MODELING OF A GAS CONDENSATE RESERVOIR

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A THESIS PRESENTED TO THE DEPARTMENT OF PETROLEUM ENGINEERING
UNIVERSITY OF BENIN, BENIN CITY, EDO STATE, NIGERIA
IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE AWARD OF MASTER OF ENGINEERING

NOVEMBER, 2022

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A THESIS APPROVED BY THE DEPARTMENT OF PETROLEUM ENGINEERING

APPORVED

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CERTIFICATION

This is to certify that the project was written by **EYO, EYO BASSEY** with matriculation number **PG/ENG/1918204** in partial fulfillment of the requirements for the award of Master of Engineering (M.Eng.) Degree in Petroleum Engineering.

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EXTERNAL EXAMINER

DEDICATION

This work is dedicated to the Almighty God for his grace and wisdom and also to my family for all their love and support all through from day one to this point.

ACNOWLEDGEMENT

First and foremost my thanks goes to God Almighty who by His grace and favor guided me all through my stay at the University of Benin, Benin Campus.

Secondly, I also want to use this opportunity to express my heartfelt gratitude to my Supervisors, my lecturers, the faculty staff for the knowledge they imparted, the Head of the Petroleum Engineering Department, the Coordinator of the post graduate studies of the Department of Petroleum Engineering Department through whose effort contributed to a successful academic sessions

I also thank my Late Father Chief Eyo Bassey, my beloved mother Mrs Henrietth Eyo, my Sisters Laura, Eka, Bassey and Brothers Mr Adolphus, my friends Mr Nathaniel and wife, Pastor Steve, Emeka and everyone that contributed in no immeasurable way through financial assistance and prayers and words of encouragement to the smooth running of my program. May The God almighty bless you all.

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ABSTRACT

Gas condensate is very important reservoir fluid because it is made up of a mixture of low density mixture of hydrocarbon in which during processing it yields other products like associated dry gas and also creates condensate oil after being extracted. A condensate reservoir exhibits a unique characteristic which make it special and at the same time difficult to recover due to liquid banking which is formed as a result of pressure and temperature change during production. In other to optimize production in a gas condensate reservoir proper attention must be paid to its phase behavior.

The objective of this study is to model a gas condensate reservoir. The approach used in this study is the compositional analysis (the use of software) to determine the components of the gas condensate and compared with experimental approach which involve constant composition expansion (CCE) test and constant volume depletion (CVD) test. CCE provides information about the dew point, relative volume of fluid and condensate liquid while CVD provides information about condensate oil saturation and condensate oil and gas recovery. Finally the empirical method which is the equation of state model (EOS) using a simulation software to match the results gotten from the different approaches.

The result of the study from compositional analysis simulation shows that the P-T diagram of critical pressure, temperature can be constructed and its results shows that composition significantly varies as a function of fluid phase behavior and also affects the producing sequence of a condensate reservoir. It as well pointed out the need to conduct more studies on characterization in other to be able to make the best recovery choice for optimal production from a gas condensate reservoir.

CHAPTER ONE

INTRODUCTION

1.1 GENERAL INTRODUCTION:

Energy is one of man’s basic need as its importance cannot be overly emphasized and the demand for energy is on the rise on the daily basis therefore it is of necessity to ensure that this basic need is meet and this has led to the invention and discovery of various sources and forms of energy ranging from wind energy, solar energy, hydro, fossil fuel etc. though the sources where these energy forms are derived are numerous in most cases they have to be converted from one form(it’s initial state) to a useable form or state. This applies to fossil fuel which petroleum and natural gas products is one of it and it involves several processes from exploration to production and getting it to the market where consumers can access it. The energy of concern in this work is fossil fuel narrowed down to petroleum and further narrowed to gas condensate as a component part of petroleum. A gas condensate are low density mixture of hydrocarbon liquid separated from natural gas and consist of higher molecular weight hydrocarbons that exist in the reservoir as a constituents of natural gas but are recovered as liquid produced out in gas processing plant. In recent years the global move to use natural gas is an evolution in energy market that is changing economy and the environment for the better (Tillerson, 2015). Gas condensate it is a very important and sort after petroleum liquid for geologist. large field deposits has been discovered in various part of the world such as Arun field in Indonesia, Shtokmanovskoye field in Russia, North field in Qatar (South Pars field in Iran). Cupiagua field in Colombia, Khuff gas-condensate reservoir known as north field in Qatar and south pars field in Iran. Khuff is the world biggest gas-condensate reservoir in the world, holds between 1000 – 2000 trillion cubic feet initial gas in place and 30 to 70 billion barrels of condensate in place. It is called a condensate because it is condensed out of gas produced by a well. From its chemistry point of view it can be defined as a straight chain alkanes in the C2 to C6+ range that condenses out of gas when pressure drop is sufficiently low. Gas condensate is very important reservoir fluid because it is made up of a mixture of low density mixture of hydrocarbon in which during processing it yields other products like associated dry gas and also creates condensate oil after being extracted. It is of uttermost importance to measure condensate as it enable the well engineer to know the types of fluids that are present along with their physicochemical characteristics and this information are obtained with the aid of Pressure, Temperature and Pressure (PVT) analysis on fluid sample of the reservoir and also obtaining preliminary values of properties such as compositional analysis, molar weight (MW), condensate to gas ratio, maximum retrograde condensation (MRC), dew point are also very important.

A gas condensate reservoir is a reservoir initially containing natural gas that will precipitate hydrocarbon liquid (retrograde condensate) during pressure depletion. It can also be defined as an underground sources from which condensate can be produced. Condensate reservoir can be found and located at different locations across the world as it is not limited to a specific place or region, the frequency of its discovery has increased due to the act of drilling wells with deeper depth. Gas condensate reservoir are usually discovered as a single phase but during production as the reservoir experiences a decline in pressure, a compositional change also occurs which makes the system very difficult to handle, because of its complex nature production in gas condensate reservoir is immensely affected by the simultaneous flow of liquid and gaseous phases near the wellbore and possibly water, phase redistribution in and around the wellbore and also retrograde condensation. This pressure depletion when it is below the dew point pressure, liquid condenses out of the gas phase initially existing in the reservoir this continues until a condensate bank is formed in the near wellbore, this condensate bank increases in radius as the reservoir pressure inside the reservoir drop below the dew point pressure (El-Bandi and McCain, 2000). It is also on record that retrograde condensate reservoir produces gas to liquid ratio of about 3MMCF/STB to 150MMCF/STB and condensate surface yields at a range of 7MMCF/STB to 333MMCF/STB (McCain, 1990).

The major problem with the formation of condensate banking is loss in productivity which also include loss in well deliverability, loss of most of the condensate oil and reduction in the effective gas permeability. Gas condensate are usually located between the critical temperature and the cricondentherm on the reservoir fluid's Pressure- Temperature (P-T) phase diagram. However the major problem with the formation of condensate banking is loss in productivity which also include loss in well deliverability, loss of most of the condensate oil and reduction in the effective gas permeability. Gas condensate are usually located between the critical temperature and the cricondentherm on the reservoir fluid's Pressure- Temperature (P-T) phase diagram. Historically, there are three main methods for gas condensate recovery (Hernandez et al, 1999): natural pressure depletion to the abandonment Pressure, full pressure maintenances by gas cycling and partial pressure maintenance by means of gas cycling after previous natural depletion, though the simplest of the three natural depletion will result in rapid well productivity reduction below the dew point, resulting from the formation of a condensate bank near the well bore. In order to reduce the impact of the condensate accumulations near the wellbore, gas cycling is usually employed to prevent liquid. Condensation and to also vaporize dropped out liquid. From a technical viewpoint, full pressure maintenance may provide maximum condensate recovery.

1.2 PROBLEM DEFINITION

- Being able to obtain a representative formation fluid sample that will be used for compositional and Pressure, Volume and Temperature (PVT) analysis is crucial, as ensuring that maintaining a monophasic sample which is as close as possible to that of the actual reservoir condition.

- The challenge of how maximize reservoir fluid recovery with a minimum amount of retrograde condensation at reservoir condition. It is documented that flow behavior of gas condensate reservoir differs from the conventional oil well system in several phases especially in phase distribution and behavior (Jamiolahmady et al 2000).

- Understanding of phase and fluid flow behavior relationship is essential if we want an accurate engineering computations for gas condensate system e.g., well testing, estimating of reserve and predicting of production of production trend.

- The profitability of gas condensate development venture is dependent on four factors like field location, local markets for separated gas and condensate, phase behavior of reservoir fluid and government tax system.

- Good Knowledge of reservoir simulation and computer literacy.

- Getting the total number of compositional gases present in a condensate gas is impossible which in a way leave room for error with regards to predicting its phase behavior.

1.3 AIM OF STUDY

The aim of this study is to come up with a model which best describe a condensate reservoir so that the best optimum production can be easily decided.

1.4 OBJECTIVES OF STUDY

- The purpose of this study is to perform a compositional modeling of as condensate reservoir using Pressure, Volume and Temperature system to establish its behavior during different conditions of reservoir depletion, development and pressure.
- To use compositional models, principles and assumptions to model the behavior of condensate reservoir system
- To conduct Constant Volume Depletion (CVD) test
- To conduct Constant Composition Expansion (CCE) test

1.5 SCOPE OF STUDY

The scope of this work is to determine the phase behavior properties of a condensate gas reservoir using

- Equation of state model
- To use a PVT modelling software to validate the result.

1.6 LIMITATIONS OF STUDY

In the course of this study some sets of assumptions were made which may not be applicable to live field challenges, this however was done in order to idealize the model in order to achieve the projects goal.

The following are the limitations:

- The compositional equation of state remains valid across the reservoir.
- Gas compositions are the same in the entire reservoir.
- Predicted isothermal conditions
- The effects of capillary pressure we neglected

CHAPTER TWO

LITERATURE REVIEW

2.1 PETROLEUM RESERVOIR FLUID AND CLASSIFICATION

A petroleum reservoir fluid is composed of mainly of hydrocarbon constituents, water is also present in gas and oil reservoir in an interstitial form but the influence of water on the phase behavior and properties of hydrocarbon fluid in most cases is of minor consideration. Reservoir fluid is composed of thousand s of compounds but for easy application in the industry it is classified into various groups such as dry gas or lean gas, wet gas, volatile black oil and gas condensate etc.

Dry gas or Lean gas: is a natural gas with so little natural gas liquid that is nearly all methane with only minor amount of ethane, propane, butane and little or no heavier hydrocarbons.

Gas condensate: condensate gas liquid are generally straight chains alkanes C2 to C6+ range that can condense from gas when the temperature and pressure drops sufficiently low to form a liquid phase.

Volatile Black Oil: These are generally easily evaporated oil, usually has an API gravity above 40^{o}

Wet Gas: wet gas as gases containing condensable hydrocarbons or other liquids or hydrocarbons gases with heavier ends (C2+).

2.2 RESERVOIR FLUID COMPOSITION

According to various hypotheses regarding the formation of petroleum from organic materials which we will look into in the next section, these view suggest that the composition of a reservoir fluid depends on the depositional environment of its formation, its geological maturity and migration path from the source to trap rocks. Therefore fluids trapped in reservoir may be of different composition owing to the fact that it was formed at different geological time and environment, hence reservoir are mainly composed of hydrocarbon molecules of small and medium sizes and some light hydrocarbons compounds like nitrogen, carbon dioxide whereas oil is composed of heavier molecules. The composition of a reservoir is also affected by its temperature and pressure which determines the compositional grading etc.

2.3 ORIGIN, SOURCES, FORMATION AND ACCUMULATION OF GAS CONDENSATE RESERVOIR

Origin:

Crude oil and fossil fuel is scattered throughout the earth crust which is divided into chronological strata that are based on the distinctive system of organic debris as well as fossils minerals. Carbonaceous natural materials and products such as coal, crude oil and natural gas occurs in many of these geological strata. The actual origin of fossil fuel within this formation is still subject to debate and still open to further debate.

