PVT Model for Libya Fields Using PVT\textsubscript{i} Software

Submitted to the Petroleum Engineering Department at the University of Sabha as a Partial Fulfilment of the Requirements for the Degree of Bachelor of Science in Petroleum Engineering.

Prepared by:
Hassan Ahmed Gehiny

Supervised by:
Eng. Hammdi Mumen

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Dedication

We dedicated this project to our parents, brothers, sisters, and friends whose supported us during study duration.
Acknowledgment

First of all, we would like to thank Allah the almighty for everything we have achieved.

Secondly, we would like to thank Eng. Hamdi Mumen for his patience, guidance, and constant support. We are very grateful for all of his help and encouragement, he was always there for us whenever we needed help or guidance, without him this work would not have been possible.

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Abstract

Knowledge of The Pressure Volume Temperature (PVT) parameters is a requirement for all types of petroleum calculations such as determination of hydrocarbon flowing properties, predicting future performance, designing production facilities and planning methods of enhanced oil recovery etc.…

Ideally the PVT properties of hydrocarbon are obtained from laboratory analysis and correlation using either bottom-hole samples or recombined surface samples. However, laboratory data are not always available due to economical and/or technical reasons. In this case empirical techniques are used to estimate the properties.

In this study PVT models for Libya fields was performed using equation of state by defining the fluid component and experimental data that collected from Libya fields from two PVT reports into PVT software.

In Farrud Field (Ghani Field) the Tuning and regression process was performed on PVT model by splitting C_{7+} into two fractions with different frac percent. The percentage for first frac was 65% and the other was equal 35%. Also, first contact miscibility experiment was performed in order to determine minimum miscibility pressure “MMP” for different injection gases. The MMP result from PVT model when inject different gases “CO_2,N_2, C_1 and H.C mixture” was equal was equal 2576, 14690, 8789 and 4113 Psi respectively. And in A Field (NC-186A) the Tuning and regression process was performed on PVT model by splitting C_{7+} into two fractions with different frac percent. The bubble point pressures of BHS in A-03 (West) are very close (794.7 psig) and after tuning using the software was (794.77 psig), The Error (RMS) values the difference between the observed and calculated values is divided by the observed value), in this case it is below 2%.
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Chapter One

Introduction
1.1. Introduction

To understand and predict the volumetric behavior of oil and gas reservoirs as a function of pressure, knowledge of the physical properties of reservoir fluids must be gained. These fluid properties are usually determined by laboratory experiments performed on samples of actual reservoir fluids. In the absence of experimentally measured properties, it is necessary for the petroleum engineer to determine the properties from empirically techniques. The PVT data on most of these fluid properties are usually determined by laboratory experiments performed on samples of actual reservoir fluids accurate laboratory studies of PVT and phase-equilibria behavior of reservoir fluids are necessary for characterizing these fluids and evaluating their volumetric performance at various pressure levels. There are many laboratory analyses that can be made on a reservoir fluid sample.

In the differential liberation process, the solution gas that is liberated from an oil sample during a decline in pressure is continuously removed from contact with the oil, and before establishing equilibrium with the liquid phase. This type of liberation is characterized by a varying composition of the total hydrocarbon system.

Separator tests are conducted to determine the changes in the volumetric behavior of the reservoir fluid as the fluid passes through the separator (or separators) and then into the stock tank. The resulting volumetric behavior is influenced to a large extent by the operating conditions, i.e., pressures and temperatures, of the surface separation facilities. The primary objective of conducting separator tests, therefore, is to provide the essential laboratory information necessary for determining the optimum surface separation conditions, which in turn will maximize the stock-tank oil production. In addition, the results of the test, when appropriately combined with the differential liberation test data, provide a means of obtaining the PVT parameters (Bo, Rs, and Bt) required for petroleum engineering calculations. These separator tests are performed only on the original oil at the bubble point.

The Phase Behavior of a hydrocarbon reservoir is a dynamic event that is controlled by pressure, temperature and composition. To effectively manage the production of a hydrocarbon system that changes as it is being depleted, it is essential to be able to predict
the physical properties of the reservoir fluid that will exist and govern that production process. Some of the predictive techniques available to the reservoir engineer are used for:

1. Prediction of original oil in place.
4. Reservoir fluid flow.
5. Fluid properties for financial and governmental requirements.

The PVTi program is an Equation of State based package for generating PVT data from the laboratory analysis of oil and gas samples. The program may be used through an interactive menu system or run in a batch mode. An interactive session can be saved as a batch input file, which contains commands to reproduce the interactive operations. Alternatively, a batch input file can be run from an interactive session.

1.2. Objective of Study

This study outlines the procedures used to analyze available reservoir fluid PVT data for the Farrud Reservoir (Ghani Field) in order to perform a good PVT model for the field and use it to predict fluid minimum miscibility pressure “MMP” for different injection gas. The objectives of this section were:

1. To review existing fluid property data including PVT, gas, and oil analyses.
2. Predict the hydrocarbon fluid properties and phase behavior by adapting an equation of state (EOS).
3. Predict MMP for different injection gas and compare it with the result obtained from laboratory experiment.
Chapter Two

Literature Review
2.1. Introduction

Knowledge of the PVT parameters is a requirement for all types of petroleum calculations such as determination of hydrocarbon flowing properties, predicting future performance, designing production facilities and planning methods of enhanced oil recovery...etc. Ideally the PVT properties of hydrocarbon are obtained from laboratory analysis using either bottom-hole samples or recombined surface samples. However, laboratory data are not always available due to economical and/or technical reasons. In this case empirical correlations are used to estimate them.

Reservoir fluid properties are very important in reservoir engineering computations such as material balance calculations, well test analysis, reserves estimate, and reservoir simulations. PVT (Pressure-Volume-Temperature) represents the behavior of hydrocarbon reservoir fluids (i.e., oil, gas and water). Pressure Volume Temperature (PVT) analysis is the study of the changes in volume of a fluid as function of pressure and temperature during fluid transfer from reservoir to surface/processing facilities. Knowledge of the pressure–volume–temperature (PVT) properties is a requirement for all types of petroleum calculations such as determination of hydrocarbon flowing properties, design of fluid handling equipment, and reservoir volumetric estimates. For the development of a correlation, the geological condition is considered important because the chemical composition of crude oil differs from region to region. Data on most of these fluid properties are usually determined by laboratory experiments performed on samples of actual reservoir fluids. In the absence of experimentally measured properties of crude oils, it is necessary for the petroleum engineer to determine the properties from empirically derived correlations. [1]

Accurate laboratory studies of PVT and phase-equilibrium behavior of reservoir fluids are necessary for characterizing these fluids and evaluating their volumetric performance at various pressure levels. There are many laboratory analyses that can be made on a reservoir fluid sample. Among the PVT properties is the bubble point pressure (Pb), Gas solubility (Rs) and oil formation volume factor (B_o), which is defined as the volume of reservoir oil that would be occupied by one stock tank barrel oil plus any dissolved gas at the bubble
point pressure and reservoir temperature. Since it is crucial that all calculations in reservoir performance, production operations and design, and formation evaluation be as good as the PVT properties, therefore precise prediction of Pb and Bo. There are many empirical correlations for predicting different PVT properties such as the equation of state (EOS), linear or non-linear multiply regression or graphical techniques. Many correlations already exist in the oil and gas industry such as the: Standing, Glaso, Begs and Vasquez correlations etc. In some cases, PVT data are not available or reliable. At these occasions, empirical correlations are used which are developed for PVT properties estimation. Accuracy of the correlations depends on similarity of fluid properties and fluid that used for developing correlations, thus results of the predictions may not be accurate for new samples.

2.2. Fluid Sampling

Reservoir fluids should be sampled as early as possible during the production life of a reservoir. The sample can be collected either as a single phase at the bottom hole when the pressure is still above the saturation value, or at the surface. There are essentially three sampling techniques for obtaining reservoir-fluid samples for analysis of the pressure, volume, and temperature (PVT) relations. These three techniques are commonly known as:

1. Bottom-hole sampling.
2. Surface sampling.

2.2.1. Bottom-hole Sampling

A well must be selected and properly prepared before any of the sampling techniques can be applied. The engineer should select a well with a high productivity so as to maintain as high a pressure as possible in the formation surrounding the well. It is suggested that the well should be as new as possible so as to minimize free gas saturation. The well selected should not be producing free water. If the only available well does produce water, special care must be exercised in locating the sampling bomb. A series of productivity tests should be conducted on the well to determine the bottom-hole flowing pressures which exist at various rates of flow. These tests aid in selecting the well which will have the highest
flowing bottom-hole pressure at the stabilized flow rate. The producing history of the wells should be studied. The well selected for sampling should have been producing with a stabilized gas-oil ratio. If a well exhibits a rapidly increasing gas-oil ratio, the saturation conditions would probably prohibit the collecting of a representative sample.

