate are applied.

Comparison between lean gas injection and nitrogen injection were conducted by Donohoe and Buchanan (1981) with three different fluid composition where each of them is accounted for three contrasting different technique. The depletion case studied is no injection, nitrogen injection and lastly lean gas injection. Referring to the analysis, Donohoe and Buchanan (1981) predicted that the reservoir composed of condensate more than 100 BBL/MMCF should be evaluated for nitrogen injection implementation due to economical consideration and comparable recovery efficiency with lean gas injection.

As mentioned before, nitrogen has been common in application of pressure maintenance in most of the field. Vogel and Yarborough (1980) has carried out an experiment which to discover the reaction of varying nitrogen quantity on three type of reservoir fluid which possessed different composition and gas-liquid ratio. Based on the experiment, the result shows that the injection of nitrogen raise the dew point pressures for the three different fluids significantly which then leads to higher evaporation of condensates. The author also found that additional contact by nitrogen causes substantial increment of condensate revaporization of which is around 70% to 80% of recovery.

However, in contrast, nitrogen injection promotes liquid dropout in mixing zone which eventually decrease the gas productivity (Sanger & Hagoort, 1998). This statement is supported by Kossack and Opdal (1988) as they study a new approach of eliminating condensate blockage by injection of methane slug injections followed by injection of nitrogen slug. The function of methane is to prevent the mixing of nitrogen with the condensate as it could lead to reduction in productivity. The mixing process of nitrogen and gas condensate is really significant as it could increase the dewpoint pressure of the mixture which is much more larger than reservoir pressure (Moses & Wilson, 1981).

In a comparison study carried out by Sanger and Hagoort (1998), methane tends to perform higher gas condensate recovery compared to nitrogen in both laboratory analysis and simulation studies. In term of static phase behaviour, methane is more stable compared to nitrogen as injectant because the percentage of liquid dropout during the mixing with nitrogen is more than 20% while methane shows less value than nitrogen. Besides, sensitivity towards dispersion is highly possessed by nitrogen flooding than methane flooding due to multiple-contact miscible process. Nevertheless, the author concludes that nitrogen is one of the best alternatives to gas cycling in removing condensate blockage.

Siregar, Hagoort, and Ronde (1992) carried out a simulation study to examine the evaporation capacity of dry gas (methane) and nitrogen which is injected in varying concentration. Dry gas is always considered as one of the option in removing condensates in gas condensate reservoir. However, the cost and availability of dry gas remains a major concern in the field application. Based on the investigation carried out by Siregar et al. (1992), the outcome shows that methane possessed more stable PVT static behaviour compared to nitrogen when those composition is reacted with the condensate. This is proved when methane could evaporate more condensate with just 55% mole fraction of methane injection compared to nitrogen injection which is 98% mole fraction.

In addition, Gachuz-Muro, Gonzalez Valtierra, Luna, and Aguilar Lopez (2011) in the laboratory experiment carried out in resemblance of naturally fractured reservoir under HP/HT condition mentioned that among nitrogen, carbon dioxide and lean gas, nitrogen shows very minimal performance than the rest as the condensate recovery is very low. This reflects that nitrogen has lower condensate evaporation capacity.

2.2.2 Carbon Dioxide

As the amount of CO_2 keep increasing from day to day due to extensive growth in industrial and energy sector. This promotes burning of coal, gas and other hydrocarbons which emits the CO_2 to the atmosphere in uncontrolled way (Kumar, Zarzour, and Gupta (2010); Helle, Myhrvold, and Bratfos (2007)). This leads to greenhouse effect which is a drawback to the environment as well as human beings. Thus, some researches has suggested CO_2 capture technology in order to utilize it in more beneficial way (Kumar et al. (2010); Stein, Ghotekar, and Avasthi (2010); Oldenburg and Benson (2002)).

In a simulation study, Kurdi, Xiao, and Liu (2012) investigated the effectiveness of supercritical CO_2($SCCO_2$) in minimizing condensate banking effect. Based on the outcome, the author concludes that CO_2 minimize the condensate surface tension and viscosity which in turn leads to higher microscopic displacement efficiency.

In a separate study, Zaitsev et al. (1996) proved the reliability of CO_2 injection in maintaining reservoir pressure and liquid build-up evaporation by comparing it with other three gases which is methane, nitrogen and separator gas in the study. As the result of the research, CO_2 proves to be the most effective gas in cleaning the condensate blockage.

In a simulation study conducted by Moradi, Tangsiri Fard, Rasaei, Momeni, and Bagheri (2010) to compare the mechanism of different scenario on condensate recovery and permeability reduction which will eventually decide the gas well productivity. This study is carried out in five different scenario which is natural depletion, gas recycling, methane, carbon dioxide and nitrogen. Based on the simulation study, Moradi et al. (2010) deduce that carbon dioxide shows the highest recovery of condensate and gas compared to other scenario.

Gachuz-Muro et al. (2011) has carried out a laboratory experiments which involve carbon dioxide nitrogen and lean natural gases in order to study efficiency of these gases in dissolving condensate build-up in gas condensate reservoir which composed of natural fractures and slits. The study is designed with pressure of 8455 psia and temperature of 334 ^{o}F to depict the HPHT reservoir condition. The study testifies that carbon dioxide tends to perform better in term of condensate recovery, but slightly lower compared to natural gas.

Carbon dioxide has been also utilized in huff-n-puff technique to mitigate the condensate blockage issue which create the same effect as skin in the radius of damage (Odi, 2012). Carbon dioxide huff-n-puff technique works by pumping adequate amount of carbon dioxide near the wellbore, shutting the well for some time and open it back to achieve miscible displacement of natural gas and condensate. The reduction of dewpoint pressure at the reservoir temperature depends on concentration of carbon. The pressurizing effect will allow reservoir fluid to maintain its single phase. Based on this study Odi (2012) concluded that carbon dioxide can improve the productivity of well affected by condensate banking and the performance of this method is very sensitive towards the time the technique initiated. Figure 3 shows the simple diagram on the huff-n-puff CO_2 processes.

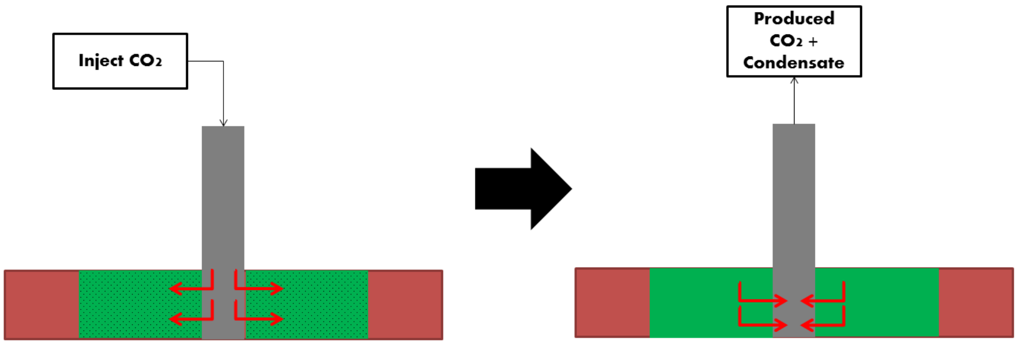

Figure 3: CO2 Huff-n-Puff injection (Odi, 2012)

Taheri, Hoier, and Torsaeter (2013) has carried out a simulation based research to investigate the capability of miscible and immiscible gas injection in dissolving condensate accumulation near the wellbore region in fractured gas condensate reservoir. In this simulation study, the author modelled fractures surrounded single matrix block and implemented natural depletion, miscible and immiscible gas injection scenario in the model. Methane, nitrogen, carbon dioxide and stock tank gas composition are used as injectant in this study. Taheri et al. (2013) identified that miscible gas injection which in this case is CO_2 recovers more condensate than immiscible gas injection. Besides, enhancement of carbon dioxide level in stock tank gas provides higher condensate recovery in effect to reduction of minimum miscibility pressure from the interaction.

2.2.3 Propane

Propane is very useful in industry and daily application. In the petroleum industry, it is heavily used as injectant to increase the recovery of heavy oil by reducing its viscosity (Akhondzadeh and Fattahi (2014); Yarranton, Badamchi-Zadeh, Satyro, and Maini (2008)) . Based on Paszkiewicz (1982), propane is highly available in petroleum and natural gas producing nation because it is a residue as a result from natural gas production and refinery processing. The increment of propane demand arises steadily due to the finding of new applications of propane which elevates its market from time to time (Adminstration, 2014).

In Adena Field, Colorado, the propane gas injection technique was applied as tertiary oil recovery technique to recover the left over from waterflooding applied before (Holm, 1972). The author finds that propane injection could mobilize the oil by miscible displacement. However, a proper injection strategy has to be applied to avoid loss of injectant and channelling effect.

In heavy oil reservoir, Ferguson, Mamora, and Goite (2001), has done an experimental study on the effectiveness of propane addition to enhance recovery from Morichal Field, Venezuela by steam injection. Experiments have been conducted by varied propane: steam mass ratio starting from pure steam injection to 5:100 ratio of propane to steam. The result indicates that there is significant increment of oil production by 20% compared to steam alone.

Another separate study with the same objective which is to assess the effectiveness of propane in heavy oil recovery is done by Venturini, Mamora, and Moshfeghian (2004) for Hamaca heavy oil. The study is carried out by numerical simulation by employing a 3D cartesian grid model which incorporated with ten pseudo-component oil model to resemble Hamaca oil. Based on the study, the author concludes that higher propane steam mass ratio will result in acceleration of oil production and three times incremental oil recovery compared to pure steam injection.

In gas condensate study, constant composition expansion (CCE) studies were conducted by Jamaluddin et al. (2001) in order to investigate the impact of carbon dioxide (CO_2) and propane (C_3) on the liquid dropout vaporization in the near well bore region. By using 30% mol and 40% mol of carbon dioxide and 28% mol and 40% mol of propane, CCE test by Jamaluddin et al. (2001) shows that carbon dioxide increases dewpoint pressure and decreases the total liquid dropout below the dewpoint whereas propane decreases both dewpoint pressure and total liquid dropout. The author initiate an idea to inject propane in the field using huff and puff technique beneath several condition due to ideal phase behavior of propane (Jamaluddin et al., 2001).

