EVALUATION OF RECOVERY PERFORMANCE OF GAS-CONDENSATE RESERVOIR USING LIMITED COMPOSITIONAL SIMULATOR

A Thesis Presented to the Department of

Petroleum Engineering

African University of Science and Technology, Abuja

In partial fulfillment of the requirements for the award

Master of Science

By

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Abuja, Nigeria

March, 2018

CERTIFICATION

EVALUATION OF RECOVERY PERFORMANCE OF GAS-CONDENSATE RESERVOIR USING LIMITED COMPOSITIONAL RESERVOIR SIMULATOR

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ABSTRACT

In the past years, several researches have been done on gas-condensate reservoir recovery performance using fully compositional simulators. Fully compositional simulators are more expensive, time consuming and have complex data requirement as compared to limited compositional reservoir simulators. An alternative method of evaluating gas condensate reservoir recovery has been considered in this research; it is four-component limited compositional reservoir simulator. The limited compositional simulator makes use of the black-oil Todd-Longstaff model to simulate gas-condensate reservoir production. The work was started with collection of quality data which served as an input data to the development of the reservoir model. After model development, four simulation scenarios were set up; these include the base case or primary depletion with no injection, water injection case, water alternating gas injection case and gas injection case. The four simulation scenarios were compared to derive the best reservoir development strategies which will be instrumental in decision making. The outcome of this work is similar to that of fully compositional simulation. It is recommended that the limited compositional simulator should be considered for the gas-condensate project feasibility studies and optimization of gas-condensate reservoir recovery performance.

Keywords: fully compositional simulator, limited compositional simulators, gas condensate, reservoir performance, gas injection, water injection, water alternating gas injection, project feasibility studies, optimization.

DEDICATION

I dedicate this thesis to my late father, Chief Lahai Audu, my beloved mother, Mrs. Jinnah Lahai and my lovely fiancée, Dr. Rosalitta Toogbabu.

ACKNOWLEDGEMENT

I will like to say Alhamdulillah to almighty Allah for granting me the opportunity, courage and His infinite guidance and protection upon me in accomplishing this milestone of achievement.

I also immensely appreciate Directorate of Technical Corporation in Africa, (DTCA), for the sponsorship they provided for me to go through this course of study.

I further acknowledge African University of Science and Technology for the provision of the various facilities such as the ECLIPSE SOFTWARE, internet access, etc. I used to carry out this research work.

I highly appreciate the effort of my supervisor, Professor David O Ogbe for being with me throughout my thesis work to see that the right things are done.

The efforts of AUST faculties especially the petroleum engineering stream faculty greatly helped me to carry out this research. The various courses taught were all very instrumental in successful execution of my research work.

The prayers, pieces of advice and training I received from my parents really helped me a long way in my day-to-day activities and I will always remain grateful to them.

Behind every successful man there is a woman, I greatly appreciate the courage and meaningful pieces of advice from my lovely fiancée, Dr. Rosalitta J. Toogbabu. She has been so instrumental to me since the time we met up to date and God will bless her abundantly.

Last but not the least is the contributions from my fellow students at AUST, you have been so helpful to me and the almighty God will see us through in all our undertakings.

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CHAPTER ONE

1.0 Introduction

1.1 Background of Study

Reservoir fluid classification as a black oil, volatile oil, gas condensate, wet gas, or dry gas is important because application of appropriate engineering practices to predict reserves and rates traditionally requires this knowledge. Figure 1 shows the schematic of a pressure/temperature *(p-T)* diagram for a multi-component hydrocarbon mixture of constant composition [Raghavan et al., 1996]. From the schematic, the region inside the envelope formed by the bubble-point curve, critical point (C), and dewpoint curve is where liquid and vapor exist in equilibrium. Inside this region, lines of constant liquid volume are shown. Fluids initially at temperature and pressure marked as Positions I through V would be classified as a black oil, volatile oil, gas condensate, wet gas, and dry gas, respectively [Raghavan et al., 1996]. Gas condensates are separated from the other fluid types by two characteristics: the condensation of a liquid phase at reservoir conditions during isothermal depletion and the retrograde (re-vaporization) nature of this condensation. Retrograde behavior of the condensing liquid phase can be seen by tracing the change in liquid volume along the constant-temperature line beginning at Point M as shown in Figure 1. After crossing the dewpoint line, the volume of liquid increases to approximately 10% at Point N and then begins to decrease with continued reduction in pressure [Raghavan et al., 1996].

The type of fluid should be determined based on laboratory experiments. Because experimental tests take time to conduct and analyze, reservoir fluids can be initially classified by rules of thumb based on the initial producing gas/oil ratio (GOR), gravity, and color of the produced liquids [Raghavan et al., 1996]. Laboratory determination of fluid type requires reliable data for reservoir temperature, initial pressure, and a representative fluid sample. Near-critical gas condensates may require very precise estimates of these reservoir properties to classify the sample under consideration with confidence. The real difficulty usually arises in obtaining a representative fluid sample, which is a fluid with the same composition as the initial composition of the reservoir fluid [Raghavan et al., 1996]. The best way to obtain such a sample for a gas-condensate system is to sample the producing fluid so that the down-hole flowing pressure remains higher than the dew point pressure while a high enough rate is maintained to ensure that no liquid holdup occurs in any part of the production string or surface lines. For this case, a sample obtained by a recombination of the high-pressure separator vapor and liquid phases at the measured producing GOR should be representative of the initial reservoir fluid. This scenario is obviously an ideal case because most wells must be initially flowed for cleanup before the produced stream consists solely of reservoir fluids. A successful sampling program should consider well conditioning before sampling, choice of collection site, collection mechanics, and quality-control checks [Raghavan et al., 1996].

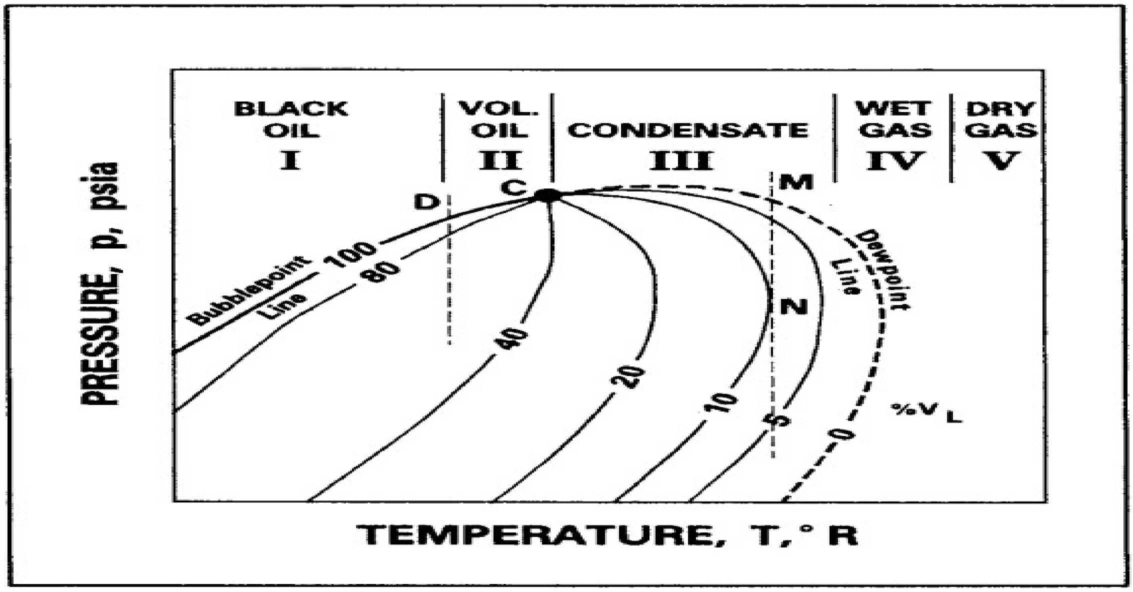


Figure 1.1 Pressure-temperature classification of hydrocarbon systems **[Raghavan et al., 1996]**

1.2 Problem Definition

The simulation of water, gas and water alternating gas (WAG) injections into a gas-condensate reservoir can be modeled by approximating the phase behavior with four components i.e. condensate, water, free/solution gas and injection gas as described by Todd-Longstaff [Kossack, C. A., 1987]. This process can also be modeled by accurately simulating the phase behavior with n-components whose K-values are complex functions of pressure, temperature, and composition [Kossack, C. A., 1987]. A precise set of rules of when one may approximate the recovery performance with four components and when one must use the fully compositional formulation is generally unavailable. Much discussion in the technical field is ongoing but all too often the decision of which model is used comes from time, money computer, or data available or purely subjective reasons [Kossack, C. A., 1987]. According to the Society of Petroleum Engineer (SPE) fourth comparative solution project, good agreement between results from different simulators for the same problem does not give validity of any of the result, but a lack of agreement does give cause for some concern [Kossack, C. A., 1987]. The SPE's comparative solution projects (CSP's) are recognized suites of test datasets for specific problems and the hub of conducting independent comparison of reservoir simulation from different developers [Islam, A.W. and Sepehhrnoori, K., 2013]. This is designed to measure the capability of the state-of-the-art simulation for challenging and most up to date problems encountered in the oil and gas industry.

Gas condensate reservoirs manifest a complex thermodynamic behavior that cannot be described by simple pressure dependent functional relations. The reservoir fluid compositions keep on changing during production by pressure depletion or by cycling above and below dew point pressures [Bulent I., 2003].

It has been noted that volatile oil and gas-condensate reservoirs cannot be accurately modeled with conventional black-oil models. One major variation to the black-oil approach is the modified black-oil (MBO) model that allows the use of a simple and less expensive computational algorithm than a fully compositional model which can result in significant time saving in full field studies, [Bulent I., 2003].

Gas injection becomes increasingly important for oil recovery and environmental considerations in oil field development. Gas injection processes are most effective when the injected gas is nearly or completely miscible with the oil in the reservoir [Jákupsstovu, S., 2001]. Gas injection is becoming a significant and economic IOR method, often implemented as a miscible or "near miscible" WAG project. WAG injection is employed to gain better profile control in a gas injection project Numerical dispersion effects in standard compositional simulation of WAG processes can cause serious errors in the predicted phase behavior, so that the compositional results for large area models can be very misleading. In some situations, minimal water involvement is desired, and WAG is not applicable [Jákupsstovu, s., 2001].

1.3 Aim of the Research

This study seeks to evaluate the recovery performance of gas condensate reservoirs through limited compositional reservoir simulation studies by running three production schemes. It describes how to improve recovery optimization of gas condensate reservoirs through pressure maintenance by injecting water, gas, and water alternating gas (WAG) to produce the reservoir fluid.

1.4 Motivation of the Research

In previous years, fully-compositional simulation was the main reliable solution used to evaluate gas-condensate reservoirs. This type of simulation was having many drawbacks which made research to continue in this field to find more convenient method that can perform the same job with ease and maintain the same quality output. There came in the method of limited-compositional simulation. This later method of simulating gas-condensate reservoirs has lot of advantages over fully-compositional simulation method. Some of these advantages of using limited-compositional simulator on gas condensate reservoir over fully-compositional simulator are as follows.

- Less time is needed to carry out the simulation
- It involves low cost to perform the simulation and
- The data involve in limited-compositional simulation is less complex.

The petroleum industry like other industries aims to maximize profit from their operations. Thus, optimization of the industrial process to raise money by reducing operational costs is a vital option. In the gas-condensate reservoir case, optimization is desirable because the profits mostly come from the condensate. This can be seen in a simple profit calculation, in which only knowledge of fluid composition and its properties are needed [Syzdykov, M.].