2.2.2. Surface Sample
Surface samples are commonly collected from test separators. The oil (condensate) and gas samples must be collected as single-phase fluids. The production rate of each phase should be monitored over an extended period to ensure a steady and stable flow. The separator temperature and pressure, along with the producing gas/liquid volumetric ratio are reported to the PVT laboratory. The information is used to evaluate the integrity of collected samples received in the laboratory, and to use in the recombination process [5]. It is usually the cheapest method, and provides large volume of easily available samples. Two common problems with conventional separator sampling and recombination are liquid carry over into the gas stream and gas carry under into the liquid stream. The most common method of sampling surfaces sampling. [4]

2.3. Methods Determining PVT Properties
Fluid properties can be determined by two methods:
1. Laboratory Analysis of Reservoir Fluids.
2. Empirical Correlations.
2.3.1. Laboratory Analysis of Reservoir Fluids
Accurate laboratory studies of PVT and phase-equilibrium behavior of reservoir fluids are necessary for characterizing these fluids and evaluating their volumetric performance at various pressure levels. There are many laboratory analyses that can be made on a reservoir fluid sample. The amount of data desired determines the number of tests performed in the laboratory. In general, there are three types of laboratory tests used to measure hydrocarbon reservoir samples.\(^5\)

- **Primary Tests:** These are simple, routine field (on-site) tests involving the measurements of the specific gravity and the gas-oil ratio of the produced hydrocarbon fluids.\(^4\)

- **Routine Laboratory Tests:** These are several laboratory tests that are routinely conducted to characterize the reservoir hydrocarbon fluid. They include:
  1. Validity check tests.
  2. Constant-composition expansion.
  3. Differential liberation.
  4. Separator tests.
  5. Viscosity measurement.

- **Special Laboratory PVT Tests:** These types of tests are performed for very specific applications. If a reservoir is to be depleted under miscible gas injection or a gas cycling scheme, the following tests may be performed:
  1. Slim-tube test.
  2. Swelling test.

**PVT results from lab are used with cautions because:**
1. Usually conducted at reservoir temperature.
2. May not be available early in the life of the reservoir (for economic reasons).
3. The results of the laboratory analysis of a reservoir fluid sample questionable since there are related to whether or not the sample obtained is truly representative of the reservoir fluid.\(^4\)
2.3.2. Routine Test
2.3.2.1. Validity Check Tests

The main target from these tests is to make sure the sample is representative to the hydrocarbons of reservoir. The tests consist of three parts:

1. **Opening pressure test**: to make sure the final pressure of sample is the same as the reservoir pressure.
2. **Drain test**: is to make sure of sample is contain pure hydrocarbons.
3. **Transfer test**: to know exactly the volume of sample and know if it’s enough to do all tests or not.

2.3.2.2. Constant-Composition Expansion Test

The (CCE) experiment is performed to determine the type and the volumetric characteristic of any given composition fluid, primarily under initial reservoir condition. The test is conducted for the purposes of determining:

a) Saturation pressure.

b) Isothermal compressibility coefficients of the single-phase fluid at pressures in excess of saturation pressure.

c) Compressibility factors of the gas phase.

d) Total hydrocarbon volumes as a function of pressure at a constant temperature.

e) The saturated fluid density.

![Diagram](image-url)

**Figure 2.2. Constant Composition expansion test procedure.**[8]
The relative volume is equal to one at $P_d$. The gas compressibility factor at pressures greater than or equal to the saturation pressure is also reported. It is only necessary to experimentally measure the $z$-factor at one pressure $P_1$ and determine the gas Deviation factor.

2.3.2.3. Differential Liberation Test

The differential liberation process consists of decreasing the pressure of a sample at reservoir temperature from initial static pressure down to atmospheric one removing the liberated gas continuously from the system. The pressure is first decreased from initial static pressure down to bubble point one, and then the pressure is decreased in a series of steps (typically 6 to 8) down to atmospheric pressure. At each step the gas phase in equilibrium is removed from the cell before decreasing the pressure to the next one.

The experimental data obtained from the test include:

- Amount of gas in solution as a function of pressure.
- The shrinkage in the oil volume as a function of pressure.
- Properties of the evolved gas including the composition of the liberated gas, the gas compressibility factor, and the gas specific gravity.
- Density of the remaining oil as a function of pressure.
Commonly called separator tests, are conducted to determine the changes in the volumetric behavior of the reservoir fluid as the fluid passes through separator (or separators) and then into the stock-tank. The resulting volume the behavior is influenced to a large extent by the operating conditions, i.e., pressures and temperatures of the surface separation facilities. The primary contribution of separator tests is to provide the essential laboratory information necessary for defining the set of surface separation conditions that will maximize stock-tank oil production. The experimental procedure is illustrated schematically in. Separator tests are basically performed to determine:

a) Optimum separation conditions: separator pressure and temperature.
b) Compositions of the separated gas and oil phases.
c) Oil formation volume factor.
d) Producing gas-oil ratio.
e) API gravity of the stock-tank oil.
The optimum separator pressure is an intermediate pressure which yields a maximum value of stock-tank API gravity and minimum values of oil formation volume factor and gas-oil ratio. At high separator pressure, large amounts of light components will remain in the liquid phase and be lost along with other valuable components to gas phase at the stock-tank. On the other hand, at low separator pressure, large amounts of light components will be separated from the liquid and they will attract substantial quantities of intermediate and heavier components.

Figure 2. 5. flash Separator test. [9]

Figure 2. 6. Optimum separator pressure. [9]
2.3.2.5. Viscosity Test

The Ruska rolling ball viscometer is used to determine the viscosity of bottom hole and surface samples at elevated temperatures and pressures, up to 10,000 psi and 300 °F. This instrument operates on the rolling ball principle, where the roll time of a ¼ inch diameter ball is used to obtain viscosity data.

The viscosity is calculated as:

\[ \mu = K \cdot t \cdot (\rho_{ball} - \rho_{fluid}) \]  
……………………………………eq(2.1)

Where: \( \mu \) is viscosity, \( K \) is constant, \( t \) is roll back time, \( \rho_{ball} \) is Density of the ball and \( \rho_{fluid} \) is Density of the fluid

2.4. PVT Data Characterization

PVT (Pressure-Volume-Temperature) represents the behavior of hydrocarbon reservoir fluids (oil, gas and water) during life of the field, as well as effect of changes in temperature and pressure during fluid transfer from reservoir to surface/processing facilities. Phase behavior is the behavior of vapor, liquid, and solids as a function of pressure, temperature, and composition, that is mean the phase behavior is depends on the PVT data of reservoir fluids. In order to estimating PVT data characterization, using the experiments in the laboratory such as pressure depletion experiment, saturation pressure experiment, separator experiment, …etc., and using correlations to estimate the PVT characterization. The most important PVT characterization in oil industry:

1- Bubble point pressure, \( P_b \).
2- Oi formation volume factor, \( B_o \).
3- Gas Oil Ratio, \( GOR \).
4- Oil density, \( \rho_o \).
5- Oil viscosity, \( \mu_o \).

2.4.1. Bubble Point Pressure, \( P_b \)

The bubble-point pressure \( P_b \) of a hydrocarbon system is defined as the highest pressure at which a bubble of gas is first liberated from the oil. This important property can be measured experimentally for a crude oil system by conducting a constant-composition expansion test.
In the absence of the experimentally measured bubble-point pressure, it is necessary for the engineer to make an estimate of this crude oil property from the readily available measured producing parameters. Several graphical and mathematical correlations for determine \( P_b \). These correlations are essentially based on the assumption that the bubble-point pressure is a function of gas solubility \( R_s \), gas gravity \( \gamma_g \), oil gravity API, and temperature \( T \).