The study of the origin of a condensate reservoir is based on the study of carbon isotopic composition of natural gas which is the main geochemical parameter basis to successfully study the origin and maturity of a gas condensate. Carbon isotopic composition of methane is controlled by maturity and as well depend on the organic matter type of source rock. The presence of coal source rock widely distributed, lithology is mainly sand and mudstone interbedded, coal seam but basically the presence of a mature coal rock widely distributed is the major factor for the formation of gas condensate reservoirs.

Formation:

From the theory of the formation of fossil fuel organic matters are important intrinsic geological elements, the environment of deposition and depth of burial, temperature and pressure, time, maturity and several other factors plays major role in its formation. There are two main theories for the origin of carbon fossil fuel which ae the Abiogenic or Abiotic theory and Biogenic or Biotic theory

Abiogenic or Abiotic Theory: abiogenic theory proposes that carbon deposit from when the planet was formed at the depth of hundreds of kilometers beneath the earth crust converts to hydrocarbon at a high temperature and pressure without the aid or activities of bio-organisms. However experimental studies and thermodynamic calculations confirms that n-alkanes do not evolve methane at pressure typically found in sedimentary basins. The abiogenic origin rather suggest deep generation.

Biogenic or Biotic Theory: biotic theory proposes that remnant of buried plants and animal sediments accumulating over the materials compresses and covers it at a depth of several hundred meters beneath the earth with increasing temperature and pressure hydrocarbon fuel begins to form. Further experiments proofs the presence of plant and animal materials like chlorophyll, keratin etc. (Holm and Charlou, 2001; Sherwood Lollar et al.,2002 Kieft et al.,2005; Glasby, 2006; Kvenvoken, 2006; Speight, 2014a.)

The geologic time scale diagram

The same also applies to the formation of a condensate gas reservoir with a little difference being that the gas content in hydrocarbon is far more than that of the liquid and the creation condition of the liquid phase, as stated before the impact of high temperature and pressure cannot be over stated. The necessary condition for the formation of a gas condensate reservoir is that the formation pressure is higher than the dew point pressure, formation temperature is between the critical temperature and the cricondentherm.

High abundance and widely distributed mature coal source rock are the important factor for the formation of gas accumulation formation, this could be shallow marsh lake, coal organic source rock.

High quality reservoir is the main controlling factor for the enrichment and the high yield of gas condensate; the presence of fan delta and braided river delta, the reservoir physical property is controlled by phase belt and diagenesis, development of multiple secondary porosity zone such as dissolution pores mainly feldspar, debris and carbonate interstitial material, mud and coal seam

A thick mudstone cover; good cap rocks helps to effectively maintain the proportion of oil and gas and stable critical temperature and pressure.

Accumulation:

A basic requirement for oil and gas formation is a source rock which is for the accumulation or storage of the fluid and a cap rock to prevent its escape. The rock properties like porosity and permeability is also important but recent discovery of oil and gas in shale formation present a contradictory view of a typical reservoir rock properties (Speight, 2013d, Speight, 2014a). A good reservoir rock must possess qualities like fluid holding capacity otherwise known as porosity and transmitting capacity known as permeability which is as a result of the pore space between rock grains, opening formed by fracture. Pores generally account for the bulk storage. Most often oil and gas can be formed

2.3.1 Properties/ Nature of a Gas Condensate Reservoir and Classification

A gas condensate reservoir has the following properties:

- Gas oil ratio: a condensate gas oi ratio is between 8,000 to 70,000 SCF/STB but lower gas oil ratio is approximately 3,300SCF/STB and upper limit is over 150,000SCF/STB. Condensate gas oil ratio increases due to heavy components loss. (Moses, 1986; Moses and Donohoe, 1987).
- Condensate is an oil but an extremely light one, it can be in a liquid form or gaseous form depending on the temperature and pressure at the time when it is released, with an API usually above 40^o. (Whitson and Brule, 2000)
- It composition is dominated by saturated hydrocarbons like butane, pentane and hexane etc. and also contain polycyclic aromatic hydrocarbon.
- It contains impurities like methane, ethane, nitrogen, carbon dioxide etc.
- The fluid color varies from brown, light yellow to colorless, greenish and orange.
- Has a low density and low viscosity
- Has a very low solubility in water and are highly volatile.
- It’s gas oil ratio is the basis for its classification as either a
    I. Low content gas condensate
    II. Condensate oil
    III. High gas condensate oil
    IV. Condensate gas reservoir

The two main characteristics that distinguish all gas-condensate reservoirs from other type of hydrocarbon systems are introduced by Raghavan and Jones, (1996) as follow:

- The condensation of the gas at reservoir conditions during isothermal depletion.
- The retrograde and re-vaporization of the condensate liquid by further decline in pressure (Raghavan and Jones, 1996).

2.3.2 Environmental Impact of a Condensate Gas

Condensate is highly inflammable, explosive and also capable of causing asphyxiation when there is a spill, it is much more difficult to contain but on the other hand it evaporates easily than normal crude oil if spill occurs on sea it floats on the surface due to its low density and evaporates quickly for this reason it is classified as “non-persistent” according to IOPC Funds definition. For this reason compensation for a condensate gas spill is not covered but it I under hazardous and noxious substance convention when it spills.

2.3.3 Uses of Condensate Gas

Here are the basic uses of a condensate gas to mention but a few

- Gas condensate can be used fuels like gasoline,
- it contains key element for the making of plastics
- It can be used as an effective dilutant, used to stabilize heavier crude oil and get the heavier crude oil to its desired weight before it is being transported to the refinery.

2.4 PHASE BEHAVIOR OF A GAS CONDENSATE

Hydrocarbon reservoir fluid is made up of many components mixture of organic compounds that can either liquid or gas or a combination of both gas and liquid. To appropriately represent it and understand the changes that occurs when there is an increase or a decrease in temperature and pressure in the reservoir, using a phase diagram is assumed to be the best method as it gives more information on the behavior of the reservoir fluid during production and this is determined by the shape of its phase diagram and the position of its critical points. To the production engineer and the reservoir engineer, the phase behavior of the reservoir and its characteristics at its early life is very important as it gives the engineer a clue on the prediction of future occurrence, development and performance of the reservoir.

Petroleum reservoir is classified into two, the gas and oil reservoir based on the phase diagram

2.4.1 Classification of Gas Reservoir Fluid

Generally, when reservoir temperature is higher than hydrocarbon fluid critical temperature the reservoir is considered as a natural gas.

There are three types of gas reservoir namely

- Retrograde gas
- Wet gas
- Dry gas

All the gas reservoir fluid types can be distinguished based on their stock tank liquid gravity (API), the color of liquid, heptane-plus, producing gas oil ratio, compositional analysis of fluid mixture, initial formation temperature and pressure and production surface temperature and pressure. Their differences in phase behavior lead to different physical properties of each reservoir.

2.4.2 Phase Diagram

Definition of Terms Associated with a Phase Diagram:

- Two phase Region or Phase Envelop: it is a region enclosed by the dew point curve, where gas and liquid coexist in equilibrium phase.
- Dew Point: it is pressure at which the vapor phase is separated from the two phase region.
- Critical Points: is the critical pressure (P_c) and critical temperature (T_c) of the mixture at which liquid and gas phases properties are equal.
- Cricondenbar : Is a maximum pressure above which only liquid or gas can be found
- Cricondentherm: is the maximum temperature above which only liquid or gas can be found
- Quality Lines: it is the dashed lines inside the phase diagram that define the temperature and pressure for equal volume of liquid

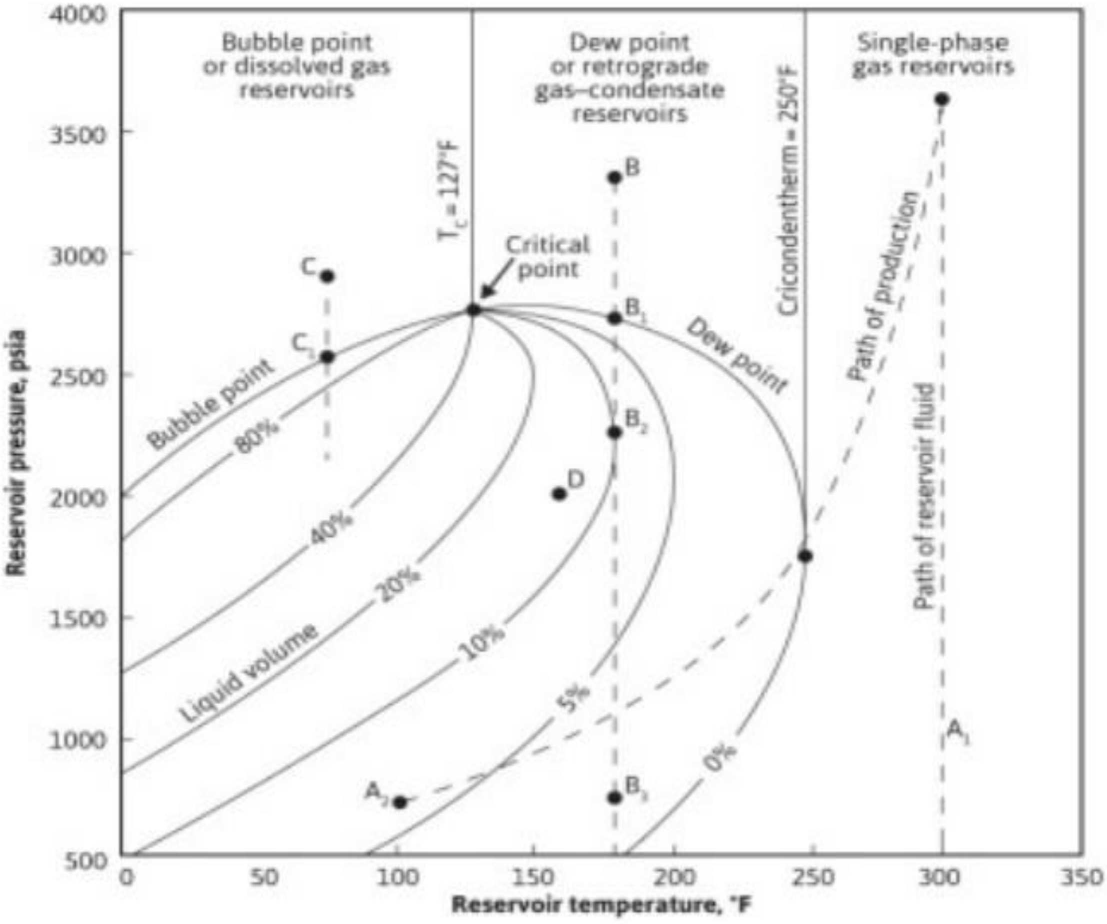


Figure 2.1: Phase Diagram of Reservoir Fluid with both single and double phase, Source: B. C. Craft and M. F. Hawkins (1959)

The phase diagram shows both the single phase and the double phase gas reservoir, if we follow the isothermal path B-B_1-B_2-B_3. As we move from B to B_1 the pressure is at the dew point, further move away from B_1 to B_2 the pressure drops below the dew point and a liquid phase is formed and further reduction in pressure to B_3 lead to vaporization back to a single phase