Propane has many characteristics that make it one of the injectant that should be considered in condensate recovered. It has been used as gas injection in tertiary recovery technique as well as in steam injection in heavy oil reservoir and the output has been quite convincing due to its ability to reduce the viscosity and increase the mobility of oil.

2.3 Horizontal Drilling Technique

Horizontal well has been implemented in various reservoir applications. Horizontal drilling technique has been mostly implemented in gas reservoir, fractured reservoir and heavy oil reservoir. The first horizontal drilling technique is carried out in 1927 although the major thrust of drilling the well using this technique started in 1980 (Joshi, 2003). As stated by Sayed and Al-Muntasheri (2014), the horizontal well is really beneficial in lowering the pressure drop near the wellbore where it will delay the building of condensate in gas condensate reservoir which in turn will improve the productivity. Horizontal well technique is very efficient due to its ability to delay condensate banking phenomenon and large contact area between wellbore and the reservoir.

Muladi and Pinczewski (1999) done an extensive study to compare the difference of horizontal and vertical well in term of production performance for various heterogeneities of gas condensate reservoir. Based on the study, the author concludes that horizontal well depict higher production performance compared to vertical well in average permeability reservoir. The performance of horizontal wells is optimized when it is placed in high permeability layer. Muladi and Pinczewski (1999) reaches the same observation with Fevang and Whitson (1996) in agreeing that production of horizontal gas condensate wells are very sensitive towards the permeability distribution. Thus, Fevang and Whitson (1996) emphasized that detailed study on determining k_v/k_h ratio is needed in the analysis as it affects the final forecast result.

Miller, Nasrabadi, and Zhu (2010) investigated the applications of horizontal wells in North Field Qatar, which is one of the largest gas condensate reservoir that faced the condensate banking phenomenon. The North Field Qatar is labelled as the highest non-associated gas field in the world which stores more than 900 trillion cubic feet of proven natural gas reserves. From the study, Miller et al. (2010) manage to prove that horizontal well has a smaller drawdown pressure which delayed the condensate build-up compared to vertical well. The ratio of productivity index (PI) of horizontal to vertical well is 6.11 when pressure reaches dew point pressure.

CHAPTER 3

METHODOLOGY

3.1 Research Methodology

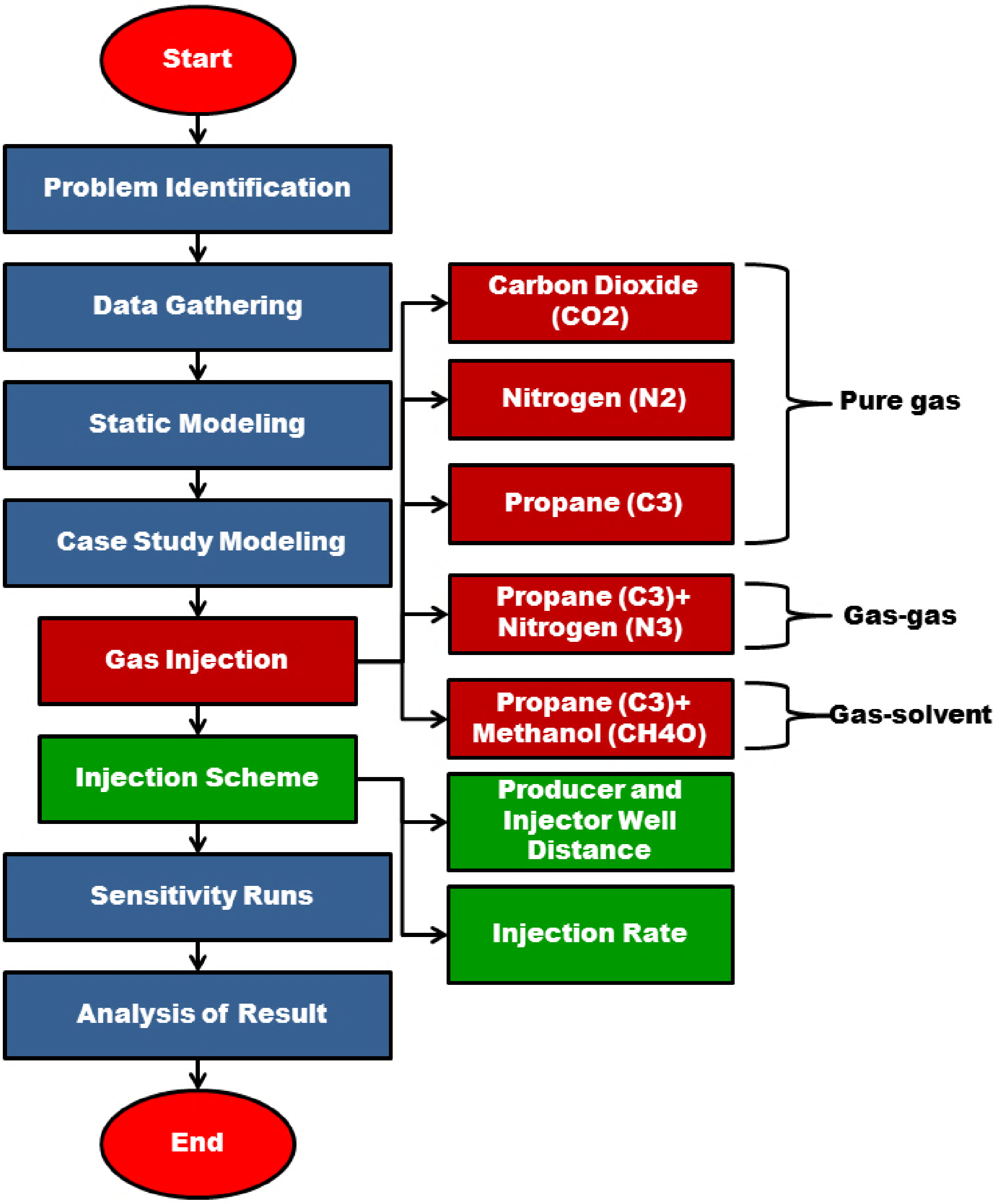

Figure 4 : Final Year Project process flowchart

The flow chart in Figure 4 briefly shows that the methodology of the FYP in brief. The first step of FYP is title selection which is the most significant step in FYP. Following title selection, the objective and the problem of the project is identified. From the problem, the literature review is carried out based on the SPE papers, journals and thesis related to gas condensate reservoir and condensate banking phenomenon. This step is very important in order to study the mechanism of condensate formation as well as analysing the advantage and limitation of condensate recovery technique.

The next step is data gathering where most of the parameters and input of this study are gained from literature review as well as tutorial model which is based on comparative study. The data gathered are fluid data, reservoir rock properties and the reservoir characterization. The data gathered will be incorporated into the compositional simulator, which in this study the simulator used is ECLIPSE 300.

After the reservoir model data has been incorporated into the simulator, the simulation is run in order to investigate the performance of different gas injection in condensate recovery as well as the effect of different injection scheme (well distance and injection rate) on the condensate production and well productivity improvement.

Finally, thorough analysis will be carried out based on the result retrieved from the simulator and the result will be discussed in the report.

The core activities of studies can be divided into three main stages:

1. Literature review and data gathering
2. Modelling and simulation
3. Analysis of result

For the first part which is the literature review and data gathering part, the process was conducted in Final Year Project I. For the modelling, simulation and analysis part, it is carried out in Final Year Project II phase. These activities will be explained in detail manner in the following section.

3.1.1 Literature Review and Data Gathering

In this section, the activities involve is reading and reviewing the papers and journals related to gas condensate reservoir Most of the literature taken from Society of Petroleum (SPE) chapter to ensure the reliability and accuracy of the information gathered.

Most of the paper reviewed is up-to-date and highly relevant to the study. To make the studies more systematic, the study is carried in chronological order which starts from gas condensate reservoir characteristics, followed by technique that applied by industry to solve the problem faced in this type of reservoir. The journal/papers on gas condensate reservoir are abundantly available as condensate banking is one of the biggest problems faced by the engineers due to the reservoir complexity. The mitigation technique mainly focuses on the gas injection and solvent as the main intention of this study is on the effect of gas injection in gas condensate recovery. However, the study on propane injection is limited as less study is done on the injection of propane to the gas condensate reservoir.

3.1.2 Modelling and Simulation

The simulations were carried out using a simulator developed by Sclumberger which is ECLIPSE. ECLIPSE software consists of packages of applications to be used for various modelling and simulation purposes. Based on the scope of this project, only few applications has been utilized which is ECLIPSE 300, PVTi, Floviz and Office.

ECLIPSE 300 is the option used to simulate the compositional model. As this study focus on gas condensate reservoir which consists of multicomponent phase, ECLIPSE 300 is the most suitable numerical simulator to model the condensate effect. Besides, different gas injection of gas can be implied in the simulator as it has the options to specify the gas injection composition. PVTi is used to model the reservoir fluid based on its composition and thermodynamic behaviour. While for Office, it is used to generate the result from the simulation and portrays the result in graphical form.

3.1.2.1 Static Modeling

The static modelling is done by using ECLIPSE 300 as all the available data is inserted in the software to form hypothetical gas condensate reservoir. The reservoir model is constructed based on ‘Third SPE Comparative Solution Project: Gas Cycling of Retrograde Condensate Reservoirs’ paper (Kenyon, 1987). However some modification is done on the SPE3 model to comply with this project objective. Figure 5 shows the relative permeability data which is utilized in this study. The gas-oil permeability is very important in this study as this study focuses on the flow of this both phases which affects the condensate recovery.