### 2.4.2. Oil Formation Volume Factor

The Oil Formation Volume Factor, Bo, is defined as the ratio of the volume of oil (plus the gas in solution) at the prevailing reservoir temperature and pressure to the volume of oil at standard conditions.

\[
B_o = \frac{(V_o)_{P,T}}{(V_o)_{Sc}} \quad \text{eq(2.2)}
\]

Where:

- **Bo**: Oil Formation Volume Factor, bbl/STB
- \((V_o)_{P,T}\): volume of oil under reservoir pressure \( p \) and temperature \( T \), bbl
- \((V_o)_{Sc}\): volume of oil is measured under standard conditions, STB

![Figure 2. 7. Oil Formation Volume Factor Pressure Diagram.](image)

### 2.4.3. Gas Solubility

The gas solubility \( R_s \) is defined as the number of standard cubic feet of gas that will dissolve in one stock-tank barrel of crude oil at certain pressure and temperature. The solubility ofa
natural gas in a crude oil is a strong function of the pressure, temperature, API gravity, and gas gravity.

2.4.4. Crude Oil Viscosity

Crude oil viscosity is an important physical property that controls and influences the flow of oil through porous media and pipes. The viscosity, in general, is defined as the internal resistance of the fluid to flow. The oil viscosity is a strong function of the temperature, pressure, oil gravity, gas gravity, and gas solubility. The viscosity is usually reported in standard PVT analyses. If such laboratory data are not available, engineers may refer to published correlations.

According to the pressure, the viscosity of crude oils can be classified into three categories:

- **Dead Oil Viscosity**
  The dead oil viscosity is defining as the viscosity of crude oil at atmospheric pressure (no gas in solution) and system temperature.

- **Saturated Oil Viscosity**
  The saturated (bubble-point) oil viscosity is define as the viscosity of the crude oil at the bubble-point pressure and reservoir temperature.

- **Under-saturated Oil Viscosity**
  The under-saturated oil viscosity is defining as the viscosity of the crude oil at a pressure above the bubble-point and reservoir temperature.
2.5. PVT\textit{i} Software

The PVT\textit{i} program is an Equation of State based package for generating PVT data from the laboratory analysis of oil and gas samples. The program may be used through an interactive menu system or run in a batch mode. An interactive session can be saved as a batch input file, which contains commands to reproduce the interactive operations. Alternatively, a batch input file can be run from an interactive session.\textsuperscript{[6]}

PVT\textit{i} is a compositional PVT equation-of-state based program used for characterizing a set of fluid samples for use in our ECLIPSE simulators. PVT\textit{i} needed because it is vital that we have a realistic physical model of our reservoir fluid sample(s) before we try to use them in a reservoir simulation. PVT\textit{i} can be used to simulate experiments that have been performed in the lab on a set of fluid samples and then theoretical predictions can be made of any observations that were performed during a lab experiment, in order that we can test the accuracy of our fluid model. Any differences between the measured and calculated data are minimized using a regression facility which adjusts various Equation of State parameters. This ‘tuned’ model is then exported in a form suitable for one of our ECLIPSE simulators. We look to use ECLIPSE to generate PVT model to use it in reservoir simulation to simulate the reservoir and the production process and how the PVT can affect to production process. The PVT model was needed in the reservoir simulation because the pressure in the reservoir decline due to production then the fluid properties change that the software need to fluid system to simulate the process in the reservoir. And after we complete the PVT model we export it in to the ECLIPSE model and after that we begin to reservoir simulation by use the PVT model.\textsuperscript{[6]}

2.5.1. Fluid Definition

Multiple fluid samples can be defined by specifying components as one of three types. Library components require only that the appropriate component mnemonic be entered. Characterized components define properties of plus fractions from a limited set of information. Finally, all the properties of a component can be defined, a facility which can be used selectively to edit the properties of existing components.\textsuperscript{[6]}
2.5.1.1. Simulation of Experiments
Experiments may be performed on the fluid systems defined using the equation of state model. Possibilities are:

1. Saturation pressures
2. Flash calculations
3. Constant composition expansions
4. Constant volume depletions
5. Differential liberations.

2.5.1.2. PVT Data for ECLIPSE Simulators
Black oil and equilibration Tables for ECLIPSE can be prepared, using the liquid and gas compositions obtained from constant volume depletion or differential liberation experiments passed through a separator system using the Coats or Whitson and Torp methods. Water properties may also be output for use the programs. Default values for formation volume factor, compressibility, etc., are constructed using well-known correlations from specification of the pressure, temperature, salt and gas content of the water, though these may be changed. [6]

2.5.2. Defining Fluid System
In this part we learn how we use ECLIPSE to generate a fluid model and how we get start to open the project and program option and selecting equation of state.

2.5.2.1. Get Start In ECLIPSE
To get start in ECLIPSE to generate fluid model you must following the step below:

1. Start the ECLIPSE Program Launcher.
2. Click on the PVTi button.
3. Select the version and working directories as required.

2.5.2.2. Generate a Fluid Model
After you get start in ECLIPSE you must input your fluid component (CO2, C1, C2…. etc.) to import or input your fluid component you following the steps:

1. Start PVTi.
2. Select PVTi: File | New...
3. Enter the project name in the file selection window.
4. Click on Open on PC or OK.

The Fundamentals panel opens so that basic project information can be entered.

a) Enter CO2, N2, C1 and C6 into the Components column.

b) Click Apply.

c) Click Yes so that PVTi fills in the library component names.

d) Enter the mole fractions from Table (2.1) and the details for the C7+ component into the Fundamentals panel and click OK.

Table 2.1. Example of Fundamental panel.\(^6\)

<table>
<thead>
<tr>
<th>Component</th>
<th>% Mole Fraction</th>
<th>Mole Weight</th>
<th>Specific Gravity</th>
</tr>
</thead>
<tbody>
<tr>
<td>C₂</td>
<td>9.67</td>
<td></td>
<td></td>
</tr>
<tr>
<td>C₃</td>
<td>6.95</td>
<td></td>
<td></td>
</tr>
<tr>
<td>IC₄</td>
<td>1.44</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NC₄</td>
<td>3.93</td>
<td></td>
<td></td>
</tr>
<tr>
<td>IC₅</td>
<td>1.44</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NC₅</td>
<td>1.41</td>
<td></td>
<td></td>
</tr>
<tr>
<td>C₆</td>
<td>4.33</td>
<td></td>
<td></td>
</tr>
<tr>
<td>C₇+</td>
<td>33.29</td>
<td>218.0</td>
<td>0.8515</td>
</tr>
</tbody>
</table>

2.5.2.3. Selecting an Equation of State

to select your equation of state following the steps:

1. PVTi: Edit | Fluid Model | Equation of State...

   This opens the Equation of State and Viscosity Correlation panel.

2. Select the equation that is good and is perfect to your system.

3. Click on OK.

4. Click on OK to change the parameters to the equation that you chose.

2.5.2.4. Program Options

1. PVTi: Utilities | Program | Options...

   This opens the Program Options panel.

2. Set the Separator GOR calculation to use Liquid at Stock Tank Conditions.

3. Set the Temperature-dependence for volume shifts to be calculated by Polynomial correlations.

4. Set Treatment of Volume Shifts to Independent and click on OK.
The Program Options panel should now contain the following data Table (2.2)

Table 2.2. Program option.[6]

<table>
<thead>
<tr>
<th>Field</th>
<th>Data</th>
</tr>
</thead>
<tbody>
<tr>
<td>Definition of Liquid Saturation in CCE</td>
<td>Sliq=Vliq/Vsat</td>
</tr>
<tr>
<td>Treatment of volume shifts</td>
<td>Dependent</td>
</tr>
<tr>
<td>Separator GOR Calculation</td>
<td>Liquid at Stock Tank Conditions</td>
</tr>
<tr>
<td>Temperature dependence for volume shifts</td>
<td>Polynomial correlations</td>
</tr>
<tr>
<td>Specify/Calculate density and molar volume units</td>
<td>User units</td>
</tr>
<tr>
<td>Specific Heat Capacity Coefficients and Calorific Values</td>
<td></td>
</tr>
<tr>
<td>Calculated compositions</td>
<td>No Save to samples</td>
</tr>
<tr>
<td>Component Library</td>
<td>Katz-Firoozabadi</td>
</tr>
<tr>
<td>Experimental Compositions</td>
<td>Output to Screen/PVP</td>
</tr>
<tr>
<td>Experimental Results</td>
<td>Always Output to PVP</td>
</tr>
<tr>
<td>Plot Vectors</td>
<td>No Output to file</td>
</tr>
<tr>
<td>Print File Output</td>
<td>A4 format</td>
</tr>
<tr>
<td>Definition of GOR in Diff Lib</td>
<td>Normal</td>
</tr>
<tr>
<td>Definition of Oil relative volume in Diff Lib</td>
<td>Oil FVF = Voil(p)/Voil(stc)</td>
</tr>
<tr>
<td>Black Oil Table Output</td>
<td>All Data</td>
</tr>
<tr>
<td>Flash Calculations</td>
<td>E300 Flash</td>
</tr>
<tr>
<td>Sample mole fractions when regressing</td>
<td>Keep Fixed</td>
</tr>
</tbody>
</table>

2.5.2.5. View Fluid Attributes

Now that a fluid has been defined, there are two plots available to review the fluid that entered in the software. First is the fingerprint plot of mole fraction versus molecular weight; the second is a phase plot.
1. Right-click on ZI in the project tree-view and select Fingerprint Plot from the pop-up menu.