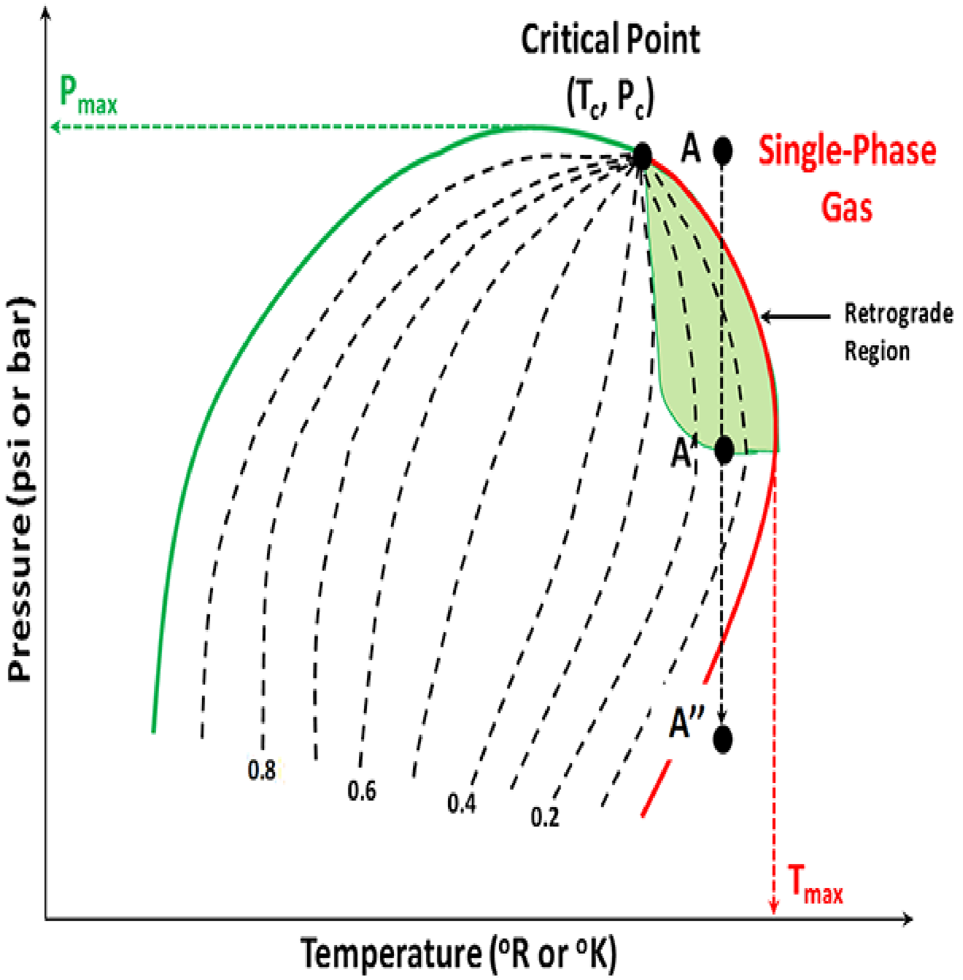


Figure 2.2: Phase Diagram of a Gas Condensate Fluid Showing the Retrograde Region

Source: George King

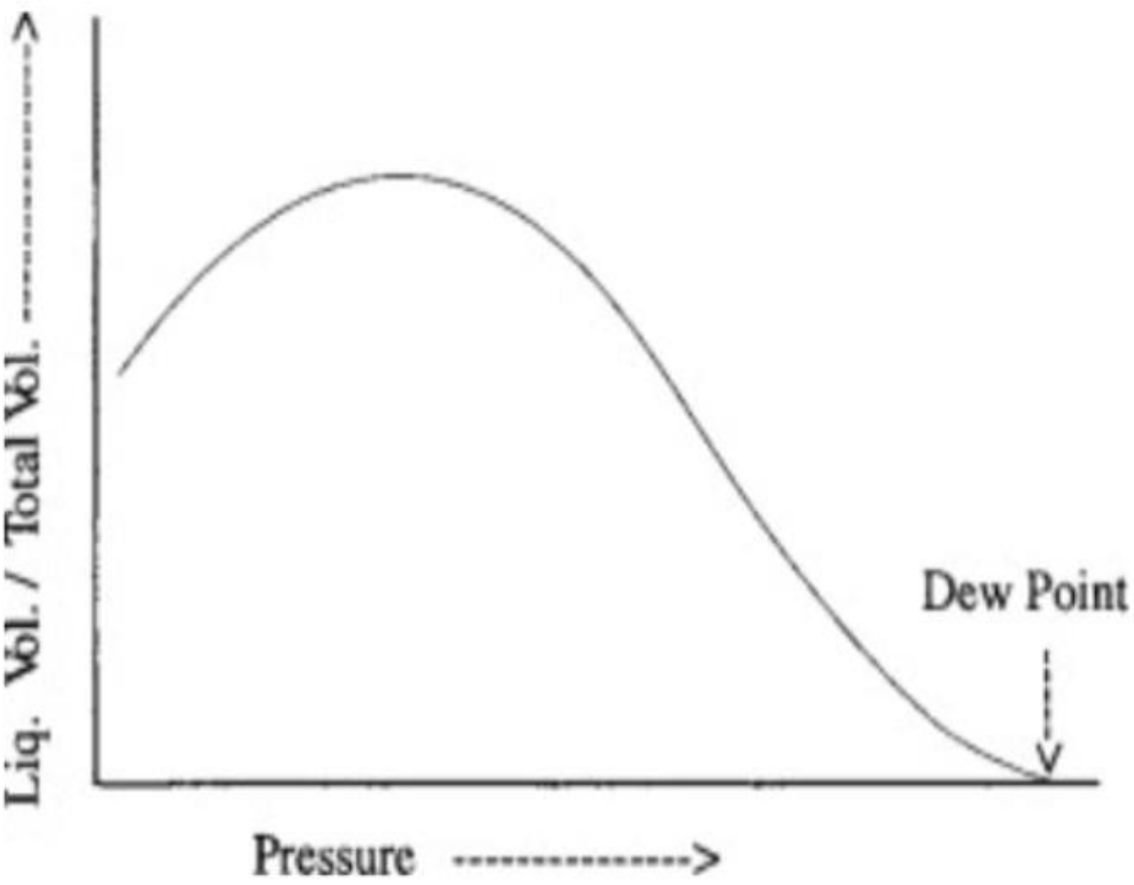


Figure 2.3 Liquid Drop-out Behavior of Gas condensate, Source: George King

The figure above shows the liquid drop out behavior of a gas condensate. The amount of liquid dropout is dependent on the richness of the condensate fluid, it riches it's maximum and then decreases by vaporization during pressure depletion. It shows however that when pressure drops sufficiently low that condensate can be recovered by vaporization, but the original phase diagram will no longer be valid as the system composition has already under gone changes during the production period.

2.5 PHASE BEHAVIOR

Gas-condensate reservoir behavior is a function of two parameters of phase envelope of the fluid and condition of the reservoir (Roussennac, 2001). These phase envelop diagram consists of bubble point line where the first bubbles of gas vaporizes from the liquid content, dew point line where the first droplet of liquid condenses from the gas phase. The bubble point line and dew point line meets at the critical point. The critical point represents a state where all properties of gas and liquid phases are equal (Ahmed, 2010; Craft and Hawkins, 2015). The cricondentherm and cricondenbar are maximum temperature and pressure respectively that above them the mixture is only in the form of gas or liquid exists as only one phase.

As the reservoir produces, the formation temperature normally does not change (isothermal behavior) but the average reservoir pressure and flowing bottom hole Pressure varies. In gas condensate reservoirs the fluid is initially in single phase (point B on the Figure. 2.1), which consists of predominantly methane “C_1” and other short chain hydrocarbons. Isothermal pressure depletion to below the dew point line causes heavy end hydrocarbons to drop out of the solution and form the liquid inside the reservoir (Between point B_1 and B_2). The liquid phase known as condensate liquid has zero mobility ratio to the associated gas between B_1 and B_2. At this point only gas flows where the heavy end hydrocarbons are left behind in the reservoir. This phenomenon causes a compositional changes of the reservoir mixture.

Further reservoir pressure decline lead to further accumulation of the liquid to the maximum level at point B_2 (known as critical oil saturation). At this point condensate liquid have enough energy to overcome the gravity segregation in porous media and move towards the wellbore simultaneously with gas phase. The dashed lines on the phase diagram represents the percentage of the vapor phase that is gas phase in the mixture. Additional reduction of reservoir pressure, move down point B_2 towards point B_3. Between point B_2 and point B_3 the accumulated condensate liquid vaporizes and turn back to gaseous state. At point B_3 most of the condensate liquid re-vaporizes and the reservoir fluid returns to gaseous form only (100% vapor). This thermodynamically anomalous phenomenon was first noticed by Kunene, (1892) and called it “Retrograde Condensate”.

The permeability of the reservoir formation is drastically affected by condensate drop out and the gas flow even the drawdown behavior of the reservoir near the wellbore region changes as well. The amount of liquid phase changes is not only dependent on compositions of the mixture alone but also on other reservoir properties and production strategy (depletion model of recovery). The amount of generated condensate normally determines if the reservoir is lean or rich gas-condensate. If the reservoir generates small amount of liquid normally less than 100 barrels per million square cubic feet the gas-condensate known as lean whereas if the amount of liquid between 150 to 300 barrels per million square cubic feet its known as rich gas-condensate reservoir.

2.6 DRAWDOWN BEHAVIOR

A reliable model for accurate prediction of phase and drawdown behavior is of high demand in the industry for well performance and financial planning. If depletion drive system is selected as mode of recovery for any hydrocarbon reservoirs, the energy for producing hydrocarbon on the surface comes from the difference between formation pressure gradient (reservoir pressure) and well bore flowing pressure (P_{wf}) of the well. The bottom hole flowing pressure is the pressure at the formation of the wellbore of the producing well (Ahmed, 2010, p. 354). In gas condensate reservoirs with depletion mode of recovery when reservoir pressure declined due to the production, well bore flowing pressure of the wells need to be changed to compensate reservoir pressure decline, and keep the pressure gradient to meet predetermined rate on the surface. The relationship between a well constrained well bore flowing pressure and the rate of the production is known as well deliverability (Fevang, 1995).

When the well bore flowing pressure keeps decreasing and reaches the point known as dew point pressure that is the point where the first drop of liquid evolves from gas, the physics of the flow inside the reservoir is changes and three flow regions are established, these three main flow regions as proposed by Fevang, (1995) extends from wellbore outward and these regions are gradually changing during lifetime of a gas-condensate reservoir. The bottom hole flowing pressure controls the production of hydrocarbon fluids on the surface. If the bottom hole flowing pressure is above the dew point pressure, the fluid in the reservoir will remain as a single phase and regions 3 will exist if the bottom hole flowing pressure falls below the dew point pressure, region 2 starts to grow and two phases of gas and condensate (oil) exist. In region 2 only gas flows toward the wellbore and condensate (oil) phase is immobile. The saturation of condensate phase is increasing with time and reaches critical condensate saturation (S_{or}). When the maximum S_{or} is reached the transition starts from region 2 to region 1, where both phases are flowing toward the wellbore.

Region 1 is the main source of deliverability loss in gas-condensate wells because of higher pressure drop in this region caused by condensate accumulation. Condensate accumulation in region 1, would decrease gas phase permeability to flow sharply. The amount of condensate saturation in region 1 is a function of fluid properties that entering this region and the production rate (Fevang, 1995; Roussennac, 2001).

These properties consist of viscosity of the original mixture, formation volume factor and solution oil to gas ratio. Condensate drop out further apart the behavior of the gas condensate reservoir mixture from ideal gas law. This deviation is determined by compressibility factor (Z factor), among the fluid properties condensate (oil) viscosity in each depletion stage has the highest uncertainty for the purpose of the modelling in such reservoirs accurate Z factor prediction also plays a key role for reliable modelling of gas-condensate well deliverability (Fevang, 1995; Fevang and Whitson, 1996; Mott, 2002; Whitson and Kuntadi, 2005).