1.5 Research Objectives

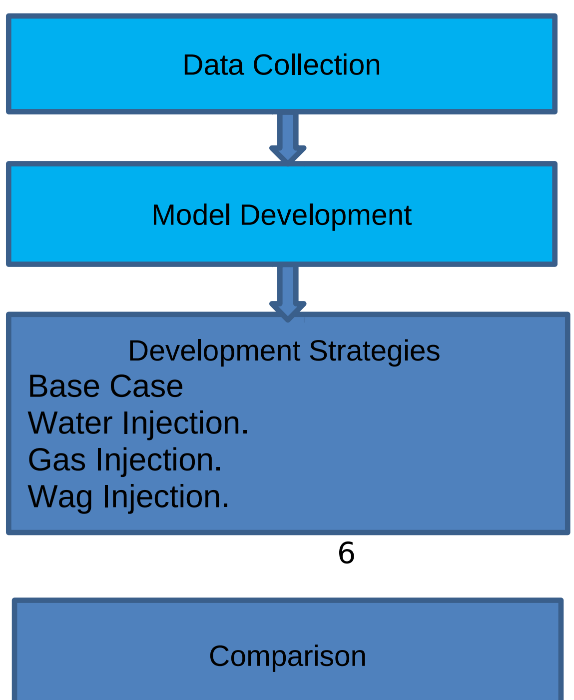
To achieve the above aim of this research, the following objectives will be taken into consideration:

1. Develop a gas condensate reservoir model using a limited compositional simulator.
2. Use the model to evaluate the production of a gas condensate reservoir by simulating four recovery scenarios i.e., primary depletion without any fluid injection; injection of water; injection of gas; and by water alternating gas injection scheme.
3. Determine the optimal scheme for production of the gas condensate reservoir from the results of the simulations.

1.6 Research Methodology

Reservoir modeling and simulation were utilized in this project through the application of limited compositional simulator. To accomplish this, there was need of sound background in reservoir engineering and fluid properties or PVT modeling.

Below is the flow chart showing the methodology of this work.



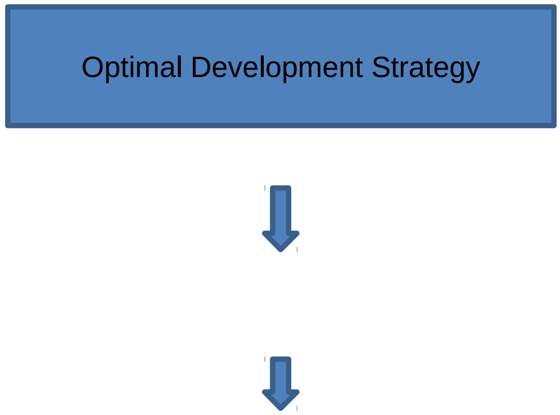


Fig.1.2 Flow diagram of methodology

Some of the PVT properties which were utilized in this work are: Z factor, Liquid dropout, Gas density, Gas-oil ratio, Dew point pressure, fluid viscosity etc.

CHAPTER TWO

2.0 Literature Review

2.1 Review of Existing Literature

A gas condensate reservoir can be defined as a single-phase hydrocarbon fluid system at original reservoir conditions, i.e., pressure and temperature. It predominantly consists of methane and other short-chain hydrocarbons, but it also contains long-chain hydrocarbons termed heavy ends. Under certain conditions of temperature and pressure, this fluid will separate into two phases, a gas and a liquid that is also known as a retrograde condensate [Fan, L. et al].

In gas condensate reservoir, the initial reservoir condition is in the single-phase area to the right of the critical point (Figure 2.1). As reservoir pressure declines, the fluid passes through the dew-point and a liquid phase drops out of the gas. The liquid keeps accumulating until the critical liquid saturation is attained. Once the liquid starts flowing, the flow of gas and liquid is subjected to the law of multiphase flow in porous media [Mindek, C., 2005]. The more interesting phenomena in gas condensate reservoirs is the re-vaporization of the liquid as the pressure crosses the lower dew point line on two-phase envelope of P-T phase diagram (Figure 2.1). This behavior is simply called retrograde behavior [Mindek, C., 2005]. The percentage of vapor decreases but can increase again with continued pressure decline. The cricondentherm is the highest temperature at which two phases can coexist [Fan, L. et al].

The main difference between a gas condensate field and a dry gas field is the additional income derived from surface condensate production [Whitson, C. H., 1999]. Condensate production evolves from produced reservoir gas or well-stream as the well-stream is processed at the surface. The reservoir gas production can most time be handled with traditional gas engineering tools [Whitson, C. H., 1999].

From an engineering point of view, the extra issues which must be addressed in a gas condensate reservoir are:

- How the condensate yield will vary during the life of the reservoir and
- How two-phase gas/oil flow near the wellbore affects gas productivity.

Both of these issues are strongly related to the PVT properties of the fluid system though productivity is more affected by relative permeability effects.

PVT properties important to the engineering of all gas condensate reservoir includes

- Z-factor
- Gas viscosity

A few extra properties needed to handle the condensate part of a gas condensate reservoir are:

- Compositional (C_{7+}) variation with pressure
- Oil viscosity and liquid dropout [Whitson, C. H., 1999]

Conceptually, flow in gas-condensate fields can be divided into three reservoir regions, although in some situations not all three are present (Figure 2.2). The two regions closest to a well can exist when the bottomhole pressure is below the dewpoint of the fluid. The third region, away from producing wells, exists only when the reservoir pressure is above the dewpoint [Fan, L. et al].

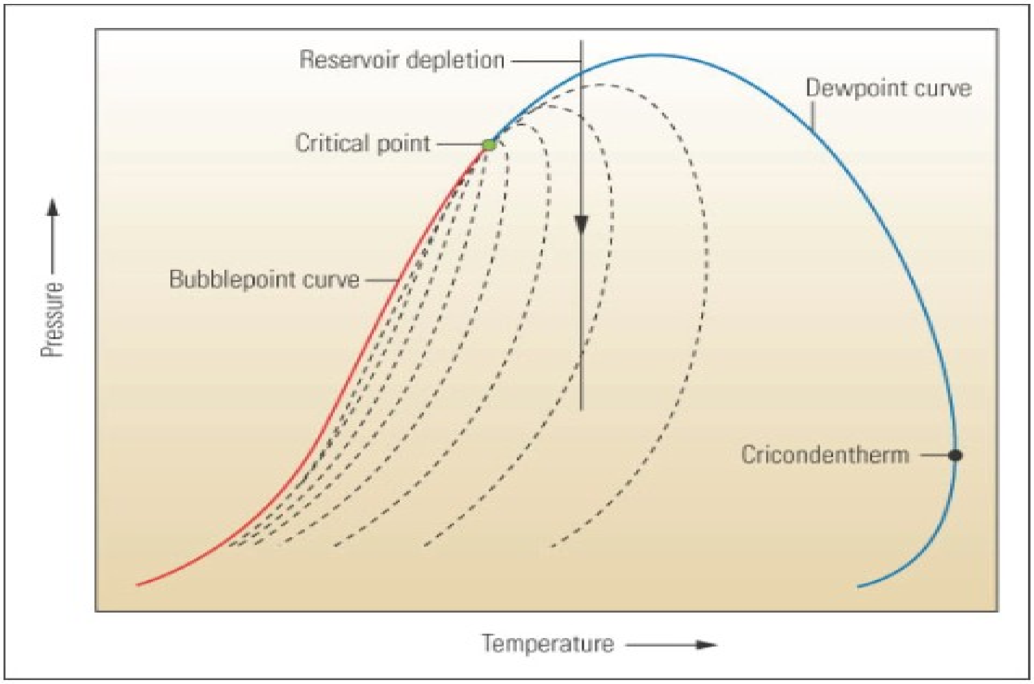


Figure 2.1: Phase Envelope of Retrograde Condensate System (Ahmed Tarek, 2000)

This third region includes most of the reservoir away from the producing wells. Since it is above the dewpoint pressure, there is only one hydrocarbon phase, gas, present and flowing. The interior boundary of this region occurs where the pressure equals the dewpoint pressure of the original reservoir gas. This boundary is not stationary, but moves outward as hydrocarbons are produced from the well and the formation pressure drops, eventually disappearing as the outer-boundary pressure drops below the dewpoint [Fan, L. et al].

In the second region, the condensate-buildup region, liquid drops out of the gas phase, but it saturation remains low enough that it is immobile and there is still single-phase gas flow. The amount of liquid that drops out is determined by the fluid's phase characteristics as indicated by its PVT diagram (See Figure 2.1). As the liquid saturation increases, the gas phase becomes leaner as gas flows toward the wellbore. This region's inner-boundary saturation usually is near the critical liquid saturation for flow, which is the residual oil saturation [Fan, L. et al].

In the first region, closest to the producing well, both gas and condensate phases flow. The condensate saturation here is greater than the critical condensate saturation. This region ranges in sizes from tens of feet for lean condensates to hundreds of feet for rich condensates. Its size is proportional to the volume of gas drained and the percentage of liquid dropout. It extends farther from the well for layers with higher permeability than average since a larger volume of gas has flowed through these layers. Even in a reservoir containing lean gas with low liquid dropout, condensate blockage can be significant, because capillary forces can retain a condensate that builds to a high saturation over time [Fan, L. et al].

This near-well condensate blockage region controls well flow deliverability. The flowing condensate/gas ratio is essentially constant and the PVT condition is considered a constant composition expansion region. This condition simplifies the relationship between gas and oil relative permeabilities, making the ratio between the two a function of PVT properties [Fan, L. et al].

However, additional relative-permeability effects occur in the near-well region because the gas velocity, and therefore the viscous force, is extreme. The ratio of viscous to capillary force gives rise to capillary number. Conditions of pressure gradient caused by high velocity or low interfacial tension have high capillary numbers, showing that viscous forces dominate, and the relative-permeability to gas is higher than the value at lower flow rates [Fan, L. et al].

At even higher near-well flow velocities, the inertial or Forchheimer effect decreases the gas relative permeability somewhat. The basis of this effect is the inertial drag as fluid speeds up to go through pore throats and slows down after entering a pore body. The effect is lower apparent permeability than would be expected from Darcy’s law. We usually refer to this effect as non-Darcy flow [Fan, L. et al].

The overall impact of the two high velocity effects is usually positive which reduces the impact of condensate blockage. Laboratory core-flood experiments are required to measure the inertial and capillary number effects on relative permeability.

A gas-condensate reservoir can choke on its most valuable components. Condensate liquid saturation can build up near a well because of drawdown below the dew-point pressure, eventually restricting the flow of gas. The near well choking can reduce the productivity of a well by a factor of two or more. This phenomenon is called condensate blockage or condensate banking (Figure 2.2).

The condensate banking results from a combination of factors which include fluid phase properties, formation flow characteristics and pressures in the formation and in the wellbore. These factors need to be well understood at the beginning of field development; otherwise, the well production performance will sooner or later suffer [Fan, L. et al].

Fan et al reported that well productivity in the Arun field, in North Sumatra, Indonesia, declined significantly about ten years after production began. This was a serious problem since well deliverability was critical to meet contractual obligations for gas delivery. Well studies including pressure transient testing, indicated the loss was caused by accumulation of condensate (i.e., condensate banking) near the wellbore [Fan, L. et al].

Producing gas condensate fields has become a global challenge within the oil and gas industry, and it has become necessary to define, and thereby avoid conditions that will promote retrograde condensation as the effect may choke the flow string, surface lines, and well testing equipment thereby resulting to low recovery and productivity. This study will focus mainly on the optimization of gas-condensate reservoirs using four-component limited compositional reservoir simulator; hence, the need for understanding the modes of development and operations of gas-condensate reservoir [Islam A.W and Sepehrnoori K., 2013].