![Fingerprint Plot: Sample ZI](image)

**Figure 2.9. Fingerprint plot.** [6]

2. **PVTi:** View | Samples | Phase Plot...

3. Request Sample ZI, 5 quality lines then click Ok.

![Phase Plot: Sample ZI](image)

**Figure 2.10. phase plot.** [6]

2.5.2.6. **Saving the System**

The fluid sample definition can output as the RUNSPEC and SYSTEM sections of a PVI file.

1. **PVTi:** File | Save.

2. Call the file and click OK.
Chapter Three
Reservoir Background
3.1. Geological Overview

The name “Farrud” is used locally. The name refers to a regressive carbonate depositional cycle that is contained within the Beda formation. Although the Farrud is sometimes called a “formation” it is actually a litho-stratigraphic “member” of the Beda formation. (“members” make up “formations”, “formations” make up “groups”). Figure (3.1) shows the Chrono-Stratigraphic sub-division of geological time. This is not the only way to subdivide geological history. This subdivision is valid world-wide. There is also a subdivision based on lithology (rock-type), biology (fossils) and magnetic characteristics. The lithological subdivision is valid locally.[1]

In the oil industry we Chrono-Stratigraphic names as well as Litho Stratigraphic names are commonly used. In early Exploration reports of area 87 88 103, when lithological units were not yet well defined, the explorers often used the fossil content to date horizons. Once the lithological units were defined, fossils seem to disappear from the picture.[1]

The Beda formation is overlying the Hagfa formation and is followed by the Dahra formation. The Hagfa formation is the oldest (first deposited) formation of the Paleocene, the Beda formation was formed during “middle” of the Paleocene, about 60 million years ago, and the Dahra formation represents the younger Paleocene. The youngest formation of the Paleocene is the Zelten formation, which also crosses the boundary into the younger Eocene Epoch. The Paleocene is the oldest Chrono-Stratigraphic “epoch” of the Tertiary (which is a “period”). A number of epochs from periods, a number of periods from an era, a number of eras forms an eon. There are only two Eons: The Phanerozoic and the Precambrian. The Tertiary (a “period”) follows the Cretaceous. The youngest (last deposited) Cretaceous formation (litho-stratigraphic unit) in the Sirte Basin is the Kalash formation.

The Farrud is best referred to as a “unit” or a “reservoir” and is also known as “Beda C”. The Beda formation is made up (from old to young) by the Thalith, the Beda C (or Farrud) and the Mabruk members. The last (youngest) one is subdivided in Mabruk A and B.[1]
The Beda formation is overlain by the Dahra formation also subdivided in Dahra A and B member. Mabruk A and B as well as Dahra A and B are all oil producing reservoirs. The Hagfa, Beda and Dahra formations were all deposited during the Paleocene, which is on average 60 million years old. The Paleocene was followed by the Eocene, the next younger chrono-stratigraphic unit, during which the Gir formation, also a main oil producing formation, was deposited. This will put the Farrud in its place in time. Looking at the big picture the Farrud is sandwiched between the Hagfa Shale and the
Dahra formation, which also consists mainly of shale. This is a first indication that
during Farrud time marine conditions had changed from deep to shallow marine, and
that transport of land derived clasticsediments (like clay) into the basin had stopped or
bypassed the area where the Farrud was deposited. That is why the Farrud unit is
referred to as a regressive depositional cycle caused by a drop in relative sea level.[1]

3.2. Farrud Depositional Setting and Lithology

The Farrud has an average thickness of 76 feet and consists of a mixture of dolomite
and limestone. In general dolomite dominates but occasionally limestone can be an
important component. The original sediment most likely consisted entirely of calcium
carbonate, both in the form of lime mud, fossils and fossil fragments, peloids, ooids and
a significant amount of other poorly defined components. The sediment also contains
non-carbonate material, mainly pyrite (trace), celestite (a diagenetic product associated
with the dissolution of shell material), anhydrite in the form of nodules and cement, and
also dark organic residue associated with peloids often concentrated along poorly
preserved bedding planes. This concentration indicates that some pressure solution of
the rock may have taken place during its diagenetic history. Although some clay is
expected to be present, it is considered a very minor component, particularly higher in
the reservoir. Log Gamma ray response over the Farrud reservoir shows fairly high
levels of radio-activity. This radio-activity is caused by uranium present in the reservoir
and not by detrital clay. Clay gamma radiation is usually caused by Potassium isotopes,
not uranium.[1]

The depositional setting of Farrud is shallow and fairly open marine. Although the
energy levels were not high in general several beds contain well sorted fossil fragment
while other are composed of ooids or a mix of the two. This indicates that energy levels
at times were sufficiently high to winnow the sediments and wash out most if not all
lime-mud. The coarser and higher energy Farrud sediments are particularly present in
the areas where shoaling (shallowing) occurred and where the Farrud reservoir is
exceptionally thick.[1]
3.3. Farrud Diagenesis

Diagenesis was responsible for the creation of one of the best reservoirs present in the area. Although much of the Farrud had poor porosity initially, diagenesis changed this dramatically, at least in terms of the porosity of this reservoir. As the calcium carbonate was transferred into dolomite, through the introduction of magnesium, and the sediment was almost entirely re-crystallized, a reservoir with high porosity was created. This probably happened rather quickly after the sediment had been deposited. The re-crystallization of the sediments was so complete that little remains of the original structures and textures of the sediments. In thin sections some of the original components can still be recognized. The diagenetic process going from a lime-mud to a porous dolomite rock is complex, and probably involved introduction of meteoric (fresh) water as well as hyper-saline fluids. Why some parts of the Farrud now consist of limestone rather than dolomite is not clear.\[1\]

3.4. Farrud Reservoir Characteristic

The reservoir characteristics of the limestone are not inferior to the properties of the dolomites. In any case the resulting rocks can be characterized as high porosity and low permeability reservoirs. Farrud porosity averages somewhere in the high twenties and in some portions of the reservoir in the low thirties. Low permeability is directly related to the extremely fine size of the dolomite rhombs that now the bulk of the reservoirs, resulting in minute pore throats. The only factor that enhances permeability is the presence of some vuggy and moldic porosity that resulted from the dissolution of larger fossils or fossil fragments. In spite of the low permeability of the reservoir rock, the reservoir was capable of producing at very high levels initially. If production of 5000 barrels per day can be achieved the possibility of fractures was considered. If any fractures are present, none were detected on image logs or in cores; their contribution is not expected to dominate the contribution of the reservoir matrix. Vertical permeability is expected to be close to horizontal permeability, particularly on a macroscopic scale. On a small scale some bedding and laminations must impair vertical permeability somewhat. The porosity system in carbonates is expected to be created early in the burial history of the sediments. Very little signs are presents that this porosity system changed much later. Only minor signs of further compaction are
reported. Once the oil displaced moveable water out of the reservoir diagenesis probably stopped altogether. There are indications that diagenesis in Farrud reservoirs in the water-leg continued to destroy porosity. There are also indications that porosity in wells that are structurally deepest, but still oil filled is slightly lower. These reservoirs were charged with oil last. The Farrud reservoir contains a lot of micro-porosity. It is reasonable to expect that a portion of that micro-porosity is not connected and can be considered ineffective.

Figure 3. 2. Shows location of Ghani Field Farrud Reservoir.\textsuperscript{[1]}

Figure 3. 3. Shows Depth Structure Map at Top Farrud.\textsuperscript{[1]}

\textsuperscript{[1]}
Since the reservoir was initially fully water (brine)saturated it can be expected that not-connected porosity still contains water rather than oil. Concerning the reservoir fluids, PVT data were collected at different times throughout the producing life of the field and at various locations. PVT samples were reviewed and analyzed in details to evaluate their internal coherency as well as if they are representative of the reservoir fluid at the sampling time. 3 PVT samples were taken before the production start or very close to it. The other samples might be affected by fluids movement due to the depletion of these reservoirs. This is the case for Farrud reservoir (Ghani Field) fluid samples taken after the production startup because due to the pressure sink created by the production, the reservoir pressure reached very quickly the initial bubble point pressure and a gas phase was liberated in the reservoir.