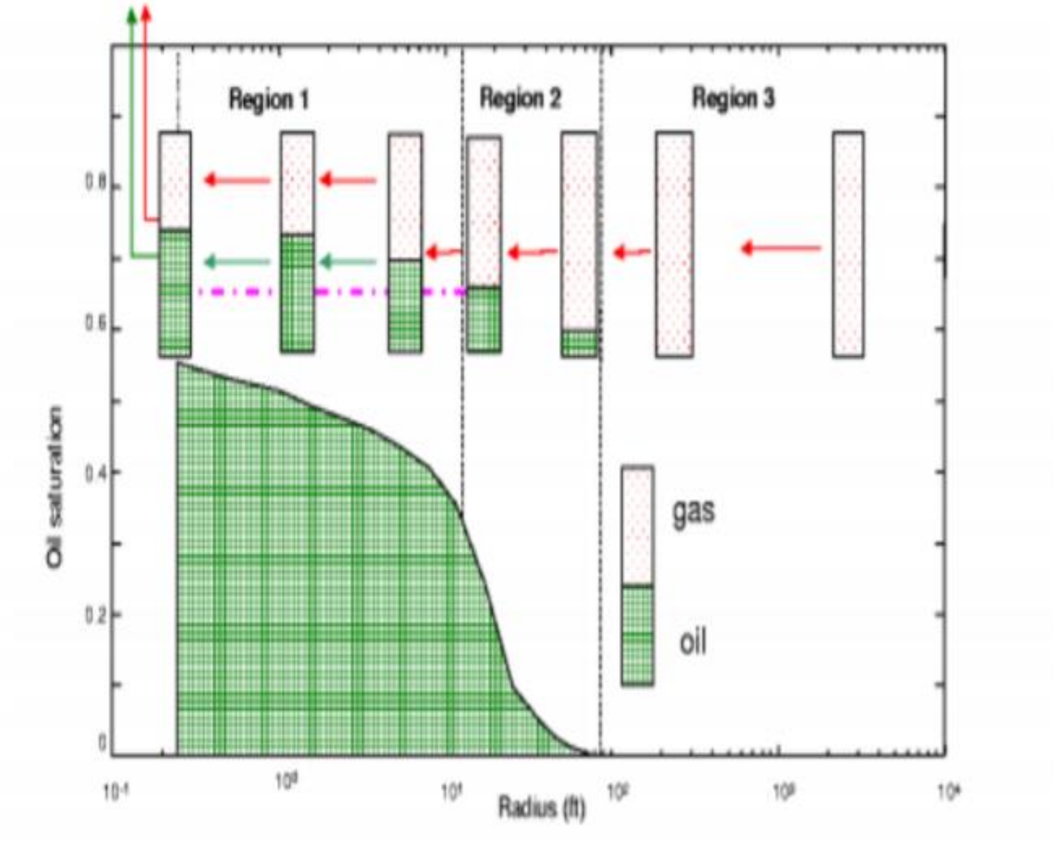


Fig 2.4 Gas Condensate Three Region Flow Behavior (Roussennac, 2001)

2.7 WELL DELIVERABILITY

Extensive research have been conducted in general well deliverability modelling of gas condensate reservoirs but there are still some outstanding issues and shortfall in this area. Modelling and calculation of well deliverability in gas condensate reservoirs is a historical issue without simple solution (Fevang and Whitson 1996). Reliable calculation of well deliverability requires great understanding of phase and drawdown behavior in reservoir condition. Gravity segregation of the heavy hydrocarbon components in gas-condensate reservoirs, triggers the formation of the heavy ends below the saturation pressure. The concept of well deliverability modelling requires an accurate estimation of fluid phase behavior to determine the reliability of the developed model. The phase behavior of gas-condensate mixture is one of the most complex due to existence of 10 to 15% of heptane and heavier hydrocarbon components in the mixture. Estimating fluid properties of such system to develop phase envelope require advance knowledge of each composition as a function of pressure and temperature. However Rawlins and Schellhardt, (1936) developed an empirical equation known as backpressure equation, that defines relationship between the gas flow rate and some constraint average reservoir pressure (P_R) and bottom hole flowing pressure (P_{wf}). Their empirical equation $q_g = (P_R{}^2 - P_{wf}{}^2)^n$ is widely accepted in petroleum industry for estimating gas flow rate (Eilerts, Sumner and Potts, 1965; Gondouin, Iffly and Husson, 1967; Fevang, 1995; Akhimiona and Wiggins, 2005; Al-Attar and Al-Zuhair, 2009; Ogunrewo, 2014). The equation also referred as backpressure equation or well deliverability equation. The well deliverability equation is valid for calculating gas flow rate for reservoir pressure of less than 2500 psia. If the average reservoir pressure (P_R) is greater than 2500 psia, then ΔP^2 should be replaced by ΔP. If the coefficients of n and C are known, the gas flow rate at the surface for any bottom-hole flowing pressure (P_{wf}) can be estimated from well deliverability equation. Plotting q_g vs. P_{wf} results in constructing Inflow Performance Relationship (IPR) curves. IPR curve is demonstrating ability of the reservoir to produce gas/condensate to the wellbore (Sousa, Garcia and Waltrich, 2017). In gas condensate reservoirs undergoing depletion, accumulation of condensate drop out near wellbore region creates condensate blockage, which introduce extra pressure drop. This would results in well productivity reduction at the surface. Condensate blockage and its effect on well deliverability should be considered for reliable and accurate prediction of gas condensate well performance. Introducing condensate blockage into well deliverability equation has been an active area of research for many years and will not be considered here. The most common approach of modelling well deliverability of gas-condensate reservoir and predicting well performance is through reservoir simulation studies. The simulation models incorporate the rock and fluid properties to predict the dynamic influence of condensate blockage over gas and condensate production (Fan *et al.*, 2005). The standard compositional industry simulator is Eclipse – 300 that enables better prediction of well deliverability by using small grids near wellbore region, where condensate blockage exist (Fan et al. 2005).

2.7.1 Factors Affecting Near Wellbore Behavior and Deliverability

To effectively determine the deliverability of a gas condensate reservoir it is very important to understand the factors influencing its behavior. Various research work has been done on this topic in order to determine the underlying factors that affect the deliverability of a condensate gas wells, such factors are;

- The interfacial tension
- The relative permeability
- The capillary forces or number

2.7.1.1 Interfacial Tension:

Interfacial tension of a gas condensate can be define as the force that holds the surface of two phases together. Phase deliverability of a gas condensate reservoir is inversely proportional to its interfacial tension. It has a very close relationship with relative permeability, experimentally it has been proven that if interfacial tension is reduced relative permeability increases and hence an increase in well deliverability is observed. Gas reservoir and gas condensate reservoir shows the same behavior at a low interfacial tension values but the only difference is that the gas condensate reservoir produces more liquid than the gas reservoir because of the difference in critical point.

2.7.1.2 Relative Permeability:

Relative permeability is a dimensionless parameter and a ratio of effective permeability to absolute permeability at a given fluid saturation. Whenever there are multiple phase present in a reservoir the need to calculate relative permeability is expedient to predict the production of hydrocarbon phase in the reservoir. In a gas condensate reservoir when pressure drops below its dew point pressure, liquid condensate forms from the gas thereby forming a liquid bank around the wellbore a portion of condensate get trapped in the pores and causes a reduction in flow and the relative permeability is also reduced. The reduction of relative permeability is adversely affects the productivity of the well.

2.7.1.3 The Capillary Number:

Capillary number can be defined as the ratio of viscous forced to capillary force. Capillary force occurs due to frictional forces between the walls of the wellbore and the flowing fluid as the pressure in the reservoir drops this causes liquid to be trapped in the pores in the wellbore which prevents free flow of fluid thereby leading to liquid banking. There is a relationship between capillary forces, relative permeability and interfacial tension. An increase in capillary forces and relative permeability of a gas condensate reservoir increases and improves the deliverability of the reservoir, while a reduction in the interfacial tension with respect to capillary forces increases the well deliverability and vice versa.

2.8 OPTIMAL PRODUCTION AND RECOVERY IN GAS CONDENSATE RESERVOIR

The performance of a gas condensate reservoir is loosely linked to its phase behavior, the possibility of maintaining the pressure of gas condensate reservoir above the dew point can prevent the formation of a liquid bank. Having a good understanding of the phase behavior gives an idea of how to deal with this kind of gas reservoir because the phase behavior determines the fluid chemical composition. The degree to which a condensate occurs in a gas condensate is dependent on the rock permeability and the presence of heavy hydrocarbon content. Pressure draw down can as well be carried out to achieve a stabilized pressure to enhance wellbore deliverability with the aid of other remedial procedures, this can be done either be chemical or mechanical method.

2.8.1 Chemical Treatment

The chemical treatment can be achieved by several methods and are used to repair damage due to condensate banking and can as well be used all through the life of the well. Firstly, the method functions by shifting the interfacial tension to enhance to the relative permeability of gas by injecting weak acidizing organic solvent like methanol into the formation. It works by extending the time it takes to form condensate banking. It effectiveness is affected is controlled by the type of rock, post treatment of methanol residual saturation and reservoir heterogeneity.

Secondly, the use of chemicals to increase the temperature of the accumulated liquid above its vapor phase through exothermic reactions.

Thirdly, the injection of carbon dioxide (CO_2) or Nitrogen (N_2) has been discovered to improve gas condensate as it causes a change in the PVT fluid behavior in the reservoir by reducing the tow phase envelop. This technique is very expensive to implement and requires a close monitoring of operational management.

Fourthly, by hydraulically fracturing the formation beyond the liquid bank can temporarily increase the productivity of the well as a result of condensate accumulation around the fractured zone in the reservoir.

2.8.2 Mechanical Treatment

The mechanical method of condensate treatment for condensate recovery can as well be acknowledged as an enhancement recovery method, it is achieved by the use of an electric heater downhole to maintain the temperature of the reservoir above the geothermal gradient that is the temperature above the cricondentherm, the maximum temperature above which no liquid can be form regardless of the pressure.

2.9 PRESSURE, VOLUME AND TEMPERATURE (PVT) MODELING

The PVT properties which control fluid production during pressure depletion are viscosities of the two phases, Z-factor, liquid dropout and compositional variation of the heavier components with pressure. PVT properties of hydrocarbon mixtures are estimated using black oil model and compositional model. The compositional model provides better accuracy for gas condensate reservoirs, because it has the ability to monitor each component's saturation at all reservoir pressure and temperature stages (Khanal, Khoshghadam and Lee, 2016). However its challenge is that it has a more complex computational procedure and requires more time to run in compare to black oil model.

The development of the compositional model gained popularity due to increasing occurrence of gas condensate and volatile oil reservoirs. The phase equilibrium and fluid properties such as compressibility, density, and viscosity are determined by equation of state (EOS). An equation of state represents a theoretical relationship between pressure, volume and temperature. The Peng and Robinson, (1976) and Soave Redlich Kwong (1972) equations of state are commonly used in the petroleum industry.

In this technique, the phase composition is determined by flashing the fluid over wide range of pressures, the mass balance equation for each composition is used, where sum of the saturations should be 1 (100%). The phase behavior of the fluid has to be consistent with pressure, temperature and composition in each grid cell in reservoir simulations.

The number of mass balance equations increase as the number of compositions in the system increase. This would add extra computation time in simulation studies. Recently, full compositional simulation become more feasible with advancement in computational techniques, however for large number of cells it is still impractical.

Despite advantages associated with the compositional modeling of PVT properties, it requires more computational effort than black oil model due to its great complexity. The prediction accuracy of equation of state in compositional simulation deteriorate in near critical regions (e.g., rich gas-condensate fluid and highly volatile oil) (Elsharkawy, 2006). This can restrict the model application in reservoir studies where significant compositional variations occur (Gomes and Corrêa, 1992).

An attempt to modifying black oil PVT model was developed known as modified black oil (MBO), where the knowledge of expansion of gas and shrinkage of oil in the surface due to the amount of dissolved gas is added to the MBO (Izgec and Barrufet, 2005; Nassar, El-Banbi and Sayyouh, 2013). Many studies show excellent agreement of MBO with compositional models (EOS) for simulating gas-condensate fluid (Whitson and Torp, 1983; Coats, Thomas and

Pierson, 1995; Mott, 2002; Chowdhury *et al.*, 2004; Fan *et al.*, 2005; Behmanesh, Hamdi and Clarkson, 2017). MBO is much simpler than compositional formulation using EOS.

Two basic fundamental approaches to studying PVT model in any hydrocarbon reservoirs are “classical” and “modern” techniques. Classical approach based on utilizing analytical solutions of linear differential equations while modern methods consist of numerical simulation models. Use of analytical technique can be regarded as more specialized and difficult to apply because it requires considerable knowledge to use a particular equation to describe a physical situation in a reservoir (Dake, 2001).