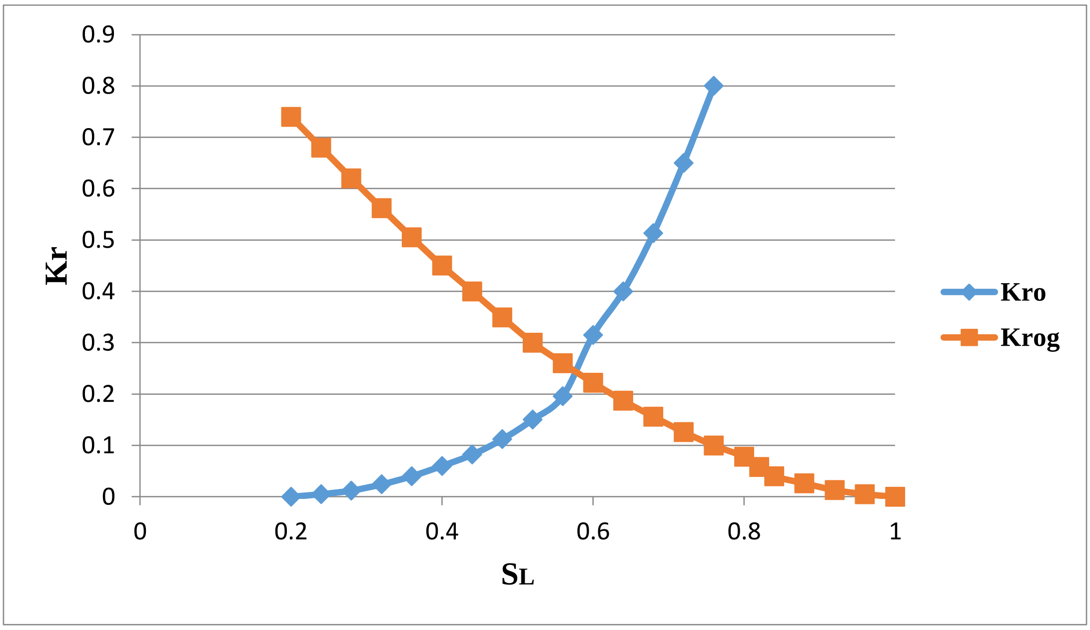

Figure 5: Gas-Oil relative permeability curve

In the context of reservoir grid and saturation data, the model will be having 18x18x4 grids in i, j and k direction. As the grid is symmetrical, it will have same width and length which is 146.65 ft for each grid. The model has the thickness of 160 ft which for the first two layers is 30 ft each and the last two layer 50 ft each. The porosity utilized is 0.13 which is assumed to be same throughout the model because it is assumed to have a simple geological characterization. However, to make the study more realistic and practical, each reservoir grid layer has been assigned with different horizontal permeability. The compressibility of water is set to 3×10^{-6} psi^{-1}. Table 1 shows properties of the reservoir model.

Table 1: Properties of hypothetical gas condensate model (Kenyon, 1987)

Properties	Values
Grid Dimension	18x18x9
Hydrocarbon pore volume	20.24MMrb
Datum (subsurface)	7500 ft
Gas/water contact	7500 ft
Water saturation at contact	1.00
Initial pressure at contact	3550 psia
Water density at contact	63.0 lbm/ft^3
PV compressibility	4.0 x 10^{-6}
Horizontal permeability	Layer 1 - 130 mD Layer 2 - 40 mD Layer 3- 20 mD Layer 4 - 150 mD

Figure 6 below shows the gas condensate model in 3D viewer. The colour represents the gas saturation in the reservoir at initial stage.

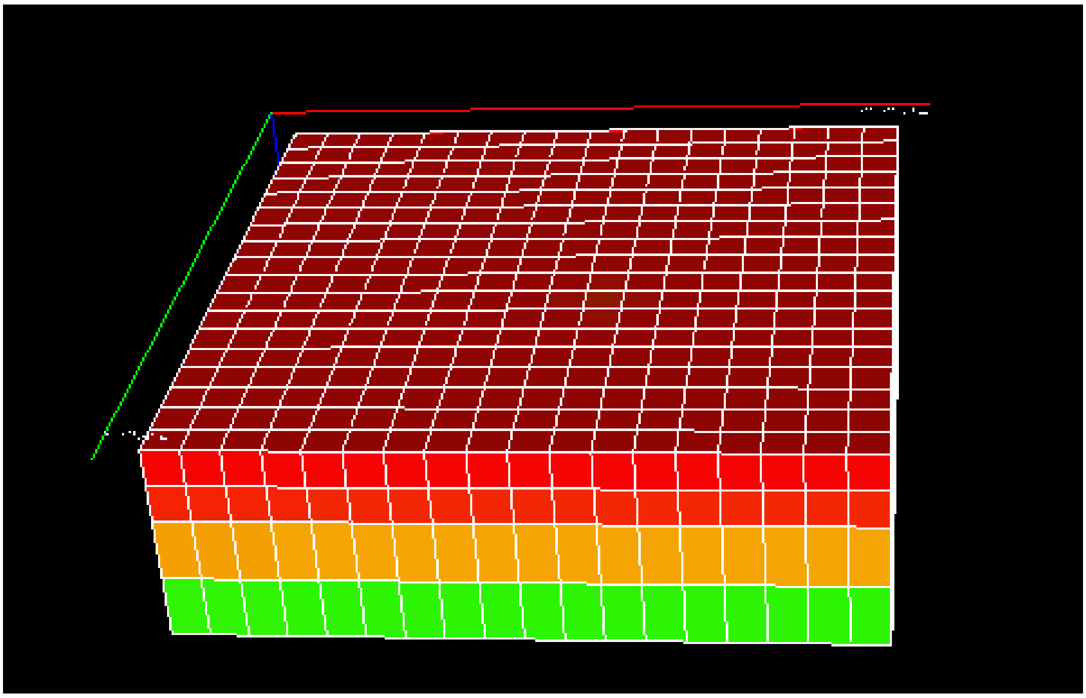

Figure 6: 3D view of the hypothetical gas condensate model

3.1.2.2 Fluid Study

The tool used in modelling the fluid in ECLIPSE in PVTi. PVTi functions to model fluid behaviour perform PVT calculations and reservoir fluid characterization. Table 2 depict the hydrocarbon analysis incorporated in this study.

Table 2: Composition of Reservoir Fluid Sample (Kenyon, 1987)

Component	Mol %
Carbon dioxide	1.21
Nitrogen	1.94
Methane	65.99
Ethane	8.69
Propane	5.91
C_{4-6}	9.67
C_{7+1}	4.7448
C_{7+2}	1.5157
C_{7+3}	0.3295

Figure 7 shows the phase envelop of the reservoir fluid. The measured dew point pressure for the reservoir fluid is 3817 psi while the observed dew point pressure is 3428 psi. The gas temperature of the hypothetical gas condensate reservoir is 200 ^{o}F.

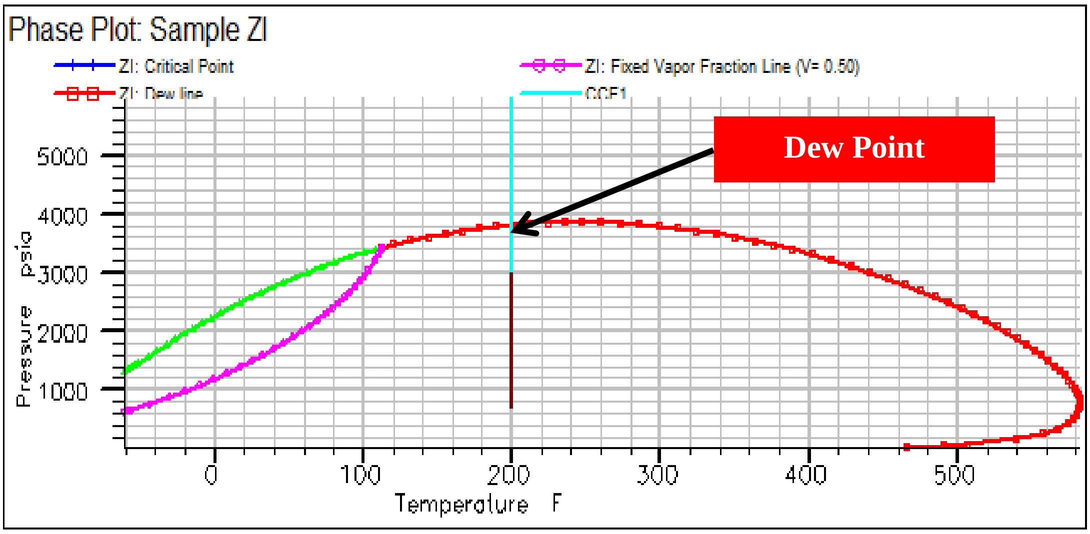

Figure 7: Phase plot of the reservoir fluid

The fluid data is extracted from the SPE3 model as the literature has all the PVT data for the gas condensate reservoir condition. The PVT data composed of the fluid molecular weight, fluid compositions, constant-composition expansion (CCE) and constant volume depletion (CVD) which is prepared synthetically in the laboratory. This composition is widely used in gas-condensate study because of its reliability (Moses & Wilson, 1981). The PVT modelling was performed by using Peng-Robinson EOS.

As methanol is not incorporated in the ECLIPSE software, it has to be introduced in the model by using PVTi. As there is no experiments is carried out in this project, the methanol data is incorporated from the literature review (Bang, Pope, & Sharma, 2010). The data used in the PVTi is given in Table 3.

Table 3: EOS parameters for methanol

Component	Molecular Weight	Critical Temperature (^{o}F)	Critical Pressure (Psia)	Acentric Factor
Methanol	32.042	922.68	1174.21	0.559

The parameters of pure gas injection which includes propane, nitrogen and carbon dioxide are readily available in library of PVTi. Thus, it is directly used from the simulator to study its effect on the reservoir performance. As for newly introduced methanol, adjustment of binary interaction is done to match the observed data with the calculated data. This is very important to ensure methanol could represent the phase envelop and behaviour for all the pressures involved. The binary interaction parameters between hydrocarbon and methanol are given in Table 4.

Table 4: Binary interaction parameters between hydrocarbon and methanol

Component	K_{ij} with Methanol
Methanol	0
Methane	0.29
n-butane	0.25
n-heptane	0.075

3.1.2.3 Dynamic modelling

After all the data has been incorporated, the gas condensate model has been initialized for the simulation run. The dynamic modelling is carried out to simulate our cases based on the objective defined. There are two parts of dynamic section which can be divided as this project carries two main objectives.

For the first objective, which is to study the effect of different injection gases in condensate recovery, three types of gases have been studied which is:

- A rarely used propane
- Conventional gas which is carbon dioxide and nitrogen.

1 pore volume (PV) of slug is injected for each case in the duration of 10 years which is 0.1 PV per year. For the first 5 years, the reservoir is producing by natural depletion scenario which is the base case in this section. The function of 5 years of natural depletion is to build the scenario of condensate blockage. Thus, it will divide the simulation to two parts which is pre-treatment and post treatment. The injection rate of each case is designed to inject 1 PV of slug in 10 years. The injection rate can be viewed from Table 5.