Table 3. 1. Reservoir fluids and rock properties.[1]

<table>
<thead>
<tr>
<th>Reservoir Fluid Characteristics</th>
<th>Farrud Reservoir (Ghani Field)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Area, Acres</td>
<td>7200</td>
</tr>
<tr>
<td>Average Net Pay Thickness, Ft</td>
<td>76</td>
</tr>
<tr>
<td>Porosity, %</td>
<td>22</td>
</tr>
<tr>
<td>Oil Saturation, %</td>
<td>86</td>
</tr>
<tr>
<td>Original Reservoir Pressure, Psia</td>
<td>2335</td>
</tr>
<tr>
<td>Bubble Point Pressure, Psia</td>
<td>1900</td>
</tr>
<tr>
<td>Reservoir Temperature, °F</td>
<td>185</td>
</tr>
<tr>
<td>Density at Psat, g/cc</td>
<td>0.661</td>
</tr>
<tr>
<td>Oil Viscosity at Psat, Cp</td>
<td>0.31</td>
</tr>
<tr>
<td>Original Solution GOR, Scf/Stb</td>
<td>966</td>
</tr>
<tr>
<td>Formation Volume Factor</td>
<td>1.6095</td>
</tr>
<tr>
<td>Oil Gravity, °API</td>
<td>41.05</td>
</tr>
<tr>
<td>Tank Oil Density, g/cc</td>
<td>0.802</td>
</tr>
<tr>
<td>Datum, SS Ft</td>
<td>5070</td>
</tr>
</tbody>
</table>
Table 3.2. Farrud Reservoir (Ghani Field) – Main Characteristics of PVT Fluid Samples.\textsuperscript{[1]}

<table>
<thead>
<tr>
<th>Well</th>
<th>Sampling Depth (ft)</th>
<th>Temperature °F</th>
<th>Saturatio n Pressure (psia)</th>
<th>Rs Sef/Stb</th>
<th>Bo vol/vol</th>
<th>Density g/cc</th>
<th>Residual Oil Density (g/cc)</th>
<th>Viscosity Cp</th>
<th>Tank API</th>
</tr>
</thead>
<tbody>
<tr>
<td>RRR-02</td>
<td>5949</td>
<td>185</td>
<td>2091</td>
<td>996</td>
<td>1.686</td>
<td>0.641</td>
<td>0.834</td>
<td>0.42</td>
<td>42.2-42.3</td>
</tr>
<tr>
<td>RRR-10 S</td>
<td>5780</td>
<td>168</td>
<td>2122</td>
<td>981</td>
<td>1.605</td>
<td>0.669</td>
<td>0.833</td>
<td>0.315</td>
<td>40.8-41.2</td>
</tr>
<tr>
<td>RRR-10 F</td>
<td>5780</td>
<td>168</td>
<td>2108</td>
<td>980</td>
<td>1.603</td>
<td>0.669</td>
<td>0.833</td>
<td>0.32</td>
<td>40.8-41.3</td>
</tr>
<tr>
<td>RRR-33</td>
<td>6000</td>
<td>189</td>
<td>1927</td>
<td>988</td>
<td>1.674</td>
<td>0.658</td>
<td>0.843</td>
<td>0.357</td>
<td>41.2-42.74</td>
</tr>
<tr>
<td>RRR-21</td>
<td>5903</td>
<td>186</td>
<td>1900</td>
<td>830</td>
<td>1.558</td>
<td>0.665</td>
<td>0.835</td>
<td>0.38</td>
<td>41.5</td>
</tr>
<tr>
<td>RRR-25</td>
<td>5850</td>
<td>186</td>
<td>1859</td>
<td>876</td>
<td>1.585</td>
<td>0.664</td>
<td>0.836</td>
<td>0.36</td>
<td>42.1-42.3</td>
</tr>
<tr>
<td>RRR-42</td>
<td>5861</td>
<td>186</td>
<td>1906</td>
<td>943</td>
<td>1.677</td>
<td>0.641</td>
<td>0.836</td>
<td>0.37</td>
<td>42.1</td>
</tr>
<tr>
<td>RRR-46</td>
<td>5895</td>
<td>186</td>
<td>1841</td>
<td>792</td>
<td>1.538</td>
<td>0.675</td>
<td>0.842</td>
<td>0.39</td>
<td>40.9</td>
</tr>
<tr>
<td>RRR-48</td>
<td>6269</td>
<td>185</td>
<td>1900</td>
<td>966</td>
<td>1.61</td>
<td>0.662</td>
<td>0.802</td>
<td>0.32</td>
<td>41.0</td>
</tr>
</tbody>
</table>
3.5. Minimum Miscibility Pressure Experiment

In 2012 a slim tube test experiment in laboratory study for Farrud field (Ghani Field) to determine Minimum Miscibility Pressure. As known a single experiment at a single pressure is not enough to measure the Minimum Miscibility Pressure (MMP). Rather, a series of experiments is required at different pressures, so that the amount of oil recovered (either total ultimate cumulative oil produced, or oil produced at 1.0 or 1.2 P.V. injected, etc.) is plotted vs. the test pressure. Normally, the amount of oil produced increases significantly with increasing pressure if it is immiscible, and increases little with increasing pressure if it is miscible. Therefore, the Minimum Miscibility Pressure (MMP) can usually be determined as the intersection of two straight lines on that plot of oil recovery vs. pressure. Another commonly used criteria for determination of MMP is the pressure at which a high oil recovery (such as 90%) is achieved.

A sight glass at the outlet of the slim tube allows viewing of the produced effluent and provides third criteria: if immiscible, the transition zone between the oil and the injection gas will show an interface or interfaces (bubbles), and if miscible, the transition will be gradual with no interface. The optional densitometer measures the effluent density, and the optional gas chromatograph measures the produced gas composition is not including for this MMP. A video recording for miscible transition zone for this test. [2]

The summary tables and plotted of the study was shown in the following:

Figure 3.4. Test Report generated by software of MMP apparatus at 1800 psig and 85°C. [2]

<table>
<thead>
<tr>
<th>Test Back Pressure (psig)</th>
<th>1800</th>
</tr>
</thead>
<tbody>
<tr>
<td>Test Temperature (°C)</td>
<td>85</td>
</tr>
<tr>
<td>Oil Formation Volume Factor</td>
<td>1.0046</td>
</tr>
<tr>
<td>Oil Thermal Expansion Factor</td>
<td>1.0164</td>
</tr>
<tr>
<td>Displacement Gas Thermal Expansion Factor (cc/cc)</td>
<td>2.8686</td>
</tr>
<tr>
<td>Initial Measured Gas / Oil Ratio</td>
<td>-1.15</td>
</tr>
<tr>
<td>Total Pore Volume (cc)</td>
<td>129.3</td>
</tr>
<tr>
<td>Slim Tube Pore Volume (cc)</td>
<td>119.3</td>
</tr>
<tr>
<td>Initial Fill Liquid Thermal Expansion Factor</td>
<td>1.0744</td>
</tr>
<tr>
<td>Initial Fill Liquid Formation Volume Factor</td>
<td>1.0723</td>
</tr>
<tr>
<td>Oil Recovery (%) at 1.0 Pore Volumes Injected</td>
<td>60.3</td>
</tr>
<tr>
<td>Oil Recovery (%) at 1.2 Pore Volumes Injected</td>
<td>61.8</td>
</tr>
<tr>
<td>----------------</td>
<td>---------------------------------</td>
</tr>
<tr>
<td>15:04:00</td>
<td>0</td>
</tr>
<tr>
<td>15:06:14</td>
<td>0.05</td>
</tr>
<tr>
<td>15:08:30</td>
<td>0.101</td>
</tr>
<tr>
<td>15:10:46</td>
<td>0.151</td>
</tr>
<tr>
<td>15:13:02</td>
<td>0.201</td>
</tr>
<tr>
<td>15:15:18</td>
<td>0.251</td>
</tr>
<tr>
<td>15:17:34</td>
<td>0.302</td>
</tr>
<tr>
<td>15:19:50</td>
<td>0.352</td>
</tr>
<tr>
<td>15:22:06</td>
<td>0.402</td>
</tr>
<tr>
<td>15:24:22</td>
<td>0.452</td>
</tr>
<tr>
<td>15:26:37</td>
<td>0.503</td>
</tr>
<tr>
<td>15:28:53</td>
<td>0.553</td>
</tr>
<tr>
<td>15:31:09</td>
<td>0.603</td>
</tr>
<tr>
<td>15:33:25</td>
<td>0.653</td>
</tr>
<tr>
<td>15:35:41</td>
<td>0.704</td>
</tr>
<tr>
<td>15:37:57</td>
<td>0.754</td>
</tr>
<tr>
<td>15:40:13</td>
<td>0.804</td>
</tr>
<tr>
<td>15:42:29</td>
<td>0.855</td>
</tr>
<tr>
<td>15:44:45</td>
<td>0.905</td>
</tr>
<tr>
<td>15:47:01</td>
<td>0.955</td>
</tr>
<tr>
<td>15:49:17</td>
<td>1.005</td>
</tr>
<tr>
<td>15:51:34</td>
<td>1.056</td>
</tr>
<tr>
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Figure 3.5. Displacement of stock tank oil by CO2 at 1800 psig and 85°C and recovery of stock standard condition. [1]
Figure 3. 6. Displacement of stock tank oil by CO2 at 3200 psig and 85°C and recovery of stock tank at standard condition. [2]
Figure 3.7. Displacement of stock tank oil by CO2 at 3200 psig and 85°C and recovery of stock tank at standard condition. [2]
Figure 3.8. Determination of MMP at standard 1.2 of injected gas. [2]
3.6. Field Background