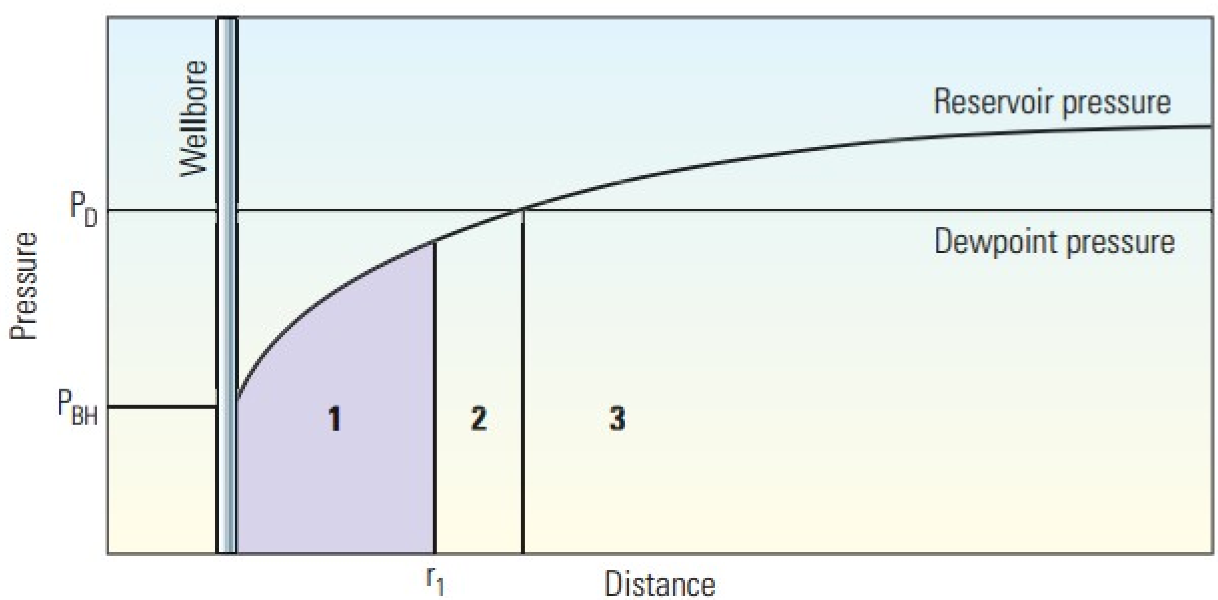


Figure 2.2: Three Regions of a Gas-Condensate Reservoir.

2.2 Theoretical Background

Theoretical Background is presented because for optimization of any petroleum systems, gas-condensate reservoirs in particular, simulation studies are carried out to provide the needed information of the fluids, reservoir, and wells. This information is useful to plan the installation of down-hole or surface equipment, in secondary recovery projects such as water injection or gas injection rates and well locations.

Black-oil models are utilized in the study of conventional recovery techniques in reservoirs for which fluid properties can be expressed as a function of pressure and bubble-point pressure. Compositional models are used when either the in-place or injected fluid causes fluid properties to be dependent on composition also [Young et al., 1983].

2.3 Reservoir Modeling

Reservoir simulation can be defined as the combination of physics, mathematics, reservoir engineering, and computer programming to develop a tool for predicting hydrocarbon reservoir performance under various operating conditions. Reservoir modeling involves the use of simulator. A simulator is a program used to perform material balance calculations to determine pressure and saturation distribution of the reservoir as a function of time.

Validation of reservoir simulators for complex recovery processes is a particularly difficult problem because analytical solutions are available under only a few limiting conditions [Islam A.W and Sepehrnoori K., 2013].

2.3.1 General Description of Simulators

This part introduces the non-thermal numerical reservoir simulators used in the oil and gas industry. Compositional and black oil simulators and an extended black oil simulator also known as modified black oil simulator are introduced with an emphasis on modeling of miscible displacement. Compositional simulators are defined as the numerical reservoir simulators which use multi-component vapor-liquid equilibrium (flash) calculations. On the other hand, extended black-oil simulators do not use flash calculations and requires classical black-oil data which fluid properties, such as formation volume factor and viscosity, are function of pressure solely [Karacaer, et al].

2.3.2 Compositional Simulators

Compositional simulation is required for many applications such as gas injection and other enhanced oil recovery procedures. It is also applicable for the modeling of geological carbon storage. Compositional simulation may be expensive computationally, especially for finely resolved models with multiple components, because the resulting systems can be large and highly nonlinear. For applications such as production optimization, hundreds or thousands of simulation runs must be performed, so models that run efficiently are required [He, J., & Durlofsky, L. J., 2014].

Formulating a compositional simulator requires the knowledge of fluid properties calculated at reservoir conditions. Compositional models capture these changes using a built-in Equation-of-State (EOS) model, where fluid properties are calculated based on changes of pressure, temperature, and compositions. [Al Ghamdi B.N., 2016].

2.3.3 Black-Oil Model

This is a special case of the compositional model. This model defines one component in the water phase; all of the gas is one component, two components in the oil phase which are dissolved gas and residual or black oil left after gas evolution. We have three-component model which are gas, oil and water.

In black-oil simulation, we assume the followings:

- No phase transfer between water and gas
- No phase transfer between oil and water
- Oil does not vaporize into the gas phase
- Gas can be dissolved or liberated from oil phase
- Gas can be dissolved or liberated from water
- Gas can be found in two phases
  - Dissolved gas can be found in the oil phase
  - Liberated gas in the free gas phase
- Can handle primary production, water injection, or dry gas injection, miscible gas injection, etc. [Prof. David O. Ogbe, 2017]

2.3.4 Modified or Extended Black-Oil Models

We cannot accurately model volatile oil and gas condensate reservoirs with conventional black oil models. Conventional black-oil models make use of the three pressure-dependent functions B_o, B_g and R_s. The primary setback of these techniques is that they do not account for the liquid that condenses out of the vapor phase [Bulent I., 2003]. The modified black oil PVT model permits reservoir engineers to account for complex PVT behavior that occurs in gas condensate and volatile oil reservoirs [Energy Blogger, 2015]. These reservoir fluids can be also modeled accurately with full compositional models [Bulent I., 2003].

The Modified Black Oil (MBO) also called Extended Black-Oil; simulation approach was introduced by Spivak and Dixon in 1973. These MBO simulations consider three components which include dry gas, oil, and water. The main difference between the conventional black-oil simulation and the MBO simulation lies in the treatment of the liquid in the gas phase [Fattah, K.A., 2012]. The PVT functions for MBO simulation and material balance calculations of gas condensate and volatile oil are: oil-gas ratio, R_v; solution gas-oil ratio, R_s; oil formation volume factor, B_o; and gas formation volume factor, B_g. The MBO approach assumes that stock-tank liquid component can exist in both liquid and gas phases under reservoir conditions. It also assumes that the liquid content of the gas phase can be defined as a sole function of pressure called vaporized oil-gas ratio, R_v. This function is similar to the solution gas-oil ratio, R_s, normally used to describe the amount of gas-in-solution in the liquid phase [Fattah, K.A., 2012].

The compositional variation in MBO model is due to the depth variation of solution gas-oil ratio and oil-gas ratio. These two black-oil PVT properties in fact represent composition and should, accordingly, be used to initialize the reservoir model. Despite an initialization of composition with depth in a black-oil model, where solution gas-oil and oil-gas ratio are taken directly from the compositional EOS mode, we know that the saturation pressure versus depth will not be represented properly in the black-oil model because a single PVT table is used for a MBO model and fluid at each depth has its own set of PVT tables [Bulent I., 2003].

According to the liquid content and oil-gas ratio, the first dry gas injected will vaporize liquid in MBO model. The ability of vaporizing gas to vaporize oil diminishes as it flows through the reservoir. Thus for this gas, oil-gas ratio is not simply a function of pressure but depends upon the path it takes and the oil with which it comes into contact [Bulent I., 2003]

In modified black-oil model, the primary compositional effect, the stripping of the liquid components in inverse proportion to their molecular weight is completely ignored and by doing this the standard black-oil model disregards the compositional dependence of PVT properties. The kind of formulation used in MBO model allows the dry gas to pick up oil until the gas becomes saturated, which is an optimistic approximation to the real reservoir behavior [Bulent I., 2003].

In consequence to that, when dry gas is injected into a condensate reservoir below its dew point, the gas continues to re-vaporize liquid at a rate governed only by the pressure. The liquid saturation profiles should vary smoothly with increasing distance from the injector.

2.3.5 Limited Compositional Simulation in Eclipse

Eclipse is a widely used industry standard commercial simulator and provides a broad range of modeling facilities [Karacaer, et al]. The Eclipse simulator suite comprises two separate simulators: Eclipse 100 for black-oil modeling and Eclipse 300 for compositional modeling. Eclipse 100 is a fully-implicit, three-phase, three-dimensional, general purpose black oil simulator with pseudo-miscible option. Eclipse 300 is a compositional simulator and can be run in fully implicit, IMPES and adaptive implicit (AIM) modes with cubic equation of state. Primary solution variables are pressure and two-phase saturations for black oil cases in Eclipse 100; pressure, water saturation, molar densities of each component in Eclipse 300. Newton's method is used to solve non-linear conservation equations [Karacaer, et al].

Eclipse 100 provides three and four-component Miscible Flood Model. The three-component miscible flood option assumes that the reservoir fluids consist of three components: reservoir oil (stock tank oil and solution gas), injection gas (solvent) and water. The reservoir oil and solvent gas components are assumed to be miscible in all proportions. Physical dispersion (viscous fingering) of the miscible components is treated using the Todd- Longstaff model [Karacaer, et al].

Todd-Longstaff mixing parameter is an input parameter in Eclipse to account effects of viscous fingering. Formulation in Todd-Longstaff method uses either fully miscible or fully immiscible cases. In reality, there should be a transition between the two displacement characters. Transition between miscibility and immiscibility can be modeled by miscible model with a pressure dependent miscibility function which can be tabulated between 0 and 1; where 0 indicates immiscible displacement and 1 represents miscible displacement. This function interpolates immiscible and miscible PVT properties, relative permeabilities and capillary pressure data [Karacaer, et al].

Solvent model is an extension to miscible flood option, and it consists of four components, water, reservoir oil, reservoir gas and solvent gas. In this model, solvent displacement can be modeled in the presence of free hydrocarbon gas. The solvent gas gravity can differ from the free solution gas [Karacaer, et al].

Another advantage of miscible flood or solvent model is that it can model residual oil saturation to miscible flood. Compositional simulators cannot handle residual oil saturation to miscible flood directly.

2.4 Simulation of Gas Condensate Reservoir Performance

Gas condensate reservoirs are frequently simulated with fully compositional models. Pseudoization procedure is employed to reduce the multi-component condensate fluid to a pseudo two-component mixture of surface gas and oil. This allows the use of modified black oil model which is simpler, less expensive and that can account for both gas dissolved in oil and oil vapor in the gas [Coats et al, 1985].

The term Pseudoization denotes the reduction in the number of components used in EOS calculations for reservoir fluids. Pseudoization is important in reservoir calculations because of the large number of real components in reservoir fluids. Compositional model computing times can increase significantly with the number of components used [Coats et al, 1985].

A major question in the use of the black-oil model is whether the two-component description can represent adequately the compositional phenomena active during the depletion or the cycling of gas condensate reservoirs. This question is especially pertinent to near-critical or very rich gas condensates [Coats et al, 1985].