Table 5: Injection rate for each gas

Pure gas	Injection rate (MSCF/day)
Carbon Dioxide	9832
Propane	9260
Nitrogen	5437

For all the cases in this section, the changing parameter is only the gas injection composition while other parameters are kept constant. For the well data, the injection well is set at the grid of 6, 6 with the perforation are targeted at the top layer which is layer 1 and 2. As for production well, it is placed in the location of 13, 13 where perforation is targeted at bottom layer which is Layer 3 and Layer 4 specifically. The bottomhole pressure for producer is minimally set to 500 psi. The placement of the well can be viewed from Figure 8.

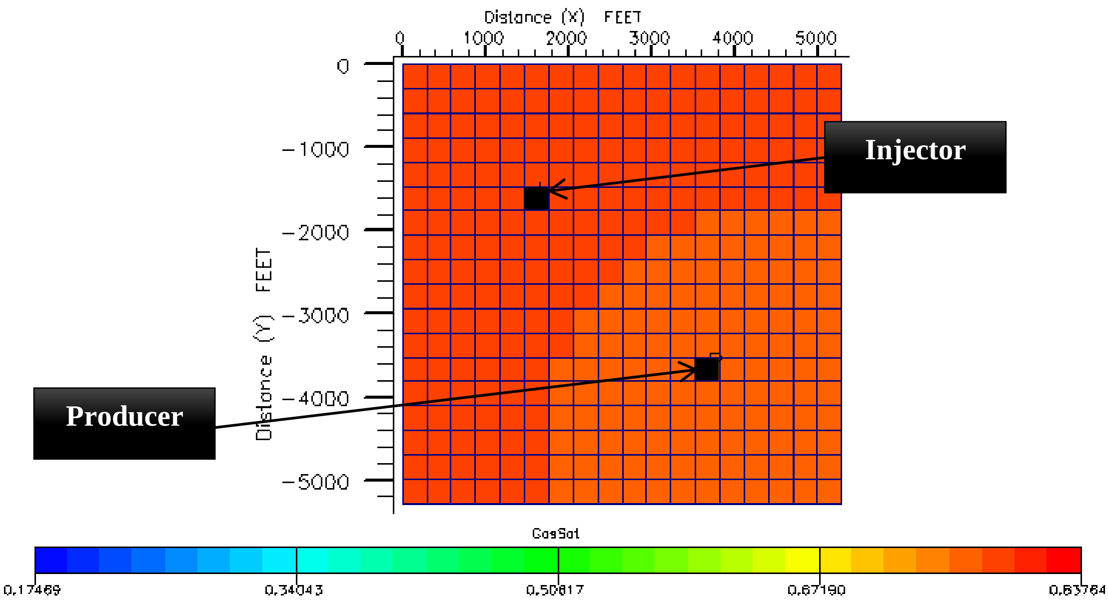

Figure 8: Top view of the hypothetical gas condensate model in the function of gas saturation

Further study is carried out for propane injection by utilizing the technique of gas-gas injection and gas-solvent injection. This technique is approached as propane is not abundant in term of availability as it is the residue produced during natural gas production (Paszkiewicz, 1982). Thus, with such technique, the injection of propane can be reduced significantly. For gas-gas injection, nitrogen is used as secondary slug as nitrogen is cheap, abundant and very good in term of pressure maintenance (Kossack and Opdal (1988); Donohoe and Buchanan (1981)). As for gas-solvent injection, methanol is used as it is one of the mostly used chemical in removing condensate banking and besides, it is readily available in the market. The injection is carried out in term of alternating flooding for 10 years which is 0.1 PV per year for both cases. The detail of injection is explained in the diagram below:

Gas-gas injection

For the second objective, the aim of the simulation is to analyse the effectiveness of different injection scheme in recovering the condensate and removing the condensate banking. The injection of gas used in this injection study is propane as our study area focuses on propane injection. The result is compared with natural depletion as it is the base case for this project. There are two areas which are focused on this study which is:

- Distance between injector and producer
- Injection rate

Volume of gas injected is the same for all the cases which is 1 PV. The perforation for the injector is carried out at the top layer which is layer 1 and 2 while for producer the perforation is targeted at layer 3 and 4. The analyses for distance between injector and producer are done by giving different distance regarding to the blocks. The placement of the well for each case is shown in Figure 9.

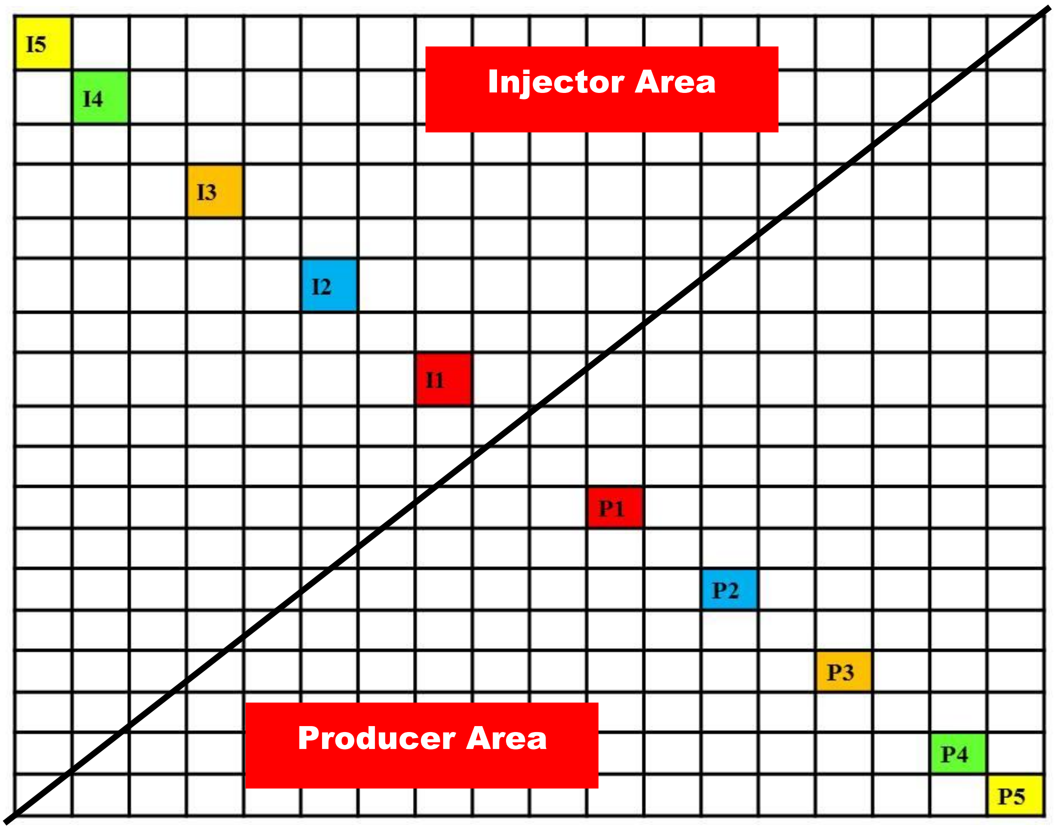

Figure 9: Placement of injector and producer well from top view of the well

The different colour shows different case of injection well and producer well distance. The relationship between the colours and distance in Figure 8 is given in Table 6.

Table 6: Distance between injector and producer

Case	Legend	Block distance/factor	Distance(ft)
P1, I1		2	414.8
P2, I2		6	1244.4
P3, I3		10	2074
P4, I4		14	2903.6
P5, I5		16	3318.4

As for the injection rate, three different rates are studied in this project which is:

- 2000 MSCF/d
- 4000 MSCF/d
- 8000 MSCF/d

The rate increment is in the factor of two to show the significant difference of rate between each case. The study is carried out for each well distance to see the relationship between the well distance and injection rate. However, the focus of injection rate will be on well distance of 6 blocks as it is the optimum case in this study.

3.1.3 Analysis of result

Analysis of result is carried out by using ECLIPSE Office and Excel to output the graphical form of the result for better understanding. Most of the cases are compared by using the condensate production total result to observe the performance of each cases of condensate recovery. Other result will be used as a support to justify the condensate production total result.

Lastly, the result and the analysis will be compiled and documented in form of report which consists of literature review, result, discussion and conclusion.

3.2 Gantt Chart FYP I

Table 7 : FYP I Gantt Chart

Activities	Weeks													
	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Final Year Project topic selection														
Introduction on: • Natural Gas – current and future world demand • Gas Condensate Reservoir – Condition and challenges • Condensate Banking – problem and mitigating strategy														
Literature Review: • Mitigating strategy – application, advantages and limitation • Propane, Carbon Dioxide, Nitrogen and Methanol														
Extended Proposal submission														
Proposal Defense														
Familiarization of ECLIPSE 300 & PVTi														
Interim Report submission														

Key Milestone

3.3 Gantt Chart FYP II

Table 8: FYP II Gantt Chart

Activities	Weeks													
	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Simulation learning (ECLIPSE 300 & PVTi)														
Static Modeling: • Defining Grid • Incorporate porosity, permeability and relative permeability curve														
Fluid Modeling: • Creating a retrograde based fluid system to incorporated in the model based on the literature														
Dynamic Modeling: • Creating different scenario based on the injectant/solvent • Designing cases for different injection scheme														
Progress Report submission														
Pre-SEDEX presentation														
Dissertation submission														
Final Presentation & Viva														

Key Milestone

CHAPTER 4

RESULT AND DISCUSSION

This project aimed to simulate and examine the effect of gas injection in condensate recovery. The efficiency of gas-gas flooding and gas-solvent flooding in removing condensate is also being examined. Besides, injection scheme which covers different well distance between injector and producer as well as injection rate is also simulated to examine the condensate production performance. The results from the simulation are presented in this chapter.

4.1 Effect if gas injection in condensate recovery

Figure 10 shows the graph of total condensate recovery versus year. This graph portrays the condensate production total in respect to time with different case studied.