The A Field (NC-186A) (Figure 3.9.) is located in Murzuq Basin, SW Libya, lies 7.5km west of the (H Field- NC186). A-field was discovered in December 2001 by the exploration well A-1. The structure comprises two classic Hawaz Paleo-highs created during the post Hawaz erosional event.

The Hawaz reservoir is subdivided into 8 units. These are Hawaz Layers, H1 to H8. The Achebyat formation underlies the Hawaz and is known throughout the Murzuq Basin as a regional aquifer. This aquifer is used for water source required for water injection.

The sequence stratigraphy geological and geophysical assessment subdivided Hawaz formation into an upper reservoir, Top H1 to Top H4 and a main productive reservoir, Top H4 to Top H7.

Figure 3.9. A-Field (NC-186) satellite structural map
3.7. PVT fluid characterization study of A-Field (NC-186)

3.7.1 Overview

14 fluid samples from four different wells on the A-Field (NC-186) were taken and analyzed at different laboratory experiments.

Two of the wells are located on the East part of the Field (A-01 & A-12) and the two other wells are located on the West side (A-02 & A-03).

A detailed analysis and QC of the different experimental data of the samples were done to choose one representative sample that will be used for further PVT studies.

The comparison between the different fluid samples shows same type of fluid from East and West side of the A-field.

The PVT study is divided into two main sections, the first section contains the quality check of the available PVT of the different samples with conclusions, and the second section is the selection of the representative fluid sample for the field.

3.7.2 Quality check of the experimental data

Table (3.3) summarizes the number of taken samples from A-field (NC-186)

Table 3.3 Summary of Taken Samples

<table>
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<th>Well name</th>
<th>Surface Sample</th>
<th>BHS</th>
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<td>1</td>
</tr>
<tr>
<td>A-02</td>
<td>-</td>
<td>1</td>
</tr>
<tr>
<td>A-03</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td>A-12</td>
<td>-</td>
<td>3</td>
</tr>
</tbody>
</table>

The quality of the laboratory experiments results are checked using different conventional methods.

The quality check of the bubble point pressure was already done during the reporting of the laboratory experiments.

The bubble point pressure of the separator oil samples and bottomhole samples were determined at separator and reservoir conditions.

Figure (3.10.) shows bubble point pressures of collected bottomhole samples for the four wells.
3.7.3 Methodology and results

Four conventional QC methods were used to validate the reported PVT data. These methods are:

- Material balance plots
- Hoffman plots
- Y-function
- FG method.

The Material Balance plot and FG plots are used as a rigorous criterion for consistency while the Hoffman plot is considered a qualitative assessment of data quality. The Y Function is used for Constant Composition Expansion experiment validation.

The reservoir fluid composition (Zi) is calculated by mathematical recombination of liquid and evolved gas from flashed reservoir oil at atmospheric pressure. In this case the plot of
Conventional QC methods should show a straight line which indicates that recombination is done correctly.

The material balance test is used as a rigorous test to evaluate compositional consistency between feed composition and separator vapor and liquid compositions. It provides a good check on the overall consistency of the analyses. The test is derived from component material balance criteria:

\[ Fz_i = Lx_i + Vy_i \]

Or

\[ \frac{y_i}{z_i} = \frac{F}{V} - \left( \frac{L}{V} \right) \frac{x_i}{z_i} \]

Where:
- \( F \) = Total moles of feed
- \( L \) = Total moles of separator liquid
- \( V \) = Total moles of separator vapor
- \( z_i \) = Mole fraction of component \( i \) in the feed
- \( x_i \) = Mole fraction of component \( i \) in the liquid
- \( y_i \) = Mole fraction of component \( i \) in the vapor

The plot of the \( (y_i/z_i) \) versus \( (x_i/z_i) \) should yield to a straight line as shown in the figures (3.11, 3.12, 3.13, 3.14) for wells A-03, A-012, A-01, and A-02 respectively.
Figure 3.12. Material Balance check for (NC-186) A-03 BHS
Figure 4: Material Balance check for (NC-186) A-12 BHS

Figure 5: Material Balance check for (NC-186) A-01 BHS
The Hoffman plot is used to check the quality of the reported vapor and liquid composition. When log (K*P_{sep}) is plotted versus F (Hoffman Factor) for each component, the result should be a nearly straight line for light hydrocarbons. Light non-hydrocarbons should be close to the behavior of light hydrocarbons, but not necessarily on the same line. Iso-and normal-butane and pentane often fall on either side of a straight line. Additionally, some curvature might occur for heavier hydrocarbons, but extreme curvature can be indicative of potential data issues, often losses in the vapor phase heavy components, fluid recombined to erroneous GOR, Inaccurate plus fraction properties or Liquid carryover.

The F function is defined by the following equation:

**Figure 3.14 Material Balance check for (NC-186) A-02 BHS**

![Figure 3.14 Material Balance check for (NC-186) A-02 BHS](chart.jpg)
Chapter Three

Reservoir Background

- $T_{sep}$ = separator temperature ($R^\circ$)
- $T_b$ = boiling temperature ($R^\circ$)
- $T_c$ = critical temperature ($R^\circ$)
- $P_c$ = critical pressure (psia)

Due to the unavailability of $P_c$, $T_c$ and $T_b$ in the PVT reports of (NC-186A) (A-01 and A-02), therefore Hoffman factor was not calculated.

On the other hand, Hoffman plot for (NC-186A) A-03 (BHS) has given good results which indicates good data consistency as shown in figure (3.15.)

![Hoffman Plot (A-03)](image)

**Figure 3.15. Hoffman plot for A-03 BHS**

The Y function calculation is qualitative method for data validation of the CCE experiment. The plot of the Y function Versus Pressure should yield a straight line. Any curvature from a straight line means an erroneous data.

The Y function is defined as: $Y = \frac{P_b - P}{(V_r - 1)}$

Where:
- $P_b$: Bubble point pressure (Psi)
- $V_r$: Relative volume
The Y function calculations of the 3 BHS samples show that the CCE experiment of (NC-186A) The A-01 (BHS) and A-02 (BHS) might be in error (Figure 3.17, 3.18.) Y-function calculations for (NC-186A) A-03 BHS yielded a straight line as shown in figure (3.16.) which indicates a correct CCE experiment.

**Figure 3.16 Y Function of (NC-186A) A-03 BHS**

**Figure 3.17. Y-Function of (NC-186A) A-01 BHS**
The composition comparison between the different reservoir samples shows similarity in the fluid’s compositions shown in figure (3.19.) even though the samples taken are from different accumulation (East and West).
Figure 3.19. Reservoir fluid composition comparison of all samples
The FG factor is also used as data quality check. FG factor represents the recombined mole fractions of the separator sample showing the rounding errors for the mole values, which are supposed to be constant for all components. It is defined as:

\[ FG = \frac{(Z_i - X_i)}{(Y_i - X_i)} \]  \hspace{1cm} (5)

Where:

\[ z_i = \text{mole fraction of component (i) in the feed} \]
\[ x_i = \text{mole fraction of component (i) in the liquid} \]
\[ y_i = \text{mole fraction of component (i) in the vapor} \]

Figure 3.20. FG factor for (NC-186A) A-03 BHS
Figure 3.21. FG factor for (NC-186A) A-12 BHS

Figure 3.22. FG factor for (NC-186A) A-01 BHS
Chapter Four
Case Study
4.1. Introduction

This study outlines the procedures used to analyze available reservoir fluid PVT data for the Farrud Reservoir (Ghani Field) in order to perform a good PVT model for the field and use it to predict fluid minimum miscibility pressure “MMP” for different injection gas. The objectives of this section were:

1. To review existing fluid property data including PVT, gas, and oil analyses.
2. Predict the hydrocarbon fluid properties and phase behavior by adapting an equation of state (EOS).
3. Predict MMP for different injection gas and compare it with the result obtained from laboratory experiment.