The two models give identical results for cycling above dew point provided that certain conditions are satisfied. However, the black oil model is not applicable to cycling below dew-point, so results of the compositional model are compared for different multi-component descriptions to estimate the minimal number and identity of components necessary for acceptable accuracy [Coats et al, 1985].

CHAPTER THREE

3.0 Study Methodology

3.1 Research Methodology

The flow diagram below shows the various steps involved in the methodology of this research.

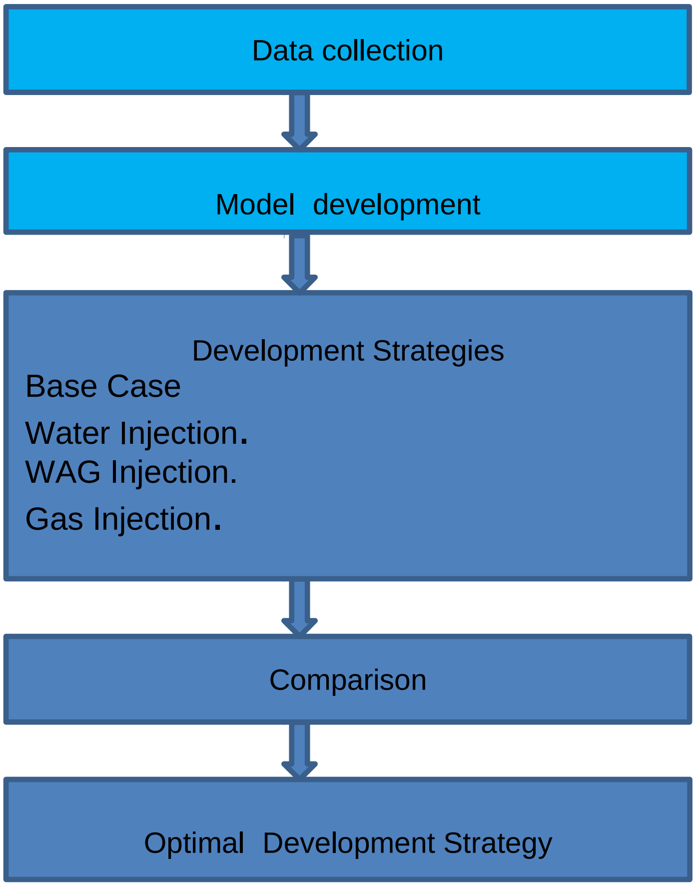


Figure 3.1 Study methodology flow-diagram

3.1.1 Data Gathering

Data gathering is a vital aspect of almost every engineering research work and care must be taken to get quality data. This simply means that quality data can lead to quality results as simulators are garbage in garbage out. In this work, the data were obtained from the published literature describing typical case studies of gas condensate reservoirs in the Niger Delta. Table 3.1 is a summary of the data used in the simulations.

3.1.2 Simulation Model Development

A gas condensate reservoir simulation model was developed in this study using Eclipse black oil software. The model was designed to capture the production characteristics of a gas condensate reservoir in the Niger Delta. The reservoir is undulated and has two regions namely, the North-

West Region and the South-East Region. The North-West Region is a gas dominated zone while the South-East Region is an oil dominated zone. The reservoir is highly rich in hydrocarbon with total field oil in place of 148.8 Million stock tank barrels and 205 billion standard cubic feet (SCF) of gas in place. The field average pressure is 4182PSIA and the average porosity is 0.18. Figure 3.1 shows the initial fluid distribution in the model.

The PVT and SCAL data were generated using ECLIPSE office and SCAL packages respectively. A Carter-Tracy aquifer was modeled to provide additional pressure support to the reservoir. Figure 3.2 shows the three aquifer segments used in the simulations. The rock and fluid property model was developed using ECLIPSE OFFICE software. The input data used for this purpose such as API, specific density, gas oil ratio, reservoir temperature and reservoir pressure were obtained from papers on Niger Delta. The SCAL data was also obtained from a publication from the Niger Delta.

3.1.3 Simulation of Production of Gas Condensate Reservoir

Simulation is simply the imitation of the operation of a real-world process or system over time. This work involves gas condensate reservoir simulation which consists of four production schemes. These include the base case, water injection, gas injection and water alternating gas injection schemes. In the base case, the simulation was to produce the gas condensate reservoir without any injection and the process is referred to as natural depletion stage. This base case was used as a template for the other schemes.

The second case considered water injection scheme. In this case, water was injected in both regions of the reservoir and recovery of oil and gas was recorded. In the third case, gas was injected in the two regions of the reservoir to displace the oil.

For the fourth case of the simulations, water and gas were injected alternatively to displace the oil. This process started with water injection first for four years followed by gas injection for the next four years and finally another water injection for the last four years.

For all the above three injection schemes studied, fluid injection started at Year 8 of the production period. This simply means that natural pressure support was used for the first eight years of production and the remaining twelve years were supported by fluid injections.

The simulation was done for the base case with the aid of six production wells, three in each region. In North-West Region, the total production was set at target flow rate of 12MMSCF per day. The total production in the South-East Region was set at target flow rate of 10MSTB per day.

To simulate the fluid injection cases, two injection wells were drilled, one in each region. In the North-West Region, gas was injected at the maximal injection rate of 3MMSCF per day and water injection rate of 1000STB per day. In the South-East Region, the gas injection rate target was 6MMSCF per day and the water injection rate target was 1000STB per day. Single well was used in each region for the purpose of water alternating gas injection

An extensive sensitivity analyses were carried out to determine the best options for wells placement, maximal production target rate, maximal gas oil ratio, bottom hole flowing pressure subject to reservoir operational constraints.

3.2 Comparison of Development Strategies

The simulations for the four cases were carried out and the results were analyzed to determine the optimum development strategy to produce the gas condensate reservoir.

Table 3.1 Reservoir properties, grid parameters and production constraints

PARAMETER	VALUE	UNIT
SURFACE PROPERTIES		
Oil API	56	Deg. API
Gas gravity	0.72	Dimensionless
Gas oil ratio	82	MSCF/STB
Salinity	0	Fraction
SURFACE CONDITIONS		
Standard Temperature	60	Deg. F
Separator Temperature	60	Deg. F
Standard pressure	14.7	Psia
Separator pressure	14.7	Psia
RESERVOIR CONDITIONS		
Reservoir Temperature	176.7	Deg. F
Dew point pressure	4191	Psia
Porosity	0.18	Fraction
Rock type	Consolidated sandstone	
FIELD DIMENSION		
No of cells in X Direction	48	
No of cells in Y Direction	31	
No of cells in Z Direction	3	
Grid model	3-Dimension	
Delta X	900	Ft
Delta Y	900	Ft

Delta Z	34	Ft
Depth	10300	Ft
Radius of Producer wells	0.29	Ft
Radius of injector wells	0.24	Ft
Rock properties		
Porosity	0.18	fraction
Perm X	910	Md
Perm Y	910	Md
Perm Z	91	md
Compressibility	3e-6	1/psia
Water properties		
Water Reference pressure	4191	Psia
Water Formation volume factor	1.0125	Rb/STB
Water compressibility	2.9e-006	1/psia
Water viscosity	0.36	Cp
Water density	62.42	lb/ft^3
Hydrocarbon properties		
Gas density	0.045	lb/ft^3
Oil density	47.065	lb/ft^3
SDENSITY	0.06243	lb/ft^3
AQUIFER PARAMETERS		
Type of aquifer	Carter-Tracy	
Number of aquifers	3	
Datum depth	10224	Ft
Initial pressure	4300	Psia

Permeability	1000	Md
Porosity	0.21	fraction
Total compressibility (rock and water)	5.8978e-6	1/psia
Aquifer internal diameter	2618	Ft
Angles	Aquifer 1= 180, Aquifer 2= 90, Aquifer 3= 180	degrees
Number of influence tables	7	
MISCIBILITY PARAMETER		
Todd-Longstaff Mixing Parameters	0.8	dimensionless
WELL DATA CONTROL PARAMETERS AND CONSTRAINTS		
Oil Producers minimal oil rate	100	STB/D
Oil Producers minimal gas rate	10	MSCF/D
Gas Producers minimal gas rate	50	MSCF/D
Oil producers Maximal water cut	0.98	Fraction
Oil producers Maximal gas oil ratio	5	MSCF/STB
SOUTH-EAST REGION		
Datum depth	10224	Ft
Initial pressure	4191	Psia
Water oil contact	10300	Ft
Oil gas contact	10124	Ft
Water oil capillary pressure	0.6	Psia
Gas oil capillary pressure	1.2	Psia

NORTH-WEST REGION		
Datum depth	10240	Ft
Initial pressure	4200	Psia
Water oil contact	10300	Ft
Oil gas contact	10140	Ft