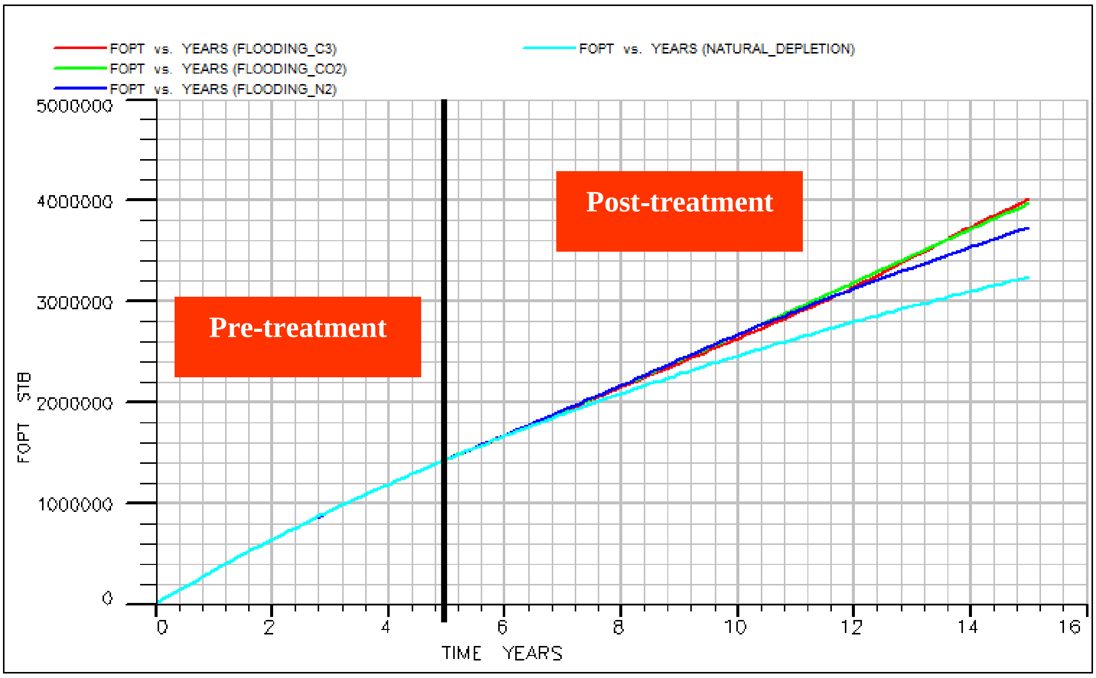

Figure 10: Total condensate recovery based on type of gas injection

Based on Figure 10, the amount of condensate for the first 5 years increase in the same trend for all the cases as the reservoir is producing by natural forces where no alteration or changes is done in the period. However, starting from the 5^{th} year, the trend started to change based on the injected cases. The highest condensate production is by propane injection followed by carbon dioxide, nitrogen and lastly natural depletion (base case) which is not involved in any treatment or injection.

Propane shows better condensate recovery as the addition of propane in the reservoir reduces the dew point pressure of the reservoir. Based on Table 9, the original reservoir dew point pressure is 3817 psi while the dew point pressure after addition of propane is 3493 psi. The same behavior is exhibited by carbon dioxide where the dew point pressure is suppressed to 3759 psi. The contrasting action is shown by nitrogen where it increases the reservoir dew point pressure up to 4164 psi. This clearly shows that propane reduces the dew point pressure the most compared to other conventional gases. The study done by Jamaluddin et al. (2001) clearly shows that the addition of propane in the reservoir fluid will decrease the dew point pressure which is agreeable with the study. The authors also mentioned that carbon dioxide addition increases the dew point pressure which is contradicted with this study.

However, Odi (2012) shows the same finding as this study where the increased diffusivity of carbon dioxide causes increment of carbon dioxide concentration in the condensate which will reduce the dew point pressure. As for nitrogen, many of the studies has proved that it increases the dew point pressure (Vogel and Yarborough (1980) ; Moses and Wilson (1981)). The reduction of dew point pressure could delay the formation of condensate in the reservoir which will then maintains the single phase in the reservoir for long duration of time.

Aside from dew point reduction, the continuous injection of gas will aid in the reservoir pressure maintenance. Based on Figure 11, nitrogen shows better performance in term of pressure maintenance compares to carbon dioxide and propane. Nevertheless, all cases maintain the pressure in the range of 2950 psi to 3150 psi during the injection period. The pressure of the reservoir could be maintained by higher rate of gas injection.

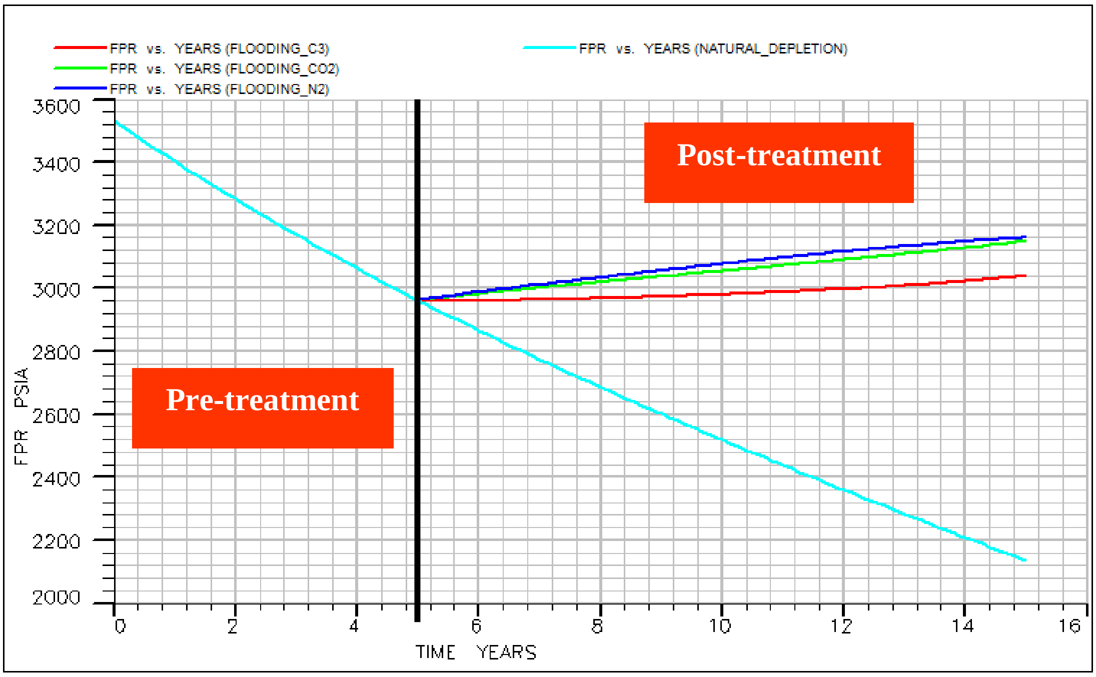

Figure 11: Field Pressure before and after the gas injection

Another mechanism that contributes in higher condensate production is the condensate viscosity reduction. Based on Table 9, the viscosity of original reservoir fluid is 0.065 cp. Thus, it is observable that the viscosity reduction for propane is higher than carbon dioxide which is 0.0625 cp and 0.064 cp respectively. For the nitrogen case, it shows that the viscosity is higher than original reservoir fluid which is 0.066 cp. However the increment is too diminutive which is 0.001 cp.

The reduction of viscosity by propane injection is higher than other cases due to the characteristics of the pure component itself. As propane is an intermediate hydrocarbon component, some of the injected propane will condense and undergo solubility with reservoir fluid to form more condensate. Due to the characteristic of propane which is more lightly compared to other component, it will start to dilute the condensate and decrease its viscosity. In a study conducted by Kariznovi, Nourozieh, and Abedi (2011), in heavy oil application, the study shows that at fixed temperature, the high content of propane in the mixture could reduce the viscosity of heavy oil by big margin. The concept is quite same like in gas condensate reservoir as condensate mainly made up of heavy and intermediate component. This clearly shows that propane is a very good agent in reducing the viscosity of heavy component.

As for carbon dioxide, it also reduces the viscosity, although it is not as efficient as propane. According to Vayenas et al. (2002), the density of carbon dioxide is lower than condensate but higher than natural gas. Continuous injection of carbon dioxide will decrease the condensate phase density (ρ_r). Based on Lohrenz, Bray, and Clark (1964) correlation to calculate the condensate viscosity(μ), it could be observed that by having less condensate density, it help in reducing condensate viscosity (Kurdi et al., 2012). This relation is shown in Equation 1:

$$\boldsymbol{\mu = \mu^{*} + \int_{m}^{-1}\left[\begin{pmatrix} 0.1023 + 0.023364\rho_r + 0.058533\rho_r^2 - \\ 0.040758\rho_r^3 + 0.0093724\rho_r^3 \end{pmatrix}^4 - 1 * 10^{-4}\right]} \quad \textbf{(1)}$$

Nitrogen injection shows that it does not alter much of the condensate viscosity as the mixing of nitrogen with reservoir fluid is minimal. Continuous injection of nitrogen will increase its concentration as well as its viscosity. Higher viscosity of injectant could improve the flood sweep efficiency. Thus, it will act almost like piston displacement to provide an external force to push the condensate on to the surface. This piston like movement will accumulate the condensate to the producer well and causing the viscosity of the condensate to be higher at the well bore. At the same time, the piston like force also helps in condensate production to the surface.

Table 9: PVT analysis of fluid composition

Gas Injection (0.1 mole %)	Viscosity (cp)	Dew Point (psia)	Condensate volume @ 700 psia (%)
Original reservoir fluid (no injection)	0.065	3817	18
Carbon Dioxide	0.064	3759	16.2
Nitrogen	0.066	4164	17.4
Propane	0.0625	3493	15

Viscosity controls the ease of flow of the fluids. Thus, as the viscosity of condensate decreases, it causes the flow of condensate much easier. Based on the understanding of mobility which is the ratio of effective permeability to phase viscosity, the lower the viscosity (μ), the higher would be the mobility (M). Propane and carbon dioxide has major advantage in removing condensate blockage as both of them have high evaporation capacity, while for nitrogen, the effect is minor. The relationship can be viewed from Equation 2:

$$\boldsymbol{Mobility} = \frac{\boldsymbol{k(effective\ permeability)}}{\boldsymbol{\mu(viscosity)}} \qquad \textbf{(2)}$$

Addition of propane, carbon dioxide and nitrogen in reservoir fluid could alter the volume of condensate formation with respect to pressure. As for propane injection, it reduces the condensate volume to approximately 15% which is the highest reduction compared to carbon dioxide and nitrogen which is 16.2% and 17.4% respectively. From here, we could observe that propane reduces the condensate volume the most followed by carbon dioxide and lastly nitrogen. Nitrogen only manages to reduce 0.6% of the original fluid condensate volume. Many studies proved that the injection of nitrogen promotes liquid drop out (Sanger and Hagoort (1998) ; Kossack and Opdal (1988)). The amount of condensate volume near the wellbore will affects the gas relative permeability and the well productivity.