The fluid PVT data for the Farrud field (Ghani Field) is only from one well “X-well”. The measured bubble point pressure, \( P_b \), is 1841 psia with a solution gas-oil-ratio, \( R_s \), at the bubble point pressure of 985 SCF/STB.

4.2. Methodology

The study was conducted on Farrud formation (Ghani Field) in order to improve reservoir performance by achieve the objectives. The methodology of this study was listed below:

1. Collect the reservoir fluid data (one report was developed in this field).
2. The available date in this study is a set of a routine PVT laboratory tests for seven bottom-hole fluid samples for a Farrud formation at (Ghani Field).
3. Differential liberation (DL), constant composition expansion (CCE) data are available for well with slim tube test as special PVT.
4. Perform a PVT model using PVTi software and use fitting techniques to match measured data with calculated data from software calculations. The fitting techniques was EOS, Regressions and Splitting.
5. Tuning and building EOS model.
6. By add some experiments and fluid component in the final EOS model the MMP can be estimated.
7. Use first contact miscibility to estimate fluid MMP with different injection gas such as CO\(_2\), N\(_2\) and H.C gases.
4.3. PVT Model Procedure

The following procedure is how to generate a PVT model:

a. Defining the fluid system by insert the fluid compositions and mole fraction for each component. Table 4.1 introduce the fluid component data for Farrud field.

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<tr>
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Define the previous component in the software the following figure show the defined fluid system in the software.
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b. Introduce the phase behavior diagram and fingerprint plot for the system. Figure 4.2 & 4.3 shows the plots.

Figure 4. 1. PVT model data.

Figure 4. 2. Show the phase behavior diagram for the Farrud Reservoir (Ghani Field) fluid model.
c. Defining the experiment from laboratory data, the experiment is saturation pressure experiment, pressure depletion experiments (CCE, DL).

d. Fitting the equation of state (EOS), the best equation of state that introduce a low error is 3-parameter Peng-Robinson (PR3).

e. Plot the defining data in the model to perform error between measured and calculated data from software. The first error between measured data and calculated data was bigger than 50 percent for some experiment. The first error for bubble point around 25 percent. The following figure shows main plots.
Figure 4.4. Relative volume "CCE" results from first run "without tuning".

Figure 4.5. Oil formation volume factor results from first run "without tuning".
f. Fitting an equation of state by use regression and splitting method, the PVT component have C7+ with mole-fraction 37.92%. The C7+ splitting to 2-components with different mole-fraction. The first fraction “FRC1” takes 65% from the original and the other fraction “FRC2” take 35%. Figure 4.8 introduce the splitting panel.
Figure 4. 8. Splitting panel for the system.

After the splitting the sensitivity analysis was applied on the system “Regression techniques” to predict a best PVT model with very low error between the measured and simulated value. The tri and error process were applied in the model to perform a best PVT model. Figure 4.9 shows the best regression parameters.

Figure 4.9. regression variable panel.

After regression process the error between measured and calculated data was very small. The Rms from PVT model shows the error around 0.4%. the error for bubble point was around 0.34%. The actual point equal 1841 psi and the measured was 1835 psi. The following figures introduce the regression results for some parameters from the model.
Figure 4.10. Relative volume results for the best run "with tuning".

Figure 4.11. Oil formation volume factor results for the best run "with tuning".
Figure 4.12. Gas oil ratio results for the best run "with tuning".

Figure 4.13. Oil viscosity results for the best run "with tuning".
4.4. Minimum Miscibility Pressure “MMP”

After the PVT model performed and the matched was acceptable the other objective in this study was determine MMP for Farrud fluid and compared the calculation with slim tube test experiment that mentioned in chapter three for CO
2
 gas as injection. The other was determine MMP for N
2
 and H.C gases. To perform a miscibility experiment in PVT, Software the following step must be followed:

1. Defining the gas component from the main tool: Edit: Sample: Name. After that insert the name of mixture.
2. Define the mole fraction for each insert component. Edit: Sample: Composition.

![Sample Compositions](image)

**Figure 4.14. The composition Panel for the system.**

3. Perform a first contact miscibility experiment. Edit: Experiment. in Experiment panel press: Add: Injection Study: First Contact Miscibility. From the panel chose the injection fluid and apply the experiment.
4. Repeat step 3 for all injection fluid after that run the program to introduce the MMP results. The following table introduce the MMP results for each injection fluid.

<table>
<thead>
<tr>
<th>Slim Tube</th>
<th>EOS (PR3)</th>
<th>EOS (PR3)</th>
<th>EOS (PR3)</th>
<th>EOS (PR3)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO2 =100%</td>
<td>CO2 =100%</td>
<td>N2 =100%</td>
<td>C1=100%</td>
<td>H.C Mixture</td>
</tr>
<tr>
<td>2800 PSI</td>
<td>2576 PSI</td>
<td>14690 PSI</td>
<td>8789 PSI</td>
<td>4113 PSI</td>
</tr>
</tbody>
</table>

Table 4.2. MMP Result for different injection gas.
4.5. PVT Model

Two methods have been used to generate PVT tables for A-Field (NC-186A), these method are:

- PVT data adjustments to stock tank conditions by the use of correlations
- Fluid equation of state tuning and PVT adjustments using PVTi software

4.5.1 PVT data adjustments to stock tank conditions by the use of correlations

The most important step in the application of oil PVT data for reservoir calculations is the conversion of differential solution gas-oil ratio ($R_{sd}$) and differential oil FVF ($B_{od}$) to a stock-tank oil basis. For engineering calculations, volume factors $R_s$ and $B_o$ are used to relate reservoir oil volumes to produced surface volumes.

The main assumptions for these adjustments are:

1. The gas in solution at reservoir conditions below the bubble point that will be liberated at the surface by flash vaporization is equal to the difference between the original gas in solution and the liberated gas by differential liberation at the reservoir pressure.

$$R_s = R_{sf} - (R_{sfb} - R_{sdb}) \times \frac{B_{ofb}}{B_{odb}}$$

Where:

- $R_{sfb}$: $R_s$ at bubble point from multistage- separator flash (scf/stb)
- $R_{sdb}$ and $B_{odb}$: are the values from the differential liberation test (scf/stb) & (bbl/stb) respectively
- $B_{ofb}$: $B_o$ at bubble point from multistage- separator flash (bbl/stb)

2. The relation between the FVF of flashed and differentially liberated samples remains constant over the entire operating pressure.

$$B_o = \frac{B_{ofb}}{B_{odb}} \times B_{od}$$

3. Above the bubble point pressure, the gas in solution will remain constant ($R_s = Constant$) until the bubble point pressure is reached, also oil FVF above bubble point is related to the relative volume with the following equation:

$$B_o = B_{olb} \times v_r$$

Where:

- $v_r$ : The relative volume.
Chapter Four

Case Study

The following figures (4.15, 4.16 and 4.17) show a detailed adjustments of Rs & Bo to Stock-Tank conditions of (NC-186A) A-03 bottomhole sample.

**Figure 4.15:** Adjustment of Rs and Bo to separator conditions

**Figure 4.16:** Adjustment of Rs and Bo to separator conditions
The same adjustments were applied to the bottomhole samples of (A-01) and (A-02), the following figures shows the comparison between the Bo & Rs before and after adjustment.