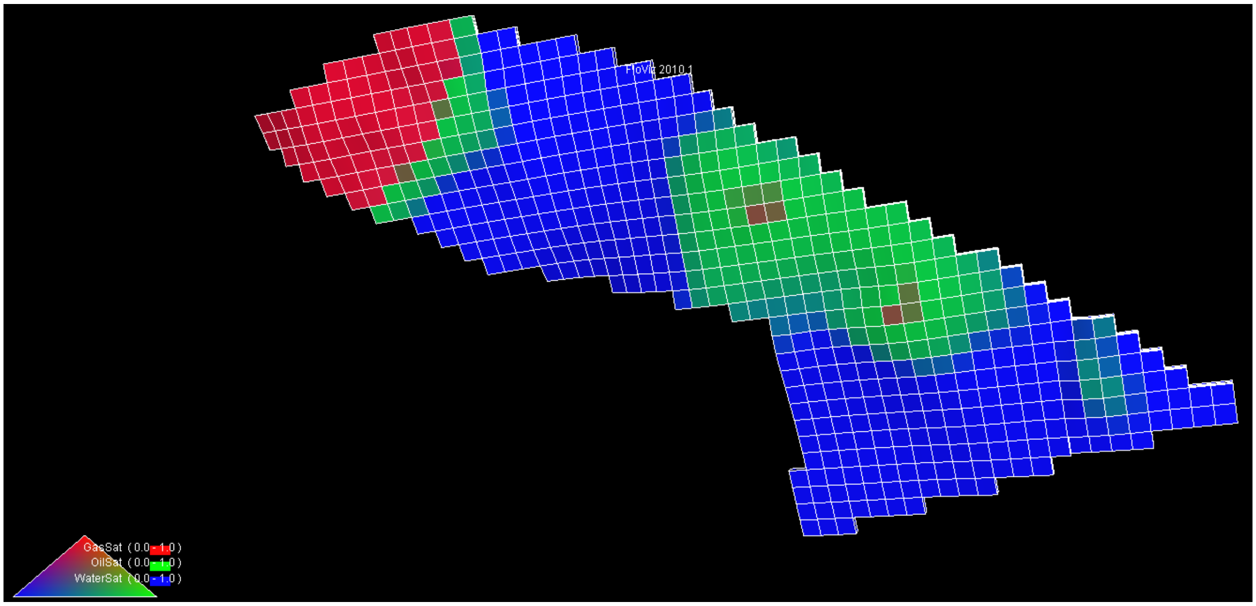


Figure 3.2 Ternary diagram of the model

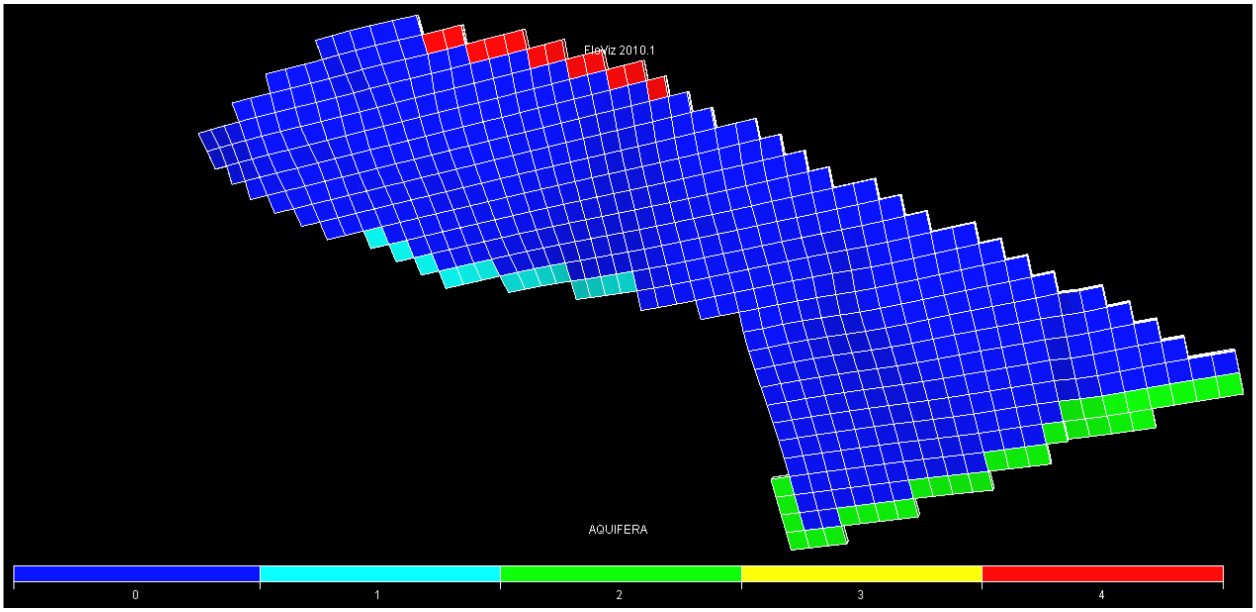


Figure 3.3 Simulation model showing three segments of Carter-Tracy aquifer

CHAPTER FOUR

4.0 Results and Discussion

4.1 Introduction

The results of this work are pressure, oil and gas recovery versus time from the production of the gas condensate reservoir. Four different production schemes were evaluated in this study. The first scheme was the base case in which the simulation model was ran without injection. This process is called natural depletion or primary depletion.

The three fluid injection schemes were also simulated. The first injection scheme was the water injection. In this case, water was injected in the two regions of the reservoir after 8 years of primary depletion.

The second injection scheme was the water alternating gas (WAG) injection in which water was first injected after the eighth year of primary production for four years. This was then followed by another four years of gas injection; and after which water was again injected for the last four years, i.e., 12 years of WAG injection.

The third injection scheme was gas injection. In this case, the hydrocarbon gas produced was re-injected starting from the ninth year of production period up to the final stage of production.

4.2 Results of Production by Natural Depletion, Gas-Flood, Water-Flood and Water Alternating Gas (WAG)

This section presents results of this work and detailed discussion of the results is given.

4.2.1 Pressure-Time Profile

Figure 4.1 above shows the pressure profiles of the various reservoir development strategies studied in this work. The black curve shows the base case pressure performance; the blue is pressure profile from water injection simulation scenario; the green represents the pressure time curve for water alternating gas injection and the red curve represents the pressure profile from gas injection.

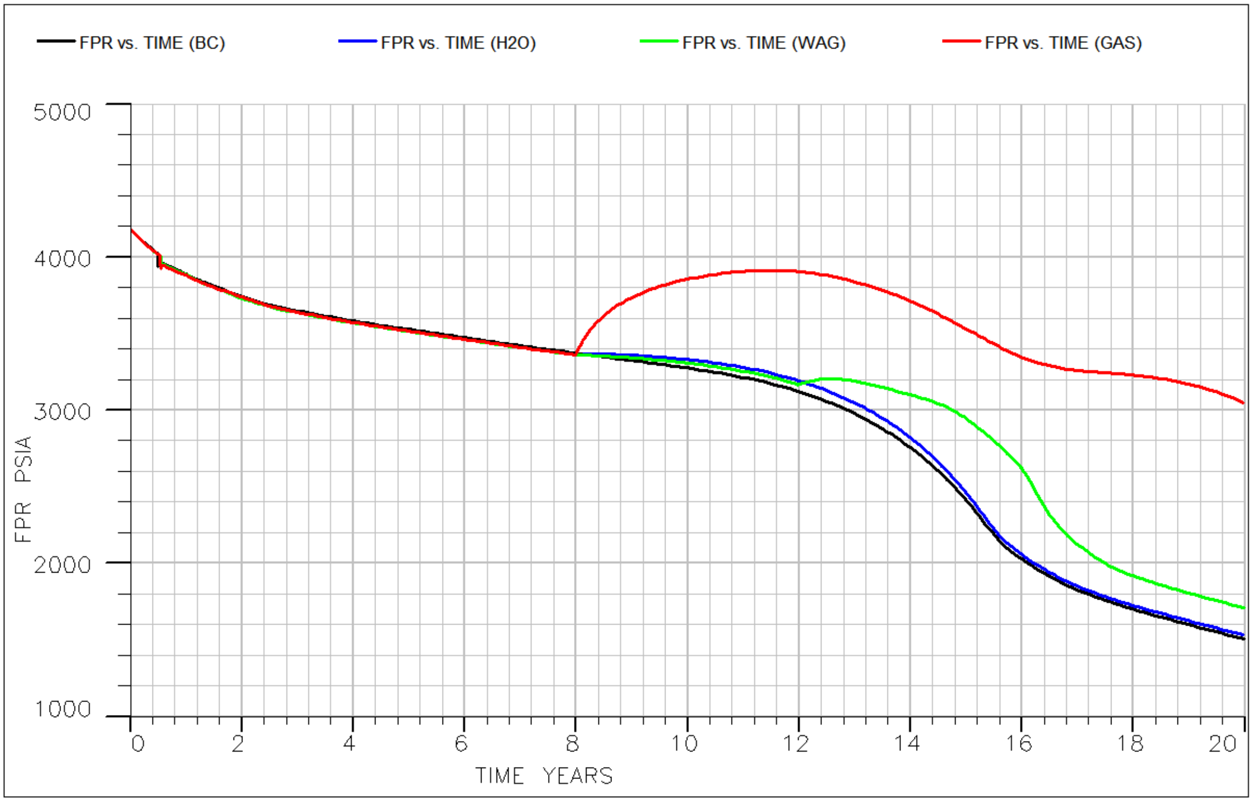


Figure 4.1 Field pressure versus time

<u>Observations</u>: From the pressure profile diagram in figure 4.1, it was observed that the base case shows the lowest pressure maintenance during the gas condensate reservoir production. When water injection was carried out, there is marginal improvement in pressure profile (Blue Curve). For water alternating gas injection, (WAG), there is no remarkable difference between the curve and that of water injection curve from Year 9 to Year 12 of the simulation. But we can notice a sharp improvement of the pressure profile after the twelfth year of production, which is the point where gas injection of the WAG process came into play. For the case of gas injection (the Red Curve), there is significant increment in reservoir pressure and this was maintained throughout the remaining simulation life span. The reservoir pressure remains fairly above 3,000 psia at the end of twenty years of the simulation and it turns out to be the highest pressure maintenance from the simulations.

Discussions: The above pressure profiles show that gas injection gives the highest pressure maintenance followed by WAG injection, then by water injection and lastly by natural depletion. There is insignificant incremental effect of pressure maintenance by water injection and as a result, the pressure profile for water injection is very close to that of the base case or natural depletion. Gas is highly compressible and water is incompressible. The gas has high mobility which makes the injection time to be shorter and can easily occupy the pore space devoid of fluids due to production; all of which helps in remarkable pressure maintenance from gas injection.

4.2.2 Field oil rates and cumulative production

Figure 4.2 shows the field oil production rate and the cumulative oil production. The broken lines represent the field oil production rate plots and the solid lines show the field cumulative oil production. For both cases, there are four simulations. The black plots show the base case or natural depletion without any injection. The blue lines show the water injection scenario, the green plots are for water alternating gas injection case and the red plots are for gas injection.

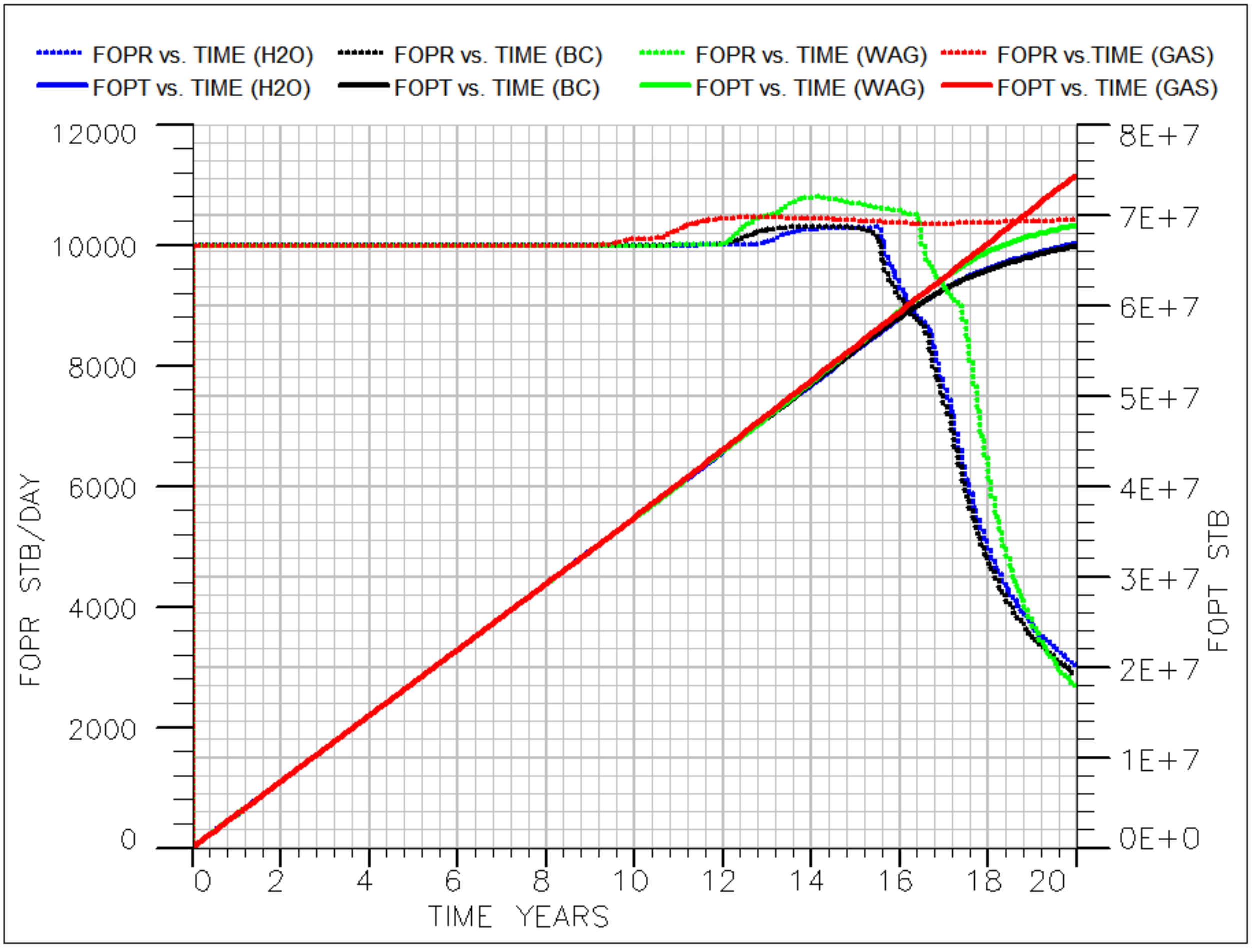


Figure 4.2 Field Oil Production Rate and Oil Cumulative Production

<u>Observation:</u> From figure 4.2, it is observed that the base case shows the least oil recovery vs time followed by the water injection. The water alternating gas injection (WAG) shows a good improvement in oil production. All of the three aforementioned production scenarios started dying (rapid decline) around Year 16 of the production period. The gas injection case maintains constant oil production rate up to around Year 10 of the simulation period; and there is a slight increment in production rate and this was later maintained throughout the remaining simulation period. The cumulative oil production plots follow the same patterns as the production rate curves for all the four simulation scenarios. The oil rate and the cumulative oil produced for base case and the water injection case are almost the same throughout the simulation period. There is

some improvement in oil recovery from both the water alternating gas injection and gas injection compared to the previous two cases. The oil recovery performance by gas injection is more pronounced than the WAG injection scenario.