CHAPTER THREE

METHODOLOGY

For the purpose of this study the phase behavior experiment was carried out on the gas condensate in other to properly determine its components using compositional model and also PVT properties determination such as gas and oil densities, viscosity, gas solubility in reservoir oil, condensate content of reservoir gas, shrinkage volume factor of oil and gas from reservoir to surface condition, equilibrium phase compositions. Using the constant composition expansion (CCE), the constant volume depletion (CVD) test and the thermodynamic model of the equation of state (EOS) model for fluid characterization and also the use of a simulation software ECCLIPSE

3.1 COMPOSITIONAL MODEL (GAS CHROMATOGRAPHY)

The compositional model for the gas condensate reservoir was done by performing a laboratory experiment using a gas chromatography system

Apparatus: A gas chromatography system which comprises of gas carrier, thermostatic oven, sample injector, detector or pressure gauge and injector.

Experiment:

The gas condensate sample is collected from the reservoir at the reservoir temperature and pressure, it is injected into the gas chromatography system. The range of the components being analyzed is read from the detector.

Its accuracy is dependent on reproducible retention time. Some sources of error in gas chromatography analysis can arise from

- Improper handling of the sample before injection into the gas chromatography system
- Method used for injection
- Decomposition of sample during analysis

- Calibration error
- Bad chromatographic system either by tailing or overuse of the system

Pressure Volume Temperature (PVT) Test

PVT modeling is done using the constant composition expansion (CCE) and constant volume depletion (CVD) test.

Both tests uses the same set of apparatuses, a PVT cell, pressure gauge, thermostat, mercury pump

Constant Composition Expansion (CCE) Test

The constant composition expansion test is the first to be done once the compositional analysis of a gas condensate is determined

Procedure:

A sample of a gas condensate reservoir is injected into a PVT cell at a temperature equal to the reservoir temperature and a pressure higher than the dew point pressure. The pressure is gradually decreased at constant temperature by removing mercury from the cell. The change in the total condensate volume is measured for each pressure increment. The saturation pressure and the corresponding volume are observed and recorded and used as a reference volume.

Constant Volume Depletion (CVD) Test: the test is carried out on a reservoir fluid sample in other to simulate the depletion of the actual reservoir fluid in a case in which retrograde liquid generated during production remains immobile.

Procedure:

A measured amount of the gas condensate from the reservoir with known composition is injected into the PVT cell at the dew point pressure, the temperature of the cell is maintained at reservoir temperature throughout the experiment. The initial volume at saturation is measured and used as the reference volume. The cell pressure is reduced to a level below the dew point by withdrawing mercury from the cell, a drop below the dew point causes the second phase to form the (gas to oil phase) and consequently the volume increases, gas is depleted from a valve on the cylinder to keep the total volume of the two phases equal to the saturation volume at a constant pressure. The percentage of the depleted gas as to the original gas is measured as well as the percentage of the liquid dropout of the liquid volume as to the saturation volume. The changes in the PVT properties of the gas condensate is obtained during the process.

3.2 FLUID CHARACTERIZATION AND GENERATION OF COMPOSITIONAL PVT MODEL TABLE

Gas condensate fluids are meant to be handled with good care during the numerical compositional simulation because they have the ability to change their phases within the pressure and temperature range in the reservoir and in the wellbore conditions as production goes on. Since these phase changes usually affects the relative permeability of gas and condensate, it is necessary to describe the fluid characteristics properly. The fluid properties including the phase behavior are greatly dependent on the properties of each component or pseudo-component and composition. In addition, the heavier components have various isomers for the same carbon number components and hence they have different characteristics by the presence of different isomers. Hence, the tuning procedure for EOS parameters to match the available experimental PVT data is requires to represent a more realistic fluid. The fluid used for the simulation was obtained from a gas condensate field in the Niger Delta region of Nigeria. ECLIPSE's PVT*i* for fluid characterization was used to develop the fluid PVT properties and the results were exported to ECLIPSE compositional simulator.

The composition of the fluid is shown in Table below, the fluid existed at a temperature of 255^{o}F at reservoir conditions with a dew point of 4940 psia.

Component	Symbol	Mol%
Nitrogen	N_2	0.04
Carbon dioxide	CO_2	3.35
Hydrogen sulphide	H_2S	0
Methane	C_1	85.35
Ethane	C_2	5.3
Propane	C_3	1.99
Iso-butane	$1C_4$	0.4
N-butane	NC_4	0.56
Iso-Pentane	IC_5	0.23
N-Pentane	NC_5	0.21
Hexanes	C_6	0.3
Heptanes	C_7	0.48
Octanes	C_8	0.37
Nonanes	C_9	0.28
Decanes	C_{10}	0.22
Undecanes	C_{11}	0.17
Dodecanes plus	C_{12}^{+}	0.75

Table 3.1: Reservoir Fluid Composition @255ºF

The 3-parameters Peng Robinson Equation of State was selected for tuning the data obtained from the Constant Composition Expansion (CCE) and Constant Volume Depletion (CVD) experiments. The data tuned includes the liquid saturation, relative volume, and gas compressibility factor and saturation pressure. Table 3.2 and 3.3 show the experimental data used for the simulation.

Table 3.2: Constant Expansion Composition Table @255ºF

Pressure (psia)	**Relative Volume (fraction)**
5945	0.8956
5765	0.9112
5445	0.9425
5050	0.9843
4953	0.9983
4940	1
4870	1.0105
4795	1.021
4655	1.042
4500	1.0683
4300	1.1052
4095	1.1473
3875	1.2001
3500	1.3058
3140	1.4382
2802	1.5973
2500	1.7831
2050	2.1754

Table 3.3 Constant Volume Expansion data @225ºF

Pressure (psia)	Vapor Z Factor (fraction)	Vap. Visc (cp)	Liq. Saturation (%)	Moles Recovered (fraction)
4940	0.973	0.0296	0	0
4300	0.925	0.0268	1.15	0.08432
3700	0.895	0.0242	2.05	0.19094
3100	0.883	0.0214	2.75	0.30852
2500	0.889	0.0191	3.29	0.43649
1900	0.889	0.0173	3.65	0.57084
1300	0.906	0.0159	3.63	0.70487

The experimental results of CVD and CCE from the PVT analyses were used for the tuning of the EOS parameter, the maximum liquid dropout in CVD analysis was 3.6 % in the experimental data. Liquid dropout is an important parameter that affects the cumulative condensate production history when the gas cumulative production and the pressure decline history are matched to those of the field data.

While tuning the EOS to experimental data, it is necessary to reduce the number of components. However, before this was done the C7+ fraction was split into three further fractions of C7+, C14+, and C25+. This was to enable a good or better characterization of the heavier components of the fluid mixture. The components were then lumped into groups of pseudo-components. The first pseudo-component group (GRP) is composed of carbon dioxide only as the only significant non-hydrocarbon.

The second group pseudo-gas contains nitrogen, methane, and ethane. The amount of nitrogen is not significant; hence, it is assumed that this pseudo-component contains only methane and ethane. The third group pseudo-component contains the gasolines; propane, butanes, pentanes, and hexanes. The fourth group is C7 to C13, while the fifth is C14 to C24. The final group is the heaviest, C25+ components.

Table 3.5 shows the final molar composition of the pseudo components and once the pseudo components were defined the EOS tuning process was initiated. The 3-parameter Peng-Robinson equation of state was selected for this purpose, as it is one of the most widely used for characterizing gas condensate fluids. The tool used for this was the PVTi (Geoquest), version 2005a. The parameters selected for regression were the binary interaction coefficients (BICs), critical pressures, critical temperatures, and the shift factors. The final values for the binary interaction coefficients are presented in Table 3.6 below.

Table 3.4 Grouping of components

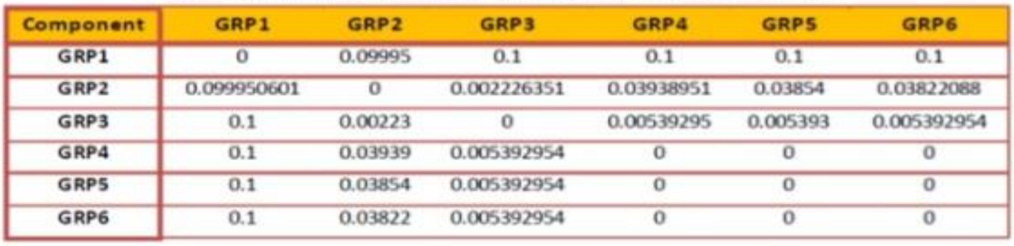
Group	**Component**
Group 1	CO_2
Group 2	N_2, H_2S, C_1, C_2
Group 3	$C_3 – C_5$
Goup 4	$C_7 – C_{13}$
Group 5	C_{14} -C_{24}
Group 6	C_{25}

Table 3.5 composition of pseudo-component

Component	Mole(%)	Weight fraction (%)
Group 1	3.35	6.7572
Group 2	90.96	70.112
Group 3	3.69	9.1893
Group 4	1.9992	11.142
Group 5	0.26079	2.6309
Group 6	0.010017	0.16876

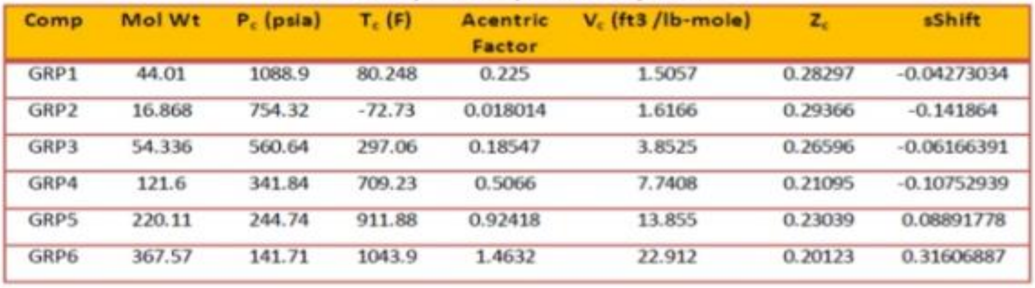
After regression was performed a good match was obtained, the experimental dew point pressure indicating a proper tuning of the EOS.

Table3.6: Binary Interaction Coefficients for the pseudo-components



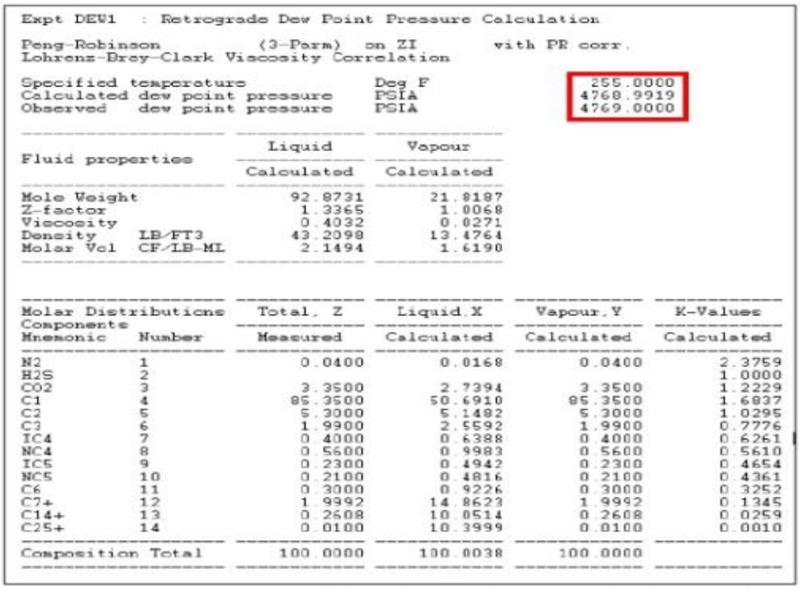
Component	GRP1	GRP2	GRP3	GRP4	GRP5	GRP6
GRP1	0	0.09995	0.1	0.1	0.1	0.1
GRP2	0.099950601	0	0.002226351	0.03938951	0.03854	0.03822088
GRP3	0.1	0.00223	0	0.00539295	0.005393	0.005392954
GRP4	0.1	0.03939	0.005392954	0	0	0
GRP5	0.1	0.03854	0.005392954	0	0	0
GRP6	0.1	0.03822	0.005392954	0	0	0