Figure 12 shows the changes in gas relative permeability starting from the 5th year for 20 years until 25th year. For each year, 0.1 PV of slug is injected and total of 2 PV of slug injected for all the cases.

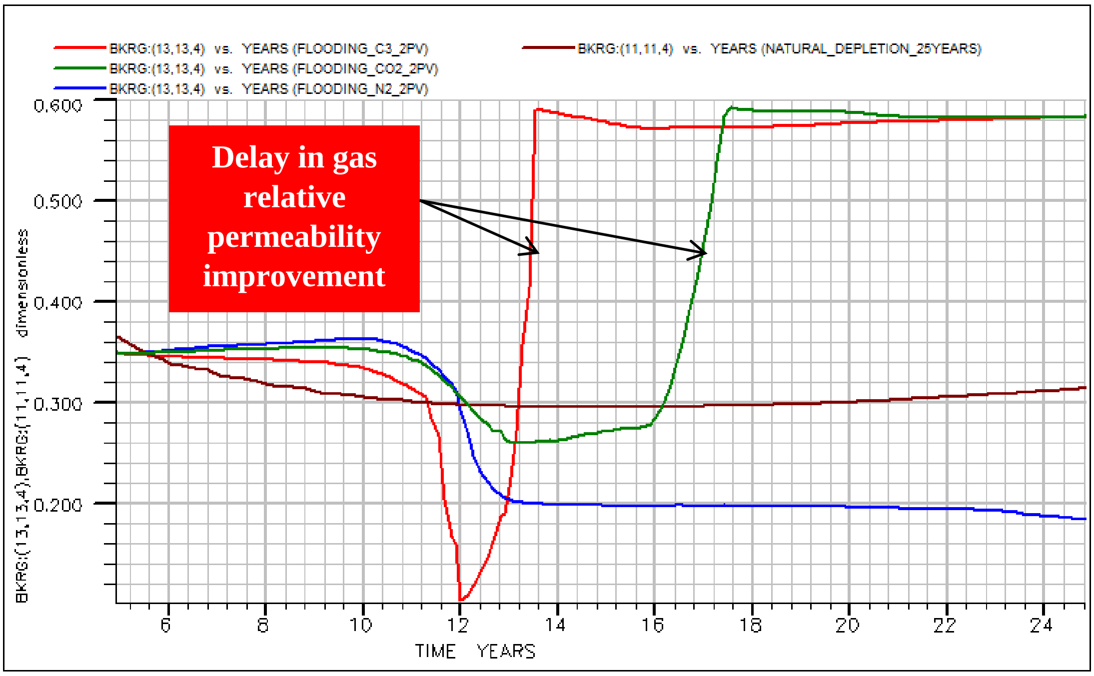

Figure 12: Gas relative permeability for each case

Based on Figure 12, it clearly shows that propane shows better gas permeability compared to carbon dioxide and nitrogen. In early stage of injection, nitrogen and carbon dioxide shows better gas relative permeability compared to propane until the 11^{th} year. During this period, the constant trend of gas permeability of all the cases is due to slow establishment of the solvent concentration in the interface. However, after the establishment had occurred, the trend stars to undergo changes. There is sudden decline of gas permeability for the propane injection case at year 11^{th}. This is because during this time, propane increases the permeability of condensate from the effect of improved condensate mobility where most of the condensate will be produce during this period. After that, the concentration of condensate decreases significantly near the well bore which will simultaneously decrease its relative permeability. This will clear the path for the gas to move towards the wellbore and the relative permeability of gas near the well bore region will increase drastically due to condensate removal and action of continuous injection. The same mechanism is showed by the carbon dioxide injection. However, it needs higher concentration of carbon dioxide to achieve the same feat as propane. Propane only needs 0.7 PV of gas to remove most of the condensate and increase the gas productivity while carbon dioxide needs 1.1 PV to give the same effect as propane. The gas relative permeability of nitrogen reduces at the 12^{th} year to 0.2 and the trend maintains until the end of simulation. During this period, the condensate is displaced by nitrogen in slower rate and this delay the gas productivity improvement. Besides, nitrogen also promotes liquid-drop out which also a factor gas relative permeability suppressing.

As the gas relative permeability increase, this will decrease the skin factor considering condensate banking act as a damage to gas production (Odi, 2012). This can be expressed by Equation 3:

$$\boldsymbol{S_{cond} = (1 - k_{rg,d}) In \left(\frac{r_d}{r_w}\right)} \qquad \textbf{(3)}$$

Skin is a factor which calculates the production efficiency of a well by comparing actual conditions with ideal conditions. Positive skin value indicates some damage which causes impairment in well productivity while negative skin value indicates enhanced productivity.

4.1.1 Effect of gas-gas and gas-solvent flooding on condensate production

To minimize the use of propane during the injection, two alternating flooding techniques has been implemented which is gas-gas injection which involve the injection of propane and nitrogen and as well as gas-solvent which utilize the flooding of propane and methanol. The usage of nitrogen and methanol in this study has been justified in the methodology part. The injection of pure propane will be used as the base case in this study. Figure 13 below shows the condensate recovery based on different flooding technique starting from fifth year where the injection started.

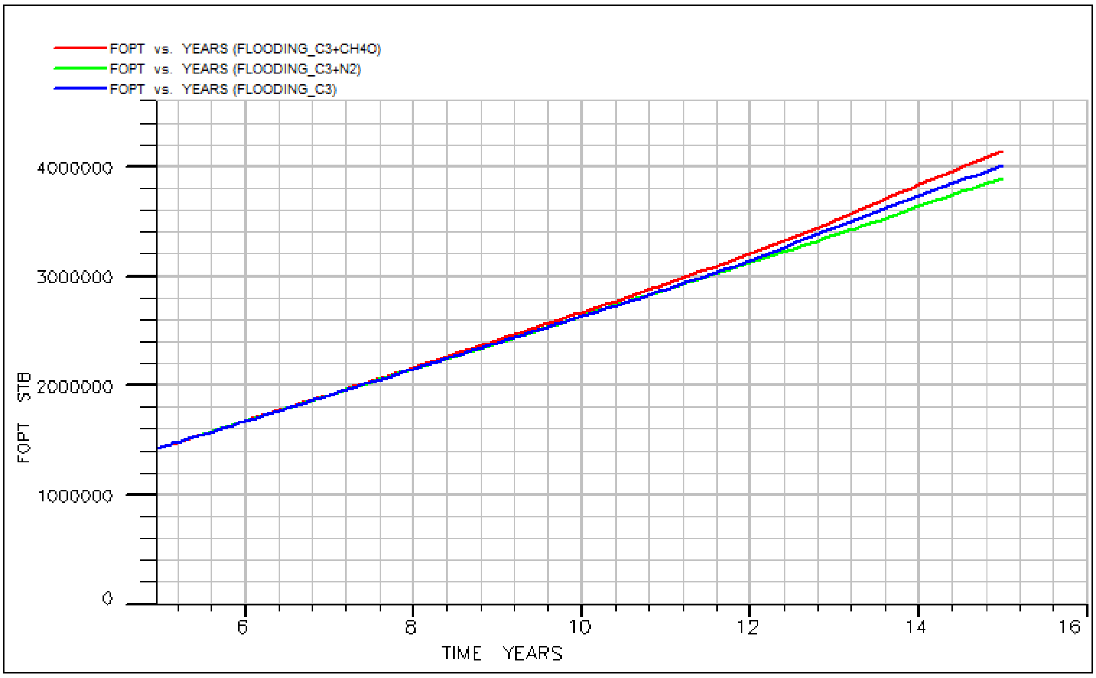

Figure 13: Condensate production based on gas-gas injection and gas-solvent injection technique

Refering to Figure 13, it could be observe that alternating of gas-solvent flooding(Propane+methanol) shows the highest recovery followed by propane injection (base case) and lastly gas-gas flooding(Propane+nitrogen). The reason of this effect is due to the interaction between the injection mixture and to the reservoir fluid. Methanol has low molecular weight and it is composed in high amount of intermediate phase (Hamoud A. Al-Anazi et al., 2002). The nature of methanol mentioned by the authors can cause methanol to achieve solubility with condensate. As propane is also intermediate component, it will increase the solubility and enhance the displacement of condensate. The high displacement of condensate will improve the gas relative permeability significantly. The result can be viewed from Table 10 where the pre-treatment shows the relative permeability of gas after 5 years of natural depletion without any treatment while post treatment shows relative permeability of gas after treatment. The addition of methanol boost the gas relative permeability compared to pure propane injection. Studies by Du, Walker, Pope, Sharma, and Wang (2000) also shows that methanol plays a big role in gas relative permeability improvement as well as condensate reduction near the wellbore.

Besides, methanol also reduces the dew point pressure which will retard the condensate accumulation (Bang et al., 2010). This shows that methanol possessed many same characteristics with propane. However, the effect of methanol is only last for short period (Hamoud A. Al-Anazi et al. (2002); Hamoud A. Al-Anazi et al. (2005)). Thus, by alternating injection of gas and solvent, the condensate displacement will be continuous and steady.

As for gas-gas injection which is flooding of propane and nitrogen, it shows lower recovery than pure propane injection (base case). Nitrogen injection as discuss before is not effective in term of condensate recovery, but it is abundant, cheap and environmental friendly. Nitrogen is non-hydrocarbon component and propane is intermediate hydrocarbon. Thus, propane will act as barrier from mixing of nitrogen with the condensate as propane (Kossack & Opdal, 1988). As the displacement front is led by propane, most of the condensate contacted with propane and provide higher condensate production and nitrogen will act as a driving force to displace the condensate and maintain the pressure.