Discussion: In any displacement process, the recovery of oil depends on the volume of reservoir contacted by the injected fluid. The quantitative measure of this contact is the volumetric displacement efficiency. Volumetric sweep is a macroscopic efficiency which can be defined as the fraction of reservoir pore volume invaded by the injected fluid. The observations made from the FOPR/FOPT plots of the four production schemes indicate that gas injection at 36 MMSCF/day in a gas flooding process is optimal for oil recovery from this reservoir. For water injection, the optimal volume of water is about 2000 rb/day and for water alternating gas injection, the volume of water injected is 2500 rb/day and that of gas is 16 MMSCF/day. It was observed that injection of water and gas above the optimal rates did not contribute to any incremental oil recovery. The observation may be explained by the fact that the optimal rate provides all the sweep efficiency needed for the movable oil in the reservoir and any additional gas would not have any substantial effect on oil recovery.

4.2.3 Field Water Cut

Figure 4.3 shows the field water cut versus time from the simulations of this work. As stated in the previous diagrams, the base case is represented by black, the water injection is represented by blue, the water alternating gas injection is represented by green and the gas injection scenario is represented by red plot.

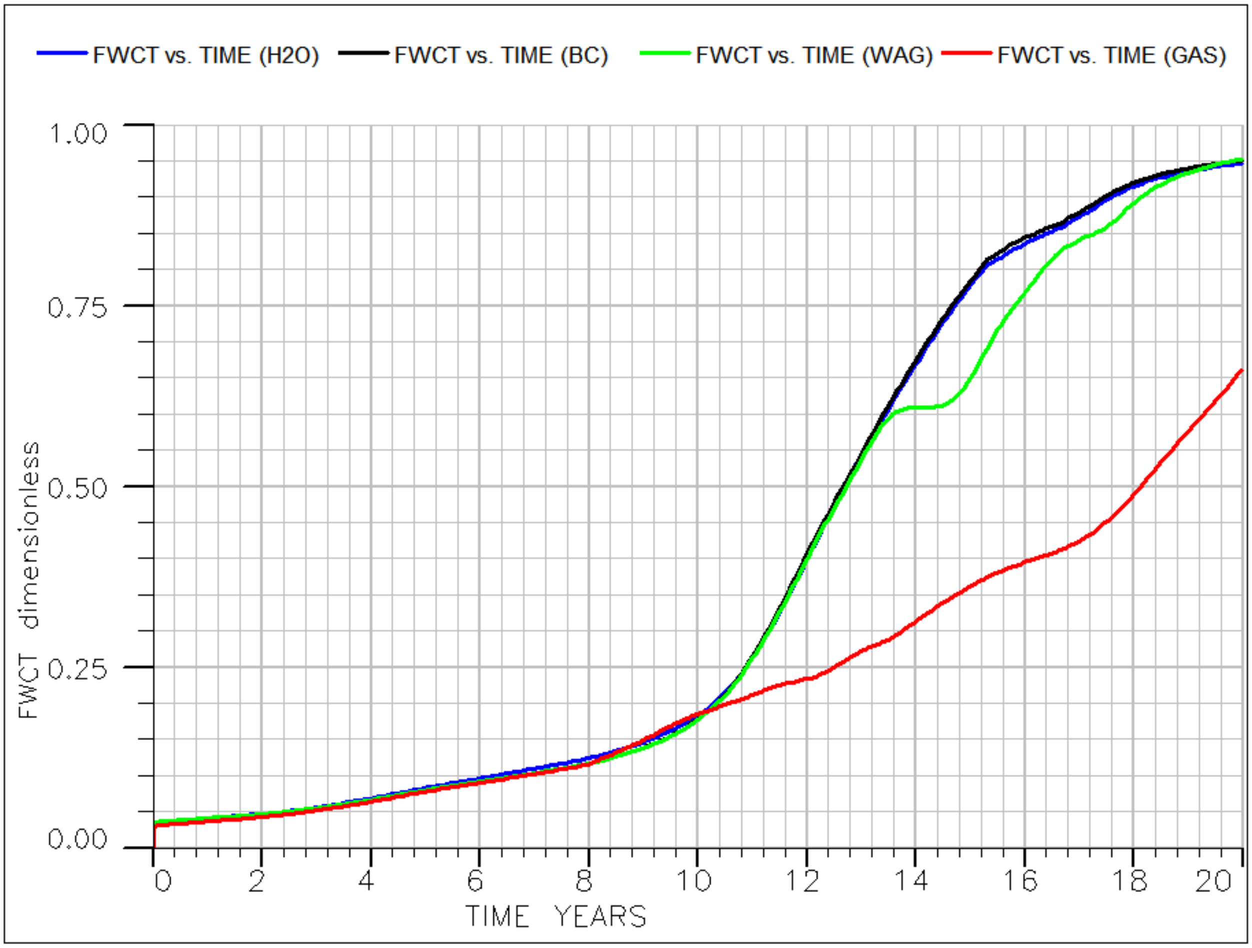


Figure 4.3 Field Water Cut

In this plot, the water cut profile from the base case and the water injection case are almost the same throughout the simulation. These are followed by the water cut profile from the water alternating gas injection which deviates from the first two plots after Year 13 of the simulation period. All of the three cases almost end at the same point which is 95% water cut at the end of the simulation period. For gas injection scenario, the deviation of the water cut profile from the base case starts after Year 10 of the simulation and this continues throughout the remaining simulation duration. At the end of the simulation, the water cut is about 60% lower than the 95% cut-off for the field water cut.

4.2.4 Field Gas-Oil-Ratio

The plots of the field gas oil ratio (FGOR) vs. time from the results of the simulations are shown in figure 4.4. The color scheme used to plot the data in this figure is not different from the previous diagrams. As in the previous cases, the black curve represents base case, the blue is water injection, the green is water alternating gas injection and the red is gas injection scheme.

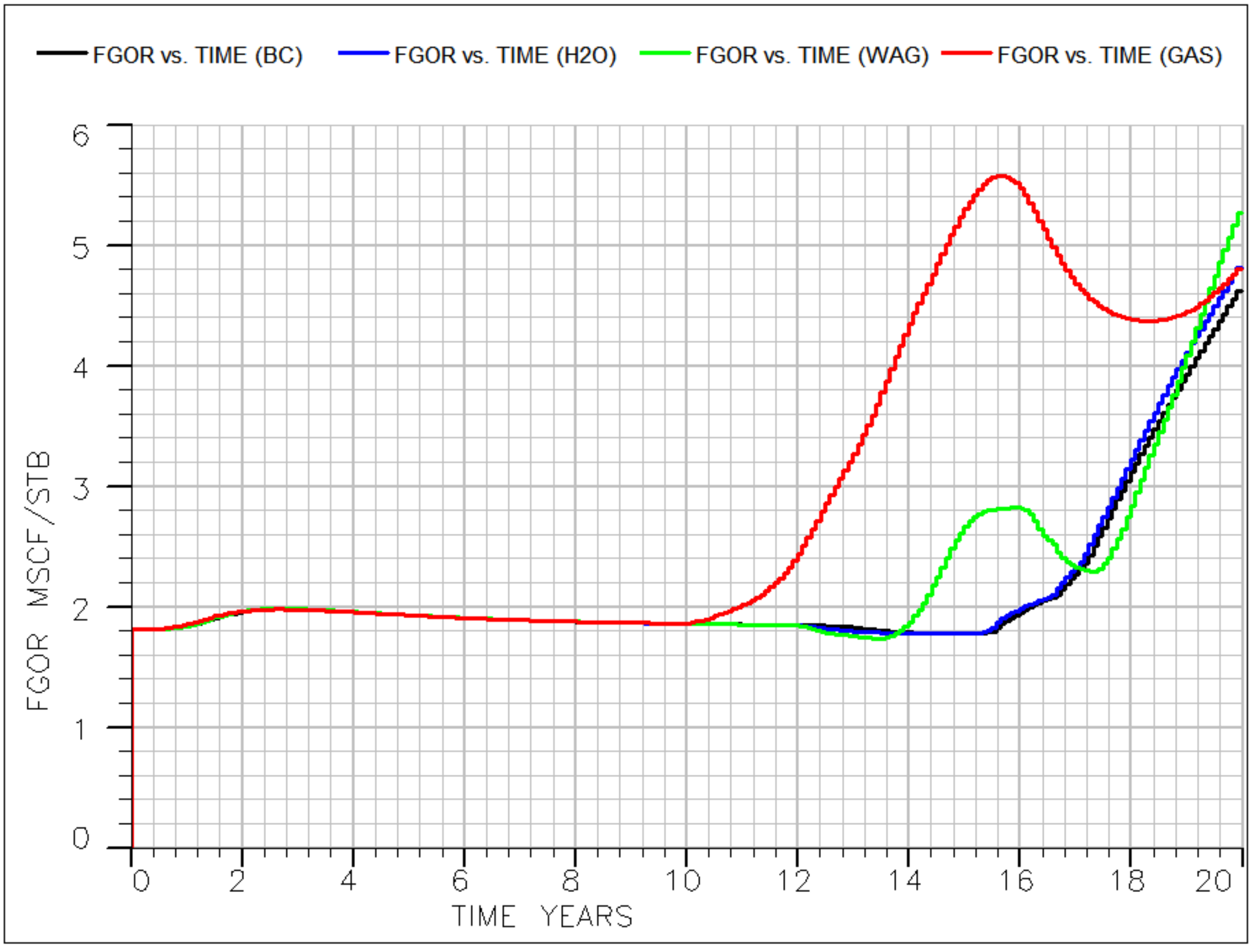


Figure 4.4 Field Gas-Oil Ratio (GOR)

<u>Observation:</u> It is observed from figure 4.4 that the profiles of the gas oil ratio vs. time for, the base case and the water injection scenarios are almost the same throughout the simulation period. Next to the first two cases is the gas oil ratio profile from the water alternating gas injection which shows higher GOR after Year 14. For the gas injection scenario, notice that after Year 10

of the simulation, there is a deviation of the GOR performance plot from the three previous cases. There is a sharp rise in GOR during production by the gas injection and this rise continues almost to Year 16 of the simulation period; and the GOR profile for this case declines gently for a short period before it increases again for the remaining simulation time.

Discussion: Recall that the results shown earlier for natural depletion case (base case) and water injection case indicated that the reservoir pressure is depleting at a faster rate along with increasing water cut during the 20-year production of the reservoir. This shows that reservoir pressure maintenance by other means than water injection will be required to limit the impact of black-oil recovery and condensate drop-out during the production. Therefore, gas injection and water alternating gas injection methods have been introduced as the more efficient recovery schemes with the following objectives:

- To maintain the pressure and avoid condensate drop-out.
- To recover the already precipitated condensate.