Table 3.7: Properties of pseudo-components



Comp	Mol Wt	P_c (psia)	T_c (F)	Acentric Factor	V_c (ft3 /lb-mole)	Z_c	sShift
GRP1	44.01	1088.9	80.248	0.225	1.5057	0.28297	-0.04273034
GRP2	16.868	754.32	-72.73	0.018014	1.6166	0.29366	-0.141864
GRP3	54.336	560.64	297.06	0.18547	3.8525	0.26596	-0.06166391
GRP4	121.6	341.84	709.23	0.5066	7.7408	0.21095	-0.10752939
GRP5	220.11	244.74	911.88	0.92418	13.855	0.23039	0.08891778
GRP6	367.57	141.71	1043.9	1.4632	22.912	0.20123	0.31606887

The phase envelope for the fluid reveals the complexities associated with gas condensate systems. The phase envelope does not close because the reservoir temperature and pressure exist beyond the display of the simulator.



```
Expt DEW1   : Retrograde Dew Point Pressure Calculation

Peng-Robinson         (3-Parm)  on ZI        with PR corr.
Lohrenz-Brey-Clark Viscosity Correlation

Specified temperature             Deg F                 255.0000
Calculated dew point pressure     PSIA                 4768.9919
Observed   dew point pressure     PSIA                 4769.0000

------------------- ------------ ------------
                       Liquid       Vapour
Fluid properties    ------------ ------------
                     Calculated   Calculated
------------------- ------------ ------------
Mole Weight              92.8731      21.8187
Z-factor                  1.3365       1.0068
Viscosity                 0.4032       0.0271
Density    LB/FT3        43.2098      13.4764
Molar Vol  CF/LB-ML       2.1494       1.6190
------------------- ------------ ------------


------------------- ------------ ------------ ------------ ------------
Molar Distributions   Total, Z     Liquid,X     Vapour,Y     K-Values
Components          ------------ ------------ ------------ ------------
Mnemonic   Number     Measured    Calculated   Calculated   Calculated
------------------- ------------ ------------ ------------ ------------
N2         1              0.0400       0.0168       0.0400       2.3759
H2S        2                                                     1.0000
CO2        3              3.3500       2.7394       3.3500       1.2229
C1         4             85.3500      50.6910      85.3500       1.6837
C2         5              5.3000       5.1482       5.3000       1.0295
C3         6              1.9900       2.5592       1.9900       0.7776
IC4        7              0.4000       0.6388       0.4000       0.6261
NC4        8              0.5600       0.9983       0.5600       0.5610
IC5        9              0.2300       0.4942       0.2300       0.4654
NC5        10             0.2100       0.4816       0.2100       0.4361
C6         11             0.3000       0.9226       0.3000       0.3252
C7+        12             1.9992      14.8623       1.9992       0.1345
C14+       13             0.2608      10.0514       0.2608       0.0259
C25+       14             0.0100      10.3999       0.0100       0.0010
------------------- ------------ ------------ ------------ ------------
Composition Total       100.0000     100.0038     100.0000
------------------- ------------ ------------ ------------ ------------
```

Figure 3.1: Result of saturation pressure EOS tuning showing the matched dew point pressure

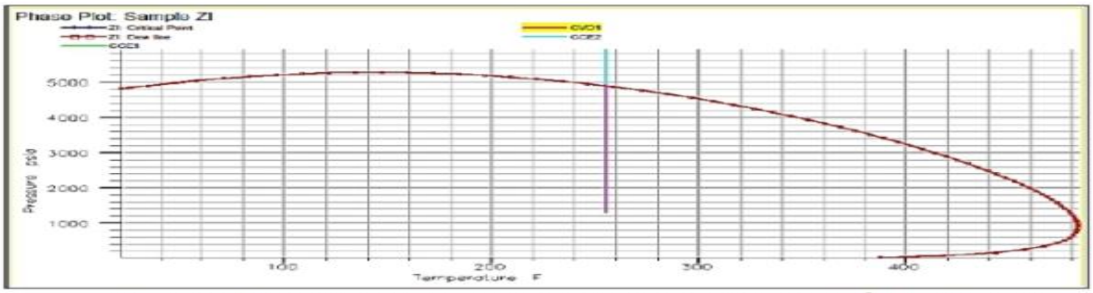


Figure 3.2: Phase envelope for the gas condensate sample; T_r =255°F, P_i =4953psia

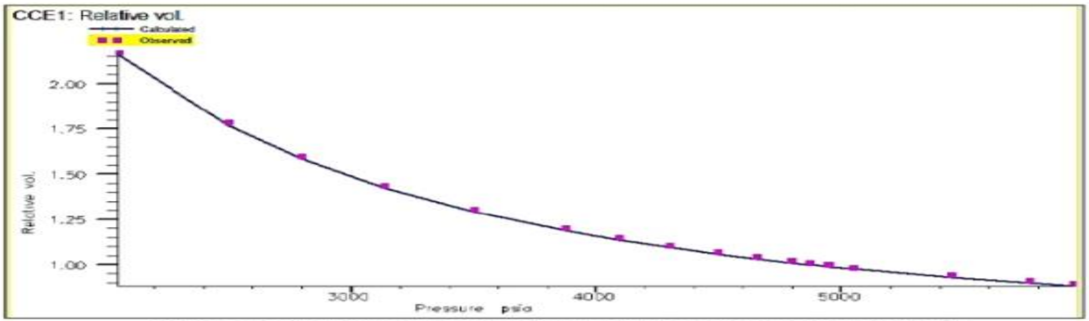


Figure 3.3: experimental and simulated relative volume for CCE @ 255°F

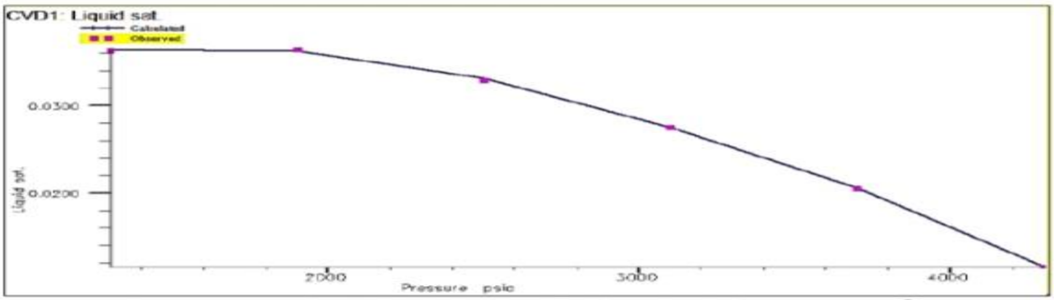


Figure 3.4: Experimental and simulated liquid saturation for CVD @ 225°F

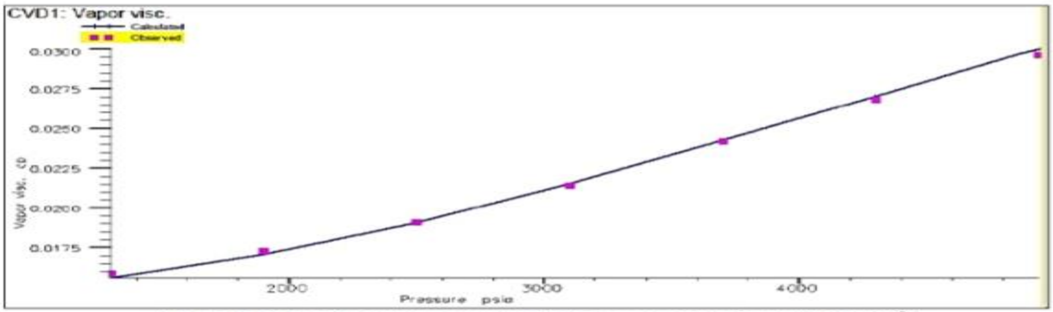


Figure 3.5: Experimental and simulated gas viscosity for CVD @ 255°F

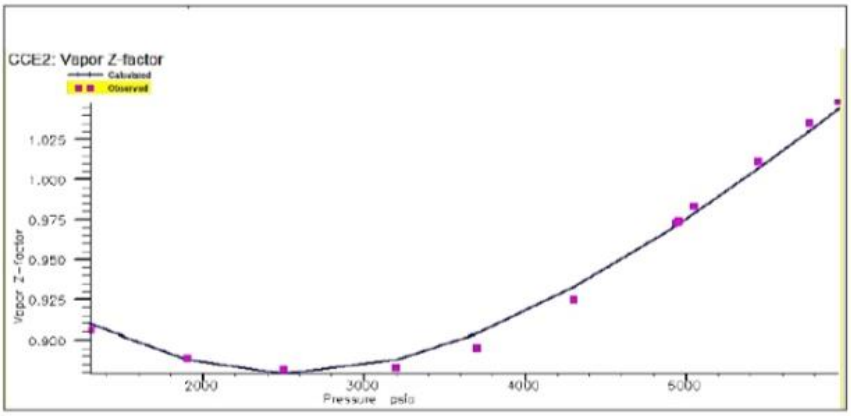


Figure 3.6: Experimental and simulated gas compressibility factor data for CVD @ 255°F

3.3 A SIMULATION MODEL AND EXPERIMENTAL DESIGN

A simple five-spot model was built for representation of the whole field. The model is hypothetical but includes the fluid description of a real gas condensate reservoir. The synthetic model has Cartesian coordinates with block-centered geometry having length of 328 ft. in the X and Y directions, with varying thickness.

The number of grids selected was 10x10x7 and the top of the model is at 9560 ft. with an initial reservoir pressure of 4953 psia. The five-spot model consists of four producers at the boundaries of the model and an injector at the center of the reservoir model as shown in Figure 3.7. This was focuses majorly on sensitivity runs, therefore only few of the properties are constant over the course of simulation. These properties are described in Table 3.8 and 3.9. Injection was performed for 5,475 days.

One of the aims of this work is to study the effects of different parameters on gas and condensate recovery. In selecting the parameters of investigation, it is very important to note that only the parameters that significantly affect the production of gas and condensate are selected. To achieve this, a statistical approach was employed, using experimental design**.**

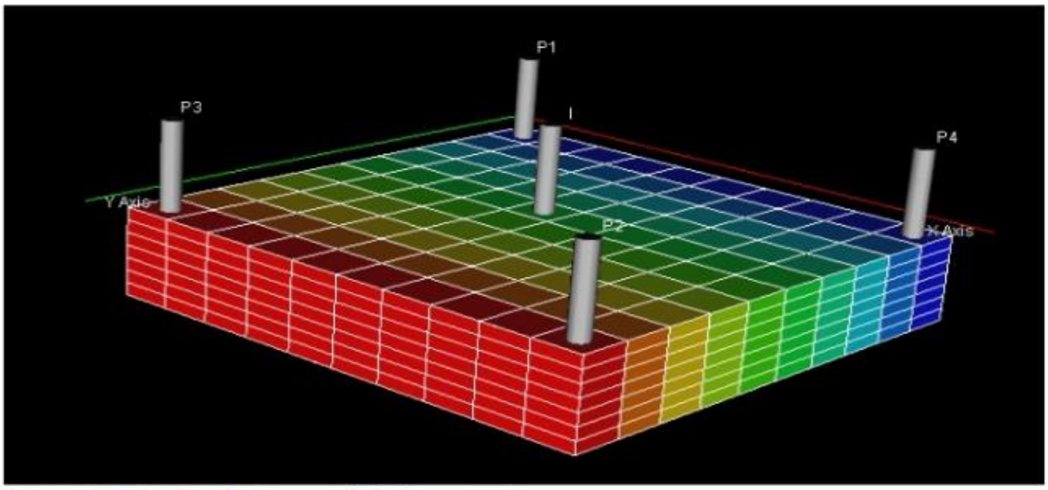


Figure 3.7: 3D simulation model of reservoir

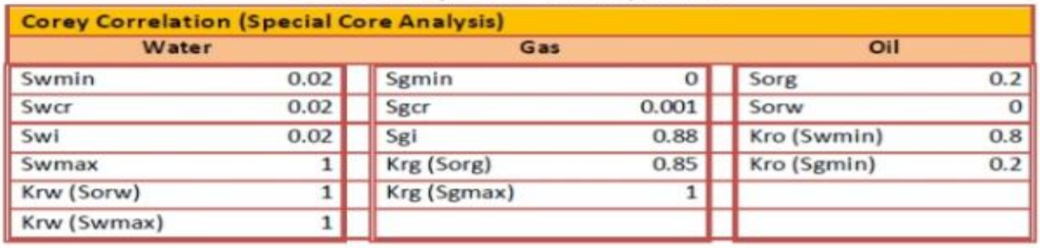
The Plackett-Burman Design for selection of significant parameters was used for eleven factors (parameters), where each factor was varied over two levels. This method is best suited for ruggedness testing where it is hoped to find little or no effect on the response due to any of the factors some of the properties of the reservoir that are constant throughout the productive life of the retrograde condensate reservoir are as shown in the designed below**.** This generates a set of saturated screening designs based on Plackett-Burman structures, which is offered by the

Design-Expert package. The number factors allowed is one less than the number of runs. Hence, in this case, twelve runs were created by the design (since we are studying eleven factors). These runs are a mixture of the different levels of the factors listed in a tabular form (Table 3.11).