Table 10: Gas relative permeability before and after treatment

	Pre-treatment	**Post-treatment**	
		Propane (C_3)	**Propane(C_3)+Methanol(CH_4O)**
Gas relative permeability(Krg)	0.54	0.59	0.65
Viscosity (cp)	0.065	0.0625	0.0601

On top of that, addition of methanol also helps in reducing the condensate viscosity. Based on Table 10, it could be seen that addition of propane reduces the viscosity of the condensate by 0.0025 cp while addition of methanol together with propane reduce the viscosity of condensate up to 0.0049 cp. The higher reduction of liquid viscosity will increase the condensate mobility much higher.

Table 11 shows the summary of gas injection which involve pure gas injection and combined gas injection which is gas-gas injection and gas-solvent injection. The effect of horizontal drilling is also portrayed in the result.

Table 11: Summary of gas injection performance on condensate recovery

Case	Condensate Recovery	Increment compared to Base Case (%)
Base Case	3,240,164 (16%)	-
Nitrogen (N_2)	3,733,220 (18.5%)	15.2
Carbon Dioxide (CO_2)	3,969,405 (19.5 %)	22.5
Propane (C_3)	4,011,570 (19.8%)	23.8
C_3 (Horizontal Drilling)	4,028,328 (20%)	24.3
Propane + Methanol	4,138,308 (21%)	27.7
Propane + Nitrogen	3,955,401 (19.4%)	22.1

Based on Table 11, it clearly shows that injection of propane shows the highest efficiency in term of condensate recovery. Carbon dioxide also serves as good agent in condensate recovery as the performance of carbon dioxide is very near to propane. Nitrogen serves as poor injection gas among other injectant. The condensate recovery for gas-gas injection (propane+nitrogen) show lower recovery than propane and carbon dioxide. However, the difference in term of recovery is very small.

4.1.2 Effect of horizontal well configuration on condensate recovery

Figure 14 shows the condensate saturation for horizontal well and vertical well. Horizontal well denoted by the red line, while vertical well is represented by green line.

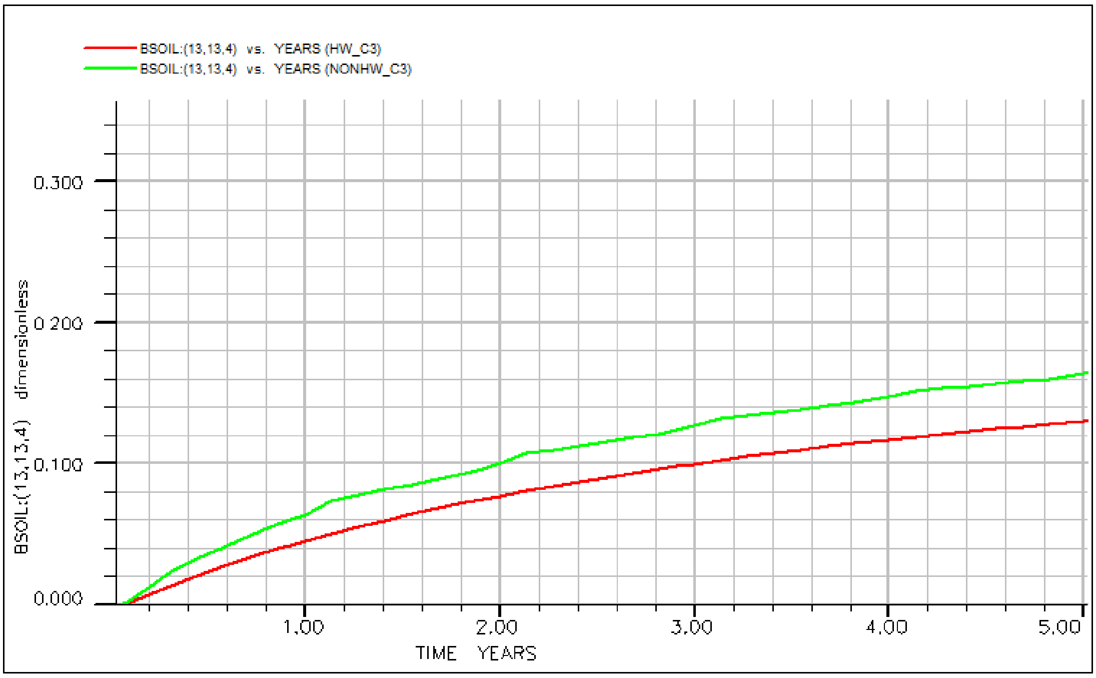

Figure 14: Condensate saturation based on well configuration

One of the techniques to improve condensate recovery and well productivity is horizontal drilling. Based on this study, the horizontal drilling technique has been applied in propane injection and the result is agreeable with other research (Muladi and Pinczewski (1999); Ghahri, Jamiolahmady, and Sohrabi (2011)). It shows higher recovery than vertical propane injection. Horizontal drilling result in condensate banking reduction as the pressure reduction around the well bore is reduced (Hashemi & Gringarten, 2005). The effect can be viewed in Figure 14 where the condensate build up for vertical well is higher than horizontal well for the first 5 years of natural depletion. Horizontal well also provides higher surface area which provides bigger contact with the formation. Thus, the rate of contact between injected gas and condensate is higher compared to vertical well. As a result, it will lead to higher gas production and at the same time improve well productivity. However, this technique has its own limitation considering the cost and drilling complexity to initiate this technique.

4.2 Effect of injection scheme on condensate recovery

4.2.1 Effect of different injector and producer distance on condensate recovery

From the result of the section above, it clearly shows that propane serves as best injectant compared to other conventional gas injectant. Thus, further study is done to investigate the suitable injection scheme to be implemented in order to get the optimum condensate recovery by using propane injectant. The injection scheme studied is focusing on different producer and injector well distance and injection rate. For well distance, five different cases has been designed which is 414.8 ft (2 blocks), 1244.4 ft (6 blocks), 2074 ft (10 blocks), 2903.6 (14 blocks) and 3318.4 ft (16 blocks).

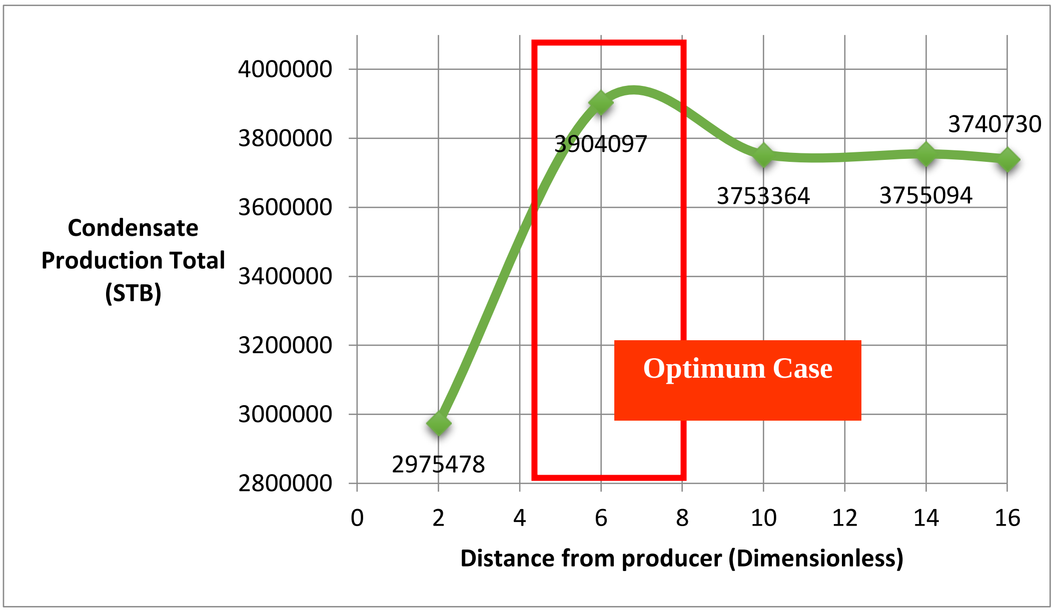

Figure 15: Condensate production based on well distance

Based on the Figure 15, it is observable that the smallest distance of well (2 blocks) shows lowest condensate recovery. For the medium well distance (6 blocks), the condensate recovery is significantly high compared to the further well distance which is 10 blocks, 14 blocks and 16 blocks.

Based on Figure 16, the shortest well distance shows lowest condensate recovery because the injected gas propagates to the production well to form condensate bank in short period of time due to the well distance and velocity of injected gas. During this time, the producer block has low relative permeability of gas and large relative permeability of liquid. Thus, due to mobility differences (injected gas is less viscous than condensate), the injected gas will flow to the high permeable zone and finger through the viscous zone which will cause injectant loss (Sänger et al., 1994). As for medium well distance (6 blocks), the injected gas manage to contact with large amount of condensate and as propane improves condensate mobility, the recovery increases significantly. As for the cases further than 6 blocks distance (10 blocks, 14 blocks and 16 blocks), it needed higher amount of propane to be injected as 1 PV of propane does not have enough force to exhibit the same reaction as the 6 blocks distance case. Sufficient distance between injector and producer will contribute to higher oil recovery (Ehlig-Economides, Fernandez, and Economides (2001) ; Akhondzadeh and Fattahi (2014)).