It is observed from the results of the simulations that both water alternating gas injection and gas injection methods made significant impacts on the cumulative oil recovery, lower water cuts and therefore improved recovery performance of the gas condensate reservoir. It is also observed that the higher the fraction of gas re-injected the higher condensate and black-oil recoveries are; and the lower the drop-out is.

It should be recalled that the fundamental goal of this research is to provide guideline and preliminary forecast results to support the decisions on the optimal exploitation of the gas condensate reservoir. This goal has been achieved as this study has used a Niger Delta case study of a gas condensate to quantify the following:

- The number of gas and oil producers requires to optimally produce the reservoir
- The need for fluid injection (gas and/or water) and the associated volumes to be injected
- The estimated overall production potential of the reservoir
- The expected recovery factors of gas and condensates from the reservoir

CHAPTER FIVE

5.0 Conclusion and Recommendations

5.1 Summary and Conclusion

In summary, limited-compositional simulator was used in this work to evaluate the recovery performance of gas-condensate reservoirs. Quality data collection was carried out which served as input to the simulation model. These data were used to build the limited-compositional simulation model. Carter-Tracy aquifer was included in this model which function was to provide pressure support for the gas condensate reservoir.

The simulation model was used to carry out four (4) development strategies which include the base case or primary recovery, water injection, gas injection and water alternating gas (WAG) injection. Results of the four (4) different recovery schemes were generated which include pressures, oil and gas recovery vs. time from the production of the gas condensate reservoir. The various results were compared and gas injection showed good performance which was followed by WAG injection. However, water injection and primary recovery show poor performance for this work.

The following conclusions were derived from the study conducted:

1. Base case of primary depletion recovery factor was about 40% of the oil in place after 20 years of production
2. Water injection gave about 41% recovery efficiency which is 1% higher than of the base case
3. WAG injection gave about 46% recovery of the oil in place which is 6% excess compared to the base case.
4. Gas injection gave the highest recovery efficiency of about 53% recovery of the oil in place and the lowest water cut of all the production schemes studied in this work.

5.2 Recommendations

The following recommendations are suggested for future research.

1. An economic analysis needs to be carried out for this work to assess the profitability of producing the gas condensate reservoir and to support decision of its development.
2. This study used only vertical wells to produce this reservoir. It is suggested that the use of horizontal wells should be evaluated to know the recovery efficiency and profitability of applying these IOR (improved oil recovery) methods in this reservoir.
3. Only constant WAG cycles and volumes were considered in this work. The tapered water alternating gas injection concept needs to be considered in future work.

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APPENDIX: A

Field Gas Production Rate and Cumulative Field Gas Production

Figure A.1 shows the graph of both the field gas production rate and the cumulative field gas production. In this figure, the broken lines show the field gas production rate and the solid lines indicate the cumulative field gas production. The black lines are for the base case, the blue lines are for water injection scenario, the green lines are for water alternating gas injection and the red lines are for the gas injection.