Table 3.8: Some constant properties of reservoir

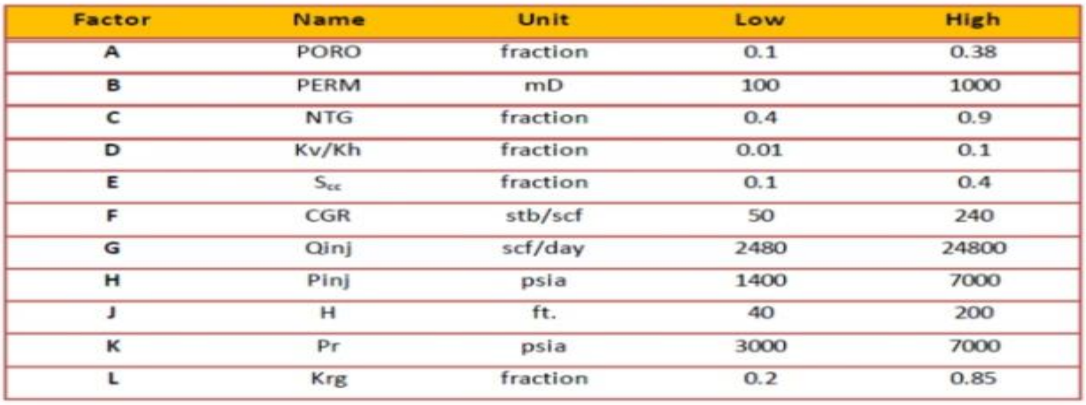
Property	Value
X Permeability	1000 mD
Y Permeability	1000 mD
Z Permeability	K_v/K_h * PERMX
X Grid Block Size	328 ft.
Y Grid Block Size	328 ft.

Table 3.9: Special Core Analysis data



Corey Correlation (Special Core Analysis)					
Water		Gas		Oil	
Swmin	0.02	Sgmin	0	Sorg	0.2
Swcr	0.02	Sgcr	0.001	Sorw	0
Swi	0.02	Sgi	0.88	Kro (Swmin)	0.8
Swmax	1	Krg (Sorg)	0.85	Kro (Sgmin)	0.2
Krw (Sorw)	1	Krg (Sgmax)	1		
Krw (Swmax)	1				

Table 3.10: Plackett-Burman Design showing the factors and levels (Low and High)



Factor	Name	Unit	Low	High
A	PORO	fraction	0.1	0.38
B	PERM	mD	100	1000
C	NTG	fraction	0.4	0.9
D	Kv/Kh	fraction	0.01	0.1
E	S_{cc}	fraction	0.1	0.4
F	CGR	stb/scf	50	240
G	Qinj	scf/day	2480	24800
H	Pinj	psia	1400	7000
J	H	ft.	40	200
K	Pr	psia	3000	7000
L	Krg	fraction	0.2	0.85

Table 3.11: Experimental Design Table showing the factors and responses used for the design

	Factor 1	Factor 2	Factor 3	Factor 4	Factor 5	Factor 6	Factor 7	Factor 8	Factor 9	Factor 10	Factor 11	Response 1	Response 2
Run	A:PORO *fraction*	B:PERM *mD*	C:NTG *fraction*	D:Kv/Kh *fraction*	E:Scc *fraction*	F:CGR *stb/scf*	G:Qinj *scf/day*	H:Pinj *psia*	J:H *ft.*	K:Pr *psia*	L:Krg *fraction*	Gas Prod *Mscf*	Cond Prod *bbls*
1	0.38	100	0.9	0.1	0.1	240	24800	7000	40	3000	0.2	135780000	1113184.1
2	0.1	1000	0.4	0.1	0.4	50	24800	7000	200	3000	0.2	135780000	747511.69
3	0.1	100	0.4	0.01	0.1	50	2480	1400	40	3000	0.2	2242552.8	51224.289
4	0.38	100	0.9	0.1	0.4	50	2480	1400	200	3000	0.85	95895064	2225145.8
5	0.1	100	0.9	0.01	0.4	240	2480	7000	200	7000	0.2	52022840	1503648
6	0.38	1000	0.9	0.01	0.1	50	24800	1400	200	7000	0.2	135780000	4400179
7	0.1	1000	0.9	0.01	0.4	240	24800	1400	40	3000	0.85	135780000	212694.67
8	0.1	1000	0.9	0.1	0.1	50	2480	7000	40	7000	0.85	9727697	276220.78
9	0.38	1000	0.4	0.1	0.4	240	2480	1400	40	7000	0.2	15023919	425837.5
10	0.38	100	0.4	0.01	0.4	50	24800	7000	40	7000	0.85	135780000	1034212.6
11	0.1	100	0.4	0.1	0.1	240	24800	1400	200	7000	0.85	85265984	196071.72
12	0.38	1000	0.4	0.01	0.1	240	2480	7000	200	3000	0.85	4651961	101806.91

Also in this table are the expected responses. To generate the responses (gas and condensate production), a full dynamic simulation was carried out using the different parameters on each row. The results of these sensitivity dynamic modeling were entered as the response information as gas and condensate production. This now generates the expected design that was used to analyze the various levels of significance of the eleven parameters on the gas and condensate production response.

To test for the effects of the different parameters on gas and condensate production, an analysis was run using the various statistical tools provided within the Design-Expert package. Three approaches were employed for this purpose;

- The Normal Probability Plot
- The Half-Normal Probability Plot
- The Pareto Chart

The normal probability plot can be used to choose significant effects. It is a plot of the ordered values of a normal percentage probability versus the expected standardized effects from the true population. In this plot, the parameters having an effect on the responses appear as outliers of an approximately straight line.

The plot is designed in such a way that the parameters with positive effects are separated from those with negative effects as is shown in Figure 3.9

The half-normal probability Plot follows the same principles as the full normal probability plot, except that the sign of the effect is ignores in plotting. Thus, large absolute values show up as outliers in the upper right-hand section of the graph.

The Pareto chart is an additional graphic used to display the t values of the effects. The t value is the number of standard deviations separating the coefficient from zero. Two basic different t limits are plotted on the graph. One based on Bonferroni corrected t, and the other a standard t. Generally, the effects that are above the Bonferroni are almost certainly significant, while the effects above the t-value are possibly significant. The Pareto chart gives a more comfortable viewing for the selection of significant effects. From Figure 3.8, it can be seen that three factors (B, K, and F) lying to the left hand side of the line have negatively significant effects on gas production, while those on the right hand side of the line (J, A, C, E, and G) have positively significant effects. Three other factors, D, H, and L, which lie on the line, have very little effects on the gas production response

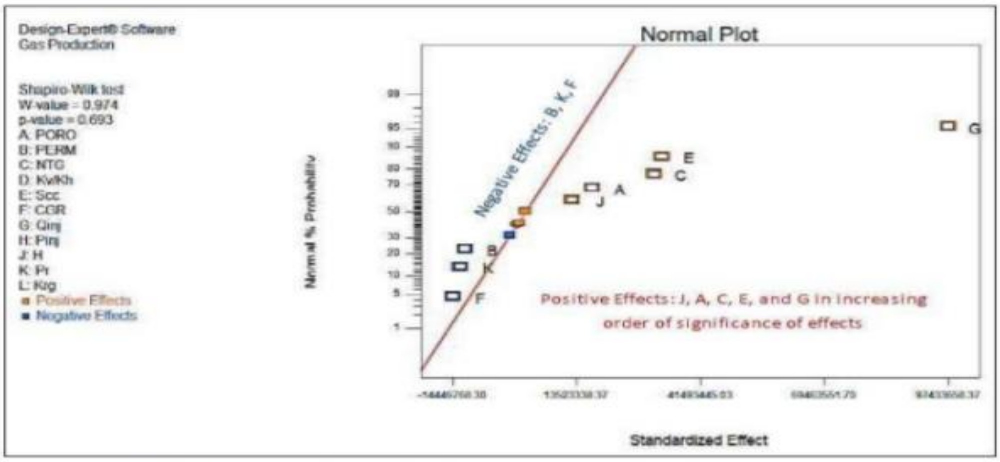


Figure 3.8: Graph of Normal % Probability Vs. Standardized Effects for Gas Production

For condensate production (Figure 3.9), it can be seen that only two parameters have little or no significance on condensate production. These are the parameters lying on the line (B and E). The rest show either positive or negative significant impact on the response.

The half-normal plots (Figure 3.10 and 3.11) for gas and condensate are the same as that of the normal plot, except that there the absolute values are used. This means that all the effects are regarded as neither negative nor positive. The outcome remains the same.

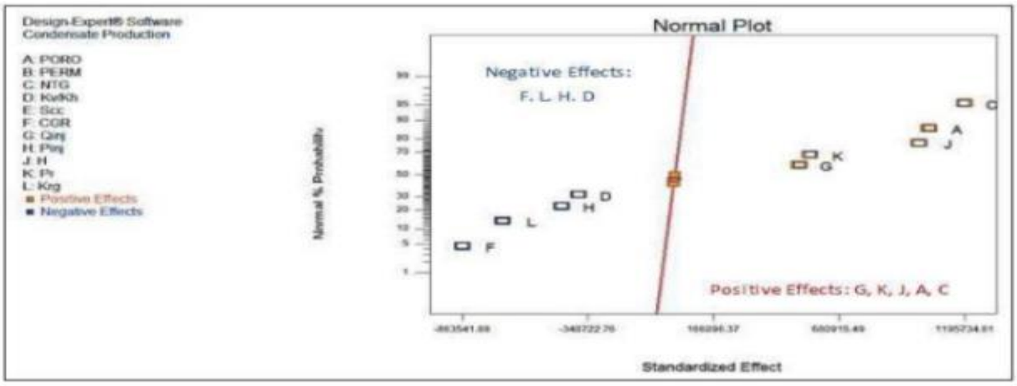


Figure 3.9: Graph of Normal % Probability vs. Standardized Effects for Condensate Production

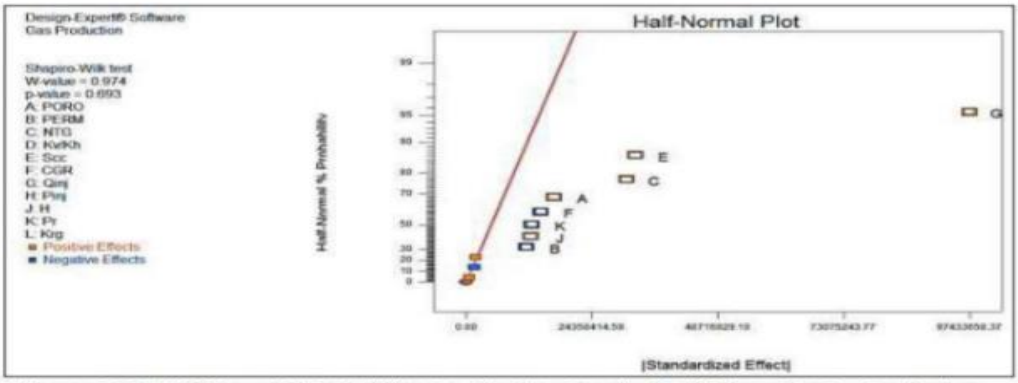


Figure 3.10: Half-Normal % Probability Vs. Absolute Standardized Effects for Gas Production