**Figure 4.17: Adjustment of Rs and Bo to separator conditions**

**Figure 4.18: Bo Adjustment for (NC-186A) A-03 BHS**
Figure 4.19: Bo Adjustment for (NC-186A) A-01 BHS

Figure 4.20: Bo Adjustment for (NC-186A)A-02 BHS
Figure 4.21: Rs Adjustment for (NC-186A) A-03 BHS

Figure 4.22: Rs Adjustment for (NC-186A) A-01 BHS
Figures (4.24 and 4.25) show the comparison of Bo and Rs after adjusting them to Stock-Tank conditions.
Figure 4.25: Comparison between Rs for all BHS

Figure (4.26) shows API comparison for all bottomhole samples

Figure 4.26: Comparison of API for all BHS
### Summary table for results

**Table (4.3): Summary of PVT results for (A-NC186) Samples**

<table>
<thead>
<tr>
<th>Field</th>
<th>Sampling Date</th>
<th>Sample Type</th>
<th>Reservoir Pressure</th>
<th>Reservoir Temperature (F)</th>
<th>Multi Stage Separator GOR (scf/stb)</th>
<th>DL GOR (scf/stb)</th>
<th>Bubble Point Pressure (Psig)</th>
<th>API</th>
<th>Density stock Tank (gm/cc)</th>
<th>Density at Pb (gm/cc)</th>
<th>Density at Pi (gm/cc)</th>
<th>DL Bo at Pb (bbl/stb)</th>
<th>DL Bo at Pi (bbl/stb)</th>
<th>Separator Bo (bbl/stb)</th>
<th>Viscosity at Pb (cp)</th>
<th>Viscosity at Pi (cp)</th>
<th>Oil Compressibility at Pb E-06 (1/psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well</td>
<td>(A-03)</td>
<td>(A-12)</td>
<td>(A-01)</td>
<td>(A-02)</td>
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<td>1423 psig</td>
<td>1759 psia</td>
<td>1705 psia</td>
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<td>Multi Stage Separator</td>
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<td>DL GOR (scf/stb)</td>
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<td>421</td>
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<td>Bubble Point Pressure</td>
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<td>785</td>
<td>921</td>
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<td>API</td>
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<td>Density stock Tank</td>
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<td>0.825</td>
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<tr>
<td>Density at Pb</td>
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<td>0.7139</td>
<td>0.676</td>
<td>0.665</td>
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<tr>
<td>DL Bo at Pb</td>
<td>1.383</td>
<td>1.242</td>
<td>1.447</td>
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<td>1.425</td>
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<tr>
<td>Separator Bo</td>
<td>1.264</td>
<td>n/a</td>
<td>1.318</td>
<td>1.352</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Viscosity at Pb</td>
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<td>Viscosity at Pi</td>
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<td>Oil Compressibility at</td>
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<td>15.8</td>
<td>16.86</td>
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</tr>
</tbody>
</table>
4.5.2 Fluid equation of state tuning and PVT adjustments using PVTi software

Based on the previous analysis, it is clear that the bottomhole sample of the A-03 well is the most representative sample for the (A-NC186) field.

The PVT data of this well was loaded into the PVTi software for EOS tuning, Pen_Robinson (Three Parameters) EOS was selected to match the experimental data.

Figure (4.27) shows the phase diagram of the BHS before grouping and tuning.

![Figure 4.27: Phase diagram of A-03 BHS before EOS tuning](image)

Whereas the following plot (figure 4.28) shows the phase diagram after grouping and tuning.

![Figure 4.28: Phase diagram of A-03 BHS before EOS tuning](image)
The following figures (4.29 – 4.36) show the results of the fluid EOS after tuning using the software.
Figure 4.31: Gas Oil Ratio from DL Experiment

Figure 4.32: Oil Relative Volume from DL Experiment
Figure 4.33: Gas Gravity from DL Experiment

Figure 4.34: Gas FVF from DL Experiment
Chapter Four

Figure 4.35: GOR from SEP Experiment

Figure 4.36: Liquid Viscosity
The Bubble point pressure was matched exactly with the bubble point in the lab as shown in Figure 4.37.

![Image of PDF page]

Figure 4.37: Observed and Calculated Bubble Point after Tuning

Figure (4.38.) shows the RMS values (the difference between the observed and calculated values is divided by the observed value), in this case it is below 2%.

![Image of PDF page]

Figure 4.38: Total & weighted (Normalized) RMS fit
1.3.2.1 Summary of results

PVT tables were generated after EOS tuning, dead oil dry gas export keyword was chosen.

- Table (4.4): bubble point pressure and solution gas oil ration

<table>
<thead>
<tr>
<th>Rs (Mscf/stb)</th>
<th>Pb (psia)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.3076</td>
<td>794.7277</td>
</tr>
</tbody>
</table>

Table (4.5): Oil Properties

<table>
<thead>
<tr>
<th>Pressure Psia</th>
<th>Bo rb/stb</th>
<th>Viscosity cP</th>
</tr>
</thead>
<tbody>
<tr>
<td>794.7277</td>
<td>1.2631</td>
<td>0.5659</td>
</tr>
<tr>
<td>814.7</td>
<td>1.2626</td>
<td>0.5678</td>
</tr>
<tr>
<td>914.7</td>
<td>1.2604</td>
<td>0.5772</td>
</tr>
<tr>
<td>1014.7</td>
<td>1.2582</td>
<td>0.5866</td>
</tr>
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<td>1114.7</td>
<td>1.256</td>
<td>0.5959</td>
</tr>
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<td>1214.7</td>
<td>1.254</td>
<td>0.6052</td>
</tr>
<tr>
<td>1514.7</td>
<td>1.248</td>
<td>0.6329</td>
</tr>
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<td>1819.7</td>
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</tr>
<tr>
<td>2014.7</td>
<td>1.239</td>
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</tr>
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<td>2514.7</td>
<td>1.231</td>
<td>0.7231</td>
</tr>
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<td>3014.7</td>
<td>1.2237</td>
<td>0.767</td>
</tr>
<tr>
<td>3514.7</td>
<td>1.2171</td>
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</tr>
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<td>4014.7</td>
<td>1.2111</td>
<td>0.8527</td>
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</tbody>
</table>
Chapter Five
Conclusions & Recommendations
5.1. Conclusions

1. The PVT properties are keys for reservoir management, they are used by reservoir engineers for estimating oil initial in place.

2. The PVTi program is an Equation of State based package for generating PVT data from the laboratory analysis of oil and gas samples. The program can be used to simulate experiments, then theoretical predictions can be made of any observations that were performed during a lab experiment.

3. Two PVT reports was collected on this study to perform a PVT model for Libya fields.

4. The best equation of state that indicate a low error for calculation result was PR-3 “3-Parameter Peng-Robinson”.

5. The tuning process for PVT model performed by splitting C7+ into two fractions and regression process for fluid variables.

6. The Error for bubble point pressure between measured data [1841 Psi] and simulated data [1834.7 Psi] was equal 0.34 percent.

7. The minimum miscibility pressure “MMP” for Farrud field (Ghani Field) when inject CO2gas in lab stud “Slim tube test” was equal 2800 Psi.

8. The minimum miscibility pressure “MMP” for Farrud field (Ghani Field) with different injection gas “CO2, N2, C1 and H.C mixture” using PVT model was equal 2576, 14690, 8789 and 4113 Psi respectively.

9. The Error between MMP calculation from two methods lab and Software was equal 8 percent.

10. The CCE experiment data from (A-NC186) A-01 (BHS) and A-02 (BHS) show error (Y-Function Curvature)

11. The Field A-12 is located in the East field and A-03 located in the West field, also the bubble point pressures of BHS in A-01 (East) and A-03 (West) are very close (785 & 780 psig)

12. Bottom hole sample retrieved from the (A-NC186) A-12 well showed good quality check results, but, unfortunately, a complete CCE and DL tests are not
available, and the Adjustment of Bo & Rs was not carried on due to the unavailability of the Separator Test Data.

13. The bottomhole sample from A-03 well have good quality data and enough experiments (Pb pressure, CCE, DL and separator experiments).

14. The PVT data of BHS from A-03 is the most representative fluid sample for A-West Whilst BHS from A-01 is the most representative for A-East.

15. A-03 bottomhole sample was chosen as the representative fluid sample for both culminations (East and West), PVT data of this sample were loaded into PVTi software for EOS tuning.

16. A good match of the experimental data was obtained, and PVT table were generated to be used in reservoir simulation.

Figure 5.1. Conclusion
5.2. Recommendations

1. It is recommended to take more PVT samples from Farrud Field (Ghani Field) to investigate the quality of used PVT reports.
2. Perform a laboratory study “Slim tube” to compare the MMP results from PVT model for the different injection gases C\textsubscript{1}, N\textsubscript{2} and H.C mixture.
3. Import the performed PVT model in this study to Farrud field (Ghani Field) simulation model in order to investigate the reliable of this PVT model in history match process.
References

1. Al-Horoj Oil Company, Farrud Field Descriptions.

2. Abdelbased Hadid & M Ahmed, “MMP Experiment for Farrud Field”,
   Tripoli University. Petroleum Department, 2012.