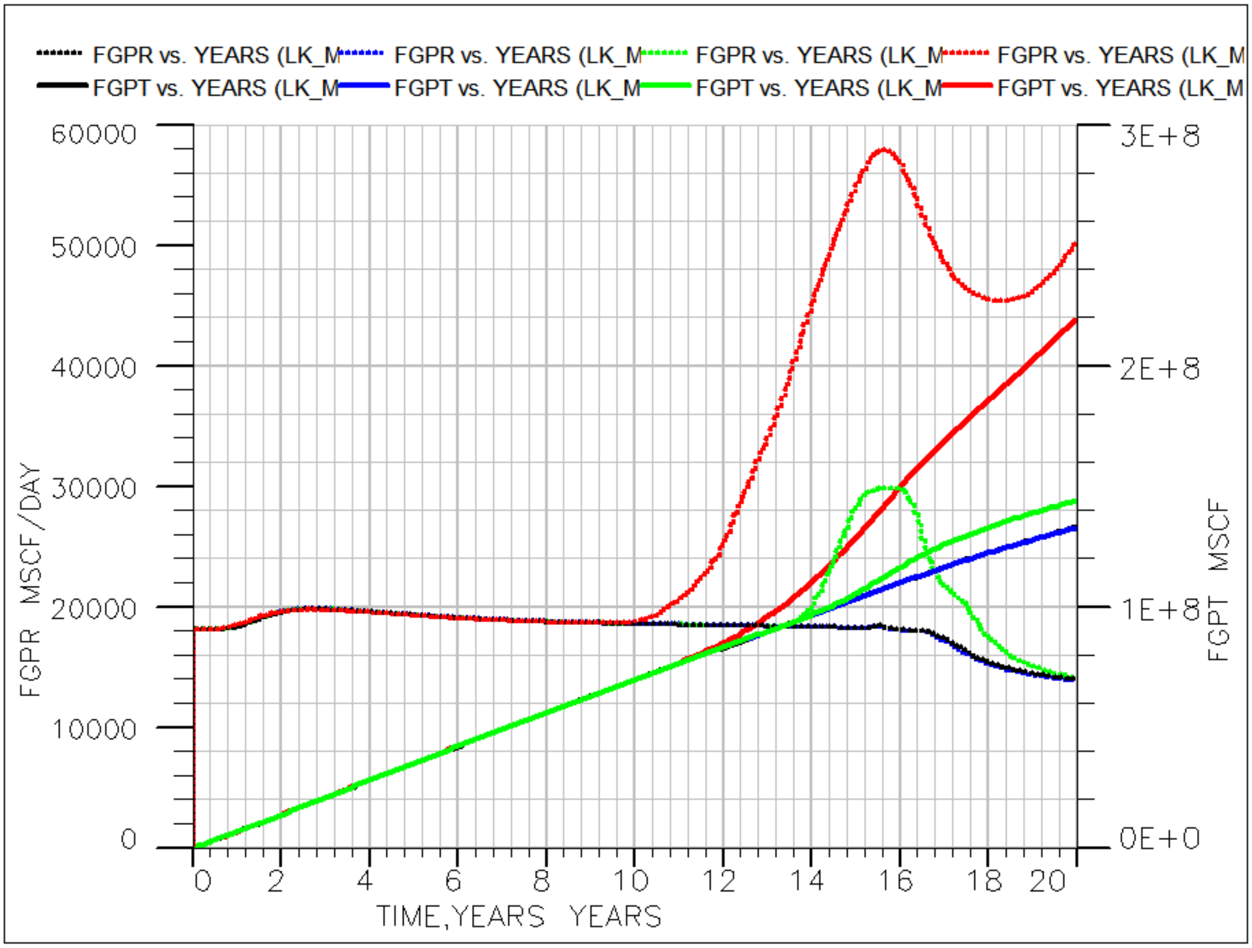

Figure A.1 Field Gas Production Rate And Cumulative Gas Production Versus Time

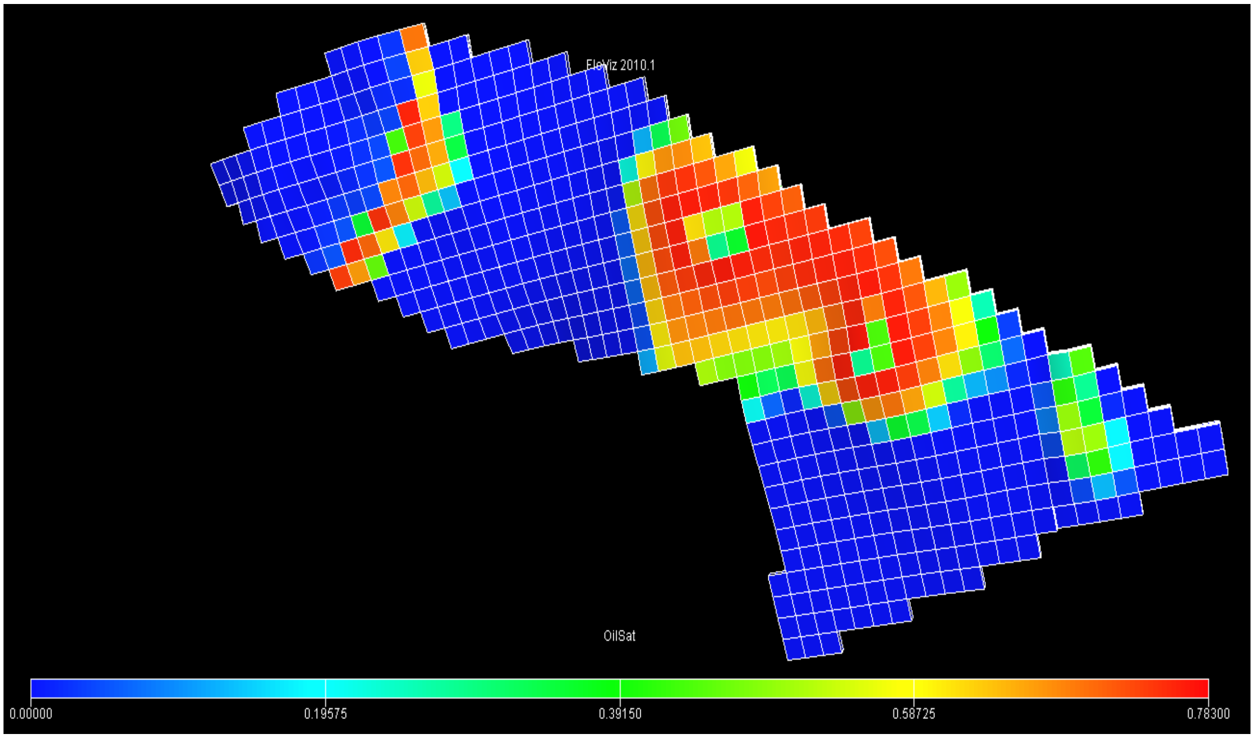

Figure A.2 Floviz of Oil Saturation

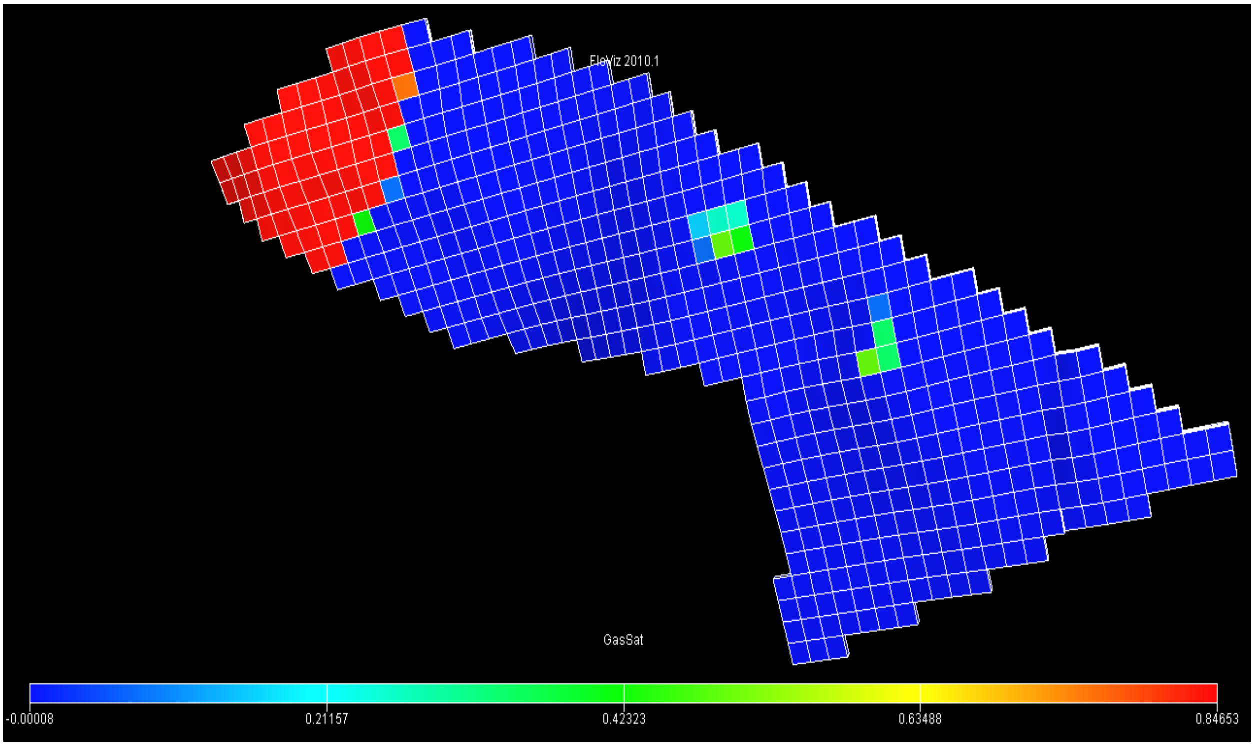

Figure A.3 Floviz of Gas Saturation

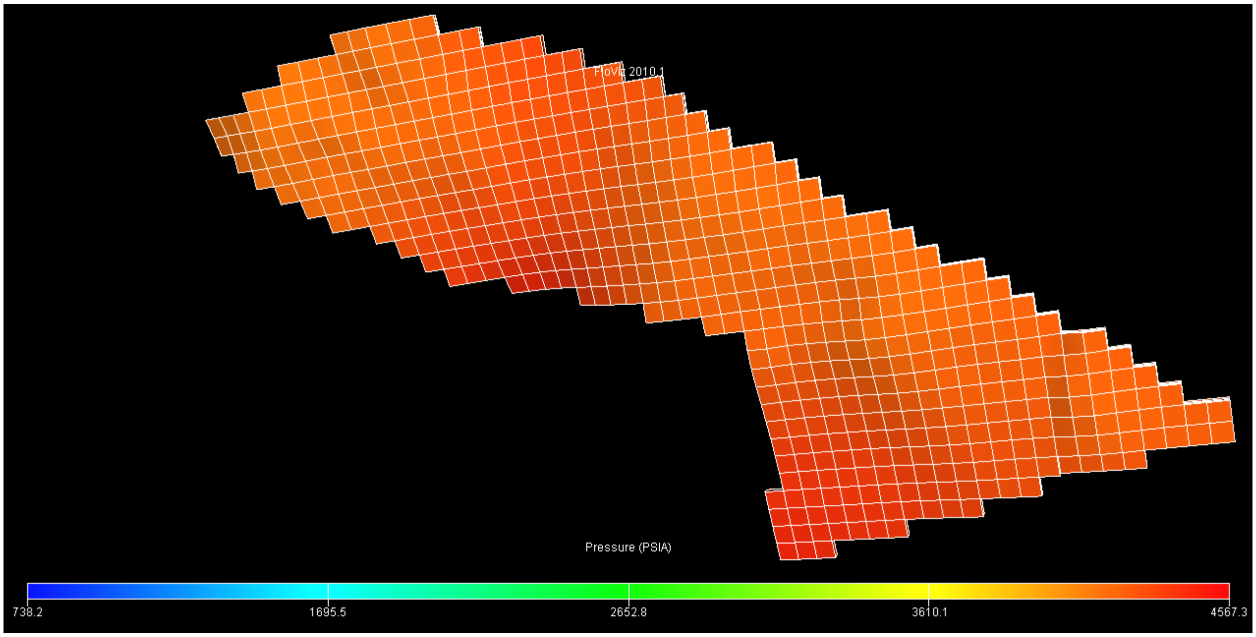

Figure A.4 Initial Reservoir Pressure Profiles

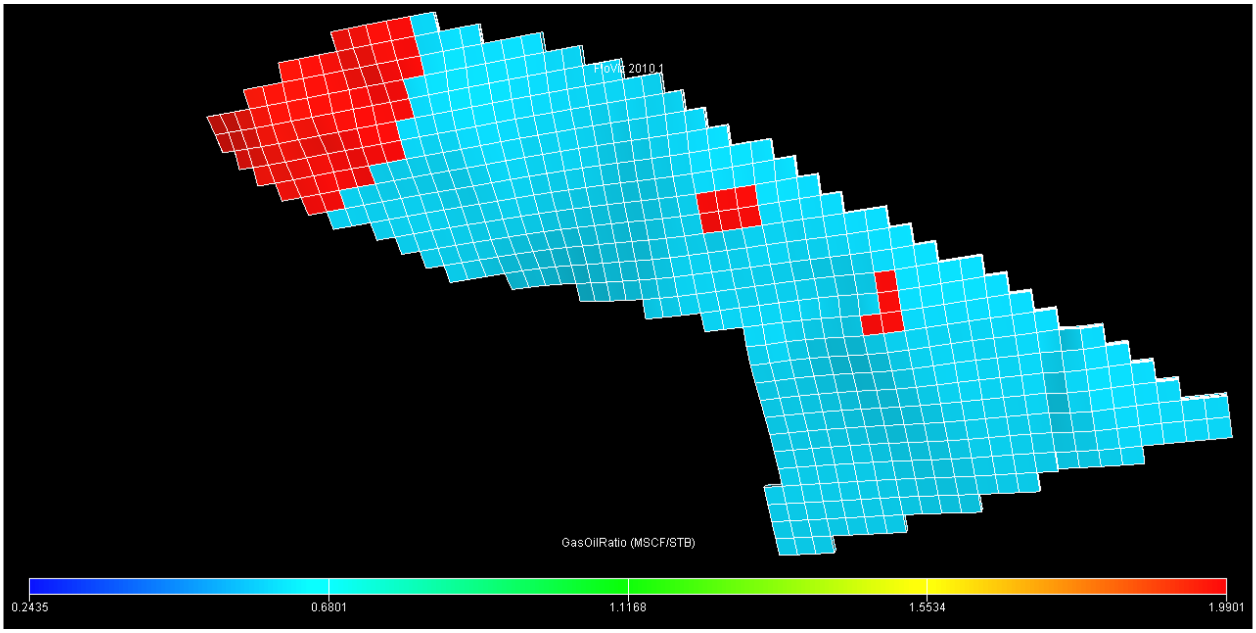

Figure A.5 Dissolved Gas Oil Ratio

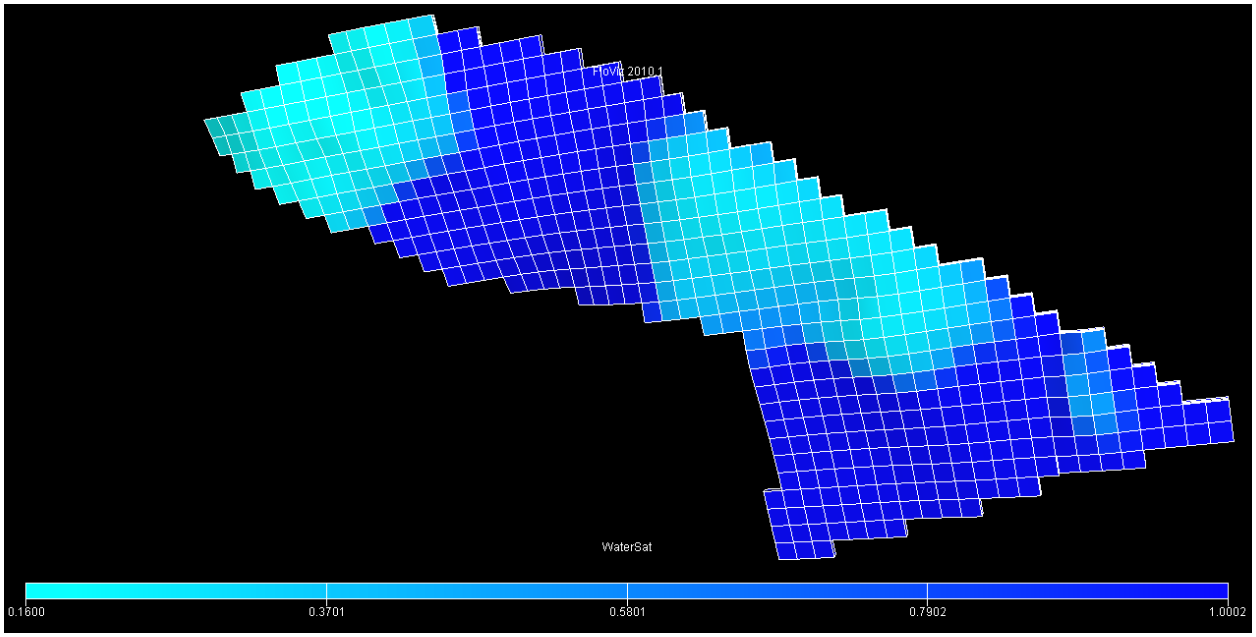

Figure A.6 Connate Water Saturation

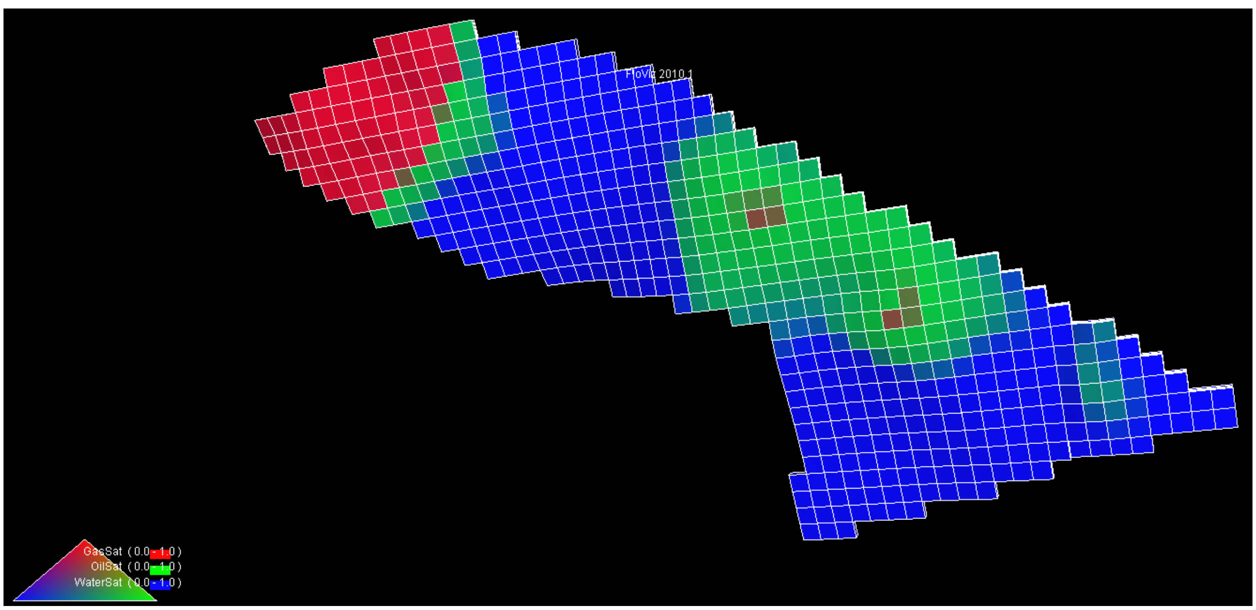

Figure A.7 Ternary diagram of the model