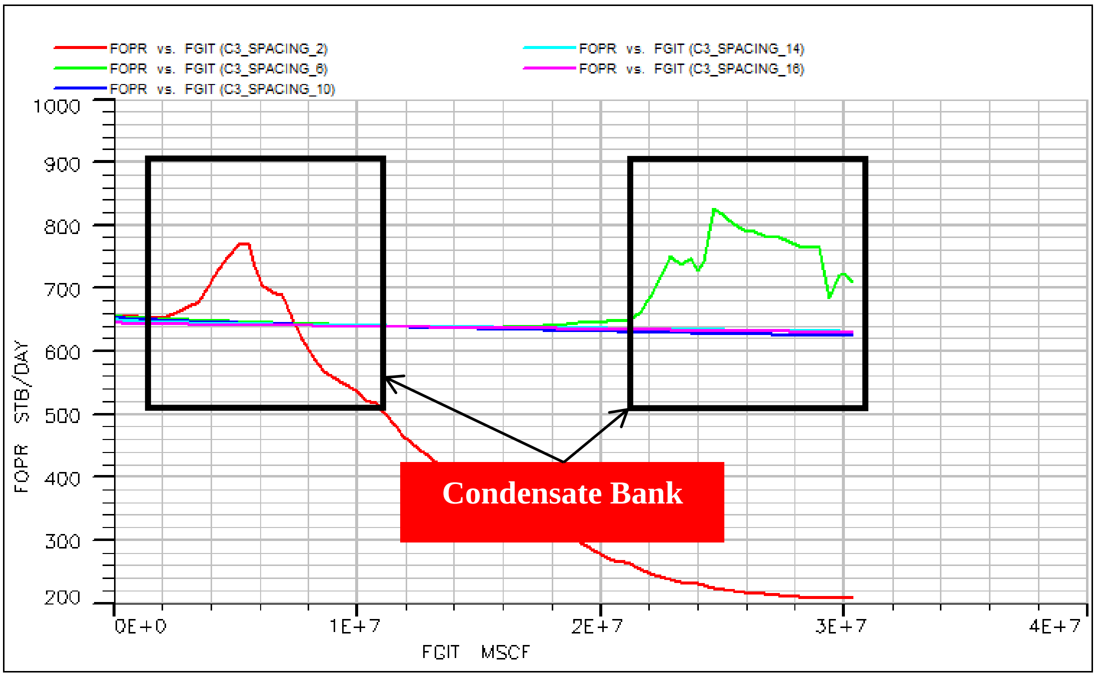

Figure 16: Field condensate production total based on amount of propane injected

Besides shorter distance of well will undergo rapid bypassing compared to further well distance as the reservoir possessed different distribution of permeability and due to gravity override effect. Injection take place at layer 1(130 mD) and 2 (40 mD), while production takes place at layer 3 (20 mD) and layer 4(150 mD). As injected gas is less dense it will preferably travels at the top layer which aided by higher permeability layer as well as gravity override. This will reduce the contact frequency between the condensate and gas and at the same time causing injectant losses. However, as the injected gas density increase which results from the continuous injection and condensate sweeping, it will start to move to downwards where the effect of gravity override is balanced.

4.2.2 Effect of injection rate on condensate recovery

The other injection scheme that effects the condensate recovery is injection rate (Shahvaranfard, Moradi, Tahami, & Gholami, 2009). Three different cases of injection rate has been simulated which is injection of propane which is 2000 MSCF/d, 4000 MSCF/d, and 8000 MSCF/d. The cases are run with different well distance (2 blocks, 6 blocks, 10 blocks and 14 blocks) to observe the relationship between the well distance and injection rate. The injection rate is studied by using 6 well block distance as it shows optimum condensate recovery among other cases.

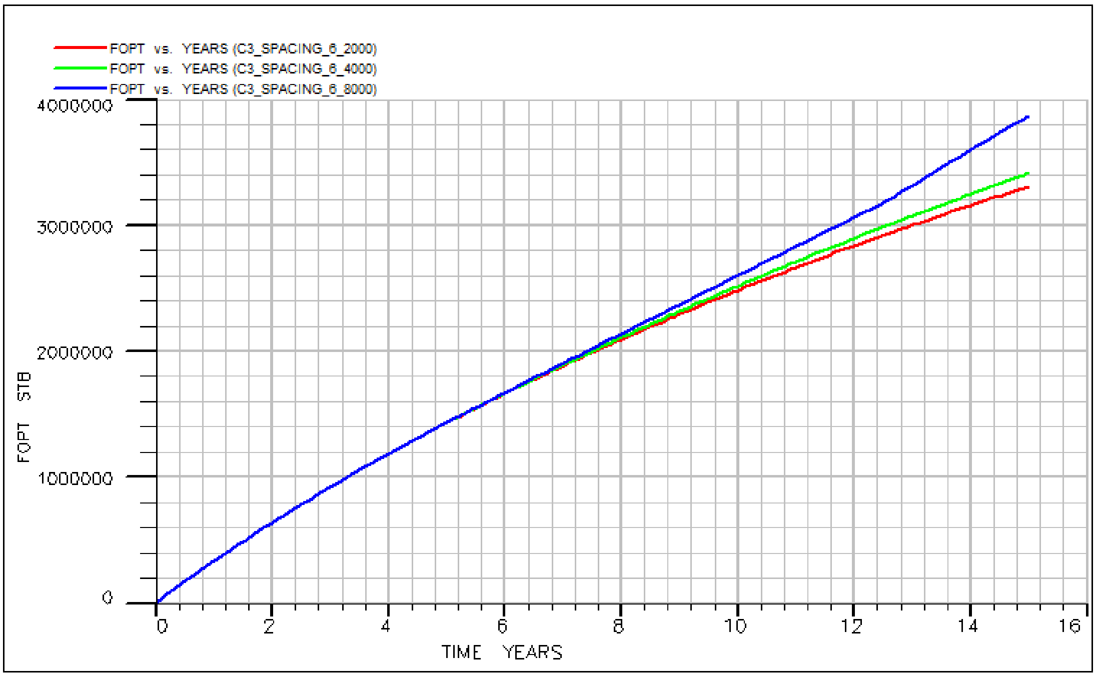

Figure 17: Condensate production total based on injection rates (6 blocks)

Based on Figure 17, it shows that the highest condensate recovery is from the case of highest injection rate (8000 MSCF/d) followed by 4000 MSCF/d and 2000 MSCF/d. Higher injection rate increases the concentration of propane in the reservoir. The high concentration of propane will exert stronger force to sweep higher amount of condensate and evaporates it at the producer. Based on simulation analysis by Amini, Aminshahidy, and Afshar (2011), the injection rate of gases brings considerable effect to the condensate recovery.

4.2.3 Relationship between different well distance and injection rate

Table 12 shows the condensate recovery for each well distance case with different injection rate.

Table 12: Condensate recovery based on relationship between injection rate and well distance

Well Distance	Injection Rate (MSCF/D)	Condensate Recovery (STB)	Difference with Base Case (%)
2	2000	3286856	(+)1.45
(414.8ft)	4000	3199377	(-)1.25
	8000	2990576	(-)7.7
6	2000	3310572	(+)2.2
(1244.4ft)	4000	3418334	(+)5.5
Optimum Case	8000	3871670	(+)19.5
10	2000	3304458	(+)2.0
(2074ft)	4000	3409302	(+)5.22
	8000	3721700	(+)14.9
14	2000	3295960	(+)1.7
(2903.6ft)	4000	3405158	(+)5.0
	8000	3723153	(+)15.0

As for case of shortest well distance (2 blocks), the condensate recovery for 4000 MSCF/d and 8000 MSCF/d is lower than natural depletion (base case). This is due to at high injection rate, the frontal displacement move faster, not giving the injectant sufficient period to sweep most of the condensate along the propagations. As for other well distance cases (6 blocks, 10 blocks and 14 blocks), their condensate recovery increases with increasing injection rate.

Based on all the analysis above, it clearly shows that propane is one of the best alternatives to be considered in enhancing gas-condensate reservoir performance.

CHAPTER 5

CONCLUSIONS

5.1 Conclusions

In this study, the effectiveness of different gas injection has been studied with propane injection as the main focus due to the limited study done on this injectant. As a result of propane injection, it clearly shows that it possessed some characteristics that helps is condensate recovery enhancement:

- Increase the mobility of condensate by reducing the viscosity of condensate.
- Reduce the dew point pressure which helps delaying condensate formation.
- Improve the condensate relative permeability and gas relative permeability with only 0.7 PV of propane injection
- Manage to increase the condensate recovery by 23.8% which is the highest among other conventional gases.
- Methanol addition improves condensate production by 27.7% due to its properties which increase the gas relative permeability and reduce condensate viscosity.

The injection scheme also gives a big impact on condensate recovery as well as well productivity. Based on the relationship between well distance between injector and producer and injection rate, it clearly shows that:

- Horizontal well configuration delays condensate build up and increase condensate recovery
- Sufficient injection rate is needed for different well distance where shorter distance works well with lower injection rate while longer distance needs higher injection rate to increase the production.

Most of the result shows very little differences between one case to another. Considering this study is carried out in a small hypothetical model, the differences could become significant in the real field application study as it is in a larger scale.

5.2 Recommendations

Gas condensate reservoir study is very complex due to its phase behaviour and thermodynamics. There are many areas that have to take into account in the gas condensate study. Based on this study, the focus are more on the technique to mitigate condensate banking as well as to improve the productivity. Thus, based on this study area there are some recommendations to be proposed for further expansion or continuation.

- Detailed experiment which includes swelling test, miscibility test, constant-composition expansion and constant-volume depletion test should be done in order to get correct experimental data which will lead to correct modeling. Detailed experimental data can gives more accurate behaviour of injected gas toward reservoir fluid and its effect towards gas productivity. Besides, simulation should be carried out using real reservoir characteristics to study the exact propagations of injectant in much more complex reservoir characterization.
- Deep studies must be done towards propane injection in gas condensate reservoir as the experimental data is very limited and less published in the literature. More detailed study must be done on the applicability of the propane injection towards different type of gas condensate reservoir as different studies provides different outcome.
- Detailed study most also be done in gas-solvent injection technique as the technique proves to be really efficient in this study. Applying this technique in real field application study would provide a new alternative in order to optimize the gas condensate reservoir performance.
- Aside from phase behaviour, more attention should be given to relative permeability modelling in gas condensate study as the relative permeability prediction near the well bore still remains ambiguous although there are many studies that has been published on this particular area.

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APPENDICES

<u>Example of injection rate calculation</u>

Injection Rate Calculation for CO_2

- Reservoir pore volume = **20.240000 MMrb**
- Bg = **0.564 rb/Mscf**
- 0.1PV = 1/10 x 20.240000 MMrb = **<u>2024000 rb</u>**

The following shows the injection rate for 0.1 pore volume injection of CO_2:

- Convert to surface condition:
  - 0.564 rb/Mscf = 2024000 rb/V(Mscf)
  - V(Mscf) = 3588652.482 Mscf
- Qg = V(surface condition) / t(days)
  - Assumed injection period = 365 days
  - Injection rate, Q = **<u>9832 Mscf/day</u>**

Based on the above calculation, it shows that for each year, 0.1 PV of CO_2 slug will be injected to the reservoir.