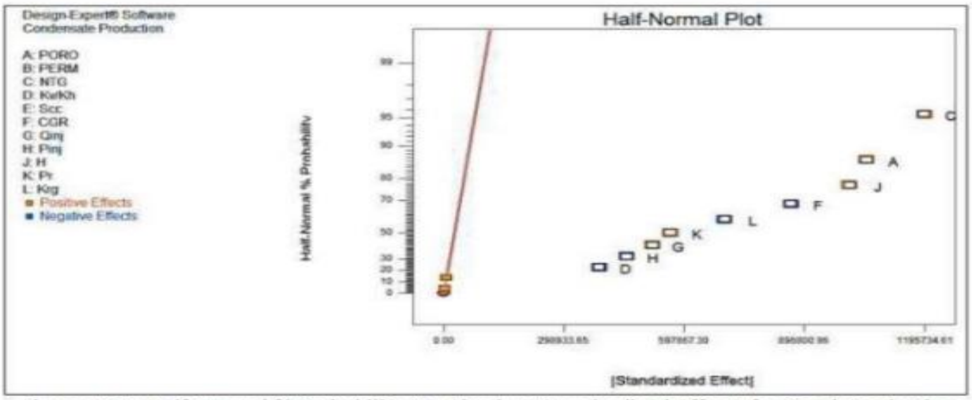


Figure 3.11: Half-Normal % Probability Vs. Absolute Standardized Effects for Cond. Production

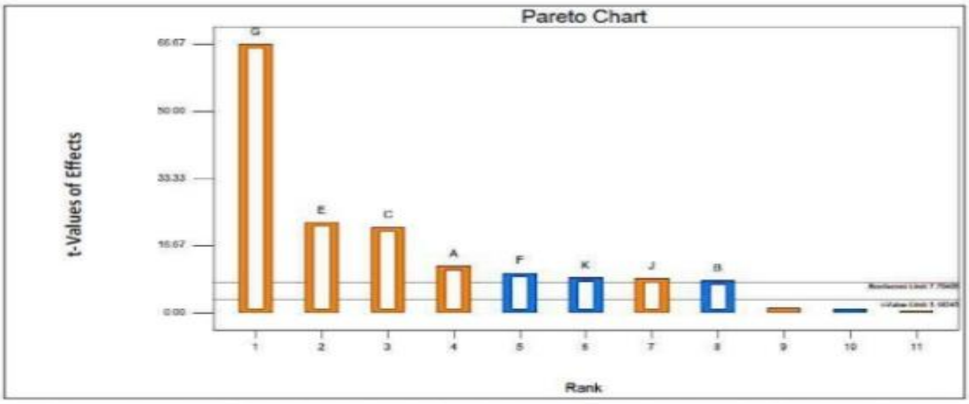


Figure 3.12: Pareto Chart for Gas Prod., showing factor G as the most significant parameter

The Pareto chart shows a simple bar chart illustration of the half-normal plot (Figures 3.12 and 3.13). The factors (represented as bars) which are above the Bonferroni limit (orange line), are the significant parameters while those below it show little or no significance in the responses.

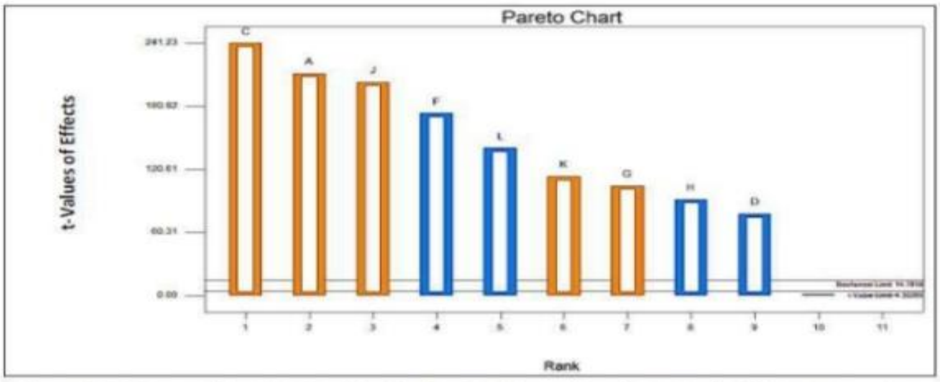


Figure 3.13: Pareto Chart for Cond Prod., showing factor C as the most significant parameter

With this design, seven parameters, which actively contribute to gas and condensate production, were chosen for sensitivity study.

These parameters are

- Porosity
- Net-to-Gross ratio
- The ratio of vertical permeability to horizontal permeability (Kv/Kh)
- Injection Rate
- Injection Pressure
- Thickness
- Reservoir Pressure

The sensitivity will involve multiple mixtures of these parameters to generate a table of possible interactions between different parameters

3.4 DEVELOPMENT OF PROXZY

The sensitivity model to be developed for the study of the effects of these parameters on gas and condensate production will involve multiple dynamics simulations with the Eclipse reservoir-modeling tool. This will undoubtedly be very tedious and would consume a lot of time and computer storage space slowing the overall modeling process. To abate this, a proxy/model was developed to mimic the performance of the Eclipse simulation tool. This was done using D-optimal Response Surface Method (RSM). Response surface method designs helps to quantify the relationships between one or more measured responses and the vital input factors or parameters. The D-optimal criteria is one of the optimality that selects design points in a way that minimizes the variance associated with the estimates of specified model coefficients. The aim is to generate a model that represents the responses using quadratic interactions of the factors. Using the quadratic model, Design-Expert was used to create an overall candidate point set, after which fifty –five specific design points (the experimental runs that would be done) are chosen. To generate the required proxy, all fifty-five runs were simulated in Eclipse platform and the needed responses (gas and condensate production) were generated and fed into the RSM as shown in Table 4.1. In this table, each row represents the parameters used in simulation and their corresponding gas and condensate production. Mixtures of the interaction of the different parameters were then used to generate a proxy, which represents the dynamic model simulated by Eclipse. The statistical analysis of the created proxy will be discussed in the next chapter. With the generated proxy, a parametric study of the effects of different factors on gas and condensate production was performed using simple spreadsheet logic. Further details regarding the result of the sensitivity study will be discussed in the next chapter of this research.

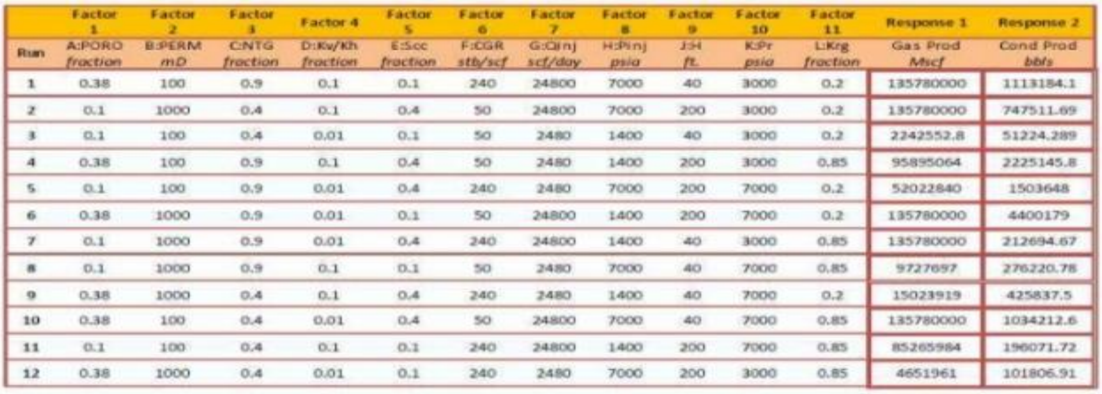
CHAPTER FOUR

RESULTS AND DISCUSSION

The basis for the application of design of experiment to reservoir modeling was introduced in this work as a substitute to already established dynamic simulation tool (Eclipse). Through statistical optimization of the response surface model, a study of the effects of different parameters on gas and condensate production was done by developing a proxy used to carry out a sensitivity study. This proxy was tested using statistical indicators to ascertain its degree of error. Statistical analyses of the generated model are shown in Tables 4.2 and 4.3 for gas and condensate production respectively.

It can be seen that for gas production model, the predicted R-squared of 0.8221 is in reasonable agreement with the adjusted R-squared of 0.96467, which implies that the proxy can be used beyond the range of the sample data used to develop the model. The adequate precision value measures the signal to noise ratio. A ratio greater than 4 is desirable. The gas production model has a ratio of 20.918, indicating an adequate signal. Hence, this model can be used to navigate the design space**.**

Table 3.11: Experimental Design Table showing the factors and responses used for the design



	Factor 1	Factor 2	Factor 3	Factor 4	Factor 5	Factor 6	Factor 7	Factor 8	Factor 9	Factor 10	Factor 11	Response 1	Response 2
Run	A:PORO *fraction*	B:PERM *mD*	C:NTG *fraction*	D:Kv/Kh *fraction*	E:Scc *fraction*	F:CGR *stb/scf*	G:Qinj *scf/day*	H:Pinj *psia*	J:H *ft.*	K:Pr *psia*	L:Krg *fraction*	Gas Prod *Mscf*	Cond Prod *bbls*
1	0.38	100	0.9	0.1	0.1	240	24800	7000	40	3000	0.2	135780000	1113184.1
2	0.1	1000	0.4	0.1	0.4	50	24800	7000	200	3000	0.2	135780000	747511.69
3	0.1	100	0.4	0.01	0.1	50	2480	1400	40	3000	0.2	2242552.8	51224.289
4	0.38	100	0.9	0.1	0.4	50	2480	1400	200	3000	0.85	95895064	2225145.8
5	0.1	100	0.9	0.01	0.4	240	2480	7000	200	7000	0.2	52022840	1503648
6	0.38	1000	0.9	0.01	0.1	50	24800	1400	200	7000	0.2	135780000	4400179
7	0.1	1000	0.9	0.01	0.4	240	24800	1400	40	3000	0.85	135780000	212694.67
8	0.1	1000	0.9	0.1	0.1	50	2480	7000	40	7000	0.85	9727697	276220.78
9	0.38	1000	0.4	0.1	0.4	240	2480	1400	40	7000	0.2	15023919	425837.5
10	0.38	100	0.4	0.01	0.4	50	24800	7000	40	7000	0.85	135780000	1034212.6
11	0.1	100	0.4	0.1	0.1	240	24800	1400	200	7000	0.85	85265984	196071.72
12	0.38	1000	0.4	0.01	0.1	240	2480	7000	200	3000	0.85	4651961	101806.91

CHAPTER FIVE

5.1 CONCLUSION

The result and analysis in chapter 4 shows the following;

- The dependency of critical condensate saturation on the permeability which is a rock property is a direct variation.
- The dependency of critical condensate saturation on the porosity which is a rock property is also a direct variation.
- The dependency of critical condensate saturation on changes in temperature in very negligible and as such does not determine the attitude of a gas-condensate system.
- The dependency of critical condensate saturation on the viscosity which is a fluid property is a direct variation.
- The dependency of critical condensate saturation on the NTG and the thickness which are rock properties is a direct variation.
- The dependency of critical condensate saturation on the injection rate and pressure which are operational properties is an indirect (inverse) variation.
- The dependency of critical condensate saturation on the production rate and designed production pressure are direct variation.

The dependency of critical condensate saturation on the relative permeability which is a rock-fluid property is a direct variation from these statements, a hypothetical relationship can be established which connects these parameters and can be used to design the production parameters which is the only adjustable variables.

5.2 RECOMMENDATION

In this study critical issues concerning gas condensate reservoir and its productivity has been discussed, however,

- A developed intelligent model could be used in other to ease the prediction gas condensate viscosities and two phase Z factor.
- Further research should be encourage in this area.
- More responsibility is on the Production Geologist, the Reservoir Engineer and the Production Engineer to design the best production parameters that enhance an optimize production scheme.

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